CHAPTER 1:
A RISK-ADJUSTED APPROACH TO ESTIMATING THE COST OF ELECTRICITY FROM FOSSIL AND RENEWABLE SOURCES

Cost-of-electricity estimates for various generating technologies are widely used in policymaking and in regulation. Managers and public policy makers want a simple means of determining what it will cost to generate a kilowatt-hour (kWh) of electricity using, for example, a wind turbine, over the next 20 years, as compared to generating a kWh of electricity using a combined-cycle gas turbine. Such information helps governments shape various tax incentive and R&D policy and other measures. In traditionally regulated jurisdictions, such comparisons help utilities and regulators establish investment plans under so-called "least cost" or Integrated Resource Planning (IRP) procedures that are used in many countries. These procedures presume that if every new capacity addition is chosen through a "least cost" competition, then the resulting total generation mix will also be "least cost."

This book introduces an investment-oriented approach to estimating the cost-of-electricity (COE) for energy resource options. This approach includes two important considerations that affect the COE: market risk and the effect of income taxes. Market risk deals with the variability of the operating and capital cost streams associated with each generating technology. For example, fuel outlays for a fossil-based project are riskier than the outlays for fixed maintenance. Technologies that require large fossil fuel outlays hence create a risk cost that must be borne by either the producer or its customers.

Similarly, taxes affect the ultimate cost of electricity in a number of ways, principally, because operating outlays as well as depreciation allowances are subtracted from revenue thereby reducing the producer's taxable income as discussed in greater detail subsequently. Taxable income is the basis for computing the tax liability, which producers must ultimately recover through the prices they charge for electricity.[1]

Because they include the effects of both market risk and taxes, the COE estimates in this book are more meaningful. They also differ from traditional engineering-economics based cost estimates.[2] Typically, such procedures ignore both risk and taxes. Their cost-of-electricity estimates are predicated purely on the nominal accounting or engineering costs of the alternative resource options. The market-based approach produces cost estimates as they appear to private, for-profit, taxable, electricity generators and their customers and hence provide a meaningful basis for

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[1] Taxes also affect investors' net rates of return, which means that discount rates must be adjusted accordingly.

[2] For further discussion of traditional engineering-oriented electricity cost models see Kreith and West (eds.), 1988. While some engineering-economics models reflect tax effect, their treatment of depreciation is not precise enough to support proper comparisons between capital-intensive technologies such as renewables and more conventional expense-intensive technologies such as fossil.

policy-making. Engineering-oriented estimates, by contrast, have no economic interpretation: i.e. engineering-based cost rankings will not necessarily reflect the after-tax rankings of alternative technologies when the opportunity cost of capital is reflected.[3]

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Traditional, engineering-economics oriented cost models used in many countries were first conceived a century ago, and have been discarded in other industries[4] because of their bias towards lower-cost but riskier alternatives. This issue is discussed more fully in Chapter 2. In the case of electricity cost estimates, engineering models will almost always imply that fossil alternatives are more cost-effective, which is roughly analogous to telling investors that high-yielding junk bonds are categorically a better investment than lower yielding but lower-risk government bonds.

Engineering cost models work reasonably well in an environment characterized by technological stasis and homogeneity– i.e., in a static technological environment where technology alternatives all have similar financial characteristics and a similar mix of operating and capital costs.[5] This environment held for most of the last century but no longer exists. Planners today can choose from a broad variety of resources options that ranges from traditional, risky fossil alternatives to low-risk, passive, capital-intensive renewables with virtually no operating cost risk.

The model presented in this book, represents a *financial economics* approach to valuation, which differs from widely used traditional engineering-economics approaches. The engineering approach produces relies on arbitrary discount rates or a range of rates to produce present value estimates. The results have no economic interpretation. Finance theory uses the term *present value* in a market-oriented sense: it represents the *market value* of a future stream of benefits or costs. Thus the present value for a 20-year stream of fuel outlays is the price at which a contract for those

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[3] Arguably, however, this does not imply that engineering costs estimates contain no information content. For example, accounting rates of return have no economic interpretation (e.g. see Franklin M. Fisher and J. J. McGowan "Accounting Rates of Return," *American Economic Review*, 1986** although a significant body of research suggests that it is not devoid of information content, i.e.: investors know how to interpret it (see: S. Awerbuch "Note: Accounting Rates of Return," *American Economic Review*, Volume 78, No. 3 (June) 1988, 581-587.

[4] They were discarded by US manufacturers primarily on the basis of hindsight: i.e. only after global competitive pressures, beginning in the 1970s, clearly exposed their inability to reflect the costs savings— by then obvious— of CIM and other innovative, capital-intensive process technologies. In prior decades, when American manufacturers still enjoyed a relatively greater level of global market power, they were more complacent and willing to rely on inappropriate investment valuation procedures.

[5] S. Awerbuch, "The Surprising Role of Risk and Discount Rates in Utility Integrated-Resource Planning," ***The Electricity Journal***, Vol. 6, No. 3, (April) 1993, 20-33.

purchases would trade if a market for such contracts existed. Engineering results have no such economic interpretation.

A note on Options-Based-Valuation

The most important criticism of any cost estimate based on discounted cash flows— this includes the risk-adjusted estimates of this book— may be its inability to deal with "optionality." By its nature, the COE estimate does not reflect valuable managerial options that may present themselves to project owners over time as further discussed in Chapter 2. The presence of such options in today's competitive energy markets affects the value of renewable energy technologies (RETs) as well as conventional technologies. For example, when spot gas prices rise, the owners of independent gas-fired generating plants may be able to reduce electricity production and profitably sell their contract gas supplies to others. Similarly, if peak electricity system demand and resulting high electric prices are linked to periods of high insolation[6] (or reliable winds)— as has been shown to be the case in many parts of the US— then photovoltaics or wind energy converters may create valuable options to exploit such markets.

Such possibilities, widely referred to as *real options* in today's literature, cannot easily be accommodated in a discounted cash flow approach.[7] More importantly, perhaps, options valuation requires a major change in the analytic focus from the current emphasis on cost-of-electricity to project *net present value* (NPV). NPV assessment for energy alternatives can enrich the decision-support criteria for policy-making, but it is unclear whether it can entirely replace the cost framework: although NPV valuation makes sense for investors trying to assess alternative technologies, it does not necessarily reflect the interests of customers in oligopoly markets.

Investors want to maximize profit, which is synonymous with maximizing NPV. This is usually consistent with welfare maximization goals, although in the case of electricity, welfare maximization is more generally synonymous with minimizing

[6] Meaning the incidence of sunshine;

[7] In some cases they can be studied using Monte Carlo and other simulation methods; see for example: Julia Frayer and Nazli Uludere, "What is it worth? Application of real options theory to the valutaion of generation assets", *The Electricity Journal*, Volume 14, Issue 8, (October) 2001, 40-51. The option value of renewables and other distributed is given in: Thomas E. Hoff, (1998) "Using Distributed Resources to Manage Risks Caused by Demand Uncertainty," *Energy Journal,* Special Issue/Distributed Resources, Vol. 21 (February) pp. 63-84; other papers by Hoff relating to modularity and flexibility in resource valuation can be found at: www.clean-power.com/

(risk-adjusted) electricity costs.[8] Hence a policy-making emphasis on electricity cost— not NPV— makes considerable sense.

Finally, the options framework is not sufficiently developed to produce fully developed options-based valuation. In many cases the embedded options cannot be specified, let alone measured (e.g. see Richard DeNeufville, ****)

Cost Measurement

The planners and analysts who generate cost-of electricity (COE) estimates do not spend much time thinking about their methods, which may even seem obvious to them. But cost measurement in most settings is neither simple nor obvious. We are used to familiar, traditional cost concepts such as cost/mile for automobile ownership and generally do not think about how they work and how they affect decision-making. This often means that inappropriate costing techniques linger even when new technologies and ways of doing things diminishes their ability to properly reflect cost and cost-causation. Manufacturers discovered this problem in the 1970's, when radically new technologies and processes challenged existing mass-production paradigms and the "cost/unit" measures that were developed to provide managerial information within the mass-production context a half-century earlier began to fail. This is further discussed in Chapter 2.

Public (and corporate) policies and decisions emerge directly from the cost measures we conceive. These measures significantly influence how we view and value energy alternatives.[9] The principal message of this book is that risk differentials affect COE estimates in a powerful way. A second message is that reliance on direct unit cost measures similar to the cost-of electricity, led to the near-collapse of other industries. Policy makers in both private and public sectors may therefore want to consider placing more emphasis on other "intangible" measures of a particular generating technology's costs. It may turn out, as it did with manufacturing technologies, that today's so-called intangibles, become the central cost drivers in tomorrow's environment.

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[8] This assumes electricity is sold on a kWh basis, and that there are no new customer driven products that consumers may value more than the underlying kWh.

[9] An example is the widely used *busbar* cost concept, discussed in Chapter 2, which represents the *direct* unit cost of delivering a kilowatt-hour of electricity to the busbar– the inter-connection point between the generating unit and the grid. The busbar measure ignores overheads and is hence biased in favor of technologies with low *direct* costs, independent of how much overhead cost they consume. In spite of these significant limitations, the busbar cost is widely used, although few recognize that it does not represent the total cost of producing electricity, let alone delivering it. For further discussion see Amory Lovins "Small is Proiftable," ****, and Walt Patterson, Keeping the Lights on, Royal Institute for International Affairs, www.****.

Indeed based on the experience of the manufacturing sector 30 years ago and the voluminous literature that has evolved, it is arguable that the attributes of modular, distributed RETs and fossil-fired technologies properly understood and exploited, undoubtedly could form the basis for re-engineering the electricity production and delivery process to create a vast new array of energy efficiencies and cost reductions. The challenge is to learn how to value the new benefits of modularity and flexibility that these new distributed renewable and conventionally-fired generating technologies offer.

The Nature of Risk

The cost-of-electricity estimates in this book are adjusted for market risk and for taxes, which distinguishes them from traditional, engineering-oriented estimates. This section overviews the way in which risk affects electricity cost estimates. The effects of taxes are discussed subsequently in this chapter. Risk and taxes are discussed in greater depth in Chapters 3, 4 and 5.

Market risk is a cost— just like any other cost— that must be borne by electricity producers and their customers. Market risk can be quantitatively measured and included in electricity cost comparison models. The finance concept of risk is well understood by investors, although not as it relates to renewable energy technologies. Energy planners and policy makers, on the other hand, tend to understand renewables, but do not understand the important risk concepts that differentiate them from fossil alternatives. Any projected cost stream associated with a particular electricity resource contains some degree of risk. While projected fossil fuel outlays clearly present the greatest risk, other cost streams, such as projected labor costs associated with O&M outlays also carry an element of risk. Compared to traditional evaluation methods, the inclusion of risk tends to raise the electricity cost estimate for conventional technologies whose principal cost inputs are risky fuel and maintenance streams.

By contrast, the cost outlays in the case of capital intensive technologies such as wind, PV, and, to a lesser extent, other RETs, are largely "sunk,"[10] which makes them "systematically riskless," or nearly so, in a finance sense. More precisely, we can say that the asset betas of capital-intensive renewables are close to zero. The maintenance costs of RETs are just as risky as those of fossil technologies, but they are generally so small that they contribute little to overall project risk. The risk-adjusted market-based estimates presented later in this Chapter reflect the risk of all projected cost streams for all technologies, including the relatively "safe" expected tax savings produced by depreciation tax allowances. By ignoring such risk differentials among technologies, traditional analyses tend to incorrectly *overstate* the costs of RETs.

[10] This term is used in the common sense, although it is not technically correct since at least some of these costs can be recovered by dismantling and selling the assets.

Risky Cost Streams

In the context of energy projects, financial risk can be defined as the periodic (e.g. month-to-month or year-to-year) variability in the level of a particular operating cost stream or outlay.[11] Variability is measured by the standard deviation of the periodic costs. "Risky" costs, for example, such as spot-based outlays for natural gas, will exhibit a monthly or yearly pattern that is widely scattered around the mean or *expected value.* Relatively "safe" cost streams, such as fixed maintenance outlays or the interest payments on long-term-debt do not fluctuate much from one time period to the next. They will therefore cluster more closely around the expected value in each time period.

All else being equal, investors prefer "safe" outlays over a risky ones.[12] For example, investors would rather obligate themselves to making a fixed $100 monthly payment over a risky payment that also averages $100, but might be $50 one month and $150 the next. They prefer the "safe" stream to the risky one. Euro-for-Euro (and dollar-for-dollar), "safe" cost streams are more desirable and hence have lower negative present values.[13] Under an engineering approach, *risky* annual cost streams have the same present value as an equivalent but *safe* cost stream. This violates fundamental finance theory and distorts utility investment and purchase decisions.

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[11] Although there is a second aspect of risk, introduced subsequently, which deals with the cost stream's covariance with project revenues, or with returns to a broadly diversified asset portfolio.

[12] This is the Mean-Variance Hypothesis (e.g. see: Richard Brealey and Stewart Myers, McGraw Hill, 1991 or any finance textbook), which says that given two streams with equal means, investors will prefer the one with the smaller variance or standard deviation. In the case of inflows, or positive cash flows, this means that safe streams have a *higher* present value— e.g. an expected income stream of €100/month from a government bond is worth more than a promised payment of €100 /month from a risky low-grade "junk" bond. In the case of cash outflows— i.e. negative cash flows— the valuation seems reversed but is actually not: safe outflows have *lower,* absolute (i.e. smaller negative) present value.

[13] "Safe" cost streams are therefore discounted at a higher rate, consistent with capital market theory and the Capital Asset Pricing Model (CAPM). This leads to consistent, symmetric valuation required by finance theory. In perfect markets, the value of a cash flow stream is invariant with the payer or recipient; both must value it at the same discount rate. Given perfect information, both payer and recipient will use the same discount rate to value the payment stream.
It can readily be shown that under ordinary conditions, any "safe" cost outlay for the paying entity will become a risky inflow to the recipient. This is illustrated subsequently in this Chapter and in Chapter 3. The familiar maxim therefore holds: risky investment returns or *income* streams, which are "safe" to the paying entity, are discounted at higher rates. For additional discussion, see S. Awerbuch, "Market-Based IRP: It's Easy!!!," *The Electricity Journal*, Vol. 8, No. 3 (April) 1995, 50-67.

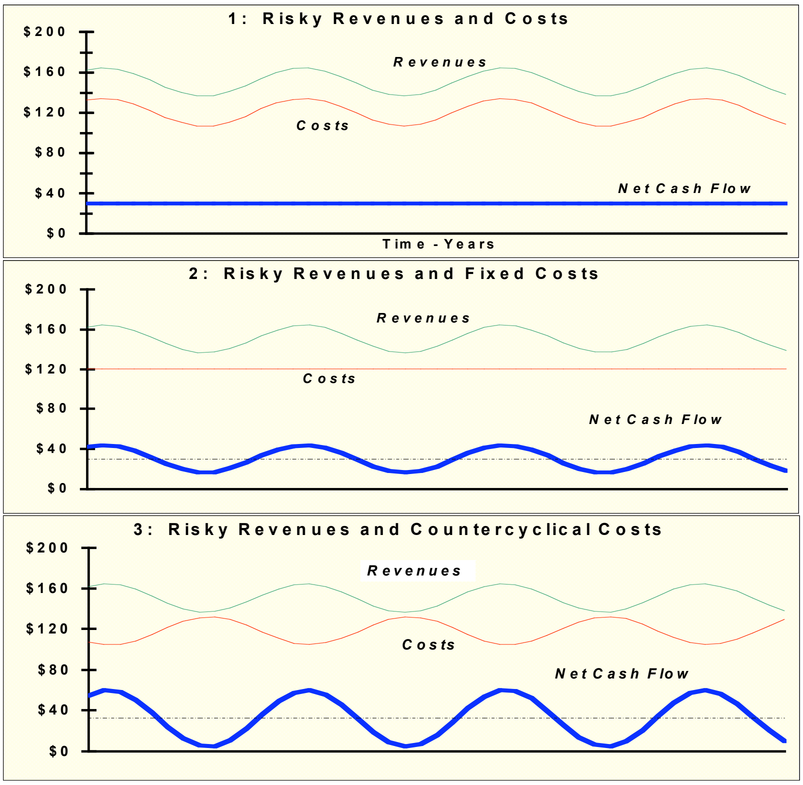
This intuition— that a risky cost stream is less desirable— seems to be widely understood. Homebuyers in the US, for example, overwhelmingly choose mortgage loans whose interest rates are fixed over the life of the loan,[14] even though adjustable rate loans carry initially lower interest rates. The fixed rate loan provides a monthly payment stream that is constant over the life of the loan, as compared to an adjustable rate loan, whose payments could vary month-to-month as interest rates change. Borrowers prefer the fixed payment stream; according to their assessment therefore, it has a lower present value and thus is more desirable.

The valuation that mortgage borrowers all investors and make can be better understood by clarifying risk further: risk involves not just the degree of variability, but also the extent to which the cost stream co-varies *systematically* with revenues. More properly, where the assumption of diversification holds, the covariance is measured against returns to a broadly diversified asset portfolio.[15] This measure of risk, called *systematic risk,* is the basis for asset valuation. Cost streams that move (i.e. co-vary) *positively* with revenues or with returns to a broad market portfolio are less risky than those that move in the opposite direction. Cost streams that move in unison with revenues are "safe" in the sense that they fall when revenues fall and hence produce a more constant, low-risk set of profits or returns. Cost streams that rise at a time when revenues are falling are riskier in the sense that they have a more detrimental affect on investors and individuals. Figure 1.

[14] In the early 1990's, about 80% of residential mortgages were fixed rate, as opposed to adjustable-rate. In 1992, fixed-rate loans carried an effective interest rate of 8.5% as compared to 6.6% for Adjustable Rate Mortgages (ARM's); Source: *Survey of Mortgage Lending Activity,* DC: US Department of Housing and Urban Development, and, *Mortgage Bankers Association of America.* This trend continues, with the fixed-rate mortgage accounting for "over 90%" mortgage lending", [Chief Economist David Seiders, *National Association of Home Builders News*, November 9, 2001.] In February 2002, fixed-rate loans carried an effective interest rate of 6.8% as compared to 5% for ARMs (source: Freddie Mac Weekly Survey of Commitment Rate And Points, Weekly Releases, 2002).

[15] This book uses the *Morgan Stanley (MSCI) Europe Index* as a measure of portfolio risk. An equivalent US-based market risk index is the *S&P 500*.

Figure 1-1
Costs that co-move with Revenues reduce project risk. Costs that are fixed or move opposite revenues raise project risk.



Mortgage loans provide an intuitive illustration. Let's assume an ordinary fixed rate mortgage carries a rate of 8%. Both borrower and lender use this rate to value the monthly payment stream— in their estimation the present value of the monthly payments is equal to the loan proceeds. If that were not so, the loan would not be concluded. The 8% return or discount rate on the loan compensates the lender for the risks it undertakes– i.e.: some of its loans will go into default.

Now suppose the lender offers a new product— a loan whose monthly payments can be reduced temporarily if the borrower becomes unemployed or ill, and will be raised later when income rises. This type of loan reduces the borrower's risk— if income falls, the loan payments will be temporarily lowered and the shortfall recovered when income rises again. The borrower will prefer such a loan– average or *expected* payments will be the same as the fixed rate loan, but the loan is "safer" in the sense that its payment stream moves in unison with income.[16] Let's assume the lender charges 10% interest, an extra 2 points, for this flexible loan, and that the borrower is willing to pay.

In making this judgement, the borrower implicitly values the flexible loan at the higher 10% discount rate. The borrower applies a higher 10% discount to a flexible, "safer" payment stream that better tracks income. To the borrower, this is comparable to insurance. In the event that income falls during bad economic times, the loan payment will be reduced as well. And what about the lender? The lender values the higher monthly stream at 10% also. The return on the loan is now higher, but the risk for an income-tracking loan is greater as well since interest income will fall during bad economic times. So a variable payment stream that tracks overall economic movement reduces risk for the borrower and increases risk for the lender. Both use the same higher 10% discount rate to value the flexible stream as compared to the 8% they used for the fixed stream.

Risky Cost Streams and Market Value

Fossil fuel is an example of a high-risk cost stream. Fuel prices fluctuate unpredictably over time, but, more importantly, they do so in a *negative* systematic manner relative to the economy and to the returns on other assets (Figre 1 – Panel 3). This negative relationship between economic activity and fossil prices is widely recognized,[17] and is further discussed in Chapter 3. This important relationship has significant implications for both electricity cost estimation and for energy security. These have gone largely unnoticed.

Other cost-streams are less risky. Fixed maintenance and various contractual obligations fluctuate less on a periodic basis (and also exhibit less systematic variation). Their risk is similar to the risk of the firm's long-term interest payment. Indeed, by convention, fixed maintenance and contractual obligations can be considered "debt-equivalents," which are discounted at the firm's post-tax cost of debt.[18] Capital-intensive renewables, such as photovoltaics and wind turbines, exhibit low systematic risk— we have referred to them as essentially zero beta assets— because their costs are almost entirely in the form of up-front capital outlays and their yearly operating costs are small and predominantly fixed.

The *financial economics* approach uses the term *present value* in a market-oriented sense: it represents the *market value* of a future stream of benefits or costs. The present value for a 20-year stream of fuel outlays is the price at which a contract for those purchases would trade if a market for such contracts existed. Where such

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[16] i.e. the covariance of the payments with income is positive.

[17] e.g. see Awerbuch and Sauter, "Exploiting the Oil-GDP Effect to Support Renewables Deployment," *SPRU Working Paper* _____, December 2004.

[18] e.g. see Richard Brealey and Stewart Myers, *Principles of Corporate Finance*, McGraw Hill, 1991.

markets do not exist, estimating the present value of a particular cash flow stream entails estimating its market-based discount rate. At least one utility has taken a more novel and direct approach to estimating fuel price risk. Xcel Corporation requires its fossil-based electricity suppliers to provide a long-term— at least 10 years— fixed price quote for electricity delivery. (Box 1-2) It has thereby pushed the estimation problems up to its suppliers, and has in the process created for itself an opportunity no utility has had before: it can look at two long-term price proposals, one wind-based and the other gas-based, and evaluate the relative attractiveness directly on the basis of the quoted price.

BOX 1- _: Properly Comparing Risk-free Renewables to Fossil Alternatives:
Xcel Energy

In July 2001, Xcel Energy, an American investor-owned utility, proposed a competitive bidding process designed to provide for unbiased treatment of all generation types. Excel recognized that renewables should be credited for the fuel price certainty they bring to a utility's portfolio and should not be penalized for their operating characteristics. To properly account for the fuel price risk of gas-fired generators, Xcel requires bidders who submit fuel-indexed price proposals to also submit an otherwise identical proposal with fixed fuel pricing for at least 10 years.[1]

1. *Wind Energy Weekly*, Vol. 20, No. 955, 27 July 2001.

Implications for Energy Security and the Economy

Energy security, an important, reemerging issue, is not well understood quantitatively. There are two important aspects of energy security: fuel supply disruption and fuel price volatility. The threat of fuel supply disruption is widely recognized as a security issue, as are the diplomatic and military reasons to it. Fuel price volatility, on the other hand, is more subtle and less well understood quantitatively as a security issue, even though fuel price volatility may well have more profound implications for economic performance than temporary supply disruptions (Awerbuch and Berger, 2003). The effect of fossil fuel on economic performance needs to be explicitly recognized for its importance as an aspect of energy security. Chapter 7 presents a portfolio-based approach that addresses energy security.

Why should policy makers concern themselves more with fossil price volatility? Is price volatility not a part of any commodity market? A substantial body of evidence indicates that when fuel prices rise, economies decline (e.g. see Awerbuch and Sauter 2004).[19] This produces the worst possible set of circumstances for energy consumers since fuel costs will tend to be relatively high during bad economic times. High fuel prices thus tend to hit consumers when they are already feeling recessionary pressures— low incomes, layoffs, and depressed home values and pressure on savings— thereby exacerbating their economic situation. Fossil price risk has a greater impact on national income than other risky commodity prices.

Energy is a basic input to the economies of fossil consuming nations. The real risk of volatile energy prices is not simply that they are unpredictable, but that they cause

[19] This is further discussed in Chapter 3.

severe economic dislocations. The effect becomes newsworthy and politically important only when energy prices "spike" significantly, as has happened recently and at least three other times in the last quarter century. The negative effect does not go away in between the spikes, when energy costs are less noticeable. Those "quiet" periods are marked by political and general indifference to fossil prices. However, even during the "quiet" periods when energy price fluctuations are smaller and not a constant topic of conversation, they still produce a statistically measurable negative impact on economic activity. This statistical co-variance is estimated and discussed further in Chapter 6.

How Taxes Affect Cost-of-electricity Estimates

Taxes affect all investment costs. A projected $1000 outlay for fuel or maintenance by a firm in a marginal 40% tax bracket will effectively reduce income by $600 on an after-tax basis since the outlay is "expensed" or subtracted from taxable income. Only the after-tax operating cost– $600 in this case– is relevant for electricity cost estimation.

In addition to reducing incremental operating costs, taxes also affect capital outlays through the depreciation mechanism, the process by which a prescribed portion of the total investment outlay is deducted from income each year over a given period as permitted by the tax codes. For example, where the tax code specifies a 10-year, straight-line depreciation recovery, a firm that installs a $10 million gas turbine will subtract $1.0 million annually from its taxable income for 10 years. If the firm is in the marginal 40% tax bracket, this depreciation allowance will create an annual tax reduction of $1.0 million × 40% = $400,000. Meaningful cost estimates must reflect the investment outlays as reduced by the depreciation tax shelters. Tax mechanisms clearly have a pronounced effect on threshold investment decisions and on the estimated cost of electricity produced.

Because depreciation affects capital-intensive technologies more, the inclusion of taxes in the analysis reduces the risk-adjusted costs of capital-intensive RETs as compared to traditional estimates, and as compared to conventional technologies. The most significant operating risk for capital-intensive RETs is recovery of depreciation tax shelters or other capital grants. Some engineering approaches approximate tax effects[20] although they usually do not fully explicitly reflect tax depreciation. This may be acceptable for comparisons involving homogeneous fossil technologies, where capital costs and hence depreciation effects are small. When the comparisons involve capital-intensive RETs, the tax depreciation must be treated in detail.

Another essential but little recognized issue is that EPRI-TAG and similar cost models that incorporate taxes, produce an output— widely called the busbar cost— that is not a *cost*, but is more properly interpreted as a tax-inclusive *price* since it reflects the so-called "gross-up" for income taxes created by the sale. This leads to

[20] e.g. Electric Power Research Institute, *Technology Assessment Guide* (EPRI-TAG) 1978 –** need full cite; see also Frank Kreith and Ronald West,. MIT Press – *op. cit.*

considerable confusion and serious errors when unit electricity "costs" are compared. The busbar measure is defined in Chapter 4.

Traditional COE estimates are based on the engineering (i.e. accounting) costs of material, equipment, labor and fuel, although tax-paying entities experience cost on an after-tax basis. This significantly affects the cost estimates because tax effects are not distributed uniformly across technologies as discussed above. Capital-intensive RETs benefit more from tax depreciation allowances. By ignoring taxes, therefore, engineering-oriented cost estimates are biased in favor of expense-intensive fossil-fired technologies.

Illustrative Risk-Adjusted Busbar Cost Estimates

Figure 1-2 shows a set of post-tax, risk-adjusted cost estimates for a range of fossil and renewable technologies. For reference, the market-based estimates are compared to the costs inputs used in IEA's WEO-2000, a highly regarded source of energy cost data.

The COE estimates of Figure 1-2 are empirically derived using the historic price risk for coal and natural gas. They are based on the idea that past fossil price fluctuations provide the best indication of fuel price risk over the next 30 years and. The empirical procedures are presented and illustrated in Chapter 5. Electric generators however, balance their spot market purchases with long-term contracts, although terms as long as 30 years, which corresponds to the life of the fossil assets, do not generally exist. As a counterpoint to the historic risk estimates, this section provides additional fossil COE estimates that assume the existence of long-term contracts.

The risk-adjusted COE estimates have a different interpretation than traditionally determined costs. The COE estimates can be interpreted as the fixed cost at which a contract for future delivery of electricity would trade given perfect markets. For example, Figure 1-2, which is based on recent historic fuel price risk, indicates that a *firm*, 30-year fixed contract for Gas-CC-generated electricity would trade for about 7 US cents per kWh.[21] This is not to say that future prices will materialize at this level. Rather, the current risk-adjusted 30-year COE estimate based on investor *expectations*. The investor expectations in Figure 1-2, in turn, are based on the historic risk of fuel and other costs. Figure 1-3 presents COE results that are based on different assumed risk conditions.

[21] Plus tax-gross-ups; actual contracts may contain various escape clauses and provisions for renegotiation which reduce risk and hence lower the fixed per-kWh price.

Figure 1-2
Risk-Adjusted Generating Cost and Tax-inclusive Price for Conventional and Renewable Technologies Using Historic Fossil Risk Estimates
(Source for Fig 1-2: "Base Case 2- final for graphs.XLS")

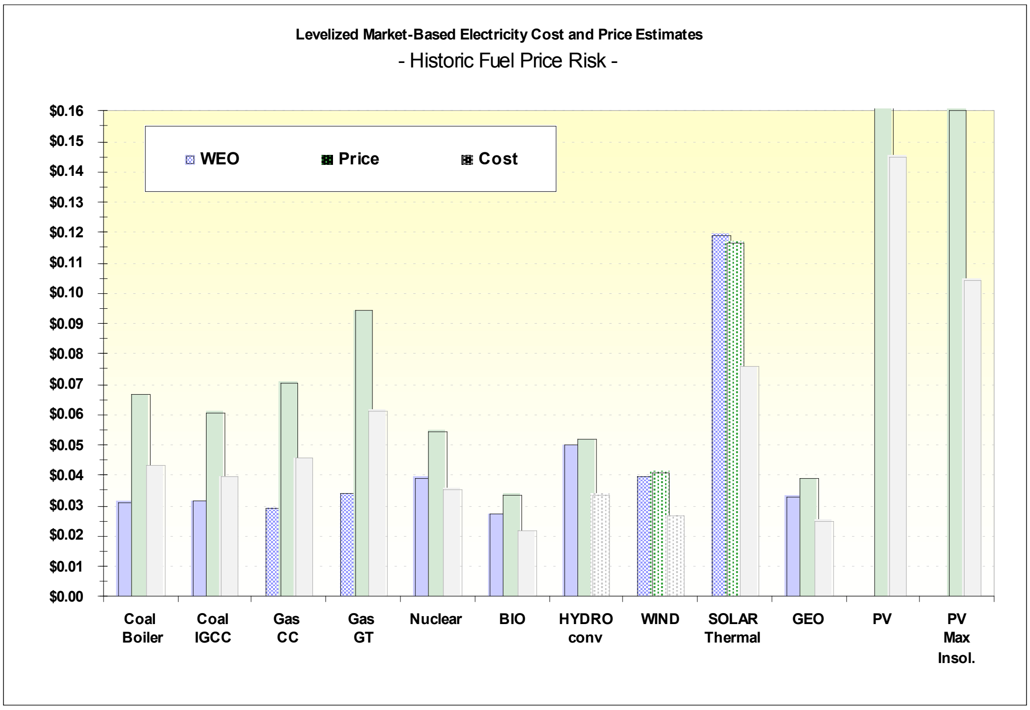

Figure 1-3
Risk-Adjusted Generating Cost and Price for Conventional and Renewable Technologies Using “Contract Fuel” Fossil Risk Estimates