Economic and Environmental Evaluation of Residential Fixed Solar Photovoltaic Systems in the United States

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Abstract: While the majority of electricity generated in the United States comes from fossil fuels such as coal and natural gas, a comparatively small amount comes from renewable sources such as solar and hydropower. As global environmental issues become a greater concern, more generation may need to come from renewable sources. One often-mentioned alternative is residential solar photovoltaic (PV) systems, which could be an especially attractive source of energy in the southwestern United States, where high amounts of solar radiation are available. In this paper, we compare the life-cycle costs of current solar photovoltaic technology in Arizona versus New York to highlight the relevant issues related to the economic and environmental renewable energy decision-making process. We find that solar PV systems alone are currently inferior to grid electricity across a wide range of scenarios, including prospective technology improvements. Net metering with PV systems, where customers sell solar electricity to the grid and buy back their demand, may be competitive given real-time electricity pricing. Using PV systems in remote systems looks to be a viable alternative.

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Introduction

Electricity services are essential to maintaining today's daily living standards and to prolonging vital economic activities worldwide. The United States relies mainly on the consumption of fossil fuels to produce electricity: 71% of the electricity generated and 86% of the total energy consumed in the United States come from fossil fuels, with 20% of the remaining electricity generation obtained from nuclear generators (DOE 2003a,b). A growing economy with an increasing demand for energy and rolling blackouts in California in 2000 and 2001 have drawn attention to electricity issues nationwide. Transmission constraints are further confounding the ability to provide sufficient quantities of electricity to certain regions (DOE 2002). Regional transmission problems can be solved either by building more transmission lines or by siting more generation in areas with transmission constraints. Both options attempt to match electricity supply with demand.

The generation of electricity is a capital- and energy-intensive process that needs to be carefully planned and executed over time. Electricity generation is also the primary source of air pollution and greenhouse gas emissions (EPA 2003a,b). Alternatives to fossil fuels should be considered at the same time as potential greenhouse gas emissions targets are considered. Currently, the alternatives on the market that provide examples of successful implementation are wind farms, solar cells, nuclear, biomass (alcohol fuels, wood and waste combustion), hydropower, and geothermal energy. Beyond generation and transmission, conservation is an important component of the portfolio of electricity services.

The objective of this paper is to evaluate one of the alternative technologies currently available in the market to generate electricity—solar photovoltaics (PVs). We will apply a net present value and equivalent annual net cost approach to evaluate the economic implications of installing and using a fixed solar energy system to provide electricity to a typical household in Phoenix, Arizona, and to one in Albany, New York. These two cities are chosen in order to evaluate the economic feasibility of using solar energy for electricity generation in regions of the United States that are obvious as well as less obvious locations for utilization of solar resources. In addition, some environmental implications will be commented upon as part of the conclusions. Note that most electricity consumption data are at the state level, so these cases will be representative of Arizona and New York rather than of the specific cities. Similar work has been done for commercial PV installations (Herig et al. 1998).

Background on Solar Technology

The amount of energy generated from solar sources in the United States peaked at about 20 TW·h (terawatt-hours) in 1995 and has since decreased slightly. Overall, renewable sources provide less than 10% of U.S. energy, with solar contributing less than 1% of renewable energy (DOE 2003c). In terms of electricity generation, the fractions are similarly small: 9 and 0.1%, respectively (DOE 2003a). Solar energy can be produced via solar thermal systems (e.g., to make hot water in homes) and via PV methods.

For residential PV systems, generation of electricity using solar energy depends on the amount of direct sunlight available at the location where it is needed. Sunlight varies with the season as

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the rotational axis of the Earth shifts to lengthen or shorten days. As an example, the daily amount of solar energy (in kWh) per square meter in Phoenix can be 1.5 to 2 times greater than in Albany (NREL 2003). June (the month with the longest days) generally is the highest solar radiation month in the northern hemisphere. In the premier solar resource areas of the United States the average annual solar radiation exceeds 8 kW·h/m^2/day.

The PV array should be positioned based on the amount of sun striking the modules (e.g., fixed in an optimal position, or with a system that tracks the sun throughout the day). In addition, PV systems produce direct current (DC), so it is necessary to install an inverter to change direct into alternating current (AC) for compatibility with most household systems and appliances. Such a system also requires the use of a secondary power source to maintain the power in case of unexpected sunlight blockage or power outage.

In this paper, we consider the implementation of currently available PV modules—due to their ability to be fixed on roofs of houses—and not tracking systems, which could lead to aesthetic or land-use concerns. At present, these modules are each approximately 2×1 m in size. We assume the modules are attached to houses such that they are facing south at a fixed tilt of 0°, as if placed on a flat roof. To minimize cost, we design the systems based on assumed average solar radiation for noncloudy months.

Costs of Photovoltaic Technology

In the consumer retail market, the average price for emerging solar PV cells at the end of 2003 is approximately \$4.50/Wp (Watt-peak) while the overall average is about \$6/Wp (SolarBuzz 2003). A Watt-peak unit represents the maximum amount of electricity a module is able to provide (thus a 100 Wp unit would cost approximately \$450). Most of the modules in the SolarBuzz sample were in the 100 Wp range, which is typical in residential installations.

The average household spent \$75 on electricity (for 877 kW·h) per month in 2001 (DOE 2003d). The amount of electricity per household is expected to increase in the short run. The U.S. Department of Energy (DOE) offers two main reasons that would explain this increase: (1) Residential building in the warmer climate areas of the United States, where most new homes require central air conditioning, is increasing; and (2) more consumer electronics and electric appliances such as personal computers, dishwashers, and clothes washers and dryers will be used. In addition, newer homes across the country are on average larger than existing homes, therefore requiring more energy (either for heating or cooling and lighting), even with the use of more efficient equipment (DOE 2004).

With these facts in mind, we considered the economic cost-effectiveness of grid-connected residences in two U.S. cities, given current technology as well as local factors such as amount of solar radiation, electricity price, and electricity consumption.

Solar Photovoltaic System Design Issues

While a solar PV system is designed with consideration of the amount of solar radiation available, the system will need to operate under a range of climatic conditions, that is, given the amount of available sunny or partly cloudy days (that is, noncloudy days) where the system would be able to operate. We design a general system based on the average of the solar radiation values of the relative noncloudy months as this value varies significantly, even across noncloudy months. As an example, the monthly solar radiation values for modules placed on a flat surface relative to the ground (that is, zero tilt) in Phoenix and Albany are provided in Table 1 (NREL 2003). These values have a listed uncertainty of 9%. Note that solar radiation data are also provided for modules installed at a tilt equal to the latitude of the site (for example, 33° for Phoenix and 43° for Albany) and at tilts of ±15° from latitude. However, the average annual solar radiations are at most 15% greater with any of these nonzero tilt configurations. In practice, if installed on top of houses they would inherit the existing tilt of the roof. Houses in Phoenix tend to have flatter roofs than Albany, but since the variance in solar radiation rates due to tilt are small, we ignore these differences.

Table 1. Monthly Solar Radiation for Flat-Plated Fixed Collectors Facing South at Fixed Tilt (Nontracking)

	Solar radiation (kWh/m^2/day)	
Month	Phoenix	Albany
January	3.2	1.8
February	4.3	2.6
March	5.5	3.6
April	7.1	4.7
May	8.0	5.5
June	8.4	6.0
July	7.6	6.1
August	7.1	5.2
September	6.1	4.1
October	4.9	2.8
November	3.6	1.7
December	3.0	1.4

Note: Source is NREL (2003).

Phoenix is chosen as a case study because it is in the southwestern United States, with high levels of solar radiation and also in a geographical area with a fast-growing suburban population. Albany was chosen because it is representative of the northeastern United States, with a large population base but not known for high solar radiation levels. The combination of these two city case studies will represent near extremes of the range of residences in the United States but is not meant explicitly to assume the best- and worst-case sites for solar PV installations.

Sizing a system for the maximum June solar radiation rate would minimize the number of modules and undersupply electricity most of the year, requiring additional grid electricity purchases. For example, in Phoenix the average monthly solar radiation in June is 8.4 kW·h/m^2/day for fixed (nontracking) flat-plate modules, yet only 6 kW·h/m^2/day in March and September (almost 30% less). Phoenix also has 81% noncloudy days during the year (NOAA 2003). As a simplifying assumption, we assume that the system would operate exclusively for 10 months of the year (that is, 80% of the days) and take electricity from the grid for 2 months. We assume the 10 months considered in the system design would be the months with the highest solar radiation rates, and design the system using the average of those months' rates. The highest solar rates are centered in the summer months, when the electricity is also otherwise the most expensive.

As shown in Table 1, the lowest solar radiation months for Phoenix are December and January. The average of the remaining 10 months is a best-case 6.3 kW·h/m^2/day, and this is the value of solar radiation that would be used in an initial estimate of the system design. Note that the worst-case average over any 10-

Table 2. Key Assumptions in Model Cases

Assumptions	Phoenix	Albany
Annual average electricity use per household (kWh) (DOE 2003d)	12,892	6,532
Average solar radiation for system design (Table 1)	6.3	5.3
Grid electricity cost (\$/kW·h) (DOE 2003d)	\$0.083	\$0.14
Number of months of grid electricity	2	6

Table 3. Summary of Model Cash Flows (Costs) for Phoenix and Albany

Year	Phoenix	Albany	Comment
0	\$56,700	\$35,841	Upfront costs from Eq. (1)
1–20	\$180	\$460	Yearly grid electricity purchases
7	\$11,300	\$5,700	First battery replacement
14	\$9,570	\$4,850	Second battery replacement

month period is 5.3 kW·h/m^2/day. Conversely, Albany has 50% noncloudy days (NOAA 2003), so we assume the solar PV system could be used 6 months, April–September, with an average solar radiation rate of 5.3 kW·h/m^2/day, and use grid electricity the remaining months. Note that in neither case do we adjust for monthly fluctuations in electricity consumption.

NREL (2002b) provides a guide for designing solar PV systems given solar radiation values and average electricity use. In short, the total cost depends on local equipment, the daily household electricity (E) used in Watt-hours, the percent (P) of the electricity to be provided by solar, and the amount of solar radiation (S) available [see Eq. (1) below]. We assume daily electricity demand can be estimated by dividing annual demand by 365.

We assume the following initial (year 0) costs for all installations (NREL 2002a,b, SolarBuzz 2003): wiring/labor for batteries, \$2,500; module support structure for roof, \$1,000; combiner boxes/charge controls, \$2,000; module installation, \$2,000; controller/switchboard, \$150; and delivery, \$250. The sum of these items is \$7,900. In addition, three other cost items occur: first, an inverter, which costs \$0.85/W (SolarBuzz 2003) and will last 20 years; second, the solar modules, assumed to cost \$4.50/Wp. (SolarBuzz 2003); and finally, batteries (for storage in case of solar unavailability), which are assumed to cost \$150/kWh (NREL 2002a). We assume that periodic maintenance can be done by homeowners and is negligible.

From NREL (2002b), Eq. (1) estimates upfront costs, including terms for the fixed equipment costs, inverter, batteries, and modules. Eq. (1) assumes 2.5 days of battery storage, a current market average of 120 Wp for modules at \$4.50/Wp (\$540/module), and a coefficient of system inefficiency of 1.2. We ensure a whole number (rounded up) of modules will be used.

$$\$7{,}900+(\$0.85\times P)E/S+(2.5\times\$150)E$$

$$+(\$540\times m1.2)E(P/S)/120 \qquad (1)$$

The net present value (NPV) of the system can be found by considering Eq. (1) for up-front costs and yearly grid electricity costs as well as replacement of storage batteries over time. The current expected lifetime of solar PV modules is assumed to be 20 years, and for lead-acid batteries used for power storage in PV projects, about 7 years (NREL 2002a). Table 2 summarizes the key assumptions needed for the 2 cases. Grid electricity would cost \$120 per year in Phoenix and \$460 in Albany. We assume that batteries are replaced twice, in years 7 and 14, and that battery prices decrease 15% over each 7-year period. We then find the discounted cash flow for each city over a 20-year period at a 5% discount rate. Summary cash flows for Phoenix and Albany for the base case above are presented in Table 3. The NPV for the Phoenix option is −\$72,000 and for Albany is −\$48,000.

Neither of the NPVs above is overly helpful in making a decision or in comparing the solar PV system against simply buying electricity from the grid in either city. To facilitate this comparison, we find the equivalent annual net cost (EANC) of each option and compare it to the yearly cost of buying electricity from the grid. Finding the EANC is a useful method for annualizing NPVs and can be done by dividing the NPV by the annuity factor, in this case $(P|U, 5\%, \text{and } 20)$, or about 12.5.

Table 4 shows that it is marginally more cost-effective to have a solar module system in Albany than in Phoenix. This only means that the EANC is closer to the alternative grid electricity payment and does not support a positive NPV. The main reasons behind this finding are that the increased cooling needs of the average Phoenix household demand a higher electricity load for the year, requiring marginally more modules to be needed (and thus costing more up front). Note that 34 modules would be needed in Albany and 57 in Phoenix. In addition, the relatively low price of electricity in Phoenix acts as an economic disincentive—Arizona's average 12,892 kW·h of electricity in Albany would cost \$1,800 per year. Note that both options have negative NPVs and thus represent a cost premium for solar electricity of \$3,000 to \$5,000 per year (or about \$0.45 to \$0.60/kW·h).

Sensitivity Analysis and New Scenarios

The numbers above depend on a variety of assumptions, the most important being the amount of household electricity to be provided by solar and the amount of solar radiation used as the design constraint. Significant economic cost savings could be achieved by improving both categories. For example, as is shown above, it is not currently economical to support 100% of electricity demand with battery storage for the average residence via solar modules. Lower EANCs could be achieved either by reducing the PV system capacity while buying more electricity from the grid or by installing smaller PV systems, for example, on residences where significant energy efficiency or conservation techniques have already been applied.

Considering deployment of solar PV systems in already-efficient homes is reasonable because it is likely that the types of consumers interested in solar technology are already incorporating more energy-conscious practices. Thus we considered a best case of implementing solar PV technology at residences in Phoenix and Albany where households are already consuming 30% less electricity than the average household in the state, and where the PV system is designed around the highest monthly solar radiation rate (June). In this case, the EANC for Albany is reduced to \$3,100 and for Phoenix to \$4,400. Even in this more ideal case, the Albany system has a lower price premium over grid electricity: the costs per kilowatt-hour are only slightly lower—about 45 cents. Designing for a house using 50% less electricity than average and with June solar radiation would result in a cost of \$2,700 per year in Albany and \$4,000 in Phoenix. Table 4 summarizes these scenarios.

Note that most current solar marketing documents (for example, online calculator tools) recommend designing the PV sys-

Table 4. Comparative Financials for Base Case in Phoenix and Albany

Financial results	Phoenix	Albany
Annual 100% grid electricity cost (DOE 2003d)	$1,069	$918
Scenario 1: base case–no conservation, average solar radiation		
EANC of solar PV system	$5,800	$3,900
Cost premium for solar ($/year)	$4,700	$3,000
System electricity cost ($/kWh)	$0.45	$0.60
Scenario 2: 30% conservation, June solar radiation		
EANC of solar PV system	$4,400	$3,100
Scenario 3: 50% conservation, June solar radiation		
EANC of solar PV system	$4,000	$2,700
Scenario: first prospective technology		
EANC of solar PV system	$2,100	$1,700
Scenario: second prospective technology		
EANC of solar PV system	$1,300	$1,200

Note: PV=photovoltaic; EANC=equivalent annual net cost.

tem based on the maximum (June) solar radiation rate. This has the desirable effect of reducing the initial installation cost by reducing the number of modules needed (and thus making the technology somewhat more financially attractive) but also creates a side effect—the system is generally unable to produce enough electricity in non-June months (or causes more use of the battery storage system). This would then require additional grid electricity to be purchased. While we did not adjust for this loss in the calculation above, it would increase the EANC of each system.

Note that Arizona has a state tax credit for solar installations, but it is currently limited to $1,000. New York also has a credit, with a maximum of $3,750. Given the 20-year time horizon of the PV projects presented, the EANC values would only decrease by $100 to $300, which would not change the decisions compared to grid electricity.

The cases above present a pessimistic view of residential solar installations as of 2003. While technology is sure to improve system efficiencies and reduce costs, it would take breakthrough technology to make the above systems cost-effective. As mentioned above, no single assumed change (partial sensitivity analysis) can drive the system to be comparable in cost to the current grid. This is a result of the system requiring both modules and batteries for normal use. Thus, greatly improving module technology with marginal battery technology improvements cannot alone solve the problem (or vice versa).

A first prospective technology scenario, with highly aggressive changes to assumptions (70% of average electricity consumption, system inefficiency coefficient of 1, 240 Wp per module, $2/Wp per module, 1-day battery storage, battery cost of $75/kW·h, 20-year battery lifetime) would still generate an EANC of $800 to $1,000 more than the grid cost in Albany or Phoenix.

A second prospective technology scenario can be seen with extreme conservation (50% less electricity consumption per house), system inefficiency coefficient of 1, 240 Wp per module at a price of $100 per module ($0.50 per Wp), 1 day of battery storage, and $50 (per kW·h) of batteries that last 20 years. In this case, the system would cost the same as grid electricity in Arizona and would still cost $200 more per year than grid electricity in New York.

Net Metering

While battery storage is attractive to maximize the value of generating solar electricity, it also adds significantly to initial and periodic costs. Many areas in the United States are able to support net metering, where the residence's electricity meter literally runs backwards as excess locally generated electricity is provided to the grid. Note that this is generally possible with existing meters. If net metering were fully integrated with a PV system, then you could operate without local battery storage—and effectively use the grid as the storage source. One downside of this alternative from an environmental standpoint is that the electricity used from the grid is not generally from solar sources.

Table 5 summarizes the results of three net metering case studies, assuming negligible net metering costs and avoiding battery and charge controller purchases. In Net Metering Case 1 (equivalent to the base case of Table 4 but without batteries, charge controllers, etc.), net metering would still be about $2,000 more expensive per year. In Net Metering Case 2 (30% conservation compared to Case 1), the cost premium is reduced to $1,000–$1,500 per year. Note that while a significant number of residential net metering projects do not yet exist, there would likely be some nonnegligible initial and recurring costs for such a system.

One final model scenario fully considers the benefit of net metering as opposed to simply removing battery storage. If the PV system is designed for the maximum solar radiation rate during the noncloudy months, then it is likely that substantial

Table 5. Costs of Residential Solar Photovoltaics Systems with Net Metering

	Case 1 (100%)		Case 2 (70%)		Case 3 (70%, no grid)	
Costs	Phoenix	Albany	Phoenix	Albany	Phoenix	Albany
EANC	$3,500	$2,600	$2,600	$2,000	$2,000	$1,500
Cost premium ($)	$2,400	$1,700	$1,500	$1,100	$900	$600
System cost ($/kW·h)	$0.27	$0.40	$0.20	$0.31	$0.15	$0.23

Note: EANC=equivalent annual net cost.

Table 6. Break-Even Analysis for Solar Photovoltaic Net Metering System

Analysis	Phoenix	Albany
Percent of household electricity supplied	25%	26%
Price per Watt-peak	\$1.4	\$1.5

amounts of excess electricity could still be generated that was not being used on site—especially in months of the year without extreme temperatures that lead to significant HVAC costs. Since the system is designed for the average electricity use (without substantial peak considerations), there likely will be times during daylight hours where a significant amount of electricity would be produced and given back to the grid only to be offset with some purchases later in the day.

To try to estimate the effects of this grid sell-back via net metering, we thus assume a Net Metering Case 3 that is otherwise equal to Case 2, but for which June solar radiation is used and no net grid electricity would be purchased due to the negative offsets created by selling excess electricity onto the grid. In short, this is an investment analysis with only up-front costs and no recurring costs. Case 3 is about \$600 to \$900 more costly per year than pure grid electricity—still a significant cost premium. Table 5 also shows that while the cost per kilowatt-hour is much lower for net metering, even in the best case it is roughly double the current grid electricity costs.

Net metering generally measures only the electricity flowing in and out of the residence and the grid, and no relative financial value of the electricity flow is associated with it. If real-time pricing effects were considered for residential customers (where prices are actually higher during the day than at night to match peak demand periods), significant savings might be achieved because the peak solar times would be in the middle of the day. Thus this electricity mostly would be sent to the grid instead of consumed on site (because most customers would not be at home at the time), and so there would be a relative economic benefit from producing and selling peak power versus consuming off-peak power in the morning and evening. No data were available to show the solar energy production and electricity consumption values for a typical residence along with real-time residential prices. However, as the net metering example above showed, the effective cost per kilowatt-hour of electricity produced was down to about double the grid cost, and thus significant peak and off-peak price differentials could make the system nearly break even.

One of the primary benefits from net metering comes from removing the batteries from the system. This also makes a hypothetical analysis of technology more feasible. As Net Metering Case 3 showed, there is only a \$600 to \$900 annual premium required of an ideal net metering system in Phoenix or Albany.

Eq. (1) without the costs of batteries and charge controllers shows an estimate of the NPV for Net Metering Case 3. When considered over the range of annual demand (6,500 to 15,500 $\mathrm{kW \cdot h}$ per household per year) and solar radiation values (2 to 7 $\mathrm{kW \cdot h/m^2/day}$), it can be shown that many areas of the United States would have similarly small annual net costs compared to grid electricity, given the average U.S. electricity bill of about \$1,000 and a system sized for 70% of average demand.

Table 6 shows the break-even values needed individually in the estimates above for the solar PV systems to have EANC values equal to the grid prices. In other words, the system would have to be sized for only 25 to 26% of demand, or the price per Watt-peak of the panels would need to decrease to \$1.4 to \$1.5.

Remote Systems

The primary niche market for PV solar power is in areas where there is poor access to the electricity grid, that is, in remote or rural areas. Presumably residences built in these areas could be designed specifically for a solar electricity source, with roofs at the optimal angle, and so on. However, these same residences would need to be designed with substantial battery storage as there would be no grid backup.

We considered an adaptation of the best-case values above for remote locations in New York or Arizona. Thus these residences already had 30% less electricity consumption than average houses in the state, but were designed with the lower monthly average solar radiation values to ensure production. We further assumed 10 days of battery storage. The New York NPV was −\$80,000 and Arizona −\$140,000. Thus these systems would be cost-effective only where grid connection costs were in the hundreds of thousands of dollars. Since the costs of connecting to the nearest grid point can range from \$15,000 to \$50,000/mile, depending on terrain, these systems could be quite feasible (NREL 1997), even with current technology assumptions.

Environmental Impacts of Photovoltaic Systems

While many sources have promoted solar as a free source of green energy, other studies have discounted the green qualities of solar PV electricity. In short, there are considerable impacts from the manufacture (and disposal) of the photovoltaic cells—similar to the impacts of producing semiconductors (Tillman 1995; Pacca and Horvath 2002). These manufacturing impacts are often forgotten when considering the beneficial use-phase energy impacts from offsetting fossil-fueled grid production.

However, the use of PVs causes a relative offset of grid electricity in the area near the location. Table 7 estimates the yearly emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) in Phoenix (zip code 85001) or Albany (zip code 12201) from 100% grid electricity by using the EPA E-GRID Power Profiler (EPA 2003a). Table 7 also estimates the dollar-per-ton costs of emissions avoided for the basic PV systems (found by taking the EANCs of the first three scenarios of Table 4) and the net metering systems (found by taking the EANCs from Table 5) and dividing separately by the three pollutants. Note that these values are one to two orders of magnitude higher than the range of external cost values used in the scientific and policy literature for air pollutants (Matthews and Lave 2000). Thus, the environmental benefits come at a comparatively high cost.

If the environmental impacts of fossil-fired generation were incorporated into electricity prices, the solar option would be more attractive. Adding these external air pollution costs could raise the effective cost of electricity by as much as 95% (Matthews and Lave 2000). Arizona's local grid electricity mix is still highly dependent on fossil fuels, with a large amount from coal-fired production. Even modest solar house deployments would have negligible impact on the electricity generation assets needed in either state. Thus any generation mix changes (and their associated environmental impacts) are not considered.

Discussion

The annual cost of the grid-connected PV system in some of the examined cases is 5 to 6 times higher than the cost of usage of the

Table 7. Cost-Effectiveness of Solar Photovoltaic Net Metering Systems

Estimates	Arizona	New York
Nitrogen oxides (lb)	42	10
Sulfur dioxide (lb)	30	36
Carbon dioxide (lb)	20,010	6,000
Net metering scenarios		
NO_x cost ($1,000 s/ton)	$100–$200	$310–$1,100
SO_2 cost ($1,000 s/ton)	$130–$290	$90–$300
CO_2 cost ($/ton)	$200–$420	$500–$1,800
Full PV system scenarios		
NO_x cost ($1,000 s/ton)	$220–$330	$1,100–$1,600
SO_2 cost ($1,000 s/ton)	$320–$470	$300–$430
CO_2 cost ($/ton)	$470–$700	$1,800–$2,600

grid. The reasons are the large installation cost and the periodic replacement of batteries and even of the entire system in 20 years. More important, the comparative results between Phoenix and Albany are driven by the significant difference in residential demand and electricity prices. Given the large costs for solar power per kilowatt-hour, it does not make as much economic sense to install solar in Phoenix, which already has among the lowest electricity prices in the United States, even with consideration of local tax incentives. While estimated in this paper, the results could change if we considered a house better optimized for solar efficiency. The stand-alone PV system has an obvious benefit compared to the conventional electricity system only in those areas where the electricity grid is not or scarcely available.

While Phoenix and Albany are mentioned consistently in this paper, the cases should be considered generically as for ‘‘high solar radiation versus low solar radiation’’ areas and ‘‘low versus high electricity prices.’’ Results for most other metropolitan areas in the United States will fall between these cases in terms of NPV, and so on. The ideal location for a solar PV-powered residence would be one with high electricity costs, a reasonable amount of electricity demand, and high solar radiation. The southwestern United States has the highest solar radiation rates, but all southwestern states except California and Nevada have low electricity prices, and only the noncoastal areas of California have significant electricity demand due to the mild climate. In the end, it is difficult to find an ideal place in the United States for PV systems at present.

The costs can be reduced by using a more effective solar thermal system (power tower, solar dish, or parabolic trough system) instead of the PV modules, or if the price of modules would decrease by a larger scale than we assumed. Increased efficiency of PV cells would also reduce the cost of the system. Ongoing research shows that a group of second-generation, thin-film PV modules can absorb sunlight more efficiently than silicon-based, first-generation cells (Green 2000), which can result in the use of the PV system on cloudy days as well.

Overall, this paper has shown that determining the relatively more cost-effective locations of solar PV sites is counterintuitive. Instead of simply locating them where a large amount of solar energy is known to be available, the local price of electricity should be a primary factor. The northeastern United States is near the top of the list in residential electricity prices, and thus solar power becomes an attractive option due to the economics, even without the amount of solar radiation available in Arizona.

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