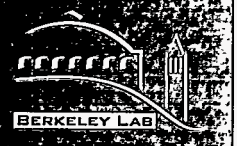
LBNL-39826
UC-1321



ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Financing Investments in Renewable Energy: The Role of Policy Design and Restructuring

Ryan Wiser and Steven Pickle
Environmental Energy Technologies Division

March 1997

LBNL-39826
UC-1321

Financing Investments in Renewable Energy: The Role of Policy Design and Restructuring

Ryan Wiser and Steven Pickle

Environmental Energy Technologies Division
Ernest Orlando Lawrence Berkeley National Laboratory
University of California
Berkeley, California 94720

March 1997

The work described in this study was supported by the Energy Foundation and by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Contents

Tables

Figures

Abstract

The costs of electric power projects utilizing renewable energy technologies are highly sensitive to financing terms. Consequently, as the electricity industry is restructured and new renewables policies are created, it is important for policymakers to consider the impacts of renewables policy design on project financing. This report describes the power plant financing process and provides insights to policymakers on the important nexus between renewables policy design and finance. A cash-flow model is used to estimate the impact of various financing variables on renewable energy costs. Past and current renewable energy policies are then evaluated to demonstrate the influence of policy design on the financing process and on financing costs. The possible impacts of electricity restructuring on power plant financing are discussed and key design issues are identified for three specific renewable energy programs being considered in the restructuring process: (1) surcharge-funded policies; (2) renewables portfolio standards; and (3) green marketing programs. Finally, several policies that are intended to directly reduce financing costs and barriers are analyzed. The authors find that one of the key reasons that renewables policies are not more effective is that project development and financing processes are frequently ignored or misunderstood when designing and implementing renewable energy incentives. A policy that is carefully designed can reduce renewable energy costs dramatically by providing revenue certainty that will, in turn, reduce financing risk premiums.

Acknowledgments

This report was supported by the Energy Foundation and by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. The authors would particularly like to thank Doug Ogden from the Energy Foundation and Diane Pirkey from the U.S. Department of Energy for their support of this work and for the valuable comments they provided on drafts of this report. In addition, we would like to thank the following people for providing information and assistance, and/or for reviewing drafts of this report. All remaining errors and omissions remain the responsibility of the authors.

Tom Austin
Regulatory Assistance Project

Robert DeBoer
Staff, Minnesota House of Representatives

John Elwood
University of California, Berkeley

Joe Eto
Lawrence Berkeley National Laboratory

Chuck Goldman
Lawrence Berkeley National Laboratory

Bill Golove
Lawrence Berkeley National Laboratory

Tom Hinrichs
Geothermal Energy Association

Ed Holt
Ed Holt and Associates

Ed Ing
Attorney-at-Law

Evan Jones
Lawrence Berkeley National Laboratory

Richard Kettle
U.K. Department of Trade and Industry

Suzie Kito
Lawrence Berkeley National Laboratory

George Lynch
U.S. Department of Energy

Meg Meal
MRW and Associates, Inc.

Lawrence Miles
The WindTurbine Company

Catherine Mitchell
Science Policy Research Unit, University of Sussex

Mac Moore
Solar Energy Industries Association

David Moskovitz
Regulatory Assistance Project

Kevin Porter
National Renewable Energy Laboratory

Karl Rabago
Environmental Defense Fund

Nancy Rader
American Wind Energy Association

Phil Reese
California Biomass Energy Alliance

Jim Spaeth
U.S. Department of Energy

Andy Vaudin
National Wind Power

Carl Weinberg
Weinberg Associates

Howard Wenger
Pacific Energy Group

Acronyms and Abbreviations

AMT	Alternative Minimum Tax
AWEA	American Wind Energy Association
CfD	Contract for Difference
CPUC	California Public Utilities Commission
DSCR	Debt Service Coverage Ratio
EDF	Environmental Defense Fund
EIA	Energy Information Administration
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
IRR	Internal Rate of Return
IRRC	Investor Responsibility Research Center
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-Hour
LUZ	Luz International Limited
MACRS	Modified Accelerated Cost Recovery System
mmbtu	Million British Thermal Units
MRPR	Minimum Renewables Purchase Requirement
MW	Megawatt
NFFO	Non-Fossil Fuel Obligation
NREL	National Renewable Energy Laboratory
NUG	Non-Utility Generator
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
RAP	Regulatory Assistance Project
RD&D	Research, Development, and Demonstration
REC	Renewable Energy Credit
REPI	Renewable Energy Production Incentive
RET	Renewable Energy Technology
ROE	Return on Equity
RPS	Renewables Portfolio Standard
SEGS	Solar Electric Generating System
SERI	Solar Energy Research Institute
U.S. DOE	United States Department of Energy

Executive Summary

The restructuring of the electricity industry and the introduction of retail competition is occurring throughout the world. As part of the restructuring process, a number of countries and several U.S. states are considering new mechanisms to promote the development and use of renewable energy technologies (RETs). Past experience with renewable energy commercialization policies, which have been enacted at state and national levels in the United States and abroad, has been mixed. While many U.S. policies have been successful in promoting renewables development, one of the key reasons policies have not been more effective is that the financing processes used in the private sector have often been ignored or misunderstood when designing RET incentives. Depending on their design, programs to support renewables can have positive or negative impacts on project financing and financing costs. The goals of this report are to describe the power plant financing process and to provide insights to policymakers on the important nexus between policy design and financing. We emphasize these interactions because creating a market for renewables requires a regulatory, political, and business climate that is conducive for investment. Armed with a better understanding of the relationships between policy design and financing and with concrete lessons from past policies, policymakers should be better prepared to design and implement new renewable energy programs within electricity restructuring efforts.

This report begins with a background to the renewable energy business development and financing process. Using a cash-flow model, we then estimate the impact of a number of financing variables on renewable energy costs. To demonstrate the influence of policy design on the financing process and on financing costs (and therefore on overall policy effectiveness), we then evaluate a number of past and current renewable energy policies. Experience with these policies provides lessons for the design and implementation of future RET programs. We then discuss the possible impacts of electricity restructuring on power plant financing and identify key issues that will have to be addressed in the design of three of the most popular approaches being considered for supporting renewables post-restructuring: (1) surcharge-funded policies; (2) renewables portfolio standards; and (3) green marketing programs. We also briefly analyze several policies that are intended to directly reduce financing costs and barriers. Nearly all of the chapters in this document are self contained and, because the report emphasizes policy case studies, some repetition is unavoidable. Therefore, readers are encouraged to approach the report somewhat like a reference document, focusing on those sections that are particularly relevant to their own interests.

The Renewable Energy Financing Process

There are two primary ways of financing a power plant: project financing and corporate financing. The renewable energy industry, and the non-utility generator (NUG) industry as a whole, has largely relied on project financing. In these arrangements, lenders look primarily

to the cash flow and assets of a specific project for repayment rather than to the assets or credit of the promoter of the facility. Long-term power purchase agreements that provide a relatively secure revenue stream have historically been necessary for project financing, especially for capital-intensive technologies such as renewables.

Financing is particularly important to renewables because RETs often have high capital costs. In addition, renewables are currently disadvantaged in the financing process *vis-à-vis* other generation technologies because of perceived resource and technology risks, small project size, and small industry size.

Impact of Financing on Project Costs: Wind Power and Photovoltaic Case Studies

To evaluate the impact of financing variables on overall project costs, a financial cash-flow model that closely replicates those used in the private power industry was created. The model tracks revenues, expenses, debt payments, and taxes over a 20-year period and estimates an after-tax, net equity cash flow. The model then calculates the 20-year levelized cost of electricity from the project being evaluated. The results of our analysis indicate how sensitive overall renewables costs are to financing inputs and confirm that the return on equity (ROE), debt interest rate, debt maturity, and capital structure all have a significant influence on levelized costs. For example, given our wind power and photovoltaic (PV) project input assumptions, a change in the ROE from 18% to 12% is estimated to reduce the 20-year levelized cost by approximately 22% for wind power and 18% for PV. Increasing the debt repayment period from 12 years to 20 years is shown to reduce wind power costs by 12% and PV costs by 17%.

Lessons from Current and Past Renewable Energy Policies

We demonstrate the impacts of policy design on renewable energy financing through five case studies of current and past renewable energy policies. These case studies also provide lessons for the design of future renewable energy programs. Table ES-1 briefly lists the case studies and the most pertinent lessons.

Impacts of Electricity Restructuring on Renewable Energy Financing

Electricity industry restructuring and retail competition promise to fundamentally change the financing of power projects in general and renewable energy projects in particular. In a restructured electric industry with retail competition, the long-term (20-30 year) power sales contracts that have traditionally facilitated project financing are likely to become increasingly scarce. To attract project financing in a restructured industry, power developers are likely

Table ES-1. An Overview of the Case Study Lessons

Case Study	Lessons
Tax policies and tax appetite	The effectiveness of tax incentive policies is reduced by limitations on the tax appetite of investors and by the alternative minimum tax (AMT). Partial AMT relief for RET projects should be considered. The use of direct cash subsidies rather than tax incentives would largely eliminate tax appetite limitations, as would the ability to "sell" tax credits directly to other investors.
Tax credit uncertainty and its impact on RET investors	The importance of policy stability to renewable energy developers and financial investors should not be underestimated. To the extent possible, RET policies should be stable so that equity investors and lenders are encouraged to supply capital to RETs at reasonable costs.
Production tax credit and impacts on project capital structure	Production tax credits can push the optimal mix of debt and equity in the capital structure of RET projects toward higher-cost equity, reducing the value of the credit moderately.
Renewable energy production incentives and program funding uncertainty	If cash production incentives are used for renewables support, it is important to provide enough year-to-year certainty in program funding so that the incentive payments can be used as debt security and can substantively affect investment decisions.
The U.K.'s non-fossil fuel obligation and contract length	Contract duration and contract sanctity have important impacts on financing. RET policies that provide contracts or incentive payments to renewable energy projects should be designed as long-term commitments. Short contract periods and "out" clauses should be minimized.

to require more equity, less debt, and shorter debt repayment periods. Developers will probably attempt to sign bilateral contracts with large end users, marketers, aggregators, and utilities, but contract terms are likely to be shorter than in the past. Financial hedging arrangements will become increasingly common. NUGs may find it impossible to secure contracts for all of their generation output in advance. Therefore, an increasing focus on merchant plant development is expected. Corporate balance-sheet financing may also become more common.

Although all NUGs will be faced with these new financing challenges, there are several reasons to believe that renewables will be particularly disadvantaged. First, given their capital-intensiveness, RETs are especially vulnerable to increased financing costs and shortened contract periods. Second, renewables are often more costly than competing sources of generation and may therefore have difficulties financing projects based on anticipated future electricity prices. Finally, many renewable energy developers are not sufficiently capitalized and do not have a strong enough track record to attempt corporate financing for large projects. Mergers and acquisitions involving renewable energy companies are therefore likely to continue.

Supporting Renewables in a Restructured Electricity Industry

While the decline of long-term contracts may make financing more difficult and costly for renewables developers, emerging retail markets for "green" power and/or the establishment of public policies designed to benefit renewables could create an investment climate in which renewable energy can flourish. In fact, new support programs can and are being crafted within state and federal restructuring proceedings to encourage the continued development of renewable energy. We identify several important financing issues that will have to be addressed in the design of three of the most frequently discussed renewables support mechanisms: (1) surcharge-funded policies; (2) renewables portfolio standards; and (3) green marketing programs.

Surcharge-Funded Programs: Electric service distribution surcharges are a way to collect revenues from electric customers to support various policies with public benefits, including renewable energy programs. Once collected, there are a large set distribution possibilities for these funds. We emphasize those distribution mechanisms that provide funding directly to new renewable energy projects through incentive payments. Such mechanisms can be structured as production incentives or above-market contracts, and to select among competing projects three approaches are possible: (1) competitive auctions; (2) first-come; or (3) administrator's discretion. Regardless of the distribution and project selection mechanisms chosen, we emphasize the need for a long-term and predictable payment stream for the development of RETs that use project financing. Therefore, legislators and regulators should ensure, to the extent possible, that policies promising long-term production incentives or above-market contract payments to RETs will continue to be funded throughout the payment period and that "out" clauses are minimized. Because surcharges are effectively a tax on electric service, they may be particularly vulnerable to political attack and repeal. If funding uncertainties are unavoidable and/or long-term commitments impractical, policymakers may want to consider using up-front grants rather than long-term incentive payments. Alternately, investment in market transformation activities (e.g., fuel source disclosure requirements, customer education of "green" power options, etc.) or renewable energy infrastructure development may be the best use of limited funds.

Renewables Portfolio Standards: A renewables portfolio standard (RPS) allows regulators and/or legislators to require that a certain percentage of annual electric use in a given jurisdiction comes from renewable energy. To implement the policy, a renewables purchase requirement could be imposed upon retail electric suppliers. Individual obligations could be made tradeable through a system of renewable energy credits (RECs). In a restructured electricity industry featuring an RPS, renewable energy project owners would have a revenue stream that comes from two "commodity" markets: the power market and the REC market. Lenders may be able to obtain credit support from both revenue sources. The stability and duration of the RPS will affect the ability of the REC market to supply this credit support, however. If long-term policy stability is assured, long-term REC sales contracts are likely to develop. However, if legislative and regulatory commitments are weak, long-term REC

purchases are less likely and the financing costs of new RETs will increase. Our analysis suggests that overall renewables costs could increase by up to 25-50% in an unstable REC market compared to the probable cost under a stable market.

Green Marketing Programs: Green marketing takes advantage of customers' willingness to pay for products that provide a range of public environmental benefits and private benefits. Market research indicates that there are a significant number of electric customers who state a willingness to pay a premium, if given the chance, to purchase renewable energy. Whether utility-supplied programs pre-restructuring or non-utility-supplied programs post-restructuring, the primary financing issue related to green marketing is the risk of fluctuating customer participation rates. Participation risk (e.g. the danger that program participation may fall to levels below what is needed to sustain renewables facilities) can be largely eliminated by structuring the program such that funds are not committed beyond those that are already collected (e.g., the "annual participation" option). Within the "sustained participation" model, which has been more commonly used in utility-supplied green pricing programs, four non-mutually-exclusive options are possible to reduce participation risk for the renewable energy investor: (1) development of large intermediaries (utilities or marketing agents) to take on these risks; (2) requirements that customers demonstrate a long-term commitment to the program; (3) increased emphasis on corporate financing; and (4) a focus on low-risk renewables projects (e.g., existing facilities, retrofits, and small new projects).

Direct Mechanisms to Reduce Renewable Energy Financing Costs

Throughout most of this report we emphasize ways in which program design can indirectly influence renewable energy financing, and therefore impact the overall effectiveness of RET incentives. There are, however, a number of direct approaches that can be used to reduce financing costs. These programs include low-interest government-subsidized loans, project loan guarantees, and project aggregation. Although all hold significant promise, the largest barrier to the creation of effective programs of this type (particularly low-interest loans) is the potential loss of state and federal tax credits under subsidized financing programs. Policy interactions of this type should be considered closely when discussing the implementation of subsidized financing programs.

Conclusions

Renewable energy policies should be designed with consideration given to the realities of power plant financing. Policies that do not provide long-term stability or that have other negative secondary impacts on investment decisions will increase financing costs and may reduce policy effectiveness. Stable and predictable policy commitments can, on the other hand, lead to a decrease in financing costs, which should result in reductions in renewable energy costs and in more effective policies. In the long-term, such commitments will also help

create a regulatory, political, and business climate that is conducive to continued and sustained development of the renewable energy industries.

CHAPTER 1

Introduction

Depending on their design, policies to encourage the development and use of renewable energy technologies (RETs) can have positive or negative impacts on renewable energy financing and financing costs. The goals of this report are to describe the financing process for renewable energy projects and to identify important relationships between policy design and renewables finance.[1] Recognizing the critical impacts of electricity restructuring on power plant financing and on RET policies, we analyze and offer suggestions on the design of a number of proposed renewable energy policies. We also examine several policies that can directly reduce financing costs. We combine qualitative assessments of the interactions between policy design and power plant financing with quantitative analysis of some of these interactions. Our emphasis is on policies that promote the near-term commercial development of renewable energy projects. We recognize, however, that a necessary complement to these commercialization strategies are research, development, and demonstration programs that encourage longer-term cost reductions and technology improvements.

Compared to fossil-fuel generation, renewable energy provides many benefits to society that are not now fully internalized in investment decisions. These benefits include pollution reduction and the mitigation of electricity price variability. Renewables are often more costly than other electricity generation alternatives, however, and a number of institutional barriers have thwarted the development of renewable energy resources (Jackson, 1992). To overcome these barriers, policies have been enacted at state and national levels, both in the United States and abroad, to encourage renewable energy technology and project development. These policies include tax incentives, cash payments, renewables set-asides, standardized contracts, low-interest loans, and environmental adders.

Ideally, policy design should link incentive mechanisms to the goals of the policy, subject to technical, market, and financial constraints. This criterion is not always met, however, and political considerations often dominate policy design and implementation. Although many U.S. federal and state policies have been successful in promoting renewables, a number of policies have not been as effective as they could have been if designed differently (some of these specific policies are identified and discussed in Chapter 4). These shortcomings are often a result of mismatches between the policy's incentive mechanisms and technical, market, or financial constraints.

---

1 Our emphasis in this report is on non-hydroelectric renewables that have used or may use commercial financing, including: wind, geothermal, biomass, solar thermal, and photovoltaics (PV). We do not consider the financing arrangements used by households or firms for customer-sited renewable installations in detail, but instead generally focus on larger financial transactions.

In this report we emphasize power plant financing as an integral consideration in the design of renewable energy policies.[2] Financing is particularly important to renewable energy facilities because RETs are often capital intensive (Wiser, 1997; Jackson, 1992; Mitchell, 1995a). In addition, renewables are disadvantaged in the financing process *vis-à-vis* other generation technologies because of perceived resource and technology risks, small project size, and small industry size. We find that one of the key reasons that RET policies are not more effective is that project development and financing processes are frequently ignored or misunderstood when designing and implementing renewable energy policies. We show that a renewables policy that is carefully designed can reduce renewable energy costs dramatically by providing revenue certainty that will, in turn, reduce financing risk premiums. Policies that provide this certainty will either promote more renewables per dollar invested or will be more cost effective in supporting a given amount of development. Policies that do not provide long-term stability or that have negative secondary impacts on investment decisions may have the opposite effect, increasing financing costs and complicating project development. At a time when the emphasis appears to be on shorter and more market-driven renewable energy policies than those used in the past, highlighting the financing implications of policy design is all the more essential.

Electric industry restructuring, by increasing project risks and decreasing the availability of long-term power sales contracts, may further handicap renewables in the financing process. New investment approaches will be needed, some of which may not be amenable to the current structure of the renewables industry. Although restructuring threatens the future viability of renewables, it may produce significant new markets for RETs, and restructuring proceedings provide a forum in which to discuss the future role of renewables and renewable energy policies. Existing RET policies may be inadequate and/or inappropriate in a restructured electric industry, and new approaches for supporting renewables are being sought (Wiser, Pickle, and Goldman, 1996). An understanding of the possible pitfalls if policies are not designed to account for the financing process is particularly important for those interested in developing mechanisms to promote renewable energy deployment in a restructured industry.

This report is organized as follows:

- In Chapter 2, we provide a background to the renewable energy project development and financing process. We describe the two primary power plant financing approaches, introduce a variety of financing terms that are used

---

2 We recognize, however, that project finance is but one of many issues that must be considered when designing and implementing renewable energy support programs. In fact, some of the most favorable policy attributes from the perspective of developers and investors might run counter to what some consider "good public policy." Our intent in this report is to highlight financing as a critical issue in program design, without implying that there are not other design factors of equal, or greater, importance.

throughout the report, and discuss the financing of renewable energy projects in particular.

- In Chapter 3, we use a cash-flow model to illustrate the effects of various financing variables on renewable energy project costs.

- In Chapter 4, we employ a series of brief examples to demonstrate that many past and current RET policies have not fulfilled expectations, due, in part, to their impacts on financing. These examples provide concrete lessons for the design of future RET policies.

- In Chapter 5, we outline the potential impacts of electricity restructuring on renewable energy financing.

- In Chapters 6-8, we identify the key finance-related design issues associated with programs that have been proposed to support renewables in a restructured electricity industry: (1) surcharge-funded policies; (2) renewables portfolio standards, also called minimum renewables purchase requirements; and (3) green marketing programs.

- In Chapter 9, we briefly introduce and evaluate three policies that can directly reduce renewable energy financing costs: low-interest government-subsidized loans, project loan guarantees, and project aggregation.

- Chapter 10 summarizes the key results of the report.

Most of the chapters in this document are self contained and, because the report emphasizes policy case studies, some repetition is unavoidable. Readers are encouraged to approach the report somewhat like a reference document and target those sections that are particularly relevant to their own interests.

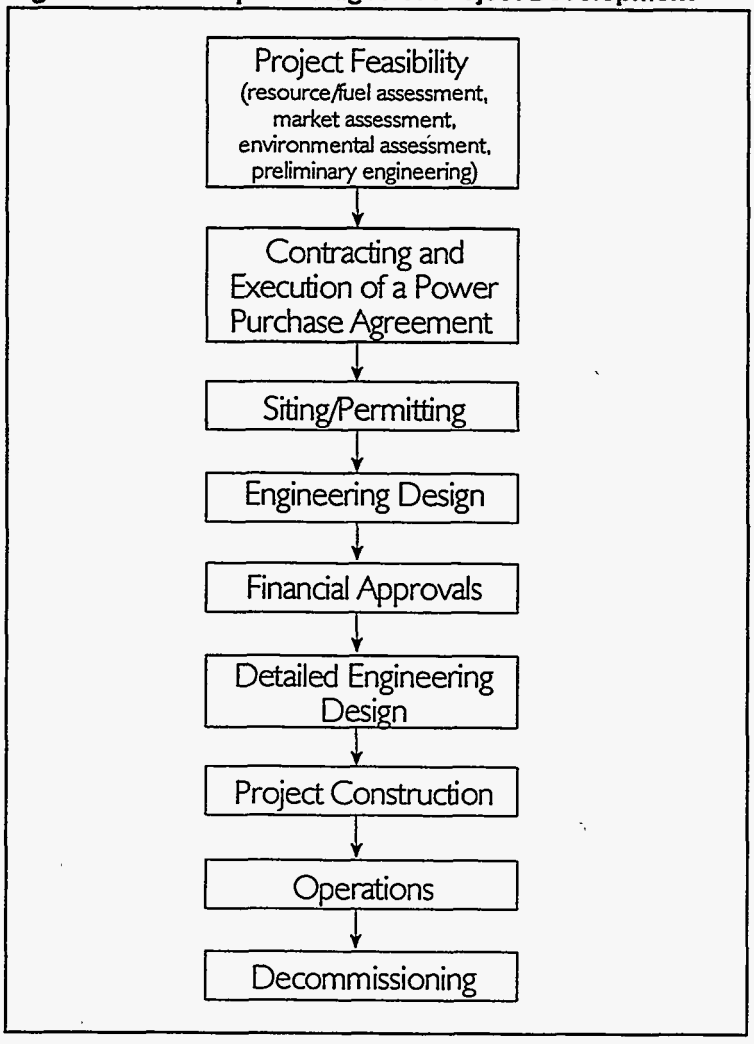
The Renewable Energy Financing and Project Development Process

In this chapter we provide much of the background required to understand the financing of renewable energy projects. In Section 2.1, we introduce the power plant development process. Then, in Section 2.2, we discuss some of the key concepts, terms, and variables used in power plant financing. Finally, in Section 2.3 we identify the most common financing arrangements used in the renewables industries and describe the financing barriers facing renewables compared to more traditional generation alternatives.

2.1 Project Development

It is important to understand the overall process of project development before specifically addressing renewable energy finance. While we cannot specify a project development process that is applicable to all types of power projects and to all business situations, almost all non-utility generator (NUG) projects that use project financing must pass through similar development stages (see Figure 2-1). Figure 2-1 depicts a project moving from one stage to the next; in reality, however, many of these activities are ongoing and overlap.

Figure 2-1. Conceptual Stages of Project Development



Final financial approvals (closing) are one of the later stages of project development prior to construction and operation. Although financial institutions are frequently approached earlier in order to scope-out financing costs for the contracting stage and determine

investor interest in the project, final financial approvals (especially loan agreements) are typically obtained only after all significant engineering, contracting, and permitting requirements are met (Kahn *et al.*, 1992).

2.2 Financing a Power Project

2.2.1 Sources of Capital: Debt and Equity

Project developers typically obtain capital for the up-front cost of building a power project through a combination of debt (a loan) and equity investment (ownership). There are a large number of ways to structure loan agreements, and debt can be obtained through public markets (bonds) or private placements (bank loans and institutional debt). Equity can be procured from internal sources or external investors in public or private markets.

Equity investors and lenders view and analyze projects (and firms) very differently. Equity investors have the potential for unbounded returns from project (or firm) success. Equity investors will therefore frequently take high-risk investments if the potential rewards are large. Investments are analyzed from a risk-return tradeoff with an emphasis on the expected investment return.

Most lenders, on the other hand, tend to be far more risk averse and are not in the venture capital business. The debt contract is a fixed obligation and the lender does not profit, beyond a certain level, from project (or firm) success. Up to the limit of unacceptable risk, lenders adjust debt interest rates and terms for default risk (e.g., higher interest rates on riskier loans). As a result of credit rationing, however, lenders will simply not take some risks. If a project (or firm) is likely to default or come close to default in any single year, lenders will often not supply a loan. Therefore, unlike equity investors, lenders typically analyze a project (or firm) from a worst-case perspective (Kahn and Stoft, 1989).

2.2.2 *Project and Corporate Financing*

There are two primary ways to finance a power plant: project financing and corporate financing. These two financing structures differ primarily in how debt is structured.

Project Financing: Non-utility generators have generally relied on project financing. In these arrangements, lenders look primarily to the cash flow and assets of a specific project for repayment rather than to the assets or credit of the promoter of the facility. The strength of the underlying contractual relationships among various parties is essential in project financing. Credit support (i.e., support for a loan) in project financing comes in large part from the revenues associated with the power purchase agreement (PPA). Therefore, long-term power purchase commitments that, at least partially, guarantee a revenue stream are essential,

especially for high capital-cost technologies such as renewables. An unpredictable or unspecified revenue stream is a risk that most project financing lenders are unwilling to take.

Debt is frequently less costly than equity (Brealey and Myers, 1991). As such, there is a tendency for developers to maximize debt leverage (i.e., the percent of debt used to finance a project) under project financing. This tendency is limited, in part, by debt service coverage requirements, described in Section 2.2.3. Debt for NUGs is frequently obtained via the private placement market, often from commercial banks or institutional lenders, although publicly placed debt has also been used. Equity can be acquired from internal sources (i.e., from the developer and/or its parent corporation) or from third-party investors (institutional investors, utility subsidiaries, etc.).

Corporate Financing: When corporations borrow money from either public or private markets, lenders look to the entire corporate balance sheet for repayment. Corporate financing (often called internal or balance-sheet financing) therefore lacks the degree of asset-specificity found in project financing. The primary requirement made by lenders in corporate financing is a restriction on the issuing of debt beyond certain limits (Smith and Warner, 1979). Additional debt can hurt bondholders and other lenders because it reduces the ability of a firm to pay interest on existing debt. The use of corporate financing to supply the capital needs of individual power projects is common in the electric utility industry and is likely to become more frequent in the independent power market if electricity restructuring results in a reduced availability of long-term power sales contracts (see Chapter 5).

Comparing the Two Financing Options: Project financing has several advantages to corporate financing. Loans are generally non-recourse (sometimes limited-recourse) to the parent company and therefore do not have a substantial impact on the company's balance sheet or creditworthiness. As a result, small- and medium-sized developers are free to pursue several projects simultaneously without large negative company-wide impacts. In addition, the reduced market risks and the non-recourse nature of debt in project financing allows higher debt-equity ratios, which can result in reduced financing costs. Nevitt (1983) and Brown (1994) identify a number of negative aspects of project financing compared to corporate financing, including the large transactions costs of arranging the various contracts, high legal fees, higher debt costs, and a greater array of restrictive loan covenants.

2.2.3 Key Financing Variables

Table 2-1 provides a list and summary of the key financing variables used in this report (see Wiser and Kahn, 1996 for a more thorough description of these variables).

Table 2-1. Summary of Financing Variables

Term	Description
Capital Structure	Capital structure refers to the mix of debt and equity that is used to finance a project or a firm. Debt-equity ratios are frequently used to describe the capital structure of a particular facility.
Return on Equity (ROE)	In exchange for their up-front capital outlay, equity investors require a minimum expected return on their investment, typically expressed as a yearly percent ROE. Equity represents a residual claim on all surpluses generated by the project. Equity returns can come in the form of direct project cash flows and/or as tax shields (tax credits and accelerated depreciation).
Debt Maturity	Debt maturity, or debt term, refers to the length of a loan.
Debt Interest Rate	All lenders charge interest. The interest rate will typically depend on the maturity of the loan and its risk.
Debt Amortization	Debt payments consist of principal and interest. Debt amortization refers to the debt payment schedule. In project financing, debt principal payments are typically made throughout the life of the loan, often with mortgage-style repayment.
Debt Service Coverage Ratio (DSCR)	To reduce default risk, lenders typically require that a project or firm maintain a minimum expected ratio of the available cash to total yearly debt service. This constraint is usually expressed as a minimum acceptable value for the DSCR (yearly operating income/total yearly debt service).

2.3 Developing and Financing Renewable Energy Projects

2.3.1 Financing and Ownership Arrangements Used in Renewables Development

Most large-scale, non-hydroelectric renewable energy projects in the U.S. have been developed, owned, and financed by non-utility generators.[3] Electric output is then sold to nearby utilities through long-term PPAs, often contracts developed under the Public Utilities Regulatory Policies Act of 1978 (PURPA).[4] Although not as common, utility ownership and financing of non-hydroelectric renewables projects has occurred. This form of ownership has

---

3 The Renewable Energy Annual (1995) indicates that, as of 1994, 89% of all U.S. non-hydroelectric renewable energy generation came from NUGs. NUG ownership represented 97% of biomass generation, 59% of geothermal generation, 99% of solar generation (primarily solar thermal), and 99% of wind generation.

4 PURPA requires that utilities purchase the power output from certain types of non-utility renewable energy and cogeneration power plants at the utility's "avoided cost." In response to the federal legislation, several states, including California, developed long-term, standard offer contracts that were supplied to renewable and cogeneration facilities.

been primarily limited to geothermal facilities, although some utility-owned biomass, photovoltaics (PV), and wind projects exist and others are in the development stage.

The U.S. renewable energy industry consists of both private and public companies. Since the early 1980s, the industry has relied extensively on project financing. Some of the larger corporations have the ability to develop projects via corporate financing, but most renewable energy developers do not currently have the resources or track record to finance large projects on their balance sheets (IRRC, 1991). Project financing arrangements can and have been structured in numerous ways, including, but certainly not limited to, partnerships[5] and sale/leaseback arrangements.[6] Long-term PURPA contracts have been the basis for most of the project financing activity.

Differences in financing and ownership, as well as sources of debt and equity, exist among the renewable energy technologies. Table 2-2 provides additional detail on the financing arrangements that have become common within each of the renewables industries.

2.3.2 *Renewables Are at a Financing Disadvantage Compared to Other Forms of Generation*

Financing terms are particularly important to RETs because renewables are often capital intensive, and therefore require a greater degree of up-front debt and equity than power plants with lower capital costs. A number of additional factors make it more difficult for renewables to obtain financing at reasonable costs than for more mainstream generation technologies (e.g., gas or coal):

Project Risks: Many RETs are perceived by the financial community to have high resource and technology risks (Brown, 1994; Wiser, 1997). Most financial institutions do not have significant experience evaluating renewable energy resource risks (wind variability and biomass availability, for example). Many RETs are also perceived as unproven, with large

---

5 During the early to mid-1980s, much of the renewables industry was driven by the large tax credits available at the federal and state levels. One of the most common development structures was the tax-advantaged limited partnership of third-party individual investors. In these arrangements, the general partner typically organizes and manages the financing, using equity investment from limited partners and obtaining loans for the remainder of the necessary capital. The limited partners receive cash and tax benefits. The general partner, often the renewable energy developer, is given management control of the project, while providing a tax shelter to the limited partners.

6 Sale/leaseback structures were also common during the 1980s. In this type of transaction, a third party (frequently a bank, insurance company, corporate finance subsidiary, or leasing company) purchases and finances an asset, and leases it back to the project developer under a long-term contract. The lessor is entitled to the tax credits, depreciation allowances, and interest deductions associated with the asset. During the 1980s, RET developers frequently did not have the tax liability to fully absorb the large tax benefits of their projects directly. Through sale/leaseback arrangements, these tax benefits were indirectly passed on to the developer (the lessee, frequently) through lower lease payments.

Table 2-2. Technology-Specific Financing Arrangements and Sources of Capital

Technology	Financing Arrangements and Sources of Capital
Biomass	The wood-fueled biomass industry consists of a wide variety of organizations, and includes small and large private and public companies. Prior to the 1980s, wood-fueled biomass projects were financed predominately with corporate financing by companies in the paper and timber industries interested in wood-waste reduction, steam production, and electricity sales (Reese, 1996). During the mid-1980s through the present, the industry has used NUG project financing extensively to develop PURPA-based projects. These projects have frequently been highly leveraged. Equity has generally been obtained from internal sources (i.e., the developer and/or its parent corporation) and debt has been received from commercial banks, institutional investors, and through tax-exempt bonds (Reese, 1996). The landfill gas and municipal solid-waste industries have relied on a number of different financing and development structures (often in partnership with local governments), including project financing (see Williams and Bateman, 1995 for a more detailed description of the structures common in these two industries).
Geothermal	The geothermal industry contains private and public companies. Before the mid-1980s, the industry was dominated by large petroleum companies and a few smaller steam-field development companies. Both of these types of companies frequently developed the geothermal field and sold the steam to public utilities, which were the primary owners/operators of the geothermal power plants (Williams and Bateman, 1995). These early companies generally used corporate financing arrangements and joint ventures to finance projects (Hinrichs, 1996). Most developers are now medium-sized firms and most oil companies have ended their geothermal activities (except Union Oil). Since the implementation of PURPA in the early 1980s, NUGs have built, owned, and operated geothermal projects; these developers typically use project financing (Hinrichs, 1996).
Solar	The photovoltaic industry includes small private companies and wholly owned subsidiaries of large public corporations. Until recently, the PV industry has been dominated by manufacturers selling directly to customer markets and/or utilities. Utility PV owners generally use corporate financing while electricity end users can finance projects through internal funds, bank loans, or mortgage payments. Although PV manufacturers have used internal equity to finance project capital needs in a limited number of circumstances (Williams and Bateman, 1995), NUG development and ownership is only beginning to play a more substantive role in this market. Project financing arrangements have not yet taken place, but the Amoco/Enron partnership and other developments may possibly result in an increasing number of these financial structures (Wenger, 1996). The solar thermal industry, under Luz International Limited (LUZ), developed projects in the mid- to late 1980s through third-party project financing arrangements. Equity sources included utility subsidiaries and institutional investors (Lotker, 1991).
Wind	The wind industry consists of private and public companies. During the early 1980s, almost all wind power development occurred through tax-advantaged limited partnerships of third-party individual investors. Sale/leaseback structures were popular in the mid- to late 1980s, but more traditional non-recourse project financing with independent debt and equity investors has now become the dominant form of wind power development (Williams and Bateman, 1995). More recently, a number of utilities have expressed interest in owning wind plants (Wiser and Kahn, 1996).

performance risks. Institutional memory of past project failures makes raising capital difficult and costly for many renewables developers (Brown, 1994). These real and perceived risks generally result in financing that is more costly than that available to more traditional generation sources. Wiser and Kahn (1996), for example, estimate that if wind developers received similar financing terms and costs as gas-fired NUGs, the nominal levelized cost of wind power might decrease by 25%.

Industry Size and Investor Interest: The U.S. renewable energy industry is still relatively small, and many investors do not feel that the work necessary to follow technology and performance trends is worth the effort (Brown and Yuen, 1994). The shortage of independent RET experts compounds the problem (Brown, 1994). Investors are typically reluctant to invest in technologies that have not been followed closely.

Small Project Size: Not only is the U.S. renewable energy industry as a whole relatively small, but most renewable energy projects are also small compared to coal and natural gas facilities.[7] Many financing institutions are not interested in small transactions (Pistole, 1995). Even if financing is available, the transactions costs per megawatt are much higher for smaller projects because many of the same financing and development steps must be followed regardless of facility size (IRRC, 1991; deLucia, 1995).

Unpredictable Policies: The economics of many renewable energy projects relies heavily on government policies (tax credits, set asides, etc.). These policies have often been unpredictable and subject to manipulation; tax policies have been changed frequently, for example. To the extent that unpredictability in these policies provides some uncertainty to the underlying economics of RETs, financiers will be reluctant to invest.

7 Renewable energy projects are frequently small (e.g., under 100 MW) for a number of reasons, including fundamental resource constraints and PURPA size restrictions.

Impact of Financing on Project Costs: Wind Power and Photovoltaic Case Studies

In this chapter we use a financial cash-flow model to demonstrate the impact of a variety of specific financing variables (debt interest rate, debt term, equity return, and capital structure) on renewable energy costs. We model two RETs: wind power and photovoltaics. We find that even small changes in financing terms can have a consequential impact on the levelized cost of renewable energy.

3.1 Overview of the Financial Model

To evaluate the impact of financing variables on overall project costs, a financial cash-flow model that closely replicates those used in the private power industry was created. The model tracks revenues, expenses, debt payments, and taxes over a 20-year period and estimates an after-tax, net equity cash flow. With minor modifications, the spreadsheet model can be used for all types of power supply projects. Cash-flow models of this form are typically used by NUGs to compute bid prices and determine project profitability, and by financial institutions in project evaluation. Using a constrained optimization algorithm, the model calculates the 20-year levelized power purchase price (and therefore the power purchase cost) required to meet all cost and financial constraints. Subject to the minimum return on equity and debt service coverage requirements, the levelized cost is minimized by optimizing the debt-equity ratio. The two model outputs are, therefore, the optimal capital structure (i.e., debt-equity ratio) and the levelized cost of energy. We emphasize the latter output in this chapter and report all costs on a nominal 20-year levelized cost basis in 1998 dollars. For a more detailed description of the model, its inputs, and its development, applied to a wind power facility, see Wiser and Kahn (1996). Two examples of the model (one with base-case PV assumptions and the other with wind power assumptions) are included in Appendix A.

3.2 Wind Power and Photovoltaic Project Input Assumptions

We evaluate cost sensitivities for a representative utility-scale wind power facility and a hypothetical grid-connected photovoltaic installation.[8] We assume that both facilities are

[8] We model a large-scale PV facility for illustrative purposes only. Grid-connected PV facilities of this size are not currently economic unless substantial ancillary benefits are obtained through transmission and distribution cost reductions, reliability increases, etc. In the medium- to longer-term, these facilities may prove economic as PV costs decrease and the value of PVs in niche markets is realized. In the near term, however, PVs are most likely to find markets where their benefits exceed their costs, for example, in smaller off-grid and value-added applications.

developed by NUGs with project financing under long-term power sales contracts. Our base-case model input assumptions are listed in Table 3-1. Because we are most interested in the financing sensitivities, we attempted to simplify model inputs as much as possible.

Table 3-1. Base-Case Wind and PV Cash-Flow Model Inputs

Input Variable	Wind Power Project	Photovoltaic Installation
Project Size	50 MW	5 MW
Capacity Factor	30%	25%
Capital Cost ($1997)	$1,000/kW	$4,000/kW
Total Operating Expense ($1998)	1.2 ¢/kWh	0.6 ¢/kWh
Federal Tax Credit	10-year, 1.5¢/kWh production tax credit (increasing with inflation)	10% investment tax credit
Energy Price and Operating Expense Escalation Rate	3.5%/year	3.5%/year
Depreciation Schedule	5-year MACRS	5-year MACRS
Minimum Return on Equity	18%	18%
Debt Interest Rate	9.5%	9.5%
Debt Maturity	12 years	12 years
Minimum DSCR	1.4	1.4
Debt/Equity Ratio[9]	Flexible--Optimized to minimize levelized cost	Flexible--Optimized to minimize levelized cost

Our wind plant input assumptions are generally consistent with other sources.[10] Few large-scale grid-connected PV facilities have been constructed and, to our knowledge, no facility has yet been developed through project financing.[11] Moreover, PV costs have been falling rapidly. Therefore, our PV facility input assumptions are necessarily uncertain. We assume a PV capital cost of $4,000/kW, which is optimistic compared to recent PV orders (Osborn

---

9 In the cash-flow model, the debt/equity ratio can be optimized in order to minimize levelized cost, or can function as a fixed input variable.

10 These include Conover (1994), Electric Power Research Institute (1993), Hadley, Hill, and Perlack (1993), Karas (1994), OEM Development Corporation (1996), Wiser and Kahn (1996), and Wong (1995).

11 Because of their modularity, PVs are often used in customer-sited applications. In these situations, PVs frequently compete with retail electricity rates and ownership and financing arrangements are very different than for utility scale renewable energy projects. Customer financing (through internal funds, bank loans, or mortgage payments) and leasing arrangements are much more common for these smaller PV applications.

and Collier, 1996; Ahmed, 1994). Given the economies of scale inherent in a large, 5 MW grid-connected facility, however, this estimate may not be inappropriate. In fact, it is far higher than the costs reportedly offered by Amoco/Enron Solar Power Development Company.[12] Generally speaking, our assumptions are compatible with other estimates[13]. Because PV facilities have not yet been developed under project financing, we assume that financing costs for the hypothetical PV project are similar to those for wind plants.

3.3 Cost Sensitivity Results

Under the base-case assumptions listed in Table 3-1, the nominal levelized cost of the photovoltaic facility is estimated to be 26.3¢/kWh (20.7¢/kWh in real terms); the nominal levelized cost of the wind power facility is 5.5¢/kWh (4.3¢/kWh in real terms).[14] Although the absolute value of these levelized cost estimates depends on many input assumptions, our base-case estimates are near those cited in many of the reports referenced above.[15]

Figures 3-1 through 3-4 show the sensitivity of PV costs to financing inputs. Figures 3-5 through 3-8 illustrate similar results for the hypothetical wind plant. For each sensitivity, an individual financing term was varied while all other inputs were held constant. While we do not evaluate these specific impacts in extensive detail in this report, our results confirm that the return on equity, debt interest rate, debt term, and capital structure all significantly impact overall project costs. Although changes in each financing variable have a similar effect on the estimated cost of the PV and wind power facilities, the differences that do occur are a result of our project performance, cost, and tax input assumptions.

Capital Structure: Figures 3-1 and 3-5 demonstrate the effect of capital structure (i.e., the equity fraction) on the cost of PV and wind power. We ignore the impacts of capital structure on the debt interest rate and on the minimum ROE requirement, and our results should therefore be considered approximations. The "optimal" capital structure (i.e., the one

---

12 Amoco/Enron Solar Power Development Company is pursuing the construction and financing of large, multi-MW PV plants. A 4 MW facility proposed in Hawaii is claimed to cost $1,750/kW (Utility Photovoltaic Group and Amoco/Enron, 1996).

13 These include Ahmed (1994), Hadley, Hill, and Perlack (1993), SERI (1990), Shugar *et al.* (1991), Wenger *et al.* (1996), Wenger (1996), and Williams and Bateman (1995).

14 We emphasize that, because PV and wind turbine facilities operate in very different product markets and therefore serve different needs, simple cost comparisons between the two technologies can be misleading.

15 Amoco/Enron Solar Power Development Company has proposed a 100 MW PV facility in Nevada, which it claims will be able to sell power profitably for 5.5¢/kWh. There is some skepticism about this claim, however, and a number of industry observers speculate that Amoco/Enron's strategy is to capture market share through significant forward pricing and that the proposed project is unlikely to be profitable (Wenger *et al.*, 1996).

that minimizes the levelized cost of renewable energy) depends, in part, on the relative cost of debt and equity and on the minimum debt service coverage ratio. The requirement to meet minimum DSCR levels results in the need for higher-cost equity capital. We find that, given our base-case inputs, the optimal capital structure for the PV facility is approximately 45% equity and 55% debt, whereas the optimal capital structure for the wind plant is 59% equity and 41% debt. If the debt fraction is increased beyond these "optimal" levels, the power purchase price must increase to meet the DSCR constraint. At higher equity fractions, on the other hand, the levelized cost increases because equity is more costly than debt. The curves are therefore U-shaped. The high equity fraction estimated for the wind plant is explained by Wiser and Kahn (1996) and discussed briefly in Section 4.3 of this report.

Equity Return: Renewable energy costs are highly sensitive to the cost of equity capital. Figures 3-2 and 3-6 depict the effects of the cost of equity on overall levelized project costs. As one would expect, renewable energy costs increase with the minimum ROE. A change in the ROE from 18% to 12% is estimated to result in a cost reduction of approximately 18% for PV and 22% for wind power.

Debt Interest Rate: As shown in Figures 3-3 and 3-7, debt interest rates also have a significant impact on levelized renewable energy costs. Reducing the debt interest rate from 9.5% to 5%, for example, is estimated to decrease PV costs by 14% and wind power costs by 11%.

Debt Term: As shown in Figures 3-4 and 3-8, debt term has a considerable effect on the levelized cost of renewable energy. We ignore the impact of debt term on debt interest rates in this analysis and our results should therefore be considered approximations; debt interest rates will typically rise with debt term. Given our assumptions, increasing the debt repayment period from 12 years to 20 years is shown to reduce PV costs by 17% and wind power cost by 12%.

Figure 3-1. Impact of Capital Structure on PV Costs

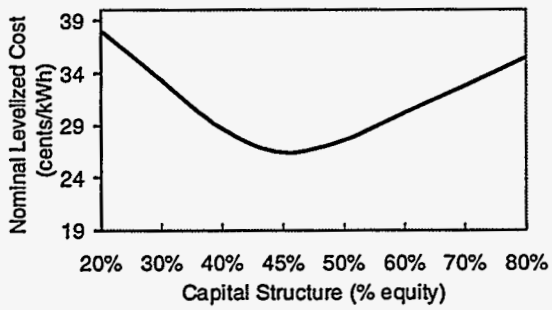


Figure 3-2. Impact of the Return on Equity on PV Costs

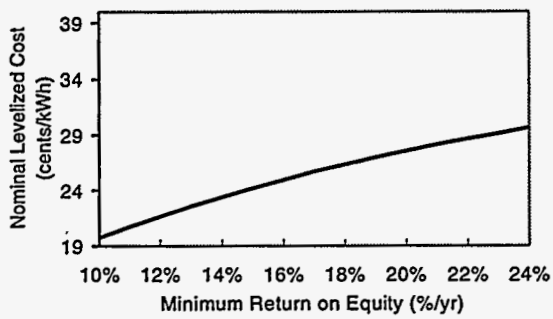


Figure 3-3. Impact of Debt Interest Rate on PV Costs

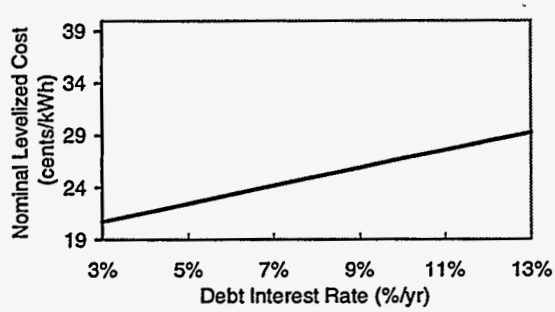


Figure 3-4. Impact of Debt Term on PV Costs

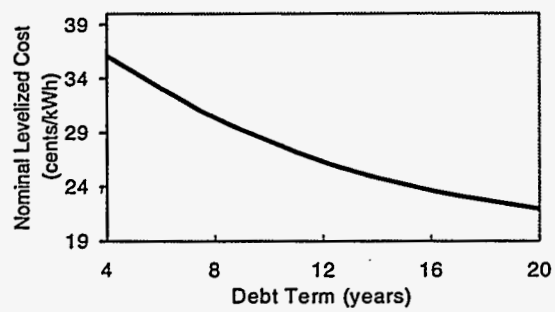


Figure 3-5. Impact of Capital Structure on Wind Power Costs

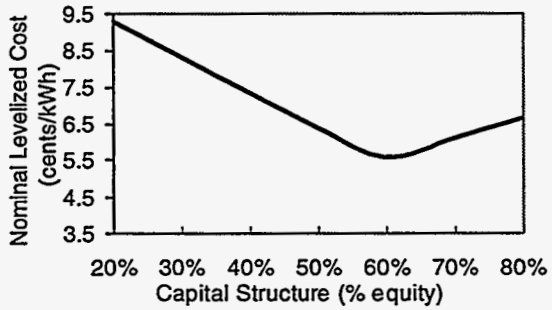


Figure 3-6. Impact of the Return on Equity on Wind Power Costs

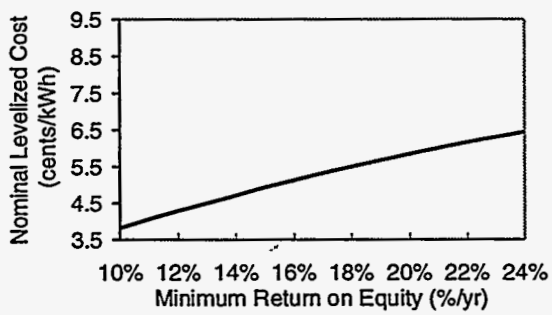


Figure 3-7. Impact of Debt Interest Rate on Wind Power Costs

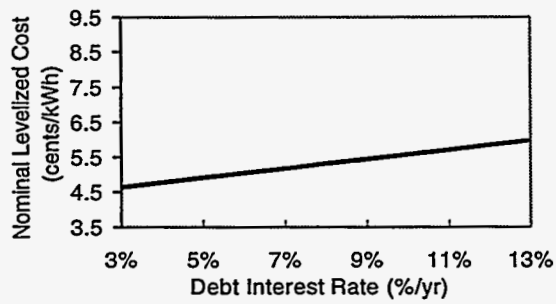
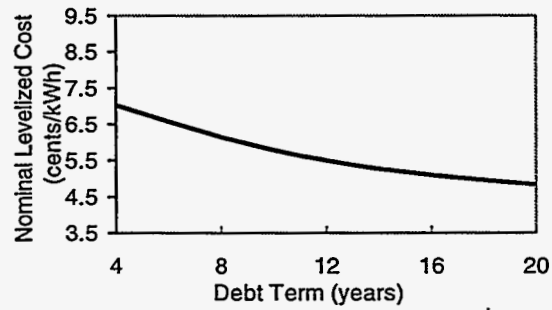


Figure 3-8. Impact of Debt Term on Wind Power Costs



CHAPTER 4

Lessons from Current and Past Renewable Energy Policies

Various policies, including tax incentives, cash payments, renewables set-asides, standardized contracts, low-interest loans, and environmental adders have been used in the U.S. to support the commercial development of renewable energy. Many of these state and federal policies have been successful in promoting the development of renewable energy resources. However, a number of policies can and have had unintended negative impacts on the financing process and on financing costs, reducing the overall effectiveness of these policies.

In this chapter we highlight the importance of policy design for renewable energy financing through five case studies of current and past renewable energy policies. Each of these shows how specific policy design variables can negatively impact financing, and each therefore provides discrete policy lessons. The case studies include: (1) tax policies and the ability of equity RET investors to use tax benefits; (2) policy uncertainty and its impact on RET project developers and investors; (3) the effect of production tax credits on the capital structure of renewables projects; (4) the renewable energy production incentive and program funding uncertainty; and (5) the U.K.'s renewables policy and contract length. Many of the lessons extracted from these case studies are used later in this report to highlight key design issues for renewables policies in the context of electricity industry restructuring.

4.1 Tax Policies and Tax Appetite

Tax incentives have played a prominent role in energy policy and can have a large impact on RET project costs (Hadley, Hill, and Perlack; 1993; Rader and Wiser, 1997; Ing, 1995; Oberg, 1992). For renewable energy promotion, beneficial tax policies have included accelerated depreciation, investment tax credits, production tax credits, and property and sales tax reductions or exemptions. The primary justifications for these policies have been: (1) to promote diversity in energy supply; and (2) to offset other tax-related barriers to renewables and promote tax "equity" across electricity generating alternatives (Burtraw and Shah, 1995; Jenkins and Reilly, 1995).

In 1978, the U.S. Congress enacted several tax incentives to stimulate the commercialization of RETs. By 1982, most renewable energy projects were eligible for a 10% business investment tax credit, a 15% business energy investment tax credit, and five-year accelerated depreciation (Swezey, 1992). Customer-sited renewables (PV and solar hot water) also received valuable federal tax credits. Additional tax incentives were available in many states, including investment tax credits, sales tax exemptions, and property tax reductions. The 1986 Tax Reform Act reduced the federal tax incentives available to renewables projects and many of the state tax incentives have been eliminated over time. In 1992, however, Sections 1914

and 1916 of the Energy Policy Act (EPAct) created a 10-year, 1.5¢/kWh production tax credit (PTC) for wind and closed-loop biomass and permanently extended the 10% business energy investment tax credit (ITC) for non-utility investors in solar and geothermal facilities.

Although tax policies have significantly influenced renewable energy development, tax incentives can have undesirable secondary finance and non-finance impacts.[16] Three specific financing-related issues have been raised by RET tax incentive policies, all of which have reduced the effectiveness of these programs. These include:

- the alternative minimum tax and limitations on the tax "appetite" of investors;
- the effect of policy instability on renewable energy developers and financiers; and,
- secondary impacts of production tax credits on the capital structure of renewable energy projects.

In this section we discuss the first of these issues; the other two issues are examined in Sections 4.2 and 4.3, respectively.

Accelerated depreciation and income tax credits can give significant tax benefits to equity investors in RETs. However, not all equity investors have sufficient income (from renewables and non-renewables activities), and therefore tax loads (referred to as tax "appetite"), to absorb the full value of these tax benefits.[17] The ability of investors to: (1) use the renewable energy tax benefits to offset other (non-renewables project) tax loads; (2) carry forward or carry back tax benefits to other years to offset income tax liabilities; and (3) allocate the tax benefits among investors regardless of ownership share, can all help alleviate the tax appetite problem. Some of these steps have largely been integrated into the federal tax code.[18]

---

16 Experience with the investment tax credits and accelerated depreciation of the early to mid-1980s, for example, demonstrates the negative impacts of specific policies on incentives for project performance. These incentives helped cause a California wind rush that resulted in large wind plant capacity additions and impressive cost reductions, but provided wind power owners with limited incentives for project performance (Cox *et al.*, 1991).

17 The federal PTC and ITC, for example, are included within the business credits of the Internal Revenue Code. Under Section 38 of that code, a limit is imposed on the amount of business credits a taxpayer can claim in any given year. The limit is the lesser of: (1) net income tax over the alternative minimum tax; and (2) 25% of net tax liability over $25,000.

18 For example, if a wind plant investor cannot use the PTC in any given year, it can be carried back for three years and carried forward for fifteen years to offset income tax liabilities in these other years (Ing, 1993). If a corporate investor has taxable income from other non-renewables project activities, the RET project's tax credits and depreciation allowances can generally be used to offset this income (additional limitations apply to this offset for individual investors). Similar rules apply to the federal energy ITC for solar and geothermal property. In addition, unused accelerated depreciation deductions can be used over 15 years as part of the net operating loss carry forward (Ing, 1996).

Alternative minimum tax (AMT) requirements often exacerbate problems associated with tax appetite. In the Tax Reform Act of 1986, Congress enacted the present AMT to ensure that the benefits of tax preferences are limited and to guarantee that taxpayers pay a minimum level of taxes. The AMT is computed with a modified depreciation schedule that is less favorable than the five-year modified accelerated cost-recovery system (MACRS) allowed for normal tax purposes. Most tax credits, including energy-related credits, cannot be credited against the AMT. Under the AMT, once taxable income is adjusted by the alternative depreciation schedule, a lower tax rate of 20% is applied. If income taxes are higher using the AMT than in the normal calculation, the entity must pay the AMT amount. The AMT can therefore postpone the use of tax credits and favorable depreciation allowances. Because of the time value of money, the value of these tax benefits decrease the longer they are carried forward. If a company is perpetually AMT limited, tax credits and accelerated depreciation may never be used.

Because renewable energy developers are often smaller companies in capital-intensive industries and have high depreciation allowances and tax credit benefits, they are frequently subject to the AMT (Ing, 1996). Even without the AMT, some of these companies may not generate enough taxable income to fully utilize tax benefits without significant carry-forwards. Hadley, Hill, and Perlack (1993) find that the AMT can have an enormously negative impact on the internal rate of return for renewable energy projects, but has minimal impacts on returns for conventional technology. For example, using a simplified cash-flow analysis, Hadley et al. estimate that the AMT alone can reduce the overall internal rate of return (IRR) for a PV project by 29%, 23% for biomass, 25% for geothermal, and 35% for wind power (assuming that equity investors can absorb negative tax liabilities from the RET facility). If project owners do not have sufficient income from other activities with which to offset tax losses from the RET facility, these tax benefits must be carried forward to future years when sufficient income does exist, and overall project IRRs are reduced even more dramatically: 40% for PV, 26% for biomass, 35% for geothermal, and 76% for wind. The reduction in IRR for conventional generation sources (coal, gas, and nuclear) was found to be, at most, 8%.

When subject to the AMT constraint, renewable energy developers often seek to obtain outside equity investors who are not limited by the AMT and who have sufficient taxable income to absorb the full value of the tax policies (Ing, 1996; Hinrichs, 1996). Not all renewable energy developers have a sufficient track record to easily attract outside investors, however.[19] In addition, lenders and third-party investors frequently require developers to contribute some portion of a project's equity to maintain performance incentives and demonstrate a long-term financial commitment to the project. Even if a renewables developer can access outside investors, the AMT limits the number of investors interested in renewable

19 Institutional investors are typically rather conservative, often requiring that a developer have a good track record and a proven product. Passive loss limitations, enacted by the Tax Reform Act of 1986, largely removed individual investors from the investment pool available to renewable energy projects (Ing, 1996). These individual investors played a prominent role in renewables development during the early 1980s.

energy facilities. Lotker (1991) contends that many of the large investors that might otherwise have been interested in investing in Luz International Limited's (LUZ) solar thermal trough systems were in an AMT-limited situation, reducing the investor pool. The net effect of the AMT is therefore to dampen demand for investment in RET projects, creating a need for higher yields to attract investors.

Pursuing partial AMT relief has been a priority of the wind and geothermal industries (Marvin, 1993; Hinrichs, 1996).[20] The American Wind Energy Association (AWEA) has suggested loosening the AMT for wind and allowing the PTC to offset up to 25% of a taxpayer's AMT (Marvin, 1993). Lotker (1991) suggests that renewable energy tax credits and/or accelerated depreciation be allowed in the calculation of the AMT. Alternatively, using direct cash subsidies (rather than tax incentives) would remove the tax appetite limitations of tax incentive policies and would not require changes to tax laws. Finally, the development of "assignable" tax credits (tax credits that could be sold directly to an unrelated party that has the tax liability to absorb the full value of the credit) could increase the effectiveness of tax credit policies from the developers' perspective (Reese, 1996).[21] Several wind power developers have considered ways to sell the PTC for cash (Kahn, 1995; Wong, 1995), but no transactions have been completed in part because of legality concerns.

LESSON: *The effectiveness of tax incentive policies is reduced by the inability of some renewable energy investors to fully absorb tax benefits. Allowing tax credits to offset the AMT would increase the value of tax policies to investors. Alternatively, using direct cash subsidies (rather than tax credits) or allowing tax credits to be "sold" to other investors would largely eliminate tax appetite limitations. The ability of investors to offset other (non-renewables project) tax loads, carry forward or carry back tax benefits, and allocate tax benefits among investors regardless of ownership share can also help alleviate the problem.*

20 Under current law, partial AMT relief is provided to taxpayers with investments in other types of energy production, including oil and gas (Geothermal Resources Council Bulletin, 1992).

21 In California, a 1.5¢/kWh production tax credit for existing biomass facilities was considered in the 1996 legislative session. Reese (1996) indicates that only half of the existing projects would have been able to use the credit; the other half do not have sufficient tax liability to absorb tax credits. The biomass industry briefly considered the legality of making the credits "assignable."

4.2 Policy Uncertainty and the Demise of LUZ

Changes in renewable energy subsidies have tended to be abrupt and therefore disruptive to developers and investors. In some cases, this has made it more difficult to attract investors and has increased financing costs. In this section we illustrate the problems associated with policy instability by describing a specific case, that of Luz International Limited (LUZ).

Although many of the federal tax incentives were phased out in 1986, Congress included the 10% business energy ITC within a group of other tax credit policies called "extenders." These tax credits had to be renewed by Congress on a yearly basis. Consequently, although the incentive was not eliminated, it's existence could not be guaranteed beyond a given year, creating great uncertainty among developers as to its availability from one year to the next. This uncertainty was magnified in California, which provided a 25% state ITC. The state ITC was available to projects larger than 30 MW only if the federal tax credits were also in place, therefore amplifying the impact of the federal ITC uncertainty (Lotker, 1991).

Until 1991, LUZ was the most successful developer of parabolic-trough solar thermal power plants in the world. Financed by outside investors through third-party project financing, but designed, constructed, and operated by LUZ, the nine Solar Electric Generating Systems (SEGS) located in the Mojave Desert in California total 354 MW. Construction began in 1984, with roughly one plant designed, licensed, and constructed for a different set of investors each year for seven years. In 1991, LUZ and its subsidiaries filed for bankruptcy. Although there are a number of reasons for the ultimate business failure of LUZ, the year-to-year uncertainties surrounding the renewal of both state and federal tax incentives, which led to a loss of confidence both within the company and among potential investors, has been cited as a key factor (Lotker, 1991).

Investors in SEGS plants wanted assurances that projects would be complete before the end of each year so that there was certainty in the provision of the federal ITC. Each construction period needed to be complete and the plant generating electricity by December 31 of the construction year; planning and construction became severely constrained, and project costs increased dramatically (Lotker, 1991). Parrish (1991) describes the process as follows, " the annual ritual was set: lobby Congress to pass an extension of the federal tax credit; in the first months of each new year, rush to get site approval from the California Energy Commission; frantically raise capital from investors, and finally, build the plant before year-end, when the tax credit would run out." Investors ultimately required LUZ to guarantee that they would receive the ITC. This guarantee had to be backed by a letter of credit from LUZ that was, itself, backed by cash or other security. Under this arrangement, any delay in project completion beyond December 31 would result in substantial losses for LUZ.

These risks impacted LUZ in several ways:

- a significant portion of LUZ's revenues were tied up in the letters of credit;
- investors realized that a failure to meet the deadline could significantly affect LUZ's ability to pay off the letters of credit, and a higher risk premium was required, raising financing costs; and,
- vendors and construction lenders charged large risk premiums on both goods and loans because of the high risks involved (Lotker, 1991).

In 1989, the business energy ITCs were only extended for nine months. LUZ decided to go ahead with the SEGS IX facility, but a seven-month rushed construction period resulted in an approximate $30 million cost over-run (Kearney, 1992). Meanwhile, in California, the company lost another battle. An error by the state's financial office showed that LUZ's property tax exemption would cost the state a total of $60 million. Based on that assessment, the governor vetoed the property tax exemption bill for solar properties. Faced with increased risk, a number of LUZ's investors (banks and equity) backed out, citing political and economic uncertainty (Lotker, 1991). While the financial office's error was eventually found and the governor did sign the property tax exemption bill, it was already too late for LUZ, which decided to file for bankruptcy.

LESSON: *Policy stability is essential to renewable energy project developers if they are to have success finding and retaining equity investors and lenders. Long-term certainty in subsidy levels and project eligibility help minimize investment risk and encourage equity investors and lenders to supply capital to RETs at reasonable costs.*

The LUZ experience demonstrates the impacts of an uncertain policy on finding and retaining investors. Many renewable energy developers continue to rely on state and federal renewables policies, including tax incentives, and RET projects can take one to more than five years to develop, permit, and construct. Therefore, developers must absorb significant risk during the development of a project unless they are ensured that a particular policy will apply to their project when it comes on-line. Even where policies survive attempts at legislative intervention, agency and/or court rulings can significantly alter a policy's applicability and implementation.[22]

22 An example of this phenomenon is a 1993 IRS rulings on the Section 29 tax credits provided to landfill gas facilities. This ruling diminished the benefits of the credit to some facility operators by requiring that the credit be shared with landfill owners that retain a royalty interest in the project (some projects were developed on the basis that tax incentives would not have to be shared). When the royalty-receiving landfill owner is a municipality or other government entity, the fraction of the tax credit that must be shared with that owner is simply lost because government entities are not able to use tax credits. Project financial structures have had to be revised to account for this ruling (Martin, 1994a; Martin, 1994b).

Although it is impossible to design state or federal policies that eliminate all policy instability risk, year-to-year uncertainty can increase financing costs dramatically and reduce the efficacy of these policies. Long-term and predictable policy commitments can, on the other hand, contribute to reduced financing costs and can help create a business climate that is conducive for investment. Policymakers may want to consider "grandfathering" provisions in RET policies. Such provisions would allow projects to prove eligibility and would pledge policy support some time before a project begins construction and operation. Renewables companies could then develop their projects with reduced policy uncertainty. While some repeal risk remains, the EPAct's permanent extension of the 10% energy ITC for solar and geothermal and the creation of a 1.5¢/kWh PTC for wind power and closed-loop biomass were heralded by RET developers for the stability they provide in comparison to the earlier tax credit "extender" approach.[23]

While a long-term, predictable policy is advantageous from the renewables developer and investor perspectives, there can, however, be costs associated with long-term policy commitments. Most importantly, such commitments can result in a loss of policy flexibility. If an existing renewables policy is determined to be unnecessary, or needed but at a lower level of support, a long-term commitment may reduce the ability of policymakers to eliminate or alter the program. Alternatively, if a policy is more costly and/or less effective than expected, it would be valuable to have the flexibility to re-design the policy. Finally, if legislative and/or public priorities change, long-term commitments can constrain the ability of policymakers to transfer funds to other priority areas. To improve flexibility without sacrificing stability, contingency clauses and off-ramp triggers could be built in to the policy. For example, the federal PTC is reduced if wind power costs rise above a particular level. Ultimately, however, policymakers may have to make trade-offs between long-term stability and flexibility. We fear that these trade-offs are frequently not considered directly in policymaking. Rather, inattention to and/or misunderstandings of the financing and business development processes for renewables may be behind the shortcomings of many renewables policies.

---

23 Once a RET project receives the first year of a tax incentive, the project will generally not be subject to significant tax incentive repeal risk; tax incentive changes typically apply to new projects. For example, once the first-year PTC is received by a wind project owner, the owner can be relatively certain that the PTC will be provided for the remainder of the 10-year eligibility period. The risk of repeal can disrupt projects that are being developed under the assumption of future support, although grandfathering provisions can reduce this risk significantly. When the Congress repeals a tax incentive, its usual policy is to grandfather or transition taxpayers who show detrimental reliance on the old law. For example, a power project that has entered into a binding power sales contract that relies on the availability of the tax incentive may not be subject to the repeal. This increases the certainty associated with tax policies, but does not totally eliminate repeal risk because tax changes may occur during a project's early development.

4.3 Effect of the PTC on Renewables Project Capital Structure

The U.S. federal government currently provides a 10-year, 1.5¢/kWh production tax credit (PTC) to qualified wind power and closed-loop biomass facilities. Although this incentive has stimulated wind power development, it inadvertently raises financing costs because of its impact on the capital structure (i.e., the mix of debt and equity used to finance projects) of RET projects. This secondary impact has reduced its effectiveness moderately (Wiser and Kahn, 1996). Because confidentiality constraints preclude us from evaluating individual projects' financial structures, direct empirical evidence of this effect is not available. However, Wong (1995) suggests that the analysis presented below matches the wind industry's experience with the PTC's impact on capital structures.

To assess the value of the federal production tax credit, the wind power cash-flow model was run with and without the PTC (see Table 4-1). In addition to the levelized cost, we also report the "optimal" capital structure (i.e., the capital structure that minimizes levelized project costs). We assume that investors have sufficient tax loads to absorb the full value of the tax credit. Although this is not a completely accurate assumption (see Section 4.1), the loss of accuracy should not impact our general capital structure results.

Table 4-1. Impact of the PTC on the Nominal Levelized Cost of Wind Power

Scenario	Levelized Cost (¢/kWh)	Optimal Capital Structure (% equity)
With PTC	5.5	59%
Without PTC	7.2	39%

As shown in Table 4-1, the PTC is estimated to reduce wind power costs by approximately 1.7¢/kWh. This cost reduction is greater than the quoted tax credit size of 1.5¢/kWh for two reasons. First, the PTC escalates with inflation. Second, tax credits provide secondary benefits by reducing project tax loads. Specifically, the tax credit allows developers to reduce their power sales price, therefore decreasing operating revenues and reducing taxes even more than the direct value of the tax credit (Wiser and Kahn, 1996).

The results shown in Table 4-1 indicate that inclusion of the PTC leads to a greater proportion of equity in the project's capital structure, however.[24] Because debt is less costly than equity, the altered capital structure reduces the PTC's value compared to an equivalently-sized, firm (tax-exempt) cash payment.

The benefits of a tax credit appear only on the tax returns of equity investors; tax credits are useless for servicing debt and meeting minimum DSCR requirements. Although the PTC

[24] These results are consistent with claims made by Wong (1995) that the optimal debt fraction prior to the PTC was 70%, but that 50% debt is now common in U.S. project-financed wind plants.

allows a reduction in the wind power sales price (because it provides a return to equity investors), if capital structure is unchanged, a decrease in the energy price can result in a violation of the minimum debt service coverage requirement (i.e., operating income is not sufficiently high to service the full debt payments). To combat this problem, the project developer must increase the fraction of higher-cost equity in the capital structure, therefore also increasing the contract price from what it would be under an equivalent cash incentive (which can be used to service debt).

LESSON: *Renewable energy policies can have secondary impacts on the financing structures of renewables projects. Tax credits, especially production tax credits, can push the optimal mix of debt and equity in the capital structure toward higher-cost equity, and therefore reduce the value of the credit moderately compared to an equivalently sized direct cash incentive. These secondary capital structure impacts. should be considered during policy selection and design.*

Kahn (1995) suggests that bankability of the PTC (i.e., the ability to "sell" the PTC for cash) would result in an incremental debt fraction of 20% (e.g., an increase in debt leverage from 50% debt to 70% debt). This result is generally consistent with our cash-flow analysis. Kahn also estimates that the penalty associated with a PTC compared to a tax-exempt cash incentive is an increase in financing cost of approximately 10%. The use of direct cash production incentives or the development of "assignable" tax credits would eliminate the capital structure impacts.

4.4 REPI and Program Funding Uncertainty

The renewable energy production incentive (REPI), created by Section 1212 of the 1992 Energy Policy Act, provides a 1.5¢/kWh ($1992) cash payment to non-profit owners of renewable energy projects (state or local government-owned facilities or non-profit electric utilities). The incentive payment is available for ten years, starting when the project begins operation. Eligible technologies for the REPI payments include geothermal (excluding dry steam), solar energy, wind power, and biomass (excluding municipal solid waste) (Federal Register, 1995). Some types of projects are given priority access to the funds, including solar, geothermal, wind, and closed-loop biomass.[25]

Funding for the REPI program is subject to yearly congressional appropriation and is therefore highly uncertain. Moreover, the EPAct only authorized appropriation for 1993-

25 The payments are available to projects that come on-line between October 1993 and September 2003 (Federal Register, 1995). In FY94, total REPI payments were $693,000, allocated to one wind (13% of funds), two PV (1%), and four landfill gas (86%) projects (DOE, 1995). In FY95, total REPI payments were $2,398,000, allocated to two wind (9% of funds), four PV (0.6%), and five landfill gas (91%) projects (DOE, 1996).

1995; Congress must periodically renew the authority for these appropriations (Williams and Bateman, 1995). The REPI was created as the non-profit analogue to the PTC and ITC programs offered to taxable owners of renewable energy facilities because tax credits cannot be used by tax-exempt entities. In contrast to the REPI, however, the 10-year PTC is a relatively stable incentive.

Although the REPI was created to stimulate incremental renewable energy development, in its current incarnation it can only be considered a limited success. Because of the uncertainty associated with the funding for the REPI payments, the REPI cannot be used as security for debt repayment and is often not even included in the investment decision-making process for publicly owned renewable energy facilities.[26] Non-profit RET owners clearly have no assurance that they will receive the payment throughout the 10-year eligibility period, an issue that was repeatedly raised during the policy's implementation (Federal Register, 1995).

To determine the value of the REPI to non-profit renewables project owners, we informally surveyed representatives from each of the FY95 REPI recipients (seven owners representing eleven projects). We inquired whether the REPI's existence affected their decision to proceed with their RET project(s). Realizing that some of these RET projects were in the development stage when the REPI was created (and, therefore, that the REPI had not been considered in project decisions), we also asked whether the REPI would be considered in the evaluation of future projects. To quantify the results, each respondent was asked to express their evaluation on a scale from one to four. A "1" indicates that the existence of the REPI did not (would not) affect project decisions; a "4" signifies that the project would (will) not have moved forward without the REPI. Table 4-2 shows the results of this survey (see Appendix B for additional contact and project information).

Table 4-2. Impact of the REPI on Project Decisions: Survey Results

		Limited Effect on Project Decisions <---> Strongly Affects Project Decisions			
		1	2	3	4
Impact of REPI on Existing Projects	# Utilities	4	2	0	1
	% FY95 REPI Funds	83%	17%	0%	0.1%
Impact of REPI on Future Projects	# Utilities	2	4	0	1
	% FY95 REPI Funds	46%	54%	0%	0.1%

26 Unlike the PTC and ITC, where only the renewable energy project owner can receive the credits, the REPI program will make payments to either the owner or operator of the RET facility. The benefits and risks of future uncertain payments can be assigned as the owner and operator see fit. The REPI therefore provides more freedom than the tax credit policies, which may slightly reduce the financing constraint associated with the REPI (Ing, 1995).

All respondents appreciated the existence of the REPI, but the survey results suggest that the REPI, as currently designed, is not a particularly effective incentive.[27] Despite the fact that the expected value of the REPI payments is certainly not zero, nearly all REPI recipients interviewed did not and would not rely heavily on the REPI in project cost estimation and investment decisions (as illustrated by the large number of owners that placed themselves in the "1" or "2" category). The REPI serves as a post-development bonus for those projects that manage to secure financing on their own, but it does not appear to generate a significant amount of development that would not otherwise occur.[28] As predicted, the REPI is expected to be a slightly more effective incentive for future projects than for existing ones. Every RET owner surveyed placed a large priority on "firming up" the REPI payments, and each identified funding uncertainty as an important flaw in the REPI's design.

To improve the policy, production payments should to be firmed up so that non-profit RET owners are assured of a 10-year revenue stream. Alternatively, an entirely different policy could be used to promote RET development by non-profit owners. For example, payments could be made as up-front grants, eliminating some of the problems associated with 10 years of payment uncertainty. Regardless of which approach is taken, it is essential that the policy provide an incentive that can be used in loan applications and in bond offerings, and that can easily be integrated by non-profit decision-makers in financial and project evaluations.

LESSON: *If long-term production incentives (or contracts) are to be used for renewables support, it is important to provide enough year-to-year certainty in the payments so that they can be used as debt security and included in financial evaluations of RET projects. Program funding uncertainties should be minimized.*

At the legislative level, at least two approaches can be used to decrease year-to-year program funding uncertainties and to firm up the production incentive: (1) create a pool of capital that is large enough to be pledged for current-year and future payments (a trust fund, for example), obviating the need for repeated, yearly appropriations; or (2) establish some sort of standing (or open) appropriation that reduces the likelihood of future funding suspension. The "pool of capital" approach was suggested by Mitchell (1995b) for the U.K.'s renewables policy (see Section 4.5) and by a number of parties during the design of the REPI. It is an approach often used by state and federal governments to fund public works projects (Grandy, 1996; Park, 1996). Typically, however, legislatures treat capital appropriations for public

---

27 We emphasize that REPI funding uncertainty was not the only consideration in the responses to our questions. The underlying economics of the project was also a variable. For example, if a project is economic without the REPI, the REPI will not substantively affect a "go"/"no go" project decision regardless of its funding certainty.

28 We should note that our survey results may paint a more negative picture of the REPI than is warranted. For example, a number of potential non-profit RET owners have indicated to the U.S. DOE, in pre-application inquiries, that the REPI does have an impact on project decisions (Spaeth, 1996).

works projects very differently than operating appropriations for program expenditure (Rabago, 1996; Elwood, 1996). Most legislative bodies are wary of appropriating money not committed for specific expenditure. Where "uncosted balances" develop, they can be ripe targets for reappropriation--often an appropriate reaction given that funds left uncommitted and unmonitored can be misused as personal or institutional "slush funds."

Standing or open appropriations provide a second way to increase funding stability. In these arrangements, a legislature establishes a *commitment* to appropriate either a fixed (standing appropriation) or variable (open appropriation) amount of money to a given program over several years. Although funds are not provided up front, as in the "pool of capital" approach, yearly funding decisions are somewhat insulated from the legislature. These types of appropriations have been used to fund the U.S. Department of Energy's Clean Coal Technology Program, and to fund Minnesota's 10-year, 1.5¢/kWh renewable energy production incentive (Lynch, 1996; DeBoer, 1996; Grant, 1996). While standing or open appropriations can promote funding certainty, there is no guarantee that future legislatures will faithfully recognize past commitments; each legislature can alter spending commitments as it sees fit. To prevent a break in a standing or open appropriation, and to promote stability in renewables policies more generally, legislatures should be alerted to the dangers that funding changes pose to developers and investors. Statutory language specifying the legislative intent to fund a program for a long period should be sought wherever possible.

The U.S. Department of Energy is aware of the shortcomings of the REPI policy (Federal Register, 1995) and has taken steps to partially reduce the uncertainty in the REPI payments. Although the U.S. DOE cannot guarantee an incentive payment because of program funding uncertainties, the DOE will, at least, provide a preliminary and conditional determination of eligibility for the REPI payments. This determination reduces the risk of a project being deemed ineligible for funds after-the-fact. In addition, by giving priority access to the REPI payments to certain technologies, the incentive to invest in these priority technologies increases slightly because the probability of adequate annual funding to that category is higher. The U.S. DOE is also considering ways to alter the policy so that it provides a more powerful incentive for RET development (Spaeth, 1996).

4.5 U.K. NFFO and Contract Length

The United Kingdom's electricity industry was privatized and restructured in 1989. As part of the restructuring process, a program was set up to subsidize nuclear and renewable energy. This program, called the Non-Fossil Fuel Obligation (NFFO), has promoted renewables through a competitive set-aside and auction since 1990, and provides RET projects a premium energy sales price if they are successful in their bid for a contract. The NFFO requires the major distribution companies in the U.K. (the Regional Electric Companies) to purchase this renewable energy via a power purchase contract. The Regional Electric Companies are reimbursed the difference between the contract price and the average monthly

power pool rate through a fossil-fuel levy on electricity, paid via customer electricity bills. Thus far, four NFFO auctions (called tranches) have been conducted, each overseen by the U.K. Department of Energy, the Office of Electricity Regulation, and the Regional Electric Companies. One more tranche is slated to occur before 2000.

Mitchell (1995a), Elliot (1992), and Jackson (1992) describe the financing shortcomings of the NFFO. A major influence on the ultimate costs of the first two solicitations was a decision made by the European Commission that support under the NFFO should not extend beyond 1998,[29] limiting the fixed-price power purchase contract length to a *maximum* of eight years. A number of projects that won the bidding process in the early 1990s were unable to obtain planning permission rapidly enough to take advantage of the contracts, and therefore were never constructed (Mitchell, 1995b). Even more importantly, the shortened contract period increased financing costs and raised price premiums.

LESSON: *Contract duration and contract sanctity have important impacts on financing. Shortened contract periods and "out" clauses can result in reduced debt maturity, debt and equity risk premiums, and therefore increased costs of power supply. Long-term commitments allow less costly financing and reduce overall renewable energy costs.*

As noted in Section 2.2.1, lenders typically assess projects on a worst-case basis. If a project is likely to default or come close to default in any single year, lenders will often not provide a loan. Therefore, lenders are frequently unwilling to provide debt for terms that exceed the fixed-price period of a PPA, especially for projects that are unlikely to be competitive without price supports (Brown, 1994; Naito, 1995).[30] With an uncertain revenue stream post-1998 and an expectation that power pool prices would not be sufficient to meet debt service coverage requirements, lenders were unwilling to provide long-term loans to renewable energy companies during the first two tranches of the NFFO. Six- to eight-year debt was therefore common, dramatically increasing the price premium required by renewable energy developers (Wind Energy Weekly, 1992). As shown in Chapter 3, decreasing the debt

29 See Elliot (1992) for a description of the events leading up to the 1998 contract end date.

30 It is interesting to note that in the mid-1980s to early 1990s, the biomass industry in California was frequently able to obtain 15-year debt even with 10-year fixed-price contracts. Banks were generally willing to lend to these facilities because of high avoided cost projections after the tenth year. However, lenders frequently insulated themselves from significant risk by including a "sweep" clause in the debt contract. This clause allows banks to re-examine avoided cost projections for year 11 after approximately five years of project operation. If the newly projected energy payments are below a floor level, lenders are allowed to accelerate debt repayment to shield themselves from project revenue risk. Many banks are invoking this clause because current avoided costs are far below those predicted in the mid-1980s (Reese, 1996). The geothermal industry was also able to obtain 12- to 15-year debt under 10-year, fixed-price PURPA contracts. However, debt repayment was often front-loaded to minimize revenue risk after the tenth year. In addition, at the time, the projected avoided cost and capacity payments after year 10 were expected to be sufficient to meet all debt coverage requirements (Hinrichs, 1996). This condition may no longer hold, and lenders may not invest in future RET projects on this basis.

repayment period from 12 years to 6 years, and holding all else constant,[31] results in an increase in PV costs of approximately 26% (7¢/kWh) and wind costs of 20% (1¢/kWh). A reduction in the contract period could also result in increased equity premiums, further exacerbating the financing problem.

The third tranche of the NFFO (contract winners announced in December 1994) overcame some of the financing problems associated with NFFO1 and NFFO2. First, NFFO3 allowed contracts to begin within five years of the contract award date, which provided ample time for developers to site and construct projects. Second, contract lengths were raised to 15 years, allowing debt to be repaid over a longer period of time and partially dispelling the image of renewables as being overly expensive (Mitchell, 1995b). Table 4-3 demonstrates the dramatic bid price reductions in the various technology bands between NFFO2 and NFFO3 (Mitchell, 1995b). These reductions are largely attributable to the longer contract period, but are also a result of falling RET capital and development costs (Mitchell, 1995b).

Table 4-3. NFFO Renewable Energy Cost Reductions

Technology	NFFO2 Technology Band Price (¢/kWh)[32]	NFFO3 Technology Band Price (¢/kWh average)
Wind	18.2	7.1 (larger projects) 8.7 (smaller projects)
Hydro	9.9	7.4
Landfill Gas	9.1	6.3
Waste Combustion	10.9	6.3
Other Combustion	9.7	8.4
Sewage Gas	9.7	None
Average	**11.2**	**7.4**

Two new clauses were inserted at the request of the Regional Electric Companies into NFFO3 contracts. The first clause states that if the fossil-fuel levy ceases during the contract period (i.e., the Regional Electric Companies are no longer reimbursed the expense of the renewables contract through the distribution levy), the Regional Electric Companies are not required to fund the shortfall between the pool and premium price. This clause clearly reflects the Regional Electric Companies' fear that the government may discontinue funding for the renewables contracts via the fossil-fuel levy mechanism. The second clause states that

---

31 Debt interest rates typically increase with debt term (referred to as the term structure of interest rates). Therefore, the cost of a decrease in the debt term is offset, somewhat, by a reduction in the interest rate that results from the shorter debt repayment period. This offsetting factor is, typically, relatively insignificant compared to the debt maturity impacts (Kahn, 1995).

32 Based on an exchange rate of $1.655 = 1£.

if renewable energy supply exceeds 25% of a Regional Electric Company's electricity business, the Regional Electric Company is not required to purchase any additional renewable energy. While it appears as if the first clause has not had a large negative impact and that the second clause has had no effect,[33] contract "out" clauses of this type can reduce the effectiveness of renewables policies by increasing revenue uncertainty. If the NFFO's funding is not certain, or it becomes necessary to increase the Regional Electric Companies' confidence in cost recovery, Mitchell (1995b) suggests the creation of a large pool of capital controlled by the Regional Electric Companies for renewables funding.

---

33 The U.K. Department of Trade and Industry NFFO administrator, Richard Kettle, reports that, while a few developers have reported bank concern over the out clauses, the clauses do not yet appear to have had an undue influence on financing (Kettle, 1996). National Wind Power's Andy Vaudin (1996) confirmed this appraisal. If these assessments are correct, project developers and lenders must expect that continued funding for the NFFO contracts is relatively certain.

Effects of Electricity Restructuring on Renewable Energy Finance

To this point, we have emphasized the traditional approach to financing a NUG facility, namely project financing under long-term PPAs. But electric industry restructuring promises to fundamentally change the financing of power projects in general and renewables projects in particular. In a restructured industry, long-term (20-30 year) power sales contracts, which have traditionally allowed for extensive project financing, are likely to become increasingly scarce. Thus, we expect that new power plants will be financed with more equity, less debt, and shorter debt terms or, possibly, through corporate balance-sheet financing. "Merchant" projects (facilities that are developed based in part on anticipated demand rather than firm sales contracts) are likely to become more common. Renewables developers may be disadvantaged by these altered financing mechanisms compared to more traditional forms of generation.

5.1 Electric Industry Restructuring and Long-Term Contracts

The U.S. electric industry is in the midst of significant change. Historically, the provision of electric power was viewed as a natural monopoly and electric utilities were regulated accordingly. In response to technical, economic, and political changes, however, the U.S. Congress, the Federal Energy Regulatory Commission, and many states have promoted wholesale electric generation competition, beginning with the enactment and implementation of PURPA in 1978. In the last couple of years, serious discussions about retail competition have begun, and retail competition is already being planned in a number of states and studied in most of the rest. Retail competition pilot programs have also been introduced. Retail competition will eliminate the regulated utility as the sole end-use electric service provider (other than on-site, self-generation); customers will be allowed to contract directly with generators and marketers for power supply.

The impact of restructuring on renewables development will depend on a host of factors, including: (1) the ultimate structure of the electricity market; (2) the size of the voluntary green power market; (3) bidding, scheduling, and transmission rules; and (4) public policies that are enacted to support RETs (Wiser, Pickle, and Goldman, 1996). Regardless of these factors, absent certain types of RET policies, renewables developers (and all power suppliers, for that matter) are unlikely to be able to depend on the same types of long-term power sales agreements that have traditionally been the signature of the NUG industry.

Long-term power sales agreements, initially developed under PURPA, provide a steady stream of revenue that has been particularly important in acquiring non- and limited-recourse loans for capital-intensive RET projects (Wiser and Kahn, 1996; Hoff and Herig, 1996).

Comnes *et al.* (1995) evaluate 26 private power contracts from the early 1990s, and find that contract duration varies from 20 to 40 years, with most contracts in the 20- to 30-year range. Project financing for renewables has, historically, relied heavily on these long-term contracts. As noted in Chapter 2, although there are costs to project financing, it does allow greater debt leverage and shields corporate balance sheets from large debt obligations.

In a restructured electric industry, power purchasers have less incentive to sign 20- to 30-year contracts. Evidence from the restructuring of the natural gas market in the U.S. suggests that shorter-term contracts will become more common (Goldman *et al.*, 1993). In fact, electric utilities have already begun to move away from long-term PPAs as cost-containment pressures have increased and wholesale competition has intensified. Under full retail competition, utilities will no longer have the fixed set of captive customers that have historically been the basis for long-term PPAs. The current oversupply of electric capacity in the U.S. may further limit the availability of long-term contracts. During the transition to retail competition, utilities may be particularly hesitant to enter into long-term commitments in order to reduce risks associated with a fluctuating customer base and to minimize uneconomic investments. Although some electricity customers will sign longer-term contracts with retail electric suppliers, these contracts are not expected to be long and secure enough to become the basis for a significant number of 20- to 30-year PPAs.

Restructuring will not, however, result in the elimination of all medium- to longer-term commitments and a complete reliance on spot-market purchases. To insulate electricity generators and users from price variability, a variety of direct bilateral contracts and hedging arrangements will become standard. One such hedging mechanism, called a contract-for-difference (CfD), allows power producers and electricity purchasers to contract at a fixed strike price. Under a two-way CfD, if the strike price exceeds the actual spot market price, the generator earns additional revenues (beyond the spot price) equal to the difference between the strike price and the spot price. If the strike price ends up below the spot price, however, the generator must pay the purchaser the difference between the spot price and the strike price (Wolak and Patrick, 1996). The net result is that, regardless of the spot price, electricity is always bought and sold for the strike price. In the wake of electricity privatization and restructuring in the U.K., CfDs have become a dominant contracting mechanism for new power projects.

Although bilateral contracts and financial hedges can provide a measure of revenue certainty, they are unlikely to provide a secure revenue stream for the length of time typical of current NUG contracts (20-30 years). For the reasons identified above, medium-term contracts of, *at most*, 15 years will almost certainly be more common; many contracts are likely to be less than 5 years. Traditional approaches to developing, contracting, and financing NUG facilities fit poorly into this new competitive marketplace.

5.2 Post-Restructuring Prospects: Merchant Plants and Balance Sheets

To attract project financing in a highly competitive and risky environment without a full set of secure long-term contracts, power developers are likely to require more equity, less debt, and shorter debt terms. Many analysts suggest that debt-equity ratios will be 50:50, not the 70:30 or 80:20 that have been traditional in NUG financing (Churchill, 1996; Electrical World, 1996). Debt term has often been tied to the length of the fixed-price power purchase agreement; therefore, if contract durations decrease, debt terms are also expected to shorten. Where non- or limited-recourse debt is pursued, developers will seek medium-term bilateral contracts and CfDs (up to 15 years, perhaps).[34] NUGs may find it impossible, however, to secure contracts for all of their generation output in advance.

Many analysts expect merchant plant financing to become common in the U.S. as competition increases and long-term contracts become scarce (Electrical World, 1996; Meal and Lavinson, 1996). Merchant power plants are generating facilities developed without a full set of sales contracts in place, but with good prospects for future sales. This form of development is used in nearly all competitive industries and can be compared to commercial office buildings, which are constructed without all of their space committed, but with several core tenants signed up. Meal and Lavinson (1996a) note that a rule of thumb for debt availability in merchant plant financing is that, "with X percent of output under contract, X percent of a project's total capital structure could be provided in the form of a senior securitized debt." In the U.K., restructuring has brought about a number of merchant plant developments.[35]

Ultimately, if the risks are high and medium- to long-term contracts are largely unavailable, project financing could become too difficult and/or costly. In some cases, banks may simply refuse to offer non-recourse financing and will instead focus on corporate, balance-sheet arrangements (Churchill, 1996). Corporate financing lacks the degree of asset-specificity found in project financing and allows investors to look to the assets of the entire corporation for repayment, reducing investment risks. Large companies will be best positioned to secure financing for new projects because these companies have the financial resources to obtain significant quantities of debt at reasonable costs and absorb the risks that corporate-financed power projects entail. The entire structure of the NUG market is therefore in the process of change as smaller NUGs (and renewable energy companies) partner with larger corporations.

---

34 In the U.K., for example, Enron Development Corporation was able to obtain predictable cash flows on 1,725 MW of its 1,875 MW gas-fired Newcastle project using a series of CfDs. In doing so, Enron was able to secure over $1.5 billion dollars in non-recourse financing (Lacoursiere, 1996).

35 Edison Mission Energy's purchase of two pumped storage hydro projects from the National Grid Company in the U.K. provides one example. When purchased by Mission in 1995, neither of the facilities was under a long-term contract; both were used as peaking units, which could respond quickly to sudden demand changes (Lacoursiere, 1996). Mission was able to finance the acquisition on the basis of hedging arrangements and assessed prospective demand.

5.3 Prospects for Renewable Energy Developers

A number of factors suggest that renewable energy developers may be disadvantaged by the contracting and financing structures expected in a world of vigorous retail competition.

- First, increased investment risks and the scarcity of long-term contracts will probably result in shortened investment horizons, reductions in debt maturity, increased equity requirements, and larger debt and equity risk premiums. Although these changes will affect all electric generating sources, they will have a differentially large impact on technologies, such as RETs, that have high capital costs (and therefore larger financing requirements).

- Second, renewables are often more costly than competing sources of generation. While a lender may be willing to invest in a low-cost natural gas facility based on expected future electricity prices (Nevitt, 1983), developers will have a difficult time "selling" a RET facility to a lender in this way unless additional mechanisms exist to support the above-market costs (Brown and Yuen, 1994).

- Third, some renewable energy developers are not sufficiently capitalized and do not have a strong enough track record to attempt corporate balance-sheet financing for large projects (IRRC, 1991). In response to the increasing need for capital, mergers involving renewables developers are already occurring and can be expected to continue as the industry shakes-out and consolidates.

Ultimately, the effects of restructuring on renewable energy finance will depend upon the structure, organization, and operation of the deregulated power market as well as the adoption of public policies to promote renewables. While there is cause for concern, there are a number of scenarios under which a renewable energy developer could obtain needed capital. For example, if restructuring creates a viable and extensive green power market, renewables developers may be able to sign sufficient short- to medium-term contracts with end-use customers or green power aggregators and point to enough "green" demand that merchant plants can develop. Moreover, should significant additional policy incentives be established at the state or national level, renewables developers are again likely to be able to obtain capital. Finally, some believe that industry restructuring could provide new markets and opportunities for distributed grid-support and on-site renewable energy applications (e.g., PV).

During the transition period between the current and restructured industry, however, investment apprehension and uncertainty about the depth and breadth of the green power market may make financing particularly costly and difficult for small renewable energy companies. In the next three chapters we discuss renewable energy support mechanisms designed to help overcome these and other handicaps and provide a bridge between the regulated and restructured industry.

CHAPTER 6

Surcharge-Funded Renewable Energy Policies

As discussed in Chapter 5, electric industry restructuring may result in financing approaches that disadvantage renewable energy developers. Moreover, many of the existing public policies used to support RETs will be inadequate and/or inappropriate given retail competition. Nonetheless, within state and federal restructuring proceedings, new programs can and are being crafted to encourage the development of renewable energy. A number of support mechanisms have been proposed, but three of the most frequently discussed approaches are: (1) distribution surcharge-funded policies, which can provide renewable energy developers access to new sources of public funding; (2) renewables portfolio standards, which can be used to mandate a minimum level of renewables development; and (3) mechanisms to promote green marketing, which may create significant new markets for renewables.

This chapter introduces the concept of surcharge-funded programs and identifies a number of the important financing issues that will have to be addressed in the design and implementation of this policy. The following two chapters discuss the financing issues associated with renewables portfolio standards and green marketing.[36] Although we discuss them separately, these three support mechanisms are not mutually exclusive. In fact, combinations of policies are likely to be the most effective way to promote renewables development. Each of the three programs can be used to support existing and/or new renewable energy projects; we emphasize their impact on new projects because existing facilities have already received financing. As will be shown in this chapter and in Chapters 7 and 8, many of the lessons and policy design issues discussed in Chapter 4 (e.g., policy stability, contract length, etc.) are pertinent to the design of surcharge-funded policies, renewables portfolio standards, and green marketing programs.

6.1 Description of Concept

Electric service distribution surcharges, also called "wires charges" and "system benefits charges," are a way to collect funds from electric customers to support various policies with public benefits, including renewable energy programs. Distribution surcharges have generally been proposed as a volumetric fee, such as a charge per kilowatt-hour, but could also be applied on a fixed-fee basis (e.g., a customer access charge) or through a combination fixed-fee/volumetric charge (RAP, 1995). The charges are intended to be non-bypassable and competitively neutral.

---

36 There are, of course, other issues that must be considered when determining the "optimal" approach for supporting renewables (Wiser, Pickle, and Goldman, 1996). We do not discuss these issues and therefore do not provide an overall assessment of proposed policies, but rather focus on the important financing concepts.

Once surcharge funds are collected for renewables programs, method(s) of distribution must be devised. There are, as one might expect, a large set of distribution possibilities (see Table 6-1). We break out these fund distribution mechanisms into four broad categories: (1) infrastructure development programs; (2) programs to encourage green marketing; (3) low-cost financing policies; and (4) incentive payments to renewable energy projects.[37]

Table 6-1. Renewables Programs that Could Be Funded by a Distribution Surcharge

Infrastructure Development Programs	Programs to Encourage Green Marketing
• *Renewable Energy Resource Availability Studies*	• *Public Education and Marketing Programs for Renewable Energy*
• *Development of Renewables-Specific Siting and Permitting Regulations*	• *Monetary Incentives to Customers that Voluntarily Purchase Renewables*
• *Technology Research, Development, and Demonstration*	• *Monetary Incentives to Marketers that Sell Renewables to Electricity Customers*
• *Incentives for Renewable Energy Equipment Manufacturing*	
Low-Cost Financing Policies	**Incentive Payments to Renewables Projects**
• *Low-Interest Government Loans*	• *Above-Market Power Sales Contracts*
• *Government-Aided Project Aggregation Programs*	• *Production Incentives (i.e., cents-per-kWh production payments)*
• *Project Loan Guarantees*	• *Investment Incentives (i.e., up-front grants)*

Distribution surcharges have already been used in targeted situations by a few U.S. electric utilities (Holt, 1995). They have not yet been implemented on a statewide basis, but are currently being considered in several states as part of electric industry restructuring efforts. California has chosen to use a surcharge-funded approach for the support of renewable energy, energy efficiency, and RD&D activities. Rhode Island, Massachusetts, New York, Washington, Oregon and others are all also pursuing surcharge-based policies, some of which will include funding for renewable energy. Surcharge-based programs could also be implemented at the federal level.

In this chapter we primarily emphasize the distribution methods identified in Table 6-1 that provide funding directly to new renewable energy projects through incentive payments; we focus on financing-related design issues. Policies that reduce financing costs directly (low-

37 Decisions on whether to target low-cost and/or emerging renewable technologies, and new and/or existing projects also have to be made.

interest loans, loan guarantees, and project aggregation programs) are discussed in Chapter 9. Financing issues related to green marketing are examined in Chapter 8.

In Section 6.2, we describe two basic approaches to distributing surcharge funds: production incentives and above-market power sales contract. In Sections 6.3 and 6.4, we discuss the importance of a stable policy with low eligibility risks and the need for a predictable revenue stream for surcharge-based policies that use either incremental production incentives or above-market power sales contracts. In Section 6.5, we describe the advantages and disadvantages of using up-front grants rather than long-term production support. Then, in Section 6.6, we briefly highlight the use of surcharge funds for market transformation and infrastructure development activities. Finally, in Section 6.7, we evaluate the benefits and costs of front-loading production incentive and above-market contract payments.

6.2 Production Incentives versus Above-Market Contract Payments

Two of the primary approaches to structuring a surcharge-funded renewables policy include incremental production incentives (i.e., a ¢/kWh incentive adder) and above-market contract payments (i.e., a premium PPA). Methods for selecting among competing projects include: (1) competitive auctions; (2) a first-come first-served approach; and (3) through the discretion of the administrator. Table 6-2 describes these project selection and fund distribution options.

Of the project-selection methods, first-come will often provide the greatest degree of overall certainty in investment markets because it supplies some *ex ante* certainty in obtaining the incentive; long-term investment in technology and project development is more likely to occur under these conditions.[38] Competitive auctions and discretionary selection, while they do have a number of other benefits, frequently introduce a greater risk to the developer that individual projects will not be selected for funding.

Regardless of the project-selection procedure, an above-market contract will typically provide a greater amount of revenue certainty to the investor than a production incentive. A production incentive does not supply full revenue predictability because the renewable energy developer is still responsible for power sales negotiations. To minimize revenue risk, the renewables developer would presumably require either: (1) certainty in the power sales revenue stream through a longer-term sales contract (under restructuring, either a CfD or bilateral contract); or (2) higher production incentives to offset uncertainty in the value of the power market. Therefore, if a long-term forward contract market did not materialize for power sales, renewables developers may require higher production incentive payments to offset revenue risk. Under an appropriately structured above-market contract policy,

38 We should note, however, that first-come project selection does not eliminate all uncertainty unless there is a strong expectation that an individual project will be selected before a subscription cap is met.

however, the investor is provided full revenue certainty for their power sales during the contract period.

Table 6-2. Production Incentive and Above-Market Contract Policies: Design Variations

Project Selection	Policy Description
First-Come	Under first-come distribution, a fixed cash production incentive (¢/kWh) would be provided to eligible renewable energy projects (up to a cost or subscription cap) for a specified number of years (similar to the REPI). Under the above-market contract approach, standard contracts would be dispensed to eligible projects (much like the standard contracts supplied under PURPA).
Competitive Auction	If a competitive auction were used to select among competing renewables projects, production incentives could be auctioned and supplied to the winning bidders. Renewables projects that require the least incremental support (beyond what they obtain in the power market) would bid a lower cents-per-kWh and would receive the production incentive (if the auction is a simple, price-only scheme). The Environmental Defense Fund (EDF) has been a leading proponent for this type of policy (EDF, 1995). In EDF's proposal, 10-year production incentives would be auctioned to the lowest bidders for the development of new renewable energy projects. An auctioned above-market contract would be similar to the U.K.'s NFFO and state set-aside programs for RETs. Low-cost bidders would receive a long-term power sales contract. The purchasing party could be reimbursed via the surcharge for the above-market payments which, in the U.K., are defined as the difference between the contracted price and the average monthly power pool price.
Discretionary Selection	Under discretionary project selection, the administrator would not be required to abide by first-come or lowest-bidder rules, but could use her own discretion to provide funds to those projects that are deemed most deserving (for environmental, cost, or other reasons).

Given this appraisal, the "best" policy from a developer and financing perspective would be a first-come, above-market contract program (e.g., standard contracts as developed under PURPA). Of course, other public policy considerations may suggest that a different approach be used. For example, auctions may be desired to increase competitive pressures and production incentives might be used so that the renewables developer is forced to find a customer-driven market for their power. The "best" approach from this broader public policy perspective will depend on trade-offs made by policymakers between sometimes conflicting objectives (e.g., competition auctions vs. investment certainty). We simply urge policymakers to consider the reduction of financing costs as one of the important policy objectives.

6.3 Policy Stability and Eligibility Risks

As demonstrated by the LUZ and REPI examples provided in Chapter 4, the risk of policy change or elimination can compound financing difficulties, increase financing risk premiums, and therefore reduce overall policy effectiveness. Even well defined programs can be subject to policy "drift," or elimination, over time.[39] To be fully effective, however, surcharge-based policies--or any RET policy for that matter--must be stable enough to allow longer-term development planning. Although full policy stability may not be possible or desirable from a public policy perspective (see Section 4.2), policymakers should seek to remove as much of the potential for sudden or capricious changes as possible.

Eligibility risk refers to the risk that a particular project may be deemed ineligible for surcharge funding after significant cash outlays have occurred during the project's development. To reduce or eliminate this risk, which can hamper project financing, it may be appropriate for the renewables program administrator to provide a determination of eligibility some time before the renewables project begins construction and operation. Clear policy guidelines can also reduce confusion over which types of projects are eligible and when policy cost or subscription caps are likely to be met.

6.4 Creating a Long-Term, Predictable Revenue Stream

As discussed in Chapter 5, project financing for RETs has traditionally required a full set of long-term power sales commitments that largely guarantee a revenue stream. At the very least, contracts have typically contained a fixed floor payment corresponding to the debt repayment period (EPRI, 1990). Given project financing, the creation of a long-term, predictable revenue stream is an essential component of a surcharge-funded policy that provides cash production incentives or long-term contracts. To meet this objective, three elements are essential: (1) a long-term payment period; (2) a funding mechanism that is secure; and (3) a contract that does not contain significant "out" clauses.

[39] Policy drift can occur when a policy is coopted by interests other than those originally working to establish the policy (Elwood, 1996). As future parties alter and amend older policies, even long-lived and well-crafted policies can change dramatically over time.

6.4.1 *Long-Term Payment Period*

In Section 4.5, we emphasized the need for a long-term payment period, especially for capital-intensive RETs, because the availability of lower-cost, non-recourse debt hinges on the existence of a stable revenue stream. Because of the short contract periods in the U.K.'s NFFO1 and NFFO2, financing costs increased dramatically resulting in high price premiums (Mitchell, 1995a). Contract periods of at least 10 years will allow a reasonable debt amortization period and provide equity investors a fixed revenue stream that can reduce risk premiums.

6.4.2 *Secure Funding Mechanism*

Even more critical than a long payment period is the security of the funding mechanism. This issue is of fundamental importance for a range of policies designed to encourage renewables development, not just surcharge-based mechanisms. As noted in Chapter 4, the REPI provides an example of a poorly designed policy because funding security has not been forthcoming. Without some assurance that funds will be available to make future incentive or contract payments, the policy support cannot be used as security for debt repayment.

LESSON: *A long-term and predictable payment stream is essential for the development of RETs that use project financing. Legislatures and regulators should ensure, to the extent possible, that policies that promise long-term production incentives or above-market contract payments to RETs will continue to be funded throughout the payment period and that "out" clauses are minimized.*

In Section 4.4, we identified several ways to increase funding security for legislatively-directed renewables policies. Applied specifically to surcharge-funded programs, these strategies suggest several possibilities. To the extent that surcharge funds are not treated formally as taxes and are not routed through the legislature, surcharge-based programs may be somewhat immune to yearly funding changes. In these cases, legislatures need not appropriate the funds on a yearly basis and can create a renewables program with multi-year funding (through the surcharge) and spending authority. In contrast, where surcharge funds are treated directly as taxes, they must be appropriated yearly by a legislative body. In this case, stability may be best achieved through the creation of a standing or open appropriation, and/or through the creation of a "pool of capital" that is large enough to be pledged for current year and future payments (e.g., a trust fund).

Regardless of whether surcharges are treated formally as taxes, they will be perceived as an additional tax on electric service. Surcharge-funded renewables programs may therefore be particularly vulnerable to funding changes. Consequently, legislative language that demonstrates a strong commitment to continued surcharge funding is essential.

6.4.3 *Contract Sanctity and "Out" Clauses*

The sanctity of power sales contracts has become a key issue recently as utilities have attempted to withdraw from their PURPA obligations. As described by Michael Reddy of Toronto Dominion Bank, "If there is one issue, one hot button, in the industry right now that impedes potential development whether it's renewables or otherwise, it is the assault on the sanctity of the contract. These non-recourse project financings rely on the predictability of cash flow and if you remove that predictability, you cast a significant cloud over it" (Brown and Yuen, 1994). Policies that force or encourage contract "out" clauses can significantly impair the ability of developers to obtain project financing (Hamrin and Rader, 1993). For example, if the de-funding risk of a surcharge-based program is high, contract "out" clauses might be encouraged. In the future, financiers are likely to be very reticent of investments in projects whose revenues are uncertain because of "out" clauses.[40]

6.5 Grants

In most circumstances, renewables policies should be designed so that subsidy levels are tied to project performance, not capital investment. However, if the conditions necessary for creating a long-term, predictable revenue stream cannot be met, policymakers may want to consider distributing surcharge funds as cash grants rather than production incentives or above-market contracts. Grants could be provided up-front or could be spread over several years contingent upon reaching performance or design objectives. A grant does not entail a long-term policy commitment to any individual project, however, therefore reducing one of the key risks of production incentives and above-market contract payment policies.[41]

For small customer-sited projects (rooftop PV, for example), this form of capital support may be particularly useful because of the high initial costs of these facilities and the difficulties in obtaining financing. Moreover, because these facilities are often used to supply on-site electric use, production incentive policies may be more complex (due to metering requirements) than capital support. Up-front grants may also be especially helpful to projects that use new technologies and/or have particularly high performance risks. Capital support can partially insulate investors from these performance risks because, unlike production incentives, the subsidy level is not directly tied to uncertain electricity production forecasts.

---

40 For example, in Michigan a 34-MW wood-waste-fired project, developed by Decker Energy International, was initially delayed because of a regulatory out clause in the contract that would have allowed Consumers Power to lower the power purchase rate if cost recovery was disallowed (NREL, 1994). In the U.K.'s NFFO, uncertainty in the long-term funding prospects for the above-market renewables contracts led to the insertion of two "out" clauses in the Regional Electric Companies' contracts with renewable generators.

41 To reduce "double-dipping," some RETs are not allowed to take advantage of both grant programs and federal and/or state tax credits, therefore reducing the effectiveness of capital support policies. For a thorough discussion of the "offset" issue, see Wiser (1996). In Chapter 9, an abbreviated description of this issue is provided.

Previous attempts to promote renewables via incentives tied to capital investment rather than production have not all been successful in encouraging project performance. For example, the investment tax credits and accelerated depreciation of the early to mid-1980s caused a California wind rush that resulted in large wind capacity additions, but provided wind power owners limited incentives for project performance (Cox *et al.*, 1991). Lenders typically like to see project structures in which all participants stand to benefit if the project does well, and would therefore generally prefer a subsidy tied to performance over one tied to capital investment. Consequently, up-front cash grants may need to be designed to give project developers incentives to install RETs capable of operating with reasonable performance. For example, funding could be contingent on state or federally imposed performance or operations requirements.

LESSON: *If significant uncertainty exists on the duration and magnitude of the surcharge collection, or if legislative or regulatory action could eliminate funding at any time, long-term production incentives and above-market contract payments may not be viable. Grants, with appropriate project performance requirements, might be considered in these situations.*

6.6 Using Surcharge Funds for Market Transformation and Infrastructure Development

If funding uncertainties are unavoidable and/or long-term commitments impractical, policymakers may also want to strongly consider the use of surcharge funds for market transformation and/or infrastructure development activities. Although a long-term perspective would be desirable, these types of activities do not require the longer-term commitments necessary for project financing. These activities may also be deemed preferable to the capital support policies described in Section 6.5, which may not provide proper performance incentives.

Eto *et al.* (1996) define market transformation as activities that reduce market barriers due to market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed. Market transformation has been most widely discussed as a mechanism for increasing the adoption of energy-efficiency investments, but the concept also applies to renewable energy markets. Activities that attempt to encourage the development of a voluntary "green" power market (listed in Table 6-1 and discussed in greater depth in Chapter 8) may be classified as market transformation efforts. Fuel source disclosure and labeling requirements and "green" certification programs are also considered

market transformation activities.[42] Infrastructure development programs, including those items listed in Table 6-1, may also help stimulate a renewable energy market, lessening the need for a fixed level of long-term support. While programs to directly encourage the commercial development of renewable energy projects remain important, these other activities can help "lay the groundwork" for the renewables industry.

6.7 Front-Loading the Payment Stream

If production incentives or above-market contract payments are used, it might be appropriate to consider front-loading the support payments to RETs. Although the pattern of electricity pricing is important to all projects, it is critical to many RETs because of their capital-intensity (Kahn, 1988). Renewable energy projects can often benefit from a front-loaded payment stream because this payment structure generates higher revenue in the early years when capital-intensive projects have high debt amortization requirements; payments decrease in the latter years after debt is repaid. Front-loaded payments can reduce debt service coverage constraints and decrease overall project costs.[43] Some existing PURPA contracts provide front-loaded payments. The NFFO also effectively provides for front-loading because the above-market contract period lasts for approximately the duration of the loan (7 years initially and currently 15 years).

LESSON: *Although the pattern of electricity pricing is important to all projects, it is critical to many RETs because of their capital-intensity. Front-loading of the payment stream (whether an above-market contract or incentive payment) can reduce debt service coverage constraints in the early years of project operation, therefore reducing overall project costs.*

Although front-loading is often preferable from the project investor's perspective, it creates an exposure to the risk that the supplier will abandon the project and default before the purchasing agent has been repaid for excess contract payments made in the early years of project operation.[44] Because of the risks involved, many past competitive power solicitations

---

42 Although we have presented the concept of market transformation in a cursory way, we believe that support for activities of this type holds significant promise. We therefore recommend further research into the benefits of different types of market transformation investments.

43 We should note that many renewable energy developers have been able to back-load debt repayment, which has a similar effect as front-loading the payment stream (Wiser and Kahn, 1996).

44 As long as the payments are sufficient to cover operating costs, the risk exposure will be minimized because it will continue to be profitable for the facility owner to keep the plant operating with high performance.

have penalized front-loaded bids through large security requirements and/or scoring deductions.[45]

We can evaluate some of the trade-offs associated with front-loading by using the cash-flow model developed in Chapter 3. We assume that payments are front-loaded during the 12 years in which debt is repaid and are constant in real dollars during this period. After year twelve, we assume that payments drop to 2¢/kWh real. We can then determine what front-loaded payment level (¢kWh) would be required in years 1-12 to make the project economic. Using a discount rate of 10%, we also estimate the 20-year nominal levelized cost under the front-loaded scenario. Table 6-3 shows our results for the wind power and PV facilities and compares these results with those for the non-front-loaded scenario presented in Chapter 3, which assumed that payments are constant in real dollars over the 20-year assessment period.

Table 6-3. Effect of Front-Loading RET Costs

Cost of Energy Measure	Technology	Non Front-Loaded Payments	Front-Loaded Payments
First Year Cost of Energy	Wind Power	4.3¢/kWh	4.6¢/kWh
	Photovoltaic	20.7¢/kWh	22.7¢/kWh
20-Year Nominal Levelized Cost of Energy	Wind Power	5.5¢/kWh	4.8¢/kWh
	Photovoltaic	26.3¢/kWh	21.7¢/kWh

The results demonstrate that the 20-year levelized cost of energy under the front-loaded scenarios is lower than without front-loading: 13% reduction for wind power (4.8¢/kWh compared to 5.5¢/kWh) and 17% for PV (21.7¢/kWh compared to 26.3¢/kWh). As expected, however, the first-year cost in the front-loaded cases is higher than without front-loading: 7% higher for wind power and 10% for PV. These results confirm that under front-loading, the overall levelized cost of energy can decrease (because of reduced debt service constraints), but that front-loading does require greater near-term payments and thus leads to some risk exposure by the power purchaser.

[45] Kahn *et al.* (1989) evaluate front-loading as an implicit loan and conclude that many of the imposed penalties are overly severe to the developer of a capital-intensive project.

CHAPTER 7

Renewables Portfolio Standard Policies

7.1 Description of Concept

The renewables portfolio standard (RPS), sometimes called a minimum renewables purchase requirement (MRPR), allows regulators and/or legislators to require that a certain percentage of a state's annual electric use comes from renewable energy (the RPS could also be applied at the federal level). To implement the policy, a renewables purchase requirement (as a percent of energy sales) could be imposed upon retail electric suppliers.[46] To add flexibility in meeting the purchase requirement, individual obligations could be made tradeable through a system of renewable energy credits (RECs); this flexibility is expected to allow the renewables target to be met in the most cost-effective manner. The RPS therefore requires, as a condition for doing business in a state (or country), that each retail electric supplier obtain RECs equivalent to some defined percentage of its total annual energy sales. These RECs would be created when a renewables facility generates a kilowatt-hour of electricity that is contracted for sale into the state (or country). To meet the purchase requirement, retail electric suppliers could: (1) construct and operate their own renewable energy facilities; (2) purchase RECs bundled with renewable power purchases from independent RET facilities; and/or (3) purchase RECs from a private REC market without the associated renewable energy. The REC and renewable power sales markets are therefore partially separated, and the price of the RECs would represent the above-market costs of the renewable energy. There are a number of different ways to implement an RPS and a large set of design details to consider up-front.[47] For a more detailed description of a particular type of RPS, see Rader and Norgaard (1996).

The RPS was first introduced by the American Wind Energy Association in the California Public Utilities Commission's (CPUC) electricity restructuring proceedings.[48] Although not

---

46 It would also be possible, although perhaps not as desirable, to impose the requirement on electricity generators.

47 Some of these design issues include: (1) determining the level of the purchase requirement; (2) incorporation of cost containment mechanisms; (3) synergies with green marketing; (4) defining eligible renewable energy technologies; (5) treatment of out-of-state projects, self-generation, renewables under PURPA contracts, and utility-owned resources; and (6) promotion of emerging and high-cost renewables. Wiser, Pickle, and Goldman (1996) and Renewables Working Group (1996) cover many of these implementation issues and design variations.

48 The CPUC supported the RPS in their December 20, 1995 restructuring decision, and created a Renewables Working Group to help resolve many of the implementation details. The RPS was also considered in the California State Legislature. See Wiser, Pickle, and Goldman (1996) for a detailed description of the RPS policy debate in California.

adopted in California, an RPS-based policy is being pursued at the national level and a number of other states are considering the RPS in their restructuring proceedings.[49]

7.2 Policy Stability and Markets for Renewable Energy Credits

As with many of the other policies discussed in this report, the ability of an RPS to cost-effectively support the development of new renewable energy facilities hinges on its ability to provide sufficient long-term revenue certainty to developers, investors, and lenders. The costs of existing projects, many of which have already repaid their debt, are less affected by policy instability and duration.

Under an RPS, renewable energy project owners would have a total revenue stream that comes from two "commodity" markets: the power market and the REC market.

7.2.1 The Power Market

Within a restructured electricity industry, it is unlikely, in the near term, that new renewable energy facilities will be developed based solely on a variable spot market price. Lenders are typically unwilling to take such large default risks, especially for generation technologies that have high capital costs. Direct bilateral contracts and CfDs will probably be more common. In the short-term (less than 5 years), the market clearing price of U.S. spot markets is likely to average between 2-4¢/kWh.[50] For the purpose of this analysis, we assume that a new renewable energy project will be able to obtain a power sales contract (bilateral or CfD) at a rate of, approximately, 3.5¢/kWh (a gross estimate, of course). Given current renewable energy costs, this price is unlikely to be sufficient to meet the debt service coverage that lenders require and maintain sufficient equity returns for new RET projects. Therefore, additional revenue will be required to provide credit support to lenders.

---

49 These include Vermont, Maine, and Arizona.

50 Assuming the marginal plant is typically a gas facility with 30% efficiency, and taking gas prices as $2-$3/MMBtu (approximately $2/MMBtu—consistent with EIA forecasts—at the well-head with, at most, a $1/MMBtu transmission markup), the pool price would equal approximately 3¢/kWh.

7.2.2 *The REC Market*

The REC market can also supply a revenue stream to the renewable energy developer and, therefore, provide credit support for the lender. To maximize revenue certainty, a renewables developer would likely seek a long-term REC sales contract with a REC buyer, which would provide debt security, allow longer maturity and less costly debt to be obtained, and reduce equity costs.

The regulatory and legislative stability and duration of the RPS will affect the ability of the REC market to supply this credit support. From the REC buyer's perspective, REC purchases could be obtained on the spot market, through short-term contracts, and through long-term contracts. Futures and options markets might also be created. If long-term policy stability is assured, a range of purchase types are likely to occur. REC buyers will transact through the long-term contract market when they want to reduce REC price risks or when such purchases are expected to be less costly than future spot and short-term REC contract purchases.

If the policy is not stable and its duration is unknown, long-term REC purchases are less likely. In this case, long-term REC purchases may be less costly in the early years; but, if the policy is terminated before the REC contract expires, the buyer would be forced to continue purchasing RECs that are unnecessary and for which no secondary market exists. Therefore, if regulatory and legislative commitments are weak, or if the RPS is enacted for a short period, it seems likely that REC buyers will prefer spot and short-term contract purchases. REC contract lengths may be limited to the expected duration of the standard itself.[51] This situation would probably lead to shortened debt terms, higher debt interest rates, more restrictive debt contracts, and higher equity costs, resulting in higher-cost renewables development than if longer-term, predictable contracts were available. For example, if power contracts are available for 10 years and REC contracts for four years, four year debt terms might be expected because the 4th-10th year REC market cannot be predicted with certainty. Alternatively--and perhaps more likely--developers may use multiple loans of different lengths, each tied to a different revenue source, or may simply reduce the amount of debt in the capital structure of their projects so that the power contract revenue is sufficient to meet all debt service coverage requirements.

---

[51] If longer REC contracts do develop, they are likely to include "out" clauses in the case of changes to the RPS policy.

7.2.3 *Effect of RPS Duration and Stability on Renewable Energy Costs*

We use the model developed in Chapter 3 to approximate the possible impacts of RPS uncertainty on the overall levelized cost of new renewable energy projects. In our base-case analysis in Chapter 3, we assumed a 12-year debt maturity for PV and wind power facilities. Let us now assume that there is a chance of RPS policy termination in four years and that REC buyers are unwilling to commit to REC contracts above four years in duration. If this causes a reduction in debt maturity to four years, PV costs are estimated to rise by approximately 35% (9.2¢/kWh) and wind power costs by 25% (1.4¢/kWh). Uncertainty in the revenue stream could also increase equity risk premiums over the base-case scenarios. In the wind power case, if debt maturity decreases to four years and equity costs rise to, for example, 22% (an estimate), levelized costs increase by 55% to 8.5¢/kWh.

As noted earlier, developers may decide to simply decrease the amount of debt in the capital structure of the plant so that the revenue provided by the power market contract is sufficient to meet debt service coverage requirements. Equity investors are more willing to take revenue risks and, for a risk premium, would probably be willing to take-on REC price risk. Assuming that a forward power sales contract is available for 3.5¢/kWh over 12 years, it can be shown that the capital structure of the wind plant would have to be approximately 70% equity and 30% debt to meet typical debt service requirements. Given this capital structure, and assuming that equity investors charge an additional risk premium such that the return on equity equals 22%, the nominal levelized cost of the wind plant is estimated to be 7.6¢/kWh, a 40% increase over the base-case scenario.

LESSON: *If long-term regulatory and legislative commitments are weak, a long-term REC market will not form within the RPS and financing costs for new RETs will increase significantly relative to the probable costs under a more stable policy.*

REC price uncertainty could motivate renewable energy investors to use corporate financing, therefore absorbing the overall project risks within their own corporate structure; this would favor the largest renewable energy companies. Smaller renewable energy developers may partner with larger corporations that are willing to take the corporate risks associated with balance-sheet financing if expected returns are high. Despite the appeal of this approach, it does not fundamentally alter the results of our analysis. Although the increased use of corporate financing and partnering may appear to reduce finance costs, these reductions frequently come with an increase in risks to the corporation.

7.2.4 *Policy Implications*

Because the RPS rewards performance (kWh, not kW) and, if stable, could promote long-term REC commitments, the policy could help reduce financing costs. If the market is unstable, and regulatory and legislative commitments are weak, however, our analysis suggests that the cost of new renewable energy projects could increase by up to 25-50% compared to the probable cost under a stable market. Existing and new RET facilities are likely to compete for REC sales. Therefore, an increase in the relative cost of RECs from new facilities (because of policy instability) could lead to increased use of existing projects to meet the purchase requirement. Lower-risk repowers and retrofits might also be preferred over new development that has significant financing requirements.

To help solve the financing problem, most of the California RPS proposals did not have a sunset date (except to the extent that renewables become cost competitive, in which case RECs have no value) and many urged policy stability as a key design objective (Renewables Working Group, 1996). Legislators are generally hesitant to revoke or change policies if such changes substantially impact parties that have already entered into contracts. Although the RPS only indirectly results in REC contracts, language specifying that the legislative intent is to create a long-term program, and that contracts are likely to develop based on the program, may provide some modicum of stability. As noted elsewhere, weak policy commitments and a short policy duration should be avoided if at all possible.

CHAPTER 8

Green Marketing Programs

8.1 Description of Concept

Green marketing takes advantage of electric customers' willingness to pay for products that provide both public environmental benefits and private benefits (e.g., electricity price stability). Market research indicates that there are a significant number of electric customers who state a willingness to pay a premium, if given the chance, to buy "green" electric services (including renewable energy).[52] There are a number of ways to capitalize on this demand and support the development of renewable energy, including:

- offering renewable power supply (often at a premium rate) to electricity customers;
- offering donation programs, the proceeds of which are used to purchase renewable energy; and,
- creating investment opportunities that offer investors a lower rate of return in order to supply capital to renewable energy projects at attractive rates (e.g., direct on-site RET ownership and investment in renewable energy companies).

We characterize the first two approaches as "green power purchase" programs (often called green pricing when supplied by electric utilities), while the third category is referred to as "green investment." In addition, we fully expect new and innovative strategies to market "green" power because programs of this type allow electricity suppliers to differentiate what might otherwise be commodity products and provide valuable services to niche markets. We again focus primarily on the impacts of program design on the financing of new renewable energy facilities.[53]

State regulators and/or legislators could mandate or encourage utilities to offer green power purchase options, but mandates may not result in the development of effective programs unless utilities are internally motivated. Although legislative and regulatory involvement in green marketing is not essential if retail competition exists, state and federal policies could help stimulate the creation of viable green power markets for RETs. The most direct form of involvement would be for state and/or federal government agencies to purchase a minimum percentage of renewable energy. Indirect actions might be particularly useful, however. For example, fuel source disclosure and/or "green" certification could be required and aggregation

---

52 This research has generally found that a large number of consumers are willing to pay a 5 to 15 percent premium for the satisfaction of purchasing "green" energy supply (Green Pricing Newsletter, 1994; Green Pricing Newsletter, 1995; Baugh *et al.*, 1995; Smith, 1996; Farhar and Houston, 1996), but customer participation estimates frequently exceed actual participation rates (Marcus *et al.*, 1995).

53 Until now, we have primarily discussed design issues for renewable energy policies. In this chapter we also discuss design details for privately-supplied green marketing programs.

of customer loads might be encouraged. Customer education of green power options and publicly-funded marketing campaigns may also be effective uses of public funds. In addition, to help buy-down the cost of renewable energy purchases and "kick-start" the new market, distribution surcharge funds could be used to provide monetary incentives to customers that purchase renewable energy. Alternatively, the incentives could be supplied to the retail marketer of renewable energy. Using surcharge-funds for these market transformation activities is being considered in California. As discussed briefly in Chapter 6, this use of surcharge funds may be particularly appropriate where long-term funding and policy uncertainties are unavoidable.

A number of utilities, both in the U.S. and abroad, have initiated green pricing programs and many others have investigated and performed market research on the concept; utility experience with these programs has been mixed (Holt, 1996). Under retail competition, successful green marketing programs may be more likely to come from unregulated retail electric suppliers than existing electric utilities.[54] Based on experience from the New Hampshire and Massachusetts direct access pilot programs, it is clear that retail electric suppliers are likely to use "green" claims as a marketing tool.[55] At this stage, however, experience with green marketing programs is too limited to make any conclusion on the size of the potential new market for renewable energy.

8.2 Fluctuating Participation Rates in Green Power Purchase Programs

A number of design issues have been raised for green marketing programs (both utility and non-utility provided) that involve the payment of a premium electricity rate for renewable energy (Moskovitz, 1993; Holt, 1996). While experience with green marketing is limited, here we emphasize what is expected to be the primary issue related to financing: fluctuating customer participation rates.

---

54 Some utilities may not have the institutional desire, entrepreneurial spirit, or financial incentives to effectively pursue green marketing programs. Moreover, some electric utilities may not have the customer trust necessary to sell a green product. In some instances, non-utility retail electric suppliers, particularly ones that are associated with non-profits or other entities that engender public trust, may be able to market these programs more profitably and successfully.

55 It has also become apparent that fuel source disclosure and/or "green" certification requirements will be essential to reduce misleading advertizing (Green Pricing Newsletter, 1996). In New Hampshire, a number of companies used misleading advertising to market "green" products.

8.2.1 *"Sustained" vs. "Annual" Customer Participation Options*

Customer participation rates in green marketing programs will fluctuate yearly and, initially, the level of customer participation may be very difficult to estimate. Given participation uncertainties and the fact that new renewable energy projects typically require a longer-term revenue commitment, a decision must be made on whether to base a green marketing program on: (1) "sustained customer participation," or (2) "annual customer participation" (Moskovitz, 1993). The principal difference between these two approaches lies in the period over which a given level of renewable energy is acquired. In the "sustained participation" option, customers fund the annual incremental cents-per-kWh cost premium for a renewable energy project. Green marketers commit to acquiring renewable energy over a long time period under the assumption that long-term customer participation will continue to fund the program. Because this type of program requires relatively constant customer participation over many years in order to recover the full cost of the facility, these programs are at risk should customers opt out of the plan and participation rates fall.[56]

In order to overcome risks posed by fluctuating participation, green marketers could use the "annual participation" model. Green marketers employing this approach effectively use annual funds to buy-down the initial cost of the renewable energy facility and do not commit any customer funds beyond that which is already collected. Therefore, unlike the "sustained participation" approach, a customer contributing annually actually "obtains" green energy over a long period. Risk to shareholders, lenders, and non-participating customers (if a utility is providing the service) is eliminated because each participating customer's yearly contribution pays fully for the lifetime cost premium of the renewable resource.[57] Although both of the payment strategies (and combinations of the two) have been used in current utility-supplied green pricing programs, the "sustained participation option" is the dominant program type. "Annual participation" programs may be more difficult to explain to customers (Moskovitz, 1996).

---

56 "Replacement" customers could step in to cover the lost revenues from departing customers. However, sustained participation programs may have difficulty recruiting replacement customers, many of which might prefer to contribute to a new renewables facility rather than support an existing one.

57 A brief example illustrates the distinction between the "sustained" and "annual" participation options. Assume that an electric customer uses 6,000 kWh per year and wants to purchase 100% renewables through a green power purchase program. Under the "sustained participation" approach, the customer is assumed to participate indefinitely or be replaced by another customer. When an additional customer decides to participate, the green marketer is effectively obliged (because renewable energy projects require a long-term revenue commitment) to acquire new renewable resources that are able to produce 6,000 kWh per year for the lifetime of the facility or contract. Under the "annual participation" approach, the customer would receive the 6,000 kWh spread over the lifetime of the facility or contract. For example, the green marketer may sign a 15-year contract to buy 400 kWh per year to fulfill its 6,000 kWh obligation. The longer customers contribute to the program, the more renewables are acquired.

Given the prevalence of the "sustained participation" model, yearly participation fluctuations are unlikely to provide a constant and predictable revenue stream to the renewable energy investor, creating difficulties in obtaining project financing debt for new RET facilities. Although equity investors will be willing to bear customer participation risk if supplied an adequate return, non- or limited-recourse lenders are simply not willing to take on significant risks. Within the "sustained participation" approach, there are four non-mutually-exclusive ways to help resolve the financing difficulty: (1) generation of risk-taking intermediaries; (2) longer-term customer contracts; (3) alternative financing arrangements; and (4) emphasis on lower-risk renewables projects (e.g., existing projects, retrofits, and small new facilities). The need for these mechanisms is largely avoided if a pure "annual participation" model is used.

8.2.2 *Intermediaries*

Power marketing intermediaries are likely to step in to shoulder some of these participation risks. These companies could offer a fixed or predictable revenue stream to the renewable energy developer for a number of years, allowing the developer to receive financing. The marketing agent would then sell the "green" power to its customers and therefore absorb participation risk. Under these conditions, lenders will be willing to invest in the renewable energy facility with project financing only if sufficient security is provided by the marketing intermediary (which might require that the intermediary be a relatively large company with significant assets). Intermediaries might also include local governments, some of which may aggregate customer loads (especially the residential and small commercial classes) when retail electricity competition exists. In existing utility-supplied green pricing programs, the utility effectively acts as the marketing intermediary. The utility can then choose to either purchase renewable energy via a fixed or predictable contract with an independent renewable energy supplier (who may then be able to receive project financing) or own the renewable energy facility itself, financed internally via the utility's balance sheet.[58] In either case, utility shareholders and/or non-participating customers bear the risk of under-recovery of costs.

8.2.3 *Customer Contracts*

To help insulate shareholders, lenders, and non-participating customers from undue risk, some utility green pricing programs require customers to sign contracts for participation. This approach is also likely under retail competition when unregulated companies are allowed to market "green" energy products. Although one would not expect to be able to persuade many residential customers to sign long-term contracts for the supply of renewable energy, Moskovitz (1993) notes that shorter-term commitments (several years or less) might be

---

58 In most existing U.S. green pricing programs, utilities have owned the renewable energy facility; however, planned programs include both utility ownership and power purchases.

imposed without a significant loss in customer interest.[59] In Traverse City, Michigan, for example, a municipal utility runs one of the more successful green pricing programs, which has resulted in the installation of a wind turbine. In this program, residential customers made a 3-year commitment and commercial customers a 10-year commitment to pay the specified price premium (Holt, 1996).[60] These commitments, while reducing participation risk, are probably not sufficiently secure for project financing (especially residential customer contracts). Even if customers are willing to sign up for 10-year periods, such contracts with residential customers are unlikely to be adequate for project financing unless secured with significant assets (e.g., a home mortgage). Moreover, even if the contracts are legally binding, the costs of enforcement would probably be too large to merit legal action. A possible role for a government or private intermediary might be to insure and back these contracts. For a fee, this insurance entity could shield the project owner or green marketing agent from participation risk.

LESSON: *Customer participation risk is the largest financing issue related to green marketing. Participation risk can be reduced through longer-term customer commitments or the use of the "annual participation option." Otherwise, large intermediaries will be needed to take-on these risks (utilities or marketing agents), balance-sheet financing will become increasingly common, and green marketers are likely to emphasize lower-risk renewables projects.*

8.2.4 *Alternative Financing*

As with RPS REC price risk, customer participation risk could result in altered financial approaches that move away from traditional project financing structures and toward increases in equity financing and the use of balance-sheet, corporate financing. As discussed in Chapter 5, electricity restructuring is already beginning to cause these changes and we expect these new financing approaches to become more common. Corporate financing does not require certainty in project-specific revenue streams. Thus, corporations should be able to absorb participation risks more easily than facilities developed with non-recourse debt. As noted earlier, corporate financing tends to favor the largest renewable energy companies.

---

59 It is possible that residential customers will be more loyal to green energy suppliers than commercial and industrial customers, and therefore may be willing to enter into longer contracts than other electricity customer classes.

60 Detroit Edison, which is using green pricing to pay for the premium price of a PV facility, provides another example. To reduce participation risk, residential customers are required to sign a 2-year contract, which will be extended automatically after that period unless the customer requests in writing that the agreement be terminated. Commercial customers may also participate, but a 10-year commitment is required (Holt, 1996). The Sacramento Municipal Utility District, Northern States Power, and Wisconsin Public Service also ask for 5-10 year customer commitments.

8.2.5 Lower-Risk Projects

In the short-term (when participation uncertainties are particularly high), green marketers can be expected to emphasize green power sales from lower-risk renewable energy projects that require a less significant power purchase commitment. These might include: (1) existing projects; (2) retrofits, repowers, and additions to existing facilities; and (3) small new facilities.[61] Large-scale, new projects are far less likely. Existing projects will not generally require as secure a revenue stream or as long a purchase commitment from the green marketer because financing has already been acquired. While they may need some additional financing, retrofits, repowers, and additions to existing projects often need less significant commitments than large, new projects. Finally, to the extent that entirely new projects are developed, the emphasis may be on smaller facilities. Small renewable energy companies, for example, are unlikely to absorb customer participation risks for large-scale projects, although they may for smaller RET facilities.

8.3 Green Investment

One form of green marketing gives "green" investors the opportunity to directly invest in renewable energy facilities and renewable energy companies, rather than simply purchasing the output or contributing funds to these facilities. In contrast to typical investments, "green investment" opportunities offer investors a lower rate of return in order to supply capital to renewable energy technologies at attractive financing rates (e.g., lower equity or debt costs). These financing cost reductions can significantly reduce overall project costs. For example, if equity investors in PV facilities are willing to provide capital with a 10% ROE, PV costs are estimated to decline by 25% (6.5¢/kWh) from the base-case 18% ROE scenario. If the cost reductions are sufficient to make some forms of renewable energy competitive with more traditional generation alternatives, then "green investment" of this type can stimulate the development of renewable energy projects.

The simplest type of "green investment" is the purchase or lease of a small-scale RET installation (e.g., PV or wind) to meet home energy needs even when other electricity supply alternatives are more cost-effective. More indirect mechanisms of green investment include socially responsible mutual funds, green equity funds, and "ethical" banks. There may also be innovative opportunities to combine the "green investment" and "green power purchase" program types. For example, ownership interests in renewable energy projects could be sold to electric customers but with project dividends dispensed not only as cash but also as kilowatt-hours supplied to equity investors (Moskovitz, 1996).

---

61 There are also non-finance reasons to expect green marketing to emphasize existing projects, upgrades, and small new facilities. First, these projects may be less costly on an incremental basis than new facilities. Second, customer demand for renewable energy may materialize too quickly for new projects to absorb in the short-term; new projects frequently take several years to develop.

Although a number of socially responsible mutual funds exist in the U.S. (and a smaller set of socially responsible lending institutions), these funds have not had a significant impact on renewables development. The use of "green investment" is more common in Europe, where it has been used extensively to reduce the cost of financing for renewable energy projects. In Germany, for example, actual equity shares were sold to the public for the installation of a 7.5 MW wind farm; 21% of the total investment came from this source, the return for which was considerably less than demanded by traditional sources of investment funds (i.e., venture capitalists) (Holt, 1996). This approach has also been considered by Ontario Hydro (Kelly and Boone, 1996). In the U.K., an investment fund targeted specifically to renewable energy (Wind Fund plc) intends to invest in small wind and hydroelectric projects (Clean Energy Finance, 1996). Finally, in several European countries, wind cooperatives have been created for the development of wind plants. The members of these cooperatives are driven to invest in wind projects by both economic and social factors.

Low-cost debt investments are also possible. "Ethical" banks in Denmark, Germany, the Netherlands, and other European countries have provided low-interest loans to a large number of small renewable energy projects (Mitchell and MacKerron, 1994). In these arrangements, low-interest loans are made available to RET projects because bank depositors are willing to accept a lower rate of return than is available from commercial banks. In Denmark, for example, Faellskassen (one of the largest ethical banks) provided funds to investors in a large cooperatively owned windfarm (3 MW) at an interest rate of 4% (compared to the 10% interest rate that might have been available without the program) (Mitchell and MacKerron, 1994). Because of limitations in the size of the pool of capital (i.e., the number of people interested in putting their savings into low-return ethical banks), these types of lending arrangements have worked well for the smaller renewables projects that are typical of Europe, but are much less plausible for the larger projects that have dominated the U.S. renewable energy market (Mitchell, 1996).

Direct Mechanisms to Reduce Financing Costs

In Chapters 6-8, we discussed three specific ways to support renewables that might be used in a restructured electric industry. In these three chapters, and in Chapter 4, we emphasized the ways in which program design can *indirectly* impact renewable energy finance. In each case, the financing implications were a by-product, rather than an intended consequence of the given policy. There are, however, a number of policies that are designed to address RET financing issues *directly*. This chapter focuses on these policies, which include low-interest government-subsidized loans, project loan guarantees, and project aggregation. Funding for these programs can come from federal or state general funds, state or federal bonds, or from "public" benefits surcharges collected by distribution utilities.

Although our analysis suggests that these policies can reduce renewable energy costs and alleviate financing difficulties, there are a number of barriers to their effectiveness (particularly low-interest government-subsidized loans). Of greatest importance is the potential conflict between subsidized financing programs and federal and state tax credits for renewable energy. To eliminate "double dipping," the federal PTC for wind and closed-loop biomass is reduced for certain types of subsidized financing obtained by the project. Therefore, certain types of subsidized financing programs could result in a reduction in the federal PTC payments for qualifying facilities, diminishing the effectiveness of these financing policies. Similarly, if commercial solar or geothermal property is financed in whole or in part by certain types of subsidized energy financing, then only that portion of the investment that is not so subsidized is eligible for the federal ITC. Reductions often occur for state tax credits as well. Despite various IRS rulings, it is not entirely clear what constitutes "subsidized energy financing" for the purposes of federal tax credit offsets. Under the ITC provisions, loan guarantees are apparently not included in the definition; additionally, if the source of and/or control over the program's funds is not the government (e.g., if it were administered and funded by an electric utility and its ratepayers), the policy may not offset the ITC (Wiser, 1996).

Interactions between subsidized financing programs and other state and federal subsidies force the renewable energy developer to trade-off the benefits associated with different incentive programs. Policy interactions of this type should be considered closely when discussing the implementation of subsidized financing programs.[62]

---

62 Other forms of state policies also offset the value of the federal tax credits for RETs. For a more complete description of this problem, see Wiser (1996).

9.1 Low-Interest Government-Subsidized Loans

Debt interest rates and debt maturity have notable impacts on the levelized cost of renewable energy, and renewable energy projects are commonly subject to higher financing risk premiums than gas and coal power plants.[63] RET projects without a certain revenue stream and developers without a good track record may be incapable of securing a loan.

Low-interest loan programs can be administered by state or federal agencies, local authorities, electric utilities, or private banks. Through these programs, federal and state governments can directly provide capital to renewable energy projects at lower interest rates and with longer repayment periods than are available through private capital markets. Alternatively, states and/or the federal government could subsidize private banks that provide such loans to eligible projects. Although due diligence procedures (which include technical, market, and financial evaluation of a project by the lender) would often be similar to those used for typical commercial loans, state and federal loan programs may also offer more flexible loan terms than are available in private markets. The value of these programs could increase with electricity restructuring because long-term PPAs, historically essential for obtaining debt, may become scarce.

Low-interest loan programs can be particularly helpful to small-scale renewable energy facilities (e.g., residential PV and wind systems) because of difficulties in obtaining reasonably priced bank loans for these projects (or, even more importantly, an inability to obtain any loan). High capital costs often act as a significant barrier to customer investment in these systems. Additionally, these on-site, customer-owned systems are often not eligible to receive federal tax credits and are therefore not subject to the tax credit offset issues that plague larger-scale systems.

A number of states have established loan programs administered through a state agency or utility for renewable energy systems (Shirley and Sholar, 1993; Rader and Wiser, 1997). These programs have taken many shapes, but have traditionally been focused on reducing financing costs for smaller renewable energy installations, often solar and wind. For example, a Minnesota law allows farmers to receive low-interest loans of up to $50,000 through the state's Department of Agriculture to construct small wind power systems. In Idaho, loans with an interest rate of 4% are available to owners of small renewable energy projects. Although less common, low-interest government-subsidized loans have also been offered to utility-scale renewables projects. For example, a number of biomass developers have been able to take advantage of tax-exempt pollution control bonds (Reese, 1996).

---

63 Utility-scale wind systems, for example, frequently obtain debt with an interest rate that is 1-2 percentage points higher than for gas-fired projects (Wong, 1995).

Two primary factors currently inhibit the effectiveness of low-interest loan programs in encouraging renewables development. First, the benefits of some types of low-interest loan programs may partially offset other state and federal tax credit benefits.[64] Second, the Tax Reform Act of 1986 limits the amount of state funds that can be raised for private purpose activities. Competition among alternative uses for these funds frequently restricts the level of funding allocated to low-interest renewable energy loan programs. If these barriers were eliminated, low-interest loans could become a very valuable incentive for renewables development.

Low-interest loans can significantly reduce the cost of renewable energy supply, therefore increasing the competitiveness of renewables relative to other generation technologies. Using the cash-flow model developed earlier, and ignoring the impact of subsidized financing on federal tax credit programs, Figures 9-1 and 9-2 show how wind power and PV costs vary with the debt interest rate and debt term. As expected, longer debt repayment periods and decreased interest rates reduce overall costs. Given that a typical low-interest loan program may offer interest rates of below 6% and a repayment period of up to 20 years, the cost savings associated with these programs can be significant.

In cases where loan programs reduce state and/or federal tax credit payments (or impact other policies more generally), policy trade-offs will be required by project owners. Wiser (1996) quantitatively evaluates the potential trade-off by estimating the federal "takeback" of state funds. This "takeback" represents the fraction of funds supplied through a state low-interest loan program that would effectively be provided to the federal treasury through the tax credit payment reductions. Given a low-interest loan program for a geothermal project under different debt maturity (15-year and 20-year debt) and interest rate (0% to 6%) assumptions, the potential benefits of the program are estimated to exceed the lost benefits of the ITC. The federal "takeback" fraction is estimated to be as high as 50%, depending on the program's design. These results suggest that, even if the tax credit offset does occur, the net benefits of a low-interest loan program may still be quite high.

9.2 Project Loan Guarantees

Project loan guarantees could be provided by the state or federal government. A program of this type would guarantee lenders (banks or institutions) of loan repayment and would therefore shield the lenders from project risks, reduce debt interest rates, and perhaps increase

64 A simple example of the federal tax credit offset may prove useful. For commercial PV facilities, only that portion of the investment that does not use subsidized financing is eligible for the 10% federal investment tax credit. Therefore, if a low-interest loan is provided to meet 60% of a project's initial cost, then the federal ITC is reduced to 4% (i.e., 10% ITC * (1 - 0.6)).

Figure 9-1. Impact of Debt Interest Rate and Debt Term on Wind Power Costs

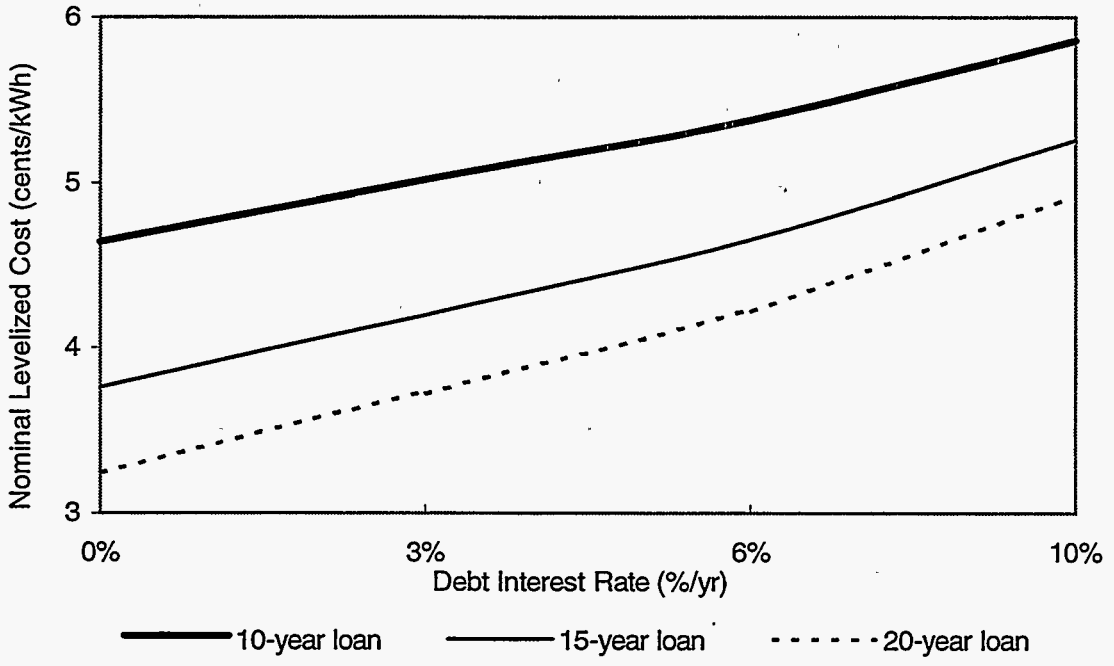
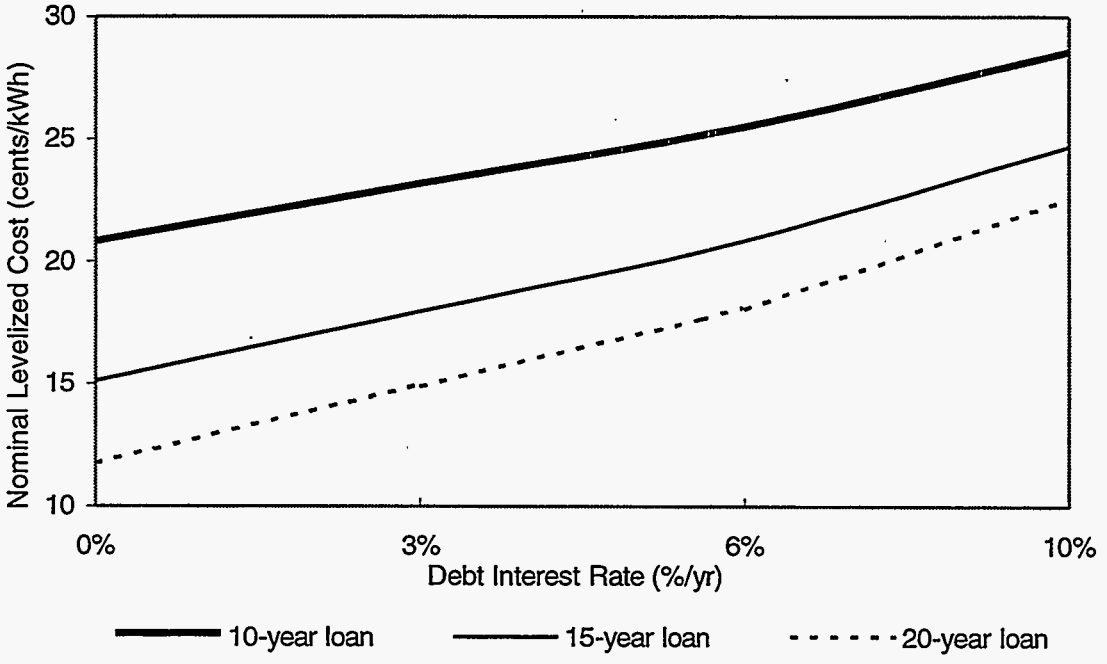


Figure 9-2. Impact of Debt Interest Rate and Debt Term on PV Costs



debt maturity. In the most extreme case, without a guarantee, loans may simply not be available for some types of risky renewable energy projects (e.g., facilities without a long-term contract or for developers and technologies without a good track record). In this situation, loan guarantees would provide the assurance lenders need to even consider a loan. The cost to the government from a loan guarantee program would come, primarily, from payouts to lenders in the event of project defaults. As security for these guarantees, the guarantor (the state government, for example) might require a "cash pool" (out of which payments would be made) or may need to explicitly provide security through the government's taxing authority. These guarantees could provide risk insurance for all or a portion of a project's risks. If full coverage is provided, however, there may not be an adequate incentive for the renewable energy facility owner to maximize project performance and profitability.

Loan guarantees have been used by the U.S. federal government for energy and non-energy programs and are applied extensively in international markets for electric power projects. Beginning in 1974, the U.S. Department of Energy provided loan guarantees to geothermal developers under the Geothermal Loan Guarantee Program, established by the U.S. Congress in the Geothermal Energy Research, Development, and Demonstration Act (P.L. 93-410). The objective of this policy was to assist the public and private sectors in overcoming the financing risk barriers to the development and operation of facilities using the then newly emerging geothermal technologies (Schochet and Mock, 1994).[65] Because the guarantees were primarily used by geothermal developers that were unable to obtain funds from private sources (Hinrichs, 1996), the guarantees proved valuable for projects using new technology and for developers with a limited track record (NREL, 1994).[66] Despite the successes of this program, small business entrepreneurs often found that they were unable to qualify for the guarantees and that the loan guarantee was too burdensome to be useful (Meyer *et al.*, 1980).

Internationally, multilateral and bilateral banks and export promotion agencies frequently provide loan guarantees to financial institutions on behalf of power project developers. The U.S. Export-Import Bank, for example, provides some project debt guarantee coverage. In Denmark, a government-supported guarantee company has offered loan guarantees to wind power projects using Danish turbines that are located in countries outside of the European Commission (Nielsen, 1993).

---

65 The guarantees were backed by the full faith and credit of the U.S. government. Guarantees were only provided to projects that had no realistic chance of obtaining commercial loans. Loan guarantees could be supplied for a maximum of 30 years, with collateral generally limited to project-related assets. The cumulative amount of all guarantees was not to exceed $500 million (Schochet and Mock, 1994). Nine separate guarantees were ultimately furnished to geothermal projects before the program was suspended in 1982 (Schochet and Mock, 1994).

66 A number of the projects that received these guarantees refinanced their loans in the private market shortly after operational experience was gained (i.e., within three years).

Loan guarantees are apparently immune to the federal tax credit offset (Wiser, 1996). Loan guarantees could significantly reduce the cost of renewable energy supply; see Figures 9-1 and 9-2 for the quantitative effects of debt interest rate and debt maturity on wind power and PV costs. If the guarantor insures against all project risks and the debt maturity is constant (12 years), debt costs may be reduced to the treasury rate for debt of similar terms, currently approximately 6% (assuming the credit rating of the guarantor is good). This results in a reduction in the nominal 20-year levelized cost of PV of approximately 11% (3¢/kWh) and a 9% (0.5¢/kWh) reduction in the cost of wind power. If loan guarantees allow debt maturity to increase, the cost savings are even more substantial. For example, assuming a post-guarantee debt interest rate of 6% and a debt maturity of 20 years, the PV cost savings are approximately 30% (8¢/kWh) and the wind power cost reduction is 25% (1.3¢/kWh). Loan guarantee programs may be most appropriate in cases where commercial loans are simply not available to the RET developer. In these cases, a loan guarantee underwrites the start-up risk and helps projects with high technology and/or resource risks obtain necessary capital.

9.3 Project Aggregation

Because of the small size of most RET projects, the transactions costs per unit of installed capacity associated with developing and financing a renewable energy facility are commonly quite high. In some cases, renewable energy project sizes fall below the minimum threshold of interest to commercial lenders.

Project aggregation (or bundling) has been suggested as a way of decreasing renewable energy financing costs. Proponents of this concept claim that project aggregation can decrease overall project costs by: (1) reducing the transactions costs of developing and financing small individual projects; and (2) decreasing financing costs by diversifying project risks (Bodington, 1993).[67] Aggregation might also provide significant non-finance-related benefits including: (1) power firming to resolve intermittency problems associated with some renewables; (2) reduced transmission costs; and (3) reduced power sales contracting and marketing costs. Project aggregation services could be provided by a private management company, non-profit organization, or government-run entity; many forms of project aggregation do not require government action. If the aggregation agent is a government agency, longer-term, low-cost debt funds may be tapped. Aggregation programs that provide subsidized financing in this manner could result in reduced federal tax credit payments, however.

Project aggregation and securitization of debt (combining debt from smaller projects into one liquid security to reduce debt costs) has occurred outside of the energy sector in the U.S.

---

67 Aggregation may be particularly helpful to smaller renewable energy projects, which are often not even considered by large investors for commercial loans.

(e.g., home mortgages and student loans), but is a relatively recent development in the independent power market (Bodington, 1993). Although not fully developed, the Solar Enterprise Zone (a government-aided development concept that will primarily aggregate and market solar projects developed in Nevada) will provide many of the benefits of aggregation. The Solar Enterprise Zone plans to use government land, provide low-cost financing, supply a guaranteed market through government purchases, arrange transmission access, and utilize public/private partnerships to develop 1,000 MW of solar capacity over a seven-year period ending in 2003. AWEA (1994) and McFarland *et al.* (1993) propose that a "Renewables Power Marketing Authority" and its financing counterpart be created as a domestic aggregation mechanism that would provide financing and other benefits to renewable energy projects. There is also some experience with project aggregation overseas. For example, the Asia Alternative Energy Unit, founded by the U.S. DOE, the Government of the Netherlands, and the World Bank, was created to bundle small renewable energy projects into larger loan packages.

Additional research on the benefits of project aggregation will be required before an overall assessment of its feasibility and usefulness can be determined. An identification and analysis of the possible roles for government involvement would also be helpful.

CHAPTER 10

Summary and Conclusion

In this chapter we summarize key lessons, recommendations, and conclusions from this report. We organize the chapter as follows: (1) the impact of financing on renewables development and project costs; (2) electricity restructuring; (3) uncertainty and risk in RET policies; (4) secondary financing impacts of renewables policies; (5) direct policy mechanisms to reduce financing costs; and (6) conclusions.

The Impact of Financing on Renewables Development and Project Costs

- Financing terms are particularly important to renewable energy facilities because RETs are often capital intensive. In addition, renewables are disadvantaged in the financing process *vis-á-vis* other generation technologies because of perceived resource and technology risks, small project size, small industry size and a lack of investor interest, and an uncertain policy environment that adversely affects the economics of many renewable energy installations.

- Using a financial cash-flow model for wind power and PV facilities, we demonstrate the impact of various financing terms on the cost of renewable energy. Our results illustrate how sensitive renewable energy costs are to financing inputs, including capital structure, equity returns, debt interest rate, and debt term.

Electricity Restructuring

- Electric industry restructuring is proceeding rapidly in a number of states across the U.S. and will significantly impact the financing of renewable energy projects. As retail competition intensifies, it is likely that the type of long-term contracts (20-30 years) typical of the current NUG industry will become increasingly scarce. Although bilateral contracts, CfDs, and other contracting mechanisms will play an important role in the new market, power contracts are more likely to be of the short- to medium-term variety (less than 15 years).

- In this new environment, NUGs may rely, in part, on merchant plant development; that is, development of new facilities without a full set of up-front power sales agreements. The corresponding increased risk will result in more costly project financing arrangements, including more equity, less debt, and shorter debt terms. Because RETs are frequently capital intensive and more costly than gas-fired generation, and because renewable energy developers are often not sufficiently large to attempt balance-sheet financing, renewables developers may be disadvantaged by

the contracting and financing structures expected in a world of vigorous retail competition.

- While the decline of long-term contracts may make financing more difficult and costly for renewables developers, "green" markets and/or the establishment of public policies designed to benefit renewables (including surcharge-funded and/or RPS programs) could create an improved investment climate for renewables.

Uncertainty and Risk in RET Policies

A number of risks are encountered when developing power projects, many of which can be reduced through risk allocation and management techniques. Changes and uncertainties in RET policies, however, are often unpredictable and difficult to manage. Many RET programs have failed to perform as well as expected because of: (1) uncertainties in the eligibility of specific renewables to obtain program support; (2) year-to-year uncertainties in the availability and level of the financial incentive; (3) a lack of assurance that the policy would remain in effect and provide a long-term, predictable revenue stream; and (4) for green marketing, participation risk. These uncertainties increase financing costs and difficulties.

- Eligibility: Eligibility risk refers to the risk that a particular project may be deemed ineligible for program funding after significant cash outlays have occurred during the project's development. To reduce or eliminate this risk, it may be appropriate for the program administrator to provide a conditional determination of eligibility some time before the project begins construction and operation. In addition, clear policy guidelines and rules can reduce confusion over which types of projects are eligible and when policy cost or subscription caps are likely to be met.

- Policy stability: Regulatory and political risks are a concern to all investors. Changes in RET policies have often been sudden and disruptive to developers and investors. Developers must absorb significant "policy uncertainty" risk during the development of a RET facility unless they are ensured that a particular policy will still be available when their project comes on-line. Although it is important to maintain some flexibility in policy implementation and design, to the extent possible, RET policies should be stable enough such that longer-term business and investment planning are possible.

- Predictable and long-term payment schedules: If a policy is intended to directly or indirectly provide long-term support to a RET project, it should be designed so that the yearly payments are sufficiently certain to be used as debt security and included in project evaluation. Long-term and predictable policy commitments can lead to reduced financing costs, sustained orderly development of the renewable energy industries, and ultimately to sufficient RET development and manufacturing economies to substantially reduce renewable energy costs. Short payment periods,

contract "out" clauses, uncertain funding arrangements, and unknown legislative commitments—all of which should be avoided—can result in reduced debt maturity, debt and equity risk premiums, and therefore increased costs of power supply. If funding uncertainties are unavoidable and/or long-term commitments impractical, policymakers may want to consider investment support (i.e., up-front grants rather than longer-term incentive payments). Alternatively, investment in market transformation activities (i.e., the encouragement of new renewable energy markets through, for example, green marketing) or renewable energy infrastructure development may be the best use of limited funds.

- Participation risk: Customer participation risk is likely to become an important financing issue in green marketing. Participation risk can be eliminated through the use of the "annual participation option" in green marketing programs. Otherwise, we expect that: (1) large intermediaries may take on these risks (utilities or marketing agents); (2) customers may be required to demonstrate a long-term commitment to the program; (3) balance-sheet financing will become increasingly common; and (4) the emphasis will be on low-risk renewables projects (e.g., existing facilities, retrofits, and small new projects).

Secondary Financing Impacts of Renewables Policies

Some renewable energy policies have a more indirect impact on power plant financing and financing costs. Secondary financing impacts can reduce the efficacy of these policies and should be considered during policy design.

- Tax Appetite: The effectiveness of tax incentive policies is reduced by limitations on the tax appetite of investors and the alternative minimum tax. The ability of investors to offset other (non-renewables project) tax loads, carry forward or carry back tax benefits to other years, and allocate the tax credit benefits among investors regardless of ownership share can help alleviate the problem. Partial AMT relief for RET owners might also be considered. The use of direct cash subsidies, rather than tax credits, would largely eliminate tax appetite limitations, as would the ability to "sell" the credits directly to other investors.

- Capital Structure: Renewable energy policies can have secondary impacts on the financing structures of RET projects. In particular, production tax credits flow to equity investors (not lenders) and can increase the amount of equity in a project's capital structure, reducing the value of the credit moderately compared to an equivalently sized direct cash incentive.

- Production Tax Credits vs. Cash Production Incentives: In recognition of the poor productivity incentives inherent in some forms of investment support, many new RET

policies are likely to reward production rather than investment through either tax credits or cash incentives. Although non-finance factors must enter the decision of whether to use tax or cash incentives, financing trade-offs exist between these two approaches. Tax incentives are subject to the financing problems identified above, i.e. tax appetite limitations and capital structure impacts. Cash production incentives can be subject to long-term funding uncertainties.

Direct Policy Mechanisms to Reduce Financing Costs

- There are a number of direct approaches that can be used to reduce financing costs for renewables, therefore decreasing overall project costs and improving the competitive position of renewables relative to other generation alternatives. These policies include low-interest government-subsidized loans, project loan guarantees, and project aggregation.

- Although all hold promise, barriers currently exist to the creation of effective programs of this type, particularly low-interest government-subsidized loans. These barriers include: (1) the benefits of certain types of subsidized financing programs can partially offset state and federal tax credit benefits; and (2) the Tax Reform Act of 1986 limits the amount of state funds that can be raised for private purpose activities.

- If the barriers listed above were removed, low-interest loan programs could be an effective method for supporting utility-scale renewables development. In part because of these limitations, however, low-cost financing programs may currently be more useful for stimulating the development of small, residential-scale RET systems than for larger installations. These smaller facilities are often unable to obtain bank loans and their high capital costs are a serious barrier to customer investment. Moreover, customer-sited renewables may not encounter the tax credit offset.

Conclusions

Developing effective mechanisms to support new technologies is difficult, and policies often do not perform as well as predicted or expected. The primary goals of this report have been to describe the power plant financing process and to provide insights to policymakers on the important nexus between RET policy design and finance. We have emphasized financing as an integral consideration in the design of renewable energy policies because creating a market for renewables requires a regulatory, political, and business climate that is conducive for investment. Although numerous state and federal renewables policies in the U.S. have stimulated technology and project development, secondary financing impacts and policy uncertainties can and have reduced the effectiveness of some policies.

We have shown that a renewables policy that is carefully designed can reduce renewable energy costs dramatically by providing revenue certainty that will, in turn, reduce financing risk premiums and financing costs. Policies that provide this certainty will either promote more renewables per dollar invested or be more cost effective in supporting a given amount of development. As the electric industry is restructured and new renewables policies are created, it will be even more critical for policymakers to consider the impacts of renewables policy design on financing.

References

Ahmed, K (1994), *Renewable Energy Technologies: A Review of the Status and Costs of Selected Technologies*, World Bank Technical Paper #240.

American Wind Energy Association (AWEA) (1994), "National Energy Policy Plan," comments by Jamie Chapman, president-elect of AWEA, 29 September.

Baugh, K, Byrnes, B, Jones, C and Rahimzadeh, M (1994), "Green Pricing: Removing the Guesswork," *Public Utilities Fortnightly,* 133 (15).

Bodington, J (1993), "Securitizing Project Debt," *Independent Energy,* 23 (6).

Brealey, R and Myers, S (1991), *Principles of Corporate Finance*, Fouth Edition, McGraw-Hill Inc., New York, NY.

Brown, M (1994), *Financing Renewable Energy: Obstacles and Solutions*, A Report of the Urban Consortium Energy Task Force, prepared by the New York City Department of Telecommunications and Energy, June.

Brown, M and Yuen, M (1994), "Changing a Historical Perspective," *Independent Energy*, 24 (7).

Burtraw, D and Shaw, P (1995), *Fiscal Effects of Electricity Generation: A Full Fuel Cycle Analysis*, Resources for the Future, Discussion Paper 95-16.

California Public Utilities Commission (CPUC) (1995), *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation* (D. 95-12-063 as modified D. 96-01-009), 20 December.

Churchill, A (1995), "Beyond Project Finance," *The Electricity Journal,* 8 (5).

Clean Energy Finance (1996), "UK Wind Fund Set to Break Ground this Year," Volume 1, Number 1.

Comnes, G, Belden, T and Kahn, E (1995), *The Price of Electricity from Private Power Producers*, Lawrence Berkeley National Laboratory, LBL-36054.

Conover, K (1994), "Wind Energy Financial Due Diligence," presented at the American Wind Energy Association's Wind Technology Update: Opportunities for Finance and Investment in Wind Energy, 10 November.

Cox, A, Blumstein, C and Gilbert, R (1991), "Wind Power in California: A Case of Targeted Tax Subsidies," *Regulatory Choices: A Perspective on Developments in Energy Policy*, ed. R. Gilbert, University of California Press.

DeBoer, R (1996), Staff, Minnesota House of Representatives, personal communication, 31 October.

deLucia, R (1995), *Financing Renewable Energy Projects: Issues, Options, and Innovations for Asia and Beyond*, June.

Department of Energy (DOE) (1996), "DOE Announces Second Payments for Renewable Energy Electricity Production," 2 October.

Department of Energy (DOE) (1995), "DOE Announces First Payments Under REPI Program," 7 November.

Electric Power Research Institute (EPRI) (1993), *Technical Assessment Guide, Volume 1: Electricity Supply*, report TR-102276-V1R7.

Electric Power Research Institute (EPRI) (1990), *Competitive Procurement of Electric Utility Resources*, prepared by Charles River Associates, report CU-6898.

Electrical World (1996), "Conference Report: Cogen, IPP Conference Signals Market Convergence," May.

Elliot, D (1992), "Renewables and the Privatization of the UK ESI: a Case Study," *Energy Policy*, 20 (3).

Elwood, J (1996), University of California, Berkeley, personal communication, 23 October.

Environmental Defense Fund (EDF) (1995), "Comments on the California Public Utilities Commission's Proposed Policy Decision," R. 94-04-031/I.94-04-032, 24 July.

Eto, J, Prahl, R and Schlegal, J (1996), *A Scoping Study on Energy-Efficiency Market Transformation in California Utility DSM Programs*, Lawrence Berkeley National Laboratory, LBNL-39058.

Farhar, B and Houston, A (1996), *Willingness to Pay for Electricity from Renewable Energy*, National Renewable Energy Laboratory, report TP-461-20813.

Federal Register (1995), "Renewable Energy Production Incentives," 10 CFR Part 451, 60 (138), 19 July.

Geothermal Resources Council Bulletin (1992), "Energy Bill Signed: $1 Million in Alternative Minimum Tax Relief for Independents," December.

Goldman, C, Comnes, G, Busch, J and Wiel, S (1993), *Primer on Gas Integrated Resource Planning*, prepared for the National Association of Regulatory Utility Commissioners, Lawrence Berkeley National Laboratory, LBNL-34144.

Grandy, D (1996), California State General Services Administration, personal communication, 21 October.

Grant, W (1996), Izaak Walton League of America, personal communication, 29 October.

Green Pricing Newsletter (1996), prepared by the Regulatory Assistance Project, October.

Green Pricing Newsletter (1995), prepared by the Regulatory Assistance Project, May.

Green Pricing Newsletter (1994), prepared by the Regulatory Assistance Project, October.

Hadley, S, Hill, L and Perlack, R (1993), *Report on the Study of the Tax and Rate Treatment of Renewable Energy Projects*, Oak Ridge National Laboratory, report #6772.

Hamrin, J and Rader, N (1993), *Investing in the Future: A Regulator's Guide to Renewables*, National Association of Regulatory Utility Commissioners.

Hinrichs, T (1996), Geothermal Energy Association, personal communication, 11 October.

Hoff, T and Herig, C (1996), "Managing Risk Using Renewable Energy Technologies," *Proceeding of the Symposium on the Virtual Utility*, 31 March - 2 April.

Holt, E (1996), "Green Pricing Experience and Lessons Learned," *Proceedings: 1996 ACEEE Summer Study*, Pacific Grove, California, 25-31 August.

Holt, E (1995), *System Benefits Charge Case Studies*, Regulatory Assistance Project, August.

Ing, E (1996), Attorney-at-Law, personal communication, 10 October.

Ing, E (1995), "Effect of Tax and Production Incentives on Wind Projects," *Proceedings: American Wind Energy Association's Windpower 1995*, Washington, D.C., 26-30, March.

Ing, E (1993), "Making Sense of the Federal Tax Code: Incentives for Windfarm Development," *Proceedings: American Wind Energy Association's Windpower 1993,* San Francisco, California, 12-16 July.

Investor Responsibility Research Center, Inc. (IRRC) (1991), *A White Paper on Renewable Energy Financing Barriers and Constraints*, prepared for the World Resources Institute, November.

Jackson, T (1992), "Renewable Energy: Summary Paper for Renewables Series," *Energy Policy,* 20 (9).

Jenkins, A and Reilly, H (1995), "Tax Barriers to Solar Central Receiver Generation Technology," presented at the ASME Solar Energy Conference, Maui, Hawaii, 19-24 March.

Kahn, E (1995), *Comparison of Financing Costs for Wind Turbine and Fossil Powerplants*, Lawrence Berkeley National Laboratory, LBL-36122.

Kahn, E (1988), *Electric Utility Planning and Regulation,* American Council for an Energy-Efficient Economy, Washington D.C.

Kahn, E, Goldman, C, Stoft, S and Berman, D (1989), *Evaluation Methods in Competitive Bidding for Electric Power*, Lawrence Berkeley National Laboratory, LBL-26924.

Kahn, E, Meal, M, Doerrer, S and Morse, S (1992), *Analysis of Debt Leveraging in Private Power Projects,* Lawrence Berkeley National Laboratory, LBL-32487.

Kahn, E and Stoft, S (1989), *Designing a Performance Based Cost-Sharing System for the Clean Coal Technology Program*, Lawrence Berkeley National Laboratory, LBL-28057.

Karas, K (1994), "Wind power economics," presented at the American Wind Energy Association's Wind Technology Update: Opportunities for Finance and Investment in Wind Energy, 10 November.

Kearney, M (1992), personal communication, 1 December.

Kelly, B and Boone, C (1996), "Green Energy Pricing at Ontario Hydro," paper presented at the DOE/EPRI Green Pricing Workshop, Golden, Colorado, 11 April.

Kettle, R (1996), U.K. Department of Trade and Industry, personal communication, 25 October.

Lacoursiere, C (1996), "Hedging Strategies," *Electrical World*, March.

Lotker, M (1991), *Barriers to Commercialization of Large-Scale Solar Electricity: Lessons Learned from the LUZ Experience*, Sandia National Laboratory, report #91-7014.

Lynch, G (1996), U.S. Department of Energy, personal communication, 17 October.

Marcus, W, Helmich, J, Schilberg, G, Nahigian, J and Ruszovan, G (1995), *Photovoltaic Regulatory and Policy Issues*, JBS Energy, Inc.

Martin, K (1994a), "IRS Ruling Makes Tapping Into Landfill Gas Tax Credits A Little Trickier," *Solid Waste Technologies*, January-February.

Martin, K (1994b), "Structuring Agreements to Get Full Value of the Landfill Gas Tax Credits," *Solid Waste Technologies*, July-August.

Marvin, M (1993), "Legislative Action and the Emerging Market for Wind Power," *Proceedings: American Wind Energy Association's Windpower 1993,* San Francisco, California, 12-16 July.

McFarland, J, Caldwell, J and Jablonski, L (1993), *Sustained Orderly Development of Renewable Resources*, prepared for the California Energy Commission State Energy Plan, August.

Meal, M and Lavinson, M (1996a), "Hybrid Power Projects: Newest Finance Structures," *Private Power Executive*, July-August.

Meal, M and Lavinson, M (1996b), MRW, personal communication, 24 October.

Meyer, R, Coe, B, Nasr, L and Bixler, M (1980), "The Geothermal Loan Guarantee Program: Recommendations for Imrpovement Including New Simplified Application Procedures for Small Projects," *Geothermal Resources Council Transactions,* Volume 4.

Mitchell, C (1996), Science Policy Research Unit, University of Sussex, personal communication, 23 October.

Mitchell, C (1995a), "The Renewables NFFO: A Review," *Energy Policy,* 23 (12).

Mitchell, C (1995b), *Renewable Energy in the UK: Financing Options for the Future*, prepared for the Council for the Protection of Rural England, August.

Mitchell, C and MacKerron, G (1994), *The Financing of Small Renewable Energy Projects: A Review of Methods and Recent Experience,* ETSU, Report #K/FR/0053.

Moskovitz, D (1996), Regulatory Assistance Project, personal communication, 17 October.

Moskovitz, D (1993), "Green Pricing: Customer Choice Moves Beyond IRP," *The Electricity Journal*, 6 (8).

Naito, T (1995), "Project Financing for Geothermal Power Projects," *Proceedings of the World Geothermal Congress,* Volume 4.

National Renewable Energy Laboratory (NREL) (1994), *Profiles in Renewable Energy: Case Studies of Successful Utility-Sector Projects*, Golden, Colorado.

Nevitt, P (1983), *Project Financing,* 4th Edition, Euromoney Publications.

Nielsen, P (1993), "Development of Wind Energy in Denmark," *Proceedings: American Wind Energy Association's Wind Power 1993,* San Francisco, California, 12-16 July.

Oberg, K (1992), "Impact of Production Incentives on Financing Wind Energy Projects," *Proceedings: American Wind Energy Association's Wind Power 1992,* Seattle, Washington, 19-23 October.

OEM Development Corporation (1995), *Wind Energy Costs,* prepared for the National Wind Coordinating Committee, Draft, December.

Osborn, D and Collier, E (1996), "Utility Grid-Connected Photovoltaic Distributed Power Systems," *Proceedings: National Solar Energy Conference, ASES Solar 1996,* Asheville, North Carolina, April.

Park, T (1996), California Division of State Architect's Office, personal communication, 30 October.

Parrish, M (1991), "How the Sun Failed to Shine on Solar Firm's Dreams," *Los Angeles Times*, 8 December.

Pistole, C (1995), "Structuring Small Projects," *Independent Energy,* 25 (9).

Rabago, K (1996), Environmental Defense Fund, personal communication, 22 October.

Rader, N and Norgaard, D (1996), "Efficiency and Sustainability in a Restructured Electricity Market: The Renewables Portfolio Standard," *The Electricity Journal,* 9 (6).

Rader, N and Wiser, R (1997), *Strategies for Promoting Wind Energy: A Review and Analysis of State Level Policy Options*, prepared for the National Wind Coordinating Committee, forthcoming.

Reese, P (1996), California Biomass Energy Alliance, personal communication, 8 October.

Regulatory Assistance Project (RAP) (1995), *System Benefits Charge,* Issuesletter, September.

Renewable Energy Annual (1995), prepared by the Energy Information Administration, December.

Renewables Working Group (1996), *Renewables Working Group Report*, filed to the California Public Utilities Commission in its restructuring proceedings (D. 95-12-063 as modified D. 96-01-009), 23 August.

Schochet, D and Mock, J (1994), "How the Department of Energy Loan Guarantee Program Paved the Way for the Growth in the Geothermal Industries," *Geothermal Rresources Council Bulletin*, September/October.

Shirley, L and Sholar, J (1993), "State and Utility Financial Incentives for Solar Applications," *Solar Today*, July/August.

Shugar, D, Eyer, J, Hay, G, Newberger, J and Kearney, D (1991), "Comparison of Photovoltaics with Solar Thermal Trough Electric Systems as a Central Station Utility Resource in the 1990s," *Proceedings: Twenty Second Photovoltaic Specialists Conference*, October.

Smith, C, and Warner, J (1979), "On Financial Contracting: An Analysis of Bond Covenants," *Journal of Financial Economics, 7.*

Smith, K (1996), *Customer Driven Markets for Renewably Generated Electricity*, Center for Energy Efficiency and Renewable Energy, August.

Solar Energy Research Institute (SERI) (1990), T*he Potential of Renewable Energy: An Interlaboratory While Paper*, SERI/TP-260-3674, prepared for the Office of Policy, Planning, and Analysis, U.S. Department of Energy.

Spaeth, J (1996), U.S. DOE, personal communication, 11 October.

Swezey, B (1992), "The Current Status of Renewable Electric Generation in the U.S.: Deployment, Economics, and Policies," presented to the NARUC-DOE Fourth National Integrated Resource Planning Conference, 13-16 September..

Utility Photovoltaic Group and Amoco/Enron (1996), joint press release, 5 January.

Vaudin, A. (1996), National Wind Power, personal communication, 23 October.

Wenger, H (1996), Pacific Energy Group, personal communication, 19 September.

Wenger, H, Hoff, T and Pepper, J (1996), *Photovoltaic Economics and Markets: The Sacramento Municipal Utility District as a Case Study*, sponsored by the Sacramento Municipal Utility District, the California Energy Commission, and the U.S. Department of Energy's PV Compact Program.

Williams, S and Bateman, B (1995), *Power Plays: Profiles of America's Independent Renewable Electricity Developers*, Investor Responsibility Research Center.

Wind Energy Weekly (1992), "UK Expected to Expand Renewable Energy Program," 18 May.

Wiser, R (1997), "Renewable Energy Finance and Project Ownership: The Impact of Alternative Development Structures on the Cost of Windpower," forthcoming in *Energy Policy.*

Wiser, R (1996), *Evaluating the Impacts of State Renewables Policies on Federal Tax Credit Programs*, Lawrence Berkeley National Laboratory technical paper, prepared for the California Energy Commission Renewables Program Committee.

Wiser, R and Kahn, E (1996), *Alternative Windpower Ownership Structures: Financing Terms and Project Costs,* Lawrence Berkeley National Laboratory, LBNL-38921.

Wiser, R, Pickle, S and Goldman, C (1996), *California Renewable Energy Policy and Implementation Issues: An Overview of Recent Regulatory and Legislative Action,* Lawrence Berkeley National Laboratory, LBNL-39247.

Wolak, F and Patrick, R (1996), *The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market*, Industrial Organization Seminar, University of California, Berkeley.

Wong, D (1995), Kenetech, personal communication, 15 November.

Wind Power and Photovoltaic Cash-Flow Model Examples

In this appendix we provide examples of the cash-flow model that is described briefly in Chapter 3. Figure A-1 shows this model with the base-case wind power inputs; Figure A-2 does the same for the base-case PV inputs. See Wiser and Kahn (1996) for a detailed description of the model.

Figure A-1. Base-Case Wind Power Cash-Flow Model

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Total Capital Cost ($/kW)	1000	($1997)
Total Operating Expense ($/kWh)	0.012	($1998)
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductible)
Production Tax Credit ($/kWh)	0.015	($1992). Increases with inflation
GNP Inflation Rate (%/yr)	3.5%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated
Energy Price Escalation Rate	3.5%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.70
Minimum Debt Service Coverage	1.400
After-Tax IRR on Equity	18.00%
Real Levelized Price ($1998/kWh)	0.0433
Nominal Levelized Price ($1998/kWh)	0.0551
First Year Electricity Price	0.0433

Scenario 1
Base-case

5-yr MACRS Depreciation Schedule					
1	2	3	4	5	6
0.2	0.32	0.192	0.1152	0.1152	0.0576

FINANCING ASSUMPTIONS:	Fraction	Term	Rate	Notes
Equity Fraction	58.9%	NA	18.00%	Minimum equity return
Debt Fraction	41.1%	12	9.50%	Assumed

PRO-FORMA CASH FLOW:

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)		0.043	0.045	0.046	0.048	0.050	0.051	0.053	0.055	0.057	0.059	0.061	0.063	0.065	0.068	0.070	0.073	0.075	0.078	0.080	0.083
Operating Revenues ($000)																					
Revenues		5693	5892	6098	6312	6532	6761	6998	7243	7496	7758	8030	8311	8602	8903	9215	9537	9871	10216	10574	10944
Operating Expenses ($ 000)																					
Total Operating Expenses		1577	1632	1689	1748	1809	1873	1938	2006	2076	2149	2224	2302	2383	2466	2552	2642	2734	2830	2929	3031
Operating Income ($000)		4116	4260	4409	4563	4723	4888	5059	5236	5420	5609	5806	6009	6219	6437	6662	6895	7137	7387	7645	7913
Financing($000)																					
Debt Funds	20532																				
Equity Funds	29468																				
Total Capital Investment	50000																				
Cash Available Before Debt		4116	4260	4409	4563	4723	4888	5059	5236	5420	5609	5806	6009	6219	6437	6662	6895	7137	7387	7645	7913
Debt Interest Payment		1951	1857	1754	1641	1517	1382	1234	1072	895	701	488	255								
Debt Repayment		989	1083	1186	1299	1422	1558	1705	1867	2045	2239	2452	2685								
Total Debt Payment		2940	2940	2940	2940	2940	2940	2940	2940	2940	2940	2940	2940	0	0	0	0	0	0	0	0
Tax Effect on Equity ($000)																					
Operating Income		4116	4260	4409	4563	4723	4888	5059	5236	5420	5609	5806	6009	6219	6437	6662	6895	7137	7387	7645	7913
Depreciation (5 yr, MACRS)		10000	16000	9600	5760	5760	2880														
Interest Payment		1951	1857	1754	1641	1517	1382	1234	1072	895	701	488	255								
Income Taxes (w/o credit)		-2977	-5167	-2639	-1078	-971	238	1454	1582	1719	1865	2021	2186	2363	2446	2532	2620	2712	2807	2905	3007
Production Tax Credit		2423	2508	2595	2686	2780	2878	2978	3083	3190	3302										
Total Tax Liability (savings)		-5400	-7674	-5234	-3765	-3751	-2640	-1525	-1500	-1471	-1437	2021	2186	2363	2446	2532	2620	2712	2807	2905	3007
After Tax Net Equity Cash Flow ($000)	-29468	6576	8994	6703	5388	5534	4588	3644	3797	3951	4106	845	883	3856	3991	4131	4275	4425	4580	4740	4906
Pre-tax Debt Coverage Ratio		1.40	1.45	1.50	1.55	1.61	1.66	1.72	1.78	1.84	1.91	1.97	2.04								

Figure A-2. Base-Case Photovoltaic Cash-Flow Model

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	5	Assumed
Capacity Factor	0.25	Assumed
Total Capital Cost ($/kW)	4000	($1997)
Total Operating Expense ($/kWh)	0.006	($1998)
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductible)
Income Tax Credit (% Capital Cost)	10.0%	Assumed
GNP Inflation Rate (%/yr)	3.5%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated
Energy Price Escalation Rate	3.5%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.70
Minimum Debt Service Coverage	1.400
After-Tax IRR on Equity	18.00%
Real Levelized Price ($1998/kWh)	0.2070
Nominal Levelized Price ($1998/kWh)	0.2634
First Year Electricity Price	0.2070

Scenario 1
Base-case

5-yr MACRS Depreciation Schedule					
1	2	3	4	5	6
0.2	0.32	0.192	0.1152	0.1152	0.05576

FINANCING ASSUMPTIONS:	Fraction	Term	Rate	Notes
Equity Fraction	45.1%	NA	18.00%	Minimum equity return
Debt Fraction	54.9%	12	9.50%	Assumed

PRO-FORMA CASH FLOW:																					
Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric Output (MWh)		10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950	10950
Electricity Sales Price ($/kWh)		0.207	0.214	0.222	0.229	0.238	0.246	0.254	0.263	0.273	0.282	0.292	0.302	0.313	0.324	0.335	0.347	0.359	0.371	0.384	0.398
Operating Revenues ($000)																					
Revenues		2266	2346	2428	2513	2601	2692	2786	2883	2984	3089	3197	3309	3425	3544	3668	3797	3930	4067	4210	4357
Operating Expenses ($ 000)																					
Total Operating Expenses		66	68	70	73	75	78	81	84	87	90	93	96	99	103	106	110	114	118	122	126
Operating Income ($000)		2201	2278	2357	2440	2525	2614	2705	2800	2898	2999	3104	3213	3325	3442	3562	3687	3816	3949	4088	4231
Financing($000)																					
Debt Funds	10978																				
Equity Funds	9022																				
Total Capital Investment	20000																				
Cash Available Before Debt		2201	2278	2357	2440	2525	2614	2705	2800	2898	2999	3104	3213	3325	3442	3562	3687	3816	3949	4088	4231
Debt Interest Payment		1043	993	938	877	811	739	660	573	479	375	261	136								
Debt Repayment		529	579	634	695	761	833	912	998	1093	1197	1311	1435								
Total Debt Payment		1572	1572	1572	1572	1572	1572	1572	1572	1572	1572	1572	1572	0	0	0	0	0	0	0	0
																				0	
Tax Effect on Equity ($000)																					
Operating Income		2201	2278	2357	2440	2525	2614	2705	2800	2898	2999	3104	3213	3325	3442	3562	3687	3816	3949	4088	4231
Depreciation (5 yr. MACRS)		3800	6080	3648	2189	2189	1094														
Interest Payment		1043	993	938	877	811	739	660	573	479	375	261	136								
Income Taxes (w/o credit)		-1004	-1822	-847	-238	-180	296	777	846	919	997	1080	1169	1264	1308	1354	1401	1450	1501	1553	1608
Income Tax Credit		2000																			
Total Tax Liability (savings)		-3004	-1822	-847	-238	-180	296	777	846	919	997	1080	1169	1264	1308	1354	1401	1450	1501	1553	1608
After Tax Net Equity Cash Flow ($000)	-9022	3633	2528	1632	1106	1134	745	356	382	407	430	452	472	2062	2134	2209	2286	2366	2449	2534	2623
Pre-tax Debt Coverage Ratio		1.40	1.45	1.50	1.55	1.61	1.66	1.72	1.78	1.84	1.91	1.97	2.04								

FY95 REPI Recipients

In Section 4.4, we provide the results from our informal survey on the impact of the federal renewable energy production incentive (REPI) on non-profit owners of renewable energy projects. In this appendix we list the non-profit entities surveyed and supply some additional information on their RET projects. Table B-1 provides this data, extracted from DOE (1996).

Table B-1. Non-Profit REPI Recipients Surveyed (i.e., RET Owners Receiving FY95 Funds)

Non-Profit Owner	Facility	Energy Source	FY95 Payment
Sacramento Municipal Utility District	Solano Wind Project	Wind	$202,139
	Hedge Substation, Photovoltaic-94	Solar	$5,547
	Hedge Substation, Photovoltaic-95	Solar	$1,455
	Solar Pioneers, Photovoltaic-94	Solar	$5,848
	Solar Pioneers, Photovoltaic-95	Solar	$1,824
City of Glendale, California	Grayson Power Plant	Landfill Methane	$946,919
Lycoming County, Pennsylvania	Lycoming County Landfill Gas Co-Generation System	Landfill Methane	$146,184
Emerald Peoples' Utility District, Oregon	Lane County's Short Mountain Landfill	Landfill Methane	$194,154
University of California, Los Angeles	UCLA Energy Systems Facility	Landfill Methane	$875,635
Pacific Northwest Generating Cooperative	Coffin Butte Resource Project	Landfill Methane	$15,325
Wavery Light and Power	Skeets 1	Wind	$3,441