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Investing in Renewables: Risk Accounting and the Value of New Technology [*/]

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Introduction: It's Not the Technology (Stupid)

It puzzles me that forty years after the development of the Capital Asset Pricing Model (CAPM) and its widespread acceptance as a basis for financial valuation,[1] the comparative valuation of PV relative to other resource alternatives is still largely performed using outmoded *engineering economics* ideas.[2] Engineering economics concepts were formalized in the post World-War II era,[3] well before the introduction of the CAPM and other modern finance principles that explain how to adjust project valuation for risk and uncertainty. Other valuation measures, such as "flexibility/reversibility," and "modularity," have also evolved to help explain these previously non-measurable attributes,[4] which serve to increase the value of PV relative to traditional fossil alternatives. By ignoring financial risk and other technology attributes in their analyses, lenders and investors understate the value of PV projects relative to fossil alternatives.

In addition, modern finance theory would counsel us to evaluate PV not on the basis of its *stand-alone* cost, but on the basis of its *portfolio cost*— i.e. its cost contribution relative to its risk contribution to a portfolio of generating resources.[5] Along these lines it can be shown [Awerbuch, 2000, 1995b] that the inclusion of PV in a portfolio of generating assets serves to

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[1] The Capital Asset Pricing Model (CAPM), one of the important foundations of modern finance, is a one-factor model that is remarkably robust in its ability to explain the relationship between risk and the investor-required return or discount rate for an asset. Most investors are familiar with β (beta), the CAPM risk measure, which is widely used in valuing stocks. The CAPM is generally attributed to Nobel Laureate William Sharpe [1964; see Varian 1993, 165].

[2] For example, the International Energy Agency [IEA, 1999] recently held a conference whose "principal focus" was engineering-economic techniques for assessing energy and environmental issues. Similarly, recent EC energy valuations [see Nuñes, 1999] seem to use engineering models that ignore financial risk.

[3] Although they date back to the early part of the century; see Awerbuch, Dillard, et. al. [1996] and Awerbuch, Carayannis and Preston, [1997]

[4] These attributes, developed in the late 1970's, helped explain the advent and ultimate supremacy of "lean" or flexible manufacturing.

[5] Portfolio theory, another major development of modern finance, is generally attributed to Nobel Laureate Harry Markowitz [1952]. The application of portfolio principles suggest that PV and other resource alternatives whose costs do not co-vary with the current fossil portfolio can reduce generating costs at any given level of risk.

reduce overall portfolio cost and/or risk. This somewhat counter-intuitive result holds even though PV "costs more" on a stand-alone basis. The important implication of portfolio theory is that the true relative value of PV (as well as other technologies) can be determined not by evaluating alternative resources, but by evaluating alternative resource *portfolios.*

Finally, a significant body of economic literature, beginning with A. C. Pigou [1931], (and more recently, culminating with the work of Robert Lind and Kenneth Arrow [1982]), supports valuation principles, which, if applied to environmental externalities, would yield significantly *higher* present values for these societal cost streams.[6] PV differs from fossil alternatives in that it creates no emissions. In order to develop accurate societal valuations of PV it is therefore essential to correctly value the environmental externality costs associated with fossil alternatives. However, energy planers routinely ignore the special discounting procedures required to properly value environmental costs, thereby significantly understating the true value of PV relative to traditional fossil alternatives.

Radical Architectural Innovations

PV and other modular distributed technologies represent a *radical architectural* innovation [Henderson and Clark, 1990] in the electricity production/delivery process.[7] Such technologies create technological discontinuities: they dramatically alter production economics and present new risk and benefit-cost tradeoffs that are generally not fully understood until the technologies are more fully exploited. Indeed this was the case with new manufacturing process technologies such as computer integrated manufacturing (CIM) in the late 1970's. Although it *seemed* intuitively appealing, traditional investment analysis techniques failed to show a positive benefit-cost relationship. Even though CIM clearly reduced cost, it could not be justified using strict traditional project valuation techniques.[8]

There are a number of reasons why the full exploitation of new cost-cutting technologies, particularly *broadly-applicable technologies* [Porter, 1990] requires years and sometimes decades. First, it is usually possible to fully exploit radical innovations only after other aspects of the production process have been rearranged to accommodate them. As an

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[6] For example, using published externality cost streams designed for resource planning in the US, Awerbuch [1993c] estimates present values for coal-fired electricity that are three times as large as those produced by standard engineering valuation approaches.

[7] For additional discussion of this idea see: Awerbuch, [1993b], Awerbuch, Carayannis and Preston, [1997], Awerbuch, Dillard, *et. al.* [1996] and the literature cited therein.

[8] For a fascinating discussion and illustration of this problem see Kaplan [1986].

illustration, consider the Bessemer steel process developed in the mid-1800's.[9] It changed the way steel was made by reducing batch production time to 15 minutes. But existing mills in England could not fully exploit the technology because they were organized around the previous open-hearth technology under which it took several days to make a batch of steel [Clark, 1987]. Fully capturing the cost advantages of Bessemer required the establishment of new factories in the US, which were laid out around the new production process [Clark, 1987]. This meant new floor plans, new job classifications and new logistics— new processes for moving raw materials and finished product. Using the identical Bessemer process, the new US factories produced nearly four times as much steel as their European counterparts [Clark, 1987].

Extending these lessons to PV and other passive distributed technologies we can only conclude that we probably do not understand how to fully exploit them and that we probably understand even less about their ultimate costs and benefits. Our electricity production processes are centered around "active"19th century central-station fossil technology [Awerbuch, Dillard et.al. 1996] which require the support of complex organizations that can manage the complicated logistics and maintenance functions needed to literally keep the wheels spinning. Such technologies therefore exhibit considerable agglomeration (scale and scope) economies. Photovoltaics do not fit well into this industrial organization. In fact, they are probably more cost effective when deployed outside of such hierarchical organizations for a number of reasons:[10]

i. They show few agglomeration or scale economies; this means they can be deployed in smaller applications. A large corporate installation has few additional efficiencies as compared to a smaller installation.

ii. They require very little, and hence do not benefit from, traditional corporate maintenance and overhead support. For example, PV does not depend on a staff of attorneys to negotiate fuel contracts. In a manner similar to manufacturing innovations, the ultimate benefits of PV may be largely *complementary* in nature[11]— i.e.: they may reduce costs elsewhere in the process. They may reduce overheads and indirect costs, e.g.: by providing a way of reducing supply-demand imbalances and other uncertainties.

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[9] This illustration is more fully described in S. Awerbuch, L. Hyman and A. Vesey, [1999, Chapter Four].

[10] These reasons are more fully discussed in Awerbuch, Dillard, et. al. [1996] and Awerbuch Carayannis and Preston, [1997].

[11] Complementary benefits were first identified in manufacturing by Paul Milgrom and J. Roberts, [1990].

Like CIM, PV is intuitively appealing. Like CIM, we will probably have to develop a new vocabulary of benefits in order to understand it fully and value it more properly. This includes additional activity-based-costing (ABC) analysis to better understand how traditional fossil alternatives consume corporate overheads.[12] The cost-benefit justification of CIM also had to await the development of new benefit concepts including the idea of *capability* and *flexibility* options and new costs insights gained from the application of ABC.[13] Finally, the full exploitation of PV and similar passive, distributed resources will undoubtedly require new electricity production and delivery paradigms.

While we can not value *all* the unique properties of PV with existing techniques and accounting vocabulary, we can effectively capture its unique risk properties using risk adjusted, finance-oriented valuation tools (see Appendix). And while such risk-adjusted valuation procedures are well known, they are not applied. Why this is so remains a mystery to me. The next section discusses how our limited understanding of PV technology affects lending and investment practices. The following section reviews the analytic shortcomings of existing models in greater detail and offers specific recommendations. Finally, the appendix to this paper provides an illustrative, risk adjusted cost estimate for PV and gas-based generation.

Correcting Financial Misconceptions: Lending and the Risk Properties of PV

The investment analysis tools used to evaluate energy resource alternatives have not changed in almost 100 years. They were OK for comparing one central-station fossil alternative to another [Awerbuch 1993a] but they are not useful in today's dynamic environment with technologically and institutionally diverse resource options whose risk and benefit-cost tradeoffs have been significantly altered.[14] Lenders and investors, however, are slow to catch on to the new economics and altered risk structures. This is OK— it keeps them from making obvious mistakes, like investing in a technology that goes bust. But it does not keep them

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[12] For a discussion of the application of ABC to manufacturing see Kaplan [1990]; a description of ABC can be found in Atkinson et. al. 1997, Chapter 6.

[13] Capability options and their role in valuation are discussed in Baldwin and Clark [1992]. For a discussion of flexibility, (especially the option-to-wait) see Dixit and Pindyck [1994]; other flexibility option values of PV have been explored by Hoff, Wenger and Farmer [1996], Hoff [1998] and Felder [1996].

[14] E.g.: A central station plant may produce the cheapest electricity *on paper*, but this calculation is useless if you judge demand growth incorrectly so that your 500MW plant produces at only half capacity. In any event, given the pace technological progress, small turbines are no longer necessarily inferior to large-scale plant and may in fact soon be more efficient (Vesey [1999]).

from making *less* obvious mistakes— like missing out on profit-making opportunities involving new technologies. Then again, opportunity losses, which are economically indistinguishable from cash losses, concern them much less since probably no one will ever know.

As a consequence, lenders and investors concoct various reasons to explain their reluctance to support PV projects. Some of these ideas sound astonishing given the financial properties of PV. The key ideas are that PV is free of fuel price risk, and, moreover, has virtually no operating expenses since almost all costs are in the form of up-front investment outlays. PV is therefore essentially riskless, i.e.: it comes about as close as a real asset can to providing the systematically risk-free (zero-*beta*) characteristics of a US Treasury bill (Awerbuch, 1995b). This, of course, does not mean that PV is entirely riskless, but the remaining risk, the so-called random or *technology risk*, is fully diversifiable [Interstate Renewable Energy Council, 1996] so what's the problem? Moreover, these technologies, by virtue of their modularity and flexibility, *reduce* or *eliminate* a number of risks such as the risk of creating costly excess capacity, a risk that is quite significant in the case of lumpy central-station resources. Obviously there is some lack of communication or understanding; perhaps lenders and investors have lost sight of the finance fundamentals.

Capital intensity

Lenders apparently worry about the capital-intensity of PV [Mendis, 1999]. Loans for PV projects tie-up a high percentage of annual cash flow, which makes these seem riskier to bankers. It seems to them as if their loan includes the cost of, for example, the future fuel-stream (PV uses no fuel) whereas for a fossil technology, the fuel is paid for out of annual revenues and is not part of the obligation to the lender. This idea reflects a fundamental misunderstanding of the risks and economics of the renewables investment. PV is a low-*beta* asset. Overall risk is the sum of the underlying business or asset risk plus the financing risk. Any business with a low business risk (i.e. a low asset-beta) can take on more financing and still have an acceptable overall beta. It seems lenders would want as much of such a project as they could get. For the same amount of paperwork they can get a bigger loan than, say, on a gas turbine. That's good, isn't it?

But bankers still worry; their loan ties up a much higher percentage of the project's cash flows than it would on, say, a loan on a gas turbine, where the loan drains much less of the annual cash flow leaving more for other expenses. And that's the key– there are virtually no other expenses with capital-intensive PV. Where the asset is nearly systematically riskless, high loan to-value makes a lot of sense. Everyone seems to understand that. For example, when you put up riskless Treasury bills against your margin loan, your broker might lend you 90% of their value. But you might only get 50% or 75% of value if you put up risky stocks.

The confusion here, which one hears expressed often, also has to do with a misunderstanding of operating leverage. Lenders think that PV resources have high-operating leverage. A high operating leverage project is riskier because a high proportion of the cash flows are committed to fixed outlays, outlays that cannot easily be reduced when revenues fall. But PV actually creates very *low* operating leverage since there are virtually no fixed costs. The problem here is that lenders include the loan payment as part of the operating leverage calculation, which is incorrect— financing decisions are never part of the operating leverage calculation— just check out any finance textbook.[15] In any event, the bottom line may be the same: in the case of highly leveraged (financial leverage) PV projects, a high proportion of the cash flows is indeed committed to covering debt service. But, again, why should this be problematic?

The high debt outlays associated with PV resources are offset by the low asset betas (just like high margin loans on low risk securities). Bankers should understand this idea— they have no trouble lending against shopping centers, office buildings and other real-estate where very high proportions of the operating cash flow goes to servicing the mortgage. In such cases bankers worry more about the credit worthiness of the tenants. And perhaps this is what it comes down to in the case of PV projects— what is the credit worthiness of the power purchasers. Given purchasers with equal creditworthiness, PV projects are considerably *less* risky than fossil-based projects. And most any flexible, distributed project will be less risky than an equivalent central-station installation. The sunk costs for a distributed project will generally be lower, which in some sense raises *reversibility*, an important determinant of project risk and flexibility, no matter how defined.

Risk and Project Return

Investors are as confused as lenders are about renewables. Based on existing economics, they don't see how these technologies can produce the high rates of return to which they have become accustomed. The answer of course has to do with risk differentials. Establishing a distributed PV installation involves buying and erecting PV modules and attendant devices, entering into some maintenance contracts, signing up buyers on firm contracts for the electricity at a price that will cover the loan payments, the modicum of maintenance costs, and the expected component replacements. This is not rocket science! Insolation values are widely available or can be readily measured at a given site. The year-to-year variability in insolation, it turns out, is very small [Awerbuch, 1992c] so that revenues should remain rather constant[16]— assuming the customers are as good as they say they are. And out of pocket expenses are also very small (i.e. operating leverage is low) so that with proper planning, they should not significantly alter the bottom line even in a bad year.

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[15] For example, Ramesh Rao, [1992, 193-95], defines operating leverage as the commitment to fixed *production* costs (see also Brealey and Myers, 1991, 199-200). Financing costs are never part of the operating leverage computation since they are a financing decision, and a project can always be financed using more equity.

[16] Weather variations can now also be hedged with weather futures which are starting to trade in the US.

Viewed in this manner, the production of PV-based electricity sounds like a simple, clean business with controllable costs and little risk. It does not require visionaries at the helm; it does not require extraordinary technical or managerial ability. So, why should investors expect a PV investment, which can be made virtually riskless, to generate the higher returns that might be expected from, say, a risky hi-tech business with virtually unknown revenue streams, technology life-cycles that last two weeks and the possibility that the value of the firm's technology or patents could vaporize overnight?

Moreover, as discussed subsequently, the value of PV-based electricity, and hence the value of PV investments tends to be counter-cyclical in nature, i.e. it will rise as the returns to other assets are falling.[17] Based on the CAPM, negative-beta assets will generally provide returns that are lower than even the riskless rate. The beauty of a true negative beta asset, however, is that its value will rise just as the rest of the portfolio is tanking. This "insurance" value, therefore offsets the lower returns provided by PV.

Modularity, Loan Size and Perceived Lending Risks

PV's modularity and reversibility increases flexibility, which, in turn, reduces risk. An aspect of the modularity/reversibility property is that sunk costs are relatively small as compared to traditional central station generators.[18] From a finance perspective, this makes PV projects readily reversible, i.e.: projects can be stopped and started at any time, and modules can be resold (as were the Carissa Plains modules).

While all of this adds to PV's value, it seems to make bankers nervous about the safety of the PV assets that secure their loan. They seem to worry that the modules may disappear, presumably through theft or fraud. While this concern seems legitimate, one must wonder why the industry has not figured out how to mitigate the problem. Are underwriters willing to provide casualty insurance on installed PV modules? In the US, bankers seem to gladly lend on all sorts of transportable assets including cars, computers and refrigerators. In the case of cars, they routinely require theft and other insurance.

A final concern about PV lending, frequently expressed by bankers, is the small size of PV loans, which raises costs. While this is no doubt accurate, this perceived obstacle

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[17] This is not inconsistent with the above view of PV as a zero-beta asset, given fixed contracts for its electric output. However, spot electricity prices will rise with rising fossil prices, which in turn will serve to increase the value of PV investments generally since their costs are fixed. Further, as discussed subsequently, historic fossil prices seem to co-vary negatively with the returns to other assets in the economy, which means that the value of PV investments will rise precisely when the returns to those other assets are falling.

[18] This means that salvage values are relatively high.

needs to be further examined and one must wonder, why the industry has not figured out how to overcome this obstacle. In the US, banks routinely lend on consumer appliances, restaurant kitchen equipment (often in the form of leases) and a host of other specialized equipment. The key seems to be specialization— lenders have learned how to effectively promote loan packages in their area of expertise— whether it is lending on small airplanes or leasing the furniture and equipment in a dentist's office. To the extent that such financing is well established in the US, one wonders why such specialization has not emerged with regard to international lending for PV.

Loan size, and the security of chattel may present greater impediments in certain countries with less developed commercial practices. In the US, where such practices are well established, lender's are protected by the Federal *Uniform Commercial Code* (UCC) and by state statutes, which typically spell out the means of recording liens and perfecting claims, as well as the basic obligations of borrowers (and lessees) vis-à-vis chattel encumbered by liens. By standardizing the basic requirements, the UCC thus reduces lending costs. To the extent that emerging nations may not have established commercial codes and practices, chattel mortgages may be riskier and more costly to administer and supervise.

So, we return to the opening idea: it's not the technology— it's the way we conceive it and the way we measure its attributes. And along these lines, as this paper has already suggested, we have a lengthy history of using inappropriate engineering-oriented valuation and investment analysis tools that ignore risk differentials and a variety of other important technology attributes. These analysis tools have failed miserably in other industries [Awerbuch, 1993b]. Why do we continue to use them? Because engineers and planners are almost always familiar with them, while knowing little about more appropriate finance-oriented valuation methodologies.

WHAT IT TAKES TO IMPROVE INVESTMENT ANALYSIS FOR PV TECHNOLOGY

Energy planners, it seems to me, place less emphasis on *planning* and more on *engineering-economics* oriented cost analysis. Although it ignores financial risk, as already discussed, engineering economics has provided a practical, accounting-based means to help engineers value project alternatives. The evidence suggests [Awerbuch 1993a] that engineering economics may work reasonably well (i.e., decision choices will probably not change with the use of more sophisticated techniques) under the following restrictive conditions:

> <u>Condition 1: It makes sense to model the asset or project on the basis of its cash flows:</u> The practice of representing asset by their cash flows— revenues and costs— is so widespread that we tend to forget about this basic assumption, which probably does not hold for many new, passive technologies.

For example, it is virtually impossible to capture the benefits of a fax machine on the basis of its cash flows [Awerbuch, 1993b] since the costs— additional phone charges incurred over the savings in postage and possible clerical time— are trivial when compared to the non-accounting benefits of the technology: the ability to access the information network, to make rapid decisions and to establish working relationships not otherwise possible. This illustrates the limitations of accounting measurement, i.e.: there exists no accounting entry for recording these benefits.

<u>Condition 2: It makes sense to assume an environment of static technology coupled with relatively homogeneous technological choices:</u>

This condition, which no longer holds in most parts of our economy including energy, has two important implications for valuing investments. The implication of the homogeneous technology is that risk is not dependent on technological choice. The implication of technological stasis is a predictable future, which means that various *strategic* and *managerial* options have little value. [19]

The assumption of technological homogeneity probably posed little difficulty fifty years ago, given the relatively limited choice of options— oil and coal fired central station steam. These technologies are homogeneous in the following ways:

i) They use similar fossil fuel inputs with highly correlated prices.

ii) Their cost mix consists of similar proportions of capital and operating outlays.

iii) They have a similar mix of direct and indirect costs.

iv) They have similar operating cost structures so that operating leverage is similar;

v) Choosing a particular technology did not create different strategic options— options that might alter the future technological path; for example: future capabilities were not significantly enhanced by choosing, say coal over oil-fired steam generation.

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[19] The application of traditional engineering economics to the valuation of electric generating alternatives seems to originate with Paul Jeynes [Kahn 1988, 23] who was rather careful to note the principal shortcomings of the approach, i.e.: that it works only where expected revenues and the firm's rate of return remain unaffected by the technology choice [Jeynes, 1951, 1956], thus implying that all resource options show the same degree of financial risk.

vi) The technologies were all equally 'lumpy' and irreversible.

These conditions are not easily met in today's technological environment, which presents planners with a broad range of supply and demand-side resource options. Some of these options, including PV, offer unique cost and risk characteristics. This calls for the use of more suitable valuation approaches that treat resource alternatives as components in a portfolio of generating assets as previously discussed, thus measuring the relative cost contribution of each asset against its relative risk contribution to the entire generating portfolio. Valuation approaches must also be sensitive to the severe limitations that exist when we try to use accounting-based information for decision-making. Along these lines they must try to incorporate non-accounting benefits including *quality* and managerial options. Finally, such approaches must reflect changing technology costs over time as technologies mature, or, must be adapted to meet new needs. These issues are further discussed in the next section.

The Limitations of Traditional Engineering-Oriented Models for Valuing PV[20]

Energy planners have used engineering-economics based models to estimate the cost of electricity for different generating technologies for nearly a century.[21] While these procedures are almost universally used to estimate the kWh cost of electricity (COE) for PV and other planned energy resources, it is not generally understood that the approaches are rule-of-thumb proxies which yield only rough approximations of true cost. As previously discussed, this may have been reasonably useful where technology choices were homogeneous.

However, if we are to develop efficient energy policies that properly value PV and other renewables, we will have to adopt more sophisticated finance-oriented valuation procedures. Surprisingly, national energy policy in the US, the UK and elsewhere has not focused on appropriate procedures for costing and valuing PV and other resource alternatives. Everyone, it seems, is quite content to leave the arcane procedures for estimating the COE to the green-visor types, which is a mistake: the complexity of choices

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[20] An abbreviated version of this section originally appeared in *Energy Magazine,* (September 1996, pp. 3–6) which is published by Business Communications Co., Inc., (www.buscom.com).

[21] In the US, for example, these procedures were formalized by the Electric Power Research Institute (EPRI) in 1978 where they are widely known as "EPRI-TAG" procedures [see, for example, EPRI, 1991]. Strictly speaking these procedures yield a price or *revenue requirement*, which exceeds *cost* by about 50%. This crucial difference is not widely understood.

available makes open discussion of how to value PV and other decentralized and conventional technologies even more crucial.

Improper investment analysis has had far-reaching national implications in other industries. For example, myopic capital budgeting contributed in part to the near collapse of the American steel industry in the 1970's: accounting-based analyses suggested that existing technology was less costly than innovative alternatives. But this is not an isolated example. Traditional, accounting-based cost analyses almost always suggest that the incumbent technology is a better bet and that the innovation is too costly! [Kaplan, 1986]. Flawed engineering-based analyses also kept American manufacturers from making timely investments in innovative manufacturing process technologies such as CIM and computer-aided-design (CAD) which led to a loss of world preeminence for these manufacturers who then spent the next two decades regaining a leadership position. Given the dismal record engineering-based cost models have in identifying promising innovations in manufacturing, it is unreasonable to expect that they will help us understand the costs and benefits of PV [Awerbuch, Carrayannis and Preston, 1997].

Now some will argue that the last thing we need is public debate about appropriate resource valuation models since under the emerging competitive energy structures low-cost providers will prevail thus making cost-analyses irrelevant. But power purchase decisions involve uncertain future cost streams and hence require sophisticated valuation procedures. Risk and other financial properties vary widely with the underlying generation technology: in a competitive market kilowatt-hours are not all equal. So while the financial diversity of the technological alternatives has never been greater, planners use investment analysis procedures that were conceived around the time of the Model-T Ford. It is not possible to make efficient investments in today's complex environment without state-of-the-art valuation tools. Rule-of-thumb approaches that were "close enough" in simpler times will no longer suffice; policies that rely on them will lead to good investment decisions only by accident.

EPRI-TAG and similar engineering-oriented busbar cost models generally favor expense-intensive over capital-intensive technologies. There are a number of reasons why traditional, engineering-based valuation approaches do not correctly reflect the relative value of PV. These are discussed below.

1. Traditional Approaches Ignore Financial Risk:

Loosely defined, financial risk is the variability of annual costs. Under an engineering approach a *risky* annual cost stream has the same present value as an equivalent but *safe* cost stream. This violates fundamental finance theory. Dollar for dollar, a risky cost stream, such as future outlays for fuel, must have a *higher* present value since it is less desirable than a safe cost stream.[22]

This intuition— that a risky cost streams are less desirable— seems to be widely understood. For example, homebuyers in the US overwhelmingly choose fixed-rate mortgages even though adjustable-rate mortgages carry initially lower interest rates. These borrowers obviously conclude that the projected fixed-rate stream of payments has a lower present value— it is more desirable. Similarly, investors of all types and all risk-aversions purchase riskless US Treasury obligations even though they yield much less for a given $1000 investment than do riskier instruments such as low-grade bonds.

Engineering cost approaches will always indicate that riskier, lower cost alternatives are more economic, which is equivalent to arguing that junk bonds are a better investment than US Treasury bills because they promise a higher annual payment stream for each $1000 invested and are hence "cheaper." For example, the Appendix presents an illustrative analysis that compares cost estimates derived using traditional engineering-oriented approaches to those obtained with risk-adjusted (finance oriented) models.

2. Traditional Approaches Produce "Stand-Alone" Instead of Portfolio Costs

Financial portfolios are widely used by investors to manage risk and to maximize performance under a variety of unpredictable economic outcomes. Similarly, it is important to conceive of electricity generation not in terms of the cost of a particular technology today, but in terms of its *portfolio cost*. At any given time some alternatives in the portfolio may have high costs while others have lower costs, yet over time, the astute combination of alternatives serves to minimize overall generation cost relative to the risk.

By contrast, traditional energy valuation approaches focus on finding the single *least cost* alternative— a questionable procedure that is roughly analogous to trying to identify yesterday's single best performing stock and investing in it exclusively. Rather than focusing on finding "least-cost" options, assuming this is even possible in today's dynamic environment, our energy policies must focus on developing efficient (i.e. optimal) generating portfolios that include PV and other diverse technological alternatives.

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[22] Note that this is the opposite of the intuition for risky *benefit* streams, which would have a *lower* present value than a "safe" stream. The difference arises because risky cost streams move systematically against economic cycles (i.e. they are high when the economy, and hence income, is low). Note that such a stream— which is high when other income is low— is quite attractive to a recipient who would value it by discounting at a discount rate below the riskless rate of return. Given perfect information, both payer and recipient will use the same discount rate to value the payment stream. For additional discussion see Awerbuch [1995a].

Using such an approach, the relevant selection criterion is not minimum stand-alone cost, but overall portfolio generating cost, coupled with its expected risk (i.e. its year-to-year price fluctuations) as discussed in the previous section. And while a detailed portfolio-based valuation of PV is beyond the scope of this paper, it can be shown, using standard portfolio theory principles, that PV, which "costs more," will serve to *reduce* the cost of a generating portfolio at any given level of risk. Indeed the evidence indicates [Awerbuch, 2000] that small additions of PV— on the order of 3% to 6%— can serve to reduce generating costs or risks as compared to the existing fossil portfolio.

Implications for Lenders and Investors

Portfolio concepts also have important implications for the diversification of the private portfolios of lenders and investors. Fossil fuel price movements affect the value of other investments in the economy. My own analyses indicate that historically, they have co-varied *negatively* with the returns to other assets [e.g. see Awerbuch, 1995b, 1993a].[23] This means that, to the extent fossil prices continue their to co-vary negatively with other assets, PV investments may provide a valuable form of insurance to diversified portfolios, i.e.: their value will be greatest when the returns to other assets are low. Such defensive or counter-cyclical investments, however, will provide relatively lower yields consistent with their low systematic risk.[24]

3. Traditional Approaches Rely Exclusively on the Direct (Busbar) Cost:

This means that overhead and indirect resources that are consumed on such activities as fuel purchasing, or Clean Air Act compliance are ignored in the cost comparison. By ignoring overheads and indirect costs, busbar-cost comparisons implicitly assume that such costs represent a constant percentage of the total costs of each resource alternative. While this assumption probably held at one time, it no longer does. Overhead requirements for PV, for example, are significantly lower than for most fossil alternatives. This issues cannot be resolved without more detailed activity-based cost analyses which may help us better understand the *total* costs of operating particular technologies.

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[23] This seems consistent with the results reported by Lind [1982, 63], who finds that renewable investments will be negatively correlated with GNP, i.e.: they will provide a form of insurance that pays off when the economy is doing poorly. More recent evidence [Sadorsky, 1999] further suggests that fossil price movement affect the volatility, and hence value, of other assets.

[24] As discussed previously, true negative-beta assets will yield an expected CAPM return below the riskless rate.

4. Traditional Approaches Ignore Managerial and Strategic Options That PV May Create

Experience in manufacturing suggests that new technologies often create valuable managerial or strategic options which can be "exercised" at a later time. While the existence of such options clearly increases the value of a particular project, this value yields no immediate benefit in terms of reducing annual accounting costs. The literature divides options into several categories, although there can be overlap between them.

> Flexibility Options: PV technology is modular which creates valuable *flexibility* options since managers can install capacity slowly, over time, to match load increases. Recent work on the value of flexibility suggests that when valued in a traditional manner, inflexible projects are comparable to flexible ones only if their present value is considerably greater.
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> Strategic Options: The adoption of PV, even in small amounts, can create *strategic options* [e.g. see Aggarwal, 1993, 1997] for managers by creating opportunities to serve new customers, or provide different levels of quality and reliability as well as different types of services. Additional work will be required to better understand how to conceive of these options so we might begin to measure their value.
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> An excellent illustration of the strategic option concept in manufacturing is given by Kaplan [1986], who observes that manufacturers that adopted numerically controlled process technology in the 1970's were able to more readily adopt CIM a decade or so later.
>
> Numerically controlled technology enabled production machinery to be controlled by coded paper-tape. The technology required workers to learn how to resolve product shapes and the required machine movements into a series of numerical instructions based on a set of X-Y coordinates. This training and experience created a *capability* in the work force thus making the firm to more receptive to CIM, which requires similar work force skills.[25]
>
> It is difficult to value strategic and capability options because it is hard to see the future. In the case of paper-tape technology, hindsight clearly implies that no matter what the initial cash-flow-based benefit-cost analyses may have indicated, the original adoption of numerically-controlled equipment was ultimately cost-effective, not necessarily because of direct cost savings (although these may have accrued as well) but because of the capabilities and strategic options it created. Clearly, such benefits do not lend themselves to traditional discounted cash flow approaches.

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[25] More strictly speaking, the numerically controlled technology created a *capability option* that was subsequently exercised with the adoption of computer-based technology.

5. Traditional Approaches Ignore *Cost-of-Quality* in Electricity Production/Delivery

In manufacturing, *Cost-of-Quality* concepts fairly well understood [e.g. Kaplan, 1990; Kaplan and Atkinson, 1989, Chapter 10], and generally involve the elimination of wasteful activities such assembly-line set-ups, the maintenance of parts inventories or the re-manufacture of defective products. As of yet, there is no generally accepted definition of the cost-of-quality in electricity production and delivery, although it undoubtedly implies the reduction or elimination of inherently wasteful activities such as traditional reserve requirements and transactions such as meter-reading and the ordering, movement and storage of fuel and other materials, etc. Of course attaining such a result requires that we substantially re-conceptualize the entire generation/delivery process just as manufacturing was largely re-conceived (from mass-production to flexible production, sometimes equated with "lean manufacturing") in the late 1970's. PV, which can easily be located close to loads and, in principle, does not require metering, will no doubt help us re-conceptualize the process in such a fashion.

Traditional cost accounting does not identify wasteful activity. For example, there is no manufacturing cost category for "producing defective parts." Similarly, the costs of maintaining such essentially useless resources as idle or spinning generation reserves are not explicitly recorded so that managers have little incentive to focus on these activities in order to reduce cost. Instead, managers focus on line-item cost-accounting items such as fuel or maintenance. This is similar to the earlier focus of production managers, who equated cost reduction with, for example, substituting low cost materials, a strategy that would be ridiculed in today's competitive global manufacturing. Moreover, traditional cost accounting does not properly categorize most transactions costs including the negotiation, purchase, movement and storage of fuel and other supplies or the activities associated with meter-reading and billing, which may be significant in the case of small accounts.

Finally, quality manufacturing implies the production of goods that deliver value through intelligent design, which meets customer needs and expectations. In this sense, observes Peter Drucker [1992] manufactured products contain higher information content, coupled with lower energy, material and labor content. The idea applies to electricity production/distribution as well: the focus needs to shift from one of simple busbar cost minimization to one of delivering fewer, "smarter" kilowatt-hours that have a higher value to customers [see: Awerbuch, Hyman and Vesey, 1999, Chapter 4]. In such an environment, the somewhat higher stand-alone cost of PV-based electricity may be more than offset by the greater value.

6. Engineering Approaches Focus on Current Technology Costs

The relative costs of fossil versus PV-based generation will change drastically when a new need is imposed, such as a requirement for zero or low carbon emissions, or, when changing economic conditions alter the relative costs of input factors, e.g. labor costs might rise over time relative to capital costs without any offsetting productivity gains in operation and maintenance.

In spite of such obvious possibilities, energy valuation procedures tend to be almost exclusively based on costs as *currently conceived and constructed*, without reflecting underlying future changes in technology cost or operating conditions. This practice is quite astonishing given the long planning horizons— typically twenty years or more— used in most valuation exercises.

In addition, planners use the *currently conceived* accounting costs for resource alternatives even though energy policies often represent inter-temporal *investment strategies* that need to reflect *anticipated* costs. PV technologies, for example, are on a declining cost curve while fossil technologies are on the mature part of the technology curve— recent efficiency gains not withstanding. The real cost of fossil alternatives are likely to rise with real increases in labor and fuel, and with future attempts to adapt them to new needs.

Effective valuation procedures must therefore consider future changes in technology costs. This involves, in part:

i) Assessing and valuing contingencies such as future environmental requirements;

ii) Using learning (experience) curves and other tools to develop assessments for relatively mature as well as emerging technologies.

The Era of Technological Change: The Need for Technology Assessment

Qualitative technology assessment can help properly capture the relative cost of *using* a particular technology such as PV as the world changes in the future. And although planners project O&M costs to the future, this does not properly capture the true costs that might be encountered when operating conditions, competitive pressures and the cost of alternatives may change in the future. There is plenty of evidence to illustrate this point: we routinely discard computers, copiers and fax machines because they have gotten too expensive to use, even though the original cost is sunk and we have made no unanticipated maintenance outlays. In other words, *the technologies obsolesced even though the original cost projections materialized precisely*.

In these cases, although the engineering cost projections were on target, *relative* costs changed as the result of new operating requirements or new needs to which the technology could not be easily adapted. We might, for example, discard a paper copier because it does not reduce/enlarge, or a fax machine because it does not cut the paper. This feature may not have been important at the time of purchase but over time, operating conditions change, e.g., the volume of usage increases (or the cost of labor rises – see below). This alters the cost picture so that it now becomes too expensive to deal copiers that cannot reduce or with continuous scrolls of fax paper. In other words, the technology has become too expensive even though its accounting costs as originally projected have remained unchanged. This is especially true if competitors have all switched to the newer technology.

Energy resource options are similarly subject to cost changes as they are adapted to new market, regulatory and operating conditions so that it also might become too costly to operate a particular option even though costs materialize as projected. The most obvious changing conditions are:

i) Environmental Regulation: More stringent emissions requirements might require sizable retrofits to meet air quality standards. Such contingencies are frequently ignored even though they have significant present value costs,[26] which serves to bias the analysis against PV.

ii) The development of new, lower cost technologies: Planning techniques need to evaluate the efficiencies— and hence costs— of future vintages of PV and gas turbines since these may differ from the costs used in today's screening analyses. Along these lines, S-shaped (logistic) curves coupled with engineering assessments can be used to help estimate efficiency increases (i.e. reduced heat-rates, improved ramp-up, lower maintenance requirements) for existing technologies such as gas turbines. Similarly, experience curves can be used to help estimate manufacturing cost reductions as PV (and other emerging technologies) mature.[27]

iii) Changes in the relative cost of labor and other input factors: Resource cost estimates project labor costs forward generally using arbitrary escalation rates, which do not reflect the underlying economic changes in the relative costs of factor inputs. A more detailed analysis might reveal that, absent productivity gains, the substitution of capital for labor may become increasingly attractive

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[26] For example, consider the possibility of a $300 million outlay to meet new emissions requirements in the tenth year of a coal-fired project. Such an outlay has a present value of $100 million-- *even if the likelihood of this contingency is only 50%.* This is significant relative to the $600 million or so cost of a 500 mW_e coal-fired plant.

[27] The results of such experience curve analysis can dramatically change estimated costs in a new technology such as PV if we conceive of the resource as being installed incrementally over the planning horizon. Using a set of projected experience curves for photovoltaics developed by Williams and Terzian [1993], we obtain a vintage-levelized cost for PV-based electricity that is nearly 50% lower than the currently installed cost [see Awerbuch 1995b].

in electricity generation just as it has in manufacturing. Such structural changes could easily swing the advantage away from expense-intensive fossil technologies, towards PV.

Clearly these forces can join to radically alter the currently conceived operating cost picture for a given technology. For instance, absent significant efficiency gains, a scenario of relatively undramatic annual operating cost increases for gas turbines coupled with more stringent emissions requirements could combine with experience-based cost reductions in PV to make the latter the low-cost choice at some not too distant future time. Such relative cost changes are obscured when all technologies are evaluated using their currently-constructed present value costs.

Policy Prescriptions and Implications

In Europe as well as the US it is essential for energy planning agencies to abandon outmoded concepts and adopt the state-of-the-art valuation and investment models described in this paper. The divergence between valuation theory and practice is perhaps nowhere greater than in energy planning, where outmoded accounting concepts and engineering approaches, long since discarded in manufacturing and other industries, still provide the *sole* basis for decision making.

PV and similar passive renewables present a unique menu of risk, cost and quality choices. Traditional valuation models, conceived long before such choices became technologically feasible, cannot "see" the special attributes and values[28] because they are steeped in the vocabulary of a different technological era— one of *active, expense-intensive* production technology. The unfortunate outcome of using such models is that planners continue to undervalue PV, and worse, to ignore its unique properties. Properly understood and exploited, these attributes could undoubtedly form the basis for re-conceptualizing (reengineering) the electricity production and delivery process in ways that we can yet not imagine. The literature is rich with prescriptions for how to proceed.[29] Energy planners and policy makers have a responsibility to broaden the analytic horizons to include new valuation approaches that more properly reflect the unique attributes of PV and other renewables.

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[28] As always, there are exceptions. Nobel Laureate George Stigler [1949, 129], while discussing "indivisible and unadaptable fixed plant," inadvertently illustrates an unimaginable (then) technology with zero marginal costs. PV may be the first production technology that approximates Stigler's remarkable insight.

[29] For example, a recent special issue of this journal devoted to the valuation of renewables, [*Energy Policy*, Volume 24, No. 2, (February) 1996] presented models and procedures applicable to the valuation of diverse energy alternatives in a dynamic environment of institutional and technological change.

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APPENDIX

Illustrative Risk-Adjusted Busbar Cost Comparison (Ignoring Options) of PV and Gas Combined Cycle

Revenue Requirements versus Actual Cash Costs

The general valuation or costing procedure involves two steps: first future annual operating costs for a particular resource alternative are estimated; these are then discounted to their present values. Sometimes the present value is "levelized" or annuitized to produce a levelized kWh cost. The process and the mathematics are quite straightforward but utility planners in the US, and perhaps elsewhere, needlessly complicate things by working in revenue requirements which are arcane enough to cause anyone's eyes to glaze over. While this insures continued job security for planners (and their complicated revenue requirements models), it means that their analyses receive little meaningful outside review. Policy level managers lack the time, expertise or inclination to get into the thicket which means that some of the firm's most important decisions are made on the basis of black-box output that few truly understand.

Fortunately alternatives exist. Rather than modeling the complexities of regulated revenue requirements, most of which do not affect present value,[30] it is much simpler to work in actual cash flows. So doing reduces a complex revenue-requirements spreadsheet to about four lines. Why is this important? It means that managers not familiar with the intricacies of revenue requirement analysis can gain some intelligence about the **real** costs for a particular resource alternative. Using the cash flow approach, the present value cost of a capacity addition can be written as:

$$\text{Present Value Cost} = \text{PVC} = (\text{IO} - \text{ITC}) - (\text{PVTD} \times \tau) + (\text{PVOC} \times (1- \tau)) \qquad (1)$$

Where:

IO is the initial capital outlay,
ITC is the investment tax credit, if any,
PVTD is the present value of the yearly tax depreciation allowances,
τ is the firm's marginal tax rate and,
PVOC is the present value of annual operating costs (fuel, O&M, property taxes and insurance).

[30] For example, the cash flows to equity and debt investors, discounted at the WACC, yields a present value equal to the initial project outlays. Revenue requirements models needlessly complicate matters by including annual debt payments, depreciation recovery and earnings when these can be replaced by a single value— the initial project outlay.

In order for the PVC to have any economic interpretation, PVTD and PVOC must be obtained using the correct market-based discount rate. If this is done, then the PVC is the cost that would be incurred by any entity to produce the electricity. Now, if desired, a simple transformation can be made to convert costs to present value revenue requirement:[31]

$$PVRR = PVC / (1 - \tau) \qquad (2)$$

where:

PVRR is the present value revenue requirement and,
PVC are the present value costs estimated in equation (1).

The PVRR is the **price** of the electricity produced. The distinction between cost and price is quite basic, but the two are frequently confused because planners do not understand whether their analysis produces a cost or a price.[32]

An Illustration

Let's illustrate these ideas with two examples that contrast the engineering approach with the finance approach to valuation, with option values ignored. The first involves a 200 mW combined cycle unit recently proposed in the northeast US; the second, a 50 mW photovoltaic project in Lualualei, Hawaii, where the state offers a 40% investment tax credit for PV.[33] Table 1 gives the estimated costs and economic assumptions for each project. Table 2 shows the computations using WACC-based as well as market-based discounting.[34] The first block shows the capital costs beginning with the initial outlay and the tax credits (IO - ITC in equation (1)) followed by the present value of the depreciation

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[31] It is not possible to fully show the equivalence between a simple cash flow approach (which seemingly ignores such items as depreciation recovery, tax and interest payments) and the more complex revenue-requirements method. A demonstration of this is given in IREC, 1996; see also EPRI [1990, Chapter 9]. A rigorous proof is given in Tardiff and Bidwell, 1990].

[32] For example, planners sometimes improperly compare a value derived using EPRI-TAG, which yields a **price** (i.e., revenue requirement) to an avoided cost.

[33] The value of this investment tax credit does not begin to approach the likely savings in societal environmental externality costs, which are in the range of $7,000 per kW [Awerbuch, 1993c].

[34] A fuller discussion of discount rate estimation can be found in [IREC, 1996].

shelter (PVTD × τ).[35] The market-based approach, which values (discounts) depreciation tax shelters at the riskless rate, yields larger present values for these than the traditional approach which discounts all cash flows at the WACC.[36]

Subtracting the depreciation tax shelter from the net outlay yields the Net Post-Tax Outlays. Note that the WACC-based approach overstates this post-tax outlay for both projects, although the bias is considerably worse in the case of PV, where the WACC estimate ($1191) overstates the market-based outlay ($872) by 36%. Indeed this is one of the ways in which engineering-based cost models bias against *any* capital intensive technology, whether a computer or a PV-module. And since most new process innovations tend to be capital-intensive, the process invariably biases against *any* innovation.

Next the table shows the present values for the after-tax operating costs, (PVOC × (1 – τ) in equation (1); present value computations are not shown). These are divided into two groups— the debt-equivalent group and the cyclical group. Debt-equivalents are those outlays that represent fixed, debt-like obligations such as property taxes, fixed O&M and land leases. Recipients of these obligations would value them much the same way they do the firm's debt with a required rate of return or discount rate equal to the after-tax cost of debt (Box 2).[37] Fuel costs are also included in the debt-equivalents group because projected fuel prices in the example are based on a long-term contract, which in essence is a fixed obligation. Different discounting might be appropriate for fuel purchased on the spot-market.

Note that the WACC-based present values for this group of operating costs understate the market-based present values by approximately half, with the most significant dollar error coming from the estimated present value of the fixed fuel contract. (In the case of the PV, the errors are not significant since the operating costs are small). By understating operating costs in this manner, engineering cost estimates further bias the comparison in favor of existing, expense-intensive technologies and against new, capital intensive ones.

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[35] Revenue requirements models do not compute the depreciation tax shelter explicitly. Rather, it is part of the yearly income tax computation.

[36] Depreciation tax shelters are riskless cash flows— almost like money in the bank— which will accrue to the firm as long as there is sufficient income to offset the deductions. They are therefore discounted at the (after-tax) riskless rate obtainable on US treasury obligations [see, for example EPRI, 1990, Chapter 9].

[37] The valuation of debt equivalents is discussed in: Brealey and Myers [1991, 473-474. It is not possible here to fully discuss the theory relating to discount rate estimation for cash outflows. This is discussed in: Awerbuch [1993a, 1995a, 1995b], Copeland and Weston [1988, 414-419] Seitz [1990, Appendix 11-A].

The last block of Table 2 shows the kWh cost estimation. The total present value costs is annuitized or levelized using the WACC (8.8% in this case).[38] The WACC-based cost estimate for the combined-cycle unit is \$0.034 per kWh, a 32% understatement of the market-based estimate of \$0.054. In the case of PV, the WACC-estimated cost overstates the correct market-based estimate (\$0.044) by 46%.[39] Finally, the costs are transformed to a revenue requirement per equation (2). The important point of the illustration is that the WACC-based approach incorrectly implies that the combined-cycle unit is cheaper when the opposite conclusion is indicated by a proper market-based analysis. Finally, all the estimates ignore overheads or any embedded options the two technologies may provide.

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[38] The WACC is appropriate for levelization; for proof see EPRI [1990]. This is the only appropriate use for the WACC in performing cost estimates.

[39] The attractive kWh cost estimates for PV-based electricity in Hawaii are to some extent the result of generous investment tax credits. Absent this credit the risk-adjusted PV generating cost is \$0.139 per kWh.

Box 1
Present Value of MACRS Depreciation Tax Shelter per kW of Capacity

I. Combined Cycle

Year	MACRS Allowance	Tax Depreciation	Tax Shelter
1	0.0875	$60.73	$24.29
2	0.0913	$63.36	$25.34
3	0.0821	$56.98	$22.79
4	0.0739	$51.29	$20.51
5	0.0665	$46.15	$18.46
6	0.0599	$41.57	$16.63
7	0.0590	$40.95	$16.38
8	0.0591	$41.02	$16.41
9	0.0590	$40.95	$16.38
10	0.0591	$41.02	$16.41
11	0.0590	$40.95	$16.38
12	0.0591	$41.02	$16.41
13	0.0590	$40.95	$16.38
14	0.0591	$41.02	$16.41
15	0.0509	$35.32	$14.13
16	0.0155	$10.76	$ 4.30
SUMS	1.0000	$694.0	$277.60
		WACC Present Value	**$149**
		Riskless Present Value	**$229**

II. Photovoltaics

Year	MACRS Allowance	Tax Depreciation	Tax Shelter
1	0.2000	$914	$366
2	0.3200	$1,462	$585
3	0.1920	$877	$351
4	0.1152	$526	$211
5	0.1152	$526	$211
6	0.0576	$263	$105
SUMS	1.0000	$4,570[a/]	$1,828
		WACC Present Value	**$1,455**
		Riskless Present Value	**$1,774**

a. Depreciable basis is the initial outlay ($4,810 per kW) reduced by 50% of the federal energy credit ($240).

Box 2
Discount Rate Estimates for Valuing PV and Combined Cycle

I. Recent Market Rates

Single-A Utility Bond Yield:	7.0%
Long-Term US Government Bond Yield:	6.0%

II. Nominal Discount Rates

	Pre-Tax	Post-Tax[b]
Riskless Rate (for depreciation tax shelters)	4.5%[a]	**2.7%**
Cost of Debt (for fuel and fixed O&M)	7.0%	**4.2%**
Cyclical Discount Rate (for variable O&M)	10.0%	**6.0%**
WACC		**8.8%**

a. US Government Bond yield less 1.5% term premium
b. Post-tax discount rate = pre-tax rate × (1 - tax rate)

Table 1

Input Data
200 mW Combined Cycle and 50 mW Photovoltaic

Economic Assumptions:

Marginal Corporate Tax Rate:	0.40
Inflation Rate	0.04

Cost Inputs:

	Combined Cycle	Photovoltaic
Project Useful Life (Years):	30	30
MACRS Tax Life (Years)	15	5[a]
Cost per kW	$ 694	$4,810
First year Fuel Cost per kWh:	$ 0.0248	---
Fixed O&M per kW:	$14.40	$3.25
Variable O&M per kWh	$0.0043	$0.0021
Land Lease/kW	--	$0.88
Annual Output-- kWh/kW	4,818	2,155
Capacity Factor	0.550	0.246
Heat Rate(BTU/kWh):	7,514	--
Federal Tax Credit	-----	0.10
State Tax Credit	-----	0.35

a. Assumes non-utility investor.

Table 2

Estimated Cost and Revenue Requirement per kWh

Combined Cycle and Photovoltaic Generation

Present Value Post-Tax Costs per kW	**Combined Cycle**		**Photovoltaics**	
	WACC	**Market-Based**	**WACC**	**Market-Based**
Capital Costs				
Initial Outlay	$694	$694	$4,810	$4,810
Less: Immediate Tax Credit	$0	$0	($2,165)	($2,165)
Net Outlay	$694	$694	$2,646	$2,646
Present Value Depreciation Shield	($149)	($229)	($1,455)	($1,774)
Net Post-Tax Outlay	$545	$465	$1,191	$872
Debt-Equivalent Outflows				
Property Tax	$85	$154	$1	$3
Fixed O&M	$134	$242	$26	$52
Land Lease	$0	$0	$7	$14
Fuel Costs (Long-Term Contract) per kW	$763	$1,589	$0	$0
Cyclical Outflows				
Variable O&M	$190	$267	$37	$51
Total Present Value Cost/kW	$1,717	$2,718	$1,262	$992
Levelization Rate	*8.8%*	*8.8%*	*8.8%*	*8.8%*
Levelized Charge	$164	$260	$121	$95
Hours per Year	4,818	4,818	2,155	2,155
Levelized Cost per kWh	**$0.034**	**$0.054**	**$0.056**	**$0.044**
Revenue Requirements: $/kWh	***$0.057***	***$0.090***	***$0.093***	***$0.073***