Second Edition

HANDBOOK OF PHOTOVOLTAIC SCIENCE AND ENGINEERING

Editors **ANTONIO LUQUE** • **STEVEN HEGEDUS**

WILEY

Handbook of
Photovoltaic Science
and Engineering

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Second Edition

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About the Editors

Professor Antonio Luque was born in Malaga, Spain, in 1941. He is married with two children and five grandchildren. A full Professor at the Universidad Politécnica de Madrid since 1970, he currently serves at the Instituto de Energía Solar that he founded in 1979. There he has formed over 30 PhD Students and the research group he leads (Silicon and PV Fundamental Studies) is ranked first among the 199 consolidated research groups of his university.

In 1976 Professor Luque invented the bifacial cell and in 1981 he founded ISOFOTON; a solar cell company with a turnover of about 300 million dollars (2007). In 1997 he proposed the intermediate band solar cell (321 citations in WOK registered journals by September 2010). Today more than sixty research centers worldwide have published on this topic (WOK registered) with citation of his work.

The main focus of Professor Luque's present research is in further understanding and developing the intermediate band solar cell, but further to this he is involved in two major additional actions: the establishment (as founder, and CEO) of the silicon ultrapurification research company CENTESIL (owned by two universities and three corporations) to further reduce the costs of silicon solar cell; and the supervision as Chair of the Scientific International Committee of the new institute ISFOC for Concentrator Photovoltaic (CPV) systems, established under his plan to stimulate the introduction of the CPV technology worldwide. This institute has granted contracts (through the board he chairs) to seven companies (three from Spain, two from the USA, one from Germany and one from Taiwan) and over two MW of panels have already been installed at ISFOC using the new multijunction cell technology that has given cell efficiencies above 41%.

He has been honored by several important prizes and distinctions, including the membership to the Royal Academy of Engineering of Spain, the Honor membership of the Ioffe Institute in St. Petersburg and two Honoris Causa doctorates (Carlos III University of Madrid and Jaen University). He has also received three major Spanish National Prizes (two delivered by the King of Spain and one by the Crown Prince) on technology and environmental research as well as one from European Commission and one from the US IEEE-PV Conference, both on photovoltaics.

Dr. Steven Hegedus has been involved in solar cell research for 30 years. While earning a BS in Electrical Engineering/Applied Physics at Case Western Reserve University (1977) he worked on a solar hot water project. He worked on integrated circuit design and modeling at IBM Corp from 1977–1982, during which time he received a Masters in Electrical Engineering from Cornell, working on polycrystalline GaAs solar cells. In 1982 he joined the research staff of the Institute of Energy Conversion (IEC) at the University of Delaware (UD), the world's oldest photovoltaic research laboratory. He has worked on nearly all of the commercially relevant solar cell technologies. Areas of active research include optical enhancement and contacts to TCOs, high growth rate of PECVD nanocrystalline Si, thin film device analysis and characterization, a-Si/c-Si heterojunction processing, and stability under accelerated degradation conditions. While at the IEC, he got a Ph.D. in Electrical Engineering from UD. He has contracts with the US Department of Energy and several US companies, large and small, to assist their development of thin film and c-Si PV products. Dr. Hegedus has been lead author of nearly 50 papers in the field of solar cell device analysis, processing, reliability and measurements. He teaches a graduate class at UD in Solar Electric Systems. Dr. Hegedus is keenly aware of the impact of policy on solar energy commercialization and was appointed a Policy Fellow by UD's Center for Energy and Environmental Policy in 2006. He was the first resident of his town to install a rooftop PV system.

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Preface to the 2nd Edition

The first edition of the *Handbook of Photovoltaic Science and Engineering* was published in 2003. It described the results of 50 years of research, technology, product development, and applications of solar cells and modules. This included the first generation of terrestrial PV – crystalline Si wafers – the second generation of PV – thin films of amorphous Si, CdTe, or $CuInGaSe_2$ – and the third generation PV – organic dye-sensitized junctions mimicking photosynthesis or advanced very high efficiency theoretical concepts such as multiphoton and intermediate band solar cells, which had yet to be demonstrated in practice. It also included chapters on III–V based multijunctions (having the highest demonstrated efficiency) and concentrators. Applications of PV installed in outer space and on earth – from urban offices to rural villages – were described. Components of systems such as batteries and power conversion electronics such as inverters had their own chapters. Finally we included chapters on fundamental physics, measurements and characterization, and how to calculate the energy produced from a module installed anywhere for any configuration.

Almost coincident with this publication, interest in PV exploded. Sales and production increased over tenfold, from 600 MW of production in 2003 to 7300 MW in 2009. Growing interest in PV generated significant private and public investment, resulting in significant improvements in technology and applications. Much of this was driven by innovative national policies. Hundreds of companies, from brand new small start-ups to mature giant multinationals, tried to ride the surging wave of popular and technical interest in PV. Many of them bought copies of the first edition to help educate and inform their engineers, managers, analysts and investors. The PV field was maturing – companies were finally making profits, merging, scaling up production, and expanding. New technologies were finding their way into the marketplace.

A second edition was planned to represent these new developments. Ultimately, this second edition has benefited from the dose of reality of the past year's economic crisis. But it is a testament to the power of an idea whose time has come, that PV has continued to grow and prosper, one of the few industries which still increased its sales during the New Great Depression. In many countries, nurturing a PV industry has become a prominent strategy in economic recovery and job creation, in addition to being a potent weapon in the battle against global climate change.

What's new in this second edition? There are three completely new chapters, discussing the role of national energy policy in encouraging PV growth, transparent conductive oxides for thin film PV, and third-generation organic polymer-based devices. Five chapters have all new authors, giving a fresh view of crystalline Si wafer technology, second-generation thin film silicon cells, concentrating PV, power conditioning electronics, and off-grid and on-grid system design. All the other chapters have been significantly updated with new technical advances, state-of-the-art cell efficiencies, manufacturing status, and installation-related data.

The editors dedicate this book to all those who have worked so hard for over half a century to bring solar electricity to its present success, and to our colleagues present and future who must work even harder in the next half century to ensure that PV fulfills its potential as a widely available, carbon-free clean energy source.

The editors also owe tremendous debt to the authors of each chapter. Their long hours spent writing the best possible chapter covering their field of expertise, only to suffer a storm of editorial criticisms and corrections, has hopefully made this a high-quality publication of lasting value.

Finally we want to express our gratitude to our loved ones – Carmen, Ignacio, Sofia, (and their children), and Debbie, Jordan, Ariel – for many hours stolen from family life while working on this book.

Antonio Luque & Steven Hegedus
June 2010

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Achievements and Challenges of Solar Electricity from Photovoltaics

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1.1 THE BIG PICTURE

Congratulations! You are reading a book about a technology that has changed the way we think about energy. Photovoltaics (or PV) is an empowering technology that has shown that it can generate electricity for the human race for a wide range of applications, scales, climates, and geographic locations. Photovoltaics can bring electricity to a rural homemaker who lives 100 kilometers and 100 years away from the nearest electric grid connection in her country, thus allowing her family to have clean, electric lights instead of kerosene lamps, to listen to a radio, and to run a sewing machine for additional income. It can pump clean water from underground aquifers for drinking or watering crops or cattle. Or, photovoltaics can provide electricity to remote transmitter stations in the mountains, allowing better communication without building a road to deliver diesel fuel for its generator. It can allow a suburban or urban homeowner to produce some or all of their annual electricity, selling any excess solar electricity back into the grid. It can help a major electric utility in Los Angeles, Tokyo, or Madrid to meet its peak load on hot summer afternoons when air conditioners are working full time. Finally, photovoltaics has been powering satellites orbiting the Earth for 30 years or vehicles roving over the surface of Mars.

Every day the human race is more aware of the need for sustainable management of its Planet Earth. It upholds almost seven billion human beings of which one billion have adopted a

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high-consumption lifestyle which is not sustainable. “High consumption” used to refer materials that could become scarce, but it increasingly refers to energy. Here the term energy, refers to “useful energy” (or exergy), that once used is degraded, typically to waste heat, and will be no longer be useful.

Here we are concerned with electrical energy which is a secondary form of energy. Fossil fuel (coal, petroleum and natural gas) combustion and nuclear fission are the primary processes which create heat to turn water into steam which rotate giant turbines which generate electricity. When the C–H bonds in fossil fuels are burned in the presence of air for heat, they produce CO_2, and H_2O. The latter waste is not a problem because there is already so much water in the seas and in the atmosphere. But CO_2 is a different story. Analysis of the air bubbles embedded in Antarctic ice layers provides information on the CO_2 concentration of the atmosphere in the last 150 000 years. This content shows an unprecedented growth in the last 300 years, coinciding with the beginning of the industrialization. This fact is linked by most scientists to global climate change, including global warming, sea level rise, more violent storms, and changes in rainfall. This will disrupt agriculture, disease control, and other human activities. Thus, a substantial fraction of our energy must be generated without any C emissions within the next 10–20 years, or else the Earth will become a dangerous experiment. Besides, fossil fuels cannot last forever. Supplies of petroleum and natural gas will both peak and then decrease within decades if not years, and coal within few centuries. We must develop large-scale alternatives to burning fossil fuels very soon.

Another primary energy source for electrical generation is radioactivity in the form of uranium, which when conveniently transformed, fuels nuclear plants through nuclear fission. Concerning the uranium, most of it consists of the 238 isotope, which is not “fissile” (not a nuclear fuel) and only about 0.7% is the 235 isotope, which is fissile. With the present technology, nuclear fuel will peak within decades. However, uranium 238 can be converted to an artificial fissile fuel by proper bombardment with neutrons. With this technology, not fully commercial today, it would be possible to have nuclear power (with unproven cost effectiveness) maybe for a millennium. Nuclear fusion, which is a totally different nuclear technology, could be practically inexhaustible, but its practical feasibility is very far from being proven.

While nuclear plants emit no CO_2, they are still inherently dangerous. Nuclear engineers and regulators take many precautions to ensure safe operation, and (excepting very few cases) the power plants function without catastrophic problems. But the storage of highly radioactive wastes, which must remain controlled for centuries, remains an unsolved issue worldwide, along with the possibility of diversion of nuclear fuel to making a bomb.

So the situation at the beginning of the 21st century is that the previous century’s methods of generating our most useful form of energy, electricity, are recognized as unsustainable, due to either increasing CO_2 poisoning of the atmosphere or the increasing stockpile of radioactive waste with no safe storage. What about using existing energy more efficiently? This will be crucial for slowing and perhaps even reversing the increased CO_2 levels. Doing more with less energy or just doing less (considered unpopular with growth-oriented economic advocates) are certainly necessary to reduce our demand for energy. But a growing world population with a growing appetite for energy is difficult to reconcile with using less energy. Besides, there is a large group whose voices are often not heard in this discussion – namely, the one out of three human beings who lack any electricity at all.

In fact, access to and consumption of electricity is closely correlated with quality of life, up to a point. Figure 1.1 shows the human development Index (HDI) for over 60 countries, which includes over 90% of the Earth’s population, versus the annual per capita electricity use (adapted from [1]). The HDI is compiled by the UN and calculated on the basis of life expectancy, educational achievement, and per capita gross domestic product. To improve the quality of life in many countries, as measured by their HDI, will require increasing their electricity consumption by factors of 10 or more, from a few hundred to a few thousand kilowatt-hours (kW h) per year.

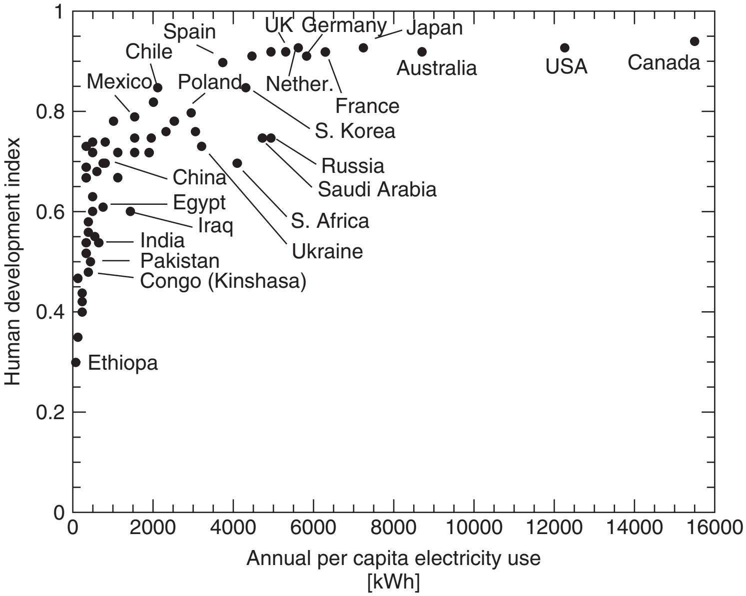

Figure 1.1 Human development index (HDI) versus per capita kW usage in year 2000 [1]

Adding two billion more inhabitants with increasing appetites for energy to the high-consumption pattern of today's one billion in the developed World, as would be expected from the development of China and India, would lead to unbearable stresses both in materials and energy. Barring their access (and that of others) to the wealth of the Western lifestyle is unfeasible, in addition to being unethical.

Renewable energies, and in particular solar energy, are the only clear solution to these issues. As matter of fact the amount of energy arriving on Earth from the Sun is gigantic: in the range of 10 000 times the current energy consumption of the human species. The ability of various forms of renewable energy to meet the "terawatt challenge" of providing world's present demand of 13 TW has been published [2]. We can also add geothermal energy (not renewable, properly speaking) and tidal energy, but they are insignificant in global terms, although locally, in some cases, their exploitation may be attractive.

Wind is generated by the solar energy (through the differential heating of the Earth in equatorial and polar regions). It has been calculated [3] that about 1% of the solar energy (10 times the global current consumption of energy) is converted into wind, but only a 4% of this is actually usable (but still 0.4 times the current consumption). It is estimated that with aggressive exploitation, land- and water-based wind generation is capable of providing about 10% of the world's expected energy demand [2]. Biomass converts solar energy in fuels but its efficiency is also very low, and its use for food has priority. Waves are caused by the wind and therefore a small fraction of the wind energy is passed to them. Sea currents, as winds also originate in the solar energy. The fraction passing to them is uncertain, but probably small. Finally, hydropower, produced by the transport of water from the sea to the land by means of solar energy, represents a tiny fraction of the total energy income, and the most promising sites are already in use. Summarizing, the direct exploitation of the solar energy is the real big energy resource [4].

Using photovoltaics with an efficiency of 10%, solar energy can be converted directly into enough electricity to provide 1000 times the current global consumption. Restricting solar collection to the earth's solid surface (one quarter of the total surface area), we still have a potential of 250 times the current consumption. This means that using 0.4% of the land area could produce all the energy (electricity plus heat plus transportation) currently demanded. This fraction of land is much smaller than the one we use for agriculture.

Achieving the required strong penetration of solar energy is not trivial. In the rest of this chapter we shall present a description of the status PV and broadly outline some of the challenges for it to become a TW scale energy source. But let us advance arguments that are seldom spoken: (a) PV is technologically more mature than advanced nuclear fission or nuclear fusion technology, the two non-renewable CO_2-free energies permitting substantial increments of the global energy production; (b) even well-developed wind energy cannot match the amount of energy directly available from the sun; (c) biomass energy can expect further scientific development, but will probably not reach efficiency levels that will make of it a global alternative to solve the issues presented; (d) concentrating solar thermal power (CSP) could produce electricity in concurrence with PV. We think that PV has a bigger innovation potential and has also modularity properties (it operates at small or large scale) and lacks the geographic limitations of CSP which makes it a clear winner in this competition.

1.2 WHAT IS PHOTOVOLTAICS?

PV is the technology that generates direct current (DC) electrical power measured in watts (W) or kilowatts (kW) from semiconductors when they are illuminated by photons. As long as light is shining on the solar cell (the name for the individual PV element), it generates electrical power. When the light stops, the electricity stops. Solar cells never need recharging like a battery. Some have been in continuous outdoor operation on Earth or in space for over 30 years.

Table 1.1 lists some of the advantages and disadvantages of PV. Note, that they include both technical and nontechnical issues

Table 1.1 Advantages and disadvantages of photovoltaics

Advantages of photovoltaics

- Fuel source is vast, widely accessible and essentially infinite
- No emissions, combustion or radioactive waste (does not contribute perceptibly to global climate change or air/water pollution)
- Low operating costs (no fuel)
- No moving parts (no wear); theoretically everlasting
- Ambient temperature operation (no high-temperature corrosion or safety issues)
- High reliability of solar modules (manufacturers' guarantees over 30 years)
- Rather predictable annual output
- Modular (small or large increments)
- Can be integrated into new or existing building structures
- Can be very rapidly installed at nearly any point-of-use

Disadvantages of photovoltaics

- Fuel source is diffuse (sunlight is a relatively low-density energy)
- High initial (installed) costs
- Unpredictable hourly or daily output
- Lack of economical efficient energy storage

What is the physical basis of PV operation? Solar cells are typically made of semiconductor materials, which have weakly bonded electrons occupying a band of energy called the valence band. When energy exceeding a certain threshold, called the bandgap energy, is applied to a valence electron, the bonds are broken and the electron is somewhat "free" to move around in a new energy band called the conduction band where it can "conduct" electricity through the material[1]. Thus, the free electrons in the conduction band are separated from the valence band by the bandgap (measured in units of electron volts or eV). This energy needed to free the electron can be supplied by photons, which are particles of light.

Figure 1.2 shows the idealized relation between energy (vertical axis) and the spatial boundaries (horizontal axis). When the solar cell is exposed to sunlight of sufficient energy, the incident solar photons are absorbed by the atoms, breaking the bonds of valence electrons and pumping them up to higher energy in the conduction band. There, a specially made selective contact collects conduction-band electrons and drives these freed electrons to the external circuit. The electrons lose their energy by doing work in the external circuit such as pumping water, spinning a fan, powering a sewing machine motor, a light bulb, or a computer. They are restored to the solar cell by the return loop of the circuit via a second selective contact, which returns them to the valence band with the same energy that they started with. The movement of these electrons in the external circuit and contacts is called the *electric current*. The potential at which the electrons are delivered to the external world is less than the threshold energy that excited the electrons; that is, the bandgap. It is independent of the energy of the photon that created it (provided its energy is above the threshold). Thus, in a material with a 1 eV bandgap, electrons excited by a 2 eV (red) photon or by a 3 eV (blue) photon will both still have a potential voltage of slightly less than 1 V (i.e. both of the

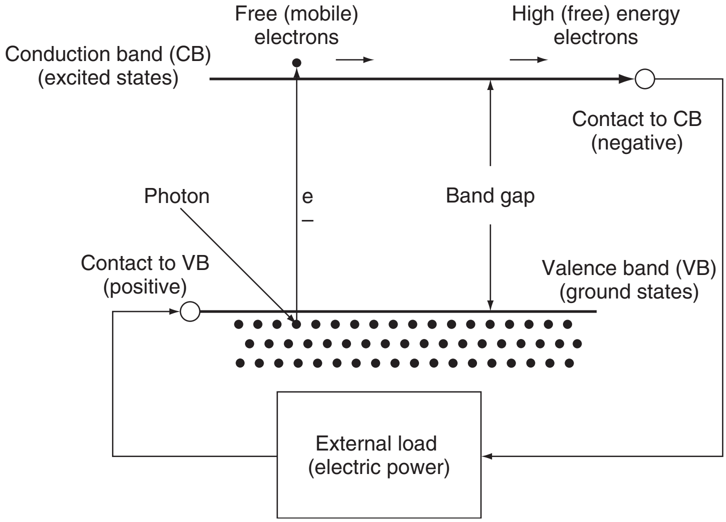

Figure 1.2 Schematic of a solar cell. Electrons are pumped by photons from the valence band to the conduction band. There they are extracted by a contact selective to the conduction band (an *n*-doped semiconductor) at a higher (free) energy and delivered to the outside world via wires, where they do some useful work, then are returned to the valence band at a lower (free) energy by a contact selective to the valence band (a *p*-type semiconductor)

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[1] The bandgap energy or energy gap is a fundamental and unique parameter for each semiconductor material. To be a good absorber of solar energy on earth, a semiconductor should have a bandgap between about 1 and 2 eV. See figure 4.3.

electrons are delivered with an energy of about 1 eV). The electrical power produced is the product of the current times the voltage; that is, power is the number of free electrons times their electric charge times their voltage. Brighter sunlight causes more electrons to be freed resulting in more power generated.

Sunlight is a spectrum of photons distributed over a range of energy. Photons whose energy is greater than the bandgap energy (the threshold energy) can excite electrons from the valence to conduction band where they can exit the device and generate electrical power. Photons with energy less than the energy gap fail to excite free electrons. Instead, that energy travels through the solar cell and is absorbed at the rear as heat. Solar cells in direct sunlight can be somewhat warmer (20–30 °C) than the ambient air temperature. Thus, PV cells can produce electricity without operating at high temperature and without moving parts. These are the salient characteristics of PV that explain safe, simple and reliable operation.

At the heart of almost any solar cell is the *pn* junction. Modeling and understanding is very much simplified by using the *pn* junction concept. This *pn* junction results from the "doping" that produces conduction-band or valence-band selective contacts with one becoming the *n*-side (lots of negative charge), the other the *p*-side (lots of positive charge). The role of the *pn* junction and of the selective contacts will be explained in detail in Chapters 3 and 4. Here, *pn* junctions are mentioned because this term is often present when talking of solar cells, and is used occasionally in this chapter.

For practical applications, a certain number of solar cells are interconnected and encapsulated into units called PV modules, which is the product usually sold to the customer. They produce DC current that is typically transformed into the more useful AC current by an electronic device called *an inverter*. The inverter, the rechargeable batteries (when storage is needed), the mechanical structure to mount and aim the modules (when aiming is necessary or desired), and any other elements necessary to build a PV system are called the *balance of the system* (BOS). These BOS elements are presented in Chapters 19–21.

Most of the solar modules today in the market today are made of crystalline silicon (c-Si) solar cells (Chapters 5–7). About 10% are made of the so-called thin film solar cells (TFSC), comprising in reality a variety of technologies: amorphous silicon (a-Si, Chapter 12), copper indium gallium diselenide (CIGS, $Cu(InGa)S_2$, Chapter 13), cadmium telluride (CdTe, Chapter 14), and others (Chapter 11). Many think that thin film cells are more promising in reducing costs. There is also an incipient market of concentrator photovoltaics (CPV) where expensive and efficient multijunction (MJ) solar cells receive a high intensity of sunlight focused by concentrators made of lenses or mirrors (Chapters 8 and 10). The motivation of all these technologies is the same: to decrease the module costs compared with the dominant Si technology. Other options are under research and development, including organic solar cells (Chapters 15 and 16) and the new (or third) generation solar cells (Chapter 4).

1.2.1 Rating of PV Modules and Generators

A fuel-fired power generator is rated in watts (or kW or MW). This means that they are designed to operate producing this level of power continuously, as long as they have fuel, and will be able to dissipate the heat produced during its operation. If they are forced to operate at more than the rated power, they will use more fuel, suffer more wear and have a shorter lifetime. Some can be operated at lower power output, although with loss of efficiency, but many cannot be controlled at less-than-rated power.

PV modules, instead, are rated in watts of peak power (W_p). This is the power the module would deliver to a perfectly matched load when the module is illuminated with 1 kW/m^2 of insolation (incident solar radiation) power of a certain standard spectrum (corresponding to bright sunlight) while the cell temperature is fixed at 25 °C. An array of modules is rated by summing up the watts peak of all the modules.

These "standard test conditions" or STC are universally applied to rate peak power output of a solar cell in a laboratory or a module out in the field, but rarely occur in real outdoor applications (see Chapter 18 for a complete discussion of testing conditions and Chapter 22 for real outdoor conditions). Generally, the irradiance (insolation power) is smaller and the temperature higher. Both factors reduce the power that can be delivered by the module to the matched load. In some cases the load is not so well matched (or the modules among themselves) reducing further the power. Thus while the output power is well defined under these STC, output power under real conditions varies considerably. While a 10 kW diesel generator produces 10 kW so long as it has diesel fuel, a 10 kW PV array will produce from perhaps 0–11 kW, depending on sunlight and temperature.

To enable useful predictions, the energy (not power) in kW h produced by the solar radiation falling in a generator in one year (or one month or one average day) is obtained by multiplying the rated power in kW_p times the number of "effective hours" of irradiance falling on the generator in one year (one month, one average day) times the performance ratio (PR), which accounts for losses above mentioned in real operation plus those in the wiring, the inverter (whose efficiency may be 0.90–0.97), etc. Time for maintenance is also included here. The PR in well-designed installations varies from 0.7 to 0.8 as discussed in Chapter 19, but may be even lower in warmer climates because the efficiency of the cell is reduced with the temperature.

What are the "effective" sun hours? Since the rating irradiance is 1 kW/m^2, the number of "effective" hours at the rating power is the number of kWh/m^2 falling on a plane with the same orientation of the PV generator. Thus, a typical mid-latitude location might receive a daily average of 4 kWh/m^2 of sunlight integrated over a period of 24 hours (including night time) on a horizontal surface, due to an incident power that ranged from 0 to 1 kW/m^2. This is equivalent to a constant incident solar power of 1 sun = 1 kW/m^2 for a period of only 4 hours, hence 4 'effective sun hours'. Locations such as Phoenix (United States), Madrid (Spain), Seoul (South Korea) or Hamburg (Germany) have respectively, 2373, 1679, 1387 and 1059 kW h/m^2 per year (or equivalently the same number of effective hours) for optimally oriented surfaces (facing south and tilted about 10° below the latitude). In these locations a PV plant of 1000 kW optimally oriented, with PR = 0.75 will produce 1 779 375; 1 2259 250, 1 040 250 and 793 857 kW h in one year. Table 1.2 shows, for four widely varying cities, the average daily input in solar irradiance, equivalent hours of full sunlight (at 1 kW/m^2), and average annual yield in kW h from each kW of installed PV, assuming a system performance ratio PR = 1. Once multiplied by the actual PR, this average yield is independent of the efficiency or area of the modules, thus demonstrating the simplicity of this method. These represent close to the entire range of sunlight conditions found where most people live. A world map with the effective hours on horizontal surface (kW h/m^2·year) is presented in Figure 1.3.

Table 1.2 Daily irradiance (kW/m^2), equivalent daily "sun hours" of 1 sun = 1 kW/m^2, and annual energy production per kW of installed PV (assuming PR = 1), all for optimum latitude tilt

City	Phoenix	Madrid	Seoul	Hamburg
Daily kW h/m^2	6.5	4.6	3.8	2.9
Daily "sun hours"	6.5	4.6	3.8	2.9
Annual kW h/kW	2372	1679	1387	1058

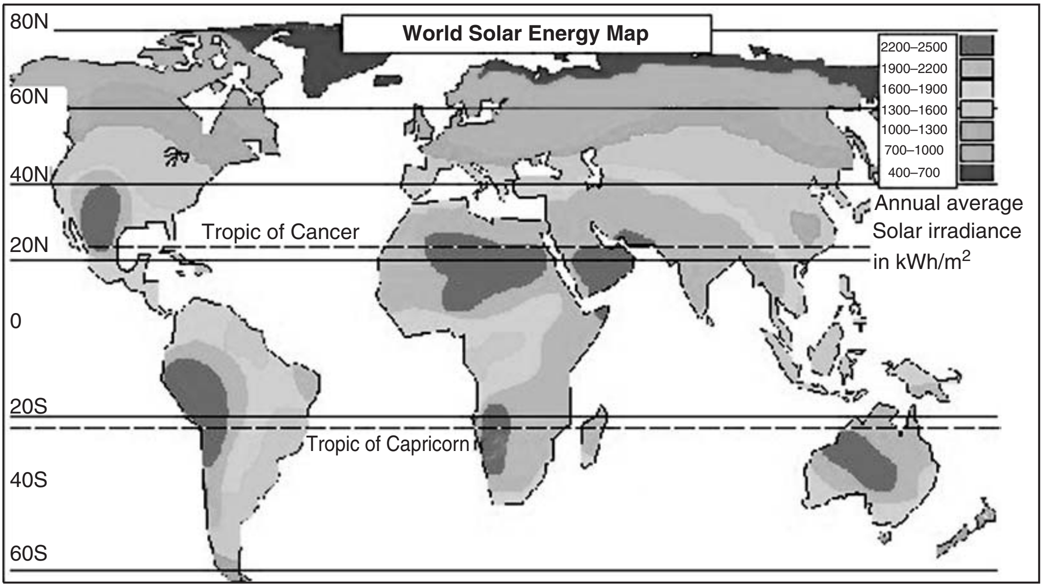

Figure 1.3 World distribution of the annual solar radiation (kW h/m^2) [obtained from www.rise.org.au/info/Applic/Array/image003.jpg] See Plate 1 for the colour figure

The rating of concentrator plants is still a subject of debate. Rating such a plant by summing the rating of the modules may be impossible as some concentrators do not have modules or they are too big for indoor measurements. However in other concentrators it might be applicable.

Chapter 22 contains much more detailed methods to calculate the incident sunlight and the PV module output as a function of location, time of day, month of year, etc. or various on-line calculators are available [5].

1.2.2 Collecting Sunlight: Tilt, Orientation, Tracking and Shading

Potential residential or commercial PV customers often worry "Does my roof have the right slope? Does my house have good solar exposure?" These are indeed important questions for fixed non-tracking arrays. Chapters 19 and 22 address these in more detail. The tilt angle to optimize yearly production for fixed non-tracking arrays is usually some few degrees below the local latitude (there is more insolation in summertime). However, many people are surprised to find that annual output is only weakly dependent on tilt, hence the slope of their roof. In fact, nearly any reasonable tilt is good, and even flat roofs are good for solar below 45° latitude. For example, at mid-latitudes, the difference in annual averaged effective hours varies by 10% as the tilt angle of the modules varies from horizontal (0°) to latitude tilt. Thus, for a home in Washington DC or Madrid or Seoul or Wellington, New Zealand, all at very roughly 40° latitude, the difference in annual effective hours between a horizontal flat roof (~4.4 effective hours per day) or a 40° tilted roof (~4.6 h/day) is 5%. The reason is that the sun's angle at that latitude varies from 27° to 72° between winter solstice to summer solstice at this latitude. In winter, a steeper roof will have more output than a shallow slope, and vice versa in summer, so the difference between flat and tilted averages out somewhat during the year.

What about orientation? For solar installations in the northern hemisphere, the optimum orientation for fixed non-tracking arrays is true south. But again, it is not very sensitive to minor deviations. An array oriented to the southeast will get more sunlight in the morning and less in the afternoon. Thus, for an array installed at 40 °N latitude with 40° tilt and oriented from 45° east or west of true south, the annual output will be only 6% less compared to the optimum true south orientation.

Or, you can install modules on movable supports that "track" the sun. They can track from E to W (oriented in long N–S linear arrays) called single-axis trackers. They can also be installed on special mounts that track the sun in both its daily E–W motion across the sky and its daily and seasonal variation in vertical height, called two-axis trackers. Single- and double-axis tracking generally increase the sunlight collected by 15–20% and 25–40%, respectively. They typically are only employed in large, utility-scale ground-mounted arrays. Of course, costs are higher than for fixed-mount arrays.

So, are there any limits to the location for the installation of an array such as on a roof or in a farmer's field? Yes! The array must not have much shadowing on it, at least not during the peak production hours from 9 am to 3 pm (solar time). The first obvious reason is that the shaded parts produce negligible energy because although PVs can operate with diffuse light, the amount of energy in this diffuse light is rather small. But there are other effects that are more insidious. Even a slight shadow, such as due to a thin pole or leafy tree, on a corner or edge of a module could dramatically reduce the output from the shadowed module and also from the entire array. This is because the modules are connected in series; restricting the flow of current in one cell will restrict the output of all other cells in that module and thus in all modules connected in it in series. But the use of bypass diodes in series strings reduces these losses to very acceptable values. This topic is further analyzed in Chapters 7 and 21. The shadow issue may present a significant limit in cities or towns with lots of trees or tall buildings. A proper preinstallation design will include a shading analysis. Some governments are considering "guaranteed solar access" laws to prevent a newly constructed building or neighbor's trees from shading another roof's array, but the legal problem is not trivial.

1.2.3 PV Module and System Costs and Forecasts

Although the important figure of merit for cost is \$/kW h, typically \$/W_P is used. Policy makers and consumers alike often ask "How much do PV modules cost?" Prices for the same module can differ from country to country. There are challenges of discussing a unique module price even within a single country such as Germany with a very mature and well-regulated PV market, educated consumers and high-volume installers. For example, using average module selling price data in Germany during 2009 [6], the factory gate price for c-Si modules was 2.34 €/W. Due to the excess inventory caused by the failure of the Spanish market in 2009 (a fact that will be explained later), the "market" price for c-Si modules was 16% lower. Market prices for less-efficient thin film a-Si and CdTe modules were about another 10% lower, approaching 1.50 €/W. Market prices for c-Si modules made in Asia were 19% below the average. This is consistent with a more detailed study showing 25% higher costs due to labor for a hypothetical 347 MW c-Si PV module factory in the US or Germany compared with China [7]. This range of module pricing in the most advanced PV market in the world indicates the difficulty of answering the question "how much does a module cost".

But what about the cost for complete systems? This is what really determines the price of solar electricity. We turn to a report analyzing installed costs of 52 000 PV systems (566 MW) installed in the US, mostly in California, from 1998 to 2008 [8]. The average price, before applying any incentives or state refunds, decreased from \$US 10.8/W to \$US 7.5/W, a 3.6% annual decrease.

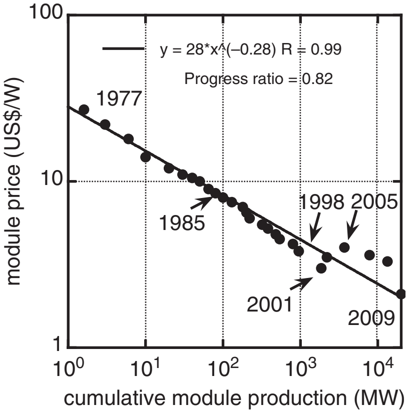

Figure 1.4 Experience curve for photovoltaics from 1976 until 2009. Straight line is fit indicating an experience factor of $1 - 2^{-0.28} = 0.18$ or equivalently a progress ratio $2^{-0.28} = 0.82$

As expected, prices decreased as the system size increased (2008 prices): $US 9.2/W for small (2 kW) residential systems versus $US 6.5/W for large (500–750 kW) commercial-scale system. Excluding any taxes, installed prices of residential systems in 2008 was $US 6.1/W in Germany, $US 6.9/W in Japan compared with $US 7.9/W in the US. But prices decreased significantly in 2009 as this was being written.

Therefore, any discussion of module or system prices is complicated by numerous factors, including location, size of the system, discounts or incentives, and the PV technology. Furthermore, it is strongly time dependent. Nevertheless, analysts worldwide commonly assume some price in order to analyze trends and market influences, as in Chapter 2. A common method predict the cost evolution is the so-called learning curve that states the “price” (whatever definition of this is adopted) of the modules is reduced by a factor 2^n every time the cumulated production is doubled. Figure 1.4 shows a learning curve for PV modules based on their past prices. It suggests that to reach $US 1/W at the present rate will require an order of magnitude increase in cumulative production.

1.3 PHOTOVOLTAICS TODAY

1.3.1 But First, Some PV History

The history of photovoltaics goes back to the nineteenth century. The first functional, intentionally made PV device was by Fritts [9] in 1883. He melted Se into a thin sheet on a metal substrate and pressed an Ag-leaf film as the top contact. It was nearly 30 cm^2 in area. He noted, “the current, if not wanted immediately, can be either stored where produced, in storage batteries, … or transmitted a distance and there used.” This man foresaw today’s PV technology and applications over a hundred years ago. The modern era of photovoltaics started in 1954 when researchers at Bell Labs in the US accidentally discovered that *pn* junction diodes generated a voltage when the room lights were on. Within a year, they had produced a 6% efficient Si *pn* junction solar cell [10]. In the same year, the group at Wright Patterson Air Force Base in the US published results of a thin film heterojunction solar cell based on Cu_2S/CdS also having 6% efficiency [11]. A year later, a 6% GaAs *pn* junction solar cell was reported by RCA Lab in the US [12]. By 1960, several key papers by Prince [13], Loferski [14], Rappaport and Wysocki [15], Shockley (a

Nobel laureate) and Queisser [16], developed the fundamentals of *pn* junction solar cell operation, including the theoretical relation between bandgap, incident spectrum, temperature, thermodynamics, and efficiency. Thin films of CdTe were also producing cells with 6% efficiency [17]. By this time, the US space program was utilizing Si PV cells for powering satellites. Since space was still the primary application for photovoltaics, studies of radiation effects and more radiation-tolerant devices were made using Li-doped Si [18]. Similar achievements took place in the former USSR whose Sputnik II satellite in 1957, was already powered with silicon cells. In 1970, a group at the Ioffe Institute led by Alferov (a Nobel laureate), developed a heteroface GaAlAs/GaAs solar cell [19] which solved one of the main problems that affected GaAs devices and pointed the way to new device structures. GaAs cells were of interest due to their high efficiency and their resistance to the ionizing radiation in outer space. A significant improvement in performance occurring in 1973 was the "violet cell", having an improved short wavelength response leading to a 30% relative increase in efficiency over state-of-the-art Si cells [20]. GaAs heterostructure cells were also developed at IBM in the US having 13% efficiency [21]. Finally, in October 1973, the first world oil embargo was instituted by the Persian Gulf oil producers. This sent shock waves through the industrialized world. Several governments began programs to encourage solar energy, ushering in the modern age of photovoltaics and giving a new sense of urgency to research of photovoltaics for terrestrial applications.

An excellent history of the PV early times can be found in a book by John Perlin [22] or, more briefly, in Chapter 1 of the first edition of this book.

In the 1980s, the industry began to mature, as emphasis on manufacturing and costs grew. Manufacturing facilities for producing PV modules from Si wafer *pn* junction solar cells were built in the US, Japan, and Europe. New technologies began to move out of government, university and industrial laboratories, and into precommercialization or "pilot" line production. Companies attempting to scale up thin film PV technologies such as a-Si and $CuInSe_2$, which had achieved $>10\%$ efficiency for small area ($\sim 1\,cm^2$) devices made with carefully controlled laboratory-scale equipment, found that this was far more complicated than merely scaling the size of the equipment. Unfortunately, by the 1980s most large US semiconductor and oil companies gave up their R&D or pilot-scale efforts in the absence of large infusions of private or government support. One common result was the purchase of American companies and their technologies by foreign companies, displacing the center of the PV industrial activity from the US to Japan and Europe and later to China, currently the world's largest solar cell producer.

1.3.2 The PV Picture Today

In the last decade (1998–2008) the market of PV modules has multiplied by more than 20. The explosive growth transformed PV from a dream for environmentally conscious citizens to a reality that attracts investors eager to exploit this new Eldorado.

Who is making all the PV modules? Figure 1.5 shows where these modules have been produced. The US led the world in production during most of the 1990s (not shown) when Europe and Japan had relatively static manufacturing growth. Then in 1998, progressive and supportive government policies in Germany and in Japan resulted in substantial increases in their production. These policies were driven partly by a strong commitment to CO_2 reduction, as prescribed by the Kyoto Protocol, and partly to develop PV as an export.

But the big story in PV production since the first edition was published is the rapid rise of Chinese production since 2006. In 2003, none of the top ten manufacturers were from Asia. In 2008, three are from China and one from Taiwan. In 2009, China is expected to appear as the top manufacturing location.

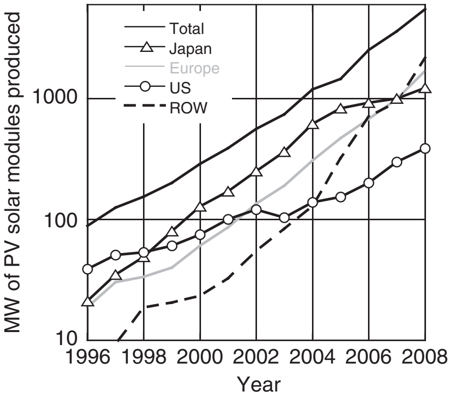

Figure 1.5 Production of PV modules by country or region (ROW = rest of world, mostly China and Taiwan, Europe is mainly Germany and Spain)

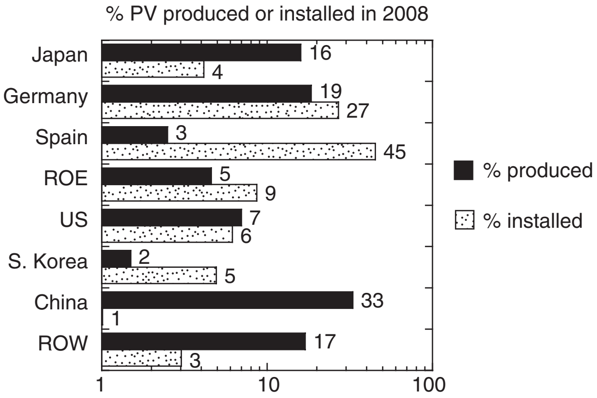

Figure 1.6 Percentage of PV cells/modules produced [23] and installed [24] in 2008 by country or region. Note the logarithmic scale. ROE = rest of Europe, ROW = rest of world (mostly Taiwan and India.). Total installed = 5500 MW; total produced = 7900

Where are the modules being installed? Figure 1.6 shows the geopolitical breakdown for 2008 including the top four producers – China, Germany, Japan, and the US – and the top four installers – Spain, Germany, US, and South Korea. Note that Spain installed 15 times more PV than they produced and China produced 30 times more than they installed. The US was nearly balanced in terms of imports and exports (6–7%). In 2008, Spain became the top destination for PV modules for the first time, overtaking Germany. Most of these modules were installed in large centralized plants >10 MW such as the one presented Figure 1.10. But the brief two years of Spanish leadership in PV installation, created by favorable feed-in tariff (FIT) legislation, ended in 2009 due to restrictive modifications of the law.

The difference between production and installation for 2008 has been variously quoted as 1500–2500 MW. This may represent a double counting of production caused by including both the cells produced in one factory and delivered to a second one for making into modules, and also counting the modules made in the second factory. Some believe that this discrepancy can be caused by a surplus in inventory of unsold modules, but this is doubtful because the module prices were high throughout 2008 and the market experienced a shortage. Prices only decreased significantly in 2009, when the Spanish markets collapsed.

1.3.3 The Crucial Role of National Policies

The real origins of today's surging PV growth started in the mid 1990s when residential scale grid-connected applications in Europe and Japan began to grow rapidly, primarily owing to strong government support. Until then, the primary destination for a PV module was in an off-grid application, whether a rural home in developing country, a water pump for cattle or people, a vacation cabin in the mountains, or a radio transmission antenna. The relative change in dominance of the three main PV applications – off-grid, grid-connected residential and commercial, and large utility scale – is shown in Table 1.3. There are two types of incentive programs responsible for the success of grid-connected residential or commercial applications. One approach, pioneered in Japan and later copied by many US states, provides home or business owners a rebate from the government or their electric utility agency for 10–50% of the PV system cost. Then, their electric bill is determined by the utility using "net metering" where the customer pays only the net difference between what they used and what they generated. Thus, they get a reduction in the initial price of the system, and their PV electricity is valued at the same rate as their utility electricity. This initiated the new market of grid-connected residential and commercial buildings, PV's first big burst in growth, beginning around 1995. Interestingly, government support of photovoltaics in Japan has been decreasing while the market for PV homes has continued to show a good growth rate. The second approach, pioneered by Germany, paid the home or business owners for the electricity they feed into the public electric grid at a rate that is several times greater than the rate that they buy electricity from the grid. Additionally, German banks provided generous loans for purchasing the installation. But there is no government rebate to reduce initial cost. This has resulted in solar arrays being installed on German houses, barns, commercial roofs, government buildings, schools, dairy farms, abandoned airports, and parking garages – in short, any place they can face the sun and still be connected to the grid. This concept, called either a feed-in tariff (FIT) or production tax credit (PTC), has been implemented in Spain, the Netherlands, South Korea, Canada, recently in Japan and soon will be in a few municipalities or states in the US. The German FIT initiated the second great wave in grid-connected PV growth in the mid 2000s. Chapter 2 discusses these and other funding policies to promote PV, including solar renewable energy certificates (SRECs) and mandated renewable energy portfolios (REPs). And the Spanish FIT resulted in the explosive growth of utility scale PV projects in 2007–2008. While many people, especially PV engineers and scientists, might think otherwise, the rapid growth of grid-connected PV, hence all PV, is due more to innovations in policy than to advances in technology.

Table 1.3 Approximate percentages (±20% relative) of different types of application installed

Year	Off-grid (%)	Grid-connected residential or commercial (%)	Grid-connected utility scale (%)	Total installed each year (MW)
1996	95	5	<1	89
2000	60	40	1	288
2004	30	68	2	955
2008	10	35	55	5600

Table 1.3 shows very approximate percentages (±20% relative) of each type of application installed in that year. Off-grid includes single module rural homes, cabins, water pumping, diesel hybrids, and remote communication transmitters. Grid-connected residential and commercial is typically roof-mounted arrays <200 KW in 1996 and 2000, but maybe <1000 kW in 2004 and 2008. Anything larger defined as utility scale. Data and definitions vary from a variety of sources [25].

The importance of the Spanish market in 2007–2008 (3.4 GW_p in total) and its sudden collapse deserves some reflection. The subject is very well explained in Chapter 2, but we want to add here some additional thoughts. The FIT, issued by a Royal Decree, guaranteed a generous price (of about 43–46 €cents/kW h in 2008) over 25 years for the electricity privately produced and sold to the grid by a PV installation, finished and registered in that year. Three Royal Decrees were necessary to permit the market to expand. The first Royal Decree limited FIT payments to generators of less than 5 kW. Some entrepreneurs circumvented this limitation by gathering many small investors and making bigger plants, called solar farms, where each investor owed 5 kW. A second Royal Decree in 2004 lifted the power limitation per owner to 100 kW. The reaction of entrepreneurs was to register dozens of 100 kW installations to effectively create MW plants. Clearly there was higher profitability in larger installations. Finally in 2008 any restriction on size was removed, triggering a frantic activity to build big plants in Spain, so that by the end of 2008 they had built 40 of the 50 biggest plants in the world [26], totaling 2.6 GW in only one year, including the world's biggest PV installation at Olmedilla de Alarcón of 60 MW. No other energy technology can expand so quickly. A 1 GW nuclear plant with about five times more capacity factor (equivalent to 5 GW PV plants) would require at least 10 years to be built, so utility scale PV can be built five times faster.

The trend to build big plants has continued and by early 2010 there were 15 plants with power above 25 MW: 8 in Spain, 5 in Germany, 1 in Portugal and 1 in the US [26]. There are 1000 plants in the world of 1.3 MW or bigger totaling a power of 4.5 GW out of the total 14.7 GW installed. Thus, the Spanish FIT was responsible for the third wave of steep growth, namely that of utility scale projects after 2006.

Unfortunately, the unexpected success of this program resulted in overwhelming the funds which had been allocated, requiring a significant reduction in scale. The collapse of this market in 2009 reportedly resulted in the firing of 25 000 of the 75 000 people working in PV in Spain. It was caused by the unexpectedly strong and fast growth of the market and downturn in the world economy, neither of which was foreseen by the Government. The present regulation plans for a market of only 500 MW in 2009, divided between installations smaller than 20 KW (26.7 MW) and larger than 20 kW (241.3 MW) and the rest in ground installations. The offer for ground installations has largely exhausted the quota by several times (the excess being on a waiting list) while the quota is still open for roof-mounted plants. To date, the FIT regulations have been the most successful policy to expand PV. They explain why Europe (where the climatic conditions are not the best) leads the world in PV installation, with over 70% of the world's total cumulative installed PV power. Some countries are reluctant to adopt a FIT program, sometimes because they consider it an unacceptable intrusion into the market laws.Yet the FIT allows the competition between various PV technologies (Si wafer, thin films, concentrators), installation strategies (roof-top, ground mount, BIPV) and companies. A well-designed FIT must decrease with time (the time when the installation is commissioned, not the time years later when the kW h are sold) in a predictable way to force the industry to reduce their costs and hence their selling price.

1.3.4 Grid Parity: The Ultimate Goal for PV

The ultimate goal for PV is to reach grid parity without subsidies. The relevant parameter to evaluate the long-term cost of any energy source cost is the levelized cost of energy (LCOE). Calculation of LCOE ($/kW h) for PV is complicated; it includes the output of the system over its lifetime (efficiency, solar irradiance and temperature at that location, tilt angle, system losses, annual degradation rate), cost to install and maintain the system (design, permits, BOS costs, site preparation, replacement cost of the inverter, batteries, repairs, profits), and cost of financing the system (discount rate, loans, inflation). Here, we present results from a model developed by NREL (US) called Solar Advisor Model (SAM) [27, 28]. A price in \$/W is determined in six categories: module, inverter, BOS, installation, indirect (financing, design, permits, site preparation, and profits), and operation plus maintenance or O + M (replacing inverter, module cleaning, inspection) considering a given lifetime. The calculated value of LCOE can then be compared with the grid-supplied consumer or wholesale price to determine grid parity, cost–benefit for a given installation, etc. Table 1.4 shows the breakdown in costs and assumptions for four systems using SAM: 4.5 kW residential, 150 kW commercial, 12 MW single-axis tracking at tilt, and 12 MW two-axis tracking concentrator system. Parameters common to all are listed in the table. In the reference cited, each system is analyzed for 2005 (benchmark year using real data), and projected to 2011 and 2020 (using extrapolated data representing improved performance and costs). We list projected results for 2011. These results should not be taken as absolute values, but rather as relative comparisons.

According to this model, the residential system has the highest inverter, BOS, installation and LCOE costs. This derives from the higher design and fixed costs for the smaller systems, and less economy of scale. Note that the smaller inverters have lower lifetime, partly because they are supposed to lack professional inspection services. In reality, smaller systems like this would probably have higher module prices as well since volume purchases drive down costs. The 150 kW commercial system has the lowest LCOE costs, due mostly to the assumed lower installation costs. The two different 12 MW utility systems have very low inverter costs in common; most other parameters are quite different, yet they end with the same LCOE. They both have higher BOS costs, possibly due in part to having to purchase or rent land, unlike the other two rooftop applications. Module price is less than half of the total system price for the 4.5 kW residential, while it is more than half of the other types of systems. The LCOE ranges from \$US 0.10 to 0.15/kW h, compared with the expected retail price for standard grid electricity of \$US 0.07–0.12/kW h. An often neglected aspect of PV systems is the lifetime. Increasing the lifetime from 20 to 30 years decreases the LCOE by \$US 0.023/kW h or 13%.

Table 1.4 LCOE analysis from NREL model SAM for four different systems, located in Phoenix (6.5 kW h/m^2·day) and projected for 2011. Common parameters: 96% inverter efficiency, 35 year lifetime, 1% degradation/year

Parameter (units)	Residential	Commercial	Utility 1-axis tracking	Utility concentrator
System rating	4.5 kW	150 kW	12 MW	12.5 MW
Module price (\$/W)	2.20	2.20	2.20	3.00
Efficiency (%)	16	16	16	25
Inverter price (\$/W)	0.69	0.51	0.35	0.35
Inverter life (yr)	10	15	15	15
BOS (\$/W)	0.40	0.36	0.73	0.53
Installation (\$/W)	0.57	0.17	0.16	0.33
Indirect (\$/W)	1.14	0.76	0.46	0.09
O + M (% costs)	0.3	0.3	0.3	0.6
Installed price (\$/W)	5.00	4.00	3.90	4.30
LCOE (\$US/kW-hr)	0.15	0.10	0.12	0.12
Retail price of electricity (\$US/kWh)	0.12 Residential	0.10 Commercial	0.07 Industrial	0.07 Industrial

Compared with the retail electric rates for the US shown at the bottom, the LCOE cost of a PV system in a very sunny location is very close to grid parity, in particular for the so-called commercial applications (roofs of factories or supermarkets). This is why in the US there is increasing interest in this type of system. Of course, such predictive calculations are only as valid as their assumptions, which do seem reasonable.

There is considerable uncertainty in future electric rates due to possible environmentally driven costs (carbon tax) and the need for substantial reinvestment in new transmission and grid control systems (which will probably be paid for by customers through higher rates). Thus, predicting the price of either PV or conventional electricity is problematic.

Figure 1.7 shows the dependence of the LCOE on available sunshine (irradiance in annual kW h/m^2) for module prices of $US 1 or 2/W. The system was assumed to be a 2.5 kW residential array with a 30 year mortgage at 6% and 30 year lifetime with 1% annual degradation. The other fixed costs were taken from Table 1.4, and amounted to $US 2.80/W. The module price of $US 2/W is close to today's selling price, and $US 1/W represents what many believe is achievable with reasonable advances in today's technologies in the near future. The symbols indicate the average residential electricity rate for various cities indexed by their annual irradiance. Already in 2009, PV electricity prices matched a few markets in the US and Europe that have relatively high-price electricity and/or high solar irradiation such as Italy, Hawaii, New York and California (San Diego, not shown), when determined as the LCOE. Similar analysis has been published using different assumptions (system cost of $EU 3/W) but showing similar trends and conclusions [7]. In reality, the cost of conventional electricity is presently less than the PV LCOE for most cities but the gap is narrowing. The LCOE cost would be less for a larger system as in Table 1.4 due to lower installation costs. This graph shows that grid parity is a complex relation between geographic location, price of electricity, and price of PV system (related to size of PV array). Note that increasing the incident sunlight, hence module output energy, by a factor of two reduces the LCOE by the exact same amount, thus having significantly greater impact than decreasing the price by a factor of 2.

In order to reduce the LCOE, it is acknowledged that efficiency must increase and cost must decrease. But what is their relative contribution? Where should we put our efforts? Figure 1.8(a) presents the dependence of LCOE on module efficiency for module costs of $US 1 and 2/W (again) for a 2.5 kW system in two US locations, sunny hot Phoenix or temperate coastal Philadelphia,

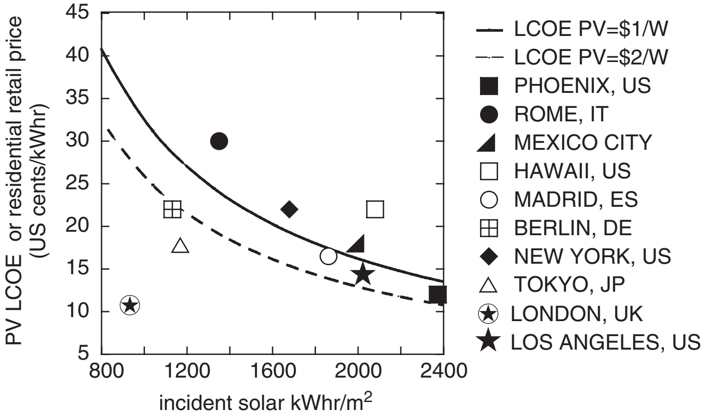

Figure 1.7 LCOE and cost of residential electricity versus average annual incident irradiance. LCOE calculated using SAM model parameters explained in the text assuming a 2.5 kW array with $US 1 or 2/W module cost

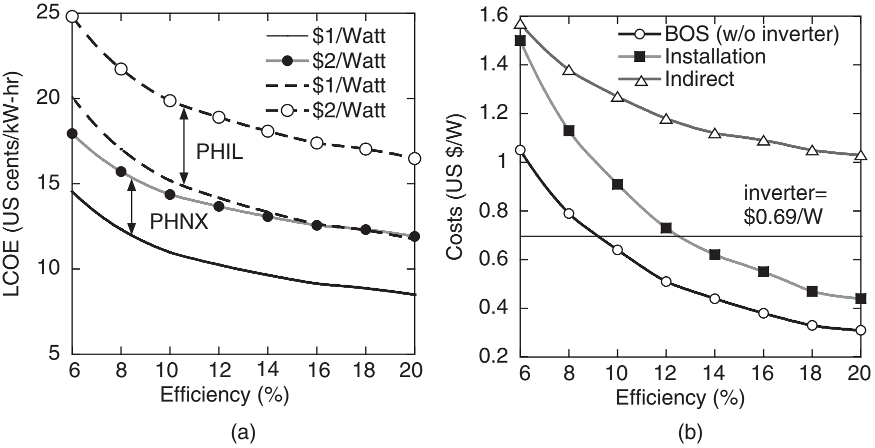

Figure 1.8 (a) Calculated impact of efficiency and module cost on LCOE for Phoenix (sunny, 2370 kW h/m^2/yr, solid lines) and Philadelphia (temperate, 1680 kW h/m^2/yr, dashed lines) for 2.5 kW systems at latitude tilt. (b) Fixed costs as function of efficiency. Indirect for $US 2/W module. A 30 year lifetime is assumed in all cases. Other assumptions are described in the text or caption for Figure 1.7

calculated using SAM with the same parameters as in Figure 1.7. (Philadelphia has comparable solar irradiance to Shanghai, Melbourne, New York or Madrid.)

As efficiency increases, the module area and hence area-related costs decrease. In this study, the number of 1 m^2 modules decreased from 41 to 12 as efficiency increased from 6 to 20%. The area-related costs were: BOS = \$64/m^2, installation \$91/m^2 and indirect \$180/m^2 as derived from Table 1.4 for the 2011 residential case. The 2.5 kW inverter cost $1725 ($0.69/W). For a factor of 2 decrease in module cost, the LCOE decreases by 12% (at 6% module efficiency) to 22% (at 20% module efficiency), independent of location. For a factor of 2 increase in efficiency (from 10 to 20%), the LCOE decreases by ∼20%, independent of location. For a factor of two decrease in module cost (at 16% efficiency), the LCOE decreases by ∼25%, independent of location. Thus both price and efficiency have comparable impact on LCOE. This weak correlation between either module cost and efficiency with LCOE might surprise some readers, but this just indicates the importance of area-related and fixed costs. The indirect costs are much greater than either the BOS or installation. This could be alleviated with lower interest rates for PV projects, and shorter mortgages. Figure 1.8(b) shows how the area related costs decrease with efficiency. Decreases in both LCOE and area related costs are steeper at low efficiency, becoming less sensitive at higher efficiency, suggesting the relatively greater impact of increasing the efficiency of low-efficiency thin film modules (rather than lowering their price) compared with high-efficiency Si modules. Together, these figures indicate the importance of efficiency and module cost as a driver to lower LCOE, but also the impact of reducing fixed or area-related costs as well, which are often neglected by research and development funding agencies. Finance charges must be minimized.

1.4 THE GREAT CHALLENGE

In this section, we discuss the requirements and limitations to very large-scale PV energy production in terms of the amount of land and raw materials needed, the environmental impact, the net energy balance, the reliability, and the readiness of manufacturing capacity.

First, what is size of the task? Estimating the world's demand for electricity in 2030 or 2050 is complicated by many assumptions. Will a larger fraction of our primary energy be shifted from chemical and thermal to electric (i.e. electric cars)? How large a role will efficiency and smart growth play in decreasing demand? How large a role will population and economic growth in developed versus developing countries play in increasing demand?

The 2007 Nobel Prize winning organization UN Intergovernmental Panel on Climate Change (UN-IPCC) [29] estimates the world will need the equivalent of 32 000 terawatt hours ($1\,\mathrm{TW\,h} = 10^9\,\mathrm{kW\,h} = 10^{12}\,\mathrm{W\,h}$) of electrical energy by 2030, but efficiency improvements might reduce this to 22 000 TW h. Analysis by their Mitigation Working Group III on how this can be best accomplished to minimize the cost per ton of avoided CO_2 concludes that PV could only meet about ∼1–2% of this demand (∼150–300 TW h), limited largely by *cost* not technology or resource availability. This would be mostly to meet demand from rural electrification in developing countries. However, other bodies set higher targets for PV. The European Photovoltaic Industry Association (EPIA) predicts that PV could provide 12% of Europe's energy by 2020. The International Energy Agency anticipates the PV could provide over 11% of the world's electricity by 2050 [30]. California has a mandate to produce 33% of their electricity by renewable energy by 2020. Originally, PV was expected to contribute only about 10% relative (about 3.2% total) but due to recent PV price decreases,[2] the relative fraction of PV has been increased to 40% (about 15% total). Thus, Europe and California have similar expectations for PV, and are consistent with analysis of the ability of a well-regulated grid, without storage, to accept a variable energy source such as PV sets an upper limit of 10–20% by 2030 [31]. For instance, in Spain PV already provides about 2% of the annual demand, but if we add wind energy, the total intermittent energy is actually 14%.

How can we calculate how many GW (or more precisely GW_p) of installed PV would be required to produce a TW h of electricity?

In fuel power plants the concept of capacity factor (CF) is widely used. It is the ratio of the energy actually produced to the theoretical maximum energy that the plant could produce in one year (typically equal to the nameplate power rating times 8760 h). Thus, a 1 GW power plant operating at full capacity for half the year (or at half capacity for the entire year) has a $\mathrm{CF} = 50\%$, and would produce $1\,\mathrm{GW} \times 8760\,\mathrm{h/yr} \times 0.50 = 4380\,\mathrm{GW\,h/yr}$. The CF is usually below unity not only because the plants might need to stop for maintenance (the case of nuclear plants) but also because the management of the electric grid requires some plants to idle for certain periods.

In a PV plant CF is calculated as the effective sun hours (see Section 1.2.1) times performance ratio divided by the total number of hours in the year (even though the sun only shines 50% of the year on any location on earth). The CF for PV generators ranges from 0.08 (Hamburg, fixed panels) to 0.26 (Albuquerque, sun tracking[3]), so we will use 0.15 as an average. Thus, to provide 300 TW h in 2030, we would need 230 GW of installed PV capacity, or an installation rate of 11.6 GW per year for the next 20 years. In fact, the world produced about 7 GW in 2009, and

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[2] In 2008, with installed system costs of $US7/W or $US0.30/kW h, it was expected most of California's 3.2% PV demand would be large, centralized power plants. By 2009, system costs fell to $US3.70/W or $US0.17/kW h due to availability of lower-cost thin film modules. Combined with land use permitting and transmission access difficulties for the large PV power plants, distributed small-scale PV looked more attractive to provide much of the 15% demand (from Garrett Hering in Photon International December 2009, 12–14.)

[3] Sun tracking increases the CF. The number of equivalent hours in a sun-facing plane (called a two-axis tracker) increases by about 40% with respect to the fixed optimally oriented module. This is discussed further in Chapters 19 and 22.

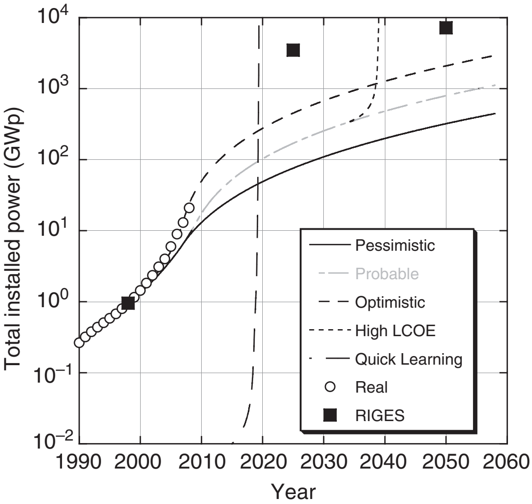

Figure 1.9 Forecast of the cumulative global PV installed power by year. (see [32] for details). "Real" represents the actual installed power (from P. Maycock, *Photovoltaic News*, 19(3) 1 (2000), more recent data from the *Photon International* yearly reports in the March issue). The dots labeled "RIGES" are the goals in Reference [33]

expects around 10–12 GW in 2010. So meeting the relatively low expectations of the UN-IPCC for PV will be easy, requiring no growth or scale-up at all.

In 2001 one of us published a paper [32] in which a differential equation for the evolution of the yearly market was formed by coupling the learning curve (Figure 1.4) and the demand elasticity (the relative reduction of price in a certain year divided by the relative increase of the yearly market). The price evolution was deduced as well as the cumulative sales for every year. For the initial forecasting period, the model parameters were extracted from past experience in yearly markets and prizes. The cumulative sales, approximately equating the total installed PV power, are represented in Figure 1.9 for several parameter choices.

The three curves: "optimistic" (developed countries are willing to spend 0.1% of their GDP on higher cost PV electricity), "probable" (spending 0.05%), and "pessimistic" (spending 0.025%) show a rapid increase followed by a slowing in growth as markets saturate compared with a given price of electricity. Note the striking coincidence between the actual PV installations up through 2008 (labeled "real" in the figure) and the "optimistic" forecast predicted in 2001. This coincidence gives credibility to the other implications predicted by this model. For 2030 this model predicted 1.6% of the total demand of 22 000 TW h forecasted by the IPCC under the hypothesis considered "probable" in 2001. This is not very different from the modest contribution of 1.4% assumed by the IPCC. But if we look at the real installations trend, which follows closely the "optimistic" forecast, the result is that by 2030 PV will be supplying the 4.4% of the demand. This is more than three times the prediction of the IPCC, but still modest.

So, let us assume that PV is to supply 12% (2,640 TW h) of the world's electricity by 2030, hence we would need to install on average 100 GW ($\cong 2640/(365 \times 24 \times 0.15 \times 20)$) per year (a nice round number) for the next 20 years. In fact a constant average annual production is completely unrealistic, but it serves to give the scale of the task. Some studies assume producing

20–30 GW/yr of PV until 2020 then ramping up an order of magnitude each decade until 2050 [34] while others see rapid initial growth followed by slowing as the installed capacity reaches its limit.

The paper which developed the model in Figure 1.9 stated in 2001:

> *First we predict several years of explosive market growth.... But this period cannot last too long. Not more than a decade. If it does, the capital involved will become excessive. Powerful voices will cease to consider PV as a curiosity and will question cost effectiveness. Other voices, not less powerful, will support PV. The equilibrium will determine subsequent growth. This equilibrium will induce a slower market growth, but at levels that are no longer negligible, at least in terms of business volume, but probably not enough for pollution abatement. Price decrease will continue, but slowly. For the next half-century they will be not competitive with common electricity unless some of the following facts happen.*
>
> (*a*) *Electricity prices rise.*
> (*b*) *Commercial schemes substantially reduce commercialization, installation and financing costs.*
> (*c*) *New inventions of lower initial costs or with more cost reducing potential appear.*

As the paper predicted, PV has become a substantial business (about €50 billion in 2008) but society has started to question its cost effectiveness, especially in view of the worldwide financial problems of 2009. For instance, there was the dramatic reduction of public support in Spain in 2009 discussed above, and less dramatic reduction in Germany in 2010, the world's two most active markets in 2008.

But let us examine now whether the conditions for competitiveness in the second part of the statement are being fulfilled or not. The model, intended to be simple, considers PV competing with only the wholesale price of the electricity, but if the retail price is taken into account instead, this would allow for a substantial growth within the first half of the century. The case is considered in the curve labeled "High LCOE". With this choice of parameters (consult the paper for details) a vertical asymptote appears around 2040 (assuming a module price of \$1.25/W_p). Since the actual trend is following the curve "optimistic", according to the model, the asymptote will appear before this date, maybe towards 2025. Thus, if a contract offered by the regional electric power provider is based on the retail price of electricity (essentially net metering), including the price paid to PV power plants, condition (a) would be automatically fulfilled.

The steep asymptotic increase in "High LCOE" is just an artifact of the model caused by the assumption that the electricity market is infinite. This is valid only if one knows when the LCOE "tipping point" is reached, not for studying the subsequent growth. In reality this asymptote will appear as a surge in the installations which will inevitably saturate and slow when sales to the new market sector are exhausted.

But, in addition, the model assumed that the cost of a PV installation was distributed in equal thirds, one for the module, one for the BOS and one for the commercialization, installation and financing. This is a reasonable assumption for distributed small home markets (prevalent when the model was developed) but the recent development of big power plants has drastically reduced the commercialization costs, leading to a situation where the plant cost is about twice (and not three times) the module's cost, according to the SAM model presented in Table 1.4. This fulfills condition (b) and brings the date of the surge in installations even closer.

Thus, what the model explains is what is already anticipated by many analysts, including the study presented in Figure 1.8 for a system price of \$US 2/W_p. This price is already being offered in Spain for big ground-mounted PV power plants, and we think that expected surge will take place within the next five years in several countries (or US States) where the combination of insolation and the electricity retail price are high enough to reach grid parity with the retail electricity price.

Note that the retail electricity price includes the cost of generation as well as transmission, distribution and commercialization; therefore, it is only fairly applicable to homes and commercial PV plants. Utility-scale PV power plants should compete with the much lower wholesale price of generation. The application of the retail price to big plants is dependent on political decisions that waive the cost of the distribution for the big PV producers. Yet the application of FIT incentive suggests that this policy can be adopted in many countries.

Thus we have justified why the goal of meeting 12% of the world's electric demand by 2020 or 2030 with PV is not just wishful thinking, at least from the point of view of reaching reasonable prices.

But this is not enough. At the end of this century, many analysts expect solar energy to provide a large part of the demand, i.e. about 60% of the energy demand (not only electricity) [34]. This requires fulfilling condition (c), a technological breakthrough with a faster learning curve (curve labeled "quick learning"). It might happen at any time (2015 is assumed in the figure). It is possible that it is already happening. Consider the recent success of First Solar, a thin film manufacturer, who became the biggest solar cell producer in the world in 2009. Maybe the breakthrough will appear in 5–10 years with the concentrator systems intended to exploit the ultra-high-efficiency (over 40%) MJ solar cells. Or maybe, at an even later moment, the exploitation of novel concepts for a higher efficiency will permit this faster learning curve and therefore dominate the wholesale production of electricity. Certainly the so-called third-generation concepts aim at this. This is why we said that PV has more technological options than concentrating solar thermal electricity and we qualified PV as a winning option.

But this high penetration (>20%) will only be possible if some cheap and efficient procedure for electricity storage is developed. Advanced PV and storage have to be among the leading tasks for all this century for scientists and technologists.

Let us concentrate now on other constraints and challenges associated with our immediate 12% goal implying the installation of 100 GW_p per year, on average, during the next 20 years.

1.4.1 How Much Land Is Needed?

Estimates of *household* electricity usage from various sources for the US, Japan and Europe indicate about 5 kW h/person/day, or 20 kW h/day per family of four. With a CF of 0.15 this demand can be satisfied with a PV installation $20/(24 \times 0.15) = 5.5\,kW_p$. For a rated module efficiency (at STC) of 15% ($150\,W_p/m^2$) this requires an area of $5500/150 = 37\,m^2$ of modules. There are many properly oriented roofs (with a lot of flexibility in the tilt and orientation, but generally facing southwards if in the northern hemisphere) with $37\,m^2$ of well-oriented roof available (see Chapter 23 for architectural integration). In fact, many roofs are larger, and many homes have sunny areas of this size around them, so it is possible for a family of four, with all the conveniences of a typical modern home, to provide all their power averaged over a year from PV modules on their house or on racks on their yard.

Let us assume that of the 100 GW we must fabricate each year 25 GW_p are grid-connected homes of 5 kW_p. This will imply installing 5 million residential generators per year. This is certainly a challenge, but is not impossible if we consider that the car industry produces more than 60 million cars per year. Neither is the availability of capital a problem, if the business is profitable.

Perhaps it is illustrative to know that the 125 more densely populated towns in the world [35], (whose density of population ranks from 26 650 people/km^2 in Mumbai to 1550 in Denver) with a total of 619 million inhabitants occupy an area of 124 000 km^2. With the same daily electricity consumption of 5 kW h per person and the same capacity factor of 0.15, the area of 15% efficient modules required is 129 000 km^2, practically the same as the total town area. Obviously in Mumbai there will not be enough room for this, but in Denver it will be easy. There are many more towns less densely populated. We think this clarifies that space is not a limitation for generating a sizeable fraction of the electricity we use with PV, or for meeting our goal of 25 GW_p per year.

In the first edition we calculated how much land it would take to replace a 1000 MW coal or nuclear power plant. The answer was 60 km^2 (or 24 square miles). This is a square 8 km (or 5 miles) on a side. For the same electricity production, this is equivalent to the area for coal mining during a coal-powered plant's life cycle, if it is surface mining, or three times the area for a nuclear plant, counting the uranium mining area [36].

But building this size of PV plant is not a solution adopted by PV investors for the moment. Actually the 34 biggest plants built in the world comprise 1010 MW, occupying an area similar to the one calculated above. The size of these plants ranges between the 60 MW of the Olmedilla (Spain) plant to the 19.4 MW of the Helmeringen (Germany) plant. Figure 1.10 is a picture of the 10 MW plant at Jerez de los Caballeros (Spain) showing how PV is well integrated in the environment, permitting for instance, cattle raising. The PV "trees" are about the same size as the oak trees around, but collect solar energy about 100 times more effectively.

In any case we must not hide the fact that the annual electric energy (MW h) produced by the 1000 MW plant (or ensemble of plants) is less than the one powered by coal or nuclear energy because of the smaller capacity factor (0.15 in our example compared with at least 0.5 for the fuel plants).

Finally, how much land would be needed for PV to supply the 12% of worldwide demand (2 TW) we want for 2030. Others have analyzed very large-scale PV (VLS-PV) at seven extremely sunny, arid desert locations worldwide, roughly one per major geopolitical land area [37]. In those deserts, they would produce about 50% more energy per area than our typical, mid-latitude array analyzed above, so 100 MW requires approximately 1.7 km^2 of barren land. Scaling these areas from the VLS-PV study to our hypothetical 2 TW yields an area of 34 000 km^2, or about 5000 km^2 in each of the seven deserts. Certainly, an area of $70 \times 70\,km^2$ (43×43 miles) could be found in these deserts where the installation of PV arrays would be accommodated without significant disruption of the natural surroundings. (We point out again that PV does not require water for its operation.)

Figure 1.10 The Jerez de los Caballeros 10 MW PV plant. Reproduced by permission of Guascor Solar SAW

But following the actual trend, the construction of 1000 plants per year of average size of 75 MW will lead to the 75 GW that, added to the 25 GW in buildings, will complete our goal of 100 GW per year. This will be a challenge, but not impossible if the business is profitable. Remember that in the last 2–3 years 1000 plants of average size 4.5 MW have been built (totaling 4.5 GW) and the biggest are approaching the 75 MW size.

1.4.2 Raw Materials Availability

Are there sufficient raw materials on Earth to make enough PV modules to provide a significant fraction of our energy in the future? This is an important question, because if the answer is "no", then PV will be ultimately relegated to a minor role.

The main material used today to make solar cells is silicon. Being the second most abundant material in the Earth's crust (after the oxygen), there is not a foreseeable shortage. High-purity quartzite (SiO_2) ore is used to produce Si today. The present production of Si is about 50 times more than needed for PV use and can be easily increased, so that producing 12% of the electricity with PV, which implies an increase of the cell production by at most, 15 times, can be easily supplied.

But for non-Si based cells, this is a very complex question, requiring decisions about how much of a given element is economically recoverable and at what rate (ton/yr or equivalently converted to GW/yr of PV). Several studies [38–40] are in general agreement that the potentially limiting materials for PV are Ag for contacts to Si cells (but Ag is not essential), In for $Cu(InGa)Se_2$, Te for CdTe, and Ge for Ge substrates commonly used for III–V concentrators cells or a-SiGe cells. In and Te metals are not actually mined, but are dilute by-products of other metal refining; i.e. Te from Cu ore; In and Ge from Zn ore and also from ashes in the combustion of coal. Conclusions differ significantly as do the assumptions, but generally these studies find that solar cells based on In or Te could provide a few percent of the world's future electricity without significant reductions in utilization (i.e. thickness), thus potentially meeting the entire, although trivial, requirement for PV assigned by the IPCC. Another view suggests that historical production rates of In and Te could easily provide 20 GW/yr [39], thus meeting about 20% of our hypothetical PV requirement of 100 GW/yr with CdTe and $Cu(InGa)Se_2$. This does not mean they should not be considered, since it is unlikely a single PV technology will dominate. Supplies of In and Te can enable multi-billion dollar annual PV industries[4]. Reducing the cell thickness, recycling of waste and expired modules, and increasing efficiency in manufacturing will reduce the total demand for a given raw material and extend its ability to meet these targets. These are all promising and active areas of research.

As for III–V/Ge concentrator devices, operating at 500–1000×, there are not major problems in producing 100 GW/year [41]. The main limitation comes from the Ge, and from plastic for lenses. The use of hybrid glass–silicone lenses, beginning to be common today, would remove the limitation on plastics (because they use a very thin layer of silicone). As for the Ge, it is probable that enough can be found in other sources, but it could be recycled or substituted by Si.

1.4.3 Is Photovoltaics a Clean Green Technology?

Would large-scale PV manufacturing and deployment degrade the environment, although in a different way from conventional energy production?

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[4] There are also competing technological uses to consider. For example, Indium usage has increased substantially in recent years due to the need for transparent conductive indium tin oxide (ITO) layers in flat panel displays.

One of the most valuable characteristics of photovoltaics is its well-deserved image as an environmentally clean and “green” technology, resulting from the cleaner operation of a PV electricity generator compared with a fossil-fuel or nuclear-fired generator. But this must also extend to the manufacturing process itself as well as the recycling of discarded modules. Let it be stated at the beginning that the present Si-based PV technology which dominates the market has few environmental concerns and is considered totally safe to the public.

Hazards can be classified by whether they affect workers at a PV manufacturing plant, customers with photovoltaics on or near their homes, or members of the public who consume air and water near the PV plant. Very little risk is associated with the public or the PV owner or installer; the main risk being that of electric shock already existing with conventional electricity, but more severe because large areas can be electrically live. Adequate grounding is strongly recommended.

Safe handling procedures for some of the materials and processes are already well established from the integrated circuit or glass coating industries. But in the case of some unique materials and processes, safety procedures had to be developed by the PV industry. The PV Environmental Health Safety Assistance Center at Brookhaven National Laboratory in New York, USA provides worldwide leadership in risk analysis and safety recommendations for the PV industry [42]. An industry-focused PV Safety Working Group has been established in Europe [43].

Si modules, currently the most widely used, are totally free from the suspicion of releasing dangerous materials. Si module manufacturers have long used Pb-based solder to interconnect the wafers, as did the electronic chip manufacturers. This represents a minor risk that nevertheless is being further reduced through the use of Pb-free solders.

There has been considerable research into occupational and accidental exposure and risk analysis of one PV material in particular – thin films of CdTe – since Cd is a known carcinogen. The general conclusion is that CdTe thin film modules do not pose a risk to the public [44]. Much of the concern is misguided for two reasons: there are significant toxicological differences between elemental Cd (toxic) and compound CdTe (much less so), and because the CdTe is hermetically sealed between two sheets of glass. Those concerned about Cd sealed in CdTe modules should consider that most Cd in our environment is released directly into the atmosphere by combustion of coal and oil. Chapter 14 has more about Cd environmental issues. Even in the event of a house fire, studies have shown that roof-mounted PV modules do not release any potentially hazardous materials [45], and this is also true for those containing cadmium.

A related issue is what to do with PV modules at the end of their projected 25- to 30-year life. An excellent strategy is to recycle the modules. This solves two problems at once, namely, keeping potentially hazardous materials out of the environment and reducing the need for additional mining and/or refining of new materials. Semiconductor vendors have indicated a willingness to accept used modules, and to extract and purify the CdTe, CdS, or $Cu(InGa)Se_2$ for resale and reuse. As for the recycled Si, it is inherently purer than the Si used today as raw material.

Thus, we can say with confidence that PV is the cleanest and safest technology with which to generate electricity even at the GW production scale.

1.4.4 Energy Payback

Can PV modules produce much more energy over their lifetime than it took to make them; i.e. are they net energy producers? This oft-expressed concern is baseless. This concept is quantified by the “energy payback time ” or EPT, which is how many years the PV system must operate to produce the energy required for its manufacture. After the payback time, all of the energy produced is truly new energy.

Many studies have concluded that EPT's have steadily decreased over the past decades, now estimated at 1.5 to 2.5 years for crystalline Si and 1 to 1.5 years for thin films [45, 46]. Thus, all the energy needed to produce our fictional 100 GW every year will be paid back to the grid within the next two years.

For crystalline Si, melting and forming the crystalline wafers is the major energy requirement. For thin films, where the semiconductor layers are 100 times thinner, and deposited at much lower temperature, their energy requirement is negligible. Instead, it is the energy embodied in the glass or stainless steel substrate, which is the major energy sink. The cosmetic Al frame around the module is responsible for a surprisingly large fraction of energy, and is being phased out. Although thin film modules have a shorter energy payback, they also have lower efficiency, which means a larger BOS is needed to support the larger number of modules. Thus, a larger amount of energy is embodied in the BOS for thin film photovoltaics compared to crystalline Si photovoltaics.

The case of concentrators is less studied, but again the use of semiconductor is reduced and the BOS becomes more important than even for the thin films because the concentrating structures are more massive. However, their efficiency is much higher. In summary, we can guess that their EPT will be similar to the case of thin films.

Recently, PV has been examined in terms of its potential for Carbon reduction [46–48]. The amount of CO_2 released during manufacture of PV systems is much less than the CO_2 avoided by the power it produces during its lifetime. PV technologies are responsible for about 30–50 g CO_2 emission per kW h produced over their life-cycle (all due to fossil fuel energy consumed during manufacturing) while coal-powered generating plants release about 20–30 times more. As the CO_2 load from our energy sources decreases, the amount of CO_2 per kW h of PV will decrease as well. Thus, PV is an excellent strategy to mitigate global climate change.

1.4.5 Reliability

Most modules seem to lose about 0.5–1% of their relative output annually for a variety of reasons. For the past few years, most modules have been sold with guarantees to maintain at least 90% of their rated output after 10 years and at least 80% after 20 or 25 years. They must pass rigorous reliability testing using accelerated extreme weather conditions. A recent study of >200 modules [49] produced in the early 1980s, before many of today's more rigorous standards and improved encapsulation methods and materials were available, found that after >20 years continuous operation outdoors, only 18% of them had lost more than 20% of their rated power (and they were only warranted for 10 years back then!). And remember, even if they lose 20% of their output after 20 years, they are still providing free electricity! Also, solar modules have been operating in space, a very harsh environment, for decades.

1.4.6 Dispatchability: Providing Energy on Demand

Could PV meet all of the world's needs today if we would just pass laws requiring photovoltaics and halting all fossil and nuclear plants?

The first technical problem faced would be the intermittent nature of the solar radiation, available only during the day and strongly reduced in overcast skies. Energy storage would solve this problem, but no cheap storage method appears on the horizon, although pumped hydro storage [50] is already used and compressed air [51], grid-tied electric vehicle batteries (when parked and plugged in) called V2G [52], and new battery technology (Chapter 20) are being actively explored.

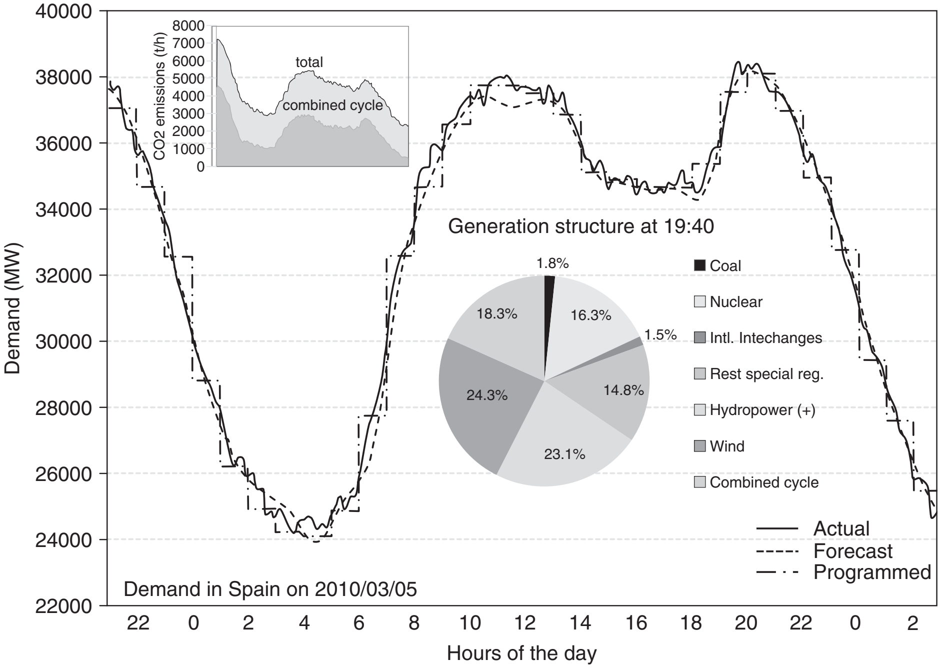

Figure 1.11 Dispatching of electricity in Spain over 24 hours on 2010-03-05; actual, forecast and programmed (dispatching plan). The wind energy resulted in 24.3% at the peak consumption time. PV is not independently registered. It is included in "Rest special regime" of 14.8% (the estimate for PV is about 2%). The high penetration of renewable is permitted by the high proportion of hydro/gas (combined cycle) plants which are easily dispatchable. Coal generation, very important in the past, has almost disappeared to allow for renewable introduction. Coal is the most CO_2-intensive source. Adapted with permission of Red Eléctrica de España

The problem of electricity storage is not specific to the intermittent production of electricity. It is a general need of the grid management. Actually, electricity demand is quite variable with the hour of the day and even seasonally, where differences of 40% are possible daily between its peak (maximum) load and its base (minimum) load. Thus, the electricity operators, who have a statistical knowledge of the demand behavior, plan the connection or disconnection of power plants to produce enough energy that approximately matches the demand as shown in Figure 1.11. The output of power plants is adjustable within certain limits. This process is called dispatching.

The production of intermittent electricity is also predicted statistically and the output needed from fuel-based power plants can be planned accordingly. In Spain, about 14% of the yearly demand is intermittent or variable and this fraction may be much higher in specific windy or sunny moments. Baseload coal or nuclear power generators must be permanently connected and generally run at full power. As the wind/solar fraction grows (assuming no storage), on windy/sunny days when the intermittent generation alone can meet the demand, some of the wind/solar generation will have to be shut down, because conventional baseload plants cannot be disconnected or decreased quickly. A cheap storage, such as pumped hydro plants, would permit more penetration of intermittent renewable electricity. Either way, in any grid (even without intermittent renewable energy) there is always some idle generation capacity and the associated financial losses, but this can be increased by excessive intermittent generation. Adequate grid management would allow up to 35% of the electric production to be intermittent [33], even without sensible storage.

1.5 TRENDS IN TECHNOLOGY

Most of this book's chapters deal with technology. This section will give a broader perspective that the specific chapter authors cannot provide.

In 2008 almost 8 GW_p of modules were manufactured. The breakdown among the different technologies appears in Table 1.5 for 2003 and 2008. The crystalline Si (c-Si) modules dominated the market (87% in 2008) and are divided into multicrystalline (multi-Si), single- or monocrystalline (mono-Si), or ribbon silicon, depending on the type of Si wafer used. The thin film modules, a minority, but whose market share is expanding, are divided into a-Si, CdTe and CIS modules. The rest of the technological options are yet too immature to appear in the market breakdown.

As shown in Figure 1.8a, efficiencies are one of the most critical factors to reduce cost of electricity generated. "Champion" cell efficiencies are presented in Figure 1.12 for several technologies. Two technologies not yet commercially significantly appear in this figure (ironically having the highest and lowest efficiencies). Improvements in champion cell efficiency have slowed in the last decade, except for the III–V based multijunctions and CIGS. The efficiency of champion cells is typically 25–50% higher than the efficiency of the commercial products because the techniques used for making the highest efficiencies are seldom acceptable for cost effective manufacturing. This seems to be in contradiction with the statement that efficiency is the main driver of cost reduction, so we will qualify it as follows: the industry goal is to obtain the highest module efficiency compatible with a reasonably cheap, high-throughput, high-yield and reproducible process. Figure 6.18 in Chapter 6 shows a historic view of the evolution of the breakdown among technologies.

1.5.1 Crystalline Silicon Progress and Challenges

Table 1.5 show that c-Si, as either single or multicrystalline wafers or ribbons, was responsible for almost 90% of worldwide PV production. How did its dominance occur? First, Si cell technology has benefitted from the tremendous development of microelectronics that is also based on the same Si. While thin film cell researchers had to develop their own manufacturing equipment, Si

Table 1.5 Total MW of production and percentage of the three Si wafer and three thin film technologies in 2003 (when the first edition was published) and 2008

Technology	2003		2008	
	MW	%	MW	%
Multi-Si	429	57	3773	48
Mono-Si	242	32	3024	38
Ribbon-Si	33	4	118	1
a-Si	*34*	*4.5*	*403*	*5*
CdTe	*8*	*1*	*506*	*7*
$Cu(InGa)Se_2$	*4*	*0.5*	*79*	*1*
Total Crystalline Si	704	93	6915	87
Total Thin Films	*46*	*7*	*988*	*13*
total	750	100	7910	100

Data from *Photon International*, March 2009, p. 190

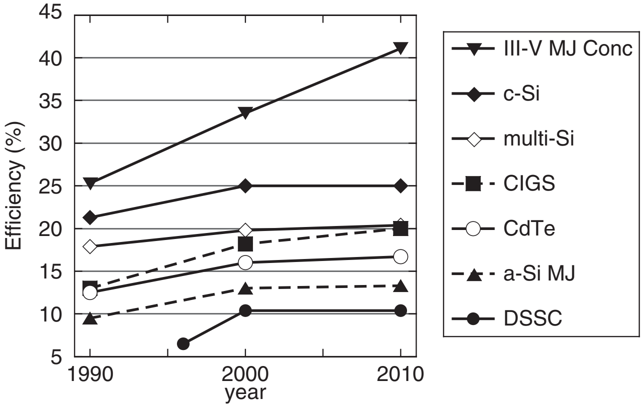

Figure 1.12 Best small-area (0.5–5 cm^2) efficiency for various cell technologies measured under standard laboratory test conditions as of 1990, 2000, 2010. MJ concentrators are double junctions before 1995, and triple junctions after. MJ a-Si represents stabilized efficiency after extended light soaking (see Chapter 12). Data for 2000 and 2010 from independently verified Solar Cell Efficiency Tables (*Progress in Photovoltaics*, John Wiley & Sons, Ltd, UK)

cell researchers could use that already developed for microelectronics, sometimes off-the-shelf and sometimes with some minor modifications. Second, the silicon bandgap, of 1.1 eV, is almost optimal to make a good solar converter (see Figure 4.3 in Chapter 4). Furthermore it is very abundant, clean and nontoxic. Finally, Si solar cells are very stable, even without encapsulation.

However, Si has mechanical limitations (it is brittle) and optical limitations (it absorbs sunlight weakly), requiring relatively thick cells. Therefore, some of the electrons pumped by the photons to the conduction band have to travel distances of the order of the thickness, to be extracted by the front face through the selective contact (the one-way valve of Figure 1.2 representing the *pn* junction). Consequently, a good material with high chemical purity and structural perfection is required to fight the natural tendency of the conduction-band electrons to return to the valence band. To avoid this loss process, called *recombination*, the electrons must be highly mobile, as they are in perfect silicon. Impurities and imperfections must be avoided as they can absorb the extra energy of the conduction-band electrons, thus eliminating the free electron.

Metallurgical grade (MG) Silicon is obtained by reduction of quarzite (SiO_2) with charcoal in an arc furnace. PV only uses about 2% of the world production of MG-Si. Then it is highly purified, commonly by a method developed by and named after the Siemens Company, consisting of the fractional distillation of chlorosilanes, which are obtained from the reaction of a chlorinated source with Si. Finally, chlorosilanes are reduced with hydrogen at high temperatures to produce hyperpure silicon, usually called s*emiconductor grade* (SG) s*ilicon* or just *polysilicon* which has many random grains of crystalline Si, typically of about 1 mm. Methods to produce polysilicon or a lower-cost form called solar grade Si are described in Chapters 5 and 6.

In the past, the polysilicon was produced by about half a dozen factories for the microelectronic manufacturers. Today PV is the biggest user of this polysilicon and more new factories are appearing now specializing in solar grade polysilicon. The definition of this grade is the subject of controversy as some manufacturers obtain it as enhanced MG-Si with reduced impurities, leading to a cheaper material, but unable to make high-efficiency cells; others want to keep the high purity, even with higher cost, necessary for the higher efficiency. More about this debate can be found in Chapters 5 and 7.

By melting and recrystallizing polysilicon, the wafer producers grow either single mono-Si crystal ingots by the Czochralski (Cz) technique or cast multi-Si blocks (grain size about 1 cm). Both methods yield large solid blocks which must be sliced into wafers (150–250 μm thick). Conventional Si cells are made by diffusing the junction and screen printing the contacts. Mono-Si wafers produce cell efficiencies of about 16–17% while the multi-Si wafers produce cells of about 13–15%. Mono-Si wafers are necessary to implement the unconventional and higher-efficiency structures such as the HIT and IBC cells, both with champion cell efficiencies of over 20% (see Chapter 7 for details).

Wafering the silicon blocks implies kerf losses and a sizeable proportion (40%) of the expensive polysilicon is lost in "sawdust". To avoid this, sheets of silicon can be grown as "ribbons". However the cell efficiency is not quite as high as multi-Si. The same few factories making Si ribbon also integrate it into cells.

Most crystalline solar cells are fabricated from wafers by the screen printing technology that is described in Chapter 7. There are some exceptions, such as the IBC and HIT cells also explained in that chapter. The bigger cell factories integrate the crystal growth and wafering processes.

The mono-Si technology comes directly from the microelectronics industry and was the first to be used for solar cells. The multi-Si technology was developed specifically for PV to avoid the high costs of the Cz growth process. But it has not been able to clearly dominate the market because of the slightly lower efficiency. There is considerable research to develop processing steps to reduce the efficiency gap between mono-Si and multi-Si. Concerning ribbon, besides the low efficiency, the growth per cm^2 is slower than for wafers, leading to higher capital costs. The production of fast ribbon growth without losing efficiency is the desired goal, but it is difficult, in part because the ingot formation is also a purifying step that is incompatible, for physical reasons, with fast ribbon growth (Chapter 6).

Once the cells are manufactured they are assembled into encapsulated modules, as described in Chapter 7. This is done, either in the cell factories or in module assembly factories that purchase cells from a variety cell factories. Thus nearly identical Si cells can be bought from a variety of suppliers and integrated into modules. This is an important origin for double counting the module production in market studies (because the cell manufacturers may count all their cells as MW$_p$ produced and then the module manufacturer counts them again). This may cause discrepancies in the reports on manufacturing as well as in the breakdown between technologies (that are not very substantial).

A consortium of European Si PV companies and research groups (CrystalClear) has been collaborating on reducing the cost per watt of various Si PV cell technologies [53]. They established the cost structure for the current baseline standard multicrystalline Si module, called Basepower, averaging 2.1 €/W (2005 reference technology). Figure 1.13a presents the costs in terms of process step and Figure 1.13b is the cost in terms of manufacturing cost category.

The fraction of polysilicon cost (i.e. feedstock) is only ∼14%, but during 2008 (in the explosion of the Spanish market) a shortage of polysilicon caused its price to rise occasionally in the spot market to about 10 times its normal price (of about US$50/kg). The combined shortages and high prices of Si modules gave an opportunity to less-mature technologies, such as TFSC and CPV to find a place in the market. Not everyone was prepared to profit from this, but we think that the extraordinary success of First Solar (the world's biggest company in 2009) with its thin film CdTe modules is partially due to this unique opportunity.

Increasing efficiency, followed at a distance by reducing the polysilicon cost, are the main single drivers of cost reduction in Si technology. In this respect the appearance of such technologies as the IBC of SunPower and HIT of Sanyo, both able to produce wafer-sized cells of more than 20%, are very promising. It is not really known if they are more cost effective than conventional screen printed cell technology (still largely dominating). But in 2008 they became the ninth and

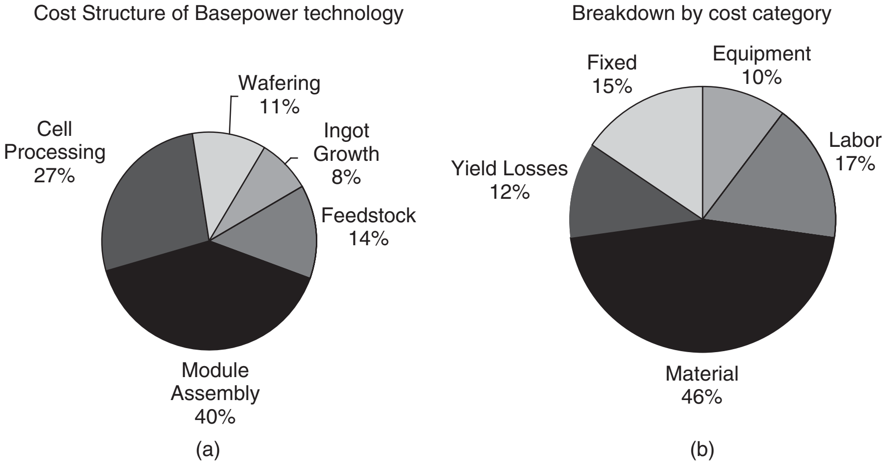

Figure 1.13 Breakdown of costs in the fabrication of a Si-wafer-based PV module. (a) The left-hand side is the percentage in terms of technical process steps; (b) the right-hand side is the percentage in terms of financial activities (adapted from del Cañizo *et al. Progress in Photovoltaics* 17, 199–209 (2009)). About half of the module assembly costs are materials

tenth largest solar cell manufacturing companies in the world, SunPower with 3% of world market and Sanyo with the 2.7%.

1.5.2 Thin Film Progress and Challenges

Why develop a totally different semiconductor technology for photovoltaics when Si is so well established? The simplest answer is in order to achieve lower cost and improved manufacturability at larger scales than could be envisioned for Si wafer-based modules.

The TFSC are based on materials that strongly absorb sunlight so that the cells can be very thin (1–3 micrometers). The electrons freed by the photons need to travel only this short distance inside the cell to the cell contacts (and from there to the external circuit to produce power). This reduces the demand for high purification and crystallinity of the material, one of the causes of the high cost of the Si cells. However, where the thin films have a real business advantage is that they are made directly into modules and not in cells. In other words, while Si cells are manufactured from wafers, then processed and assembled to form a module, in TFSC technology many cells are made and simultaneously formed as a module.

But there are disadvantages and in fact they have not yet dominated the market. We must understand why.

It was recognized almost as early as c-Si PV cells were developed in the 1950s that thin film semiconductors could make good solar cells. When fabricated into useful devices, they are so thin that they must be deposited on a foreign material, called a substrate, for mechanical support. This can be a glass and metal or a sheet of plastic, all of them of low cost (at least as compared with the self-supporting Si wafer). A framework for analyzing the material properties, device structures, device physics, and manufacturing issues unique to TFSC had to be developed since they differed considerably from Si wafers [54, 55]. Between 1981 and 82, four thin film technologies demonstrated the ability to cross the magical 10% efficiency barrier, thus becoming candidates for serious consideration: Cu_2S/CdS [56], a-Si [57], $CuInSe_2/CdS$ [58], and CdTe/CdS [59]. Of these four TFSC technologies, Cu_2S/CdS would soon be rejected for commercialization due to fundamental and fatal stability problems related to electrochemical decomposition [60]. In contrast, a-Si has a minor stability problem that, once stabilized, is predictable, reversible and seasonal, as discussed in Chapter 12. No fundamental stability problem has been found with $Cu(InGa)Se_2$ and CdTe modules, although they can develop unique degradation modes if not properly encapsulated. Consequently, significant industrial and government-sponsored research and resources have been directed worldwide at TFSC technology. This led to steady progress in champion cell efficiencies through the 1990s, as seen in Figure 1.12.

But the efficiency of TF modules is 25–50% lower than for Si modules which makes it difficult to translate the low cost per m^2 of TFSC modules to cost per W_p. This lower efficiency causes a higher area-related BOS cost when a TF array is installed, partially negating the natural cost advantage of TFSC, as discussed in connection with Figure 1.8b.

To obtain low manufacturing costs, TFSC plants must be operated at high volume throughput to offset the initial capital investment[5]. A detailed study of thin film module manufacturing options concluded that costs of current technologies would decrease 30–50% as the production facility increased from 25 to 200 MW per year [61].

The TFSC manufacturing process is designed such that they are deposited sequentially on moving substrates as in a continuous 'in-line' process or on many substrates at a time in a stationary batch process. This minimizes handling and facilitates automation, including laser scribing, to isolate and interconnect individual cells on the module, called monolithic integration. They are deposited at relatively low temperature (200–500 °C compared with ∼800–1450 °C for the different main processes of c-Si). TFSC are either polycrystalline with small ∼1 μm sized grains such as $Cu(InGa)Se_2$ or CdTe, amorphous like a-Si, or mixed amorphous/crystalline Si phases called nanocrystalline Si. The noncrystalline structure is a consequence of being deposited at temperatures too low and at rates too fast to allow perfect crystalline bond formation. TFSC typically consist of 5–10 different layers whose functions include reducing resistance, forming the *pn* junction, reducing reflection losses, and providing a robust layer for contacting and interconnection between cells. Some of the layers are only ∼20 atoms thick (10 nm), yet they may be a meter wide! This requires excellent process control.

Besides the lower efficiencies (so far), TFSC have a much less-developed knowledge and technology base compared with c-Si, and their properties are more difficult to control. Consequently, under-capitalized companies have had to struggle to develop not only an understanding of the materials and devices, but also the equipment and processing to manufacture them. The thin film PV industry has had to develop the technologies all by itself with considerably less financial resources than the Si PV industry had. They were not able to adopt a mature technology from the Si electronics industry. These factors can lead a purchaser to hesitate to buy a product that is less mature, and not so cheap (because of the small manufacturing volume), and thus to prefer the standard Si wafer-based product.

What are the strengths and remaining challenges for the TFSC industry? We will review the salient characteristics of the three leaders: a-Si, $Cu(InGa)Se_2/CdS$, and CdTe/CdS.

Amorphous Si (Chapter 12) is deposited from hydride gases such as SiH_4 using plasma to decompose the gas. This is called *plasma-enhanced CVD* (PECVD) and allows for large areas to be coated rather uniformly and with excellent control, using the same technology as large-area flat panel displays. The a-Si film has 1–10% hydrogen bonded to the Si, and is often designated

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[5] This is being proven by First Solar which has been manufacturing CdTe thin film modules for 10 years, achieving the lowest manufactured price per watt since 2008 (<1.00 $US/W), becoming the world leader in PV module production in 2009.

as *a-Si:H*. The H atoms passivate a large number of the defects resulting from the incomplete bonding of the Si atoms. The atomic structure lacks the long-range order of other crystalline or polycrystalline materials. This can be an advantage because the light absorption is increased with respect to c-Si. Films are typically deposited between 150 and 250 °C, the lowest temperature of any of the TFSC materials, allowing the use of lower-cost, low-temperature substrates. a-Si solar cells are deposited on glass, stainless steel foil, or plastic. The last two substrates are flexible allowing for "roll-to-roll" manufacturing where all the layers are deposited as the roll moves through their process zone. Nearly all a-Si modules contain multiple junction devices where two or three junctions are grown on top of each other. This allows for more efficient utilization of the sunlight. Increasingly, a nanocrystalline form of thin Si is being used as the low bandgap partner in making "micromorph" a-Si/nc-Si multijunction cells (Chapter 12, Section 12.5). The highest reported cell efficiency was 15% for a triple junction, which degraded to about 13% before stabilizing [62]. Micromorph modules 1.4 m^2 or larger are being reported with 8–10% stabilized efficiency, as discussed in Section 12.6, but standard products (not micromorph) are in the 5–7% range. The three major challenges for a-Si technology are: (1) to improve the standard module efficiency to 10–12%; (2) to minimize or eliminate the self-limited degradation which reduces efficiency by 2–3% (absolute); and (3) to increase the deposition rate of the layers and utilization of the gases, especially the nanocrystalline layer to allow faster, lower-cost manufacturing.

Polycrystalline layers of $Cu(InGa)Se_2$ (Chapter 13) alloys have produced the highest efficiency TFSC devices and modules. TFSCs based on $CuInSe_2$ (no Ga) achieved 12–15% efficiency, but were limited by the low bandgap. Alloying with Ga and/or S increases the bandgap and increases the efficiency of delivering the electrons to the circuit. While many deposition methods have been explored in the laboratory, there are two different processes under commercial development. Co-evaporation forms the alloy by simultaneous evaporation of the Cu, In, Ga, and Se from sources onto a heated substrate. The other process is called *selenization*, because layers of Cu, In, and Ga are deposited by a wide variety of methods onto a substrate, then heated in the presence of Se from a gas such as H_2Se or a Se vapor, thus contributing the fourth constituent of the alloy. A very active area of research is developing methods to incorporate these atoms and others into low-defect alloys to increase the bandgap even further.

Substrate temperatures typically reach 500–600 °C during some stage of the growth unless the substrate is a polymer, in which case 450 °C is the maximum. Substrates of Mo-coated glass are typically used although Mo-coated metal foils or plastic are in manufacturing. If sodium is not available from the substrate (diffusing from glass), it must be provided directly, either during or after deposition, to enhance electronic quality of the $Cu(InGa)Se_2$ and increase voltage. The $Cu(InGa)Se_2$ films are *p*-type, typically 1–3 µm thick and have crystallites or grains on the order of 1µm. The *pn* junction is formed by depositing an *n*-type layer of CdS, ZnO, or other new materials under development to replace the CdS (largely for "environmentally friendly" bragging rights). The highest reported cell efficiency is presently 20.0% [63] and several companies have limited manufacturing capacity (<20 MW) of modules with 10–13% efficiency. Transferring a high-efficiency small scale laboratory process on a stationary substrate to manufacturing on a large area moving substrate has proven more difficult for $Cu(InGa)Se_2$ than for a-Si or CdTe. The three major challenges for $Cu(InGa)Se_2$-related technology are: (1) to control the composition (Ga, S, Se, or Na) of the alloy through the film in a manufacturing environment on a moving substrate; (2) to find alternative junction partners to replace CdS; and (3) to find new alloys (with Ag, S, Te) or new deposition methods to give high-performance devices with higher-bandgap alloys.

Polycrystalline layers of CdTe (Chapter 14) have been investigated for photovoltaics since the 1970s. In contrast to limited process options for a-Si or $Cu(InGa)Se_2$, there are over 10 methods to deposit the CdTe films that have produced CdTe solar cells exceeding 10% efficiency. Four have reached precommercialization: spray pyrolysis (SP), electrodeposition (ED), vapor deposition (VD) and close-spaced sublimation (CSS). Some take place in liquid baths that are barely warm

~50 °C, with CdTe deposition rates of μm/h (ED) while others take place in vacuum systems at temperatures high enough to soften glass ~600 °C, with CdTe deposition rates of μm/min (CSS). There seem to be three critical steps, however, that all efficient CdTe solar cells require. First, they need a post-deposition anneal in the presence of Cl and O_2 at around 400 °C. This chemical/thermal treatment enlarges the grains, passivates the grain boundaries, and improves the electronic quality of the CdTe. Second, all CdTe layers need a surface treatment before applying a contact. This treatment can be a wet or dry process and prepares the CdTe surface by etching away unwanted oxides and leaving a Te-rich layer needed to make a low-resistance contact. Third, nearly all high- efficiency devices have a Cu-containing material somewhere in their CdTe contact process but again, there are many ways this can be achieved. Details of these three process steps tend to be very proprietary. Whichever process is used to deposit the CdTe, it has been found that the entire device process is highly coupled since processing steps strongly influence previous layers. This is partially due to the CdTe grain boundaries which act like paths for interdiffusion.

The *pn* junction is formed by first depositing an *n*-type layer of CdS on a glass substrate with a transparent conductive oxide contact layer (typically SnO_2) followed by the 2- to 8-μm-thick CdTe layer and appropriate chemical annealing. Once the solar cell is made, the CdTe films are slightly *p*-type with crystallites or grains of the order of 1 μm. The highest reported efficiency for a CdTe/CdS device is presently 16.5% [64] and modules are around 10–11%. Some CdTe modules have been in outdoor field-testing for over 10 years with negligible degradation. Of the three leading TFSC technologies, CdTe has surged into first place in terms of manufacturing capacity and lowest cost on the strength of a single company. The three key challenges are: (1) to better understand the various post-deposition optimizing treatments so they can be simplified and transferred into production; (2) to increase the output voltage commensurate with its bandgap; and (3) to maintain and evolve the safe and cost-effective Cd usage in the workplace, followed by recycling at the end of the module's life.

Technically astute investors know that other factors can be more important than efficiency in selecting a technology for development. This point is made obvious by examining the relative performance of the three major TFSC technologies – $Cu(InGa)Se_2$, CdTe, and a-Si – in Figure 1.12. Note that a-Si has always had the lowest efficiency. Yet, of the three, it was a-Si that was commercialized much earlier and more widely. This is partly because there has only been one generic deposition technology – PECVD – while CdTe and Cu(InGa)Se2 have a wide range of technologies, meaning each company must develop the unique process technology and equipment themselves. a-Si also had a stronger scientific research base, partly due to the other applications such as flat panel displays, which ensured that the relation between deposition conditions and fundamental material and device properties were well characterized, which comforted investors. In contrast, CdTe and $Cu(InGa)Se_2$ are "orphans" because they have no real application outside of photovoltaics. In 2008, Table 1.5 shows that a-Si accounted for about 4%, CdTe for 7%, and $Cu(InGa)Se_2$ still about 1%. Yet $Cu(InGa)Se_2$ has had the highest laboratory efficiency for two decades (Figure 1.12). This shows that translating research-grade champion cell performance into production modules coming off the production line day after day is a very challenging task. The phenomenal growth of CdTe is due to one company, First Solar, whose modules are among the lowest priced on the market. But it took them over 15 years of research and development with significant public and private investment to get there.

Conjecturing that the ideal PV technology would have some of the merits of c-Si (abundance, nontoxicity, stability) but be deposited as a thin film a few micrometers thick, several groups have tried to achieve the "best of both worlds" by developing thin films of multi-Si deposited on an inexpensive non-Si substrate. This is the subject of Chapter 11. At present, the best thin film multi-Si modules have the same efficiency ~10% as their $CuInGaSe_2$, CdTe, or a-Si based predecessors. This is partly because multi-Si thin-film photovoltaics also inherits some of the problems of both c-Si and thin films. In particular, passivation of grain boundaries and surfaces seems to be a major problem, yet many of the well-established passivation methods from c-Si are not applicable to multi-Si thin films due to temperature limitations ($<600\,^\circ$C).

There are new thin-film technologies such as the solid–liquid junction dye-sensitized (Chapter 15) and polymer-based organic (Chapter 16) solar cells that operate on very different principles than an all-solid-state solar cell. Their main attraction is the potential for very low cost. However, these fascinating new technologies present many new challenges, including strong sensitivity to air and water vapor, hence the need for excellent encapsulation. There are some private investment efforts to scale them to manufacturing.

1.5.3 Concentrator Photovoltaics Progress and Challenges

Concentrator Photovoltaic Technology or CPV is based on separating the area for collection of sunlight from its conversion. The collection area is an optical element, mirror or lens, which casts the light into a much smaller area of solar cells. This allows using high-efficiency but more expensive solar cells since the area of cells is >100 times smaller than the light collection area. The design and operation of CPV is described in Chapter 10.

PV technologists were aware of this possibility from the beginning of PV development. In general CPV needs sun-tracking systems that makes it unsuitable for small-scale applications of PV. There were attempts in the 1980s when Si solar cells were still too expensive and the markets were still too small.

The interest in CPV has spread in the last five years when MJ III–V-based solar cells, discussed in Chapter 8, developed for space applications, started to approach 40% efficiency, which they have already surpassed, as shown in Figure 1.12. CPV can take advantage of these ultra-high-efficiency cells, which are inherently very expensive, because the total cell area is reduced under high concentration, thus mitigating their high cost. Concentration levels of 500× (the cell is 500 times smaller than the optical aperture) are common with this technology and there is a trend to move towards the 1000× which presently operates at slightly less efficiency. Projected costs of such concentrator systems might be very small [65]. Concentration helps to increase the efficiency which theoretically increases as the logarithm of the intensity, until it reaches too high a value of current density, leading to ohmic losses that reduce the efficiency. Thus concentrator cells must be specially designed to have very low series resistance.

However, there are disadvantages. First, CPV does not utilize diffuse radiation, thus losing ability to convert at least 10% of the global radiation even in the best climates, and often much more. Second, at 500–1000×, CPV requires tracking the position of the sun very accurately every minute of the day which adds cost and complexity to the installation. Non-imaging optics is a new scientific tool that may soften this requirement. Third, the optical elements reduce the overall efficiency. Nevertheless module efficiencies of 30% have been presented at conferences and are about to appear commercially. Finally, CPV modules must be able to dissipate a significant amount of heat, leading to complex construction and reliability issues.

Another temporary issue is the rating. An array is usually formed by modules mounted on a tracking system, but only when mounted can the efficiency of the array be determined because the tracking itself affects the efficiency. Even in a good tracking system it varies in about 5% from second to second because of small misalignments, so that defining the kW rating of an array, and how to measure it, is not yet decided. Under these conditions the bankability of a concentrator system is still difficult to assess or guarantee. Nevertheless, under the silicon module shortage in 2008 the Spanish company Guascor Solar, with license of the American Amonix, installed over 9 MW of concentrators, being so far the first in installed CPV.

With the short learning curve in CPV, competing with the cheap Si modules from China, and to some extent with the cheap CdTe modules from First Solar, is very difficult. It will be necessary to demonstrate good credibility in performance at low installed prices to see this technology widely deployed. The recently created Institute of CPV systems in Spain (ISFOC), has subsidized the installation of 3 MW from seven companies (three from Spain, two from the USA, one from Germany and one from Taiwan) to provide accredited performance data to help gain this credibility and to establish the rules for measuring CPV performance.

Some think that they will be able to make a low-concentration system with Si cells that will beat in prices the complex high-CPV systems and the flat panel systems alike. As matter of fact the Guascor Photon sales have been obtained using highly efficient (∼25%) IBC-silicon cells, although they are moving now to MJ III–V cells.

So the result is that many companies, start-ups and established, are today involved in developing CPV options in the high and low concentration ranges. The next years will tell us about the success of these efforts.

1.5.4 Third-Generation Concepts

In 1961 Shockley and Queisser (SQ) published a paper [66] setting the thermodynamic efficiency limit[6] of a single-junction solar cell of about 40% under certain hypotheses that were thought to be fundamental and absolute. Cells based on principles that violate some of these hypotheses are called third- [67] or next-generation [68] solar cells.

The most studied (called by some revolutionary) third-generation solar cells [69] are: the Intermediate band solar cell [70] which discards the SQ hypothesis that photons below the bandgap are not absorbed, the multi exciton generation solar cell [71], which discards the SQ hypothesis that a photon can only pump one electron; and the hot carrier solar cell [72] which discards the QS hypothesis that the electrons are at the lattice temperature.

Some progress has been made in all three concepts since the first edition of this book, but a high-efficiency cell has not been produced with any of them. The 1st and 2nd generation solar cells used today have required decades to yield reasonably high efficiencies and a reliable manufacturing process. It will be the same with these new concepts. They will probably not be available to meet the 2030 challenge. Third-generation concepts may enable TFSC to operate with efficiencies above 20% or may permit achieving efficiencies of 50% in CPV cells permitting modules of 40%. To accomplish this, we will need detailed knowledge of these new fundamental concepts and more importantly how to integrate them into a functional device.

1.6 CONCLUSIONS

The human race is increasingly aware of the need for sustainable development. Solar energy is almost the only, and certainly the most developed way of producing energy for this sustainable development. This will be possible mainly through PV.

PV constitutes a new form of producing electric energy that is environmentally clean and very modular. It is highly appreciated by the public. It is unique for many applications of high social value such as providing electricity to people who lack it in remote areas. In recent years PV has experienced an unprecedented burst of growth. Today PV is a big business of around $US 50 billion

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[6] This limit applies to the individual cells in a MJ stack, but not to the stack as a whole.

worldwide and growing at ~50% annually. PV-powered homes, commercial buildings, and power plants have been built around the world. It has been recently shown (in Spain) that PV electricity can be installed five times faster than nuclear power plants and that a penetration of intermittent electricity of around 15% can be handled by the electric grids with positive environmental effects.

Common forecasts predict that PV electricity will contribute only a few percent by 2030. We have shown that there is easily enough land, raw materials, safety protocols, capital, technological knowledge and social support to allow PV to provide over 12% of our electrical needs by 2030. And we have to be much more ambitious for the future because PV has to become the biggest supplier of electricity by the end of the century. This will require finding new ways of energy storage.

The present PV development has been possible by the public support, driven by public opinion, which has led to governments spending substantial money to subsidize PV. However, this has not been a waste. It has been an investment. Today PV electricity is very close to grid parity. Thanks to this we predict that PV will continue to grow at a fast pace towards the 12% goal by 2030. Still strong political support will be necessary. And the promise of significant growth in employment – due to raw materials processing, module manufacturing, installation, and non-PV system components – is becoming a major driving force behind that political support.

PV possesses a panoply of novel technologies that ensure a continuous advance in the reduction of costs throughout the whole century. In this PV is unique compared with other energy technologies. Nations that want to lead this irrepressible movement will have to support it by investing in R&D, industry and markets.

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2

The Role of Policy in PV Industry Growth: Past, Present and Future

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2.1 INTRODUCTION

Recently, the photovoltaic (PV) industry has experienced phenomenal growth, with market demand expanding at an annual rate in excess of 40% [1, 2]. Technological improvements, increased economies of scale and manufacturing experience have allowed PV manufacturers to lower costs of production and, thereby, stimulate the market. But policy has been an equally important factor, and in some instances the most important driver of an industry boom (e.g. rapid growth in German and Spanish markets) that could rival global experience in computation and communications. Key policy instruments spurring PV's expansion include market and tax incentives (e.g. Feed-in tariffs, rebates and tax credits), regulations (e.g. renewable portfolio standards, new building codes requiring zero-energy capable operation, and solar energy mandates) and public research and development (R&D).

This chapter first provides a comprehensive review of policy strategies in key countries and markets and then offers a model to analyze and compare policy mechanisms to promote still wider and more rapid adoption of PV. With rising costs of conventional fuels and growing concern about carbon emissions from the energy sector, an even more rapid pace of PV's diffusion is likely to be needed if we are to address the challenge of sustainability [3–5].

2.1.1 Changing Climate in the Energy Industry

Over the course of the twentieth century, the energy sector became heavily dependent on fossil fuels and, recently, uranium for nuclear reactors. Although the share of fossil fuels (oil, natural gas and coal) in global energy supply has slightly decreased from 1980 levels (when they comprised 91% of worldwide commercial energy supply) by end of 2008 fossil fuels still supplied 87% of primary global energy (Figure 2.1). When nuclear energy is included, the conventional energy supply system is the source of 93% of current energy use. Due to high supply risks, volatile fuel

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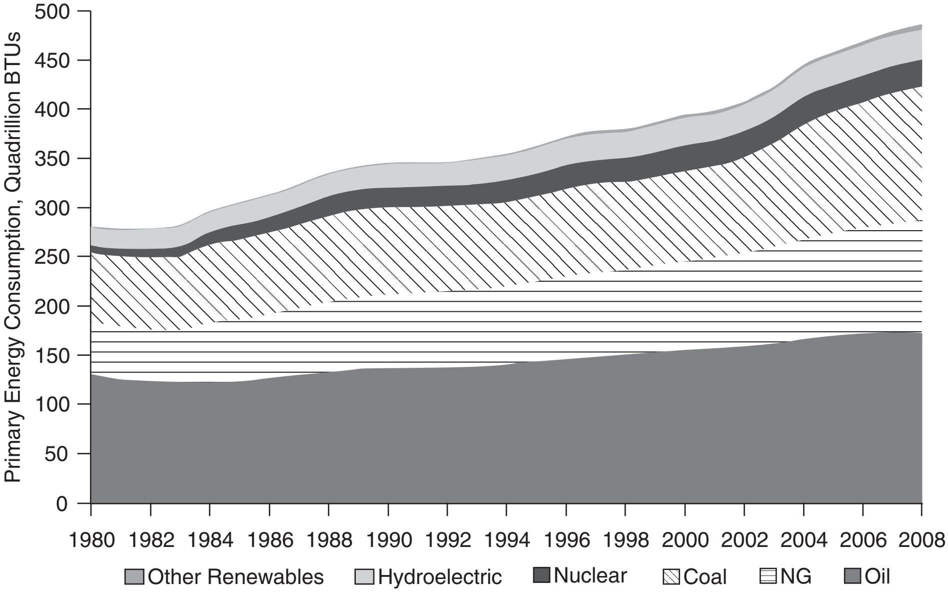

Figure 2.1 Global primary energy consumption. Data source [7]

prices and long-term environmental implications of fossil energy use, the existing energy supply structure is regarded by many as no longer viable [3, 5, 6].

For the last decade, energy prices for conventional power generation have significantly increased (Figure 2.2). Based on data from the US Energy Information Administration for 2000–2008, wholesale prices of residual fuel oil (No. 5 and 6 distillates) have increased by over 219% ($0.61/gallon to $1.94/gallon); the cost of natural gas used for electricity generation has increased by 113% (from $4.38/MCF to $9.35/MCF); the weighted average cost of uranium

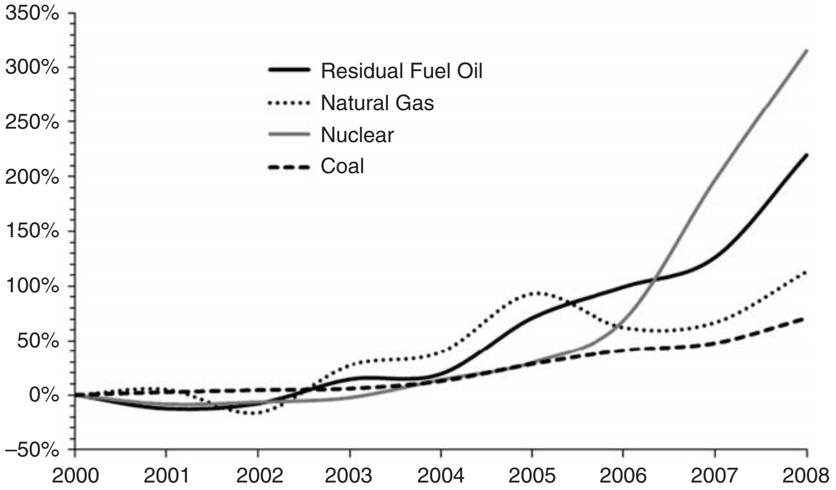

Figure 2.2 Energy price fluctuations for power generation in the US 2000–2008. Data source [9]

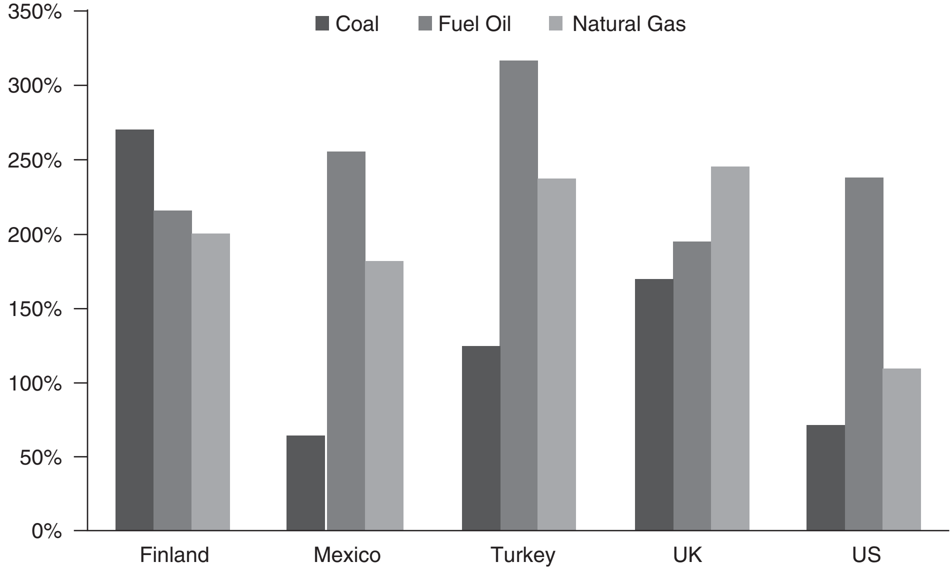

Figure 2.3 Percentage increase in energy price for power generation in selected countries, 2008 compared with 2000. Data source [10]

oxide (U_3O_8) used in nuclear power plants has increased by 316% ($11.04 to $45.88 per million pounds); and coal prices, despite being the least volatile, have also witnessed an increase of 72% ($27.5 to $47.4 per metric ton). Similar trends were also observed in other countries (Figure 2.3). In 2009, on the heels of the worst economic crisis since the 1920s, world oil prices fell, but only by about one-third of their peak 2008 value. Conventional fuel prices and downward pressure on material prices such as steel and copper resulting from the current economic crisis could reduce energy costs to end users in the short term, but the long-term trend is clear – conventional energy will cost more and, soon, much more [7, 8]. Higher conventional energy prices and the likelihood of significant fluctuations in the foreseeable future have made, and will continue to make, energy from PV power increasingly attractive.

Mounting concerns over global climate change and other environmental problems associated with conventional energy use are adding to the momentum to rethink the architecture of the energy sector. According to the IPCC [11], energy efficiency, changes in land use practices and wider adoption of renewable energy technologies are likely to be the principal tools to decarbonize the world economy (Figure 2.4). The baseline scenario in its 2007 assessment of mitigation options contains an IPCC forecast of 340 TW h of 2030 electricity generation, resulting in a decrease of 0.25 gigatons (GT) in CO_{2e} emissions. IEA's *World Energy Outlook* forecasts PV to provide 525 TW h or 2% of electricity demand under the 450 Scenario [7]. As discussed later in the chapter, these baseline scenarios can reasonably be surpassed, with as much as 25% of electricity needs supplied by PV, if the proper policy menu is embraced.

2.1.2 PV Markets

Over the last decade, the global PV industry has grown rapidly, faster than any renewable or non-renewable energy option. World PV annual cell production grew from 277 MW_p in 2000 to 6850 MW_p in 2008 (an annual average growth of more than 40%), reaching a cumulative worldwide

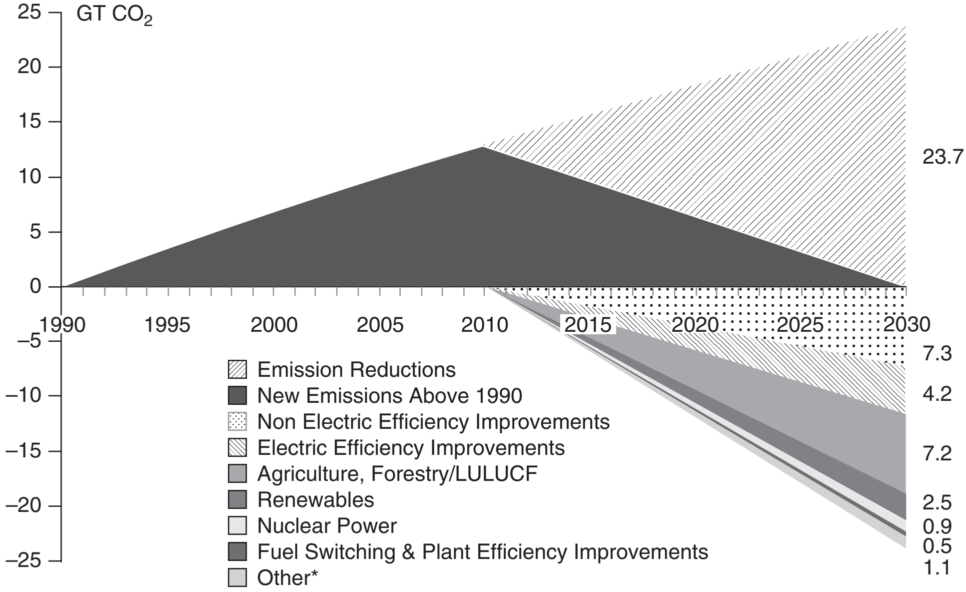

Figure 2.4 Potential GHG emissions avoided by 2030. * "Other" includes CO_2 capture and storage (0.4 GT) and improved waste management (0.7 GT). Data source: [11] (calculated by this chapter's authors based on information in the Fourth Assessment of WGIII)

PV cell shipment of over 19 GW_p at the end of 2008 (Figure 2.5). Japan, Germany and the US are traditional leaders in PV cell manufacturing. However, in recent years new players have emerged, especially China, which manufactured 2150 MW_p of PV in 2008 and became the largest PV producer in the world (followed by Germany (1510 MW_p) and Japan (1230 MW_p)).[1] The US has lost its standing as a manufacturer, producing only 430 MW_p in 2008, less than one-half of the output of Taiwan (865 MW_p). While Spain supplied less than 200 MW_p in 2008, its industry growth is expected to lead it past the US in the next few years [12, 13].

In 2008, annual new PV installations reached a record high of 5950 MW_p [17]. The major PV markets that have fueled PV demand and growth are Spain, Germany, the US, South Korea, Italy and Japan, which at the end of 2008 accounted for 41%, 31%, 6%, 5%, 4% and 4% of demand, respectively, while the "rest of the world" and the "rest of Europe" accounted for 5% and 4% respectively [17]. Although Germany is a leader in cumulative solar PV installations (5.3 GW_p), its annual installations of 1.86 GW_p is now second to Spain, with the latter installing an impressive 2.5 GW_p (up from 0.64 GW_p in 2007). Use of the technology in the US is much slower, reaching 0.4 GW_p (an increase from 0.2 GW_p in 2007) [12, 17]. At the end of 2008 it was estimated that cumulative global PV installations for power production reached 16.4 GW_p [2], with most of the installations occurring in industrialized countries (Figure 2.6).[2] While the cumulative installed capacity of PV reached a significant milestone in 2008, it is only a small fraction (0.4%) of the total global installed electric power generation capacity of about 4000 GW_p [18].

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[1] Nearly all of the PV cells manufactured in China are exported to other markets.

[2] Discrepancies between cumulative PV cell shipments and installations can be attributed to delays in installation after shipment. This can be significant under a fast growing PV market. According to industry analysts, on average there is a delay of two quarters between a module being shipped and its connection to the grid [132]. At the beginning of 2009, the industry had started with over 2 GW_p of inventory [21].

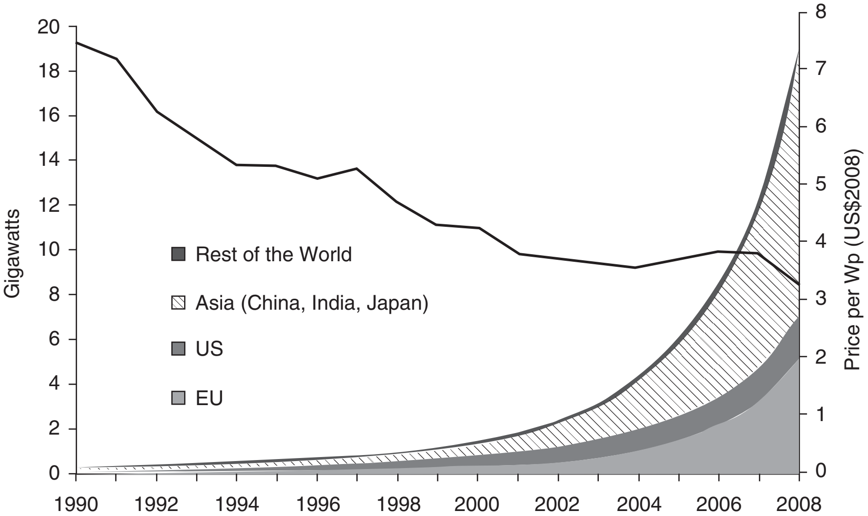

Figure 2.5 World cumulative photovoltaic shipments and retail prices (W_p) 1990–2008 (solid line = price per W_p). Data sources: [12, 14–16]

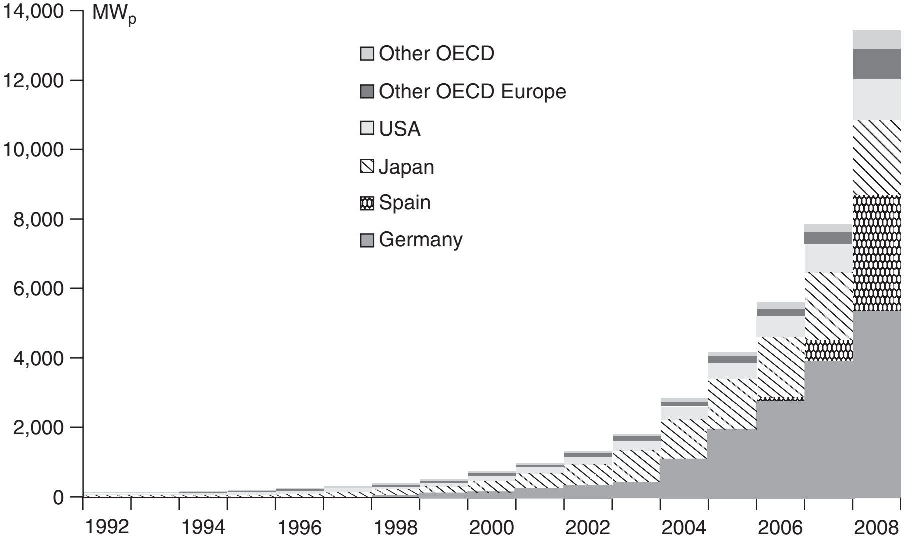

Figure 2.6 Cumulative photovoltaic installations in OECD countries 1992–2008. Data source: [12]

Until recently, upstream manufacturing improvements combined with downstream system integration experience served to drive down PV prices. However, since 2005 high demand for the technology led to a departure from this decade-long trend (Figure 2.5). A major contributor to the price increase was a shortage of polysilicon supply [19, 20]. Polysilicon historically sold at about \$35/kg, but since 2004, the spike in demand caused by PV market growth led to spot market prices above \$400/kg in 2008 [19, 21]. In response, a number of new polysilicon production lines were added around the world (particularly in China). As more suppliers enter the market, analysts expect polysilicon contract prices to settle at around \$70–80/kg [19]. Accordingly, module prices are expected to return to their historical downward trend by 2010.

2.2 POLICY REVIEW OF SELECTED COUNTRIES

Although significant cost reductions have been achieved, currently electricity produced from PV is not cost-competitive with conventional sources of generation.[3] National and local governments have supported PV deployment through a broad range of incentive, tax, regulatory and R&D instruments that include tax credits and exemptions, preferential interest rates and loan programs, direct incentives (e.g. performance-based incentives, capital subsidies), building code mandates, feed-in tariffs, renewable portfolio standards, voluntary green power programs, net metering, interconnection standards and "demonstration" or pilot projects [12, 22]. Policy leaders for PV deployment are Germany, Spain, Japan, South Korea and the U.S. Each country's national and, in some cases, local policies are reviewed below.[4]

2.2.1 Review of US Policies

In recent years, federal and state policies have facilitated strong demand for PV systems in the US. In 1998, the US had only 100 MW_p of installed PV capacity; ten years later, cumulative PV installations have reached 1.2 GW_p, of which 68% are grid-connected [12]. On the national level, the solar Investment tax credit (ITC) and modified accelerated cost recovery system (MACRS), a tax depreciation rule for PV and other capital equipment, have played key roles in reducing PV developer costs.

The ITC was first established in 1978 under the Energy Tax Act, which provided a tax credit of 15% of installed cost for solar energy installations. The Tax Reform Act of 1986 gradually reduced the ITC to 10%, and it remained at this level until 2005 [23]. The Tax Reform Act also introduced MACRS depreciation rules for commercial entities, allowing PV installations for the business sector to qualify for rapid 5-year tax depreciation. The Energy Policy Act of 2005 (EPAct 2005) increased the ITC to 30%. The Energy Improvement and Extension Act (EIEA) of 2008 removed the previous cap for residential installations (US \$2000) and extended the 30% ITC through 2016 [24]. In 2009, the American Recovery and Reinvestment Act (ARRA) allowed commercial entities to receive cash grants from the US Treasury for PV installations occurring in 2009 and 2010. Cash grants provide incentives for those businesses which do not have high tax obligations to fully utilize benefits of the 30% federal tax credit. ARRA also provided a bonus depreciation benefit of 50% for projects implemented in 2009 [25]. For business applications, the ITC and MACRS can reduce initial PV project development costs by more than 50% [26].

In addition to federal policies supporting PV deployment in the US, an increasing number of states have used two instruments to improve PV marketability. One is a policy called a renewable portfolio standard (RPS), in which load-serving entities (LSEs) in the electricity sector must provide a fraction of their electricity supply from PV or distributed renewable energy technologies (which also includes PV). By the end of 2009, 29 states and the District of Columbia had broad RPS mandates. Importantly, 14 states and the District of Columbia (Washington,

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[3] It should be noted that this comparison does not consider the relative subsidies for PV and its retail market competitors. When these are factored in, some analysts conclude that PV is very near to a market parity [19, 131]. If pollution and other external costs are included in the cost of conventional fuels, it is likely that PV is less expensive, at least over the long run [133].

[4] While China is the world's largest solar manufacturer, it mostly sells its production to overseas markets. This section focuses on policies to stimulate domestic use of PV and, for this reason, does not include China. Future editions of the *Handbook* will almost certainly need to profile China's domestic market which recently began to expand.

DC) had specific solar or distributed generation requirements for LSEs under their RPS laws. In addition, California, Oregon and Texas have created specific targets for distributed generation or PV unrelated to their RPS laws [25]. The second favored policy instrument among US states is net metering. Currently, 43 states and Washington, DC support net metering of PV electricity. Net metering allows customer-sited PV generators to offset electricity provided by the LSE with kW h supplied by their PV system [27, 25]. With net metering, electricity generated by PV is valued at the retail electricity price, providing additional incentive for PV deployment.

Historically, states and electric utilities have also supported PV deployment through rebate programs. In recent years however, support has begun to shift towards production or performance-based incentives. By early 2010, 29 states had production-based incentives embodied in utility obligations to purchase Renewable Energy Certificates (RECs). Sixteen of these states had solar electric sales mandates, which included either production-based incentives (viz. solar REC purchase obligations for utilities) or credits (applied to meet RPS mandates) [25]. Nevertheless two states, California and New Jersey, represented 67 and 9%, respectively, of the total US grid connected systems, and were the policy leaders in the country. Their approaches to market development have been successful, causing, for example, an increase in grid-connected PV installations between 2005 and 2008 of 208% (California) and 622% (New Jersey) [28–30]. The PV policies of these key states are reviewed below.

2.2.1.1 California

California has a long history of solar market development. In 1984, the Sacramento Municipal Utility District (SMUD) installed a 1 MW_p PV plant (PV1) – one of the first large-scale PV power plants in the world [31]. Over the past two decades, PV1 showed steady performance and it was gradually expanded, reaching 3.2 MW_p by 2004 [32]. In 1993, Pacific Gas and Electric Company (PG&E) installed a grid-connected 500 kW_p PV system (in Kerman) to serve peak power demand. Performance of the PV system demonstrated that PV output could reduce coincident utility load peaks [31–33]. More significantly, it demonstrated the value of PV to the utility in avoided costs that were comparable to the value of electrical energy itself [34].

In 1998 as part of California's electricity sector deregulation, financial incentives were created for renewable energy technologies under the California Energy Commission's Renewable Energy Program [35]. The initiative contained a special provision for "emerging renewables" which referred specifically to on-site generation technologies – primarily PV and small wind. From 1998 to 2004, the California Energy Commission's Emerging Renewables Program (CEC-ERP) offered rebates, which on average amounted to 40% of the installed price, to reduce (buy-down) the initial cost of the system. Beginning in 2005, the CEC-ERP offered participants the following options: (1) they could receive rebates amounting to 40% of installed costs; or (2) they could receive incentive payments based on actual system performance in the amount of 50 cents per kW h for three years [36, 37]. The CEC-ERP supported PV installations by customers of the three major investor-owned utilities (IOUs) serving the state PG&E, Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).[5] Under the program (which ended in 2006), PV system size was limited to 30 kW_p. By the end of the program, 120 MW_p of grid-connected residential PV had been installed (this includes projects started under the program and completed in 2007 and 2008) [38].

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[5] As with many jurisdictions in the US, IOUs are only one source of electricity supply. Customers may also receive power from so-called municipal or publicly owned utilities (utilities owned and operated by a governmental jurisdiction such as a city or incorporated region), electric cooperatives (suppliers owned by their customers which often are not subject to conventional utility regulation), and special federal authorities such as the Tennessee Valley Authority and the Bonneville Power Administration. IOUs serve approximately 97 million customers, while municipal utilities, cooperatives, special federal and state authorities together serve 40 million customers. Retail power marketers serve the remaining 6 million customers of the US [123].

In 2001 the California Public Utilities Commission created its Self-Generation Incentive Program (CPUC-SGIP). It was intended to complement the California Energy Commission's program[6] and provided incentives for PV installations exceeding 30 kW_p. By end of 2008, 135 MW_p of grid-connected PV systems were installed under this program [38].

These two policy initiatives were instrumental in promoting PV markets for IOU service areas. At the same time, a number of publicly owned utilities (POU) began developing policies to support PV installations within their service territories. Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP) were two major POUs pioneering PV use. As previously motioned, SMUD was one of the first public utilities in the world with a large-scale PV installation. Between 1998 and 2007, 11 MW_p of on-site PV was installed, utilizing a then-unique policy tool in which a SMUD citizen or business could elect to pay a higher electricity price and the utility would install, operate and maintain the system. This policy tool gave rise to a stream of new policies culminating in the property-assessed clean energy (or PACE) program in which electricity users voluntarily pledge an increase in their property tax assessments in order to retire the capital debt incurred by the installation of the PV system. This model is now being imitated across the US, and is the subject of national legislation [39, 40].

On August 20, 2004, California's governor announced the Million Homes Solar Plan which laid the groundwork for the 2009 Go Solar California campaign. Go Solar California aims to install an additional 3.0 GW_p of PV in the state within 10 years and is funded by ratepayers in the amount of $3.3 billion [41]. Go Solar California was launched in 2007 and includes two new solar incentive programs – the California Solar Initiative (CSI) and the New Solar Homes Partnership Program (NSHP). Residences that are served by publicly owned utilities (e.g. local municipal utilities) are not eligible for the CSI and NSHP programs. However, California now requires publicly owned utilities to offer an equivalent incentive program for their customers [42].

The CSI began in 2007 and led to the rapid installation of more than 130 MW_p in PV installations in one year (Figure 2.7). For 2007–2016, the CSI Program has a budget of $2.2 billion and a target of 1.75 GW_p of installations from the mainstream incentive program and an additional 190 MW_p from its low-income program (CPUC, 2008). Initially rebates stood at \$2.50/W_p for residential and commercial systems and \$3.25/W_p for government entities and the nonprofit sector. The incentive levels are scheduled to decline as the aggregate capacity of PV installations increases [25]. Installed and in-pipeline projects have already met 20% of the CSI target [38, 41].

The New Solar Homes Partnership Program provides funding for builders and developers who install PV systems on new, energy-efficient residential buildings that are served by investor owned utilities. NSHP is administered by the California Energy Commission. The program has a budget of $400 million and a goal of installing 400 MW_p of PV on new homes by 2016. This includes a 36 MW_p target for new low-income housing (California Energy Commission, [44]). Initially rebates range from \$2.50/W_p to \$3.50/W_p (for low income housing) and gradually decrease as PV installations increase [25].

The CSI and NSHP incentives are designed to stimulate rapid market demand while reducing incentive levels as the market for PV becomes viable. Depending on system size and customer choice, incentives are paid on a dollar-per-watt or cents-per-kilowatt-hour basis. The former is referred to as an expected performance-based buy-down (EPBB) incentive and the latter is called a performance-based incentive (PBI). EPBB is intended for residential and small commercial customers with systems less than 50 kW_p capacity. The incentive is in the form of a lump-sum, up-front payment. PBI is intended for large commercial, government and nonprofit customers. It is mandatory

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[6] The CPUC has regulatory authority over the IOUs serving the state, while the California Energy Commission has responsibility for long-term energy policy and planning with special responsibilities for the promotion of energy efficiency, conservation and renewable energy (see www.energy.ca.gov/commission/index.html).

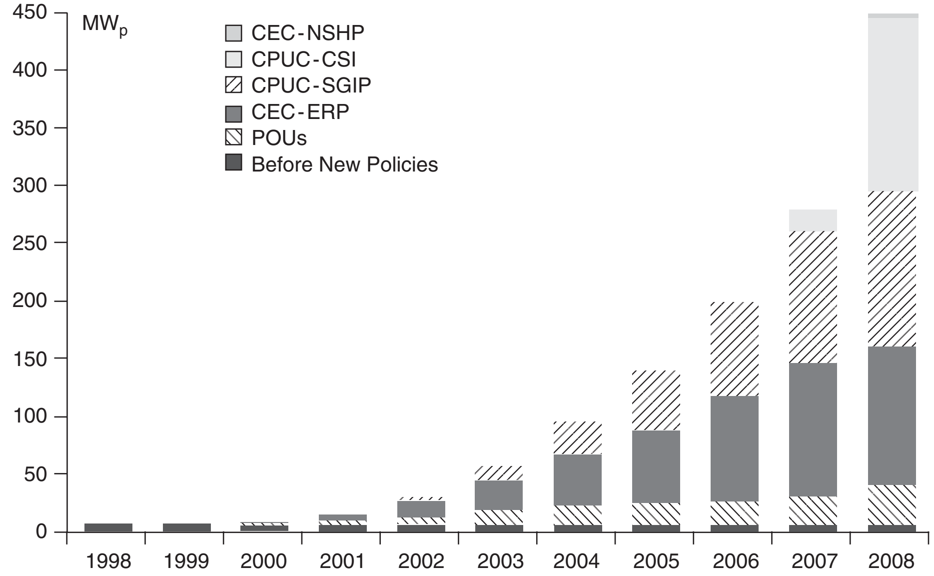

Figure 2.7 Cumulative grid-connected photovoltaic installations in California by policy, 1998–2008. Data source: [38]

for all systems greater than 50 kW_p capacity (systems less than 50 kW_p in size can opt in to PBI). The PBI program provides payments to PV users of 40–50 cents per kW h for five years. The incentive levels are scheduled to decline as the aggregate capacity of PV installations increases. Both incentives are performance based. In the case of EPBB, lump sum payments are predicated on a system's *expected* performance (factors include system AC rating, location, orientation and shading). This requires accurate and transparent predictive models. In the case of PBI, incentives are based on *actual* energy production and monthly payments are made during a 60-month period [42–44].

Energy policy innovation has been a hallmark of California for decades, and the promotion of PV use is no exception. The state hosts the largest PV capacity and greatest number of installations per capita of any US jurisdiction. Its policy tools have been widely adopted both in and beyond the country.

2.2.1.2 New Jersey

New Jersey has grown to be the second largest PV market in the US (by the end of June 2009, the state had 90 MW of installed PV systems). It was one of the first states to set specific targets for renewable energy sources in state electricity supply. In 1999 under the Electric Discount and Energy Competition Act (EDECA), a statewide renewable portfolio standard (RPS) was adopted and went into effect in 2001. A specific carve-out for PV was included which requires load-serving entities to procure 2.12% of electricity from PV by 2020. EDECA and the RPS laid the foundation for New Jersey's Clean Energy Program administered by the New Jersey Board of Public Utilities (BPU) [45].

From its launch in 2001, the Clean Energy Program (CEP) has directed significant funds for renewable energy development. Under CEP there were two initiatives supporting renewables: the Customer On-site Renewable Energy (CORE) strategy and the Renewable Energy Project Grants and Financing (REPGF) opportunity. CORE provided rebates for on-site renewable generation projects with less than 1 MW_p capacity. REPGF was to support development of so called Class 1 renewable energy resources (which includes PV, solar thermal electric, wind, geothermal, fuel cells, landfill gas recovery and sustainable biomass) larger than 1 MW_p capacity for power generation [45].[7]

CORE has proved to be instrumental for PV market development in the state. Initially it provided rebates from \$3.75/W_p (for 100–500 kW_p systems) to \$5.50/W_p (for systems less than 10 kW_p). Later rebates were gradually reduced as installations increased and prices fell [46]. Under the program, 70 MW_p of PV have been installed [47] and an additional 50 MW_p of PV systems have been approved for rebates. In 2009, the Clean Energy Program redesigned its incentive program based on the success of CORE. A Renewable Energy Incentive Program (REIP) was created with lower rebates, but aggressive pricing for "solar renewable energy credits" (see below). Under REIP, a residential customer can receive a rebate of \$1.75/W_p for up to 10 kW_p of installed on-site PV if the customer agrees to receive a free energy audit (the rebate falls to \$1.55/W_p without an audit). Nonresidential customers can receive \$1.00/W_p rebates for up to 50 kW_p of installed PV [48].

The backbone of New Jersey's solar policy is now its Solar Renewable Energy Credits (SREC) initiative. In a significant departure from its previous incentives, up-front capital incentives are being phased out, replaced by an emphasis on performance-based production incentives. In fact, the state intends to terminate all rebates by 2012 [49]. SRECs are tradable certificates that represent the clean energy benefits of electricity generated from a solar electric system. Each time a PV system generates 1 MW h of electricity, an SREC is issued that can then be sold or traded separately from the power. New PV projects and projects already in the CORE program queue are eligible to participate in the SREC program. However, starting in 2009 customers were required to forgo rebates to participate in the SREC program.

New Jersey has also adopted an 8-year Solar Alternative Compliance Payment (SACP) schedule intended to enable project financing for large PV systems without up-front rebates. Utilities are required to pay an SACP of \$711 per MW h if they do not meet the state's Solar RPS through the purchase of SRECs. The SACP schedule gradually declines, reaching \$594 per MW h in 2016 [25–49]. The high SACP rate (the highest in the US) has led to high market prices for SRECs. In May 2009, for example, the weighted average price for SRECs was \$500/MW h, much higher than in previous years when prices hovered around \$240/MW h [50]. Only SRECs from PV installed within the state can be used by utilities to comply with New Jersey RPS [51].[8]

As a result, the SREC initiative has spurred rapid growth in the state's PV installation rate, outpacing the experience of the state's earlier and quite successful CORE program (Figure 2.8). When given the choice between up-front capital incentives (REIP) and production incentives (SRECs), customers have shown an overwhelming preference for the latter.[9] This policy innovation is now being actively considered in many jurisdictions throughout the country.

2.2.1.3 Other states

While California and New Jersey are acknowledged leaders of US solar policy innovation, several other states also qualify as pioneers in this area. Table 2.1 identifies ten American states with the highest per capita PV installation rates by the end of 2008. Importantly this group includes not only "sunny" locations or large markets, but also smaller states (e.g. Delaware with a population

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[7] New Jersey has yet to build a PV project under the REPGF program.

[8] Across the US, policies regarding out-of-state SREC registration varies. At the beginning of 2010, New Jersey, and Maryland did not allow an out-of-state SREC registration, while Delaware, Ohio, Pennsylvania and the District of Columbia have accepted out-of-state SREC registrations [51].

[9] Customer support for the SREC approach may reflect the preference of solar project developers who reduce prices when SRECs are assigned to them. Because an SREC assignment for 8 years represents a predictable revenue stream, developers can sometimes find it easier to borrow needed capital from lending institutions.

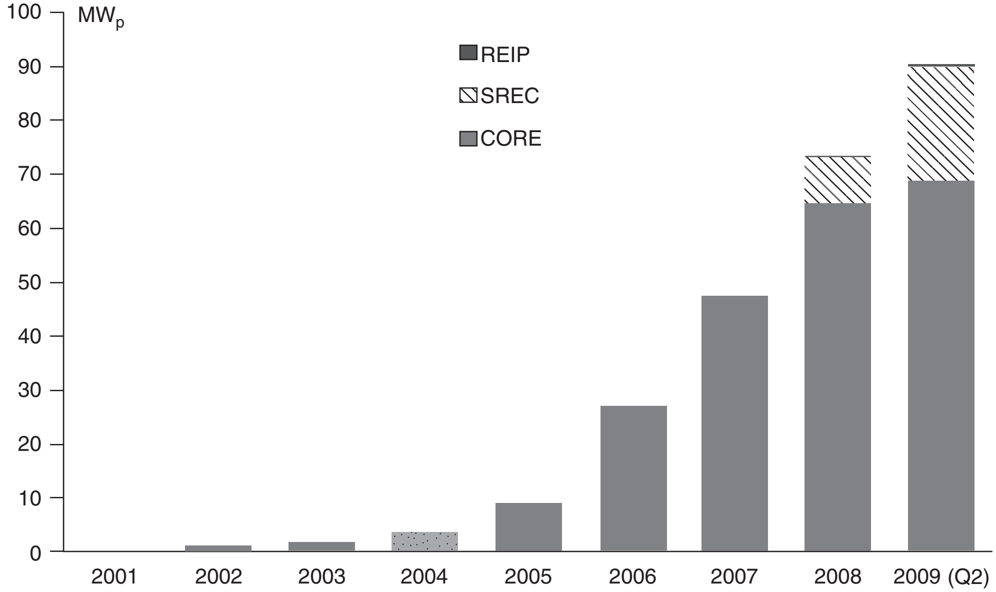

Figure 2.8 Cumulative grid-connected photovoltaic installations in New Jersey 2001–2009 (Q2). 2009 includes cumulative installations through second quarter (Q2) of 2009. Data sources: [52, 53]

Table 2.1 Top ten states by per capita capacity

	Per capita installed power in 2007 (W$_p$/person)	Per capita installed power 2008 (W$_p$/person)
California	9.1	14.6
Nevada	7.8	14.2
Hawaii	3.0	10.6
New Jersey	5.0	8.1
Colorado	3.1	7.7
Arizona	3.1	4.3
Connecticut	0.8	2.5
Delaware	1.4	2.2
Oregon	0.8	2.1
Vermont	1.2	1.8
National average	1.6	2.7

Data sources: [28, 29]

of approximately 900 000 residents) and those with above-average colder and cloudy days (Connecticut and Oregon). As the diversity of state leaders indicates, solar development is not necessarily driven by geographic, weather or insolation characteristics. Policy – both governmental and business – shapes how and how much PV is used. Four of states can be used to illustrate this point.

Nevada deploys PV on a per capita basis at the second highest rate in the country. The drivers for its performance are intersecting government and utility policy initiatives. The state was one of the earliest to create a carve-out provision in its RPS, requiring 1.5% of electric sales to come from PV by 2025. Having established an aggressive schedule for utility involvement in solar energy development, the state organized a Task Force on Energy Conservation and Renewable Energy [25] to design utility programs to spur the market. A rebate program was launched in 2004 providing \$2.30/W_p of PV installed on residences and small businesses, and \$5.00/W_p for public buildings [54]. In addition, the state's largest utility agreed to buy SRECs for 20 years from the 14 MW_p PV plant at Nellis Air Force Base, making the project profitable. The state also took the initiative of supporting a 12.6 MW_p thin film solar farm in 2008 and its private backers – Sempra and First Solar – were able to obtain a long-term power purchasing agreement with the California utility Pacific Gas and Electric. The project showcases the benefits of a public–private partnership, with installed cost at \$3.20/W_p which some analysts have suggested is comparable to grid power [55].

Colorado also illustrates the importance of public–private partnerships. With only a moderate carve-out target of 0.8% of solar from PV by 2020, the state nonetheless hosts the third highest installation volume among the American states [28]. Its market has grown because utility programming has attracted investors. The state's largest utility, Xcel Energy, initiated a Solar Rewards Program that includes a rebate of \$2.00/W_p coupled with an SREC purchase agreement for 20 years at \$55 per MW h. Other utilities have followed suit, pushing Colorado's installed capacity above 38 MW_p by the end of 2009 [25, 56].

While Nevada and Colorado can count on large markets and good to excellent insolation, a state like Delaware has neither. Yet, its progress in promoting solar development is impressive. In 2005, the state adopted one of the most aggressive carve-out targets in the country, by which 2% of sales must come from PV by 2019, and created incentives which cover approximately one-third of installed costs [25]. By the end of 2009, installations already surpassed the RPS target for 2011 [57, 58]. But a major driver in Delaware has been its creation of the country's first Sustainable Energy Utility (SEU). With capital from proceeds of the state's participation in quarterly carbon allowance auctions under the Regional Greenhouse Gas Initiative [59], the SEU has become the largest SREC off-taker in the initial production years of the 10 MW_p SUN Park in the state's capital, Dover. The SUN Park will be completed in 2011 and will be one of the largest solar plants built on the American east coast. The SEU's participation is a key reason for the SUN Park's favorable economics. The SEU's program for SREC pricing has stimulated additional projects in Delaware, including a 2 MW_p rooftop application as part of a two-phase 6 MW_p PV installation at the state's largest university [60, 61] and another 2 MW_p distributed application on four campuses of the state's community college. Completion of these projects will catapult Delaware to a leader on a per capita basis from its present ranking as eighth (Table 2.1). The rapid growth in Delaware's sustainable energy market received national attention, with a recent story in the *New York Times* complimenting the SEU for its innovative policies [62].

Another small state – Vermont – is advancing an innovative strategy for PV market development. In 2005, its legislature created the Clean Energy Development Fund (CEDF) with authority to invest in PV and other clean energy options. The CEDF offers a wide range of financing from grants to loans, equity investments and direct incentives [63]. So far, the Fund has underwritten approximately 1 MW_p of PV installations [63]. Additionally, 1.7 MW_p was installed under Vermont's Small Scale Renewable Energy Incentive Program [64]. Vermont has also created its own tax credit for businesses investing in solar systems which covers 30% of initial capital outlays. Together with US tax credit of 30%, the state has dramatically lowered the up-front cost hurdle for investors [25].

Each state has crafted policies and programs that seek to take best advantage of the particular market and social assets of their jurisdictions in order to stimulate rapid growth in the utilization of PV. While some may worry that such policy diversity may create market confusion, state initiatives in the US have proven to date to be the incubators of policy innovation creating the country's fast expanding demand for solar energy. Indeed, researchers have shown that state policy innovation has nurtured a powerful civil society commitment to sustainable energy which is effectively challenging the country's traditional energy policies [65].

2.2.2 Europe

2.2.2.1 Germany

Germany has more than a 25-year policy history of promoting PV use. In 1983, with government support, the first 4 kW_p grid-connected PV system in Europe was installed on the roof of an occupied residence in Munich [66]. Yet, the German PV market was still in its infancy, accounting for only 1 MW_p in cumulative installations in 1989. The German 1000 Roofs Measurement and Analysis Program, introduced in 1990 as a pilot, spurred interest in the technology and led to more than 2000 roof-mounted systems with a capacity of 5.3 MW_p in just 5 years [67]. Performance of these systems was extensively monitored by government and university researchers, which led to significant technical and regulatory improvements. Several federal- and state-funded programs followed, which furnished capital subsidies per kW_p of installed PV ranging from 25 to 50% of initial investment costs [66]. These programs provided the initial government stimulus for funding PV systems.

At the end of 1990, Germany adopted the world's first feed-in tariff (FiT). Under the law, electric utilities were required to purchase electricity from PV systems at a price equal to at least 90% of retail electricity rates [68]. The first feed-in rate was not sufficient to spark significant development of PV. In contrast, wind, which initially shared the same tariff as PV, increased its penetration in electricity supply from 0% in 1990 to 1% in 1998 [18]. Nevertheless, the feed-in law, in combination with the country's 1000 Roofs Program and local grant initiatives, created a PV market of 54 MW_p of installed capacity by 1998 – a tenfold increase in just 5 years [69]. This experience would set in motion a policy regime that has arguably proved to be the most successful in the world.

In 1999, the national government initiated the 100 000 Roof Solar Energy Program, providing 10-year, zero-interest loans with the final installment (10% of the principal) being waived. By end of 1999, nearly 4000 systems with a total capacity of 10 MW_p were installed under the program [66]. In 2000, the government adopted the Renewable Energy Source Act (RESA), which increased the feed-in tariff for PV sixfold (from US$ 0.08 to US$ 0.50) and required utilities to sign minimum contracts of 20 years for a system's output [70, 71]. The high feed-in tariff, long contract length, and favorable financing through zero-interest loans created a rush to install PV projects throughout the country. During the first 4 months, more than 70 MW_p of PV projects sought government and utility support [66]. This was more than the existing 69 MW_p of installed capacity accumulated since 1983 [69]; in other words, in four months the new policy had created demand for PV that had taken 17 years to realize under the old approach. The capacity was much higher than anticipated (the original plan was to install 27 MW_p by 2000) and the government put a temporary moratorium on applications, dropped the waiver provision for the final installment of the loan, and increased the loan interest rate to 2%. It also increased the target for new PV system installations in the first year of the program from 27 to 50 MW_p, and shifted by one year the program's final target of 300 MW_p from 2004 to 2003.

The 100 000 Roofs Program met its goal by the end of 2003. To maintain growth in the PV market, the government then created the Solar Power Generation Program, administrated by the KfW Promotional Bank [72], to continue its low-interest financing incentive. In 2004, the Renewable Energy Source Act was again amended, setting the feed-in tariff still higher, to between €0.54 per kW h (for systems larger than 100 kW_p) and €0.57 per kW h (for systems smaller than 30 kW_p) for building-based applications; and for ground-mounted systems, the feed-in rate was set initially at €0.46 per kW h [73].[10] The law required a decline in the tariff paid to PV system owners of 5% per year for building-based systems and 6.5% per year for ground-mounted systems. This

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[10] These rates in 2004 US dollars are equivalent to \$0.66–\$0.70 per kW h for building-based PV systems and \$0.57 for ground-mount edPV systems (see http://www.bankofcanada.ca/en/rates/exchform.html).

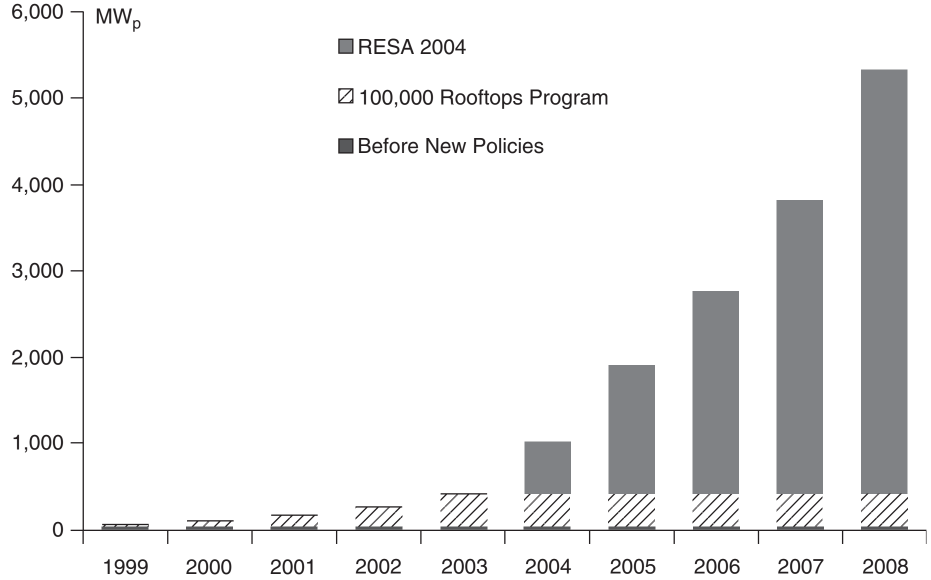

Figure 2.9 Cumulative grid-connected photovoltaic installations in Germany by policy, 1999–2008. Data sources: [12, 66]

reduction schedule applied through the end of 2008 (e.g. the 2008 feed-in rate paid to PV building system owners for applications smaller than 30 kW_p was €0.47.[11] The revised feed-in law created strong, sustained demand for PV in Germany and by the end of 2008 cumulative installed power reached 5.3 GW_p (Figure 2.9).

In 2009, the annual FiT schedule was again adjusted, with PV tariffs declining by 8% per year in place of the earlier 5% rate and the new rate applies to all systems less than 100 kW_p in size. For all ground-mounted applications and building-based systems greater than 100 kW_p, the tariff declines 10% per year. Beginning in 2011, the FiT is set to fall 9% per year for all systems. Additional adjustments may occur if actual annual PV installation rates grow faster than projections (Table 2.2). If the upper target is achieved early in a given year, the decrease in price will increase by 1%. Likewise, realization of the lower target will slow the FiT reduction rate by 1% [12, 74].

Table 2.2 German feed-in tariff reduction schedule: 2009–2011

	2009	2010	From 2011
Tariff reduction rate for small systems (<100 kW)	7% (<1000 MW) 8% (1000–1500 MW) 9% (>1500 MW)	7% (<1100 MW) 8% (1100–1700 MW) 9% (>1700 MW)	8% (<1200 MW) 9% (1200–1900 MW) 10% (>1900 MW)
Tariff reduction rate for large and ground systems (>100 kW)	9% (<1000 MW) 10% (1000–1500 MW) 11% (>1500 MW)	9% (<1100 MW) 10% (1100–1700 MW) 11% (>1700 MW)	8% (<1200 MW) 9% (1200–1900 MW) 10% (>1900 MW)

Data source: [12, 74].

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[11] Due to the decline in the value of the US dollar, this rate was *higher*, nearly \$0.74 per kW h, when valued in American currency.

Through a combination of low-interest financing and multi-year FiT pricing, Germany grew its market faster than any country had previously achieved and catapulted it to the top of the world's nations in installed PV capacity. This stunning achievement demonstrates the central role of policy in PV market development.[12]

2.2.2.2 *Spain*

Until 2004 Spain did not have a sizable PV market (2003 installed PV capacity stood at 12 MW_p [12]). In 2004, the country's law governing renewables [75] was amended establishing a new legal and financial framework for renewable energy applications. For PV systems with a capacity of less than 100 kW_p, a feed-in rate of 575% of the reference tariff for 25 years was created; any output after 25 years of operation would receive 460% of the reference tariff. The reference tariff was based on the national average electricity generation price.[13] For large systems (i.e. above 100 kW_p) the Spanish feed-in rate was set at 300%. The high FiT and the requirement that electric utilities purchase power from PV systems for a minimum of 25 years led to a rapid rise in PV installations.

By the end of 2004, PV installed capacity almost doubled, reaching 23 MW_p. In 2005 the Spanish government approved a new Renewable Energy Plan which established a national target of 400 MW_p PV installed by 2010 [76]. The announcement of the new Plan spurred even faster growth and by 2006 installed PV capacity had tripled from 48 MW_p in 2005 to 145 MW_p. Indeed, expansion of the Spanish market was so quick that the Plan target of 400 MW_p by 2010 was reached by the fall of 2007. The government promptly increased its target to 1200 MW_p [77]. In 2007 by

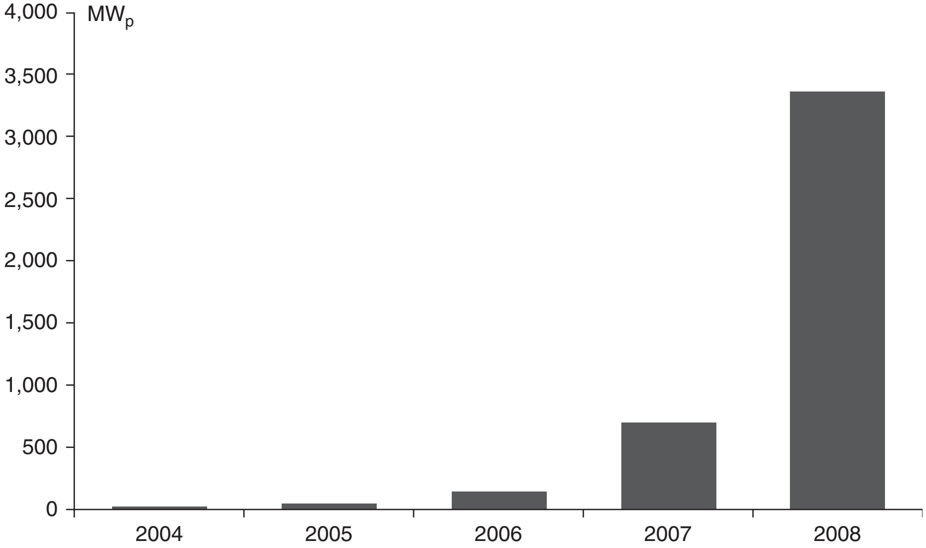

Figure 2.10 Cumulative grid-connected photovoltaic installations in Spain 2004–2008. Data source: [12]

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[12] The importance of policy applies more generally to renewable energy as the German case confirms. The country has employed its FiT and financing approaches to wind, solar hot water and biomass markets with similarly impressive results, making Germany the leader in newly installed capacity in all of these markets [71].

[13] In 2004, the average price in Spain was 7.24 Euro cents per kW h or 9.0 US cents, making the PV FiT equal to nearly 52 US cents for 25 years.

Royal Decree 661, the government modified the FiT structure for PV systems: small systems (less than 100 kW_p) receive €0.44 per kW h; a new category of system size with a range of 0.1–10 MW_p, receives €0.42 per kW h; and large systems (10–50 MW_p) receive €0.23 per kW h. All contracts are for a minimum of 25 years [78].[14]

In 2008, Spain's PV market experienced even higher growth, increasing installed capacity fivefold, to 3.4 GW_p of installed capacity, second only to Germany [12]. The extremely rapid rate of installation within one year created significant financial pressure on ratepayers [77] and distorted world PV module pricing. In September 2008, Royal Decree 1578 set new feed-in tariffs for PV systems installed after September 29th of 2008. Under the new tariff structure, roof-mounted systems smaller than 20 kW receive €0.34 per kW h for 25 years. Roof-mounted systems larger than 20 kW_p and ground-mounted systems receive €0.32 per kW h.[15] The decree also capped the size of systems receiving FiT support at 2 MW_p for roof-mounted and 10 MW_p for ground-ounted systems. Total new installations receiving FiT support are limited to 500 MW_p in 2009, 502 MW_p in 2010 and 488 MW_p in 2011 [79] (Figure 2.10).

2.2.3 Asia

2.2.3.1 Japan

Japan has a long track record of supporting PV system deployment. In 1992, the government started the PV Field Test for Public and Other Facilities Program, which led to the installation of 4.9 MW_p of PV on public buildings such as schools, hospitals, clinics and government offices by 1997 when the program was ended. In 1997, the Japanese government through its Ministry of Economy, Trade and Industry (METI) initiated the Residential PV System Dissemination Program, managed by a government-created New Energy Foundation (NEF).[16] The program was instrumental in promoting rooftop PV technology in Japan. Initially, subsidies covering 50% of installed costs were provided to residential customers, with the subsidy rate declining as system costs fell [80]. The program was closed in 2005 after resulting in 932 MW_p of installed PV capacity. This was nearly two-thirds of the total installed capacity of Japan [81, 82]. The government concluded that the program was no longer needed because market mechanisms were sufficient to drive growth [81].

In 1998, Japan initiated a Field Test Project on Photovoltaic Power Generation Systems for Industrial and Other Applications, which led to a total of 18.1 MW_p of PV installations by the time it ended in 2002. A successor program titled the Field Test Project on New Photovoltaic Power Generation Technology has led to 62 MW_p, of industry-scale installed PV [83]. The purpose of the latest field testing program is to promote medium- and large-scale PV systems, with 50% of the system cost subsidized by the government.

The government has now folded its PV promotion efforts into a broad action plan to create a low-carbon society. Under the plan, 70% of new buildings are to have PV systems on their rooftops [84]. The plan sets aggressive goals for PV installation of 14 GW_p by 2020 and 53 GW_p by 2030 [12]. In addition to the national programs, up to 300 local governments have announced programs to support of PV installations. One of the largest programs was announced by the Tokyo Metropolitan Government, which is supporting the installation of about 1 GW_p of PV systems on homes and apartment buildings by 2010 [12. 84]. In addition, electric utilities have announced plans to build 30 centralized PV power plants with a total capacity of 140 MW_p by 2020 [12] (Figure 2.11).

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[14] In 2007 US dollars, these FiT rates are $0.60, $0.57 and $0.31 per kW h.

[15] In 2008 US dollars, these FiT rates are $0.63 and $0.50 per kW h, respectively.

[16] The program began as the Residential PV System Monitor Program in 1994 [81].

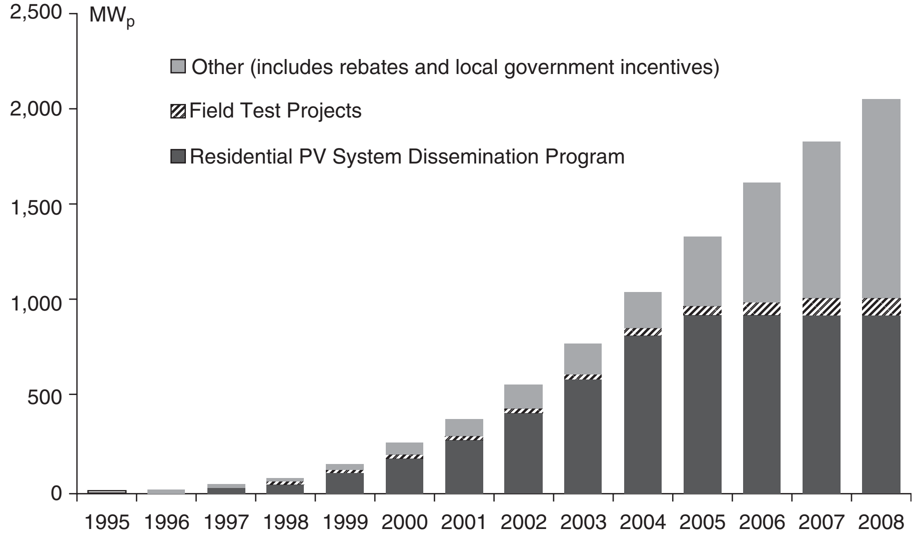

Figure 2.11 Cumulative grid-connected photovoltaic installations in Japan by policy, 1995–2008. Data sources: [12, 81, 83, 85–87]

2.2.3.2 South Korea

Since 1993, South Korea's Ministry of Commerce, Industry and Energy (MOCIE)[17] has been responsible for implementing PV demonstration and field test projects. However, results were meager – by 2004 less than 10 $\mathrm{MW_p}$ of PV systems were installed, half of which were off-grid applications (12). In December 2003, the Korean government announced a goal of meeting 5% of total energy consumption from renewable sources by 2011. For PV, a goal of 1.3 $\mathrm{GW_p}$ in cumulative installed capacity was set for 2012 and 4 $\mathrm{GW_p}$ by 2020 [88]. Following this announcement, growth in the PV market was significantly accelerated.

Successful programs include a rooftops initiative in which the government initially supported 50% of the installed cost of 1–3 $\mathrm{kW_p}$ PV installations in the residential sector, hoping to reach its target of 100 000 rooftops by 2012 [89]. In 2008, the government adopted a national plan to construct one million green homes and 200 green villages by 2020. For this task the government provides 60% of the initial PV system cost for single-family and private multi-family residences, and covers all initial costs for public multi-family rental buildings [12].

The government further supports PV development in the public sector through its General Deployment Program and Public Building Obligation Program. The Program serves schools, public facilities, and universities. Under this program PV systems from 5 to 200 $\mathrm{kW_p}$ are installed with government funds covering up to 60% of the installation cost. Under the program, new public buildings larger than 3000 $\mathrm{m^2}$ must spend 5% of their total construction budget on renewable energy system installations [89, 89].

These programs targeting public buildings and residential sector have played important role, but the major driver for the recent significant expansion of PV installations in Korea is a newly adopted feed-in tariff policy. Feed-in tariffs are paid for 15–20 years at 700 Korean Won per kW h.[18] By the

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[17] The name of the ministry was recently changed to the Ministry of the Knowledge Economy (MKE).

[18] In 2008 US dollars, this FiT rate is equivalent to \$0.68 per kW h.

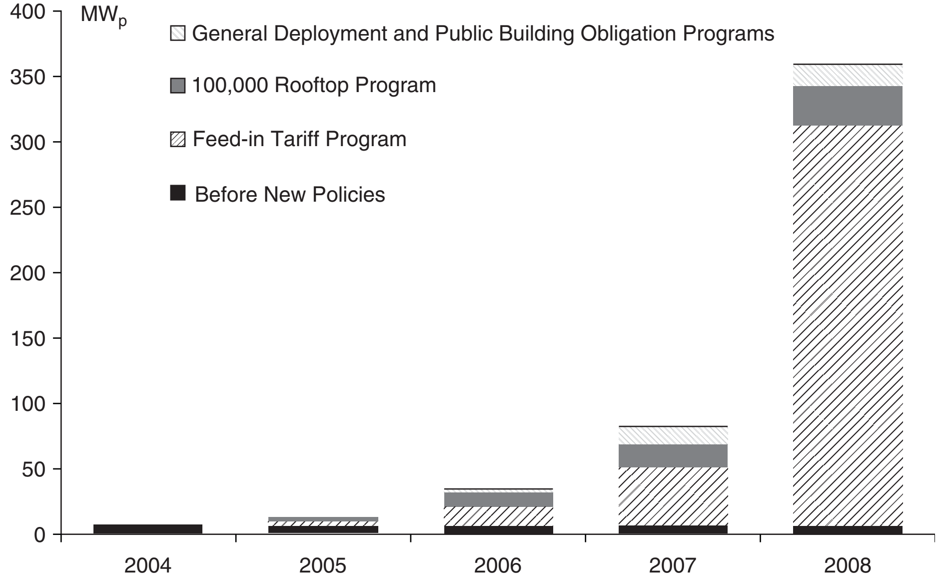

Figure 2.12 Cumulative grid-connected photovoltaic installations in Korea by policy, 2004–2008. Data sources: [12, 88–91]

end of 2008, approximately 300 MW_p of systems were installed under this scheme, 90% of which are larger than 100 kW_p in capacity, reflecting the very high percentage of residential, public and commercial buildings that are more than ten stories [12]. Beginning in 2012, the government intends to replace its feed-in tariff system with renewable portfolio standard scheme [90] (Figure 2.12).

2.3 POLICY IMPACT ON PV MARKET DEVELOPMENT

The US, Germany, Spain, Japan, and South Korea are the leading markets for grid-connected PV. By the end of 2008, the combined PV installations in these five countries stood at 12.4 GW_p, representing more than 90% of cumulative PV installations in the OECD bloc [12]. Review of PV deployment experience in these countries underscores the significance of policy in market development, market growth, and technology diffusion. It also enables us to identify policy effectiveness by the types of tools employed by this group.

Initial drivers of PV deployment in the US, Germany, Japan and South Korea were programs targeting small-scale installations in the residential sector. Germany and South Korea supported PV through their solar rooftop programs and Japan used its Residential PV System Dissemination Program to promote this sector's use of the technology. Likewise, California implemented its Emerging Renewables (CEC-ER) program, which supported PV installations in the residential sector. In order to achieve modest market start-up, these programs found that subsidies of 50% or higher of initial system costs were needed. Despite major differences in housing stock, these programs were able to launch small PV markets in the residential sector.

After initial success of PV deployment programs targeting small-scale residential applications, Japan, South Korea and the US supported programs with similar designs for their commercial

Table 2.3 Cumulative R&D spending in selected countries (in millions of US$ 2008)

	1975	1980	1985	1990	1995	2000	2005	2008
Japan	12	49	403	726	1029	1459	2095	2268
Germany	42	278	633	1006	1405	1680	1909	2073
US	8	812	1568	1872	2332	2739	3160	3469

Data sources: US data for 1991–2008 was provided by Robert Margolis from NREL. Data for Japan and Germany, for 1975–2008 and US for 1975–1990 was obtained from the IEA Database [92].

and public buildings sectors. Here again, market development was modest, but steady. An important contribution of these programs was the confidence they built in the technology.

The policy history of these countries shows a marked shift in the last 10 years away from investment incentives and toward production-based approaches. Feed-in rates and tradable solar renewable energy certificate (SREC) schemes are the preferred policy tools in this period. Germany, Spain and South Korea have implemented feed-in laws, which have triggered significant market growth. Amendments to national FiT schemes have ensured a wide array of market applications (commercial, industrial, and public as well as residential uses) and technology configurations (e.g. thin film as well as silicon; ground-mounted as well as roof-mounted). In the US, New Jersey has shown an ability to replicate the fast growth of FiT strategies with its vibrant SREC market approach, and California has used production-based Incentives to quickly grow its Go Solar Initiative. It can be expected that production based incentives will gain more prominence through SREC trading in the US and other countries (e.g. South Korea is planning to implement an RPS scheme in 2012), and through the use of solar carve-outs in national target-setting for renewable energy use.

Financial assistance of PV deployment projects is crucial for wider adoption of this technology. However, it is also important to have strong government support for research and development (R&D). Indeed, the governments of Germany, Japan and the US have provided significant R&D funding over the last 25 years (Table 2.3).

R&D expenditures have enabled countries to spur improvements in technology performance and, thereby, reduce user costs. As we will show in the following section, this factor is very important for the goal of building a policy strategy for a *long-term* sustainable PV market.

Direct government incentives, whether capital or performance based, combined with R&D funding have played a major role in PV cost reduction. An Important analytical question is to what extent direct government incentives, combined with R&D funding or other policy tools, such as carbon taxes, can impact future adoption of PV. In the following section, we describe the methodology for conducting such an analysis, and then we show concretely how different policy tools affect PV diffusion paths over the short and long term.

2.4 FUTURE PV MARKET GROWTH SCENARIOS

2.4.1 Diffusion Curves

The evolution of technology has been the focus of research for a long time. A prominent view holds that technology evolves in three phases: invention, innovation and diffusion [93]. Invention refers to the initial development of a scientifically or technologically innovative process or product while innovation refers to the point when the new product or process reaches the market. Diffusion is the final stage in this evolution, and is the focus of this section. It refers to the process of dissemination through which successful innovations come to be widely available through the adoption by individuals and/or firms (Schumpeter, 1942, quoted in [93]). While the three stages of invention, innovation and diffusion are described sequentially, in actual practice there is a cyclical relationship between them. In this regard the role of feedback arising from diffusion, including second- or third-generation invention and innovation is important [93].

An interesting aspect of diffusion of innovation is the fact that not all potential buyers make the decision to invest in a product or process at the same time. Adopters can be categorized into five types based on personality and behavior, values and attitudes [94–96]. They include "innovators" who constitute about 2.5% of adopters; "early adopters" who constitute about 12.5–13.5% of adopters; "early majority" who constitute about 34–35% of adopters; "later majority" who constitute 34–35%; followed finally by the "laggards" who make up the remaining 15–16% of adopters [94–96].

Rogers [94] also proposes general characteristics for each adopter category, based on socioeconomic, personality and communications behavior. For instance, the "innovators" and "early adopters" tend to display characteristics such as more years of education and greater knowledge of the technology. This view has been modified by the argument that adopters who are "innovators" for one product, could be "laggards" for another product. This point underscores the importance of compatibility of a product, for instance photovoltaics, with the lifestyles, attitudes and values of potential adopters.

A useful addition to the diffusion of innovations theory is the idea of a "chasm" between the "early adopters" and the "early majority". The entry of the early majority in the market is critical to the commercial viability of a product or service. Unlike the "innovators" and "early adopters" this "early majority" is unlikely to take the long-term view and put up with inconveniences and product complexity. The incorporation of innovations, product enhancements and other "attractive" features, often based on feedback from early adopters is required to win this segment over [97].

Nature, markets and technologies experience growth patterns which are usually confined by some limits. These limits could be the size of the potential market, as in the case of technological innovations, or an ecosystem's carrying capacity, as in the case of animal and plant populations. The graphical representation of this type of growth resembles an S-shaped curve [98]. The diffusion of innovations, i.e. growth in the market for innovations, such as photovoltaics, computers or cellular phones, has also been found to follow an S-shaped or logistic growth curve [99, 100].

Logistic growth models have proven to be accurate tools for forecasting a wide range of phenomena, from human population growth (used by the Belgian mathematician Pierre Verhulst in 1838) to oil development [101, 102]. Often, technologies (e.g. computers or cell phones) grow exponentially during an initial phase. However, as a device eventually reaches saturation in the potential market, the rate of growth is seen to slow down and finally taper off. This methodology is commonly used to anticipate the entry of new technology [98, 103, 104], including new energy technologies [105, 106] (Figure 2.13).

A logistic growth curve, according to Laherrère [102] and Meyer *et al.* [98], can be represented by the following equation:

$$Q_t = \frac{U}{1 + e^{-b*(t-t_m)}} \tag{2.1}$$

where Q_t is the forecast variable (e.g., percentage of electricity supply by PV in a given year), U is the saturation (maximum) level for Q_t (e.g. maximum percentage of electricity supply assumed to feasibly come from PV), b is the slope term, reflecting an initial growth rate, t is a time variable (in years), and t_m represents the midpoint of the logistic curve.

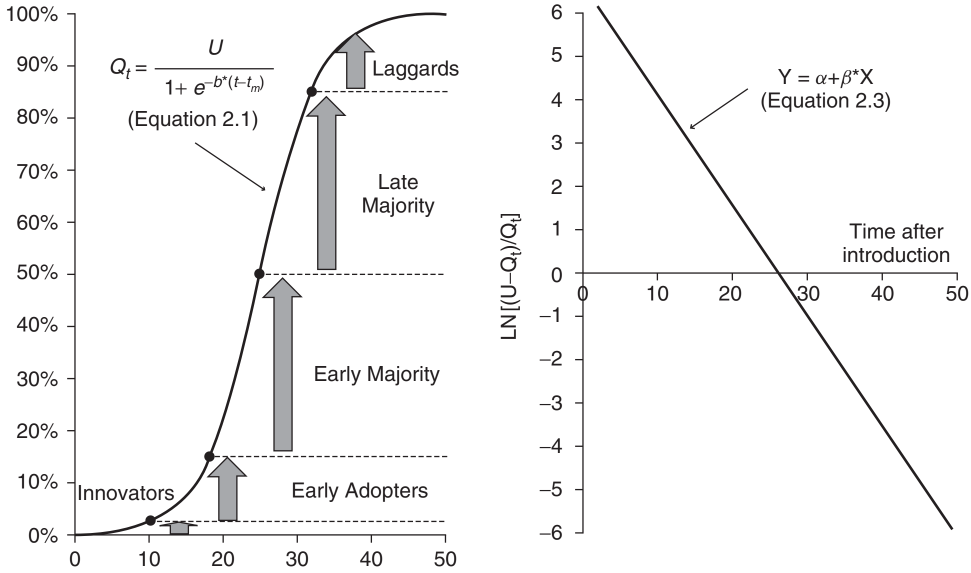

Figure 2.13 Representation of technology diffusion by an S-shaped curve and its linear form

Rearranging terms in Equation (2.1) and taking the logarithm of both sides gives:

$$\ln\left(\frac{U - Q_t}{Q_t}\right) = -b * t + b * t_m \tag{2.2}$$

Grouping variables, we then obtain:

$$Y = \ln\left(\frac{U - Q_t}{Q_t}\right)$$

This yields the familiar linear equation:

$$Y = \alpha + \beta * X \tag{2.3}$$

where $X = t$, parameter $\alpha = b^* t_m$ and parameter $\beta = -b$.

Applying statistical regression methods to Equation (2.3), the parameters α and β can be robustly estimated.

Noting that $t_m = -\alpha/\beta$ and $b = -\beta$, Equation (2.1) can be presented as:

$$Q_t = \frac{U}{1 + e^{\beta\left(t + \frac{\alpha}{\beta}\right)}} \tag{2.4}$$

Equation (2.4) and the linear regression method used to estimate parameters in Equation (2.3) are consistent with the classic Fisher–Pry form of a logistic growth curve widely used to model technology diffusion [103]. In this way, a forecasting model can be built on available empirical experience to date for the technology of interest (PV, in this case). A key factor in the diffusion of new technology is cost-competiveness with its alternatives. At the initial phase, technology diffusion can be supported through government programs and incentives. However, for wide-scale adoption the technology should have an advantage over other alternatives and at least be cost-competitive.

The link between technology diffusion and technology cost trends can be characterized through experience curves described in the next section.

2.4.2 Experience Curves

Experience curves, also referred to as learning curves, describe the link between long-term cost trends and adoption rates for new technologies. In 1936, Wright [107] was the first to provide a mathematical representation of the experience curve [108, 109]. Since then experience curves have become a helpful tool for analysts to assess trends in the cost-competitiveness of different technologies [110–115].

Experience curves are typically used for long-term strategic rather than short-term tactical analysis. But in the formulation of competitive strategies, experience curves can be powerful instruments to model market development of innovations [114]. According to Neij [110], experience curves offer a means of projecting future cost trends based on past cost developments.

Figure 2.14 provides a schematic representation of an experience or a learning curve for PV on double-logarithmic scales. On the horizontal axis is the cumulative installation of PV systems; on the vertical axis is system price per W_p.[19] As cumulative installations of PV systems grow, so do the producers' and installers' experiences, leading to reductions in manufacturing and deployment costs. Mathematical representation of this relationship can be expressed as [112]:

$$C_t = C_o * \left(\frac{n_t}{n_o}\right)^{\beta} \tag{2.5}$$

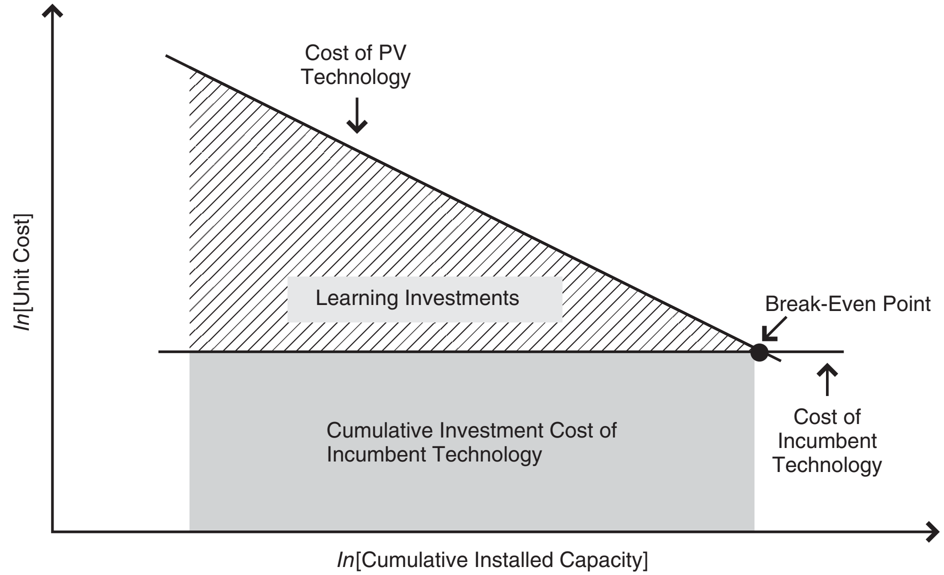

Figure 2.14 Schematic representation of learning curves and learning investments. Adapted from [116]

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[19] System price is the installed cost of a system including the PV device, balance of system (e.g. inverters, wiring, and panel array structure) and labor and other installation costs, as well as rates of return to the manufacturers and installers.

where C_t represents the expected cost at an n_t cumulative production level at some time in the future. C_o is the known cost of the product or installation at the initial phase of product deployment. Typically, C_o is calculated when cumulative production $n_o = 1$ (e.g. 1 $\mathrm{MW_p}$ or 1 $\mathrm{GW_p}$). The exponent β is very important in characterizing the rate of price decrease as discussed below. In logarithmic form, Equation (2.5) can be written as:

$$\ln(C_t) = \ln(C_o) + \beta * \ln(n_t) \tag{2.6}$$

This yields the familiar linear equation:

$$Y = \alpha + \beta * X \tag{2.7}$$

where $X = \ln(n_t)$ and parameter $\alpha = \ln(C_0)$.

If data points for the experience curve are known, the parameters for the underling Equation (2.7) can be obtained through linear regression analysis. Equation (2.6) shows that, in logarithmic form, the change in the cost per unit is directly proportional to change in cumulative output.

There are two important metrics devised to parameterize the information contained in an experience curve and to apply it for analysis: the progress ratio (PR) and the learning rate (LR).

Comparison of different experience curves can be made by determining the change in price, when cumulative production volume doubles. The corresponding change in price gives the progress ratio. Thus, if the cost per unit reduces to 0.80 of the original price by doubling the cumulative output, then the progress ratio of such a technology is 80%. The learning rate for a particular technology is derived from the progress ratio by subtracting it from 100%. Thus, if the progress ratio is 80%, the corresponding learning rate for the technology is 20%. Progress ratios and learning rates can be obtained through the following equations:

$$PR = 2^{\beta} \tag{2.8}$$

$$LR = 1 - PR \tag{2.9}$$

where β is the slope parameter that can be obtained through the regression (Equations 2.6 and 2.7).

It is important to provide policy support until a technology becomes cost-competitive with alternative sources. The point at which technology becomes cost-competitive is referred to as the break-even point (Figure 2.14). Experience curve analysis can show the level of investments required to make a technology market competitive. However, experience curves do not forecast when, in time, this break-even point would be reached. Even so, experience curves can be an effective tool for energy policy makers to set targets and implement measures to enable new technologies to become economically viable.

The level of required investments needed to reach a break-even price can be calculated by integration under the learning curve (Figure 2.14). Learning investments (LI) can be calculated as follows (adapted from Zwaan and Rabl [112]):

$$LI = \int_{n_c}^{n_b} (C_c - C_b) * dn = \frac{C_c}{\beta + 1} * \frac{n_b^{\beta+1} - n_c^{\beta+1}}{n_c^{\beta}} - (n_b - n_c) * C_b \tag{2.10}$$

where β is a slope parameter derived from equation (2.7), C_c is the technology's current cost, C_b is its cost at a break-even point, n_c is the current cumulative production level, and n_b is the cumulative production at a break-even point, which can be derived from the following equation:

$$n_b = n_c * \left(\frac{C_b}{C_c}\right)^{1/\beta} \tag{2.11}$$

Recently, several researchers have proposed to extend the simple formulation of learning curves (described above), also referred to as a single-factor learning curve, to two-factor learning curves (2FLC) [117–120]. The 2FLC model provides the added ability to measure the impact of research and development (R&D) activities on technology cost reduction. The two-factor learning curve can be expressed as:

$$\ln(C_t) = \ln(C_o) + \beta * \ln(n_t) + \gamma * \ln(K_t) \tag{2.12}$$

where K_t represents the stock of knowledge in time period t acquired due to past investments. The knowledge stock is defined as a function of past R&D investments that includes depreciation and time lag factors. The knowledge stock can be expressed as [118, 119]:

$$K_t = K_{t-1} * (1 - \rho) + ARD_{t-i} \tag{2.13}$$

where ρ is the annual knowledge stock depreciation rate, ARD is the annual expenditure in R&D, and $\acute{\iota}$ is the time lag between R&D investment and its effect. For PV technology, a typical value used for the annual knowledge stock depreciation rate ρ is 3%, and for the R&D time lag $\acute{\iota}$, researchers use two to three years [118, 121, 122].

The 2FLC results in two learning rates. The first is the learning-by-doing rate (LDR), representing experience gained through increasing scale of production and deployment and its impact on cost (analogous to an LR for single-factor learning curves). The second is the learning-by-searching rate (LSR), representing the impact of increased knowledge, obtained through R&D, on system cost. LDR and LSR can be represented as follows:

$$LDR = 1 - 2^{\beta} \tag{2.14}$$

$$LDR = 1 - 2^{\gamma} \tag{2.15}$$

where β is the learning-by-doing index and γ and is the learning-by-searching index.

The major problem with the 2FLC model is that its independent variables are highly correlated (i.e. high multicollinearity between cumulative installations and R&D knowledge stock). A common solution is to use a predefined value for the knowledge stock index (i.e. γ) and estimate the learning-by-doing index (i.e. β) by regression analysis. In our modeling, a value of to $\gamma = 0.154$ is assumed (based on [118, 120]). Our findings using a 2FLC model are reported below.

2.4.3 PV Diffusion in the US under Different Policy Scenarios

As discussed earlier, the US PV Market in recent years has experienced very rapid growth. PV cumulative installations have increased from 43.5 $\mathrm{MW_p}$ in 1992 to 1168 $\mathrm{MW_p}$ by the end of 2008. However, even with such rapid growth, PV's share in the US electricity supply in 2008 was only 0.04% [12, 123]. Nevertheless, if the current trend continues, the share of PV will likewise increase. Below, we model this process and estimate the rising share of US electricity supply from solar electric power under three policy scenarios: (1) a national carbon tax cap-and-trade policy; (2) a national renewable portfolio standard; and (3) an expanded national commitment to R&D to promote higher-efficiency, lower-cost PV modules.

2.4.3.1 Building a business-as-usual benchmark for US PV market development

For our diffusion analysis, under different policy scenarios, we have assumed 25% as a reasonable target for the maximum share of grid electricity supply provided by PV in the next few decades (see, e.g. [124]). A standard diffusion model based on values obtained from Equation (2.2) above (i.e. values of

$$\left[\ln\left(\frac{U-Q_t}{Q_t}\right)\right]$$

plotted against a time variable) is used, which adopts empirical estimates from regression analysis of diffusion rates for the period 1990–2008 (Figure 2.15). From the figure, it is evident that the regression trend line has changed with PV diffusion accelerating after 2000. The β value (i.e. diffusion rate) for the initial period of 1992–2000 is −0.1172, but it more than doubles (−0.2543) for the later period of 2001–2008.

Between 2000 and 2008, PV's share of US electricity supply increased by approximately 30% per year. Based on this historical trend, we built a diffusion model to estimate future PV supply, when saturation is assumed to occur at 25% of total electricity generation.[20] Additionally, it was assumed that electricity generation in the US will increase by 1% per year. This assumption mirrors that of the US EIA for the period between 2010 and 2030 [8], and our analysis extended this assumption after 2030 until 25% saturation is reached under each policy scenario, when necessary.

Utilizing EIA projected total electricity supply for 2010–2030 and assuming a 1% growth rate thereafter, estimates of total and PV-sourced electricity generation were obtained (Figure 2.16 and Table 2.4). The projected path of PV supply in Figure 2.16 is treated as the business-as-usual scenario (BAU). The BAU projects PV capacity to increase from 1.8 GW_p in 2010 to 1076 GW_p in 2055; correspondingly PV's share of US electricity supply grows from 0.07% to 25% during the same period.

The BAU projections derived from our analysis are well within reach, particularly when we compare them with targets established by current state level RPS policies for PV and customer-sited

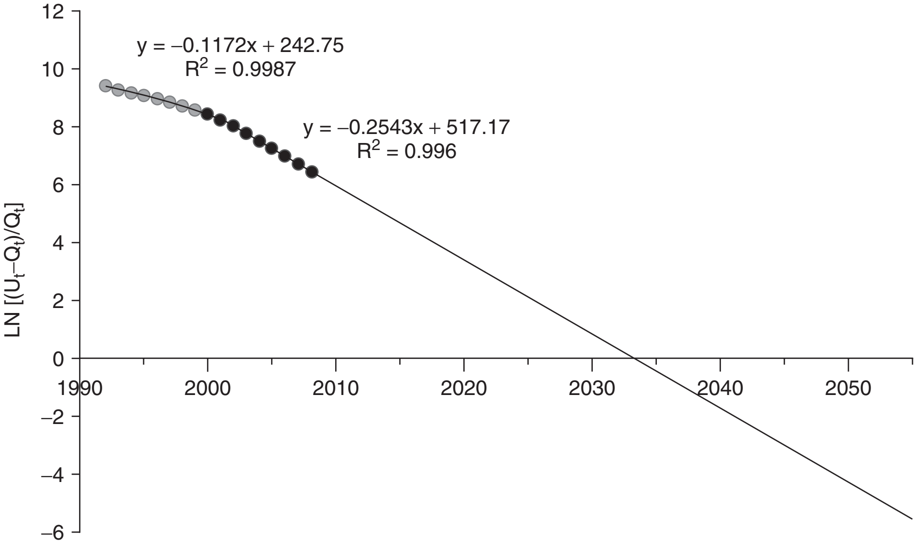

Figure 2.15 Regression analysis using a logistic growth model for US PV installation. Data sources: [12, 123]

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[20] This saturation rate is based on research suggesting that the integration of intermittent resource into grid supply has a technical limit roughly at this rate (e.g. [124])

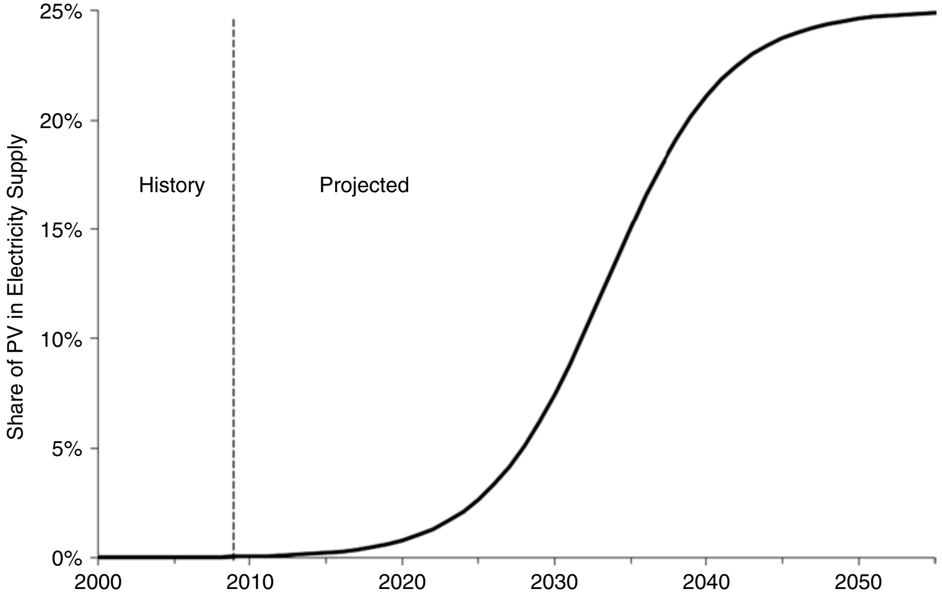

Figure 2.16 PV diffusion in the US under a business-as-usual scenario. This projection is based on the regression analysis shown in Figure 2.15, which assumes $U = 25\%$, and gives regression parameters of $\beta = -0.2543$, and $t_m = 2034$

Table 2.4 BAU projected PV generation and installed capacity

	US electricity generation* (billion kW h)	PV's share of US electricity supply (%)	PV generation (billion kW h)	PV capacity GW_p**
2010	4162	0.07	2.72	1.8
2015	4339	0.23	10.07	6.7
2020	4573	0.81	37.02	24.7
2025	4840	2.67	129.16	86.1
2030	5055	7.48	377.90	251.9
2035	5312	15.09	801.79	534.5
2040	5583	21.12	1179.09	786.1
2045	5868	23.78	1395.21	930.1
2050	6166	24.64	1519.96	1 013.3
2055	6482	24.90	1614.01	1 076.0

*2010–2030 numbers are from [8]; for 2030–2055, 1% of annual growth is assumed.

**Assumes annual energy production of 1500 kW h per kW_p for PV.

distributed energy sources. As noted earlier, 14 states and the District of Columbia (Washington, DC) have specific solar or distributed generation carve-outs in their RPS requirements. California, Oregon and Texas have specific targets for distributed generation or PV [25]. Applying current PV/DG RPS requirements to these states' electricity consumption (based on 1% annual increases in electricity demand), and using state-specific solar radiation, we determined the PV installation capacity needed to meet the RPS carve-outs (Table 2.5). Results show that states with PV/DG RPS will, in total, require 3.5 GW_p in 2015 and 11.8 GW_p in 2020 to meet their legislated targets. These

Table 2.5 State PV and distributed generation carve-out

	Solar carve-out				Projected installations (MW)			
	2010	2015	2020	2025	2010	2015	2020	2025**
AZ*	0.50%	1.50%	3.00%	4.50%	143	452	951	1499
CA							3500	3500
CO	0.20%	0.60%	0.80%	0.80%	70	219	308	323
DC	0.00%	0.20%	0.40%	0.40%	3	16	40	42
DE	0.00%	0.60%	2.00%	2.00%	2	54	204	214
IL	0.00%	0.60%	1.10%	1.50%	0	716	1317	1978
MD	0.00%	0.30%	1.50%	2.00%	11	115	724	1014
MO	0.00%	0.10%	0.20%	0.30%	0	66	138	218
NC	0.00%	0.10%	0.20%	0.20%	23	168	254	265
NH	0.00%	0.30%	0.30%	0.30%	4	30	32	34
NJ+	0.22%	965 GW h	2164 GW h	4610 GW h	137	742	1664	3545
NM	0.20%	0.60%	4.00%	4.00%	27	87	607	638
NV	0.60%	1.20%	1.30%	1.50%	131	276	319	381
NY*	0.10%	0.10%	0.10%	0.10%	108	176	185	195
OH	0.00%	0.20%	0.30%	0.50%	12	187	445	688
OR							20	20
PA	0.00%	0.10%	0.40%	0.50%	15	188	610	723
TX*							500	500
Total					686	3492	11 818	15 777

*Distributed generation (DG).

**Most of the RPS carve-outs have targets which must be reached by 2020.

+In January 2010, New Jersey changed its percentage-based solar target to a GW h target.

Data sources: [8, 25].

The analysis, based on EIA's most recent electricity forecast (8), assumes electricity consumption will grow 1% annually. The PV capacity required to meet solar or DG carve-outs is calculated using average daily solar radiation data from NREL [125], and a PV system performance ratio of 75%.

are nearly half (48–52%) of what is projected under our BAU scenario (i.e. 6.7 GW_p in 2015 and 24.7 GW_p in 2020). The selected 17 states (Table 2.5) and Washington DC represent one-half of US electricity demand (49%). Thus, if the remaining states follow similar policy initiatives and/or if the pioneering 18 US jurisdictions upgrade their targets while the bulk of the states without RPS rules adopt a policy strategy that approximates the goals of the early adopters, the BAU targets in Table 2.4 will be readily achievable. Moreover, in the BAU scenario, the projected PV share is 0.8% of total US electricity supply by 2020, which is not overly aggressive if we consider the current installed capacity of PV in other OECD countries.[21] Germany and Spain, for example, already reached this level of PV adoption in 2008 [12].

A key factor in the rate of PV deployment is the cost of PV electricity relative to other generating fuels and technologies. Historically, the levelized cost of electricity (LCOE) of conventional electricity supply sources has been significantly lower than PV, even after accounting for transmission and distribution costs.[22] For substantial penetration of grid-connected PV, the LCOE

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[21] The BAU scenario presented here, assumes maximum level of PV share electricity supply at 25%. This level is projected to be reached in 2055.

[22] LCOE provides the means for economic evaluation and comparison of different electricity generation technologies. LCOE accounts for all costs over a technology's lifetime, including initial investment, operations and maintenance, cost of fuel, and cost of capital.

for PV production needs to decrease and/or non-PV LCOEs must increase. LCOE can be calculated as follows [112, 126, 127]:

$$LCOE = IC * \left(r_{O\&M} + \frac{r_{\text{int}}}{1 - (1 + r_{\text{int}})^{-n}} \right) \tag{2.16}$$

In this equation IC is initial capital cost including installation, $r_{O\&M}$ is the annual operation and maintenance cost (O&M) as a percentage of IC, r_{int} is the real interest rate, and n is the economic system lifetime in years. In this formulation, fuel costs appear in $r_{O\&M}$.

In 2009, the capacity-weighted average installed system cost of a PV system was \$6.80 per W_p [30]. According to a Deutsche Bank report, in the US, the financing rate associated with project development ranged between 6 and 8% [19]. For the annual inflation rate for 2010–2030, we utilized the EIA reference case [8], which assumes 2% per year for this timeframe, resulting in a real interest rate for PV of 5%.[23] Using a typical PV generation of 1500 kW h per kW_p for the US, with a project lifetime of 25 years, an installed cost of \$6.80 per W_p, annual O&M costs at 1% of initial installed cost, and a 30% federal tax credit, we estimated the LCOE for PV at 25.7 cents per kW h.[24] At the same time, the recent average weighted retail electricity price for commercial and residential customers in the US is 10.6 cents per kW h [123]. EIA projects no significant real price (adjusted for inflation) increases in their projections of US electricity retail prices [8]. Using this very conservative assumption, a \$2 per W_p PV system cost is required to be competitive with conventional grid-supplied electricity in the residential and commercial sectors. This \$2 per W_p system cost represents the PV break-even price.

The experience curve, as discussed above, offers a useful method for assessing cost-cutting knowledge gained through increasing scale of PV production and deployment. The cost reductions associated with this experience is expressed by a learning rate. Based on data obtained from NREL on the annual average installed system cost for 1998–2005 and cumulative installed capacity [30], an experience curve for the US PV system cost is derived. In the analysis, recent years affected by polysilicon shortages are excluded.[25] The resulting curve presented in double-logarithmic form is shown in Figure 2.17.

The slope parameter (β in Equations 2.5–2.8) for the experience curve displayed in Figure 2.17 has the value −0.214. Using Equations (2.8) and (2.9), the US PV system cost trend exhibits an 86.2% progress ratio and a 13.8% learning rate. Based on this learning rate, a break-even price of \$2 per W_p system cost will be reached when cumulative installations equal 280 GW_p. Under the BAU scenario, this level of PV installation in the US would be met by 2031.[26] As shown in Figure 2.17, before PV installations reach a break-even level, the cost differential between system cost and break-even price needs to be subsidized. The total subsidy required to reach the break-even point is illustrated as the shaded area, labeled learning investments.[27] Government

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[23] 5% was obtained using 7% as a midpoint of Deutsche Bank's financing values, adjusted for 2% inflation (i.e. $[1.07/1.02 - 1] \approx 0.05$).

[24] This rate does not include other federal (e.g. MACRS) and local incentives. If MACRS depreciation rules are included, PV's LCOE in the BAU case falls to 14.5 cents per kW h. Inclusion of tax benefits is justified on the ground that all power plants and non-renewable fuels in the US have been subsidized by tax and other policy treatments. It should be noted that, typically, LCOEs for fossil fuel power plant include the MACRS tax benefit.

[25] During 2006–2008, silicon PV module prices actually increased the first time in 30 years. Then in 2009, they fell rapidly as new production capacity made it to market. For a discussion of this situation see Chapter 1, Section 1.2.3 in this *Handbook*.

[26] As Figure 2.16 reports, once a break-even price is reached in 2031, PV market share will grow and realize the target of 25% of total US electricity assumption in just 24 years (i.e. the rapid-growth interval of 2031–2055 in Figure 2.16).

[27] These investments are of the learning-by-doing variety.

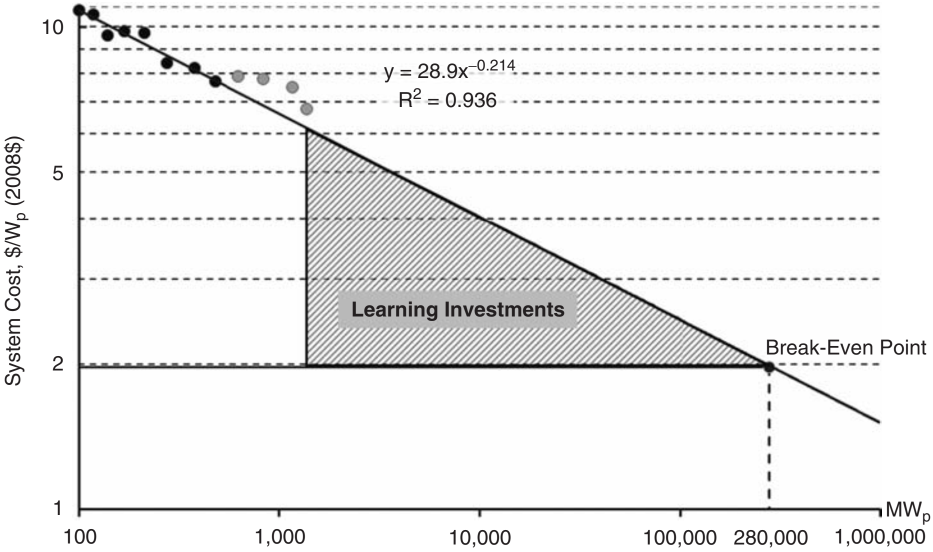

Figure 2.17 US PV system cost experience curve. Data sources: [30, 12]. The curve was derived based on system cost data for 1998–2005 and cumulative installations in the US Data from recent years affected by polysilicon shortages ware excluded

programs and incentives can increase the rate of PV production and deployment, driving PV system costs down the experience curve. The level of subsidy required each year to meet targets outlined under the BAU diffusion path in Figure 2.16 are calculated based on Equation (2.10).

The results of this calculation are displayed in Figure 2.18, and show that the level of subsidies to meet BAU annual installation targets need to increase between 2010 and 2025,

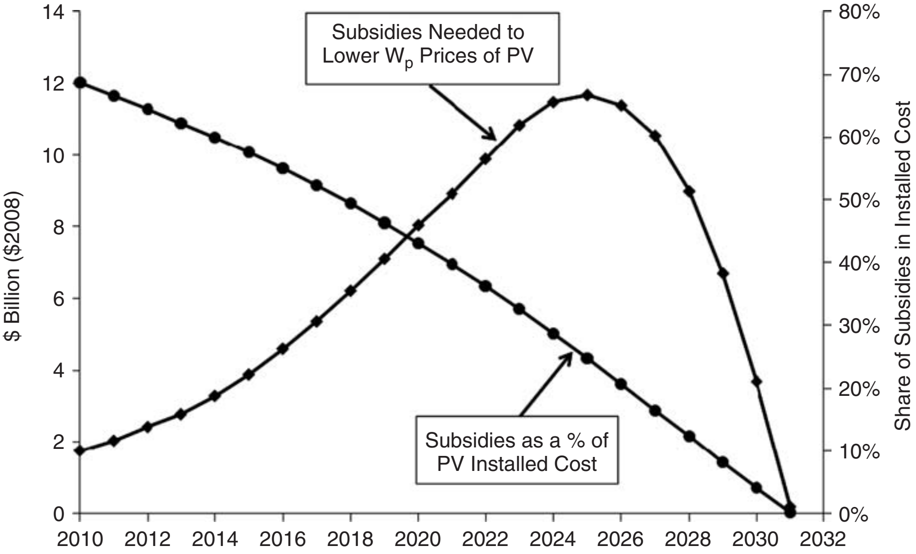

Figure 2.18 PV system cost subsidies required to follow BAU diffusion scenario

Table 2.6 Learning parameter estimates

	Index	Progress ratio (%)	Learning rate (%)
Learning-by-doing, estimated	−0.2028	86.9	13.1
Learning-by-searching, fixed	−0.1520	90.0	10.0

Annual R&D expenditure data for 1991–2009, used for these estimates was provided by Robert Margolis (NREL). Additional data for 1975–1990 was obtained from IEA Database [92]. The fixed learning-by-searching rate is taken from research Miketa and Schrattenholzer [118] and Kouvaritakis *et al.* [120].

with a subsequent decline thereafter. The share of subsidy in total PV investments gradually decreases from approximately 70% of total installed cost in 2010, until it reaches zero by 2031. This translates into a total learning investment of $142 billion (in 2008 dollars). However, this number does not account for cost reductions associated with research and development (R&D) expenditures. This is discussed below.

To estimate the impact of R&D, a two-factor learning curve (2FLC) is developed. Following the methodology described in the previous section (see Equations 2.12–2.15), parameters for the 2FLC model were obtained. The results are presented in Table 2.6. The estimated "learning-by-doing" parameters reflect cost reductions due to manufacturing and other experience gained through PV system deployment. "Learning-by-searching" indicators represent cost reductions associated with R&D expenditures. After factoring in the impact of R&D, the learning rate attributed to experience gained through PV system deployment and associated cost reductions is reduced from 13.8 to 13.1%.

In order to assess the level of annual R&D investments required to continue the same trend of cost reduction in Figure 2.17, the single-factor and two-factor learning curves must be harmonized so that system costs in Equations (2.6) and (2.12) are equal for the same cumulative installation level n_t. Our method to achieve this is now presented. Equations (2.17) and (2.18) modify the original forms in order to reflect different intercept and slope parameters for learning-by-doing and learning-by-searching.

$$\ln(C_t) = \ln(C_{o1}) + \beta_1 * \ln(n_t) \tag{2.17}$$

$$\ln(C_t) = \ln(C_{o2}) + \beta_2 * \ln(n_t) + \gamma * \ln(K_t) \tag{2.18}$$

After combining these equations and rearranging terms, the stock of knowledge variable K_t introduced in Equation (2.12) can be derived as:

$$K_t = n_t^{(\beta_1-\beta_2)/\gamma} * \exp\left(\frac{\ln(C_{o1}) - \ln(C_{o2})}{\gamma}\right) \tag{2.19}$$

After combining Equations (2.13) and (2.19), required annual R&D expenditures can be determined. An average of $122 million per year in R&D is needed to meet targets outlined under the BAU diffusion path. Thus, between 2010 and 2031, in addition to $142 billion required as learning investments, an estimated $2.7 billion in R&D is projected to be needed to reach the break-even point.

2.4.3.2 US PV policy scenarios

In addition to tax subsidies and R&D programs that have traditionally supported PV deployment, a new array of policy mechanisms in support of a US transition to a "green energy" economy are being discussed. This section evaluates three policy tools to ascertain their likely impact on the diffusion of PV into the national electricity market.

2.4.3.2.1 *Pricing carbon*

The first policy tool we examine is a carbon tax or carbon cap-and-trade strategy.[28] Due to the dominance of fossil fuels in electricity generation, the introduction of a carbon pricing scheme will increase the cost of grid supplied electricity. This in itself will raise the necessary break-even price for PV, at which the technology is cost-competitive with grid-supplied electricity. An effective carbon tax at \$25 per ton of CO_2 will increase the break-even system cost by \$0.32/W_p and a carbon tax at \$50 per ton of CO_2 will increase the break-even system cost by \$0.64/W_p (see Figure 2.19).[29]

A carbon price of \$25 per ton is at the high end of the trading value in the EU [128]. The US is struggling to pass cap-and-trade legislature that would likely result in carbon prices less than \$25 per ton [129]. An additional scenario using a high price of \$50 per ton is included to capture what currently appears to be the outer reach of political possibility with regard to this tool.

Increasing the break-even cost will reduce the amount of cumulative PV system installations required to reach the break-even point. For the case of a \$25 per ton cost of CO_2 emissions, a break-even point will be reached at 139 GW_p, and for a \$50 per ton cost of CO_2 emissions a break-even point at 76 GW_p is needed (Figure 2.19).

The amount of required learning investments will be reduced from \$142.2 billion to \$47.0 billion under a \$50 per ton of CO_2 cost scenario and to \$79.5 billion under a \$25 per ton of CO_2

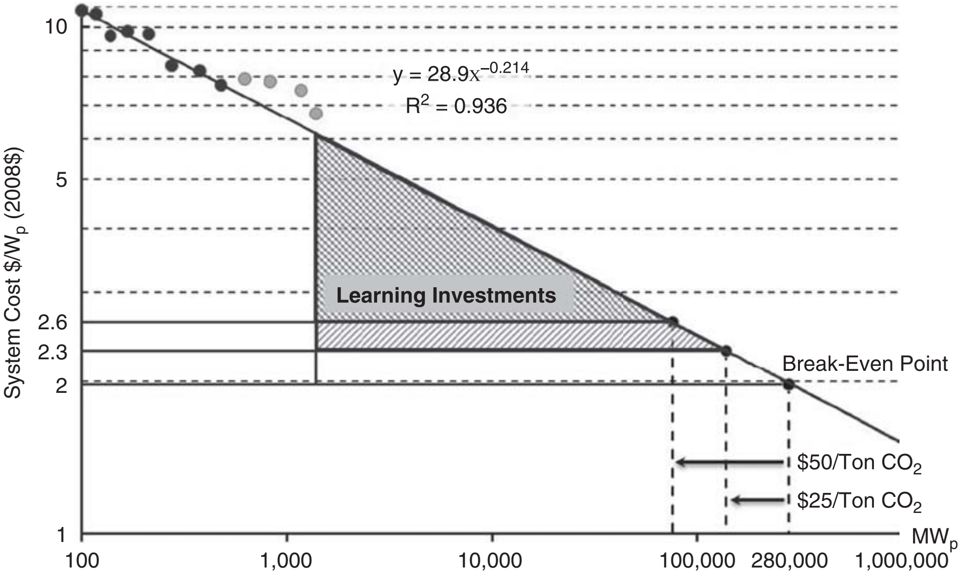

Figure 2.19 Impact of a carbon pricing policy on the break-even point for PV

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[28] Although important differences exist between a carbon tax and a cap-and-trade strategy in terms of implementation, we focus here only on the effect on retail electricity prices. For this reason, we do not distinguish between the two in our analysis.

[29] For Figure 2.19, we assumed 0.6 tons of CO_2 is emitted per MW h of electricity generation, PV generation at 1,500 kW h per installed kW_p, and 25 year product life. A real 5% discount rate was assumed.

cost scenario. In this respect, if carbon taxes or cap-and-trade allowances collected from fossil fuel generators are directed to provide additional support for non-fossil fuel generation technologies, then PV deployment projects will not only gain from a higher break-even price, but would also benefit from increased public investment. For example, if PV generators, before reaching the break-even point, are paid \$50 or \$25 per ton for avoided CO_2 emissions, then additional monetary benefits to PV project development can be quantified at \$48 billion or \$44 billion, respectively.[30]

We can now estimate the impact of the two carbon pricing scenarios on PV diffusion. For a carbon price of \$25/ton, and including the price effect on conventional grid power and the effect of using the proceeds of carbon pricing to incentivize PV use, we project grid parity to occur in 2024 and 25% saturation to be reached in 2050. For \$50/ton, we project PV to reach grid parity in 2020 and to realize 25% saturation in 2045.

2.4.3.2.2 *The impact of PV R&D*

We now turn our attention to the impact of R&D policy on PV diffusion. What would be the likely impact of increasing public investment in R&D? To answer this question we analyzed the R&D scenario under which R&D investments are committed at the same level as learning-by-doing investments (i.e, rebates, tax credits and other project level incentives), shown in Figure 2.18. Increased investment in R&D facilitates faster decline of PV system costs. We modeled the following scenario: conventional policy incentives for PV development were decreased by approximately \$25 billion over 8-year period; instead \$25 billion was dedicated to public R&D; this increased R&D during 8-year period by roughly factor of ten – that is from \$2.7 billion to \$27.9 billion. As is demonstrated in Figure 2.20, increase of R&D spending tenfold raises the slope on the US

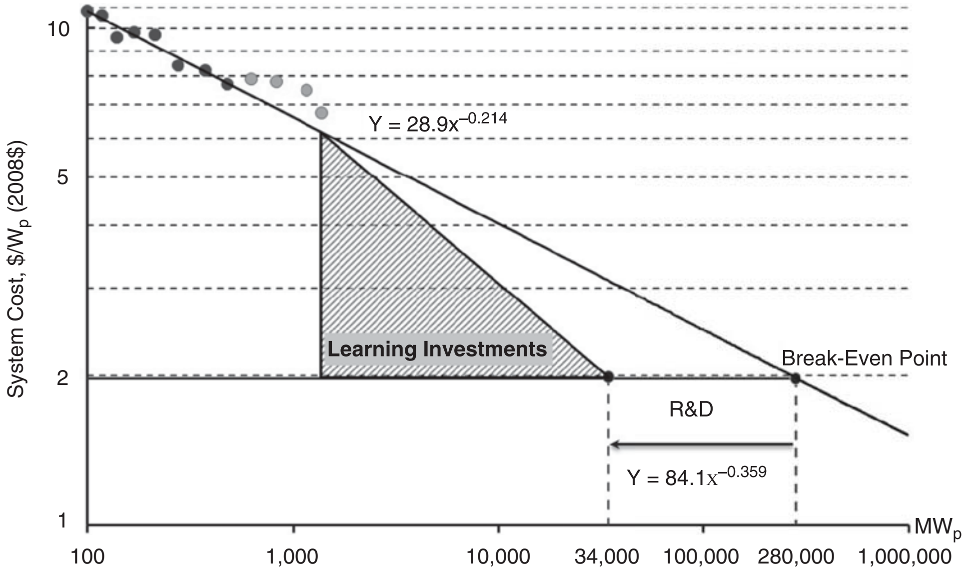

Figure 2.20 Impact of increased R&D expenditures on the break-even point for PV

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[30] These numbers are based on the assumptions in footnote 29, and using the products of previously obtained numbers for carbon tax impact on break-even price and amount of additional cumulative PV installations required to reach a break-even point (i.e., \$0.64/W_p*[76 – 1.3], and \$0.32/W_p*[139 – 1.3]).

Table 2.7 Effect of R&D on total investments for reaching a PV break-even point, \$2 per W_p

	BAU scenario	Increased R&D scenario
R&D Investments (billion \$)	2.7	27.3
Learning-by-doing Investments (billion \$)*	142.2	27.3
Combined Investments (billion \$)	144.9	54.6

*Learning-by-doing investments equal the total policy incentives (rebates, tax credits, etc. see Figure 2.18)

experience curve from −0.214 to −0.359, thus, increasing the learning rate from 14 to 22% (see Equations 2.8 and 2.9).

Based on the results obtained, which are shown in Figure 20 and Table 2.7, it can be seen that Increases in R&D expenditures can significantly reduce the amount of combined (learning and R&D) investments needed to reach a break-even point.

Using these learning rates, we calculated that tenfold increase of US public R&D for PV would accelerate the year when grid parity would be reached to 2018 (from the BAU of 2031). It would also shorten the time to 25% saturation from a BAU of year 2055 to 2040.

2.4.3.2.3 Effect of a solar carve-out policy

Another policy option for rapid deployment of PV is the promotion of a solar carve-out under a national RPS, similar to those implemented in a number of US states (see Table 2.5). Under a Solar RPS requirement, energy suppliers need to create SRECs through their own power generation, or purchase them from third-party solar power providers. A well-structured RPS with sufficiently high noncompliance fees and a legal requirement for utilities to purchase SRECs through multi-year contract can result in rapid PV deployment similar to the German experience with feed-in tariffs. An RPS with a solar carve-out could create significant demand for Solar Renewable Energy Certificates (SRECs). By 2010, in states with established SREC markets, SRECs ranged from \$200 to \$700 per MW h [51]. For a national solar market, more conservative prices for SRECs were considered: SRECs are initially traded at \$200 per MW h (20 cents/kW h) in 2010 and gradually decrease to \$100 per MWh (10 cents/kW h) by 2020.

This scenario relies on an SREC pricing schedule that is below those in play in 14 pioneer states. Indeed, recent policy reforms in Delaware, Pennsylvania, Massachusetts, New Jersey and other states have led to SREC trading above \$200 per MW h [51]. In this sense, the carve-out scenario analyzed in Figure 2.21 is quite conservative. Under this scenario, the break-even point will be achieved at 66 GW_p of cumulative installations, and additional learning investments required to reach grid parity is \$30.5 billion (Figure 2.21).[31]

Under this conservative SREC pricing scenario, we project PV to reach grid parity by 2018 and to achieve a 25% market saturation by the year 2035.

2.4.3.3 Comparing policy impacts

Table 2.8 summarizes results of the policy scenarios discussed in this section. Under the BAU scenario, grid parity is reached in 2031 and it would require up to \$145 billion in cumulative combined learning investments (i.e. R&D and learning-by-doing). Of this amount, \$142.2 billion

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[31] As with the carbon pricing and R&D scenarios, required learning investments needed to reach grid parity are assumed to be financed by rebates, incentives and other public and utility policy tools.

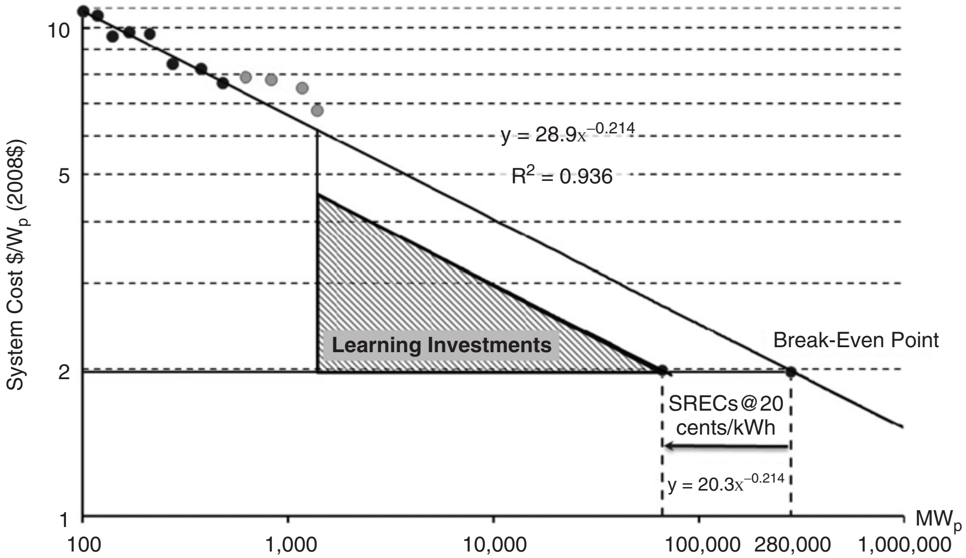

Figure 2.21 Impact of a national SREC requirement on the break-even point for PV

Table 2.8 Total investments required for reaching a PV break-even point, \$2 per W$_p$ under different policy scenarios

	BAU scenario	CO$_2$ Price of \$25 per ton scenario	CO$_2$ Price of \$50 per ton scenario	Increased R&D scenario	SRECs at 20 cents/kW h scenario
R&D Investments (billion \$)	2.7	2.7	2.7	27.3	2.7
Learning-by-doing Investments (billion \$)	142.2	79.5	47.0	27.3	30.5
Combined Investments (billion \$)	144.9	81.2	49.7	54.6	33.2
Time to grid parity	2031	2024	2020	2018	2018

All scenarios assume learning-by-doing investments will be maintained at the schedule outlined in Figure 2.18 until break-even point is reached.

is policy incentives would be needed to reach grid parity in 2031. The introduction of carbon pricing (either through taxation or a cap-and-trade carbon market) would help non-carbon-based technologies, such as PV to compete with conventional fossil-based power generation technologies (natural gas turbines, coal plants, etc.) and would reduce the required learning-by-doing investments needed to reach grid parity. At a higher price per ton of CO$_2$ released, the cumulative volume of learning-by-doing investments needed to reach the break-even point on the learning curve would be lower (see Figure 2.19). Learning investments are reduced from \$142.2 billion to \$47.0 billion under a \$50 per ton of CO$_2$ emissions scenario and to \$79.5 billion under a \$25 per ton of CO$_2$ emissions scenario. Tenfold increase of public R&D would reduce the amount of learning-by-doing investments required to reach grid parity by \$115 billion to \$27.3 billion (the scenario assumes that same amount of cumulative investments are made in R&D). This dramatic reduction is mostly due to

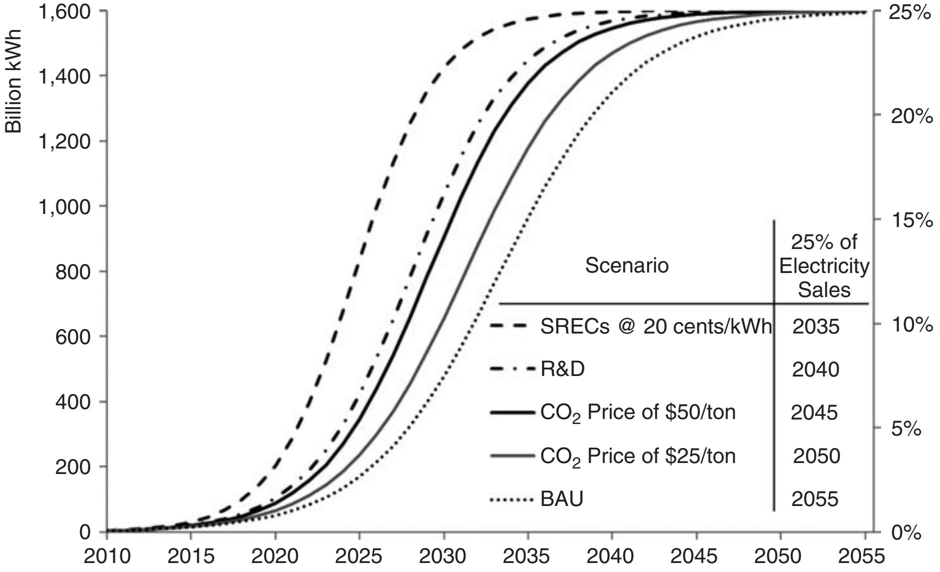

Figure 2.22 PV diffusion under different policy options in the US

the much earlier realization of grid parity, namely, 2018 for the R&D strategy compared with 2031 for the BAU strategy. Finally, the introduction of a national SREC market can reduce cumulative learning-by-doing investments to $30.5 billion and shorten the time to grid parity by 13 years (i.e. the BAU case of 2031 to the SREC case of 2018). Again, the savings from this scenario are very large – nearly $110 billion – and are attributable to the faster realization of the grid parity.

Diffusion curves under each of the policy scenarios investigated in this chapter were also constructed. The diffusion scenarios are benchmarked against the BAU scenario (see Figure 2.16). Based on this assumption, corresponding diffusion curves are constructed for each policy scenario. The results are presented in Figure 2.22, and show that a national RPS facilitates the fastest deployment of PV. A solar carve-out with SREC prices initially at 20 cents per kW h will shave nearly 20 years off the BAU time horizon of PV reaching 25% of the US electricity market share. That is, our BAU projection finds that 25% saturation will not occur until the year 2055, but a national SREC policy would hasten the achievement of that goal to 2035.

Increasing R&D funding for PV will also expedite the diffusion process. An expanded R&D policy can reduce the time needed to reach the 25% goal by almost 15 years. It may also rightly claim the benefit of strengthening the knowledge infrastructure to promote a green energy economy and, more broadly, a low-carbon future for the planet.

Finally, carbon taxes or cap-and-trade allowances have a noticeable impact, on PV diffusion, lessening the time for PV to reach the 25% goal by 5–10 years (compared with the BAU case). With regard to the effects of carbon pricing, three observations are in order. First, by comparison, the price of carbon modeled here is less than the SREC price options on a per kW h basis.[32] Thus, it is understandable why its impact is weaker. Of course, it is also important to observe that US jurisdictions have been able to enact laws leading to substantially higher SREC prices than the scenarios we have modeled. By contrast, no country or region has been able to sustain carbon

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[32] A $25 per ton price of carbon emissions would increase the average retail electricity price in the US by about 1.5 cents per kW h, while a $50 per ton price would raise electricity prices by 3.0 cents per kW h.

pricing at or above $25 per ton. This leads to the third observation. Carbon pricing is perhaps the most complex and difficult policy approach to legislate because its effects are wide-ranging and will adversely affect the economics of some of the most powerful industries and companies in the world. Evaluated in this light, PV R&D and SREC have a contained policy reach and do not directly require raising the costs of fossil fuel competitors. Equally true, these tools only modestly affect the cost–benefit matrix that underlies the US and world economies. In this sense, their impacts can be strategically large, but cannot substitute for the systematic effect of a carbon pricing policy, even when its effective pricing of the pollutant is modest.

2.5 TOWARD A SUSTAINABLE FUTURE

In one of the boldest maps in print for our future, Herman Scheer's *The Solar Economy* [4] plots a worldwide shift from a non-renewable and unsustainable energy system to a renewable and, hopefully, sustainable future. Some may agree and others will disagree with assumptions behind the map or calculations he presents in support of its path. But one aspect of the map is indisputable: achieving a sustainable future requires solar energy to be at the center of the new economy.

Realizing this fact will not be easy, and almost certainly the world will disappoint Scheer with the slow pace and lack of vigor in its pursuit of a solar economy. Just because there is no other safe harbor for our future does not mean that humanity will avoid getting lost in its journey. That said, there are reasons and evidence for hope. In the last 15 years, policies have sprouted across the planet that have led to truly remarkable progress. Compared with where we were, a steady stream of policy incentives put into action – feed-in tariffs, solar carve-outs, renewable portfolio standards, community solar financing, and sustainable energy utilities – demonstrate a capacity for change that few would have predicted. In this regard, Scheer is more accurate about our ability to realize a different future than policy skeptics, or even policy moderates. The policy review in this chapter provides a detailed portrait of real change that has been gained, and underscores the potential for vastly larger improvement by using already invented tools which have been tested in very different national contexts, but with common results – a measurable advance in realizing a solar economy.

The policy analysis occupying the last half of the chapter offers a concrete projection of large-scale change built upon the use of already invented policies. Surely a global solar economy requires significant US participation, and the analysis plots a course of action for that country which would result in 25% of its electricity supply from solar generation in as little as 20 years. Achieving the goal will require public investment in PV R&D to sustain progress in the technology's performance and economic value while incentives are utilized to organize at-scale investment in solar energy. The experience of Germany, Spain and South Korea, among others, with the feed-in tariff tool (invented by Scheer)[33] indicates that policy can work to mobilize capital and can evolve markets that sustain significant PV penetration rates. Because national politics and economies differ, tools that aspire to the same outcome are also needed. The imitation of a feed-in tariff with a properly designed RPS, carve-out and SREC policy suite can promise the needed result and this chapter's analysis of the option shows that a transformed US electricity supply path is feasible.

It is also clear that systematic policy regime for realizing a solar economy will require comprehensive pricing of carbon uses and emissions. In the case of this tool, designs that initiate the process, even when carbon pricing is modest, have a demonstrable impact. In the longer run, this tool will guarantee that *all* energy decisions and investments reflect this factor. At the same time, a systematic policy regime *must have* specific initiatives such as FiT or SRECs to ensure rapid, concrete change. It would be a tragic error in policy design to fail to adopt the PV-focused policies modeled above.

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[33] The 2009 Karl Boër Solar Medal was awarded to Hermann Scheer for his invention of the FiT [134].

The challenge of sustaining a future in the greenhouse remains large, daunting, and even unnerving [130]. The policy record is mixed and advances are slow. Still the interface of policy, technology and society is hopeful. Large change has happened before and the improvements of the last 15 years are promising.

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3

The Physics of the Solar Cell

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3.1 INTRODUCTION

Semiconductor solar cells are fundamentally quite simple devices. Semiconductors have the capacity to absorb light and to deliver a portion of the energy of the absorbed photons to carriers of electrical current – electrons and holes. A semiconductor diode separates and collects the carriers and conducts the generated electrical current preferentially in a specific direction. Thus, a solar cell is simply a semiconductor diode that has been carefully designed and constructed to efficiently absorb and convert light energy from the sun into electrical energy.

A simple conventional solar cell structure is depicted in Figure 3.1. Sunlight is incident from the top, on the front of the solar cell. A metallic grid forms one of the electrical contacts of the diode and allows light to fall on the semiconductor between the grid lines and thus be absorbed and converted into electrical energy. An antireflective layer between the grid lines increases the amount of light transmitted to the semiconductor. The semiconductor diode is fashioned when an n-type semiconductor and a p-type semiconductor are brought together to form a metallurgical junction. This is typically achieved through diffusion or implantation of specific impurities (dopants) or via a deposition process. The diode's other electrical contact is formed by a metallic layer on the back of the solar cell.

All electromagnetic radiation, including sunlight, can be viewed as being composed of particles called photons which carry specific amounts of energy determined by the spectral properties of their source. Photons also exhibit a wavelike character with the wavelength, λ, being related to the photon energy E_λ by

$$E_\lambda = \frac{hc}{\lambda} \tag{3.1}$$

where h is Plank's constant and c is the speed of light. Only photons with sufficient energy to create an electron–hole pair, that is, those with energy greater than the semiconductor bandgap

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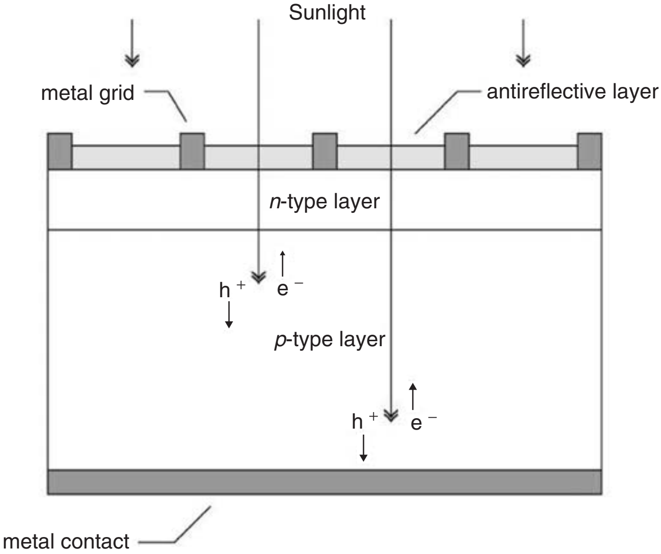

Figure 3.1 A schematic of a simple conventional solar cell. Creation of electron–hole pairs, e^- and h^+, respectively, is depicted

(E_G), will contribute to the energy conversion process. Thus, the spectral composition of sunlight is an important consideration in the design of efficient solar cells.

The sun has a surface temperature of approximately 5762 K and its radiation spectrum can be approximated by a black body radiator at that temperature. Emission of radiation from the sun, as with all black body radiators, is isotropic. However, the Earth's great distance from the sun (approximately 93 million miles or 150 million kilometers) means that only those photons emitted directly at the Earth contribute to the solar spectrum as observed from the Earth. Therefore, for most practical purposes, the light falling on the Earth can be thought of as parallel streams of photons. Just above the Earth's atmosphere, the radiation intensity, or solar constant, is about 1.353 kW/m^2 [1] and the spectral distribution is referred to as an *air mass zero* (AM0) radiation spectrum. The air mass is a measure of how absorption in the atmosphere affects the spectral content and intensity of the solar radiation reaching the Earth's surface. The air mass number is given by [1]

$$\text{Air mass} = \frac{1}{\cos\theta} \tag{3.2}$$

where θ is the angle of incidence ($\theta = 0$ when the sun is directly overhead). The air mass number is always greater than or equal to one at the Earth's surface.

A widely used standard for comparing solar cell performance is the AM1.5 ($\theta = 48.2°$) spectrum normalized to a total power density of 1 kW/m^2. The spectral content of sunlight at the Earth's surface also has a diffuse (indirect) component due to scattering and reflection in the atmosphere and surrounding landscape, and can account for up to 20% of the light incident on a solar cell. The air mass number is therefore further defined by whether or not the measured spectrum includes the diffuse component. An AM1.5g (global) spectrum includes the diffuse component, while an AM1.5d (direct) does not. Black body ($T = 5762$ K), AM0, and AM1.5g radiation spectrums are shown in Figure 3.2. The air mass and solar radiation are described in more detail in Chapters 18 and 22.