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Sun City Progress Report: Policy Effects on Photovoltaic Adoption for City Planning

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Abstract

This progress report documents the Sun City modeling approach, intended to be an analytic tool for city planners. It is midway in development and this report provides the design basis to provide the mathematics for policy considerations applied to PV market acceleration. It assesses the effects on market diffusion for nine commonly used policies: cash incentives, third party financing, group purchase programs, community solar projects, feed-in-tariffs, property assessed clean energy financing, low interest loans, property and sales tax incentives, and streamlined PV permitting processes. Generic forms of all of these policies are modeled in a system dynamics PowerSim Studio™ model using a concept called the photovoltaic favorability (PVF). PVF is equal to the difference between the ratio of conventional electricity costs to levelized electricity costs of a PV system and four barrier ratios. The barriers are present to model inhibiting influences on human decisions and financial limitations. They include down payment costs, month to month payment costs of financing, time to net profit, and time to lower payments. Each barrier term is divided by a tolerance term which represents the potential that consumers of the region can typically invest. PVF is quantified across a range of limited budget financing and cash incentives options which are then consumed from greatest PVF to least PVF. Finding the overall PVF requires iteration on a variation of the Bass diffusion model. This iterative scheme is tied in a feed-back loop to local and national PV learning curves which in turn quantify reductions in the cost of PV for future time steps based on user input learning rates. The modeling has been wrapped into a graphical user interface which will allow city planners to easily compare and demonstrate multiple scenarios. Data for the DOE sponsored Solar America Cities and for Albuquerque, New Mexico has been entered into the model in order to minimize data collection efforts by city planners.

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CONTENTS

FIGURES

TABLES

NOMENCLATURE

$	Indicates U.S. dollars
B	Indicates a Budget of Spending (user input)
c	Denotes a capacity factor (% of energy turned into useful work)
cons, Con	Consumer
C	Denotes a cost of purchasing PV ($/W installed) or cost of electricity generated ($/Kwh)
CSF	Community solar financing
DI	Disposable income – Money which people actually receive to spend (salary minus all income taxes)
DOE	Department of Energy
F, f	Factor or fraction
FIT	Feed-in-tariff
FPVF	Fractional photovoltaic favorability – This is the PVF calculated for many different options which are consumed from the highest PVF option to the lowest
GHG	Greenhouse Gas
GPP	Group purchase program
I	Denotes an amount of installed Photovoltaics (Watts installed)
IN	Inflation (%/yr)
LCOE	Levelized Cost of Electricity
lat	Latitude
lon	Longitude
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
p	Bass model innovator coefficient, also denotes power consumption elsewhere (KWh)
pop	Population
P	Denotes price for a PV system ($)
PACE	Property Assessed Clean Energy Financing
PC	City Population variable
PV	Photovoltaic
PVF	Photovoltaic Favorability
q	Bass model imitator coefficient, when used as a subscript q indicates the state and/or city chosen by the user
R	Indicates an exponential increase rate per year. In PVF equation only refers to a yet unused Risk term
r	ratio
S	Indicates Spending or Saving
SF	Purchase size function for PV starting at 1.0 for 1KW and decaying to a value less than one but greater than zero.
SNL	Sandia National Laboratories
SolarDS™	Solar Deployment System model created by NREL
SR	Spending Rate
Studio™	Powersim Studio™ software (see http://www.powersim.com/)
t	Denotes a time. Usually a year (i.e. 2010)

t_s	Time Step (1yr)
TPF	Third Party Financing
U	Use logical switch variable, these are switches the user changes to turn policies and other effects on an off
U.S.	United States

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EXECUTIVE SUMMARY

The process of a new product or concept being adopted by a society is called "diffusion of innovations" [40]. Generating electricity by the power of the sun is one such innovation which is extremely important to U.S. policy makers. Solar power installations are expected to accelerate over the next twenty years based on recent forecasts [1, 16]. The Energy Improvement and extension act of 2008 renewed a tax credit rebate of up to thirty percent of the costs of purchasing and installing solar power systems until 2016. In addition to the federal incentives, many state governments, local governments and utilities are adding their own incentives. For example, the California Solar Initiative offers either a lump sum of $2.50 per Watt installed or $0.50 per kWh to accelerate solar power installations in California [41]. These incentives decrease in the future to transition smoothly to an incentive free market.

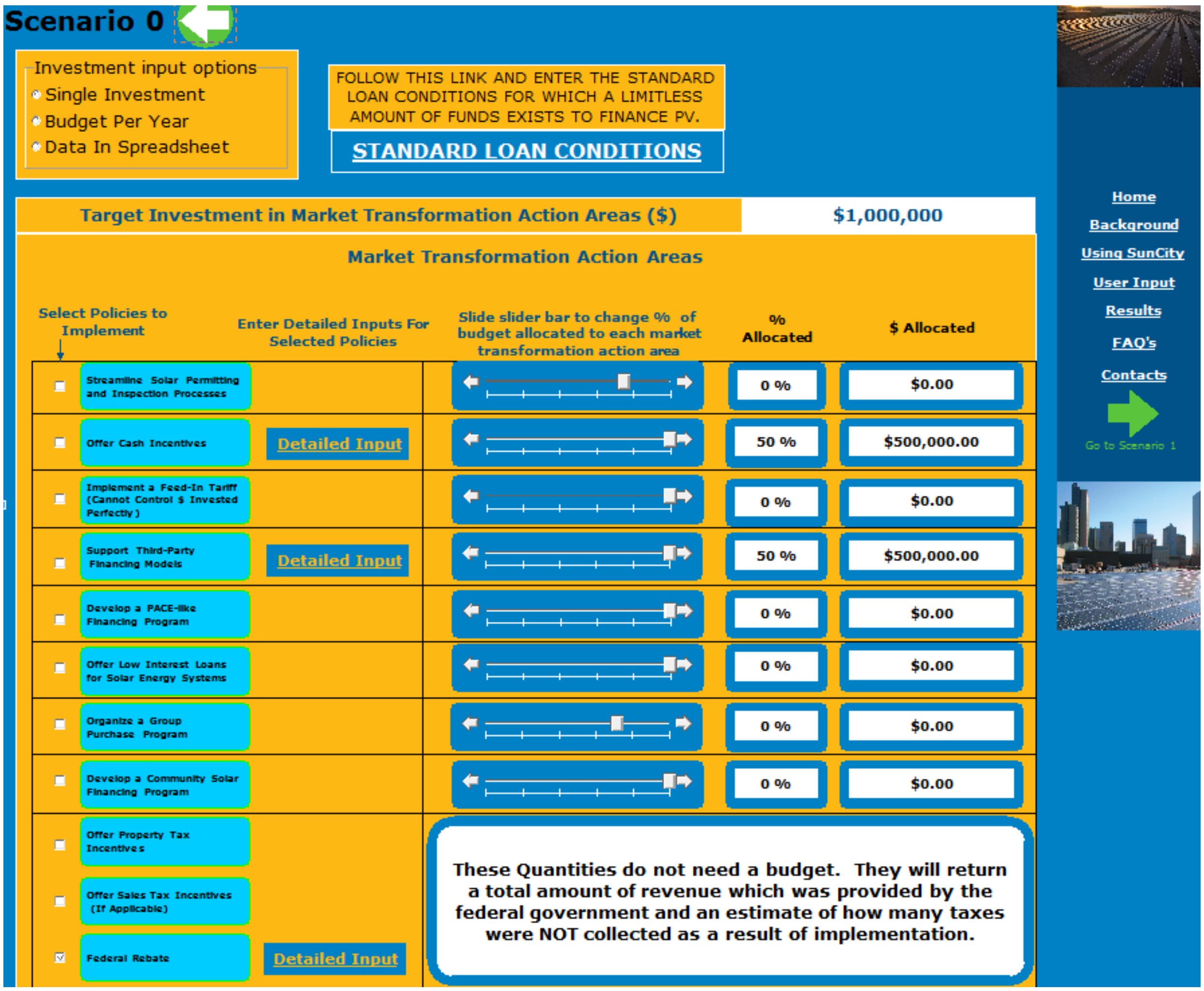

Figure 1. Sun City policy scenario input screen

As decisions about solar power incentives are made, tools are needed which analyze the policies being proposed. No single policy is best for every local area. Some policies which are good for one community could disadvantage others. It is the goal of the Sun City project to provide a user friendly interactive platform which informs city planners about the effects on their communities of different types of photovoltaics (PV) policy. PV is a large portion of the solar power market which converts solar radiation directly into electricity. This goal does not include using Sun City for predictions. The purpose is to compare relative policy effects.

The Sun City modeling framework allows the user to activate up to nine different generic types of policy. The current options include cash incentives, feed-in-tariffs, property and sales tax incentives, low interest loans, property assessed clean energy financing, third party financing, community solar financing, group purchase programs, and streamlined solar permitting processes. A dataset for the Department of Energy Solar America Cities (http://solaramericacommunities.energy.gov/) and Albuquerque, New Mexico has been connected to the model so that many of the inputs to the model are suggested automatically.

The user starts with entering a limited budget and distributing funds to whichever policies are desired. Additional detailed inputs to the policies can then be adjusted. This process can be repeated for a second scenario. Figure 1 shows the policy mixture input screen. This is the only area which requires adjustment to compare different scenarios once all the population, income, power use, and national PV growth projections have been input. Figure 2 shows a comparison between two scenarios. The first case, represented by the red line, involves an immediate purchase at the start time of one million U.S. dollars of PV which is equal to 166KW of installed PV at the assumed price. The second case, represented by the green line, offers one million U.S. dollars of a fifteen percent cash rebate off the total purchase price split equally between residential and commercial sectors. This second scenario is predicted to be more effective based on the model's calculations since it produces 1.97MW more PV installations by the year 2028. It is not expected that the projection of this analysis will predict the future. Its purpose is to inform the user that one policy is probably a better choice than the other based on the input data and theory behind the Sun City model.

The Sun City model's behavior is based on three key concepts: learning curve analysis, a diffusion model, and a way to connect rate of diffusion to prices and consumer preferences. Learning curve analysis involves projecting how fast prices will fall as a product's total adoption increases. The learning rate is a key input to the Sun City model. Since its inception, the PV industry has followed a learning rate of 15 to 22% [14]. This means that the price of PV is predicted to drop by 15 to 22% for every doubling of installations.

Sun City uses a variation of the Bass diffusion model [6, 28]. Several examples of the "S-shaped" curve are shown on the right hand side of Figure 3. The horizontal axis represents time and the vertical axis represents the amount installed. The bass model has three important parameters called the innovator coefficient (p), imitator coefficient (q), and market potential (m). The left hand side of Figure 3 shows the model's behavior as p and q are changed.

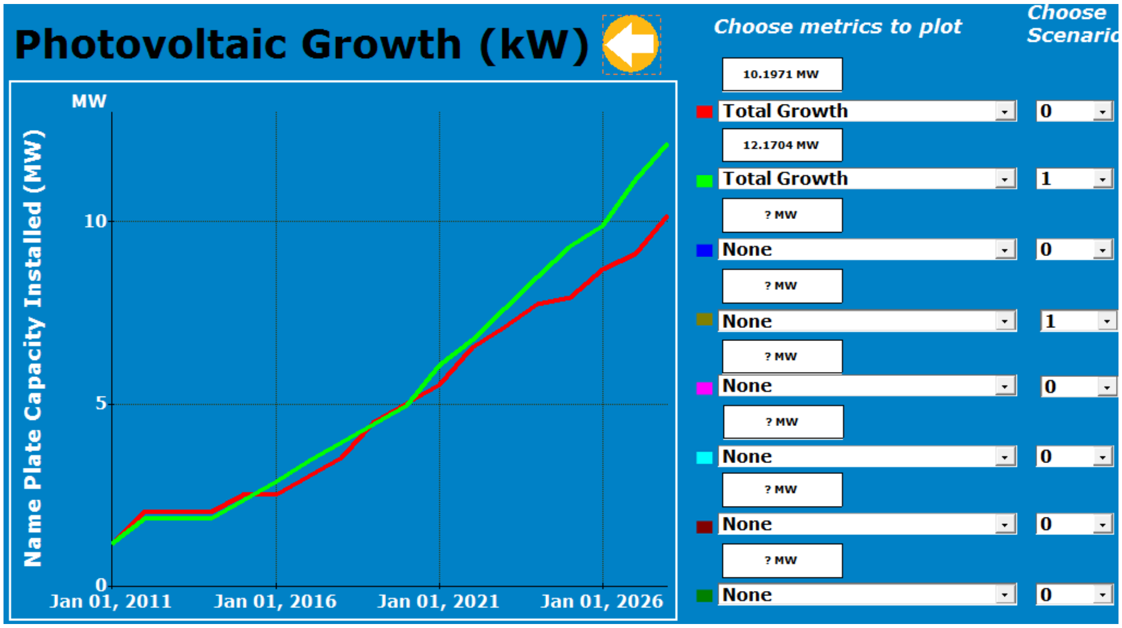

Figure 2. Illustrative example of PV growth in Albuquerque due to one million USD invested in two ways. The green line shows the case where a 15% cash incentive is offered. The red line shows a case where the money is used to make a city solar project of 166KW installed. The model predicts that the cash incentive produces 1.97MW more PV installed by 2028.

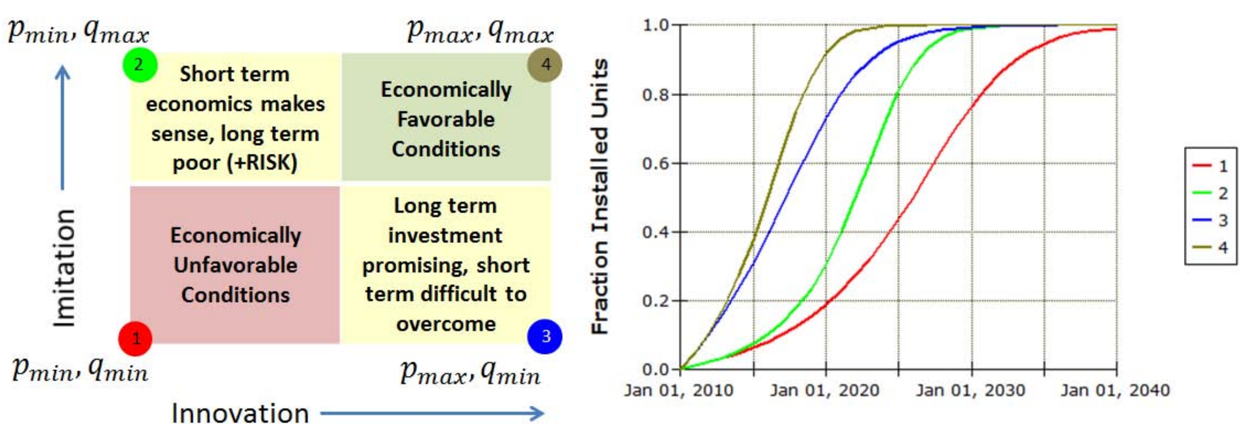

Figure 3. Innovator and imitator link to economic situation. Values used for the coefficients are chosen to highlight the model behavior and do not reflect a PV market (pmax=.05, pmin=0.01, qmax = 0.5, qmin=0.3, m = 1.0)

The missing link between these two tools is a way to connect prices and consumer preferences to the Bass model coefficients. Once the coefficients are known, the Bass model predicts the next time step's rate of adoption, whereby a price drop can then be calculated using the learning curve. The ratio of current electricity costs versus how much it would cost if solar power is used is a common measure to determine if solar power will be purchased. This is a simple idea but raw numbers cannot be compared directly. The solar powers costs have to be spread over the PV system's lifetime. In addition, financing costs, maintenance, taxes, and performance reductions have to be taken into account. The total cost of electricity has to be projected into the future. Once a set of economically and physically consistent assumptions have been made, the PV costs vs. alternative costs are considered to be comparable. This process is called levelizing costs. If the levelized cost ratio is greater than one, it is a rationally correct choice to purchase PV because savings will result if the future assumptions turn out to reflect the actual future.

This ratio would work well by itself as long as consumers make rational choices and always have sufficient access to funds to install PV. This is seldom the case. Humankind's measured, psychological tendencies to discount future benefits in comparison to present benefits and our inability to make balanced choices about our future perceived resources make additional "barrier" terms necessary [15, 22]. The Sun City model uses four barriers:

1. Ratio of down payment to average down payment tolerance
2. Ratio of monthly payment to monthly payment tolerance
3. Ratio of time to net profit to tolerance to waiting for net profit
4. Ratio of time to lower payments to tolerance to waiting for lower payments

The first and second barriers involve how much money is required to finance versus how much money a typical consumer actually has to put down. The tolerance terms are determined from savings and income data of the local population. No down payment makes the down payment barrier zero. The second and third ratios involve how long it takes to reach profits. The first is easier to measure since it involves an analysis concerning the time it takes before the consumer really has broken even on their PV investment. The second is important since people would rather pay less now. It is equal to the time it takes for the consumer to reach lower monthly payments divided by a threshold of time they are willing to wait for lower payments. Immediate lower payments make this barrier equal to zero. The barriers are taken away from the levelized cost ratio to form a potential called the photovoltaic favorability (PVF). A conceptual representation of PVF is shown in equation 0.1.

$$PVF = \frac{Expected\ Future\ Electricity\ Costs}{Levelized\ Photovoltaics\ Costs} - \sum Barrier\ Ratios \qquad 0.1$$

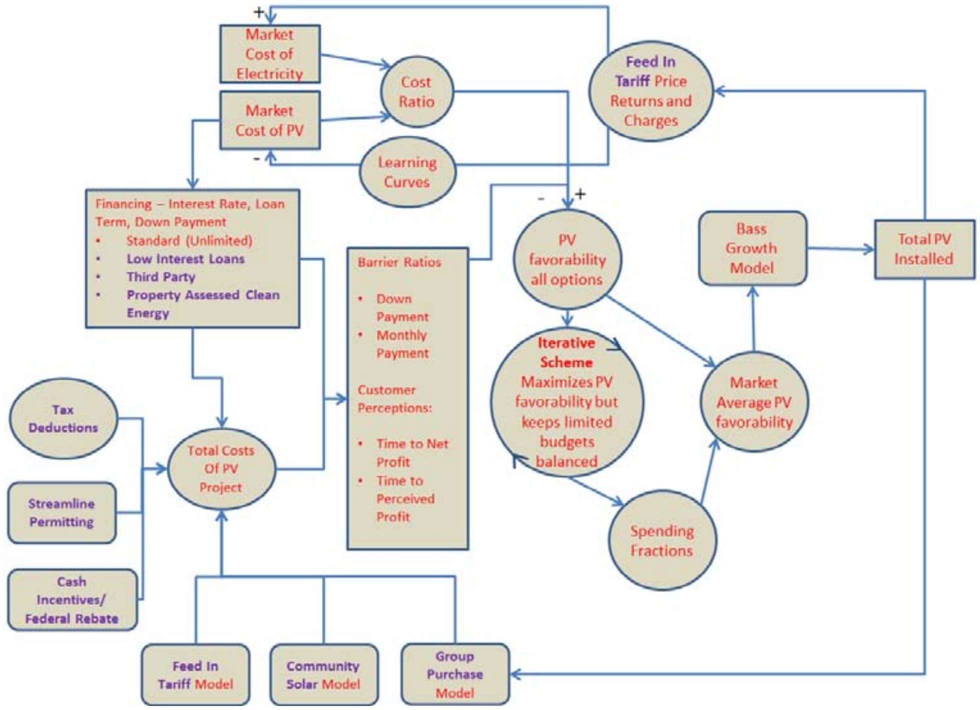

Figure 4. High level view of the Sun City policy effects model. A number of dynamics have not been included to allow the global view to be cohesive and to emphasize the overall feedback loop between policy, costs, and PV installed. Policies are shown in purple.

The *PVF* output can be calibrated against a local market's known past performance so that an empirical relationship between *PVF* and the Bass coefficients (p,q,m) has been determined. Considerable work is needed to migrate this generic framework to a real case study. Each generic policy model has to be updated to fit local conditions and regulations to be useful. Policies which offer incentives can be modeled so that they directly influence the *PVF* function. As time progresses in the simulation, different results will be obtained for policies which spread resources versus policies which provide a short, intense growth as observed in the example in Figure 2. The three ingredients of learning curve analysis, Bass diffusion, and *PVF* form a complete feedback loop which allows policy effects to be calculated. This feedback loop is illustrated in Figure 4. Complexity arises due to limited budgets and combinations of multiple policy options which require iterating to get a solution for each time step. These complications are discussed in detail within the main report, and do not change the underlying premise.

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1. INTRODUCTION

1.1. Purpose

Photovoltaic (PV) systems will become economically competitive if they become less expensive than conventional electricity generation systems [16, 17, 18]. The U.S. government currently provides a 30% cost rebate until 2016 which is expected to increase PV adoption rates. Future PV adoption will have considerable spatial variations throughout the U.S. due to varying local costs and policies. The spatial heterogeneity of the PV adoption problem has been addressed by the National Renewable Energy Laboratory (NREL) model SolarDS [1]. Sandia National Laboratories (SNL) has been tasked with providing a regional scale tool suitable for city planning needs which allows users to compare varying scenarios for nine types of policy. The resulting system dynamics model [38] and user interface has been named Sun City. The policies modeled are local cash incentives, third party financing, group purchasing programs, community solar projects, feed-in-tariffs, property assessed clean energy financing, low interest loans, property and sales tax incentives, and a streamlined PV permit process. The tool includes data for the twenty-five Department of Energy (DOE) sponsored “Solar America Cities” and for SNL’s hometown Albuquerque, New Mexico. The models used are theoretical. Future work is required to validate the proposed approach.

The first step to characterize future effects of policies is to formulate a mathematical model which has the capacity to mimic expected behaviors. This paper summarizes a model which has sensitivity to several key PV related parameters which are arranged into a single potential parameter named the photovoltaic favorability (PVF). The PVF is calculated for several limited budget options and an overall PVF is calculated based on highest PVF options being consumed first. The overall PVF is then connected to the Bass diffusion model to produce a prediction of photovoltaic adoption [2].

1.2. Scope and Limitations

At this point of development, the Sun City modeling effort represents a framework which broadly addresses policy effects on PV diffusion. The purpose of this work is not focused on producing predictions by which policy choices are optimized but is rather intended as a tool for learning the relative effects of policy choices on PV diffusion. There are many mathematical parameters included which require calibration before confidence can be gained for meaningful relative comparisons are meaningful. A high level view of the model’s flow diagram is depicted in Figure 5. This modeling approach will produce distinct variations due to policies but the sub-models employed have factors which need calibration using real data.

The Sun City model does not include any effort to include changes of value of the U.S. dollar, inflation or other complicating economic factors. The modeling does not include how local economies are affected by revenue transfers. Disruptive influences on the PV market are not endogenous to Sun City. This model assumes a constant learning rate for solar PV prices and a known future for electricity prices, which can be used to simulate a sudden obstacle to PV growth.

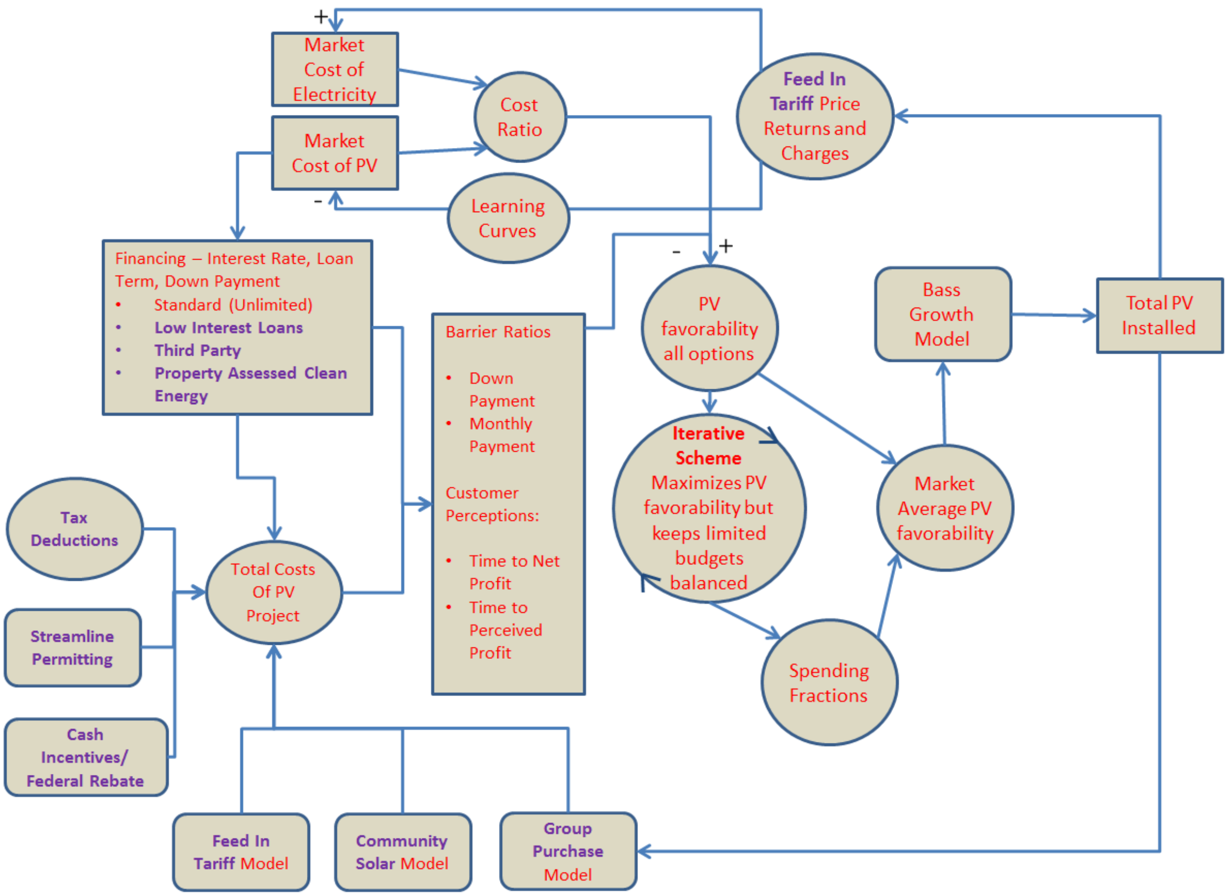

Figure 5. High level view of the Sun City policy effects model. A number of dynamics have not been included to allow the global view to be cohesive and to emphasize the overall feedback loop between policy, costs, and PV installed. Policies are shown in purple.

1.3. Mathematical Notation and Principles

The Sun City model was created in PowerSim Studio^{TM}, which is a system dynamics software. System dynamics is a methodology invented by Jay Forrester in the late 1950's and early 1960's [19, 38]. It incorporates the concepts of stocks, flows between stocks, and delayed feedback to capture highly nonlinear behavior. Unlike continuous systems of differential equations, the flows, which are numerical derivatives of the stocks, can be governed by discontinuous logic. This recipe can capture non-linear behaviors which often mimic counterintuitive phenomena observed in the social and management sciences [19, 38]. Studio^{TM} uses arrays which have names rather than numbers to represent each entry. Throughout this model indices are always subscripted and separated by commas. The following subscripts are used throughout this paper.

$$m = \{WithCashIncentives, NoCashIncentives\} \quad 1.1$$

$$j = \{Standard\ Loan, Low\ Interest\ Loan, Third\ Party, PACE\} \quad 1.2$$

$$i = \{Residential, Commercial, Utility\} \quad 1.3$$

$$s = \{Scenario\ 0, Scenario\ 1\} \quad 1.4$$

$$y = \{\{Ann\ Arbor, \ldots All\ Solar\ America\ Cities\}, Albuquerque, NM\} \quad 1.5$$

$$k = \{2011, 2012, \ldots, 2028\} \quad 1.6$$

$$b = \{DP, P, PN, PI\ (barriers)\} \quad 1.7$$

$$n = \{Years\ To\ Forecast = 1,2, \ldots, t_f\} \quad 1.8$$

$$t = \{1,2, \ldots time\ step\ number, \ldots 18\} \quad 1.9$$

The acronyms in equation 1.7 are down payment (DP), monthly payment (P), time to net profit (PN), and time to lower payments (PI). They represent four barriers to consumers adopting PV.

Whenever subscripts are mixed, the result will always contain the total union of all subscripts unless a summation symbol is used to aggregate an index. The operation being suggested is a simple component by component mathematical operation which is governed by multiple loops in Studio. This is illustrated in equation 1.10.

$$C_{i,j} = A_i B_j \ \ implies\ C_{i,j} = For(i, j |\ A_i B_j) \quad 1.10$$

Variables are listed in tables at the end of each section. This will hopefully aid the reader in navigating the model and finding links between variables.

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2. CONCEPTUAL FRAMEWORK

2.1. Bass Diffusion Model

The Bass diffusion model is a mathematical function proposed by Frank Bass [6, 28], which is one of the most commonly-used diffusion process models. The bass model with non-linear exponent has four parameters which direct its behavior. The recursive version of the equation is used to allow seamless changing of parameters between time steps.

$$\Delta I_{s,i,t} = p_{s,i,t}\left(m_{s,i,t} - I_{s,i,t-1}\right) + q_{s,i,t}\frac{I^{\delta}_{s,i,t-1}}{m_{s,i,t}}\left(m_{s,i,t} - I_{s,i,t-1}\right) \qquad 2.1$$

Where p is the innovator coefficient, q is the imitator coefficient, m is the total market potential of the product, I is the total product adopted, ΔI is the rate of product adoption, and δ is an exponent which is equal to one in the current model. The model behavior for generic values of the coefficients is shown in Figure 6. These are typical values which represent the span of known studies which have characterized Bass behavior for products which have been characterized such as household appliances [39]. An innovation driven adoption rate reflects a population which recognizes any benefits of new innovations and adopts them quickly. Imitator driven adoption rates take longer to develop. A strong economic situation for PV will increase both coefficients. The Bass adoption rate model is used in the iterative algorithm for limited budgets discussed in section 2.3.3. This algorithm also quantifies the rate of spending on PV as described in section 3.1. The spending rate is not a simple function of the adoption rate because prices of the PV being purchased vary with financing type, the presence of cash incentives, and policy inputs.

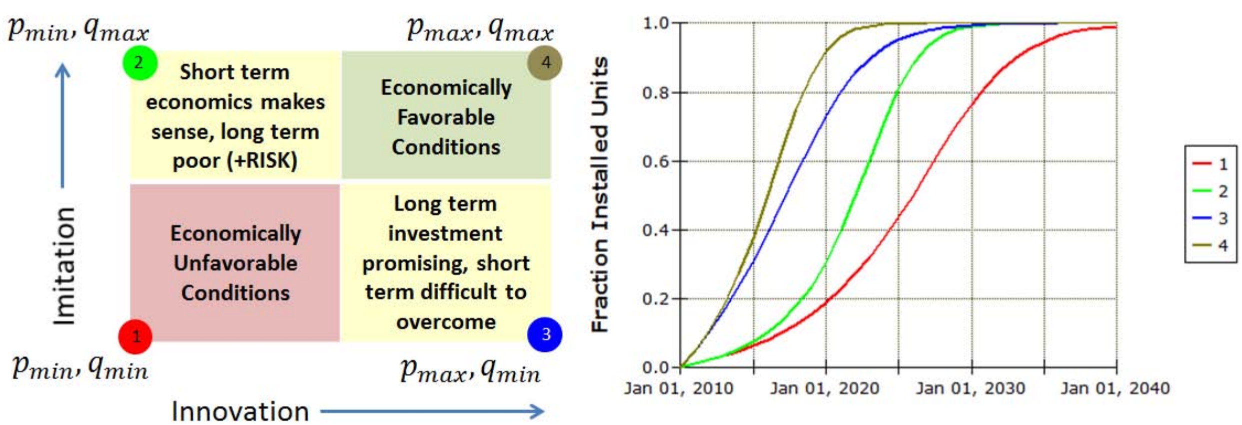

Figure 6. Innovator and imitator correlation to economic situation . Values used for the coefficients are chosen to highlight the model behavior and do not reflect a PV market (p_{max}=.05, p_{min}=0.01, q_{max} = 0.5, q_{min}=0.3, m = 1.0)

2.2. Existing PV Diffusion Models

Adoption of products with long term returns and financial obligations like PV is not well understood [Section 3.4 of reference 1]. There are several tools which have been developed to predict future installation rates of PV. SolarDS™ (Solar Deployment System) [1] is a model developed by the National Renewable Energy Laboratory (NREL) which takes an in-depth look at spatial distributions of PV potential across the nation. Several financing assumptions in the Sun City model are based on the SolarDS model. However, the methods used in Sun City are mostly independent from SolarDS and the models have very different objectives. SolarDS requires heterogeneous data for building types, sizes, and ages; utility rate structure; and local solar insolation [Section 3.5 of reference 1]. Sun City requires typical inputs for parameters within the bounds of a local market being analyzed. The Solar DS documentation mentions several other PV adoption models which have been developed [Section 1.1 of reference 1]. The National Energy Modeling System (NEMS) is the most notable which is designed to be comprehensive in its treatment of energy systems growth in the United States.

The SolarDS model documentation makes it clear that forecasting of future demand for PV is needs further development [Section 3.4 of reference 1]. The primary driver of market potential in the SolarDS and NEMS models is the net time to positive cash flow [1, 10]. This parameter, which is analogous to the PVF term T_{PN} (time to net profit), is empirically related to the maximum market potential for PV [Section 3.4 of reference 1]. The advantage of this single parameter method is that a number of studies have been done to quantify the relationship. The wide variation in the estimated function suggests that more information is needed to determine market potential for PV [Figure 14 of reference 1]. The PVF equation contains more terms as an attempt to capture sensitivity to other factors. If necessary, the PVF model can be reduced to the time to net profit model.

The concepts behind the PVF have been developed external to the SolarDS model. Other efforts have many similarities to the PVF approach. Gary Lilien produced a considerable body of literature studying PV adoption/diffusion in the late 70's and early 80's and also provides a thorough review of the efforts of that time [11, 12]. Lilien's work is very well posed with a strong theoretical basis but it requires heterogeneous inputs which are too high resolution for the Sun City model. The Sun City model uses continuous functions whereas Lilien uses screening tests to individually eliminate the possibility of PV adoption for individual decision making [Page 24 of reference 12]. There are many parallels in the computational methods used by Lilien and those in the Sun City model such as government policy effects for a limited budget [11] and the use of feedback to quantify the continued price drop of PV. Lilien's criticism of PV market penetration modeling cogently emphasizes the need for connecting real data sources with modeling efforts [12].

Much more recently Lobel and Perakis have applied a model which is centered on the concept of "average customer's perceived utility" which is considerably different in formulation but has the same objective of quantifying PV adoption rates [13]. Lobel and Perakis provide a very useful literature review of customer perceptions and policy design in section 1.2 of their report [13]. Sterman developed a learning tool which is focused on teaching PV suppliers to compete for a portion of the market [28].

2.3. Photovoltaic Favorability

The theory which influenced the concept of photovoltaic favorability (PVF) being proposed is that potential customers will purchase PV in proportion to their "perceived maximum utility" of PV. This key concept is discussed by Lobel and Perakis [13]. The influence of perceived maximum utility theory on the formulation of (PVF) is represented by subtracting barrier terms from the ratio of conventional electricity costs to the PV levelized cost of electricity (LCOE) (C_E/C_{PV}). This ratio is a good indicator of PV marketability [23]. If the consumer has confidence in the projections used to calculate PV LCOE, it is a rational choice to purchase PV when the cost ratio is greater than one (i.e. $C_E > C_{PV}$) People's psychological tendencies to discount future benefits and common inability to make balanced choices about future perceived resources make additional barrier terms necessary [15, 22]. Lynch and Zauberman eloquently address some of these issues. Examples include the measured observation that people do not want to give up present resources which provide immediate pleasure but are much more willing to give away future resources or that they think that they have more time in the future and therefore tend to overcommit and then not follow through on important price reduction mechanisms like rebates [15]. In contrast to long term investment products like PV, Cachone and Swinney present consumer behavior for products which allow immediate payoffs. Strategic consumers behave rationally for these easier one time purchase type products such as TVs and clothes [21]. Adoption of these types of products is better understood than for long term investments like PV.

Changing the arrangement of payments can be used to increase PVF even though rational utility for buying PV is not increased by these changes. PVF is therefore arguably an enhanced measure to indicate whether typical consumers will buy PV. The merits and deficiencies of the proposed definition need further scrutiny and testing. The definition will hopefully become more insightful as research continues and understanding of human cognitive processes progresses [37]. Considerable further work is needed to link PVF to human psychological tendencies.

2.3.1. Discussion of Equation Terms

The photovoltaic favorability (PVF) modeling approach overlooks the local conditions of individual interactions and uses average data. PVF ranges from zero to one. Zero represents conditions for which PV's marketability against alternative products is not competitive. If the PVF falls between zero and one it is reaching the transition phase for which policies will have a significant effect on the market growth of the product. A value of one indicates that PV is self-sustaining. Policy investments are not needed for market growth to occur. Even though these limits cut off sensitivity to PV adoption it is posed in this way intentionally. The first limit is active when a policy is insufficient to raise PVF past zero. The changes in PV growth will also be zero. The model is suggesting to the user that PV policy needs a larger budget for it to be effective and that the input revenue has insignificant effect. The second limit warns that revenue input is excessive and that less investment can accomplish the same amount of growth since PV is gaining its own momentum in the market.

Four barriers terms are subtracted from the LCOE ratio to determine the PVF. All of the barriers are ratios of financial or temporal factors which affect the decision making process of individual customers within a local market. Some are included as separate terms in order to allow leveraging of psychological issues common to humans [15].

1. Ratio of down payment to average down payment tolerance
2. Ratio of monthly payment to monthly payment tolerance
3. Ratio of time to net profit to tolerance to waiting for net profit
4. Ratio of time to lower payments to tolerance to waiting for lower payments

Each barrier has been chosen to provide leverage into the psychology of human decision making or to include local financial status and cost of living as variables in the PV diffusion model. For example, the time to lower payments barrier can be used to cause PVF to be driven by people's desire to lower their monthly bills even though this is not the best rational choice. Down payment can be a barrier because of finances and because people do not want to spend a large amount of money. The distinctiveness of these four barriers allows for experimentation, however, a methodology for isolating these effects remains to be developed. The first two barriers can be quantified in a fairly straightforward manner using population income and savings data as defined in section 4.5. The second two involve the areas of psychological decision making [15, 22]. Here, these two terms are direct user inputs for which further research is needed to justify their assigned values.

For mathematical flexibility, each of these barriers is multiplied by a weighting factor which can allow barriers to be weighted in order of importance. There is currently no basis from data or connection to theory which validates the values of these weighting factors so they are presently assigned equivalent values. The model always normalizes the sum of the weights for each barrier to be equal to one.

$$\sum_{b} w_{b,i} = \{1\}_i \qquad 2.2$$

The model alters the values of weighting input by the user depending on the whether financing ends in system ownership. This change is necessary because the time to net profit does not exist for leased systems. For third party financing, calculation of the weighting factors is described by equation 3.24 of section 3.2.

A risk factor is included in the equation but perceptions about risk are also not well understood and for the present the risk term is only a place holder for an important concept. People's willingness to take action to protect the environment was initially going to be included but was omitted. In Bamburg [3] it is demonstrated that the grand majority of the population will not make significant or sometimes even minor sacrifices to protect the environment even if they assert a pro-environment stance.

The Sun City model allows several financing options and other incentives to exist simultaneously for PV. In the real world consumers would compete for these options based on credit rating and other variables. For this reason the PVF has to be calculated for as many options as exist. The array of PVF values for each option is called the fractional PVF (FPVF).

The FPVF is expressed below in equation 2.3 as the cost ratio minus the four barriers discussed above. It is a multidimensional array of user input policy scenarios, financing type, presence of cash incentives, and sector.

$$FPVF_{s,m,j,i,t} = \frac{C_{E\,s,i,t}}{C_{PV\,s,m,i,t}} - A_{F\,i}\left(w_{DP,i}\frac{C_{DP\,s,m,j,i,t}}{C_{DP\,To\,i,t} + A_{DP\,s,m,i,t}} + w_{P,i}\frac{C_{P\,s,m,j,i,t}}{C_{P\,To\,i,t}} + w_{PN,i}\frac{T_{PN\,s,m,j,i,t}}{T_{PN\,To\,i}} + w_{PI,i}\frac{T_{PI\,s,m,j,i,t}}{T_{PI\,To\,i}} + R_{PI\,i,t}\right) \qquad 2.3$$

The terms of equation 2.3 are described in Table 1. It is important to note that the ratio of conventional electricity costs to the PV LCOE (C_E/C_{PV}) does not contain the financing index "j" in the levelized cost of PV. This is a simplifying assumption which keeps a large portion of the modeling from being tied to the iterative process defined in section 2.3.3. This is justifiable because many purchasers only think in terms of a single price tag rather than planning for *all* potential costs in the future.

Different policies can affect many of the factors in the FPVF equation. For example, offering lower interest rates will decrease C_{PV} and will simultaneously decrease the time to net profit, time to lower payments, and monthly payments which leads to a simultaneous reduction of barriers. The actual level of influence a given policy will have is difficult to quantify but the FPVF is a functional relationship which provides a consistent interface for policy effects.

The FPVF is calculated for all options based on user input and is then input into the iterative process of section 2.3.3 which maximizes the total PVF by using maximum FPVF options first while keeping limited budgets on cash incentives from becoming negative. Once the iterations are complete, a set of spending fractions, $f_{s,m,j,i,t}$, is output which are the fraction of total spending for a particular option. This array of fractions can be used to derive the total PVF.

$$PVF_{s,i,t} = \begin{cases} 0 & \sum_{m,j} f_{s,m,j,i,t}\, FPVF_{s,m,j,i,t} \le 0 \\ \sum_{m,j} f_{s,m,j,i,t}\, FPVF_{s,m,j,i,t} & 1 > \sum_{m,j} f_{s,m,j,i,t}\, FPVF_{s,m,j,i,t} > 0 \\ 1 & \sum_{m,j} f_{s,m,j,i,t}\, FPVF_{s,m,j,i,t} \ge 1 \end{cases} \qquad 2.4$$

The total PVF can then be fed into a constitutive relationship between PVF and the Bass model coefficients as described in section 2.3.2 The Bass model then produces a PV installation rate as described in section 2.1.

There is room in this modeling effort to change the mathematical form of the PVF. The PVF's purpose is to create a mathematical potential function, which provides sensitivity between policy decisions and the choice to purchase a PV system, rather than using electricity from other sources.

Table 1. PVF equation terms explanation.

Variable	Meaning
s	Scenario index (0 1)
m	Cash incentives index (WithCashIncentives, NoCashIncentives)
i	Index representing range of sectors being modeled
j	Financing index
t	Time step number for the years 2011 to 2028.
$FPVF_{s,m,j,i,t}$	Fractional photovoltaic favorability (ratio)
${C_{PV}}_{s,m,i,t}$	Average levelized cost in $/kWh of PV power
${C_E}_{s,i,t}$	Cost in $/kWh of current electric bill
${C_{DP}}_{s,m,j,i,t}$	Average cost of down payment ($)
${C_P}_{s,m,j,i,t}$	Average cost of payment per year for financing ($)
${C_{DP}}_{{To}_{i,t}}$	Tolerance to down payment (threshold at which population is willing and able to make down payment) ($)
${A_{DP}}_{s,m,i,t}$	Adjustments to down payment tolerance coming from third party financing (section 3.2) and community solar (section 3.4) policy types. ($)
${C_P}_{{To}_{i,t}}$	Tolerance to payments (threshold at which average population is able to take on a monthly payment) ($)
${T_{PN}}_{s,m,j,i,t}$	Amount of time to begin making a net profit (years) defined in section 2.6.1
${T_{PN}}_{{To}_i}$	Tolerance to waiting to make a net profit (yr)
${T_{PI}}_{s,m,j,i,t}$	Time to begin making an immediate profit in month to month payments (years)
${T_{PI}}_{{To}_i}$	Tolerance to waiting to make an immediate profit (yr)
$w_{DP,i,j}, w_{P,i,j}, w_{PN,i,j}, w_{PI,i,j}$	Weighting factors which usually should be constrained to summing to one for each i, j, and are a function of user input weights and the financing type which sets the PN (net profit) barrier to zero and recalculates weights for the third party financing type in section 3.2 (unitless)
${A_F}_i$	Amplifying factor (calibration term typically equal to 1) (unitless)
${R_{PI}}_{i,t}$	Yet to be defined risk function (unitless)
$PVF_{s,i,t}$	Total PVF (unitless)
$f_{s,m,j,i,t}$	Fraction derived from iterative process outlined in section 2.3.3 (unitless)

2.3.2. Map to Bass Model Coefficients

The PVF needs to be mapped through a monotonically increasing function to the bounds of the *p*, *q*, and *m* coefficients as discussed in sections 4.1 and 4.4. The relationships are assumed to be linear. The *p*, *q*, and *m* coefficients are determined by the following expressions.

$$p_{s,i,t} = (p_{max} - p_{min})PVF_{s,i,t} + p_{min} \tag{2.5}$$

$$q_{s,i,t} = (q_{max} - q_{min})PVF_{s,i,t} + q_{min} \tag{2.6}$$

$$m_{s,i,t} = m_{max_{s,i,t}} max\left(PVF_{s,i,2011}, PVF_{s,i,2012}, \ldots, PVF_{s,i,t}\right) \tag{2.7}$$

The innovator and imitator coefficient upper bounds, p_{max} and q_{max}, are determined in section 4.1. Zero is currently assigned to the lower bounds $p_{min}$and q_{min}. The user input maximum market potential,m_{max}, is determined in section 4.4 equation 4.25.

For the Solar DS model [1] and other efforts it references, the market potential's (m) relationship has been characterized by the projected payback time (T_{PN}) [Page 19 in reference 1]. The Sun City model sets the current Bass model market potential equal to the user input maximum market potential multiplied by the largest PVF yet experienced. This function can only grow. This serves well to avoid obtaining an inconsistent negative adoption rate for the discrete PV market adoption model described in section 2.3 but is not a good assumption for modeling disruptive technologies. The growth will definitely decrease if disruptive technologies emerge which would be embodied in a sudden decline in electricity prices.

2.3.3. Iterative Determination of Photovoltaic Favorability for Limited Budgets

For each time step FPVF from equation 2.3 is calculated for a range of potential financing options (third party, low interest, property assessed clean energy (PACE), and standard financing) and with and without cash incentives. The cash incentive budget and financing option budgets are independently set in the user input. The model also is able to handle multiple scenarios and PVF is tracked independently for residential, commercial, and utility sectors. The FPVF therefore becomes a 4-dimensional array (Scenarios, Cash Incentives, Financing, Sectors). The key assumption is that maximum FPVF options are consumed first. The fraction of total spending applied to each FPVF option, *f*, is constrained by the budgets. An initial set of fractions equal to the previous time step's optimal set of values is used to calculate PVF which is the input to the PV market adoption model described in section 2.3. The set of spending fractions for each financing option and cash incentives status can then be used to balance all of the budgets. This is nontrivial since some budgets may be fully spent in the time step and others may be untouched or partially spent depending on the rate of PV installations calculated.

The required logic to calculate PVF is somewhat cumbersome. It involves balancing spending and limited budgets of several different options. Each option has its own FPVF. Figure 7 illustrates the process but neglects the complexity associated with the fractions of spending and plots the budgets (B1, B2,…B5) versus the FPVF. Refer to appendix A for a comprehensive look at the logical steps required.

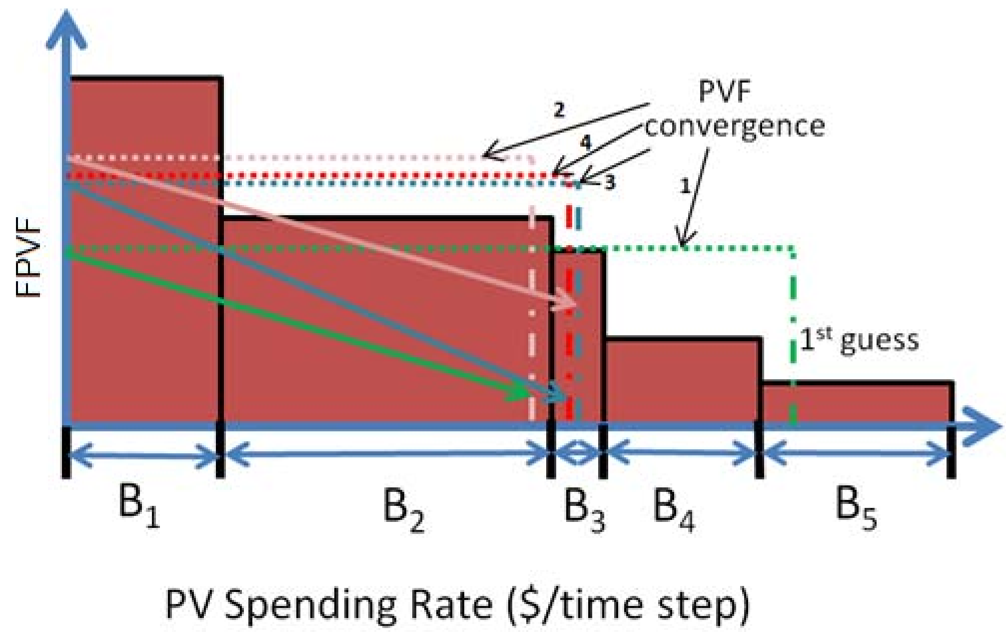

Figure 7. Determination of PVF applied in an iterative loop with 5 budgets with varying FPVF. The solution usually converges in 4 to 5 iterations.

2.4. Discrete PV Market Adoption Using the Bass Model

Once PVF has been calculated as described in section 2.3.3 and appendix A, the PVF for each sector is applied to the linear relationships expressed in equations 2.5, 2.6, and 2.7 of section 2.3.2. This produces the current time step's p, q, and m Bass model coefficients which quantify the installation rate of PV, ΔI as seen in equation 2.1. The continuous Bass model is then run through several checks to assure that growth never exceeds the current market potential. This is necessary because, even though installations are occurring in a continuous sense, they are first accumulated in a "construction" stock which then outflows at discrete intervals of the user input average installation sizes I_{avg} into an "installed" stock. The total amount of PV under construction and installed can be expressed as seen in equation 2.8. Terms are defined in Table 2. Equation 2.9 describes the installation rate ΔI_L subject to some limitations

$$I_{T_{s,i,t-1}} = I_{C_{s,i,t-1}} + I_{I_{s,i,t-1}} \qquad 2.8$$

$$\Delta I_{L_{s,i,t}} = \begin{cases} 0 & m_{s,i,t} \leq 0 \\ 0 & I_{T_{s,i,t-1}} > m_{max_{s,i,t}} \\ \Delta I_{s,i,t} & otherwise \end{cases} \qquad 2.9$$

The term m_{max} represents the absolute largest amount of PV that the city can handle due to grid, space, or other limiting factors. The construction adoption rate ΔI_C is run through further logic which keeps the model from exceeding $m_{max_{i,t}}$. Overshoot is still possible because it is informed by data one time step behind the adoption rate and Bass coefficients can change every time step.

$$\Delta I_{C_{s,i,t}} = \begin{cases} \dfrac{m_{max_{s,i,t}} - I_{T_{s,i,t-1}}}{t_s} & \Delta I_{L_{s,i,t}} t_s + I_{T_{s,i,t-1}} > m_{max_{s,i,t_{s,i,t}}} \\ \Delta I_{L_{s,i,t}} & otherwise \end{cases} \qquad 2.10$$

The installation flow, ΔI_I, occurs in the maximum number of installations of size I_{avg}which can occur for the construction stock $I_{C_{s,i,t-1}}$.

$$\Delta I_{I_{s,i,t}} = \begin{cases} 0 & \dfrac{I_{C_{s,i,t-1}}}{I_{avg_i}} < 1 \\ I_{avg_i} Floor\left(\dfrac{I_{C_{s,i,t-1}}}{I_{avg_i}}\right) & otherwise \end{cases} \qquad 2.11$$

The installed stock has a retirement out-flow based on the user input PV system life time L_i. This is accomplished by a delay function which follows the flow $\Delta I_{s,i,t}$after L_i time has passed.

$$\Delta I_{R_{s,i,t}} = delayPPL\left(\Delta I_{s,i,t}, L_i, 0\right) \qquad 2.12$$

The Studio function *delayPPL* takes an input function and outputs the same function a specified length of time after the input. Once all of the flows have been quantified, the stocks can be updated for the next time step.

$$I_{C_{s,i,t}} = \Delta I_{C_{s,i,t}} + I_{C_{s,i,t-1}} - \Delta I_{I_{s,i,t}} \qquad 2.13$$

$$I_{s,i,t} = \Delta I_{s,i,t} + I_{s,i,t-1} - \Delta I_{R_{s,i,t}} \qquad 2.14$$

The installation rate is used to calculate the rate of spending on PV defined in section 3.1.

Table 2. Diffusion model variables

Variable	Meaning
$I_{T_{t-1,i}}$	Total stock of "installed" and "construction" PV for previous time step t-1 and sector i. (KW)
$I_{C_{t-1,i}}$	"Construction" stock of PV (KW)
$I_{I_{t-1,i}}$	"Installed" stock of PV (KW)
$\Delta I_{L_{t,i}}$	Intermediate logic on "construction" flow (kW/yr)
$m_{t,i}$	Bass m coefficient from equation 2.1 (kW)
$m_{max_{i,t}}$	Maximum potential for PV from equation 2.7 (kW)
$\Delta I_{t,i}$	Bass model adoption/installation rate of PV (kW/yr) from equation 2.1
$\Delta I_{C_{t,i}}$	"construction" continuous installation rate equal to the Bass model installation rate unless logical limitation interfere (kW/yr)
t_s	Time step (1yr)
$\Delta I_{I_{t,i}}$	Installation rate occurring in increments of I_{avg_i}. (kW/yr)
$Floor$	Integer found when number is rounded downwards
$DelayPPL$	PowerSim delay function
L_i	User input system life time (yr)
$\Delta I_{R_{t,i}}$	PV system retirement flow (kW/yr)

2.5. Local and National Learning Curves for PV

Significant data indicates that technology prices decrease as research, development, and adoption happen [6]. Despite the clear relationships between adoption and cost reduction, extrapolating these curves into the future is subject to extreme sensitivity to the learning rate [6]. Wene quotes the Stern report which argues that increasing adoption will not necessarily increase learning rates. "The data shows technologies starting from different points and achieving very different learning rates." [Stern, 8, from Wene, 7]. Wene also argues system boundaries are necessary in learning curve analysis [7]. Bhandari and Stadler provide a more comprehensive look at learning curve analysis for the worldwide and German markets [16]. Nordhaus [36] demonstrates several of the dangers associated with using learning curves. Their empirical nature makes it difficult to separate "exogenous technical change" from learning [36]. The Sun City model is not concerned with most of these problems since it is not intended to be predictive in nature and only focuses on PV without the possibility of cross interactions between technologies.

Watanabe and Kwok [9] elaborate upon the separation between national/global PV module reductions and local market learning which requires customized knowledge of the local conditions [9]. Sun City's approach does not replicate the methodology but does provide the option to separate the learning into national and local scales. The national scale can be modeled through a time series or through a learning curve. If a learning curve is used, the national scale is largely unaffected by the local market PV growth unless the local market is a significant fraction of the total market. The national scale should only include cost of the materials. The local learning curve should reflect learning rates for installation and design of PV systems. It should not include the cost associated with permitting since another portion of the model is reserved for this effect. If the local market exceeds the national growth rate, the excess growth is added to national market. If it is less than the national rate the difference in percentage is taken away from the national market. This is a non-consequential effect for most city markets but could be meaningful if the model is used for entire states or other significant fractions of the U.S. PV market.

In the following discussion the costs are for purchase and installation of 1KW of PV panel with no incentives, taxes, or certification costs included. The local cost of PV can be expressed as a typical learning curve which uses an exponential rate of decay of cost as installations occur as seen in equation 2.15. Refer to Table 3 for explanations.

$$C_{LPV_{s,t}} = C_{LPV_{min}} + \left(C_{LPV_0} - C_{LPV_{min}}\right)\left(\frac{\sum_i I_{I_{s,i,t-1}}}{I_{RI}}\right)^{-E_{LLC}} \qquad 2.15$$

I_{RI} is equal to the initial number of installations unless is it smaller than the standard installation size I_{avg} as seen in equation 2.16.

$$I_{RI} = \begin{cases} \sum_i I_{avg_i} & if \ \sum_i I_{I_{s,i,0}} < \sum_i I_{avg_i} \\ \sum_i I_{I_{s,i,0}} & otherwise \end{cases} \qquad 2.16$$

The user input national installation rate, is integrated to produce the total national installations. The national installation rate, ΔI_{NPV_t} from section 4.1, is given a weak feedback from the local installation rate which is proportionate to the rate of change of the local market minus the rate of change of the national market times the local amount of installation as seen in equation 2.17 below.

$$R_{NLG_{s,t}} = \frac{\Delta I_{NPV_{s,t}}}{I_{NPV_{s,t-1}}} - \frac{\sum_i \Delta I_{s,i,t}}{\sum_i I_{s,i,t-1}} \qquad 2.17$$

$$I_{NPV_{s,t}} = I_{NPV_{s,t-1}} + \Delta I_{NPV_{s,t}} + R_{NLG_{s,t}} \sum_i \Delta I_{s,i,t} \qquad 2.18$$

The national installations can then be used for a national learning curve.

$$C_{NPV_{s,t}} = C_{NPV_{min}} + \left(C_{NPV_0} - C_{NPV_{min}}\right)\left(\frac{I_{NPV_{s,t}}}{I_{NPV_0}}\right)^{-E_{NLC}} \qquad 2.19$$

The total costs associated with a single 1KW purchase can then be summed.

$$C_{PVpre_{s,i,t}} = C_{LPV_{s,t}} + C_{NPV_{s,t}} + C_{PV_{permit_{s,i,t}}} \qquad 2.20$$

The exponential multipliers E_{LLC} and E_{NLC} must be greater than zero. They are typically expressed in terms of a learning rate. The learning rate of a product is the percent drop in price for every doubling of the total sales of that product. An exponential term "E" can be expressed as a function of the learning rate L_R as seen in equation 2.21.

$$E = -\frac{LN(1 - L_R)}{LN(2)} \qquad 2.21$$

Where L_R is the learning rate. Another metric often used in the literature is the progress ratio P_R which is one minus the learning rate.

$$P_R = 1 - L_R \qquad 2.22$$

From its beginnings the PV industry has followed a learning rate of 15 to 22% [14].

Table 3. Learning curve variable explanations

Variable	Meaning (all costs are $/W to purchase 1KW, installations kW)
${C_{LPV}}_{s,t}$	Local costs of PV (installation and design costs) must not include the permitting costs for purchasing 1KW
${C_{LPV}}_{min}$	Minimum value which local costs can reach due to learning effects for 1KW
${C_{LPV}}_0$	Initial local costs for 1KW of PV at start of simulation (2011) ($ to buy 1KW)
${I_{NPV}}_{s,t}$	Current installations in the US. (KW)
${I_I}_{s,i,t}$	PV installations in the city being modeled (is set to the residential installation size if a 0 is entered) this term is calculated in section 2.4. (KW)
${I_{avg}}_i$	Average installation size (KW)
${R_{NLG}}_{s,t}$	Rate comparison of national and local growth (ratio)
${C_{NPV}}_{s,t}$	National costs in $ of PV for 1KW (materials – PV modules, inverter, mounting hardware, wiring etc…)
${C_{NPV}}_{min}$	Minimum value which national costs can reach due to learning effects ($ per 1KW purchase)
${C_{NPV}}_0$	National initial cost of PV ($ for 1KW)
${C_{PVpre}}_{s,i,t}$	Cost of PV before taxes and incentives ($ for 1KW)
E_{LLC}	Local learning exponent (function of local learning rate) (unitless)
E_{NLC}	National learning exponent (function of national learning rate) (unitless)
${C_{PV}}_{{permit}_{s,i,t}}$	Solar permitting costs defined in section 3.9. ($ for 1KW)

2.6. Human Decision Model

The Sun City model uses simple methods to estimate human decisions. It is assumed that the methods used represent the average behavior of all potential consumers in the market.

Alignment with the market is approximated through the use of average disposable income, savings rates of disposable income, and U.S. national inflation as described in section 4.5. The calculations for actual payments and down payments are presented later in section 3.7 using the uniform capital recovery factor and a constant interest rate. The time to net profit and time to lower payments both involve projecting electricity prices into the future.

2.6.1. Time to Net Profit

The time which it takes for a PV investment to become profitable is a function of the future changes in power costs. If power costs do not increase, a PV system may never become economically profitable. Since the future is uncertain, PV customers use various analytical methods to determine whether PV will be profitable for them. Profits occur if total costs associated with PV become less than the equivalent electricity costs obtained from a conventional source.

In this discussion the time equal to zero is not the start time of the simulation but is rather the present time step. For an estimated constant rate of change of electricity costs R_{EP}, the total expenses "n_0" years into the future for consumer who do not install PV is seen in equation 2.23. Consumers calculate that they will incur expenses of P_{withPV} in equation 2.24 if they purchase a PV system. Refer to Table 4 for variable explanations.

$$P_{noPV_{s,i,t,n}} = C_{E_{s,i,t}} p_{avg_{i,t}} \sum_{u=1}^{n} \left(1 + R_{EP_i}\right)^u \qquad 2.23$$

$$\begin{aligned} P_{withPV_{s,m,j,i,t,n}} &= C_{F_{s,m,j,i,t}} + C_{E_{s,i,t}} p_{avg_{i,t}} \sum_{u=1}^{n} \left(1 + R_{EP_i}\right)^u \\ &- c_{PV} I_{avg_i} \sum_{u=1}^{n} C_{ES_{s,i,t,u}} \left(1 + R_{ES_{i,u}}\right)^u \\ &+ n\left(M_{C\,i} + F_{proptax_{s,i,t}} \frac{P_{PV_{s,m,i,t}}}{\left(1 + F_{tax_{s,i,t}}\right)}\right) \end{aligned} \qquad 2.24$$

The yearly maintenance and tax costs of equation 2.24 require division by the total taxes fraction to cancel out the sales tax fraction applied to P_{PV} in equation 4.12. C_{ES} and R_{ES} are terms which are different than C_E and R_{EP} if a feed-in-tariff (FIT) is in place which offers more payback than selling at the price of electricity. C_{ES} is the cost that the electricity generated by PV can be sold back at. If a FIT is present, this will be higher than the conventional cost of electricity but this could change in time and it is assumed that the consumer will be able to reap the higher payback. Feed-in-tariffs are discussed in section 3.5.

2.25

$$R_{ES_{i,w}} = \begin{cases} 0 & U_{FIT_s} = true \ \& \ C_{FIT_{s,i,t}} > C_{E_{s,i,t}} \sum_{u=1}^{w} \left(1 + R_{EP_i}\right)^u \\ R_{EP_i} & otherwise \end{cases}$$

$$C_{ES_{s,i,t,w}} = \begin{cases} C_{FIT_{s,i,t}} & U_{FIT_s} = true \ \& \ C_{FIT_{s,i,t}} > C_{E_{s,i,t}} \sum_{u=1}^{w} \left(1 + R_{EP_i}\right)^u \\ C_{E_{s,i,t}} & otherwise \end{cases} \qquad 2.26$$

The first term in equation 2.24, C_F, is the total cost of financing of a PV system defined in section 3.7 equation 3.65. The second and third terms are the difference in power production between the PV system electricity consumption. If the consumer purchases a PV system which is smaller than their power consumption, then they will still be affected by increases in electricity prices. On the other hand if the PV system is larger than needs, the PV system begins to pay for itself by generating extra revenue. The fourth set of terms represents the costs associated with maintenance of the PV system and future property taxes (see sections 3.8 and 4.3). In this forecast it is assumed that the electricity consumption of the consumer remains constant over the entire process even though the rest of the model has a time series input for electricity consumption per consumer. The time it takes to reach a net profit is the time "n_0" in the future at which these two costs are equal to each other.

$$Res_{s,m,j,i,t,u} = P_{withPV_{s,m,j,i,t,u}} - P_{noPV_{s,i,t,u}} \qquad 2.27$$

The residual Res is calculated for each year "n" into the future up to a limit time t_f.

$$T_{PN_{s,m,j,i,t}} = \begin{cases} n_{0_{s,m,j,i,t}} & Res_{s,m,j,i,t,n_0} = 0 \ AND \ n_0 < t_f \\ 0 & SO_{j,i} = false \end{cases} \qquad 2.28$$

A root is not always present. The procedure for solution is to solve for an upper bound number of years and then to search for the two points which switch from positive to negative. If no zero is found the number of years is set to t_f. Interpolation can then be used to estimate the exact crossing point n_0 to a precision beyond the time step. For the third party financing option (section 3.2), system ownership is not obtained and the net time to profit is excluded from the PVF calculation. A basic depiction of the solution procedure for linear functions is shown in Figure 8.

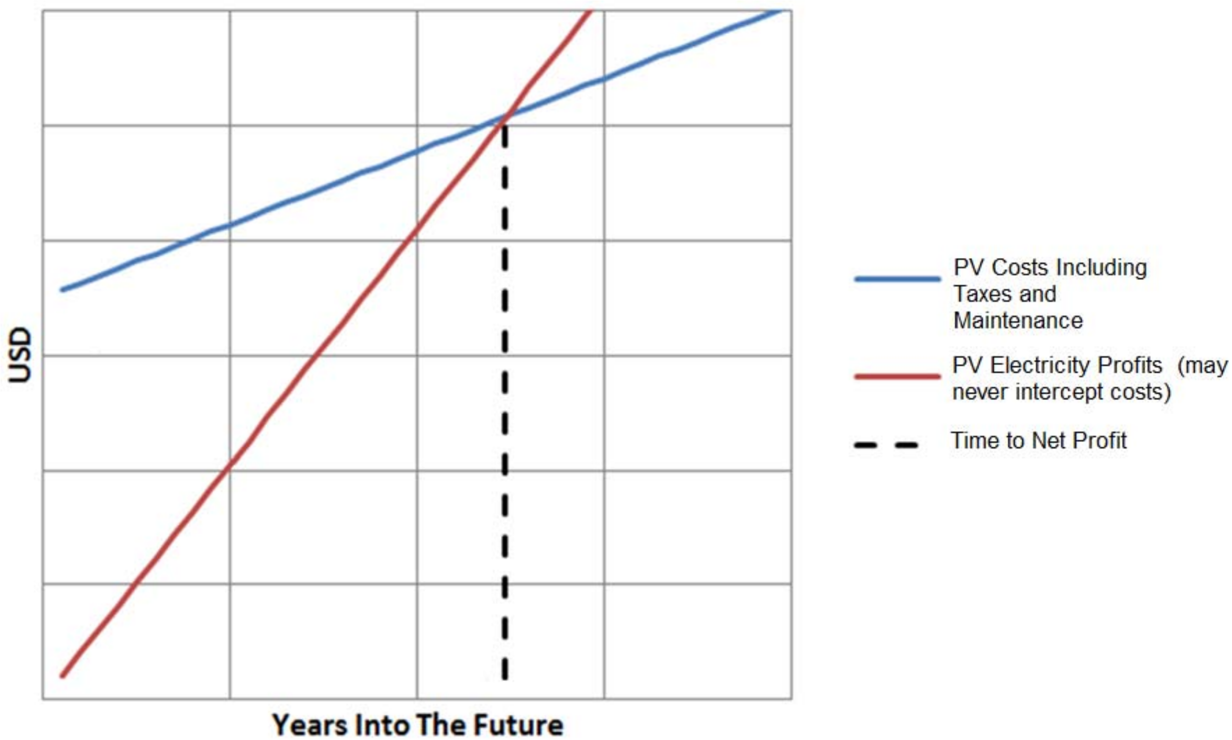

Figure 8. Illustration of time to net profit calculations.

Table 4. Time to net profit and time to lower payments variable explanations

Variable	Meaning
u	Dummy index used to project from 1..*n* and 1..*w*
w	Index projecting from one to the current time in the future being evaluated. *w* = 1..1, 1..2, 1..3, 1..4,…,1..n
t_f	Number of years projected into the future
n_0	Number of time steps to reach PV profits
R_{EP_i}	User input guess at what consumer thinks the rises in electricity costs will be. For the current model this is equated to the user input actual increases. If a feed-in-tariff takes place these “perceptions” will not be exact. (%)
$C_{E_{s,i,t}}$	Current time step cost of electricity
p_{avg_i}	Average power consumed (USD/(yr*consumer)) this is a user input defined in section 4.4
$P_{noPV_{s,i,t,n}}$	Payments n years into the future if no PV is purchased
$P_{withPV_{s,m,j,i,t,n}}$	Payments n year into the future if PV is purchased
$C_{F_{s,m,j,i,t}}$	Cost associated with financing PV. Quantified through section 4.3 and then section 3.7.
c_{PV}	Average capacity factor for the geographic region being analyzed derived in section 0.
I_{avg_i}	Average PV installation size

${C_{FIT}}_{s,i,t}$	Feed-in-tariff current time step costs. The index "k" has been dropped because the history of feed-in-tariff prices is not needed in this calculation (see section 3.5)
${C_{ES}}_{s,i,t,n}$	The greater of feed-in-tariff payback rates or electricity costs. One replaces the other if they intersect n years into the future
${R_{ES}}_{i,n}$	Term which accounts for the increase in electricity costs but is zero feed-in-tariffs since offers stay constant
${M_C}_i$	Maintenance costs (see section 4.3)
${F_{proptax}}_{s,i,t}$	Fraction to be applied to PV costs due to property taxes. (see section 3.8)
${P_{PV}}_{s,m,i,t}$	Incentivized job cost of a PV system ($) calculated in section
${F_{tax}}_{s,i,t}$	Total tax term defined in section 3.8
${U_{FIT}}_s$	Use feed-in-tariff switch
$Res_{s,m,j,i,t,n}$	Residual array used to simultaneously solve for time to net profit for all policy options.
${n_0}_{s,m,j,i,t}$	Roots of $Res_{s,m,j,i,t,n}$
${T_{PN}}_{s,m,j,i,t}$	Time to net profit term used in the models PVF equation in section 2.3.1.
$SO_{j,i}$	System ownership status for each type of financing. Currently SO is true for all but third party financing.
${P_{EM}}_{s,i,t,n}$	Projected electricity immediate costs n years into the future (as opposed to total costs used in time to net profit)
${P_{PVM}}_{s,m,j,i,t,n}$	Projected PV immediate costs n years into the future (as opposed to total costs used in time to net profit)
${C_{FMP}}_{s,m,j,i,t}$	Immediate payment on PV loan equal to zero if the loan term is exceeded.
${C_P}_{s,m,j,i,t}$	PV financing loan payment defined in section 3.7

2.6.2. Time to Lower payments

Lower payments are achieved when conventional electricity costs per time step are equal to or less total PV costs per time step. This is very similar to the time to net profit of section 2.6.1 but has some differences. Refer to Table 4 for variable names explanations. The immediate costs for each time step of electricity must be greater than the corresponding immediate PV costs. The first time "n_0" in the future for which this condition is true is sought.

$$ {P_{PVM}}_{s,m,j,i,t,n_0} - {P_{EM}}_{s,i,t,n_0} = 0 \qquad 2.29 $$

The PV costs can be expressed as the sum of financing payments, maintenance, and property taxes incurred minus the amount of cost recovered by selling back or using PV electricity depending on the feed-in-tariff status.

$$P_{PVM_{s,m,j,i,t,n}} = C_{FMP_{s,m,j,i,t}} + C_{E_{s,i,t}} p_{avg_{i,t}} \left(1 + R_{EP_i}\right)^n - c_{PV} I_{avg_i} C_{ES_{s,k,i,t,u}} \left(1 + R_{ES_{i,n}}\right)^n + \left(M_{C\,i} + F_{proptax_{s,i,t}} \frac{P_{PV_{s,m,i,t}}}{\left(1 + F_{tax_{s,i,t}}\right)} \right) \quad 2.30$$

$$C_{FMP_{s,m,j,i,t}} = \begin{cases} C_{P_{s,m,j,i,t}} & if\ n < Lt_{s,i,j} \\ 0 & otherwise \end{cases} \quad 2.31$$

The payments on electricity per time step can be expressed as seen in equation 2.32.

$$P_{EM_{s,i,t,n}} = C_{E_{s,i,t}} p_{avg_{i,t}} \left(1 + R_{EP_i}\right)^n \quad 2.32$$

Equation 2.29 can be solved using the same interpolation procedure used in the net profit calculation by incrementing into the future until zero is crossed. If zero is never crossed then t_f is assigned as the time to lower payments. If the first value is a negative number then the time to lower payments is immediately reached and the time to lower payments is set equal to zero. Figure 9 provides an illustration of the time to lower payments solution for a single case for a hypothetical residential sector and 1% growth in electricity costs per year.

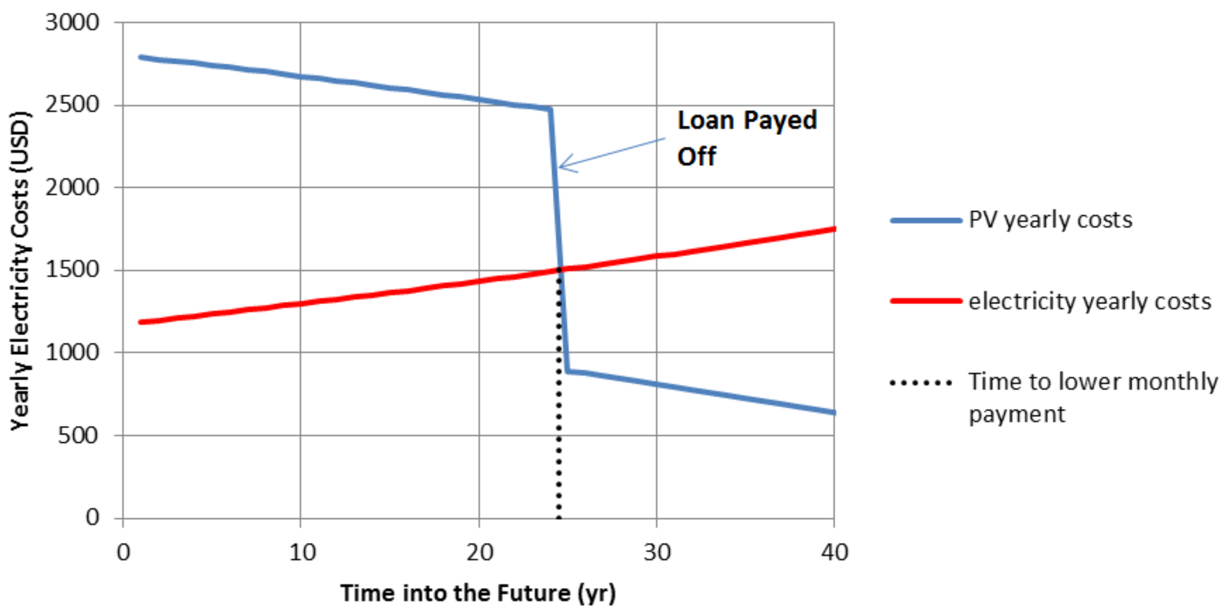

Figure 9. Example calculation of time to lower monthly payments for electricity.

3. POLICY MODELS

This chapter involves linking nine different forms of policy to various parameters within the FPVF equation 2.3. Here, the user can create scenarios which mix any of these policies with limited budgets. This is an initial implementation of this very flexible concept and the power behind it is seen in Figure 10.

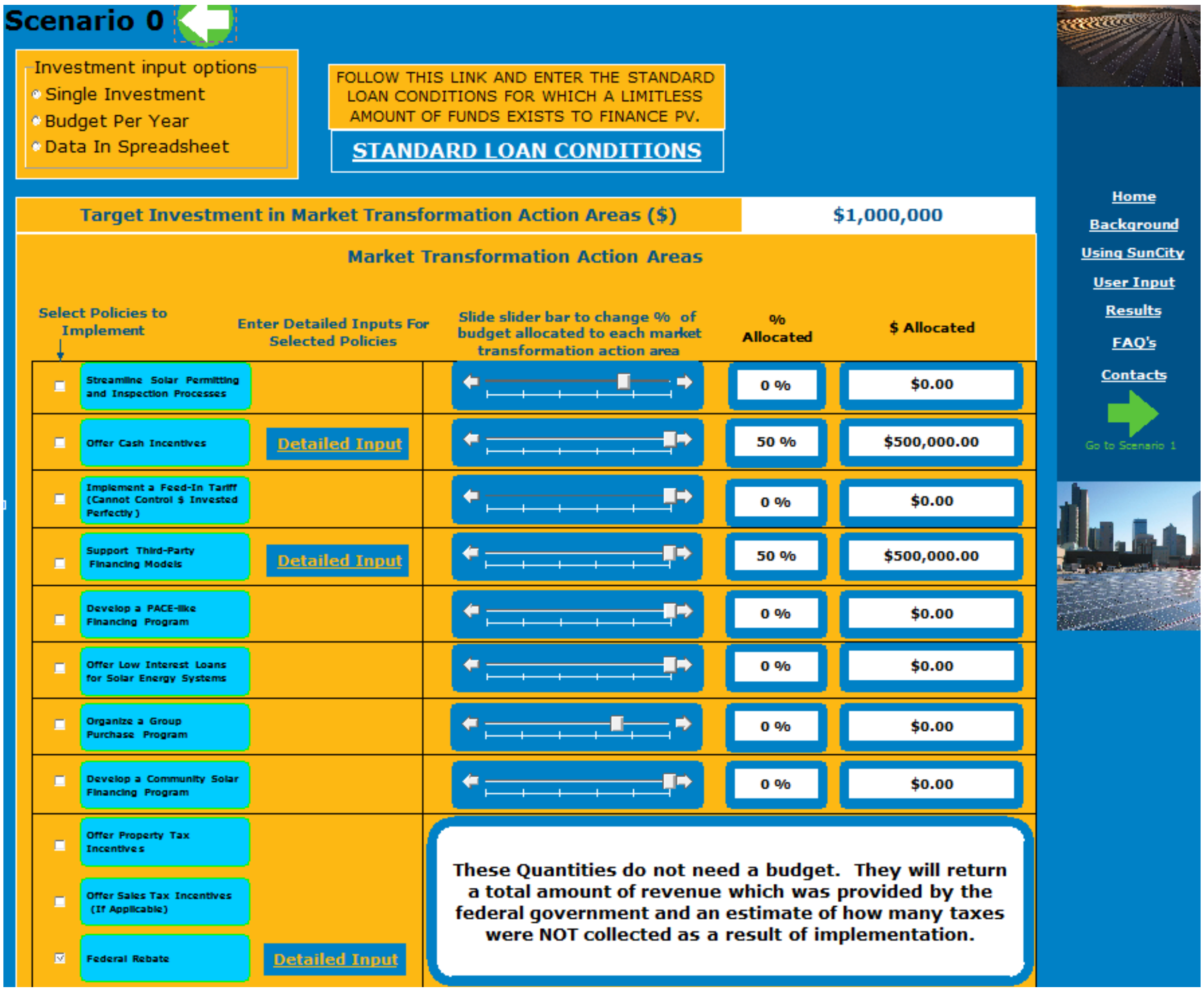

Figure 10. Sun City policy scenario input screen

The energy supplied by a flow of funding can produce increased PV growth but the efficiency of the transfer process of converting dollars input into a policy to total additional PV installed is not well understood [1]. In general, some policies are easier to model than others because they are more analytical in nature. None of the policy models have yet been tested for validity. The current state of this model is therefore a demonstration whose merits can be judged based on the theory and assumptions provided. Table 5 provides a summary of the status of the models for each policy type.

Table 5. Model readiness status

Policy	Status
Cash Incentives	Conceptually complete model which can be expanded to handle a broader range of conditions
Feed-in-tariff	Nearly complete conceptually with some additions needed. The current version overshoots the target spending. A stronger algorithm for spending costs for feed-in-tariff is needed
Property and Sales Taxes	Conceptually complete which probably need to be expanded to handle a broader range of conditions
Low interest loans, property assessed clean energy financing, PACE	Updates needed to the conceptual model. Model assumes the funding is being used to form complete loans. A much better approach is to buy down interest of standard loan conditions.
Third Party Financing	Needs further development
Solar Community, Group Purchase, Streamline solar permitting process	Needs further development

An awareness of the bigger picture is needed when using Sun City because the current model isolates PV effects and does not include other factors. For example, a feed-in-tariff will increase PV purchasing but will also increase power costs. The model quantifies the increase in market costs of electricity but it does not provide an economic impact analysis of such increases nor does it endogenously include any feedback of negative effects of increased electricity prices on PV. A feed-in-tariff may be a poor policy approach if it sharply increases electricity costs even though it may elevate PV considerably in Sun City.

Sun City does not keep track of loan payment status after PV has been purchased. All of the financial calculations only serve to quantify differences in PVF at the time of purchase. Policies are allowed to be applied simultaneously with no regard to legislation which could limit options. The nine policies covered can be grouped into three different strategies for inducing PV growth as seen in Table 6. The power of the Sun City model lies in the fact that each policy can be turned on or off with different inputs for a range of scenarios. The model currently only has two scenarios imbedded but more can easily be added.

Table 6. Strategies to increase PVF

Strategy	**Applicable Policies**
Provide Better Financing Options	Low Interest Loans, Property Assessed Clean Energy Financing (PACE), Third Party Financing
Offer Incentives	Feed-in-tariff, Cash incentives (Grants, Rebates), Property and sales tax incentives, Streamlined solar permitting and inspection process
Transfer Resources Across Sectors to Encourage Cooperation	Group Purchase Program, Community Solar, Third Party Financing

3.1. Cash Incentives

Cash incentives involve offering payments which offset some of the costs of PV. This section provides a detailed mathematical description of how making such an offer affects the spending rate on PV in the bass model. The concept of offering cash incentives is simple if an unlimited budget is allowed. When the budget is limited the formulation becomes more difficult. The objective of this section is to show how a limited budget cash incentive affects the spending rate of PV.

The Sun City model neglects the effects that delays may have on people's choices. Cash incentives have a start and end date and can also have a limited budget. The algorithm about to be described is applied iteratively (section 2.3.3). The Bass installation rate (ΔI) which is determined in section 2.3 equation 2.11, is already calculated. In this discussion several indices are dropped in order to simplify the expressions. All of the equations are arrays of time, scenario, and sector. The costs are derived with and without cash incentives but are separated here. The incentive rate offered, ${F_{CI}}_{s,m,i,t}$ from section 4.3, is included in the costs below.

$$C_{noI} = {C_{PVP}}_{s,NoCashIncentives,i,t} \qquad 3.1$$

$$C_I = {C_{PVP}}_{s,WithCashIncentives,i,t} \qquad 3.2$$

Where C_{PVP} is the cost in revenue per kilowatt installed of a PV purchase derived in section 4.3. The limited financing budgets are redefined below.

$$B_I = {B_I}_{s,i,t-1} \qquad 3.3$$

In the presence of a finite budget B_I for cash incentives, a mixture of spending with and without must be formulated. There are three solutions which are possible. The first is that there are no incentives, the second is that the spending rate is greater than the budget, and the third is that the budget is greater than the spending rate. For the first case all of the spending occurs at the price without incentives and the solution is trivial.

$$PV_{SR} = \Delta I_I C_{noI} \;\; if \; B_I = 0 \qquad 3.4$$

Where ΔI_I is the installation rate from section 2.3 equation 2.11 and $PV_{SR}$is the PV spending rate. The Sun City model allows B_I to accumulate as a stock if all of the budget is not spent so that additional funds are available for the next time step. The second case applies when the expression below is true.

$$B_I < (C_{noI} - C_I)\Delta I_I \qquad 3.5$$

Under these conditions, the spending rate on PV can then be expressed as

$$PV_{SR} = \Delta I_I (F_I C_I + (1 - F_I) C_{noI}) \qquad 3.6$$

Where F_I is the unknown fraction of spending which did obtain incentives. Since the entire cash incentives budget B_I is used, it can be expressed as seen below.

$$B_I = \left(\frac{PV_{SR}F_I}{C_I}C_{noI} - PV_{SR}F_I\right)t_s \qquad 3.7$$

Equation 3.7 can be simplified to equation 3.8

$$F_I = \frac{B_I}{PV_{SR}R_p t_s} \qquad F_I \leq 1 \qquad 3.8$$

Where R_p is determined in equation 3.9. R_p is an important parameter which is used repeatedly to form logical distinctions in the financing PVF balance calculations of appendix A Note that F_{CI} and R_p are different because of the application of taxes and other incentives and the order in which the other factors are applied.

$$R_p = \frac{C_{noI}}{C_I} - 1 \qquad 3.9$$

Combining equations 3.6 and 3.8 to eliminate F_I produces a quadratic equation for PV_{SR} whose largest root is equal to the expression in equation 3.10. R_p drops out of the equation.

$$PV_{SR} = \frac{C_{noI}\Delta I_I + \sqrt{(C_{noI}\Delta I_I)^2 - \dfrac{4\Delta I_I B_I C_I}{t_s}}}{2} \qquad 3.10$$

This term is always a real number when the condition of equation 3.5 is met. If the square root term is compared to itself by substituting the right hand side of equation 3.5 for B_I, the following inequality is known to be true.

$$(C_{noI}\Delta I_I)^2 - \frac{4\Delta I_I B_I C_I}{t_s} > (C_{noI}\Delta I_I)^2 - \frac{4\Delta I_I\big((C_{noI} - C_I)\Delta I_I\big)C_I}{t_s} \qquad 3.11$$

This can be rearranged to the expression below.

$$(C_{noI}\Delta I_I)^2 - \frac{4PV_{AR}B_I C_I}{t_s} > \Delta I_I^{\,2}\left(C_{noI}^{\,2} - 4\frac{C_{noI}C_I}{t_s} + 4\frac{C_I^{\,2}}{t_s}\right) \qquad 3.12$$

If $t_s \geq 1$ then the far right hand t_s can be replaced with $t_s^{\,2}$without negating the truth of the inequality since this causes a positive term to decrease for a term that is less than another. The expression can then be rewritten

$$(C_{noI}\Delta I_I)^2 - \frac{4\Delta I_I B_I C_I}{t_s} > \Delta I_I^{\,2}\left(C_{noI} - 2\frac{C_I}{t_s}\right)^2 \qquad 3.13$$

But the right hand side of this equation is always positive. It therefore follows that

$$(C_{noI}\Delta I_I)^2 - \frac{4\Delta I_I B_I C_I}{t_s} > 0 \quad if \quad B_I < (C_{noI} - C_I)\Delta I_I \ \ and\ t_s \geq 1 \qquad 3.14$$

If the budget is greater than PV_{SR} then all of the spending will occur at the incentives price and $F_I = 1$.

$$B_I \geq (C_{noI} - C_I)\Delta I_I \qquad 3.15$$

$$PV_{SR} = \Delta I_I C_I \qquad 3.16$$

The entire formulation is summarized in equation 3.17. The indices follow from the definitions of other equations as mentioned in the discussion above.

$$PV_{SR_{s,i,t}} = \begin{cases} \Delta I_I C_{noI} & if\ B_I = 0 \\ \dfrac{C_{noI}\Delta I_I + \sqrt{(C_{noI}\Delta I_I)^2 - \dfrac{4\Delta I_I B_I C_I}{t_s}}}{2} & if\ B_I < (C_{noI} - C_I)\Delta I \\ \Delta I_I C_I & if\ B_I \geq (C_{noI} - C_I)\Delta I \end{cases} \qquad 3.17$$

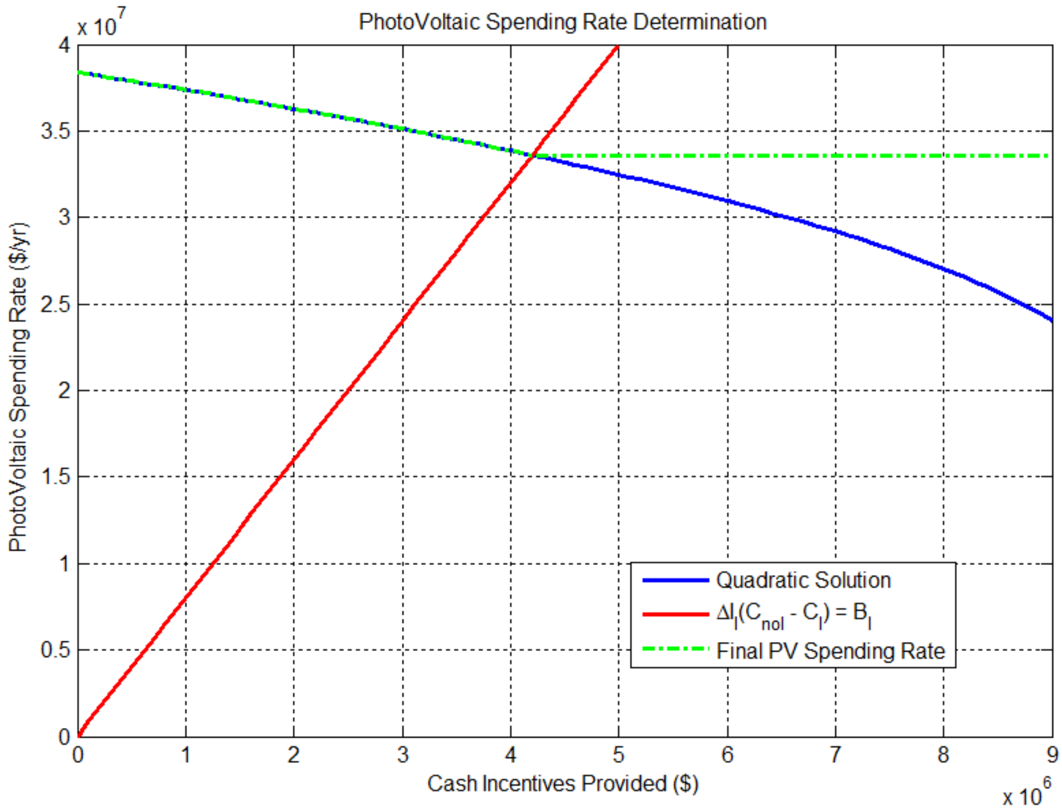

Figure 11. Cash incentives vs. PV spending rate determination for an example set of fixed values for other parameters. ΔI_I = 6000 KW-installed/yr, F_{CI} = 12.5%, C_{nol} = 6400 $/KW-installed, t_s = 1yr. The decline in spending rate is due to the fact that ΔI_I is already fixed

PV_{SR} is illustrated for no incentives, incentives covering some of the spending, and incentives covering all of the spending in Figure 11. The spending rate declines with increased cash incentives because the installation rate is already fixed in the iterative process used to converge on values for all of the variables. The PV spending rate is combined with the fractions of spending for each option derived in section 2.3.3 to redistribute the aggregated Bass model calculations to all cash incentive and financing options. The total cash incentives budget and financing budgets are balanced as seen in equations 3.18 through 3.23. The iterative scheme described in section 2.3.3 constrains budgets to remain positive.

$$\Delta B_{I_{s,i,t}} = PV_{SR_{s,i,t}} \sum_j f_{s,CashIncentives,j,i,t} \tag{3.18}$$

$$\Delta B_{F_{s,j,i,t}} = PV_{SR_{s,i,t}} \sum_m f_{s,m,j,i,t} \tag{3.19}$$

$$B_{I_{s,i,t}} = B_{I_{s,i,t-1}} + B_{UII_{s,i,t}} - \Delta B_{I_{s,i,t}} \tag{3.20}$$

$$B_{F_{s,j,i,t}} = B_{F_{s,j,i,t-1}} + B_{UIF_{s,j,i,t}} - \Delta B_{F_{s,j,i,t}} \tag{3.21}$$

Where B_{UII} is the user input cash incentives budget, B_{UIF} is the user input financing option budgets, B_I is the available cash incentives, and B_F are the available funds for financing options.

3.2. Third Party Financing

Third party financing (TPF) enables cooperation across sectors to leverage mutual advantages. In Sun City TPF slows down the utility sector PV growth because the utility down payment is reduced for utilities in order to offer a lower down payment to the residential or commercial sectors. Such a strategy is efficient for cases where the utility's PV installation potential (*m* Bass coefficient) is nearly reached while residential and commercial potentials are greater. The down-payment can be reduced for the residential and commercial sectors and the payments set to a competitive price by the utility. The utility is able to pay-off the PV system faster and the residents involved reap the benefit of constant pricing for several years. The lease terms are important parameter inputs to the model. Since the utility is the lender, TPF is the only algorithm which attempts to track the financing status of TPF loans over time.

The cost of PV derived in section 4.3 equation 4.11 can be reduced even further if it is assumed that a third party agreement can leverage utility prices due to bulk purchases but still use the federal rebate since the installation site is residential. Sun City currently operates with this assumption which needs to be confirmed to be valid. The potential savings is expressed below where the size factor for the utility replaces the size factor for commercial and residential. Refer to Table 7 for variable definitions.

$$S_{TPF_{s,m,i,t}} = \left(1 - \frac{F_{size_{utility}}}{F_{size_i}}\right)\left(C_{PVP_{s,m,i,t}}\right) \tag{3.22}$$

It is not expected that the utility will share all of these savings with the residential or commercial sectors. It is also assumed that the lease being financed does not end in ownership by the residential or commercial sectors. The result is that only a fraction of the costs have to be paid off at the end of the term. The amount to be paid during the TPF lease is shown in equation 3.23.

$$P_{TPF_{s,m,i,t}} = I_{avg_i} F_{TPFP_i}\left(C_{PVP_{s,m,i,t}} - F_{TPFS_i} S_{TPF_{s,m,i,t}}\right) \tag{3.23}$$

Once the amount to be paid is known, user input interest rate, lease length, and down payment fee can be used to derive payment, down payment, and total financing costs for the third party financing agreement as outlined in section 3.7. These parameters in turn provide new, reduced barrier terms for the residential and commercial sectors in the PVF equation 2.3. The fact that the system is not owned at the end of the lease causes the PVF equation net time to profit term calculated in section 2.6.1 to be excluded. The weighting factors are reassigned new values proportionate to each other.

$$w_{b,i} = \begin{cases} w_{U_{b,i}} & if\ SO_{j,i} = true \\ 0 & if\ SO_{j,i} = false\ AND\ b = PN \\ \dfrac{w_{U_{b,i}}}{\sum_{b=DP,P,PI} w_{U_{b,i}}} & otherwise \end{cases} \qquad 3.24$$

The cost of financing is absorbed by lowering the utilities down payment tolerance term by the amount of financing which has been extended in the current time step. This requires the amount of payments being made and total amount financed to be tracked. The spending rate for third party financing can be determined for the previous time step using the spending rate fractions $f_{s,m,j,i,t}$ determined in section 2.3.3 and the overall PV spending rate $PV_{SR_{s,i,t}}$ determined in section 3.1.

$$S_{PTPF_{s,m,i,t}} = f_{s,m,"Third\ Party",i,t} PV_{SR_{s,i,t}} \qquad 3.25$$

This can be used to quantify a continuous approximation for lease payments which are being added each time step. The spending rate over the total cost of financing is an approximation for the number of loans being taken out. This can be multiplied by the payment for third party financing to establish the influx of third party payments as seen below.

$$\Delta P_{TPF_{s,i,t}} = \begin{cases} 0 & if\ i = Utility \\ \sum_m \left(C_{P_{s,m,TPF,i,t}} \dfrac{S_{PTPF_{s,m,i,t}}}{C_{F_{s,m,TPF,i,t}}} \right) & otherwise \end{cases} \qquad 3.26$$

The payments are accumulated and outflow after the term length of the third party lease. The resulting stock can be expressed as seen in equation 3.27.

$$P_{TPF_{s,i,t}} = P_{TPF_{s,i,t-1}} + \Delta P_{TPF_{s,i,t}} - delayppl\left(\Delta P_{TPF_{s,i,t}}, n_{s,i,TPF}, 0\right) \qquad 3.27$$

The total amount of third party loans being financed can then be expressed as the total spending minus the payments stock.

$$C_{FTPF_{s,t}} = C_{FTPF_{s,t-1}} + \sum_{m,i} \left(S_{PTPF_{s,m,i,t}} - P_{TPF_{s,i,t}} \right) \qquad 3.28$$

The down payment taken away from the utility is limited by a user input fraction since it is not expected that the utility would loan out all of its financial capacity. The limited budget financing algorithm of the Sun City model is the same for all options but for third party financing.

$$\Delta B_{F_{s,j,i,t}} = \begin{cases} B_{UI_{s,j,i,t}} & U_{s,j} = TRUE\ \&\ j \neq TPF \\ B_{UI_{s,j,i,t}} & C_{FTPF_{s,t}} > C_{DP_{ToUt,t}} F_{TPF_i} \\ C_{DP_{ToUt,t}} F_{TPF_i} & otherwise \end{cases} \qquad 3.29$$

Table 7. Third party financing variable explanations

Variable	Meaning
b	Index over the four barriers in the PVF equation 2.3 (see section 1.3)
$C_{PVP_{s,m,i,t}}$	Cost of PV ($/W installed) defined in section 4.3 equation 4.11
F_{size_i}	Purchase size fraction for sector “i” defined in section 4.3 equation 4.8
$S_{TPF_{s,m,i,t}}$	Potential savings by using a third party agreement. The savings come from combining the lower costs of utility bulk purchasing and the residential/commercial federal rebate and/or other residential/commercial incentives which are unavailable to the utility
F_{TPFS_i}	User input fraction of the potential savings which is shared by the utility as a benefit for making TPF a strong option for leasing solar power.
F_{TPFP_i}	User input fraction of the total system costs which are paid back in the lease agreement.
I_{avg_i}	User Input average system size for sector “I” in terms of nameplate capacity (kW)
$P_{TPF_{s,m,i,t}}$	Total price of doing a lease on amount of solar. ($)
$w_{U_{b,j,i}}$	User input weighting factor in the PVF equation 2.3 (altered only for Third party financing)
$SO_{j,i}$	System ownership array (currently only Third party financing does not end in ownership)
$w_{b,j,i}$	PVF weighting parameters (equation 2.3) after system ownership (SO) filter has been applied
$PV_{SR_{s,i,t}}$	Photo-voltaic spending rate quantified in section 3.1
$f_{s,m,\text{"Third Party"},i,t}$	Fraction of spending associated with third party financing (see section 2.3.1)
$S_{PTPF_{s,m,i,t}}$	Spending on third party financing for the current time step
$C_{P_{s,m,TPF,i,t}}$	Monthly payment of TPF lease defined in section 3.7
$C_{F_{s,m,TPF,i,t}}$	Cost of financing of TPF lease defined in section 3.7
$\Delta P_{TPF_{s,i,t}}$	Flow of payments for third party financing leases
$P_{TPF_{s,i,t}}$	Payments for third party financing leases
$delayppl$	Delay function in Studio™ which copies a function with a fixed lag.
$C_{FTPF_{s,t}}$	Total amount of third financing loans currently in place
$n_{s,i,TPF}$	TPF lease length
$B_{UI_{s,j,i,t}}$	User input budgets for limited financing and cash incentives options
$\Delta B_{F_{s,j,i,t}}$	Filtered budget influx for the current time step for all options (only third party financing has a restriction on the amount of funding which can be expended).
$U_{s,j}$	Use switch which turns the different types of financing on or off
$C_{DP_{To_{Ut,t}}}$	Down payment tolerance for the utility coming from equation 2.3

F_{TPF_i}	Fraction of down payment tolerance which can go from the utility to sector i. $F_{TPF,utility}=0$

3.3. Group Purchase Programs

Group purchasing programs (GPP) have a high potential for introducing savings for residential and commercial smaller scale customers by taking advantage of reduced prices on bulk purchases. Their effectiveness is hard to quantify in terms of money invested. If every small-scale project in a local area formed a single group, the discount would be tremendous but this will not happen unless everyone is willing to wait longer to coordinate and negotiate a much larger purchase. The dynamics of such a process is very complex and an exponential model is proposed as a place-holder.

One possible model would be to make the product of the amount of money currently put into a GPP times the total money put in over all time divided by the time tolerance to net profit of the PVF equation 2.3 exponentially proportional to the total number of groups as seen in equation 3.30 below. This makes the equation sensitive to total budgetary input and current budgetary input. For example, if a lot of money has been put into a GPP but then funding is set to zero, the cooperation immediately disintegrates because there is no funding. A major cut in funding will not completely end the progress made but will drastically reduce the effectiveness of the GPP. This model needs to be compared to actual group program data to assess its effectiveness at quantifying group purchasing programs.

$$N_{GPP_{s,i,t}} = \left(N_{max_{s,i,t}} - N_{min_{s,i,t}}\right) e^{-\frac{A_{GPP_{s,i}} B_{GC_{s,i,t}} B_{GT_{s,i,t-1}}}{T_{PN_{To_i}}}} + N_{min_{s,i,t}} \qquad 3.30$$

$$B_{GT_{s,i,t}} = B_{GT_{s,i,t-1}} + B_{GC_{s,i,t}} \qquad 3.31$$

The terms N_{max} and N_{min} represent upper and lower bounds for the number of groups which can be formed. $A_{GPP}$is a calibrating constant. This model should not be used for anything other than demonstration until this constant has been determined from GPP effects data. A reasonable estimate for the maximum number of groups possible is obtained by dividing the spending rate on PV coming from the Bass growth model which is derived in section 3.1 by the price of a PV system with only the size reduction included as computed in equation 4.9 of section 4.3. After this upper bound is set, another calibration constant is used to set the minimum number of groups. The group clustering factor model assumes that there is a constant linear relationship between N_{max} and N_{min}as seen in equation 3.33.

$$N_{max_{s,i,t}} = \begin{cases} 1 & \dfrac{PV_{SR_{s,i,t}} t_s}{P_{PVsize_{i,t}}} < 1 \\ \dfrac{PV_{SR_{s,i,t}} t_s}{P_{PVsize_{i,t}}} & otherwise \end{cases} \qquad 3.32$$

$$N_{min_{s,i,t}} = \begin{cases} 1 & \dfrac{N_{max_{s,i,t}}}{G_{CF_{s,i}}} < 1 \\ \dfrac{N_{max_{s,i,t}}}{G_{CF_{s,i}}} & otherwise \end{cases} \quad 3.33$$

Once the number of groups N_{GPP} is known, the purchase size I_{avg} can be replaced by the installation rate of PV according to the current Bass model iteration.

$$I_{GPP_{s,i,t}} = \frac{\Delta I_{I_{s,i,t}} t_s}{N_{GPP}} \quad 3.34$$

Once this is known, the size function (SF) mentioned in equation 4.10 can be used to produce a new cost fraction. This is divided by the size fraction which is already applied for the average installation size I_{avg} so that this factor is canceled out and replaced by the GPP fraction.

$$F_{GPP_{s,i,t+1}} = \frac{Interpolation\left(SF\left(I_{GPP_{s,i,t}}\right)\right)}{F_{size_i}} \quad 3.35$$

Table 8. Group purchase program variable definitions

Variable	Meaning
N_{max}	Maximum number of groups possible
$N_{min_{s,i,t}}$	Estimated minimum number of groups
$G_{CF_{s,i}}$	User input group clustering factor – this is a parameter which is an indicator of how much purchasers will cooperate. Setting it very large will make the minimum number of groups equal to 1.
$PV_{SR_{s,i,t}}$	Last time step total spending rate on PV derived in section 3.1 ($/yr)
$P_{PVsize_{i,t}}$	Price of a PV system with only size discount included (see section 4.3) ($)
$N_{GPP_{s,i,t}}$	Number of groups which result due to GPP costs input
$A_{GPP_{s,i}}$	User input GPP proportionality constant which can be adjusted to match real data for effectiveness of GPP's when revenue is put into coordinating purchases ($yr^2/\$^2$)
$B_{GC_{s,i,t}}$	User input budget time series for GPP ($/yr)
$B_{GT_{s,i,t}}$	Total budget put into the GPP over the life of the GPP. If the GPP has 0 funding for any given time step this will need to reset to 0. ($/yr)
$\Delta I_{s,i,t}$	Installation rate for bass model per sector and current time step (KW/yr)
$I_{GPP_{s,i,t}}$	Installation size for entire group purchase program (KW)
SF	Size Function. Numerical data array of a fraction starting at 1 (for 0-1KW) and decaying to a value between one and zero which

	represents a discount in price from the original C_{PVpre} cost. A second numerical array of KW's installed provides a way to linearly interpolate any installation value.
F_{size_i}	Size factor established in equation 4.10 (unitless)

3.4. Community Solar Financing

The community solar financing (CSF) model allows a transfer of residential and commercial sectors resources to the utility sector. Similar to TPF, this may be good for populations which lack commercial or residential potential but have plenty of utility potential. The average down payment can therefore be reduced for investments in solar and the time to profitability will also decrease if the cost ratio for PV to other electric is favorable. In Sun City the utility sector "requests" donations of a specific amount D_{CSF}. These donations have to accumulate into a full scale utility size project before the savings begin to be distributed. The objective of this model is not to quantify when such a project is completed exactly but rather to figure out how many residents will donate to help the utility create another project from which they will eventually benefit. The primary relationship needed is quantifying the percentage of a population which will use some of its resources to build a community solar facility. To do this several preliminary calculations are needed. The cost of the solar financing program is assumed to be based on a taxation rate for the total amount of the money put into the program. The user supplies a time series budget for the program, and if this budget does not supply enough revenue to pay for the costs, then the program taxes the potential benefits of the CSF program. Otherwise the extra budget supplied is used to reduce prices even further. The savings normalized by power consumption can be expressed as the user input budget minus the taxation rate to run the CSF as seen in equation 3.46.

$$S_{ACSF_{s,i,t}} = \frac{B_{F_{s,CSF,i,t-1}} - \frac{B_{CSF_{s,t-1}} F_{CSF_{s,i}}}{t_s}}{p_{C_{i,t}}} \qquad 3.36$$

This term is used along with several other variables to quantify the current savings offered to the commercial and residential sectors in terms of an electricity price drop when a project is completed. The utility is only assumed to share a fraction of the potential price drop associated with its capacity to procure lower prices by making larger purchases.

$$S_{CSF_{s,m,i,t}} = \frac{S_{ACSF_{s,i,t}} + \left(C_{E_{s,i,t}} - C_{PV_{s,m,i,t}} + F_{SCSF_{s,i}}\left(C_{PV_{s,m,i,t}} - C_{PV_{s,m,Ut,t}}\right)\right)}{t_s} \qquad 3.37$$

The fraction of the population which will buy into the CSF program if a set investment amount is required can then be expressed as an exponential relationship to S_{CSF}.

$$F_{PCSF_{s,m,i,t}} = \begin{cases} F_{ICSF_{s,i}}\left(1 - e^{\frac{-A_{CSF_{s,i}} pc_{i,t} S_{CSF_{s,m,i,t}} T_{PN_{To_i}}}{D_{CSF_{s,i,t}}}}\right) & S_{CSF_{s,m,i,t}} > 0 \\ 0 & otherwise \end{cases} \quad 3.38$$

The eligible population for buying into the CSF program is estimated as the number of consumers minus the number of consumers who have already purchased PV.

$$Con_{CSF_{s,i,t}} = \begin{cases} Con_{i,t} - \frac{I_{s,i,t}}{I_{avg_i}} & Con_{i,t} - \frac{I_{s,i,t}}{I_{avg_i}} > 0 \\ 0 & otherwise \end{cases} \quad 3.39$$

It is now possible to calculate the total down payment tolerance lost from the residential and commercial sectors due to their investment and the gain to the utility down payment tolerance.

$$C_{DPCS_{To_{s,m,i,t}}} = \begin{cases} 0 & U_{CSF_s} = False\ OR\ i = Utility \\ D_{CSF_{s,i,t}} F_{PCSF_{s,m,i,t}} \frac{Con_{CSF_{s,i,t}}}{Con_{i,t}} & C_{DP_{To_{i,t}}} > F_{PCSF_{s,m,i,t}} D_{CSF_{s,i,t}} \\ C_{DP_{To_{i,t}}} \frac{Con_{CSF_{s,i,t}}}{Con_{i,t}} & otherwise \end{cases} \quad 3.40$$

The down payment tolerance gained by the utility can then be expressed as seen in equation 3.41. The same amount of revenue input by the other sectors is renormalized to the number of utilities in the simulation.

$$C_{UDPCS_{To_{s,m,i,t}}} = \begin{cases} 0 & i \neq Utility \\ 0 & U_{CSF_s} = False \\ D_{CSF_{s,i,t}} F_{PCSF_{s,m,i,t}} \sum_i C_{DPCS_{To_{s,m,i,t}}} F_{PCSF_{s,m,i,t}} \frac{Con_{CSF_{s,i,t}}}{Con_{Utility,t}} & otherwise \end{cases} \quad 3.41$$

The next time step is resolved by quantifying the budget input into the CSF with these terms as seen in equations 3.42 and 3.43.

$$\Delta B_{CSF_{s,t}} = Con_{Utility,t} \sum_{m,i} C_{UDPCS_{To_{s,m,i,t}}} f_{I_{s,m,i,t}} + \sum_i \Delta B_{F_{s,CSF,i,t}} \quad 3.42$$

$$B_{CSF_{s,t}} = \Delta B_{CSF_{s,t}} + B_{CSF_{s,t-1}} - delayppl(\Delta B_{CSF_{s,t}}, t_s, 0) \quad 3.43$$

Where f_I is the fraction of spending with incentives which can be expressed as seen in equation 3.44.

$$f_{I_{s,m,i,t}} = \begin{cases} \sum_j f_{s,WithIncentives,j,i,t} & m = WithIncentives \\ \sum_j f_{s,NoIncentives,j,i,t} & m = NoIncentives \end{cases} \quad 3.44$$

Table 9. Community solar financing variable meanings

Variable	Description
$F_{CSF_{s,i}}$	Fraction of budget input which is required to run the community solar financing program. (unitless)
$B_{CSF_{s,t-1}}$	Total revenue input into the community solar financing program by the community for the previous time step. ($)
t_s	Time step of the simulation
$B_{F_{s,CSF,i,t}}$	Exogenous user input budget of the community solar financing program as a function of time. The limited budget is described in section 3.1 and section 2.3.3 equation 3.19 ($)
$p_{C_{i,t}}$	Power consumed throughout the city (Kwh/yr) derived in section 4.4 equation 4.23.
$S_{ACSF_{s,i,t}}$	Savings or deficit associated with incentives put into the CSF program and the costs required to run it. ($)
$C_{E_{s,i,t}}$	Cost of electricity for the simulation derived in section 3.5 equation 3.55 ($/
$C_{PV_{s,m,i,t}}$	Levelized cost of PV with all incentives included derived in section 4.3 equation 4.17
$F_{PCSF_{s,i}}$	Fraction of profits which can be obtained by utilities lower price of PV shared by utility for CSF program
$S_{CSF_{s,m,i,t}}$	Savings or deficit offered to the community to purchase a community solar power project ($)
$D_{CSF_{s,i}}$	Contribution amount ($) required to buy 1 share of the community solar program (local laws often require community solar buy in to be larger sums of money (i.e. ~500-$1000) to avoid distribution of costs over too large of a population.
$A_{CSF_{s,i}}$	Community solar calibration exponential constant (yr). This is a key factor which makes this model useless unless a basis for the value assigned has been established
$F_{ICSF_{s,i}}$	Fraction of population which is able to participate in CSF (different than eligible population below)
$I_{s,i,t}$	Number of PV installations (bass model section 2.1) (KW)
I_{avg_i}	User input average installation size (KW)
$Con_{i,t}$	Number of consumers derived from user input population data and consumer to population ratios described in section 4.4 (consumers)
$Con_{CSF_{s,i,t}}$	Eligible consumers to participate in the community solar financing program
U_{CSF_s}	Switch to turn CSF on and off per scenario. (Boolean)
$C_{DPTo_{i,t}}$	Down payment tolerance of the population derived in section 4.5 ($)
$C_{DPCSTo_{s,m,i,t}}$	Amount of down payment tolerance from residential and commercial sectors which will be transferred to the utility based on CSF participation
$C_{UDPCSTo_{s,m,i,t}}$	Amount of down payment tolerance gained by utility based on

	$C_{DPCS\,To_{s,m,i,t}}$ and renormalization to the number of utilities ($)
$delayppl$	Studio™ delay function
$\Delta B_{CSF_{s,t}}$	Inflow rate for $B_{CSF_{s,t}}$ ($/yr)
$f_{I_{s,m,i,t}}$	Fractions of spending with and without incentives (0-1 unitless)
$f_{s,m,j,i,t}$	Fractions of spending derived in section 2.3.3 (0-1 unitless)

3.5. Feed-in-tariffs

A feed-in-tariff (FIT) sets an above market price on renewable energy produced. This is intended to increase investment in renewable energy. The cost of a FIT is redistributed to all energy users through higher utility bills. FIT's which have sufficient economic incentive to ensure profit are well proven to produce favorable results for PV adoption in Germany and Spain [20]. A causal loop diagram illustrates the FIT effects in Figure 12**.** Two different effects which both support increases in PV installations are present. The first is to reduce the PV costs. Investors know that they will receive a bigger return for every kWh they produce and can account for this in their cost analysis. This reduces several barrier terms and increases the cost ratio in equation 2.3 which increases the PVF. The second is a slower effect which is felt as the number of feed-in-tariff payments increase in size. The market electricity costs, C_E go up which also increases the PVF. The enforced cost spread and reward of buying PV make feed-in-tariffs a potent policy choice but care must be exercised in designing one [26]. It is important that the economic sustainability of the amount of feed-in-tariff payments be thoroughly investigated and that local economics be taken into account in order to avoid local instabilities due to rising energy costs. A local feed-in-tariff can especially be damaging if rises in electricity costs cause a region to become less economically competitive than surrounding areas. For Germany and Spain, the costs are spread throughout the entire country [Page 22 of reference 26].

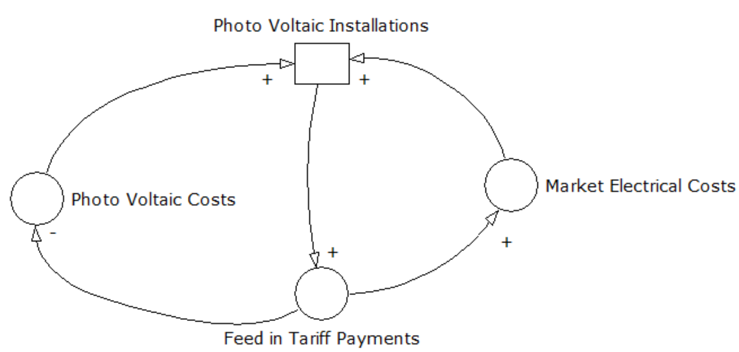

Figure 12. Feed-in-tariff causal loop which doubly reinforces growth of the target technology by reducing PV costs while also increasing market electricity costs.

Feed-in-tariff policies are usually posed with a number of restrictions which enable policy makers to control the maximum amount of money which will be circulated due to the feed-in-tariff. In the Sun City model there are seven inputs which are used to form a FIT policy.

1. Maximum amount of PV installed which receive PVF benefits

2. *Target* maximum amount of revenue expended by the local government or utility maintaining the FIT (perfect control of spending is not enforced in the current version)
3. Fraction which indicates the amount of PV installations which obtain FIT benefits
4. Term length of time during which payments will be made after installation
5. Fraction which indicates what percentage of total FIT payments is required to maintain the FIT program.
6. Maximum PV installations which can receive the feed-in-tariff benefits
7. Offered price for feed-in-tariff electricity production (in USD/kWh)

The target maximum revenue expended requires forecasting of the total payments into the future. The Sun City model will stop FIT installation growth if the predicted payments for the remaining term of each payment exceeds the maximum target revenue. This will not guarantee an exact expenditure at the end of the simulation though.

The feed-in-tariff installation rate is equal to the bass model installation rate of equation 2.11 multiplied by a user input fraction which is between 0 and 1. This fraction, F_{FIT}, indicates the fraction of installations for which the feed-in-tariff applies. Refer to Table 10 for variable explanations.

$$\Delta I_{FITin_{s,k,i,t}} = \begin{cases} F_{FIT_{s,i}} \Delta I_{I_{s,i,t}} \quad if \begin{cases} t \leq t_{FIT_{end_{s,i}}} \ AND \\ U_{FIT_s} = TRUE \quad AND \\ I_{FITtotal_{s,i,t}} \leq I_{FIT_{max_{s,i}}} \quad AND \\ C_{E_{t,i}} \leq C_{FIT_{s,k,i,t}} \quad AND \\ B_{FIT_{proj_{s,i,t}}} \leq B_{FIT_{target_{s,i}}} \end{cases} \\ 0 \qquad\qquad Otherwise \end{cases} \tag{3.45}$$

ΔI_{FITin} is non-zero only if five conditions are met simultaneously as shown by equation 3.45. The index "k" is a new range which spans the entire history of the simulation (2011…2028). It is needed in order to keep varying prices, installations, and expiration times stored in memory. The five conditions are stated below.

1. Offer end date has not been exceeded.
2. Current Scenario switch indicates FIT is to be used
3. A user input maximum amount of KW of PV installations under the feed-in-tariff has not been reached
4. The cost of electricity is less than the feed-in-tariff offer (this is only to force a reasonable policy). A good user will never input such a condition since there is no point in offering a negative effects policy.
5. The projected total costs of the FIT not exceed the target total cost of the FIT.

The fifth logical condition concerning projected total costs requires a forecast which saves the feed-in-tariff variable histories in a vector of stocks whose entries are not altered after each time step. This is a computationally expensive way to save the histories but a better methodology for the calculations could not be found using Studio. The first stock is the payment expiration future for each installation.

$$t_{FIT_{s,k,i,t}} = t_{FIT_{s,k,i,t-1}} - t_s \quad if \begin{cases} k < t \quad AND \\ t_{FIT_{s,k,i,t-1}} > 0 \end{cases} \tag{3.46}$$

This expression states that the time for feed-in-tariff payments to expire in the past reduces by one time step every time step until no more payments are due. This variable is constructed so that installations in the past have a known time before expiring. It requires an initialization as shown below.

$$t_{FIT_{s,k,i,0}} = \begin{cases} t_{FIT\,term_{s,i}} & if \;\; t_k \le t_{FIT\,end_s} \\ t_{FIT\,term_{s,i}} + t_{FIT\,end_s} - t_{start} - (t_k - 1) & if \; t_{FIT\,term_{s,i}} + t_{FIT\,end_s} - t_{start} > (t_k - 1) \\ 0 & otherwise \end{cases} \tag{3.47}$$

An example of the initial value and t_{FIT} after 10 years is shown below with a 20 year feed-in-tariff term, start time of January 2010, and cut-off date of December 31, 2019.

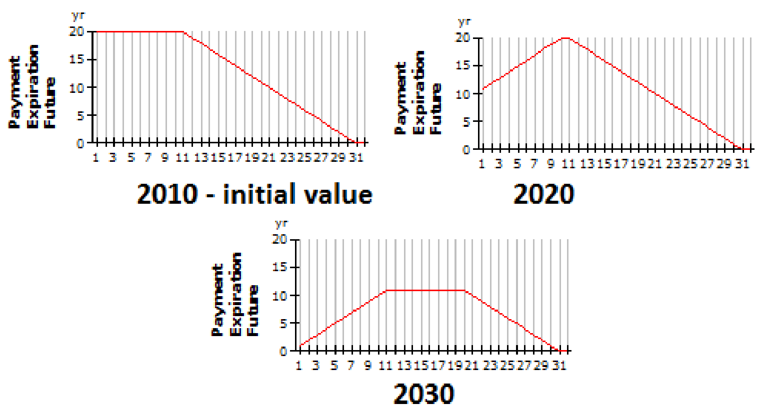

Figure 13. Feed-in-tariff payment time left history.

The second and third stocks used to store histories are the history of feed-in-tariff payment offers C_{FIT} (\$/kWh) and feed-in-tariff installations ΔI_{FITin}. Both of these stocks are initialized as zero vectors and receive an inflow only on the place holder for the current time step so that the histories can be stored and benefits ended using t_{FIT}. If installations are occurring they are accumulated in a stock I_{FIT}. The installations stay in I_{FIT} only as long as the feed-in-tariff agreement. A delay function is used to accomplish outflow from I_{FIT}.

$$\Delta I_{FITout_{s,k,i,t}} = \begin{cases} \dfrac{\Delta I_{FITin_{s,k,i,t}}}{t_s} & if \;\; t_{FIT_{s,k,i,t}} \le 0 \\ 0 & otherwise \end{cases} \tag{3.48}$$

$$I_{FIT_{s,k,i,t}} = I_{FIT_{s,k,i,t-1}} + \Delta I_{FITin_{s,k,i,t}} - \Delta I_{FITout_{s,k,i,t}} \tag{3.49}$$

$$I_{FITtotal_{s,i,t}} = \sum_k I_{FIT_{s,k,i,t}} \qquad 3.50$$

The rate of installations provides a way to calculate the amount of additional payments which will have to be made due to the feed-in-tariff guaranteed rate of return. The payment rate must be locked in since the user can input a time history variation in the incentives offered. The total payments for each time step is expressed below.

$$C_{PFIT_{s,i,t}} = \sum_k \begin{cases} c_{PV} I_{FIT_{s,k,i,t}} \left(C_{FIT_{s,k,i,t}} - C_{E_{s,i,t}}\right)\left(1 + F_{TaxFIT_{s,i,t}}\right) & if\ C_{FIT_{s,k,i,t}} - C_{E_{s,i,t}} > 0 \\ 0 & otherwise \end{cases} \qquad 3.51$$

C_{FIT} is the user input price offer history for the FIT in USD/KWh. c_{PV} is the average capacity factor calculated in section 0. The total increase in electricity costs due to the FIT can then be expressed as seen in equation 3.52.

$$C_{E_{FIT_{s,i,t}}} = \frac{C_{PFIT_{s,i,t-1}}}{p_{avg_i}} \qquad 3.52$$

The FIT must have an associated cost for enforcement by the utilities involved. It is assumed that the utilities tax the total payments by a flat rate F_{TaxFIT}. Equation 3.53 quantifies the total costs taxed by the utility to pay for the FIT.

$$C_{UtFIT_{s,t}} = C_{UtFIT_{s,t-1}} + \sum_i F_{TaxFIT_{s,i,t}} C_{PFIT_{s,i,t}} \qquad 3.53$$

The cost of electricity can then be expressed as the sum of the unaltered cost of electricity and the increase due to feed-in-tariff payments.

$$\Delta C_{E_{s,i,t}} = \frac{C_{EU_{i,t}} - C_{E_{s,i,t-1}} + C_{E_{FIT_{s,i,t}}}}{t_s} \qquad 3.54$$

$$C_{E_{s,i,t}} = C_{E_{s,i,t-1}} + t_s \Delta C_{E_{s,i,t}} \qquad 3.55$$

The cost of electricity, $C_{E_{s,i,t-1}}$, cancels out if you insert 3.55 into 3.54. The equations are written this way because Studio™ allows feedback to work using a flow and stock written in this manner but assumes the equations are being requested to be solved simultaneously otherwise.

The fifth condition in equation 3.45 needs further explanation. It consists of attempting to project the model behavior so that the feed-in-tariff expenses do not exceed a specified budget $B_{FIT_{target}}$. The rate of change of electricity costs can be projected linearly into the future. The

Studio™ sliding average function is used to keep spurious changes from making the calculation unstable. For the sliding average function the first input is the signal to calculate the sliding average value for, the second is the number of time steps to calculate a sliding average for, and the third input is the initial value to give the sliding average before the number of time steps indicated in the second input have passed.

$$\Delta C_{ESavg_{s,i,t}} = SlidingAverage\left(\Delta C_{E_{s,i,t}}, N_{Savg}, \Delta C_{E_{s,i,t}}\right) \qquad 3.56$$

Once this linear rate is known, the amount of time before electricity prices exceed feed-in-tariff prices can be calculated for the entire price history.

$$t_{EFIT_{s,k,i,t}} = \begin{cases} 10^{10} yr & \Delta C_{ESavg_{s,i,t}} \leq 0 \\ \dfrac{C_{FIT_{s,k,i,t}} - C_{E_{s,i,t}}}{\Delta C_{ESavg_{s,i,t}}} & C_{E_{s,i,t}} < C_{FIT_{s,k,i,t}} \\ 0 yr & otherwise \end{cases} \qquad 3.57$$

This time interval has to be compared with payment expiration interval $t_{FIT_{s,k,i,t}}$ from equations 3.46 and 3.47. The shorter of the two intervals is equal to the amount of time before payments for the FIT are no longer effective.

$$t_{SFIT_{s,k,i,t}} = \begin{cases} t_{FIT_{s,k,i,t}} & t_{FIT_{s,k,i,t}} < t_{EFIT_{s,k,i,t}} \\ t_{EFIT_{s,k,i,t}} & otherwise \end{cases} \qquad 3.58$$

The expected future electricity costs can now be calculated as the area of a triangle bounded by the feed-in-tariff costs, sliding average increase in electricity costs, and the time to price equivalence a seen in equations 3.59, 3.60, and Figure 14.

$$C_{Efut_{s,k,i,t}} = I_{FIT_{s,k,i,t}}\left(C_{E_{s,i,t}} t_{SFIT_{s,k,i,t}} + \frac{1}{2}\Delta C_{ESavg_{s,i,t}} {t_{SFIT_{s,k,i,t}}}^2\right) \qquad 3.59$$

$$C_{FITfut_{s,i,t}} = \sum_k \left(c_{PV} C_{FIT_{s,k,i,t}} I_{FIT_{s,k,i,t}} t_{SFIT_{s,k,i,t}} - C_{Efut_{s,k,i,t}}\right) \qquad 3.60$$

If the sum of the future costs of the FIT in equation 3.60 times the utility taxation rate F_{TaxFIT} plus the money already spent in equation 3.53 exceeds the user supplied threshold $B_{FIT_{proj}}$, then the feed-in-tariff is shut down as seen in the fifth condition of equation 3.45.

$$B_{FIT_{proj_{s,i,t}}} = C_{UtFIT_{s,t}} + F_{TaxFIT_{s,i,t}} C_{FITfut_{s,i,t}} \qquad 3.61$$

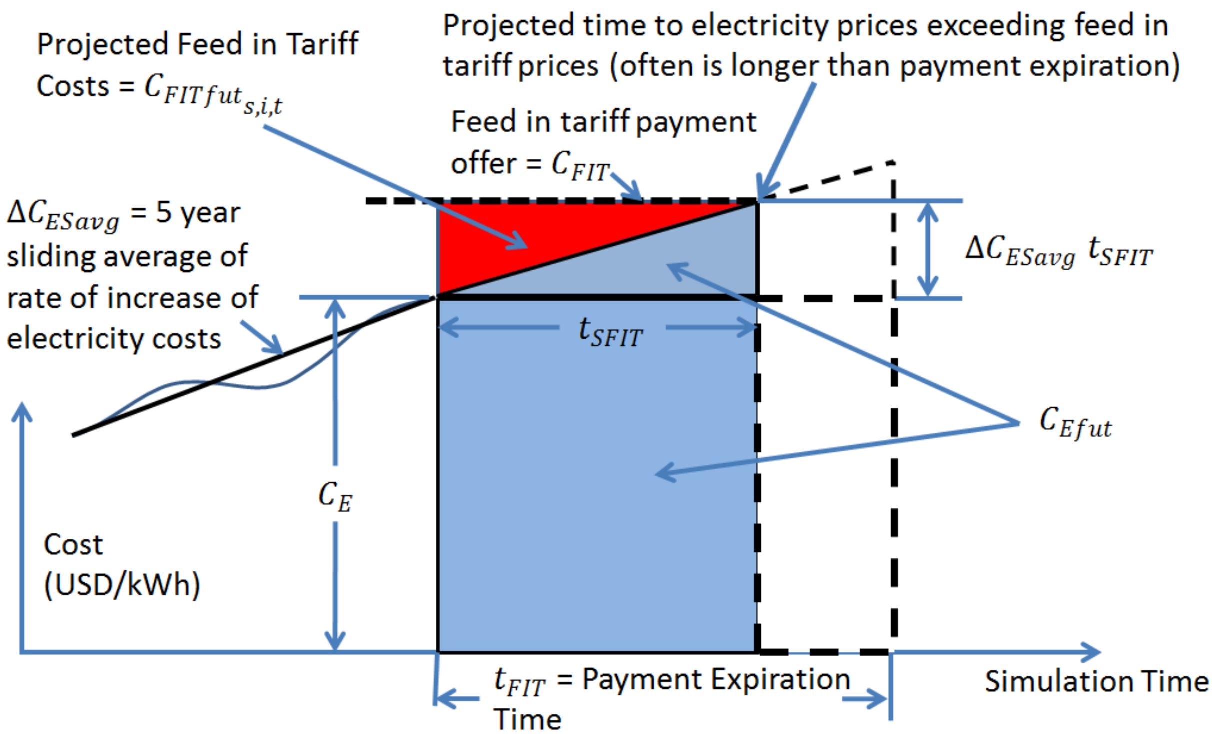

Figure 14. Projected total cost of feed-in-tariff . This will only produce an exactly correct answer if the rate of change of electricity prices is held constant and the average irradiance stays constant for the time period.

Table 10. Feed-in-tariff variable definitions

Variable	Meaning
$\Delta I_{FITin_{s,i,t}}$	Feed-in-tariff installation rate for scenario "s", sector "i", and time "t" (kW/yr)
$\Delta I_{FITout_{s,i,t}}$	Feed-in-tariff retirement rate for scenario "s", sector "I", and time "t" (kW/yr)
$I_{FIT_{s,k,i,t}}$	Feed-in-tariff installation history stock. (kW)
$I_{FITtotal_{s,i,t}}$	Total feed-in-tariff installations per sector and scenario at time "t". (kW)
$F_{FIT_{s,i}}$	Fraction of Bass model installations (equation 2.1) which apply to the feed-in-tariff. It is expected that some installers will not know about the FIT or that there may be restrictions which keep 100% effectiveness from happening.
$C_{E_{t,i}}$	Cost of electricity ($/kWh)
$t_{FIT_{s,k,i,t}}$	Present time "t" to future expiration of feed-in-tariff payments for installations which occurred at time k. Sector "i" and scenario "s" have independent values.
$t_{FIT_{end_s}}$	End time after which no feed-in-tariff benefits will be offered.
$t_{FIT_{term}}$	Length of time which feed-in-tariff benefits last after installation has occurred (typically 20 years)
t_{start}	Simulation start year (2011).
t_k	Current time step year. K added to indicate that the entire range of years is stored since past installations need to be tracked
$C_{FIT_{s,i,t}}$	User input promised payback for PV in $/kWh. This offer can be made to be a function of time if desired.
U_{FIT_s}	Use feed-in-tariff switch. Turns feed-in-tariff on and off based on user input for

	scenario s.
$B_{FIT\,proj_s}$	Projected spending on feed-in-tariff based on current amount spent and projection of payments and installations.
$B_{FIT\,target_s}$	This is the target budget input by the user. If the projected budget exceeds this, the installations for feed-in-tariffs are set to zero.
$C_{EU\,i,t-1}$	User input cost of electricity. This is the cost of electricity if there is not feed-in-tariff.
$F_{TaxFIT\,s,i,t}$	Fraction of feed-in-tariff payments which is taxed by the utility to enforce and maintain the feed-in-tariff capability
$C_{PFIT\,s,i,t}$	Feed-in-tariff payment costs to the general population which are used to pay feed-in-tariff beneficiaries. ($)
$C_{E\,FIT\,s,i,t}$	Cost of electricity increase due to the feed-in-tariff ($/kWh)
$C_{UtFIT\,s,t}$	Costs Utility adds to feed-in-tariff to pay for the services provided
N_{Savg}	Number of years to include in the sliding average calculation
$t_{EFIT\,s,k,i,t}$	Time interval until electricity costs are equal to feed-in-tariff price offer.
$\Delta C_{ESavg\,s,i,t}$	Sliding average electricity costs
$t_{SFIT\,s,k,i,t}$	Lesser of the time to expiration of payments for the FIT or the time to electricity prices exceeding the feed-in-tariff cost. This is for every purchase year (range k)
$C_{Efut\,s,k,i,t}$	Projected future electricity costs with no feed-in-tariff in place ($)

3.6. Property Assessed Clean Energy

Property assessed clean energy (PACE) financing is a funding method which helps property owners to start large projects that increase the efficiency of their buildings or to acquire clean energy technologies such as PV. The model currently is generic but the inputs to this model need to reflect the advantages PACE could bring. The interest rate of PACE will be exceptionally low because the loan is very low risk. It is low risk because the loan is tied to the property taxes of the building. Regardless of owner changes or default of a mortgage, the loan provider has the right to payment through the property taxes. The funding can also be provided with very small upfront costs. There are many limiting factors which may exist with respect to establishing PACE funding which will change from location to location in the US. Care must therefore be taken before the level, interest rate, down payment (i.e. total fees), and loan term for PACE funding is set. See the algorithm description for the low interest loan policy option equations used.

3.7. Low Interest Loans, Financing Calculations

Four financing options exist in the current model: standard loan, low interest loan, property assessed clean energy financing, and third party financing. Community solar is not considered to be a financing option since it usually involves putting down smaller sums of money to purchase a portion of a large project. Presently, the standard loan is given a budget which makes it inexhaustible. If this is removed the financing availability could deplete and the market would stop growing. All of the other financing packages have limited yearly budgets which are part of the external input to the model. Setting the budgets to zero turns off the corresponding option for a given time step. Funds may or may not be consumed depending on competition between modes of financing. If funds are not depleted, they are available in the next time step. For example, if PACE and low interest loans are being offered but PACE has zero down payment and a better interest rate, then the PACE funds will be consumed first followed by the low interest loan option. Any lack of funding beyond this will be covered by standard loans with the lowest PVF. The PVF changes with the proportions of financing used which in turn changes the amount of funding consumed. An iterative process is therefore needed to determine the balance between market growth caused by PVF level and funding proportions from different kinds of financing.

The PACE, low interest, and standard loans all have the exact same formulation with constant interest rate, down payment percentile, and loan term inputs. These terms could easily be extended to be time series inputs also as needed. Even though there is no difference in the formulations, serious consideration needs to be put into what level of financing is achievable for each category. For example PACE type financing enables low interest rates and often close to zero percent down-payment by tying the loan to the property tax bill. The ability to attain a low interest rate is probable for this type of financing. The burden is therefore on the modeler to research and enter realistic financial offers and magnitudes of funding available. Each option uses a down payment percentage required, constant interest rate of the loan. The interest rate is used to calculate the uniform capital recovery factor.

$$UCRF_{s,i,j} = \frac{R_{s,i,j}\left(1 + R_{s,i,j}\right)^{n_{s,i,j}}}{\left(1 + R_{s,i,j}\right)^{n_{s,i,j}} - 1} \qquad 3.62$$

The loan payment, down payment, and total cost of financing can then be calculated to be equal to the following expressions which use the total project cost $C_{PVP_{s,m,i,t}}$ from section 4.3.

$$C_{P_{s,m,j,i,t}} = UCRF_{s,i,j} C_{PVP_{s,m,i,t}}\left(1 - d_{s,i,j}\right) \qquad 3.63$$

$$C_{DP_{s,m,j,i,t}} = C_{PVP_{s,m,i,t}} d_{s,i,j} \qquad 3.64$$

$$C_{F_{s,m,j,i,t}} = C_{P_{s,m,j,i,t}} Lt_{s,i,j} + C_{DP_{s,m,j,i,t}} \qquad 3.65$$

The current algorithm needs to be updated to make the financing budget an interest buy down rather than the complete financing of loans. For example the policy maker could take the standard loan interest rate and buy it down 2% points by paying all of the interest.

Table 11. Financing variables

Variable	Meaning
$R_{s,i,j}$	Financing constant interest rate (%/yr)
$Lt_{s,i,j}$	Loan term (number of years)
$d_{s,i,j}$	Down payment required for financing type j sector I and scenario s (%)

$UCRF_{s,i,j}$	Uniform capital recovery factor for sector i.
$C_{PVP_{s,m,i,t}}$	Cost of a PV project based on scenario, cash incentives, sector, and time from section 4.3
$C_{P_{s,m,j,i,t}}$	Cost of Payments which links back to the fractional PVF equation 2.3
$C_{DP_{s,m,j,i,t}}$	Cost of Down Payment which links back to the fractional PVF equation 2.3
$C_{F_{s,m,j,i,t}}$	Total cost of financing which links to section 2.6

3.8. Property and Sales Tax Incentives

Local governments can increase the marketability of PV by reducing sales and property taxes incurred due to a PV installation. A reduction of sales tax is equivalent to providing a cash incentive of whatever percent would usually be charged to PV purchases. A property tax exemption can have a double effect. It reduces the costs for the current year of the purchase and also permanently reduces the amount of taxes which the owner has to pay for installing the PV system. A PV system will increase the appraised value of a home and will therefore increase the taxes which the owner has to pay. Action to reduce property taxes decreases PV costs and decreases the time to net profit and time to lower payments. The user must input the predicted taxation rates. It is assumed in the model that the PV system increases the property value by it's a user input fraction of its full value.

The lack of taxation introduces a void in city funding and therefore has a cost equal to the taxes not collected. The effective rate of taxation for property is determined by the fraction reduction offered as an incentive, fraction of the total PV system value which is added to the property value, and property tax rate.

$$F_{proptax_{s,i,t}} = \left(1 - f_{ptx_{s,i,t}}\right) F_{PVtx_i} R_{ptx_{s,i,t}} \qquad 3.66$$

The effects of sales tax reduction is similar except that the user does not have to guess at how much value the PV system is adding to the property.

$$F_{saletax_{s,i,t}} = \left(1 - f_{stx_{s,i,t}}\right) R_{stx_{s,i,t}} \qquad 3.67$$

These two factors can be added together to form a total price increase factor due to taxes. This factor is applied to the PV cost assessment of section 4.3 and to the human decision models of section 2.6.

$$F_{tax_{s,i,t}} = F_{proptax_{s,i,t}} + F_{saletax_{s,i,t}} \qquad 3.68$$

Table 122. Property and sales tax variables

Variable	Meaning
$R_{ptx_{i,t}}$	User input property tax projection. Usually is a constant but the option for a general time projection in a spreadsheet is allowed (%/yr).
F_{PVtx_i}	Fraction of PV system cost which is added to the overall property value (amount

	of PV system which will be taxed). Input for each sector but constant over time for the current model. Must be between 0 and 1.
${f_{ptx}}_{i,t}$	Fraction discounted from property taxes offered as an incentive for PV. This value is usually constant but has the option to be a general projection into the future via a spreadsheet. Must be between 0 and 1. A logical switch is used to turn this effect on or off for different scenarios
${F_{proptax}}_{i,t}$	Fraction to be applied to PV costs due to property taxes.
${R_{stx}}_{i,t}$	Sales tax version of ${R_{ptx}}_{i,t}$
${f_{stx}}_{i,t}$	Sales tax version of ${f_{ptx}}_{i,t}$
${F_{saletax}}_{s,i,t}$	Sales tax fraction
${F_{tax}}_{s,i,t}$	Total tax fraction used in section 4.3

3.9. Streamline Solar Permitting Process

There are indications that the solar permitting process could save the PV industry one billion dollars in time spent by installers delayed by inefficient local permitting policies which translates to up to $2,500 average savings per PV installation [4, 5]. Eliminating unneeded permit processing barriers will also reduce the amount of time it takes to install solar from months to days [4]. Even though the potential time and money savings are large, removing legislation which slows down the permitting process is a formidable barrier tied to land use regulations [4]. Germany has considerably decreased the costs of their permitting processes by eliminating the need for a permit for residential installations.

Similar to the group purchase plan, and community solar policies, a model to quantify the changes to permitting processes is difficult. The effectiveness of such programs is therefore left to a calibrating constant which requires further data before the model's accuracy with respect to conversion of money input to drops in PV prices is credible. Unlike the group purchase program, the process does not decline if funding is cut since the working permitting system is assumed to not require maintenance once it is in place.

$$C_{PV_{permit_{s,t}}} = \begin{cases} \left(C_{Pinitial_s} - C_{Pmin_s}\right) e^{-A_{perm_s} \sum_{n=1}^{t} B_{perm_{s,n}}} + C_{Pmin_s} & U_{sspp_s} = TRUE \\ C_{Pinitial_s} & otherwise \end{cases} \quad 3.69$$

Table 133. Streamline solar permitting process variables

Variable	Meaning
$C_{PV_{permit_t}}$	Current cost of permitting ($/W installed)
$C_{Pinitial}$	Initial cost of permitting in the simulation ($/W)
C_{Pmin}	Minimum achievable cost of permitting ($/W installed)
A_{perm}	Calibrating exponential constant for permitting process (requires data based verification)
B_{perm}	Budget being applied to improving the permit process.

U_{sspp_s}	Scenario switch to turn solar permitting effects on and off

3.10. Federal Rebate

The federal rebate is not controllable from the city level but it has provisions for making changes in order to keep the model general. The user is able to change the rebate amount, which sectors the rebate applies to, and the expiration date of the rebate. All of these should be left at the default values of 30%, applicable to residential and commercial, and expiring in 2016.

$$F_{FR_{s,i,t}} = \begin{cases} F_{fr_i} & if\ U_{fr_s} = True\ and\ t_{fr_i} \geq t \\ 0 & Otherwise \end{cases} \qquad 3.70$$

Table 144. Federal rebate variables

Variable	Meaning
t_{fr_i}	Federal rebate expiration date for sector I (2016 is the default)
U_{fr_i}	Switch to turn rebate on and off
F_{fr_i}	User input rebate amount (30% for residential and commercial, 0% for utility)
$F_{FR_{s,i,t}}$	Final resultant federal rebate factor as a function of time, sectors, and scenario

4. MODEL USER INPUT, CALIBRATION, AND DATA

The term calibration is used in a way that is different for models which predict into the future in comparison to modeling for which the output is observable. In engineering and science calibration usually refers to the process of determining model parameters based on measuring a known set of standards. This process is often repeated beyond the minimum requirement over a range of conditions in order to provide a robust understanding of the errors involved and to verify that the observations are not drifting over time due to unknown systematic errors. Other methods for dynamic processes such as the Kahlman filter are also used to account for time varying signals but these usually involve processes which have large amounts of data coming in and predictions are continuously corrected as data accumulates. PV data are not available in a continuous stream and repetition of the history and the errors in the history are not known. Modeling schemes to replicate the known data easily fit the data if enough parameters are provided. The good fit can be deceptive though. It does not guarantee that all of the factors which influence the growth of PV are included in the model so that a projection into the future will have predictive value. The term calibration in this discussion means that the model has been configured to be consistent with what is known about past PV growth. This makes the future prediction feasible in comparison to predictions which disregard past known data. The accuracy of the prediction depends on the level that the underlying theory captures reality.

4.1. Bass Model Coefficient Determination

As emphasized in section 2.5, the Sun City model depends on user input of local and national learning curves. The Sun City model predicts the local PV growth and a national PV growth trend is entered while viewing the past trend. The growth model for the U.S. curve has a corresponding PVF time history input by the user. This history is currently assumed to be linear growth from an start year t_{US_0} with PVF value PVF_{US_0}. In the current discussion τ refers to the discrete set of years {1999, 2000,…,2028}. Refer to Table 15 for variable explanations

$$PVF_{US_\tau} = \begin{cases} NaN & 1999 < \tau < t_{US_0} \\ \dfrac{1 - PVF_{US_0}}{t_{US_1} - t_{US_0}}\tau + \dfrac{PVF_{US_0} t_{US_1} - t_{US_0}}{t_{US_1} - t_{US_0}} & if\ t_{US_0} < \tau < t_{US_1} \\ 1 & otherwise \end{cases} \qquad 4.1$$

This PVF history is intended to be an input which is not regularly changed by users. This will cause the behavior of the national drop in PV to be consistent. A study is needed to justify the values of the three parameters. The current guess for the parameters (based on the author's impressions from the literature) is shown in Figure 15.

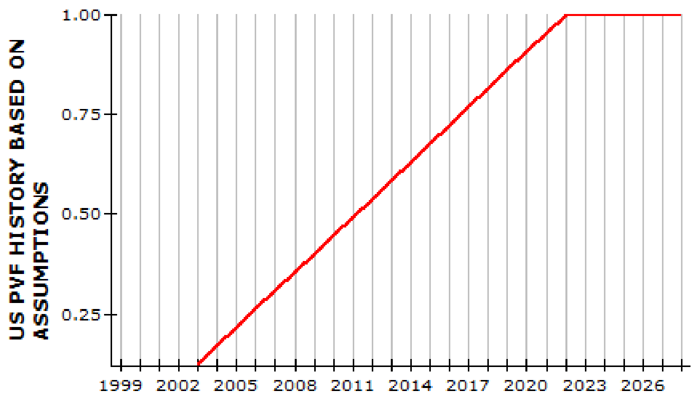

Figure 15. Example U.S. PVF history with begin year = 2003, PVF_{US0} = 0.15 and retail grid parity year = 2022.

Once this history is known the Bass parameters can be bounded based on what is known about PV growth in the United States. The analytical form of the Bass equation can be used to visually fit the U.S. historical data from 1999 to 2010 by adjusting p_{US} and q_{US} which are the upper limits of the imitator and innovator coefficients. This expression is the Bass exponential with an offset of t_{US0} and PVF_{US_t} scaling the coefficients. The expression below has to be scaled so that the total area under $\Delta I_{US_{un_t}}$ is equal to 1 which will be accomplished later.

$$\Delta I_{NPV_{un_\tau}} = PVF_{US_\tau}\frac{(p_{US}+q_{US})^2}{q_{US}}\frac{exp\left(-(p_{US}+q_{US})PVF_{US_{\tau-t_{US_0}}}\right)}{\left(1+\frac{q_{US}}{p_{US}}exp\left(-(p_{US}+q_{US})PVF_{US_{\tau-t_{US_0}}}\right)\right)^2}, \quad \tau > t_{US_0} \qquad 4.2$$

The magnitude of solar power which will be reached is controlled as a function of the total U.S. power consumption expected in the future. The user inputs what fraction of total power use in the United States is expected to come from PV. The user can also cause this power use to increase or decrease as an exponential model as seen below.

$$P_{US_t} = P_{US_{start}}(1+R_{USPV})^{t-t_{start}} \qquad 4.3$$

These inputs can be used to calculate a total U.S. PV installation potential as seen below.

$$m_{US_t} = \frac{R_{US}P_{US_t}}{c_{US}} \qquad 4.4$$

Finally the expression is complete as seen below. Refer to Table 15 to understand all of the explanations for variables. This discussion determines variables which are used in section 2.5.

$$\Delta I_{NPV_t} = \frac{m_{US_t} \Delta I_{US_{un_t}}}{\sum_{t=t_{US_0}}^{t_{end}} I_{US_{un_t}}} \quad 4.5$$

The coefficients calculated are inserted into equations 2.5 and 2.6 of section 2.3.2

$$q_{max} = q_{US} \quad 4.6$$

$$p_{max} = p_{US} \quad 4.7$$

Table 155. U.S. market growth variables

Variable	Meaning
τ	{1999, 2000,…,2028}
PVF_{US_t}	United States PVF time history into the past and projected out to the end of the simulation
t_{US_0}	Begin year for which the PVF history
t_{US_1}	Year at which the United States reaches PVF = 1 on average (i.e. approximately equal to the grid parity year)
p_{US}	US **innovator** coefficient which the user adjusts to make the U.S. installation history match the projected future U.S. history per the Bass model and assumed PVF_{US} history.
q_{US}	US **imitator** coefficient which the user adjusts to make the U.S. installation history match the projected future U.S. history per the Bass model and assumed PVF_{US} history.
$P_{US_{start}}$	Total power consumption in the U.S. at the start time
$\Delta I_{NPV_{un_t}}$	Unadjusted bass model adoption rate. It has to still be scaled by the potential coefficient $m_{us}(t)$ and divided by its total sum of area over all years.
R_{USPV}	% Rate of growth or decline of U.S. power consumption from start time to end time.
t_{start}	Start time of the simulation (2011)
P_{US_t}	Projected power consumption in the U.S. from 2011 to 2028
R_{US}	Percentage of power consumption that is assumed to potentially become PV
c_{US}	Average capacity factor for the U.S. from 2011 to 2028 (reasonably estimated to be equal to 0.175)
m_{US_t}	Potential coefficient for the bass model of the U.S. PV growth projection
ΔI_{NPV_t}	Projected U.S. PV installation rate based on user fit to past U.S. power consumption data (approximate using the average capacity factor c_{US}) and known adoption rate. This term is used in section 2.5.

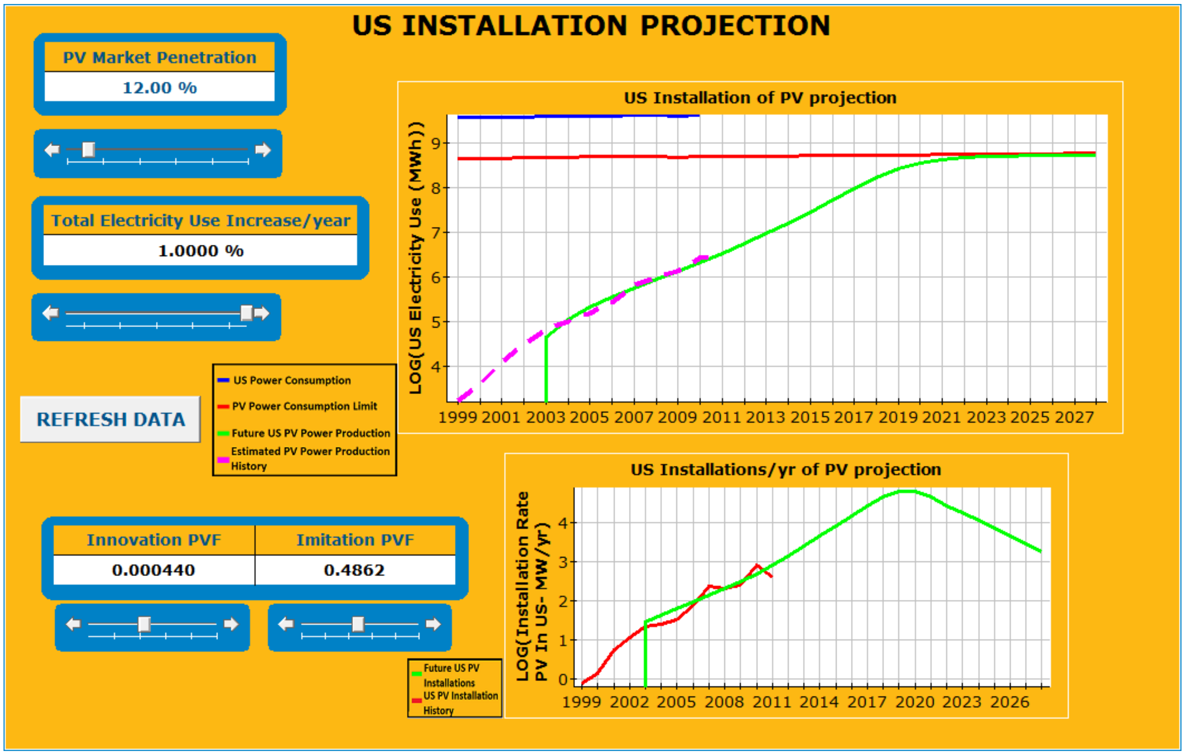

Figure 16. U.S. PV installations and power consumption User interface . The user can adjust coefficients to a first order fit to past data. The trends are made clearer by using a log scale.

4.2. Capacity Factor for PV Systems

A capacity factor for any electricity producing system is a fraction which when multiplied by the name plate capacity of a power producing device produces the average power output. The fraction is usually well below a value of one. Capacity factors can be calculated over different spans of time. Typically the capacity factor falls below 0.25 for PV. Calculating capacity factors is a problem which can be very complex because capacity factors are affected by location, design, local shading conditions, PV module efficiencies, degradation over time, weather conditions, and a host of other loss factors. There are a large number of tools designed to solve this problem as summarized by Klise and Stein [32] and Yates and Hibbard [33]. The Sun City model uses NREL's PVWatts™ tool which is available online [34]. The details of the calculations [34, 35] are not addressed in this report but the assumptions used by Sun City which constrain the PVWatts™ tool are listed below.

1. AC-DC derate factor default is 0.77 which is the PVWatts™ default. The user can alter this in the excel spreadsheet that is linked to the Sun City model.
2. Weather year for 1990 used. This is an input which didn't appear to introduce variations if the year was changed.
3. Fixed system with no tracking of the sun
4. Tilt equal to latitude
5. Azimuth angle of 180 degrees
6. Annual degradation of system is 0.5%/yr and analysis is for 30 years (independent of Sun City system lifetime input).
7. All other defaults for PVWatts™ accepted.

It is important to note that the PVWatts™ tool includes system degradation which is not addressed directly by the Sun City model. The capacity factor can therefore be expressed as a black box function which varies based on the user input AC-DC derate factor and latitude and longitude of the city being analyzed.

$$c_{PV} = PVWatts(lat, lon, F_{ACDC}) \qquad 4.8$$

It must be remembered that the Sun City model capacity factor needs to represent the average capacity factor across all systems installed in a city. This may make it necessary to enter a non-standard value for the F_{ACDC} parameter in order to represent a range of technologies and designs for PV installations.

4.3. PV Cost Analysis: Levelized Cost

The Sun City PV cost analysis neglects tax and carbon emission avoidance benefits. It serves its purpose to provide functional variation to the cost of PV and local financial conditions. Initial price input by the user, system size, learning effects (section 2.5), and several policies affect the final price of the average PV system being evaluated.

The national learning curve cost before incentives, C_{PVpre}, is defined in equation 2.20. This cost does not include purchase size effects. The Sun City model assumes a single purchase size for each sector in the present version. It may be desirable to include a purchase distribution per size category in the future since the purchase size to cost function is nonlinear (applying a size distribution gives a different answer for average cost than average size will). The purchase size function is input by the user for which data is readily available through NREL's open PV project "PV Data Mapper" tool [25].

$$P_{PVsize_{s,i,t}} = F_{size_i} C_{PVpre_{s,t}} I_{avg_i} \qquad 4.9$$

$$F_{size_i} = Interpolation\left(SizeFactorData, I_{avg_i}\right) \qquad 4.10$$

The term "Interpolation" indicates that *SizeFactorData* is a table of kW installed vs. cost reduction factor which probably doesn't have I_{avg} as an entry. A linear interpolation between the two bounding points is required. After the size effects have been calculated, policy factors which directly affect the cost of the PV system are applied. The cash incentives fraction F_{ci} from section 3.1 can be expanded to its general form of an array over scenarios, cash incentives, sectors, and time as follows in equation 4.11.

$$F_{CI_{s,m,i,t}} = \begin{cases} F_{ci_i} & if\ U_{CI_s} = true\ and\ m = WithCashIncentives \\ 0 & otherwise \end{cases} \qquad 4.11$$

Combining the group purchase factor from equation 3.35, cash incentives fraction from equation 4.11, federal rebate factor from equation 3.70, and total tax factor from equation 3.68 creates the final price of the PV system of size I_{avg_i}.

$$P_{PV_{s,m,i,t}} = P_{PVsize_{i,t}} F_{GPP_{s,i,t}} \left(1 - \left(F_{FR_{s,i,t}} + F_{CI_{s,m,i,t}}\right)\right)\left(1 + F_{tax_{s,i,t}}\right) \qquad 4.12$$

$$C_{PVP_{s,m,i,t}} = \frac{P_{PV_{s,m,i,t}}}{I_{avg_i}} \qquad 4.13$$

Simultaneous application of factors may not apply for certain policy types and this equation may have to be generalized in future versions to permit a range of rules for how incentives are applied. For example, the New Mexico cash incentive rate of ten percent applies to the post federal rebate cost and an entire range of potential expenses do not apply which would change the way this cost is calculated [29]. In addition, this formulation neglects the time delays associated with many incentives. This is justifiable under the assumption that these complicating effects are well accounted for by their effects on actual PV growth data. This underscores the need for accumulation of PV adoption data as time progresses in order to increase the robustness of calibration. It also emphasizes how many factors are affecting the PV growth performance which can cause calibrating efforts to be restricted to a specific region.

The cost of PV in revenue per Watts installed has to be converted into a levelized cost which can be compared to electricity prices. The first step is to determine the cost spread over the lifetime of the PV system. This will include the costs of maintenance. Maintenance costs of utility scale PV have been assessed in detail by Moore et al. [30]. The worst case year 2003 in [30] was used. The current Sun City maintenance costs for utilities is 31.86 $/KW/yr. The commercial and residential rates of 45.82 and 59.78 $/KW/yr are estimated from information in [31] and have been assumed to be higher than the utility scale costs. This analysis needs further investigation based on feed-back from sources which are more familiar with this subject area.

The spread cost per year of PV over the lifetime of the system can be expressed in revenue per year as seen in equation 4.14.

$$C_{PVT_{s,m,i,t}} = \frac{C_{PVP_{s,m,i,t}}}{L_i} + \left(M_{C_i} + F_{proptax_{s,i,t}} C_{PVP_{s,m,i,t}}\right) + C_{EPA_{s,i,t}} \qquad 4.14$$

$$C_{EPA_{s,i,t}} = \begin{cases} C_{EPAraw_{s,i,t}} & if\ C_{EPAraw_{s,i,t}} > \$0/yr \\ \$0/yr & otherwise \end{cases} \qquad 4.15$$

$$C_{EPAraw_{s,i,t}} = \begin{cases} C_{E_{s,i,t}} p_{avg_i} - C_{FIT_{s,i,t}} c_{PV} I_{avg_i} & if\ U_{FIT_s} = true\ \&\ C_{E_{s,i,t}} \le C_{FIT_{s,i,t}} \\ C_{E_{s,i,t}} \left(p_{avg_i} - c_{PV} I_{avg_i}\right) & otherwise \end{cases} \qquad 4.16$$

M_{C_i} is the maintenance cost per year, L_i is the PV system lifetime, and $F_{proptax_{s,i,t}}$is the fraction of total costs at purchase which gets added to the property tax bill for the property which is defined in section 3.8. $C_{EPA_{s,i,t}}$ is the electricity production analysis cost which balances the system power output, average consumption of electricity, electricity costs, and feed-in-tariff benefits. Once this cost is calculated, the remaining ingredient lies in calculating the average capacity factor for the location of the PV system which is determined as indicated in section 0.

$$C_{PV_{s,m,i,t}} = \frac{C_{PVT_{s,m,i,t}}}{p_{avg_i}} \qquad 4.17$$

This final variable is inserted into the PVF equation 2.3 to form the cost ratio between electricity and PV power production. The electricity costs are a user supplied time series which can be elevated further by the presence of a feed-in-tariff.

Table 166. Levelized cost analysis variables

Variable	Meaning
$C_{PVpre_{i,t}}$	PV cost ($/W) for 1KW before incentives and size effects for sector “i” and time “t”
F_{size_i}	Cost reduction factor based on size for sector (i) based on I_{avg_i}
I_{avg_i}	Average purchase size (user input) for sector (i) for the entire city market. This is the only purchase size the Sun City model allows.
SF	Size Function. Numerical data array of a fraction starting at 1 (for 0-1KW) and decaying to a value between one and zero which represents a discount in price from the original C_{PVpre} cost. A second numerical array of KW’s installed provides

	a way to linearly interpolate any installation value.
${P_{PVsize}}_{i,t}$	Price ($) of PV system for sector i at time t.
F_{ci}	Cash incentives fraction defined in section 3.1
${F_{CI}}_{s,m,i,t}$	Cash incentives fraction after USE filter.
${U_{CI}}_{s}$	Cash incentives switch turned on and off by user
${F_{tax}}_{s,i,t}$	Tax fraction calculated in section 3.9
${F_{FR}}_{s,i,t}$	Federal rebate fraction (30%).
${F_{GPP}}_{s,i,t}$	Group purchase fraction
${P_{PV}}_{s,m,i,t}$	Incentivized job cost of a PV system ($)
${C_{PVP}}_{s,m,i,t}$	Incentivized cost per watt of a PV system (materials and design only)
${C_{PVT}}_{s,m,i,t}$	Spread cost per year of PV with maintenance, future property taxes, and current energy production to price cost analysis applied to the life of the system
${M_{C}}_{i}$	Maintenance costs
${F_{proptax}}_{s,i,t}$	Property tax fraction defined in section 3.9
L_i	User input system life (yr)
${C_{EPA}}_{s,i,t}$	Electricity production analysis costs ($/yr)
${C_{EPAraw}}_{s,i,t}$	Electricity production analysis costs in their “raw” form which can be negative if the PV is very profitable (negative costs are profits). The PVF will be 1.0 in cases like these.
${C_{FIT}}_{s,i,t}$	User input feed-in-tariff price of PV power production offered ($/kWh) see section 3.5
c_{PV}	Average capacity factor for the PV system
${C_{E}}_{s,i,t}$	User input cost of conventional electricity
${p_{avg}}_{i}$	Average power consumption per consumer for sector “i”
${U_{FIT}}_{s}$	Use controlled FIT logical switch for scenario “s”
${C_{PV}}_{s,m,i,t}$	Levelized cost of PV used in the PVF equation 2.3.

4.4. Consumers, Population, and Power Consumption

The Sun City model depends on projected futures for population growth, electricity consumption per capita, and people per consumer ratios for each sector. One consumer represents a household for the residential sector, a business for the commercial sector, and a utility for the utility sector. For utilities it must be remembered that “consumers” in the Sun City model refers to an entity which will purchase solar power and is not referring to the production versus use of electricity. The consumer ratios for each sector are estimated using data from the U.S. Energy Information Administration (EIA) and the U.S. Census Bureau (see Table of appendix C for references). They are assumed to be constant throughout the simulation. Historical data is available but this would require projection of two additional variables into the future.

In this section the use of the “y” index differentiates values which are suggested based on the target city selected by the user. Its absence represents user inputs for the same variable name. For example, $PC_{0,q}$is a suggested value whereas $PC_0$is the actual user input. This distinction has to be made because of a limitation within Studio™. Constant values cannot be changed and retained as changed unless they do not have predecessors. It is therefore not possible to populate the input with suggested values and then allow the user to alter them as needed. A compromise is to suggest values but have a separate input variable so that general input is still permitted.

$$r_{pc_{i,y}} = \frac{pop_{2009,y}}{cons_{2009,i,y}} \qquad 4.18$$

The user input r_{pc_i} is used in section 4.5 equation 4.30 to determine the down payment and payment tolerances of the PVF equation.

The population input suggested values $PC_{0,y}, R_{PC_y}$ are based on U.S. Census Bureau data for the Solar America Cities and an exponential projection to 2011. The user inputs whatever values deemed appropriate which are compared against historical data in a single plot as seen in Figure 17.

$$PC_t = PC_0(1 + R_{PC})^t \qquad 4.19$$

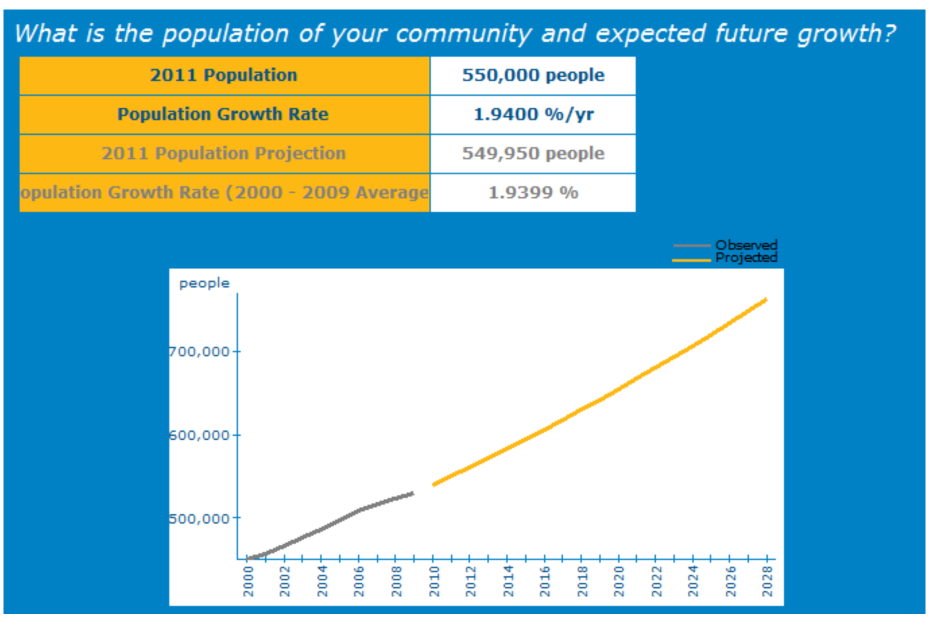

Figure 17. Population growth user input dialogue.

The projected consumers per sector can then be expressed as the quotient of the population and the population to consumer ratios. This history is used in the community solar financing section 3.4

$$Con_{i,t} = \frac{PC_t}{r_{pc_i}} \qquad 4.20$$

Once the population projection is known, the power use projection can be entered.

$$p_{PC_t} = f(user\ input, t) \tag{4.21}$$

Fractions of total power use per sector are also needed. The current model offers suggested values based on EIA electricity sales per sector data for the year 2009 (Appendix C, Table). The suggested value for utilities is based off of the industrial sector. The difference between utilities and the industrial sector is an area of the Sun City model which will need to be reworked in a future version.

$$F_{pc_{i,y}} = \frac{Electricity\ Sales_{i,y,2009}}{\sum_i Electricity\ Sales_{i,y,2009}} \tag{4.22}$$

The population, power consumption, and sector fractions can be multiplied to form an estimate of the total power consumption in the city per sector.

$$p_{C_{i,t}} = F_{pc_i} p_{PC_t} PC_t \tag{4.23}$$

The power consumption for the entire city can be normalized to produce the power consumption per consumer.

$$p_{avg_{i,t}} = \frac{p_{C_{i,t}}}{Con_{i,t}} \tag{4.24}$$

Once the total power consumption is known per sector, this information can be used to control how much potential the city has for PV installations. This is done by entering a percentage of the total power consumption which can be filled up with PV. It is extremely important to understand this input. This input determines the potential which drives the Bass diffusion model. This means that inputting 10% and then 20% will double the resulting PV installations which occur if all other inputs are kept constant. The range permitted is zero to one hundred percent with no restrictions for what value is entered so caution must be used to assure a realistic value is entered for the region of interest. The burden is left to the user to identify what a reasonable value is. A check is provided in the form of how much land is being consumed by the proposed peak amount of PV based on estimates of acres consumed per megawatt of PV installed. This area of the model needs further development to correlate city data with the inputs in order to provide better guiding principles to the user.

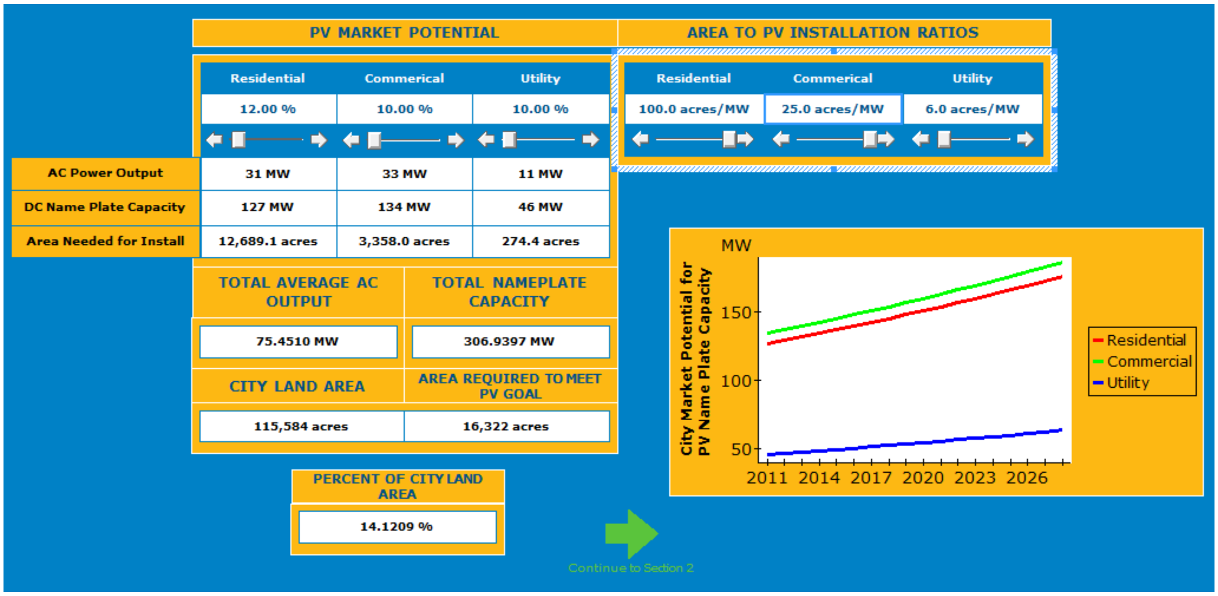

Figure 18. Establishing the market potential for PV in the city being analyzedby the Sun City model. The values shown are for illustration only.

The maximum market potential which is used in equation 2.8 of section 2.3.2 is calculated from the inputs as defined in equation 4.25 below.

$$m_{max_{i,t}} = \frac{F_{PC_i} p_{c_{i,t}}}{c_{PV}} \qquad 4.25$$

Table 17. Consumer ratio variable descriptions

Variable	Meaning
i, y	I indicates sector, y indicates city chosen by user
$r_{pc_{i,y}}$	Suggested ratio of population (people) to consumers = number of people per average household for residential, average business for commercial, utility for utility
$PC_{0,y}, PC_{t,y}$	Suggested parameters for population user inputs and State population for city q and the year 2009
$cons_{2009,i,y}$	State number of consumers for sector I, state of city q for the year 2009 (EIA data see Appendix C, Table)
$pop_{2009,y}$	State population of the state of the city q for the year 2009 (US Census data see Appendix C, Table)
PC_t	Population of the City time series based on user input parameters which usually matches historical trends.
p_{PC_t}	Power consumption projection per capita for Sun City population
$Electricity\ Sales_{i,y,2009}$	EIA data for electricity sales 2009 (see Appendix C, Table)
$F_{pc_{i,y}}$	Suggested fraction of electricity consumption coming from sector "I"
$p_{c_{i,t}}$	Power consumption per sector for user input data projections.
$p_{avg_{i,t}}$	Power per consumer per sector projection (kWh/consumer)
$Con_{i,t}$	Consumers per sector projection
F_{PC_i}	User input fraction of total power production per sector which can become PV power production.

4.5. Deriving Payment Tolerances Using Financial Conditions

The PVF payment tolerance terms within the barrier portion of equation 2.3 must relate to the local financial capacity within the city being analyzed. The current derivation scheme for these parameters consists of the user projecting financial data of disposable income, savings rates as a function of disposable income, and inflation. Historical data has been accumulated to aid the user to make a feasible projection. Reversal of the historical trends can be used to study the effects of the financial situation on PV growth. The model is very sensitive to these variables since a poorer community will not be able to buy PV.

Each projection is modeled as an exponential growth model into the future as seen in Figure 19. The disposable income rate of increase and initial disposable income per person produces the non-inflation adjusted disposable income which is used as a visual aid to match the historical trend for disposable income but is otherwise not used.

$$DI_{noIN_t} = DI_0(1 + R_{DI})^t \qquad 4.26$$

The initial savings rate, growth in savings per year, initial inflation rate, and inflation change rate produce projections for the inflation and saving.

$$S_{DI_t} = S_{DI_0}(1 + R_{SDI})^t \qquad 4.27$$

$$IN_t = IN_0(1 + R_{IN})^t \qquad 4.28$$

Suggested values for the savings come from national average savings rate times the Nest Egg Index (see Table). The inflation adjusted disposable income can then be calculated by subtracting the inflation in equation 4.28 from the rate term in equation 4.26.

$$DI_t = DI_0(1 + R_{DI} - IN_t)^t \qquad 4.29$$

The down payment and payment tolerances of the PVF equation 2.3 are assumed to be equivalent and are defined using the inflation adjusted disposable income of equation 4.29 multiplied by the savings projection of equation 4.27 and population to consumer ratios of equation 4.18.

$$C_{P_{To_{i,t}}} = C_{DP_{To_{i,t}}} = DI_t S_{DI_t} r_{pc_i} \qquad 4.30$$

Even though there are some broad assumptions in this analysis, it provides a straightforward method for determining two of the barrier tolerance terms in the PVF equation. There are other factors which can be used as calibration constants to try and match PV growth to PVF quantities. The user interface provides feedback concerning the future predicted financial situation for the community just below the forms in Figure 19 as seen in Figure 20.

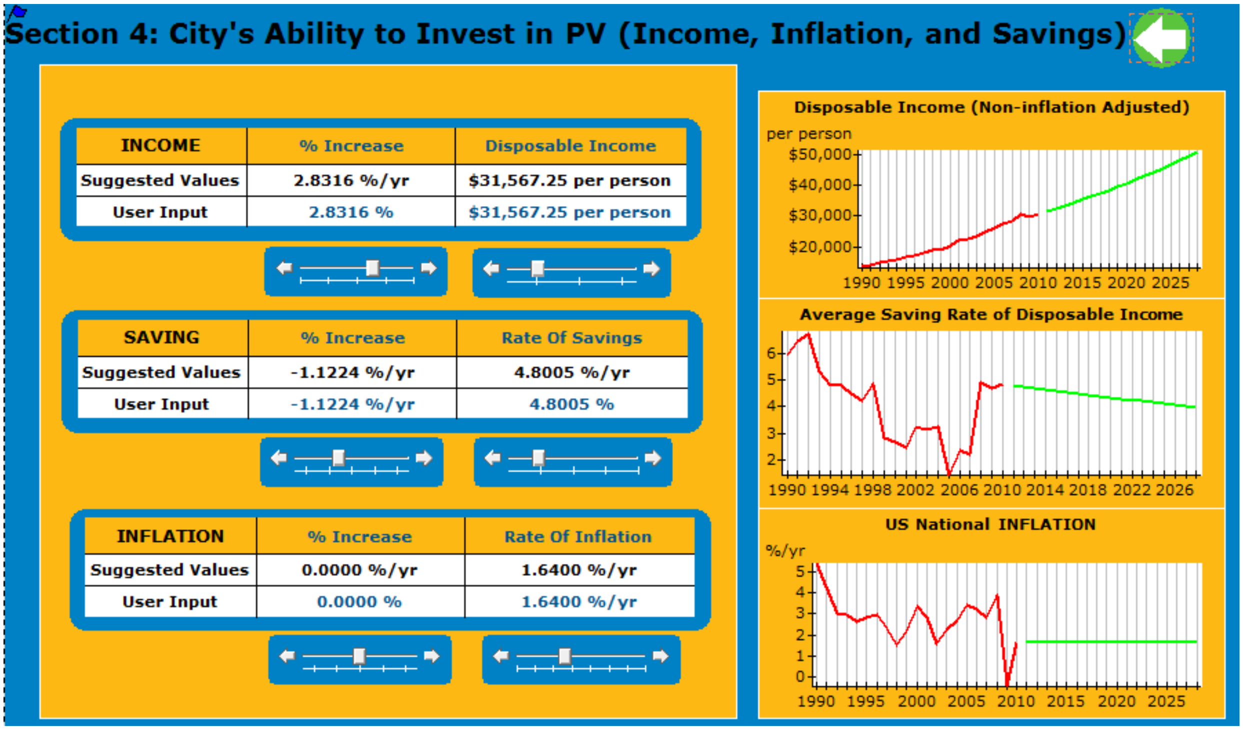

Figure 19. U.S. income variables input screen: average disposable income, average saving rate of disposable income, and inflation rate.

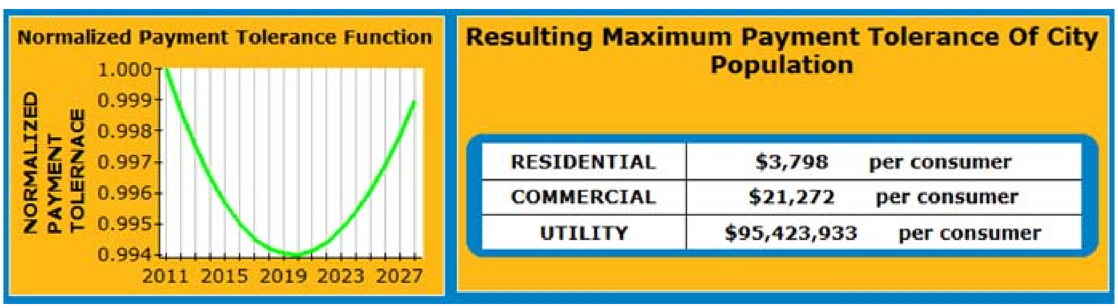

Figure 20. Financial payment tolerance future. The right hand table provides the maximum payment tolerance (future or present) and the graph to the left indicates the relative fraction of this maximum amount over time.

Table 18. Consumer and power variables

Variable	Meaning
DI_{noIN_t}	Projection of disposable income with no inflation adjustment included
R_{DI}	Rate of increase (%/yr) of disposable income with not inflation adjustment included
DI_0	Initial disposable income in 2011
S_{DI_t}	Savings rate (%/yr) of total disposable income
S_{DI_0}	Initial savings rate of disposable income.
R_{SDI}	Rate of change of savings rate (%/yr/yr)
IN_t	Rate of inflation (%/yr)
R_{IN}	Rate of change of inflation (%/yr/yr)
IN_0	Initial inflation rate

DI_t	Inflation adjusted disposable income ($/yr)
r_{pc_i}	People per consumer ratios from section 4.4.
$C_{PTo_{i,t}}$	Payment tolerance coming from the main fraction PVF equation 2.3
$C_{DPTo_{i,t}}$	Down payment tolerance coming from the main fraction PVF equation 2.3

4.6. Greenhouse Gas Emissions

Estimates for greenhouse gas (GHG) emissions offset naturally flows out of the Sun City framework. The total lifecycle GHG footprint of PV systems can be represented empirically as a function of two calibrating constants, system life time, and system capacity factor (section 0).

$$PV_{GHG_i} = \frac{A_{GHGO}}{c_{PV} L_i} + A_{GHGC} \qquad 4.31$$

The empirical constants can be resolved using the data compiled by Lenzen [27]. A reasonable fit is shown in Figure 21. The red line is the empirical fit and the green dot represents the current point based on the user input capacity factor and system lifetime. The blue diamonds mark the data points compiled in [27].

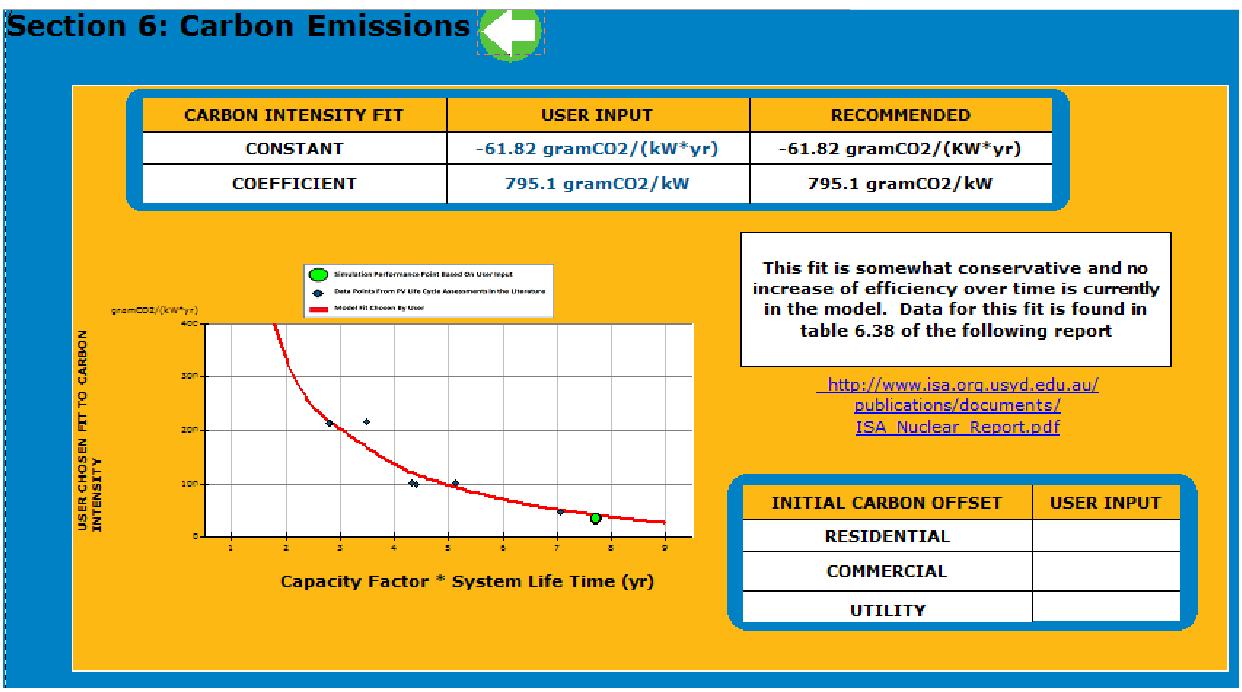

Figure 21. PV system GHG emissions footprint empirical fit.

The offset of carbon by installing PV is estimated by a user input projection of carbon emissions density for power production in the city. This projection is guided by state wide carbon dioxide emissions intensity data from the environmental protection agency described in Appendix C. Figure 22 provides an example of the available data and a user input projection. As GHG emissions intensities drop due to PV and other factors, additional PV installations will offset less and less GHG emissions.

$$E_{GHG_t} = E_{GHG_0}(1 + R_{GHG})^t \qquad 4.32$$

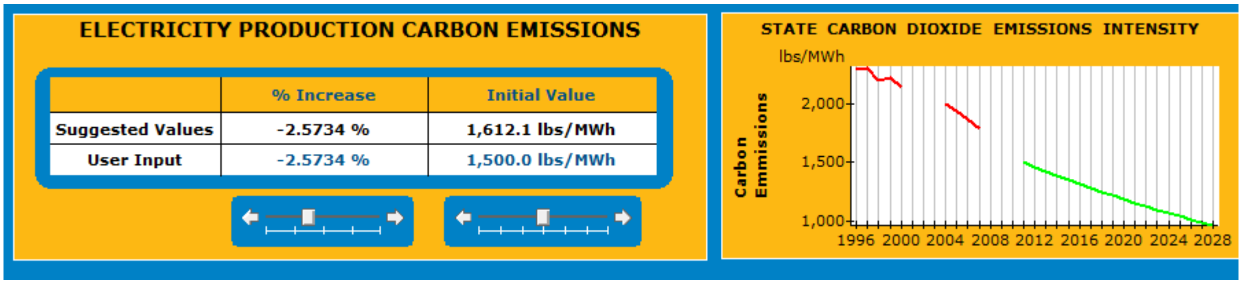

Figure 22. Projection of GHG intensity

.

Once these two inputs are complete, the rest of the required variables are already calculated by the Sun City model. The GHG emissions offset due to installation of PV can be quantified using the rate of GHG saved due to GHG electricity production minus the total GHG produced for each PV installation.

$$O_{GHG_{s,i,t}} = O_{GHG_{s,i,t-1}} + c_{PV} I_{s,i,t-1} E_{GHG_t} - PV_{GHG_i} \Delta I_{s,i,t} L_i \qquad 4.33$$

The total carbon emissions can be calculated as seen in equation 4.34. These metrics can be used in assessing whether GHG goals are being met. They do not have any feedback into the model and are purely a post processing set of calculations.

$$GHG_{s,i,t} = GHG_{s,i,t-1} + \begin{cases} PV_{GHG_i} \Delta I_{s,i,t} L_i & c_{PV} I_{s,i,t-1} > p_{C_{i,t}} \\ \left(p_{C_{i,t}} - c_{PV} I_{s,i,t-1}\right) E_{GHG_t} + PV_{GHG_i} \Delta I_{s,i,t} L_i & otherwise \end{cases} \qquad 4.34$$

Table 19. Greenhouse gas modeling variables

Variable	Meaning
A_{GHGC}	Constant term which is chosen to calibrate the GHG lifecycle emissions of PV installations
A_{GHGO}	Coefficient which is chosen to calibrate the GHG lifecycle emissions of PV installations
c_{PV}	Average capacity factor for PV systems discussed in section 0
L_i	User input system lifetime for PV
PV_{GHG_i}	PV lifecycle GHG emissions intensity
R_{GHG}	Exponential rate of GHG emissions intensity decline/growth projected into the future
E_{GHG_0}	Initial GHG emissions intensity
E_{GHG_t}	Projection of GHG emissions intensity
$I_{s,i,t-1}$	Total installations of PV for the previous time step (section 2.1)
$\Delta I_{s,i,t}$	Rate of PV installations for the current time step (section 2.1)

$O_{GHG_{s,i,t}}$	Offset GHG emissions
$GHG_{s,i,t}$	GHG emissions
$p_{C_{i,t}}$	Power consumption derived in section 4.4

5. PATH FORWARD

5.1. Results Demonstration

The intended capabilities of Sun City version 1.0 have been demonstrated to audiences several times. The model interface has been built so that it is able to output plots across scenarios, sectors, and aggregate results for similar variable types. The model and theory has not undergone V&V and, for this reason, the behavior of the model is for demonstrating concepts. The illustration presented here compares to scenarios which use one million dollars in different ways. Perhaps buying PV at the beginning of the simulation would produce better results. The input for utility scale PV of $6/W would be able to buy 166KW. When an installation this size is made at the beginning of the simulation, the end result is 10.19MW. The second invests in a 15% cash incentive to the residential and commercial sectors. The resulting growth produces 12.17MW PV power in Albuquerque by 2028 as seen in Figure 23. This is 1.97MW greater than the 10.19MW which is installed for the cash incentives case. It can therefore be concluded that, even though the cash incentive case does not produce immediate results, it is more effective than just buying and installing one million dollars of PV. Figure 24 shows the residential sector PVF as a function of time. The cash incentives case keeps PVF higher for most of the history. The one million budget is not expended until 2027. For the second scenario the PVF is raised insignificantly by the installation of 166KW. The learning curve price drop due to this installation is predicted to only be five cents per kilowatt which makes much less difference in the long run.

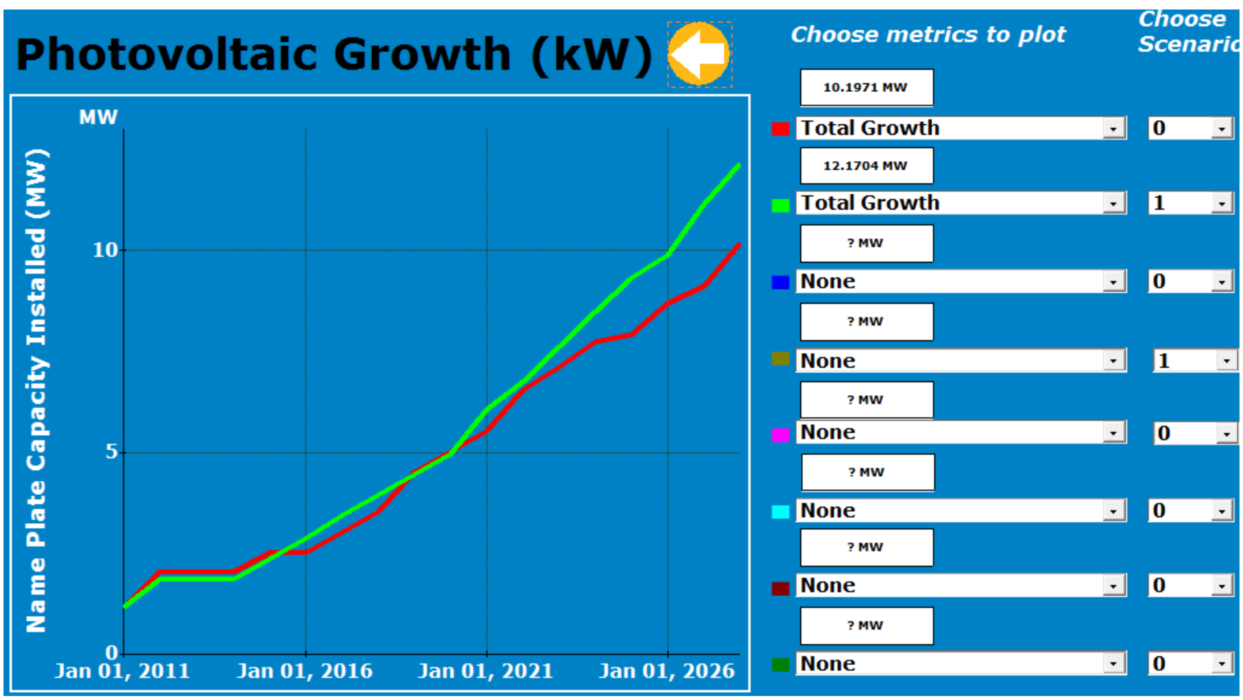

Figure 23. Example PV growth in Albuquerque due to a one-time one million USD invested in a 15% cash incentive off residential PV purchase prices. Red line shows a case where 166KW was installed at the start time. Green line shows the case where 1Million is offered in a 15% cash incentive.

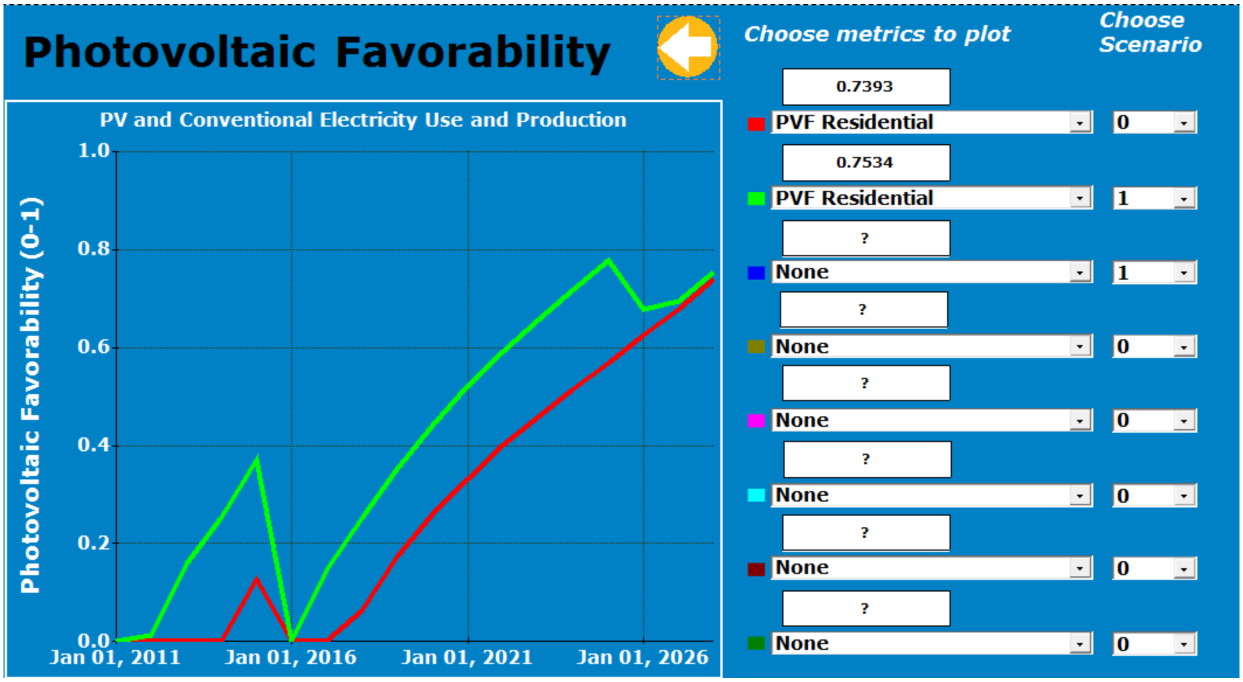

Figure 24. PVF for scenarios 0 and 1.
0 = purchase 1M of PV at start time (red), 1 = 15% cash incentive with one million dollar budget (green).

5.2. Stake Holder and Peer Review Feed Back

In December 2011 and January 2012 three different meetings were held to promote knowledge of the Sun City model and receive critical feedback. Sun City was well received but it is clear that the model needs updates and that the next phase of model development will involve planning verification and validation. The most important feedback which will require changes to the model are listed below.

1. One of the time history inputs of electricity demand and electricity cost need to be modeled endogenously. Having both of these time series inputs as independent variables allows the user to put in values which do not reflect economic processes.
2. Loans should not be bought in full by loan type incentives. Loan type incentives are usually used to buy down interest on “standard” loan conditions to offer better financing to the public.
3. Drop the concept of policy effectiveness
4. A plan needs to be made to separate the utility and industrial sectors. There are some inconsistencies in how these two sectors are overlapped.
5. The iterative procedure in section 2.3.3 does not always converge and needs to be made more robust.
6. The feed-in-tariff algorithm needs an iterative component which causes it to spend only the specified budget. The current algorithm uses a predictor corrector algorithm which often overshoots budget by large amounts.

7. Sensitivity studies need to be conducted on the model to find out whether some of the inputs are unimportant and can be dropped.
8. The national learning curve approach should be replaced with a time series. The current approach is subject to very large uncertainties. The PVF coefficient bounds can still be calculated the same way though.
9. The maintenance cost calculations need to be revisited and any gross errors corrected.

5.3. Future Work

The Sun City modeling effort broadly addresses the problem of evaluating the effects of applying a limited budget policy to solar power diffusion. It has been an ambitious attempt to begin to inform policy mathematically and may have use in future market diffusion efforts. Should the opportunity arise, the current formulation needs to be applied to a specific community and policies for further examination and possible validation. Making the model a useful tool beyond demonstration will take considerable communications efforts between individual cities and the model developers to make algorithms suitable to individual needs. .

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6. CONCLUSION

The theory and assumptions of the Sun City model have been presented in detail. PVF has been proposed as an alternative to the electricity costs ratio. PVF is argued to have greater capability to harness the effects of local financial limitations and psychological human behavior. A general framework for applying policy effects to diffusion rates has been formulated which involves linking the PVF to the Bass diffusion model based on past U.S. PV growth. The nine policy types applied to the PVF are therefore in no way unique. They serve as a demonstration of using concepts to formulate models which route through the PVF. Policies can be applied as long as a quantitative method with plausible assumptions can be proposed which introduces a variation to the terms in the PVF equation. Quantifying actual sensitivities between policy and PVF growth remains as a challenge. PV market diffusion is an area of active research and further development needs to move toward applying the model to individual cases which allow calibration of individual parameters to produce responses which are historically consistent. Focusing on an individual site will provide a sufficient resolution of data to establish confidence in the modeling approach.

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APPENDIX A: ITERATIVE SPENDING FRACTION ALGORITHM

The algorithm steps for determining the variable "Fraction" which represents the fraction of spending applied to a given cash incentives status, financing type, sector, and scenario are summarized below. The sum of fraction is equal to one for each sector. The Bass growth model (section 2.3) and cash incentives spending rate algorithm (section 3.1) are replicated in the VBFUNCTION. Additional conditions are present in the actual script to eliminate extreme cases from crashing the program. The VBscript code may be available upon request but will require a software release process if the request is external to Sandia National Laboratories. The script is maintained separately from Studio™ and is inserted after it has been debugged and checked.

1. Set "Fraction" to previous converged solution "PreviousFractions." If the previous value for a given sector, scenario, financing option, and cash incentive status is zero, then set the fraction to a very small value to avoid calculating zero by default.
2. Initialize convergence error to a non-zero value
3. Filter out any Financing Budgets which have negative values and set them to zero.
4. Enter the sector loop each of the steps below apply to each sector
5. Sort the PVF options across financing options from highest PVF to lowest PVF using the values with cash incentives. The order of indices is mapped in the variable INDEX
6. Enter into while loop until error ratio is < 1 or IterationsToStop has been exceeded (i.e. convergence is too slow)
7. Enter into Sector For Loop (i)
8. Initialize PVF(i) to 0
9. For current "Fraction" array, calculate the average PVF(i) by multiplying by the PVF for all financing and cash incentives options
10. Run The PVF calculated through the PhotoVoltaic Growth Model (Section ??). This produces the PV adoption rate for sector i
11. Run the PV adoption rate through the cash incentives spending rate calculations outlined in section 3.1. This produces the spending rate on PV for the current fractions and PVF data for all cash incentives and financing options provided. R_p of equation 3.9 is an important term in the logic between which options are exercised.
12. Initialize the budgets for financing (data never changes but the budget has to be restored to full value each iteration).
13. **Iterative Core**: Determine fractions based on balancing limited budgets of cash incentives and financing options. The budgets are maintained independently (all cash incentives are consumed first with the highest PVF options in financing). Each budget balance is sequentially reduced. Standard funds always refers to the standard loan which has an infinite amount of funds available. The standard funds are used if the spending rate exceeds the available limited budget financing options.

    RemainingFunds(j,i) → Funds remaining in each financing option except for the inifinte standard loan. If the user has not allocated a budget this will always be zero.
    NonStandardFundsLeft → summation of Remaining Funds over all nonstandard financing options (is not subtracted from sequentially like FundingLeft)
    CashIncentivesLeft → Amount of cash incentives still available from budget

RemainingMoneyForStandardLoans → Amount of spending which will have to be financed by standard loans (may be 0 if enough is available in the limited budgets) FundingLeft
Rp → see step 11.
FundingLeft → Total amount of non-standard funding which is unspent and is successively reduced as options are expended.

Pseudo-Code

For m = 0 To 1   (0 is with incentives, 1 is without incentives)

Skip to the end of loop if cash incentives are not profitable or if budget for cash incentives is 0 (i.e. all cash incentives fractions = 0)

Set NonStandardFundsLeft = 0

Subtract FundsSpent (will be = 0 for m = 0) from RemainingFunds. RemainingFunds sequentially reduces toward zero but all limited budget financing may not get spent depending on the spending rate calculated in step 11.

Sum non-standard funds left

Calculate Remaining money for standard loans (may be zero or less than one if there is an excess of NonStandard Funds left

IF remaining money for standard loans is less than or equal to zero then the standard loan is not needed

Loop over Financing Options excluding standard loan

IF RemainingFunds for the next highest PVF option > FundingLeft Then This option will use up the rest of the funds available. Find out if cash incentives is the limiting factor

IF (m = NoCashIncentives) OR (CashIncentivesLeft >= FundingLeft*Rp) Then FundingLeft is the limiting budget for spending

NewFraction(s,m,INDEX(j,i),i) = FundingLeft/TotalSpent
FundsSpent(INDEX(j,i),i) = FundingLeft
CashIncentivesLeft = CashIncentivesLeft - FundingLeft*Rp
FundingLeft = 0
Exit loop of financing options

ELSE we are in the cash incentives loop (i.e. m = WithCashIncentives) and all of the cash incentives have to be spent

NewFraction(ss,m,INDEX(j,i),i) = (CashIncentivesLeft/Rp)/TotalSpent

FundsSpent(INDEX(j,i),i) = CashIncentivesLeft/Rp
FundingLeft = FundingLeft - CashIncentivesLeft/Rp
CashIncentivesLeft = 0
Exit loop of financing options

ENDIF

ELSE the highest PVF option only uses up a fraction of the funding available

IF (m = NoCashIncentives) OR (CashIncentivesLeft >= RemainingFunds(INDEX(j,i),i))*Rp) Then the RemainingFunds Budget is the limiting factor

NewFraction(ss,m,INDEX(j,i),i) = RemainingFunds(INDEX(j,i),i)/TotalSpent
FundingLeft = FundingLeft - RemainingFunds(INDEX(j,i),i)
CashIncentivesLeft = CashIncentivesLeft - Rp*RemainingFunds(INDEX(j,i),i)
FundsSpent(INDEX(j,i),i) = RemainingFunds(INDEX(j,i),i)

ELSE the cash incentives are the limiting factor on spending and the next financing option consumes them all

NewFraction(ss,m,INDEX(j,i),i) = (CashIncentivesLeft/Rp)/TotalSpent
FundingLeft = FundingLeft - CashIncentivesLeft/Rp
FundsSpent(INDEX(j,i),i) = CashIncentivesLeft/Rp
CashIncentivesLeft = 0
Exit loop of financing options

ENDIF
ENDIF

END Financing options loop

ELSE the standard loan is used but may not be needed for the cash incentives portion

Loop over financing options excluding the standard loan

IF (m=NoCashIncentives) OR (CashIncentivesLeft > Rp*RemainingFunds(INDEX(j,i),i) Then the remaining funding for the current financing options is the limiting factor

NewFraction(s,m,INDEX(j,i),i) = RemainingFunds(INDEX(j,i),i)/TotalSpent
FundsSpent(INDEX(j,i),i) = RemainingFunds(INDEX(j,i),i)
CashIncentivesLeft = CashIncentivesLeft - Rp*RemainingFunds(INDEX(j,i),i)
FundingLeft = FundingLeft - RemainingFunds(INDEX(j,i),i)

NonStandardFundingLeft = NonStandardFundingLeft - RemainingFunds(INDEX(j,i),i)

ELSE cash incentives are the limiting factor

NewFraction(s,m,INDEX(j,i),i) = (CashIncentivesLeft/Rp)/TotalSpent
FundsSpent(INDEX(j,i),i) = CashIncentivesLeft/Rp
FundingLeft = FundingLeft - CashIncentivesLeft/Rp
NonStandardFundingLeft = NonStandardFundingLeft - CashIncentivesLeft/Rp
CashIncentivesLeft = 0
Exit financing options loop

ENDIF

END Financing options loop

IF (m=NoCashIncentives) OR (CashIncentivesLeft > Rp*RemainingMoneyForStandardLoans) Then → The standard loan fund Is the limiting factor

NewFraction(ss,m,0,i) = RemainingMoneyForStandardLoans/TotalSpent
CashIncentivesLeft = CashIncentivesLeft - Rp*RemainingMoneyForStandardLoans
FundingLeft = FundingLeft – RemainingMoneyForStandardLoans

ELSE the cash incentives are the limiting factor

NewFraction(ss,m,0,i) = (CashIncentivesLeft/Rp)/TotalSpent
FundingLeft = FundingLeft - CashIncentivesLeft/Rp
CashIncentivesLeft = 0

ENDIF

Calculate the SubError from Fraction to NewFraction divided by the ErrorTolerance

ENDIF

End For (m)

14. Check the newly calculated fractions minus the previous iterations values and divide by the error tolerance (Sum SubErrors). This is the next iterations error which will exit the while loop if the error is less than 1.
15. Reassign new fractions to old fractions variable (Fraction = NewFraction)

APPENDIX B: MODEL INPUT TIME SERIES

SERVES to provide a comprehensive listing of the driving exogenous time series needed by the Sun City model. A large array is used to pass all of these variables into the Policy effects model in Studio^{TM}.

Table 17. Input variables to Sun City

Input Column	Variable Description	Units	Sectors (Residential, Commercial, Utility)
1	Predicted Amount of PV installed nationwide	KW/yr	N/A
2	Cost of PV Electricity to purchase 1KW materials only with no taxes, permitting, or Incentives included	USD/KW Installed	N/A
3-5	Maximum PV Potential	KW	All
6	Group Purchasing Program Funding	USD	N/A
7	Weather reduction off nameplate capacity	%	N/A
8-10	Feed-in-tariff Average Pay Back Rate	USD/KWh	All
11	Third Party Maximum Fraction taken from Utilities Down Payment Tolerance	%	Utility
12-14	Low Interest Loan Funding	$/yr	All
15-16	Third Party Financing Down Payment funds Taken from Utility to Residential and Commercial	$/yr	Residential, Commercial
17-19	PACE funding	$/yr	All
20-22	Local Property Tax Rates	%	All
23-25	Local Sales Tax Rates	%	All
26-28	Policy % to discount property tax	%	All
29-31	Policy % to discount sales tax	%	All
32	Streamlining Permit Process Budget	$/yr	N/A
33-35	Local Cash Incentives Budget Offered	$/yr	All
36-38	Local Cash Incentives % discount offered	%	All
39-41	Population Power Consumption	KWh/yr	All
42-44	Number of consumers per sector	consumers	All
45-47	Cost of Electricity	USD/KWh	All
48-50	Target Spending on the Feed-In-Tariff across subpopulations	USD/yr	All
51-52	Community Solar Budget	USD/yr	Residential, Commercial

APPENDIX C: SUN CITY DATASET SOURCES

The Sun City model is informed with a mixture of city, state, national, and international data. This data is used to help the user with data input. None of the inputs directly go into the model though. Values are only suggested or are provided as graphical feedback so that the user can independently enter whatever is needed. The dataset has been accumulated as is without any investigation into quality. Most of the sources are from government agencies which probably have their own quality procedures. In addition to this, considerable rearranging of the data had to be done in order to get it into the format needed to isolate effects on the Solar America Cities and on Albuquerque, New Mexico. A critical review of the calculations done on the original data sources is needed in the future.

Table 16. Sun City dataset sources

Data Description	Source/DataNotes	Hyperlink	Used By Model / Level
Existing Incentives	Cost Convergence Calculator / This data was extracted manually from the website, it is useful but has not yet been incorporated	http://www.pvcostconvergence.org/Assumptions.aspx	No / City
City Population History (2000 – 2009)	US Census Bureau / These numbers are estimates between census data points.	http://www.census.gov/popest/data/cities/totals/2009/index.html	Yes / City
City PV Installed (2007-2010) Residential and NonResidential	Solar America Cities DOE website / Data Was Extracted Graphically. This data may help with model calibration	http://solaramericacommunities.energy.gov/solaramericacities/	No /City
Electricity Market Metrics across sectors: Utility Names, Number of Consumers, Sales, Revenue, Average Retail Price, Energy Consumption Density	Energy Information Administration (EIA) / Processed in the spreadsheets: EIA_Electricity_Table_6_Residential.xlsx, EIA_Electricity_Table_7_Commercial.xlsx, EIA_Electricity_Table_8_Industrial.xlsx, EIA_Electricity_Table_10_AllSectors.xlsx	http://www.eia.gov/electricity/data.cfm#sales	Partially / By Utility (only averages used to approximate city level)
House Hold Income Data	US Census Bureau / Data Processed in "IncomeDataUSCensusMetroPolitanAreas 2005-2007.xls"	http://www.census.gov/compendia/databooks/2010/www/income.html	No – superseded by disposable income / City
Nest Egg Index	Forbes for 3 cities, state master website, and BLR website for state wide data. This index is used to scale national savings data to differentiate savings rates in different cities which is a strong indicator of whether or not people have expendable income and are making responsible choices financially.	Minneapolis, San Francisco, San Jose: http://www.forbes.com/2006/09/01/cz_kb_090506_nestegg_top_slide.html?thisSpeed=14000&partner=yahoo All Other http://www.statemaster.com/graph/eco_nes_egg_ind-economy-nest-egg-index Another Source http://hr.blr.com/HR-news/Benefits-	Yes / Minneapolis, San Francisco, and San Jose have City level data. The rest are statewide averages

		Leave/Retirement-Savings-401k/50-States-Ranked-by-Workers-Nest-Eggs/	
Power Consumption per capita History 1990 to 2009	Energy Information Administration (EIA) for total energy consumption, U.S. Census Bureau for state population / Look under "Detailed Historical Data". The derivation is contained in TotalElectricityConsumptionByStateEIA.xlsx	http://www.eia.gov/electricity/data.cfm#sales AND http://www.census.gov/popest/states/NST-ann-est2008.html	Yes / State
State wide number of consumers across sectors history 2001 - 2009	Energy Information Administration (EIA) / CONSIDERABLE FILTERING OF THIS DATA WAS DONE IN THE SPREADSHEET ElectricityDataEIA-2000-2009.xlsx	http://www.eia.gov/cneaf/electricity/page/eia826.html	Yes / State
State Populations and Number of Utilities	Energy Information Administration (EIA) for total energy consumption, U.S. Census Bureau for state population / Look under "Detailed Historical Data". The derivation is contained in TotalElectricityConsumptionByStateEIA.xlsx	http://www.eia.gov/electricity/data.cfm#sales AND http://www.census.gov/popest/states/NST-ann-est2008.html	Yes / State
First 8 City Zip Codes and approximate Latitude and Longitude	US Federal Government Zip Codes site / Latitude/Longitude is for a specific zip code and does not represent the center of each city	http://federalgovernmentzipcodes.us/	Yes for lon/lat, No for Zip codes / City
Disposable Income History by State (1990 – 2010)	Bureau of Economic Analysis (BEA)	http://www.bea.gov/iTable/download.cfm?ext=xls&fid=7C620C477B35EC2789C68AAEE520EF9928FD1BD07F2BD050B4A6ED08CA1D759E7678C08BFF5595B4C1F04D5812CAA1FB403D28A266E75DFFB93DF84ED3920B4D	Yes / State
Carbon Emissions Density by State history (1996-2000, 2004, 2005, 2007)	Environmental Protection Agency eGRID database	http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html AND http://www.epa.gov/cleanenergy/energy-resources/egrid/archive.html	Yes / State
US Personal Savings Rates history (1990-2010)	Economic Research Federal Reserve Bank of St. Louis which cites the U.S. Department of Commerce: Bureau of Economic Analysis / This is multiplied by the Nest Egg Index to approximate state and city level savings rates.	http://research.stlouisfed.org/fred2/data/PSAVERT.txt	Yes / National
Inflation	InflationData.com / From the website: The Inflation rate is calculated from the Consumer Price Index (CPI-U) which is compiled by the Bureau of Labor Statistics and is based upon a 1982 Base of 100.	http://inflationdata.com/Inflation/Inflation_Rate/HistoricalInflation.aspx	Yes / National
PV Carbon Life Cycle Data Points	This data comes from Lenzen, M. (2008) “Life cycle energy and greenhouse gas emissions of nuclear energy: A review” Energy Conversion and	http://www.isa.org.usyd.edu.au/publications/documents/ISA_Nuclear_Report.pdf	Yes / International

	Management 49, 2178-2199.		
US PV installation history	NREL Open PV data base, EIA for total U.S. energy consumption / several estimations are made to estimate total solar photovoltaic power electricity output. Solar data also contains reflected solar applications which are not relevant to the Sun City model	http://openpv.nrel.gov/visualization/index.php AND http://www.eia.gov/electricity/annual/	Yes / National
Land Area Available	US Census Bureau	http://www.census.gov/geo/www/guidestloc/files/cbsa10.txt	

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