Greenhouse Gas Reduction with Renewables

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Technical Report

Renewable Energy

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Greenhouse Gas Reduction with Renewables

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REPORT SUMMARY

At some time in the future, renewable energy sources—solar, wind, biomass, and geothermal—will play a major role in reducing fossil carbon emissions. This report assesses that prospect; addresses the role, timing, and costs; and discusses barriers, key issues, and efforts to develop or prove the technologies. The report will assist power generation companies as they plan and publicize their own roles in renewable power.

Background

Renewable electric power generation is a substantial and growing business activity, both in the United States and worldwide. Wind power has grown over 30% per year for the past two years (1998 and 1999) and now has a worldwide installed capacity of 13,400 MWe. Biomass power grew rapidly during the 1984-1993 decade and is today the largest fraction of the world's non-hydro renewable generating capacity, approximately 20,000 MWe of biomass power having been installed. Geothermal capacity is approximately 7,000 MWe worldwide. Solar power is a much smaller fraction of renewable capacity worldwide, only approximately 800 MWe. However, solar power systems are installed in some special high-value applications that will provide the basis for a rapid expansion from a small current capacity—an expansion that can do much to reduce the cost of solar power through vastly improved economies of scale. Solar also is the renewable that has a potential supply large enough to generate much more electricity than total worldwide future needs, even needs projected out beyond 100 years.

Objective

To assess the potential of renewable energy sources for reducing emissions of fossil CO_2 in the future, both in the United States and worldwide.

Approach

EPRI staff consulted a number of reports, papers, and EPRI files to compile estimates of the costs and the role that non-hydro renewable energy sources could play in reducing future emissions of greenhouse gases. The non-hydro renewables covered are solar, wind, biomass, and geothermal. The geothermal resources are hydrothermal (steam and hot water), not "hot dry rock."

Results

The principal results of this project are estimates of the amount, timing, and costs of reducing fossil carbon emissions by increased use of renewable energy sources and technologies. Costs of using renewables instead of fossil fuels are based on estimated differences between costs estimated for a number of renewable power options versus two major fossil alternatives: coal and natural gas. The extra costs of the renewable technology— costs above those of the two fossil

base cases—range from zero to $15, or even $50, per MWh. Compared to future pulverized coal, a $15/MWh extra cost of renewable electricity is equivalent to paying $64/tonne of fossil carbon avoided. Compared to advanced natural gas, that same $15/MWh is $165/ tonne-C.

The report develops "growth scenarios" for renewables covering the period 2000 to 2050. These growth scenarios are compared to other investigations, namely, cases developed by the U.S. DOE Energy Information Administration, the WEC/IIASA, and the EPRI Electricity Technology Roadmap. For 2050, some comparisons are as follows: Out of a total energy input ("primary energy") of 22.4 Gtoe in 2050, the low case in this report is 3.0 Gtoe from non-hydro renewables and the high case is 6.4 Gtoe. (1 Gtoe is 10^9 tonnes of oil equivalent, which is $39x10^{15}$ Btu.) The EPRI Roadmap gives about 6 Gtoe (5.8-6.8). The WEC/IIASA gives a range from 4 to 6 Gtoe. As a greenhouse gas reduction measure, 4.4 Gtoe of renewables replacing fossil in electric power generation reduces annual carbon emissions by 3,300 million tonnes, if renewables replace coal, and by 1,250 million tonnes, if renewables replace natural gas. There is no fossil carbon reduction if renewables replace nuclear power generation. For reference, in 1990 the global carbon emissions from fossil fuels were 6,000 million tonnes, and for 2050 the EPRI Roadmap gives 7,200-9,600 and the WEC/IIASA gives 5,000-15,000 million tonne-C. These are tonnes of carbon, C, that are 12/44 of the tonnes of CO_2.

EPRI Perspective

The data, perspectives, cost estimates, and future scenarios in this report will be valuable to companies and organizations engaged in a range of energy-related activities: power generation; power distribution and marketing; fuel or energy production; and, environmental protection and improvement. This report, together with EPRI reports and ongoing research regarding specific renewables—solar PV, wind, geothermal, biomass, green power marketing, and hydroelectric power—can help these companies and organizations in several ways. Specifically, it will help them see their own specific renewable energy programs, plans, or options in the context of potential global developments in greenhouse gas mitigation, other environmental issues, economic development options, and renewable energy research, development, and deployment.

Keywords

Biomass
Wind
Solar
Geothermal
Landfill gas
Methane
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Greenhouse gases
Renewables

ABSTRACT

This report presents statistics on the current (circa 1996-1999) use of renewable energy sources in the US and the world. It reviews issues that affect the extent to which renewable sources can play a role in greenhouse gas reduction worldwide and in the US for the 2020, 2050 and 2100 time frames. The data sources and analyses used in the report include the following: the EPRI Electricity Technology Roadmap, the 1995-98 studies by the World Energy Council and the International Institute for Applied Systems Analysis, the US President's Committee of Advisors on Science and Technology, the U.S. Dept. of Energy's Energy Information Agency, the DOE/EPRI Renewable Energy Technology Characterizations, and recent analyses by staff members of the EPRI research program in renewable energy. Costs of using renewable sources of electricity generation instead of fossil sources are calculated for the US, based on the "goal technology" values in the DOE/EPRI technology characterization report of 1997. Data and scenarios for worldwide use of renewables are presented.

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1 INTRODUCTION

During the 21st Century, biomass, solar, wind, and other renewable energy generation technologies are expected to contribute a substantial fraction of global electricity generation. At the same time, renewable energy will help reduce global emissions of carbon dioxide and methane emissions by reducing the energy generation required from combustion of coal, oil, natural gas, and other fossil fuels. Although renewable power generation is not currently competitive with fossil power generation, the cost is declining rapidly and some renewable energy technologies are already approaching the point of being economically competitive on their own merits, especially wind power and niche applications of solar and biomass energy. In addition, it is anticipated that renewable portfolio standards and other policy initiatives will drive the growth of renewable energy in the in the short term.

A previous EPRI report, “Role of Renewables in Greenhouse Gas Reduction,” EPRI TR-111883, November 1998, addressed the potential role of renewable energy in meeting electricity demand and reducing global greenhouse gas emissions in the United States. This report extends that analysis (Ref.1) to the global arena.

The objective of this report is to assess the potential contributions of solar, wind, biomass, geothermal and other non-hydro renewable energy sources to global electricity supply and to the reduction of global greenhouse gas emissions during the 21st Century. The report also provides a new section on issues and developments to watch as renewable energy’s participation in worldwide power markets grows.

Historically, long before there were steam and internal combustion engines, industry and agriculture used renewable energy to drive lumber mills, gristmills, water pumps, and other primitive mechanical power needs via water wheels and windmills. Today, hydro-power, contributes about 10% of the electricity generating capacity and 10% of annual generation in the United States. (Worldwide, hydro provides nearly 17% of <u>generation</u>, estimated below for 1997 as 2300 TWh out of 13,740 TWh of electricity generated.) Table 1-1 presents the status of electricity generation in the United States, as of the year 1996, from the final numbers for 1996 as given by the U.S. Dept. of Energy (DOE) Energy Information Administration (EIA) in the EIA outlook for 1998 (Ref.2).

Table 1-1
Sources of Electricity in the United States - 1996* (Ref.2)

Type of Energy Source	Capacity GWe	Generation TWh/year	Capacity Factor Hours	Capacity Factor %
Coal				
Coal-Generators	305	1758	5764	65.8
Coal-Cogenerators	7	39	5574	63.6
Subtotal for Coal	**312**	**1797**	**5760**	**65.7**
Natural Gas				
Natural Gas-Generators	182	288	1582	18.1
Natural Gas-Cogenerators	28	174	6214	70.9
Subtotal for Natural Gas	**210**	**462**	**2200**	**25.1**
Petroleum				
Oil-Generators	51**	80	1569	17.9
Oil-Cogenerators	1	6	6000	68.5
Subtotal for Oil	52	86	1654	18.9
Nuclear	**101**	**675**	**6683**	**76.3**
Conventional Hydropower	**79**	**346**	**4380**	**50.0**
Geothermal	**3.02**	**15.7**	**5199**	**59.3**
Municipal Solid Waste				
MSW Generators	2.91	18.85	6478	73.9
MSW Cogenerators	0.41	2.09	5098	58.2
Subtotal for Municipal Solid Waste	**3.32**	**20.94**	**6307**	**72.0**
Wood and Other Biomass				
Wood/Biomass Generators	1.91	7.27	3806	43.5
Wood/Biomass Cogenerators	5.41	39.17	7240	82.7
Subtotal for Wood/Biomass	**7.32**	**46.44**	**6344**	**72.4**
Solar				
Solar-Thermal	0.36	0.82	2278	26.0
Solar-Photovoltaic (PV)	0.01	0	0	0
Subtotal for Solar	**0.37**	**0.82**	**2216**	**25.3**
Wind	**1.85**	**3.17**	**1714**	**19.6**
Pumped Hydro	**21**	**-2**	**NA**	**NA**
TOTAL	**791**	**3451**	**4364**	**49.8**

*Reference (Ref.2): U.S. Dept. of Energy (DOE), Energy Information Agency (EIA), “Annual Energy Outlook 1998, with Projections through 2020,” December 1997. Most recent statistics given, and used for this table, are for 1996. Data in this table are derived from pages 112 and 196-199.

**Total capacity of natural gas plus oil is 233 GWe. Capacities given above are prorated based on generation in TWh with total fixed at 233 GWe. Most of this capacity is capable of burning either fuel.

In the case of what we would now call a "residential" energy use, heat from wood was the first thermal energy source used by humans, long before coal or any of the other fossil fuel sources mentioned in Table 1-1. However, wood for heat—and much later for power via steam engines—was not used in a renewable manner. Forests were eventually cut down faster than they grew back. Today, in the United States, wood is a renewable source because net forest growth is about 3% per year. The wood and wood residues used for fuel are the products or byproducts of a nationwide forest biomass system that is increasing by 3% each year in total biomass contained in standing wood, despite the amount harvested for use each year (Ref.3).

Table 1-2 shows similar data for the world, as of 1997.

Table 1-2
Sources of Electricity, Worldwide - 1997

Type of Energy Source	Installed Capacity (GWe)	Electricity Generation (TWh/year)	Measures of Capacity Factor: Hours	Measures of Capacity Factor: (%)
Coal-based electric power	900	5148	5720	65
Natural-gas-based electric power	920	2004	2178	25
Oil-based electric power	630	1373	2179	25
Nuclear power	350	2430	6943	79
Conventional hydropower	647	2595	4011	46
Geothermal power	7	49	7000	85
Municipal solid waste (MSW)	9	58	6500	74
Biomass (wood and other)	10	65	6500	74
Solar-Thermal	0.4	0.9	2250	26
Solar-Photovoltaic (PV)	0.3	0.6	2000	23
Subtotal for solar	**0.7**	**1.4**	**2000**	**24**
Wind**	8**	14	1700	20
Pumped hydro	?	?	?	?
TOTAL	**3481**	**13,740**	**3947**	**45**

**Note that wind is growing very fast, and by yearend 1999 the capacity installed was 15 Gwe, not the 8 GWe of 1997, and in 1999 the growth was 34% of the 1998 capacity.

Sources: EPRI, "Electricity Technology Roadmap: Vol.2 - Supply," (Ref.5) for TWh in 1995, then added 4% to get TWh in 1997. Then, assigned capacity factors close to USA in 1996 as basis to calculate installed capacity. Renewables were not done this way. For renewables, the results from Table 8-2 in this report were used. Hydro capacity was estimated as 647 GWe, as follows: the scenario in Table 8-4 here in this report was adjusted downward from the 667 for year 2000 to correct back to 1997, using the 1%/yr growth rate applied in Table 8-4 for the 2000 to 2010 growth.

Size of the Renewable Power Industry

The size of today's (year 2000) renewable energy technology business can be estimated from the amount of installed capacity and generation given above in Tables 1-1 and 1-2. In the case of solar PV, the relevant size of the industry is based on the manufacturing capacity that has built and is building the cells and modules going into the markets that now exist for solar electricity—markets that are now niche markets, not bulk power markets. From the current (circa 1997) levels of capacity and generation given above, the following estimates can be made regarding the current size of the renewable energy industries in the USA and worldwide.

- Wind power is growing at 20% per year on a 10,000 MWe base. (Actually, from 1998 to 1999 wind grew from 10,000 MWe to 13,400 MWe, a 35% annual growth.) To estimate the size of the investment to date, an approximate value of $1000/kW is a reasonable choice. On this basis, the 2500 MWe installed in the U.S. means approximately a cumulative investment value on the order of $2500 million, and worldwide, with over 12,000 MWe, there has been an investment of over $12,000 million.
- Biomass power is growing more slowly now than in the past: now less than 5% per year, after a 15% annual growth rate from the early 1980s through the early 1990s. In the U.S. biomass power amounts to an installed capacity of over 7000 MWe (over 9000 counting municipal solid waste "MSW" and landfill gas) at a cumulative investment value on the order of 7 GWe times $1500/kWe, which is over $10,000 million, and a worldwide total (this time including a substantial share in power from municipal solid waste "MSW", which is in Europe and Japan) of over 20,000 MWe and over $40,000 million invested. (Here $2000/kWe was adopted to estimate worldwide investment because some of the capacity is based on MSW and costs as much as $4000/kWe, because much of the high cost is paid back out of waste disposal fees collected by the power plants.)
- Geothermal power in the U.S. reached a 3000 MWe installed capacity in the early 1990s and has not grown appreciably since then. In fact, due to decline in geothermal steam production at The Geysers field in California, some 800 MWe that had been installed came off line. Worldwide there was very rapid growth during the 1990s as the Philippines, Indonesia, Iceland, Italy, New Zealand and others added geothermal capacity (Ref.68), and that growth may be resuming after a pause, a pause that was primarily due to the 1997-2000 financial crisis in Southeast Asia. Cumulative geothermal installed capacity is approximately 3000 MWe and about $3,000 million in the U.S., and nearly 8000 MWe (Ref.68) and approximately $10,000 million worldwide. (This is based on using $1000/kWe capital cost as typical of the U.S. and $1250/kWe for a world average.)
- The size of the solar PV power industry is best expressed in terms of the annual production of photovoltaic (PV) modules. Both in the U.S. and worldwide this production is growing at over 20% per year. In the U.S. the cumulative installed PV manufacturing capacity has reached about 30 MWe/year with an estimated total investment value of $10,000 million. Worldwide the solar PV manufacturing capacity is on the order of 100 MWe/year and represents a cumulative investment value of about $30,000 million.
- Solar thermal still has more installed generation capacity than solar PV, at about 350 MWe in the U.S. and about 400 MWe worldwide, adding, perhaps, some $3,500 million and $4,000 million to cumulative investment totals.

The totals for all five of these non-hydro renewable power categories, therefore, adds to the following: (1) U.S., 13,000 MWe installed generating capacity and a cumulative investment value in renewable power generation on the order of $30,000 million; and (2) worldwide, about 38,000 MWe installed generation capacity and an investment accumulating to about $95,000 million.

Contents of This Report

This report presents information relevant to estimating the extent to which renewable energy sources can reduce emissions of fossil fuel carbon to the atmosphere. It also addresses some questions of the timing, the costs and the environmental consequences. While the answers given in the report are, to some extent, still preliminary, the report presents information and results from related and relevant work by EPRI and others. The EPRI work includes the Electricity Technology Roadmap (Refs.5,6) and the DOE/EPRI Renewable Energy Technology Characterizations (Ref.4). The others include the Energy Information Administration (EIA) of the U.S. Dept. of Energy (Refs.2,7,8,9,10), the U.S. President's Committee of Advisors on Science and Technology ("PCAST" Ref.11), and the World Energy Council's project with the International Institute for Applied Systems Analysis (IIASA, Ref.12). The other sections of this report are described in the subsections below.

Issues and Approach (Section 2)

Section 2 gives an overview of some issues and numbers related to the role of renewable energy sources. It outlines how the cost estimates are made.

Questions about Biomass: Is It Green? Is It CO_2 Neutral? (Section 3)

Biomass raises some special issues. Given that biomass combustion, and also gasification followed by combustion, gives off CO_2, why does biomass energy help avoid greenhouse gas emission? Why is it “CO_2 neutral” or “zero carbon?” And, even if biomass is CO_2 neutral, does not this source of energy have potential impacts that are otherwise undesirable, such as particulate and unburned hydrocarbon emissions, loss of forests, or expansion of chemically intensive cultivation? These issues are addressed in Section 3.

Cost of Renewable Power (Section 4)

This report uses cost estimates and projections from the 1997 DOE/EPRI “Renewable Energy Technology Characterizations” (Ref. 4) with the addition of some cases involving landfill gas and animal wastes, and with some updates on biomass cofiring. The primary question investigated is: how much more does electricity generated from renewables cost than electricity generated from fossil fuels? The fossil alternatives considered are natural gas combined cycles and state-of-the-art coal-fired power systems. Capital, operating, and fuel costs, plus heat rates and capacity factors, are used here to estimate the extra costs of the renewables per unit of electricity, a unit sometimes given as a kilowatt-hour (kWh) and sometimes as a megawatt-hours (MWh). These results are developed in Section 4.

Cost of Greenhouse Gas Mitigation (Section 5)

Having first (in Section 4) calculated the extra cost of renewables, in \$/MWh or cents/ kWh, this report goes on to calculate the cost in terms of the equivalent cost per unit of fossil carbon emission avoided. The greenhouse gas warming potential is based on equivalent amount of fossil carbon dioxide CO_2. In order to compare costs on the basis of warming potential, costs are converted from \$/MWh to \$/tonne-C, i.e., dollars per metric ton (tonne) of the equivalent amount of fossil CO2 emission expressed per weight of carbon. The calculation method quite properly gives landfill gas power systems, which convert a CH_4 (methane) emission into a recycled CO_2 emission, an advantage of 21 tons CO_2 equivalent for each ton of methane, based on the relative strength of the greenhouse effect of the two gases. A similar advantage accrues to animal waste disposal technologies that also avoid methane emissions. Section 5 addresses the conversions from fossil electricity displacement in MWh to metric tons of the CO_2 equivalent of fossil carbon emissions.

Biomass Cofiring Supply Curve (Section 6)

The supply curve, i.e., the amount of fossil carbon reduction that may be achieved in the future and the estimated costs as a function of the amount of reduction achieved, are the next topic (Section 7). A special case—nearer term and lower capital cost—is taken up first: biomass cofiring in existing coal-fired power plants. Section 6 addresses this case.

Supply Curve for All Greenhouse Gas Control Options (Section 7)

Extending the biomass cofiring example, all the renewables are put into “supply curve” format. This is the scope of Section 7. However, as in the case of biomass cofiring, the displays are in tabular form, in order to show explicitly the values and the assumptions adopted. All the renewable options are presented: biomass cofiring, other biomass, geothermal, wind and solar.

International Context (Section 8)

All previous sections were based on the United States. Section 8 presents numbers on the current and possible future deployment of the renewable energy technologies (solar, wind, biomass and geothermal) worldwide, by country and/or groups of countries or by regions. The conventional energy sources are also shown, i.e., coal, oil, gas, hydro and nuclear.

Comparisons to Other Results (Section 9)

Next the report includes, as Section 9, some comparison to other results.

What to Watch (Section 10)

Section 10 names and discusses some topics that indicate what to watch for to see how well renewable energy technologies are progressing along the paths that are expected to lead to these technologies being more competitive and more deployed.

Conclusions (Section 11)

Conclusions that summarize the numbers given in preceding sections and the topics to watch to monitor progress are given in Section 11.

Appendix A

Appendix A contains tables that show more detail on some of the numbers displayed in the main body of the report. Most of Appendix A is a display of the breakdowns of the total primary energy inputs of the renewables into the electrical generating capacity in MWe, the hours per year assumed (i.e., the capacity factors) and the heat rates (i.e., efficiencies) assumed in calculating the primary energy inputs. In the body of the report the primary energy inputs are given. For future years those inputs are the fossil energy inputs that would otherwise be used if the renewables were not deployed.

Appendix B

Appendix B displays some additional data taken from tables and figures in the WEC/IIASA book, Global Energy Perspectives (Ref.12). Some of the tables in Appendix B consist of numbers read off figures (graphs) in the book.. World totals for the three future years featured in the WEC/ IIASA book are the primary data extracted from the book and displayed in Appendix B.

Appendix C

"Units and Conversion Factors" are given in Appendix C.

Appendix D

Appendix D gives the References, covering all the sections of this report.

2
ISSUES AND APPROACH

The traditional issues for the renewable energy sources are, basically, supply and cost, plus a question on the timeframe for commercial availability:

1. How big is the resource base?

2. How expensive is the technology?

3. When could commercial energy production be online?

To address the role of renewables in reducing greenhouse gas emissions, the questions are essentially the same. However, the context for presenting the answers needs to include the costs of various options expressed in units of greenhouse gas reduction, namely $/tonne-C, which means dollars per metric ton of carbon whose emissions to the atmosphere from a fossil fuel source are avoided or offset. The emissions most often are in the form of carbon dioxide (CO_2). In analyses of global warming potential, the greenhouse effect of other gases, such as methane (CH_4) and nitrous oxide (N_2O), are normalized to their CO_2 equivalents. There are standarrds for such normalization, based on the strength or infrared absorption and the lifetime of the gaseous compounds in the atmosphere (Refs.9,10). When costs given in units of $/ton-$CO_2$ are to be converted to a $/tonne-C basis, they need to be increased by a factor of 44/12 for the molecular weight ratio of CO_2 to C, and also by a factor of 1.1 to adjust for converting from $/ton (short tons, or tons) into $/tonne (metric tons).

Some issues related to the local, not global, environmental impacts of the renewable energy technologies come into play in discussions of global warming potential and greenhouse gas emissions. These local issues arise because the benefits of greenhouse gas reduction are tied to the prevention or delay of global impacts, while on the local level it is possible than the impacts of some renewable technologies are negative. Local or regional environmental impacts could be, and, in fact, are brought into the discussion as possible offsetting negatives. One of the renewable resources, namely biomass, has a special need for discussion in a local/regional environmental context, in order to address these questions:

1. Why is biomass energy desirable, given that today's biomass energy use is primarily the burning of wood and a key future resource could also be wood, i.e., trees grown as fuel?

2. Why does biomass help reduce fossil carbon emissions even though CO_2 gets emitted when biomass fuels are used to product heat or power?

These biomass questions and related issues are addressed in Section 3 of this report.

Supply

Solar. The energy from the sun falling upon the surface of the earth is vastly more than the amount of energy used by humans for heat, power, transportation and industry. The only issue of supply sometimes cited with respect to solar energy is that of land area required. Table 2-1 shows some land area and renewable resource numbers for the U. S. based on the Technology Characterizations report (Ref.4). The relative numbers apply worldwide. For solar this shows that there is ample land area for solar energy capture, even though the land requirements for solar power are large compared to the land needed for conventional fossil fuel or nuclear power plants. (Table 2-1 does not show the land areas required for the mining of coal or uranium. However, these fossil and nuclear fuels are so high in energy content per unit of volume that the land area to mine is small compared to the land area to produce renewable energy.)

Table 2-1
Land Area Requirements (Current Renewable Technologies)*
(Source: Ref. 4)

				Land Area for 100 GWe	
	Unit Size (MWe)	Area to Support Unit Size (acres)	Power per Unit of Area (kW/Acre)	Area (10^6 Acres)	Fraction** of U.S.
Solar Thermal	75	408	180	0.54	0.028%
Solar PV					
Residential	0.0026	0***	NA	0	0
Utility Scale	2.4	24	100	1	0.053%
Wind	50	3707	14	7.4	0.39%
Geothermal	50	420	120	0.84	0.044%
Biomass	50	39400	1.3	78.7	4.1%

* To convert acres to hectares, multiply by 0.4047

** Fraction is of the 1.9 billion (10^9) acres of the continental United States

***No land is required for residential PV systems, which are installed on existing structures

Wind. Wind energy is a rather indirect form of solar energy: the flux of heat from the sun causes the thermal and pressure gradients that drive the wind. However, wind being only a small fraction of the solar heat flux on to the earth and requiring special conditions of much higher than average wind speeds to make an economically viable wind energy resource, the good sites are limited, and the potentially useable resource base is much smaller. Estimates for the U.S. range from 200 to 10,000 GWe. With U.S. electricity generation capacity being 700 to 800 GWe today, this wind resource range suggests a potential supply large enough to play a role in CO_2 emission reduction.

In a report to DOE by the Battelle Pacific Northwest Laboratory 1991 (Ref.13), the land areas of the United States (contiguous 48 states only), that have good wind resources were listed and mapped. The authors excluded lands where wind energy development may be excluded on environmental, recreational or other land-use grounds. The following are EPRI calculations based on that 1991 report:

1. Class “5” or better wind resources.
   11.5 million acres developable (0.6% of U.S.)
   713 TWh per year could be generated from this land
   204 GWe of generating capacity would have to be installed in order to generate the 713 TWh; assuming a 40% capacity factor.

2. Class “3” and “4” wind resources.
   13% of U.S. land falls into resource class “3” or better (13% of 1.92 x 10^9 acres). However, 47% of this land is excluded as unlikely to be permitted for wind development. Therefore, some 6.1% of the 1.92 billion acres is Class 3 or better and also developable: 117 x 10^6 acres. 10,062 TWh per year could be generated from the permitted Class 3 and Class 4 lands. 4,820 GWe of capacity can generate the 10,062 TWh/year, if a 30% capacity factor is assumed for Class 4 and a 20% capacity factor is assumed for Class 3.

The result for the wind supply curve is two groups as follows:

Wind Class 5 or better: 580 TWh from 11.5 million acres of land at 2628 hours/year (30% annual capacity factor) from 221 GWe or installed capacity.

Wind Classes 3 and 4: 4000 TWh from 105 million acres of land at 2628 hours/year (30% annual capacity factor) from 1520 GWe of installed capacity.

Geothermal. The only geothermal resources used for power today, and actually used since 1904 in Italy and since 1958 in California, are those called “hydrothermal.” This means hot water or steam in subsurface reservoirs that can be tapped for energy use by drilling wells into the reservoirs. The identified hydrothermal reservoirs in the U.S. could supply some 20 GWe of generating capacity. Specifically, the Technology Characterizations (Ref.4) gives 23 GWe as the 1978 USGS Circular 790 estimate (Ref.16), and an EPRI workshop in 1986 gave 7 GWe as an estimate of the resource that could be developed over a 10-year period (Ref.17). An estimate by the primary author of the geothermal section of the Technology Characterizations gave an estimate in 1997 of 5 GWe at a cost of $0.03/kWh and 10 to 20 GWe at a cost of $0.05/kWh (Ref.4). A compilation of estimates done by the EIA in 1991 shows 5.9 to 10.65 GWe based on the already-identified hydrothermal resources in the U.S. and 10.6 to 44 GWe when allowing for more years of development and/or some as-yet-unidentified hydrothermal sources to be discovered and explored (Ref.18). That EIA 1991 report cites the USGS Circular 790 (Ref.16) as estimating that 23 GWe of hydrothermal resources are "identified" and that "identified plus undiscovered" would total to 95-150 GWe (Ref.17).

The so-called “hot dry rock” resources are much more abundant, on the order of thousands of GWe in the U.S.--nearly 3000 GWe, and possibly even 17,000 GWe, are estimated in the Technology Characterizations (Ref.4). These hot dry rock resources are vastly more abundant than the hydrothermal because they do not require that all three ingredients--heat, water and fractured rock--be present together in the same volume of rock. The presence of the hot rock alone is enough, because the water supply and the fracturing of the rock are part of the energy technology introduced to tap the resource. However, only hydrothermal resources are included in this report. This is because the hot dry rock technology may not be given the necessary research and development effort or because the costs may not be driven low enough in the 30-year timeframe of most interest for this study. Nevertheless, the abundance of the resource and the tests suggesting technical feasibility make hot dry rock worthy of interest and future R&D effort.

Biomass. Estimates of biomass energy potential depend primarily on the land area considered to be potentially convertible to energy crop production. For the U.S. this estimate may well cover a range from 20 million acres (8 million hectares) to over 100 million acres. Of course the yield of biomass on these acres is also critical. In fact, the economics of biomass raised as a crop for energy applications depend more on yield than on any other single parameter. Yield is measured in dry tons per acre per year, or in tonnes/ha/year. A very important addition to the biomass energy resource base is the amount of wood waste available for use as fuel. In the U.S. a 7 GWe electric generation capacity has already been built to use this resource. Another 40 to 150 million tons (dry) per year could potentially be put into this use. The existing 7 GWe generate 46 billion kWh/year (46 TWh/year) today from an estimated 46 million dry tons of waste biomass materials, nearly all waste wood. (This estimate assumes an average heat rate of 16,000 Btu/kWh and an average energy content of dry biomass of 16 million Btu per dry ton.)

The total potential U.S. supply of biomass electricity generation is, therefore, estimated here (per the numbers used above in Table 2-1) as follows:

Already existing: 7 GWe generating 46 TWh per year from 46 million dry tons of biomass fuel in the U.S.

Additional waste wood fuel, not already used for power generation: 40 to 150 million dry tons per year, capable of generating from 60 to 230 TWh/year (at a heat rate of 11,000 Btu/kWh), which would mean a 9 GWe to 33 GWe addition to the potential biomass generating capacity of the U.S.

Energy crop fuel: 20 million to 100 million acres in the U.S. at 7 drytons/acre/year yield, adds 140 million to 700 million dry tons per year. As a future source, converted with more efficient technology at a 10,000 Btu/kWh average heat rate, this would be from 224 to 1,120 TWh of potential biomass electricity generation in the U.S., which would support 32 to 160 GWe of capacity at 7000 hours/year.

Adequacy of Supply

Can renewables do enough, soon enough? First, is the source large enough? One theoretical estimate of a possible maximum supply potential for renewables in the United States is shown in Table 2-2. This estimate, which comes to a total of over 6000 TWh/year, amounts to more than the projected total U.S. electricity supply for the year 2020, which is 4500 TWh/year per the EIA reference case (Ref.2).

Table 2-2
Theoretical Examples of Resource or Land-Area Limits Setting Maximum Potential Supply of Renewables in the United States ("Goal" Technologies, Not "Actual")

Description	Land Area (10^6 acres)	Capacity (GWe)	Annual Hours (h)	Generation (TWh/year)	Fraction of U.S. Generation[5]
Solar[1]	11	1800	2000	3600	80%
Wind[2]	29	600	3000	1800	40%
Geothermal[3]	0.2	20	7500	150	3%
Biomass[4]	50	100	7000	700	16%
OVERALL	90	2520	2480	6250	139%

Notes:

1. Solar: Based on using 0.6% of the 1920 million acres on continental U.S. land area at the PV technology performance level projected for the year 2030 (Ref.4).
2. Wind: Based on using about 1.5% of total continental U.S. land area, or about 25% of the land in wind classes 4 and higher, assuming the moderate land exclusion scenario (Ref.13).
3. Geothermal: Only hydrothermal resources, no hot dry rock included (Ref.4). Hot dry rock would make the resource at least 10 to 100 times larger (Ref.4).
4. Biomass: Based on 50 million acres of energy crops at an average yield of 7 dry tons per acre per year, converted at an average heat rate of 10,000 Btu/kWh (30% efficiency, HHV). This gives 80 GWe from crops. 20 GWe from wastes is added to give the 100 GWe here.
5. U.S. Total Generation: The fractions are based on a total future generation of about 4500 TWh/year per the EIA "Reference Case" for the year 2020 (Ref.15).

Global totals would lead to a similar conclusion regarding land areas for biomass, wind and solar, as can be seen below in this report (in Section 8 and in Appendix B). Biomass is less abundant than either wind or solar, but abundant enough to become important--important meaning something on the order of approximately 20% of global energy needs or, at least, of global electricity needs. The resource base for solar is much greater than that for wind, both for the U.S. and for the world.

Timing of Supply

Second, can this supply be brought into play soon enough? To address this Table 2-3 was prepared for the 1998 EPRI report on renewables and greenhouse gas reduction potential in the U.S. (Ref.1). Table 2-3 presents a fast growth scenario for renewable energy deployment in the U.S. Would such growth make renewables available soon enough?

Table 2-3
High-Growth Scenario for Renewables in the U.S.

				Solar		
Timeframe	**Biomass**	**Geothermal**	**Wind**	**Thermal**	**PV**	**Total**
Size in Year 2000	8 GW	3 GW	2.5 GW	0.4 GW	0.3 GW	14 GW
Growth Rate	5%	5%	10%	none	20%	
Size in Year 2005	10 GW	3 GW	4 GW	0.4 GW	0.75 GW	18 GW
Growth Rate	10%	10%	10%	10%	30%	
Size in Year 2010	15 GW	5 GW	6 GW	0.6 GW	2.8 GW	28 GW
Growth Rate	10%	10%	10%	10%	20%	
Size in Year 2015	24 GW	8 GW	10 GW	1 GW	7 GW	47 GW
Growth Rate	5%	5%	5%	20%	20%	
Size in Year 2020	30 GW	10 GW	13 GW	2.5 GW	17GW	66 GW
Growth Rate	5%	5%	5%	20%	20%	
Size in Year 2025	37 GW	13 GW	16 GW	6 GW	43 GW	96 GW
Growth Rate	5%	5%	5%	10%	15%	
Size in Year 2030	46 GW	16 GW	20 GW	9 GW	86 GW	144 GW

Views as to just how soon is soon enough differ greatly. One view, held by many energy analysts, notes that some policies may try to change the energy source mixture too fast, and that too fast a change could have bad, or at least very expensive, consequences. For example, an EPRI analysis of the cost of greenhouse gas control shows that premature retirement of power plants could make the cost of such control much greater than it need be (Ref.14). A 1998 EIA analysis (Ref.15) presents one case where aggressive, and expensive ($250/tonne carbon or about 6¢/kWh), greenhouse gas emission control allows for a large penetration of renewable power generation in 2020 (500 TWh/year). In a lower cost case where the EIA report keeps the carbon cost at approximately $60/tonne-C (about 1.5¢/kWh) the penetration of renewables comes out as a much smaller amount in 2020 (100 TWh/yr).

Are these levels of renewable energy deployment large enough, soon enough? There is no agreement as to how much renewable energy ought to be available at any particular time. Nevertheless, the questions can be addressed by comparing the growth in capacity of Table 2-3 with various cases developed in the 1998 EIA analysis (Ref.15). Table 2-4 shows the results. Table 2-4 indicates that the renewables growth scenario shown in Table 2-3 is fast enough to meet the need for renewables as set forth in EIA Case 1990+9%, but perhaps not fast enough to meet the need in EIA’s Case 1990-3% in the year 2020.

Table 2-4
Renewable Capacity Compared to the EIA "Kyoto Cases"

	Biomass	Geothermal	Wind	Solar Thermal	Solar PV	Total
YEAR 2000						
Capacity, GW*	8	3	2.5	0.4	0.3	14
Annual Cap. Factor*	0.72	0.59	0.20	0.26	0.25	NA
Generation, TWh/yr*	50	16	4	0.9	0.6	71
EIA Ref. Case, TWh/yr**	48	16	4	0.9	<0.1	69
YEAR 2010						
Capacity, GW*	15	5	6	0.6	2.8	29
Annual Cap. Factor*	0.72	0.72	0.25	0.30	0.25	NA
Generation, TWh/yr*	94	31	15	1.5	5.6	144
EIA Ref. Case, TWh/yr**	56	17	6	1.2	0.6	81
EIA Case 1990+9%, TWh/yr**	68	22	25	1.2	0.6	117
EIA Case 1990-3%, TWh/yr**	81	30	36	1.2	0.7	149
YEAR 2020						
Capacity, GW*	30	10	13	2.5	17	66
Annual Cap. Factor*	0.72	0.85	0.30	0.35	0.25	NA
Generation, TWh/yr*	188	75	33	7.5	34	326
EIA Ref. Case, TWh/yr**	58	20	9	1.5	1.4	90
EIA Case 1990+9%, TWh/yr**	133	33	108	1.5	1.4	276
EIA Case 1990-3%, TWh/yr**	295	47	123	1.5	1.4	468

* The capacities are from Table 2-3, and then the resulting generation values in TWh were calculated from the assumed capacity factors given here in this table.

** From EIA's Kyoto analysis done in 1998 (Ref.15).

Some explicit comparisons of the growth scenario in Table 2-3 and the EIA scenarios are as follows: Table 2-3 reaches 144 TWh/year from renewables in 2010. Compare this to the 149 TWh needed that year in the EIA case in Table 2-4 having the greatest "need" for renewables, which means the case with the greatest reduction in emissions of greenhouse gases. This EIA case is "1990-3%." In the nomenclature of the EIA analysis, 1990-3% means a scenario in which the greenhouse gas emissions in 2010 in the US are 3% below the total in 1990. In EIA Case 1990-3%, the trend of an increasing shift away from coal and toward natural gas (and also biomass) results in so many retirements of coal-fired power plants and generating units that by 2020 some 468 TWh/year of renewables are needed, well above the 326 TWh derived in Table 2-4 from the 66 GWe given in Table 2-3 for 2020. However, as the EIA analysts pointed out in developing a "coal sensitivity" case (not shown in Table 2-4 and one in which less coal capacity is lost) the need for renewables decreases as more coal-fired capacity is preserved. The EIA analysts prepared their "coal sensitivity" case because many will argue that coal has such economic and national security value that the nation cannot afford to retire the coal-fired capacity so fast (Ref.15). The 326 TWh from renewables in 2020, derived here from the high-growth scenario for renewables in Table 2-3, easily meets the 276 TWh needed from renewables in the much-less-severe EIA Case 1990+9%.

Therefore, the U.S. renewables high-growth scenario above in Table 2-3 is fast enough for renewables to play the role required in a case where modest progress is made toward greenhouse gas reduction in the 2000 to 2020 timeframe.

The U.S. Role in Worldwide Development of Renewables

For purposes of global climate change mitigation, actions that reduce greenhouse gas emission can be taken anywhere on the planet. Some applications of renewable energy technologies may be more economically attractive in other countries than they are in the United States. The reasons for this are as follows:

1. The United States has relatively abundant natural gas resources. Countries without such a resource will find that renewables compete better when the natural gas option is less abundant and more expensive.
2. The demand for electricity and transportation fuel is growing much more rapidly in some other countries. This could create major growth potential for renewables in those countries.
3. In some other countries, renewable resources may be relatively more abundant than in the United States, e.g., geothermal in the Philippines and Indonesia, and biomass in Brazil and other tropical countries.

These considerations will influence the ways and the regions in which the renewable energy industries grow. The fact that the United States has strong positions in both (1) renewable energy resource base and (2) technical capabilities to develop renewable energy conversion technologies suggests that the U.S. role is likely to involve developing both domestic and international resources and sales. The development of a renewable energy project overseas could be a low-cost greenhouse gas reduction, an opportunity to sell some technology and service, and also an opportunity to further develop and improve a technology for use at home. In both solar and biomass power, some U.S. utilities have collaborated with their own local industries to develop expertise and technology that would have applications close to their home base or somewhere else in the U.S., but that could also be sold abroad, to utilities, power generators, vendors, governments or other entities.

3
BIOMASS: IS IT CO_2 NEUTRAL? IS IT GREEN

Among the renewables biomass has special considerations due to the cycle of CO_2 absorption during the plant growth cycle and CO_2 emissions during the energy conversion stage. Also, biomass use for energy results in other emissions such as SO_2, NOx, and particulate matter, it has a role in solid waste management, and it has other both positive and negative environmental attributes. Some are concerned about the balance of environmental, and, particularly in this context, greenhouse gas benefits and impacts. This section addresses these issues.

The Role of Biomass in the CO_2 Cycle

Solar and wind energy technologies clearly do not emit CO_2 to the atmosphere during the power generation process. Some fossil fuel is used during their construction, but when amortized over the life time of the plants these are very small. Geothermal reservoirs can contain some CO_2 and, during power generation, most of the CO_2 dissolved in the geothermal fluid brought to the surface will be vented to the atmosphere. However, again, this is generally a small amount compared the fossil fuel combustion alternative.

In contrast, biomass power generation, or other use of biomass as a biomass energy source, results in large emissions of CO_2 and sometimes other greenhouse gases, more than produced from fossil fuels (due to lower efficiency). However, this CO_2 derives from plant biomass that was removed from the atmosphere within the recent past, typically one year to a few decades. By contrast, fossil fuels locked up their carbon over millions of years, a process now being reversed over a period of centuries. When wastes or residues, or non-commercial trees, are used for fuels, the comparison is between the emissions to the atmosphere that would take place if the biomass decomposed in the forest, field or waste dump, compared to it being used as a substitute for fossil fuels. As a substitution for fossil fuels, biomass mitigates global warming even in the absence of any renewed CO_2 fixation. In the case of energy crops, all that is required is that the biomass burned be replaced in a reasonable time (typically one to ten years) with new biomass. In a typical energy crop operation, biomass would be used at the same rate is produced. In fact, as higher-yield crops replace lower-yield ones, the biomass would be replaced faster than it was grown for fuel.

"Closed Loop" Biomass

The 1992 "Energy Policy Act" in the United States set up a tax credit (for taxable corporations) and a production payment (for tax-exempt public agencies) for the use of "closed loop biomass" in new energy production facilities. This credit is in Section 45 of the Internal Revenue Code, and is substantial, about \$1.70/MBtu at a heat rate of 10,000 Btu/kWh applied to the 1.7

cent/kWh credit at its 1999 level inflated from the original 1.5 cent/kWh in 1992. (Another, older, tax credit exists for biomass-derived gases, such as landfill methane, animal waste digester gas and/or thermo-chemical biomass gasifier products. This older tax credit for biomass gases is set forth in Section 29 of the Internal Revenue Code, and expired for facilities not brought on-line before the end of June 1998. It was a substantial incentive: the equivalent of about $1.00/MBtu.) The "closed-loop biomass" credit has never been used, because no dedicated energy crop has yet been converted to electric power or liquid fuel in a new energy conversion facility (i.e., placed on-line after December 31, 1991). The Minnesota alfalfa-to-power biomass gasification demonstration (Ref.19) had planned to use the closed-loop tax credit. Others may try to use it if it remains available.

Sometimes there is confusion about this tax credit issue. For example, the fact that the "closed loop biomass" tax credit has never been used is due, in part, to acceptance of a fallacy. The logical fallacy was that only biomass which had been grown for the purpose of fuel production would reduce greenhouse gases and be renewable. However, such is not the case. Forests are a renewable source, as already mentioned. And, in the case of energy crops, all that is required is that the biomass burned be replaced in a reasonable time with new biomass.

Logically, as discussed above, any biomass feedstock that comes from a source that is being replaced at least as fast as it was originally grown is being used in a closed loop. It is not necessary that the biomass be grown as a dedicated energy crop for the carbon to be 100% recycled with no net addition to the atmosphere. However, the wording of Section 45 only provides eligibility for a tax credit or production payment in this special case. There is interest in the bioenergy community in seeing a revision of Section 45 to permit the use of biomass wastes as a fuel for the generation of electricity, a definition that would recognize the closed-loop properties of most waste biomass fuels.

Tax incentive or not, U.S. biomass energy conversion processes are closed loop (CO_2 neutral) processes that grow back at least as much biomass as they use. Overall, the growth of forests in the United States is increasing at a faster rate than the harvesting of trees from forests for wood and paper products. The net stock of woody biomass in U.S. forests has been increasing at about 3% per year (Ref.3). Because the majority of the carbon harvested from U.S. forests is "sequestered" in lumber and paper products, and only a portion of the wood wastes generated are used as fuel, it is clear that more carbon is fixed from the atmosphere each year by U.S. forests than is combusted in biomass fuel. In addition, an increasing amount (now over 100,000 acres, i. e., some 40,000 hectares) of non-forest land is being used for "fiber farms" by the U.S. pulp and paper industry.

Fossil Energy Used to Grow, Transport and Process Biomass

Some fossil energy is used in the processes of growing, harvesting, transporting, handling, and preparing biomass fuels. Ethanol made from corn (especially before the efficiency improvements of the past decade) is notable for requiring fossil fuel inputs that are comparable to the energy in the ethanol output. However, for technologies that use wood wastes (the vast majority of today's biomass fuel), and for the developing energy crop technologies, the fossil energy inputs are much less than the amount of output energy in the energy fuel products. The

National Renewable Energy Laboratory (NREL) has done "life cycle analyses" of some renewable energy technologies, including three biomass technologies (Ref.20). NREL's results show that 2% to 8% of the energy output of a biomass power plant fueled by energy crops is required for fertilization, planting, cultivation, harvesting, transport, and fuel preparation (Refs.19,20,21,22). Most of these operations use liquid fossil fuels, although at some point in the future renewable fuels such as ethanol and biodiesel may have an important share of the liquid fuels market. For now, a reasonable approximation of the fossil fuel use for good energy crop systems would be 5% of the energy produced by the biomass plant. An EPRI study, completed in 1996 by the Swedish power company Vattenfall, gave 5% for the fossil energy use in an alfalfa energy crop system supplying a gasification combined cycle power plant (Refs.19,22).

Is Biomass Really a Source of "Green" Power?

Biomass power uses combustion technology, and hence is perceived by some as "not green." Historically, wood combustion processes were dirty, with uncontrolled emissions of smoke and haze, including soot, ash, carbon monoxide, nitrogen oxides, and hydrocarbons. Local and regional air quality problems still exist today as a result of high concentrations of fireplaces, campfires, and open burning of residues. Starting about 50 years ago, modern furnaces and boilers were developed for both wood and coal. Today, these combustion systems can operate with emissions controlled to virtually any level demanded by permit requirements. Current developments include gasification technologies (again, for both biomass and coal). Gasifiers not only provide higher efficiency power generation through integration with combined (gas and steam turbine) cycles; they also allow, and demand, a much deeper level of emissions control than the direct combustion technologies.

Most biomass fuels are significantly lower in potential air pollutants than most coals. Biomass has virtually no sulfur (often less than 1/100 that of coal), low nitrogen (less than 1/5 that in coal), and low ash content. Exceptions exist, but can be identified and controlled. For example, construction and demolition wastes, which are sometimes mixed with other wood wastes and used as biomass fuel, can have very high sulfur contents due to the gypsum (calcium sulfate) in wallboard. Treated lumber can contain trace amounts of toxic elements; one modern treatment contains a mixture of copper, chromium, and arsenic which can cause the combustion ash to be classified as a toxic waste. Crops with high protein levels or grown with high fertilizer levels can have relatively high nitrogen contents. Overall, biomass is usually far superior to coal in terms of its concentrations of sulfur, nitrogen, ash, and metals. Compared to natural gas, however, biomass cannot claim any inherent advantage in terms of emissions, except for greenhouse gas emissions.

Another perception problem for biomass power, besides combustion, is the use of forests. As mentioned above, forests are expanding in the United States. Net forest biomass is currently increasing at about 3% per year (Ref.3). Biomass fuel used for energy today is essentially all from wood wastes and residues, the majority of which originate in forest operations conducted for other purposes. In some cases, biomass fuel is provided from forest management (thinning) operations that are conducted for the specific purpose of improving forest health and value.

Nevertheless, forest products are the high value products that make woody biomass fuels have a low enough cost to be part of today's power generation industry. The wood product, such as lumber, paper or fiberboard, pays the bill for the gathering into one place as a waste product a material that would otherwise have too low an energy density to be worth the expense to gather into one place as a power plant fuel. The present-day use of waste wood as the dominant biomass fuel--about 90 or 95 percent of biomass power fuel in the U.S.--may foreshadow the future use of biomass, even biomass from agricultural crops, in ways that often now called "coproduction" and "cogeneration." Coproduction is the providing of fuel from a material that is in part, perhaps as in the case of wood products, in major part, gathered for its value for another, much higher value, product. Cogeneration is the generation of electric power from biomass in a situation where the value of some other energy product, usually steam or process heat or district heat, provides enough added value and revenue to offset what would otherwise be too high a cost (i.e., the cost of generating the electricity as the sole product of the biomass feedstock). Both coproduction and cogeneration have the potential to provide low-cost biomass power in the nearterm—i.e., low-cost relative to other renewable options, except for windpower from the best wind sites. Coproduction will probably be the way that energy crops will first come into commercial use in the future.

Today's crops, even the fastest growing trees and grasses, are still too expensive to be economic as fuels. Yet, the only way biomass can become a <u>major</u> energy source (as depicted in the future scenarios shown elsewhere in this report, and defined here as on the order of 20% of electricity, rather than only 5% or so) is through the use of energy crops. Forests will not be involved in energy crop production. Instead, energy crop production will be agriculture, conducted on lands that are now classified as part of the crop, pasture, or marginal agricultural land resource. Farmers and landowners will make rational economic decisions about which crops to plant, just as they do now. Government pro-grams, such as the Conservation Reserve Program ("CRP"), will become involved in the energy crop business to the extent that environmental benefits (e.g., soil erosion control and non-point-source water pollution control) are demonstrated. Fiber crops can be used, in part, for higher value purposes than fuel, and in that way, can replace some harvesting from forests.

Just as today's biomass power industry is an important part of our waste management system, future biomass energy production can be coupled to projects that are beneficial in waste disposal. Examples would include recovering energy from sewage sludge or animal wastes while helping control adverse impacts. Energy crop production can be part of soil remediation and water quality control projects. Energy crop production can also help restore soil nitrogen, as in the alfalfa project that was being developed in Minnesota (Ref. 19), and can also contribute to soil erosion control and habitat enhancement.

The Minnesota alfalfa project, which was cancelled in 1999 as an energy project, was also an example--and an example from outside of the pulp/paper/fiber/wood industries-- where a major part of an energy crop harvest could go for a higher-value use, and, thereby greatly enhance the economics (Ref.19). In that Minnesota case, which was a project designed under cosponsorship of DOE, industry, ratepayers and the Minnesota Valley Alfalfa Producers, the high-value product was a high-protein alfalfa leaf meal for animal feed. The upgrading to the high-value leafmeal may continue to go forward as an upgraded animal feed processing plant, without the biomass gasification powerplant com-ponent, which was the energy component of the project as originally designed.

In general, energy crop production is less intensive than conventional row crop product-ion in terms of tilling, chemical use, and other man-caused environmental changes. The Minnesota alfalfa project incorporated an alfalfa rotation into a corn/soybean rotation so as to restore soil nitrogen during the years of the alfalfa rotation.

4
COST OF RENEWABLE POWER

The economic analysis of the cost of using renewable energy to reduce global greenhouse gas emissions is based in part on estimates of the present and projected and future cost of generation for each of the renewable energy and fossil generation technologies. This section presents the cost of generation estimates for both renewable energy and fossil generation technologies. The components of the generation cost include the annual fixed charge on the capital investment, fuel costs, and annual operation and maintenance costs.

Tables 4-1 and 4-2 present the generation cost estimates for renewable energy, coal, and natural gas-fired generation technologies both future and current technologies, respectively. The renewable energy technology costs in Tables 4-1 and 4-2 are from the 1997 Technology Characterizations report (Ref.4). The fossil energy costs are from the 1993 EPRI "TAG" (Technical Assessment Guide, Ref.23) as summarized in the EPRI report on "Strategic Analysis of Biomass and Waste Fuels" (Ref.72). To obtain goal numbers for the comparison to the renewables, the fossil energy systems were assigned capital and operating costs consistent with the past EPRI reports (Refs.23,24) but with projected reduced future capital costs. The future fuel gas is high: $4.00/MBtu. Coal stays low because that is the current trend and the need to compete with natural gas is expected to keep driving coal toward lower costs. Some increase in tramsportation cost and/or fuel preparation costs could make coal be $1.25 instead of $1.00/MBtu. Gas is high because the expected great expansion of use for electric power is assumed here to drive up gas prices. As shown later in this section and in Section 9, the fossil energy costs used here are consistent with the EIA projections (Refs.5,11) and with the EPRI Roadmap (Refs.5,11), except for natural gas at $4.00/MBtu rather than $3.00 or $3.25. Sensitivity to this is discussed below. The renewable energy "goal" cost estimates in Table 4-1 are based on the year 2030 forecasts in the Technology Characterizations report, and the "current" cost estimates in Table 4-2 are based on the year 1997 estimates.

Capital Recovery Factor

The generation cost for all technologies is sensitive to the annual capital or "fixed charge" factor, especially for those technologies that are capital intensive and have low or zero fuel costs, e.g. the renewable energy technologies. The capital recovery factor is a complex function of the debt-equity ratio, interest rate, desired return on equity, book life, tax depreciation schedule, and other project financing parameters.

Residential application of solar photovoltaic (PV) power systems should be considered as a special case, because the envisioned system owners are homeowners who are not likely to be subject to the economic requirements of rapid return on investment as are the owners of larger-scale power generation systems. In particular, a homeowner could borrow the capital cost as part of a home mortgage, resulting in an annual capital recovery equivalent to 10% instead of 21%. However, residential solar is set at the 21% rate here to be consistent with the rest. A major change that makes residential solar PV much lower in “extra cost to be renewable” is the assignment of the alternative price at a 10¢/kWh retail price, rather than a 4.2¢/kWh wholesale generation price. Readers and other analysts can assign residential solar PV any of a number of combinations of capital recovery rates and alternative retail prices.

However, residential solar is set at the 21% rate here to be consistent with the rest. A major change that makes residential solar PV much lower in “extra cost to be renewable” is the assignment of the alternative price at a 10¢/kWh retail price, rather than a 4.2¢/kWh wholesale generation price. Readers and other analysts can assign residential solar PV any of a number of combinations of capital recovery rates and alternative retail prices.

Costs of Fossil Energy

Two fossil energy technologies are used in this report as the fossil alternatives against which the renewables are to be compared:

1. advanced coal-fired boilers (pulverized coal with scrubber)

2. advanced natural gas combined cycle.

The values used for future costs and future heat rates (efficiencies) of these fossil technologies play an important role in this report's calculations of the cost to reduce fossil carbon emissions via displacement of fossil energy technologies or fuels by renewable technologies or fuels.

The fossil costs used in this report are compared here with those used in the EIA Kyoto Report (Ref.15):

	This Report (Table 4-1)	**EIA Kyoto (Ref.15)**
Advanced Pulverized Coal		
Capital Cost	$800/kW	$1,079/kW
Heat Rate	9480 Btu/kWh	9087 Btu/kWh
Natural Gas Combined Cycle		
Capital Cost	$500/kW	$400/kW
Heat Rate	6400 Btu/kWh	6350 Btu/kWh

Fuel costs used here, as given in Table 4-1, are $1.25/MBtu for coal and $4.00/MBtu for natural gas. Justification and sensitivity are discussed at the end of this section (p. 4-8) and at the end of Section 7 (p. 7-15).

Table 4-1
"Goal" Generation Cost Estimates (Ref. 4)

	Fixed Capital Charge				Fuel			O&M	Total	Alt. Cost	Extra Cost
Description: Energy Source, Technology, and Other	**Capital Cost $/kW**	**Annual Capital Recovery**	**Capacity Factor**	**Result $/kWh**	**Fuel Cost $/Mbtu**	**Heat Rate Btu/kWh**	**Results $/kWh**	**O&M (non-fuel) $/kWh**	**Total Cost $/kWh**	**Low-cost Alternat $/kWh**	**Extra Cost of Renew. $/kWh**
Natural Gas, $4/MBtu, CC, 400 MW	500	0.2081	0.85	0.0140	4.00	6,400	0.0256	0.0024	0.042	0.042	0.000
Coal, advanced, 400 MW	800	0.2081	0.85	0.0224	1.25	9,480	0.0119	0.0080	0.042	0.042	0.000
Landfill Gas, 2 MW	1,100	0.2081	0.85	0.0307	0.50	13,000	0.0065	0.0100	0.047	0.042	0.005
Animal Wastes, 500 kW	1,500	0.2081	0.85	0.0419	0.00	16,000	0.0000	0.0200	0.062	0.042	0.020
Biomass, IGCC, 100 MW	1,066	0.2081	0.85	0.0298	1.50	7,580	0.0114	0.0102	0.051	0.042	0.009
Biomass Cofiring, blended	50	0.33	0.80	0.0024	0.25	11,000	0.0028	0.0027	0.008	0.000	0.008
Biomass Cofiring, separate	200	0.33	0.80	0.0094	0.25	11,000	0.0028	0.0027	0.015	0.000	0.015
Geothermal, flash	1,036	0.2081	0.85	0.0290	0.00	no fuel	0.0000	0.0074	0.036	0.042	-0.006
Geothermal, binary	1,512	0.2081	0.85	0.0423	0.00	no fuel	0.0000	0.0068	0.049	0.042	0.007
Wind, Class 5+	635	0.2081	0.45	0.0335	0.00	no fuel	0.0000	0.0066	0.040	0.042	-0.002
Wind, Class 4	635	0.2081	0.35	0.0431	0.00	no fuel	0.0000	0.0085	0.052	0.042	0.010
Wind, Class 3	635	0.2081	0.25	0.0603	0.00	no fuel	0.0000	0.0119	0.072	0.042	0.030
Solar PV, residential, good	1,190	0.2081	0.26	0.1087	0.00	no fuel	0.0000	0.0052	0.114	0.100	0.014
Solar PV, residential, average	1,240	0.2081	0.21	0.1403	0.00	no fuel	0.0000	0.0064	0.147	0.100	0.047
Solar PV, central, good	870	0.2081	0.26	0.0795	0.00	no fuel	0.0000	0.0012	0.081	0.042	0.039
Solar PV, central, average	890	0.2081	0.21	0.1007	0.00	no fuel	0.0000	0.0015	0.102	0.042	0.060
Solar Thermal, 25 MW	934	0.2081	0.28	0.0792	0.00	no fuel	0.0000	0.0102	0.089	0.042	0.047

Table 4-2
"Current" Generation Cost Estimates for Renewable, Coal, and Natural Gas Technologies (Ref. 4)

	Fixed Capital Charge				Fuel			O&M	Total	Alt. Cost	Extra Cost
Description: Energy Source, Technology, and Other	Capital Cost $/kW	Annual Capital Recovery	Capacity Factor	Result $/kWh	Fuel Cost $/MBtu	Heat Rate Btu/kWh	Results $/kWh	O&M (non-fuel) $/kWh	Total Cost $/kWh	Low-cost Alternate $/kWh	Extra Cost of Renew $/kWh
Biomass Cofiring (2-year payback)											
Biomass Cofiring, 10% * 100 MW	300	0.50	0.80	0.0214	0.25	10,480	0.0026	0.0041	0.028	0.000	0.028
Biomass Cofiring, 10% * 100 MW	200	0.50	0.80	0.0143	0.25	10,480	0.0026	0.0034	0.020	0.000	0.020
Biomass Cofiring, 10% * 100 MW	100	0.50	0.80	0.0071	0.25	10,480	0.0026	0.0027	0.012	0.000	0.012
Biomass Cofiring, 10% * 100 MW	50	0.50	0.80	0.0036	0.25	10,480	0.0026	0.0024	0.009	0.000	0.009
Coal base for biomass cofiring	0	0.20	0.80	0.0000	0.00	9,480	0.0000	0.0000	0.000	0.000	0.000
Natural Gas, $2/MBtu, CC, 744 MW	663	0.2081	0.85	0.0185	2.00	7,780	0.0156	0.0024	0.036	0.036	0.000
Coal, advanced PC, 744 MW	1,516	0.2081	0.85	0.0424	1.25	9,480	0.0119	0.0052	0.059	0.036	0.023
Landfill Gas, 2 MW	1,100	0.2081	0.85	0.0307	0.50	14,000	0.0070	0.0100	0.048	0.036	0.012
Biomass, existing 25 MW	500	0.2081	0.85	0.0140	1.50	16,000	0.0240	0.0141	0.052	0.036	0.016
Biomass, IGCC, 100 MW	1,987	0.2081	0.85	0.0555	2.10	9,474	0.0199	0.0141	0.090	0.036	0.054
Biomass Cofiring, 10 MW	100	0.50	0.80	0.0071	0.25	10,480	0.0026	0.0027	0.012	0.000	0.012
Wind, 18 mph, 100 MW	864	0.2081	0.34	0.0604	0.00	no fuel	0.0000	0.0072	0.068	0.036	0.032
Solar PV, central, 75 MW	4,334	0.2081	0.24	0.4290	0.00	no fuel	0.0000	0.0054	0.434	0.36	0.398

High Capital Recovery Required for Biomass Cofiring

One case where the annual capital recovery factor was set at a different value from the others is that of biomass cofiring. For the biomass cofiring cases, Table 4-1 used 33%, not the 21% used for all the others. The reason is because biomass cofiring requires a capital expenditure to modify an existing plant and must compete for funding against other such expenditures on an existing plant that typically require a 3-year, or even a 2-year, payback. Table 4-2, “today’s costs” uses a 2-year pay-back, i.e., 50% capital recovery, for the biomass cofiring cases displayed there. This is done as a sensitivity case, to display how that changes the numbers, and because the current cost barriers for commercial cofiring applications are expected to be greater than future ones. In the future the drivers toward reduced greenhouse gas emissions may be stronger.

Low Cost Niches

One way in which renewables can get a start despite their generally higher costs is via low-cost niche opportunities. These situations include: (1) the use of existing equip-ment—paid for already by some other source; (2) the ability to benefit from an associated high-value coproduct or related service; and (3) selling into a market where high value and high price exist, e.g., solar photovoltaic modules used in remote communication relay stations.

One example of a high value coproduct or service is the use of zero cost or negative cost fuel in biomass power projects. Some biomass wastes in urban areas are collected by wood processors in exchange for tipping fees paid by the waste generators or haulers, in much the same way that municipal solid wastes are collected by landfills. If a power plant is sited adjacent to an urban wood processor or incorporates an urban wood processor into its operation, it can obtain biomass fuel at or below zero cost. Table 4-3 shows the results of analysis performed for NREL by Appel Consultants, using data collected in the metropolitan areas of Sacramento, Denver, Boston, and Richmond (Virginia) as examples (Refs. 24, 25). This analysis for NREL involved a survey of urban wood waste supplies and costs in 30 metropolitan areas of the United States. As indicated by the bottom row of numbers in Table 4-3, the results show that such a niche opportunity can cut the cost of electricity in a biomass project by as much as 2¢/kWh.

Table 4-3
Net Revenues from Processing Urban Wood Wastes

	Sacramento	Denver	Boston	Richmond
Urban wood waste (tons/year)				
Total estimated resource	445,000	579,000	643,000	718,000
Delivered to processors	321,000	120,000	350,000	204,000
Tipping fees ($/ton)				
Landfills	28-68	18-22	50-85	21-50
Wood processors	5-25	12-13	10-45	15-42
Cost of processing wood ($/ton)	5-15	5-15	5-15	5-15
Probable average “spread” ($/ton)	5	2.5	18	18
Wood average HHV (MBtu/ton)	11	11	11	11
Net revenue from wood ($/MBtu)	0.45	0.23	1.6	1.6
Value at 13,000 Btu/kWh (¢/kWh)	0.6	0.3	2.1	2.1

Because comparison will be made later, in Section 9, to an economic assessment by EIA in 1998, an assessment that derived the costs to the U.S. economy of achieving various levels of greenhouse gas reduction, some cost and performance values used by EIA in that 1998 assessment are shown here as Table 4-4 (Ref.15). Biomass O&M costs are higher than coal, gas and solar thermal in the EIA’s Table 16, “Cost and Performance Characteristics.” For a 100 MWe biomass power plant, fixed O&M is given in Table 4-4 $43/kW-year on a capital

Table 4-4
EIA Estimates of Cost and Performance Characteristics (Ref.14)*

Technology	Size (MW)	Capital ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Fixed O&M (%/yr)
Pulverized Coal	400	1079	3.25	22.5	9,087	2.1%
Advanced Coal (IGCC)	380	1206	1.87	24.2	7,308	2.0%
Advanced Natural Gas (CC)	400	400	2.0	13.8	6,350	3.4%
Fuel Cell (Natural Gas)	10	1440	2.0	14.4	5,361	1.0%
Nuclear	1300	1550	0.4	55.0	10,400	3.5%
Biomass (IGCC)	100	1476	5.2	43.0	8,224	2.9%
Geothermal	50	2025	0.0	95.7	32,391	4.7%
Solar Thermal	100	1920	0.0	46.0	no fuel	2.4%
Solar PV	5	3185	0.0	9.7	no fuel	0.3%
Wind	50	965	0.0	25.6	no fuel	3.0%

*Study by EIA in 1998. Dollars are 1996 or 1997. EIA did not show a %/yr value for the O&M, but EPRI calculated it for this report.

investment of $1,476/kW, which is 2.9%/year. This biomass O&M compares to a 2% value that can be calculated for the coal cases, both pulverized coal boiler and IGCC (integrated gasification combined cycle). This biomass case was also an IGCC in the EIA analysis, but was a smaller unit size than the coal IGCC: 100 MW biomass vs. 380 MW coal. For coal the fixed O&M was given as $24/kW-year, about 2%/year of a $1,206/kW capital cost. The differences in fixed O&M as a fraction of capital costs are due to differences among the technologies as to unit size, likely maintenance requirements, and size of the permanent staff assigned to the power plant. In Table 4-4, the high and low values of fixed O&M as a percent of capital cost can be explained in terms of such differences.

Range of Values

The tables give single values for the many cost estimates for renewable technologies and their fossil alternatives. Of course, there are actually ranges of values that should be given, reflecting uncertainties, differences in circumstances, failure or success in research, etc. The most critical technical parameters are fuel cost, capital cost and capacity factor. Economic parameters, especially the annual capital recovery factor—or "fixed charge rate," which is where the discount rate, cost of money, financing charges, return on equity, etc. are reflected—also can have major effects on the cost of electricity. However, for purposes of this analysis, this key economic parameter is set at the same value for all technologies. This single, fixed value was chosen in order to (1) focus only on those technical parameters where research and development can have an impact, and (2) treat all of the technologies in the same way as far as economic parameters are concerned. [One exception, discussed above, is biomass cofiring, where more rapid recovery of capital costs is required due to competition with other possible capital investments to improve/modify existing power plants. There, 33% (the “goal” value in Table 4-1) is used for cofiring instead of the 21% used for all others. Table 4-2 shows the higher costs that result when 50% not 33%, is taken as the capitol recovery rate required.]

Justification for 21% Capital Recovery Rate

EPRI’s choice in this study is to focus on technical parameters subject to improvement via research and development. Keeping economics simple and unchanged among options helps keep that focus. The 21% value, actually 20.81%, was chosen because it matches a more correct but less-simple cash flow and levelized cost analysis done in EPRI’s BIOPOWER calculations (Refs.23,26). Choosing this 219 value for annual capitol recovery gives a cost of electricity (¢/kWh or $/MWh) comparable to that obtained using levelized cost cash flow calculations in “current,” as opposed to “constant” dollars. A choice of a lower capital recovery factor (or “fixed charge rate”) of about 12% would give costs of electricity closer to levelized calculations in constant (i.e., no inflation) dollars.

Justification for $4.00/Mbtu Natural Gas Price

The natural gas price in the future--2010 or later, such as in the 2020 to 2030 timeframe--was set here at $4.00/MBtu to represent a situation where some additional 150 GWe, or even 300GWe, of natural gas generating capacity has been installed, and the resulting increased demand has pushed the price up from a $2.00-2.50/MBtu today (year 2000) to the equivalent of $4.00/MBtu, as measured in today's dollars. If the future price is lower, such as the $3.25/MBtu given in a recent EIA report (Ref.70) as the reference case scenario for 2020, the result is a fuel cost at a 6400 Btu/kWh heat rate of only $20.80/MWh versus the $25.40 adopted here in Table 4-1. The effect on cost of greenhouse gas reduction would be approximately a $5/MWh increase in all the renewable energy sources as the extra cost above that of the fossil alternative. At the fossil fuel emission rates given in the next section and later in this report--0.236 tonne-C/MWh for advanced pulverized coal and 0.09 tonne-C/MWh for advanced natural gas combined cycle-- the extra $5/MWh converts to an extra carbon reduction cost of $21/tonne-C versus coal and $56/tonne-C versus natural gas CC.

5
COST OF GREENHOUSE GAS MITIGATION

The cost of greenhouse gas mitigation using renewable energy technologies depends on both the difference between the generation costs of the renewable energy option (e.g. wind or biomass generation) and the low-cost alternative (e.g. coal or natural gas generation) and the carbon emissions that are displaced by the renewable energy generation. The mitigation costs are usually expressed in units of the cost per unit fossil carbon emissions that are avoided, offset, captured, sequestered, etc.

Section 4 presented the costs of renewable energy and derived the extra costs for renewables above fossil by taking diffferences: renewables less the fossil alternative. In this section, the extra costs of the renewable power generation technologies are converted into terms of cost per unit fossil carbon emission avoided.

It is known that several "greenhouse gases" contribute to humanity's effect on the radiation balance in the atmosphere and, hence, on potential global temperature and climate effects. They include carbon dioxide (CO2), methane (CH4), nitrous oxide (NO2), and certain chloro-fluorocarbons (CFCs). (The CFCs have become most widely known for their chemical effects in the stratosphere, reacting with and depleting the ozone layer. They also absorb infrared radiation and affect global heat balance. The infrared absorption occurs much lower than the stratosphere, down in the main mass of the atmosphere, i.e., the troposphere. The infrared effect is different from, and independent of, the ozone depletion. The ozone depletion issue has to do with an effect on ultraviolet, not infrared, radiation.)

The relevant impacts of the greenhouse gases on the radiation balance vary between the greenhouse gases. Table 5-1 presents numbers that show this (Ref.9).

Table 5-1
Greenhouse Warming Strengths of the Key Gases

Gas	Lifetime in the Atmosphere	Infrared absorbing strength relative to CO2		
		20-year	100-year	500-year
Carbon dioxide (CO2)	variable	1	1	1
Methane (CH4)	12 years (+-3)	56	21	7
Nitrous oxide (N2O)	120 years	280	310	170
Chlorofluorocarbons (CFC)	not given	4900	3800	not given

Source: U.S. Dept. of Energy EIA, "Emissions of Greenhouse Gases in the US: 1996" Oct.1997 (Ref.10).

In Table 5-1, different timeframes, as well as the four different gases, are shown because the non-CO2 gases gradually are converted into CO2 over the years and will eventually be at the same strength as CO2, but not until well beyond the timeframes of interest here. In order to assess emission controls applied to different gases on a common basis for global warming purposes, the emissions of the different greenhouse gases are normalized to a common basis by expressing them as equivalent CO_2 emissions. On a mass basis, and for a 100-year timeframe, methane (CH_4) absorbs 21 times as much of the earth's outgoing infrared radiation as carbon dioxide (CO_2). Therefore, we say that the mass of the equivalent CO2 emission is 21x the mass of the methane put into the landfill gas energy system. In this section of the report the costs of greenhouse gas reduction will be expressed and compared on the basis of dollars per metric ton (tonne) of elemental carbon ($/tonne C), based on the absorbing strength when that carbon atom is in a CO2 molecule--the "CO2 equivalent." When methane is the fuel, the carbon atom is in a CH4 molecule. Hence, the factor per unit of energy will be less than the 21x. Here we use a factor of only 7.64, which is 21 x (16/44). The 16/44 is because each molecule of methane has a mass of 16, molecular weight, and goes into one atom of carbon in a carbon dioxide molecule of weight 44.

In addition to depending on the type of gas whose emission is reduced or avoided, the analysis leading to cost per unit weight of fossil CO_2 emissions avoided must take into account the type of fuel, technology and emitted gas that would otherwise have been used to generate the electricity replaced low by the renewable technology. The amount of fossil carbon emission avoided by using a renewable resource instead of a fossil fuel power generation technology depends on the fossil fuel type that is "avoided" and on the conversion technology that would have been used to make the power from that fossil fuel. Table 5-2 shows the fuel effect, based on the carbon intensity of the various fuels, as measured in units of weight of carbon per unit of energy content of the fuel.

Table 5-2
Fuel Effect on Fossil Carbon Intensity

Name	Heat Content - HHV		Carbon Content		Fossil Carbon Intensity	
of Fuel	(Btu/lb)	(MJ/kg)	(lb-C/lb)	(kg-C/kg)	(lb-C/MBtu)	(kg-C/GJ)
Coal	13,700	31.798	0.78	0.78	56.9	24.5
Oil	18,000	41.778	0.85	0.85	47.2	20.3
Natural gas	23,800	55.240	0.76	0.76	31.9	13.8
Wood (dry)	8,000	18.568	0.45	0.45	Zero*	Zero*

*Note: "Fossil" carbon intensity is the measure relevant to greenhouse gas, and by this measure wood from renewable growth of trees is zero in carbon intensity. If the carbon in the fuel is put straight into the same formula used for the fossil fuels, then the carbon intensity for the wood is 54.2 lb-C/MBtu or 23.4 kg-C/GJ.

Next, Table 5-3 shows the effect of conversion technology, and, therefore, combines the effects of carbon intensity in the fuel with the efficiency of converting the fuel to electricity. Table 5-3 gives the emissions of carbon dioxide (or carbon) from present and future fossil fuel technologies, both coal-based and natural-gas-based. (Ref.9). Efficient pulverized coal units emit about 0.95 tons CO_2 per MWh of electricity generation, which is 0.26 tons C per MWh. Advanced IGCC technology will reduce these CO2 emissions factors by about 20%. Advanced natural gas-combined cycle plants with efficiencies as high as 54% will emit about 0.37 tons CO_2 (0.10 tons C) per MWh. Therefore, to convert the extra cost of the renewable electricity, given in $/MWh, into units of $/tonne-C for the greenhouse gas reduction achieved, the $/MWh is simply divided by the tonne-C/MWh of the fuel-technology combination that is considered to be the fossil technology replaced by the renewable one.

Table 5-3
Technology Effect on Fossil Carbon Intensity

English units:	Carbon	Heat	Fossil Carbon Emission	
Fuel -	Content	Rate	CO2	C
Technology (HHV eff.)	(lb/MBtu)	(Btu/kWh)	(ton/MWh)	(ton/MWh)
Coal -				
Typical existing (0.341)	56.9	10,000	1.04	0.28
Pulverized, 95% scrubbed (0.376)	56.9	9,087	0.95	0.26
Advanced, IGCC (0.467)	56.9	7,308	0.76	0.21
Natural gas -				
Existing steam plant (0.331)	31.9	10,300	0.60	0.16
Advanced, CC (0.538)	31.9	6,350	0.37	0.10
Advanced, CT (0.427)	31.9	8,000	0.47	0.13
Advanced, fuel cell (0.637)	31.9	5,361	0.31	0.09
SI units:	Carbon	Heat Rate	CO2	C
	(kg/GJ)	(kJ/kWh)	(tonne/MWh)	(tonne/MWh)
Coal -				
Typical existing (0.341)	24.52	10,550	0.95	0.26
Pulverized, 95% scrubbed (0.376)	24.52	9,587	0.86	0.24
Advanced, IGCC (0.467)	24.52	7,710	0.69	0.19
Natural gas -				
Existing steam plant (0.331)	13.74	10,867	0.55	0.15
Advanced, CC (0.538)	13.74	6,699	0.34	0.09
Advanced, CT (0.427)	13.74	8,440	0.43	0.12
Advanced, fuel cell (0.637)	13.74	5,656	0.29	0.08

Source: Ref.15 (“EIA Kyoto”), Tables 16, 17 (pages 73-75), U.S. DOE, October 1998.

Results

The results of applying this procedure are shown in Table 5-4. Examples of how Table 5-4 was calculated for several cases follow, with special emphasis on two cases that are somewhat different from the rest: biomass cofiring, and landfill gas. In biomass cofiring the fossil alternative is not a new fossil power plant, but, instead, is simply the operation of the existing coal-fired plant on 100% coal, with no biomass displacing any of the coal. In landfill gas, which here refers to landfill gas power generation, the burning of the biomass-derived methane gas avoids the emission by the landfill of a greenhouse gas 21 times as powerful, per unit weight, as the carbon dioxide in infrared absorbing and warming strength. Taking this greenhouse strength into account makes the cost of avoiding the CO2 equivalent much lower, by the 7.64 factor derived above.

Table 5-4
Conversions of Power Costs into CO2 Reduction Costs

		Carbon Intensity Displaced		Cost of CO2 Reduction	
	Extra Cost	Coal	Natural Gas	Coal	Natural Gas
Renewable Technology	($/MWh)	(tonne-C/MWh)	(tonne-C/MWh)	($/tonne-C)	($/tonne-C)
Biomass cofiring (low cost end of range)	$ (5.00)*	0.264	not applicable	$ (18.97)*	not applicable
Biomass cofiring (high cost end of range)	$18.00	0.264	not applicable	$68.28	not applicable
Biomass gasification or other advanced biomass	$10.00	0.264	0.090	$37.93	$111.11
Wind	$10.00	0.264	0.090	$37.93	$111.11
Geothermal	$7.00	0.264	0.090	$26.55	$77.78
Solar Thermal	$47.00	0.264	0.090	$178.28	$522.22
Solar PV	$14.00	0.264	0.090	$53.10	$155.56
Landfill gas***	$5.00	2.013	0.687	$2.48	$7.28

***The landfill gas conversion factors are based on the 21x stronger greenhouse warming effect of CH4 vs. CO2, and also the factor of 16/44 to convert from a weight basis to a mole basis.

Biomass Cofiring

Biomass cofiring replaces some burning of coal in an existing coal-fired power plant. The range in cost, as measured by the extra cost to generate a unit of electricity from the cofired biomass fuel instead of the coal that would otherwise be burned, is from a negative (i.e., a cost savings value) -$5/MWh to $18/MWh. Hence, the cost of fossil carbon reduction via biomass cofiring ranges from -$18.97 to +$68.28/tonne-C. (At the high end of the range, $18/MWh, the calculation includes converting short tons to metric tons, via a factor of 1.1, and goes as follows: $18/MWh ÷ 0.285 ton-C/MWh x 1.1 ton/tonne = 18/0.259 = $68.28/tonne-C.)

Wind

Wind is an example of how the calculations of Table 5-4 are done for any of the renewables, where the key decision that determines the result in $/tonne-C avoided depends on the fossil fuel and conversion technology that is displaced by the renewable one. The extra cost of generating from the current wind resources, Class 4 and a 35% capacity factor, is 5.2¢ per kWh versus the 4.2¢/kWh of the coal or gas alternative (assuming the alternative is a new coal or gas plant, based on the future pulverized coal or future advanced combined cycle natural gas. This extra 1.0¢/kWh, which is an extra $10/MWh, then converts, as follows:

Wind Replacing New Coal. The new coal would have emitted 0.264/1.1 = 0.090 metric tons of carbon per MWh so the extra $10/MWh is 10/0.236 = $37.93/tonne C.

Wind Replacing Natural Gas Combined Cycle. Wind at the 1.0¢/kWh extra cost over new combined cycle natural gas of the advanced technology case in Table 5-1 is avoiding only 0.10 short tons of fossil carbon for each MWh generated, making this case equivalent to avoiding fossil carbon emission at a cost of $111.00/tonne C (i.e., 10 x 1.1/0.10 = 66).

Biomass Gasification (or Other Advanced Biomass)

The research goal for biomass power technology is usually an advanced system using gasification analogous to the advanced coal technology: integrated gasification combined cycle (IGCC). Adopting this for future large-scale use of biomass for power generation, the extra cost to generate from advanced biomass is $15/MWh versus both advanced pulverized coal and advanced natural gas combined cycle.

Advanced biomass could turn out to be an advanced combustion steam cycle, such as Whole Tree Energy™ or some improved fluidized bed or slagging combustion concept. One of these combustion technologies may emerge as lower cost than the IGCC approach. Therefore, the gasification case used here can be viewed, more generally, as simply the "advanced biomass" case. In any event, what is intended here for this analysis of greenhouse gas mitigation is an advanced technology with "goal" characteristics of cost that uses 100% biomass as fuel, i.e., not cofired.

Biomass Replacing Coal. The extra $10/MWh versus advanced pulverized coal converts to a carbon mitigation cost of 10(1.1/0.26) = $37.93/tonne C. If the coal replaced is a coal IGCC plant, which is more efficient than the pulverized coal (7308 Btu/kWh versus 9087 Btu/kWh) then the MWh is equivalent to only 0.22 short tons of fossil carbon and the effective cost of carbon mitigation is $50/tonne C.

Biomass Replacing Natural Gas. Because advanced natural gas combined cycle makes only 0.10 short ton of C per MWh, versus the 0.26 or 0.22 for coal, when biomass at an extra $10/MWh replaces the advanced CC fired by natural gas, the equivalent cost to reduce a metric ton of C is 10(1.1/0.10 = $111.11/tonne C.

Others

The other renewable technologies are handled in the same way as wind. The values that result were displayed above in Table 5-4. Landfill gas has the methane strength factor applied, and is therefore described specifically here under the next subheading.

Landfill Gas

A special low-cost case of biomass power, when considered in the context of greenhouse gas reduction, arises for landfill gas energy projects. These projects benefit in power generating costs by having a supply of fuel that is paid for in large measure by another enterprise, namely by the activity of proper operation of a landfill built and operated to dispose of municipal solid waste. Municipal solid waste is a renewable fuel, in that the part of the waste that decays, via anaerobic digestion of organic matter into gases, is the biomass fraction and, in the United States, comes from biomass material (especially wood and paper) that is produced in a renewable manner. See the discussion in Sections 2 and 4 above.

The extra advantage as to cost of greenhouse gas reduction comes from the factor of 7.64 derived from the greenhouse (i.e., infrared absorbing) strength of methane relative to carbon dioxide (i.e., the 21x16/44 factor derived above).

Landfill gas greenhouse "accounting" as to what credit is allowed and who gets the credit can vary since much landfill gas collection or flaring may be mandated for odor control or other conventional air emission control. However, federal rules under 1605(b), which addresses voluntary reporting and credit for avoiding or reducing greenhouse gas emissions, appear to allow for credit to be granted for nearly all gas collection used for energy, whether that gas collection is mandated or not. When landfill gas generates electricity, the credit for landfill gas greenhouse emission reduction normally accrues to the utility generating, or distributing, the electricity. In the DOE report on the voluntary reporting of greenhouse gas reduction actions taken in 1998 by U.S. companies (Ref. 26), the electric power sector reported methane waste treatment reductions (nearly all from landfill gas projects) equivalent to 9,869,851 metric tons (tonnes) of CO2, which was 96% of the methane credit reported in this sector. (Direct CO2 reductions were reported at 149,517,578 tonnes by this sector.) The sector called "alternative energy providers" reported 5,294,099 tonnes equivalent CO2 reductions due to methane in "landfill gas recovery for energy." This was out of a total of methane reductions (in CO2 equivalents) of 37,159,293 tonnes, of which the largest single element was 17,175,016 for coal bed methane emission avoidance. The next largest single item on the list for this "alternative energy" sector was 11,700,880 for "source reduction at landfills, which is a separate line item and not part of the landfill gas recovery for energy. The 5+ million tonnes CO2 equivalent for landfill gas energy was the third largest line item on methane by the alternative energy sector. (The source cited in Ref.26 is "Energy Information Admin-istration, Forms EIA-1605 and EIA-1605EZ.")

Of special interest for this discussion of greenhouse gas equivalents, and the cost in $/tonne-C of CO2 equivalent reductions, is the credit claimed for CO2 vs. the tonnes of methane avoided. The allowance for 252,100 tonnes of methane was 5,294,099 tonnes of CO2, which is a factor of

21. This was for the “landfill gas energy” part of the “alternative energy providers” sector. As explained above, to do the analysis here for costs per unit of electricity generated, the factor of 21 was cut to only 7.64 due to the desire to base the cost per kWh number on the carbon atoms and their CO2-aborbing equivalents rather than the weight equivalents in tonnes.

Summary on Converting the Extra Cost of Renewables to a Cost per Unit Mass of Fossil Carbon Avoided

This section has developed cost estimates for fossil carbon emission reductions in units of $ per tonne (i.e., metric ton) of fossil carbon avoided. This has been done by converting the extra cost of renewables--a cost expressed in $/MWh--into the equivalent cost per metric ton of fossil carbon emission avoided. When the avoided emission is methane rather than carbon dioxide, the cost is expressed in terms of the greenhouse gas warming potential based on equivalent carbon dioxide CO_2. This gives landfill gas power systems, which convert a CH_4 (methane) emission into a recycled CO_2 emission, an advantage of 21 tonnes CO_2 equivalent, based on the relative strength of the greenhouse effect of the two gases, per unit of mass. The conversion factors are presented below, in summary form and for the more advanced fossil technologies, i.e., higher than today's efficiencies on the typical existing coal plant and the natural gas steam, using instead the "pulverized coal 95% scrubbed" and the "advanced CC" for the natural gas combined cycle in Table 5-3 above and in the EIA "Kyoto report" (Ref.15):

1. If coal is displaced by a renewable, the conversion is:

   Coal: 1 MWh emits approximately 1 tonne of CO_2 which converts to 12/44 tonne of C. Therefore, displacing coal, $0.01/kWh = $10/MWh, and converts to $42/tonne-C (or, 1 cent/kWh extra cost of electricity is approximately $42/tonne-C). This is based on an efficient coal-fired steam cycle where 1 MWh results in 0.236 tonne-C (Table 5-3).

2. If natural gas in a combined cycle is displaced by a renewable, then:

   Natural gas in combined cycle: The cycle is more efficient and the fuel has less carbon per unit of heat content (Tables 5-2 and 5-3). The result is only 37% as much fossil carbon emitted (0.0909 tonne-C/MWh) compared to the coal case. Therefore, if renew-ables displace this efficient use of natural gas, the cost is

   $0.01/kWh converts into a cost of $42/0.37 = $110/tonne-C.

3. If landfill gas is used to generate a MWh of electricity, instead of the methane (CH_4) being emitted to the atmosphere, then the conversion of extra cost in $/MWh into $/tonne-C goes as follows (based on Tables 5-1, -2 and –3):

   Landfill gas: 1 tonne CH_4 is worth 21 tonnes of CO_2 emission avoided (Table 5-1). However, in combustion it is one molecule of CH_4 (weight 16) whose emission is avoided compared to the molecule of CO_2 (weight 44) that would otherwise be emitted by the coal or gas fired in some other power plant. Therefore, the coal displacement case becomes

\$0.01/kWh = \$10/MWh ➔ \$42/tonne-C x 1/21 x 44/16 = \$5.55/tonne-C.

And, the natural gas combined cycle displacement case becomes

\$0.01/kWh = \$10/MWh ➔ \$110/tonne-C x 1/21 x 44/16 = \$14.41/tonne-C.

Conclusion: Costs of Greenhouse Gas Mitigation

Here in this section the extra costs of renewable power have here been converted from the \$/MWh values in the previous section into costs per metric ton of fossil carbon emission avoided or reduced. The special case of methane emission avoidance via use of landfill gas for power generation has been addressed. Landfill gas energy production prevents the escape of methane from landfills. The use of methane in landfill gas energy systems is an application of the bio-logical process of "anaerobic digestion" and is, therefore, similar to energy systems that use animal wastes from dairy operations, cattle feed lots, etc. Hence, landfill gas is used here as a way to estimate the costs of the "animal wastes" item in Section 7, below.

6
BIOMASS COFIRING SUPPLY CURVE

An early-entry point for biomass in utility-scale power generation, as practiced by utilities and large-scale power companies, in contrast to wood-products companies and small independent power generators, could be the use of biomass-derived fuels along with coal in utility coal-fired boilers. Biomass includes a variety of wood and agricultural wastes such as sawdust, utility poles, pallets, tree trimmings, nutshells, or bark. These have a broad range of moisture contents (and, hence, heating values), size characteristics, bulk densities and ash chemical compositions.

A "supply curve" is developed in this section. By definition, a supply curve shows the amount of a pro-duct that can be supplied as a function of the price or cost of the next unit to be supplied. In this case the supply is the amount of renewable electricity generated from the biomass fuel that is being cofired along with coal in utility power boilers in the U.S. The unit of cost in this case is the extra cost in $/MWh to generate the electricity from the biomass instead of the coal. (If the biomass fuel costs enough less than the coal, this extra cost can be a negative number.) In a supply curve the supply-versus-cost relationship is displayed in a sequence from the lowest cost to the highest cost. In general, a supply curve then quantifies a relationship that shows how, as more supply is to be produced, more expensive sources and processes must be used. This is because the low cost source/process options will be used first. It costs more per unit to make the 100^{th} unit than it did to make the 10^{th} unit, for example.

The supply curve developed in this section of the report is for biomass cofiring technology and shows that as the cumulative amount of electricity generated from biomass increases the cost per unit also increases as increasingly expensive cofiring systems and/or higher-cost biomass fuels are brought into production. The supply curve can be displayed as supply of electricity vs. extra cost of that electricity, or as amount of fossil carbon dioxide emission avoided vs. the cost per tonne being paid to avoid that emission. The previous section (Section 5) presented the factors and the issues involved in converting electricity costs in $/MWh into fossil carbon reduction costs in $/tonne-C. The supply "curves" presented in this section for biomass cofiring, and in the next section for all the renewable technologies, are actually tables rather than graphical displays of curves. This has been done in order to display, all together and all at once, both electricity and carbon amounts and costs, as well as a number of the specific values that are used in doing each case of the various cost calculations.

One conclusion that can be drawn from the biomass cofiring "curve" that is developed below in this section is that the cofiring-with-coal method of making electricity from biomass is not likely to replace more than 3% of coal-based electricity in the U.S. (The total of all the market categories shown in the table below is 2.6%.) Nevertheless, the use of biomass in coal-fired power generation represents a true source of renewable energy. This use of biomass as a cofired fuel offers CO_2 mitigation as one potential benefit. Other potential benefits include fuel flexibility, lower fuel cost, improved local economies, and reduced emissions, along with advantages that will arise from early entry by coal-fired power companies into renewable power generation.

DOE/EPRI Biomass Cofiring Program

EPRI has tested cofiring of biomass in eleven coal-fired utility boilers. This has been done over the five-year period from 1994-1999 as part of a research program cofunded by the U.S. Dept. of Energy (DOE) and with the cooperation and cost-sharing of electric utility companies. Both the fossil energy and the renewable energy programs at DOE have been involved as cofunders of the program. (The DOE Office of Fossil Energy has cofunded through the National Energy Technology Laboratory, NETL, in Pittsburgh and Morgantown, and the Office of Energy Efficiency and Renewable Energy, EERE, has cofunded through the Biomass Power Program at headquarters in Washington D.C.)

The DOE/EPRI tests supplement the experience with biomass fuel in all major boiler types, including cyclones (crushed coal), wall- and corner-fired units (pulverized coal), fluidized beds, and a small industrial stoker (sized coal, crushed and without fines). A total of over 70 MW of biomass generating capacity has been tested in the DOE/EPRI program, cofired with coal at biomass input ranging from 1.5% to 10% of the total heat into the boilers. These cofiring tests have addressed many installation and operational issues for cofiring biomass. Preliminary results have shown that the cofiring of up to 7% biomass, on a heat-input basis, with crushed or pulverized coal can lower NOx emissions by as much as 15 percent depending on the firing configuration. These tests did not explore optimizing the firing configuration for biomass to maximize the NOx control potential for this renewable fuel. Some tests did not show any NOx reduction. Generally, the impact on boiler efficiency and load capacity is low and is primarily attributed to moisture in the biomass. (Refs.28,29,30,31,32,33,34,35,36)

Biomass power generation reduces the net greenhouse gas emissions of CO_2 from power plants. Because of this, DOE programs at NETL and in EERE have joined with EPRI and several EPRI-member utilities to test the feasibility of cofiring biomass and other renewable waste fuels with coal for power generation. The DOE/EPRI program has thus far included eleven full-sized tests of biomass cofiring, conducted in coal-fired boilers ranging in size from 15 to 500 MWe. (The 15 MW case was a stoker boiler, not utility-owned, and not one of the cases included in this supply curve.)

Fuel Supply

Biomass encompasses many types of wood byproducts and agricultural wastes. Wood byproducts include sawdust, bark, pallets, tree trimmings, cardboard, etc. Agricultural wastes include rice hulls and straw, walnut shells, etc., and, in the future, alfalfa and switchgrass. Wood wastes have long been used as supplemental fuels for industrial steam raising. More recently, however, utilities have investigated the use of these biomass fuels in order to reduce overall fuel costs, to generate some power from a renewable resource or as a potential way to reduce greenhouse emissions. When biomass is burned, the carbon emitted as CO_2 is recycled back into growing new trees or other crops at roughly the same rate (i.e., over tens of years, not millions of years), thus contributing a net zero loading to the existing CO_2 atmospheric inventory. Thus, the fossil fuel displaced by biomass represents a net reduction in the amount of new carbon being transferred to the atmosphere from geologic formations.

Benefits

The potential benefits of biomass cofiring do not end at CO_2 emission reductions, however. Biomass can sometimes be a low-cost opportunity fuel source, providing fuel cost savings to the plant and, at the same time, helping local industries that seek low-cost/low-risk disposal of wastes or new markets for their wastes and byproducts. The environmental benefits of burning biomass in a controlled environment can also provide the utility with a way to gain or retain customers who desire to purchase "green" power. Finally, cofiring biomass can reduce emissions of regulated ("criteria") pollutants, specifically SO_2 and NOx. The potential mandates for Renewable Portfolio Standards (RPS), recently proposed in state and federal legislation, provide additional motivation for power generators to supplement fossil fuels with "green" renewable biomass.

Supply Curve for First Round of Deployment

Cofiring tests have shown that biomass can be readily burned along with coal in a variety of coal-fired utility boilers. Tests have also shown limits. A key limit is on the fraction of biomass that can be fed through the pulverizer in a pulverized coal (PC) plant: less than 4% by mass, which is 2% by heat. Using such test results combined with design/cost studies, EPRI has developed estimates of the potential near-term role of biomass cofiring in different types and sizes of utility boilers. The estimates were prepared using a two-round deployment scenario. Tables 6-1 and 6-2 display "Round No. 1," a projected first wave of biomass cofiring deployment. (Later in this section, Tables 6-3 and 6-4 will display "Round 2," a second wave of additional or expanded deployment.)

The first two columns of Table 6-1 summarize the generating capacity in the United States for each of five categories of the major coal-fired boiler types that are candidates for biomass cofiring by electric utilities. The next four columns give (1) assumed average capacity factor, (2) resulting TWh/year of electricity generated, (3) assumed biomass cofiring level (% by heat) for that category, and (4) assumed fraction of market penetration. The last two columns show the calculated TWh/year of electricity from biomass, and the amount of biomass fuel required to generate that amount of electricity via cofiring. The results show that a total of 29.48 TWh/year (i.e., 29.48 billion kWh) of bioelectricity could be produced under this Round 1 scenario. This amount of electricity would require 18.87 million dry tons of biomass.

Table 6-1
Potential Cofiring Market: Electricity Generation and Biomass Use (Round 1 of Deployment)

Boiler Equipment	Available Gen. Capacity (GW)	Average Capacity Factor (%)	Available Annual Electricity Gen. (TWh)	Cofiring Level (% of heat from biomass)	Assumed Market Penetration (Fraction)	Bio-Electricity Gen. (TWh/yr)	Biomass Fuel Use (Mton/yr)
Large Cyclones	12	0.82	86	2.5	0.70	1.51	0.95
Other Cyclones	11	0.78	75	5.0	0.70	2.63	1.85
Large PCs	220	0.73	1405	2.0	0.40	11.38	7.20
Medium PCs	60	0.66	347	10.0	0.30	10.41	6.52
Small PCs	15	0.60	79	15.0	0.30	3.55	2.35
Total (or Avg.)	318	0.72	1992	3.5	0.47	29.48	18.87

Table 6-2 presents the costs and the amounts of CO_2 emission reductions (the "supply curve" or "CO_2 mitigation curve") for each of the coal boiler types addressed by Table 6-1.

Table 6-2
Estimated cost of biomass cofiring – Round 1

Boiler Equipment Category		Biomass Cost, $/MBtu	Biomass Use in Category, Mton/yr	Cum. Biomass Use, Mton/yr	Coal-based Generation displaced, Percent	CO2 Reduction, Mtonne/yr		Capital Cost, $/MWh	Total Cost	
						By Category	Cumulative		Incremental, $/MWh	Cumulative, $M/yr
A1	Large Cyclones	0.53	0.95	0.95	0.08	1.31	1.31	50	(2.3)	(3)
B1	Other Cyclones	0.53	1.85	2.80	0.13	2.55	3.86	50	(2.7)	(11)
C1	Large PCs	0.53	7.20	10.0	0.57	9.90	13.8	50	(1.6)	(29)
D1	Medium PCs	0.96	6.52	16.52	0.53	9.56	23.3	200	11.9	94
E1	Small PCs	0.96	2.35	18.87	0.17	3.42	26.7	230	15.6	150
	Total	-	18.87	-	1.48	26.7	-	-	-	-

The first round deployment of biomass cofiring would reduce the fossil CO_2 emitted by coal-fired electrical generating plants by 26.7 Mtonne/yr. The total cost of cofiring of this amount of biomass in the U.S. is calculated to be $150 million. Cumulative costs can be used for comparison with other CO_2 mitigating options available to the electric utility industry. Cost estimates were developed for the first three equipment categories (all of the cyclones, plus the large PCs). The values used were:

- a $1.25 (0.72 above 0.53)coal cost
- a $0.53/MBtu (Ref.37) biomass cost ($0.50/GJ)
- a capital cost of $50/kW (for each kW of biomass capacity) to modify the plant for biomass cofiring.

These three boiler equipment categories combine to yield 13.8 million tonnes (metric) of CO_2 reduction per year and consume 10 million dry tons (short tons) of biomass.

For these three categories the net cost is negative. This is because of the assumed $0.72/MBtu differential price advantage of biomass over coal. For the two remaining boiler categories (medium and small PCs), the biomass fuel cost was assumed to be $0.96/MBtu (Ref.37), and the capital cost was increased from $50/kW to $200/kW or $230/kW (medium or small). Coal cost was fixed at $1.25/MBtu, and capital costs were annualized at 33 percent per year. For these smaller size boilers, there is a net incremental cost such that the cumulative cost for all five boiler categories totals $150 million per year. The associated reduction of 26.7 million metric tonnes of CO_2 translates to an overall average cost of $5.60/tonne CO_2. The cumulative 29.48 TWh/year generated from biomass instead of coal amounts to 1.48% of the 1,992 TWh/year adopted as the amount (approx. year 1996) of coal-based electricity generation in the U.S.

More Assumptions and Discussion

Other key assumptions used in developing these cost estimates include:

- Conversion from added electricity cost in $/MWh to the cost per unit of fossil CO_2 avoided in $/ Mtonne is based on the amount and the properties of the coal being replaced by the biomass. EPRI assumed the following for all the cases: coal heat content 12,500 Btu/lb, as received; and, coal carbon 72.5% by weight of the as-received coal. For the coal heat rate of 10,000 Btu/kWh, which was assumed for the smaller cyclone and PC units, these assumptions results in 1 MWh of coal-fired electricity emits 1.103 short tons of fossil CO_2, almost exactly 1 tonne (metric) of CO_2. At better coal heat rates less CO_2 is produced per MWh: 0.95 tonne at 9500 and 0.90 at 9000. [Note: These are tonnes of CO_2 not C. Multiply 12/44 to get tonne C.
- Capital cost in $/kW is based on the biomass fraction of the generation, rather than on the total generating capacity of the unit on 100% coal. For example, a $200/kW cost for retrofit of a medium size 200 MW PC boiler during Round 1 deployment would translate to $20/kW for the assumed 10% cofiring level, or a total cost of $4M to modify the unit to cofire 10% biomass.

- Low capital cost estimates of $40/kW and $50/kW were based on the simple biomass feed systems that blend biomass with coal and feed the blended fuels through the crusher (for cyclones) or pulverizer (for PCs).
- Capital cost estimates of $175/kW, $200/kW and $230/kW were based on higher-cost retrofits that utilize separate biomass feed systems, i.e., that feed the biomass directly into the boiler through a separate injection port or ports with no blending with coal until the flames mix inside the boiler itself. In general, cyclone boilers are more adaptable than PC boilers to blended coal and biomass feed, because for cyclones the coal is crushed, rather than pulverized, and the fuel particle need not be as small. Blended fuel for a pulverized coal boiler requires that the biomass be fed through existing coal mills, and in this case the cofiring fraction will be limited (to about 2% of the heat input) by pulverizer performance: namely, throughput and coal size. For PC boilers, a separate feed system for biomass, although more expensive, has the advantages of avoiding any changes to the existing coal preparation and delivery system, and, even more important, of avoiding derate or carbon-in-ash caused by pulverizer performance limits. In general, separate firing has a capital cost estimated to be about four times that for a blended system, as measured in capital cost per unit of biomass power generating capacity.
- Incremental operating costs were developed based on one full-time equivalent added employee to operate the biomass feed system during one shift. It is possible that for separate feed more added employees will be required in order to cover other shifts. This would add to the incremental operating cost. EPRI used $70,000/year for the fully-loaded cost of the one added employee.
- Plant net heat rate for large cyclones and PCs was estimated at 9000 Btu/kWh. Medium PCs and smaller cyclone boilers were given a heat rate of 9500 Btu/kWh. Smaller PCs were assigned a heat rate of 10,000 Btu/kWh. Biomass heat rates were 17% higher than coal-only for 45%-moisture biomass (i.e., the $0.53/MBtu biomass fuel cases) and 10% higher than coal-only for 30%-moisture biomass (i.e., the $0.96/MBtu biomass fuel cases). [Biomass fuel costs per Ref. 37.]

Second Round of Deployment

A “second round” of deployment of biomass cofiring could extend bioelectricity generation and related CO_2 reduction beyond levels shown in Tables 6-1 and 6-2. The assumptions and the economics for this second round of deployment are shown in Tables 6-3 and 6-4. Specifically, the large cyclone boilers could cofire 5% by heat, instead of 2.5%, thereby adding another 1.51 TWh/year of biomass electricity. In the next category, “All Other Cyclones,” the cofiring level could be 8%, not the 5% used in Round 1, thereby adding another 1.50 TWh/year. In the “Large PC” group, the market penetration could advance from 0.40 to 0.60, thereby adding another 5.63 TWh/year. In the “Medium PC” category, the cofired fraction could be 15% of the heat instead of 10%, thereby adding another 5.20 TWh/year. The last category, “Small PC,” could advance from a market penetration factor of 0.30 to one of 0.50, thereby adding another 2.37 TWh/year.

Table 6-3
Potential Cofiring Market: Electricity Generation and Biomass Use (Round 2 Of Deployment)

Boiler Equipment	Available Gen. Capacity (GW)	Average Capacity Factor (fraction)	Available Annual Electricity Gen. (TWh)	Cofiring Level (% heat from biomass)	Assumed Market Penetration (Fraction)	Bio-Electricity Gen. (TWh/yr)	Biomass Fuel Use (Mton/yr)
Large Cyclones	12	0.82	86	5.0	No change	1.51	0.90
Other Cyclones	11	0.78	75	8.0	No change	1.50	1.00
Large PCs	220	0.73	1405	2.0	+0.20	5.63	3.36
Medium PCs	60	0.66	347	15.0	No change	5.20	3.26
Small PCs	15	0.60	79	15.0	+0.20	2.37	1.67
Total (or Avg.)	318	0.72	1992	5.14	0.19	16.2	10.2

Table 6-4
Estimated Cost of Biomass Cofiring – Round 2

Boiler Equipment Category		Biomass Cost $/MBtu	Biomass in the Category, Mton/yr	Cum. Biomass, Mton/yr	Coal-based Generation displaced Percent	CO2 Reduction, Mtonne/yr		CapitalCost, $/MWh	Total Cost	
						By Category	Cumulative		Incremental, $/MWh	Cumulative, $M/yr
A2	Large Cyclones	0.96	0.90	0.90	0.07	1.32	1.32	40	0.76	1.0
B2	Other Cyclones	0.96	1.00	1.90	0.08	1.45	2.77	40	0.80	2.0
C2	Large PCs	0.96	3.36	5.26	0.28	4.90	7.67	50	2.32	15
D2	Medium PCs	0.96	3.26	8.52	0.26	4.77	12.4	175	10.0	67
E2	Small PCs	0.96	1.68	10.2	0.12	2.34	14.7	230	16.3	105
	Total		10.2		0.81	14.7	-	-	-	-

The result is an added 16.2 TWh/year for all utility boiler categories. For the economic analysis in Round 2, EPRI assumed a delivered fuel cost of $0.96/MBtu for all the biomass fuel. The total supply of biomass at $0.96/MBtu was assumed to be 22 million dry tons, and of this 22million tons, some 8.87 were committed to the Medium PC and Small PC categories in the "first round" (Tables 6-1 and 6-2), after the 10 million tons assumed for the $0.53/MBtu biomass fuel supply had been used up by the three lower-cost categories (Cyclones and Large PC). The supply limit, i.e., the 13.13 million dry tons still remaining of the 22 million tons at $0.96/MBtu delivered cost, was not a limiting factor for the Round 2 scenario.

Overall Supply Curve (Rounds 1 and 2 Combined)

Finally, Table 6-5 presents the combination of Tables 6-2 and 6-4 into an integrated total supply curve for CO_2 mitigation via biomass cofiring. The grand total is 45.7 TWh/year of biomass cofired electricity, which is 2.29% of the assumed 1992 TWh/year of today's coal-fired power generation in the USA. As shown in Table 6-5, the cumulative cost is $256 million to eliminate 41.8 million tonnes (metric) of fossil CO_2 emissions, or an average cost of $6.17 per metric tonne of CO_2, which converts to $22.62/tonne of fossil carbon emitted as CO_2. As can be seen in Tables 6-2, 6-4 and 6-5, cofiring in cyclones and large PCs yields savings. But for the high cost category, $55 million is needed to get the last 3.42 million tons of CO_2. This puts the marginal cost for the last increment at $16.08/tonne CO_2, or $58.97/tonne C.

Table 6-5
Supply Curve For Biomass Cofiring – Rounds 1 And 2 of Deployment, Integrated and Listed in Order of Increasing Incremental Cost

	B1	A1	C1	A2	B2	C2	D2	D1	E1	E2
	All Other Cyclones	Large Cyclones	Large PCs	Large Cyclones	All Other Cyclones	Large PCs	Medium PCs	Medium PCs	Small PCs	Small PCs
Assumed Average Unit Size on Coal, MWe	250	500	500	500	250	500	200	200	100	100
Assumed Cofiring Level (i.e., fraction of heat from biomass)	5.0%	2.5%	2.0%	5.0%	8.0%	2.0%	15%	10%	15%	15%
Capital Cost, $/kW (per kW from biomass)	$50	$50	$50	$40	$40	$50	$175	$200	$230	$230
Separate Feed for Biomass	No	No	No	No	No	No	Yes	Yes	Yes	Yes
Delivered Biomass Cost, $/MBtu	$0.53	$0.53	$0.53	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Incremental Cost above 100% Coal, $/MWh	($2.70)	($2.26)	($1.62)	$0.76	$0.80	$2.32	$10.01	$11.86	$15.58	$16.25
CO_2 Reduction, Mtonne/yr (metric)	2.55	1.31	9.90	1.32	1.45	4.90	4.77	9.56	3.42	2.30
Cumulative Biomass Use, Mton/yr (short tons, dry basis)	1.85	2.81	10.01	10.91	11.90	15.26	18.52	25.04	27.39	29.06
Cumulative Bio-Electricity Generation, TWh/year	2.63	4.14	15.52	17.03	18.53	24.16	29.36	39.77	43.32	45.69
Cumulative Coal-based Generation Displaced (% of 1,992 TWh/yr)	0.13%	0.21%	0.78%	0.85%	0.93%	1.21%	1.47%	2.00%	2.17%	2.29%
Cumulative CO_2 Reduction, Mtonne/yr (metric)	2.54	3.86	13.76	15.07	16.52	21.42	26.20	35.76	39.18	41.48
Cumulative Cost, $M/yr (excess above 100% coal)	($7)	($11)	($29)	($28)	($27)	($14)	$39	$162	$217	$256

7
RENEWABLES SUPPLY CURVE

Using the Tech. Char. report (Ref.4) and other sources, the following estimates were developed to display "curves" of supply versus cost for renewable power deployed as a way to reduce fossil carbon emissions. (See the definition of "supply curve" at the start of Section 6.) Numbers are given here as single-point values, when, of course, there are usually a range of values that could apply. Therefore, the last four pages of the section show and discuss ranges and sensitivities.

Wind Technology Supply Curve

The EPRI/DOE “Renewable Energy Technology Characterizations” report (Ref.4) describes wind energy technology in the year 2030 as having a capital cost (total installed cost) of about $635/kW, O&M costs of about 0.5¢/kWh, an average annual capacity factor of 48.7% for wind power class 6, and an average annual capacity factor of 38.3% for wind power class 4. Based on this information and the estimates in the Battelle PNL wind resource assessment report (Ref.13), a supply curve for wind technology in the 48 contiguous United States was developed as described below.

Three discrete sections were assumed in constructing the supply curve (although in reality there is more of a continuum): (1) the lowest cost resource, comprised of classes 5 through 7; (2) the wind resources in class 4; and (3) the wind resources in class 3. In the simplified approach used to construct the supply curve, it was assumed that the only difference from one wind power class to the next was the capacity factor. These were assumed to be, respectively, 49%, 38%, and 25%. (The final values adopted here are actually 45%, 35% and 25%, as shown in Table 7-1, below.)

The PNL report (Ref.13) included four scenarios of land exclusions for wind power development, which ranged from a scenario with very few exclusions to one with very stringent exclusions. The scenario adopted for the purposes of this supply curve was the PNL-defined “moderate” scenario, which excludes environmentally protected lands, urban areas, wetlands, 50% of forest lands, 30% of agricultural lands, and 10% of range and barren lands. The moderate scenario is the one used in both Sections 2 and 4, above, in this report.

Table 7-1 shows the resulting supply curve. The potential supply of wind power, based on EPRI/DOE year 2000 technology assumptions (Ref.4) and the moderate land exclusion scenario developed by PNL (Ref.13), is about 700 TWh/year at a cost of about 3.6¢/kWh, plus about 4800 TWh/year at a cost of about 4.5¢/kWh, and about 5200 TWh/year at a cost of about 6.5¢/kWh.

Table 7-1
Supply Curve for Wind Energy Technology in the 48 Contiguous United States*

	Resource Ultimate Potential (Ref.13)**			Adopted for Supply Curve		
	Classes 5-7	Class 4	Class 3	Cl. 5-7	Cl. 4	Cl. 3
Percent of contiguous U.S. land area**	0.58%	5.41%	7.55%	0.031%	0.058%	0.074%
Total electric energy potential, TWh/year	713	48369	5226	35	48	52
Annual capacity factor, %	49%	38%	25%	45.5%	35.3%	25.2%
Total installed capacity potential, GW	166	1450	2386	8.8	15.5	23.5
Total installed cost, $/kW	635	635	635	635	635	635
Capital recovery factor, %/year	21%	21%	21%	21%	21%	21%
Capital cost, $/MWh	$31.00	$40.00	$60.00	$33.50	$43.10	$60.30
O&M cost, $/MWh	$5.00	$5.00	$5.00	$6.60	$8.50	$11.90
Cost of electricity, $/MWh	$36.00	$45.00	$65.00	$40.10	$51.60	$72.20

*Year 2030 technology characteristics assumed (Ref.4, "Tech. Char." by EPRI/DOE, Dec.'97)
**Moderate land exclusion scenario (Ref.13, Battelle PNL wind assessment, 1991)

For the overall supply curve for all renewables, to be displayed as Table 7-7 near the end of this section, considerations of the rate of growth and the limited fraction of electricity supply from an intermittent source such as wind, have led to a much smaller amount of wind than the physical potential of the resource that was estimated by the PNL study (Ref.13). These revised, and lower, amounts are also displayed in Table 7-1.

Finally, for wind, it should be noted that the adopted supply curve values shown in Table 7-1 (and entered into the overall supply curve at the end of this section) are above the "high renewables growth" scenario of Tables 2-3 and 2-4 above. Table 2-3 used 10%, and later 5%, annual growth to accumulate to 13 GW in 2020 and 20 GW in 2030 as the installed wind capacity for the U.S. Table 2-4 converted the 13 GW into 33 TWh in 2020, which was only one-third of the 108 TWh "needed" in the EIA "1990+9%" scenario for the EIA's Kyoto report (Ref.15). The supply curve adopted here can achieve the 33 TWh from Class 5-7 wind resources alone, and reaches about 75% of the 108 TWh from the sum of the 35 TWh in Cl. 5-7 plus the 48 TWh in Class 4. Worldwide growth in installed wind capacity has been over 30%/year for the three years 1997-1999. The EIA base case scenario for wind in the US was 9 TWh by 2020 (Table 2-4).

Geothermal

This sub-section will develop a supply curve for geothermal power in the U.S. The "curve" will be done in terms of four groups, based on a dividing of the the geothermal resource base of the U.S. into four resource/technology categories. Note that this will include only the potential for hydrothermal geothermal, and will not include the very much larger hot dry rock resources. The hydrothermal resource base, taking into account only those resource sites already identified, has been estimated at 20,000 MWe. Another 20,000 to 30,000 MWe may eventually be developed, according to one estimate (Ref.17), and some 95 to 150 GWe is the range of estimated hydro-thermal power potential in "identified plus unidentified resources" in the U.S. (Ref.16,17). An EPRI estimate in 1986, based on a workshop discussion attended by specialists in geothermal resources and geothermal power, gave a result of 7,000 MWe as being "developable in a 10- to 15-year timeframe" (Ref.18).

The major parameters determining the cost of bringing power on line from these hydrothermal resources are the following:

Resource Temperature. Hot versus moderate versus low, being groups of >400 F (204 C), 300-400 F (150-204 C), and 250-300 F (120-150 C). The hot resources will be developed via the so-called "dual flash" technology, where two different pressures of steam flow are produced by dropping the pressure from reservoir value to the "high" pressure steam inlet of the turbine and then again from "high" to "low" for entry to the low-pressure stages of the steam turbine. At each stage, the hot water "flashes" to form steam and the steam is put through a dual entry steam turbine. The moderate and low temperature resources, certainly the low and probably much of the moderate, will be developed via "binary" technology. In a binary cycle, water and steam are not taken as the working fluid for the turbine, but instead the heat is transferred from the hot water of the geothermal reservoir into a second fluid, one having better thermodynamic properties for power generation than does water/steam at the low temperatures of these resources.

Cost of Wells and Production of Geothermal Fluid. Depth to which wells must be drilled to tap the underground reservoir of hot water or steam. Permeability of the rock formation that constitutes the reservoir, and, hence, the rate of flow from the reservoir rock into the wells. Depth ranges from less than 1000 feet (300 m) to over 7000 feet (2000 m). The combined effect of permeability and well design/performance can be measured as flow rate per unit of pressure difference that drives the flow.

Based on these two major cost-determining factors and the technology performance and cost data in the Technology Characterizations report, the following matrix is used here estimate supply versus cost, using four categories of geothermal power generation:

High Temperature	**Moderate Temperature**	**Low Temperature**
> 400 F (> 204 C)	300-400 F (149-204 C)	250-300 F (121-149 C)
Good Production $800-1100/kW 2,000 MWe	Good Production $1300-1600/kW 10,000 MWe	Not used for power generation
Moderate Production $1000-1300/kW 3,000 Mwe	Moderate Production $1800-2100/kW 20,000 MWe	Not used for power generation

Table 7-2 shows the resulting supply curve for power generation from geothermal resources in the U.S. Note that the goal numbers for geothermal in Section 4 (Table 4-1) above give lower O&M costs than adopted here in Table 7-2 (and, later, in Table 7-7). Here, the higher costs for Groups 2-4, ranging from $12 to $20/MWh rather than the $6 to $8/MWh in the goal cases of Table 4-1, reflect the adverse conditions that have been and can be encountered in the geothermal field. Extra labor and material to overcome problems of scale-deposition, corrosion, down-well pump replacement and production well work-over, even the drilling of new wells at an accelerated pace: all these are contingencies reflected in Tables 7-2 and 7-7 by these higher O&M costs.

Table 7-2
Supply Curve for Geothermal

	Group 1	Group 2	Group 3	Group 4
Temperature Class	*High*	*High*	*Moderate*	*Moderate*
Production Class	Good	Moderate	Good	Moderate
Capital Cost	*$1000/kW*	*$1200/kW*	*$1500/kW*	*$2000/kW*
Resource Potential	*2 GWe*	*3 GWe*	*10 GWe*	*20 GWe*
Capacity Factor	85%	85%	85%	85%
Annual Generation	15 TWh/yr	22 TWh/yr	74 TWh/yr	149 TWh/yr
Capital cost, $MWh	*$28.00*	*$34.00*	*$42.00*	*$57.00*
O&M cost, $/MWh	$8.00	$15.00	$12.00	$20.00
Fuel cost, $/MWh	none	none	none	none
Total, $/MWh	$36.00	$49.00	$54.00	$77.00
Extra Cost (vs. $42/MWh)	($6.00)	$7.00	$12.00	$35.00
Carbon Cost, $/tonne C	($24.00)	$29.00	$51.00	$148.00

Note also that Table 7-2 (and Table 7-7, to be shown later) includes hydrothermal resources only, and does not include "hot dry rock" resources nor "geopressured" resources. Hot dry rock resources are a type many times more abundant than hydrothermal, and are characterized by man-made reservoirs of hot water created by fracturing geothermally-heated hot rock formations at depths of 2,000 to 5,000 meters. Surface water is then pumped into the hot fractures, and most of that water is recovered through production wells, as in a natural hydrothermal power system. Geopressured resources are natural deposits of hot brine found in conjunction with oil and gas deposits. Methane gas dissolved in the hot brine, plus the heat of the brine itself, gives these deposits a role as potential energy and power resources. Geopressured resources are found for the most part in the Texas-Louisiana coastal region near the Gulf of Mexico. These geopressured resources are expensive to exploit and the power generation potential associated with them is only a fraction--perhaps 20%--of the estimated U.S. hydrothermal potential.

Biomass

The biomass supply curve developed here is a result of simplifying the cofiring results from Section 6 into only two groups (blended feed and separated feed) and then adding four other groups: existing biomass power plants, landfill gas, animal waste disposal, and advanced biomass. Again, the performance and cost numbers are based on the Technology Characterizations report (Ref.4). The supply part, is based on the biomass fuel amounts estimated in each of the resource categories shown in Table 7-3. The cost of the fuel in each category is given first in Table 7-3 as a low-cost case and then, as explained in the notes, is adjusted to a higher cost used in the supply curves of Tables 7-4 and 7-7, which follow later in this section. Again, as in the case of geothermal, somewhat different numbers are adopted later in this section to produce Table 7-7 below, but numbers that are essentially the same as these within the ranges of uncertainty and accuracy of the estimates.

To complete the biomass supply curve using the fuel resource categories of Table 7-3, the technology groups are matched to the resource categories as follows:

Group 1: Existing Power Plants

> Resource Category No. 1: 40 million dry tons of $1.00/MBtu fuel.
> Because this fuel has at times cost $2.00 or even more, but is sometimes ready at hand at a $0.50 or lower cost, and because both evolutionary improvements and incentives or credits for avoiding other means of disposal can be expected, the supply curve adopts $1.50 as the cost of fuel in this group. (See last sub-section of this section, Some Specific Sensitivities, where biomass fuel cost is named as displayed--in Table 7-8--as an important uncertainty.)

Group 2: Biomass Cofiring with Blended Feed

> Resource No. 2 (10 of 30): 10 million dry tons of $0.50/MBtu fuel, $1.25 delivered.
> This group represents the low-cost biomass cofiring situation, where the biomass fuel can be blended with the coal and fed to the boiler without a separate fuel injection system for the biomass. This modification can be made for only $50/kW, counting only the kW from the biomass. (If per kW of total plant capacity, coal plus biomass, it would be $5/kW when 10%

of the output is from the biomass fuel.) Only 10 of the 30 million dry tons in the "tip fee fuel" resource category of Table 7-3 is assumed to go into be obtainable at the low cost of $0.50/MBtu. Therefore, the fuel cost for this group in Table 7-4 is set at $0.25/MBtu above the coal price, and can be thought of as representing cases where coal costs only $1.00/MBtu, and biomass is at $1.25/MBtu: $0.50 for 75% of the fuel at source, $1.00 for the other 25% at source, resulting $0.625/MBtu at the source, plus $0.25 biomass fuel preparation (screening, grinding, etc.), plus $0.375 transportation to the power plant.

Group 3: Biomass Cofiring with Separated Feed

Resource No. 2 (20 of 30): 20 million dry tons of $1.00/MBtu fuel, $1.50 delivered.
A higher fuel cost is adopted for the actual supply curve, namely $1.00/MBtu, to be consistent with Section 6, where 20 of the 30 million tons of "tip fee fuel" was given the higher cost of $0.96/MBtu, which was the high one of the two wood residue fuel cost categories used in the NREL estimate referred to in Section 6. (The low-cost one was $0.53/MBtu.) With size reduction ("grinding") included in the equipment paid for at the power plant in this "separate feed" not "blended feed" cofiring mode, the processing cost upstream of the plant can be put at half of the $0.25 used in Group 2, so the delivered biomass fuel cost is $1.50/MBtu: $1.00 at source, plus $0.125 preparation, plus $0.375 transportation, for the total of $1.50/MBtu at the plant. This corresponds to $0.25/MBtu higher than a coal price of $1.25.

Group 4: Landfill Gas

Resource No. 3: 4 GWe of capacity with a fuel gas at $0.50/MBtu.
The 4 GWe assumes use of 50% of the landfill gas in the United States. Fuel cost is very low compared to natural gas and fuel oil, only $0.50/MBtu. The fuel is methane (plus minor fuel gases and CO_2). Fuel cost is this low because the cost of collecting the gas is paid by the landfill operator who must collect the gas anyway in order to prevent odor from the aromatic organics that are among the impurities.

Group 5: Animal Wastes

Resource No. 4: 4 GWe of capacity with a zero cost fuel gas, $0.00/MBtu.
This is power generation a gas derived from odor and waste control systems installed in operations that raise food producing animals such as hogs, poultry, beef cattle and dairy cattle. Resource size is based on 50% of the total of these animal production industries in the year 2010. Fuel cost is zero. The power generator does not pay for fuel, and pays only for the capital and operating costs for the equipment to combust the fuel gas supplied by the odor/waste control system paid for by others and the equipment and to generate electricity from the heat of the combustion.

Table 7-3
Biomass Resource Categories and Amounts for U.S.

Resource Categories=>	Cat. 1	Cat. 2 "Tip Fee" Cat. 2a	Cat. 2 "Tip Fee" Cat. 2b	Cat. 3	Cat. 4	Cat. 5	
Description, units	Existing Plants	Cofire1 Blended	Cofire2 Separate	Landfill Gas	Animal Wastes	Energy Crops	Total (or avg.)
Capacity, GWe	8	3	4	4	4	40	63
Capacity factor	0.640	0.780	0.800	0.700	0.700	0.742	0.729
Generation, TWh/yr	44.9	20.5	28.0	24.5	24.5	260.0	402.4
Amount, 10^6 dry tons biomass	40	10	20	NA	21	150	241
Moisture, %	45%	35%	35%	NA	70%	50%	
HHV,dry, Btu/lb	8300	8300	8300	NA	8300	8300	
Pri. Energy, quads	0.664	0.166	0.332	0.4	0.3486	2.49	4.40
Heat Rate, Btu/kWh	16,000	11,000	11,000	13,000	16,000	10,000	
Generation, TWh	42	15	30	31	22	249	388
Capacity Factor	0.700	0.700	0.700	0.700	0.600	0.700	0.694
Gen. Capacity, GWe	6.77	2.46	4.92	5.02	4.15	40.61	63.92
Fuel Cost, $/MBtu	$1.50	$1.25	$1.50	$0.50	$0.00	$1.50	
Key to notes	(1)	(2)	(3)	(4)	(5)	(6)	
Fuel cost breakdown:							
Pay to source	$ 0.50	$ 0.63	$ 1.00	$ -	$ (1.00)	$ 1.00	
Cost to prepare	$ 0.63	$ 0.25	$ 0.13	$ 0.50	$ 1.00	$ 0.13	
Transportation	$ 0.37	$ 0.37	$ 0.37	$ -	$ -	$ 0.37	
Total (delivered cost)	$ 1.50	$ 1.25	$ 1.50	$ 0.50	$ -	$ 1.50	

Notes:

(1) $1.50 as a goal cost for what is now $0.50 to $2.00 for residue fuels to existing plants.

(2) $0.50, per the $0.53 used in Sec.6 for the low cost fuels, at source; some added costs, described in text.

(3) $1.00 per the more expensive $0.96/MBtu of Sec.6 for the majority (20 of 30 M dry tons) of the tipping-fee-credited fuels Going to cofiring in the future. Text describes added costs to derive $1.50 delilered cost to the power plant.

(4) Cost of collecting gas is paid by the landfill operator, leaving the cost to the power plant low, only $0.50/MBtu. See text.

(5) Animal wastes net zero cost. Payment for waste and odor control offsets cost to make fuel gas. See text.

(6) $1.50 is cost goal for energy crops. It is achievable via one or a combination of paths: high yields, new low-cost harvest-Ing technology, and offsets from coproduct revenues. Examples of land areas and yields for energy crops that, Combined with a 10,000 Btu/kWh heat rate, give 150 million dry tons and 250 TWh are displayed here:

Yield in units of dry ton /ac/yr (dry biomass:16.6 MBtu/ton)	million acres***	million dry tons	10^15 Btu Quads/yr	Heat Rate Btu/kWh	10^9 kWh TWh	hours and GW, 0.742 cf hours/yr	hours and GW, 0.742 cf GWe
10.0	15	150	2.490	10,000	249.0	6500	38.3
8.0	19	152	2.523	10,000	252.3	6500	38.8
6.0	25	150	2.490	10,000	249.0	6500	38.3
4.0	38	152	2.523	10,000	252.3	6500	38.8
3.0	50	150	2.490	10,000	249.0	6500	38.3
2.0	75	150	2.490	10,000	249.0	6500	38.3
1.0	150	150	2.490	10,000	249.0	6500	38.3

The last three cases, yields of only 1, 2 or 3 dt/ac/yr, represent "coproduct" cases in which only 15 to 30% of the biomass produced goes as fuel. The main product would be fiber or other high-value material.

***For comparison, total cropland in U.S. is about 350 million acres. Pastureland adds about 450 million more, but much is questionable or poor for energy crops. 10% of the 350 million acres is currently set aside and out of production in the Conservation Reserve Program (CRP). Half of this 36 million acres of CRP land is considered suitable for energy crops. An additional 10 to 40 million of the 350 million acres is often not planted in any given year.

Group 6: Advanced Biomass Power

Resource No. 5: 70 million dry tons of energy crop material from the operation of agroforestry to produce pulp and fiber, and, to a lesser extent, from crops dedicated to energy feedstock/ fuel production. Fuel cost is $1.50/MBtu (Refs.4,38). Conversion to electricity is via an advanced power system.

For the "advanced power system" in this Group 6 of the biomass categories, the integrated gasification combined cycle (IGCC) technology of the Tech. Char. report (Ref.4) has been taken as the specific advanced system used to calculate the economics here. However, it is possible, perhaps even likely in the near-term, that a combustion/steam cycle such as Whole Tree Energy™ (Refs. 39,40), advanced fluidized bed (Ref.41), slagging combustion (Ref. 42), or a fuel cell (Ref.43), or even some other power cycle, may become the advanced system of choice instead of IGCC. Therefore, IGCC should be considered as simply one specific case chosen to approximate one or more advanced biomass power systems. To show numbers for both an advanced combustion option (Whole Tree Energy™) and an advanced gasification option (biomass IGCC), Table 7-3 used a 10,000 Btu/kWh heat rate from a design proposed for the first or second Whole Tree Energy power plant--which is direct combustion in an efficient steam boiler cycle--while Table 7-4, which follows below, uses the goal heat rate of 7600 Btu/kWh for IGCC. The 7600 is rounded from the 7580 of Table 4-1, which gave the Tech. Char results per Section 4 and Ref.4.

As a result of the division into six groups and the data and assumptions set forth in the above paragraphs on each group, one possible biomass supply curve has been calculated and is shown here as Table 7-4.

Table 7-4
Biomass Supply Curve for the U.S.

Biomass Groups==> Description, units	Gp1: Existing Power Plants	Group2: Cofire1 Blended	Group3: Cofire2 Separate	Group4: Landfill Gas	Group5: Animal Wastes	Group6: Advanced Biomass	Total (or avrg.)
Capacity, GWe	7	3	4	4	4	40	62
Capacity factor	0.73	0.77	0.77	0.688	0.688	0.74	0.736
Generation, TWh/yr	44.8	20.2	27.0	24.1	24.1	259.3	399.5
Capital cost, $/kW	$0	$50	$200	$1,100	$1,500	$1,100	--
Fuel cost, $/MBtu	$1.50	$0.25	$0.25	$0.50	$0.00	$1.50	--
Heat rate, Btu/kWh	16,000	11,000	11,000	13,000	16,000	7,600	9,776
Capital recov., %/yr	21%	33%	33%	21%	21%	21%	21%
Capital cost, $MWh	$0.00	$2.45	$9.78	$38.33	$52.27	$35.63	--
O&M cost, $/MWh	$20.00	$1.00	$2.70	$10.00	$20.00	$10.20	--
Fuel cost, $/MWh	$24.00	$2.75	$2.75	$6.50	$0.00	$11.40	--
Total cost, $/MWh	$44.00	$6.20	$15.23	$54.83	$72.27	$57.23	--
Less fossil alt.	($42.00)	($0.00)	($0.00)	($42.00)	($42.00)	($42.00)	--
Extra cost, $/MWh	$2.00	$6.19	$15.23	$12.83	$30.27	$15.23	--
Tonne-C/MWh	0.236	0.236	0.236	1.805	1.805	0.236	--
GhG cost, $/tonne-C	$8.47	$26.24	$64.54	$7.11	$16.77	$64.55	--
Heat input, EJ /yr	0.756	0.235	0.313	0.331	0.407	2.079	4.120
Fuel HHV, kJ/kg (dry)	19,264	19,264	19,264	19,264	19,264	19,264	19,264
Biomass (dry), Mtonne/yr	39.2	12.2	16.3	17.2	21.1	107.9	213.9
Heat input, quad /yr	0.716	0.223	0.297	0.313	0.386	1.971	3.905
Fuel HHV, Btu/lb (dry)	8,300	8,300	8,300	8,300	8,300	8,300	8,300
Biomass (dry), 10^6 ton/yr	43.1	13.4	17.9	18.9	23.2	118.7	235.3
Heat rate, Btu/kWh	16,000	11,000	11,000	13,000	16,000	7,600	9,776

Solar Photovoltaic (PV)

The solar resource base of the continental United States is over 10^{16} kWh/year. U.S. electricity use is about 3 x 10^{12} kWh/year. Thus, the U.S., an intense user of energy, has the potential--based solely on the size of the resource and not on the cost of exploiting it--to make 3000 times as much electricity from solar energy than current electricity consumption. Worldwide, this factor is about 10,000 rather than 3000. Therefore, solar PV could, in principle, provide all the world's electricity. The size of future PV markets will ultimately be determined by the economics of PV systems. Future, lower cost PV systems (such as those based on thin films) have the potential to be used globally on a very large scale. If cost barriers can be overcome, U.S. usage (without storage) of up to 10% of our utility electricity generation (more than 400 TWh of PV electricity generation based on projected future U.S. electric capacity) is feasible. Use in developing countries could be as large or larger (Ref.4).

Residential PV systems are expected to be one of the first grid-connected applications of PV to reach cost-effectiveness with existing electrical energy sources. Residential PV systems also represent a potentially large market. There are approximately ten million single-family homes located in regions of the United States that have above-average direct sunlight and suitably tilted roofs that are not shaded by trees or buildings. This market has a potential of over 30 GW (Ref.4), which would be 92 TWh per year at a 35% capacity factor.

In June 1997 the U.S. Department of Energy announced an initiative to promote the installation of one million rooftop systems (solar thermal and PV), by the year 2010. The Million Solar Roofs Initiative signifies the readiness of residential and commercial roof solar energy systems to become an important energy source for the United States. The technology and regulatory improvements developed under this initiative will help facilitate the more rapid introduction of residential photovoltaic (PV) energy systems in the Unites States, as costs are driven down.

The EPRI/DOE "Renewable Energy Technology Characterizations" report (Ref.4) describes PV technology in the categories of residential and utility scale systems, both of which are expected to continue evolving rapidly with major cost reductions during the next several decades. Table 7-5 provides a scenario for PV technology cost and performance projected for the year 2030 (Ref.4). Two major insolation (i.e., intensity of the sunlight) categories are shown: average (e.g., Kansas), and high (e.g., the desert Southwest). The only significant difference between the two in terms of PV cost structure is the annual capacity factor (about 21% versus 26%, respectively).

Table 7-5
Supply Curve for PV Technology in the United States*

Type of System	Residential		Utility Scale	
Insolation Category	Average	High	Average	High
Insolation, kWh/m2-yr**	1,800	2,300	1,800	2,300
System capacity, kWac	4.0	4.0	16,000	16,000
Generation, MWh/year	6.156	7.866	29,000	37,000
Annual capacity factor, %	20.5%	26.3%	20.7%	26.4%
Total installed cost, $/kW***	1,210	1,210	880	880
Capital recovery factor	0.21	0.21	0.21	0.21
Capital cost, $/MWh	$140	$109	$101	$79
O&M cost, $/MWh	$6	$5	$1	$1
Cost of electricity, $/MWh	$147	$114	$102	$80
U.S. total generation, TWh/yr	22.0	27.5	40.00	23.0

* Year 2030 technology characteristics assumed (Ref. 4)
** Direct normal sunlight energy in kWh per square meter per year
*** Rating per kW peak capacity

Solar Thermal Power

Table 7-6 shows the supply curve for solar thermal power systems. This technology concentrates sunlight onto a heat transfer surface to heat a working fluid that drives a heat engine such as a steam turbine or a stirling engine.

Table 7-6
Supply Curve for Solar Thermal in the United States*

Type of System Insolation Category	Dish Stirling	Parabolic Trough	Power Tower	Adopted for Supply Curve
Insolation, kWh/m2-yr**	2700	2700	2700	2700
System capacity, MW	30	320	200	200
Generation, GWh/year	60.4	785	491	491
Annual capacity factor, %	23.0	28.0	28.0	28.0
Total installed cost, $/kW***	$1074	$1300	$934	$934
Capital recovery factor	0.21	0.21	0.21	0.21
Capital cost, $/MWh	$111	$110	$79	$79
O&M cost, $/MWh	$15	$6	$10	$10
Cost of electricity, $/MWh	$126	$116	$89	$89
U.S. total generation, TWh/yr	NA	NA	NA	27.0

* Year 2030 technology characteristics assumed (Ref. 4)
** Direct normal sunlight energy in kWh per square meter per year
*** Rating per kW peak capacity

Total Supply Curve for Renewables

Table 7-7 shows the supply curve for the U.S. adopted for this report, based on the resource and technology categories and characteristics as defined and discussed above in this section.

Notice that, as discussed earlier, solar PV residential has a high-cost **retail** value as the price of the fossil alternative: **$100/MWh**, not $42/MWh. Central station solar has the $42/MWh as the alternative fossil price to be subtracted to derive the extra cost of the renewable option.

Biomass cofiring has zero as the cost of the fossil alternative, not $42/MWh. As explained earlier, this is because, with the alternative being to run the coal plant on 100% coal, the costs were taken to be only the increment above the costs to build and operate the coal plant and to buy the coal fuel: $0.25/MBtu extra for the biomass fuel, and capital and labor costs that are only the addition above the baseline existing plant and operating staff, plus extra maintenance only for the biomass equipment added to the plant. Because of the need for rapid payback on plant modifications paid out of the plant's annual capital improvement budget, capital recovery on biomass cofiring is at 33% per year, not 21%, on the capital cost of the biomass modifications.

Renewables Supply Curve

Table 7-7
Supply Curve For All Renewables

Energy Source, Technology, and Other Desc.	Capac GWe	Gen. TWh	Cost breakdown in $/MWh: Capital $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh	Fossil Alternate $/MWh	Extra $/MWh	Extra $/tonneC	Cum. TWh	Cum. 10^6 tonneC	Cum. 10^9\$ \$B
Geothermal, hot low-cost	2	15	$29.00	$7.40	$0.00	$36.40	$42.00	($5.60)	($23.69)	15	3.5	($0.1)
Wind Class 5+	9	35	$33.50	$6.60	$0.00	$40.10	$42.00	($1.90)	($8.04)	50	11.8	($0.2)
Landfill Gas**, 2 MW	4	24	$38.30	$10.00	$6.50	$54.80	$42.00	$12.80	$7.09 **	74	55.3 **	$0.2
Biomass, existing generation	7	45	$0.00	$20.00	$24.00	$44.00	$42.00	$2.00	$8.46	119	66.0	$0.2
Animal Wastes**, 300 kW	4	24	$52.30	$20.00	$0.00	$72.30	$42.00	$30.30	$16.79 **	143	109.28 **	$1.0
Biomass Cofiring, blended*	3	20	$2.40 *	$1.00	$2.80	$6.20	$0.00	$6.20	$26.23	163	114.0	$1.1
Geothermal, hot average cost	3	22	$33.84	$15.00	$0.00	$48.84	$42.00	$6.84	$28.94	185	119.2	$1.2
Wind Class 4	16	48	$43.10	$8.50	$0.00	$51.60	$42.00	$9.60	$40.61	233	130.5	$1.7
Geothermal, warm low cost	10	74	$42.00	$12.00	$0.00	$54.00	$42.00	$12.00	$50.77	307	148.0	$2.6
Solar PV, residential good	10	28	$108.70	$5.20	$0.00	$113.90	$100.00	$13.90	$58.81	335	154.7	$3.0
Biomass, advanced technology	40	260	$35.60	$10.20	$11.40	$57.20	$42.00	$15.20	$64.31	595	216.1	$6.9
Biomass Cofiring, separate*	4	27	$9.80 *	$2.70	$2.80	$15.30	$0.00	$15.30	$64.73	622	222.5	$7.4
Wind Class 3	24	52	$60.30	$11.90	$0.00	$72.20	$42.00	$30.20	$127.77	674	234.8	$8.9
Geothermal, warm ave. cost	20	149	$56.40	$20.00	$0.00	$76.40	$42.00	$34.40	$145.53	823	270.0	$14.0
Solar PV, central good	10	23	$79.50	$1.20	$0.00	$80.70	$42.00	$38.70	$163.73	846	275.4	$14.9
Solar PV, residential average	12	22	$140.30	$6.40	$0.00	$146.70	$100.00	$46.70	$197.57	868	280.6	$16.0
Solar Thermal, 25 MW	10	27	$79.20	$10.20	$0.00	$89.40	$42.00	$47.40	$200.53	895	287.0	$17.2
Solar PV, central average	22	40	$100.70	$1.50	$0.00	$102.20	$42.00	$60.20	$254.69	935	296.5	$19.7
Totals	210	935	Cost of last increment = $254.69/tonneC. Average cost = $66.44/tonneC ($19.7B / 296.5 Mtonne).									

*Note: Biomass cofiring cases use 33% annual capital cost recovery factor, not the 21% of all the others. See text. Also, biomass cofiring is given in incremental cost above the baseline alternative of firing coal alone. Fuel at $0.25/MBtu means $1.25 when coal is $1.00, or $1.50 when coal is $1.25/MBtu. And, for cofiring, capital and operating costs are the increments above firing 100% coal, without biomass.

**Note: Landfill gas and animal wastes are energy sources that eliminate CH4, not CO2, emissions and reduce greenhouse warming impact by 21x CO2 reduction per unit weight. This cuts cost per unit C by factor of 21x16/44 = 7.6, and increases the tonnes of CO2 equivalent by that same factor. See text.

Sensitivity of Results

The costs of carbon reduction in Table 7-7 are derived from differences between the estimated future costs of the renewable technologies and the costs adopted for the fossil alternatives. The extra cost in $/MWh are the same versus both fossil alternatives, because values for the cost of electricity from new, not existing, coal- and gas-fired power plants were selected to be the same, namely $42/MWh. As discussed in Section 5 above, the conversion from extra $/MWh to cost in $/tonne-C of fossil carbon emission avoided depends on the carbon intensity in tonne-C/MWh of the fossil power system whose emission is avoided. The carbon costs in $/tonne-C in Table 7-7 are based on the coal case, which is 0.236 tonne-C/MWh. If natural gas in an efficient advanced com-bined cycle is the fossil option avoided, then the factor is 0.09 tonne-C/MWh, and the resulting carbon avoidance cost is higher by a factor of 0.236/0.09, or 2.62. (The last three columns in Table 7-8 at the very end of this section show examples of extra cost in $/MWh being converted to $/tonne-C for both coal and natural gas as the advanced fossil power plant carbon emission avoided.)

Both the coal and the gas alternatives are estimated at essentially the same cost of 4.2¢/ kWh which is also $42/MWh. A 15%, or 0.6¢/kWh, change in that 4.2¢/kWh cost will change the carbon reduction cost by $6/MWh which converts to $6 per 0.95 tonne of CO_2 or (12/44) x 0.95 = 0.26 tonne of C, i.e., $23/tonne-C. This uncertainty of $23/tonne-C is equal to the total carbon reduction cost values near the low-cost end, and is in the range of 7% to 10% of the values at the high end of the carbon costs estimated in Table 7-7. If the future cost of natural gas fuel is $3.00/Mbtu, instead of the $4.00/Mbtu, the effect is a $5/MWh lower cost of the natural gas alternative and nearly a $20/tonne-C higher cost of the renewable options.

Of course, there is a similar uncertainty associated with the estimates of the costs of the renewable technologies themselves. The uncertainty of these will range from 15% of 4¢/kWh, i.e., 0.6¢/kWh or $6/MWh, to values as large as 30% of high costs like 10¢ to 20¢/kWh at the high-cost, high-uncertainty end (i.e., 30% of costs as high as $100/MWh to $200/MWh). These translate into uncertainties in carbon reduction costs as large a proportion as ±100% of the cost at the low end of $20/tonne-C, to values on the order of ±30% of some $200 to $500/tonne-C at the high-cost, high-uncertainty end.

Some Specific Sensitivities

Economic Parameters. As discussed in Section 4, the one dominant economic parameter is set the same for all the technologies, except for cofiring. This is the 21% “fixed charge rate,” or annual capital recovery factor, used in all except biomass cofiring. As explained in Section 4 and above, for cofiring this is set at a rate of 33%, because cofiring must compete with other near-term capital expenditures for improvments at existing coal-fired plants.

As also pointed out earlier, in all the above cases solar PV has been given the advantage of a $100/MWh, which is 10¢/kWh, alternative price. Because the other renewables are shown as competing against a $42/MWh fossil alternative, this is nearly a $60/MWh, or $150/tonne-C, effect in favor of PV residential. However, the advantage is real, at least during the near- to mid-term while solar PV enters residential, commercial and remote location markets rather than bulk power markets. It reflects the actual and substantial retail versus wholesale generation price differential, and it reflects the fact that the best openings for solar PV will be where the sunlight itself is the distribution system and beats the cost of putting in the wires or bringing in high-cost diesel fuel.

Fuel Costs for Geothermal and Biomass. Biomass is the only renewable technology that pays for fuel as an ongoing operating cost. In some analyses, but not as done here, geothermal has a “fuel” input in the form of hot water flowing into the power plant. However, in this report and in the Technology Characterizations report (Ref.4), the cost to obtain this "geothermal fuel” is taken to be a capital expense, not a fuel cost. (The capital is spent to drill and complete the wells, and to buy and install the pipelines/pumps/etc. that bring hot water to the power plant and take the cooler water back from the plant into the injection wells, which inject it back into a cool part of the underground reservoir.) Therefore, for geothermal as done here, the non-capital costs are operating costs, not fuel costs. And, being for the most part fixed costs for payroll and maintenance, these operating costs are unlike fuel costs in that they are not tied closely to the plant heat rate nor to variations in the "fuel" flow rate, the rate of geothermal fluid flow to and from the plant.

Biomass. For biomass, fuel cost is very important in the economics. The fuel cost used for “advanced biomass” merits special comment, because energy crops are the fuel assumed when a potential capacity of 40 GWe is named in Table 7-7. (See, also, Tables 7-3 and 7-4.) Fuel cost of $1.50/MBtu is the basis for the “advanced biomass” case, together with a high efficiency, i.e., the low heat rate of 7600 Btu/kWh, which corresponds to a higher heating value (HHV) efficiency of 45%. The $1.50/MBtu is low compared to current estimates for energy crop costs when “dedicated biomass feedstock supply systems” are studied. A recent paper from the Oak Ridge National Laboratory (ORNL) on the price necessary to displace conventional farm crops gave $2.50/MBtu and $3.50/MBtu as the prices needed to bring millions of acres into energy crop production (Ref.44). The much lower price of $1.50/MBtu is justified here for two reasons:

1. The energy crop could be the coproduct of a pulp/fiber farm, where a high-value fiber product is 70 to 80% of the mass grown and harvested and pays nearly all of the planting, cultivating and harvesting cost.

2. The fuel has a much lower cost of harvesting than that used in ORNL analysis (about $5/dry ton, versus the $20/dry ton apparently used in Reference 44).

These two measures to reduce costs are capable of reducing the total cost of energy crop fuel by $1.00 to $2.00/MBtu, having the effect of reducing a $3 to $4 per million Btu cost down to the $1 to $2 per million Btu range. These ways to reduce energy crop costs are discussed in a 1995 EPRI paper and a 1998 EPRI report (Refs.45,46). The harvesting improvement is addressed in the first EPRI Whole Tree Energy report (Ref.39) and also in studies on energy from willows by Niagara Mohawk, DOE and EPRI (Refs.46,47).

The “existing biomass” category in the supply curve in Table 7-7 also uses a $1.50/MBtu fuel cost, as does the separe feed biomass cofiring line. This $1.50 is at the midpoint of a wide range of possible biomass fuel costs. Today, the wood-derived biomass that is the fuel for existing biomass power plants, and for most cofiring operations at coal-fired plants in the near-term future, comes at costs ranging from $0.50/MBtu to $2.50MBtu. On a dry-weight basis the price range for biomass fuels both for today and for studies of future options is from a low of $8 to a high of $40, per dry ton. (Since normal green wood freshly cut is about 50% moisture, this range in dry weight costs is a range from $4 to $20 per “as-received” ton, at this 50% moisture value.) The low end, at $0.50/MBtu, is enough to pay typical transportation costs to move the fuel some 30 to 70 miles (50 to 110 km) from source to power plant. Given such a large range in possible biomass fuel costs, the resulting range in carbon reduction costs is very large. Table 7-8 shows this.

The range of biomass power plant efficiencies is also taken into account in Table 7-8. The low efficiency end of this range is that seen in some of today's high-heat-rate plants at 16,000 Btu/kWh (16.9 MJ/kWh, and 21% efficiency on a higher heating value, HHV, basis) to future advanced plants such as biomass gasification (IGCC) at 7500 Btu/kWh (7.9 MJ/kWh and 46% efficiency on an HHV basis).

Table 7-8
Sensitivity to Biomass Fuel Cost and Conversion Efficiency

Case Identification (Fuel Cost, Heat Rate)	Biomass Fuel Cost (basis: 8300 Btu/lb, dry) $/dry ton	$/MBtu	Heat Rate (Btu/kWh)	Result: Fuel Cost ($/MWh)	Result: Carbon Cost ($/tonne-C)** Coal at 0.236 tonne-C/MWh	Nat. gas at 0.09 tonne-C/MWh
Low cost, HR = 7,500	$8.30	$0.50	7,500	$3.75	$15.89	$41.67
Low cost, HR = 10,000	$8.30	$0.50	10,000	$5.00	$21.19	$55.56
Low cost, HR = 16,000	$8.30	$0.50	16,000	$8.00	$33.90	$88.89
Mid-range, HR = 7,500	$24.90	$1.50	7,500	$11.25	$47.67	$125.00
Mid-range, HR = 10,000	$24.90	$1.50	10,000	$15.00	$63.56	$166.67
Mid-range, HR = 16,000	$24.90	$1.50	16,000	$24.00	$101.69	$266.67
High cost, HR = 7,500	$41.50	$2.50	7,500	$18.75	$79.45	$208.33
High cost, HR = 10,000	$41.50	$2.50	10,000	$25.00	$105.93	$277.78
High cost, HR = 16,000	$41.50	$2.50	16,000	$40.00	$169.49	$444.44

**Coal case is advanced pulverized coal plant with scrubber at a heat rate of 9087 Btu/kWh. Natural gas is an advanced combined cycle at a heat rate of 6350 Btu/kWh. These efficiencies are (HHV basis) 37.6% for the coal, and 53.7% for the natural gas. Emission factors are 519 lb-C/MWh or 0.236 tonne-C/MWh for the coal, and 201 lb-C/MWh or 0.09 tonne-C/MWh for the natural gas. Values from EIA Kyoto report (Ref.15), pages 73 and 75.

8
INTERNATIONAL CONTEXT

Status of Renewables

The first two tables here indicate the extent to which renewable power generation technologies are already deployed in various countries or regions of the world (Ref.48). Table 8-1 measures energy use in quads (10^15 Btu/year, where 1 quad = 0.95 x 10^18 J, i.e., 0.95 EJ). Because of the role of wood--which was, after all, the original fuel used by humans--biomass appears as the leading non-hydro renewable, as deployed to date. However, much of the biomass (i.e., wood) fuel is used for simple heating tasks. This "primitive" use of biomass fuel is often called inefficient, and most certainly is inefficient in many of its applications. Historically, the use of wood fuel has often, perhaps usually, not been sustainable, i.e., forests have been cut down faster than they grow back.

Figure 8-1
World Renewable Energy in 1988-1996 by Major Groups and Regions

(Energy in quads = 10^{15} Btu)

Country or Region	1988	1990	1992	1994	1996	1997 (quads and TWh, HR=10000)** quads	TWh
USA	0.8	0.830	0.970	1.020	0.990	0.867	86.7
Canada	0.040	0.040	0.050	0.055	0.060	0.061	6.1
Western Europe	0.080	0.090	0.100	0.110	0.140	0.494*	49.4*
Japan	0.030	0.030	0.040	0.040	0.040	0.142	14.2
Australia/NZ	0.030	0.040	0.050	0.040	0.070	0.037	3.7
EE/FSU	0.001	0.001	0.001	0.001	0.001	0.001	0.1
China	0.007	0.007	0.008	0.008	0.008	0.008	0.8
India	0.032	0.032	0.032	0.032	0.033	0.036	3.6
Indonesia	0.020	0.020	0.030	0.040	0.050	0.050	5.0
Far East/Oceana**	0.100	0.110	0.110	0.130	0.130	0.153	15.3
Brazil	0.050	0.050	0.070	0.070	0.090	0.091	9.1
Mexico	0.100	0.100	0.120	0.110	0.110	0.067	6.7
Central/South America	0.010	0.020	0.020	0.030	0.030	0.053	5.3
Africa	0.010	0.010	0.010	0.010	0.010	0.003	0.3
Mid East	0.001	0.001	0.001	0.001	0.001	0.001	0.1
World Total***	1.311	1.381	1.612	1.697	1.763	2.064	206.4
Alternate (lower) total***	1.23	1.31	1.49	1.60	1.68	1.70	170

* Western Europe in 1997 was only 35 TWh and 0.3 quad, per Table 8-4. 49.4 is at the high end of a range.
** Philippines geothermal, except for 0.010 geothermal in Vietnam in 1994 and 1996, accounts for all in "Far-East/Oceana."
Source: EIA, "International Energy Outlook, 1998." (Ref.48) with additions by EPRI, per text.

The units in Table 8-1 are quads and TWh. One quad = 10^15 Btu = 1.055 EJ = 1.055 x 10^18 joules. 1 TWh = 10^9 kWh. (See Appendix C for units and conversion factors.) Heat rates are in Btu/kWh in Table 8-1. 10,000 Btu/kWh = 10,550 kJ/kWh = 10.55 MJ/MWh.

In Table 8-1 the generation of electricity in TWh is converted to quads at heat rate of 10,000 Btu/kWh. Use of actual biomass and geothermal heat rates gives higher values in quads but overstates the fossil fuel displaced. 10,000 Btu/kWh is the heat rate of the fossil displaced, if the power plant is a new fossil fuel steam boiler system. Table 8-4, later in this section, shows other (actual) heat rates for biomass and geothermal at 15,000 and 25,000 Btu/kWh, respectively.

Table 8-1 does not include the 30 to 45 quads of non-commercial or "traditional" biomass fuel use. It is such use that makes biomass some 15% of the world's current energy supply. Such uses are not counted here as biomass, because they are outside the commercial flow of energy, are not considered to be starting points for the new biomass power and heat technologies that are the subject of this report, and, as stated at the opening above, may not be sustainable or, at least, are often not considered to be sustainable. Such fuels, if sustainable, can become part of the biomass fuel resource for the new modern efficient technologies that are the subject of this report.

Table 8-2 shows electricity generation from non-hydro renewable sources.

The column for 1997 in the first table (Table 8-1) reflects the additions for biomass power that were not included in the original source of the data for Table 8-1 (Ref.47). Most of these additions are as shown in Table 8-2, where renewable electricity generation is displayed, in units of TWh (billions of kWh).

The data added to Table 8-1 for 1997 displays the numbers shown in Table 8-2 as the additional biomass electricity. In the extra two columns added to Table 8-1, the electricity generation is shown explicitly in the column on the far right, and the primary energy input associated with that electricity is in the second column from the right. These additions are based, in part, on data from another source: the OECD/IEA World Energy Outlook 1998 (Ref.72). The OECD/IEA reference shows groups of countries and gives totals for these groups that have been used by EPRI to revise some estimates by country and region from the values otherwise obtained from the EIA source (Ref.47) or otherwise estimated by EPRI.

The OECD/IEA reference shows China as a region unto itself. This OECD/IEA source, together with an EPRI estimate to be shown next as Tables 8-3 and 8-4 below, indicates that China does have some renewable energy already deployed, even if most of the “non-commercial” biomass energy is not included in the count. As the EPRI estimates to be shown later here in Table 8-3 indicate, China is estimated as having a very large share of the world’s non-commercial biomass energy use. While a great proportion of this may be considered “primitive” rather than “new” technology, some of it, such as small-scale gasification or anaerobic digestion units producing biogas for homes and small operations, may provide a baseline for some modern renewable biomass energy systems. Therefore, a small fraction, less than 10%, of the non-commercial biomass used in China is counted as renewable power, as shown on the China line in the two 1997 columns on the right hand side in Table 8-1.

Figure 8-2
World Renewable Electricity Generation (TWh) 1988-1997

(1 TWh = 10^9 kWh)

	1988	1990	1992	1994	1996	1997	Biomass (if not in-cluded)	Total w/ biomass added
USA	60	63.9	76.8	81.3	80.3	86.8	included	87
Canada				0.1	0.1	0.1	6	6
Western Europe	4.1	4.7	5.9	7.3	9.7	12.1	18	30
Japan	1.3	1.7	1.7	2	3.5	3.7	10	14
Australia/NZ	1.2	2.1	2.1	2.1	2	1.8	--	2
EE/FSU	s*	s	s	s	S	s	--	<0.05
China	s	s	s	s	S	s	--	0.5
India	s	s	s	0.2	0.1	0.2	2	2
Indonesia	1	1.1	1	1.5	2.5	2.9	2	5
Far East/Oceana**	4.8	5.2	5.4	6.2	6.4	6.5	3	9
Brazil	4.8	4.9	6.6	7.2	8.5	9.4	included	9
Mexico	4.7	4.9	5.5	5.3	5.4	5.2	--	5
Central/South America	0.6	0.8	0.8	1.2	1.4	1.6	--	2
Africa	0.4	0.4	0.4	0.3	0.4	0.5	--	1
Mid East	0	s	s	s	0	0	--	0
	=====	=====	=====	=====	=====	=====	=====	=====
World Total	83	89.7	106.3	114.6	120.6	130.8	41	172.5
						131	←rounded	
						41	←added	
						172	←revised total	

* "s" indicates less than 0.05 x 10^9 kWh (10^9 kWh = 1 TWh)

**Nearly all Philippines geothermal (except for 0.4 Vietnam geothermal '94-'96)

The biomass fuel use of interest as a basis from which to launch and expand a future sustainable renewable energy enterprise is the relatively recent (since 1970) deployment of cleaner and more efficient boilers (for power, steam or heat) using fuel that is drawn from sustainable forest or agricultural practices. In fact, it is these newer and better uses of biomass fuel that constitute nearly all of the biomass power generation shown in Table 8-2. [Much of the modern use of wood-based fuels such as bark, sawdust and other wood residues, occurs in boilers within or closely associated with pulp and paper or lumber mills, and is combined heat and power ("CHP"). Sometimes only a rather small fraction or none at all is net power to the electrical distribution grid beyond the mill. For example, in Brazil some 600 MW or more is generated at mills with only about 30 MW being net to the grid (Ref.49).]

The numbers for the United States (USA in international tables here) that were given at the beginning of this report in Table 1-1 provide a detailed breakdown for the year 1996. From that Table 1-1 we can see that the following contributions were made in 1996:

International Context

USA 1996 (from Table 1-1)	Capacity GWe	Generation 10^9 kWh	Annual Hours*	Capacity Factor**
Geothermal	3.02	15.7	5199 .	0.593
MSW (inc landfill gas)	3.32	20.9	6307	0.720
Wood/Biomass	7.32	46.4	6344	0.724
Solar	0.37	0.8	2216	0.253
Wind	1.85	3.2	1714	0.193
Total	15.88	87.0		

* "Hours" as calculated from the Generation divided by the Capacity.

** "Capacity Factor" as calculated from "Hours" divided by 8760.

The lower total for the amount of generation given in Table 8-2, i.e., 80.3 x 10^9 kWh in the 1996 column, compared to the 87.0 above, may be due to landfill gas not being counted in the biomass category or may just be an incompatibility in some other aspects of the counting. Note that the 1997 preliminary numbers for the USA in Table 8-2 are very close to the Table 1-1 results.

The worldwide data in Tables 8-1 and 8-2 are incomplete due to the omission of some country data and of a significant amount of biomass-based power generation. Biomass was included in the EIA source (Ref.48) only for the USA and Brazil. This omits the generation from wood and wood wastes in Canada, Finland, Sweden, and some other countries where power is generated in association with wood products including pulp/paper, industries. It also omits power generation in sugar mills, although having captured biomass for the USA and Brazil, the omission of sugar mills may be a small effect. The data in Tables 8-1 and 8-2 also omit power generation from municipal solid waste, which is a significant source of renewable power in Europe and Japan.

By using other sources of information (Refs.49,50,51,52), EPRI has corrected some of the EIA (Ref.48) source's biomass omissions, as follows:

1. Canada. The biomass, which was not included in Table 8-2, is actually the dominant non-hydro renewable (Ref.50,51). The 0.1 x 10^9 kWh in Table 8-2 must be wind, and is less than 2% of the total generation in Canada. Using "Electric Power Statistics" for the year 1994 by the Industry Division of Statistics, Canada (Ref.51), EPRI counts 54 boilers at 31 different power generating stations that add up to a total of 882 MWe. At a capacity factor of 70%, these 882 MWe would be operating about 6000 hour/year and generating 5.3x10^9 kWh. The very large 70 MWe station at Williams Bay built in the 1994-95 (approx.) period would add another 0.5x10^9 kWh renewable electricity generation in Canada. The 5.5 to 6.0 TWh (1 TWh = 10^9 kWh) of biomass is wood and black liquor in about 40/60 proportions.

2. Western Europe. Finland has some 1000 MWe of wood-based power gneration and Europe's waste-to-energy power generation adds 1000 MWe. Sweden's wood waste and paper mill power generation is about 500 MWe and a comparable amount exists elsewhere in Europe. The additional 1000 + 1000 + 500 + 500 = 3000 MWe or about 18 more TWh.

3. Japan. The waste-to-energy biomass in Japan is comparable to USA, or about 2000 MWe at about 5000 hour/year, meaning 10 TWh more renewable power generation.

4. India. India began biomass power generation at some sugar mills during the 1990's, and EPRI estimates this at 500 MWe for 4000 hours per year or 2 x 10^9 kWh.

5. Philippines, Indonesia and Thailand. About the equivalent of India's at sugar mills plus a comparable amount from wood operation, i.e., saw mills and pulp mills. Total would be another 2 x 10^9 kWh from sugar mills and 500 MWe for 6000 hours per year, which gives 3 x 10^9 kWh per year, from wood wastes.

6. Total Added. The above additions of biomass electricity generation add the numbers given in the 2nd-from-right column, in Table 8-2, to those taken from the EIA source (Ref.48). The right hand column then shows the revised totals by country. These estimates of uncounted biomass add a total of 41 x 10^9 kWh to the worldwide total of non-hydro renewable power generation, making it 172 TWh.

The EIA source (Ref.48) does not show a breakdown of the renewables into the solar, wind geothermal and biomass categories, i.e., not by country. However, EPRI's general familiarity with the types of resources and major projects in many countries, plus the additional data sources used to augment the biomass numbers in Table 8-2 (Refs.49-52) and some additional sources on all four of the renewables (Refs.53,54,55,56), makes possible the estimates shown in Table 8-3 for the breakdowns into the four categories of renewable resource types. Table 8-4 shows how the values in EJ in Table 8-3 are derived from electricity measures (TWh, MW, capacity factor).

Figure 8-3
Renewable Energy in 1997 by Country and by Type (EJ, 1 EJ = 10^18 joules)

Country or Region	Non-comm. Biomass	Biomass Power	Geotherm. Power	Wind* Power	Solar Power	Renewables: Total Power
USA	2.0	1.0612	0.4134	0.0287	0.0086	1.5119
Canada	0.3	0.0945	0.0005	0.0001	0.0001	0.0952
Western Europe	1.0	0.5513	0.1614	0.0820	0.0042	0.7989
Japan	0.1	0.1575	0.1042	0.0002	0.0021	0.2640
Australia/NZ	0.1	0.0158	0.0672	0.0001	0.0011	0.0841
East.Eur./FSU	3.0	0.0002	0.0021	0.0001	0.0000	0.0024
China	10.0	0.0079	0.0005	0.0026	0.0001	0.0111
India	10.0	0.0315	0.0005	0.0167	0.0001	0.0488
Indonesia	2.0	0.0158	0.0612	0.0002	0.0001	0.0772
Far East/Oceana	1.0	0.0158	0.3743	0.0001	0.0001	0.3903
Brazil	1.8	0.1418	0.0003	0.0003	0.0004	0.1427
Mexico	0.5	0.0158	0.1462	0.0002	0.0001	0.1623
Central/So.America	0.5	0.0473	0.0601	0.0002	0.0001	0.1077
Africa	2.0	0.0032	0.0089	0.0002	0.0001	0.0124
Middle East	0.2	0.0016	0.0039	0.0001	0.0002	0.0058
World Total	**34.5**	**2.1607**	**1.4049**	**0.1318**	**0.0174**	**3.7149**

Figure 8-4
Electricity from Renewable Energy Sources by Country and Region (circa 1997)**

Country or Region	Biomass Power & CHP EJ	Geo-Therm. Power EJ	Wind* Power EJ	Solar Power EJ	Renewable Power Total EJ	Bio hr/yr = 6400, Bio HR = 15000: Biomass TWh	Bio.HR heat rate	Bio. MWe	Bio. EJ	Geo hr/yr = 7500, Geo HR = 25000: Geo. TWh	Geo.HR heat rate	Geo. MWe	Geo. EJ	Wind hr/yr = 1700, Wind HR = 10000: Wind TWh	Wind MWe	Wind EJ	Solarhr/yr = 2300, Solar HR = 10000: Solar TWh	Solar MWe	Solar EJ
USA	1.0612	0.4134	0.0287	0.0086	1.5119	67.38	15000	10528	1.061	15.75	25000	2100	0.413	2.73	1606	0.029	0.82	357	0.009
Canada	0.0945	0.0005	0.0001	0.0001	0.0952	6.00	15000	938	0.095	0.02	25000	3	0.001	0.007	4	0.000	0.008	3	0.000
Western Europe	0.5513	0.1614	0.0820	0.0042	0.7989	35.00	15000	5469	0.551	6.15	25000	820	0.161	7.81	4594	0.082	0.4	174	0.004
Japan	0.1575	0.1042	0.0002	0.0021	0.2640	10.00	15000	1563	0.158	3.97	25000	529	0.104	0.019	11	0.000	0.2	87	0.002
Australia/ NZ	0.0158	0.0672	0.0001	0.0011	0.0841	1.00	15000	156	0.016	2.56	25000	341	0.067	0.01	6	0.000	0.1	43	0.001
East.Eur./FSU	0.0002	0.0021	0.0001	0.0000	0.0024	0.01	15000	2	0.000	0.081	25000	11	0.002	0.01	6	0.000	0.001	0	0.000
China	0.0079	0.0005	0.0026	0.0001	0.0111	0.50	15000	78	0.008	0.02	25000	3	0.001	0.25	147	0.003	0.01	4	0.000
India	0.0315	0.0005	0.0167	0.0001	0.0488	2.00	15000	313	0.032	0.02	25000	3	0.001	1.59	935	0.017	0.01	4	0.000
Indonesia	0.0158	0.0612	0.0002	0.0001	0.0772	1.00	15000	156	0.016	2.33	25000	311	0.061	0.02	12	0.000	0.01	4	0.000
Far East/Oceana	0.0158	0.3743	0.0001	0.0001	0.3903	1.00	15000	156	0.016	14.26	25000	1901	0.374	0.01	6	0.000	0.01	4	0.000
Brazil	0.1418	0.0003	0.0003	0.0004	0.1427	9.00	15000	1406	0.142	0.01	25000	1	0.000	0.03	18	0.000	0.04	17	0.000
Mexico	0.0158	0.1462	0.0002	0.0001	0.1623	1.00	15000	156	0.016	5.57	25000	743	0.146	0.02	12	0.000	0.01	4	0.000
Central/So.America	0.0473	0.0601	0.0002	0.0001	0.1077	3.00	15000	469	0.047	2.29	25000	305	0.060	0.02	12	0.000	0.01	4	0.000
Africa	0.0032	0.0089	0.0002	0.0001	0.0124	0.20	15000	31	0.003	0.34	25000	45	0.009	0.02	12	0.000	0.01	4	0.000
Middle East	0.0016	0.0039	0.0001	0.0002	0.0058	0.10	15000	16	0.002	0.15	25000	20	0.004	0.01	6	0.000	0.02	9	0.000
Total of above	2.1607	1.4049	0.1318	0.0174	3.7149	137.19	15000	21436	2.161	53.521	25000	7136	1.405	12.556	7386	0.132	1.659	721	0.017
Alternative world total (used in Tables 8-1, -2)	1.5	1.2	0.14	0.02	2.9	96	15000	15000	1.512	45	25000	6000	1.181	13	7647	0.140	1.8	783	0.019

*Wind grew very fast 1997-2000. For the year 2000 world total is expected to be approx. 0.3 EJ and 30 TWh rather than only 0.13 EJ and 13 TWh.

**Note: The units are TWh for generation and MWe for generating capacity, and then, calculated from the electricity, the values in EJ (1 EJ = 1.055 x 10^15 Btu = 1.055 quad) for primary energy input to make electricity. The heat rates used to convert electricity generation in 10^9 kWh (TWh) to primary energy in EJ are: 15,000 Btu/kWh, biomass (approx.actual); 25,000 Btu/kWh, geothermal (approx.actual); and 10,000 Btu/kWh,wind and solar PV (fossil alternative, not wind and solar actual). The capacity factors used to calculate hours per year and convert TWh into MWe are: biomass 0.731, i.e., 6400 hours; geothermal 0.856, i.e., 7500 hours; wind 0.194, i.e., 1700 hours; and solar, 0.263, i.e., 2300 hours.

Tables 8-3 and 8-4 are for "today" and the values given are for 1997, or estimated for 1997 from some other year. It is important to note that wind energy use for commercial power generation is increasing very fast, and, therefore, the same table done for the year 2000 would show a world-wide total of about twice as much windpower deployment: nearly 14,000 MWe, not 7400.

Table 8-4 was used to derive the primary energy inputs in EJ displayed in Table 8-3. Table 8-4 was done starting with TWh values and then calculating EJ and MWe based on reasonable choices for the heat rates and the hours/year (i.e., capacity factors). The display in Table 8-3 is for "primary energy" and is measured in exajoules (EJ). Five columns on the left in Table 8-4 show the EJ values for each of the four renewables, and their total, and were derived from the appropriate columns farther to the right. The EJ values are the primary energy given in Table 8-3. Note that EJ values in Table 8-3 are derived from high actual heat rates, not the low (10,000) Btu/kWh) fossil displacement heat rate used in Table 8-1.

Growth Scenarios for Renewable Power Generation

In order to address the issue of whether renewable power resources and technologies could be expected, under favorable economic or other incentives, to expand fast enough to provide the amounts of electricity generation from renewables shown in various scenarios, Table 8-5 and Table 8-6 have been prepared to display explicitly the annual expansion rates over various future 10-year periods that would lead to "low" (Table 8-5) and "high" (Table 8-6) cases of worldwide expansion of renewables. It should be noted that even the "low" case assumes there are incentives that drive the world toward expanded generation of electricity from renewable sources; the growth rates are simply more modest in the "low" case.

Next, we investigate possible limits to these growth scenarios, limits that could be imposed by resource constraints. We start with the constraint often expected to severely limit biomass energy, namely the need for the land that could grow forests or energy crops to be dedicated instead to growing food and feed to support a much larger human population on the planet in the next 50 or 100 years.

Limit on Biomass

Of the various studies of food/feed needs as a limit on biomass energy, this report considers two. These two could have indicated a limit on biomass at a level below the high case presented in Table 8-6. Such a limit would arise due to competition between the possible use of arable land to grow energy crops in an agricultural (not forest) setting and the use of that arable land instead to produce food and feed for a future world population some 3 to 5 billion above today's 6 billion. Therefore, EPRI here investigates this possible limit. The limit turns out to be compatible with adoption of the high growth scenario for biomass.

One study was a part of the WEC/IIASA project to develop scenarios for world energy futures (Ref.12). The other was part of the development of an energy model at the Central Research Institute of the Electric Power Industry (CRIEPI) in Japan. The result from the WEC/IIASA

Figure 8-5
Low Renewables Growth Scenario - World

Units are GWe of installed generating capacity, unless noted otherwise.

Year	Biomass	Geothm	Wind	Solar th.	Solar PV	"Renew-ables" Total	Hydro	Renewable Total with Hydro
2000	20	7	10	0.4	0.7	38.1	667	705.1
Growth rate/yr	0.050	0.070	0.140	0.100	0.200		0.020	
2010	32.6	13.8	37.1	1.0	4.3	88.8	813.1	901.9
Growth rate/yr	0.100	0.100	0.140	0.200	0.200		0.020	
2020	84.5	35.7	137.4	6.4	26.8	290.9	991.1	1282.0
Growth rate/yr	0.100	0.100	0.100	0.100	0.150		0.020	
2030	219.2	92.6	356.5	16.7	108.6	793.5	1208.2	2001.7
Growth rate/yr	0.050	0.050	0.050	0.100	0.150		0.010	
2040	357.0	150.9	580.7	43.2	439.2	1571.0	1334.6	2905.6
Growth rate/yr	0.020	0.020	0.050	0.100	0.100		0.010	
2050	435.2	183.9	945.8	112.1	1139.2	2816.3	1474.2	4290.5
Generation (in TWh) in 2050	**2859**	**1370**	**2900**	**393**	**2495**	**10,016**	**6457**	**16,473**
CapFac in 2050	0.750	0.850	0.350	0.400	0.250		0.500	
Hours (cf*8760)	6570	7446	3066	3504	2190		4380	
2050 in units of EJ @ 0.386 eff.	**27**	**13**	**27**	**4**	**23**	**93**	**60**	**154**

Figure 8-6
High Renewables Growth Scenario - World

Units are GWe of installed generating capacity, unless noted otherwise.

Year	Biomass	Geoth.	Wind	Solar th.	Solar PV	Non-hydro Renewables Total	Hydro	Renew. Total with Hydro
2000	20	7	10	0.4	0.7	38.1	667	705.1
Annual growth rate	0.100	0.100	0.200	0.100	0.250		0.030	
2010	51.9	18.2	61.9	1.0	6.5	139.5	896.4	1035.9
Annual growth rate	0.100	0.100	0.140	0.200	0.200		0.030	
2020	134.5	47.1	229.5	6.4	40.4	458.0	1204.7	1662.6
Annual growth rate	0.100	0.100	0.140	0.100	0.200		0.020	
2030	349.0	122.1	851.0	16.7	249.9	1588.7	1468.5	3057.2
Annual growth rate	0.070	0.070	0.050	0.100	0.175		0.010	
2040	686.5	240.3	1386.1	43.2	1253.7	3609.9	1622.1	5232.0
Annual growth rate	0.030	0.030	0.050	0.100	0.150		0.010	
2050	922.6	322.9	2257.9	112.1	5072.0	8687.5	1791.8	10479.3
Generation (in TWh) in 2050	**6062**	**2404**	**6923**	**393**	**15551**	**31,332**	**8241**	**39,573**
CapFac in 2050	0.750	0.850	0.350	0.400	0.350		0.525	
Hours (cf*8760)	6570	7446	3066	3504	3066		4599	
Year 2050: Conversion to EJ @ 0.386 eff.	**57**	**22**	**65**	**4**	**145**	**292**	**77**	**369**

study was summarized in a sidebar (Box 5.2) in the WEC/IIASA report (Ref.12). It compares land needed for both agriculture and biomass energy with current use and future needs. Those future needs are for the long term, with scenarios displayed for 2050 and for 2100. Table 8-7 shows the result for the year 2050.

Figure 8-7
Year 2050 Possible Limit on Land for Biomass Energy
(calculations based on high biomass case for year 2050)
Energy units are Gtoe, 1 Gtoe = 41.9 EJ.

Land (10^6 hectare, Mha)	Industrialized Countries	Africa plus Middle East	Asia	Latin America	Total World
Forests	1770	630	600	890	3890
Pastures	1190	700	880	590	3360
Agriculture	670	150	470	150	1440
Total	3630	1480	1950	1630	8690
Potential Arable	--	990	500	950	2440
Biomass Maximum in 2050					
Traditional Energy,Gtoe	0.10	0.20	0.40	0.10	0.80
New Bioenergy, Gtoe	0.90	0.70	1.00	0.60	3.20
Residue (20%), Gtoe	0.18	0.14	0.20	0.12	0.64
Plantations (80%), Gtoe	0.72	0.56	0.80	0.48	2.56
Land in Plantations, Mha	70	110	160	50	390
Average Yield, toe/ha*	10.3	5.1	5.0	9.6	6.6
Plantations (100%), Gtoe	0.90	0.70	1.00	0.60	3.20
Land in Plantations, Mha	100	180	250	80	610
Average Yield, toe/ha*	9.0	3.9	4.0	7.5	5.2
Results:					
Bio. (80% plantations), Mha	70	110	160	50	390
**New land for food/feed, Mha	50	95	33	72	250
Total new land cultivated, Mha	120	205	193	122	640
Fraction of Potential Arable	--	21%	39%	13%	26%
Bio. (100% plantations), Mha	100	180	250	80	610
New land for food/feed, Mha	50	95	33	72	250
Total new land cultivated, Mha	150	275	283	152	860
Fraction of Potential Arable	--	28%	57%	16%	35%

*Note that toe/ha is exactly the same as dry short tons per acre, based on the following: 0.4047 Hectares/acre, 41.9 GJ/toe, 1.055 GJ/MBtu, and 16.1 MBtu per dry short ton of biomass.
**The new land added to agriculture to support global population of 10 x 10^9 (an increase of 5 x 10^9 over the 5 billion people in 1990).

Then, Table 8-8 shows the projection to 2100 from that same Box 5-2 in the WEC/IIASA report.

Figure 8-8
Year 2100 Possible Limit on Land for Biomass Energy
(calculations based on high biomass case for year 2100)
Energy units are Gtoe, 1 Gtoe = 41.9 EJ.

Land (10^6 hectare, Mha)	Industrialized Countries	Africa plus Middle East	Asia	Latin America	Total World
Forests	1770	630	600	890	3890
Pastures	1190	700	880	590	3360
Agriculture	670	150	470	150	1440
Total	3630	1480	1950	1630	8690
Potential Arable	--	990	500	950	2440
Biomass Maximum in 2100					
Traditional Energy,Gtoe	0.01	0.10	0.20	0.05	0.36
New Bioenergy, Gtoe	2.10	2.10	2.80	2.10	9.10
Residue (33%), Gtoe	0.70	0.70	0.93	0.70	3.03
Plantations (67%), Gtoe	1.40	1.40	1.87	1.40	6.07
Land in Plantations, Mha	150	140	260	140	690
Average Yield, toe/ha*	9.3	10.0	7.2	10.0	8.8
Plantations (100%), Gtoe	2.10	2.10	2.80	2.10	9.10
Land in Plantations, Mha	350	340	340	320	1350
Average Yield, toe/ha*	6.0	6.2	8.2	6.6	6.7
Results:					
Bio. (67% plantations), Mha	150	140	260	140	690
**New land for food/feed, Mha	50	95	33	72	250
Total new land cultivated, Mha	200	235	293	212	940
Fraction of Potential Arable	--	24%	59%	22%	39%
Bio. (100% plantations), Mha	350	340	340	320	1350
New land for food/feed, Mha	50	95	33	72	250
Total new land cultivated, Mha	400	435	373	392	1600
Fraction of Potential Arable	--	44%	75%	41%	66%

*Note that toe/ha is exactly the same as dry short tons per acre, based on the following: 0.4047 Hectares/acre, 41.9 GJ/toe, 1.055 GJ/MBtu, and 16.1 MBtu per dry short ton of biomass.
**The new land added to agriculture to support global population of 10 x 10^9 (an increase of 5 x 10^9 over the 5 billion people in 1990).

The conclusion of the authors of the WEC/IIASA report was that the numbers in Table 8-8 for the year 2100 show that the energy crop production is requiring an unrealistically large share of the "potentially arable land" and that a smaller role for biomass is more likely. The authors suggest the WEC/IIASA scenario B, the base case, or one of the C cases. The C cases are scenarios where growth is constrained by policies that limit fossil energy and high in either renewables or nuclear or both. The authors say that these B or C scenarios have a biomass role more likely to be achievable. Both of the lower scenarios that the authors refer to have biomass energy use at levels that are comparable to, or higher than, the “high” growth case displayed above as Table 8-6.

The second investigation of a food-based limit on bioenergy is the one by CRIEPI. The study was summarized in a paper presented at an OECD workshop held in Paris in February 1998 (Ref.57). Results from that paper on the CRIEPI analysis are displayed here as Table 8-9. The paper in the OECD workshop proceedings (Ref.57) is based on a full report (Ref.58). Table 8-9 gives results from the two graphs (bar charts) that summarize the CRIEPI report (Ref.58) in the paper in the OECD proceedings (Ref.57). The two graphs are for two different land use and food supply situations: (1) Scenario "La" in which the developing regions of the world continue to have a low-meat diet, and therefore place less demand on arable land for growth of feed for raising livestock for human food. (2) Scenario "Lb" in which the meat content of the diet in developing regions moves toward that of the developed regions.

Table 8-10 gives more details, especially the numbers from the CRIEPI paper that show the land productivity assumptions and the land area in hectares devoted to or needed for various uses. These are the numbers that were used in CRIEPI’s estimate of the amount of land that would be lost to possible energy crop production if there were an increase in per capita meat consumption applied to the population in the developing countries of the world. With more meat in the human diet there would be a greater need for land to grow feed for animals (more cereal crops) and, as a result, CRIEPI calculates that there would be no land for energy crops in the developing regions of the world. And, there would be much less land for such crops in the developed regions. This result is seen in the top row (“energy crops”) in Table 8-9. Land and yield numbers leading to this result are in Table 8-10. The CRIEPI paper (Ref.57) cites Ref. 59 as the source for the land and yield numbers used in the calculation. The result: a higher meat diet scenario for the year 2100 cuts the energy from energy crops from 155 EJ to 81 EJ, and the arable land planted in energy crops from 377 Mha to 200 Mha. Another result that emerges from the CRIEPI analysis, which is in contrast to the relative importance of future energy crops versus biomass residues in the United States, is that residues, not energy crops, are the bigger player worldwide. Table 8-9 shows this.

Table 8-11 shows the biomass energy potential as calculated in the various studies and their analyses of limits. The IIASA/WEC cases B and C, those that have less ambitious roles for biomass, are shown in Table 8-11 alongside the CRIEPI cases (high and low meat) and the growth scenarios for biomass done here in the biomass columns of Tables 8-5 and 8-6, above. Both the WEC/IIASA and the CRIEPI analyses point to "low" biomass numbers (bioenergy in the year 2100) that are slightly above, or about comparable to, the "high" case in this report. Therefore, the high biomass case here can be used without encountering a global limit due to competition with land required for food and feed.

Figure 8-9
Limit on Crop Bioenergy due to More Meat in Diet (Year 2100)

	@	Developing Regions			Developed Regions			World Total		
Source of Biomass Fuel	Rec. %	1990 Base	Less Meat #	More Meat #	1990 Base	Less Meat #	More Meat #	1990 Base	Less Meat #	More Meat #
Energy crops	100	0.0	54.8	None	4.0	100.0	81.0	4.0	154.8	81.0
Cereal residues*	25	12.0	89.7	100.0	12.0	12.0	17.0	24.0	101.7	117.0
Traditional fuelwood	100	20.5	51.7	51.7	4.0	4.5	4.5	24.5	56.2	56.2
Roundwood residues - From timber*	50	4.0	32.6	32.6	7.0	8.5	8.5	11.0	41.1	41.1
Roundwood residues - From pulp*	50	0.2	4.0	4.0	3.5	2.6	2.6	3.7	6.6	6.6
Mill residues	75	3.0	20.8	20.8	5.0	6.0	6.0	8.0	26.8	26.8
Black liquor	100	0.0	2.1	2.1	2.0	1.5	1.5	2.0	3.6	3.6
Fuelwood residues*	0	5.5	12.5	12.5	0.5	0.7	0.7	6.0	13.2	13.2
Timber scrap*	75	1.0	17.4	17.4	4.0	7.0	7.0	5.0	24.4	24.4
Paper scrap*	25	0.5	7.5	7.5	1.0	1.0	1.0	1.5	8.5	8.5
Sugarcane residues*	67	3.0	5.4	5.4	0.0	0.0	0.0	3.0	5.4	5.4
Bagasse	100	2.5	5.1	5.1	0.0	0.0	0.0	2.5	5.1	5.1
Dung*	25	6.0	19.6	24.6	7.5	8.0	8.0	13.5	27.6	32.6
Kitchen refuse*	75	3.5	8.7	9.7	2.0	2.2	2.2	5.5	10.9	11.9
Human feces*	25	3.5	8.7	9.7	2.0	2.2	2.2	5.5	10.9	11.9
Total 1: Maximum Bioenergy Potential		**65.2**	**340.6**	**303.1**	**54.5**	**156.2**	**142.2**	**119.7**	**496.8**	**445.3**
Total 2: Practical Bioenergy Potential		**25.3**	**202.2** #	**152.2** #	**13.8**	**128.8** #	**111.0** #	**39.0**	**330.9** #	**263.2** #

*Items marked * are wastes and residues set at 0% recovery for base year (1990) in the Total 2 calculation.

@The column marked @ shows the % recovered value assumed to calculate Total 2 for year 2100.

#The effect of more meat in diet is the difference between the adjacent #-marked columns, amounting to much less land available to grow energy crops, but with a small offset due to more cereal residues and food residues.

Figure 8-10
Land and Yield Numbers for Future Bioenergy Crops and Residues
(Land areas are in units of 10^6 hectares = Mha. Source for this table is Ref. 57, paper by CRIEPI.)

Item	1975	1990	2050	2100	1975	1990	2050	2100
Population (millions) --		3990	8580	10160	--	1270	1480	1500
Mature forest	2270	2050	1200	800	1665	1650	1590	1550
Growing "	50	50	600	1000	0	1	160	200
Tot.	2320	2100	1800	1800	1665	1651	1750	1750
Arable base, 1990	720	720	720	720	607	607	607	607
Deforested to arable	0	65	155	155	0	0	0	0
Other to arable	0	15	385	756	0	0	35	68
Tot.	720	800	1260	1631	607	607	642	675
Pasture base	2070	2070	2070	2070	1182	1182	1182	1182
Defor. to, pasture	0	155	365	365	0	0	0	0
Tot.	2070	2225	2435	2435	1182	1182	1182	1182
Other base	1650	1650	1650	1650	2666	2666	2666	2666
Other to arable	0	-15	-385	-756	0	0	-35	-68
Tot.	1650	1635	1265	894	2666	2666	2631	2598
Not counted					148	148	148	148
Total: all above	6760	6760	6760	6760	6268	6254	6353	6353
					6760			
					13028	world total land area		
Primary yield from forests (EJ)				103				
Resulting yield (GJ/ha)				57.222				
" " (t-biomass/ha)				3.8148				
" " (t-C/ha)				1.7167				
Timber from mature forests (EJ)				46.1				
Resulting yield (GJ/ha)				57.625				
Pulp+fuelwood from growing forests (EJ)				56.4				
Resulting yield (GJ/ha)				56.4				

Notes: Here are details and background calculations:

Conversion calculation:	Tonne bio/ha	dt bio/acre			
	3.81	1.4417		12.5354	0.18
	GJ/tonne bio	MBtu/dt bio			
	15	15.193			
Annual yield on arable land:			147.2	Land needed for 16EJ/yr more feed:	
Energy crops (EJ)	54.8			90.3 GJ/ha ===> 16/90	
Cereals (EJ)	71.2			= 177 x 10^6 ha	
Roots (EJ)	3.9			Loss of crop energy was 55+19 = 74EJ	
Sugar cane (EJ)	9.0			74 / 177 = 418 GJ/ha	
Other crops (EJ)	8.3			= 12.5 tonne-C/ha	
Resulting yield on arable land (GJ/ha)			90.3		
" " (tonne-C/ha)			2.7075		
" " (dry ton bio/acre)			2.2738		

Figure 8-11
Biomass Scenarios: High, Low, and Midrange

Description of Case	Unit	Biomass Energy ("new" plus "traditional") in EJ or Gtoe 1990	2000	2020	2050	2100	Label
WEC/IIASA high growth, high oil/gas	EJ	47	52	55	72	189	A1
	Gtoe	1.12	1.24	1.31	1.73	4.50	
WEC/IIASA high growth, high coal	EJ	47	51	65	124	264	A2
	Gtoe	1.12	1.21	1.54	2.97	6.30	
WEC/IIASA high growth, high nuc/bio	EJ	47	55	87	155	321	A3
	Gtoe	1.12	1.32	2.07	3.71	7.65	
WEC/IIASA base case, incremental	EJ	47	53	57	83	176	B
	Gtoe	1.12	1.27	1.36	1.98	4.20	
WEC/IIASA policy driven, nuc out	EJ	47	49	62	102	259	C1
	Gtoe	1.12	1.16	1.47	2.44	6.19	
WEC/IIASA policy driven, nuc grows	EJ	47	49	60	93	207	C2
	Gtoe	1.12	1.16	1.43	2.21	4.95	
CRIEPI no food limit (low meat)	EJ	39	47	70	150	331	La
	Gtoe	0.93	1.12	1.67	3.58	7.90	
CRIEPI with food limit (high meat)	EJ	39	47	60	120	263	Lb
	Gtoe	0.93	1.12	1.43	2.86	6.28	
This report, high renewables*	EJ	41.2	41.3	49	97	168	High
(* includes 40EJ "traditional biomass")	Gtoe	0.98	0.99	1.17	2.32	4.01	
This report, low renewables*	EJ	41.2	41.3	46	67	94	Low
(* includes 40EJ "traditional biomass")	Gtoe	0.98	0.99	1.10	1.60	2.24	

Conclusion: By 2100, this report's high biomass case is lower than the others' low cases, And, therefore, allows enough land for food/feed crops.

Table 8-12 displays many numbers that were used in, or that can be derived from, the CRIEPI paper (Ref.57). Beyond its use here to probe the biomass energy limit, the paper suggests gives or implies quantities that may be of interest for other studies of land use and biomass energy resources. Hence, Table 8-12 has been prepared to display the numbers.

Figure 8-12 Biomass Limit due to Land for Food

(Energy and food values are in EJ, 1 Gtoe = 41.9 EJ.)

(Land areas are in millions of hectares, 1 acre = 0.4047 ha.) ["Source1,2,etc." refers to fuel sources in columns, not references.]

Description of Item	Source 1	Source 2	Source 3	Source 4	Source 5	Total
***= only for "Developing Regions"**						
***Forest Wood Production:**	Roundwood	Fuelwood	Other	Roundwood residue	Fuelwood Residue	
Primary energy from forests	50.8	51.7	0.5	32.6	12.5	**148.1 EJ**
Forest land to produce the 148.1 EJ of biomass energy equivalent					**1,800 Mha**	
Result: calc. of average yield		148.1 EJ / 1.800 x 10^9 ha =		**82.28 GJ/ha**		
***Arable Land Production:**	Energy crops	Cereals	Roots	Sugarcane	Other	
Primary energy from arable lands	54.8	71.2	3.9	9.0	8.3	147.2
Residues from arable lands	--	89.7	--	5.4	--	95.1
Total production on arable lands	54.8	160.9	3.9	14.4	8.3	**242.3 EJ**
Land area required	264.2	1172.9	28.4	105.0	60.5	**1,631 Mha**
Result: calc. of average yield	207.42	137.18	137.16	137.18	137.19	**148.56 GJ/ha**
***Other Food/Feed Production:**	Pasture	Sea				
Production from pasture land	16.9	--	--	--	--	16.9
Other primary food (i.e., seafood)	--	0.2	--	--	--	0.2
Total other food/feed production	16.9	0.2	--	--	--	**17.1 EJ**
Result: calc. of average yield	16.9 EJ of feed from 2435 x 10^6 ha of pasture =======>**6.94 GJ/ha**					

Result: "Developing Regions"	**Wood +**	**En.Crops +**	**Food/Feed**	**+ Other**	**=**	**Total**
Biomass production (EJ)	148.1	54.8	187.5	17.1		**407.5 EJ**
Average yield (GJ/ha)	82.28	207.42	137.18	7.02		**69.46 GJ/ha**
Land used "Low Meat" (Mha)	1800	264.2	1366.8	2435.9		**5867 Mha**
Land used "High Meat" (Mha)	1800	none	1631.0	2435.9		**5867 Mha**
Revised production (EJ)	148.1	none	223.7	17.1		**388.9 EJ**

Result: "Developed Regions"	**Wood +**	**En.Crops +**	**Food/Feed**	**+ Other**	**=**	**Total**
Biomass production (EJ)	127.5	100.0	83.5	5.0		**316.0 EJ**
Average yield (GJ/ha)	82.28	288.00	137.18	4.50		**85.68 GJ/ha**
Land used "Low Meat" (Mha)	1550	347	609	1182		**3688 Mha**
Land used "High Meat" (Mha)	1550	281	675	1182		**3688 Mha**
Revised production (EJ)	127.5	81.0	92.6	5.3		**306.5 EJ**

Notes and Explanations for Table 8-12:

Average arable land yield = 147.2 EJ + 95.1 EJ = 242.3 EJ from 1631 x 10^6 ha of arable land.
242.3 EJ / 1631 Mha = 148.56 GJ/ha ave.yield
This 148.56 GJ/ha in other units would be as follows: 15 GJ/tonne at 15% moisture gives 8.4184 dry metric tons/ha/yr
16.3x10^6 Btu/dry short ton and 1.1 sht ton per metric ton (tonne) = 61.086 10^6 Btu/acre/yr
= 3.748 dry short tons/ac/yr

Source 1 = energy crops = 54.8 EJ. At food crop yields this would take an arable land area equal to 54.8/148.56 = 368.874 Mha.
But, at the higher yield of the growing forest the 54.8 EJ takes only 54.8 / 207.45 = 0.2642x10^9 ha ======> 264.2 Mha.
Using these 264.2 Mha to grow feed for meat at 137.18 GJ/ha, gives a total (grain plus residue) cereal energy of 36.243 EJ.
The grain fraction of this 36.24 EJ is 71.2 / 160.9 = 44.25% ==> 16.04 EJ, which at 11% efficient meat production = 1.76 EJ of meat.

An additional 4 EJ of grain for meat production is needed, and adds another (4/16) x 36.24 = 9.06 EJ of cereal production in the "Developed Regions." At 137.18 GJ/ha yield, this requires 65.9 Mha of land, which removes almost all of the extra 68 Mha added as arable land in the "Developed Regions." Taking this 66 Mha out of energy crops, which are assumed to have a yield of 7 tonne-C/ha/yr, reduces energy from energy crops by 290.43 GJ/ha x 0.066 x 10^9 ha = 19.168 EJ. Therefore, the 100 EJ is cut to 81 EJ from energy crops in "Developed Regions."

The numbers displayed in Table 8-12 gives specifics of what the investigators at CRIEPI find or imply regarding (1) limits on the role for biomass for energy due to land required for other needs, specifically for a higher-meat diet for people in developing regions, (2) the larger role given to residues than to energy crops as feedstocks for biomass energy technologies, and (3) quantitative estimates of the effect of diet on the amount of land available for energy crops.

Limit on Geothermal Potential

Using a survey of country and region geothermal energy specialists in several countries, the Geothermal Energy Association, on behalf of the U.S. Dept. of Energy (Ref.56), estimated worldwide geothermal energy potential (actually, hydrothermal geothermal, not including hot dry rock resources). The result of that survey would limit the geothermal electricity generation to about half of that given in the "High Renewables" case displayed in Table 8-6, above. Table 8-13 here shows the GEA numbers, modified here by EPRI in order to take out the potential of some island nations where the geothermal power that is possible is far above the likely demand of the population on the island. (This modification drops out about 75 MWe from three Caribbean islands and about 15 MWe from Iceland.) Here, for geothermal, unlike that in the case of biomass, the limit suggested by the resource base would indicate the "Low Renewables" growth scenario for geothermal, per Table 8-5. This means that the growth rate will be constrained and fall below that which would otherwise seem reasonable for feasible high growth in an industry that has good incentives.

Limit on Wind Potential

The availability of good wind sites and the land area needed in regions of moderate-to-high wind velocities did not appear to be a constraint in the USA, per Table 2-2 presented above in the overview for the United States. To investigate the similar question on a global basis, the land area that appeared to have a good wind resource was estimated for various countries and regions. This was done based on a worldwide map of wind energy density included in the OECD 1992 World Energy Outlook (Ref.60).

Figure 8-13
Global Geothermal Energy for Electricity in 2050

Assumptions used:
Geo hr/yr = 7884 (cap factor 0.90)
Geo HR = 8842 Btu/kWh (to calculate fossil fuel displaced)

	Result		Calculation Steps	
Country or Region	**(EJ)**	**Geo TWh**	**Geo MWe**	**Geo EJ**
USA	1.3992	150	19,026	1.3992
Canada	0.0466	5	634	0.0466
Western Europe	0.3731	40	5,074	0.3731
Japan	0.2798	30	3,805	0.2798
Australia/NZ	0.4664	50	6,342	0.4664
East.Eur./FSU	0.4198	45	5,708	0.4198
China	0.2798	30	3,805	0.2798
India	0.0466	5	634	0.0466
Indonesia	1.1194	120	15,221	1.1194
Far East/Oceana	0.9328	100	12,684	0.9328
Brazil	0.0466	5	634	0.0466
Mexico	0.4664	50	6,342	0.4664
Central/South America	2.1455	230	29,173	2.1455
Africa	0.9328	100	12,684	0.9328
Middle East	0.0466	5	634	0.0466
Total of above	9.0018	965	122,400	9.0018
Correction				
Alternative World Total	13	1370	184,000	13.0000
Target Potential	22			

The map showed contours of wind power density measured in watts/m^2 (W per square meter, where the area in square meters refers to the cross-section of the circle swept by the rotor blade(s) of a wind turbine). By analogy to those areas of the United States where the wind energy potential is good, it appears that the regions above about 400 W/m2 are the ones that would be Class 4 or higher and would be those counted in the estimate for the USA given above in Sections 2 and 7 (Ref. 13). Specifically, Table 2-2 and Table 7-1 were referred to for the USA case that was then used to obtain a wind energy density number in units of TWh/Mha (10^9 kWh per million hectares). That density was applied to the other countries and regions.

Table 8-14 shows the results. The numbers in the third column of Table 8-14 here show the fraction of the land area of the countries or regions listed that appear to be in the >400W/m^2 zones (Class 4 or better wind resource). Then, by calculating a land surface area in Mha (millions of hectares) from the total areas given times the fraction given, the “windy area" is derived. That area in Mha is then multiplied by the density in TWh/Mha.

Figure 8-14
Wind Energy Potential and 20% Limit by Country/Region in 2050

Country or Region	Estimate of the Windy Fraction	Fraction Class 4+	Total Land (Mha)	Class 4+ Land (Mha)	Wind (EJ)	Wind TWh	3066 hours/yr Wind MWe	8842 Btu/kWh Wind EJ	Year 2050 Electricity (TWh)	Adopted Year 2050 Max. Wind (TWh)
USA	0.3	0.0918	769	71	28.09	3012	982,233	28.09	7,462	1,492
Canada	0.4	0.1224	922	113	44.91	4814	1,570,210	44.91	758	152
Western Europe	0.4	0.1224	480	59	23.38	2506	817,463	23.38	6,034	1,207
Japan	0.6	0.1836	38	7	2.78	298	97,074	2.78	1,465	293
Australia/NZ	0.3	0.0918	735	67	26.85	2878	938,805	26.85	406	81
East.Eur./FSU	0.2	0.0612	2352	144	57.28	6141	2,002,784	57.28	5,336	1,067
China	0.2	0.0612	933	57	22.72	2436	794,472	22.72	4,464	893
India	0.2	0.0612	297	18	7.23	775	252,903	7.23	2,441	488
Indonesia	0.1	0.0306	181	6	2.20	236	77,063	2.20	470	94
Other Asia & Oceana	0.2	0.0612	662	41	16.12	1728	563,709	16.12	2,553	511
							0	0.00		
Brazil	0.2	0.0612	846	52	20.60	2209	720,389	20.60	467	93
Mexico	0.4	0.1224	191	23	9.30	997	325,282	9.30	342	68
Cen/So America	0.4	0.1224	952	117	46.37	4971	1,621,301	46.37	1,086	217
Africa	0.2	0.0612	2351	144	57.26	6138	2,001,932	57.26	1,453	291
Middle East	0.2	0.0612	1113	68	27.11	2906	947,746	27.11	1,721	344
Total			**12,822**	**986**	**392.21**	**42,045**	**13,713,363**	**392.21**	**36,458**	**7,292**

Basis for the calculations:	29.01 M acres	3320 hr/year	0.25 fraction of land not excluded	3012 TWh wind potential in US
US pattern applied to	600 GWe	1992 TWh	per Battelle PNL (Ref.13)	71 Mha x 42.67 TWh/Mha
Canada and all the rest	0.379 capac fac	11.74 M ha	42.67 25% of 169.7 TWh/Mha	113.5 Mha Canada land resource
at 42.42 TWh/Mha.	3320 hr/year	169.67 TWh/Mha	71 M ha US Cl.4+ wind lands	4814 TWh wind potential of Canada

The density comes from the average for the USA (contiguous 48 states) per Table 2-2 above, namely 600 GWe of capacity from 29 million acres, or 11.74 million hectares (Mha). This led to 42.67 TWh/Mha, after an exclusion for environmental and land-use restictions similar to those discussed in Section 2 were applied. (The basis and the details of the calculation are shown at the bottom of Table 8-14. The capacity factor of 38% or 3340 hours/year comes from Table 7-1, the wind energy supply curve for the USA.) On the resource limit issue, the conclusion is that, unlike biomass and geothermal, the growth of wind energy should not be constrained, <u>by resource considerations</u>, to values below those in the high renewables case of Table 8-6.

However, although the amount of wind available to generate electricity on environmentally suitable land does not constrain the growth scenario, a constraint arising from the intermittent nature of the wind resource would seem to be appropriate. (See the discussion below, regarding the solar resource.) Both solar and wind are intermittent power generating sources and limits based on maximum roles for each do come into play. For wind, Table 8-14 goes on to show, also, how a 20% limit affects the value adopted as the wind power contibution in the year 2050. The limits adopted here to reflect the intermittent nature of solar and wind are given as a percent fraction of the electricity generation (TWh) in a country or region. The maximum roles assigned here are 20 %, from wind, and 25%, from solar. These maximum percentages are applied to the year 2050 values for total electricity generation based on a world total of 36,000 TWh in 2050 distributed among the countries and regions as shown in Table 8-14. The 36,000 TWh comes from the high-growth scenario A2 of the WEC/IIASA book (Ref.12).

Limit on Solar and Conclusion for Total of All Renewables

As stated elsewhere in this report, no one expects resource limits on solar. However, the rapid expansion of solar in the high growth scenario eventually brings solar into a major role in electricity supply, and the scenario may need correction due to some reasonable limit on the fraction of electricity that can come from an intermittent source. The cost of solar electricity in the 1997 EPRI and DOE technology characterization report did not include an estimate of the cost of the energy storage that would be needed to make the solar into a 24-hour 7-day source of electricity. Therefore, the renewables growth scenario adopted here is that of Table 8-15. This table presents the low case for geothermal (i.e., from Table 8-5, and further constrained by the results of Table 8-13). For biomass the high case as in Table 8-6 is adopted, with a slight slowing to cut out about 10% in 2050. Wind also is the high case (i.e., from Table 8-6), but with some downward modification applied, amounting to 25% less in 2050. The downward modification for wind is made for the same reasons as for solar: both are constrained to supply no more than 25% (each) to the electricity supply in 2050 for any one of the countries/regions displayed in the tables that show allocations by country.

Therefore, in the new scenario for growth of renewables, which is Table 8-15, the solar growth of the high case in Table 8-6 has been slowed to keep solar at no more than 25% of the electricity supply of a country or region in 2050.

Figure 8-15
Renewables Growth Scenario with Limits Applied

(units: GWe, unless TWh or EJ)

Year	Biomass	Geo-thermal	Wind	Solar Thermal	Solar PV	Non-Hydro Renewables Total	Hydro	Renewables Total with Hydro
2000	20	7	10	0.4	0.7	38.1	667	705.1
Annual growth rate	0.100	0.070	0.200	0.100	0.250		0.020	
2010	51.9	13.8	61.9	1.0	6.5	135.1	813.1	1031.5
" " "	0.100	0.100	0.150	0.200	0.200		0.020	
2020	134.5	35.7	250.5	6.4	40.4	467.5	991.1	1672.2
" " "	0.100	0.080	0.120	0.100	0.200		0.020	
2030	349.0	77.1	778.0	16.7	249.9	1470.7	1208.2	2939.2
" " "	0.060	0.040	0.050	0.100	0.150		0.010	
2040	625.0	114.1	1267.3	43.2	1011.1	3060.7	1334.6	4682.8
" " "	0.030	0.015	0.030	0.100	0.100		0.010	
2050	839.9	132.5	1703.1	112.1	2622.6	5410.1	1474.2	7202.0
Generation (in TWh in year 2050):								
	5518	**986**	**5222**	**393**	**8041**	**20,160**	**8241**	**28,401**
CapFactor in 2050	0.750	0.850	0.350	0.400	0.350		0.525	
Hours (cf*8760)	6570	7446	3066	3504	3066		4599	
Year 2050: Conversion to EJ @ 0.386 efficiency:								
	51	**9**	**49**	**4**	**75**	**167**	**188**	**265**

The extent of the cutback of solar due to imposing the 25% constraint is displayed in Table 8-16.

Figure 8-16
Limit on Solar by Cut to 25% of the Total Electricity Supply in Each Country or Region in the Year 2050

Country or Region	Solar Primary Energy After Cut EJ	Solar in 2050 from Growth Scenario before the Cut			Year 2050 Total Electricity TWh	Solar After Cut to 25% of Electricity TWh
		Solar TWh	Solar MWe	Solar EJ		
USA	17.26	3000	978,474	27.98	7,462	1,860
Canada	1.77	200	65,232	1.87	758	190
Western Europe	13.99	2000	652,316	18.66	6,034	1,510
Japan	3.36	700	228,311	6.53	1,465	360
Australia & NZ	0.93	400	130,463	3.73	406	100
East.Eur./FSU	5.60	600	195,695	5.60	5,336	600
China	10.35	1600	521,853	14.93	4,464	1,110
India	14.93	1600	521,853	14.93	2,441	610
Indonesia	1.12	400	130,463	3.73	470	120
Other Asia & Oceana	3.73	400	130,463	3.73	2,553	400
Brazil	1.03	1500	489,237	13.99	467	120
Mexico	0.84	300	97,847	2.80	342	90
Central/South America	2.52	700	228,311	6.53	1,086	270
Africa	3.64	1500	489,237	13.99	1,453	360
Middle East	4.01	800	260,926	7.46	1,721	430
Total	**75.84**	**15,700**	**5,120,678**	**146.45**	**36,458**	**8,130**

* The capacity factor for solar is taken to be 35% in 2050, or 3066 hours/year. The equivalent EJ of Primary Energy displaced by the solar electricity is based on a 0.386 efficiency, or 8842 Btu/kWh. In SI units this is a higher heating value (HHV) heat rate of 9328 kJ/kWh.

Finally, Table 8-17 shows the resulting totals for the year 2050 for all the renewables, both the case without the limits on wind and solar and the case with the limits applied to those two intermittent resources: 20% on wind and 25% on solar.

Figure 8-17
Renewable Power in 2050 from Growth Scenario with and without Limits

These are the values before limits were applied:

Country or Region	Year 2050 Population (millions)	Tot. Elect. in 2050 TWh	2050 Biomass TWh	2050 Geothermal TWh	2050 Wind TWh	2050 Solar TWh	W/o Limits Sum of 4 TWh
USA	394	7500	800	300	900	3000	5000
Canada	40	760	80	20	200	200	500
Western Europe	500	6000	500	50	400	2000	2950
Japan	101	1500	50	50	100	700	900
Australia/NewZealand	28	400	100	80	200	400	780
East.Eur./FmrSovietU	530	5300	400	50	300	600	1350
China	1322	4500	600	100	1000	1600	3300
India	1707	2400	500	60	1000	1600	3160
Indonesia	331	500	400	200	300	400	1300
Other Asia & Oceana	1800	2600	300	400	300	400	1400
Brazil	228	470	1500	20	400	1500	3420
Mexico	167	340	100	200	200	300	800
Central/South America	530	1100	200	200	300	700	1400
Africa	1000	1460	400	400	1000	1500	3300
Middle East	630	1720	100	50	300	800	1250
Total w/o Limits	9308	36550	6030	2180	6900	15700	30810

These are the values after limits were applied:

Country or Region	Year 2050 Population (millions)	Tot. Elect. in 2050 TWh	2050 Biomass TWh	2050 Geothermal TWh	2050 Wind TWh	2050 Solar TWh	With Limits Sum of 4 TWh
USA	394	7500	1140	150	900	1860	4050
Canada	40	760	80	5	190	190	475
Western Europe	500	6000	300	40	400	1510	2250
Japan	101	1500	30	30	100	360	520
Australia/NewZealand	28	400	50	50	100	100	400
East.Eur./FmrSovietU	530	5300	200	45	300	600	1145
China	1322	4500	400	30	1000	1120	2540
India	1707	2400	400	5	600	600	2015
Indonesia	331	500	100	120	120	120	640
Other Asia & Oceana	1800	2600	100	100	300	400	900
Brazil	228	470	2000	5	120	120	2525
Mexico	167	340	100	50	90	90	440
Central/South America	530	1100	300	230	270	270	1100
Africa	1000	1460	300	100	360	360	1760
Middle East	630	1720	20	5	300	430	755
Total with Limits	9308	36550	5520	965	5150	8130	21515

9
COMPARISON TO OTHER RESULTS

Global View: EPRI Roadmap and WEC/IIASA

Table 9-1 shows the worldwide totals for this report on renewables and compares the results to the EPRI Roadmap and the WEC/IIASA, in both cases looking especially at high renewables scenarios. Two EPRI Electricity Roadmap (Ref.6) cases are used here: (1) the one with high growth and a major role for coal, similar to the "A2" scenario of the WEC/IIASA study, and (2) the high renewables variation of the carbon-constrained case, similar to the C1 scenario of the WEC/IIASA study (Ref.12). The Roadmap cases have a greater role for electricity than their WEC equivalents. This higher electricity trend was arrived at during the EPRI "technology roadmap" process in 1997 and 1998. The considerations that moved the Roadmap toward the higher electricity scenarios were the capacity of various electricity technologies to conserve energy, to use low-carbon-intensity energy technologies, and to enhance living standards and economic development. These considerations arose and gained in emphasis during the course of the work of EPRI staff, consultants, advisory panels and focus groups during the '97-'98 period. The correlation between electricity use and better living standards with an economic development record led the Roadmap scenarios to be structured so that by 2050 a basic minimum of per capita electricity generation is achieved. To compare the results we note that the Roadmap high growth and high electricity scenario (the one like A2 of the WEC) is also the highest in electricity (as is the A2 scenario of the WEC/IIASA study). We also note that this Roadmap case has electricity generation worldwide at 42,000 TWh in 2050, compared to the 36,000 TWh of the WEC/IIASA A2 scenario.

The Roadmap equivalent of the WEC/IIASA policy-driven, or environmental- and carbon-mitigation- driven scenarios, C1 and C2, also is structured to provide a minimum per capita level of electricity generation. Table 9-1 shows this Roadmap case as calling for some 369 EJ, or 8.81 Gtoe, of primary energy inputs from "renewables." As used in the EPRI Roadmap and also in the WEC/IIASA study, renewables includes conventional (i.e., large-scale) hydro as well as the new possibilities for small-scale hydro. In both Roadmap and WEC, however, the growth of the hydro part of renewables is small compared to that of the solar, wind and biomass. In this report, i.e., the present EPRI report on renewables and greenhouse gas reduction, EPRI has expressed the renewable energy role in the standard units of global or national energy use, e.g., in exajoules (EJ) or in 10^9 metric tons of oil equivalent (Gtoe), and has adopted the "substitution equivalent" convention for expressing the energy as the "Primary Energy" equivalent of fossil energy sources that would be required to generate the same amount of electricity as that generated by the non-fossil sources, namely nuclear, hydro and renewables.

Table 9-1
Year 2050: This Report Compared to WEC/IIASA and EPRI Roadmap

Scenario A2: HiGrowth,HiCoal	**WEC/IIASA per PCAST Report**		**A2 as reported in EPRI Roadmap** — **WEC/IIASA per Roadmap (Gtoe)**		**Roadmap "High Coal" Case (in Gtoe)**			**Roadmap "High Renew./Nuclear"**			**Potential per this report's growth scenarios** — **This Rprt: Low Renewables**		**This Rprt: High Renewables**	
					Recalc	**Original**	**Recalc**	**Recalc.**	**Original**	**Recalc.**				
Energy Technology	**EJ**	**Gtoe**	**Recalc**	**Original**	**EJ**	**Gtoe**	**Gtoe**	**EJ**	**Gtoe**	**Gtoe**	**EJ**	**Gtoe**	**EJ**	**Gtoe**
Coal	335	8.00	8.00	8.00	214	5.10	5.10	71	1.70	1.70	214	5.10	71	1.70
Oil	200	4.77	4.75	4.75	71	1.70	1.70	71	1.70	1.70	71	1.70	71	1.70
Nat. gas	230	5.49	5.50	5.50	214	5.10	5.10	285	6.80	6.80	214	5.10	285	6.80
Total Fossil	765	18.26	18.25	18.25	499	11.90	11.90	427	10.20	10.20	499	11.90	427	10.20
Nuclear	50	1.19	1.00	1.00	107	2.55	2.55	142	3.40	3.40	107	2.55	142	3.40
Hydro	40	0.95	Hydro included with the Renewables.		Hydro included with the Renewables.			Hydro included with the Renewables.			52	1.24	77	1.84
Biomass, non commercial	15	0.36	Non-commerc. biomass not included		no	No	no	no	no	no	10	0.24	10	0.24
Biomass, commercial	100	2.39	Included in the sum of the Renewables.		Included in the sum of the Renewables.			Included in the sum of the Renewables.			27	0.64	57	1.36
Solar	25	0.60	"	" "	"	"	"	"	"	"	27	0.64	49	3.56
Other	70	1.67	"	" "	"	"	"	"	"	"	40	0.95	86	2.05
Total Renewable	195	4.65	5.75	5.75	277	2.55	6.61	369	3.40	8.81	94	2.24	292	6.97
	-------	-------	-------	-------	-------	-------	------	-------	-------	-------	-------	-------	-------	-------
Total, primary energy	1065	25.42	25.00	25.00	882	17.00	21.06	939	17.00	22.41	762	18.17	949	22.64

Case "A2" is the high growth, high coal case of the WEC/IIASA scenarios (World Energy Council and International Institute of Applied Systems Analysis).

8842 Btu/kWh = 0.386 efficiency, HHV basis. This is used to recalculate Roadmap value for renewables to fossil replacement equivalent.

41.9 EJ/Gtoe = conversion of 10^9 metric tons oil equivalent (Gtoe) to exajoules (10^18 joules). 1 quad = 10^15 Btu = 1.055 EJ.

"Recalc" refers to recalculation of EPRI Roadmap numbers so as to convert renewable electricity to primary energy (fossil) replaced at 0.386 efficiency (3413/0.386 = 8842 Btu/kWh).

The EPRI Roadmap, to the contrary, uses the direct or "final" form of the energy input from renewable and non-fossil sources as the energy shown in Roadmap scenarios. This report follows the WEC/IIASA practice, a practice that is described as an option in a note in the Roadmap, by doing the conversion of final energy, in TWh of electricity generated, to primary energy fossil equivalent using the 0.386 conversion efficiency assumption. At this 38.6% efficiency, the heat rate for conversion of primary energy into electricity is 8842 Btu/kWh or 9.33 MJ/kWh. The further conversion of energy in joules to energy in equivalent oil input is 41.9 EJ = 1 Gtoe, where the Gtoe is 10^9 tonnes oil equivalent.

The EPRI Roadmap (Ref.6) points out that as renewables (which includes hydro) and/or nuclear become major sources of electricity the fossil substitution convention is less useful, or less relevant, and may give the wrong emphasis, because it fails to emphasize the value and need for the energy service, independent of the source that provides it. However, with this report's emphasis on reducing greenhouse gas emissions, which are caused by use of fossil fuels, the fossil substitution convention seemed more appropriate. Because the comparison is being made out in future years, by which time efficiency improvements can be widely deployed, the conversion efficiency adopted, which is also as that of the WEC/IIASA, is a higher efficiency than the average of today. For the greenhouse gas issue, the relevant efficiency is that of the fossil energy that would be deployed if the renewables were not. Since fossil efficiencies are higher than biomass, due mostly to the moisture content of biomass, and much higher than geothermal, due to the low temperature of geothermal fluids, using the fossil efficiency makes the primary energy role of renewables appear smaller than would a conversion using the actual (lower) efficiencies of the renewable energy systems. Today the global average for converting primary fossil energy into electricity is given in EIA reports (Refs.7,8) as about 10,200 Btu/kWh. This is in contrast to the 8842 Btu/kWh, or 9.33 MJ/kWh, that goes with the 38.6% efficiency adopted here and by the WEC/IIASA. (The EIA reports show the average conversion most explicitly in tables by country of the thermal equivalent used to convert the hydro output, which is given in the direct units of kilowatt-hours, i.e., kWh, or TWh, into units of primary energy input. This conversion is needed in order to add hydro into tabulations of the primary energy input for electricity generation together with coal, oil, gas and nuclear.)

Referring to Table 9-1, the Roadmap's number of 369 EJ, or 8.81 Gtoe, of fossil energy equivalent input of primary energy from renewables in the year 2050, for the high nuclear/renewables case, was actually used as the basis for selecting some of the parameters in the high renewables growth case for this report. Essentially, this report is exploring the possibility of reaching that role for renewables by 2050, trying to see what mix of energy supply from the four non-hydro renewable sources/technologies might build up to fulfill that major role for renewables by 2050.

Section 8 above, which addressed International Context, concluded with a table (Table 8-16) giving a growth scenario for "high renewables growth." However, that concluding table in Section 8 was constrained by not allowing the intermittent sources from wind and solar power generation to become more than 20% for wind or 25% for solar, respectively, of the total electricity generation. The total electric generation in this case was taken from the high electricity scenario of the WEC/IIASA. Table 9-2 displays a comparison of this report's renewables scenarios with the two cases in Table 9-1 from the EPRI Roadmap and with the WEC scenarios.

Table 9-2 shows, for the renewables only, the entire set of WEC/IIASA scenarios for 2050 compared to the three growth scenarios of this report and to the two cases of the EPRI Roadmap. (The EPRI Roadmap did not display a breakdown of the renewables by type; it showed the sum of hydro plus the other renewables.)

Table 9-2
Year 2050 Comparison of Scenarios for Renewables (including Hydro)
(Units are Gtoe, 1 Gtoe = 41.9 EJ = 38.9 quads = 38.9x10^15 Btu.)

Renewables by Type:	Trad.Bio.	New Bio.	Tot.Bio	Wind & Geothmrl	Solar	Tot. non-hydro ren.	Hydro	Total re-newables
Base year 1990 ➔	0.90	0.20	1.10	0.01	0.00	1.11	0.49	1.60
A1	0.55	1.09	1.64	0.99	1.74	4.37	1.17	5.54
A2	0.62	2.48	3.10	1.12	0.37	4.59	1.09	5.68
A3	0.74	1.97	2.71	1.11	2.34	6.16	1.23	7.39
B	0.79	1.59	2.38	0.99	0.50	3.87	0.69	4.56
C1	0.86	1.71	2.57	0.71	1.71	4.99	0.86	5.85
C2	0.71	1.28	1.99	0.57	1.57	4.13	0.93	5.06
RdMap1	The EPRI Roadmap does not show renewables breakdown by type.							6.61
RdMap2	" " " " " " " " " "							8.81
Low	0.50	0.64	1.14	0.95	0.86	2.95	1.51	4.46
High	1.12	1.35	2.47	2.08	3.55	8.10	1.83	9.93
HiLim	1.00	1.35	2.35	1.85	2.23	6.43	1.83	8.26

Table 9-3 presents more from the WEC/IIASA scenarios for 2050. At the bottom of Table 9-3 the short labels for the WEC/IIASA scenarios are listed.

Table 9-4 presents numbers from the WEC/IIASA book that give the amount of direct energy use and electricity use in the base year 1990 and in the future years 2020, 2050 and 2100. (Actually, electricity was given only to 2050, not 2100, in the WEC/IIASA book.)

Table 9-5 presents some additional numbers from the WEC/IIASA. In this case the numbers displayed are estimates of historical (i.e., 1850, 1900 and 1950) use of "traditional biomass" and its fraction of the total primary energy.

The EPRI Roadmap is “Electricity Technology Roadmap: 1999 Summary and Synthesis” (Ref.6). The WEC/IIASA report is published as a book *Global Energy Perspectives* in 1998 (Ref.12).

Table 9-3
WEC/IIASA Scenarios for the Year 2050 (in Gtoe, unless noted otherwise)

Energy Source	**Base Year 1990**	**Year 2050: Scenario per WEC/IIASA Case Label (Gtoe)**					
		A1	**A2**	**A3**	**B**	**C1**	**C2**
Coal	2.18	3.79	7.83	2.24	4.14	1.50	1.47
Oil	3.06	7.90	4.78	4.33	4.04	2.67	2.62
Gas	1.68	4.70	5.46	7.91	4.50	3.92	3.34
Nuclear	0.45	2.90	1.09	2.82	2.74	0.52	1.77
Renewables	1.60	5.54	5.68	7.35	4.42	5.63	5.05
	-----	-----	-----	-----	-----	-----	-----
Total	**8.97**	**24.83**	**24.84**	**24.65**	**19.84**	**14.24**	**14.25**
Electricity end use (in 083 Gtoe)		**2.88**	**3.14**	**3.03**	**2.34**	**1.79**	**1.72**
Electricity end use (in 9,658 TWh)		**33,513**	**36,539**	**35,259**	**27,230**	**20,829**	**20,015**

Breakdown of the Renewables:	**Base Year 1990**	**Scenario for Year 2050 by Case Label (units Gtoe)**					
Source		**A1**	**A2**	**A3**	**B**	**C1**	**C2**
Biomass (trad.)#	0.90	0.33	0.68	0.74	0.71	0.62	0.81
Biomass (new)	0.18	1.00	2.04	2.57	0.97	1.35	1.72
Other (wind, geo.)	0.05	0.89	1.25	1.32	1.33	0.84	0.40
Solar	0.01	2.22	0.40	1.84	0.53	1.69	1.26
Hydro	0.46	1.11	1.31	0.88	0.88	1.13	0.86
	-----	-----	-----	-----	-----	-----	-----
Total	**1.60**	**5.54**	**5.68**	**7.35**	**4.42**	**5.63**	**5.05**

Non-commercial energy, i.e., traditional biomass, is less than 6% of final energy use by 2050. (17 Gtoe is final energy use, in the A3 scenario. As above, 24.65 Gtoe is the primary energy for A3.)

Labels for the scenarios:

A. Cases of high growth –

- **A1. High Growth, High Oil**
- **A2. High Growth, High Coal (also low nuclear)**
- **A3. High Growth, High Gas (also high renewables)**

B. Base case

C. Policy-driven cases

- **C1. Low nuc, High non-biomass renewables**
- **C2. High nuc, High biomass**

Table 9-4
Electricity in the WEC/IIASA Scenarios
(direct, final use; not "primary input")

Electricity:	Direct Gtoe	direct Gtoe	direct Gtoe	Direct Gtoe	TWh	TWh
Case	**1990**	**2020**	**2050**	**2100**	**2020**	**2050**
A1	0.83	1.63	2.88		21,111	37,301
A2	0.83	1.69	3.14		21,889	40,669
A3	0.83	1.72	3.03		22,277	39,244
B	0.83	1.45	2.34		18,780	30,307
C1	0.83	1.22	1.79		15,801	23,184
C2	0.83	1.21	1.72		15,672	22,277
Total Final						
Energy in A3	6.45	11.33	17.17	24		
Electricity % of Final in A3	13%	15%	18%			

Comparison values from the EPRI "Roadmap":

(from Table 1-2 of Ref.6; the 60,000 TWh in 2050 includes 10,000 TWh for electric transportation; in 2000: 13,000 TWh) 28,000 60,000

Year	2000	2020	2050	
Primary Energy (Gtoe)	10	13	17	
Electricity fraction of Pri.En.	0.38	0.5	0.7	
Electricity conversion effic	0.32	0.4	0.5	
Calc of product of above 3 lines	1.22	2.6	6.0	←[this line is final energy as electricity in Gtoe]
Elect gen capacity (GWe)	3000	5000	10,000	
Population (billions)	6.2	8	10	

Table 9-5
Selected Numbers from WEC/IIASA "Global Perspectives"

p 66, F5.2 Global Primary Energy (p 12, F3.1 trad bio) refs BP and IIASA

Scenario	1850	1900	1950	1990	2000	2020	2050	2100
A	0.3	1.4	2.7	8.98	12.0		25	45
B	["B" used for trad bio, final and elect below]===>				11.6		20	35
C					10.8		14	22.5
Base Case "B":								
% traditional biomass	87%	43%	20%	11%	7.5%		4.5%	2%
Gtoe trad. biomass	0.261	0.602	0.540	0.988	0.870		0.900	0.700
Gtoe final energy				6.45		10.07	14.18	
Gtoe electricity				0.83		1.45	2.34	

Also shown in Table 9-5 are the estimates of the WEC/IIASA for final energy and for the part of final energy that is used as electricity. These were estimated by WEC/IIASA for the years 1990, 2020 and 2050. Case B, the baseline case, is the one from which the numbers were taken for traditional biomass, final energy, and electricity. The total primary energy is shown for what is labeled as Case A for the past years, but that is, of course, for historical years (past years), the same as is estimated for the baseline, Case B.

DOE-EIA Annual Energy Outlook - 1999 (for the USA)

To compare this report with other results for the USA a good starting point is the base-case scenario of the most recent issue of the EIA annual energy outlook report (Ref.2). Table 9-6 shows the EIA's baseline case for 1997-2020 from the 1999 Annual Energy Outlook (AEO'99, Ref.2) and the trend from 1992-96 leading up to it (Ref.9).

EIA's Analysis of the Kyoto Protocol (for the USA)

To compare the role of renewables with other options for meeting targets for greenhouse gas emission reductions, an analysis published in 1998 by the U.S. DOE's Energy Information Agency (EIA) provides another case for comparison (Ref.15). The EIA analysis was done at the request of the Science Committee of the U.S. Congress to assess economic impacts of compliance with the December 1997 Kyoto protocol. The EIA report does show a substantial role for renewables, 5% of generation in 2010 and more than 10% in 2020, in the EIA's "1990-3%" case. However, the cost given by the EIA analysis is very high: a burden on the order of $250/tonne carbon (C) on the electric power generation industry and with changes in electric generation accounting for 70 to 80% of the fossil carbon reductions achieved. Nevertheless, the EIA's analysis does present a context into which the results obtained here in Section 7 can be placed in order to see what amounts of renewables would be able to enter the market at various levels and costs of carbon reductions.

To simplify a potentially very complex analysis—complex because of the large number of variations possible—only three of the five main EIA cases and only three of the five referenced timeframes will be presented here. These are:

Cases	Timeframes	Description of Case
Reference	Current (1996 base)	Baseline, business as usual
1990+9%	2010	Achieve carbon emissions 9% above 1990 in 2010
1990-3%	2020	Achieve carbon emissions 3% below 1990 in 2010

Table 9-6
EIA Baseline (Reference) Case for Renewables, per AEO'99 (Ref.2) [with '92-'96 trends from EIA's Renewable Energy Issues and Trends 1998, March 1999 (Ref.9)]

Capacity (GWe):

Technology Label	Units	'92	'93	'94	'95	'96	1996	1997	2000	2010	2020
Geothermal (not HDR)	GWe	1.254	1.318	1.335	1.295	1.346	3.00	3.00	3.06	3.16	3.52
MSW (inc. landfill gas)	"	2.513	2.591	2.744	3.038	3.063	3.87	3.87	4.04	4.49	4.76
Wood and Other Biomass	"	6.733	6.984	7.350	6.766	7.053	7.09	7.11	7.87	9.10	13.00
Solar -- Thermal	"	0.360	0.360	0.354	0.354	0.354	0.35	0.35	0.37	0.44	0.52
Solar -- Photovoltaic	"						0.01	0.01	0.04	0.30	0.64
Wind	"	1.822	1.796	1.737	1.723	1.670	1.88	1.88	2.80	3.39	3.61
Totals	**"**	**12.68**	**13.05**	**13.520**	**13.176**	**13.486**	**16.20**	**16.22**	**18.18**	**20.88**	**26.05**

Generation (TWh):

Technology Label	Units	'92	'93	'94	'95	'96	1996	1997	2000	2010	2020
Geothermal (not HDR)	TWh	8.578	9.749	10.12	9.912	10.2	15.43	15.67	14.71	17.86	22.99
MSW (inc. landfill gas)	"	15.01	15.56	16.61	18.18	18.97	16.04	16.10	25.62	28.81	30.68
Wood and Other Biomass	"	36.810	37.93	39.361	37.99	37.9	36.95	36.90	49.37	61.56	90.71
Solar -- Thermal	"	0.746	0.897	0.824	0.824	0.903	0.90	0.90	0.95	1.19	1.44
Solar -- Photovoltaic	"						0.00	0.00	0.09	0.71	1.56
Wind	"	2.916	3.036	3.482	3.185	3.400	3.41	3.41	6.11	7.69	8.44
Totals	**"**	**64.06**	**67.16**	**70.4**	**70.09**	**71.362**	**72.73**	**72.98**	**96.85**	**117.82**	**155.82**

Capacity Factor (%):

Technology Label	Units	'92	'93	'94	'95	'96	1996	1997	2000	2010	2020
Geothermal (not HDR)	%	78.1	84.4	86.6	87.4	86.5	58.7	59.6	54.9	64.5	74.6
MSW (inc. landfill gas)	"	68.2	68.5	69.1	68.3	70.7	47.3	47.5	72.4	73.2	73.6
Wood and Other Biomass	"	62.4	62.0	61.1	64.1	61.3	59.5	59.2	71.6	77.2	79.7
Solar -- Thermal	"	23.7	28.4	26.6	26.6	29.1	29.4	29.4	29.3	30.9	31.6
Solar -- Photovoltaic	"								25.7	27.0	27.8
Wind	"	18.3	19.3	22.9	21.1	23.2	20.7	20.7	24.9	25.9	26.7
Averages	**"**	**57.7**	**58.8**	**59.4**	**60.7**	**60.4**	**51.3**	**51.4**	**60.8**	**64.4**	**68.3**

Note: Both the 1992-96 trend data (Ref. 9) and the 1996-2020 future scenario numbers (Ref. 2) are from DOE Energy Information Agency (EIA). However, the two sets are from different publications by EIA, and those publications are inconsistent on geothermal capacity and, hence, on the above calculations of capacity factor. Most likely the difference is due to the shutdown of hundreds of megawatts at The Geysers in Calif. (the only US dry steam field). Actual geothermal capacity factors have been high (i.e., 85%) not low (i.e., 60%), except for some curtailments of units at The Geysers. Those curtailments have been due to failure to get dispatched versus low-cost hydro in wet years and/or due to lack of geothermal steam as parts of the field became depleted.

The cases deserve a brief explanation. The 1990-3% case meets the Kyoto Protocol's "7% below 1990 level" standard, because control of other greenhouse gases plus allowance for carbon sinks gets the U.S. credit for the other 4%. The 1990+9% case is good enough to meet the 7% below 1990 standard if international trading of offsets and credit for actions implemented jointly with "Annex 1" countries of the former Soviet Union are allowed and are carried out. The EIA's "Reference Case" is the equivalent of 1990+34%, i.e., the EIA projects that business-as-usual, at least business without Kyoto Protocol incentives, would result in U.S. greenhouse gas emissions 34% above the level that existed in 1990 (Ref.15).

Table 9-7 displays the key EIA results for these cases and timeframes.

The most dramatic numbers in the table of EIA results (Table 9-7) are the very high carbon prices needed to bring in the reductions in fossil carbon emissions:

Case	Year 2010	Year 2020
Case 1990+9%	\$163/tonneC	\$141/tonneC
Case 1990-3%	\$294/tonneC	\$240/tonneC

Given that \$60/tonneC (i.e., a carbon price of \$60 per metric ton, or \$55 per short ton, which converts to \$15 per short ton of CO_2), has the effect of a \$1.50/MBtu increase in the fuel price of steam coal, one might expect that such huge increases would bring in more than just 10% renewables in the power generation mix in 2020. Recent incentives for unconventional coal and biomass fuels under Section 29 of the Internal Revenue Code, and production credits for solar, wind and biomass under Section 45 of the same, have been the equivalent of a range from \$1.00/MBtu to \$1.50/MBtu. These \$1-1.5 per million Btu (or about \$0.01 to \$0.015 per kWh equivalent) have, in fact, been strong enough incentives to bring into existence some wind and biomass projects in recent years.

Table 9-8 shows the cost parameters used for the various technologies in the EIA analysis and in this EPRI report. None of these parameters is markedly different, meaning different enough to cause a carbon price difference on the order of the \$100 to \$200/tonneC or the equivalent electricity price difference of \$0.03 to \$0.06/kWh. The big difference in costs between this EPRI report and the EIA analysis lies in the fuel cost. Table 9-9 shows this difference.

The EIA analysis includes a table to show the effects of carbon price on coal and natural gas power generation costs (Table 18, page 76, in Ref.15). The results are given here in Table 9-10.

Table 9-7
Selected Results from the EIA Analysis

	1996	2010			2020		
	Ref.	Ref.	1990+9	1990-3	Ref.	1990+9	1990-3
Carbon price, $/tonne	none	none	163	294	none	141	240
Coal price, $/MBtu	1.32	1.12	5.24	8.57	1.01	4.57	7.18
Natural gas price, $/MBtu	4.13	3.76	6.45	8.49	3.96	6.95	8.30
Residential electricity price, ¢/kWh	8.3	7.3	10.7	12.7	6.9	10.0	10.9
Coal Generation, TWh	1809	2126	1027	559	2237	557	128
Oil Generation, TWh	86	42	31	41	35	71	82
Natural gas generation, TWh	484	1090	1751	1922	1579	2471	2481
Nuclear generation, TWh	675	578	654	689	356	552	642
Hydro generation, TWh	336	313	313	317	313	313	318
Renewable generation, TWh	87	110	145	177	121	310	501
TOTAL GENERATION	3477	4259	3921	3705	4641	4274	4152
Breakdown of Renewables							
Geothermal, TWh	15.70	16.80	21.70	29.90	19.90	33.40	47.20
Municipal solid waste, TWh	20.94	29.30	29.10	28.80	32.10	32.00	32.10
Biomass, TWh	46.44	56.00	67.90	80.60	57.60	133.30	294.80
Solar thermal, TWh	0.82	1.20	1.20	1.20	1.50	1.50	1.50
Solar PV, TWh	0.00	0.60	0.60	0.70	1.40	1.40	1.40
Wind, TWh	3.17	6.20	24.70	35.70	8.70	108.30	123.40
TOTAL RENEWABLES	87.07	110.1	145.2	176.9	121.2	309.9	500.8
Carbon reductions, million tonnes	NA	NA	329	491	NA	461	625
Fuel expenditures, $billions	560	637	834	952	674	862	945
*Fuel expenditures above Ref., $billions	none	none	197	315	none	188	271
*Extra expenditures/tonnes C, $/tonne C	none	none	$599	$642	none	$408	$434
C red. by electric gen., million tonnes	NA	NA	248	345	NA	375	481
% of reduction by electric gen., %	NA	NA	75.4	70.3	NA	81.3	77.0
Average cost of electricity, ¢/kWh	6.8	5.9	8.8	10.5	5.6	8.1	8.9
*Cost above Ref. average, ¢/kWh	none	none	2.9	4.6	none	2.5	3.3
*Extra cost x total generation, $billions	none	none	114	170	none	107	137
*Extra electric cost/tonne C, $/tonne C	none	none	$459	$493	none	$285	$285

Rows with a star (*) are calculated for this table and are not data presented in the EIA analysis itself.

Table 9-8
Comparisons of Cost Parameters

A. Cost and Size	$/kW Today		$/kW Future		Unit Size (MWe)	
	EIA	EPRI	EIA	EPRI	EIA	EPRI
Coal	1,079	1,516	1,079	800	400	400
Natural gas CC	572	663	400	500	400	400
Geothermal	NA	2,000	2,025	1,036-1,512	50	50
Biomass	2,243	1,987	1,476	1,066	100	100
Solar thermal	2,903	2,500	1,910	934	100	25
Solar PV	4,556	4,334	3,185	870-1,240	5	2.5
Wind	1,235	864	965	635	50	100

B. Efficiency and	Heat Rate Future		Capacity Factor		Year 1996 EIA Capacity Factor		
Capacity Factor	EIA	EPRI	EIA*	EPRI*	TWh	GW	Hours
Coal	9,585	9,480	70%	85%	1758*	304*	5,783
Natural gas CC	6,985	6,400	70%	85%	932*	15.2*	6,132
Geothermal	30,000	NA	59.3%	85%	15.7	3.0	5,199
Biomass	8,224	7,580	72.4%	80%	46.4	7.3	6,344
Solar thermal	NA	NA	26.0%	28%	0.82	0.36	2,278
Solar PV	NA	NA	NA	21-26%	0.1	NA	NA
Wind	NA	NA	19.6%	25-45%	3.17	1.85	1,714

*Used a 1996 value, for purposes of calculating what capacity factor the EIA would deduce from the capacity in GW and the generation in TWh given in a recent year and assumed to hold for purposes of an estimate for the 2010-2020 time frame. For “natural gas” case, the TWh and GW here are EIA’s sum of oil generation plus natural gas generation and capacity.

Sources: EIA Kycto report (Ref.15). EPRI Tables 4-1 (future) and Table 4-2 (today). EIA 1996 TWh and GW are from Annual Energy Outlook 1998 (Ref. 2).

Table 9-9
Fuel Costs Augmented by Carbon Price

	Current Cost ($/MBtu)		2010 Cost ($/MBtu)		2020 Cost ($/MBtu)	
	EIA Ref.	This Report	EIA-3	This Report	EIA-3	This Report
FUEL						
Coal	1.29	1.25	1.10	NA	1.00	1.25
Natural Gas	2.64	2.00	3.85	NA	4.50	4.00
Biomass	*	1.50	*	NA	*	1.50
Geothermal	none	none	none	none	none	none
Solar	none	none	none	none	none	none
Wind	none	none	none	none	none	none
CARBON PRICE	none	NA	280	NA	240	NA
Coal	none	none	7.45	NA	6.10	NA
Natural Gas	none	none	3.95	NA	3.18	NA
Biomass	none	none	none	NA	none	none
TOTAL (= FUEL + CARBON PRICE)						
Coal	1.29	1.25	8.55	NA	7.10	1.25
Natural Gas	2.64	2.00	7.80	NA	7.68	4.00
Biomass	*	1.50	*	none	*	1.50

*EIA report does not display the biomass fuel cost. The EIA report is Ref.15.

Table 9-10
Effect of Carbon Price on Coal and Natural Gas Power Generation Costs

Type of Plant	Base (¢/kWh)	CF	HR	Increase due to $100 Carbon Price ¢/kWh	Increase due to $100 Carbon Price $/MBtu
Existing Coal	1.64	70%	10,000	2.57	2.57
New Coal	3.67	70%	9,087	2.49	2.72
New Gas Combined Coal	3.04	70%	7,000	0.99	1.41
Coal-to-Gas Conversion	3.45	70%	10,000 (?)*	1.49	1.49

*EIA report does not display this heat rate. The EIA report is Ref.15.

The costs are so high in the EIA analysis because coal prices have to be forced up so high (by the carbon price) in order that existing coal plants have to be forced to retire early (another cause of high cost, per the 1996 EPRI analysis) in competition against natural gas which itself has high costs due to carbon price impact and, to a lesser degree, due to capital costs to build these new plants. Coal goes up at $1.50 per $50/tonC and gas goes up at $0.50 per $50/tonC. Gas starts at a higher price and has more capital cost to pay back (since gas-fired plants are new). The question is why, at such high carbon prices, don't the renewables come in stronger in the EIA analysis. Why so much less deployment of renewables than the scenarios developed here in this report?

The answer must be found in the fact that the EIA analysis develops a scenario that becomes primarily one in which coal is displaced by high-efficiency natural gas combined-cycle. If the competition some ten to twenty years in the future is against natural gas combined cycle, then the carbon cost must be calculated versus the natural gas technology at 0.10 tonne-C per MWh, not versus the 0.26 tonne-C per MWh for displacing coal carbon. This makes the $60-100 per ton C cases in this EPRI report (per Table 7-7 above) become $150-260 per ton C cases, thereby putting this report's numbers up in the same high range as the EIA Kyoto analysis.

Conclusion

Renewables are important in any carbon reduction scenario. The agenda for building a role for renewables in greenhouse gas reduction remains that of finding some markets where these technologies can continue to flourish today and using those initial markets, along with related R&D efforts, to achieve the improved power and fuel systems that will make the renewables economically competitive.

10 WHAT TO WATCH

The potential contribution of renewable energy to global energy needs and greenhouse gas reduction over the next 100 years is uncertain and ranges from 20% to 50% of total energy. The dates for realizing these levels are also uncertain and range from as early as 2020 to as late as 2050 for a 20% contribution, to at least 2100 for a 50% contribution.

For companies and government agencies defining their individual roles and strategies for participating in the growing market for renewable energy equipment and services, it is important to monitor the progress of renewable energy technology, resources, and public and private programs and projects. This section addresses a range of renewable energy topics and issues that should be monitored. This list can serve as a starting point for future efforts, efforts that may include activities such as the following:

- Monitoring of national or global progress, or lack of progress, toward an expanding role for renewable energy technologies.
- Choosing targets for research, development, demonstration and/or deployment (RD^3) regarding renewable energy.
- Structuring and implementing programs directed at communication, education, and technology transfer regarding renewable energy technologies.
- Choosing and guiding business ventures (for companies) or financing such ventures (for development banks and government organizations).

Biomass

Topic 1: Energy Crops

Progress, or lack of it, on so called "energy crops" is important because it determines whether biomass energy will be limited to a role in the 3% to 7% range or will be able to expand to fill a role in the 10% to perhaps even 25% range. Energy crop success could mean that biomass energy will be able to expand many-fold without being stopped by the need for land dedicated to food, feed, fiber or other products that are more essential than energy, or at least have higher economic values than energy. The key performance parameters to watch are the all-important yield numbers, and, at the next level of detail, the methods and costs of achieving the yield. Yield is measured in units such as dry tons per acre per year, or dry metric tons per hectare per year (annum). In the United States the key program is the DOE-funded Biomass Feedstock Development Program at ORNL (the Oak Ridge National Laboratory near Knoxville, Tennessee). Of equal importance to the government-funded program at ORNL is the total of the efforts by about ten or twenty private companies in the USA to develop and use wood crops grown agricultural-style rather than natural-forest-style. Already, going back into the 1970's, over 100,000 acres (40,000 hectares) of such "intensive culture" woody crops have been planted in the USA. "Fiberfarms" covering areas on the order of 10,000 acres (4,000 hectares) each have been planted in Oregon, Washington and California during the 1990's. These farms achieve yields in the range of 7 to 14 dry tons per acre per year (14 to 28 dry metric tons per hectare per year). For comparison purposes, a natural forest in the U.S. that is managed, but not intensively managed, for this same purpose of yielding wood for pulp, paper and other forest products has a yield typically on the order of only 1 dry ton per acre per year (0.5 dry metric ton per hectare per annum)—sometimes as low as 0.5 tons/acre per year (0.25 tonne/ha/a) and sometimes as high as 2 tons/acre per year (1 tonne/ha/a), depending on climate and other factors, with the high of 2 being in the southeastern U.S.

On the industry side, substantial investments have been made and are being made. At the very low-cost end of estimating the investments made so far, one could expect that at least $300/acre ($750/hectare) must be spent to establish such crops. (Probably more than half the land so-planted by industry is irrigated and, therefore, could cost at least twice as much per acre, or hectare, to establish.) Operating costs must be at least $20/acre/year ($50/hectare/year). (Again, irrigation is common and much more expensive, probably multiplying annual operating costs by a factor of three or even ten.) Hence, the investment by the forest products companies is on the order of at least some $50 million in capital and another $10 million each year to operate the 100,000 acres (40,000 hectares) already planted. Industry investment has been primarily by the pulp and paper industry and secondarily by the chemical, fertilizer and agricultural industries. These have invested undisclosed amounts of their own funds individually, and have banded together to form collaborative research programs.

One such collaboration is the one EPRI joined in the mid-1990s at Oregon State University, the Tree Genetic Engineering Research Consortium (TGERC). This consortium pioneered, for pulp wood or energy wood, the implanting of gene associated with a desired trait into trees that the industry has already identified as very fast growing. In this case the desired trait was resistance to herbicides, so that weeds could be eliminated easily without hurting the young sprouting trees. By participation in TGERC, EPRI had contacts with and first-hand access to one of the research efforts that could revolutionize the potential for energy crops. The revolution would be from the application of molecular biology and biotechnology to obtain the combination of very high yields and much lower costs that would bring the biomass resource into the energy industry as the lowest-cost, non-intermittent source of renewable energy.

Beyond this "very high tech" approach to getting a breakthrough on energy crops, there are other industry-cofunded consortia where EPRI has had and could continue to have a role. These other consortia have involved the federal program at Oak Ridge along with the USDA Forest Service, state forestry, agriculture and university programs, forest and farm companies, cooperatives, and various individual researchers, farmers or landowners. The EPRI objectives as a consortium member are (1) to have first-hand and current insight into the R&D relevant to assessing, and potentially exploiting, the major use of biomass in energy production, and (2) to influence the consortium to address the energy aspects of their topic, not just the near-term high-value-product aspects, such as yield and cost of pulpwood or fiberboard. EPRI involvement in such consortia also puts EPRI "at the table" where the federal research program at ORNL and the various state and other interests (forest, environment, agriculture, university and farm extension services) meet together with the forest product companies to plan and conduct woody crop research.

Topic 2: Biomass Cofiring

Biomass cofiring with coal in existing power plants is the lowest-cost method of generating power from biomass and is a technology to watch. Some specific features to monitor are:

1. The lowest-cost biomass cofiring option, “blended feed,” involves blending the biomass fuel with coal in the fuel yard and passing the fuel mixture through the crusher and pulverizer en route to the boiler. The installed cost of the blended feed option is typically about $50/kW. The issues that need to be monitored are those related to determinations of the upper limit on the fraction of the heat input that can come from the biomass. The fraction of biomass that can be accommodated will be a function of the biomass and coal types and properties (especially the slagging and deposition properties of the coal and biomass ashes), the coal pulverizer and coal boiler types, the unit capacity, and other conditions, such as coal and biomass fuel handling and conveying systems.

2. The “separate feed” option requires separate systems to feed coal andbiomass into the boiler, including separate feeding conveyors and injectors for the coal and biomass fuel streams. The cost of adding the separate biomass feed to the unit is typically closer to $200/kW The issues that need to be monitored include the upper limit on the fraction heat input from biomass that can be accommodated, the size reduction required to ensure that the biomass fuel will burn completely in the boiler, the need for additional processing such biomass drying, and the impacts of biomass cofiring on NOx emissions, bottom and flyash properties, and boiler efficiency.

3. Can simple gasification systems provide more fuel flexibility, and, thereby, lower cost biomass fuel, by putting biomass heat into the boiler in a gaseous rather than a solid form? Can this be done at capital costs as low as $300/kW? Does it lower fuel cost and does it allow higher fractions of biomass heat input or other benefits such as targeting a larger fraction of the coal-fired boiler population?

4. Is biomass fuel supply being proved and improved by the cofiring experience? As a retrofit technology that does not add any new generating capacity, cofiring economics depend on either the fuel savings achieved, customer service or marketing advantages given, or value assigned to the renewable generation, such as a "green power premium" or a credit for greenhouse gas reduction. As cofiring is deployed, the biomass fuel supply curve (i.e., amount and quality of fuel as a function of price paid for the fuel) will be defined by actual practice. In this way, the low-cost end of the existing supply of biomass fuel based on availability of wastes and residues will be tested, and the supply “proved” or disproved. On the "improved" side, what should be looked for is whether the improved "fuel infrastructure" is in fact coming into existence due to the new market provided to potential biomass fuel suppliers. In the U.S., approximately 40 million dry tons per year of biomass fuel (over 90% of it wood and wood product wastes) are now used to generate electricity. Some 7000MWe

of generating capacity is fueled by this 40 million dry tons. If biomass cofiring is to play a role in building the infrastructure for the supply of biomass as a power plant fuel, then the fuel supply should be expanding without the cost going up as much as current cost curves would suggest. In fact, some 5000 to 8000 MWe of additional capacity based on cofiring should be the result, and the fuel for an expansion to 7,000 MWe should be some 30 million dry tons of biomass not currently in use as fuel and brought in at a cost at the low end (i.e., about $1.00/MBtu), not at the high end (i.e., about $2.00/MBtu). The second 7,000 MWe can come from only 30 million, indicated 40 million dry tons because in an efficient coal-fired boiler the effective heat rate for conversion of biomass to power can be more like 11,000 Btu/kWh instead of 15,000.

And finally, regarding biomass fuel supply, one should watch to see whether cofiring helps establish a market for fuel from crops. At the low fuel costs that an economical cofiring operation must have, it is not likely that cofiring can establish a market for crops grown purely for fuel (the so called "dedicated fuel supply systems"). However, the existence of a cofiring fuel market at prices like $1.00/MBtu should help establish the beginning of an energy crop market by means of enabling farmers to grow crops, such as poplar trees or alfalfa, for higher value markets, such as pulp wood or animal feed, while generating a substantial residue that goes into the cofiring fuel market. If cofiring is to play a major roles as a bridge to much larger uses of biomass for power generation in the future, then some shift toward crops for fuel should appear as part of the expansion of cofiring up toward the 3,000 to 10,000 MWe role. As pointed out above, under the "Energy Crops" topic, it is only through growing fuel on farm lands that biomass can move toward a 10% to 25% role in power generation, and beyond the 2% to 6% role that would otherwise be the limit.

Topic 3: Direct Combustion Biomass

When accepted as a renewable source of energy, simple direct combustion of biomass to make electric power, or power plus heat, is among the lower cost sources of renewable electricity today. This is true even for the simple grate-fired boilers, often called stokers. The total cost for biomass combustion is typically $100 to 110/MWh, assuming $2000/kW capital cost, $2.00/MBtu fuel, and $10 to $20/MWh operating costs, 6400 hours equivalent per year, 14,000 Btu/kWh heat rate, 20 to 40 MWe unit size. This is "lower cost" only when compared to some other renewable sources of power generation, such as the most abundant, but low-quality, wind resources and the solar PV resources that could be built today. Improved low-cost direct biomass combustion systems are likely to be developed and become available in the future.

In the 1990-1994 period, EPRI supported the design, cost evaluation, and testing of one possible breakthrough in lower cost direct combustion: Whole Tree Energy™ (Refs.39,40). The lower cost is brought about by building larger, being more efficient (in part through the larger size) and by tying in as directly as possible to the sustainable growth of woody crops in farm settings. Because of these features, Whole Tree Energy™ may be able to achieve $60 to $65/MWh electricity cost, $1200/kW capital cost, $1.50/MBtu fuel cost, 10,000 Btu/kWh heat rate, and $10/MWh operating costs. These cost and performance values are much improved relative to small stoker units, and are comparable to good wind resources and well below the current costs of $100 to $130/MWh for solar electricity. Thus the Whole Tree Energy technology recovers solar energy converted to biomass at half the cost of the direct solar electric (PV) technology. However, it is not at a bargain price compared to fossil energy, or compared to conversion of the best wind and geothermal resources. Compared to the standard advanced biomass conversion, i.e., the gasification gas-turbine combined cycles described in the next subsection, Whole Tree Energy™ has somewhat less potential to reach the highest efficiencies, because it is a steam-based cycle, not a combustion-turbine or gas-turbine cycle. However, WTE™ has better values of projected capital cost and fuel cost, and does not have the technical problem of cleaning a fuel gas to the gas-turbine inlet purity standards required to protect a high-performance gas-turbine power system.

Topic 4: High-Performance Biomass Gasification

The topic to follow to monitor progress toward the gas-turbine-based high efficiency biomass conversion is gas cleanup or "gas conditioning." This refers to the cleanup, or "conditioning," required to keep the gas turbine equipment itself operating reliably and efficiently. It does not refer to any special need for gas cleanup for emission control. Once the fuel gas meets gas turbine inlet standards, the gas-turbine/steam-turbine combined cycle system should exhibit the same low air emissions as the natural-gas-based combined cycle power systems that now set the standards for clean combustion power systems. One exception could be biomass fuels that are higher in fuel nitrogen that clean wood fuels. For such high-N fuels, the higher nitrogen content could lead to a need to reduce NOx emissions via some extra post-combustion treatment. One of the projects mentioned in the next paragrah, Varnamo, did include an ammonia cleanup stage in the fuel gas cleaning system.

The projects to watch in the biomass gasification area are those that test and prove gas cleanup systems for biomass gasification combined cycle power generation. The most extensive experience in building and operating such a system has been at Varnamo in the south of Sweden. There Sydkraft, an electric utility, and Ahlstrom, an equipment supplier, later bought by Foster Wheeler, built and operated a combined heat and power station of 6MWe electric output from 1994 through 1999. The Varnamo project was a high pressure gasifier with gas cleanup done at moderate temperature via a metallic membrane filter. At moderate (350-400 C), as opposed to high (>500 C) temperatures, there is not the need to also remove vaporous alkali metals, such as potassium, by an "alkali getter" reactor. An alternate, but also moderate temperature, gas cleanup system with ceramic filter elements, was tried earlier at Varnamo, but filter breakage led to the use of metallic filter elements for the long-term operation. Also, a higher temperature gas cleanup system, including an alkali getter, was tested successfully in the laboratory at IGT in Chicago and later in the field in Hawaii. The testing at IGT and in Hawaii were both done as part of a project cofunded by the U.S. DOE Biomass Power Program. In Hawaii, the project was conducted by Westinghouse, as gas cleanup and turbine supplier, together with industry/government/university partners. This project built and tested a gasification system of approximately 5-MWe-equivalent size on the island of Maui, with sugar cane bagasse as the biomass fuel. The hot gas cleanup tests on Maui were done using a slipstream having a flow approximately one-tenth the full flow of the gasifier output stream. The earlier tests in Chicago at IGT were also at a scale comparable to one-tenth the Maui operation.

Solar

Topic 5: Solar Thermal Power and "Solar Two"

Southern California Edison Company (SCE) has led in the organization of the largest test of solar thermal power generation. SCE developed and, with major DOE cofunding plus other industry cofunding, including EPRI, implemented a project that completed its testing and operations runs in 1999. It captured international attention in 1996 for generating electricity even at night, was declared a success in September 1999 by DOE, the majority cosponsor. DOE and the public/private consortium led by Southern California Edison (SCE) applauded the unique solar project, which finished its test run earlier in 1999. The sponsors called it a "revolutionary technology" that is commercially viable and could be applied to power plants as large as 100 MW to 200 MW in many parts of the world. Some facts and quotations from that September 1999 press release (Ref.61) are given here, as follows:

"We're proud of Solar Two's success, as it marks a significant milestone in the development of large-scale solar energy projects," said U.S. Energy Secretary Bill Richardson, citing the technology's performance data. "It takes us a step closer to making renewable energy a significant contributor to the global energy mix, while helping to make our environment cleaner."

By using an innovative molten salt technology to collect and store the sun's energy, Solar Two, unlike other solar power plants, was able to dispatch electricity "on demand," even at night. SCE Vice President of Power Production, Larry Hamlin, noted that the demonstration project generated approximately 8,500 megawatt hours (MWh) of clean solar power since June 1996 and produced the following results:

- Delivered electricity to the power grid around the clock for 153 straight hours, demonstrating its efficient storage system.
- Produced 1,633 MWh over a 30-day period, exceeding its 1,500 MWh one-month performance goal.
- Achieved 97 % efficiency of the storage system.

Solar Two will no longer be used to generate electricity, but some of its components will be applied to other efforts, including astrophysics research. DOE notes that the technology doesn't appear to be immediately marketable in the United States, as several parts of the nation's electric utility industry are being restructured. Domestic market introduction and acceptance is likely to be more favorable after the technology becomes more economically competitive.

"Foreign countries such as Brazil, Egypt and Spain, have shown an interest in the application," observed Gary Burch, who oversees concentrating solar power technology at DOE. "A number of companies both in the U.S. and Europe are actively engaged in pursuing business opportunities in Spain that include molten salt power tower technology."

Solar Two's design was based on lessons learned from Solar One, America's first solar power tower, which operated from 1982 to 1988. The project's $55-million design costs were shared equally by DOE and the private/public consortium, including SCE, Arizona Public Service, Bechtel Corp., California Energy Commission, Electric Power Research Institute (EPRI), Idaho Power Co., Los Angeles Department of Water & Power, PacifiCorp, Sacramento Municipal Utility District, and the Salt River Project. SCE's Hamlin noted that significant cost efficiencies were realized by adapting and extensively using equipment and systems originally built for Solar One.

Solar One used a water/steam system to drive a conventional turbine, but its inability to store energy efficiently limited its production of electricity on cloudy days or after nightfall.

By contrast, Solar Two employed nearly 2,000 giant sun-tracking heliostats (mirrors) to reflect the sun's energy on to a single collection vessel (known as a "receiver") atop a 300-foot centrally located tower. Molten salt, flowing through the receiver, was heated to 1,065 degrees Fahrenheit and was then transferred to a "hot salt" storage tank. When electricity was needed, the liquid was run through a steam generator which drove a turbine to create electricity.

Three million pounds of molten salt, a mixture of environmentally benign sodium nitrate and potassium nitrate, were provided by Chilean Nitrate Corporation.

Topic 6: Mass Production of PV Systems

The economics of photovoltaic (PV) power generation will be controlled by the nature of the technology itself, e.g., amorphous thin film, crystalline silicon, multijunction, CIS (copper indium diselenide) technology, etc., and by the size of the production operations that can sell product, i.e., economies of scale. In May 1999, Datacomm announced a market research report that put the market for solar electricity at one billion dollars per year (Ref.62). The report said that the market for solar electricity is growing rapidly, with module shipments doubling in the preceding 3 years, and that the technology is poised to play a major role in bringing telecommunications services to developing countries.

Actually, if the "market for solar electricity" is meant to encompass all system hardware and installation costs, it's been over a billion dollars for since 1998 or even, perhaps, 1997. Another statistic relevant to reducing costs through expanded production is that sometime in 1999 the 1,000th MW of PV was installed somewhere in the world. Also, assuming continued historic market growth rates and price trends, the milestone of $1B in annual PV module sales will be passed in 2002 (Ref.62).

The cost of PV systems has decreased due to research and development efforts, and due to greatly increased volumes of production over the years from 1977-1998. Sales have been into both subsidized markets, such as residential or commercial buildings with government-sponsored grants, rebates, etc., and into commercial markets where there is an unsubsidized high price for electricity in specialized applications. The dominant specialized application has been for re-charging batteries at remote stations for communication networks. The highest price market has been electricity for application in space, e.g. satellites and space probes. Perhaps the highest price for electricity in a high-volume market has been for the electricity from PV cells put into "solar powered" calculators during the 1980's. Figure 10-1, "Sales Volume and Cost Decrease for Solar PV Modules," presents historical and projected future trends in manufacturing volume and price for PV modules (Ref.63). A PV "module" is a self-contained unit consisting of an array of PV cells that requires only electrical connection to other modules, inverter, and controls to deliver power to the grid or local power user. Figure 10-1 shows two trend lines, one for conventional single-junction crystalline silicon PV cells, the other for advanced thin-film amorphous silicon and multijunction PV cells.

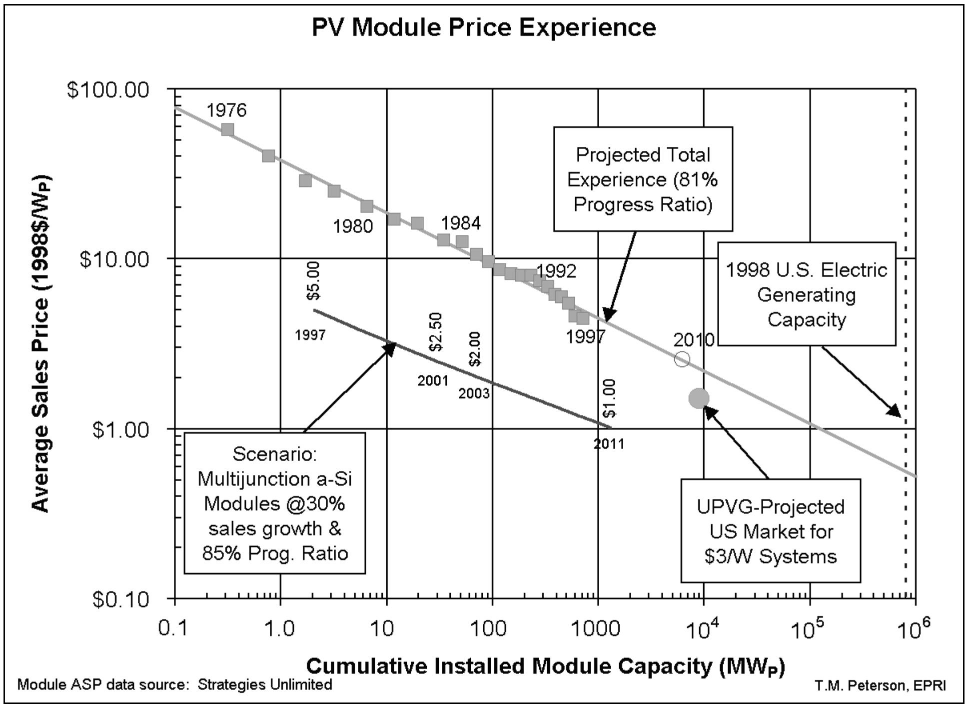

Figure 10-1
Sales volume and cost decrease for solar PV modules (Ref.63)

One aspect of achieving larger sales and therefore lower unit costs is that of finding new markets or applications for the solar cells and modules. Thus, another aspect of research and development can be that of developing technology for new uses. Even if not directly giving a lower cost for solar electricity, a technology that opens a new market helps by expanding the overall market. Such technologies need not be competitive in general electric power applications. Each such technology need only be lower cost than the competing technology for a particular application.

Figure 10-1 shows the average selling price of "modules" that generate power from sunlight falling on PV cells. The costs of cells, modules and complete power systems, and, of course, the resulting cost or price of electricity, should be very sensitive to the size of the market that dictates the size of production facilities that can be economically justified. As indicated in Figure 10-1, the trend for the type of system usually deployed is the line for crystalline silicon solar cells. This is a technology that has to date accumulated about 200 MW/year of cell production capacity. (This is also the technology involved in an example given under Topic 7, below, where an electricity sale at a premium price is the focus of the discussion, i.e., the Green Mountain

Energy project in Hopland, California.) The trend line for crystalline silicon modules runs close to a classic formula saying that the unit cost of production is cut by 20% for each doubling of the cumulative production. On such a trend line, a factor of 10 reduction in unit production cost requires eleven (11) doublings of the cumulative production, i.e., the cumulative production must increase by a factor of 2 raised to the 11^{th} power, or 2048. Assuming a 20% per year growth in production, it would take 40 years for the cumulative production to reach a factor of 2000 above that accumulated so far. However, at a 30%/year growth, it would take less than 30 years to reach that level. Conclusion: somewhere in the 2025 to 2040 timeframe solar PV using crystalline silicon could have achieved a unit cost one-tenth of today's (year 2000).

Topic 7: Sales of PV Electricity at Premium Price

Ability to sell solar electricity at a premium price may well determine whether the economics-of-scale part of the path to lower cost is being followed. During 1980's and 90's premium prices were paid for some solar electricity, paid then by electric utilities who in turn could put the added costs into the rate base approved by their regulatory commissions. The largest such sales of solar electricity were made in California for the power generated via solar thermal (not PV) at the so-called "solar trough" power systems installed originally by LUZ in the Mojave Desert north of Los Angles. Per Table 1-1 above, the EIA listed the capacity at 360 MWe (Ref.2) and the generation at 820,000 MWh in 1996. The LUZ power plants, and other solar thermal systems such as "dish stirling" and "solar power tower" do not contribute to reducing the cost of PV systems. However, the concept of achieving low unit cost through mass production can be applied to both technologies, separately.

The first commercial electricity sales based on customers signing up to pay a premium price for centrally-generated power from solar PV (not solar thermal, which has accounted for virtually all previous solar electricity sales into the commercial power market) were not announced until the summer of 1999. One such sale was that announced for a project in Hopland, California (Ref.64). The other was a project in Pennsylvania (Ref.65). Both involved sales of electricity from generating facilities built in one case by Solar Utility Company, Inc., in Pennsylvania, and in the other case by GPU Solar (a joint venture of GPU International and AstroPower) in California. The sales were announced by Green Mountain Energy Company (Ref.64). GMEC will buy the electricity from the project developers at the two sites and will then sell it to retail customers. In September 1999, DTE Energy (Detroit Edison in Michigan) also announced plans for a similar 340-kW generating plant, this one to be constructed in Pleasanton, California (Ref.65).

As "firsts," these may be projects to watch. In any case, they are representative of a potential future trend that must be watched in order to see how the cost of solar-PV-generated electricity falls as the volume of sales increases, per Topic 6 and Figure 10-1, above. Another path to reduced cost is discussed as Topic 8, below.

Topic 8: PV Technology Shift

Another aspect of potential and expected cost reduction is that arising from technology development, whether progressive improvement or a breakthrough to a new approach or technique. Technology development is directed at providing the type of quantum jump, also illustrated in Figure 10-1, that could take the cumulative production trend off of one line and onto another, thereby achieving a lower-cost starting point on a graph like Figure 10-1. Thin-film multijunction amorphous silicon is the example shown in Figure 10-1, because that technology is poised as the most likely one to enter the market and challenge the traditional silicon cell-based market leader.

Wind

Topic 9: Larger Wind Turbines

1. For wind energy, there are at least four trends to watch:
2. larger unit size with associated cost reduction;
3. lighter weight, less expensive equipment;
4. capability to predict the wind over 12 to 48 hour periods; and
5. higher capacity factors.

Because these first two are both directed at lower unit cost to build and install the capital equipment, as measured in $/kW, and because the lighter weight is part of the path to larger unit size and lower capital cost, the first two of the above four items are addressed together here. (Similarly, in the next subsection, better prediction of wind is part of better capacity factor, and those two are also discussed together.)

The economy of scale in wind power occurs via larger unit size, and, also eventually from production of many standard sized units. The size-related cost improvement occurred as the wind turbine technology progressed from the 300-kW units of 1993, to the 500 to 600-kW units of 1997, and on to the 1000-kW and larger units of 1999 and later years. For example, the base case for a 50-MW wind farm in the DOE/EPRI "Technology Characterizations" Report of 1997 (Ref.4) might have 100 500-kW units at $1000/kW installed cost of the total plant, or “farm.” In 1997, that example would have a total plant cost of $50 million and an average per turbine cost of $500,000 (500 kW x $1000/kW). At an 0.7 power law scaling factor for size this would mean a cost of $500,000 $(300/500)^{0.7}$ for the 300-kW unit size of a 1993-vintage turbine. That same scaling law would suggest $1,250,000 per turbine for the huge 1.5 MW unit size of a future (2010?) wind power plant, based on $(1500/500)^{0.7}$. (All figures in constant dollars, circa 1997 dollars.) The cost per kW trend would be from $400,000 average per turbine for a farm based on 300-kW turbines in 1993, to the $500,000 for a 500-kW unit in 1997, to only $900,000 for a 1,500 kW unit in 2010, or sooner. (The 1,500-kW unit is already appearing in Europe for off-shore sites.) The cost per unit of capacity improvement is from $1300/kW to $1000/kW, and then on down to $667/kW. The 1993 to 1997 experiences and then the 1997 to 2001 trend based on orders and quotations in press releases match this 0.7 power law relationship quite well.

The key to achieving these larger unit sizes, and the resulting lower costs per unit of generating capacity, is the ability to make lighter-weight machines and to place them higher above ground. The lighter weight makes the greater height possible. And, the greater heights reach greater velocity wind, and enable the power system to take advantage of the approximate rule that "power output goes as the cube of the wind velocity," i.e., $P = Kv^3$, where P is power output in kW and v is velocity in meters/sec, and K is a proportionality constant. The technologies that have facilitated such advances to greater height and lighter weight include power electronics, variable speed designs, and a combination of materials/design improvements for combinations of lightweight and adequate strength.

Topic 10: Higher Capacity Factors for Wind Power

To bring down the cost of electricity generated from wind, the achievement of a higher capacity factor may be as important or even more important than further reductions in capital cost, at least at the higher-velocity wind sites. However, capacity factor is not something that can be easily controlled at a specific site, as it depends on the wind resource and turbine availability. To achieve high capacity factor, it is necessary to place the turbines at the locations of highest wind energy, develop an appropriate turbine specification for the site, and maintain and operate the plant for high availability. After a plant is in place, the only thing that can be done to push up the capacity factor is to maximize availability via careful O&M practices. To place the turbines at the sites of highest wind velocity a good site investigation, with wind pattern modeling, can be critical. While the technology of the turbines themselves obviously cannot influence wind velocity, except by height of the tower, the science and technology of site selection does affect the eventual capacity factor. "Micro-siting" within the general site selected also can be critical, especially in hilly terrain and to avoid one turbine blocking some of the wind that another one could be harvesting.

The main difference between an expensive source of wind energy and an inexpensive one is not so much the installed capital cost in $/kW but is rather the difference in the annual capacity factor. Annual capacity factor is defined as the total kWh of electricity generated during a year divided by the maximum number of kWh that could have been generated if peak power (i.e., nominal peak power rating) were achieved all year at all hours. As shown in Table 1-1, which gives generation sources for the USA in 1996, there were 3.17 x 10^9 kWh generated by wind from a nominal peak power capacity of 1850 MWe, which indicates a national average capacity factor of 0.196 (3.17×10^9 kWh actually generated $\div$ 1.85×10^6 kW capacity times 8760 maximum hours in a year).

The major difference between an excellent wind energy site and a more typical one could be expressed as the high capacity factor at the excellent site, e.g., 49% for resources in Classes 5-7 versus the low capacity factor at a more common site, such as 25% at a Class 3 resource (using the values in Table 7-1, above in this report). If the excellent site could generate electricity for $36/MWh, then the more common site would generate at a cost of about (0.49/0.25)*$36 = $70/MWh, because the dominant factor in determining the cost would be the number of MWh that the capital cost and fixed operating costs would be paying for over the course of the year. Only the rather minor possible differences in capital cost and variable operating costs -- such as some replacement of parts being more frequent in the unit at the excellent site due to more wear as the unit runs for more hours and at higher loads -- would lead to cost of electricity not being simply inversely proportional to the annual capacity factor. (In Table 7-1 on wind technology, the $36/MWh for Classes 5-7 became $65/MWh for Class 3 because the O&M costs were set at the same value for both, namely $5/MWh, which does indeed allow for higher total O&M per year when the unit runs for more hours at higher power.)

These considerations lead to following the conclusions regarding capacity-factor-related matters in future cost reductions for wind energy generation:

1. The more abundant low quality resources will be used more and more as the higher quality resource sites are taken advantage of first. This trend will counteract, in part, the otherwise dominant trend toward lower costs.

2. Improved reliability of components and systems, based on learning experience and on a larger market leading to more effort to improve the equipment, will lower costs of generation. The effect will be in proportion to the extent to which the capacity factor is improved by the greater reliability and availability. In the early years of deployment of the small unit sizes (50 kW average before 1982 and 100 kW average 1982-87, roughly), EPRI-sponsored research (Ref.66) documented the potential for substantial improvements in reliability, as measuered by availability. Availability is the fraction of time that the unit is available to generate power, i.e., is ready to run as soon as the wind is there to drive it. To maximize the electricity generated it is especially important that the unit be available to run at all the times when the wind is steady and at design velocity. Low availability correlated with low capacity factor and vice versa, indicating that reliable equipment and proper maintenance could be important in the economics (Ref.66). The EPRI study on the small turbines in 1986-87 (Ref.66) showed a range of O&M costs for a subset of 289 turbines ranged from a low of $7/MWh to a high of $17/MWh. For the future, at the 500 kW to 1000 kW turbine sizes adopted in the Technology Characterizations report of 1997 (Ref.4), EPRI and DOE adopted $10/MWh for the O&M costs of 1997 technology and showed a decrease to an average of $5/MWh by 2005. (That average covered the Class 4 to Class 6 wind re-sources). Good practice includes off-season maintenance that prevents loss of availability during the windy season. The EPRI-DOE Wind Turbine Verification Program in recent years, 1996-99 (Ref.67), has found evidence that improvement can still be made in efforts to assure the turbines are ready when the wind is there. Guidelines for wind turbine productivity improvement are planned as a product of the EPRI renewables program in 2000.

The work of EPRI and others to develop and apply models to predict wind and, hence, the amount of electricity generated by equipment installed at a given site, will have important economic effects. The improved economics will come in two ways: (1) by avoiding situations where the available wind cannot be fully used because the system cannot accept the power; these situations occur when other types of generation are already in use and cannot economically or practically be cut back to allow the essentially-free wind energy to be put into and carried by the transmission/distribution system. And, (2), which is perhaps more important, by allowing the wind generation to be used as fully as possible at times of peak value; peak value comes when high-priced gas or oil in relatively inefficient generating units such as old boilers or gas turbines would otherwise be called upon to meet a peak demand. The simple economic calculations used in this report, however, do not assign any added value or lower extra cost to wind generation when it can achieve a greater share of use at times of peak demand. One way to take into account the added value of wind energy when it can be predicted and relied upon to meet peak demand during critical hours is to use a higher value, such as $80/MWh instead of $42/MWh, as the cost of the fossil energy displaced. For example, a $80/MWh cost of the fossil alternative can be derived from the following assumptions: The alternative is to install and operate a gas turbine peaking system. This system has a capital cost of $150/kW, fuel cost of $4.00/MBtu, heat rate of 11,000 Btu/kWh and a capacity factor of 0.10 (covering an assumed 876 hours per year of use of the peaking system). With these assumptions for a peaking system, the cost of the fossil alternative is $150/kW x 0.21/year ÷ 8760 hours/year, plus a fuel cost of $4/MBtu x 11,000 Btu/kWh, giving an annual capital recovery requirement of 31.5/876 $/kWh and a fuel cost of $0.044/kWh, for a total of $0.036 + $ 0.044 = $ 0.080/kWh = $80/MWh.

The conclusions, therefore, regarding what to watch for indications of reduced cost in wind power generation are as follows:

- Improved siting, availability and prediction capability so that wind generation can be counted on to be there at most times of peak demand and can then be sold at higher prices.
- National-average values for capacity factors of wind generation that do not decline over the next decade despite the fact that more low-velocity wind resources are being used. A level trend for such overall capacity factors would indicate that, on average, improved technical performance has been offsetting what would otherwise have been a decline in national or worldwide average capacity factors as lower quality wind resources are brought online. (For example, Table 7-1 shows Class 4 at a capacity factor of 38% versus 49% for Classes 5-7. And, the Class 4 is much more abundant, having a 1450 GWe resource estimate for the USA versus the 166 GWe for the Classes 5-7.)
- Improvements in reliability and availability as experience and market size increase, and, then, an eventual leveling out of the improvement trend as the technology matures.
- And, watch specific R&D projects that are designed to develop, test and improve the ability to predict wind generation in ways that increase capacity factor and allow wind-generated electricity to have a higher value in deregulated markets and where generation at peak demand can capture a higher price.

Progress, or lack of progress, towards lower costs for wind power generation will be seen, or not seen, as these improvements are tracked over the next ten years.

Fuel Cells and Hydrogen

Topic 11: Fuel Cells and Hydrogen

Future energy technologies that are often linked to renewables include fuel cells and hydrogen-fueled power or transportation systems. In the field of biomass power, fuel cells represent the way to make the gasification-based power systems enjoy a big breakthrough into very high efficiencies. And, those high efficiencies could mean that much less land is required for growing biomass to fuel a major role in power generation. For solar power, fuel cells represent a way to build-in a storage system that can make solar a less intermittent source of energy and generating capacity. This is because fuel cells offer a way to produce hydrogen, via electrolysis, as the energy storage mechanism during sunlit hours, and to follow that storage phase by conversion of hydrogen to electricity in a fuel cell as power is demanded when the sun is not shining or the sunlight intensity is not adequate to meet the demand of the moment.

Hydrogen is the direct fuel for a fuel cell, the cell being in essence an electrochemical reactor where hydrogen and oxygen react to form water and drive an electric current. The reaction is the reverse of electrolysis where electric energy input separates the hydrogen and oxygen atoms in water molecules. Although hydrogen is the immediate fuel that flows directly into fuel cells, the market for fuel cells as power generators is being started with a major existing fuel, namely natural gas. The fuel cell power system includes a "reformer' in which methane (CH_4), which is the dominant constituent of natural gas, is reformed to produce hydrogen gas (H_2) and carbon dioxide (CO_2). The attractive features from an energy system perspective are the very high efficiency – there being none of the thermo-mechanical heat engine losses intrinsic to any combustion engine or boiler steam engine system -- and the clean nature of the "combustion" products that do emerge from the fuel cell: just clean water, no sulfur, no hydrocarbons, no oxides of nitrogen.

The connection to renewables comes from the possibility of making the hydrogen for fuel cells from biomass technologies (Ref.24)--such as gasification, biomass-based ethanol, anaerobic digesters, anaerobic digestion occurring in landfills--or from solar, wind, or geothermal electricity via normal or advanced electrolysis. Beyond fuel cells, the hydrogen from these renewable energy resources could go to the future "hydrogen energy economy" envisioned often as part of an ideal carbon-free energy system of the future.

The near-term and practical link to renewable energy is probably the transition from a distributed generation market initially created by sales of natural-gas-driven fuel cells into sub-megawatt unit sizes at various demand centers. Examples of these demand centers include commercial buildings, hospitals, resorts, small industrial parks, etc. Once the natural-gas-based system is there, the renewables-based alternatives to the natural gas could be phased-in as natural gas prices get higher and renewable sources such as biomass gasification improve. The best prospects for renewables are those where high efficieny fuel cells could be applied without requiring a naturalgas-based market to be created. Examples include:

1) Biomass-based fuel cells. It may be possible to implement fuel cells based on biomass-derived gas in advance of the full establishment of the natural gas based fuel cell, perhaps starting with projects using landfill gas sources of methane or with biomass gasification systems. This biomass use in advance of the mainstream natural-gas-based fuel cell deployment could arise if there were a case where a gasification system could more economically send its biomass-derived gas (H_2, CO, CH_4, CO_2 and trace constituents, but mostly H_2 and CO) to a fuel cell rather than to a gas turbine. For instance, a molten carbonate fuel cell system may be able to tolerate the alkali carryover in a biomass gasification product stream better than could a gas turbine, thereby enabling biomass gasification power development to avoid a gas-cleanup barrier (Ref.24). Unfortunately, in general, fuel cell systems require even cleaner fuel gas input than do gas turbine systems. Therefore, in general, this bypass path, directly to biomass fuel cell technology without first going through gas turbine and natural gas technologies, appears unlikely. However, it is a possible connection to fuel cells and hydrogen, and a connection that should be watched as biomass and fuel cell technologies develop.

2) Reversible fuel cells. This concept involves solar, or wind, power systems integrated with reversible fuel cells as a solution to energy storage, intermittent resource availability, and peak demand problems. A fuel cell run backwards would be an energy storage device, storing energy in the form of the hydrogen gas generated by the reverse fuel cell unit. This reverse device is called an electrolysis unit or an "electrolyzer." Reversible fuel cells can be implemented in two ways: one where the electrolysis and power generation sub-units are separate, and the other where the same unit provides both functionsThe developments to watch for include the creation of premium prices or other niche markets, such as customers and sites with special needs for peaking, reliability, etc., where renewables offer an early high-value niche for fuel cell and hydrogen energy applications.

3) Geothermal hydrogen. Like all renewables, geothermal is capital-intensive. Like all renewables except biomass, geothermal has no fuel cost, assuming the costs to build and run the geothermal fluid collecting system are taken as either capital or other fixed costs. Unlike solar and wind, geothermal is base-loaded, not intermittent. The special connection of geothermal to hydrogen, and hence rather indirectly to fuel cells, is that geothermal energy economics are best when the capital is used at a very high capacity factor, and energy storage provides a way to keep the plant running at high capacity. The generation of hydrogen via electolyzers, or reverse fuel cells, when the electricity is not needed is a way to pay off the capital and cover the fixed operating costs. It depends on a market for the stored energy, and that market could be the hydrogen used right back again to hit peak demands at premium prices during the next day or the next few days. ("Old" technologies such as batteries and nuclear power plants have elements of this system also: very low cost of incremental electric power generation and, hence, an incentive to store electricity, such as by charging a battery. Sometimes the "old" technology finds a way to start a market before the "new" technology gets developed for that same market.)

11
SUMMARY AND CONCLUSIONS

Renewable energy technology offers the potential to provide a substantial portion of global energy needs during the 21st Century while helping to reduce fossil-fuel-derived carbon dioxide, methane, and other greenhouse gas emissions to the atmosphere. This report provides estimates of technology performance and cost, plus descriptions and perspectives, to address the following questions:

1. How large a role can renewables play in reducing future
2. fossil fuel greenhouse gas emissions?
3. How soon can renewables play a major role?
4. At what cost?
5. What should be watched to monitor progress, or lack of progress, toward a major role for renewables?

DEFINITIONS AND SCOPE

This report presents estimates of high and low growth scenarios, energy contribution, green house gas reduction potential, and emission reduction cost for six renewable energy technology categories: (1) non-commercial biomass, or traditional, non-power biomass energy sources, what might even be labeled as the "primitive" biomass technologies; (2) biomass power, including modern combined heat and power (CHP, or “cogeneration”); (3) geothermal power, but limited to the hydrothermal resources and excluding “hot dry rock;” (4) wind power; (5) solar thermal power; and (6) solar photovoltaic power (“PV”). Although it is considered a renewable energy source by many and is derived from solar energy, hydroelectric power (hydro)” is not addressed in this report. However, in order to compare results to other investigations where hydro is grouped with renewables, some data tables presented in this report include hydro in order maintain consistency with the source information.

HOW LARGE A ROLE ?

Role in Electricity. The estimated potential global renewable energy generation in the year 2050 ranges from 10,000 to 30,000 TWh/year (one TWh unit is 10^{12} Wh or 10^9 kWh). For comparison, the current (2000) global electricity supply is about 10,000 TWh/year, and the estimated total electricity supply in the year 2050 ranges from 20,000 TWh to over 40,000 TWh/yr. Thus, the potential contribution of non-hydro renewables in 2050 ranges from less than 25% up to almost 100% of the electricity supply in 2050. The high case eventually adopted here puts renewables as high as 20,000 TWh out of a total of 36,000 TWh/year in 2050, or about 55% of electricity supply. The highest case here, not adopted due to its having too high a fraction of intermittent wind and solar, would be 30,000 TWh and would be 50% of even the very high role for electricity in 2050 adopted as the high electrification case in the EPRI Roadmap (Ref.6).

Role in Fossil Carbon Reduction. Again taking year 2050 as a timeframe for an estimate, the low role for renewables would be on the order of a 6% reduction, i.e., 900 million tonne-C (Mtonne-C) attributable to renewables out of a high carbon case of 15,000 Mtonne-C. The high role would be on the order of 50%, i.e., cutting back from what would be 10,000 Mtonne-C/year in 2050 to something closer to 5,000 Mtonne-C/year.

The estimated reduction in fossil carbon emissions due to displacement of fossil sources by renewable ones depends on what source of electricity is displaced by the use of the renewable sources. If renewables displace nuclear power, there is no reduction in fossil carbon emissions. If renewables displace high efficiency natural gas combined cycle power generation, then the carbon emission reduction factor would be a low one, estimated to be 0.09 metric ton (i.e., tonne) of carbon per MWh. (Note that this is C, not CO_2, and hence a factor of 12/44 less mass than if given per ton of carbon dioxide.) If renewables displace coal, assumed to be generating power in a steam cycle driven by a conventional modern advanced boiler--a boiler that is assumed to fire pulverized coal efficiently, but with a desulfurization system installed--then the emission factor would be 0.236 metric ton C per MWh, i.e., 0.236 tonne-C/MWh. Therefore, the low estimate for the fossil C reduction here is 10,000 TWh of natural gas combined cycle replaced by renewables, giving only 10,000 x 0.091 or 910 million tonnes of C per year reduction in greenhouse gas emissions. The high case is 20,000 TWh of renewables replacing advanced pulverized coal and is, therefore, 20,000 x 0.236 or 4720 million tonnes-C per year. For comparison, in 1990 global emission from fossil fuels use was estimated at the equivalent of 6000 million tonnes of C. For a future comparison, the other investigations referenced in this report place the year 2050 emission level of fossil carbon in a range from a low of 5000 million tonne-C to a high of 15,000 million tonne-C. From the summary just given, the conclusion for this report is that the low role for renewables in the year 2050 would be on the order of a 6% reduction, i.e., 900 million tonne-C attributable to renewables out of some 15,000 tonne-C, and the high role in 2050 would be on the order of 50%, i.e., cutting back from what would be 10,000 tonne-C/year to something closer to 5,000 million tonne-C/year.

HOW SOON ?

To develop as estimate of how soon renewables could play a major role in reducing greenhouse gas emissions, EPRI generated several growth scenarios here in this report. The scenarios show starting points in the year 2000 for the deployment in MWe of each of six renewable power technology categories: (1) biomass, (2) geothermal, (3) wind, (4) solar thermal, (5) solar PV, and (6) hydro. Constant annual growth rates in %/year were selected and varied for each technology and for each 10-year period in the 2000 to 2050 interval. Both the "high" and the "low" cases assume growth rates that are reasonable for industries that have good incentives to expand; but, the "high" ones are more optimistic for expansion of renewables than the "low." The annual growth rates used range from 1% in some cases to 25% at the maximum, depending on EPRI's judgement of the situation based on incentives, cost/performance prospects, resource constraints and size of the industry upon which the expansion has to occur. A tiny industry can grow at a very high annual rate, such as 25%, while a large industry is less likely to be growing that fast on a % basis. The global growth scenarios are displayed in Tables 8-5, 8-6 and 8-15. Table 8-5 is "low" and 8-6 is "high." Table 8-15 is the adopted high case, reduced from the Table 8-6 case by imposing limits on wind and solar to keep the year 2050 total electricity generation from these intermittent sources below 20 or 25% of any one country's or region's projected electricity demand in 2050. (20% was the limit for wind and 25% was that for solar. These are based on % of generation in TWh, not capacity in MW or GW electric power.) Table 11-1 shows the results. This table shows results that are similar to Tables 8-5, 8-6, and 8-15, but with only years 2000, 2020 and 2050 shown and with additional information displayed: TWh and Gtoe and tonne-C numbers, plus comparisons to the EPRI Roadmap (Ref.6) and WEC/IIASA (Ref.12).

Table 11-1
Greenhouse Gas Reductions and Renewable Electricity: 2000, 2020 and 2050

Description of Item	This Report			EPRI Roadmap		WEC/IIASA Scenarios		
	Low	Adpopted	High	Growth	C-Limit	A2 "coal"	B "base"	C1 "solar"
Year 2000:								
Electricity - TWh	172	250	330					800
Efficiency assumed	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
Primary energy - EJ	2.06	3.00	3.96	0.00	0.00	0.00	0.00	8.65
" " - Gtoe	0.0493	0.0716	0.0945	0.0000	0.0000	0.0000	0.0000	0.2065
C Emis.Fac. - tonne/MWh	0.250	0.250	0.250	0.250	0.250	0.250	0.250	0.250
Emis.Red. - 10^6tonne-C	43.0	62.5	82.5	0.0	0.0	0.0	0.0	176.0
Global emis. - Mtonnes-C						6000	6000	6000
Reduct./6000-C - %	0.7%	1.0%	1.4%	0.0%	0.0%	0.0%	0.0%	2.9%
Year 2020:								
Electricity - TWh	1212	1824	1863			3875		
Efficiency assumed	0.333	0.333	0.333	0.333	0.333	0.333	0.333	0.333
Primary energy - EJ	13.11	19.72	20.14			41.90		
" " - Gtoe	0.3128	0.4707	0.4808			1.0000		
C Emis.Fac. - tonne/MWh	0.220	0.220	0.220	0.220	0.220	0.220	0.220	0.220
Emis.Red. - 10^6tonne-C	266.6	401.3	409.9			852.5		
Global emis. - Mtonnes-C	?	?	?	?	?	10,000	?	?
Reduction/10,000-C - %	2.7%	4.0%	4.1%	0.0%	0.0%	8.5%	0.0%	0.0%
Year 2050:								
Electricity - TWh	10,000	20,000	31,350	21,470	31,350	16,486	12,710	17,430
Efficiency assumed	0.386	0.386	0.386	0.386	0.386	0.386	0.386	0.386
Primary energy - EJ	93.28	186.57	292.44	200.28	292.44	153.79	118.56	162.59
" " - Gtoe	2.226	4.453	6.980	4.780	6.980	3.670	2.830	3.880
C Emis.Fac. - tonne/MWh	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167
Emis.Red. - 10^6tonne-C	1,670	3,340	5,235	3,585	5,235	2,753	2,123	2,911
Global emis. - Mtonnes-C	8,000	7,000	5,000	9,000	7,200	15,000	10,000	5,000
Reduction/Total* - %*	17%	32%	51%	28%	42%	16%	18%	37%

*Total in 2050 is global C plus amount of reduction in C by renewables, i.e., sum of the 2 lines above.

AT WHAT COST ?

This report has derived estimates of the extra cost of electricity from renewable resources. The estimated extra costs range from a low of $15/MWh to a high of $60/MWh. That cost range for electricity can be converted to a cost per unit of fossil carbon emission reduction. The result is $63/tonne-C at the low end to $254/tonne-C at the high end.

To estimate the cost of using renewable power generation as a way to avoid emission of greenhouse gases, EPRI took the 1997 EPRI/DOE report "Renewable Energy Technology Characterizations" (EPRI TR-109496, Ref.4) and calculated the "goal technology" cost in $/MWh for each of 18 different renewable technology/resource combinations. EPRI did this only for the U.S. (See Section 7.) The extra cost of the renewable power in $/MWh was calculated as the cost above the $42/MWh cost to generate electricity from new (not existing) coal or natural gas power plants. Thus EPRI developed Table 7-7 showing the extra cost per MWh and the equivalent in $/tonne-C for avoiding the fossil emission. The result shows some renewable generation costing an extra $15/MWh, or less, and some costing as high as an extra $60/MWh, or more. The initial two-thirds at less than $15/MWh--i.e. approximately, 600 out of 900 TWh in the U.S. per Table 7-7--would mean a cost of fossil carbon reduction of $63/tonne-C, if it displaces advanced pulverized coal, where the emission factor is 0.236 tonne-C/MWh.

All of the above costs per tonne-C are based on renewables displacing efficient coal-fired power, i.e., coal-fired power plants using efficient new boilers in a steam cycle and with scrubbers for SO_2 and NOx control. Hence, the conversion from electricity cost in $/MWh to carbon cost in $/tonne-C is based on the emission factor for efficient coal-fired boilers: 0.236 tonne-C/MWh. If renewables displace the higher-efficiency, lower-carbon-intensity natural gas gas-turbine combined-cycle, then the emission factor would be 0.0909 tonne-C/MWh, and the resulting cost in $/tonne-C would be a factor of 0.236/0.0909, or 2.60, higher. Hence the $63/tonne-C low-end cost would become $164/tonne-C and the $254/tonne-C high-end cost would become $654/tonne-C. However, natural gas is not likely to be available, even at the high future price of $4.00/MBtu ($4.22/GJ) used in this report, in many of the places where the electricity will be needed in the world in 2050. Furthermore, in a future world where priority is given to generating electricity with low fossil carbon emissions, the tendency will be to use natural gas rather than coal, so the displaced fossil fuel will tend to be coal. Therefore, the lower range, from $63/tonne-C to $255/tonne-C, is the more reasonable one to adopt as the conclusion.

WHAT TO WATCH ?

Basis for Growth: Today's Renewable Power Business. The current (year 2000) size of the renewable energy technology business can be estimated from the amount of installed capacity or, in the case of solar PV, from the capacity to manufacture the cells and modules that are put into the markets that now exist for solar electricity. From the current (1997 or 2000) levels of capacity given in Section 1 (Tables 1-1 and 1-2, and discussion following the tables), the following conclusions are reached regarding the current size of the renewable energy industries in the USA and worldwide.

- Year 2000 for the United States: biomass—8 giga-watts (GWe), 50 billion kilo-watt-hours, or tera-watt-hours (TWh), per year, \$2.5 billion/year; geothermal—3 GWe, 17 TWh/year, \$0.8 billion/year; wind—2.5 GWe, 6 TWh/year, \$0.3 billion/year; solar (thermal)—0.4 GWe, 1 TWh/year, \$0.1 billion/year. The solar photovoltaic (PV) industry is better measured by its annual production capacity in MW of photovoltaic cell manufacturing capability: 10 MW/year at \$5 million per MW for a business of \$50 million/year (\$0.05 billion/year).
- Year 2000 for the world: biomass--20 GWe, 100 TWh/year and \$5 billion/year; geothermal--8 GWe, 50 TWh and \$2.5 billion/year; wind--13 GWe, 30 TWh and \$1.5 billion/ year; and solar thermal--0.7 GWe, 2 TWh and \$0.2 billion/year. Measuring the PV industry by its annual production capacity gives 30 MW/year at \$5 million/MW for a \$0.15 billion/year estimate of the size of the global PV business.

The totals for all five of these non-hydro renewable power categories, therefore, adds to the following: (1) U.S., 13,000 MWe installed generating capacity and a cumulative investment value in renewable power generation on the order of \$30,000 million (\$30 billion US); and (2) worldwide, about 38,000 MWe installed generation capacity and an investment accumulating to about \$95,000 million (\$95 billion US).

Future Developments. Section 10 discusses a number of topics to watch as renewable energy technologies are developed, tested and deployed in various projects over the next five or ten years (2001-2010). Topics discussed there include biomass energy crops, biomass combustion, biomass gasification, fuel cells, hydrogen, solar thermal, solar PV, economics of mass production of PV modules, wind power, premium prices for "green" power, and others.

CONCLUSIONS

1. Major reductions in greenhouse gas emissions--"major" being defined here as reductions to 20% to 50% below base case projections--will require very significant expansion of renewable energy production. Such expansion will have to start from the low level of deployment today at only 1% of the 300-EJ level of primary energy input worldwide. As estimated in this report, the expansion would be to a level that would be from 5% to 20% of some future level of primary energy input, a future level that could total somewhere between 500 to 2000 EJ in the 2020 to 2030 timeframe. These numbers indicate a range for renewable energy sources from a low of only 5% of 500 EJ, or 25 EJ, to a very high level at 20% of 2000 EJ, or 400 EJ.

2. Costs to generate electricity from renewables rather than fossil fuels (coal and natural gas) range from no added cost, for small amounts of renewables with today's technologies, to very substantial added costs, for reaching levels from 3% to even 20% as the fraction of renewable electricity in the generating mix. This assumes that, based on current technologies, "very substantial added costs" means costs on the order of \$15 to \$60/MWh above an estimated \$42/MWh base case cost of electricity from new power plants that fire coal or natural gas. These are cost figures for the United States. Costs elsewhere in the world were not estimated in this project at EPRI, but are expected, in general, to be in the same range. There may be important exceptions to this, especially where the alternative is not coal- or gas-based

electricity at \$40/MWh, but is imported diesel fuel at \$100 to \$200/MWh. In some locations, and for some populations, the alternative is to have no electricity at all.

3. Section 10 of this report has discussed some topics, issues, programs and projects that are among the subjects to watch to see how renewable energy development is progressing in the next few years ahead.

4. As a summary useful to the reader doing other calculations independently of this report, some numbers and assumptions useful in evaluating costs of greenhouse gas reduction via renewable energy technologies are given immediately below, thereby concluding this report.

Converting Extra Cost of Renewables to Cost per Unit of Fossil Carbon Avoided

This report has developed cost estimates for fossil carbon emission reductions in units of \$ per tonne (i.e., metric ton) of fossil carbon avoided. The report has done this by converting the extra cost of renewables--a cost expressed in \$/MWh--into the equivalent cost per metric ton of fossil carbon emission avoided. When the avoided emission is methane rather than carbon dioxide, the cost is expressed in terms of the greenhouse gas warming potential based on equivalent carbon dioxide CO_2. This gives landfill gas power systems, which convert a CH_4 (methane) emission into a recycled CO_2 emission, an advantage of 21 tonnes CO_2 equivalent, based on the relative strength of the greenhouse effect of the two gases, per unit of mass. The conversion factors are as follows:

1. If coal is displaced by a renewable, the conversion is:

   Coal: 1 MWh emits approximately 1 tonne of CO_2 which converts to 12/44 tonne of C. Therefore, displacing coal, \$0.01/kWh = \$10/MWh, and converts to \$42/tonne-C (or, 1 cent/kWh extra cost of electricity is approximately \$42/tonne-C). This is based on an efficient coal-fired steam cycle where 1 MWh results in 0.236 tonne-C (Table 5-3).

2. If natural gas in a combined cycle is displaced by a renewable, then:

   Natural gas in combined cycle: The cycle is more efficient and the fuel has less carbon per unit of heat content (Tables 5-2 and 5-3). The result is only 37% as much fossil carbon emitted (0.0909 tonne-C/MWh) compared to the coal case. Therefore, if renew-ables displace this efficient use of natural gas, the cost is

   \$0.01/kWh converts into a cost of \$42/0.37 = \$110/tonne-C.

3. If landfill gas is used to generate a MWh of electricity, instead of the methane (CH_4) being emitted to the atmosphere, then the conversion of extra cost in \$/MWh into \$/tonne-C goes as follows (based on Tables 5-1, -2 and –3):

   Landfill gas: 1 tonne CH_4 is worth 21 tonnes of CO_2 emission avoided (Table 5-1). However, in combustion it is one molecule of CH_4 (weight 16) whose emission is avoided compared to the molecule of CO_2 (weight 44) that would otherwise be emitted by the coal or gas fired in some other power plant. Therefore, the coal displacement case becomes

\$0.01/kWh = \$10/MWh ➔ \$42/tonne-C x 1/21 x 44/16 = \$5.55/tonne-C.

And, the natural gas combined cycle displacement case becomes

\$0.01/kWh = \$10/MWh ➔ \$110/tonne-C x 1/21 x 44/16 = \$14.41/tonne-C.

A
BASIS FOR THE GLOBAL ENERGY NUMBERS

Table A-1 repeats Table 8-4 from the main text. Then, Table A-2 shows how Table A-1 was calculated.

Table A-1
Renewable Energy in 1997 by Country and Type
(EJ = 10^18 joules)

Country or Region	Noncom-mercial Biomass	Biomass Power & CHP	Geo-thermal Power	Wind* Power	Solar (th.& PV) Power	Renewables (total of the 4 to the left)
USA	2.0	1.0612	0.4134	0.0287	0.0086	1.5119
Canada	0.3	0.0945	0.0005	0.0001	0.0001	0.0952
Western Europe	1.0	0.5513	0.1614	0.0820	0.0042	0.7989
Japan	0.1	0.1575	0.1042	0.0002	0.0021	0.2640
Aust./N.Z.	0.1	0.0158	0.0672	0.0001	0.0011	0.0841
East.Eur./FSU	3.0	0.0002	0.0021	0.0001	0.0000	0.0024
China	10.0	0.0079	0.0005	0.0026	0.0001	0.0111
India	10.0	0.0158	0.0005	0.0167	0.0001	0.0331
Indonesia	2.0	0.0047	0.0612	0.0002	0.0001	0.0662
Far East/Oceana	1.0	0.0047	0.3743	0.0001	0.0001	0.3793
Brazil	1.8	0.0158	0.0003	0.0003	0.0004	0.0167
Mexico	0.5	0.0002	0.1462	0.0002	0.0001	0.1467
Central/South America	0.5	0.0016	0.0601	0.0002	0.0001	0.0620
Africa	2.0	0.0016	0.0089	0.0002	0.0001	0.0108
Middle East	0.2	0.0002	0.0039	0.0001	0.0002	0.0044
World Total	**34.5**	**1.9327**	**1.4049**	**0.1318**	**0.0174**	**3.4869**

*Note: Use of wind power is expanding very rapidly, and, as a result, if 1998 instead of 1997 were taken as the base year, the number would be 30% higher, about 10,000 MWe and 0.17 EJ, instead of only 7500 MWe and 0.13 EJ.

Table A-2
Details for Calculation of Tables 8-4 and A-1: World Renewable Power in 1997

	Bio hr/y = 6570 (0.75 capacity factor)			Geo hr/y = 7446 (0.85 cap factor)			Wind hr/y = 1700 (0.20 cap factor)			Solar hr/y= 2300 (0.30 cap factor)		
Country or Region	**Biomass**	**Bio.**	**Biomass**	**Geothrmal**			**Wind**			**Solar**		
	TWh	**MWe**	**EJ**	**Geo. TWh**	**Geo MWe**	**Geo EJ**	**Wind TWh**	**Wind MWe**	**Wind EJ**	**Solar TWh**	**Sol. MWe**	**Solar EJ**
USA	67.38	10528	1.061235	15.75	2100	0.4134375	2.73	1606	0.028665	0.82	357	0.00861
Canada	6	938	0.0945	0.02	3	0.000525	0.007	4	0.0000735	0.008	3	0.000084
Western Europe	35	5469	0.55125	6.15	820	0.1614375	7.81	4594	0.082005	0.4	174	0.0042
Japan	10	1563	0.1575	3.97	529	0.1042125	0.019	11	0.0001995	0.2	87	0.0021
Aust./NewZea.	1	156	0.01575	2.56	341	0.0672	0.01	6	0.000105	0.1	43	0.00105
East Eur./Fmr.Soviet	0.01	2	0.0001575	0.081	11	0.0021263	0.01	6	0.000105	0.001	0	0.0000105
China	0.5	78	0.007875	0.02	3	0.000525	0.25	147	0.002625	0.01	4	0.000105
India	1	156	0.01575	0.02	3	0.000525	1.59	935	0.016695	0.01	4	0.000105
Indonesia	0.3	47	0.004725	2.33	311	0.0611625	0.02	12	0.00021	0.01	4	0.000105
Far East/Oceana	0.01	2	0.0001575	14.26	1901	0.374325	0.01	6	0.000105	0.01	4	0.000105
Brazil	1	156	0.01575	0.01	1	0.0002625	0.03	18	0.000315	0.04	17	0.00042
Mexico	0.01	2	0.0001575	5.57	743	0.1462125	0.02	12	0.00021	0.01	4	0.000105
Central/South America	0.01	16	0.001575	2.29	305	0.0601125	0.02	12	0.00021	0.01	4	0.000105
Africa	0.1	16	0.001575	0.34	45	0.008925	0.02	12	0.00021	0.01	4	0.000105
Middle East	0.01	2	0.0001575	0.15	20	0.0039375	0.01	6	0.000105	0.02	9	0.00021
Total	122.71	19173	1.9326825	53.521	7136	1.4049263	12.556	7386	0.131838	1.659	721	0.0174195
Alternate lower est.	96	15000	1.512	45	6000	1.18125	13	7647	0.1365	1.8	783	0.0189

Notes:

The above conversions from electric MWe and TWh to EJ (exajoules) are based on actual heat rates of the biomass and geothermal power plants, i.e., 15,000 Btu/kWh for biomass and 25,000 Btu/kWh for geothermal. For the wind and solar 10,000 Btu/kWh was used. The biomass and geothermal values exaggerate the fossil fuel displaced because the displaced coal power plant could well have the better 10,000 Btu/kWh heat rate. For future displacement of fossil fuel, when power plants are more efficient, the WEC/IIASA uses the equivalent of 8850 Btu/kWh, i.e., an efficiency of 0.386, not the 0.3413 that gives the 10,000 Btu/kWh heat rate.

The alternate lower total estimate for the world is that of two 1998 EPRI renewable energy presentations: a set of slides on compact disk and a brochure. The EPRI estimate in 1999 is higher and is the line labeled “Total” above.

Table A-3
Solar Limited to 50% of Electricity by Country/Region in 2050

Country or Region	Solar TWh	Solar MWe	Solar EJ	Total Electricity TWh	Solar cut to 50% of Electricity TWh
USA	3000	978,474	27.98	7,462	3,000
Canada	200	65,232	1.87	758	200
Western Europe	2000	652,316	18.66	6,034	2,000
Japan	700	228,311	6.53	1,465	700
Australia & NewZealand	400	130,463	3.73	406	203
East.Eur./Fmr.Soviet U.	600	195,695	5.60	5,336	600
China	1600	521,853	14.93	4,464	1,600
India	1600	521,853	14.93	2,441	1,221
Indonesia	400	130,463	3.73	470	235
Other Asia & Oceana	400	130,463	3.73	2,553	400
Brazil	1500	489,237	13.99	467	234
Mexico	300	97,847	2.80	342	171
Central/South America	700	228,311	6.53	1,086	543
Africa	1500	489,237	13.99	1,453	727
Middle East	800	260,926	7.46	1,721	800
Total	**15,700**	**5,120,678**	**146.45**	**36,458**	**12,633**

Based on these assumptions: Capacity factor 35%, which is 3066 hours/year. Also, efficiency of fossil power generation displaced by solar = 0.386.

Table A-4
World Renewable Energy by Country/Region in 2050
(Units are EJ = exajoules = 10^18 joules = 0.95x10^15 Btu)

Country or Region	Noncom mercial Biomass	Commer-cial Power & CHP from Biomass	Geo-Thermal	Wind	Solar	Total Commercial Non-Hydro Renewables
USA	2.0	7.46	2.80	8.40	27.98	46.64
Canada	0.5	0.75	0.19	1.87	1.87	4.66
Western Europe	1.1	4.66	0.47	3.73	18.66	27.52
Japan	0.0	0.47	0.47	0.93	6.53	8.40
Australia & NZ	0.0	0.93	0.75	1.87	3.73	7.28
East.Eur./FSU	1.7	3.73	0.47	2.80	5.60	12.59
China	9.3	5.60	0.93	9.33	14.93	30.78
India	8.4	4.66	0.56	9.33	14.93	29.48
Indonesia	2.6	3.73	1.87	2.80	3.73	12.13
Other Asia & Oceana	7.2	2.80	3.73	2.80	3.73	13.06
Brazil	1.5	13.99	0.19	3.73	13.99	31.90
Mexico	0.4	0.93	1.87	1.87	2.80	7.46
Central/South America	1.7	1.87	1.87	2.80	6.53	13.06
Africa	7.8	3.73	3.73	9.33	13.99	30.78
Middle East	3.1	0.93	0.47	2.80	7.46	11.66
Total	**47.3**	**56.25**	**20.34**	**64.37**	**146.45**	**287.40**

* The non-commercial biomass here is the estimate of use in 1996. Perhaps some 2/3 of this would have disappeared by 2050, in favor of the more efficient commercial uses of biomass.

B
SCENARIOS FROM WEC/IIASA "GLOBAL PERSPECTIVES"

The tables in this Appendix were constructed from the book ***Global Energy Perspectives*** written by staff members of the International Institute for Applied Systems Analysis (IIASA) for the World Energy Council (WEC). (The book is Reference 60 here in this report.) Tables in the book display numbers for the years 1990, 2020 and 2050, but do not break down the renewables by type. Instead, these tables give a single value for the sum of all the five categories that comprise the "renewables." These categories, which include hydroelectric energy as one of them, are (1) traditional biomass, (2) new, or "commercial" biomass, (3) other (which would be wind, mostly, and geothermal), (4) solar and (5) hydro. The scenarios can be given short labels such as the following:

Labels for the scenarios:

A. Cases of high growth –

A1. High Growth, High Oil

A2. High Growth, High Coal (also low nuclear)

A3. High Growth, High Gas (also high renewables)

B. Base case

C. Policy-driven cases

C1. Low nuc, High non-biomass renewables

C2. High nuc, High biomass

The breakdowns into the five categories of renewables are shown in graphical displays, but not in tables, in the book (Ref. 60). Hence, in order to separate out hydro from the others which are the focus of this report, and in order to see how the WEC/IIASA results compare with this report and with the EPRI Roadmap (Ref. 61), the numerical vales for the categoris of renewables were read off of the graphical displays. By reading the displays, or figures, in the book, it was also possible to see how the WEC/IIASA authors projected their scenarios on out to the end of the century at the year 2100. This Appendix gives the results from reading a number of the tables and figures in ***Global Energy Perspectives*** (Ref 60).

Most of the units are primary energy inputs in Gtoe (10^9 tonnes of oil equivalent), where 1 Gtoe = 41.9 EJ (exajoules, 1 EJ = 10^18 joules) = 0.95x41.9 or 39.8 quads (quadrillion Btu, 1 quad = 10^15 Btu). Given the speculative nature of scenario building and the difficulty of reading values off of the graphs, the numbers given here to the 0.01 Gtoe are simply the result of how the estimates of % share were translated into Gtoe, and in no way suggest such an accuracy. The numbers are good to one or, at the very best, two decimal places.

Table B-1
Scenario A1 for "High Growth with High Oil"

A1 = High growth, high tech dev., high oil

Year➔	**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share: **A1**						
Bio old	16.67	9.7	7.7	5	2.2	0.5
Bio new	0	3	2.5	2.5	4.4	9.5
Other	0	0.2	1	2.5	4	4.5
Solar	0	0	0.5	1.1	7	16
Tot. Ren.	16.67	12.9	11.7	11.1	17.6	30.5
Hydro	5.83	5	5.6	5.4	4.7	3
Tot R+H	22.5	17.9	17.3	16.5	22.3	33.5
Nuc	0	5.0	5.4	5.9	11.7	15
Fossil	77.5	77.1	77.3	77.6	66.0	51.5
Tot. all %	100	100	100	100	100	100
Tot. Gtoe	2.7	8.98	12.00	15.38	24.83	45.00
Energy (Gtoe):						
Bio old	0.45	0.87	0.92	0.77	0.55	0.23
Bio new	0.00	0.27	0.30	0.38	1.09	4.28
Other	0.00	0.02	0.12	0.38	0.99	2.03
Solar	0.00	0.00	0.06	0.17	1.74	7.20
	0.45	1.16	1.40	1.71	4.37	13.73
Tot. Ren.	0.45	1.16	1.40	1.71	4.37	13.73
Hydro	0.16	0.45	0.67	0.83	1.17	1.35
Tot R+H	0.61	1.61	2.08	2.54	5.54	15.08
Nuc	0.00	0.45	0.65	0.91	2.91	6.75
Fossil	2.09	6.92	9.28	11.93	16.39	23.18
Tot. Gtoe	2.70	8.98	12.00	15.38	24.83	45.00

Table B-2
Scenario A2 for "High Growth with High Coal"

A2 = High growth, high tech dev., high coal

Year➔	**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share: **A2**						
Bio old	16	10	8	4	2.5	1
Bio new	0	2.5	3	6	10.0	13
Other	0	0	1	2	4.5	7.5
Solar	0	0	0	0.3	1.5	4.5
Tot. Ren.	16	12.5	12	12.3	18.5	26
Hydro	6.5	5.5	5	4.4	4.4	4
Tot R+H	22.5	18	17	16.7	22.9	30
Nuc	0	5	4	3.8	4.4	20.5
Fossil	77.5	77	79	79.5	72.7	49.5
Tot. all %	100	100	100	100	100	100
Tot. Gtoe	1.75	8.98	12.00	15.37	24.84	45.00
Energy (Gtoe):						
Bio old	0.28	0.90	0.96	0.61	0.62	0.45
Bio new	0.00	0.22	0.36	0.92	2.48	5.85
Other	0.00	0.00	0.12	0.31	1.12	3.38
Solar	0.00	0.00	0.00	0.05	0.37	2.03
	0.28	1.12	1.44	1.89	4.60	11.70
Tot. Ren.	0.28	1.12	1.44	1.89	4.60	11.70
Hydro	0.11	0.49	0.60	0.68	1.09	1.80
Tot R+H	0.39	1.62	2.04	2.57	5.69	13.50
Nuc	0.00	0.45	0.48	0.58	1.09	9.23
Fossil	1.36	6.91	9.48	12.22	18.06	22.28
Tot. Gtoe	1.75	8.98	12.00	15.37	24.84	45.00

Table B-3
Scenario A3 for "High Growth with High Natural Gas"

A3 = high growth, high tech dev, high natural gas and high renewables

Year➔		**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share:	**A3**						
Bio old		15	9.5	8	5	3	1
Bio new		0	2.5	4	8	8	17
Other		0	0	0.5	3	4.5	5
Solar		0	0	0.5	2	9.5	23
Tot. Ren.		15	12	13	18	25	46
Hydro		8	5	4	5	5	4
Tot R+H		23	17	17	23	30	50
Nuc		0	5	7	7	10	22
Fossil		77	78	77	72	60	28
Tot. all %		100	100	101	102	100	100
Tot. Gtoe		2.7	8.98	12.0	15.36	24.66	45
Energy (Gtoe):							
Bio old		0.41	0.85	0.96	0.77	0.74	0.45
Bio new		0.00	0.22	0.48	1.23	1.97	7.65
Other		0.00	0.00	0.06	0.46	1.11	2.25
Solar		0.00	0.00	0.06	0.31	2.34	10.35
		0.41	1.08	1.56	2.76	6.17	20.70
Tot. Ren.		0.41	1.08	1.56	2.76	6.17	20.70
Hydro		0.22	0.45	0.48	0.77	1.23	1.80
Tot R+H		0.62	1.53	2.04	3.53	7.40	22.50
Nuc		0.00	0.45	0.84	1.08	2.47	9.90
Fossil		2.08	7.00	9.24	11.06	14.80	12.60
Tot. Gtoe		2.70	8.98	12.12	15.67	24.66	45.00

Table B-4
Scenario B for "Base Case"

B = Base case scenario							
	Year➔	**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share:	**B**						
Bio old		16	10	7.5	7.5	4	2
Bio new		0	2	3	3.5	8	11
Other		0	0	0.5	0.5	5	9.5
Solar		0	0	0	0.5	2.5	5.5
Tot.Ren.		16	12	11	12	19.5	28
Hydro		6.5	5	5	4	3.5	4.5
Tot R+H		22.5	17	16	16	22	32.5
Nuc		0	5	7	8	14	23.5
Fossil		77.5	78	77	76	64	44
Tot. all %		100	100	100	100	100	100
Tot. Gtoe		2.7	8.98	11.6	13.55	19.83	35
Energy (Gtoe):							
Bio old		0.43	0.90	0.87	1.02	0.79	0.70
Bio new		0.00	0.18	0.35	0.47	1.59	3.85
Other		0.00	0.00	0.06	0.07	0.99	3.33
Solar		0.00	0.00	0.00	0.07	0.50	1.93
		0.43	1.08	1.28	1.63	3.87	9.80
Tot. Ren.		0.43	1.08	1.28	1.63	3.87	9.80
Hydro		0.18	0.45	0.58	0.54	0.69	1.58
Tot R+H		0.61	1.53	1.86	2.17	4.36	11.38
Nuc		0.00	0.45	0.81	1.08	2.78	8.23
Fossil		2.09	7.00	8.93	10.30	12.69	15.40
Tot. Gtoe		2.70	8.98	11.60	13.55	19.83	35.00

Table B-5
Scenario C1 for "Policy-Driven with Nuclear Phase-out and High Solar"

C1 = Policy driven, nuclear phase-out scenario, high solar

Year➔	**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share: C1						
Bio old	16	10	9.5	11	6	2
Bio new	0	2.5	3	3	12	25
Other	0	0	0.5	1	5	6
Solar	0	0	0	1	12	39.5
Tot. Ren.	16	12.5	13	16	35	72.5
Hydro	6.5	5.5	6	7	6	9
Tot R+H	22.5	18	19	23	41	81.5
Nuc	0	5	6	7	3	0
Fossil	77.5	77	75	70	56	18.5
Tot. all %	100	100	100	100	100	100
Tot. Gtoe	2.7	8.98	10.8	11.43	14.25	22.5
Energy (Gtoe):						
Bio old	0.43	0.90	1.03	1.26	0.86	0.45
Bio new	0.00	0.22	0.32	0.34	1.71	5.63
Other	0.00	0.00	0.05	0.11	0.71	1.35
Solar	0.00	0.00	0.00	0.11	1.71	8.89
	0.43	1.12	1.40	1.83	4.99	16.31
Tot. Ren.	0.43	1.12	1.40	1.83	4.99	16.31
Hydro	0.18	0.49	0.65	0.80	0.86	2.03
Tot R+H	0.61	1.62	2.05	2.63	5.84	18.34
Nuc	0.00	0.45	0.65	0.80	0.43	0.00
Fossil	2.09	6.91	8.10	8.00	7.98	4.16
Tot. Gtoe	2.70	8.98	10.80	11.43	14.25	22.50

Table B-6
Scenario C2 for "Policy-Driven with Nuclear Revival and High Biomass"

C2 = Policy driven, nuc expansion scenario with high biomass

Year➔	**1950**	**1990**	**2000**	**2020**	**2050**	**2100**
% share C2						
Bio old	16	10	9.5	10	5	2
Bio new	0	2.5	2.8	3	9	20
Other	0	0	0.2	2	4	2.5
Solar	0	0	0	0.3	11	30.5
Tot. Ren.	16	12.5	12.5	15.3	29	55
Hydro	6.5	5.5	6	4.7	6.5	7.5
Tot R+H	22.5	18	18.5	20	35.5	62.5
Nuc	0	5	6.5	7.5	12.5	18.5
Fossil	77.5	77	75	72.5	52	19
Tot. all %	100	100	100	100	100	100
Tot. Gtoe	2.7	8.98	10.8	11.43	14.25	22.5
Energy (Gtoe):						
Bio old	0.43	0.90	1.03	1.14	0.71	0.45
Bio new	0.00	0.22	0.30	0.34	1.28	4.50
Other	0.00	0.00	0.02	0.23	0.57	0.56
Solar	0.00	0.00	0.00	0.03	1.57	6.86
	0.43	1.12	1.35	1.75	4.13	12.38
Tot. Ren.	0.43	1.12	1.35	1.75	4.13	12.38
Hydro	0.18	0.49	0.65	0.54	0.93	1.69
Tot R+H	0.61	1.62	2.00	2.29	5.06	14.06
Nuc	0.00	0.45	0.70	0.86	1.78	4.16
Fossil	2.09	6.91	8.10	8.29	7.41	4.28
Tot. Gtoe	2.70	8.98	10.80	11.43	14.25	22.50

Table B-7
Global Energy Scenarios of the WEC/IIASA for the Year 2020

(primary energy in Gtoe, 1Gtoe = 41.9 EJ = 39.7 quads)

Energy Source	Base Year 1990	Year 2020: Scenario per WEC/IIASA Case Label A1	A2	A3	B	C1	C2
Coal	2.18	3.71	4.31	2.91	3.39	2.29	2.28
Oil	3.06	4.66	4.50	4.26	3.78	3.02	3.02
Gas	1.68	3.62	3.41	3.84	3.18	3.06	2.96
Nuclear	0.45	0.91	0.58	1.03	0.90	0.67	0.85
Renewables	1.60	2.47	2.57	3.31	2.29	2.39	2.32
	-----	-----	-----	-----	-----	-----	-----
Total	**8.97**	**15.37**	**15.37**	**15.35**	**13.54**	**11.43**	**11.43**
Use as electricity (Gtoe)	**0.83**	**1.63**	**1.69**	**1.72**	**1.45**	**1.22**	**1.21**
Electricity use (in TWh)	**9,658**	**18,968**	**19,666**	**20,015**	**16,873**	**14,197**	**14,080**

2020: Breakdown of the Renewables:	Base 1990	A1	A2	A3	B	C1	C2
Biomass (trad.)*	0.90	0.77	0.61	0.77	1.02	1.26	1.14
Biomass (new)	0.18	0.38	0.92	1.23	0.47	0.34	0.34
Other (wind, geo.)	0.05	0.38	0.31	0.46	0.07	0.11	0.23
Solar	0.01	0.17	0.05	0.31	0.07	0.11	0.03
Hydro	0.46	0.83	0.68	0.77	0.54	0.80	0.54
	-----	-----	-----	-----	-----	-----	-----
Total of Renewables	**1.60**	**2.53**	**2.57**	**3.54**	**2.17**	**2.62**	**2.28**

* Non-commercial energy, i.e., traditional biomass, is 16% of final energy use in 1990. Final energy = 6.5 Gtoe in 1990. As given above, primary energy in 1990 was 8.97 Gtoe.

Note: Electricity use is "final energy"--not "primary energy"--and is, therefore, given in direct equivalent (in Gtoe) of the TWh, at 100% not 38.6% efficiency. For all of the other numbers, the Gtoe values for the fossil fuel equivalent of the electricity generated are calculated assuming the 38.6%, which means a conversion heat rate = 8842 Btu/kWh = 9328 kJ/kWh = 0.223 Mtoe/ TWh. At the direct 100% rate, 0.0859 Mtoe is 1 TWh.

Table B-8 (same as Table 9-3 in the body of report)
WEC/IIASA Scenarios for the Year 2050 (in Gtoe, unless noted otherwise)

Energy Source	Base Year 1990	Year 2050: Scenario per WEC/IIASA Case Label (Gtoe) A1	A2	A3	B	C1	C2
Coal	2.18	3.79	7.83	2.24	4.14	1.50	1.47
Oil	3.06	7.90	4.78	4.33	4.04	2.67	2.62
Gas	1.68	4.70	5.46	7.91	4.50	3.92	3.34
Nuclear	0.45	2.90	1.09	2.82	2.74	0.52	1.77
Renewables	1.60	5.54	5.68	7.35	4.42	5.63	5.05
	-----	-----	-----	-----	-----	-----	-----
Total	**8.97**	**24.83**	**24.84**	**24.65**	**19.84**	**14.24**	**14.25**
Electricity end use (in Gtoe)	**0.83**	**2.88**	**3.14**	**3.03**	**2.34**	**1.79**	**1.72**
Electricity end use (in TWh)	**9,658**	**33,513**	**36,539**	**35,259**	**27,230**	**20,829**	**20,015**

Breakdown of the Renewables: Source	Base Year 1990	Scenario for Year 2050 by Case Label (units Gtoe) A1	A2	A3	B	C1	C2
Biomass (trad.)#	0.90	0.33	0.68	0.74	0.71	0.62	0.81
Biomass (new)	0.18	1.00	2.04	2.57	0.97	1.35	1.72
Other (wind, geo.)	0.05	0.89	1.25	1.32	1.33	0.84	0.40
Solar	0.01	2.22	0.40	1.84	0.53	1.69	1.26
Hydro	0.46	1.11	1.31	0.88	0.88	1.13	0.86
	-----	-----	-----	-----	-----	-----	-----
Total	**1.60**	**5.54**	**5.68**	**7.35**	**4.42**	**5.63**	**5.05**

Non-commercial energy, i.e., traditional biomass, is less than 6% of final energy use by 2050. [17 Gtoe is final energy use, in the A3 scenario. As above, 24.65 Gtoe is the primary energy for A3. "Final energy" (i.e., delivered, such as the electricity) as opposed to "primary energy" (i.e., such as the fuel input into electric power).]

Labels for the scenarios:

Cases of high growth –

A1. High Growth, High Oil
A2. High Growth, High Coal (also low nuclear)
A3. High Growth, High Gas (also high renewables)

B. Base case

C. Policy-driven cases
C1. Low nuc, High non-biomass renewables
C2. High nuc, High biomass

Table B-9
WEC-IIASA Scenarios for the Year 2100

(in Gtoe primary energy input, unless noted otherwise)

Energy Source	Base Year 1990	Year 2100: Scenario per WEC/IIASA Case Label A1	A2	A3	B	C1	C2
Coal	2.2	3.6	17.1	0.0	8.1	0.9	0.7
Oil	3.1	8.6	2.3	2.3	2.1	1.1	1.1
Gas	1.7	10.4	3.2	9.9	5.3	2.0	2.3
Nuclear	0.5	7.7	9.5	11.3	8.1	0.0	4.5
Renewables	1.6	14.9	13.1	21.6	11.6	18.5	14.0
	-----	-----	-----	-----	-----	-----	-----
Total	**9**	**45.0**	**45.0**	**45.0**	**35.0**	**22.5**	**22.5**
(check of sum)	9.0	45.0	45.0	45.0	35.0	22.5	22.5
Use as electricity (Gtoe)	**0.83**	-- no numbers for electricity use projected for 2100 --					
Electricity use (in TWh)	**9,658**	--	--	--	--	--	--

2100: Breakdown of the Renewables:

Energy Source	Base Year 1990	Scenario for Year 2100 by Case Label A1	A2	A3	B	C1	C2
Biomass (trad.)^^	0.90	0.23	0.45	0.45	0.70	0.45	0.45
Biomass (new)	0.18	4.28	5.85	7.65	3.85	5.63	4.50
Other (wind, geo.)	0.05	2.03	3.38	2.25	3.33	1.35	0.56
Solar	0.01	2.20	2.03	10.35	1.93	8.89	6.86
Hydro	0.46	1.35	1.80	1.80	1.58	2.03	1.69
	-----	-----	-----	-----	-----	-----	-----
Total (Gtoe) of the Renewables	**1.60**	**15.09**	**13.51**	**22.50**	**11.38**	**18.35**	**14.06**

^^ By 2100, non-commercial energy use is "virtually gone," and, per A3, final energy = 24 Gtoe, out of the 45 Gtoe given as primary above for A3.

Note: Electricity use is "final energy"--not "primary energy"-and is, therefore, given in direct equivalent (in Gtoe) of the TWh, at 100% not 38.6 efficiency. For all of the other numbers, the Gtoe for fossil fuel equivalent of the electricity generated are calculated assuming the 38.6%, which means a conversion heat rate = 8842 Btu/kWh = 9328 kJ/kWh = 0.223 Mtoe/TWh. At the direct 100% rate, 0.0859 Mtoe is 1 TWh.

Table B-10
Electricity in the WEC/IIASA Scenarios (direct, final use; not "primary input")

Electricity: Case	Direct Gtoe 1990	direct Gtoe 2020	direct Gtoe 2050	Direct Gtoe 2100	TWh 2020	TWh 2050
A1	0.83	1.63	2.88		21,111	37,301
A2	0.83	1.69	3.14		21,889	40,669
A3	0.83	1.72	3.03		22,277	39,244
B	0.83	1.45	2.34		18,780	30,307
C1	0.83	1.22	1.79		15,801	23,184
C2	0.83	1.21	1.72		15,672	22,277
Total Final Energy in A3	6.45	11.33	17.17	24		
Electricity % of Final in A3	13%	15%	18%			

Comparison values from the EPRI "Roadmap":

(from Table 1-2 of Ref.6; the 60,000 TWh in 2050 includes 10,000 TWh for electric transportation; in 2000: 13,000 TWh) — 28,000 (TWh 2020), 60,000 (TWh 2050)

Year	2000	2020	2050	
Primary Energy (Gtoe)	10	13	17	
Electricity fraction of Pri.En.	0.38	0.5	0.7	
Electricity conversion effic	0.32	0.4	0.5	
Calc of product of above 3 lines	1.22	2.6	6.0	←[this line is final energy as electricity in Gtoe]
Elect gen capacity (GWe)	3000	5000	10,000	
Population (billions)	6.2	8	10	

Table B-11
Selected Numbers from WEC/IIASA "Global Perspectives"

p 66, F5.2 Global Primary Energy (p 12, F3.1 trad bio) refs BP and IIASA

Case	1850	1900	1950	1990	2000	2020	2050	2100
A	0.3	1.4	2.7	8.98	12.0		25	45
B	used for trad bio, final and elect ==>				11.6		20	35
C					10.8		14	22.5
Base Case "B":								
% trad. biomass	87%	43%	20%	11%	7.5%		4.5%	2%
Gtoe trad. bio.	0.261	0.602	0.540	0.988	0.870		0.900	0.700
Gtoe final				6.45		10.07	14.18	
Gtoe elect				0.83		1.45	2.34	

C
UNITS AND CONVERSION FACTORS

System of International Units Conversion Table

For calculation purposes, convert British units to System of International (SI) units by combining the quantity in British units by one or more fractions of the form M/B, each fraction consisting of the number and units in column M divided by 1 of the unit in column B. Each such fraction (including their units) is unity; when you combine the fractions together the units should cancel, leaving a result in SI units only.

Example: $\frac{1}{8700\ \mathrm{Btu/kWh}} \times \frac{3.6\ \mathrm{E6J/kWh}}{1055\mathrm{J/Btu}}$ = 39.2% thermal efficiency

British unit (B)	Metric equivalent (M)	
ACRE	= 4047 m2	
ATMOSPHERE atm	= 101.325 kPa	
BARREL (petroleum, 42 gal) bbl	= 0.15899 m3	
BAR	= 100 kPa	
BRITISH THERMAL UNIT Btu	= 1055 J	
CUBIC FOOT ft3	= 0.02832 m3	
degree Farenheit (°F)	= F-32/1.8 degree Celsius (°C)	
ft3/min	= 471.9 cm3/s	= 0.0004719 m3/s
scfm (60F, 1 atm)	= 0.4474 liter/s	= 0.0004474 m3/s (0c, 1 atm)
CUBIC INCH in3	= 1.6387 E-5 m3	
CUBIC YARD yd3	= 0.7646 m3	
FOOT ft	= 0.3048 m	
ft of water @ 68F	= 2.989 kPa	
ft/min	= 0.5080 cm/s	= 0.005080 m/s
ft-lbf (*torque*)	= 1.356 J	
GALLON gal	= 3.7854 liter	= 0.0037854 m3
Gpm	= 0.22715 m3/h	= 6.309 E-5 m3/s
HORSEPOWER hp	= 746 W	
INCH in	= 0.0254m	
in Hg	= 3.3864 kPa	
in H2O	= 0.249 kPa	
KWh	= 3.6 E6J = 3.6 MJ	

MILE mi	= 1609.3 m	= 1.6093 km
Mph	= 0.4470 m/s	
OUNCE (*wt*) oz	= 0.02835 kg	
OUNCE (*liq*) oz	= 0.02957 liter	= 2.957 E-5 m3
POISE p	= 0.1000 N-s/m2	= 0.1000 Pa-s
POUND (*mass*)	= 0.4536 kg	
lb/ft3	= 16.018 kg/m3	
Lbf	= 4.448 N	
lbf/in2	= 6.895 kPa	
QUART	= 0.9464 liter	= 9.464 E-4 m3
TON ton (short)	= 907.2 kg	
TON (tonne)	= 1000 kg	

Adapted from American National Standards Institute ANSI Z210.1-1976/ASTM E 380-93/IEEE Std 268-1976.

Some Units of Special Interest for This Report

1 Btu = 1055 joules = 1055 J; 1 GJ = 10^9 J = 0.948 x 10^6 Btu = 0.948 MBtu

1 toe = energy equivalent of one metric ton of oil

1 Gtoe = 10^9 toe = 41.9 EJ = 41.9 x 10^18 J = 39.7 x 10^15 Btu = 39.7 quads

1 ha = 100m x 100m = 10^4 m^2 = 2.471 acres

1 ton = 1 short ton = 0.9072 metric ton = 0.9072 tonne

Higher Heating Value (HHV) of typical biomass = 16 MBtu per dry short ton

1 MBtu/dryton = 1.055 GJ / 0.91 dry tonne = 1.16 GJ per dry metric ton

1 toe = 41.9 GJ; 16 MBtu/ton = 18.61 GJ/tonne = 2.25 toe/tonne

1 dry ton per acre per year = (2.471*0.9072) / 2.25 = 0.9955 toe/ha/year

1 square mile = 640 acres = 259 ha = 2.59 x 10^6 m^2 = 2.59 square km

Direct normal solar flux = 1000 W/m^2 (typical, nominal value)

Average <u>annual</u> solar energy rate ("insolation" or "solar flux") = 200 watts/m^2

200 W = 200 J/sec = 200 x 3600 / 1055 Btu/hour = 682 Btu/h

3413 Btu = 3.60 MJ = 1 kWh; 1 year = 8760 hours;

200 W = 5.98 MBtu/year; 200 W/m^2 = 518 MW per sq mile = 15.5 x 10^12 Btu/yr per square mile = 15.5 quad/year per 1000 square miles = 6.3 EJ/year per 1000 sq km

Energy Equivalents Table from EIA's Annual Energy Outlook (Ref. 42)

1 quadrillion Btu = 1 quad = 25.2 million tons of oil equivalent (Mtoe)

1 kWh = 3.6 megajoules (MJ) = 3412 Btu of electricity consumption

1 short ton of coal for electric utilities = 20.525 million Btu

1 barrel crude oil = 0.159 cubic meter volume crude oil = 5.8 million Btu

1 cubic foot natural gas = 0.0283 cubic meter volume at STP = 1028 Btu

Therefore, heating value (HHV), if methane @ 1028 Btu/std.ft3, is 23,068 Btu/lb.

Metric Prefixes:

10^3 kilo k;	10^6 mega M;	10^9 giga G;
10^12 tera T;	10^15 peta P;	10^18 exa E.

Mass: 1 pound mass (lb) = 0.4536 kg	Length: 1 mile = 1.609 km
Area: 1 square foot (ft2) = 0.0929 sq meter	Volume: 1 gallon (US) = 3.785 liter

D
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Targets:

Renewable Tech Options & Green Power Marketing

Information to Support High-Value Photovaltaic Power Applications

Wind Power Development Support

Understanding Green Power Markets

Biomass Energy

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