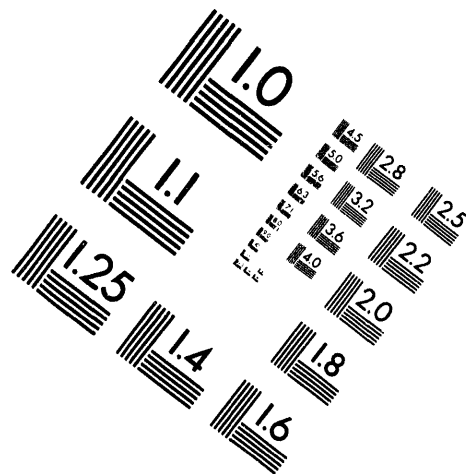
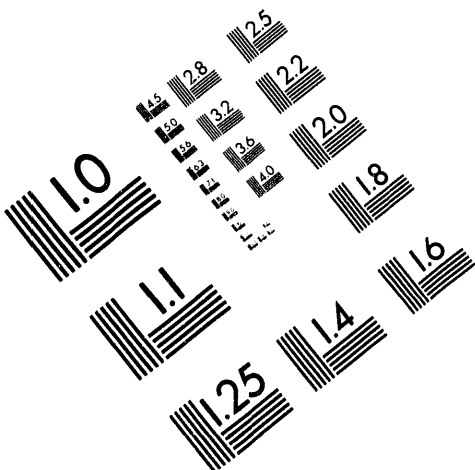




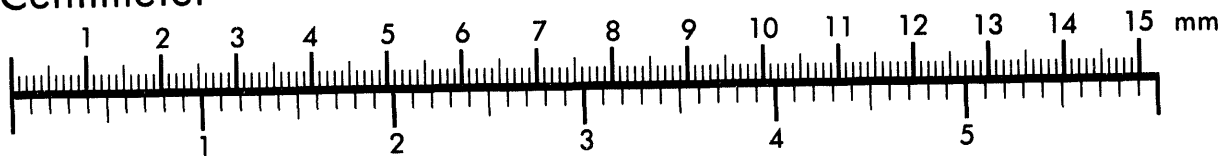
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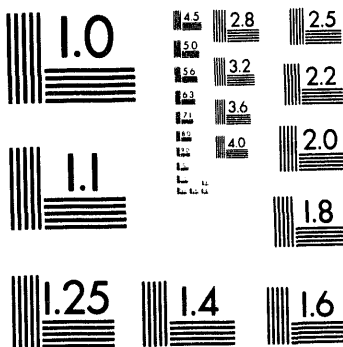
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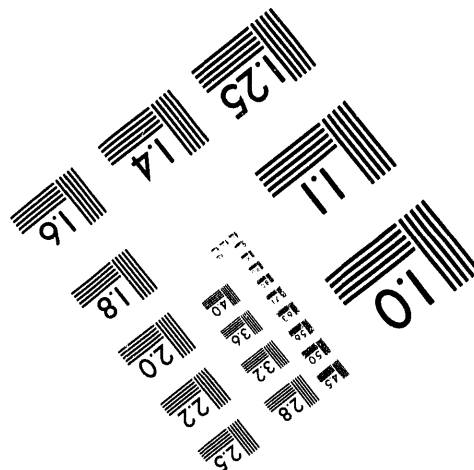
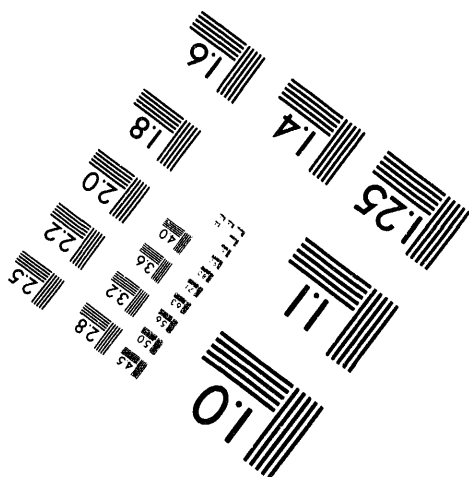
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**THE INTEGRATION OF RENEWABLE ENERGY SOURCES
INTO ELECTRIC POWER DISTRIBUTION SYSTEMS**

VOLUME I. NATIONAL ASSESSMENT

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ABBREVIATIONS AND ACRONYMS

ac	alternating current
AOC	Atlantic Orient Corporation
Btu	British thermal unit
C	Centigrade
CAAA	Clean Air Act Amendments of 1990
CF	capacity factor
CIS	CuInSe ₂
CO ₂	carbon dioxide
dc	direct current
DOE	Department of Energy
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FPL	Florida Power and Light
FY	fiscal year
GAO	General Accounting Office
GMP	Green Mountain Power
GPC	Georgia Power Company
IRP	integrated resource planning
kW	kilowatt
kWh	kilowatt-hours
LCUB	Lenoir City Utilities Board
m	meter
MVA	megavolt-ampere
MW	megawatt
NSRDB	National Solar Radiation Data Base
NO _x	nitrogen oxide
NREL	National Renewable Energy Laboratory
NUGs	non-utility-owned generators
O&M	operation and maintenance
OPALCO	Orcas Power and Light Company
ORNL	Oak Ridge National Laboratory.
PG&E	Pacific Gas and Electric
PNM	Public Service Company of New Mexico
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PVUSA	Photovoltaics for Utility Scale Applications
SCE	Southern California Edison

ABBREVIATIONS AND ACRONYMS (Con't.)

SMUD	Sacramento Municipal Utility District
SO ₂	sulfur dioxide
T&D	transmission and distribution
TMY	typical meteorological year
U.S.	United States
UPG	Utility Power Group
VAR	volt-ampere reactive (reactive power)
WT	wind turbine
ZECO	Zaininger Engineering Company

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FOREWORD

House Report 102-75, page 75 and Senate report 102-80, pages 79-80, on the Energy and Water Development Appropriations Act, 1992, Public Law 102-104, contain the following:

The Committee recommendation includes \$500,000 to support a cost-shared, industry-utility project to evaluate the use of distributed utility power generation, utilizing renewable energy systems, for improving power system performance, and generating transmission and distribution savings.

The DOE Office of Energy Management (OEM), under the Asst. Secretary for Energy Efficiency and Renewable Energy, was given responsibility for this project. The case study assessments and the national study provide an indication of the technical and economic feasibility of integrating renewable energy sources into power distribution systems, as well as the additional benefits associated with integrating at the distribution level. This work is not intended to serve as a detailed design study. Prior to actually integrating solar and wind systems into distribution circuits, utilities should conduct detailed evaluation studies using site-specific resource and utility data in the analysis.

The national study (Vol. I) has developed values for the various benefits that are representative, at the regional level, for providing an indication of the potential for renewable energy systems. Actual benefits and cost values are very utility- and site-specific, and may vary greatly from the values chosen in the study. The results of the case studies (Vol. II) are in general agreement with the representative values chosen for the national study.

ABSTRACT

Renewable energy technologies such as photovoltaic, solar thermal electricity, and wind turbine power are environmentally beneficial sources of electric power generation. The integration of renewable energy sources into electric power distribution systems can provide additional economic benefits because of a reduction in the losses associated with transmission and distribution lines. Benefits associated with the deferment of transmission and distribution investment may also be possible for cases where there is a high correlation between peak circuit load and renewable energy electric generation, such as photovoltaic systems in the Southwest. Case studies were conducted with actual power distribution system data for seven electric utilities with the participation of those utilities. Integrating renewable energy systems into electric power distribution systems increased the value of the benefits by about 20 to 55% above central station benefits in the national regional assessment. In the case studies presented in Vol. II, the range was larger: from a few percent to near 80% for a case where costly investments were deferred. In general, additional savings of at least 10 to 20% can be expected by integrating at the distribution level. Wind energy systems were found to be economical in good wind resource regions, whereas photovoltaic systems costs are presently a factor of 2.5 too expensive under the most favorable conditions.

EXECUTIVE SUMMARY

Renewable energy technologies such as photovoltaics, solar thermal electricity using dish-stirling systems, and wind turbine power are environmentally beneficial sources of energy that can be considered for electric power generation. The costs of renewable energy technologies have decreased in recent years, so that an increasing number of applications can be economically justified by utilities. Electric utilities are being encouraged by regulatory commissions and the federal government with the Energy Policy Act of 1992 (Public Law 102-486) to use cost-effective renewable energy systems as part of their generation mix. The Clean Air Act Amendments of 1990 (CAAA) (Public Law 101-549, 104 Stat. 2399) provide further encouragement for utilities to use clean, renewable energy resources. For example, Title IV, Sec. 404(f) of the CAAA (42 U.S.C. 7651c (f)) grants allowances for avoided emissions through qualified renewable energy sources. However, these renewable energy sources provide intermittent power, and large generation sites require large land areas for energy collection. The integration of generation from renewable sources into electric power distribution systems is a reasonable way for electric utilities to apply renewable energy resources, since it places the sources near the load for more efficient operation, and the large land area requirement can be spread over the distribution system.

The integration of renewable energy sources into electric power distribution systems can also provide other benefits. Renewable sources installed near the load offer the possibility of reducing system losses, deferring transmission and distribution (T&D) investment, and improving power quality and reliability, in addition to displacing electric energy produced by fossil fuels. These benefits are referred to as "distributed utility benefits." The value of the distributed utility benefits help to offset the relatively high capital cost of renewable energy technologies.

The study described in this document was requested in the House and Senate reports on the Energy and Water Development Appropriations Act, 1992, (Public Law 102-104). For this study, both the technical and the economic feasibilities of integrating solar and wind energy into electric power distribution systems were assessed. The distributed benefits of renewable sources

and their value to electric power systems were considered in the assessment. A broad scoping study of the United States was performed to determine regions where the resources, utility circumstances, and economic conditions are most favorable for the use of renewable energy technologies. The implications of environmental and institutional issues, along with technical and economic issues, were considered. The parameters used for the national study were verified or estimated from previous studies. Results from special case studies involving electric utilities, performed by the Zaininger Engineering Company (ZECO) and described in Vol. II, were also used in the national study.

The case studies were conducted using actual power distribution system data for seven electric utilities which actively participated in the study. The utilities shared costs in this effort by providing data and the results of special analysis on their systems. The utilities that participated in this study are Lenoir City Utilities Board (LCUB) in Lenoir City, Tenn., Southern California Edison (SCE), Public Service Company of New Mexico (PNM), Georgia Power Company (GPC), Green Mountain Power (GMP) in Vermont, Florida Power and Light (FPL) in southern Florida, and Orcas Power and Light Company (OPALCO) on Orcas Island near Seattle, Wash.

The economic benefits of renewable energy systems can be categorized as "generation benefits" and "distributed utility benefits." Generation benefits tend to vary regionally because of the resource availability, fuel price differences, atmospheric emissions requirements, and public utility commission (PUC) policies.

The generation benefits include the following:

- savings in the cost of fuel,
- credit for avoided generation capacity, and
- savings associated with avoided atmospheric emissions.

The consideration of externalities and set-asides in the economic assessment of new generation is mandated in some states by the PUCs. Environmental benefits were included in the economic analysis only when they were part of the utility's economic evaluation criteria for resource planning. In the case studies, tax credits and Federal incentives were also considered in the economic analysis.

The benefits associated with integrating renewable sources into the distribution system will add to the generation benefits listed above. Some of these benefits are difficult to quantify and are utility-specific; insight into these benefits is provided by the case studies. The distributed utility benefits considered in this study are not necessarily a complete set. They are as follows:

- enhanced fuel savings and avoided emissions because of avoided T&D losses,
- deferred T&D facilities,
- voltage and reactive power (VAR) control,
- enhanced reliability, and
- additional capacity credit.

The benefits for selected PV and wind applications in the case studies are shown in Fig. 1. The solar applications shown are for fixed-orientation PV. The additional investment required for tracking PV was not cost-effective in the applications assessed in the case studies. These results are summarized in Table 1 along with the installed system costs, which varied from region to region because of differences in economic assumptions, terrain, etc.

The value of the distributed utility benefits was found to be utility- and site-specific for the seven utilities evaluated in this study. For PV applications, the distributed utility benefits increased the total benefits by 4–46% above the generation benefits associated with central station applications. The largest increases were in the southwestern U.S., where certain peak loads correlate well with PV electric generation. For WT applications, distributed utility benefits increased the total benefits by 2–78%. The largest increase was for a winter peak load application that correlates to cold, windy periods. For regions where the correlation between PV and WT output and peak load is poor, the distributed utility benefits were found to increase the total benefits by only about 5–15 %.

Benefits associated with deferred distribution facilities for periods of 5 to 10 years, voltage and VAR control, and enhanced reliability are highly dependent on the resource region, the utility load, and the distribution circuit characteristics. Deferred distribution facilities are more likely to be realized with PV systems located in the Southwest, particularly in commercial buildings where load shapes tend to match the solar system output. Commercial loads, particularly office

buildings, were found to correlate well with PV output. These applications could utilize the large roof areas associated with these commercial loads for PV electric generation.

The value of voltage and VAR control is generally small because of the low-cost methods that are currently used. Enhanced reliability of a distribution circuit may be a benefit in some very special cases. In our case studies, utilities did not given credit for a reliability enhancement benefit. Additional capacity credit due to dispersing the renewable energy electric generators throughout the distribution system is also utility- and site-specific.

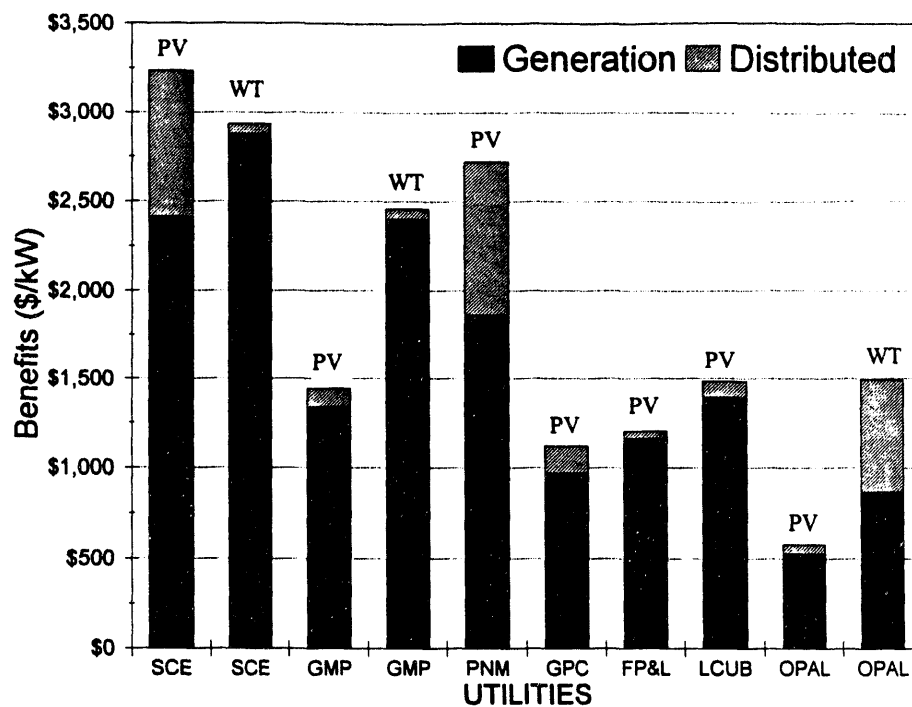


Fig. 1. Benefit results for selected photovoltaic and wind system applications.

Table 1. Summary of selected case study results in Vol. II for renewable energy applications

Case study	Photovoltaic systems			Wind turbine systems		
	Benefits ^a	Costs	Ratio	Benefits	Costs	Ratio
Southern California Edison	3237	6969	0.46	2936	1272	2.31
Green Mountain Power	1444	7197	0.20	2458	1468	1.67
Public Service Company of New Mexico	2723	6842	0.40	---	---	---
Georgia Power Company	1124	7201	0.16	---	---	---
Florida Power and Light	1203	7174	0.17	---	---	---
Lenoir City Utilities Board ^b	450	~7100	0.06	---	---	---
Orcas Power and Light Company	579	7173	0.08	1425	1058	1.35

^a Benefits and costs are listed in dollars per kilowatt.

^b Lenoir City Utilities Board (LCUB) uses a 5-year payback criterion for capital investments.

Distributed utility benefits increased the total value of the benefits by approximately 20–55% in the national study, but the range was larger for the cases studies: 2–78%. For the national study, deferred transmission investment was assumed for all regions. The increase of the benefits due to distributed utility benefits is shown in Fig. 2. Note that regions with low overall benefits have the largest benefit increase, due to the assumed deferred transmission benefit. *In general*, distributed utility benefits can be expected to increase the total benefits by at least 10–20%.

The benefit-to-cost ratio for the PV applications in the case studies ranged from 0.17 to 0.46 if the exceptional cases associated with LCUB and OPALCO are not considered. The LCUB application is atypical, in that it uses a 5-year simple payback criteria. If LCUB used life-cycle

criteria similar to that used by other utilities in this study, but with a 7% real discount rate, its benefit for PV systems would be approximately \$1485/kW, and the benefit-to-cost ratio would be approximately 0.21. OPALCO is a very unfavorable site for PV applications, due to a relatively poor resource and low fuel cost. Thus, PV systems currently are, in general, 2.5–5 times too costly to be economical for favorable sites.

The benefit-to-cost ratio for wind turbines ranged from 1.35 to 2.31 for the utilities having a good wind resource. Consequently, wind systems are cost-effective for these applications. However, siting, integrated resource planning (IRP) and competition issues need to be addressed before actually installing wind turbines. Four of the utilities are located in regions with poor wind resources. Consequently, the application of wind systems was not assessed there.

Electric utilities with good wind resources can economically justify wind turbines for applications evaluated in these studies. Costs are presently too high to economically justify PV use, even in regions with a good solar resource. However, large-scale PV production and continuing R&D efforts should cause a significant cost-reduction for future PV systems. Similar R&D efforts for wind systems and increased wind turbine production should reduce costs and increase the number of economic applications for wind as well.

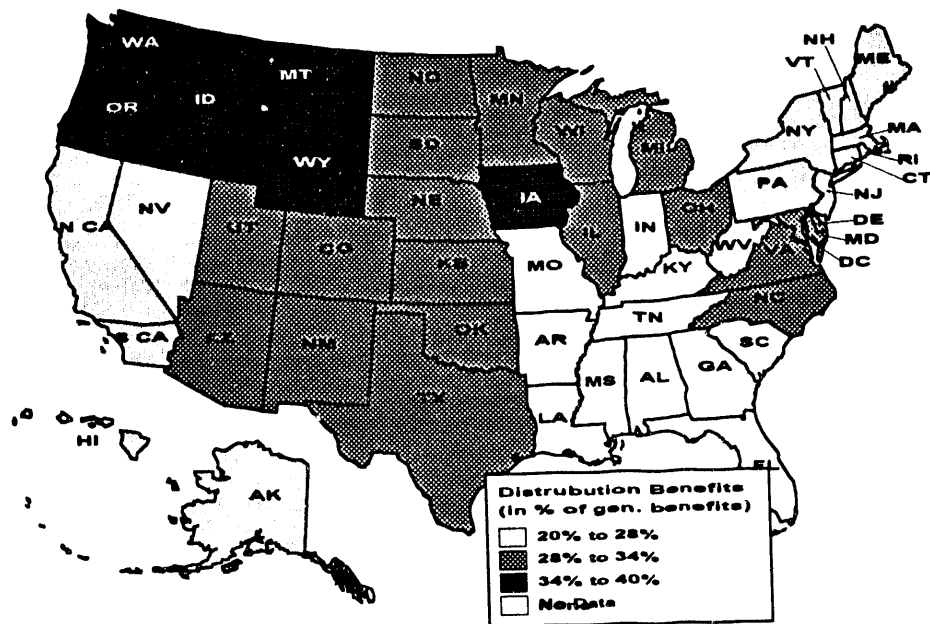
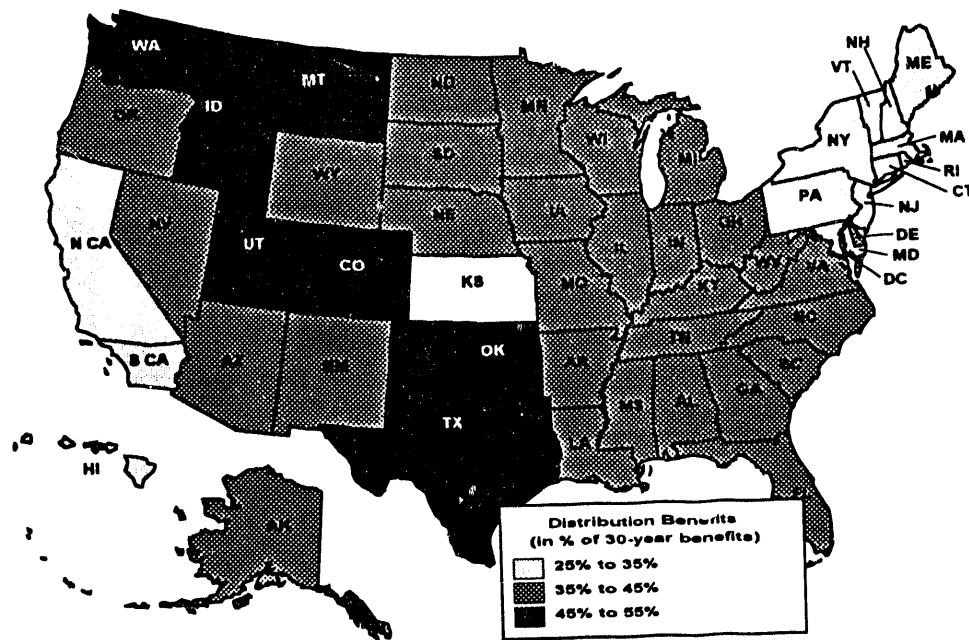


Fig. 2. Increase in benefits related to distributed utility benefits.

1. INTRODUCTION

Over the 10-year period from 1992 to 2002, electric utilities are planning to add nearly 60,000 MW of new capacity and non-utility-owned generators (NUGs) are expected to provide an additional 19,000 MW.¹ Almost half of the new utility-owned capacity will be combustion turbines fired by natural gas or oil. About 70% of our electric energy comes from irreplaceable fossil fuels burned in central station power plants. These fuels could become expensive in the future because of supply interruptions, environmental restrictions, and the depletion of known reserves. Renewable energy in the form of solar and wind are alternative, sustainable domestic energy sources that have the potential of contributing to the nation's electric energy supply.

Renewable energy technologies, such as photovoltaic (PV) power, solar thermal electricity, and wind turbine (WT) power, are environmentally-beneficial sources of electric power generation. The integration of power generation from renewable energy sources into electric power distribution systems may be a reasonable approach, since it locates the generation near the load for efficient operation, and since large land area requirements can be spread throughout the distribution system. Power generation from renewable sources installed near the load offers the potential for reducing system losses, deferring transmission and distribution (T&D) investment, and improving power quality and reliability, as well as displacing energy produced from fossil fuels.² These benefits are referred to as "distributed utility benefits". The value of such distributed utility benefits helps to offset the relatively high capital cost of renewable energy technologies.

The cost of renewable energy technologies has decreased over recent years so that an increasing number of applications can be economically justified by utilities.³ Most of the present renewable energy applications fill special needs where it is too expensive to obtain electric power from an existing power grid. However, two bills have been passed recently by Congress and signed into law that could have a major impact on electric utilities and may encourage the use of renewable energy systems: the Clean Air Act Amendments of 1990 (CAAA) and the Energy Policy Act of 1992 (EPACT). The expected impacts of these bills are considered in this report. As renewable energy technology improves and the economics of large-scale manufacturing are

realized, the associated costs are expected to decrease. This should make renewable energy more competitive with conventional energy sources.

This research project evaluates the use of renewable energy sources for distributed utility power generation. The objectives of this project are (1) to develop an assessment methodology for renewable energy electric generation and energy storage facilities integrated into electric power distribution systems which addresses the distributed benefits of electricity generation from renewable sources and their true value to the system, and (2) to apply the methodology in case studies. The case studies were performed with actual power distribution system data for several electric utilities with the active participation by those utilities in the study.

A broad scoping study of the United States was also performed to determine regions where the resources, utility circumstances, and economic conditions are most favorable for distributed wind and PV energy technologies. The approach used for this national assessment is to estimate the benefits of wind and PV energy systems on a regional basis, and to verify the results by the case studies. Estimated average values were used for the cost of deferred facilities. The fuel savings benefit, a major benefit, is estimated from the fuel costs derived from the average industrial rates and the capacity factor for the renewable energy systems. Benefits associated with avoided emissions are also estimated by state, based on PUC guidelines. While this approach does not address site- and utility-specific issues, it does provide a first-order analysis for identifying regions where solar and wind systems have the greatest potential.

This report has been divided into two volumes. Volume I describes the results of the national study and summarizes the utility case studies in the Executive Summary. Volume II describes the more detailed assessment methodology used in the case studies, the technical characteristics of appropriate renewable energy technologies for distributed utility applications, and the seven utility case studies. The utilities shared costs for this study by providing data and special analysis of their systems. The utilities that participated in this study are Lenoir City Utilities Board (LCUB) in Lenoir City, Tenn., Southern California Edison (SCE), Public Service Company of New Mexico (PNM), Georgia Power Company (GPC), Green Mountain Power (GMP) in Vermont, Florida Power and Light (FPL) in southern Florida, and Orcas Power and Light Company (OPALCO) on Orcas Island near Seattle, Wash.

2. SOLAR AND WIND ENERGY SYSTEMS

Renewable energy systems such as PV, solar thermal electricity such as dish-stirling systems, and WT are appropriate solar and wind technologies that can be considered for electric power generation at the distribution system level. Other renewable energy technologies, such as the solar central receiver, hydro-electric generation, geothermal, and large wind farms, are normally connected to the grid at the subtransmission or transmission level because of the higher power capacities of these systems. Presently, PV and WT technologies appear to be the most viable candidates for integration into power distribution systems. A brief description of the PV and WT technologies is presented below. A more detailed technical description of PV and WT technologies is presented in Vol. II, Section 3, of this report.

Solar and wind energy systems are characterized by relatively high capital costs, low operation and maintenance (O&M) costs, and zero fuel costs. The high capital cost has been a major barrier to widespread use by utilities. However, the costs of both PV and wind systems have decreased substantially in recent years and further reductions over the next 10 years are expected.

2.1 PHOTOVOLTAIC SYSTEMS

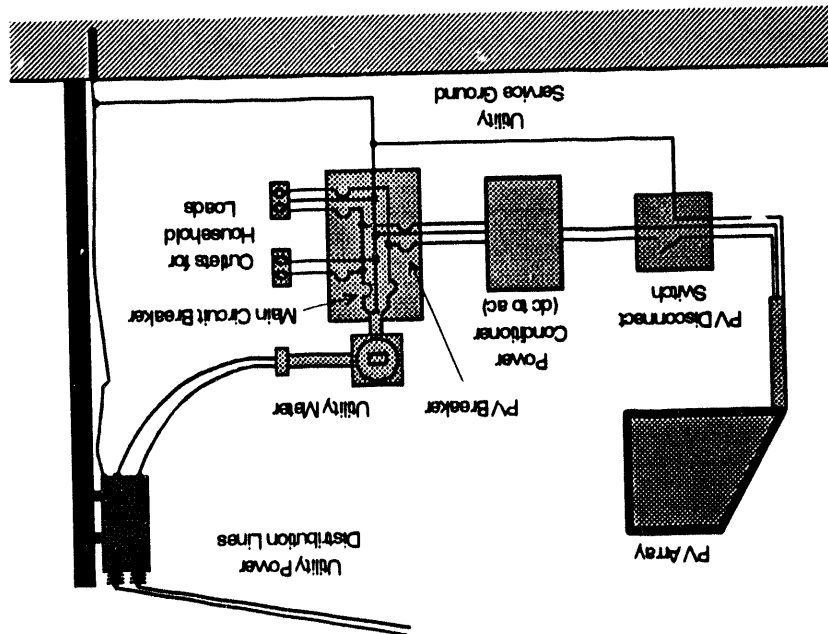
Sunlight is converted directly to direct current (dc) electricity by PV cells made of semiconductor materials such as silicon. The cells are wired in series-parallel combinations to form modules or panels. The dc is converted to alternating current (ac) by an inverter or power conditioning unit. The mounting brackets, power conditioning unit, disconnect switch, and PV breaker are called the balance of system (BOS), since they constitute all the system components except the PV modules. The basic components in a small residential PV electric energy generation plant are shown in Fig. 2.1

The utilities involved in the case studies did not have concerns about other potential technical issues such as recloser protection operation, monitoring and control, and safety. For

PV systems dispersed over the distribution circuit area are not expected to cause technical problems such as voltage regulation difficulties and harmonic distortion in 10-MVA circuits at penetration levels up to 30%.⁴ During sunny day time periods of heavy circuit loading, PV systems will reduce the voltage drop by reducing the effective circuit loading. It may be possible to maintain the circuit voltage within normal bounds at higher penetration levels, but problems could arise during highly loaded conditions if the reactive power (VAR) compensating capacitor banks are connected.⁴ For a central installation such as a 2-MW site located at the distribution substation, voltage problems could arise at lower circuit penetration levels since the power ramp rate of the PV plant could be larger than that of widely dispersed PV units. However, penetration levels of 20 to 30% appear achievable without serious problems. Central installations will require about 10 acres of land per megawatt of PV capacity.

2.1.1 Technical Issues

Fig. 2.1. A residential photovoltaic system connected to the power utility grid.



high circuit penetration levels, these issues will likely become a concern and can be addressed by detailed analysis. For this study, it is assumed that the penetration level is in the low to moderate range (on the order of 30% or less). As for safety concerns, it is good safety policy to work on a de-energized circuit as if it could become energized at any time and to ground all lines solidly while they are being serviced.

2.1.2 Capital Cost

The costs of PV modules and PV power plants, which include installation costs, have decreased over recent years. Installed PV system costs during 1992–1993 have been about \$7000/kW to \$9000/kW for large quantities of single-crystal silicon modules having a power producing capacity of 400 kW or greater. These costs are based on Pacific Gas and Electric's (PG&E's) 500-kW Kerman System and Sacramento Municipal Utility District's (SMUD's) central installation systems and 400 kW of residential PV systems consisting of one hundred 4-kW residential units.⁵⁻⁶

The future cost of PV systems should decrease because of two factors: (1) higher production volume of PV modules and systems and (2) technological breakthroughs. As the demand for PV modules and BOS components increases and plant installations develop into turnkey operations, costs are expected to drop. An Electric Power Research Institute (EPRI) study indicates that larger, more efficient PV manufacturing plants could produce polycrystalline CuInSe₂ (CIS) modules having a 25–100 MW power production capacity at less than \$1500/kW, and that installed PV plants could cost less than \$2500/kW in 1990 dollars.⁷ The use of new technology in the fabrication of PV cells—such as Texas Instruments' spherical solar modules scheduled to be available in several years—will provide additional price and performance competition in the PV market. Other possibilities for advanced PV technology include direct-mount roof modules to reduce BOS costs.

For this study, three installed capital costs are considered in the benefit-cost analysis: \$7000/kW, \$3250/kW and \$2500/kW. The mid-range value of \$3250/kW may be available by 1998, the planning period for this evaluation⁸.

2.1.3 Operation and Maintenance Costs

Information on the operation and maintenance (O&M) costs is available for a number of PV plants.⁹ O&M costs are generally low for fixed-panel and single-axis tracking sites, at about 5 mills/kWh. A 300-kW site operated by the Austin Electric Utility has had maintenance costs of approximately 4 mills/kWh, with a system availability greater than 99%.¹⁰ With improved BOS components, O&M costs should decrease below the current levels, since much of the maintenance cost has been associated with power conditioning and tracking equipment.

2.2 WIND ENERGY SYSTEMS

Wind turbines generate electric power by extracting kinetic energy from the wind to drive a turbine connected to an ac generator. The power in wind available to a turbine is proportional to the cube of the wind speed. Thus, wind speed variations will cause variations in the wind turbine power output. In recent years, wind energy systems have undergone dramatic improvements that incorporate the latest in power electronics, aerodynamics, and mechanical drive trains.¹¹ Advanced designs have attempted to reduce the level of the output power variations. An early study on wind turbine array control strategies concluded that array controls should be considered for utility system penetration levels of 10-20%.¹² For modern wind turbines dispersed along a distribution feeder, higher penetration levels should be obtainable before power variations become noticeable. However, a detailed study of the distribution circuit and expected power variations should be performed to determine the maximum penetration level that will be acceptable without additional controls.

2.2.1 Capital and Operating Maintenance Costs

Recent improvements in wind turbine design are expected to lower the construction costs from the present cost of about \$1000/kW when installed to around \$750/kW.¹³ This includes about \$175/kW BOS cost. In rough terrain, higher costs can be expected. The new AOC 15/50 advanced wind turbine is expected to have a near term equipment cost of \$1140 to \$1200/kW and an installation cost of from \$160 to \$240/kW.¹⁴ Thus, the total installed cost is expected to range from \$1300-\$1440/kW. O&M costs of 10 mills/kWh are typical for the wind energy industry.¹¹

2.3 AVAILABILITY OF RENEWABLE ENERGY RESOURCES

Energy resources provided by solar and wind systems have different characteristics. The diurnal presence or absence of sunlight can be predicted. The same is not true for wind energy. Both types of energy sources are strongly affected by unpredictable weather effects. Much of our knowledge of the characteristics of solar and wind energy is based on meteorological observations across the United States over an extended period of time. In this section, we will briefly review the characteristics of the solar and wind energy resources across the country and estimate their potential for application to the useful production of electric energy.

2.3.1 Photovoltaic Systems

2.3.1.1 The energy resource provided by the sun

Outside the earth's atmosphere, the nominal power density provided by sunlight is about 1.37 kW/m^2 .¹⁵ Although this extraterrestrial solar energy density varies slightly over the course of the year because of changes in the earth-to-sun distance and because of fluctuations in the solar energy levels, it can be taken as a constant for most practical purposes. On the earth's surface, however, the solar power density can vary considerably because of attenuation and scattering by the atmosphere and the shadowing of the sun by clouds.

The solar radiation on the earth's surface can be thought of as consisting of two major components: the direct (sometimes referred to as the beam) component and the diffuse (or scattered) component. The direct component contains the power coming directly from the solar disk without undergoing any scattering or diffraction. The diffuse component contains contributions from scattered and reflected sunlight.

The total energy density provided by the sun on the ground (referred to as insolation and measured in units of kWh/m^2) is a function of the incident solar power density and the time over which the solar power is collected. Thus, the total energy collected by a solar panel on any particular day will depend on the time of year, the latitude of the panel location, the local weather conditions, and the panel area and orientation. This daily solar energy can be expected to vary

considerably over the year because of seasonal effects. Frequently, it is desirable to obtain a yearly average of the solar radiation to smooth out this seasonal variation.

Neglecting the effects of weather and atmospheric scattering, the solar radiation on the earth's surface can be computed from simple mathematical models.¹⁵ This computation provides a crude upper bound on the maximum energy falling on the earth at any particular location. The clouds and atmosphere, however, significantly reduce this energy, and these effects should be taken into account for practical feasibility studies of solar power. Unfortunately, the chaotic nature of the atmosphere and weather patterns makes it difficult to calculate their effects on the solar insolation.

One solution to the problem of determining realistic solar insolation levels is to use *measured* data from an extensive network of solar measuring stations located across the United States. Initially, hourly data measured at 26 locations across the country were taken and included in a data base referred to as SOLMET.^{16,17} By using calculational models, these measured data were extrapolated to other locations and an expanded SOLMET/ERSATZ data base was formed. Investigations of this data base showed that there were errors of up to 50% in the average monthly direct radiation.¹⁸ This finding led to the development of a new solar energy data base, the National Solar Radiation Data Base (NSRDB), which provides for updating the SOLMET data and developing solar radiation statistics consistent with standard climatic practices.

This new NSRDB, also referred to as the National Renewable Energy Laboratory (NREL) data base, is documented in ref. 19. It consists of hourly values of the three most common measurements of solar radiation (global horizontal, direct normal, and diffuse horizontal) over 30 years, from 1961 to 1990. In developing this data base, 56 primary stations and 183 secondary stations are defined. A primary station is one having measured data for at least a portion of the 30-year reporting period. A secondary station is one having solar radiation values that are calculated from surrounding stations and suitable radiation models. Figure 2.2 illustrates the primary and secondary sites across the United States in the NREL data base.

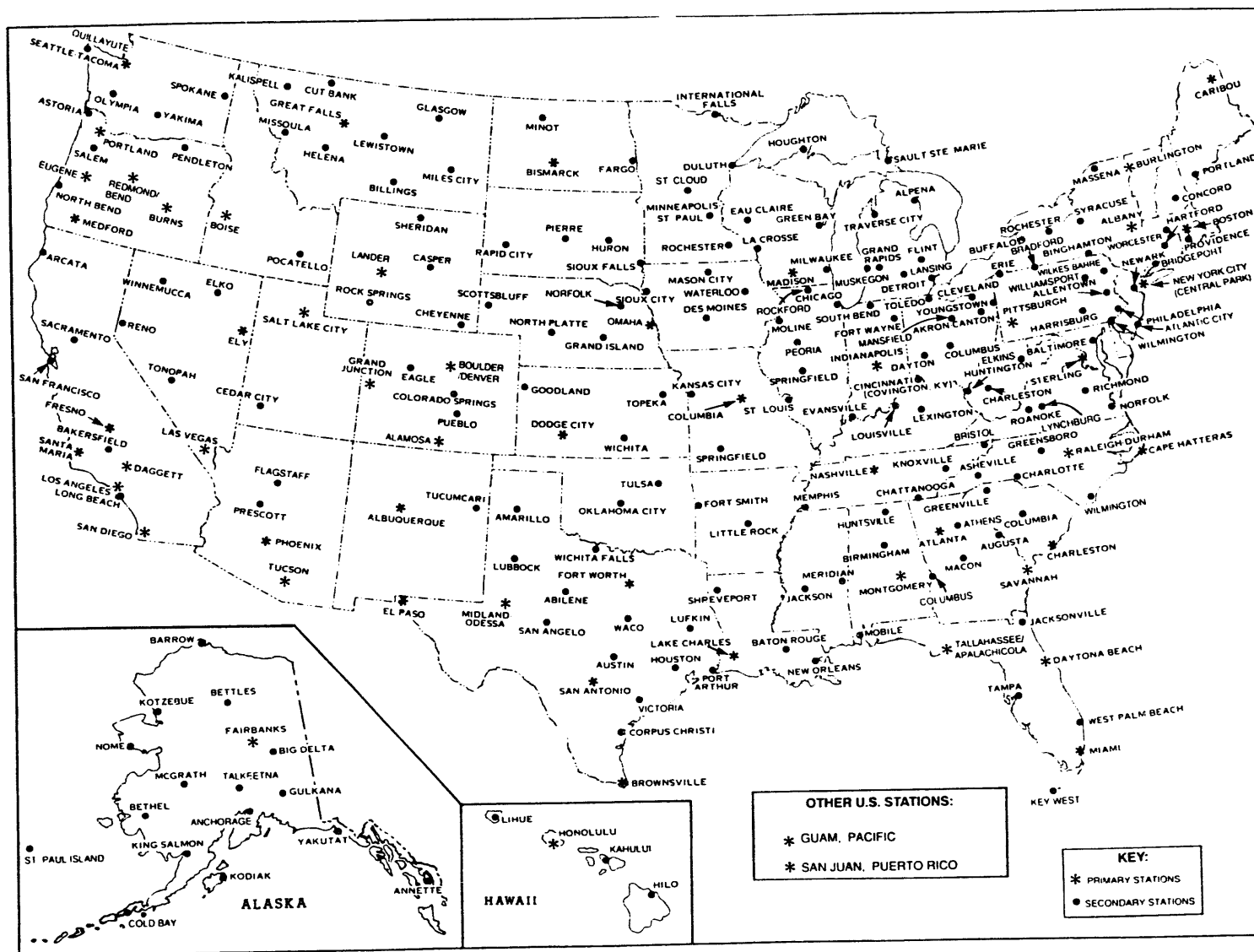


Fig. 2.2. Primary and secondary observation stations in the NREL data base. *Source: National Solar Radiation Data Base User's Manual, NSRDB-Volume 1, National Renewable Energy Laboratory, Distributed by the National Climatic Data Center, Asheville, NC, 28801, September 1992.*

Figure 2.3 illustrates the range of the yearly average solar energy density in kWh/m² for the direct normal plus diffuse solar radiation across the continental United States, as obtained from the new NREL data base. From this map, it is clear that the Southwest area of the United States has a high potential for solar energy sites and applications.

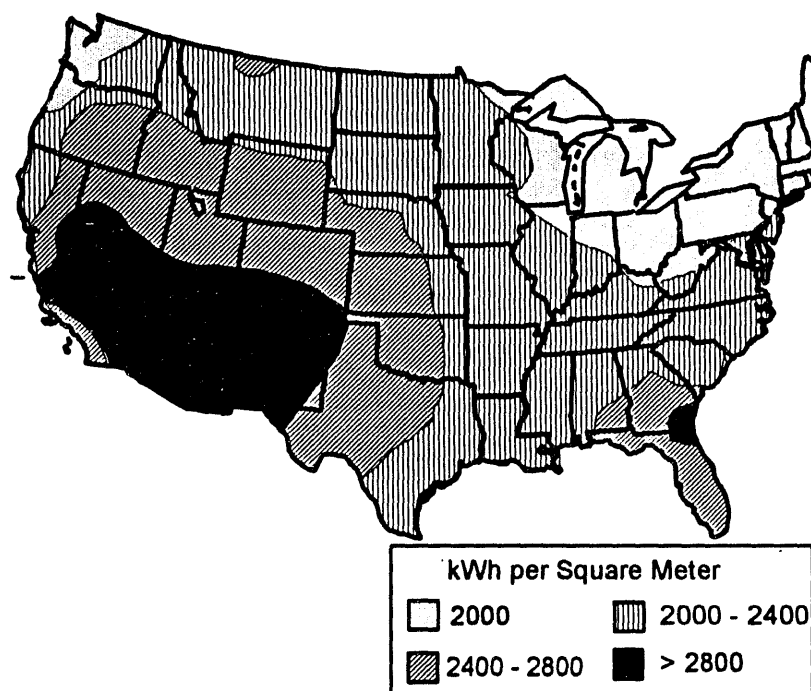


Fig. 2.3. Yearly average solar energy density across the United States.

2.3.1.2 Energy output from photovoltaic systems

Unfortunately, only a fraction of the incident energy on a solar panel can be converted into useful electric energy. System conversion efficiencies on the order of 10% are typical. There are several reasons for such a low efficiency. Aside from the inherent inefficiency of the photon conversion process (which leads to heat generation within the panel), there are reflection and transmission losses through the glass or plastic covers of the panel and losses in power conditioning and switching electronics.

An additional consideration in quantifying the behavior of a photovoltaic system is that it cannot produce electricity continuously, because of the absence of solar energy at night. This effect is described by an annual capacity factor for a system, defined as

$$\text{Annual } CF = \frac{\text{actual energy delivered in a year}}{\text{rated power output} \times 8760 \text{ hours}}$$

Care must be used in defining the rated peak power output of a PV system. Manufacturers of solar panels will typically give a rated power output for the panels, but additional system losses can further reduce the true power available.

One way of determining the capacity factor of a PV system is to measure the energy output of the system over a fixed period of time. Figure 2.4 illustrates the capacity factor (expressed as a percentage) for a PV system manufactured by the Utility Power Group (UPG) as measured at the Photovoltaics for Utility-Scale Applications (PVUSA) facility in Davis, California.²⁰ This system is a fixed-tilt, flat-plate PV system having an area of 477 m² and a tilt angle equal to the site latitude of 30°. The solar panels are made of amorphous silicon and have a tandem junction configuration. The power output is 15.1 kW at standard conditions of 1000 W/m² incident radiation density, 20° C ambient temperature, and a wind of 1 m/s. This standard condition corresponds to a panel temperature of 49° C.

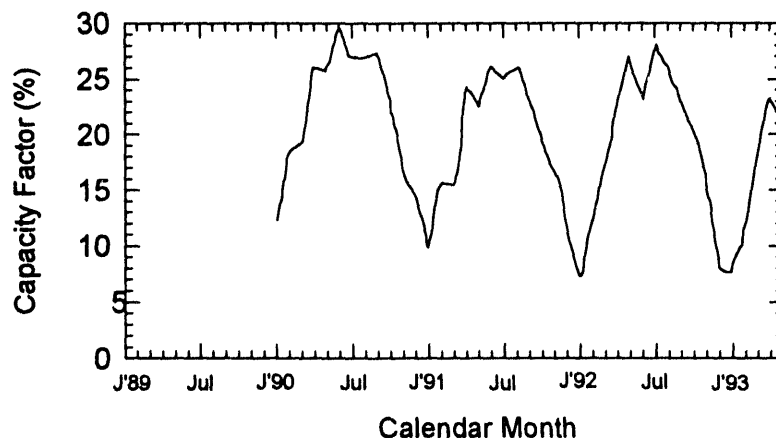


Fig. 2.4. Measured capacity factor of the Utility Power Group solar system at Photovoltaics for Utility-Scale Applications (PVUSA) in Davis, California. Source: Private communication with T. Townsend, PVUSA, Davis, CA, July 8, 1993.

In Fig. 2.4, it is evident that seasonal variations in solar insolation can have a significant effect on the system capacity factor. The largest capacity factor occurs in the summer when the days are the longest. These yearly variations can be averaged to provide a yearly capacity factor of about 18%, a number that can be used for the relative comparison of different PV systems or site locations.

PV system capacity factors may also be estimated using a computer model. Two models that are commonly available are PVFORM²¹ and PV F-CHART.²² These computer programs take a physical description of a PV system, the assumed electric loads, and a suitable set of solar data and compute the electric power that can either be used at the installation or sold back to a utility. In addition, these programs can perform an economic analysis for the PV system to illustrate the costs and possible benefits of solar systems, given assumptions for the various cost elements of the system.

The input solar data for PVFORM consist of hourly solar and weather data at a particular location. These data actually consist of averages over several years of observation, in a form referred to a "typical meteorological year" file.²³ Previously, the necessary typical meteorological year data files have been derived from the SOLMET data base. The PV F-CHART program has self-contained solar data files for its calculations. Both the older SOLMET data and the newer NREL data bases are available from observation stations across the United States.

As an example of calculated capacity factors for a typical PV system, a 10-m² fixed-plate PV array was considered to be located at each of the measurement stations in the NREL data base within the continental United States. The pertinent parameters for this solar system, which are required in either of the previously mentioned computer programs, are summarized in Table 2.1. Figure 2.5 presents the estimated capacity factor for the sample PV system, shown as a function of location across the continental United States. For these calculations, the PV F-CHART program was used with the NREL data base.

Table 2.1. Parameters for a sample photovoltaic system

Cell temperature at standard conditions	40 ⁰ C
Array reference efficiency	0.1
Array reference temperature	20 ⁰ C
Power temperature coefficient (times 1000)	4.3 1/C
Efficiency of maximum power point tracking electronics	1.0
Efficiency of power conditioning electronics	1.0
Percent standard deviation of the load	0%
Array area	10 m ²
Array slope	33.7 ⁰
Array azimuth (south = 0)	0 ⁰

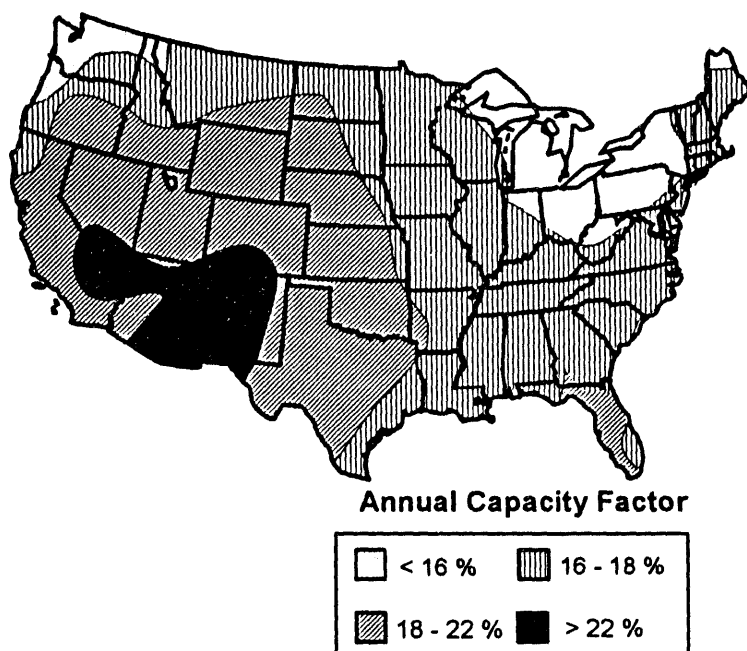


Fig. 2.5. Photovoltaic power system capacity factor (in percentages) calculated with the PV F-CHART program.

2.3.2 Wind Energy Systems

2.3.2.1 The wind energy resource

The energy contained in the wind resource is more difficult to quantify on a national scale because its characteristics can change significantly from location to location and with height above the ground.²⁴ The wind resource is typically divided into several wind classes, according to the wind speed. Table 2.2 from ref. 25 shows the wind classes 1 through 7, together with the corresponding ranges of the wind speed for heights of 10m, 30m, and 50m. The wind speed is typically modeled as increasing with height according to a 1/7 power law. Consequently, if the wind speed is V_o at a height h_o , the resulting speed V at a different height h is expressed as

$$= V_o \left(\frac{h}{h_o} \right)^{1/7}$$

The wind power density is related nonlinearly to the wind speed as shown in Fig. 2.6. Because the wind speed fluctuates throughout the year, it is common to describe the wind resource by a Raleigh probability distribution using an average wind speed. The average wind power intercepted by a wind turbine depends on the height of the unit above the ground.

Figure 2.7a presents a map of the average wind resource across the United States, shown in terms of the wind category. The average wind speed for each category may be estimated from Table 2.2 for different turbine heights, and the corresponding wind power may be found from Fig. 2.6. Similar data are presented and discussed in refs. 24 and 26 .

Figure 2.7b shows the percentage of local land area with class 3 or higher wind power.²⁴ This figure has excluded certain urban and environmentally sensitive areas (referred to as "land exclusion scenario 3" in ref. 24). The high percentage areas are potential sites for integrating wind turbines into electric distribution systems, since most mountain peaks and ridges, which are devoid of distribution circuits, are not included. The highest potential for wind sites is located in the central United States.

Table 2.2. Defined wind classes and corresponding wind speeds.

Wind power class	Wind speed (m/s) for h = 10 m	Wind speed (m/s) for h = 30 m	Wind speed (m/s) for h = 50 m
1	0 - 4.4	0 - 5.1	0 - 5.6
2	4.4 - 5.1	5.1 - 5.9	5.6 - 6.4
3	5.1 - 5.6	5.9 - 6.5	6.4 - 7.0
4	5.6 - 6.0	6.5 - 7.0	7.0 - 7.5
5	6.0 - 6.4	7.0 - 7.4	7.5 - 8.0
6	6.4 - 7.0	7.4 - 8.2	8.0 - 8.8
7	7.0 - 9.4	8.2 - 11.0	8.8 - 11.9

Source: Elliott, D.L., et. al, "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States", Pacific Northwest Laboratory Report, PNL-7789, UC-261, August, 1991.

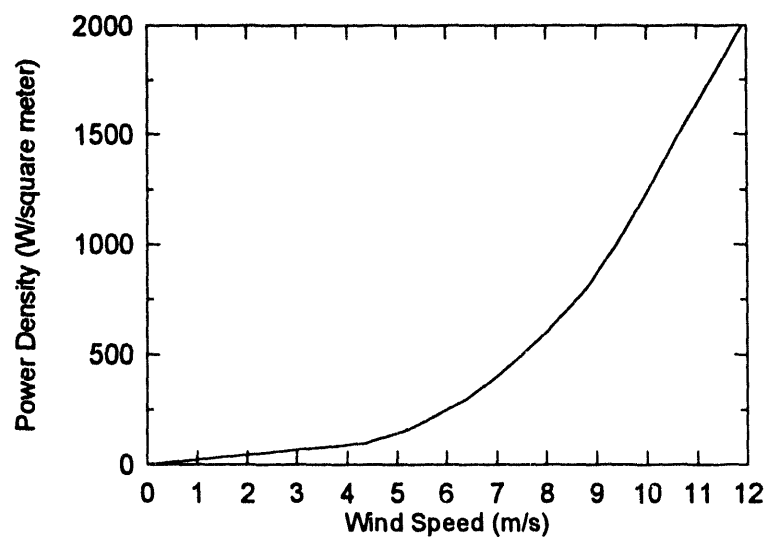
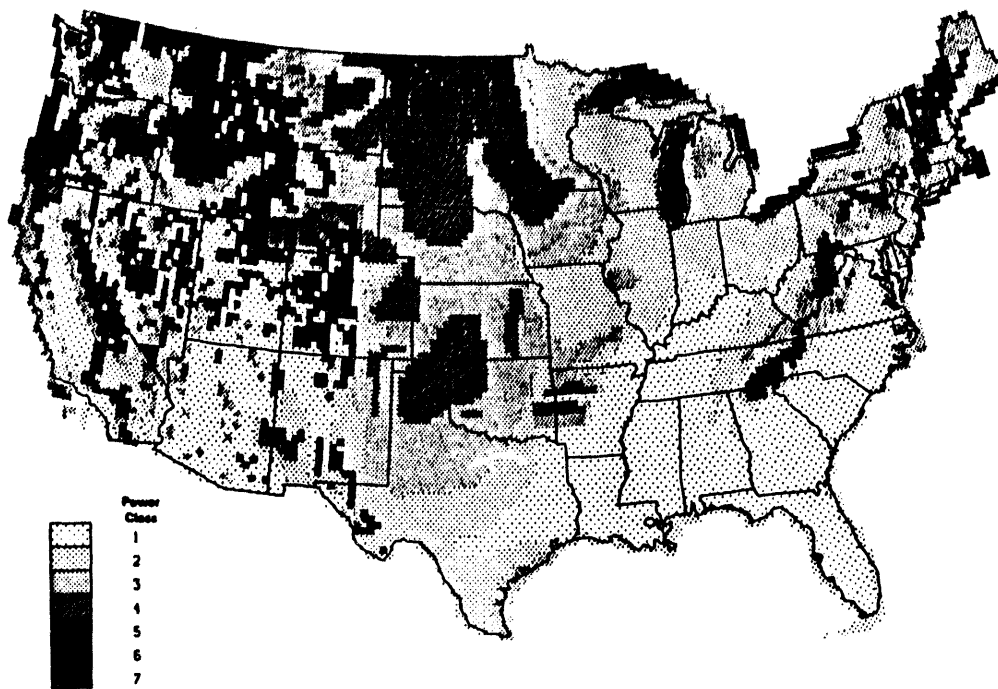
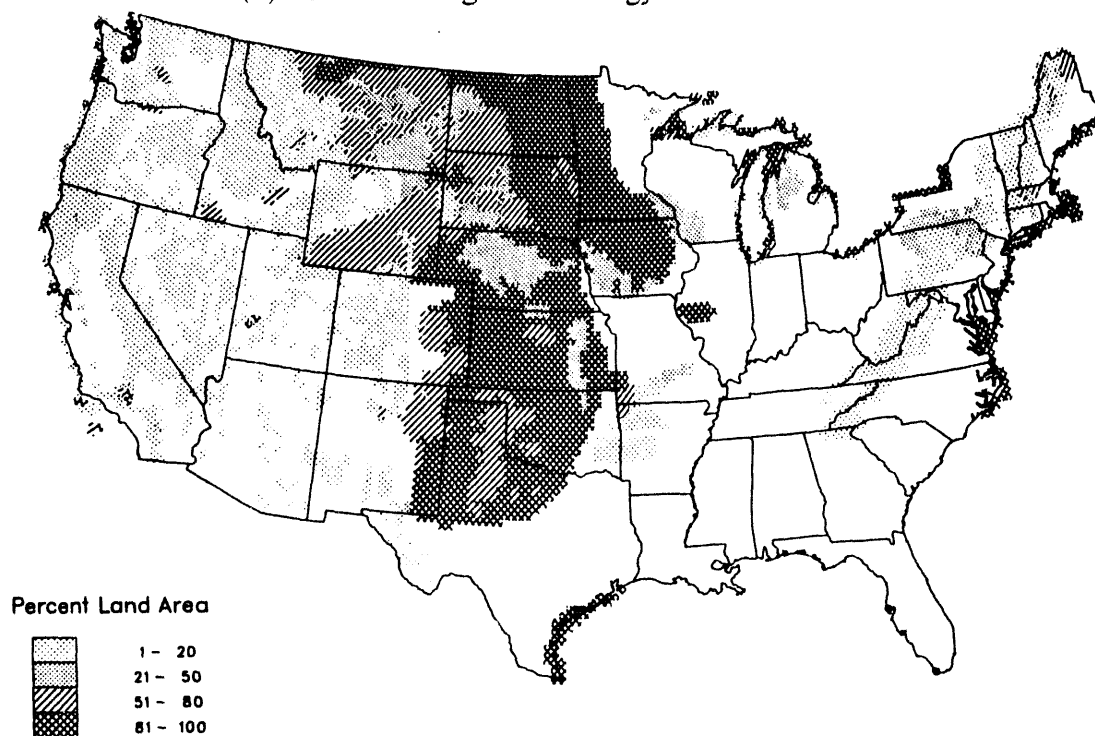


Fig. 2.6. The wind power density (in W/m²), shown as a function of the wind speed.



(a) Annual average wind energy resource estimates



(b) Percentage of land area estimated to have class 3 or higher wind power

Fig. 2.7. Wind energy resource estimates in the contiguous United States. *Source:* Elliott, D.L., et. al, "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States", Pacific Northwest Laboratory Report, PNL-7789, UC-261, August, 1991.

2.3.2.2 Energy output from wind systems

The wind energy collected by a wind turbine depends on many different factors, including the blade airfoil design and construction, the mechanical linkage design, the electric generator design, and the effects of the local terrain near the generator. A new generation of wind turbines is under development. These new turbines have a design goal of producing energy at the rate of \$0.05 per kWh.²⁷ Figure 2.8 presents the calculated power output from the turbine as a function of the hub wind speed for a new wind turbine designated as the Atlantic Orient Corporation (AOC) 15/50. This unit, which has a nominal hub height of 30 m, is designed to have a rated power output of 50 kW at a wind speed of 11 m/s at the hub.

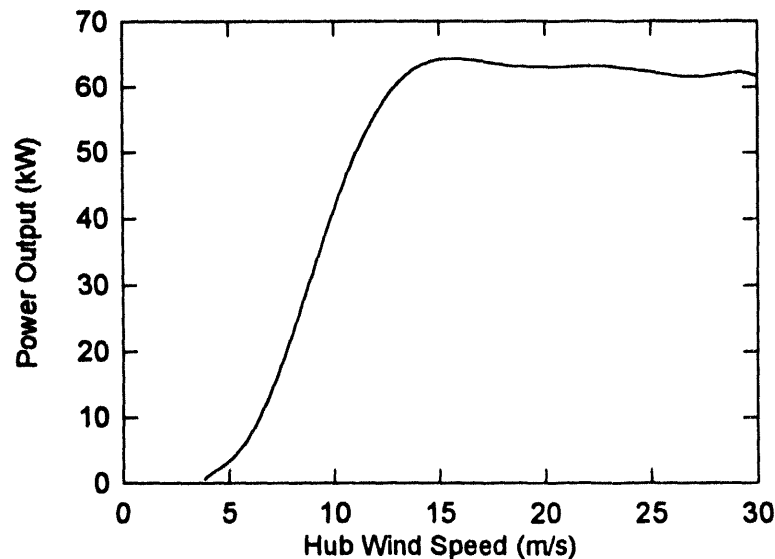


Fig. 2.8. Power output from the AOC 15/50 wind turbine as a function of the hub wind speed. Source: AOC 15/50 Wind Turbine Prototype Data, Atlantic Orient Corporation, Norwich, VT, March 1993.

The preceding data on the wind power density and the performance of the wind turbine permit the development of a capacity factor for wind generation. This annual wind generation capacity factor is defined in a manner analogous to the capacity factor for the solar system as

$$\text{Annual } CF = \frac{\text{energy provided by the turbine in a year}}{\text{rated power output of the turbine} \times 8760 \text{ hours}}$$

Figure 2.9 presents the capacity factor for this turbine as a function of the wind speed at the 30-m-high hub. The scale at the top of the plot shows the ranges of the different wind classes. It should be noted that this performance indicator depends on actual site conditions and will vary with altitude, temperature, topography, and proximity to other structures.

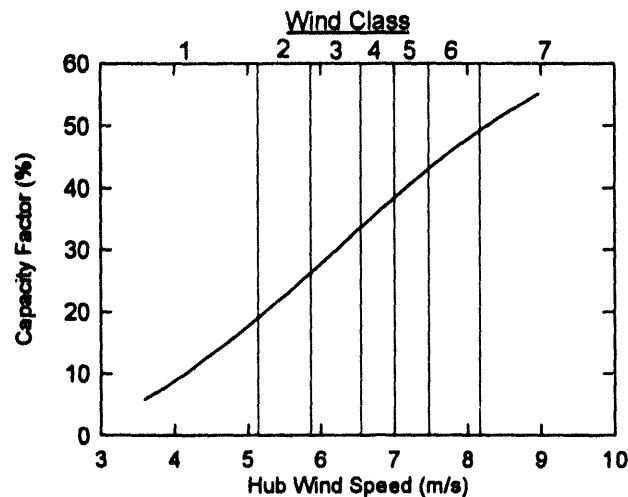


Fig. 2.9. Capacity factor for the Atlantic Orient Corporation 15/50 wind turbine generator system.

From a comparison of the wind speeds in Fig. 2.9 with those in Table 2.2 for the 30-m hub height, it is apparent that wind categories 3 and 4 correspond to a capacity factor between 30 and 35%. The regions across the United States having these wind levels, shown in Fig. 2.7, are estimated to be the best candidates for the location of wind generation turbines. Regions of lower wind speeds (categories 1 and 2) will not be as attractive from a cost standpoint, and the regions of higher speeds (categories 5, 6 and 7) are usually located on mountain ridges where either distance or various environmental considerations may preclude their development.

It is important to realize that actual capacity factors of wind power systems might vary from the values given here due to large fluctuations of wind speed. Although a yearly average wind speed might appear to be reasonable for wind power applications, there could be extended periods of very little wind, together with other periods of very high wind. As the wind turbines do not operate efficiently for the low or high velocity extremes, the capacity factor can be smaller than if the wind were constant throughout the year.

3. BENEFITS OF RENEWABLE ENERGY SYSTEMS

The economic benefits of renewable energy systems can be categorized as "generation benefits" and "distributed utility benefits." Generation benefits are defined as the costs that can be avoided by displacing the need for capacity and energy that otherwise would be provided from other units. Generation benefits tend to vary regionally because of resource availability, fuel price differences, atmospheric emissions requirements, and PUC policies. Distributed utility benefits are the additional benefits obtained by integrating renewable energy sources into the distribution system. These benefits are discussed in more detail in the utility case studies.

For this study, the benefits analysis has been conducted on a state-by-state basis, with the exception of California, which has been divided into a northern and southern part to account for different PUC externality values. For PV systems, the highest capacity factor for each state has been assumed, because newly installed equipment will probably be located in the regions of the highest solar resources. For the wind energy analysis, wind categories 1 and 2 would not provide significant useful power and wind categories 5, 6 and 7 are not likely to be usable because of their location (i.e., on the mountain ridges). Therefore, wind categories 3 and 4 are assumed to contribute the wind power generation with the maximum capacity factor for each state used.

There also may be some intangible benefits of using renewable energy systems. A public relations benefit is possible, since a utility could tangibly demonstrate its commitment to reducing environmental impacts of electric power production. A potential for reducing public concern over installing solar and wind systems in nonurban areas may reduce schedule delays in facility construction. Furthermore, with renewable energy systems there is less risk associated with uncertainty of future environmental laws and the price and availability of fuel.

3.1 GENERATION BENEFITS

The benefits of generating electricity with wind and PV systems are those savings associated with using renewable energy sources instead of conventional generation. These benefits include the following:

- savings in the cost of fuel,
- credit for avoided generation capacity, and
- savings associated with avoided atmospheric emission penalties.

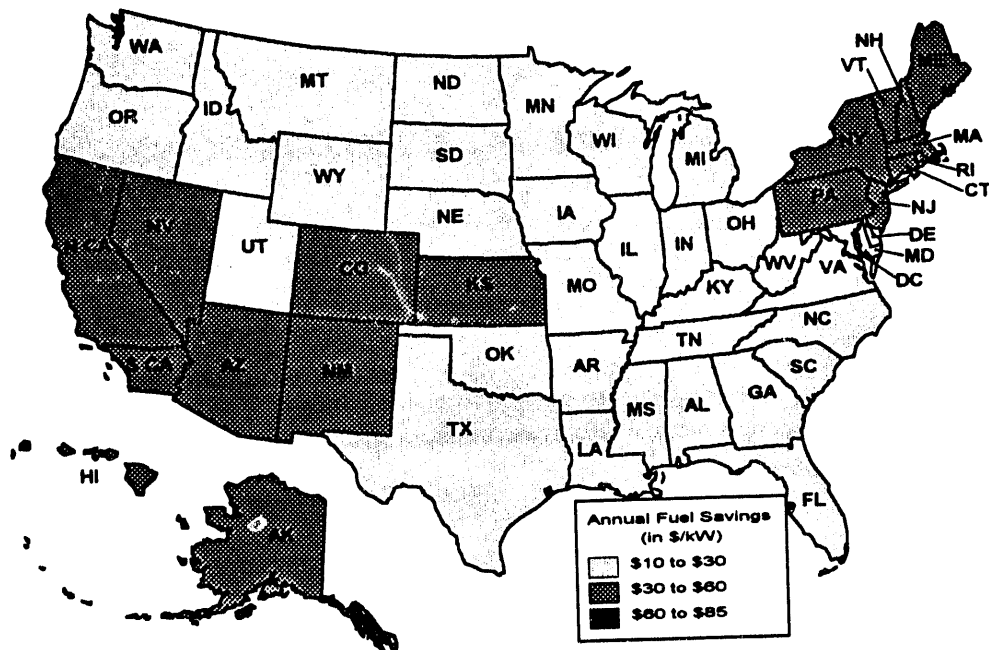
In some states the consideration of externalities and set-asides in the economic assessment of new generation is mandated by the PUCs.

3.1.1 Displaced Fuel

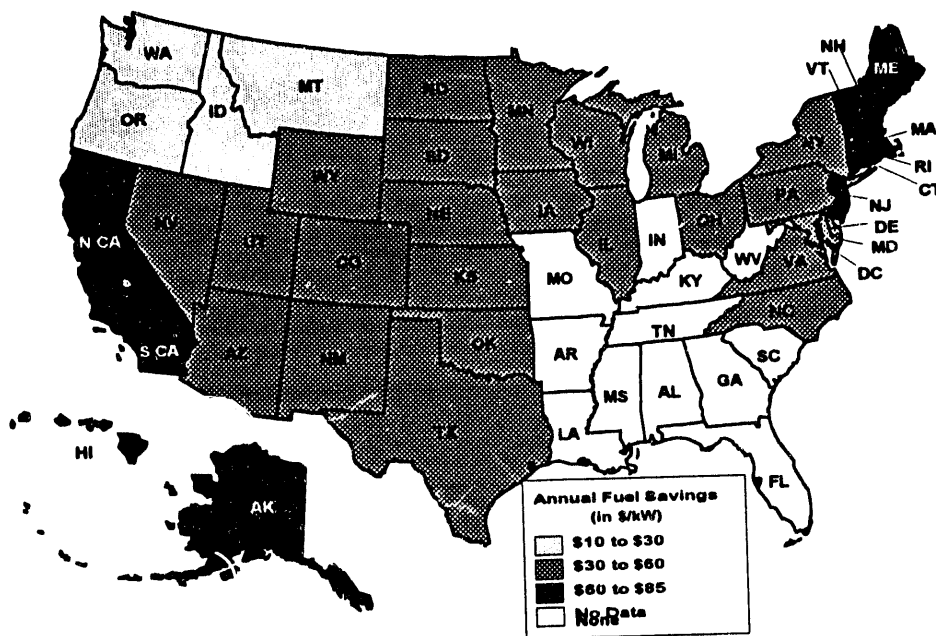
The savings in fuel costs depend on the resource availability and on the type and price of fuel being displaced. Fuel prices can vary by a factor of three from one region to another.²⁸ The generation mix and the type of conventional generation being displaced (e.g., peak generation) are also important.

To estimate the annual fuel savings for wind and PV systems, the cost of fuel is assumed to be proportional to the industrial electric rate (the rate utilities charge large industrial customers.) This approach works reasonably well for the fuel savings obtained in the various case studies. The average 1991 industrial rate for each state is available in ref. 29 . The savings in displaced fuel determined in the case studies have been scaled to the industrial rates to provide estimated fuel savings over the United States. These values are averages, with some of the fuel savings coming from displaced peak generation and the balance from intermediate load and base load following generation.

Fig. 3.1 shows the estimated average annual fuel savings for PV and wind turbines. For fixed PV systems, the annual fuel savings range from \$53/kW in California to \$13/kW in Washington. Similarly, for the AOC 15/50 wind turbine system, the annual fuel savings range from \$69/kW in Alaska to zero for low wind regions. Of course, variations within the states occur from utility to utility.



(a) Photovoltaic systems



(b) Wind turbine systems

Fig. 3.1. Annual average saving in displaced fuel per kW (in 1993 dollars).

3.1.2 Capacity Credit

Capacity credit is the amount of future conventional power generating capacity that can be avoided by renewable energy sources. This value can be calculated by assessing the amount of conventional generating capacity which can be displaced by solar or wind systems, while maintaining acceptable reliability of electricity generation. The capacity credit is a function of the renewable energy resource availability and the characteristics of the utility.

A strong correlation between renewable energy availability and electricity demand results in high values of capacity credit. In sunny areas of the Southwest, the correlation between the PV output and certain utility loads appears to be high and capacity credit can be on the order of 85%. For areas with many cloudy days and air-conditioning loads that continue well into the evening, capacity credit can be expected to be much lower, on the order of 30 to 50%. The capacity credit decreases as the penetration level increases³⁰. There appears to be a strong correlation between capacity credit and capacity factor.³¹ For low penetration (a few percent), the capacity credit for dispersed wind turbines is about equal to the capacity factor.³¹

The same study found that *distributing* the WTs over the power system increased the capacity credit by 18%. A similar study for low penetrations of PV found that dispersing the PV units increased the capacity credit by 17 to 36%, depending on penetration level.³² For a New England utility, the capacity value of residential photovoltaic units was found to be 42% of that of conventional generation.³³

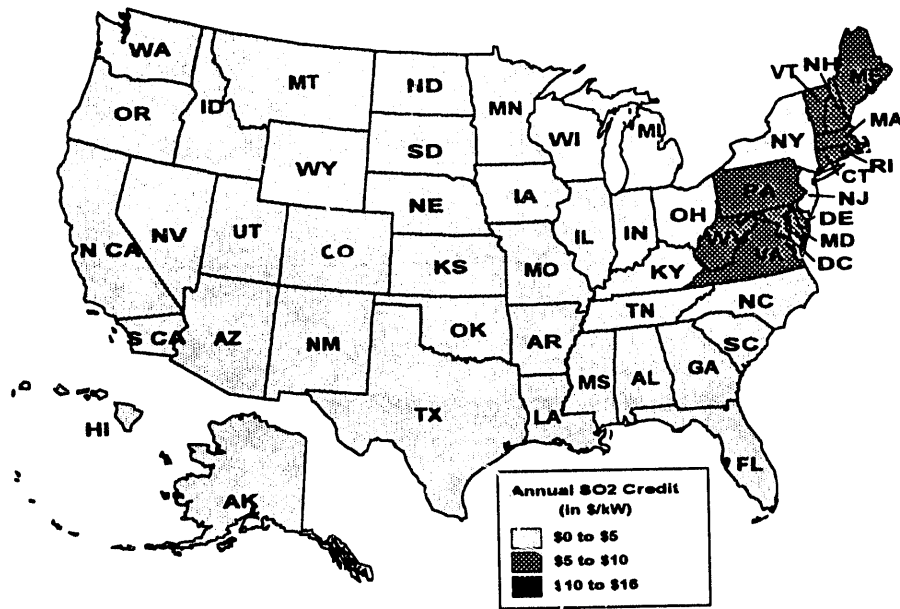
For this study, capacity credit for PV was assumed to cover a range from a low of 40% in the Northeast to a high of 85% for dispersed units in the Southwest where there is a good correlation between system load and PV power production. For wind systems, a capacity credit of 30–44% was used, with the higher values assigned to dispersed units in wind class 4 regions. These values are in general agreement with the case studies and other past studies for low penetration levels. This approach is used to provide an indication of the average value of capacity credit for each state. However, actual values for a particular utility are site- and utility-specific and may differ from the values assumed for this study.

3.1.3 Avoided Emissions

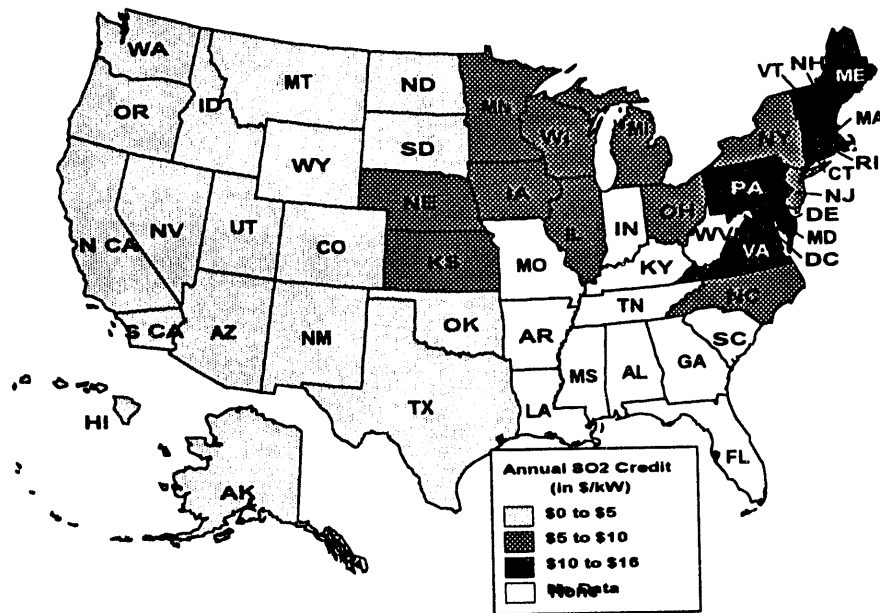
The Clean Air Act Amendments of 1990 will impose substantial costs on United States industries from 1990 to 2005; the cost of compliance in 2005 is estimated at \$24 billion (1990 dollars).³⁴ Electric utilities and heavy metals industries will be most affected. Credits to renewable energy systems for sulfur dioxide (SO₂) allowances created by the CAAA are described in Appendix A. In the late 1990s, SO₂ allowances are expected to be trading for about \$600 per ton, as described in Appendix A. The credit for renewable energy sources for \$600 SO₂ allowances is shown in Fig. 3.2. Title IV, Section 407 of the CAAA (42 U.S.C. 7651(f)), also requires a reduction in nitrogen oxide (NO_x) emissions.

Carbon dioxide (CO₂), a principal greenhouse gas, is not directly covered under the 1990 CAAA. However, Title VIII, Sec. 821 of the CAAA authorizes the Environmental Protection Agency to require affected sources to monitor carbon dioxide emissions. Moreover, the reduction of CO₂ emissions is a major focus of President Clinton's Climate Change Action Plan. The focus of this plan is to reduce greenhouse gas to 1990 levels by the year 2000, and it is being coordinated by the White House Office of Environmental Policy.

Electric utilities are major sources of carbon dioxide.³⁵ Electric power generation is responsible for about 33% of the total CO₂ emissions in the United States. Future public concerns and United States policy on global warming could make PV and wind systems much more desirable.³⁶ The carbon emissions listed in ref. 37 for various power plants are shown in Fig. 3.3. Some PUCs require that the value of avoided CO₂ emissions be considered for new generation, with values ranging from \$15 to \$33 per ton of carbon. The values of avoided CO₂ emissions are described in Appendix B. Figure 3.4 shows credit for renewable energy systems based on PUC policies.



(a) Photovoltaic systems



(b) Wind Systems

Fig. 3.2. Annual credit for SO₂ allowance of \$600 per ton.

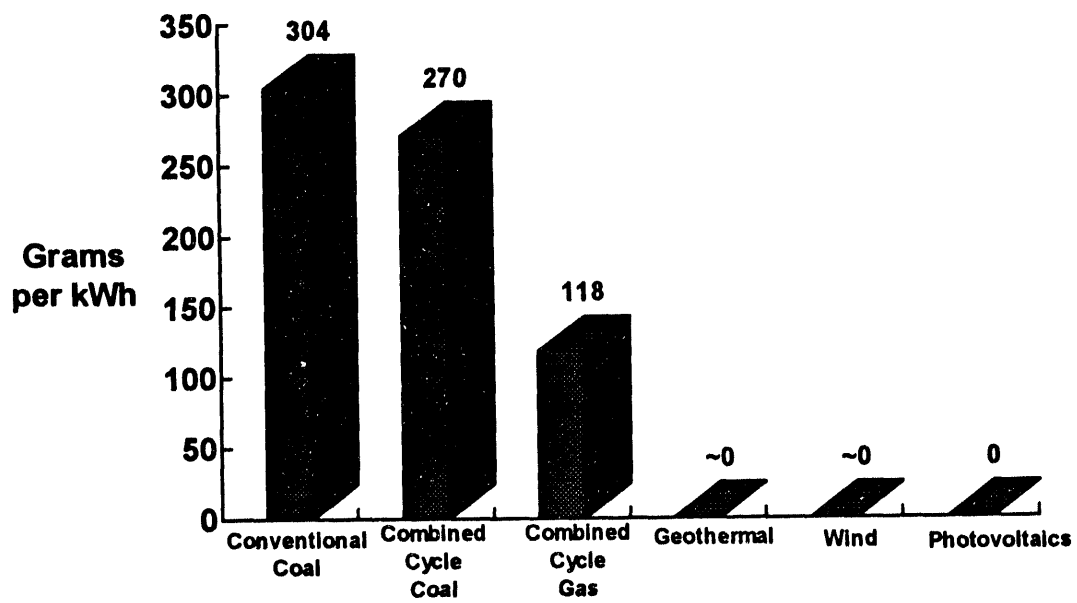
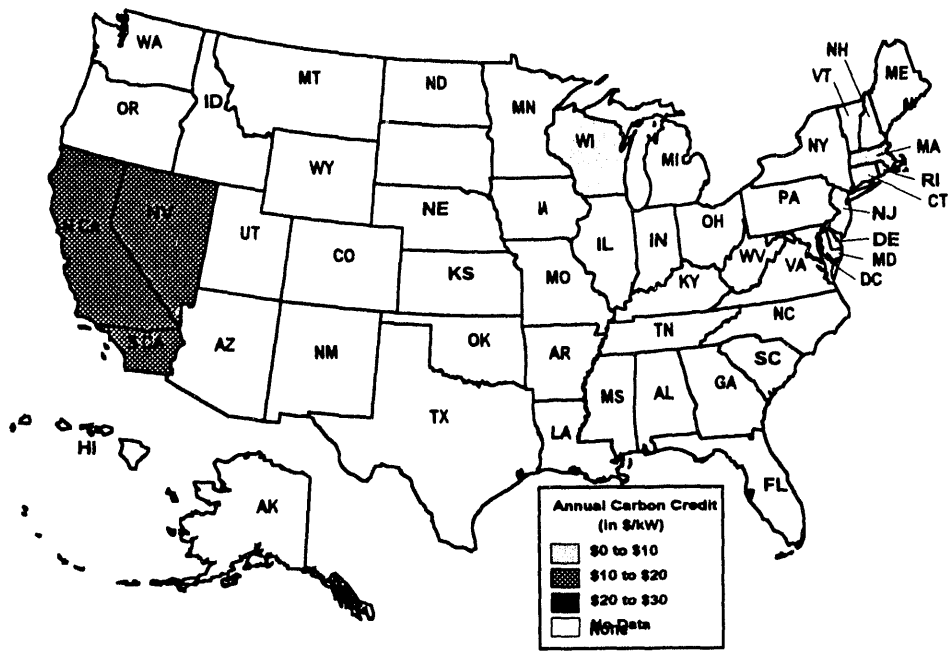
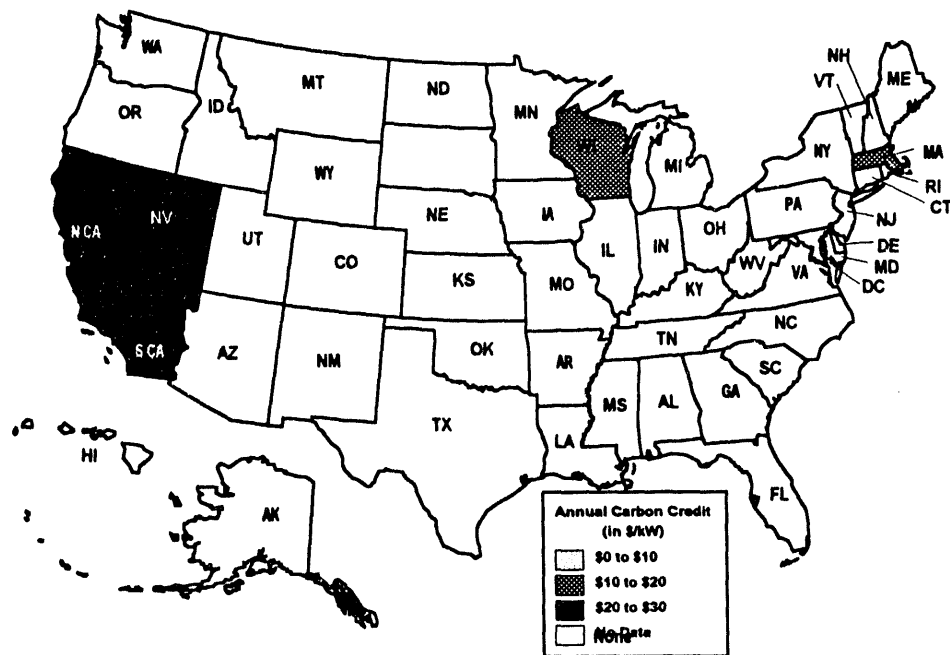


Fig. 3.3. Carbon emissions from various types of power plants.



(a) Photovoltaic systems



(b) Wind systems

Fig. 3.4. Annual carbon emissions benefit to renewable energy sources based on PUC guidelines.

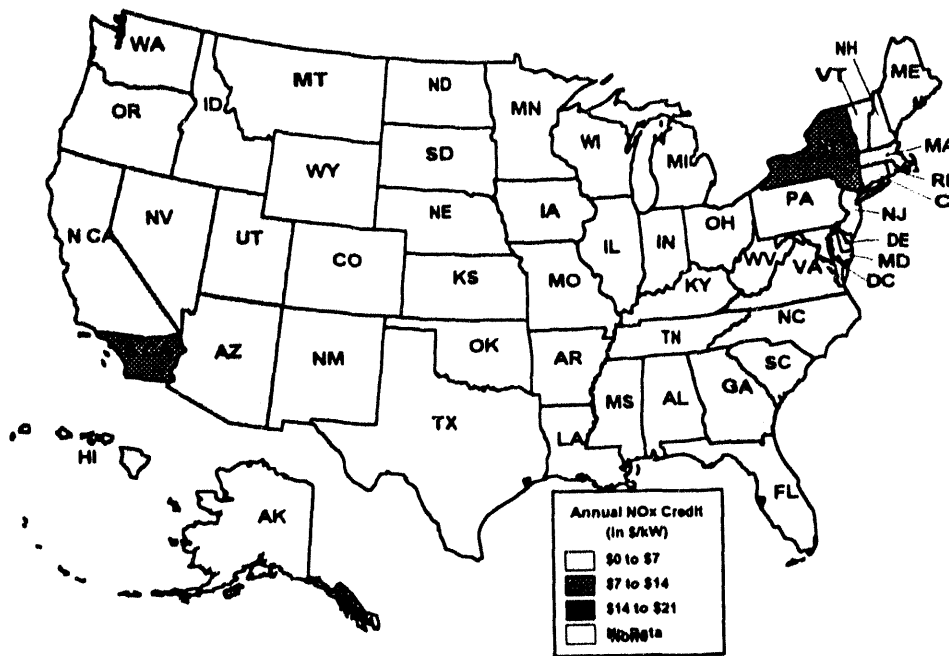
3.1.4 Externalities and Set-Asides

The use of integrated resource planning (IRP) for power production is required by EPACT of 1992, Section 111, which amends the 1978 Public Utility Regulatory Policies Act. The external costs of power production, such as environmental degradation and the cost of maintaining access to foreign sources of supply, are often included in the least-cost IRP process. Some utility regulators are already encouraging utilities to consider environmental factors in their generation planning.

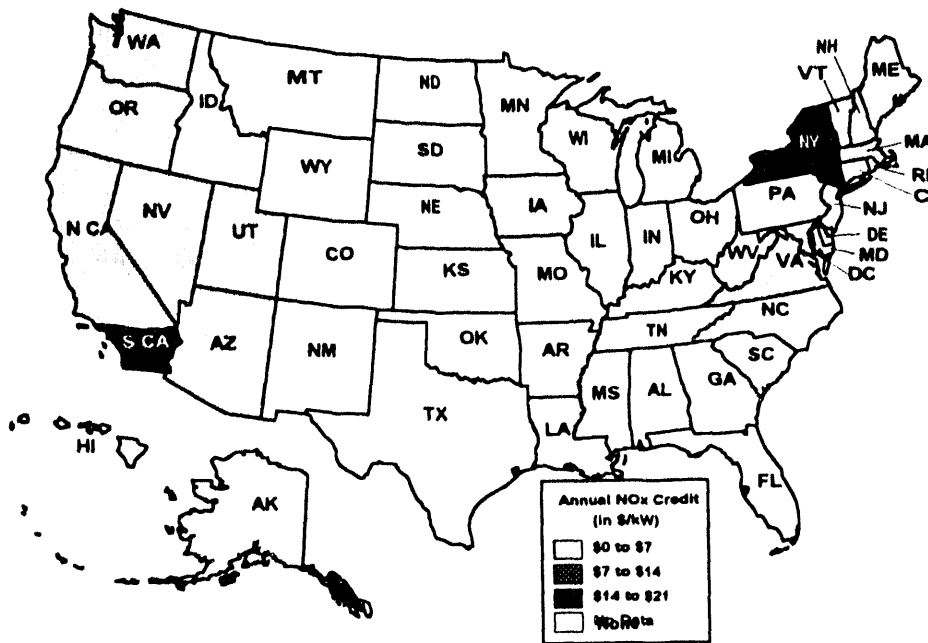
Externality emissions costs for a power plant are associated with the emissions that remain after all applicable regulations have been met. PUC externalities policies vary from state to state as shown in Fig. 3.5a. The trend is that more states are requiring externality consideration.³⁸ This trend may be accelerated by EPACT. Oregon recently developed externality guidelines that the Commission expects to be used in least-cost planning; utilities could charge rate payers for the more expensive renewable energy system.

Some PUCs are also encouraging renewable energy by the use of set-asides.³⁸ A set-aside means a certain percentage of new generation is set aside for renewable energy systems. A utility could expect to include the higher cost of solar or wind energy in the rate base. Because set asides are a recent innovation, only a few states have considered this approach, as shown in Fig. 3.5b.

Credits for solar and wind systems for avoided SO₂ emissions have been addressed by the requirements of Title IV of the CAAA (Section 404(f)(2)(F), 42 U.S.C. 7651c(f)(2)(F)). The externality values of NO_x based on PUC policies are shown in Fig. 3.6. These values are based on the NO_x emitted by clean gas-turbine technology with a heat rate of 9450 Btus per kWh and NO_x emissions of 0.397 pounds per 1000 kWh.



(a) Photovoltaic systems



(b) Wind systems

Fig. 3.6. Annual externality credit for avoided NO_x emissions, based on PUC guidelines and the emissions of clean gas-turbine technology.

3.1.5 Sum of the Generation Benefits

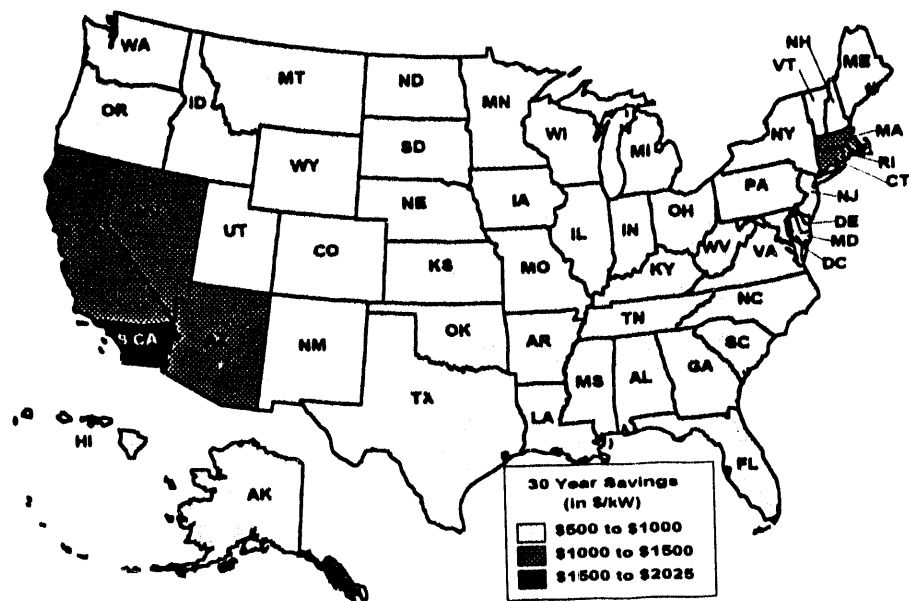
The 30-year values of the generation benefits for wind and PV systems are shown in Fig. 3.7. The value of the displaced fuel, avoided emissions, and avoided generation capacity have been summed and annualized over a 30-year period for a real discount rate of 7%. For a 7% real discount rate over a 30-year period, the present worth for each \$1 of non-fuel benefit is \$12.41. Fuel prices are assumed to escalate in real terms by 2.5% annually and the present worth for each \$1 fuel value is \$16.50.

The 2.5% real fuel escalation rate is an average fossil fuel growth rate projected for 1992-2010.³⁹ The avoided generation capacity value is based on a gas turbine at \$475/kW plus 3 mills/kWh annual maintenance cost.⁴⁰ Gas turbines are typical of the type of units that would be deferred over the next ten years. If other types of generation such as coal-fired plants are deferred, the capacity value would be higher. The real discount rate of 7% is used for benefit-cost analyses by the White House Office of Management and Budget.⁴¹

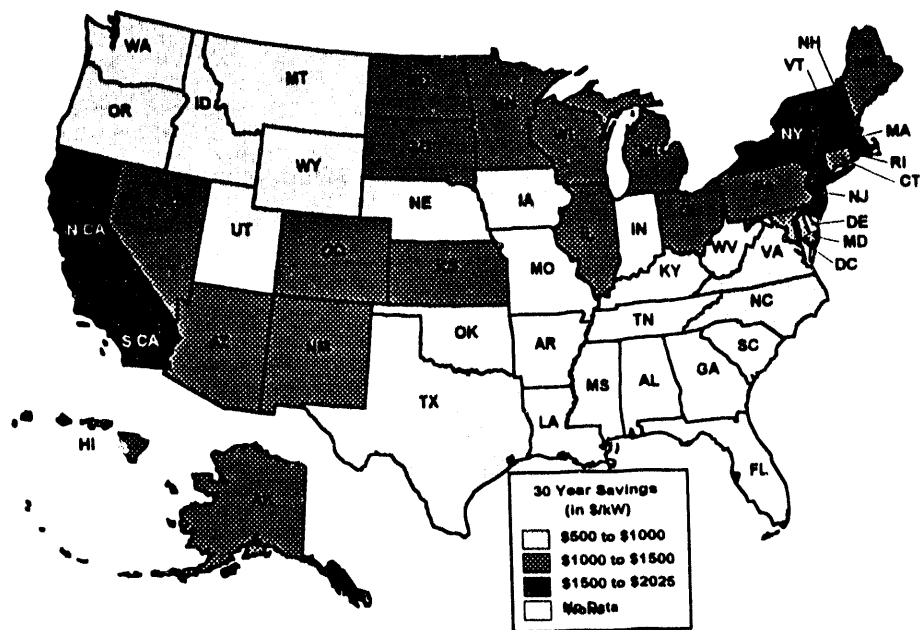
The credit for avoided SO₂ emissions, as well as credit for avoided NO_x emissions where required by state PUCs, have also been added for the 30-year period. For those states having a PUC-mandated control of CO₂ emissions, this credit has also been included in the benefits shown Fig. 3.7.

3.2 DISTRIBUTED UTILITY BENEFITS

The benefits associated with integrating renewable energy sources into the distribution system will add to the generation benefits previously listed. Some of these benefits are difficult to quantify and are utility- and/or site-specific; insight into the value of the last three benefits listed below has been provided by the case studies. The distributed utility benefits considered in this study are not necessarily a complete set. They include the following:



(a) Photovoltaic systems



(b) Wind systems

Fig. 3.7. Thirty-year generation benefits to investor-owned utilities for wind and photovoltaic systems.

- additional capacity credit,
- enhanced fuel savings and avoided emissions because of T&D loss savings,
- enhanced credit for externalities and set asides,
- deferred T&D facilities, and
- voltage and VAR control, and enhanced distribution circuit reliability.

3.2.1 Additional Capacity Credit

Dispersing PV and wind systems over the utility service area may provide additional capacity credit because the reliability of distributed renewable sources is higher. In areas with a good solar resource, dispersion may be less important; but in areas that experience passing clouds, a considerable improvement may be possible. For wind systems, dispersion may also enhance reliability and capacity credit.

The amount of enhancement depends on the penetration level. For early applications of renewable energy sources, the penetration level relative to the total system load will be small (a few percent) even though penetration at the distribution circuit level could be high, (i.e. 30% to 40%). For this study, a small enhancement is assumed for both solar and wind systems in poor-to-moderate resource regions. This enhancement value of 4–8% is about mid-range of the enhancement found in previous studies.^{32,33} The actual value is a function of the utility and the resource.

3.2.2 T&D Losses

Fuel savings, avoided emissions, and credit for externalities and set asides are enhanced because of savings in the losses in the T&D systems. The national average T&D losses are about 9% of electric generation.¹ Transmission losses account for about 60% of T&D losses. These benefits are enhanced by 6% to 10% when renewable sources are integrated into the distribution system. For this study, a simple 10% value has been used.

3.2.3 Deferred Transmission Facilities

Deferred transmission facilities may be one of the more important distributed utility benefits. Many lines often operate near capacity. Because of public resistance, it has become very difficult for utilities to install new lines. Growing opposition to new transmission lines and increased regulation have made it more difficult in many areas to build new transmission capability than to install new generation.⁴²

EPACT gives federal regulators authority to mandate transmission access on a wholesale level. The Federal Energy Regulatory Commission is in the process of developing rules that will open the transmission system to more users. These changes could result in the transmission system operating even closer to its limit and thus increase the value of distributed renewable sources in the future.

The value of deferred transmission facilities will vary from utility to utility. In the case studies, it varied from zero to over \$300/kW. The average value of transmission and distribution facilities was determined in ref. 43. The average values of transmission and distribution facilities in 1993 dollars are \$193/kW and \$207/kW respectively. The present worth of deferred transmission facilities over a 30-year period is \$186/kW at a 7% real discount rate. Since many of the nation's transmission facilities are heavily loaded much of the time, this benefit is applied to all cases. However, there are utilities that have ample transmission capacity, and this benefit is zero for those utilities.

3.2.4 Other Distributed Utility Benefits

Benefits associated with deferred distribution facilities for periods of 5 to 10 years, voltage and VAR control, and enhanced reliability are highly dependent on the particular distribution circuit characteristics and the renewable energy resource. A ten year deferment of investment for distribution facilities is possible for the case when a circuit near its load capacity and the circuit load growth is slow. The present worth of deferred distribution facilities, based on average values, is \$102/kW. This benefit is possible if there is a high correlation between the circuit peak load and the renewable energy electric generation. The value of voltage and VAR control is, in general, small because of the low cost control methods

that are used. Enhanced reliability of a distribution circuit may be a benefit in some very special cases. In our case studies, utilities did not give any credit to a reliability enhancement benefit.

Figure 3.8 summarizes the additional 30-year benefits for distributed utilities, for both PV and wind systems, for the case of including deferred distribution benefits. Figure 3.9 presents the same benefits when the deferred distribution benefits are not included in the calculation.

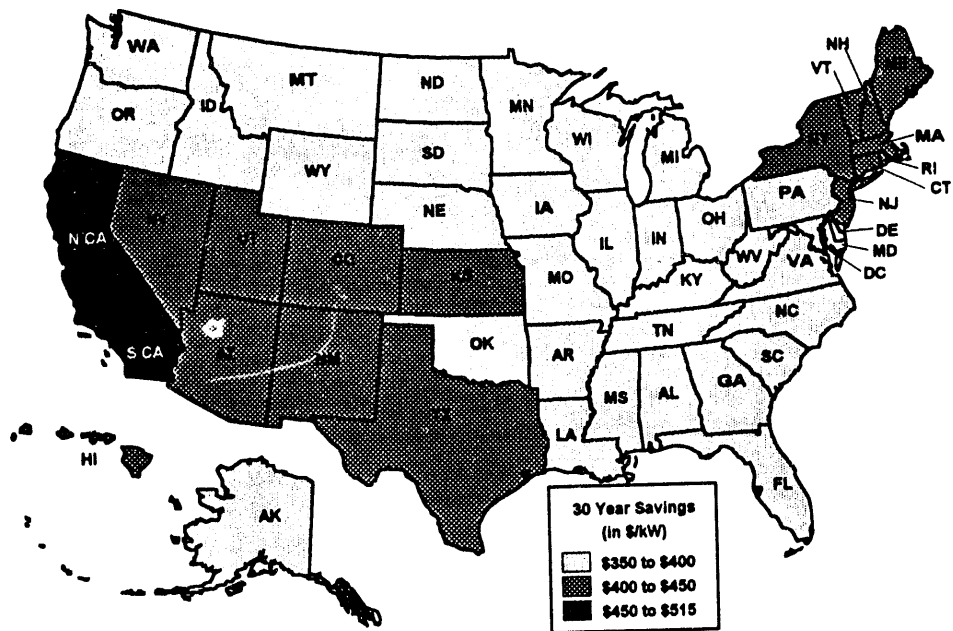
3.3 TOTAL BENEFITS

The sum of the economic benefits obtained from both the generation and distribution considerations for solar and wind energy systems is presented in Fig. 3.10. However, deferment of distribution facilities does not appear likely for most solar energy applications, except in the Southwest, because of poor peak load correlation with the PV output. Wind systems are also likely to have a poor peak load correlation throughout the country. Consequently, Fig. 3.11 shows the total 30-year economic benefits, with the deferred distribution benefits being included only for solar applications in the southwestern United States. In the case studies for utilities in the southwestern United States, peak load correlation with PV output was found to be adequate for deferring distribution investment for circuits that are near peak capacity.

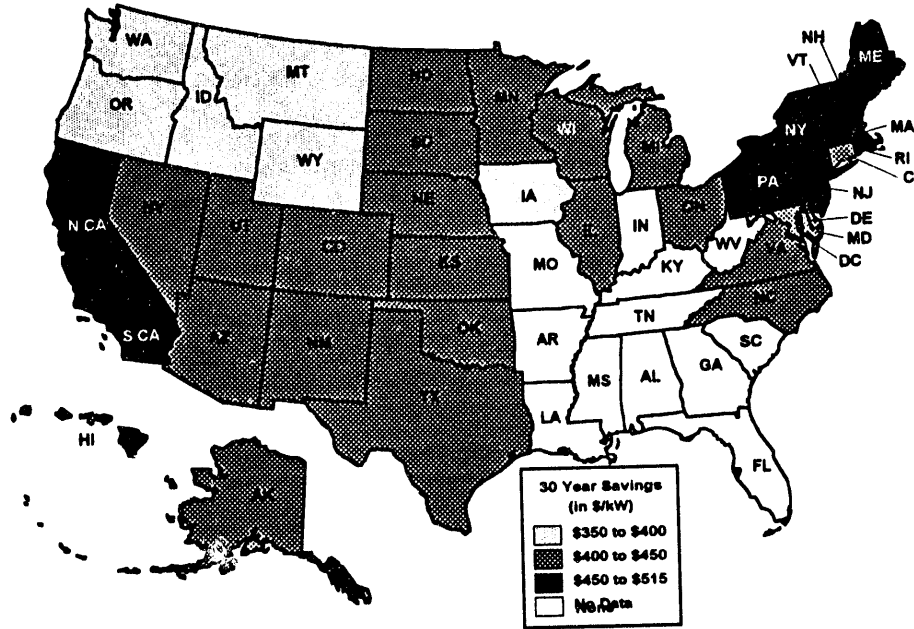
As a means of assessing the importance of the distributed utility benefits in the total 30-year savings for PV and wind energy systems, Fig. 3.12 presents the fraction of the total benefits arising from the distributed utility benefits. If deferred investment in transmission facilities were equal to zero, fractional values would increase. *In general*, distributed utility benefits increase the total benefits by at least 10–20%.

3.4 ADDITIONAL INCENTIVES

The EPACT of 1992 provides federal payments and tax credits as incentives for renewable energy systems. These incentives were considered in the utility case studies presented in Vol. II of this report. On a national basis, however, such incentive payments are considered as a transfer of money from one group to another and were not considered in Vol. I as an actual benefit.

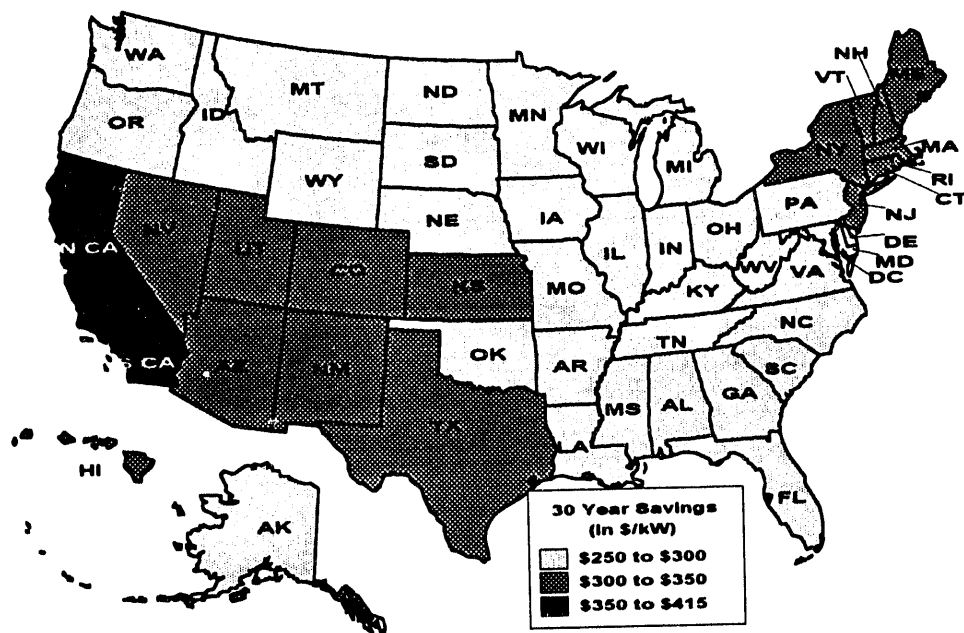


(a) Photovoltaic systems

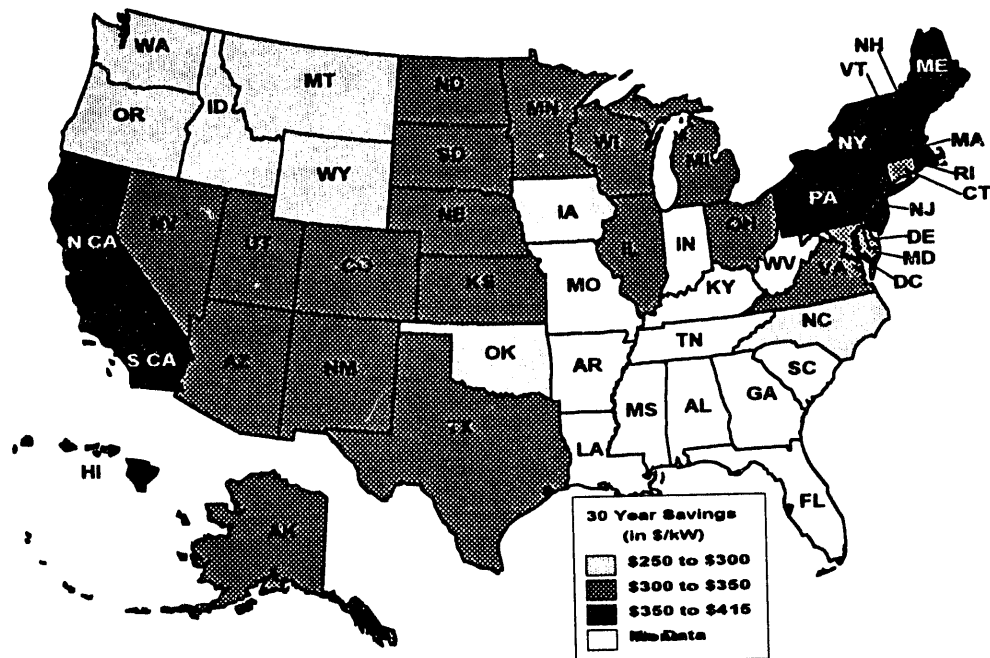


(b) Wind systems

Fig. 3.8. Thirty-year distributed utility benefits for photovoltaic and wind systems, including deferred distribution benefits.

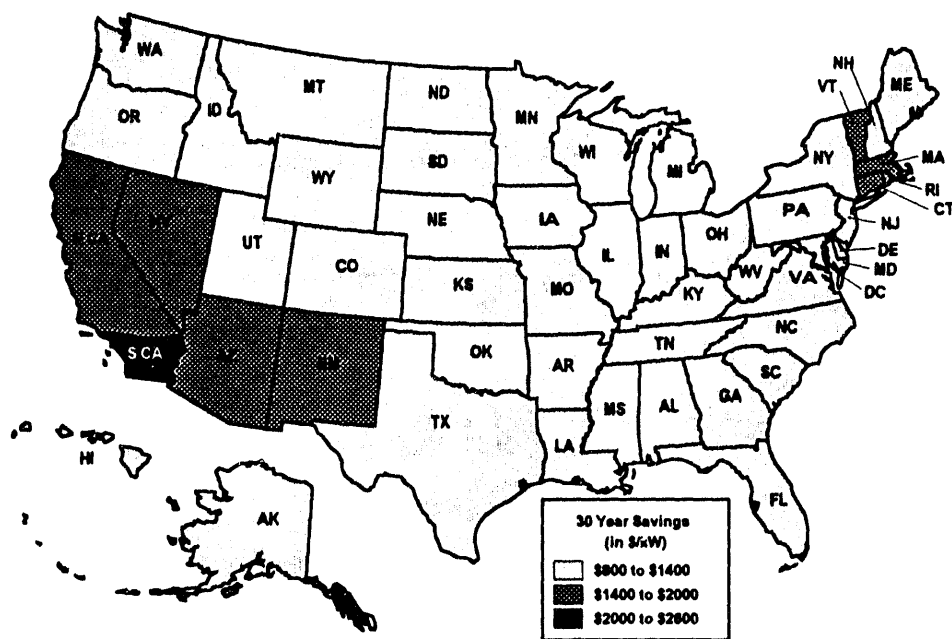


(a) Photovoltaic systems

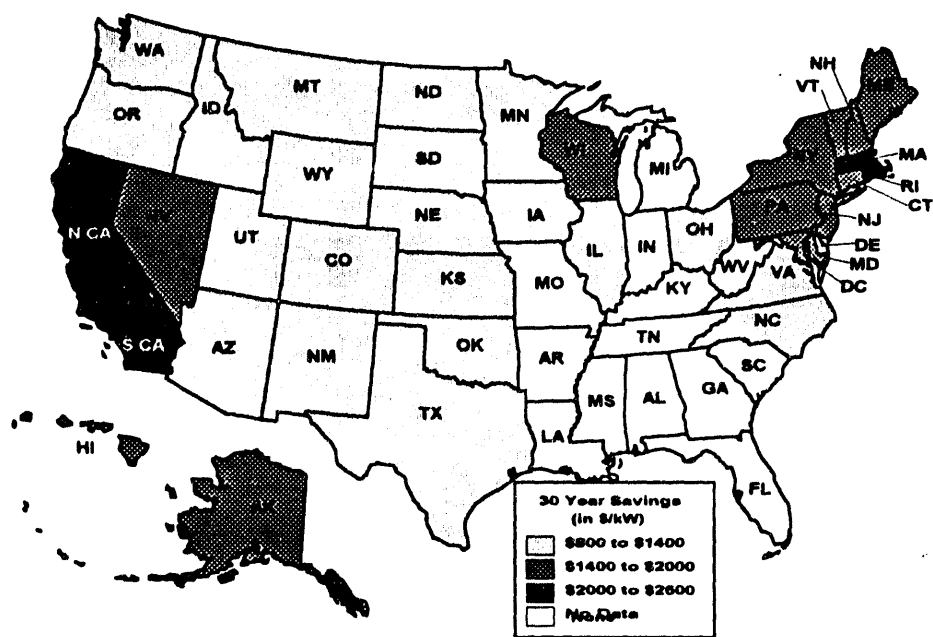


(b) Wind systems

Fig. 3.9. Thirty-year distributed utility benefits for photovoltaic and wind systems, not including deferred distribution benefits.

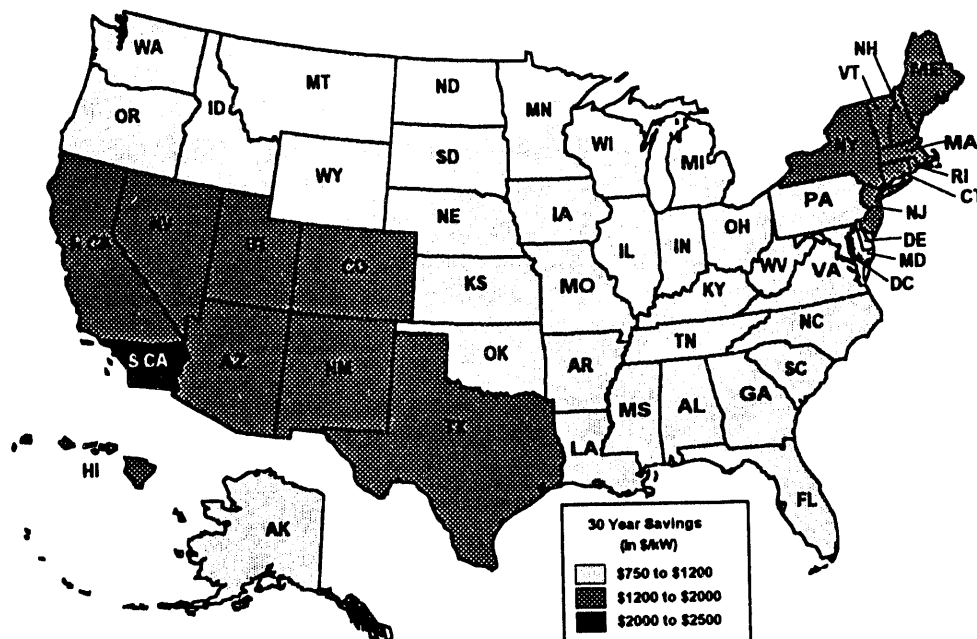


(a) Photovoltaic systems

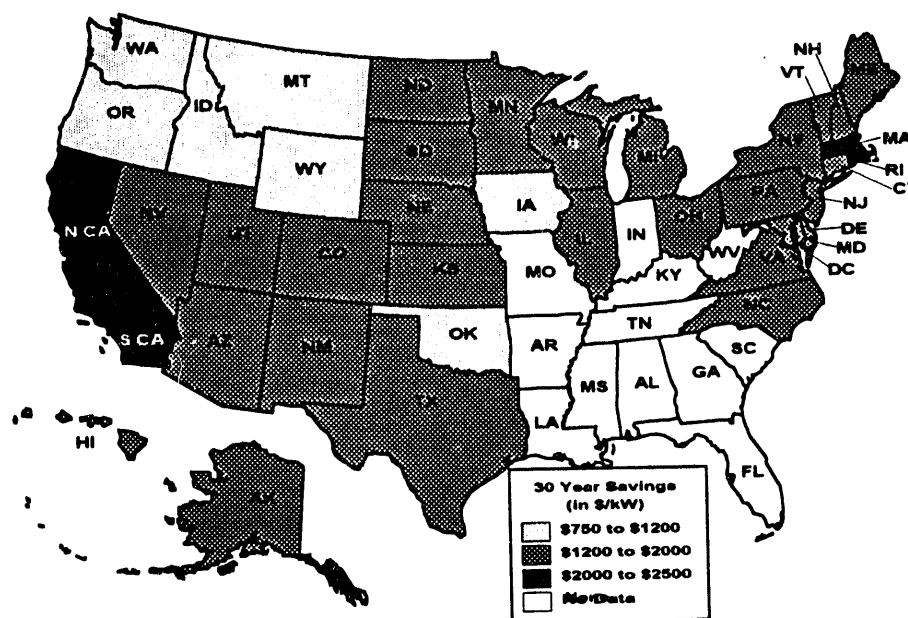


(b) Wind systems

Fig. 3.10. Total 30-year benefits for photovoltaic and wind power, including deferred distribution benefits.

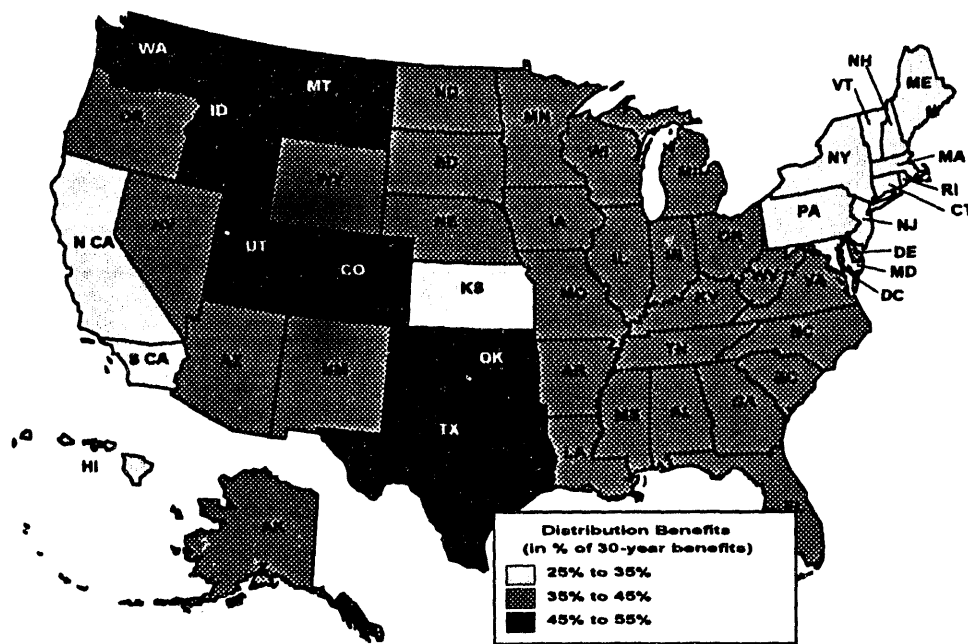


(a) Photovoltaic systems

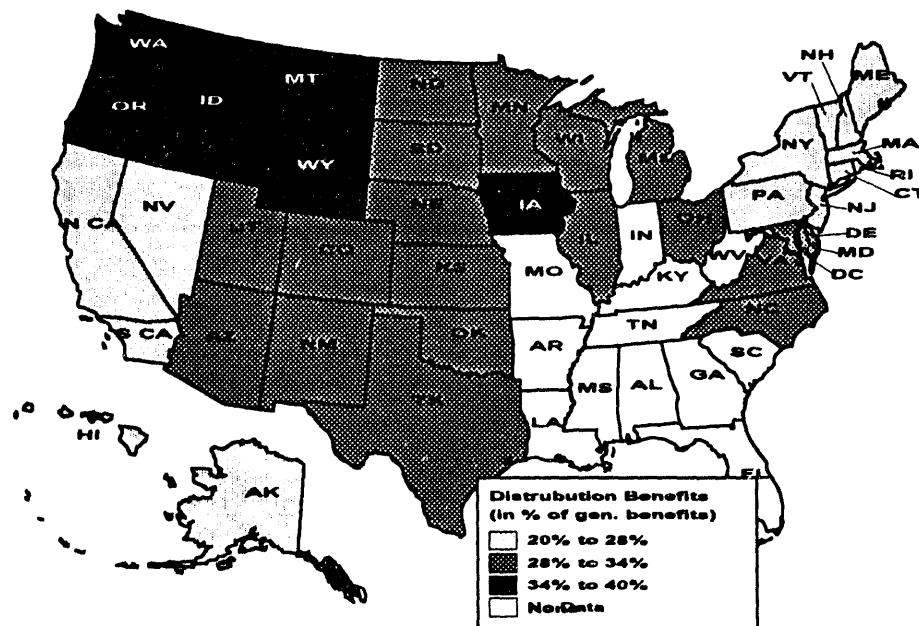


(b) Wind systems

Fig. 3.11. Total 30-year benefits for photovoltaic and wind power, with deferred distribution benefits applied only to the solar case in the southwestern United States.



(a) Photovoltaic systems



(b) Wind systems

Fig. 3.12. Fraction of the total 30-year benefits related to distributed utility benefits.

3.4.1 Publicly Owned Utilities

Subject to availability of appropriations, Section 1212 of the EPACT of 1992 (42 U.S.C. 13317) authorizes incentive payments for renewable energy facilities using solar, wind, geothermal or biomass energy. For such facilities commencing operation between October 1, 1993, and September 30, 2003, incentive payments of 1.5 cents per kWh, adjusted for inflation, are authorized for a ten-year period. These incentive payments are subject to available appropriations. Appropriations are authorized in the EPACT for FY 1993, FY 1994 and FY 1995.

3.4.2 Investor-Owned Utilities and Non-Utility Generators

For qualified wind energy systems and certain biomass energy systems, Section 1914 of the EPACT provides a production-type credit against income tax liability of 1.5 cents per kWh adjusted for inflation for a 10-year period, for facilities placed in service after December 31, 1993, and before July 1, 1999. For qualified solar and geothermal property, Section 1916 of the Act provides for a permanent extension of the previous 10% investment tax credit for NUGs.

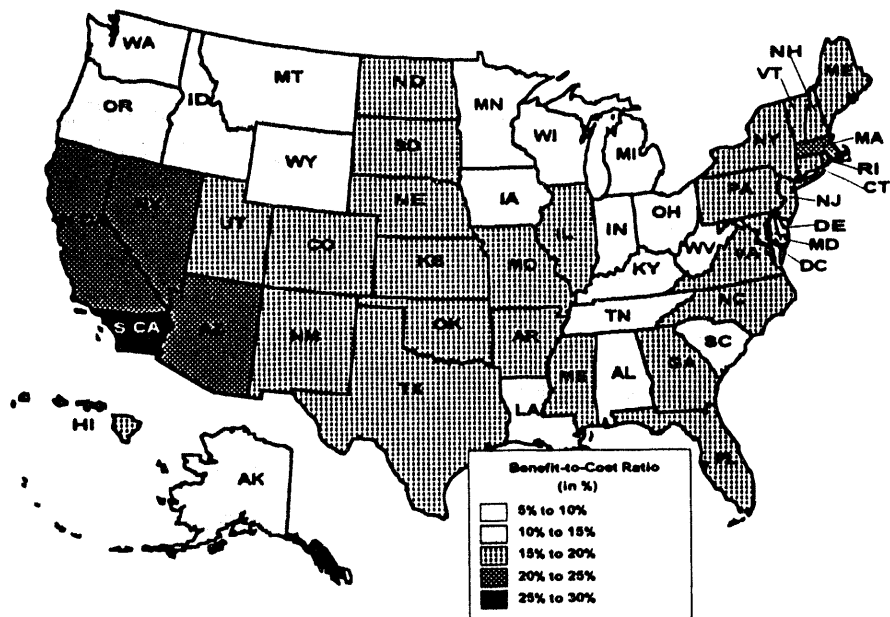
4. ECONOMIC CONSIDERATIONS

An economic assessment of renewable energy systems for utility applications is presented in this section. Many utilities use a present-worth revenue requirements analysis that includes considerations of inflation, taxes, etc. The comparison of benefits and costs presented here does not include all of the economic factors considered by utilities, but it will provide an indication of economic feasibility. Federal tax credits and incentive payments have also been excluded in this assessment.

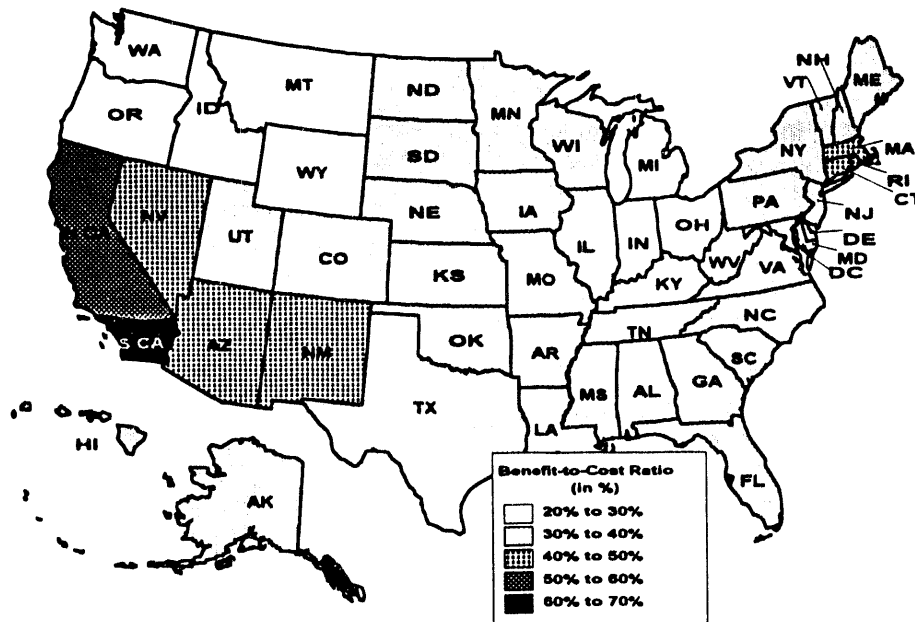
Regions such as California with a large high quality resource, high fuel cost, and high values for avoided emissions, have the largest benefits. Areas such as the Northeast, which has a relatively low solar resource but high fuel costs and high values for externalities, can have moderately high benefits. The additional value for distributed utility benefits ranges from 20–55% of the generation benefits, under the assumption that the deferred transmission investment benefit is available in all regions.

The benefits-to-costs ratios are shown in Figs. 4.1 and 4.2 for the present and lower costs of PV technologies. Three installed plant costs are considered: \$7000/kW, \$3250/kW, and \$2500/kW. O&M costs of 4 mills/kWh are used. The \$7000/kW installed cost represents the lowest present cost, while the \$3250/kW value is a cost that may be achieved by the late 1990s if PV costs continue to decrease. The \$2500/kW cost represents the cost that could be achieved if large-scale PV production plants were available.

The best PV case is representative of Southern California, where deferred distribution benefits are included. A poor PV case is representative of a low-fuel cost area, such as the Northwest, with no credit for deferred T&D. For the best solar case, present costs are about three times the value of the benefits. If projected installed PV plant costs of \$2500/kW are achieved, PV systems will be close to being economical in high-fuel-cost regions with a high solar resource. The \$2500/kW installed plant cost, which is based on the assumption of a high production volume of PV systems, and may not be achieved until sometime after the year 2000.

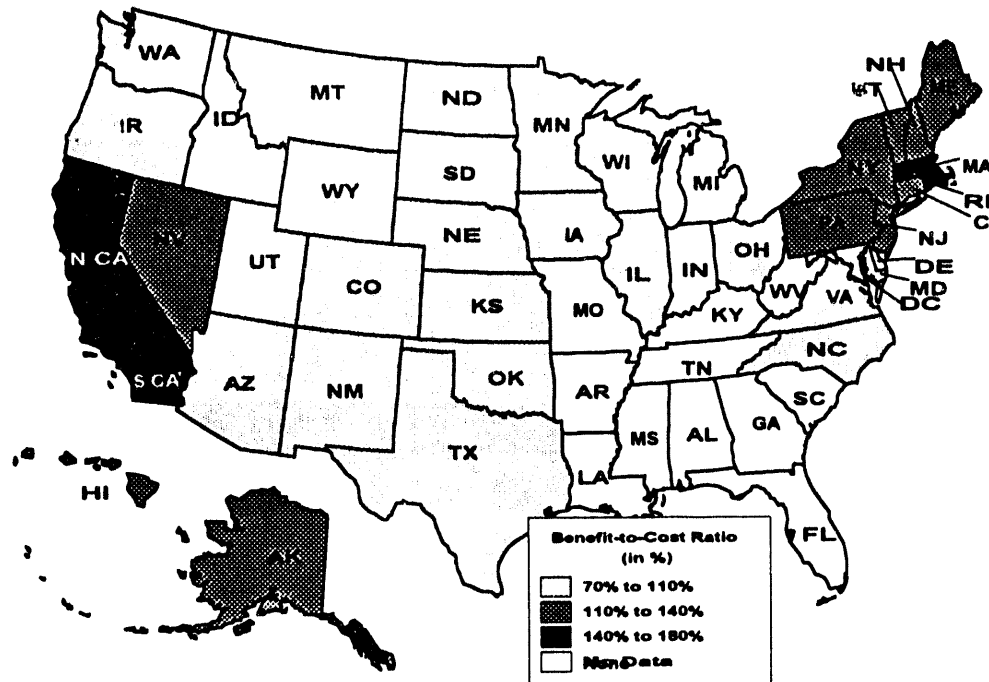


(a) For present PV costs of \$7000/kW

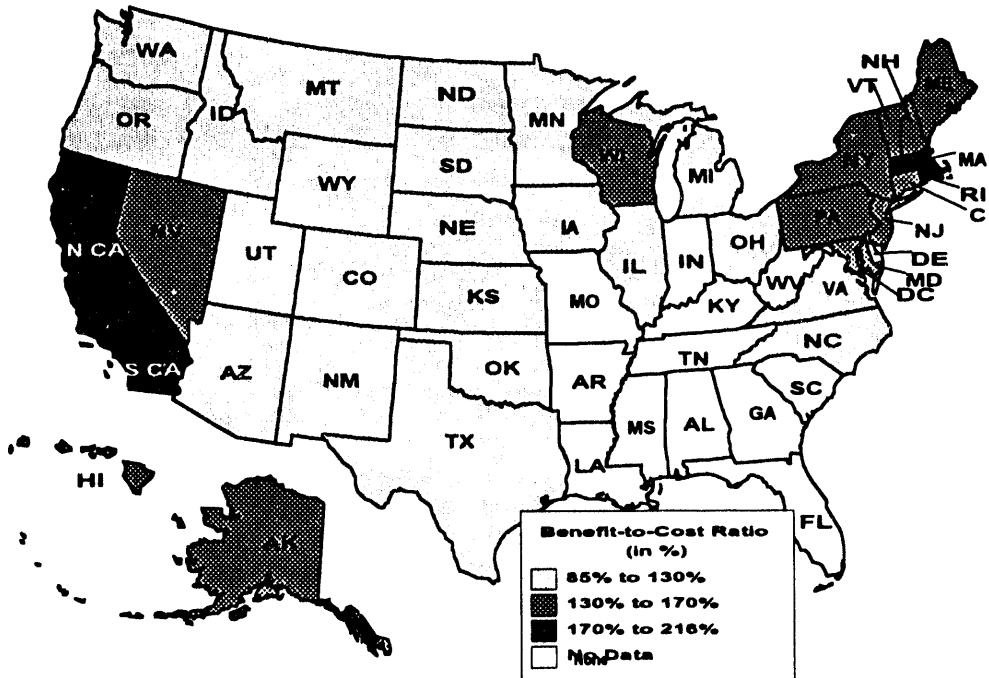


(b) For lower PV costs of \$3250/kW

Fig. 4.1. Benefit-to-cost ratio for PV systems.



(a) For present wind costs of \$1000/kW



(b) For lower wind costs of \$750/kW

Fig. 4.3. Benefit-to-cost ratio for wind systems.

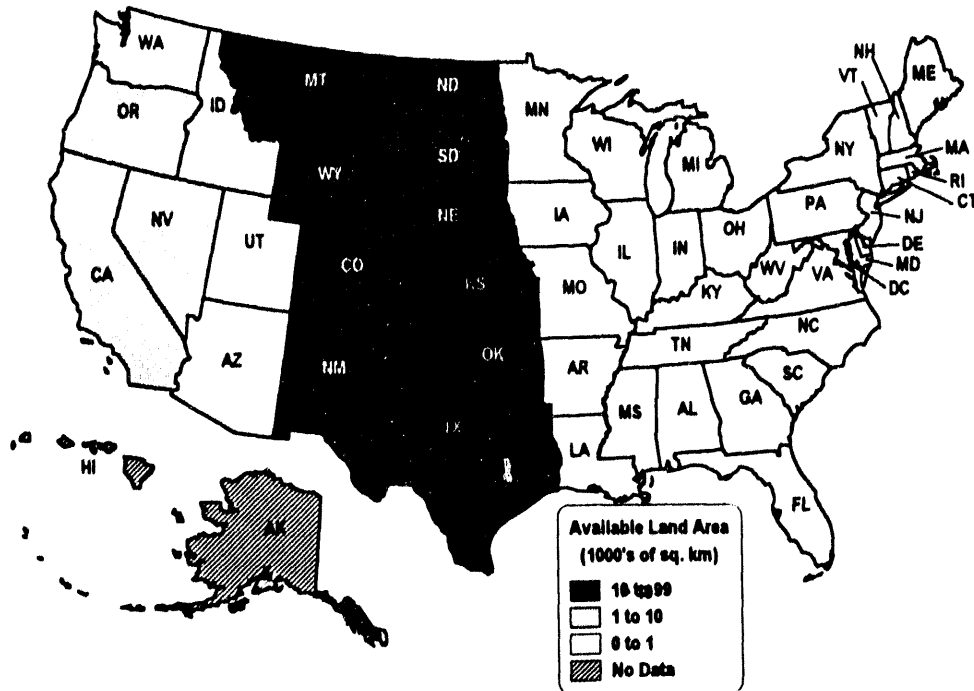


Fig. 4.4. Site potential for wind energy systems being integrated into electric power distribution systems. *Source: D. L. Elliott, L. I. Wendell, and G. L. Gower, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, UC-261, Pacific Northwest Laboratory, August 1991.*

turbines should be economical for most regions with high fuel costs and a good wind resource. Even regions with low fuel costs have averaged benefits that are near the cost at which wind systems could be considered as part of a utility's generation mix as a renewable energy set-aside. If lower costs of \$750/kW are achieved, wind system costs will be well below the value of the benefits in many regions. O&M costs of 10 mills/kWh are assumed to remain at the present levels to ensure that the life of the wind systems can be extended to the 30-year period.

5. SUMMARY AND CONCLUSIONS

A nationwide qualitative assessment on integrating renewable energy sources into electric power distribution systems has been conducted by using averaged values for the benefits. In this manner, areas with low, moderate, and high benefit values were identified. These results provide some insight into the regional potential for renewable energy integration at the distribution level. Results for specific utilities may be significantly different, however, because of items such as the utility's fuel costs, which may be lower or higher than the regional average.

The integration of renewable energy technologies into electric power distribution systems enhances the benefits associated with fuel savings and avoidance of emissions penalties. If expensive upgrades in T&D can be deferred, then additional savings can be realized. Based on past studies, no serious technical problems are expected for low-capacity penetration of up to 30% at the distribution circuit level, that is, for up to about 3 MW in a 10-MVA circuit. However, prior to interconnecting renewable energy technologies into a distribution circuit, utilities should conduct a detailed site-specific assessment. More studies also should be performed for higher penetration levels; special controls may be required to meet present criteria for power quality and system operation.

The greatest potential for renewable energy systems is in moderate-to-high resource areas with high fuel costs and large values for externality penalties. California has the highest potential for both PV and wind systems, but PV plant costs are presently 2–3 times too high to be economical. Portions of the Southeast with a good solar resource and the Northeast, where fuel costs are high, have potential for PV applications after present costs have been reduced by a factor of 4–5. PV systems would reduce the summer peak loading in the Southwestern portion of the country. However, in the eastern United States, PV will be less effective in reducing the peak load, since air conditioning loads extend the peak period well into the evening hours. PV power does provide a good match to commercial loads in many areas. In the Southwest, where PV can reduce the peak load, deferred distribution upgrade cost is an

additional benefit. PV systems could be installed on the roofs of commercial buildings, warehouses, and residences, placing them close to the loads of interest.

The largest barrier to the integration of PV systems is the cost. At present, PV system costs are 3 to 5 times too high. If projected capital cost reductions to \$2500/kW are achieved, PV would start to become economical in some areas.

Wind energy system technology has advanced in recent years to the point that it is a serious candidate for new generation in moderate to high wind resource areas. The advanced machines produce higher quality power and the capital cost is relatively low, about \$1000/kW for the larger units. However, many of the best wind resource areas are in mountainous regions where there are no distribution circuits. Wind turbines are not expected to be allowed in many other places, such as urban areas, certain agricultural areas, sea shores, national parks, and environmentally sensitive regions. In general, the largest land areas with a high wind resource close to electric distribution systems are located in the central United States. Consequently, this region has a high potential for utilizing wind energy systems integrated into the electric distribution circuits.

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**APPENDIX A:
THE CLEAN AIR ACT AMENDMENT OF 1990
AND BENEFITS OF AVOIDING SO₂ EMISSIONS**

The Clean Air Act Amendments of 1990 (CAAA) will result in additional costs for producing electricity—particularly from technologies using fossil fuels. These costs may make renewable technologies such as wind, solar, and hydroelectric power more cost-competitive. A Federal Energy Regulatory Commission (FERC) study on the net environmental benefits of renewable energy used in electricity generation was required by Section 808 of the CAAA. The FERC report *Renewable Energy and Energy Conservation Incentives of the Clean Air Act Amendments of 1990*, Dec. 1992, concludes that market-oriented approaches such as acid rain allowance trading provide environmental protection at a minimal cost. The benefits of avoiding SO₂ emissions discussed in this appendix have been determined by such a market-oriented analysis.

The following analysis attempts to approximate the credit that should be allowed per kWh in evaluating renewable technologies. Two types of analyses should be considered. First, there is the value of renewable energy systems in reducing SO₂ when they displace the regional mix of generation. Then there is the value of renewable energy technologies in reducing SO₂ compared with a specific alternative generation, for instance, if a renewable energy technology is weighed against a specific fossil-fired alternative. The distinction between these cases is somewhat arbitrary in that if SO₂ costs are incorporated for all technologies, costs can be compared simply by identifying the capacity and operating costs that would be avoided.

The first type of analysis is based on the average effects of introducing a renewable technology into an electric supply system. It is assumed that the renewable energy technology will displace some operation of existing units on the system. The analysis is performed on a regional basis for the years 1990, 2000, and 2010. Because the composition of avoided generation varies across regions and over time, the average SO₂ emission rate changes. Consequently, the pollution credit per kWh varies.

The analysis is based on the assumption that energy generated by renewable energy technologies will replace energy that would have been generated by fossil technologies. This assumption seems reasonable because the only other significant generation that it could replace would be nuclear energy. In general, nuclear plants are run because of their low variable costs compared with fossil plants; also, nuclear plants are not used for load following. Therefore, the approach was to calculate the average pounds of SO₂ emissions per kWh of fossil-fired generation and multiply this number by the assumed cost of the SO₂ emission allowance. The EIA publication *Annual Outlook for U.S. Electric Power 1991* gives estimated SO₂ emissions and total kWh of generation for 1990 and projects estimates of these variables for 2000 and 2010 for ten federal regions.

The cost of emitting SO₂ is based on the projected market price of an SO₂ allowance. SO₂ allowances are being allocated to each electric utility based on criteria related to its types of generating units and fuels used in a base year. These allowances can be bought and sold, and EPA withholds a limited number of the allowances it auctions each year to help establish a market. These allowances determine the SO₂ that a utility can emit without being fined. They provide flexibility in meeting the total SO₂ target by allowing utilities that can limit SO₂ at lower cost to sell unneeded allowances to utilities that have higher costs. This arrangement in effect results in an advantage for any technology or operating strategy than reduces SO₂. The reduction of SO₂ either allows a utility to avoid purchasing additional allowances to meet its CAAA obligation or allows it to sell allowances if it is under its CAAA obligation. In either case, the cost of an allowance is the opportunity cost of an incremental change in SO₂ emissions; therefore, it can be multiplied by the average SO₂ emission per kWh to determine the appropriate value of avoided SO₂ resulting from an additional kWh of renewable generation.

The projected price of an SO₂ allowance is difficult to project because it will be determined by the demand for SO₂ allowances, which in turn will be determined by the overall ability of utilities to meet mandated targets. The average auction price of an allowance (1 ton of SO₂ emissions) was about \$150 in 1993 (*Electric Light & Power*, May 1993, 71 (5), p.1). However, EIA experts expect the price of allowances to increase sharply as the mandated

Phase I emission limits come into effect in 1995 and the more restrictive Phase II limits in 2000. The *Annual Outlook for U.S. Electric Power 1991* (see page 40) indicates that the allowance price could be in the \$498 to \$656 range in 2000 and in the \$736 to \$814 range by 2010 (1993 prices). This range reflects different assumptions about the price of oil and economic growth. Of course there is additional uncertainty regarding market forces that will set the price of the allowances. The results of calculating SO₂ emission costs based on EIA's projections of SO₂ emissions and fossil generation, and using a range of allowance costs for SO₂ allowances, are presented in Table A1 for 1990, 2000, and 2010, for the federal regions of the United States.

The first analysis for evaluating renewable technologies with respect to the CAAA of 1990 is based on the average effect of avoiding a kWh of fossil generation. If an investment in a new renewable generation unit is compared with a specific investment in some other type of generation, the credit should be given based on the difference in SO₂ emissions between the renewable and the specific fossil technology being evaluated. For instance, a new coal-fired unit using a clean coal technology could have much lower SO₂ emissions per kWh than the existing average rate of sulfur emission per kWh. In other words, the sulfur removal efficiency and the type of fuel used should be specifically accounted for in the analysis. When comparing a fossil technology with a renewable technology emitting zero SO₂, the credit for the renewable technology would be calculated as follows:

$$\text{Credit (in mills/kWh)} = F \times S \times (1-E) \times A ,$$

where F is the number of pounds of fuel used per kWh, S is the fraction of fuel that is sulfur by weight, E is the technology's SO₂ removal efficiency, and A is the expected cost in dollars per ton of an SO₂ allowance.

For example, comparing a wind generator with a coal-fired power plant using 4% sulfur coal, assuming 10,000 Btu heat content per pound of coal, a 10,000 Btu per kWh heat rate, and 90% SO₂ removal efficiency for its scrubbers, would result in a credit of 2 mills per kWh ($1 \times 0.04 \times 0.1 \times \500). This figure would correspond approximately to a new coal-fired power plant using Illinois bituminous coal.

Table A1. Credit to renewable energy sources for a SO₂ emission allowance in mills per kWh by region

REGION:	N. England	NY/NJ	Mid-Atlantic	S. Atlantic	Midwest	South-west	Central	N. Central	West	North-west
STATES IN REGION	Me, NH, Vt, Ma, Cn, Rli	NY, NJ	Pa, Md, WV, Va, DC, De	Ky, Tn, NC, SC, Ms, Al, Ge, Fl	Mi, Wi, Il, In, Oh	Tx, NM, Ok, Ar, La	Kn, Mo, Ia, Nb	Mt, Nd, SD, Wy, Ut, Co	Ca, Nv, Az, Ha	Wa, Or, Id, Ak
Year 1990										
Lbs. SO2/kWh	0.0158	0.0108	0.0232	0.0190	0.0280	0.0051	0.0230	0.0070	0.0037	0.0153
SO2 Allowance per ton										
\$100	0.79	0.54	1.16	0.95	1.40	0.26	1.15	0.35	0.19	0.77
\$150	1.19	0.81	1.74	1.43	2.10	0.38	1.73	0.53	0.28	1.15
\$200	1.58	1.08	2.32	1.90	2.80	0.51	2.30	0.70	0.37	1.53
\$300	2.37	1.62	3.48	2.85	4.20	0.77	3.45	1.05	0.56	2.30
\$400	3.16	2.16	4.64	3.80	5.60	1.02	4.60	1.40	0.74	3.06
\$500	3.95	2.70	5.80	4.75	7.00	1.28	5.75	1.75	0.93	3.83
\$600	4.74	3.24	6.96	5.70	8.40	1.53	6.90	2.10	1.11	4.59
\$700	5.53	3.78	8.12	6.65	9.80	1.79	8.05	2.45	1.30	5.36
\$800	6.32	4.32	9.28	7.60	11.20	2.04	9.20	2.80	1.48	6.12
Year 2000										
Lbs. SO2/kWh	0.0143	0.0086	0.0169	0.0098	0.0100	0.0033	0.0068	0.0041	0.0025	0.0043
SO2 Allowance per ton										
\$100	0.72	0.43	0.85	0.49	0.50	0.17	0.34	0.20	0.12	0.21
\$150	1.07	0.65	1.27	0.74	0.75	0.25	0.51	0.31	0.19	0.32
\$200	1.43	0.86	1.69	0.98	1.00	0.33	0.68	0.41	0.25	0.43
\$300	2.15	1.29	2.54	1.48	1.51	0.50	1.01	0.61	0.37	0.64
\$400	2.86	1.73	3.39	1.97	2.01	0.67	1.35	0.82	0.50	0.85
\$500	3.58	2.16	4.24	2.46	2.51	0.83	1.69	1.02	0.62	1.06
\$600	4.29	2.59	5.08	2.95	3.01	1.00	2.03	1.22	0.74	1.28
\$700	5.01	3.02	5.93	3.45	3.52	1.17	2.37	1.43	0.87	1.49
\$800	5.72	3.45	6.78	3.94	4.02	1.33	2.71	1.63	0.99	1.70
Year 2010										
Lbs. SO2/kWh	0.0055	0.0037	0.0118	0.0072	0.0078	0.0028	0.0057	0.0025	0.0018	0.0013
SO2 Allowance per ton										
\$100	0.28	0.19	0.59	0.36	0.39	0.14	0.28	0.12	0.09	0.07
\$150	0.41	0.28	0.89	0.54	0.59	0.21	0.43	0.19	0.14	0.10
\$200	0.55	0.37	1.18	0.72	0.78	0.28	0.57	0.25	0.18	0.13
\$300	0.83	0.56	1.78	1.07	1.17	0.42	0.85	0.37	0.28	0.20
\$400	1.11	0.74	2.37	1.43	1.56	0.56	1.14	0.49	0.37	0.27
\$500	1.38	0.93	2.96	1.79	1.95	0.70	1.42	0.62	0.46	0.33
\$600	1.66	1.11	3.55	2.15	2.34	0.84	1.70	0.74	0.55	0.40
\$700	1.94	1.30	4.14	2.51	2.73	0.98	1.99	0.87	0.64	0.47
\$800	2.21	1.48	4.73	2.87	3.12	1.12	2.27	0.99	0.73	0.53

• It should be noted that the above calculations are based on projections and assumptions that attempt to capture real costs to utilities. If utilities are required by law to consider SO₂,
• using a mandated externality cost, this externality cost should not be added to the SO₂ costs that are indicated in this analysis. A mandated externality cost would make a difference only if it were greater than what the utility actually expects SO₂ costs to be. Therefore, mandated externality costs would override the type of estimates made here only if they were greater; that is, the greater costs should be used.

**APPENDIX B:
POTENTIAL CREDITS TO NON-FOSSIL GENERATION
FROM CO₂ PRODUCTION POLICIES**

There could be significant credits for renewable energy technologies if a value on carbon emissions were implemented in an effort to reduce greenhouse gases. Table B1 was generated by calculating the average reduction of CO₂ per kWh attributable to using non-fossil technologies such as renewables and nuclear power. It assumes a value on carbon emission associated with the generation of electricity that could be avoided by replacing fossil with non-fossil generation. Table B1 may somewhat overstate the benefit of renewables in the outyears, because the average emission of CO₂ per kWh would tend to be somewhat lower as the EIA projections are based on a business-as-usual approach with respect to CO₂ emissions. However, the lowest benefit per kWh would be defined by avoiding natural gas generation, while the highest benefit would be from avoiding coal-fired generation. Table B2 indicates the avoided CO₂ per kWh benefit for replacing natural gas, oil, or coal, assuming different values of carbon emission benefits.

Table B1. Credit to renewable energy sources for a carbon emission benefit in mills per kWh by region in the year 2010

	New England	NY/NJ	Mid- Atlantic	S. Atlantic	Midwest	South- west	Central	North Cent.	West	North- west
Carbon Emissions Benefit (\$/ton):										
\$5	1.2	1.3	1.4	1.4	1.4	1.3	1.5	1.6	1.5	1.4
\$10	2.4	2.6	2.8	2.7	2.7	2.5	3.0	3.1	2.9	2.8
\$20	4.8	5.3	5.7	5.5	5.5	5.1	5.9	6.3	5.9	5.7
\$50	12.1	13.2	14.1	13.7	13.6	12.7	14.9	15.7	14.6	14.2
\$80	19.4	21.1	22.6	21.9	21.8	20.3	23.8	25.1	23.4	22.8
\$100	24.2	26.4	28.3	27.4	27.3	25.4	29.7	31.3	29.3	28.5

Table B2. Credit to renewable energy sources for a carbon emission benefit in mills per kWh, assuming 10,000 Btu/kWh heat rate

Carbon Emissions Benefit (\$/ton):	Natural Gas	Oil	Coal				
\$5	0.8	1.3	1.4				
\$10	1.6	2.6	2.9				
\$20	3.2	5.2	5.7				
\$50	8.0	12.9	14.3				
\$80	12.8	20.7	22.9				
\$100	16.0	25.9	28.6				
					Nat. Gas	Oil	Coal
Value of 1kW Renewable 100% CF for 30 years at \$10/ton Carbon					\$215	\$350	\$390
Value of 1kW Renewable 100% CF for 30 years at \$100/ton Carbon					\$2154	\$3487	\$3851

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