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Communication

Should solar photovoltaics be deployed sooner because of long operating life at low, predictable cost?

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ABSTRACT

Governments subsidize the deployment of solar photovoltaics (PV) because PV is deployed for societal purposes. About seven thousand megawatts were deployed in 2009 and over 10,000 are expected in 2010. Yet this is too slow to strongly affect energy and environmental challenges. Faster societal deployment is slowed because PV is perceived to be too costly. Classic economic evaluations would put PV electricity in the range of 15–50 c/kWh, depending on local sunlight and system size. But PV has an unusual, overlooked value: systems can last for a very long time with almost no operating costs, much like, e.g., the Hoover Dam. This long life is rarely taken into account. The private sector cannot use it because far-future cash flow does not add to asset value. But we should not be evaluating PV by business metrics. Governments already make up the difference in return on investment needed to deploy PV. PV deployment is government infrastructure development or direct purchases. Thus the question is: Does the usually unevaluated aspect of long life at predictably low operating costs further motivate governments to deploy more PV, sooner?

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1. Introduction

There is no question in my mind that someday PV systems will be directly price competitive with traditional energy sources. And that this competitiveness will spread from the sunniest places and largest systems to less sunny ones and smaller systems.[1] This process has begun but may take another 20–40 years to complete. This paper is about whether we should not wait, but instead begin to seriously deploy PV at an energy-significant level at today's prices because PV has unusually long life and low operating costs (Dunlop et al., 2005; Lazard, 2008).

Today, large, ground-mounted solar photovoltaic (PV) systems without trackers operate with essentially no moving parts or on-site labor. PV modules, the key components of such systems, are warranted for 25 or more years, but no one actually knows how long they might last (Dunlop et al., 2005; Czanderna and Jorgensen, 1999).[2] Data on live modules now extends back 40 years. Although module warranties are often written for an annual degradation rate of 1%, actual modules appear to be degrading at 0.2–0.5% per year (Chianese et al., 2003). Of all the components within a PV system, only the inverter is likely to need periodic maintenance (partial replacement after 10 or more years), and inverter reliability and cost are both improving rapidly (Navigant, 2006; Mitchell, 2010; Heacox, 2010).[3] PV systems are not designed for 100 year operation yet, but if an effort were made to do so, they might last that long.[4]

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[1] For example, as the sale of PV module technologies rises along with its advancing performance, the US Department of Energy Office of Energy Efficiency and Renewable Energy found a 20% learning curve in price reductions (The US Department of Energy, 2006, p. 29). This curve has been updated and reconfirmed through 2009 in the DOE Solar Vision (2010, Figure 4–3, in review). Modules are the major driver of overall PV system cost.

[2] Dunlop et al. state: "The results of this study indicate that the current module would guarantee 90% power after 20 years…there is no visible evidence that this degradation rate is increasing with time; i.e., we have no defined "end of life" only a continuous degradation…estimated lifetime is indeed well beyond the

(*footnote continued*)
20-year assumption which is commonly made today." Modules have been tested and monitored at NREL's Outdoor Test Facility since the early 1980s and by the Joint Research Council's European Solar Test Installation (http://re.jrc.ec.europa.eu/esti/activities_projects/module_lifetime_en.htm) since 1982.

[3] Mitchell stated: "…there is no longer any catastrophic failure mechanism in inverters," implying that lifetime expectations can be extended well beyond those of the recent past. Heacox (2010) stated: "The financial modeling norm for PV projects is…to replace inverters around year ten. This is an embarrassment to the inverter industry, especially to advanced suppliers with products designed for a 20-year useful life."

[4] The major challenges to long life PV systems may be: module life, based on intrinsic instabilities and module sealing, which is not yet designed for a century (and for far less in some markets, e.g., Japan); electrical connections and insulation for field wires and cables, junction boxes, combiner boxes, inverters, and connection to the grid; and inverter operation. Inverters are an area of focus since their periodic partial replacement has the largest impact on annual O&M/kW, which could be greatly reduced if their lifetimes were extended and prices reduced. There could be a number of surprising issues over a 100-year period, even including blocked land use, plant growth, and '100-year' storms and floods. To-date, systems have been built for shorter lives, and these issues have not been examined.

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Taking PV's simple, fuel-free, operation and long life into account could be important in evaluating how soon and how much PV should be subsidized for deployment to respond to climate change (Creyts et al., 2007) and the need for energy diversity to avoid fuel price spikes.[5]

If designed for long life, one could imagine PV systems lasting for 100 years, still operating at between 50% and 80% of their initial output in the 100th year. The operating costs for such systems would be minimal, about one cent per kWh (Denholhm et al., 2009). Having such inexpensive, non-polluting electricity would be a boon for future electricity consumers and an immediate relief from carbon dioxide emissions.

It may be surprising, but there is no other source of electricity with the same combination of long lifetime and low operating costs. Others continue to burn fuel (coal, natural gas, and nuclear); have higher operating costs (hydro, wind, and solar thermal electric), or do not last as long before major replacement (wind) [6] (Lazard, 2008). The question remains: does this long, low cost, predictable operating life matter (Weinberg, 1985; Stern, 2007)? Is it sufficient to push forward the deployment of PV by governments to meet energy and environment issues, despite PV's high initial cost?[7]

2. Method

This paper uses an annual cost per kWh to compare most energy-significant sources of electricity with PV over a long duration (up to a century), with a focus on PV's low operating cost. There are other, crucial aspects of PV (e.g., more stable electricity prices; avoided environmental damage, especially CO_2 emissions; stimulation of the local economy; increased value due to daytime electricity production; and avoided external costs such as health costs and deaths from respiratory disease) that already motivate government subsidies for PV deployment. When long life is added, they each change somewhat and new insights are gained, further adding to deployment motivation.

To particularize the impact of long life, initial cost calculations are performed without any recognition of externalities (no carbon offsets, no investment tax credit, no state rebates).

2.1. Annual cost of electricity

To first order, sources of electricity can be analyzed using a simple set of numbers (Table 1):

1. Fuel costs
2. Capital costs
3. Non-fuel operating costs
4. Output

Table 1
Categories for comparative economics of power plants.

Category	Unit	Definition
Fuel	$/kWh	Total cost of fuel divided by number of kWh produced from it (often given by multiplying $/MBtu by a heat rate, Btu/kWh)
Capital	$/kW	Capital cost divided by the rated power output of the power plant
O&M (non-fuel operating and maintenance)	$/kW-yr	Operating and maintenance costs (including re-commissioning) divided by power (if power-related)
Output	kW, kWh, kWh/yr	Plant rated power (kW); total lifetime energy in kWh or kWh per time period (e.g., per year); includes operating conditions like up-time, degradation

Other costs often assigned to power production such as permitting, fees, property taxes, sales tax, and income tax are not well defined because they change based on societal and local preferences.[8]

A bottom–up engineering analysis of costs can be very complex, but estimates broken down as follows may suffice to capture information needed to make a basic assessment:

1. Fuel costs
   a. Fuel purchased[9] ($/MBtu or $/kWh)
2. Capital costs
   a. Cost of equipment and construction before the electricity begins flowing ($/kW).
3. Non-fuel operating costs
   a. Cost of operating and maintaining the power plant (proportional to $/kW-yr).
4. Output
   a. Electricity (kWh).

Total cost *in a particular year* is then:

$$\begin{aligned}\text{Annual Cost}(\$/\text{kWh}) = {} & \text{Fuel Cost } (\$/\text{kWh}) \\ & + (\text{Annualized capital cost/kW-yr} \\ & + \text{Annualized non-fuel operating costs/} \\ & \text{kW-yr})/\text{Annual Output (kWh/kW-yr)} \quad (1)\end{aligned}$$

This applies only in the year of analysis. To make sure all costs show up somewhere in the annual cost, 100% financing of the capital cost is assumed at 6% interest for a 20 year loan. This financing is used in all subsequent cases.

A levelized cost of electricity (LCOE) is defined in any operating year as the sum of all costs prior to and including that year divided by the sum of all outputs. This is a levelized cost of electricity with a *zero* discount rate, which is not the traditional metric. Levelized costs of electricity with positive discount rates will be discussed in Section 6 in the context of a government infrastructure investment.

[5] If we are also able to extend the use of electricity to transportation via electrification, this would also impact oil dependence.

[6] For wind, major replacement is required at least every 25 years, not including replacement of smaller components (e.g. gearboxes, blades, and generators) (Laxson et al., 2006).

[7] PV is being deployed today at about the 10 GW level worldwide, and this is growing rapidly (Osborne, 2010). With subsidies, PV can be quite cost competitive; and it could be argued its subsidies are only what a non-CO_2 source deserves—if others were stripped of their subsidies, PV would have a fairer chance of competitiveness. PV is cost effective right now in a few regions with the highest sunlight and electricity prices; and also when compared to extending transmission or transporting heavy primary fuels to remote villages (Mitra and Gon Chaudhuri, 2005).

[8] It is also true that these other non-hardware, non-labor costs such as delays and fees can be large. It is my contention that they represent society's somewhat fragmented response to externalities. Including soft costs makes analysis less defined than simply evaluating basic costs.

[9] The dollar/kWh fuel cost is the cost of fuel in dollars/MBtu times the Btu/kWh (heat rate) of the thermal power plant, which is about 10,000 Btu/kWh for coal. For e.g., coal at \$2/MBtu: $\$2/\text{MBtu} \times 10{,}000\ \text{Btu/kWh} \times 10^{-6}\ \text{Btu/MBtu} = \$2 \times 10^{-2} = \$0.02/\text{kWh}$. (Note the use of $/MBtu and Btu/kWh—this can lead to confusion.)

A concept called capacity factor (CF) is used by utilities to characterize annual kWh output. CF represents the percent of time the power plant would need to be at its maximum rated output in a year to produce the number of kilowatt-hours (kWh) it actually produces annually. (Usually a power plant will produce for many more hours per year but below its maximum. The CF is merely a handy convention.) Actual capacity factors are either measured or based on engineering analysis. They can be calculated by solving:

$$\text{Annual output (kWh)} = \text{CF} \times \text{Power Plant Rated Capacity (kW DC)} \times 8760\ \text{h} \quad (2)$$

Solar capacity factors depend on the amount of local sunlight and whether solar trackers are used to enhance output per rated watt.[10] They are very low, about 20% without trackers, and about 27% with one-axis tracking.[11] Traditional baseload power plants (like coal or nuclear) can be at maximum output 80% of the time or more. They produce a lot more kWh per installed kW and thus have much higher capacity factors.

2.2. *What are the annual and average costs of PV during its first 20 years of operation?*

The current status of the *lowest-cost PV for large systems* is as follows [12] :

Fuel cost is of course zero. The capital cost of a large, nontracking solar array is assumed to be \$3000/kW (DC) and then annualized as \$261/kW-yr using a 6%, 20-year loan for the entire amount. The annualized \$/kW-yr non-fuel operating cost includes replacing part of the inverter (now done once every 10–20 years for large systems[13]), keeping the modules clean (if needed), monitoring performance (perhaps off-site), and 0.25% insurance. It does not include property tax.[14]

The assumed capacity factor of 21% implies about 1840 kWh/kW-yr of system AC output. How much sunlight does this correspond to? If a system has 23% losses from DC rating to AC output, 2400 kWh/m^2-yr of sunlight on a fixed flat-plate PV array (tilted at the latitude) would produce 1840 kWh/kW-yr AC.[15] A large portion of the US Southwest gets 2400 kWh/m^2-yr—enough land to produce terawatts of output power.[16]

There is an unresolved debate about what interest rate should be assumed for PV. Conventional coal and nuclear plants can incur high interest rates, even above 10%,[17] leading some to believe similar rates should be applied to PV. On the contrary, actual solar PV systems have already been awarded much lower loan rates, about 6%. Conventional power plants have substantially higher installation and operational risks. They have startup risks due to lengthy, complex construction and environmental delays, and sometimes they are not completed (Berry, 2008). Just as importantly, they have operational fuel price and regulatory risks once they begin operation. How profitable might they be in a decade if fuel escalates or if there is a carbon tax? These risks drive up initial loan rates, since they add risk to the loan payments. Solar PV has no fuel price risk and far smaller construction or regulatory risks. Electricity production can begin during construction, as each long string of modules is wired to an inverter. Future fuel prices are irrelevant. Indeed, this is an example where PV's unusual simplicity and predictability are already being recognized and rewarded. Thus, a 6% loan rate is assumed for PV. But in an effort to be conservative, 6% is also assumed for the other energy options throughout this paper, despite their higher risks.[18]

Fig. 1 shows the annual electricity cost (\$/kWh) of a \$3000/kW (DC) PV system in the US Southwest based on Table 2 assumptions. Fig. 1, which only shows the first 20 years, the period of the 6% loan, is the usual way PV economics is understood by private sector investors and utilities. Although the electricity price is much improved over past years, it is still high (about 16 ¢/kWh).

Fig. 2 shows what happens when the period of analysis is extended beyond the 20-year loan period to a hypothetical 100 years. The steep drop in year 21 is because there are no more loan payments. The only remaining costs are operating costs near 1 ¢/kWh. Fig. 2 is almost never considered (even by governments) when making planning decisions about PV deployment because it varies so greatly from traditional levelized cost of electricity with positive discount rate metrics. Of course, 100-year life is only an expectation at this point, since no PV systems have been around for more than 40 years.

[10] Rated watts in PV can be based on a variety of conventions. In this paper, the sum of the direct current (DC) output of the modules at standard conditions is used. In other cases, the maximum output of the actual system in alternating current (AC) output is chosen. AC output is about 75–85% of DC output, and their different capacity factors are similarly related. As long as only one is consistently used, the results are interchangeable.

[11] These are CF for DC ratings. If an AC system rating were used, they would be about 25% higher, while the system rating would be that much lower, making up the difference.

[12] Solar prices are changing very quickly. Getting price data is difficult, but systems in the recent past have been publicly acknowledged at the \$4/W level by juwi group (McMahon, 2009), using First Solar modules. Private conversation in fall 2009 put the lowest prices for large systems in the \$2.5–3/W range, pressured by reduced demand, which has compressed margins. Hynes (2009) uses the \$3/W number. In April 2010, Maja Wessels, Vice President of Public Affairs for First Solar, stated that her company is able to install PV systems for \$3/W in a public meeting hosted by the GW Solar Institute. Her full statement is as follows: "So, we'll be pretty well into the sustainable market where we will be able to produce solar electricity at a sustainable cost level. Right now, we figure at, more or less, three dollars installed in some of our markets." See http://www.vimeo.com/11504342. This is one of the lowest prices quoted, and should not be compared with average or typical prices as categorized by data agencies, who are evaluating the average, not the leading edge.

[13] Inverter costs have dropped to about \$250/kW with higher volume and simplifications. If about half of an inverter is replaced every 15 years, this is \$7.5/kW-yr. 0.25% insurance on a \$3000/kW system is \$7.5/kW-yr. These two factors dominate the total operating costs.

[14] Property taxes on high capital cost, low-capacity factor PV can be 4–20 times higher than on fossil fuel sources on a per kWh basis. Most states correct this once they become aware of it (Sinclair, 2008). However, without such an assessment, property taxes alone, merely because they have been designed for fuel-burning sources, might prevent the competitive use of solar energy. For perspective, a 1% property tax on a \$3000/kW system would be \$30/kW-yr, i.e., twice as large as the assumed \$15/kW-yr hardware and labor O&M all by itself.

[15] 2400 kWh/m^2-yr of sunlight would produce 2400 kWh/kW-yr of electricity if there were no losses (note the change from sunlight incident per square meter to electricity output per installed rated kW; the fact that they are the same numerically for these units is a coincidence due to rated watts being defined at 1000 W/m^2 power). With 23% losses, this becomes 1848 kWh/W-yr, here rounded down to 1840.

[16] See http://www.nrel.gov/gis/solar.html for NREL solar maps of the US. Much of the Southwest has over 2400 kWh/m^2-yr (of 6.6 kWh/m^2-day) available for conversion by a fixed flat plate tilted at latitude. One TW can be produced in about 6 million acres (at 6 acres per MW, a common value), or about 10,000 square miles (100 miles on a side), far smaller than the available desert land.

[17] Coal carries a 12% interest rate and nuclear 15% (Deutch et al., 2009; World Nuclear Association, 2009). But using these loan rates might have been controversial and would have camouflaged the issue of long life.

[18] An analysis of actual unsubsidized loan rates (e.g., nuclear without accident protection, natural gas without the ability to shift the fuel cost to the utility customer, deep-water drilling without spill protection) for all energy options is beyond the scope of this paper but would make for an interesting addition to future cost comparisons. Since nuclear, among the conventional options, has the highest capital cost, its economics are most sensitive to this issue (as are PV and solar thermal electric, and to some degree, wind) (Lazard, 2008).

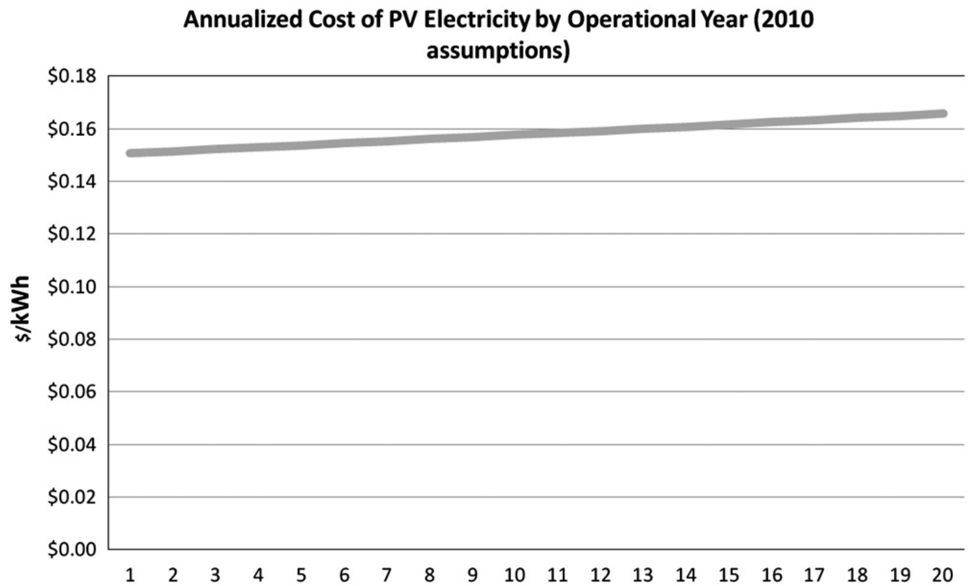

Fig. 1. The annualized cost of a $3000/kW DC PV system (no incentives) in the Southwest using 2010 assumptions during the initial loan payment period. (This and all subsequent analysis uses 100% financing with a 6%, 20-year loan.) The slight increase over time is due to the assumed 0.5% per year degradation of PV output (Chianese et al., 2003). (The costs in this figure are slightly different from those later (from Fig. 4) where an additional re-commissioning factor is included, with an additional about 0.5 ¢/kWh to the PV cost.)

Table 2
Assumptions for annualized PV economics (2010) for a $3000/kW DC, large nontracking system in the US Southwest (first 20 years).

Fuel cost ($/kWh)	Annualized capital cost ($/kW-yr) (over 20 years, 6% interest)[a]	Annualized non-fuel operating cost ($/kW-yr)	Annual output per rated kW (kWh/yr)	Year-one cost ($/kWh)
0	$261 (at $3000/kW DC)	$15	1840 kWh (at 21% capacity factor)	($261+$15)/1840=$0.15/kWh

[a] As stated previously, this assumes that the annual capital cost of each approach is 100% debt. This simplifies the analysis for broad comparisons, and puts cost in a form that can be fully annualized.

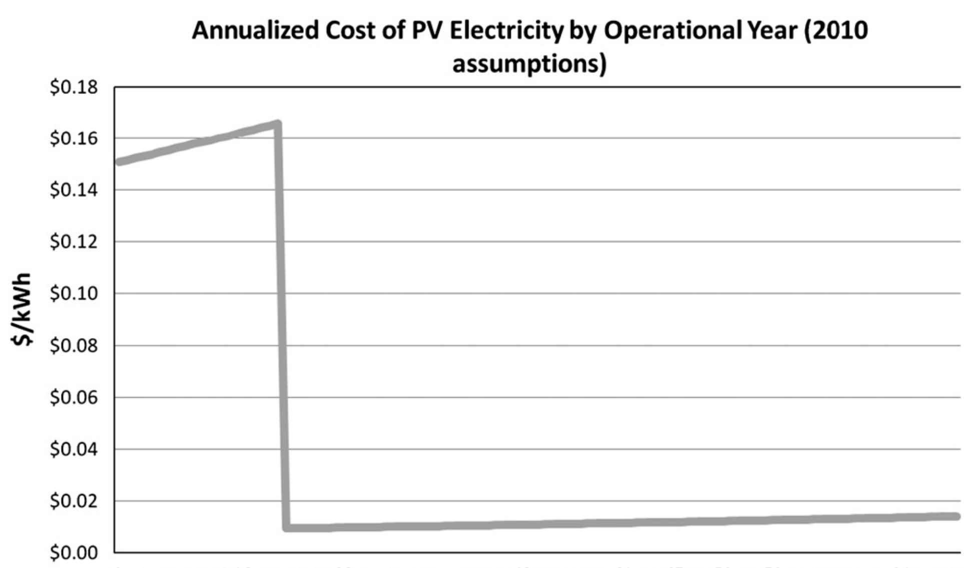

Fig. 2. The hypothetical annualized cost of a $3000/kW DC PV system (no incentives) in the Southwest using 2010 assumptions. The sudden decrease in year 21 is because loan repayments have ended. After that, the price stays below 2 ¢/kWh despite the 0.5% annual degradation assumed in the analysis.

What about levelized cost of electricity (LCOE)? The next figure shows an LCOE with a zero discount rate. (Positive discount rates are examined in Section 6.)

Fig. 3 shows that even at today's PV prices, which start far above conventional electricity, this version of a levelized cost with zero discount rate would eventually fall below 5 ¢/kWh. This is

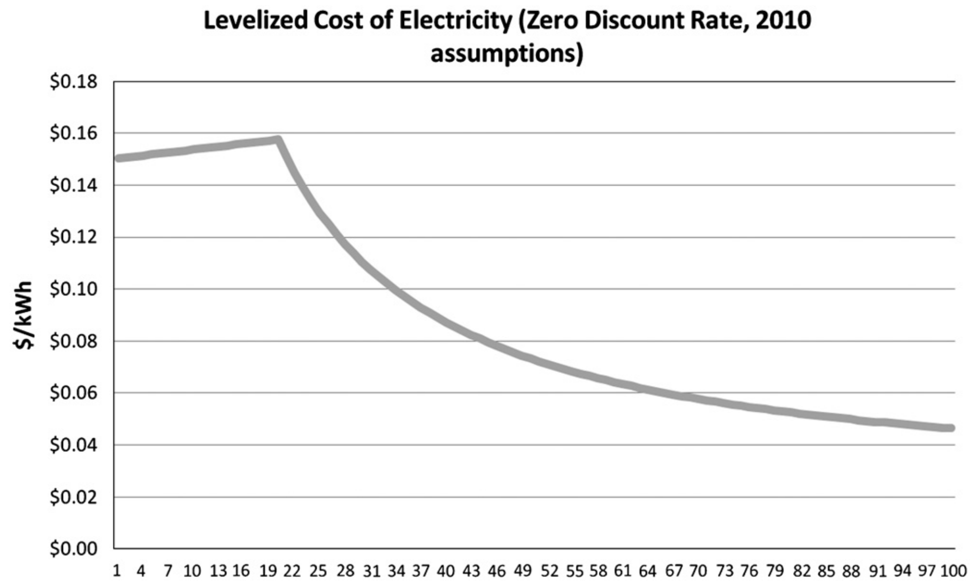

Fig. 3. The average cost of PV (2010) electricity from year 1 to year *n* (2010 Assumptions), equivalent to a levelized cost calculated for each year with a zero discount rate.

Table 3
Characteristic year-one annualized cost of electricity[a, b]

Technology and fuel cost ($/MBtu)	Fuel cost ($/kWh)	Non-fuel operating ($/kWh)	Capital cost ($/kW-yr) (over 20 years, 6% interest)	Non-fuel operating ($/kW-yr)	Annual output per rated kW (kWh/yr)	Year-one cost ($/kWh)
Baseload natural gas ($5/MBtu)	$0.04/kWh	$0.01/kWh	$87 (at $1/W)	$20	7450 kWh (85% CF)	$0.04+$0.01+($87+$20)/7450=$0.05+$0.014=**$0.064/kWh**
Baseload coal ($2/MBtu)	$0.02/kWh	$0.02/kWh (coal transport)	$262 (at $3/W)	$20	7450 kWh (85% CF)	$0.02+$0.02+($262+$20)/7450=$0.04+$0.038=**$0.08/kWh**
Wind	0	0	$157 (at $1800/kW)	$40	2600 kWh (30% CF)	($157+$40)/2600=**$0.075/kWh**
Nuclear	$0.005	$0.02	$523 (@ $6000/kW)	$30	7450 kWh (85% CF)	$0.005+$0.02+($523+$30)/7450=**$0.10/kWh**
Hoover Dam	0	$0.005	$174 (@ $2000/kW)	$15	4400 kWh (50% CF)	$0.005+($174+$15)/4400=**$0.05/kWh**
PV	0	0	$262 (at $3000/kW)	$15	1840 kWh (at 21% capacity Factor)	($262+$15)/1840=**$0.15/kWh**
Solar thermal troughs (w/ natural gas)	$0.01 (25% natural gas)	$0.003	$401 (at $4600/kW)	$80	3250 kWh (37% CF w/NG)	$0.013+ ($401+$80)/3250=**$0.16/kWh**
CCS (putative)	$0.03	$0.03 (coal transport, but no CO_2 transport)	$436 (@ $5000/kW)	$30	7450 kWh (85% CF)	$0.03+$0.03+($436+$30)/7450=**$0.12/kWh**

[a] This reflects current status; however, recent history (2008–2009) has shown that these numbers can vary significantly with demand. Also, note that this table does not include re-commissioning costs and is thus a little lower than in subsequent compilations—see below for explanation.
[b] For a comparable source of current data on conventional sources, see EIA (2009, 2010) and Lang et al. (2010). However, EIA PV data is not consistent with the assumptions here and is undergoing review. Initial private sector feedback supports use of $3000/kW DC for 2010.

quite analogous to experience with an example government energy purchase, e.g., Hoover Dam, a highly valued form of generation that initially incurred a high capital cost but now operates near 2 c/kWh.[19]

2.3. *Comparing PV with other electricity options*

To compare PV with other electricity generation, assumptions were compiled for all the typical sources of electricity (Table 3). It is well beyond the scope of this paper to give a full range of assumptions and options for each electricity source. For example, a single amount of local sunlight for solar was chosen as typical of the Southwest, even though some areas of the Southwest are sunnier. Similarly, coal transportation costs vary extensively, and a compromise figure was picked. Fuel costs vary unpredictably, and those today are substantially lower than in 2008. Loan interest rates vary among technologies, but 6% is used for all of them. Future work might address these specifics, but to a degree, general trends seem fairly robust (see Figs. 4–8).

Non-fuel operating costs ($/kWh) proportional to kWh are introduced in Table 3 to capture costs such as coal transportation and cooling water use, i.e., those that are dependent on actual kWh of output instead of kW of capacity.

[19] The government makes many investments in infrastructure or mandates such investments by the private sector—besides Hoover Dam, e.g., interstate highways, public health laws, building codes, defense, and universal literacy.

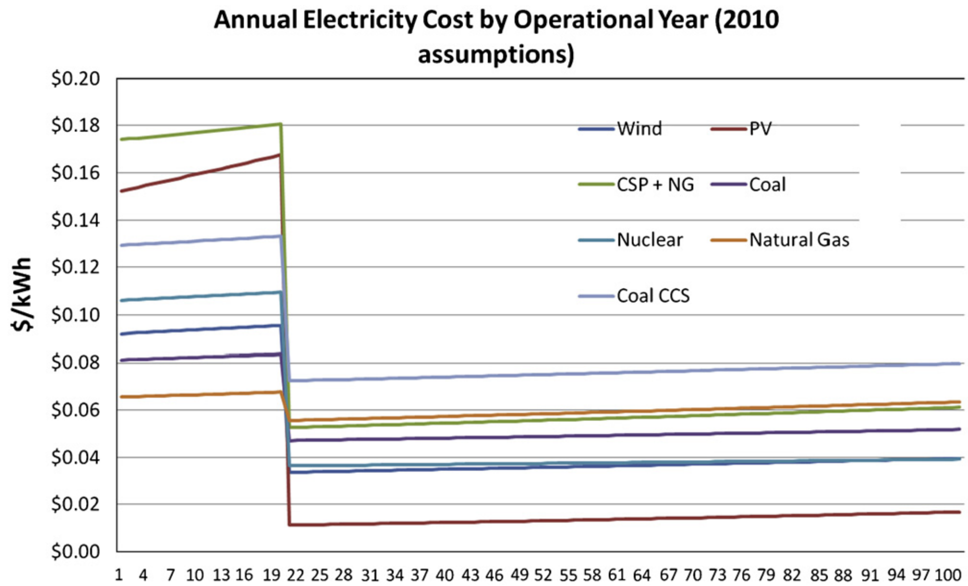

Fig. 4. The annualized electricity cost by year of all the electricity options, using the "2010" Scenario given in Appendix A, with refurbishing and degradation, but no fuel inflation. (Each curve is slightly higher than without refurbishing, including PV, see Fig. 2.).

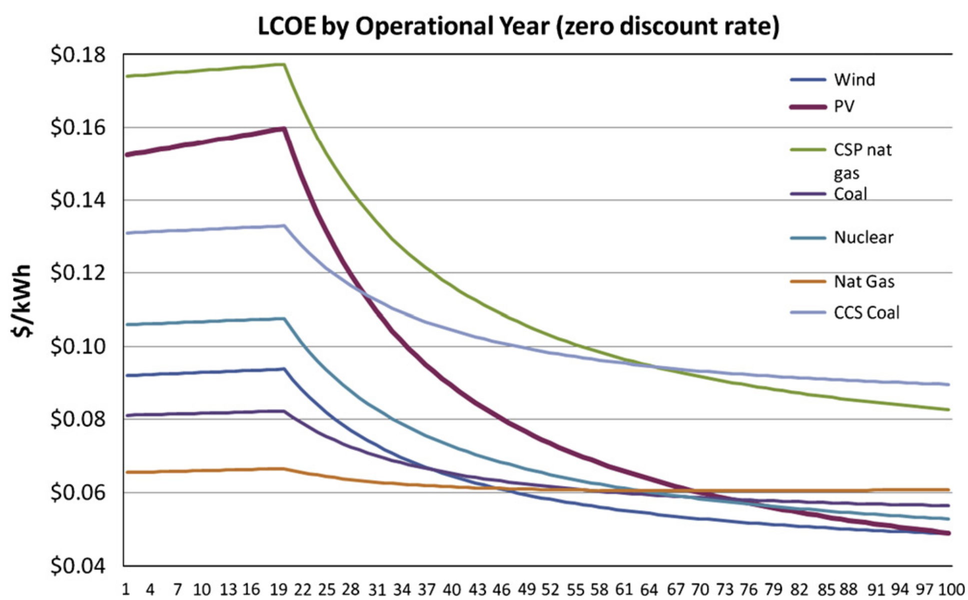

Fig. 5. LCOE (zero discount rate and zero fuel inflation above background) by year, to year $n=100$. Wind, solar PV and nuclear all eventually become less expensive than fossil fuels.

The numbers in Table 3 leave out something else that is true for all sources of electricity—they wear out. We will examine this in the next section.

2.4. *"Old power plants never die…"*

Power plants do not die. They do not even fade away (at least in the US)—they get refurbished, re-permitted, and re-commissioned. As far as we know, they may last forever (i.e., the land is never returned to other uses), as re-commissioning is a way to avoid NIMBY ("not in my backyard") problems, and it simplifies other issues such as transmission and distribution. Marland and Weinberg (1988) emphasized this in "The Longevity of Infrastructure," where they said: "The electric utility industry and its suppliers have devoted much attention recently to the extension of the life of existing power plants… Our impression is that few completely new full-scale power plants will be built in the US during the next 20 years or so. Instead, old fossil fuel and nuclear plants will be renovated…" This is in fact what has happened and continues to happen.

Refurbishing is usually much cheaper than building a new plant. Thus actual fossil fuel plants are long-lived, just like PV, and it is fairer to include this aspect (instead of new and costly plant costs every 30 years) in a long-lifetime comparison with PV. Let us look at them over the long haul, the way they really operate and the way their costs are really reflected in our bills.

What happens to power plant costs as they age?

1. They degrade.
2. Initial loan payments end.
3. At some point, an investment (over and above annual O&M) is made to refurbish the plant and keep it operating.

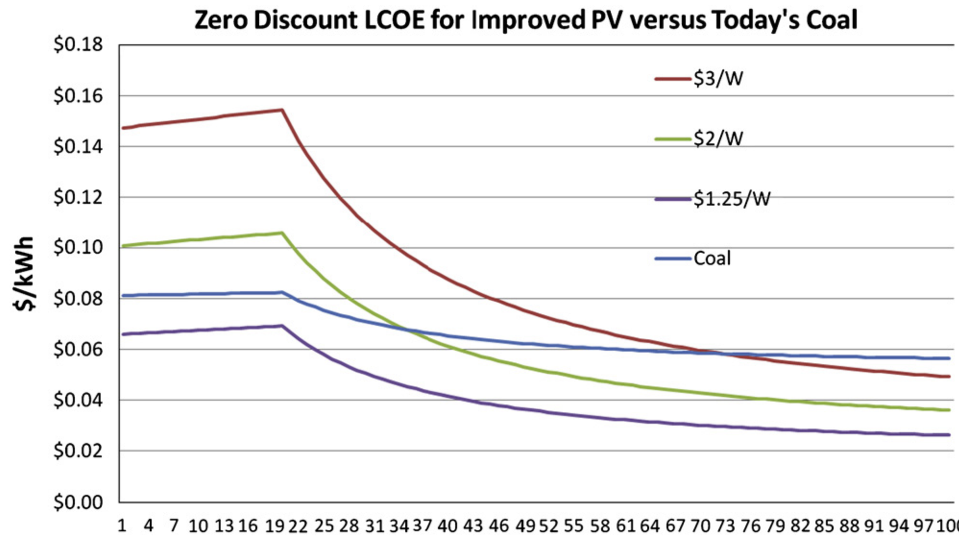

Fig. 6. PV zero discount rate LCOE (fixed, flat-plate systems in sunniest locations) for today ($3/W DC), and conservative ($2/W DC) and aggressive ($1.25/W DC) future goals (all other assumptions the same as PV in the 2010 scenario). The "Coal 2010" scenario is shown for perspective (without fuel inflation).

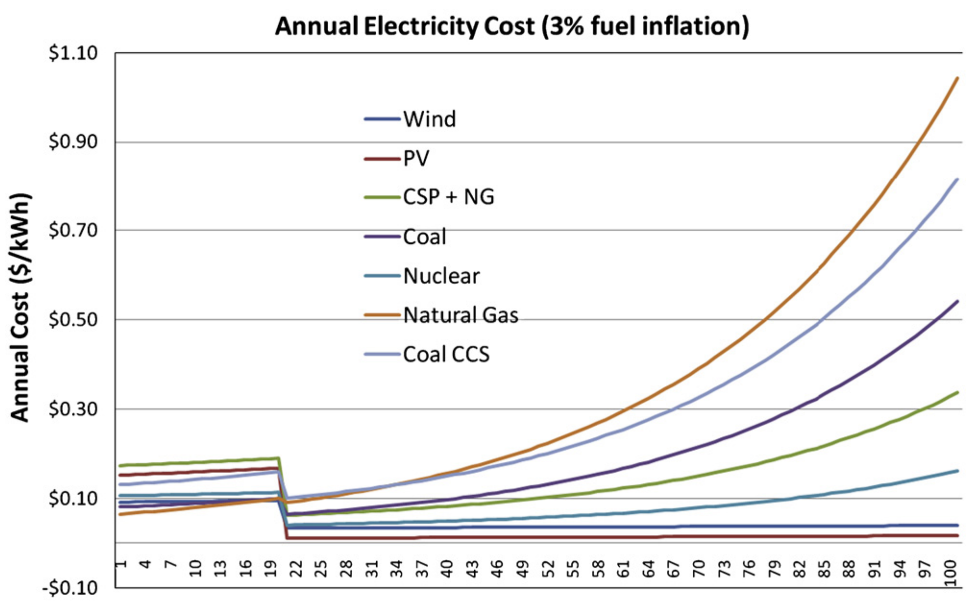

Fig. 7. Annual electricity cost if there is 3% fuel inflation. This shows the results of possible fuel price escalations. Natural gas, because fuel is its largest cost component, rises the most, followed by coal with sequestration and traditional coal.

All power plants tend to get a little less efficient with time. In PV, this is called degradation, and PV arrays currently degrade at about 0.5% per year (Chianese et al., 2003). In the future, they may degrade less, if long life becomes a priority (today 0.5% per year loss is considered sufficient). For thermal plants, boilers and turbines have their own operational issues and a typical degradation of about 0.2% (Navigant, 2007). More importantly, some big pieces of equipment get replaced or added when the power plant gets re-commissioned—e.g., a new turbine is installed, a new boiler, new piping, a new reactor, and a scrubber. But this does not happen in PV (inverter replacement is included in the annual O&M term).[20] So we need to account for: loss of efficiency over time and (in the non-PV options) significant, repeated refurbishing costs. But these costs will not be as high as building a new plant, and may well be lower than building the plant in the first place. This is because all the NIMBY-related costs will likely be much smaller (or at least smaller than building a new plant on a new site).

Table 4 is a summary of the long-lifetime parameters chosen for this analysis. It should be viewed as a scenario, since gaining precise estimates of these amounts is beyond the scope of this paper.

Table 4 says that in some number of years (the time to overhaul, TTO) an amount equal to 25% of the cost of the original power plant will have to be invested to keep the power plant going. In other words, in the given period 25% of the power plant cost will be re-invested. In this study, to keep things simple, the appropriate fraction of this amount is added to each year prior to the TTO date, as annual operating cost per kW. So if we have a $1000/kW coal plant, we assume that $250/kW is replaced over a 30 year (TTO) period, or about $8.3/kW per year. For PV at $3000/

[20] One could consider replacing the PV array with a larger, less expensive one after, say, 20–50 years, but since the O&M costs of the original, degraded array are so tiny, this does not make any economic sense unless reclaiming land is the driver.

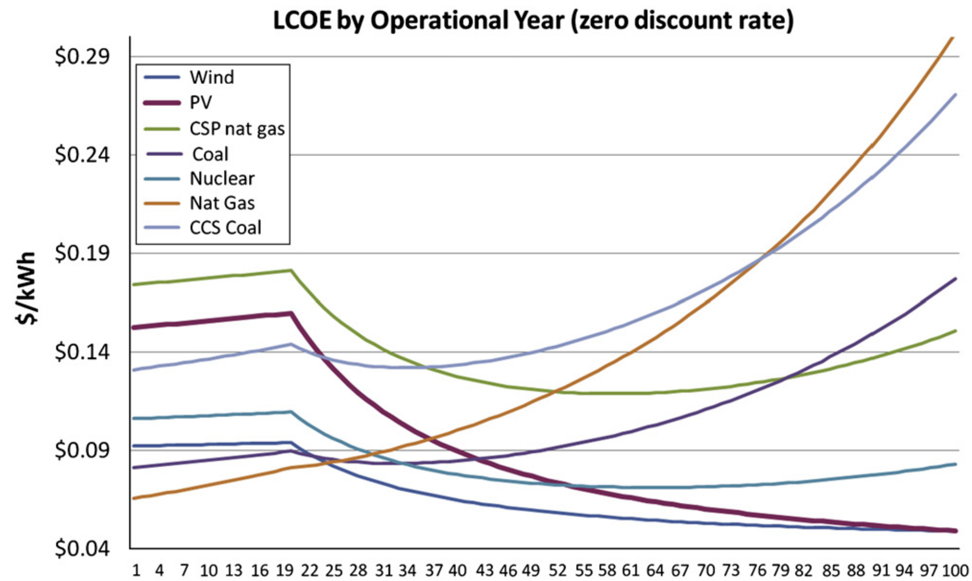

Fig. 8. The levelized cost of electricity of these options assuming 3% fuel inflation and a zero discount rate. Once again, wind and PV retain excellent prices throughout the 100 year period while everything else becomes expensive.

Table 4
Estimated degradation and estimated time to overhaul (TTO).

Technology	Estimated annual degradation (%)	TTO of 25% of plant (years)
Fossil fuels	0.2	30
Hydro	0.2	30
Nuclear	0.2	30
Wind	0.2	10
PV	0.5	200
Solar thermal electric	0.2	30
CCS	0.2	20

kW and a 200 year TTO, this comes out as ($750/kW)/200 years = $3.75/kW-yr. The TTO was not chosen to do away with the assumed degradation of each facility. That degradation is kept in the calculation. Instead, the TTO investment is an estimated added cost to keep each system running, to account for replacing big, identifiable items needed for re-commissioning. The very poor number for wind (10 years) indicates the need to replace the turbine every 25 years, moderated by the fact that a turbine is not the entire system cost (otherwise the TTO would be 5 years). These numbers are rough estimates, or scenarios, to begin the process of making this kind of operating life evaluation, and future studies could vastly improve on them.

How shall we calculate the annual cost of the power plants in year n? The main changes are annual degradation and an increase in cost for refurbishing 25% of the plant during the time to overhaul (TTO).

If kWh1 is the output in year 1 and the output degrades by D%, then the output in year n is

$$\text{Output kWh (year } n) = \text{kWh}(n) = \text{kWh1} \times (1-D\%)^{(n-1)} \tag{3}$$

The cost in year n then becomes:

$$Cn\ (\$/\text{kWh}) = C1 \times (\text{kWh1}/\text{kWh}(n)) = C1/(1-D\%)^{(n-1)} \tag{4}$$

where C1 is year 1 cost and Cn is the cost in year n. In other words, the cost rises each year as the output declines, by just the inverse of one minus the degradation rate.

The cost of refurbishing is handled by dividing it evenly over the TTO: i.e., 25% of the initial capital cost divided by the TTO will be expensed each year for eventual payment for re-commissioning. This is a rough but adequate estimate given all the other uncertainties.[21] These amounts then give a new $/kW-yr that includes the refurbishing costs; and a new annual output that includes degradation. A fuel escalation rate FE can be added to judge its importance. It is kept at 0% for conventional fuels initially so as to not obscure other drivers, but will be examined in Section 5. Future fuel uncertainties are one of the major things a high initial investment in a fuel-free option avoids, so this forms an important part of the new perspective developed by recognizing this special PV attribute.

Two equations model these constraints during and after the loan period (L):

2.4.1. During the loan period

$$\begin{aligned}&\text{Cost}(\$/\text{kWh}) \text{ in year } n \le L = \text{Fuel Cost}(\$/\text{kWh}) + O\&M\\&\quad\text{related to output}(\$/\text{kWh}) + (\text{Annualized capital cost}/\text{kW-yr}\\&\quad + \text{Annual operating costs}/\text{kW-yr})/\text{Annuall Output}(\text{kWh}/\text{yr})\\&\quad = (FC1/(1-FE)^{(n-1)})/(1-D\%)^{(n-1)}\\&\quad + OM + (\text{Annualized capital cost}/\text{kW-yr}\\&\quad + \text{Annual } O\&M/\text{kW-yr} + (25\%\ \text{Capital}\\&\quad \text{cost}/\text{TTO}))/\text{kWh1} \times (1-D\%)^{(n-1)}\end{aligned} \tag{5}$$

where $FC1$ is the first year fuel cost; OM is non-fuel $O\&M$ per kWh.

2.4.2. After the loan period remove the annualized loan cost

$$\begin{aligned}&\text{Cost}(\$/\text{kWh}) \text{ in year } n > L = (FC1/(1-FE)^{(n-1)})/(1-D\%)^{(n-1)}\\&\quad + OM + (\text{Annual } O\&M/\text{kW-yr} + (25\%\ \text{Capital}\\&\quad \text{cost}/TTO))/\text{kWh1} \times (1-D\%)^{(n-1)}\end{aligned} \tag{6}$$

The zero discount rate LCOE through year n is as before: the sum of all costs for years from 1 to n, divided by total output to year n.

[21] A fully amortized cost of each TTO investment could have been used, but it would only have increased the impact of this already estimated amount and time period.

3. Results for the "2010 scenario"

Fig. 4 shows the annual cost ($/kWh) by year of each modeled technology using the "2010 Scenario" given in Appendix A (which now includes the re-commissioning cost not included in Table 3). In the first 20 years, Fig. 4 (left side)[22] displays the typical way electricity options are evaluated, and PV looks very costly versus coal and natural gas. Of course, once the loan period is over, everything changes, and as before, the PV and the other non-fossil fuel sources are the least expensive.

An undiscounted, levelized cost of electricity in year *n* is given in Fig. 5. This indicates the average of the entire investment of the prior years.

Fig. 5 shows that (at an assumed zero discount rate):

1. For those options without fuel, the drop in cost after the loan amortization period means they become as cheap or cheaper than those that depend on fuel, *even with zero fuel inflation assumed*.
2. Even though wind requires turbine replacements every 25 years to achieve very long life, it retains its attractiveness in terms of cost (this is sensitive to assumed capital cost, capacity factor, and annual O&M, which will vary).
3. Although solar PV (even in the sunniest locations) costs start very high, the absence of fuel and a low operating cost make it among the most competitive choices for the long term, even based on *today's* prices for large systems. These prices are expected to drop with future progress, see Section 4.
4. CSP troughs with 25% natural gas do not drop as much as PV because of the presence of natural gas and other operating costs, including major replacements. Future fuel-free designs (e.g., thermal storage instead of natural gas, power towers instead of troughs) may overcome this and put CSP closer to PV. However, CSP does have a higher annual operating cost and shorter TTO than PV (Lazard, 2008).
5. Carbon sequestration (CCS), modeled here (despite the fact that it does not yet exist) rapidly becomes more expensive than PV (even with no fuel inflation), and it eventually costs the most of all the options (even with the low 6% loan interest rate, assumed here). Of course, this is also assuming a zero discount rate.
6. It is interesting to note that even with *no fossil fuel inflation*, all the lowest cost options over the long haul are non-CO_2 choices: wind, nuclear, and PV. Burning fossil fuel is more costly than simply running a plant after its capital cost is paid. (One may question whether nuclear with a more realistic loan interest rate would be as viable as what is modeled here.) Of course, again, this is assuming a zero discount rate.

Future generations will experience the choices we make now. The Hoover Dam is inexpensive now because a past generation invested in it. Society actually pays these long-lived prices, not just the costs for the first 20 years. All power plants are repeatedly refurbished and re-commissioned. Using this evaluation method, solar PV, wind, and nuclear are already less expensive than the cheapest form of electricity generation, coal (despite no fuel inflation), for the long term–and none of them produce carbon dioxide. But this would not be enough to get them deployed by the private sector because the private sector invests based on return on investment, not long-term societal value. Before we look more closely at this question (which revolves around discount rates), there are two other aspects to consider: PV cost reductions (Section 4) and fuel inflation effects (Section 5).

[22] A similar figure but confined to the period around year 20 is given in Appendix A to help clarify the shift at the end of the loan period.

4. PV cost reductions

PV has had a long history of cost reduction, to the point where module prices have been characterized as dropping roughly 20% every doubling in cumulative production (see footnote 1). Technical roadmaps exist from reputable manufacturers that suggest further reductions to below $2/W DC for installed systems (large, fixed arrays) (First Solar, 2009). This is about a 33% drop from today's best prices, which themselves are a 40% drop from those only a few years ago. Let us establish two solar PV goals for large, fixed arrays:

- $2/W DC installed (likely);
- $1.25/W DC installed (aggressive).

Indeed, DOE has been discussing an initiative to reach $1/W DC installed systems during this decade.[23] Thus these goals are not outside consideration.

Fig. 6 shows the zero discount LCOE of these goals and compares them with "Coal 2010" (and no coal price inflation). Only at $1.25/W does PV compete with coal during the 20-year loan payment period. But PV at any price always competes when compared over the real likely life of the power plants, even at today's coal and PV prices. Expected future prices of PV will expand that advantage, especially if coal prices rise, which is examined in the next section.

The history of PV cost reduction suggests that continued market growth will cause PV prices to drop to these levels as technical progress and economies of scale result from the increased revenue streams. The $2/W level may be reached with two doublings in output ($0.8 \times 0.8 \times$ $3/W); and the $1.25/W with five. Using 10 GW/yr as a baseline for worldwide production today, this would be an annual market size of 40 GW/yr for $2/W; and 320 GW/yr for $1.25/W. By accelerating deployment, these levels would be achieved sooner.

5. Fuel inflation

Fig. 7 shows what happens with a positive fuel inflation rate. The previous figures assume universal zero fuel and O&M inflation. Fig. 7 assumes a fuel inflation of 3%. It gets very ugly for fossil fuel costs in the later years.

Fig. 8 shows this as an LCOE assuming a zero discount rate.

Having electricity options without fuel can avoid major risks from fuel price escalation and spikes, and the societal behavior associated with them, e.g., political tensions over imports, or tradeoffs between the environment and jobs. However, normal discounting of future cash flow makes it impossible for the private sector to capture these gains.

6. Discount rates

To recapitulate, if we assume a discount rate of zero, PV would be a good buy right now for deployment on a large scale in the US Southwest. This would be true without assuming any fuel inflation, but becomes even more compelling with positive fuel inflation rates. What happens when more traditional, private sector discount rates are invoked?[24]

[23] Private conversations between the author and representatives of The Executive Office of the President Office of Science and Technology Policy and The US Department of Energy (July 2010).

[24] A useful definition of "discount rate" is the average cost of capital of an entity. For a company, this would be for floating shares and getting loans. For a

Table 5
The years in which PV reaches a lower levelized cost of electricity versus the named sources, assuming different discount and fuel escalation rates.

Fuel escalation		Discount rate					
		8%	**6%**	**4%**	**2%**	**1%**	**0%**
NA	**Wind**						78
0%	**Nat gas**					80	61
0%	**Coal**					85	62
0%	**CCS**			38	31	29	28
1%	**Nat gas**				71	56	48
1%	**Coal**				89	64	53
1%	**CCS**		43	32	28	27	26
2%	**Nat gas**			101	51	45	40
2%	**Coal**				63	52	45
2%	**CCS**	61	34	27	26	25	25
4%	**Nat gas**		74	44	35	33	31
4%	**Coal**			57	43	39	36
4%	**CCS**	29	25	24	22	22	22

It turns out that a traditional private sector discount rate of 6% or more obviates the advantage of PV in almost every case, even over the full 100 years.[25] This is true even for very high fuel inflation rates such as those for natural gas in Fig. 7, despite putative natural gas electricity prices rising above $1/kWh by the 100th year. Because they are discounted, it is as if the high fuel prices never happen.

By running a sensitivity analysis, one can quickly see the spectrum of possibilities. If we choose lower discount rates than 6%, there comes a point where PV has a cost advantage before 100 years. Table 5 shows the operating years after which PV has a better levelized cost of electricity in comparison with the other options assuming different discount rates and different fuel escalation rates. The absence of an entry indicates no such advantage is achieved within 100 years.

Almost none of the options are less expensive than PV for a discount rate of 8% (except carbon sequestration with fuel inflation above 2%). But at 2% discount rate or less, almost all are more expensive than PV if there is some fuel inflation. Wind, with "Scenario 2010" assumptions, is only more expensive if there is a discount rate of zero (and that is only in the 78th year).

Thus there appear to be several implications:

1. We should not expect the private sector to invest in PV until PV meets its usual expectations for fast returns. That will not happen until PV is cheaper than alternatives in the first 20 years, because those are the years that are less discounted. While we wait for this to happen (i.e., until market expansion brings the price of PV down to near a dollar per watt), society must be the source of funds for making up the difference and deploying PV (if society chooses to do so). Society will base investment on the perceived cost and value of PV deployment.
2. Societies naturally have a lower discount rate than the private sector, since they have a lower cost of capital (Zhuang et al., 2007).[26]
3. Many of PV's values would be camouflaged and inaccessible without a low discount rate. This is fine for the private sector. As we know, the private sector only maximizes profit. Discount rates for maximizing profit are designed to be as high as possible ("what is the largest profit I can get?") and are not the same as those for wider purposes.
4. Governments already invest in long-lived assets like bridges and highways; and at one time, they invested in TVA and Hoover Dam—these all emphasize long life and dependability, not immediate return on investment.

It is impossible to say with certainty within this article what a lower 'societal' discount rate for PV should be. However, it is possible to say that *some* lower rate should be used and to consider the implications.

7. Implications of a lower discount rate

If one assumes the thesis that traditional private sector discount rates are too high to capture the true societal value of long-lived options, then one can draw some interesting, if tentative conclusions:

1. Carbon sequestration (even if it worked to the extent hoped, which may be doubted) appears to be a barren idea (see Fig. 8 and Table 5), since its inefficiencies and heightened fuel costs make it almost the least desirable of any of the electricity options. The only argument that could still be made is that we would still need baseload power. But numerous options for balancing variable wind and solar are already being considered, e.g., rapid response natural gas, wind and solar forecasting, and a responsive ("smart") grid.
2. Low-cost, land-based wind is an extremely attractive option, despite the need for significant periodic investments to rebuild it. Its deployment should be accelerated, and more pressure should be exerted to allow it access to the best land-based wind sites and associated transmission corridors.
3. There are plenty of terawatts of PV sites in the US Southwest that could be exploited to add PV capacity, even at current PV prices. Since this added market would accelerate the cost reduction of PV, a societal investment in accelerating deployment of PV in the Southwest would rapidly bring down PV prices. More pressure should be exerted to allow PV access to the best sites and the associated transmission.
4. Further studies should be done of all non-fuel options based on the low-discount rate, long-operating life framework, and including transmission, loan rates that vary by technology, monetized life-cycle externalities (e.g., nuclear issues,

(*footnote continued*)
government, it is for selling government bonds. Clearly, governments have lower average cost of capital and lower discount rate assumptions.

[25] The comparison is done by calculating the ¢/kWh difference between PV and each of the other options in each operating year, weighing the calculated difference by the discount appropriate for each operating year (i.e. (1-discount rate) raised to the power of the operating year) and then summing them. For example, with a discount rate of 6%, the difference between PV and the others in the 100th year is weighted in comparison to the first year by a factor of 0.2% (0.94 to the 100th power).

[26] There is substantial discussion on the subject of infrastructure discount rates. One example is from the Association of State Floodplain Managers (ASFPM) (June 2, 2007): "The theory and application of discount rates is not uniform among government entities with economic oversight responsibility. OMB uses an "economic approach," which examines how much it costs the government in terms of lost revenue. This view treats the government as an entity separate from society. The Congressional Budget Office (CBO) allows a "social approach," which attempts to take into account the impact of expenditures on social welfare. The GAO recommends the use of a very low discount rate (defined as very near current inflation estimates) when analyzing policies with large intergenerational effects involving human life (Harvard Law School, 2006). The more that social factors are allowed to be considered in economic analyses, the lower the discount rate. For example, OMB requires that a 7% discount rate be used, but CBO and GAO policies may allow for lower rates—possibly as low as 2%."

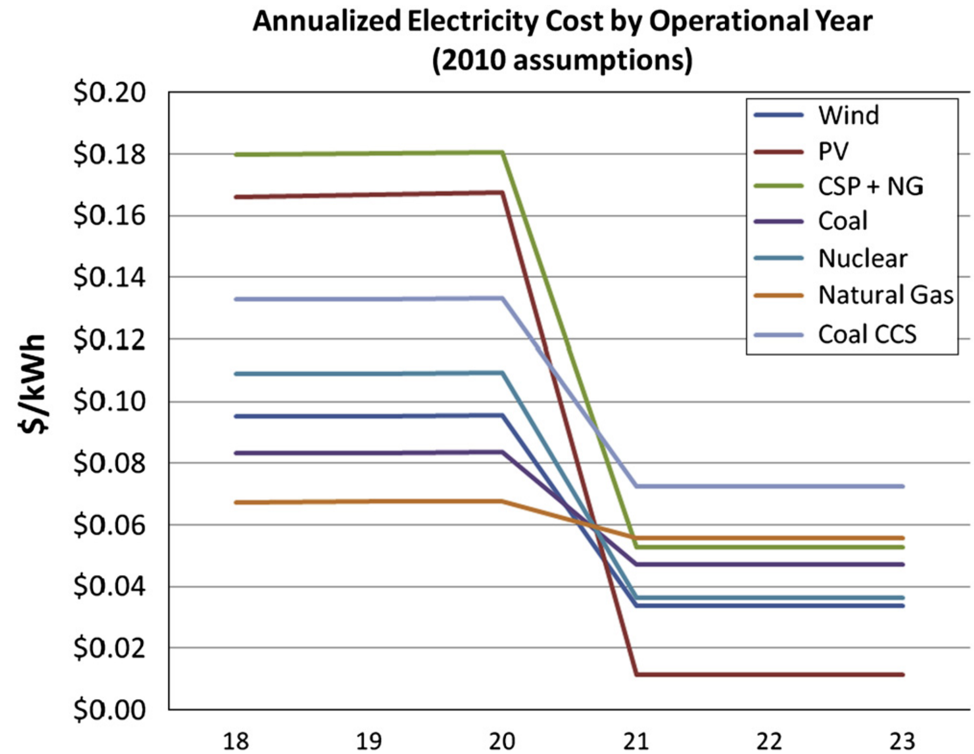

Fig. 9. Same as Fig. 4, but showing more detail around year 20, the end of the loan payments. The switch in year 20 emphasizes the level of capital cost in each option. The steady-state costs afterward are just fuel and operating costs.

Table A1
Scenario "2010" (for new plants in US; all loans are 20 years at 6%).

Case	Capacity factor (%)	Annual degradation (%)	Mean time to overhaul (years)	Fuel cost ($/MBtu) and heat rate (Btu/kWh)	Fuel cost ($/kWh)	O&M per kWh ($/kWh)	O&M per kW ($/kW-yr)	Additional annual based on TTO ($/kW/yr)	Capital ($/kW)
PV	21	0.5	200	0	$0	0	$15	$3.75	$3000
Nuclear	85	0.2	30	$0.5 (10,000)	$0.005	0.02	$30	$50	$6000
Coal	85	0.2	30	$2 (10,000)	$0.02	0.02	$20	$25	$3000
Natural gas	85	0.2	30	$5 (8000)	$0.04	0.01	$20	$8.3	$1000
CCS	85	0.2	25	$2 (10,000)	$0.03	0.03	$30	$62.5	$5000
CSP and 25% natural gas	41	0.2	30	$5 (2000)	$0.01	0.003	$80	$38.3	$4600
Wind	30	0.2	10	0	$0	0	$40	$45	$1800

international tensions), and more traditional project economics.[27] Insights should be sought about the trade-off between stable, low-risk, long-term investments and the destabilizing effect of emphasizing short term gain. Feedback loops should be examined (e.g., stable PV prices restraining fossil fuel price escalations). Other energy options such as offshore wind, solar thermal electric without natural gas, distributed PV, electric vehicles, and electric storage should be included. Doing so would help us develop a societally anchored approach to energy and the environment rather than one limited by the vision of short-term profits (as necessarily promulgated by the private sector).[28]

Extending analysis to a century, as done here, is often prevented by the use of traditional discount rates. High discount rates make 100-year analysis appear irrelevant, thus trapping us in immediacy. Perhaps we need more long-term thinking to balance our private sector compulsions.

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I would like to thank GWU colleague, Professor Denis Cioffi, who mentioned that he thought PV would be a winner because it is so simple and lasts a long time. Of course, that is the entire theme of the

[27] What would happen if we took the hidden loan guarantees, utility fuel price escalation clauses, and liability caps away from conventional primary fuels? Or what if we wait and do this in 5 years? In fifteen? How does this affect *today's* comparative economics at various discount rates and analysis periods? This is a reminder that there is more to fuel risk than laissez-faire supply and demand or even the inclusion of a carbon tax. Traditional fuels have built up a complex of deep, obscure but significant subsidies that could be withdrawn over time, changing their economics over the lifetime of existing power plants.

[28] Inevitably, there is a tendency to 'fight fire with fire'. The limitations of traditional economic analysis invite further detailed analysis and further economic discriminations – more of the same! But straining all values through a monetizing sieve inevitably leaves something behind. We should always beware of expecting our numbers to capture enough to make the right decisions.

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Appendix A. Scenario assumptions

See Fig. 9 and Table A1.

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