

Economics of Solar Electric Systems for Consumers: Payback and other Financial Tests

By Andy Black

Solar electric systems can be a good financial investment for homeowners and businesses, depending on a variety of factors including system performance, electric rates, favorable utility rate structures, and incentives. Several US states have the right combination of conditions to strongly encourage end-consumer investment in solar electric systems based on economics alone.

In places where solar is economically attractive, rates of return from 9% to 15% or better are common. If financed, the monthly net loan cost is usually less than the monthly utility bill savings. And if the home is sold, the solar system should increase the resale value by more than the system cost to install.

The above claims are big, so rigorous treatment and critical analyses from several angles including Compound Annual Rate of Return, Cash Flow, Lifecycle Payback, and Appraisable Resale Value need to be considered to do a fair assessment. Using the above analysis methods helps compare the solar investment to other investments on an even basis.

IN THIS ARTICLE:

- What factors need to be considered to determine the economic payoff of solar, including rates, rate structures, systems performance, solar RECs, and incentives
- How to test the economic value in the ways listed above

This article also includes “Policy Discussion” paragraphs to help individuals and policy makers in locations without strong economics understand the issues around creating solar-friendly policies, which motivate and leverage individual investment.

WHY DOES SOLAR PAY OFF NOW?

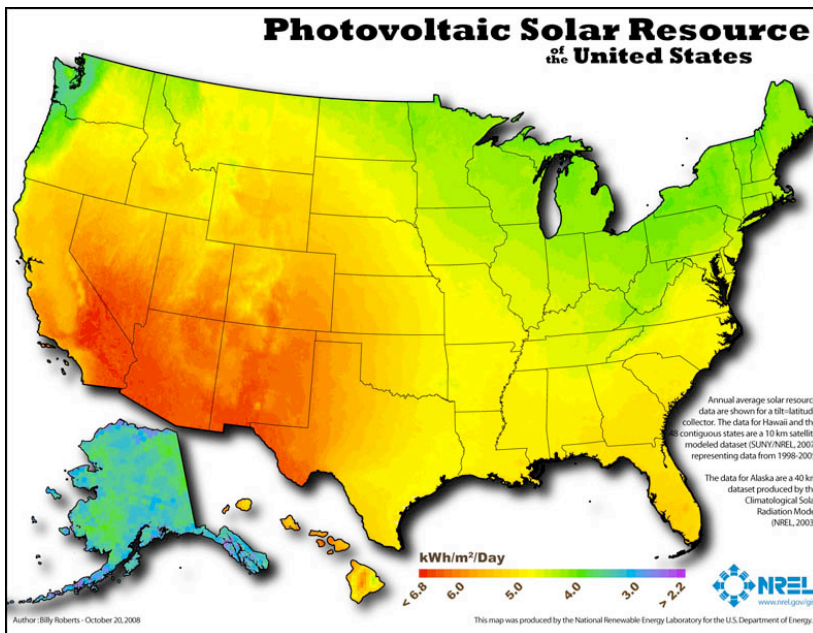
Good system performance, high electric rates, Net Metering and Time-Of-Use rate structures, Solar Renewable Energy Certificates (SRECs) and government incentives have contributed to the financial viability of solar electricity. How these factors come together varies significantly by location. Some locations have the combination of factors that yield excellent results; in others, it makes no economic sense to go solar, especially when including the maintenance and inverter replacement costs.

The key element for most analyses is the ongoing value generated by the solar system (the savings on the electric utility bill or the monetary value of system output that can be sold). A properly sited, sized, designed, and installed solar system can usually eliminate most or all of a customer’s total annual electric bill.

The next pages will discuss system performance, electric rate structures, and incentives. The pages following will detail how the economics can then be analyzed using Rate of Return, Payback and Lifecycle Payback, Property Value Increase, and Cash Flow when Financing.

SYSTEM PERFORMANCE:

Lots of Sunlight is just one of the many factors that must be included in a system performance calculation. Across much of the United States, the amount of available sunlight is surprisingly uniform, with most areas within $\pm 20\%$ of the sunlight level of Miami, Florida, as can be seen in Fig. 1. The National Renewable Energy Laboratory (NREL) has data on 239 locations across the U.S. and its territories available at: <http://rredc.nrel.gov/solar/pubs/redbook/> and its PVWatts calculator will determine performance for a user specified PV



Equivalent Noontime Sun Hours per Day (Annual Average):

| | |
|-------------------|-----|
| Portland, OR | 4.0 |
| Buffalo, NY | 4.1 |
| Chicago, IL | 4.4 |
| Newark, NJ | 4.5 |
| Boston, MA | 4.6 |
| Baltimore, MD | 4.6 |
| Raleigh, NC | 5.0 |
| Miami, FL | 5.2 |
| Austin, TX | 5.3 |
| San Francisco, CA | 5.4 |
| Boulder, CO | 5.5 |
| Los Angeles, CA | 5.6 |
| Phoenix, AZ | 6.5 |

Fig. 1. Most U.S. locations are $\pm 20\%$ of Miami’s sunlight level. Sources: NREL:

<http://rredc.nrel.gov/solar/pubs/redbook/> and <http://www.nrel.gov/gis/solar.html>

system: <http://www.nrel.gov/rredc/pvwatts/>.

There are numerous loss factors that affect real system performance including component performance, wire losses, soiling, module degradation, module mismatch, system uptime and reliability, manufacturer production tolerance, and system design factors such as tilt, orientation, shading, and air flow. The California Energy Commission has produced “A Guide To Photovoltaic (PV) System Design And Installation” available at: http://www.energy.ca.gov/reports/2001-09-04_500-01-020.PDF and is an excellent overview of system design considerations. Fig. 2 lists performance loss factors, and the significance of potential relative losses from tilt, orientation, and shading.

Inverters aren't 100% efficient, with most achieving 94-96% efficiency. Similarly, PV modules in operation put out approximately 7-14% less power at realistic operating temperatures compared to the Standard Test Conditions (STC) commonly measured in factory or laboratory settings. The State of California provides lists of module and inverter ratings at: <http://www.gosolarcalifornia.org/equipment>.

Soiling, module degradation, and module mismatch also must be accounted for. The designer and installer have some control over wire losses, but by code, must not exceed 5%. Manufacturer production tolerance losses result from some modules having a performance specification of +X%, -Y%. If there is a negative tolerance, the customer can be sure she will be on the losing end of that bargain to at least some extent.

The system designer in coordination with the property owner has control over how the modules are mounted, especially how far off the roof, affecting how much airflow occurs. Thermal stagnation starts to occur with less than 6" clear airflow space behind the modules and can reduce performance up to 10% at 0" air gap.

The designer and property owner also have control of solar system orientation (tilt angle or 'altitude' above horizontal and direction or azimuth), and usually some control over shading. **Shading and/or orientation are usually the #1 underestimated system performance loss factors** except in locations where incentive programs specifically (directly or indirectly) include these in the calculation of the incentive to be paid. It is critical that the site analyst / installer use a shade analysis tool to accurately determine shade. Quality shade tools include the Solar Pathfinder (<http://www.solarpathfinder.com/>), Solmetric SunEye (<http://www.solmetric.com/>), and the Wiley ASSET (<http://www.we-llc.com/ASSET.html>). It is impossible to estimate shading by eye, and even a few percent can be significant. Avoiding shading is often the most important criteria, even over selecting a south-facing roof.

System availability (uptime) is dependent on **system reliability and monitoring**. A well-designed system with known reliable components (particularly the inverter) is important. Placing inverters in shaded, well-ventilated locations that won't accumulate ventilation-inhibiting debris will eliminate many common overheating-related problems (reduced power output due to thermal protection or shortened component lifetime). Placing the inverter close to the utility connection point will eliminate many common utility interconnection

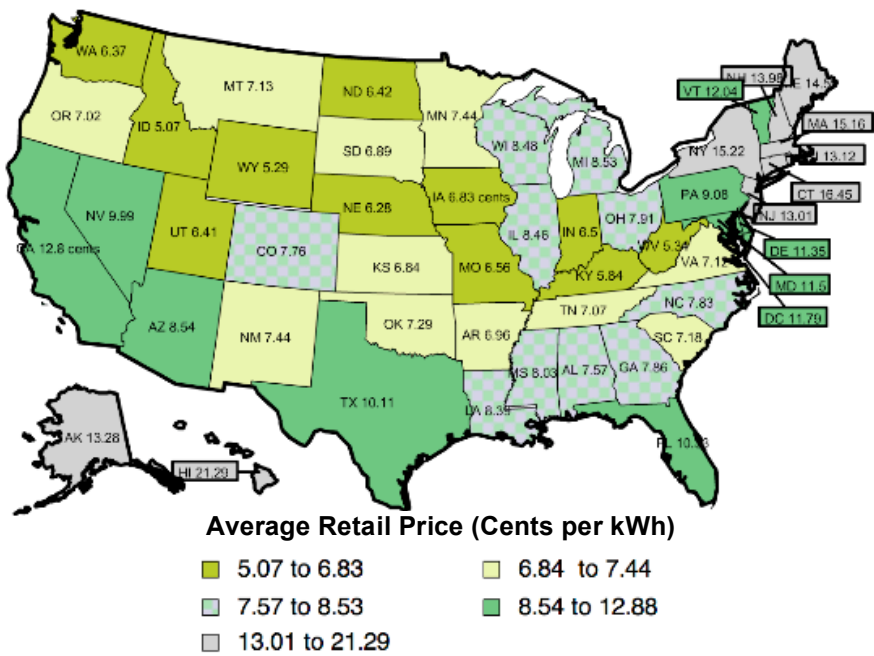
related problems (long wires can have a kind of 'voltage buildup' in the wiring causing the inverter to think the utility is not safe to connect with, requiring it to shut down for at least 5 minutes). **The only way to know if a system is operating reliably is to monitor it as often as possible.** Monthly observations via the electric bill savings are a crude minimum but can take 45 days or longer to make even a simple problem (sometimes only requiring a simple reset of the inverter) visible, resulting in over 12% of a year's energy to be lost. Active continuous real-time monitoring and automated alerting solutions are available that should more than pay for themselves in increased savings, peace of mind, and owner satisfaction.

***System Performance Factors Policy Discussion:** Including predicted or actual system performance in determining the level of incentive to be paid (then actually verifying compliance with the approved design) is an excellent way for incentive agencies to improve system quality. Before California adopted the requirements of the new California Solar Initiative (CSI) program, a significant fraction of sold and installed systems had major shading or other site-selection design problems, often only disclosed to the customer with a hand-wave of "you'll lose a little performance due to shading..." The CSI has received a lot of criticism because of the increased level of paperwork, scrutiny and repercussions for "failures" from those who would rather do things the old, easy, loosey-goosey way, but in the author's opinion, the new level of accountability is the best thing that could have happened to raise the quality of installations in the state. This higher level of quality is nothing new to those in some other states such as Colorado and in some municipal utilities like SMUD. Going forward, the author has grave concerns about the quality of systems that will be installed as a result of the expansion of the federal Investment Tax Credit, which has no performance or quality safeguards.*

| Typical Loss and Performance Factors: | | |
|---------------------------------------|--------------------|--|
| Loss Factor | Performance Factor | Variable |
| 9-12% | 88-91% | Module Temperature |
| 3-11% | 89-97% | Inverter Efficiency |
| 1.5-5% | 95-98.5% | Wiring (AC & DC combined) |
| 5-15% | 85-95% | Dust & Dirt |
| 5-10% | 90-95% | Module Degradation over 20 years |
| 1.5-2.5% | 97.5-98.5% | Module Mismatch |
| 0-5% | 95-100% | Manufacturer Production Tolerance |
| ~27-33% | ~67-73% | Typical Totals for the Best Systems |
| Additional Design-Dependent Factors: | | |
| 0-10% | 90-100% | Air Flow |
| 0-40% | 60-100% | Orientation & Tilt |
| 0-100% | 0-100% | Shading |
| 2-100% | 0-98% | System Availability (uptime) |

Fig. 2. Summary of Performance and Loss Factors

2007 U.S. Average Retail Price per kWh is 9.13 Cents



| State | 2008 Rate ¢/kWh | 2004-2008 CAGR | 2001-2008 CAGR | 1990-2008 CAGR |
|-------|-----------------|----------------|----------------|----------------|
| US | 11.4 | 6.1% | 4.1% | 2.1% |
| AZ | 10.3 | 4.9% | 3.1% | 0.7% |
| CA | 14.4 | 4.2% | 2.5% | 2.1% |
| CO | 10.1 | 4.8% | 4.5% | 2.1% |
| CT | 19.4 | 13.6% | 8.5% | 3.7% |
| DC | 12.7 | 12.2% | 7.2% | 4.1% |
| DE | 13.9 | 12.2% | 7.1% | 2.8% |
| FL | 11.7 | 6.8% | 4.5% | 2.3% |
| GA | 10.1 | 6.4% | 3.4% | 1.7% |
| HI | 32.5 | 15.8% | 10.3% | 6.6% |
| MA | 17.5 | 10.5% | 5.0% | 3.4% |
| MD | 13.8 | 15.4% | 8.8% | 3.7% |
| MN | 9.8 | 5.4% | 3.7% | 2.0% |
| NC | 9.7 | 3.6% | 2.6% | 1.2% |
| NJ | 16.0 | 9.2% | 6.6% | 2.4% |
| NM | 10.0 | 3.7% | 2.0% | 0.6% |
| NV | 11.9 | 5.3% | 4.0% | 4.2% |
| NY | 18.8 | 6.6% | 4.3% | 2.8% |
| OH | 10.1 | 4.6% | 2.8% | 1.3% |
| OR | 8.5 | 4.4% | 4.4% | 3.3% |
| PA | 11.4 | 4.4% | 2.4% | 1.2% |
| TX | 12.8 | 7.2% | 5.4% | 3.3% |
| WA | 7.6 | 4.4% | 4.2% | 3.1% |

Fig. 3. The graphic above shows the 2007 U.S. average electric rates for all sectors. The table at right shows 2008 average residential electric rates for selected states and their Compound Annual Growth Rates (CAGR) for three time periods before 2008. Source: U.S. Energy Information Administration: <http://www.eia.doe.gov/fuelectric.html>

ELECTRIC RATE STRUCTURES:

High Electricity Rates are an expensive fact of life in a number of US states and can be worse still in other countries. Hawaii has the highest electric rates in the U.S. topping out at 32¢/kWh for the average residential consumer (certain islands are higher), however, rates are also very high in Connecticut, California, New York and other states (Fig. 3).

Rates have risen fast across the land since 2001 and especially fast since 2004 (Fig. 3). Electric rate increases will likely be tempered by the Great Recession of 2009. Future rate hikes can only be guessed at, as they depend on many factors.

In comparison, the Consumer Price index (CPI-U) has been increasing at 3.1% on average since 1982. One might ask, how is it that electric rates have continuously increased faster than the CPI – wouldn't electricity become a bigger and bigger portion of our consumer expenses, until eventually something brought it into check? The answer lies in the fact that we are continuously getting more efficient with how we use electricity, so we are able to produce more economic value per unit of electricity. We are therefore able to spend more per kWh.

One of the ways consumers can be motivated to be more

efficient with how she uses electricity is to charge more for it, but there are limits to how this can be applied without disadvantaging lower income consumers. Many utilities have adopted a tiered pricing structure, as can be seen in Fig. 5, where the first part of a consumer's consumption is charged at a lower rate, but if the consumer uses more than a "baseline" allocation (an amount deemed to be required to cover a consumer's "basic needs") she will pay more for the next part of her usage. The more she uses, the more each kWh costs. The more tiers there are in the system, the more the rates

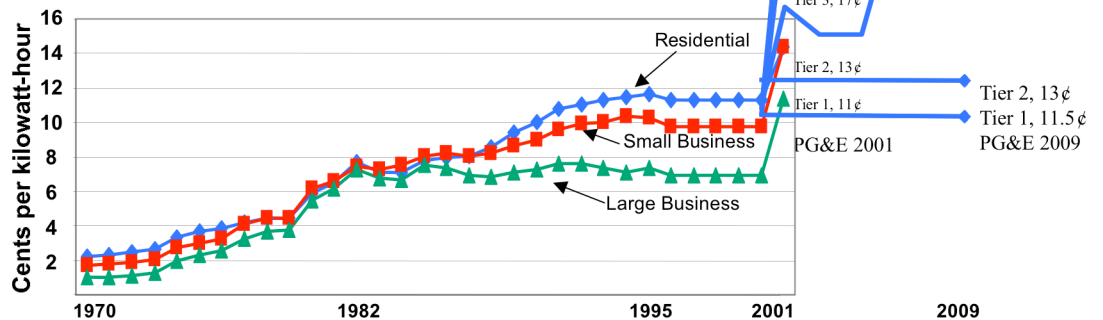


Fig. 4. Residential electric rates in California from 1970 to 2001 increased at a 6.7% compound annual rate (source: CPUC "Electric Rate Compendium" Nov. 2001 from EIA data). Since 2001, there has been no change in Tiers 1 & 2, but an exaggerated increase in Tiers 3-5. Enactment of AB413 and expiration of ABIX may alter these trends. Note: this graphic is to scale.

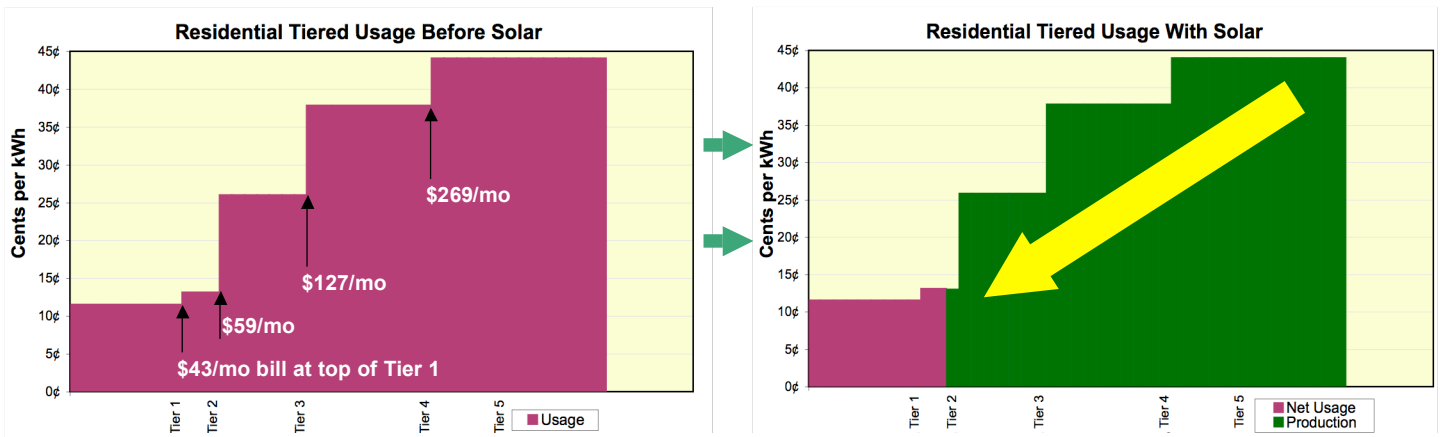


Fig. 5. Progressive tiered rate pricing penalizes large users most with a marginal electricity cost at ever increasing rates. In these cases, solar offsets the highest tier usage first, making the solar customer look like a smaller user with a lower marginal cost. The graphic on the left indicates which tier a user is in for a given monthly electric usage (1650 kWh) and bill (\$499) in San Jose, CA. On the right, the green area represents how much is offset by solar (1225 kWh and \$463 out of \$499).

can be fine-tuned, but also, the more complicated billing becomes. Fig. 5 illustrates a “progressive” pricing model for rates (similar to progressive tax structures), which attempts to discourage large use while protecting smaller using consumers. The progressive model encourages conservation, efficiency, and conveniently for the solar industry, solar installations as well. The graphic in the right half of Fig. 5 shows how a solar system makes a user look like a smaller consumer (the green area is solar generation, the red area is the remaining net usage), and offsets the most expensive electricity first, yielding the greatest savings first, boosting the economics of solar. This particular case is saving 44¢/kWh for the first set of production, 38¢/kWh for the next set, and so on. Not all utilities use the above “progressive” pricing model. Some utilities offer discounts for buying in bulk – the larger the use, the less expensive the cost of the next kWh. This may be rational in some utility cost models, but it doesn’t encourage conservation, energy efficiency or solar installation.

Fig. 4 shows the California rate history since 1970. From 1970 to 2001, rates increased at a compound annual average rate of 6.7%, as can be seen in the lower left portion of the graphic. Things got considerably more complicated in 2001 because of the California Power Crisis in conjunction with the deregulation process that affected rates starting in 1996.

During the power crisis California’s AB1X legislation froze the rates for residential users using at or below the average usage for their local climate zone (which equals usage at or below the top of Tier 2), but at the same time, created Tiers 3, 4 and 5 at much higher rates (17-26¢/kWh). The users using well above average found their bills almost doubled upon implementation of the change. It had the desired effect: high using residential consumers quickly became motivated to reduce their usage by conservation, efficiency, and some turned to solar systems, dramatically increasing the solar market.

Rate escalation in California got more complicated thereafter as well. Because state law AB1X prohibits changes to the rates for Tier 1 and Tier 2, all the increase must be borne in Tiers 3, 4 and 5. If revenue needs to increase by 10%, Tier 3, 4 & 5 rates must increase approximately 50%. That happened on January 1st, 2006 to PG&E residential customers, as seen in Fig. 4.

Rates in Tier 3, 4 & 5 have gone up and down dramatically since 2001, with a recent average rate of increase that has been very high (double digit). This high average will not continue forever because of the eventual expiration of California AB1X (the date of this is unknown for a variety of complicated reasons, but may be soon, depending on what happens with AB413). When this happens, it is anyone’s guess how the politics will fall, but one of three possibilities is likely: 1. Rates in all tiers will move in lock step at a more normal rate of escalation, 2. Rates in Tier 3-5 will be frozen while Tier 1 & 2 catch up, or 3. Rates in Tier 3-5 will be reduced and rates in Tier 1 & 2 will move up to compensate.

A conservative approach to electricity escalation suggests a 5% annual escalation – anything more than that might be viewed as “optimistic” which may cause customers to become concerned. The scenario examples depicted later will assume 5% except as noted. The goal of this article is to provide a conservative set of assumptions and a “bullet-proof” analysis methodology, that if followed, will be acceptable to the broad majority of serious potential customers, and provide them and their financial advisors a solid basis for making an informed decision.

Tiered Rate Policy Discussion: *Progressive Tiered Rates are excellent motivators of conservation and energy efficiency (and conveniently, solar), but they may also be the government and utility officials ‘public relations friend’ as well. By creating multiple tiers, policy makers can shift some of the burden of future rate increases to the larger (above average), more wasteful users (residential only) and thereby lighten the burden on the users who are at or below average consumption. This works well for residential usage, because it is easy to quantify the average consumption per typical household, however average consumption per business would be meaningless in this context, since most communities want their local business to grow (efficiently) from year to year, so penalizing ever growing usage would be counterproductive.*

High electric rates are among the most important factors determining who will have the best economics with solar, however, high rates are only valuable if the customer can also enjoy **Net Metering**, a regulatory structure set up for solar

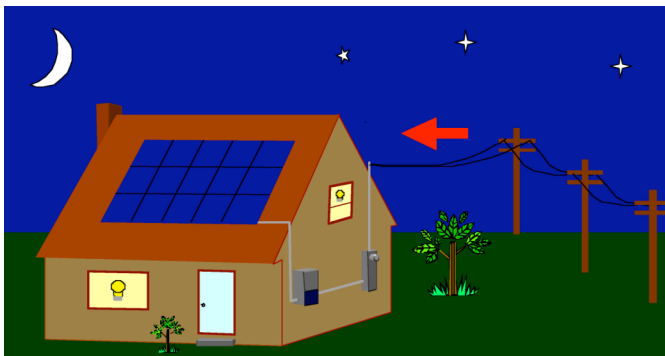
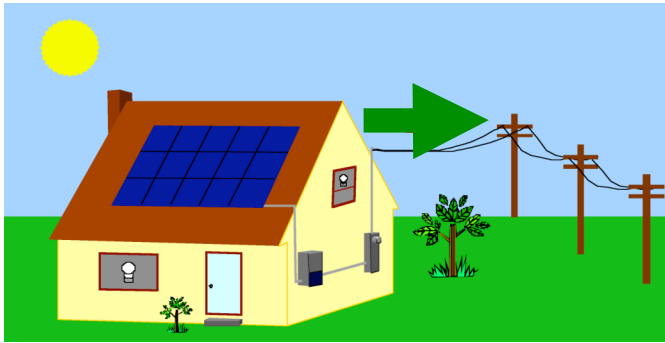


Fig. 6. Net Metering allows the exchange of electricity produced or purchased to be valued at retail rates allowing the grid to act like a 100% efficient battery for the consumer to “store” her excess production during the day or over a season until she needs it at night or during another season.

electricity producers (and sometimes certain other renewable producers depending on the state) in 42 of the 50 U.S. states.

Under Net Metering, full retail value is credited when excess electricity is produced and “sold” back to the utility, offsetting the customer’s electric bill (Fig. 6). There are a variety of Net Metering forms, the implementation of which vary by state and utility. An older form is “Monthly Net Metering,” whereby a solar producer can eliminate her monthly electric bill, and any excess production would typically be paid to the producer at the utility’s “avoided cost” or “fuel cost” per kWh (approximately 1-3¢/kWh). The problem is that solar production varies substantially by season, so it is hard to design a system that balances a user’s needs in each of the 12 months without under-producing in one season (usually winter) and over-producing in the other. Under-production results in large bills charged at high retail costs of electricity. Over-production creates small credits based on the “avoided cost” value of the excess energy.

The solution is the newer “Annual Net Metering,” which allows summer excess production to offset winter shortfalls, with the goal of allowing the customer (or her knowledgeable and experienced designer/installer) to right-size the system to fully offset the annual electric bill, but not over-size it. With annual Net Metering, the utility ends up looking like a 100% efficient battery that can store energy for up to a year at no loss or penalty. The other half of this compromise is that any excess production credit after the 12th month is given to the utility, discouraging over-sizing of systems and simplifying the utility’s accounting and saving them the processing costs of sending a check or carrying a credit.

Time-Of-Use (TOU): Most residential electricity is billed to customers on a flat (or time independent) rate schedule, where electricity costs the customer the same at any time of the day. However, utilities often have increased demand for electricity during certain times of the day and certain days or months of the year. When this “Peak” demand occurs usually depends on local climate factors. For example, Arizona and California have their peak times near 4-6pm Monday thru Friday during the summer, because that’s the overlap of the workday and home activity, which both use air conditioning, which is one of the largest loads. At night and in the morning, because of the dry climate, it cools off, so the load is less. Eastern U.S. utilities see their peak demand all day long because the humidity keeps consumers using their air conditioning 24/7 in the home, and during the workday at work, so a typical peak period is 9am-9pm.

To solve the increased demand regardless of when it occurs, utilities could build more power plants, but those plants would only run during peak times, which is only a relatively few hours of the year, and would therefore be an expensive solution on a per kWh produced basis because of the capital costs. Another solution is to encourage conservation during or load-shifting away from those “Peak” time periods.

To create this encouragement, some utilities offer Time of Use (TOU) or Time of Day (TOD) rates, where the cost of electricity depends on the time of day and sometimes on the season of year. The TOU time periods and rates are usually labeled something like “Peak”, “Part-Peak” and “Off-Peak” and often have a “Summer” and a “Winter” season.

The upper graphic in Fig. 7 shows the TOU pricing periods for the PG&E E6 rate in California illustrating peak, part-peak, and off-peak time periods. Notice that there are also part-peak rates on weekends. The lower graphic shows the typical (approximate) time periods of many Eastern U.S. utilities, such as in New Jersey, New York, and Pennsylvania.

High rates during peak periods encourage consumers to use less or to change behavior and instead, consume the electricity during off-peak periods. Easy ways to shift usage are changing what time of day laundry is done or when the pool filter pumps run at home. Small business sometimes have choice over whether to take service under a TOU rate schedule, and if so, they may be able to save money by shifting how or when they do things, such as change to 2 or 3 shifts of work hours, or change when they make ice or pump water or do other energy intensive activities. Large businesses and many agricultural (pumping and refrigeration) operations have no choice and must take TOU service, so are always encouraged in a financial way.

TOU rate differentials between Peak and Off-Peak can range from just a cent or two, to up to 20¢/kWh or more, depending on the utility’s need to motivate change. In PG&E territory in California, a further twist is that the tiered rate structure is applied on top of the TOU rates (residential only), so off-peak Tier 1 rates are as low as 9-10¢/kWh depending on season, but the summer peak Tier 5 rate can be over 61¢/kWh. That sounds expensive, and it is, and one might question the wisdom of even considering switching to a TOU rate schedule, but there is a convenient opportunity that solar customers can apply in their favor.

| Residential PG&E "E6" Time-of-Use Pricing Periods | | | | | | | |
|---|-----------|-----------|-----------|-----------|-----------|-----------|-----------|
| | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday |
| Midnight - 6am | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak |
| 6am - 10am | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak |
| 10am - 1pm | Off-Peak | Part-Peak | Part-Peak | Part-Peak | Part-Peak | Part-Peak | Off-Peak |
| 1pm - 7pm | Off-Peak | Peak | Peak | Peak | Peak | Peak | Off-Peak |
| 7pm - 9pm | Part-Peak | Part-Peak | Part-Peak | Part-Peak | Part-Peak | Part-Peak | Part-Peak |
| 9pm - Midnight | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak |

| Eastern U.S. Typical Residential Time-of-Use Pricing Periods | | | | | | | |
|--|----------|----------|----------|-----------|----------|----------|----------|
| | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday |
| Midnight - 9am | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak |
| 9am - Noon | Off-Peak | Peak | Peak | Peak | Peak | Peak | Off-Peak |
| Noon - 9pm | Off-Peak | Peak | Peak | Peak | Peak | Peak | Off-Peak |
| 9pm - Midnight | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak | Off-Peak |

Fig. 7. Time-of-Use rate structures showing typical peak, part-peak and off-peak time periods for Western and Eastern U.S. utilities.

Combining Net Metering with TOU allows a solar customer to take advantage of the benefits of Net Metering on a TOU rate schedule and, if timing and consumption patterns allow, “sell” energy to the utility during peak periods at the high rate, then buy energy during off-peak hours. The customer gets credited or charged for the value of the electricity when it is bought or sold (at its prevailing retail rate at that time). The utility then looks like a >100% efficient battery because in many cases, most solar electricity is produced during peak hours, and most is consumed in a residence during part-peak and off-peak hours. The customer gets more value for the same kWh produced, and therefore needs a smaller solar system to offset her electric bill. The greater the differential in peak to off-peak rates, and the better the solar production matches peak hours, and the better the homes consumption matches off-peak hours, the greater the benefit of opting for the TOU rate schedule upon adding the solar system.

This approach often (but not always) works well in utility areas that have large daytime summer peak loads (often due to air conditioning load), such as in the Eastern, Southern, and Southwestern U.S., because this usually matches solar production well. However, some northern utilities are winter night peaking because their peak load is caused by electric heating loads of homes. In these cases, solar is a poor match.

TOU Net Metering works best if the customer can mount her solar array in a way that maximizes production during the peak period, for example facing southwest or south at an angle near 25 degrees up from horizontal (equal to a 6:12 roof). Slopes from 5 to 40 degrees and southeast and west arrays generally also work quite well. Note: it is usually not economically feasible to tilt a solar array away from parallel with the roof’s surface to optimize performance, because the gain in production (bill savings) is often not worth the additional mounting hardware and labor cost or the aesthetic penalty.

TOU Policy Discussion: Time-of-Use rates are a powerful tool to motivate customers to voluntarily use less power during predictable times of shortage. The greater the differential

between peak and off-peak, the more motivated the user will be (solar or not) to conserve during peak pricing periods. Effective TOU rate implementations help flatten out the utility’s load profile, requiring fewer “peaker” power plants which operate at very high cost per kWh delivered (once capital costs/debt service are included), because such plants run only a few hours per year. In the right locations, solar can provide some of this “peaker” benefit. Solar advocates can use this to encourage their Public Utility Commissions and Legislatures to adopt pro-TOU policies.

Rate Structure vs. (Cash) Incentives Policy Discussion: Economically viable solar systems are incentivized thru both cash or cash equivalent (tax saving) payments and electric rate-based (or regulatory) savings. Solar-friendly rate structures are incentives because they provide a higher value benefit to solar customers compared to the “commodity” value of the electricity producers could otherwise sell into the power pool at commodity rates (as QFs or Qualifying Facilities). Using cash incentives to encourage solar is easy to understand, but it is also highly visible, and there are several drawbacks compared with solar-friendly rate structure incentives. Cash and cash equivalent incentives can and do come and go depending on the political winds. Even long-term incentive programs, such as German EEG law or the California Solar Initiative could be overturned or modified with a change in government or its attitude. Spain is learning this the hard way after the summer and fall of 2008. The U.S. solar market became painfully aware of its dependence on the extension of the 30% Federal Investment Tax Credit which was due to expire at the end of 2008 but was passed at the last moment as part of the Emergency Economic Stabilization Act of 2008. Regulatory incentives are much more difficult to achieve, however, once won, they are also much more difficult to lose. Any state with Net Metering, TOU, or Tiered rates is likely to have them for a long time and it will be a huge battle to take them away.

INCENTIVES:

There are several ways the government (in its various forms) can provide incentives for solar. Already discussed were the regulatory forms of incentive via favorable rate structures. Here, we discuss the various “Cash” or “Cash Equivalent” incentives, which include:

- Tax Credits and the U.S. Treasury Grant
- Accelerated Depreciation
- Sec. 179 Tax Deduction interaction with the ITC & Grant
- Cash Rebates and Buy-downs
- Performance Based Incentives (PBIs)
- Feed-In Tariffs
- Tax abatements (waivers of sales and/or property taxes)
- SRECs (Green Tags) mandated by state law

The Database for State Incentives for Renewable Energy (The DSIRE database, <http://www.dsireusa.org/solar/>) is a database of all state and federal incentive programs around the country for all types of renewable energy and also energy efficiency, and provides specific details and links state by state and at the federal level.

The Solar Energy Industries Association (SEIA) has put together an excellent and well researched “Guide to Federal Tax Incentives for Solar Energy”, available free to members as a membership benefit. Learn more at: <http://www.seia.org/>.

Tax Benefits such as Tax Credits and Depreciation may be available to certain taxpayers who install solar energy equipment. The information in this article regarding taxes, tax credits and depreciation is meant to make the reader aware of these benefits, risks and potential expenses, and help avoid overblown claims by aggressive salespeople. **It is not tax advice, and the author is not a qualified tax professional. Please seek professional advice from a qualified tax advisor to check the applicability and eligibility of incentives for a particular situation.**

Tax Credits come in several forms: Federal, State and Local. Thru the end of 2008, the **Federal Investment Tax Credit (ITC)** for **Residential** (individual tax filers) was 30% of system cost basis, capped at \$2,000 for systems installed before the end of 2008. From 2009 thru 2016 it is a full 30% (without cap). The residential ITC can be found in Sec. 25D of the Internal Revenue Code (IRC) and can be claimed using IRS form 5695.

The residential ITC will expire at the end of 2016 if not extended. Federal taxability of state, local, or utility rebates affect the ITC system cost basis significantly, so please see the “No Double Benefit” section of this article (below) that discusses Sec. 136(b) of the IRC.

The **Federal Investment Tax Credit (ITC)** for **Business** owned systems (IRS Schedule C business tax filers) is 30% of net system cost with no cap for systems that are “placed in service” by the end of 2016 (IRC Sec. 48). After 2016, if not extended, the tax credit will revert to the previous permanent level of 10%. The IRS current federal form is 3468 available at <http://www.irs.gov/formspubs/>.

“Placed in service” as defined by the SEIA “Guide to Federal Tax Incentives for Solar Energy” occurs when all of the following have occurred:

- Equipment delivered and construction / installation completed. Minor tasks like painting need not be finished
- Taxpayer has taken legal title and control
- Pre-operational tests demonstrate the equipment functions as intended
- Taxpayer has licenses, permits, and PTO (permission to operate)

Both the residential (Sec. 25D) and commercial (Sec. 48) ITC are one-time credits received when filing taxes for the year the system was placed in service. If not completely useable in the system installation tax year, in theory, the residential ITC can be carried forward indefinitely but may run into the practical difficulty that the 5695 tax form may no longer exist after the 2016 tax year unless the IRS makes it available. SEIA is working to address this with the IRS. The ITC can be carried forward only by necessity, and must be claimed as soon as possible (i.e. can’t be carried forward simply for convenience). The business credit can be carried forward 20 years and may be able to be carried back for certain businesses under the Net Operating Loss rules.

As part of the American Recovery and Reinvestment Act of 2009 (ARRA), in order to stimulate the economy, and in particular, the solar industry, commercial solar systems (Sec. 48 ITC only) are able to convert the ITC that would normally be received at the end of the tax year, and only if there was tax appetite, into a **U.S. Treasury Grant** that can be received as early as 60 days after project completion or application (whichever is later). Only projects placed in service in 2009 or 2010, or projects started in 2009 or 2010 and placed in service before the end of 2016 are eligible for Grant treatment. This solves the lost “time value of money” due to lengthy carry-forwards for taxpayers with limited ability to use the ITC.

Most of the rules and eligibility for the Grant are the same as for the ITC, except as noted above. More information is available at: <http://www.treasury.gov/recovery/> and <http://www.treasury.gov/recovery/1603.shtml>.

Although the ITC is received effectively “up-front” when the system is installed (or at the end of that tax year), it is actually earned over 5 years in equal 20% increments. If the property becomes ineligible for the ITC (is disposed of or sold by the taxpayer, taken out of service, or taken outside of the U.S.), IRC Sec. 50(a)(1) stipulates that the taxpayer must repay the unearned portion via the recapture mechanism. For example, if the taxpayer sells the system after 2.8 years of ownership, she has only earned 2 of 5 years (40%) of the ITC, and must repay 60%.

The U.S. Treasury Grant has the same recapture mechanism, but is slightly more relaxed. If the property is sold to another eligible party, the original party receiving the grant is not subject to recapture as long as the receiving party maintains the property’s Grant eligibility for the remainder of the 5 years. If they don’t, the original party will suffer the recapture event.

In 2008, home-based businesses (if >20% business allocation of the home) typically qualified for the ITC as well. Because the credit applies on both individual (residential) and business tax returns, but was capped on residential, it needed to be properly

apportioned on each part of the tax return to ensure the right credit amount is claimed. Home-based businesses are typically apportioned based on percentage of square footage attributed exclusively to the business. To figure the credit, one typically applies the percentages to the two separate calculations then sums the results. From 2009 to 2016 with the uncapped ITC, this distinction is probably no longer relevant.

Beginning in 2009 taxpayers (individuals and businesses) will be able to claim the federal ITC even if they are subject to the **Alternative Minimum Tax (AMT)**. Systems placed in service before the end of 2008 can suffer AMT limitation because the solar ITC (and Accelerated Depreciation discussed in the next section) are ‘Tax Preference Items’ that can cause AMT and limit the enjoyment of the ITC benefit, even if the taxpayer wasn’t subject to AMT before getting the solar system. Even with the ITC “AMT relief” starting in 2009, the Accelerated Depreciation may still cause an AMT situation for businesses.

There is an open question in the solar industry about the application of the ITC to “property used for lodging”. Sec. 50(b)(2) indicates that the Federal ITC is not available for “property used for lodging”. This sentence has created a fair bit of concern for the solar industry, because it appears to exclude hotels/motels and rental property. However, Sec. 50(b)(2)(D) seems to exempt “Any energy property” (which solar is as defined in Sec. 48(a)(3)(A)(i) “equipment which uses solar energy to generate electricity”) from this exclusion. The author has not received a definitive answer from a qualified tax professional or the IRS as to whether hotels and rentals are eligible. Thanks to Chad Blanchard and Michael Masek for helping research this.

Please seek qualified tax advice before accepting anyone’s claims of applicability of these or other tax benefits to a particular situation.

State Income Tax Credits are available in several states, such as Oregon, Hawaii, New Mexico, and New York, and can be quite generous. However, potential recipients should be aware that if they itemize their federal tax deductions, a state tax credit isn’t worth its full face value. When itemizing, state taxes are usually deductible off federal taxable income. Reducing state taxes by the state tax credit means that federal taxable net income will go up. In effect, federal income tax will be paid on the value of the state tax credit. For most people, a state tax credit is worth about 65-85% of its face value.

Depreciation and Accelerated Depreciation may be a possibility for business owned systems. Depreciation is a method of ‘writing-off’ expenses for long lasting (durable) goods such as cars, computers, etc. The ‘write-off’ is generally required to be spread over several years, depending on the type of property. Since depreciation is a write-off, it reduces taxable income, and thus reduces tax liability. The net federal benefit of depreciation is the federal tax rate times the federal depreciation basis. The federal depreciation basis amount is the federal ITC basis, minus one-half the federal ITC amount (85% of the ITC basis in the case of the current 30% ITC). For example, a system costing \$100K (ignoring any rebate for this example) would have a tax credit basis was \$100K, and thus receive a \$30K federal ITC (30%). Its federal depreciation basis would be

\$85K (\$100K minus one half of the \$30K ITC). If the customer’s federal tax rate were 28%, the federal depreciation benefit would be approximately \$24K (\$85K times 28%).

The state depreciation benefit is the state tax rate times the state depreciation basis, which may be different from the federal depreciation basis, and may be affected by any state rebates received. Unfortunately, for the same reasons that state income tax credits aren’t really worth their face value, similarly, the state depreciation net benefit must factor in the effective federal taxation effect of reducing state taxes.

Federal depreciation for solar uses the **MACRS 5-year Accelerated Depreciation** schedule and is calculated on IRS form 4562. MACRS stands for Modified Accelerated Cost Recovery System, and is a way of allowing businesses to depreciate some property more quickly than the normal schedule, to receive the write-off sooner (accelerate the benefit). Though it is called “5 year MACRS” it generally uses the “half-year convention” assuming the property is placed in service in the middle of the tax year, which allows a lesser share of the write-off in the first year and extends the write-off into the 6th year. Different numbers may apply if the property was placed in service late in the tax year. Home-based business systems may also qualify for proportional depreciation (if the business use of the property is greater than 50%).

In 2008 and 2009 only, as part of the Economic Stimulus Act of 2008 and the ARRA of 2009, businesses can also receive ‘50% Bonus Depreciation’ meaning that they can further accelerate half the future depreciation amounts into the first year (2008 or 2009) the project was placed in service (it does not mean they are getting 50% extra depreciation, just getting half of it even sooner). The 5-Year MACRS schedules (half-year convention) are:

| Year | 1 st | 2 nd | 3 rd | 4 th | 5 th | 6 th |
|--------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Not 2008 or 2009 | 20% | 32% | 19.2% | 11.52% | 11.52% | 5.76% |
| 2008 and 2009 only | 60% | 16% | 9.6% | 5.76% | 5.76% | 2.88% |

Fig. 8: MACRS Federal Depreciation Schedules for 2008 and 2009 and years other than 2008 or 2009.

State depreciation sometimes depends on the type of business. In California, it is split between “Corporate” and “Non-Corporate” businesses. Non-Corporate businesses use the regular federal MACRS 5-year accelerated depreciation (without the 50% bonus). California corporate businesses use 12-year straight-line depreciation for state depreciation. Please check the DSIRE database for the applicable depreciation for other states.

The **Sec. 179 Deduction** has a negative interaction with the federal ITC and U.S. Treasury Grant. If the taxpayer uses either the ITC or the Grant for part or all of the property, they may not also claim the Sec. 179 deduction for that part. The ITC or Grant benefit, combined with MACRS depreciation are much more valuable than the Sec. 179 Deduction. In previous situations (typically Commercial Economics classes), the author

incorrectly suggested that Sec. 179 may also be available and might be able to be used with caution in certain situations.

Rebates, Buy-downs, and Grants provide direct cash incentives to purchasers or their installers. These types of incentives are usually proportional to system size based on the rated wattage of the system, and are often limited to a percentage of total system cost and/or a fixed total dollar amount. The rating systems vary by program, using the CEC, PTC, or STC rating systems. In cases where a rebate is received, the customer can usually also enjoy savings via Net Metering on her electric bill.

Rebate programs are usually run and/or overseen by either a state agency or a utility, often in compliance with a state law or voter initiative.

Rebate payments are paid and received up front, and are not based on actual system performance. At best, they can be adjusted to account for expected performance. Expected performance rebates may be adjusted by the expected relative system performance compared to an optimal or ideal system, taking into account reductions in performance due to shading, tilt, orientation, and/or geographic location (to account for variations in sunlight levels due to location).

Performance Based Incentives (or PBIs) provide incentive payments based on actual delivered system performance, and so automatically account for shading, tilt, orientation, and geographic location, as well as the other factors mentioned in Fig. 2. The PBI amount is usually a set value in cents per kWh (commonly 10-40¢/kWh) paid for each kWh produced, measured, and reported by the system for a set number of years (commonly 1, 3, 5, 10, 15, or 20 years) from the date the system is first placed in service. Usually PBIs are received in addition to the customer savings via Net Metering of her electric bill.

Since PBI payments are paid over time the customer must wait for payment, and bear the risk that something will interfere with system performance. Because of the time value of money, and this additional risk, the total of the PBI payments must be more than a rebate would have been in order to provide an equal time- and risk-adjusted incentive. This increases the cash cost of the incentive program to the incentive provider, but increases customer attention to her system (in order to receive payment), so per kWh delivered, PBIs may be more cost effective to the incentive providing agency and funding parties than rebate-type incentives.

There is a major marketing benefit to PBI programs as well. Unlike rebates, which are received one-time up-front when the customer is already excited about her system, PBIs are received at regular intervals (usually every 1, 3, or 6 months) providing the customer a reminder of her solar system and a reason to smile (or call for warranty service). A smart installer or salesperson will time her follow-up communications to the customer to ensure the customer got her PBI check, and also to make sure she is remembered for referrals. This residual benefit can last for years, generating many new sales.

Taxability of Rebates and PBIs: Depending on the structure of the program, and the type of taxpayer (residential or commercial), rebates, PBIs, and grants may be taxable income

at either the federal or state level, or both. Contrary to what was written in previous versions of this article, there appear to be significant grounds for individual (residential) taxpayers in some states to claim the rebate payment is non-taxable. Sec. 136(a) of the IRC specifies that 'direct or indirect utility payments (i.e. from ratepayer funds) for energy conservation measures may be excluded from taxable income, where energy conservation measures reduce the consumption of energy in a dwelling.' PV systems are energy conservation measures (source: Wisner & Bolinger, Lawrence Berkeley Lab - LBL). Therefore it seems clear that utility direct paid rebates for PV to homeowners are non-taxable, such as in most of California, Colorado, New Jersey, and some other states.

Other states, such as Florida, or cities such as San Francisco, pay rebates from general funds collected from taxpayers (not ratepayers). In these cases, Sec. 136 would probably not apply, and the rebate payments would probably be taxable.

Less clear are rebates that are funded from ratepayer sources, but paid by non-utility administrators, such as the California Energy Commission or the Energy Trust of Oregon. In a private letter ruling an IRS administrative law judge found that the Energy Trust of Oregon rebate was indeed tax exempt, but the reader is cautioned to note that private letter rulings are not precedents and do not bind a different IRS administrative law judge to the same finding, nor do they apply to any other taxpayer than the one named in the ruling. It is not expected that the IRS will make a public ruling, so it's likely to remain a grey area for now.

Some state agencies, such as the California Energy Commission have issued 1099 tax forms to rebate recipients. Simply receiving a 1099 tax form may not require payment of tax on the amount. Such a 1099 may be advisory and a way for the issuer to cover itself and ensure compliance with IRS rules, even if Sec. 136 applies. On the other hand, not receiving a 1099 doesn't excuse the taxpayer from tax liability if due (i.e. if Sec. 136 doesn't apply). Please check with a qualified tax professional when making these important decisions.

It was mistakenly suggested in previous writings of this article that if the installer accepted the rebate on the customer's behalf, it might eliminate the customer's rebate tax liability. The author has been informed that this is not true, and that tax is due when value is received (including non-monetary value in the form of part of a PV system), unless specifically exempted (as may be the case if Sec. 136 applies) (source: Wisner, LBL).

Despite this, there are other reasons why it is still better for the customer to have the installer accept the rebate as part of payment for the project: 1. Less cash is required (by the customer) during the project, and 2. The customer has greater leverage over the installer should the installer do a substandard job (if either the customer or inspector doesn't sign off on the job, the rebate may be withheld). This is less attractive for the installer because it hurts her cash flow, but might provide her a sales advantage over a competitor. It doesn't impact the installer's tax return because the rebate is part of the job's revenue whether received directly or thru the customer, and all job revenue minus expenses is already subject to taxation.

A sales and cash flow optimization strategy is to have the customer pay full price and receive the incentive directly unless she requests otherwise, optimizing installer cash flow on as many jobs as possible, while providing the sales flexibility to match the competition upon customer request.

Non-profits, governments and schools don't pay income taxes, so incentives received are generally not taxable.

Business/commercial solar system rebates are likely subject to taxation, as Sec. 136 applies only to systems installed on the dwellings of individual taxpayers. There is no known exemption for business taxpayers, but it turns out that, in general, a business wouldn't want to use it – more on this later.

No Double Benefit: Sec. 136(b) states that if the rebate is tax exempt, then the taxpayer will need to reduce the tax credit basis for any related ITC, and will then get less tax credit. On the other hand, if she does pay tax on the rebate, then she does not deduct the rebate amount when she calculates the tax credit basis (and therefore get relatively more tax credit benefit).

For residential taxpayers, the above interaction and the importance that Sec. 136 apply to any rebate she has received was much more significant before 2009, because the Federal ITC was capped at \$2,000. Now that the Federal ITC is an uncapped full 30%, the impact is usually far less, and depends on the marginal tax rate of the customer. If the taxpayer's bracket is 30%, then it makes no difference to the customer whether the rebate is federally taxable or not, since she will gain the same amount either in no tax on the rebate or in higher ITC value. See the 4 cases illustrated in Fig. 9. If her tax bracket

Case 1: Non-Taxable Rebate

\$100K System Cost
 -\$30K Rebate
-\$21K Tax Credit Value (30% of \$70K after rebate cost)
 =\$49K Net Cost

Case 2: Taxable Rebate at 30% Federal Tax Bracket

\$100K System Cost
 -\$30K Rebate
 +9K Rebate Tax (\$30K * 30% Fed Tax)
-\$30K Tax Credit Value (30% of \$100K)
 =\$49K Net Cost

Case 3: Taxable Rebate at 20% Federal Tax Bracket

\$100K System Cost
 -\$30K Rebate
 +\$6K Rebate Tax (\$30K * 20% Fed Tax)
-\$30K Tax Credit Value (30% of \$100K)
 =\$46K Net Cost

Case 4: Taxable Rebate at 40% Federal Tax Bracket

\$100K System Cost
 -\$30K Rebate
 +\$12K Rebate Tax (\$30K * 40% Fed Tax)
-\$30K Tax Credit Value (30% of \$100K)
 =\$52K Net Cost

Fig. 9. Residential examples of rebate/ITC interactions.

were lower than 30%, then she would prefer the rebate be taxable (if she had a choice or if she and her tax advisor feel there is enough uncertainty in the applicability of Sec. 136) because she would then pay less in rebate tax than she would gain in getting the full ITC. On the other hand, a taxpayer in a tax bracket over 30% would prefer the rebate to be non-taxable. Each 1% of difference between the customer's tax bracket and 30% makes 1% difference in the net value of the rebate to them. For most taxpayers, this isn't going to be very much in absolute dollars either way compared to the total cost of a PV system, as is evidenced by the examples.

For business taxpayers, Sec. 136 does not apply, and there is no other known section of the IRC that might exempt the rebate from federal taxation. This turns out to be convenient, because while paying tax on the rebate is a cost, not only does it allow a larger ITC to be enjoyed, but since the depreciation basis is proportional to the ITC basis, it allows more depreciation to be enjoyed as well. The larger amounts of both ITC and depreciation far more than compensate for the tax on the rebate. See Fig. 10 for a comparison of the two results.

Even when the rebate is taxed, it is usually only taxed by the federal government. State governments that have enacted rebates in support of solar generally don't tax their own incentives, however, tax laws vary by state, so check with your state taxing authority.

PBI Taxation: Since PBIs are paid over time and the total value that will be received is unknowable at the time the federal ITC needs to be calculated, the interaction between them and the ITC is less straightforward. For businesses, PBIs are almost certainly taxable.

For residential customers however, one might be able to argue that Sec. 136 should also make PBIs paid from ratepayer funds for PV systems non-taxable, but this would create the difficulty of calculating how much to reduce the ITC basis by, since it would require the impossible task of calculating the present value of the unknowable stream of PBI payments that will be received as and if the PV system produces electricity. Even if

Case 1: Non-Taxed Rebate

\$150K System Cost
 -\$50K Rebate
 -\$30K Tax Credit Value (30% of \$100K)
-\$35K Depreciation Value (85K * 41%)
 =\$35K Net Cost

Case 2: Taxed Rebate

\$150K System Cost
 -\$50K Rebate
 +17.5K Rebate Tax (\$50K * 35% Fed Tax)
 -\$45K Tax Credit Value (30% of \$150K)
-\$52K Depreciation Value (127.5K * 41%)
 =\$20.5K Net Cost

41% = combined net federal & state tax rate (35% Federal & 8.84% CA State)

Fig. 10. Commercial examples of rebate/ITC interactions.

you could agree with the IRS on a discount rate for PBI payments to be received in the future, no one can know how many kWh will actually be produced until it has happened, which is usually well after the ITC needs to be calculated and submitted with a tax return. Guidance from Mark Bolinger at LBL (not a qualified tax professional, but someone who has studied this in greater depth than the author, see “Further Reading” at end for more info) is to assume PBIs are taxable for residential customers as well as businesses, to be on the safe side.

Of course, the ideal and much more valuable result would be for the IRS to accept an argument that the PBIs are non-taxable to homeowners due to Sec. 136, but also not challenge the higher claimed amount of the ITC since there was no rebate received up front to reduce it. The author is not advocating this potentially risky strategy, and a competent qualified tax professional should be consulted before considering this maneuver. However, it is fairly certain that even if the IRS would approve such an approach, they aren’t likely to chase the taxpayer around attempting to provide a refund unless she files her taxes in this way.

Feed-In Tariffs (FITs) are very similar to PBIs in that they provide a payment to the customer for each kWh delivered to the grid. The difference being that usually a Feed-In Tariff is the only benefit received from owning the solar system – there is no Net Metering benefit, so the customer continues to pay her regular electric bill. In order to make Feed-In Tariffs attractive, the payment per kWh needs to be higher than a comparable PBI because of the lost Net Metering. Common feed-in tariff terms are 10, 15, and 20 years.

Gainesville, Florida and Ontario, Canada have implemented feed-in tariffs. Gainesville’s tariff of 32¢/kWh for 20 years was very popular and used up the first allocation of money quickly. Ontario’s first attempt at CAD 42¢/kWh for 20 years was not high enough to be strongly popular, so in May 2009 revised incentives of CAD 44-80¢/kWh depending on system size and mounting type were proposed (not yet finalized).

Feed-In Tariff Policy Discussion: *Feed-In Tariffs (FITs) are very simple incentives for solar, and are very popular in Germany and Spain because they have very quickly created large markets in each of those countries. There are a number of risks associated with FITs however:*

- *The incentive is 100% visible, and makes solar look expensive, making it an easy target for solar detractors, whereas Net Metering ascribes value to the publicly received benefit of the electricity generated and delivered when the utility needs it. The cost to the ratepayer is equal, so it’s a matter of perceptions and visibility, however Net Metering better reflects the public benefits.*
- *The entire incentive for solar becomes vulnerable to political changes – FITs can come and go with a change of elected or appointed officials, creating potentially large changes in fortunes of the solar industry. Germany and Spain both found their incentives aggressively cut back in the summer of 2008 when they started to be viewed as too expensive. Spain’s solar*

industry (which was over 40% of the world solar market in 2008) is effectively completely shut down as of 2009.

- *Solar benefits some customers much more than others (customers high in the rate tiers, those with avoidable demand charges, and/or those who can benefit from Time-of-Use rates), each of which is a hidden artifact of Net Metering. Losing the Net Metering benefit levels the playing field, which is democratic, but removes a lot of existing sales opportunities for those who know where to look, and may completely eliminate the market if the FIT is set too low.*
- *FITs have no ‘End Game’ unless the customer can switch back to Net Metering (without other incentive) at her choice. This means that if only FITs are available (without Net Metering), the FIT payment can never be reduced to 0¢/kWh because the customer will always need some payment to make it worth going solar (since she won’t be saving on her electric bill). This makes the solar industry perpetually dependent on the existence of FITs and their future renewal. If the customer can always choose between a FIT or Net Metering, then this problem goes away, because once the Net Metering benefit becomes greater than the FIT payment, customers will chose Net Metering.*

Tax Abatements are offered by some taxing jurisdictions in the form of Sales Tax or Property Tax exemptions. Many states exempt solar systems from being included in the assessed value of a home, so installing a solar system doesn’t cause the homeowner’s property taxes to increase. For example, solar systems installed in California between January 1, 1999 and January 1, 2017, are exempt from triggering Property Tax reassessments (California Taxation Code, Sec. 73). Sales Tax exemptions help reduce the up-front cost of the solar system.

Solar Renewable Energy Credits/Certificates (often known as **SRECs**, **S-RECs**, **sRECs**, **RECs**, or **Green Tags**) are a new and growing way to value the greenness of the energy from a solar energy system. SRECs represent the bundle of legal rights to the green part of each kWh produced by a solar system. This green part can be sold for a value, which generates additional revenue for the seller.

SREC value is created in two common ways. The first is the “voluntary” market, where individuals buy SRECs as a way of “greening” their world by paying extra to someone else to install some new solar capacity, often because they can’t or chose not to make the large, long-term investment themselves. This is common for apartment dwellers and business renting the space they occupy. Business such as Kinko’s, Wal-Mart, Whole Foods, and White Wave (the makers of Silk soy milk) have bought SRECs to offset some of the emissions from their operations.

Voluntary SREC purchases do actually “green” the grid if they result in net new solar (or wind or other renewable generation depending on the type of REC or Green Tag purchased) that wouldn’t have been installed if the SRECs weren’t purchased for the agreed price. For example, a solar ‘farmer’ wants to build a solar farm on some open land or on the roof she has access too. If the value of the electricity she will be getting from the utility (via sales or Net Metering),

combined with the incentives discussed (excluding SRECs) above isn't enough to provide the rate of return the 'solar farmer' is looking for, the investment won't happen. If the 'farmer' can sell the SRECs to a buyer for enough extra value (1-5¢/kWh is common in 'voluntary' locations), the total investment may become attractive, and the 'farmer' will invest the money and effort to make it happen, and Voila! – net new generation happened in part because of the SREC value.

The second common (and very important) way SREC value is created is thru the regulatory "compliance" market where state law or voter initiative has required that a certain percentage of electricity in a given geographic or territorial area must come from solar sources. Often, the percentage is set to rise over time. Fourteen states have Renewable Portfolio Standards (RPS) with such a requirement. In these states, the utilities must either build and own solar installations (if allowed), or buy SRECs from producer/owners. Usually, there is an Alternate Compliance Payment (ACP) that sets a maximum on the value of the SREC value, whereby, if the utility isn't able to buy SRECs for less than the ACP, they can pay the ACP as a penalty for failure to do so.

New Jersey is the best known of the states where its solar program is supported mostly by SREC value. Currently, the ACP in New Jersey is the equivalent of 71.1¢/kWh. The market in which the NJ utilities can buy SRECs is set up as a bid-auction market, so supply and demand rule the price of SRECs at any given moment, with the artificial cap of the ACP. As of June 2009, the auction market in NJ had set the price of SRECs at 60-65¢/kWh. This value may continue for the short-, mid- or long-term, but there is no assurance of it. The price could also collapse if an oversupply of SRECs becomes available, depending on the rate of installation of solar systems compared to the increasing requirements of the NJ RPS.

SREC Policy Discussion: *The New Jersey style incentive using SRECs is one of the author's favorites, because it allows market mechanisms to automatically readjust the incentive (SREC) level to changes in market conditions. For example, the uncapping of the federal ITC provided a lot more federal incentive for solar, and so would require less state support and would allow the SREC level to decline, all things being equal. Similarly, the recent rapid decline in solar module prices has lowered end-customer costs, again requiring less support to be required in the form of SRECs. The U.S. economy of 2009 is in such bad shape that the above two have not actually manifested in substantially increased solar purchasing and supply of SRECs yet, but the Rate of Return on a solar investment in NJ has been increasing due to the two events. Eventually, the return will get good enough, and the economy will get stable enough, that individuals will start to buy systems and put new SRECs on the market, creating more supply to satisfy an inelastic demand, causing SREC values to come down at least somewhat.*

The missing element in the New Jersey program has been long-term contracts whereby solar customers can get an assurance of future SREC value. Without such an agreement, a potentially oversupplied SREC auction market could cause the traded price to plummet, so customers installing systems need to insist on a risk-premium. This is starting to shift. With the

assurance of long-term agreements, the customers (homes and businesses) installing solar don't need to be paid as much for their SRECs because they know the value is locked, which also saves the utilities in the short term, and probably also in the long term, because the risk-premium is eliminated.

Maryland has a 2009 ACP of 40¢/kWh which will decline over time (see the DSIRE Database for current details). Pennsylvania and other states will likely also have similar arrangements. There is no guarantee that actual value will be anywhere near the ACP unless the ultimate buyer (the utility) agrees to it.

Colorado has an RPS as well, but rather than paying for each SREC as it is produced, the two main utilities, Xcel and Black Hills Energy (formerly Aquila) buy 20 years worth of the SREC output from smaller systems for \$1.50/W STC of installed capacity (looking more like a rebate) in addition to the regular \$2/W rebate. This equates to an approximate SREC value of 5-7¢/kWh depending on sunlight levels and system performance.

California and several other states have Renewable Portfolio Standards too, but these RPSs don't have requirements that any of the energy be sourced from solar, so it is likely that most will come from wind and other sources, which are currently less expensive. That means that the SREC market in these states is voluntary (including some speculators buying or trading SRECs on the bet that they will become more valuable if/as the government and industry take on global warming). Current voluntary SREC values are estimated to be in the range of 1-5¢/kWh, which is not insignificant compared to Net Metered electricity value that is sometimes as low as 6-20¢/kWh.

The only way an SREC has any real value though, is to ensure that the bundle of legal rights to the greenness it represents has only been sold once to its ultimate consumer for "retirement", the same way as a publicly traded company can only sell a fixed number of shares of its stock. Within a state RPS compliance market, this is usually done by an administrator who tracks all the production, sales, and retirements. In voluntary markets, SRECs should be certified by a certifier such as Green-e (a service of the Center for Resource Solutions) <http://www.green-e.org/>, which is the nation's leading independent consumer protection program for the sale of renewable energy and greenhouse gas reductions in the retail market. Only then can the consumer be sure she is buying something of value.

One should take care to consider whether she really wants to sell the SRECs her system generates. By selling them, she loses the right to claim she is using any of the clean green energy generated by the system. That right would belong to the new SREC owner. The system owner could claim she is a host for the generation, but not a user. The distinction is important in order to prevent double counting of the SRECs, which is important to maintaining their value.

HOW IS THE SOLAR PAYOFF PROVEN?

Independent tests of the financial viability of solar energy include:

- Rate of Return for comparison to other interest rate based investments
- Payback in a reasonable time
- Total Lifecycle Payback
- Net increase in property value compared to solar system cost
- Positive cash flow when financing the project

All of the analyses and analysis methods presented here apply only to residential scenarios. Different mechanisms, assumptions, and accepted financial and accounting practices apply to commercial cases, which are not discussed here. For example, commercial analyses must be done on an after-tax basis, which has important consequences relating to the loss of the electric bill tax deduction a business otherwise would have enjoyed, and commercial property resale valuation is done using Capitalization Rate, rather than the method discussed here. Future versions of this article may include this material, so check back later please.

RATE OF RETURN:

Compound Annual Rate of Return on an investment is another term for effective interest rate or yield, which is a way of comparing one investment to another. For example, a savings account might pay 0.5%-1% interest, and the long-term (80 year) Dow Jones Industrial Average of the stock market, assuming dividend reinvestment had earned 8.5% per year (CAGR) to its height of 13,500 in 2008. At its level of 8,000 in June 2009, the long-term CAGR of the Dow has been 7.5%.

The author chose 10% as the test point for solar, because that compares favorably to other long term investment average returns from common, readily accessible, higher yielding investments such as stocks and bonds and provides a slight premium to compensate for solar's lack of familiarity to much of the public.

To properly value the savings from a solar system, it should be noted that solar saves after-tax expense, while most other investments earn pre-tax income. In order to compare solar to other investments, all investments should be placed on the same side of the tax equation. Since most investments are taxable (i.e. stocks, savings interest, etc.), and because most people think about their investments on the pre-tax side, it is most meaningful to convert solar savings to its taxable equivalent value (i.e. *PreTax* value).

AfterTax dollars are worth more to a taxpayer than the same number of *PreTax* dollars, because *PreTax* dollars are subject to taxation. Therefore, an *AfterTax* dollar saved (with solar) is worth more than \$1 on a *PreTax* basis, by an amount proportional to the taxation rate. To make this conversion from *AfterTax* value to *PreTax* value, the following equation can be used (where *TaxRate* is the net total effective income tax rate):

$$PreTax = \frac{AfterTax}{(1 - TaxRate)}$$

To illustrate this with an example, let's assume a Tax Rate of 50% (unrealistically high, but easy to illustrate with) and an

after-tax savings of \$100. The example would then be calculated as follows:

$$PreTax = \frac{AfterTax}{1 - TaxRate} = \frac{\$100}{1 - 50\%} = \frac{\$100}{1 - .50} = \frac{\$100}{.50} = \$100 * 2 = \$200$$

Meaning that \$100 after-tax is equivalent to \$200 pre-tax at a 50% tax rate. To put it in context of a solar system: if a customer were choosing between investing \$15K in a solar system that would save them \$100/month on her electric bill (tax-free), vs. \$15K in a taxable investment, the taxable investment would need to earn them \$200/month so that after she paid taxes on the \$200, she would have \$100 left over to pay the electric bill, for the two choices to be considered equivalent. In reality, combined federal and state tax rates are currently lower than 50%, with an effective rate of 20-40% for most taxpayers. At these rates, \$100 after-tax savings would be equal to \$125-\$165 pre-tax equivalent.

Once the value of the savings, maintenance costs and other amounts are properly adjusted to their pre-tax values, they can be inserted into a 25-year financial timeline (the warranted life of most solar electric/PV modules) representing the cash flows for each year, to calculate the Compound Annual Rate of Return. This allows the accurate inclusion of all relevant cost and benefit components.

The initial capital cost is the only amount that doesn't get adjusted. That amount is the net system up-front cost (total out of pocket), and is unaffected by the taxation or lack thereof of future savings in the utility bill. Consider it the same as principal that is invested anywhere. The principal is not taxed upon its departure or return.

Tax savings and consequences, inverter replacement, maintenance, and other significant financial events can be included at their appropriate places on the timeline. Inflation, escalation, and module degradation are also easily included. For each year, the values can be summed, creating a 25-year timeline of net expense or net savings by year. The Internal Rate of Return (IRR) function in most spreadsheets can then calculate the IRR, which is the same as the Compound Annual (interest) Rate of Return (CARR) for the investment.

One should note that there is a significant and very important difference between **Compound** Annual Rate of Return and **average** return or total return divided by the number of years an investment is held. Average return does not factor in compounding of interest, and may make an investment look more attractive than it really is. This article uses CARR for all items under consideration (solar, stocks, savings, etc).

The difference becomes more visible the longer the time horizon. A brief example: Suppose an investment doubles every year. Its CARR would be 100% because you get 100% increase each year on your investment. No matter how long you hold it, its CARR is 100% because you need to compound for the number of years it's held. Alternatively, if you were to look at the "average rate of return", over 1 year, it would still be 100%. However, if you held it 3 years, your investment would be 800% of the original, or a total return of 800%

(100%>200%>400%>800%). The average annual return would be 800%/3years-100% or 167%, which looks great, but isn't representative, because it isn't factoring in the compounding. This faulty method of analysis is highlighted here because unfortunately there are several inaccurate (misleading) solar analyses and sales presentations being given to the public that use averaging, rather than compounding.

Please see Fig. 14 for example analyses from several states and their Compound Annual Rates of Return. These cases are for full service residential system installations, using typical installed system costs on a simple composition shingle roof. Utility & state specific assumptions for the examples are listed in Fig 13. General variables and assumptions are:

- 28% federal tax bracket, corresponding state tax bracket
- Facing south, 22° pitch, simple composition shingle roof by full service provider, no complications
- Slightly conservative real system performance, no shade
- Final Net Cost = total installed system costs - Rebate (if any) - 2009 Fed 30% ITC + \$500 Permit + \$0 Utility Fee
- System maintenance cost is 0.25% of gross system cost per year, adjusted for inflation
- 5.0% electric escalation (2.2% in CO)
- Module degradation 0.5% per year
- Module PTC/STC Ratio: 89.6%, Inverter Efficiency: 95.0%
- Inverter replacement costing \$700/kW occurs in year 15

These analyses were performed using the OnGrid Tool, available at <http://www.ongrid.net/payback>. Other tools are listed in the Design and Analysis Tools section at the end.

PAYBACK:

What about calculating the **payback**? Payback is a simple but crude tool for comparing investments. Solar is an inflation-protected investment but many others are not. This improves the payback for solar (electric rates double every 15 years at 5% escalation). To properly calculate the solar payback, it is necessary to add in the rate escalation adjusted savings of each successive year, less the reduction due to module degradation and maintenance costs, until payback has been achieved. Savings in the latter years are larger than savings in the first years, so the payback is faster than simply dividing the cost by the savings. See Fig. 12 for an illustration.

Payback analysis on an after-tax basis does not reflect the true value of the saved utility expense, because after-tax savings are worth more on a pre-tax basis. However, trying to do payback using the pre-tax value gives an unrealistically optimistic view of when “payback” has occurred. The examples in Fig. 11 show how long paybacks on other investments really are in comparison to solar, when taken on an after-tax basis.

There are numerous other flaws in using payback for a

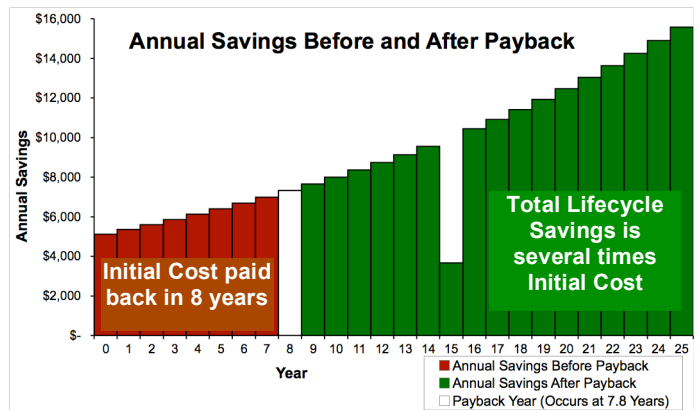


Fig. 12. Simple Payback vs. Total Lifecycle Payback. Total Lifecycle Savings over 25 years is several times the initial cost represented by the area up until year 8. Year 15 shows diminished savings due to inverter replacement.

residential long-term investment; it does not properly include the tax savings and consequences, it does not account for maintenance or inverter replacement expenses, and it makes it difficult to compare to other investments such as stocks, savings, etc. because of inflation and other factors.

TOTAL LIFECYCLE PAYBACK:

Comparing the savings of a solar electric system over 25 years of operation to its initial cost is a better way of looking at payback, because it more fairly values the savings due to the compounding effect of electric rate escalation. Because of this effect, the savings in the later years is much greater than the savings in the first few years. Typical systems give back 1.5 to 3 times their initial cost. See Fig. 14 for several examples and Fig. 12 for an illustration. One drawback to this analysis is it fails to account for the time value of money. A dollar saved in the future isn't worth as much as a dollar saved today, so that a total lifecycle payback isn't worth quite as much as it might initially appear. The better methods of comparing solar as an investment are the Compound Annual Rate of Return, Increase in Property Value, and Cash Flow.

INCREASE IN PROPERTY VALUE:

Solar electric systems increase property value by decreasing utility operating costs. According to the Appraisal Journal (Nevin, Rick et al, “Evidence of Rational Market Valuations for Home Energy Efficiency,” Oct 1998 (available at various locations on-line, including at http://www.icfi.com/Markets/Community_Development/doc_files/apj1098.pdf), a home's value is increased by \$20,000 for every \$1,000 reduction in annual operating costs from energy efficiency.

| Investment Type | Net Investment Amount | Interest Earned or Net Electric Bill Savings | After-Tax Value the First Year | After-Tax Value the Eighth Year | Payback / Time-to-Doubling including taxes & inflation |
|------------------------|-----------------------|--|--------------------------------|---------------------------------|--|
| Savings | \$30,000 | \$300 (at 1% rate) | \$196 | \$196 | 153 years |
| Stocks | \$30,000 | \$2,400 (at 8% rate) | \$1,567 | \$1,567 | 19.1 years |
| Solar – CA PG&E 5.5 kW | \$30,000 | \$2,321 (1 st year) | \$2,321 | \$3,176 | 10.4 years |

Fig. 11. Investment Payback Comparisons: Solar savings grow due to escalation (4.5% net w/ degradation). Assumed 28% federal & 9.3% state tax rates play a big role in the different outcomes. Stocks & savings are more liquid, but it's clear why Wall Street and banks don't talk “Payback”.

| Utility | Insolation | AC kWh Production per rated kW per year | Installed Cost per rated Watt (~October 2008) | Starting/Ending Rate Schedule, Peak % | Incentives |
|---------------|---------------|---|---|---------------------------------------|--|
| AZ - APS | Phoenix | 1660 / STC kW | \$8.25 STC | E-12 / ET-2, 50% | \$2.40/W Rebate (net) 25% State Tax Credit |
| CA - PG&E | San Francisco | 1630 / CEC kW | 3kW: \$9.50 CEC 6kW: \$9.25 CEC 9kW: \$9.00 CEC | E1XB / E6XB, 35% | \$1.55/W Rebate |
| CA - SCE | Los Angeles | 1675 / CEC kW | | D-10-Basic / TOU-D-1, 36% | \$1.90/W Rebate |
| CA - SDG&E | San Diego | 1700 / CEC kW | | DR-Coastal-Basic / DR-SES, 28% | \$1.55/W Rebate |
| CO - Xcel | Boulder | 1398 / STC kW | \$8.25 STC | R | \$3.50/W Rebate & SREC |
| CT - UI | Hartford | 1262 / PTC kW | \$8.75 PTC | R / RT, 45% | \$1.75/W Rebate |
| FL - FPL | Miami | 1345 / ST kW | \$8.25 STC | RS-I | \$4/W Rebate |
| HI - HECO | Honolulu | 1460 / STC kW | \$8.25 STC | Res | 35% State Tax Credit |
| MD - BGE | Baltimore | 1236 / STC kW | \$8.25 STC | R / RL-2, 65% | \$1.20/W Rebate (net), SRECs: 10¢/5yrs, 5¢/10yrs |
| NC - Progress | Raleigh | 1260 / STC kW | \$8.25 STC | RES / R-TOUD, 60% | 35% State Tax Credit |
| NJ - JCP&L | Newark | 1140 / STC kW | \$8.25 STC | RS / RT, 58% | SRECs: 48¢/1yr, 30¢/12yrs, 10¢/12yrs; \$1.55/W Rebate |
| NY - ConEd | New York City | 1178 / STC kW | \$8.25 STC | Rate I / Rate II TOU, 75% | \$2.81/W Rebate (net) 25% State Tax Credit |
| PA - PPL | Philadelphia | 1217 / STC kW | \$8.25 STC | RS / RTD R, 70% | \$2.25/W Rebate, SRECs: 10¢/5yrs, 5¢/10yrs |

Fig. 13. Utility specific residential assumptions. Module prices have dropped since October 2008, and selling prices are declining, but still in a state of flux. For now, the analyses assume 10/2008 pricing.

| Before Solar | | Size & Net Cost | | | Results, Savings, and Benefits | | | | | | | |
|--------------|----------------|---------------------|-------------------------|---|--|-------------------------|------------------|-----------------------|---|---------------|----------------|--|
| Utility | Pre-Solar Bill | kWh Usage per Month | PV System Size & Rating | Final Net Cost w/ Tax Benefits & Rebate | Cumulative Savings Over First 25 Years (including inflation) | Lifecycle Payback Ratio | Years To Payback | Pre-Tax Annual Return | Net Monthly Cash Flow Compared to 8% 30-yr Loan | | Annual Savings | Appraisal Equity / Resale Increase in First Year |
| | | | | | | | | | In First Year | In Fifth Year | | |
| AZ - APS | \$77 | 800 | 5 kW STC | \$18K | \$22K | 1.2x | 22.2 | 6.6% | \$-31/mo | \$-38/mo | \$539 | \$11K |
| CA - PG&E | \$74 | 550 | 3 kW CEC | \$17K | \$28K | 1.7x | 18.6 | 10.0% | \$-11/mo | \$-15/mo | \$671 | \$13K |
| CA - PG&E | \$258 | 1100 | 6 kW CEC | \$33K | \$120K | 3.6x | 9.7 | 19.5% | \$100/mo | \$123/mo | \$2,761 | \$55K |
| CA - PG&E | \$499 | 1650 | 9 kW CEC | \$48K | \$234K | 4.9x | 7.8 | 24.6% | \$259/mo | \$320/mo | \$5,355 | \$107K |
| CA - SCE | \$85 | 550 | 3 kW CEC | \$16K | \$36K | 2.2x | 15.5 | 12.9% | \$6/mo | \$6/mo | \$835 | \$17K |
| CA - SCE | \$414 | 1650 | 9 kW CEC | \$45K | \$193K | 4.3x | 8.5 | 22.1% | \$193/mo | \$238/mo | \$4,446 | \$89K |
| CA - SDG&E | \$97 | 550 | 3 kW CEC | \$17K | \$38K | 2.2x | 15.4 | 12.9% | \$6/mo | \$7/mo | \$877 | \$18K |
| CA - SDG&E | \$455 | 1650 | 9 kW CEC | \$47K | \$206K | 4.4x | 8.4 | 22.4% | \$207/mo | \$255/mo | \$4,722 | \$94K |
| CO - Xcel | \$72 | 800 | 5 kW STC | \$17K | \$13K | 0.7x | 31.9 | 3.1% | \$-47/mo | \$-46/mo | \$521 | \$10K |
| CT - UI | \$183 | 800 | 5 kW PTC | \$25K | \$57K | 2.3x | 15.2 | 11.9% | \$-20/mo | \$1/mo | \$1,333 | \$27K |
| FL - FPL | \$89 | 800 | 5 kW STC | \$15K | \$24K | 1.6x | 19.3 | 7.5% | \$-35/mo | \$-25/mo | \$591 | \$12K |
| GA - GaPwr | \$88 | 800 | 5 kW STC | \$21K | \$20K | 0.9x | 27.0 | 6.9% | \$-80/mo | \$-67/mo | \$493 | \$10K |
| HI - HECO | \$164 | 800 | 5 kW STC | \$25K | \$62K | 2.5x | 13.2 | 15.1% | \$-10/mo | \$16/mo | \$1,442 | \$29K |
| MD - BGE | \$131 | 800 | 5 kW STC | \$25K | \$39K | 1.6x | 18.4 | 9.3% | \$-25/mo | \$-30/mo | \$1,262 | \$17K |
| NC-Progress | \$80 | 800 | 5 kW STC | \$21K | \$25K | 1.2x | 23.2 | 9.6% | \$-66/mo | \$-51/mo | \$601 | \$12K |
| NJ - JCP&L | \$143 | 800 | 5 kW STC | \$24K | \$66K | 2.8x | 9.3 | 19.4% | \$71/mo | \$85/mo | \$2,947 | \$22K |
| NY - ConEd | \$134 | 800 | 5 kW STC | \$16K | \$40K | 2.6x | 12.4 | 16.5% | \$-2/mo | \$16/mo | \$956 | \$19K |
| PA - PPL | \$95 | 800 | 5 kW STC | \$21K | \$32K | 1.5x | 18.9 | 8.5% | \$-22/mo | \$-30/mo | \$1,100 | \$14K |

Fig. 14. Example residential cases with their net costs and financial benefits.

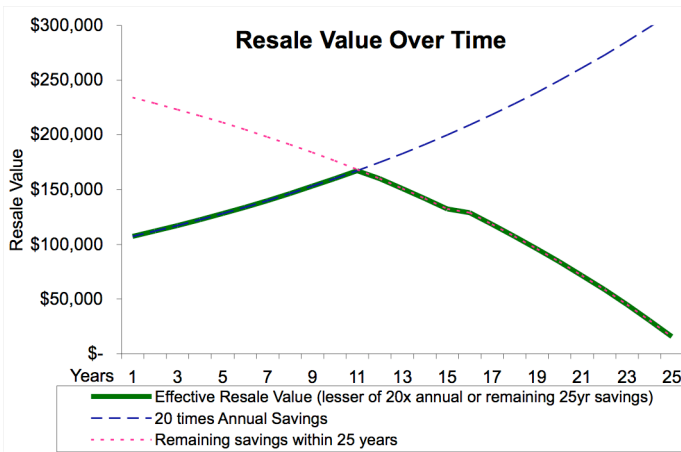


Fig. 15. Resale value increases over time because savings get larger each year. Total remaining lifetime savings in the system declines annually, putting a limit on the increase in resale value after year 11.

The rationale is that the money from the reduction in operating costs can be spent on a larger mortgage with no net change in monthly cost of ownership. Nevin states that average historic mortgage costs have an after-tax effective interest rate of about 5%. If \$1,000 of reduced operating costs is put towards debt service at 5%, it can support an additional \$20,000 of debt. To the borrower, total monthly cost of home ownership is identical. Instead of paying the utility, the homeowner (or future homeowner) pays the bank, but her total cost doesn't change. Since the Nevin article is from 1998, is it dated? No more than 2+2=4 is dated - the rationale is mathematical, not based on market whims, so it is timeless.

Please see the column labeled "Appraisal Equity Increase" in Fig. 14 for examples of the increase in home value. In some cases, a solar system can increase home value by more than its cost to install. This effectively reduces the payback period to 0 years if the owner chose or needed to sell the property immediately. It could even lead to a profit on resale.

There are two limits to the increase in resale value over system net installed cost. First, why should a homeowner pay in total more for a home with a solar system, when she could buy a non-solar home, and solarize it for less money? Yet this happens with other remodels. Decks, on average across the nation, return 104% of their cost upon resale. However, in certain markets like St. Louis, San Francisco, and Boston, decks

| Home Improvement Type | Investment Amount / Net System Cost | Resale Value Increase | % Return |
|-----------------------|-------------------------------------|-----------------------|----------|
| CA PG&E Solar 3 kW | \$17K | \$13K | 76% |
| CA PG&E Solar 6 kW | \$33K | \$55K | 167% |
| CA PG&E Solar 9 kW | \$48K | \$107K | 223% |
| Deck Addition | \$6.3K | \$6.7K | 104% |
| Bathroom Remodel | \$10.1K | \$9.1K | 89% |
| Window Replacement | \$9.6K | \$8.2K | 85% |
| Kitchen Remodel | \$44K | \$33K | 75% |

Fig. 16. Resale value comparison of various home improvements.

add more than 215% of their value upon resale (Alfano, Sal, "2003 Cost vs. Value Report", Remodeling Online – www.remodeling.hw.net downloaded March 5, 2004). Other types of remodels like kitchens and bathrooms had similar results related to geography. So it makes sense that in certain geographies where the sun shines brightly and the electric rates are high, solar would return more than its installed cost, while in other states with less sun and lower rates, the return might be much lower, with a national average comparable to other types of remodel. Fig. 16 lists projected resale value of various solar systems, compared with nationwide averages for some other home improvements.

The increase in property value is currently theoretical. A very high fraction of the grid-tied solar electric systems in California were installed since the state's Power Crisis and the Deregulation fiasco in 2001. Most of these homes have not been sold and there are no broad studies of comparable resale values available. However, some evidence is beginning to emerge that there are significant jumps in resale value being realized by some solar home sellers.

It is also interesting to note that PV systems will appreciate over time, rather than depreciate as they age. The appreciation comes from the increasing annual savings the system will yield as electric rates and bill savings rise. All the calculations in this article assume electric rate escalation will be 5%. If so, the PV system will save 5% more value each successive year, and thus gain from the 20:1 multiplier effect. The resale value will then increase 5% per year compounded, less 0.5% module degradation.

This cannot continue forever, as the increase in resale value runs into the second limit, which relates to the remaining life left in the system. For these analyses, the system is assumed to be worthless at the end of 25 years. This is probably very conservative, since the panels are warranted to be working at least 80% of their new performance. So if the system is worthless at the end of 25 years, the only value the system has as it nears that time, are the remaining savings it can generate before the end of the 25th year. Fig. 15 shows both the increasing value due to increasing annual savings and the remaining value limitation that takes over at approximately year 11. If the system does have additional resale value, so much the better.

Still, the skeptical homebuyer might question the above assertions in light of the lack of hard evidence. Perhaps the best evidence to present would be a stack of old bills showing usage and cost before solar, and a stack of new bills showing a substantial savings. The question might be posed, "What are a continuous, if not growing, stream of these savings worth to the prospective buyer?" That sort of evidence can't easily be ignored. Of course, other factors will weigh heavily in the value. How attractive is the home? A tidy, attractive installation should add all of the value shown above, but like a spa, some prospective buyers may not care or value it, while others may love it.

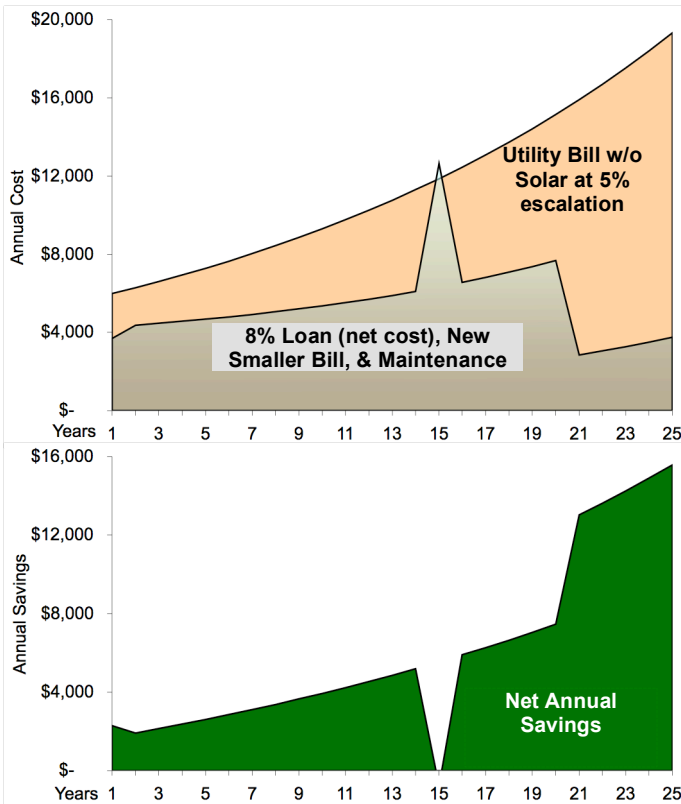


Fig. 17. Effect of a solar system financed at a fixed 8% interest rate over 20 years showing a cash-positive result from the first day of ownership, including maintenance costs and the inverter replacement at year 15.

CASH FLOW WHEN FINANCING:

Financing a solar system makes the purchase achievable to more consumers. If the situation is right, the savings on the electric bill can more than compensate for the cost of the loan and maintenance, making it a cash-positive maneuver. That is, compared to the occupant’s current cost of energy (her current electric bill), going solar but paying for it entirely with a loan (no money down) can actually be less expensive on a monthly basis.

Electric rates and electric bills are subject to electric rate escalation, as can be seen in the top graphic in Fig. 17, where the cost of energy increases steadily over the years, doubling approximately every 15 years. While interest rates might vary depending on the loan type, loans are not subject to inflation or rate escalation, so the loan payments do not increase continuously. This means that the difference between what the electric bill will become and what the loan & maintenance costs will become continues to move in the customer’s favor. Even if a customer didn’t start out cash-positive in the first year, she may become cash positive after a few years.

In the top graphic of Fig. 17, the lower line labeled “8% Loan (net cost), New Smaller Bill, & Maintenance” represents all the new costs compared to the old Utility Bill cost. While the loan rate is fixed at 8% and the monthly loan payments are steady, there are 3 components to this new set of costs that do increase over time: 1. The new maintenance cost will rise with inflation. 2. The new small electric bill will rise with electric rate escalation. 3. In fixed amortization loans, each loan payment

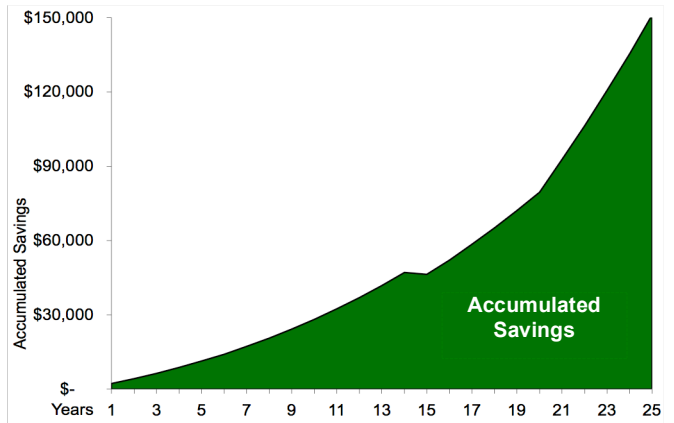


Fig. 18. Accumulated net savings of solar system financed over 20 years, including all costs, thus showing pure cash profit accumulated over time with no additional expense.

has 2 parts: principal and interest. As the balance is paid down, the interest portion of each successive payment is reduced, so the tax deduction benefit is also reduced. In after-tax terms, the loan is least expensive in the first year when the borrower is enjoying the maximum tax deduction for interest paid.

The difference between the two lines in the top of Fig. 17 is the amount the scenario is cash-positive (or cash-negative) for the customer, and is reflected in the lower graphic, which shows “Net Annual Savings” by having purchased a solar system with a loan (put no money down). In this case, the savings are substantial even before the loan is paid off in the 20th year, and gets even better after that. The Net Annual Savings can be accumulated as shown in Fig. 18 to show how much extra cash a purchaser will have in her pocket before the inverter needs to be replaced in year 15, or before the loan is paid off in year 20, or before the equipment is out of warranty in year 25.

The uncapping of the residential federal ITC has made it more difficult to figure out how much a customer should borrow. The problem is that the ITC is a significant incentive, but it isn’t received until the customer files her taxes, which can be a year or more after the system needs to be paid for.

In what one might call the “Optimistic Loan” scenario, the customer would borrow the net cost after all incentives (including the ITC) have been received. This would produce the lowest loan payments, and have the best chance of being cash-positive from the start, making the salesperson happy. However, the customer would need to have the cash to cover the ITC amount or get a bridge loan until the ITC is received because of the optimistically low loan & payments.

In an “Inefficient Loan” scenario, the customer would borrow the net cost after all other incentives, except the ITC. This will allow them to acquire the system with no money down. However it will also result in a lot of cash on hand once the ITC is received, which she is paying interest on, which is expensive and not very efficient. It is also less likely to be cash-positive, which will be a disadvantage for the salesperson.

The solution is what OnGrid Solar calls “Smart Financing” where the customer uses a “line of credit” financing source that she can borrow from and repay without pre-payment penalty. Assuming the ITC will be received in a year, and that she can

apply it to the principal of the loan at that time, one can calculate the necessary loan payment that allows them to pay off the loan in the desired number of years including interest. The calculation is complex, and is not a standard function in most spreadsheets, but can be done. The resulting loan payment will be somewhere between the Inefficient Loan and the Optimistic Loan, typically tending to be pretty close to, but slightly more expensive than the Optimistic Loan.

Results of Smart Financing can be seen in Fig. 17. A subtle feature of it is the slight dip in savings in the 2nd year. In the 1st year the loan principal is very high because it includes the ITC amount causing the interest cost to be quite high. This allows for a large 1st year tax deduction benefit, even though the loan payments are fixed and steady. Once the ITC is received and applied to reduce the principal, the interest is reduced, so the tax deduction shrinks, effectively raising the cost of the loan compared to the fixed loan payments.

Refer to Fig. 14 for several examples showing the initial and 5th year monthly cash flow assuming 100% Smart Financing of a solar system using a 30-year loan. Because of the 2nd year dip, the 5th year monthly cash flow isn't always better than the 1st year's, but is a basis for continuous improvements in cash flow going forward. Note, we use the 5th year because most depreciation (in commercial systems) and PBI benefits (both of which are applied to loan principal in the same way as the ITC) have been received and included by then.

Sources of financing funds can include:

- Unsecured
- Home equity
- Community Financing
- Power Purchase Agreements (PPAs)
- Leases

Unsecured financing can include credit cards or other types of unsecured loans. These are generally a terrible idea for any kind of long term financing because they usually have high interest rates and the interest is not tax deductible. It may be reasonable to consider them to temporarily finance the rebate or tax credit until it is received, however, it requires discipline to ensure the loan is paid off as soon as the incentive is received.

Home equity sources of funding can include 1st mortgage refinances, 2nd mortgages, Home Equity Loans, and Home Equity Lines of Credit (HELOCs). In general, home equity borrowing is tax deductible, has the best unsubsidized interest rates, and has the longest repayment terms, all of which allow for lowest monthly costs. However, the decline in real estate values have hurt Loan-to-Value (LTV) ratios for most homeowners, and the tight credit market in 2009 have put strict limits on LTV ratios, credit scores, and income requirements, making use of home equity difficult. Only the Line of Credit is likely to work with Smart Financing. Other loans tend to be less flexible on borrowing and repayment term. Attractive FHA Energy Efficient Mortgages (EEMs) may be available from the U.S. Dept of Housing and Urban Development (HUD) at: <http://www.hud.gov/offices/hsg/sfh/eem/energy-r.cfm>.

A new idea and source of funds are local loan programs called "**Community Financing**" developed by funding sources in

partnership with cities, whereby a citizen property owner can receive a loan for a solar system and have it collateralized and paid back on her property tax bill. The program was pioneered in Berkeley, California, and is now available in several cities thanks to AB811, the "Community Financing" bill.

The loans are obligations to the city, the interest is tax deductible, and the property tax bill shows the itemization of the loan amount, the principal and interest. The interest rate is set by the city and their partner bank and is generally at market rates. However, even if the financing was at what might be considered a subsidized level, because of the ARRA of 2009, there is no longer any negative interaction with the ITC (there used to be a tax rule that allowed one but not both of an ITC or subsidized energy financing to be enjoyed). The loans are generally transferable to a future buyer of the property if she is willing to agree to assume the loan payments.

These loans pose little risk to the city and their funding partner, because property taxes are considered to be in "1st position" to get paid in case of a foreclosure. This has caused a controversy in the banking community because this now places more risk on the holder of the 1st mortgage (who is in 2nd position), and the lawsuits have started. The mortgagees insist these loans be in at least 3rd position to protect their mortgages. Depending on how they are structured, that may work for the cities. Stay tuned, it's developing as this is written.

There are also two commercial financing products being applied to residential situations: **Power Purchase Agreements (PPAs)** and **leases**. PPAs are the agreement for one party to sell power to another at agreed upon terms. The sale is for kWh of energy only. The leases for solar are rentals, where a customer rents (leases) a solar system from another party. In both products, the parties owning the systems have large investors who have money to finance systems and who can use both the ITC and depreciation.

In the typical PPA scenario, the site occupant agrees to a PPA for electricity kWh at a certain price and in exchange allows a solar system to be placed on her roof. In residential applications of a PPA, the homeowner usually pays a deposit of anywhere from \$2,000 to 25% to 50% of the cost of the system in addition to the price she will pay for the electricity. Naturally, the more she puts down as a deposit, the lower the price of the electricity. The contract lengths are typically 15-20 years, and there may be a buyout cost at the end if the homeowner wishes to purchase it at that time, or she may have to pay a removal fee if she doesn't. The price of electricity may be fixed by the agreement, or it may have an escalator, causing it to get more expensive over time. There is usually a guaranteed minimum performance, but the customer must purchase any extra electricity, whether she wants it or not.

A typical residential solar lease is similar, in that there is often a deposit paid and a long-term agreement to rent a system for placement on the customer's roof. The monthly rent may include an escalator, increasing costs over time, and may include a buyout clause and termination costs. The buyout clause must not allow the system to be purchased for less than Fair Market Value (FMV) at the end of the term, and that the FMV must be determined at the end of the term, otherwise the

lease will fail to satisfy IRS tax rules. The system usually comes with a performance guarantee, and the homeowner enjoys any extra production at no extra charge.

Things a customer should watch out for regarding leases & PPAs: 1. High escalators in the contracts and their compounding nature. These vehicles can be good hedges against future rate inflation, but a customer should be cautious about overpaying for that hedge. Rates may not rise fast in the future for any number of reasons, and are certainly not likely to rise much faster than 6% per year over the long term. Currently, state or federal government does not regulate these products, so there is a lot of risk of customers agreeing to very expensive terms over the long term. 2. Large deposits without performance guarantees and without clarity in the contract on what happens to the system in the event of the provider's bankruptcy. 3. Large buyout charges or removal costs at the end of the term.

Leases and PPAs with \$0 deposits are easy to understand and sell if the monthly costs or \$/kWh are less than the customer's current costs. Otherwise the customer must figure out how soon the deposit amount will be recovered.

Leases and PPAs can be attractive to customers who have no other way of financing a system, or who can't use the ITC. But if she has her own cash, or can get her own financing, she can usually do better and keep more of the benefits for herself, rather than sharing them with the financing party and the provider. Customer shouldn't be taken in by claims that these products are a lot less expensive because of the depreciation – effectively the depreciation offsets the taxability of the revenue received the provider. These deals are currently a goldmine to developers and providers, but are just “ok” for the consumer, and will be until more competition comes along.

CONCLUSION:

It is important to compare the solar investment to other investments on an even basis. Rigorous treatment and critical analyses from several angles including Compound Annual Rate of Return, Cash Flow, and Resale Value need to be considered to do a fair assessment.

Solar will make economic sense for many, but only a hard look at the numbers will tell. The reader is encouraged to check it out. Run the numbers, get evaluations and proposals from at least 3 solar providers, and take them to a CPA to check them out. That way the smile on your wallet can be as big as the smile on your face!

SUGGESTED ADDITIONAL READING:

- OnGrid Solar's papers, publications, and presentation slides: <http://www.ongrid.net/papers>
- “A Guide To Photovoltaic (PV) System Design And Installation” http://www.energy.ca.gov/reports/2001-09-04_500-01-020.PDF, California Energy Commission
- Bolinger, Wiser, et al, LBL papers and presentations at: <http://eetd.lbl.gov/ea/emp/re-pubs.html>, particularly:
 - Shaking Up the Residential PV Market: ...
 - The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in CaliforniaAnd at: http://eetd.lbl.gov/ea/emp/cases/EMP_case.html

- Property Tax Assessments as a Finance Vehicle for Residential PV Installations: ...
- Exploring the Economic Value of EPAct 2005's PV Tax Credits
- SEIA “Guide to Federal Tax Incentives for Solar Energy” <http://www.seia.org>, Solar Energy Industries Association
- Utility Tariff and Rate Tables (see desired utility's website) – great for insomnia

DESIGN & ANALYSIS TOOLS:

- OnGrid Tool, which incorporates all of the elements of this paper, plus up-to-date rates and incentives, to allow the user to design and analyze PV systems at a high level. It also produces proposals and sales documentation: <http://www.ongrid.net/payback>
- Clean Power Estimator: <http://www.consumerenergycenter.org/renewables/estimator>.
- PVWatts: <http://www.nrel.gov/rredc/pvwatts>
- PVSyst: <http://www.pvsyst.com>
- RETScreen: <http://www.retscreen.net>
- PV Design Pro: <http://www.maisolarsoftware.com>
- QuickQuotes: clean-power.com/quickquotes/products.aspx
- CPF Tools: <http://www.cpfertools.com>

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