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The Market Value and Cost of Solar Photovoltaic Electricity Production

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Abstract: The high cost of power from solar photovoltaic (PV) panels has been a major deterrent to the technology's market penetration. Proponents have argued, however, that typical analyses overlook many of the benefits of solar PV. Some of those benefits are in the realm of environmental and security externalities, but others occur within the electricity markets. In this paper, I attempt to do a more complete market valuation of solar PV. I incorporate the fact that power from solar PV panels is generated disproportionately at times when electricity is most valuable due to high demand and increased line losses. I find that the degree to which the timing of solar PV production enhances its value depends very much on the extent to which wholesale prices peak with demand, which in turn depends on the proportion of reserve capacity held in the system. In a typical US system with substantial excess capacity, I find that the favorable timing of solar PV production increases its value by 0%-20%, but if the system were run with more reliance on price-responsive demand and peaking prices, the premium value of solar PV would be in the 30%-50% range. Solar PV is also argued to have enhanced value within an electrical grid, because the power is produced at the location of the end-user and therefore can reduce the costs of transmission and distribution investments. My analysis, however, suggests that actual installation of solar PV systems in California has not significantly reduced the cost of transmission and distribution infrastructure, and is unlikely to do so in other regions. I then bring together these adjustments to the valuation of solar PV power with calculations of its cost to analyze the market value of solar PV. The market benefits of installing the current solar PV technology, even after adjusting for its timing and transmission advantages, are calculated to be much smaller than the costs. The difference is so large that including current plausible estimates of the value of reducing greenhouse gases still does not come close to making the net social return on installing solar PV today positive.

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1. Introduction

As fossil fuel prices have risen and concerns over greenhouse gases (GhGs) and global climate change have increased, alternative technologies for producing electricity have received greater attention. Among the technologies that may help to address these concerns is solar photovoltaic cells (PVs), which capture solar radiation and convert it directly into electrical energy. Such cells are generally located at the site of the end user and thus are a form of distributed generation. The current direct cost of solar PV power is widely acknowledged to be much greater than fossil fuel generation or many other renewable energy sources.

Proponents of solar PV panels argue, however, that standard analyses fail to capture the enhanced value of solar PV power that results from its temporal and locational characteristics. Solar power is generated during daylight hours and on average generated in greater quantity when the sun is shining more intensely. As a result, in summer-peaking electricity systems, such as California and most of the U.S., power from PVs is produced disproportionately at times when the value of electricity is high. Electricity value is higher when system demand is high both because the wholesale price of electricity in the grid is greater and because the proportion of power lost through heat dissipation during electricity transmission and distribution increases with the total amount of power flowing over the lines. Because PV power is generated on-site, such losses are avoided.

On-site generation is argued to deliver another economic advantage that is often overlooked in cost analyses. Power from central station generation requires significant investment in transmission and distribution infrastructure, investment that could potentially be reduced if more power were generated on site. Thus, a valuation of solar PV electricity production that compares it to the *average* cost of generating electricity, and also ignores the potential savings in transmission and distribution infrastructure, will tend to undervalue the power from PV. Few would dispute this view, at least for transmission, but the magnitudes of these effects have not been systematically quantified.

In this paper, I use solar PV production information in conjunction with wholesale price data to estimate the actual value of power from solar PVs and the degree of bias that results from neglecting the favorable time pattern of PV production and the reduced demand for transmission and distribution capacity. I then revisit the discussion of the economics of solar PV power, incorporating the effects of these factors.

Section 2, discusses briefly the many issues raised by solar PV power in order to clarify where this research fits in the debate. In section 3, I present the basic approach to valuing solar PV power using hourly wholesale electricity prices and comparing that with an analysis that ignores the favorable timing of PV power. Section 4, discusses the data used to represent solar PV power production and section 5 discusses the data used to value that power. Results from a number of different approaches to valuing PV power are presented in section 6. The results suggest that the value of power delivered from solar PV panels is substantially greater than would result from simply valuing solar PV power at the average power cost, regardless of when it is produced.

In section 7, I move on to analyze the potential savings in transmission and distribution capacity costs that can result because solar PV generation is located at the end-users site. While temporal variation in market prices for energy reflect the production capacity constraints, locational variation in market prices reflects the transmission capacity constraints. Thus, valuation of power at the locational price of the PV systems will incorporate transmission capacity constraints. I use this approach to study the value of on-site generation that is attributable to reduced transmission needs. Theoretically this effect could be very significant, but I find that in California the effect is small. This is due both to the fact that locational scarcity rents are fairly small and to the fact that solar PV in California has not been focused in transmission-constrained areas.

These results provide one component of the analysis of the economics of solar PV. Section 8 returns to that broader discussion. Setting aside the very serious environmental and security externalities of energy consumption, I evaluate the market economics of solar PV. While accurate time-varying valuation of the power delivered from solar PVs improves its economics significantly, the overall economics of installing the currently available PV technology remains quite unfavorable. I also address the economics of the argument for subsidizing solar PV in order to grow the industry, accelerate learning-by-doing economies, and drive down costs. Though scale and experience economies are likely to be present in this industry, they are unlikely to constitute a rational economic basis for state or federal intervention in the market. Comparing the benefit-cost deficit of the current solar PV technology with the potential environmental benefit from reducing GhGs indicates that even including plausible valuations of reduced GhG emissions does not make solar PV a socially beneficial investment under current technology and costs.

2. (Mis)valuing Solar Photovoltaic Power

It has long been recognized that the timing and location of power production greatly affects the value of the electricity. Combustion turbine "peaker" plants have a much higher cost per kWh produced than baseload coal, nuclear or combined-cycle gas turbines, but they are still worth building for use only at peak electricity use times. Likewise, a high-cost plant located in a transmission-constrained area can make economic sense when compared to the cost and feasibility of transporting the power to that location. While few dispute that the direct cost of electricity from the currently available solar photovoltaic technology is relatively high, proponents point out that the value of the power is also high because of its favorable timing and location.

Figure 1 illustrates the timing advantage of solar PV. For a July weekday, it presents the hourly average demand profile in the California Independent System Operator (ISO) system and the average solar PV production of a south-facing and a west-facing installation in San Francisco. Solar PV production not only peaks in the middle of the day, when demand peaks, it does so disproportionately to demand.[2] Figure 1 also demonstrates that by turning the solar panels more towards the west, peak production from the solar panels can be more closely synchronized with system demand, but at a cost of lower overall production levels.

The location advantage of solar PV is also tangible. Power produced at the end-use location does not have to be shipped to the customer over transmission and distribution (T&D) lines. That presents two possible savings: first it reduces the losses of electricity that occur when some of it is dissipated as heat during the T&D process. On average in California, about 7% of generated electricity is lost this way, but the number is greater at peak times, so there is synergy between the locational and timing advantages of solar PV. In addition, it may be possible to reduce investment in transmission and distribution infrastructure if less electricity needs to flow over those lines. The size of this advantage will depend on the scarcity of T&D capacity.[3]

These advantage of solar PV are often stated, but estimates of the size of these effects are scarce. In general, they consist of idiosyncratic anecdotes about situations where an additional major investment in generation or transmission can be avoided by solar PV installation.[4] These claims have their own difficulties – most notably that the avoided investment is actually just postponed for a (possibly brief) period of time, not avoided – but in any case, they ignore the fact that grid-connected solar PV is hardly ever installed in a manner that targets specific capacity or transmission constraints. The diffuse adoption of solar PV suggests that an analysis of its average value in a system is likely to be more

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[2] In part, of course, this is simply due to the fact that solar PV produces no power when it is dark.

[3] Spratley (1998) discusses the value of solar PV panels in reducing T&D expense and references a number of studies of the effect.

[4] See, for instance, McCusker and Siegel (2002).

informative.

The timing and locational characteristics of solar PV power production are the attributes often cited in arguing that, externalities aside, market valuation of solar PV is too low. Failure to account for another characteristic of solar PV— intermittency of supply— is frequently cited as a downside that is not captured by market valuation of the energy. When made carefully, the argument is parsed into two components: The first is the cost of unreliable advanced planning because the system operator does not know 24 or 48 hours in advance how much power will be produced from solar PV in a given hour and therefore must acquire additional reserves as backup. The second is second-to-second grid stability if the output of solar PV panels changes rapidly. In a well-functioning wholesale electricity market, the first effect is captured either through long-term contracts for capacity availability or short-term energy price spikes that incent merchant sellers to be ready with available energy. I return below to how this effect is captured in the empirical analysis. The second effect is more difficult to quantify without detailed engineering specifications. The argument, however, is made more frequently and forcefully in the context of wind power than solar power, because spatially distributed solar PV resources are not likely to have a high second-to-second correlation in output, so threats to grid stability are generally of less concern, at least at current levels of solar PV penetration.

I do not attempt to quantify the non-market security and environmental externalities associated with solar PV. As a form of distributed generation, solar PV is also often supported for its security value. The argument is that small on-site generation makes the electricity system less vulnerable to terrorist attack, because (a) it reduces the number and degree of "high-value" targets where a single strike could cut power to many users, (b) it reduces the grid instability that could result from loss of a large power generator or transmission line, and (c) in the case of solar PV, it reduces the use of dangerous fuels that create additional potential hazards from attack.[5]

Environmental externalities are, of course, often cited as a reason to place greater social value on some alternative forms of electricity generation, including solar PVs.[6] With growing evidence of global climate change linked to greenhouse gas emissions from burning of fossil fuels, these arguments take on increased weight. Electricity from PVs reduces both

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[5] See Asmus (2001).

[6] This is obviously a vast literature. Sundqvist (2004) provides an overview and tries to reconcile disparate estimates of the environmental externalities.

GhGs and regional pollutants such as NO_x and SO_2.[7]

The focus here is on the social valuation of solar PV, or at least the market components of that analysis. I do not analyze here the private valuation of solar PV for the end-use customer. In separate papers, Wiser et al (2007) have analyzed the private consumer value for commercial and industrial customers and Borenstein (2007c) has analyzed the private value of solar PV to residential customers. Those studies consider the effects of retail tariff structures, tax credits and other subsidies that are not of first-order relevance to the social valuation.

3. The Analytics of Valuing Time-Varying Solar PV Power

Assuming the solar PV power is both produced and consumed at the end-user's site, the value of that power is the cost of the alternative technology for delivering electricity to the end user: the marginal cost of central station generation adjusted for the electricity losses in the transmission and distribution of the power. In a competitive wholesale electricity market, the market price at any point in time will reflect the marginal cost of generation in that hour.

Transmission and distribution line losses also vary over time. The standard engineering approximation of these losses is that they are proportional to the square of the flow on the lines.[8] Actual losses in transmission and distribution to any one specific end user will, of course, vary with the location of the generation and end user on the grid. For this analysis, I make the baseline assumption that the losses for delivery to solar PV owners are equal to the system average losses at the time.[9] If the system losses, L_t, are $L_t = \alpha Q_t^2$, where Q_t is systemwide central station generation at time t and α is a constant that I discuss below, then the change in systemwide losses when one unit of delivered electricity is replaced by one unit of electricity from on-site solar PV is equal to $dL_t/dQ_t = 2\alpha Q_t$. The value of the reduced line losses is then $w_t \cdot 2\alpha Q_t$, where w_t is the wholesale price of electricity on the grid.

The constant α can be derived by combining hourly system production data with

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[7] For pollutants regulated under a cap-and-trade permit system, the variable cost of generation would include the cost of permits. Whether the price of permits raises the marginal cost of electricity production by the socially efficient amount, however, depends entirely on getting the capped number of permits "right."

[8] See Bohn, Caramanis and Schweppe, 1984.

[9] Locational variation in line losses is incorporated in section 7.

the average aggregate losses in the system. In aggregate, about 7% of power generation in the California electricity grid is dissipated through line losses in the transmission and distribution system.[10] So, for some α

$$0.07 \cdot \sum_{t=1}^{T} Q_t = \sum_{t=1}^{T} \alpha Q_t^2 \qquad \Longleftrightarrow \qquad \alpha = 0.07 \frac{\sum_{t=1}^{T} Q_t}{\sum_{t=1}^{T} Q_t^2}.$$

Applying this equation for α to the California ISO system for 2000-2003 yields a weighted average proportional loss of 7% (by construction), an unweighted average hourly loss of 6.8%, a minimum loss of 4.3% and a maximum loss of 12.0%.

Thus, I take the value of one unit of alternating current electricity delivered from an on-site solar PV array at time t to be

$$v_t = w_t + w_t \cdot 2\alpha Q_t = w_t(1 + 2\alpha Q_t).$$

The value of the power delivered from a solar PV installation that produces q_t units of power at time t and operates until time T is then $V = \sum_{t=1}^{T} \delta v_t q_t$, where δ is the per-period discount factor.

The valuation, V, incorporates the time-varying valuation of solar PV and the time-varying line losses that are avoided from on-site generation. It would be useful to know, however, just how great the bias is from ignoring the time variation in valuation of on-site generation and avoided line losses.

To make this comparison, one would want to calculate a constant valuation of delivered electricity (inclusive of average avoided line losses) that is revenue-neutral compared to the hourly-varying wholesale pricing and line losses that are used in the previous calculation. In practice, this means setting a flat rate that is the system-quantity-weighted average wholesale price divided by one minus the system weighted average line losses.

Assume that we have a time series of system wholesale prices, w_t, and system demand quantities, Q_t, and that those system demand quantities were generated by a flat retail price that covered wholesale energy costs. That flat retail rate for energy (excluding capital costs of transmission and distribution, taxes and other fees) would be

$$\bar{P} = \frac{1}{1-\phi} \cdot \frac{\sum_{t=1}^{T} Q_t \cdot w_t}{\sum_{t=1}^{T} Q_t}$$

[10] This figure was reported to me by a number of different managers and researchers on transmission and distribution. It is also consistent with the difference reported by the Energy Information Administration between U.S. generation and retail sales.

where ϕ is the system weighted-average proportional line losses, assumed to be 7% in this case. Thus, with no adjustment for the time-varying production of solar PV, the output would be valued at $\hat{V} = \sum_{t=1}^{T} \bar{P} q_t$.

One goal of this paper is to calculate $V_{diff} = V - \hat{V}$ for plausible time series of P_t, Q_t, L_t and q_t. In the next section, I discuss data for the solar PV installation, q_t. In the following section, I discuss data for system prices, quantities and line losses, P_t, Q_t and L_t.

4. The Time-Varying Production of Solar Photovoltaic Cells

Solar PV cells produce power when the panels in which they are embedded are hit by solar radiation. This occurs only during the daytime and, within a day, varies according to the angle of the sun. For the same reason, PV production varies with the seasons, the latitude of the location in which the building is located, and the direction and tilt at which the panels are mounted. Production is also affected by the weather, both because cloud cover can reduce the energy received by the panel and because the PV cell production declines if the cells get too hot.[11]

There are two conceptual approaches to establishing the time-varying production of PVs. The first would be to obtain actual "metered" data from solar PV panels that are currently in use. The second is to use simulation models that control for most of the factors that affect production. Each approach is imperfect.

I have not located a dataset with metered data from numerous comparable installations. Such data would have the advantage of representing an actual installation of PV panels and would automatically take into account variation in solar radiation. These data, however, would also be idiosyncratic, affected by the particular installation, orientation, upkeep, obstructions, and other factors that affect the productivity of solar PVs. Without a detailed sample from a large number of installations, it would be difficult to know how representative the data are.

Simulation data are available from a number of sources. The most sophisticated seems to be TRNSYS (A Transient System Simulation Program) based at University of Wisconsin. I obtained TRNSYS simulated production for a 10kW (DC) installed solar

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[11] Crystalline silicon solar PV panels began to lose efficiency when the panel surface temperature exceeds approximately 25 degrees Celcius. Above that temperature, output declines by about 0.5% for each 1 degree Celsius increase in surface temperature.

PV system in San Francisco, Sacramento, and Los Angeles.[12] For each location, the runs were done assuming the panels were mounted at a 30 degree tilt facing, in different runs, South, Southwest, and West. The simulated DC power production was then converted to AC power delivered to the house using a 16% derate factor to account for inverter and wiring losses and other associated conversion factors.[13]

Weather data for TRNSYS come from the U.S. National Renewable Energy Laboratory (NREL). The weather data set is TMY2, which is described by NREL as, "[t]he TMY2s are data sets of hourly values of solar radiation and meteorological elements for a 1-year period. Their intended use is for computer simulations of solar energy conversion systems and building systems to facilitate performance comparisons of different system types, configurations, and locations in the United States and its territories. Because they represent typical rather than extreme conditions, they are not suited for designing systems to meet the worst-case conditions occurring at a location."

The TRNSYS model produces hourly simulated production data for one year. As explained in the next section, I match these data to four years of electricity system data and prices. To do this, I start by simply repeating the simulated production data four times.

The TRNSYS solar PV production data have substantial day-to-day variation, reflecting weather variation. If these were actual metered data, the higher production days for the PVs would also be, on average, the higher system demand days in a summer-peaking electricity system such as California. Because the simulated TRNSYS data are derived separately from the actual system quantity and price data, however, this relationship will be less strong than it would be in actual use. For instance, the simulated July weekday afternoon solar PV production is on average higher than the simulated February weekday afternoon solar production and the July weekday afternoon system demands are on average higher than the February weekday afternoon system demands. Within July weekday afternoons, however, the idiosyncratically higher PV production days from the simulation would not correspond in the dataset to the idiosyncratically higher system demand days. I explain below how I address this issue.

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[12] I'm grateful to Duncan Callaway for doing the TRNSYS runs that produced the simulated PV production.

[13] The 16% derate factor is in the typical range of conversion rate assumptions, though probably at the low end of that range. See http://www.nrel.gov/rredc/pvwatts/changing_parameters.html on the National Renewable Energy Laboratory website.

5. Real-time Prices for Valuing the Power from Solar PVs

As with the solar PV production data, there are two conceptual approaches to valuing solar output at wholesale prices. The first is to use an actual price series from the market in which the PV installation is located. The second is to use simulated data from a model of pricing in a competitive wholesale electricity market. I use each of these approaches, each of which has advantages and disadvantages that I discuss below.

The analysis I do using actual market prices takes the relevant hourly regional price from the California ISO's real-time market for the 4-year period, 2000-2003: the northern region (NP15) price for analysis of Sacramento and San Francisco, the southern region (SP15) price for analysis of Los Angeles. While a price series from actual market operation has the obvious advantage of credibility, it may also have a number of disadvantages compared to simulated prices. Most important is the fact that investment in generating capacity might not be in long-run equilibrium during the period in which the prices are observed. If there is excess capacity, then peak prices are likely to be damped relative to the long-run equilibrium price distribution, penalizing technologies that produce more at peak times, such as solar PV. Of course, if there is a capacity shortage during the observed time, the opposite could be true. In addition, wholesale prices may be restrained by regulation, such as a price cap. This was the case in California where a wholesale price cap was binding in many hours during the period I examine.

I see no useful way to correct the actual price data for under- or over-capacity, though the simulation approach does address that issue. The price cap constraint can be addressed in an *ad hoc* way by raising the price in hours when the cap was binding. I create such an augmented price in a rather simplistic way: during the periods in which the price cap was $250/MWh, I reset the price to $750/MWh in any hour in which the actual price was above $249 and during the periods in which the price cap was $500/MWh, I reset the price to $750/MWh in any hour in which the actual price was above $499. I do not reset the price in any hours in which the price cap was $750/MWh, the highest level it was ever set. I also do not reset the price for any hours after June 2001. The FERC imposed a low (and variable) price cap in June 2001, but by that time the market prices had crashed and the price cap was almost never binding. The reason that I do not raise any prices above $750 is that it is unlikely that the competitive market price was ever above that level during this time period. That the price hit $750 during about 35 hours of the summer 2000 is very likely due to the exercise of market power.[14] While solar PV capacity would have helped to undermine market power during the California electricity crisis, so would

[14] See Borenstein, Bushnell, and Wolak (2002).

have any other capacity. More importantly, with long-term contracts now a significant feature of the market, and generally more understanding of the vulnerability of electricity to market power, it seems unlikely that we will see such inflated margins again as a result of seller market power.

Figure 2 is the same as Figure 1, but replaces system demand with the real-time wholesale price for northern California. It demonstrates that PV production occurs disproportionately at times of high wholesale prices.

An alternative to an actual wholesale price series is to use prices from a simulated long-run model of wholesale electricity markets. In previous papers (Borenstein, 2007a and 2007b), I have constructed and simulated such a model under various demand assumptions for the same market and time period as is covered by the actual price data. The model takes the actual distribution of hourly demand and calculates the capacities of three kinds of generation technologies that would be installed in a long-run equilibrium in which firms are competitive in the short-run – all sellers are price-takers – and competitive in the long-run – sellers enter and exit to the point that all producers are just breaking even. The model includes a baseload technology with high fixed costs and low marginal costs, a peaker technology with low fixed costs and high marginal costs, and a mid-merit technology with moderate levels of both costs.[15]

The model posits that there is some demand or import supply response to high prices, though the elasticity of these responses can be very low.[16] For a range of fairly low elasticities, however, the peaking capacity recovers all of its fixed costs in a small number of hours in which prices are very high, in some cases more than one hundred times greater than average prices. Thus, these simulated wholesale prices are much peakier than the actual prices that were observed. I present results from two sets of simulated prices, one in which the demand/import supply elasticity is extremely small, -0.025, and another in which the elasticity is greater, -0.1. Not surprisingly, the simulations with extremely small elasticity produce highly volatile prices. As I discuss further below, the effect of revaluing solar PV power is similar with either set of simulated realtime prices, and is greater in

[15] The assumptions I use here for annual production cost are: Baseload (coal) Cost = \$208247/MW + \$25/MWh; Mid-merit (CCGT) Cost = \$93549/MW+\$50/MWh; and Peaker (Combustion Turbine) Cost = \$72207/MW + \$75/MWh. These figures are taken from the PJM (2005), pages 82-83. California does not have coal plants, but (a) there are coal plants in the western grid and (b) the results are not affected substantially by fixing the level of baseload capacity in advance to reflect nuclear and other must-take capacity.

[16] The elasticity results from actual customer price response, import supply, discretionary use of reserve capacity, and various demand-side management programs.

either case than from using the actual market prices.[17]

The simulated prices have the advantage that they are determined in a way that assures that capacity recovers its capital costs. Importantly, however, in the simulation, capacity cost recovery comes completely through energy prices. In most actual markets, capacity owners receive non-energy payments just for having capacity available. These payments tend to increase capacity and reduce energy price spikes. To the extent that capacity payments are made independent of the time at which the capacity produces energy, they will substitute for price spikes and will undermine the efficient long-run price signals sent by energy markets. By distorting efficient energy price signals in this way, they will reduce the economic appeal of technologies that produce disproportionately at peak times, such as solar PV. To examine this possibility, I also simulate prices with the same equilibrium capacity investments as in the previous simulations, but with the energy price never permitted to go above the marginal cost of the highest cost plants. Peaker plants then recover all of their capacity costs and other plants recover some of their capacity costs through non-energy payments, which are incorporated as a constant per-kWh fee.

The real-time prices that are reported by the California ISO and that come out of these simulations do not account for the fact that solar PV substitutes for delivered power and thus avoids the time-varying line losses that occur between generation and end-use customer. As discussed earlier, all prices are adjusted for the estimated hourly line losses assuming that losses increase in proportion to the square of the total system production. As a result, proportional losses are greater when demand is high, which further enhances the valuation of solar PV.

Unobserved Correlation Between Prices and Solar PV Production

The TRNSYS model produces typical solar PV production that includes random variation due to weather. But in actual markets, that random weather variation is correlated with demand, and thus with prices in the system: clear, hot weather produces higher system demand and high prices. Up to a point, such weather also produces higher solar PV production. Thus, simply matching the simulated solar PV production with a price series will fail to account for the unobserved correlation between solar PV production and system prices. Omitting this effect will tend to undervalue the power from solar PV.

Without a dataset of actual solar PV production, it is not possible to overcome this problem directly. However, an adjustment to the data does permit a straightforward

[17] For further information about the resulting distribution of prices, see table 1 in Borenstein (2007a).

calculation of an upper bound on its effect. The adjustment is done by reordering the PV production data within certain time periods to match the highest PV productions with the highest system demands.

For example, consider the 1-2pm weekday hours in July. With four years of data there are 85 such hours, during which system demands varied from 29923 MW to 42302 MW and the delivered value of electricity (system price adjusted for line losses) varied from \$0.30/MWh to \$642.12/MWh. Simulated AC electricity production from the assumed 10kW (DC) solar PV installation (in San Francisco with panels facing south) during these hours ranges from 4.94 MW to 6.92 MW (AC). One would expect, however, that an actual solar PV installation would produce more power in the hours that had higher system demand. To account for this, I reallocate the set of solar PV production data among these (1-2pm, July weekday) hours so that the highest hour of solar PV production corresponds to the highest system demand among these hours. I do this for every month/weekperiod/hour where "weekperiod" is either "weekday" – Monday through Friday, excluding holidays – or "weekend" – Saturday, Sunday and holidays. I do this adjustment separately for each of the nine PV production time series (PV panels in SF, LA, and Sacramento, each facing S, SW,and W).

This is a favorable assumption for valuing solar PV production. In reality, solar PV production in any of the locations I examine is positively correlated with system demand, but the rank-order correlation is far from the perfect correlation assumed here. The correlation is imperfect for at least two reasons. First, weather is imperfectly correlated across locations within the system, so high system demand may be due to sunny weather in other locations on the system while it is overcast at the location of the PV cells. Second, solar PV production increases with hotter, sunnier weather up to a point, but then declines beyond that point as further heating of the cell reduces its efficiency. Thus, while the unadjusted results understate the value of solar PV production, the results from this adjustment overstate the value. Fortunately, these upper and lower bounds differ fairly little.

6. The Value of Time-Varying Solar PV Power

The results of the calculations are shown in Table 1. For each location, table 1 presents the value of delivered power using five different price series, which are the rows for each location. "Piso" north or south is the actual hourly spot price in the region of the California ISO system in which the city is located, north for SF and Sacramento, south for LA. "PisoAugmented" is the hourly spot price with the adjustment for the low price caps described earlier.

The next two rows Psim rows are price series from the simulations described in the previous section. For calculations with many different simulate d price series the results were fairly similar, for reasons I discuss below. In the table, I present two fairly extreme cases: "PsimH - high price volatility" results from an assumed demand/import supply elasticity of -0.025, while "PsimL - low price volatility" results from an elasticity of -0.1. In the former case, price exceeds the marginal cost of the highest cost generation in about 1.1% of all hours and has a peak price of $6321.66, while in the latter case price exceeds the marginal cost of the highest cost generation in about 4.9% of all hours and has a peak price of $1051.08.[18]

The last row of each case presents the results when some capacity costs are recovered through non-energy payments in the wholesale market. In particular, I assume that the wholesale price is never allowed to exceed the marginal cost of the highest cost generation. The revenue shortfall is then paid to generators in some sort of capacity payment. I assume that these costs must still be recovered as part of the retail energy bill, so they are instead collected as a uniform fee on all kilowatt-hours sold. Under that condition, the market valuation of power delivered from solar PV is equal to the wholesale price of energy (adjusted for line losses) plus the flat per-kWh that makes up the revenue shortfall. The results shown are from applying this rule to the PsimH simulation. The results are extremely similar if the rule is applied to the PsimL simulation.

The "flat rate value" column shows the per megawatt-hour rate that is the system-quantity weighted average wholesale price over the sample period and therefore the break-even rate that would be charged for all energy if there were no time-varying pricing. The next column, "RTP value," shows, for a PV installation facing South, the average valuation of the solar power if the value is the actual wholesale real-time price at the time at which the power was produced by the solar PV, using the TRNSYS production data. The following column shows the percentage difference from the valuation under the flat rate tariff. The "RTP* value" column shows the results after the adjustment for the unobserved correlation between prices and solar PV production discussed in the previous section, and again the percentage difference from the valuation under the flat rate tariff. In all cases, the wholesale price of power has been adjusted for line losses to come up with a value of the power at the point of delivery to the end-use customer. The following columns do the same calculations for real-time valuation of solar PV power using PV installations facing southwest and then west.

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[18] These are system wholesale prices. After adjustment for the change in system line losses, the implied peak values of delivered power are $8133.01 and $1309.07.

It is clear that using actual real-time ISO prices, even augmented to raise those that were constrained by low price caps, the difference between solar PV power valuation at a flat rate and real-time rate is fairly small. As we see throughout the table, the difference is largest for a west-facing installation. This is because a west-facing installation produces more of its power in the late afternoon when demand and prices tend to be highest. This at first might suggest that one would want to turn the panels west if faced with real-time prices, but an analysis of the total value of the power produced does not support that inference.

Table 2 presents the average hourly production of the PV installations in each of their orientations (the "Avg PV Production" rows) and the total annual value of their production under each of the tariff assumptions. Though west-facing panels produce higher-value power on average, they produce quite a bit less power in total, so much so that the total value of the power they produce is always less than if the installation is oriented southwest and in some cases less than if they were oriented south. Using the Piso price series, southwest and south orientation yield nearly identical values, but with the Psim price series southwest orientation is clearly preferred in all locations.[19]

Returning to table 1, compared to use of the actual real-time wholesale prices, the simulated prices produce much larger value differentials from using real-time prices rather than flat rates. Recall that the PsimH and PsimL simulated prices assure that all generation costs are recovered through energy prices, not through capacity payments or other supplementary contracts or services. This causes larger spikes in the simulated prices than in the actual prices, and creates a larger differential between valuing PV power at a flat rate and valuing it at a real-time rate.

Interestingly, the PsimH and PsimL simulated price series yield fairly similar differentials despite having very different price peakiness. This is because with both the extremely inelastic demand/import supply and the more moderate elasticity, the peaker capacity still recovers its capital costs in a relatively small number of high-demand hours. Whether peaker capacity costs are recovered through extremely high prices during 1.1% of all hours of the 4-year sample, as the PsimH results imply, or 4.9% of hours with moderately high prices, as comes out of the PsimL results, the PV panels are producing about the same amount on average during these hours, so still collect the aggregate revenues that the peaker gas plants need to earn to cover their capacity costs.

[19] In fact, the value maximizing orientation is probably never exactly southwest or south, but slightly south or west of southwest. Given the apparent shape of the value as a function of orientation, however, the southwest orientation numbers are likely to be close to the maximum value.

The bottom row of each case demonstrates clearly that a market organization that finances capacity costs through payments that do not vary with the scarcity value of energy greatly reduces the market valuation of solar PV. Much of the valuation boost that solar PV gets from a real-time pricing valuation evaporates if those real-time prices are never permitted to rise above the marginal cost of the highest cost generation. Instead of the 30%-50% increase from time varying valuation of the power that comes out of PsimL and PsimH, the premium is only 10%-20% when prices are constrained at marginal cost of the last unit produced.[20]

Controlling for the unobserved correlation between prices and solar PV production also has fairly small effect on the estimates. A very favorable reallocation of production across days, as described earlier, yields only slightly higher valuation of the power than making no adjustment for this unobserved correlation. Thus, for a given price series, the valuations are closely bounded by the estimates with and without that control.

The simulated prices are substantially lower than the actual prices, augmented or not. These weighted averages over the entire dataset mask a significant change that occurred in the middle of 2001. Capacity shortages and the exercise of market power that occurred during the 2000-2001 California electricity crisis caused prices to be well above long-run competitive levels.[21] From July 2001 to the end of 2003, simulated prices are substantially above the actual prices. In both periods, however, the premium from valuing the production of solar PV panels at hourly prices is much greater using the simulated prices than the actual prices.

Table 2 makes clear that value of electricity delivered from on-site solar PV, and its undervaluation, depend on the direction of its orientation. If the end-use customer on a flat-rate tariff has flexibility in the orientation of the panels, table 2 suggests that south orientation would maximize the private value under a flat-rate tariff.

For each direction of orientation, table 2 shows the flat-rate valuation of the power produced and the RTP valuation, both with and without adjustment for the unobserved correlation of price and solar PV production. The "pctg diff" columns indicate the differ-

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[20] These results are dependent, however, on the assumption that the highest cost generator still has a marginal cost of $75/MWh. If the market includes even a few MW of capacity with a much higher marginal cost, then the price at peak times will be allowed to rise further and the results would be closer to those of PsimL and PsimH.

[21] See, for instance, Borenstein, Bushnell and Wolak (2002) and Joskow and Kahn (2002).

ence in valuation from flat-rate valuation for panels in the same directional orientation.[22]

Table 2 demonstrates that, using either of the Piso price series, southwest and south orientation would yield very similar payoffs under real-time pricing of the power, and either would dominate west facing orientation. For south or southwest facing panels, accurate accounting for the real-time price of the power would increase the value of the PVs by about 0%-15% in Sacramento or San Francisco, by 7%-19% in LA. If either of the simulated price series resulted, however, the southwest orientation would clearly be more valuable and the difference in value compared to a flat-rate tariff would be much more significant, in the range of 30%-50%. If for some reason the panels were required to be west facing, the value enhancement from real-time pricing would be somewhat larger.

Whether the actual or simulated real-time price scenarios are better indicators of the future real-time value of solar PV production will depend on the degree to which wholesale price spikes are allowed to take place and to significantly contribute to capacity cost recovery by peaker plants. If resource adequacy regulations assure that the system always has excess production capacity and, consistent with this approach, revenues for capacity payments to generators are collected from retail customers in a time-invariant way, then wholesale prices will indicate that power at peak times is not much more valuable than off-peak. In that case, the calculations using prices capped at the marginal cost of generation would be more informative.[23] These results turn out to be much closer to those that come from using the actual system prices over this period. If a more efficient retail pricing system is used, however, so that price spikes reduce quantity demanded at peak times, then the calculations using simulated prices will more accurately portray the value. Though California has lagged behind other parts of the U.S. – such as Georgia, New York and Florida – in adopting more efficient retail pricing, it seems only a matter of time until a significant change in that direction takes place.

7. Locational variation in the value of electricity from solar PV

The previous analysis adjusted for the average line losses that occured within each

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[22] If the user has complete flexibility, however, she would choose to orient the panels south under a flat-rate tariff, so a more appropriate comparison would be to the south flat-rate column valuations. That would lower the percentage differences about 3-4% for southwest and about 15% for west facing panels.

[23] This ignores the possibility of solar PVs being considered part of the capacity counted towards resource adequacy. Though that could occur, the degree to which it would enhance the returns to owning PV production would depend idiosyncratically on the structure of the resource adequacy requirement, capacity payments, and special provisions for distributed generation.

hour when electricity was shipped from a central station generator over transmission and distribution lines to the end user, and is avoided with power from on-site solar PV. Locational variation in line losses, however, was not incorporated.

Apart from the line losses, discussions of the value of solar PV frequently turn to savings that might be derived from reduced investment in transmission and distribution (T&D) infrastructure. Unfortunately, this value often is inferred from idiosyncratic situations, such as a particular area that is nearly in need of transmission or distribution upgrades, but is able to defer them by installing solar PV. While that might be a useful basis for analysis if solar PV were selectively installed in transmission-constrained load pockets, solar PV policies seldom if ever make this distinction.

The experience in California is that solar PV has been installed broadly across the state, with no focus on transmission-constrained areas or minimizing line losses. The same is true in the more than 30 other states that have programs subsidizing solar PV installation. In circumstances such as this, a broad-based analysis of the T&D savings and line loss reductions from from the locational characteristics of solar PV is more appropriate than extrapolation from the most favorable (or unfavorable) example.

Such an analysis does not seem to support augmented valuation for reduction in distribution infrastructure. Low-voltage local distribution systems exhibit very large economies of scale in terms of capacity per household, so local distribution systems are built to handle much greater demand than residential neighborhoods exhibit. Put differently, one might ask how much less a distribution system for a new housing development would cost to install if the developer were putting solar PV on all the houses than if it were not. The answer seems to be that the difference is negligible. Thus, solar PV installation doesn't seem to have significant value in reducing distribution infrastructure costs for either new or existing neighborhoods.[24]

In contrast, transmission infrastructure and cost could be reduced when end-use demand declines, particularly during peak times. As a form of distributed generation solar PV does just that. For a broad-based solar PV policy, the relevant question is how much would the broadly reduced grid demand resulting from solar PV save by easing constraints on transmission. One approach to estimating this value is to recognize that nodal prices in an electricity grid reflect the incremental transmission constraints and the resulting in-

[24] This discussion is based on interviews with utility managers and academic engineers who work on transmission and distribution planning issues. I have not been able to locate any published work on the subject.

creased value of power in certain areas (and decreased value in other locations). Therefore, an analysis such as the one presented in table 2 could be carried out for each node in a system using nodal prices that reflect the locational value of power due to transmission constraints.

Data recently released by the California Independent System Operator and the California Energy Commission allow one to do such an analysis. As part of a market redesign study, the CAISO has divided its California control area into 29 regions and created locational hourly prices for each of these areas for all of 2003 and 2004.[25] The 29 locational price series are used here to adjust the system prices for congestion constraints and local variations in line losses across the system.

As part of California's program to promote solar PV power, the CEC has compiled a database of all solar PV installations that have received State support, which is virtually all solar PV installations. This analysis includes the data on all installations that applied for the rebate from its inception through December 2006 (and were entered into the database as of January 7, 2007). The dataset includes the location and rated capacity of the PV installations.[26]

To analyze the locational value of solar PV power, each of the 26,522 solar PV installations in the CEC dataset (a total installed capacity of about 103 MW) was assigned to one of the 29 pricing zones. Figure 3 shows the locations of the installations, which correspond closely with the population densities. Each system was then assigned the production profile of one of the three TRNSYS simulations of (30 degree tilt, south-facing) PV systems (scaled for the size of the system) based on whether the climate and location of the system most closely reflected Los Angeles, San Francisco or Sacramento. The (simulated) power produced by these PV systems was then evaluated first using the systemwide unconstrained CAISO price, then using the locational price to which each PV system had been assigned. Finally, for purpose of comparison, the power produced from these solar PV installations was also valued at the weighted average CAISO system price over this two-year period.

The results indicate that the solar PV that has been installed in California has not

[25] More precisely, the CAISO created nodal prices for 3000 distinct locations based on dispatch constraints in its control area and aggregated them to 29 load-weighted zonal prices for regions with minimal within-region transmission constraints. These data are available at http://www.caiso.com/docs/2004/01/29/2004012910361428106.html .

[26] These data are available at http://www.energy.ca.gov/renewables/emerging_renewables/index.html.

been located where it would be disproportionately valuable in reducing congestion or line losses. The 283,115 (simulated) MWh of production from these solar panels over the two-year period are worth an average of $61.11/MWh when valued at the hourly systemwide price and an average of $61.75/MWh when valued at the hourly nodal price.[27] Accounting for the location of solar PV production in California raises its value on average by about 1%.

The small effect is not particularly surprising given that the state rebate incentives for installing solar PV are available to all customers in the service territories of any of the three investor-owned utilities. There is no greater incentive to install solar PV if the customer is in a particularly valuable location within the grid. Thus, while a carefully planned program of location-based incentives for installing solar PV could potentially enhance their value by reducing transmission congestion and the need for transmission infrastructure investment, the program in California has not had such incentives and as a result has not had such an effect. The outcome is shown in figure 4, which presents the kW of capacity located in each of the 29 zones and the average annual value of production per kW of capacity, valued at the zonal price. It is apparent that solar PV is not clustered in the most valuable locations.

8. The Market Economics of Solar PV

Correcting for the time-varying and location-varying value of electricity is, of course, only one component of a market valuation of solar PV. In this section, I combine the previous results with some basic financial analysis of solar PV systems to calculate the net financial benefit of the technology within a market setting.

Cost and Production of Solar PV

Among analyses of solar PV costs, there is perhaps surprisingly small disagreement about the installation and operating costs. Table 3 presents a middle-ground estimate of costs and PV production of a 10kW (DC) PV system, in real 2007 dollars. This would be either a very large residential system or a small commercial system. The calculations are scalable up and down, with some adjustment for the economies of scale associated with installing larger systems.

The primary costs are installation (parts and labor) and replacement of inverters. Costs have been coming down steadily for decades, though they have flattened, at least

[27] The power is worth $57.31/MWh valued at the load-weighted average systemwide price over this two-year period.

temporarily, over the last few years. The \$80,000 installation figure in table 3 is a fair representation, possibly a bit optimistic, for a typical 10kW residential system in 2007, \$8.00 per watt.[28] Costs are likely to decline in the future, an issue discussed below.

Two related issues in a cost analysis are the lifetime of the panels and the appropriate discount rate for evaluation of the project. Most panels have at least limited warranties for 20 years or longer. I assume a 25 year lifetime in the calculations. This timeframe is frequently used in solar PV analyses. The effect of extending the life to 30 years on the cost per kWh is fairly small due to discounting. The bigger issue is the discount rate assumption. Table 3 presents a range of real interest rates. Industry press suggest that the higher rates in the table are likely to be more reflective of those interest rates that most actual buyers would face. Those are likely higher, however, than the real social discount rate that one might apply to a public policy analysis. For such analyses, a lower real interest rate is probably more appropriate. I carry out the analysis using real interest rates of 1%, 3%, 5%, and 7%, where the two lower rates are likely to be more appropriate for evaluation using a social discount rate and the two higher rates are more applicable for an evaluation using the market opportunity cost of capital.

After installation, the largest cost that the owner of a solar PV system is expected to face is for replacing the inverter. Median time-to-failure estimates for inverters range from 5-10 years, so I assume 8 years, which implies that the inverter will have to be replaced twice over the 25-year life of the panels, assumed to occur in years 8 and 16. Current inverter cost for a 10kW system is in the range of \$8000, but that is likely to decline over time. Inverter costs are assumed to decline by 2% per year in real terms, consistent with a study by Navigant consulting (2006) for National Renewable Energy Laboratory.

These costs and discount rates are then combined to produce a net present cost of a solar PV system in 2007 dollars. The figures shown in the top panel of table 3.

The market benefit of the solar PV system is based on the results in table 2, increased by 1% to adjust for transmission capacity value, as discussed in the previous section. The results in Table 3 are based on production of a panel in San Francisco that faces southwest, but it is clear from table 2 that using data from Los Angeles or Sacramento would change the results only slightly. Table 3 presents results for two of the simulation cases: “Psim - price cap at peaker MC” and “PsimH - high price volatility.” These represent the

[28] This is slightly lower than the average for 2006, based on California Energy Commission data, but the costs may decline slightly in the near term as material bottlenecks loosen, and panel production and installation capacities expand.

lowest and highest valuations among the simulation results. The results using "PsimL - low price volatility" lie between the ones presented. Results using the actual ISO prices without augmentation for the price constraint are about the same as with "Psim - price cap at peaker MC." After augmentation for when the price caps were binding during the California electricity crisis, valuations are about the same as with "PsimH - high price volatility." I take the mean of the upper and lower bound in table 2 ("RTP value" and "RTP* value") as the value of the power produced at the beginning of the installation's life.

Studies of solar PV production over a panel's lifetime suggest two adjustments from the TRNSYS simulation figures behind table 2 if one is evaluating solar PV production over the life of the panels. The first is the aging effect: PV cell production declines over time, with the best estimates in the range of 1% of original capacity per year. The second is the "soiling" effect: dirty solar panels absorb less solar radiation and generate less electricity. There is a whole literature on the impact of soiling, which concludes that it depends on idiosyncratic factors, such as the amount and density of rainfall, and on endogenous factors like maintenance effort. Table 3 adjusts for the aging effect, but not for soiling. A first-order adjustment for soiling would probably reduce the value of output by about 5%.[29]

The value of electricity production from solar PV in the future, of course, is not equal to the value of that same production today. If the real cost of electricity stayed constant, then the positive real interest rate would result in future electricity production having a lower net present value than current electricity production. On the other hand, if the real cost of electricity increases over time that would tend to increase the net present value. The bottom panel of table 3 presents calculations of the net present value of the power produced by the solar PV panels under a range of real interest rates and changes in the real cost of electricity. These values are calculated under the assumptions that the panels last 25 years and that their production declines by 1% of the original level each year.

A number of conclusions are immediately apparent from table 3. First, and perhaps most important, the net present cost of installing solar PV technology today far exceeds the net present benefit under a wide range of assumptions about levels of real interest rates and real increases in the cost of electricity. Lower interest rates and faster increases in the cost of electricity obviously benefit solar PV, but even under the extreme assumption of a

[29] Hammond et al (1997) and Kimber et al (2006) discuss soiling. I also assume that the panels are completely unshaded. For a more general discussion of the parameters that affect such simulations, see http://www.nrel.gov/rredc/pvwatts/changing_parameters.html.

1% real interest rate and 5% annual increase in the real cost of electricity, the cost of solar PV is about 80% greater than the value of the electricity that it will produce. It is worth noting that even without further technological progress in energy generation from wind, geothermal, biomass, and central station solar thermal, with a 5% annual increase in the real cost of electricity, all of these technologies would be economic (without subsidies or recognition of environmental externalities from fossil fuels) well before the 25-year life of the solar panels was over. Under more moderate assumptions about the real interest rate and the escalation in the cost of electricity, the net present cost of a solar PV installation built today is three to four times greater than the net present benefits of the electricity it will produce.

Learning-By-Doing, Economies of Scale and Appropriability

Probably the most common argument among advocates of large subsidies for solar PV installation is that greater installation of panels will lead to learning-by-doing or experience effects and will drive down the cost and price of this technology. Though the argument is theoretically possible, its espousers nearly always confuse related, but distinct, effects with learning, effects with very different policy implications.

First, while the question is whether there is a learning-by-doing effect, many of the studies have simply shown that costs have come down over time as the total number of installed panels has increased.[30] Unfortunately, this fails to distinguish between an experience effect on costs and a number of other factors that have changed costs over time. In particular, exogenous technological advances in crystalline silicon solar technologies have occurred over this time. These advances were due in large part to investments made outside the commercial solar PV sector, primarily investments made under the U.S. space program and investments in the semiconductor industry. Second, the industry has simply gotten larger, which could lead to savings from economies of scale–producing more units of output in each period–rather than experience effects, which result from a larger aggregate history of production over time.[31]

The distinction between experience effects and economies of scale may seem minor, but the implications for the economic analysis of public policy are immense. To explain

[30] See, for instance, Duke and Kammen (1999) and Swanson (2004).

[31] The difficulty in separately identifying the effects of learning by doing versus economies of scale and exogenous technological progress is well-known. In regard to crystalline silicon solar PV, Margolis (2003) recognizes the potential for overstating learning by doing effects due to these factors. See also Wiser et. al. (2006) for a thorough presentation of changing PV costs over time.

this requires revisiting two of the basic market failure arguments in microeconomics. One is that there is some missing market or externality, a good (or bad) that is not priced correctly. The other is a distortion in the incentive to innovate: if a firm captures less than the full value of an innovation it develops, then it will have a sub-optimal incentive to innovate.

The mispriced good or externality is not a viable argument for subsidies targeted specifically at installation of solar PV. The fact that fossil fuel energy produces GhGs and other pollutants could certainly argue for taxing such energy (or the GhGs and other pollutants directly). If such taxes are politically infeasible, a possible second-best policy would be a general subsidy of renewable power or power than does not produce these pollutants. While each alternative power source has a different set of environmental impacts, it is not plausible that the correct implementation of such a subsidy program is much greater subsidies for solar PV–based on environmental externalities–than for other renewable energy sources.[32]

So, the argument in favor of subsidizing solar PV installation is generally based on the distortion in the incentive to innovate. In the innovation literature more generally, this is referred to as a failure of the innovator to appropriate the full benefits of its newly-created intellectual property. The key is the ability of the innovator to appropriate the benefits. Will the firm be able to maintain exclusive use of its new production or installation knowledge? Or, will competitors be able quickly to free ride, obtaining the same knowledge cheaply through observation, industrial spying, reverse engineering, or hiring away employees of the innovating company? The last of these techniques might be particularly effective in capturing the experience benefits that a solar PV competitor has gained.

Appropriability concerns do not support subsidies based on economies of scale. If one firm can drive down its costs by producing at large scale in its factory or running a large scale installation operation, those benefits are highly appropriable by that large firm. Other, smaller firms are not likely to experience a cost decline because a competitor is enjoying economies of scale. It is for this reason that significant economies of scale in any industry, short of creating a natural monopoly, are not a basis for government intervention.

[32] The huge subsidies that fossil fuel companies in the U.S. receive through favorable tax treatment are often used to justify offsetting subsidies for renewables. While the argument is correct in some cases, it must be applied carefully. For instance, the billions in tax breaks that oil companies receive for domestic exploration benefit owners of the oil companies, but they do not substantially affect the price of oil, because oil is traded in a world market and the impact of these subsidies on world supply is negligible. While this points out the disturbing lack of a rational basis for such gifts to oil company shareholders, it also means that oil exploration subsidies do not put alternative energy sources at a financial disadvantage in the marketplace.

Appropriability is much more salient in learning-by-doing concerns. But this effect has two necessary conditions: there must be both significant learning-by-doing that results from substantially increasing total historical production and the knowledge gains from a company installing more solar PV systems must significantly spill over to competititor firms. Nemet's (2006) analysis suggests that learning by doing has actually played a relatively small role in the decline of solar PV costs over the last 30 years. He finds that the scope for learning-by-doing using the current crystalline silicon technology is quite limited given the current state of the industry and the fact that even California's large solar PV subsidy program will have a small effect on world solar PV production and installation.[33] While the evidence of minimal learning-by-doing effects is not dispositive, it is more convincing than any existing research claiming significant effects. Whether such experience effects, if they exist, exhibit low appropriability–the second necessary condition to justify subsidies–is also uncertain, though one can certainly see how movement of managers among companies could have such an effect.

Technological Advance and the Value of Waiting

Understanding the declining trend in solar PV costs is critical to formulating public policy not just because of the learning-by-doing question, but also because of the durable and irreversible nature of the investment. Put simply, if solar PV costs are coming down very rapidly for reasons exogenous to the solar PV subsidy policy, then it is more likely to make sense to delay investment. If solar PV costs are declining by 20% per year, for instance, the same amount of investment (in present value terms) made 5 years from now will yield much more renewable energy than today. Given that the damage from GhGs is cumulative over time, it makes almost no difference whether the gasses are released in 2007 or 2012. Similarly, the damage is geographically cumulative; GhGs released in California have the same impact as GhGs that come from Florida. It makes no more sense to make an investment in solar PV at the more expensive time than it would to focus a subsidy on the location in which solar panel installation is most costly.

Nonmarket Value of Solar PV

As discussed in section 2, I do not attempt to quantify the nonmarket costs and benefits of solar PV. The environmental, geopolitical, and security benefits of solar PV are certainly real, but are beyond the scope of this research. The results presented here, however, indicate the range of nonmarket benefits that would be necessary in order for

[33] Interestingly, a recent policy paper by consultants to the solar PV industry, Harris and Moynahan (2007), reaches the same conclusion.

installation of solar PV today, using the currently available technology, to be socially beneficial. The net present value of these externalities would need to be at least as great as the difference between the net present cost of installing the system shown in the top panel of table 3 and the net present market value of the output, shown in the bottom panel of that table.

To make comparisons easier, I translate the figures in table 3 into levelized costs and benefits per MWh over the life of the panels. These numbers are presented in table 4. For instance, at a 3% real annual interest rate, the second column indicates that the net present cost of the solar PV installation is equivalent to purchasing each MWh over the life of the panels at a constant real price of $408/MWh. Similarly, at a 3% real annual interest rate and an expected 3% annual increase in the real price of electricity, the low price volatility case indicates that the net present value of the power generated is equivalent to avoiding purchasing all of that power at a constant real price of $111/MWh.[34]

For solar PV to satisfy the social cost-benefit test, nonmarket net benefits would have to equal at least the difference between these two figures. The bottom panel of table 4 shows that the difference for the cases considered here ranges from $148/MWh to $492/MWh. For illustration, consider the implication of a market benefit-cost differential of $300/MWh. A coal-fired electricity generation plant produces about one ton of CO_2 per MWh, so for this differential to be justified based on avoided GhG emissions, the price would have to be over $300 per ton of CO_2-equivalent GhGs (which is the standard unit of measurement). Natural gas-fired power plants create about half as much CO_2 per MWh, so the price of GhGs would have to be about twice as high, $600/ton of GhGs, to justify a switch to solar PV. Policymakers discussing a tradable GhG permit market in the United States commonly speak of "escape valves," a price at which the government would stand ready to sell an unlimited number of permits, at $20/ton or lower. Few policy analysts, including those in the environmental community, believe that the price is likely to exceed $100/ton even without an escape valve, because the economics of other renewable energy sources become quite favorable around $100 per ton.

It is more difficult to make these sorts of comparisons for geopolitical and security externalities, because monetary valuations of these effects are extremely scarce and not particularly convincing. Still, the bottom panel of table 4 presents a context for considering such valuations if and when they emerge.

[34] Of course, with the real price of electricity rising at 3% per year the power displaced early in the life of the panels would be worth less than the power displaced later. The levelized value gives the equivalent net present value of the savings from a constant real price of the displaced power.

9. Conclusion

To fully understand the costs and benefits of solar PV power requires a careful analysis of all of its market and non-market attributes. The first goal of this paper was to present a method for analyzing the market value of solar PV power recognizing that it produces a disproportionate amount of its output at times when the weather is sunny and system demand is high. Applying the method to California, a summer-peaking system, suggests that correctly accounting for the time-varying electricity production of solar panels could increase its value substantially compared to a valuation that does not adjust for the favorable time pattern of production from solar PV.

Using actual real-time prices, the change in value is between 0% and 20%, but using prices from a simulation model, which assures that peaking gas capacity covers its fixed costs through high energy prices, the increased value from real-time valuation of solar power could be in the 30%-50% range. Unfortunately, simulation of a wholesale electricity market in which capacity costs are recovered through a flat per-kilowatt-hour fee so that wholesale prices are substantially less volatile—a much more common institutional setting in the United States today—lowers the premium value of solar PV power to 0%-20% again.

While that analysis also takes into account the savings on time-varying line losses of electricity when the power is produced on site by solar PV panels, it does not account for potential savings from reduced need for transmission and distribution capacity. A separate analysis of these effects, however, indicates that they are very unlikely to amount to more than one to two percentage points in solar PV valuation.

A number of previous cost-benefit analyses for solar PV have been done, but they have not incorporated a well-grounded adjustment for the favorable timing and location of solar PV production, and many have included hard-to-justify assumptions regarding economic discounting. Unfortunately, after adjusting for these factors, the cost of solar PV remains many times higher than the market valuation of the power it produces.

The analysis does not incorporate valuation of externalities, or the reduction of externalities from other generation technologies, but the results speak to the level of such non-market value that would be necessary to make the social cost-benefit analysis favorable. This cost-benefit gap is much greater than plausible estimates of the value of greenhouse gas reduction from solar PV generation.

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TABLE 1: Change in Average Value Per MWh of Solar PV Power from Adjusting for Time-Varying Production

SACRAMENTO		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - North	$75.56	$79.01	5%	$82.78	10%	$81.66	8%	$85.66	13%	$82.97	10%	$86.97	15%
PisoAugmented	$98.34	$97.56	-1%	$107.08	9%	$100.84	3%	$110.13	12%	$101.74	3%	$109.93	12%
PsimH - high price volatility	$68.25	$87.58	28%	$90.83	33%	$97.37	43%	$102.12	50%	$104.95	54%	$110.67	62%
PsimL - low price volatility	$67.05	$85.58	28%	$88.44	32%	$93.94	40%	$98.00	46%	$100.35	50%	$105.15	57%
Psim - price cap at peaker MC	$68.25	$76.95	13%	$77.89	14%	$78.68	15%	$79.76	17%	$79.97	17%	$81.13	19%
SAN FRANCISCO		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - North	$75.56	$80.30	6%	$84.35	12%	$82.31	9%	$86.66	15%	$83.35	10%	$87.88	16%
PisoAugmented	$98.34	$101.47	3%	$110.10	12%	$103.69	5%	$112.24	14%	$103.62	5%	$111.79	14%
PsimH - high price volatility	$68.25	$89.35	31%	$92.87	36%	$98.91	45%	$103.93	52%	$106.86	57%	$112.92	65%
PsimL - low price volatility	$67.05	$86.81	29%	$90.32	35%	$94.73	41%	$99.55	48%	$101.33	51%	$107.01	60%
Psim - price cap at peaker MC	$68.25	$77.02	13%	$78.25	15%	$78.55	15%	$79.90	17%	$79.92	17%	$81.32	19%
LOS ANGELES		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - South	$69.44	$75.74	9%	$79.32	14%	$78.06	12%	$82.66	19%	$79.58	15%	$84.87	22%
PisoAugmented	$84.05	$89.55	7%	$95.37	13%	$92.16	10%	$99.43	18%	$93.03	11%	$101.23	20%
PsimH - high price volatility	$68.25	$82.31	21%	$86.93	27%	$89.78	32%	$97.44	43%	$96.54	41%	$106.16	56%
PsimL - low price volatility	$67.05	$81.23	21%	$85.00	27%	$87.71	31%	$93.39	39%	$93.60	40%	$100.48	50%
Psim - price cap at peaker MC	$68.25	$75.91	11%	$77.13	13%	$77.20	13%	$78.54	15%	$78.43	15%	$79.81	17%

TABLE 2: Change in Annual Value of Production of 10kW Solar PV System
from Adjusting for Time-Varying Production

SACRAMENTO	South Facing PV					Southwest Facing PV					West Facing PV				
	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff
Piso - North	$1,052	$1,100	5%	$1,152	10%	$1,011	$1,093	8%	$1,146	13%	$893	$981	10%	$1,028	15%
PisoAugmented	$1,369	$1,358	-1%	$1,490	9%	$1,316	$1,349	3%	$1,474	12%	$1,162	$1,203	3%	$1,299	12%
PsimH - high price volatility	$950	$1,219	28%	$1,264	33%	$913	$1,303	43%	$1,366	50%	$807	$1,240	54%	$1,308	62%
PsimL - low price volatility	$933	$1,191	28%	$1,231	32%	$897	$1,257	40%	$1,311	46%	$792	$1,186	50%	$1,243	57%
Psim - price cap at peaker MC	$950	$1,071	13%	$1,084	14%	$913	$1,053	15%	$1,067	17%	$807	$945	17%	$959	19%
Avg PV Prod (kWh/hr - AC)	1.589	1.589		1.589		1.527	1.527		1.527		1.349	1.349		1.349	
SAN FRANCISCO	South Facing PV					Southwest Facing PV					West Facing PV				
	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff
Piso - North	$1,072	$1,140	6%	$1,197	12%	$1,042	$1,135	9%	$1,195	15%	$918	$1,012	10%	$1,068	16%
PisoAugmented	$1,396	$1,440	3%	$1,563	12%	$1,357	$1,430	5%	$1,548	14%	$1,195	$1,259	5%	$1,358	14%
PsimH - high price volatility	$969	$1,268	31%	$1,318	36%	$941	$1,364	45%	$1,434	52%	$829	$1,298	57%	$1,372	65%
PsimL - low price volatility	$952	$1,232	29%	$1,282	35%	$925	$1,307	41%	$1,373	48%	$814	$1,231	51%	$1,300	60%
Psim - price cap at peaker MC	$969	$1,093	13%	$1,111	15%	$941	$1,084	15%	$1,102	17%	$829	$971	17%	$988	19%
Avg PV Prod (kWh/hr - AC)	1.620	1.620		1.620		1.575	1.575		1.575		1.387	1.387		1.387	
LOS ANGELES	South Facing PV					Southwest Facing PV					West Facing PV				
	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff	flat-rate value	RTP value	pctg diff	RTP* value	pctg diff
Piso - South	$1,003	$1,094	9%	$1,146	14%	$976	$1,098	12%	$1,162	19%	$865	$991	15%	$1,057	22%
PisoAugmented	$1,215	$1,294	7%	$1,378	13%	$1,182	$1,296	10%	$1,398	18%	$1,047	$1,159	11%	$1,261	20%
PsimH - high price volatility	$986	$1,189	21%	$1,256	27%	$960	$1,262	32%	$1,370	43%	$850	$1,203	41%	$1,322	56%
PsimL - low price volatility	$969	$1,174	21%	$1,228	27%	$943	$1,233	31%	$1,313	39%	$835	$1,166	40%	$1,252	50%
Psim - price cap at peaker MC	$986	$1,097	11%	$1,115	13%	$960	$1,085	13%	$1,104	15%	$850	$977	15%	$994	17%
Avg PV Prod (kWh/hr - AC)	1.650	1.650		1.650		1.605	1.605		1.605		1.422	1.422		1.422	

Table 3: Analysis of NPV Cost and Value of Production from 10kW Solar PV installation
(San Francisco installation facing SW, 30° tilt; all monetary figures in 2007 dollars)

Annual Real Interest Rate		1%	3%	5%	7%
Cost of PV System Installation		$80,000	$80,000	$80,000	$80,000
Years of Productive Life		25	25	25	25
Cost of Inverter Replacement in Year 8 (before discounting)		$6,806	$6,806	$6,806	$6,806
Cost of Inverter Replacement in Year 16 (before discounting)		$5,790	$5,790	$5,790	$5,790
Discounted Present Cost of System and Inverters		$91,223	$88,981	$87,259	$85,923
--					
Discounted Present Value of Power Produced					
"Excess Reserves - Very Low Price Volatility Case"			Annual Real Interest Rate		
(Psim - price cap at peaker MC)		1%	3%	5%	7%
	-1%	$19,228	$15,681	$13,071	$11,109
Annual Change	0%	$21,505	$17,368	$14,345	$12,091
in Real Price	1%	$24,148	$19,310	$15,802	$13,205
of Electricity	3%	$30,804	$24,148	$19,390	$15,919
	5%	$39,871	$30,654	$24,148	$19,467
Discounted Present Value of Power Produced					
"No Reserve Use - Very High Price Volatility Case"			Annual Real Interest Rate		
(PsimH - high price volatility)		1%	3%	5%	7%
	-1%	$24,611	$20,071	$16,730	$14,220
Annual Change	0%	$27,526	$22,230	$18,361	$15,476
in Real Price	1%	$30,909	$24,716	$20,226	$16,902
of Electricity	3%	$39,427	$30,909	$24,818	$20,375
	5%	$51,033	$39,236	$30,909	$24,917

Table 4: Levelized Cost and Value of Production Per MWh from 10kW Solar PV installation
(San Francisco installation facing SW, 30° tilt; all monetary figures in 2007 dollars)

Annual Real Interest Rate		1%	3%	5%	7%
Cost of PV System Installation		$80,000	$80,000	$80,000	$80,000
Years of Productive Life		25	25	25	25
Cost of Inverter Replacement in Year 8 (before discounting)		$6,806	$6,806	$6,806	$6,806
Cost of Inverter Replacement in Year 16 (before discounting)		$5,790	$5,790	$5,790	$5,790
Levelized Cost per MWh Produced		$337	$408	$484	$565
--					
Levelized Value per MWh Produced					
"Excess Reserves - Very Low Price Volatility Case"			Annual Real Interest Rate		
(Psim - price cap at peaker MC)		1%	3%	5%	7%
	-1%	$71	$72	$72	$73
Annual Change	0%	$80	$80	$80	$80
in Real Price	1%	$89	$88	$88	$87
of Electricity	3%	$114	$111	$107	$105
	5%	$147	$140	$134	$128
Levelized Value per MWh Produced					
"No Reserve Use - Very High Price Volatility Case"			Annual Real Interest Rate		
(PsimH - high price volatility)		1%	3%	5%	7%
	-1%	$91	$92	$93	$93
Annual Change	0%	$102	$102	$102	$102
in Real Price	1%	$114	$113	$112	$111
of Electricity	3%	$146	$142	$138	$134
	5%	$189	$180	$171	$164
--					
Difference Between Levelized Cost and Value per MWh Produced					
"Excess Reserves - Very Low Price Volatility Case"			Annual Real Interest Rate		
(Psim - price cap at peaker MC)		1%	3%	5%	7%
	-1%	$266	$336	$412	$492
Annual Change	0%	$257	$328	$404	$485
in Real Price	1%	$248	$320	$396	$478
of Electricity	3%	$223	$297	$377	$460
	5%	$190	$268	$350	$437
Difference Between Levelized Cost and Value per MWh Produced					
"No Reserve Use - Very High Price Volatility Case"			Annual Real Interest Rate		
(PsimH - high price volatility)		1%	3%	5%	7%
	-1%	$246	$316	$391	$472
Annual Change	0%	$235	$306	$382	$463
in Real Price	1%	$223	$295	$372	$454
of Electricity	3%	$191	$266	$346	$431
	5%	$148	$228	$313	$401

FIGURE 1: Hourly Average System Demand and Solar PV Production for July Weekdays

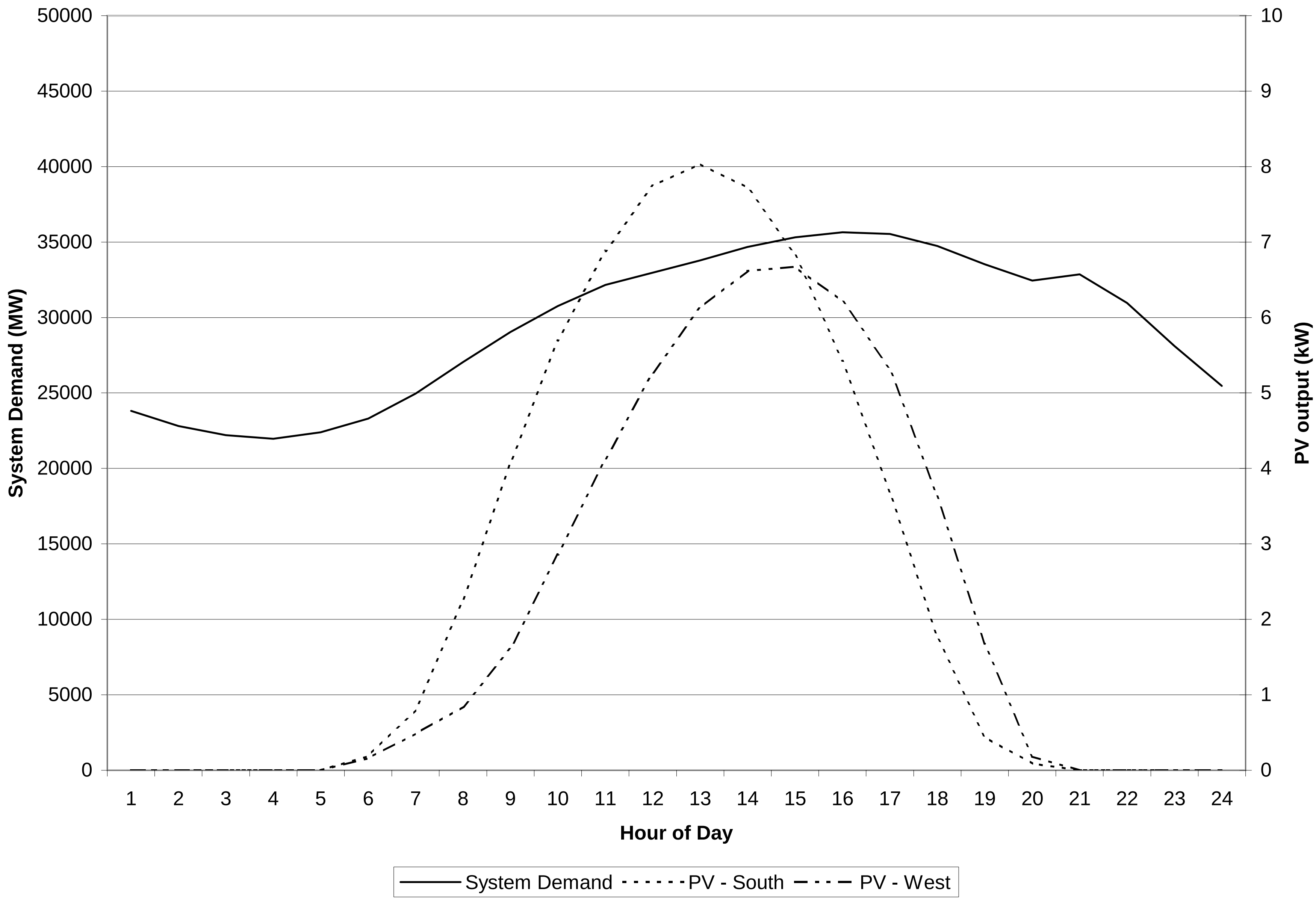


Figure 2: Hourly Average Real-time Price and Solar PV Production for July Weekdays

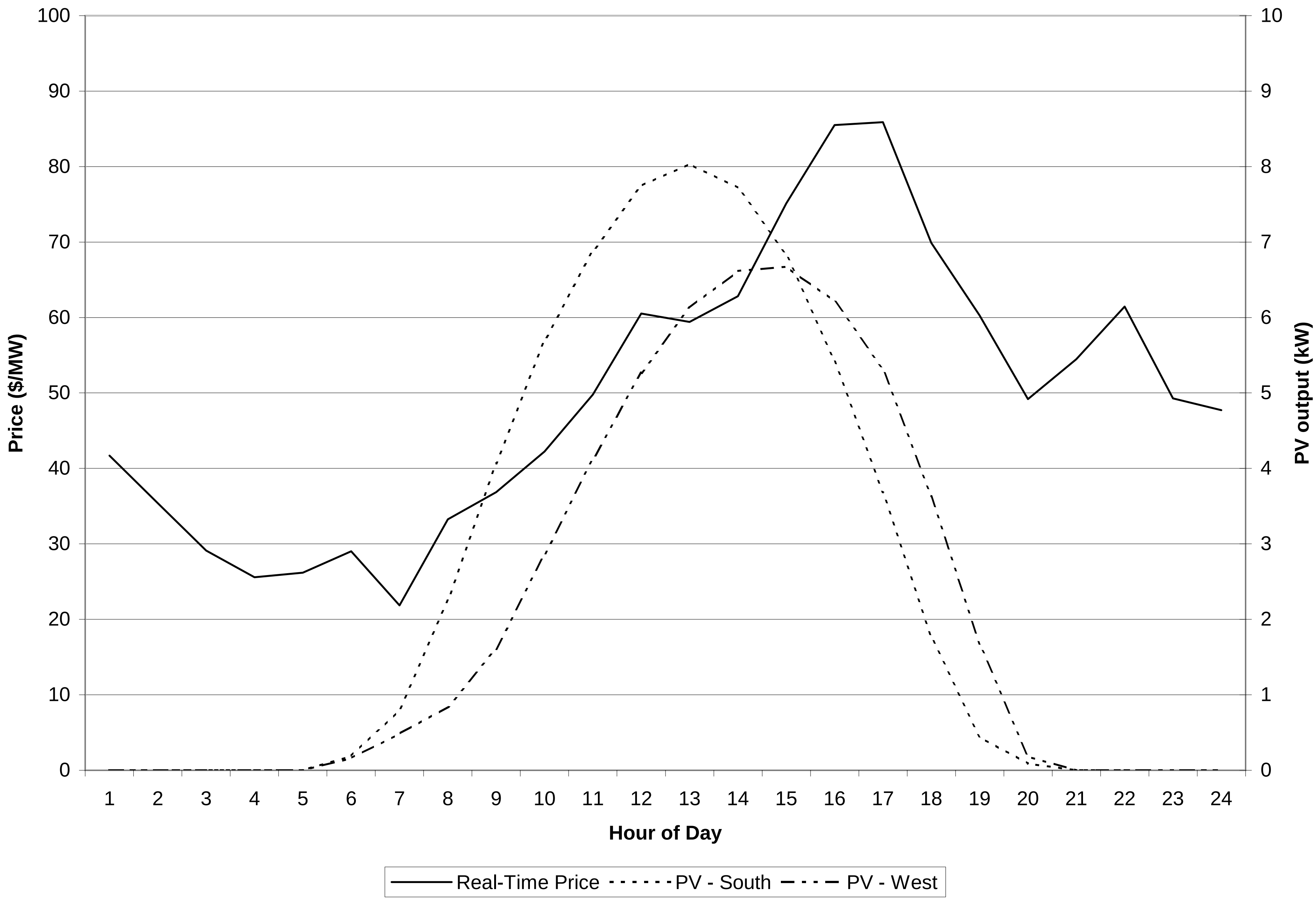


Figure 3: Solar PV Installations in California as of January 2007

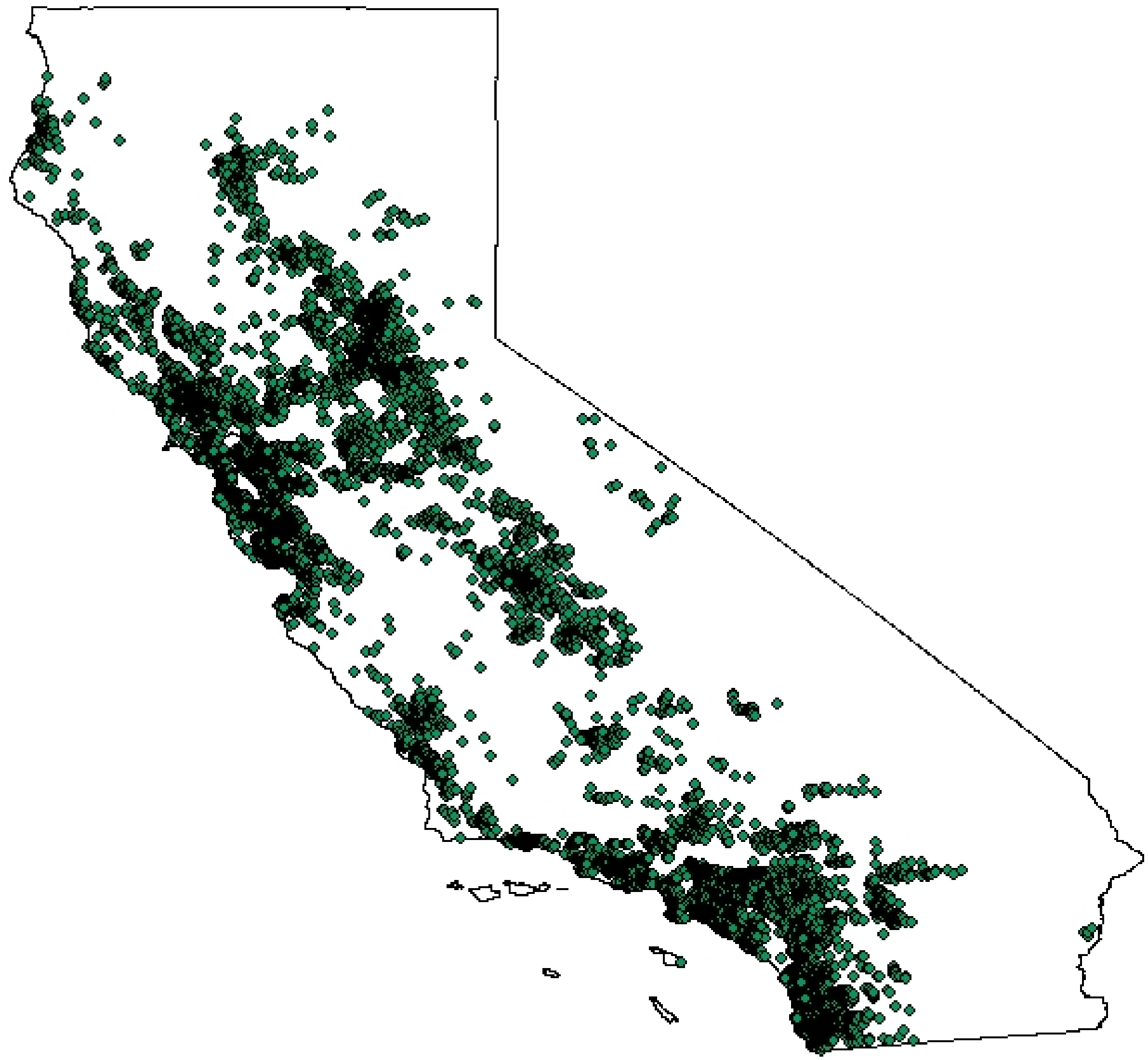
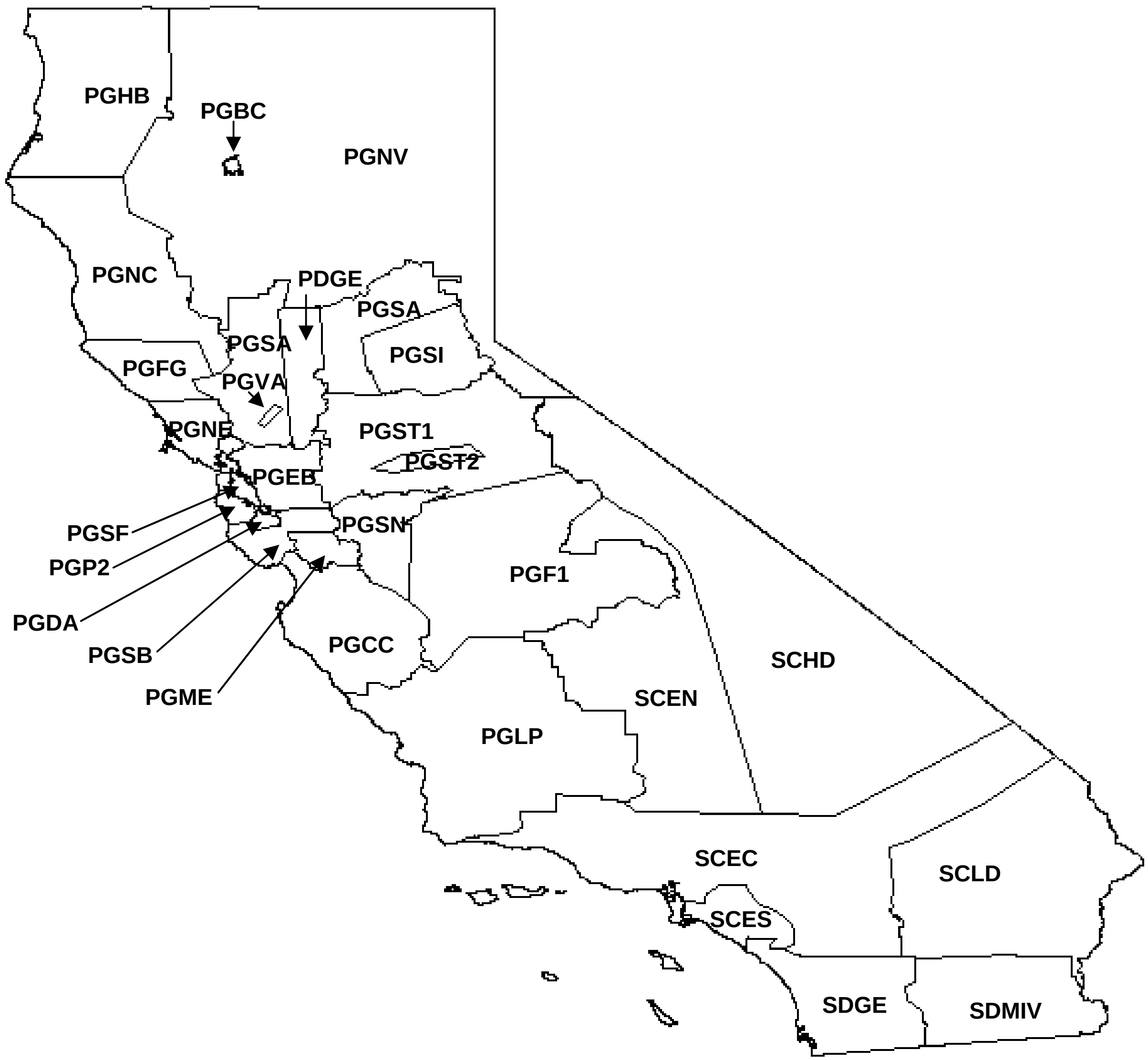


Figure 4: Installed Solar PV Capacity and Annual Value per kW by CAISO Zone



Zone	kW	$ Annual Value
SCEC	16,789	$86.13
SDGE	13,059	$100.36
PGEB	8,372	$80.37
PGNB	7,221	$82.89
PGSA	6,207	$79.36
PGF1	5,956	$81.50
SCES	5,383	$88.74
PGSB	5,377	$84.42
PGLP	4,051	$79.33
PGST1	3,837	$80.95
PGSI	3,208	$78.82
PGP2	3,208	$84.61
PGNV	2,637	$75.00
PGDA	2,374	$83.37
SCEN	2,239	$83.93
PGCC	2,118	$80.88
PGFG	2,094	$82.29
PGDE	2,050	$80.54
PGSF	1,823	$87.83
PGNC	1,471	$83.29
PGME	1,281	$82.10
PGHB	623	$86.13
PGST2	501	$80.92
SCHD	325	$72.95
PGVA	279	$80.08
SCLD	232	$83.78
PGSN	89	$80.76
PGBC	12	$77.09
SDMIV (1)	0	$68.90
Total	102,813	$85.02

(1) SDMIV had no solar installations as of January 1, 2007. Shown is the hypothetical $ / kW.