A SOLAR ENERGY ESTIMATOR

A SIMPLE SOLAR PANEL VIABILITY MODEL

EDWARD D. DUVALL

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Fremont Valley Books LLC

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Edward D. Duvall

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For further information, contact edward.d.duvall@gmail.com

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Changes made in Rev A, 24 Feb 2023:
1. Minor changes to preface
2. Adds clarification to Figure 6.9-1
3. Corrects installation cost in Figure 6.9-1
4. Adds Figure 6.9-2
5. Adds Section 6.10

CONTENTS

Preface

There is an old Three Stooges routine that goes something like this. Curly, Larry, and Moe are selling vacuum cleaners door-to-door. One lady answers the door and starts yelling at them about how much she is annoyed by the constant stream of salesmen. Moe says that they, too, are angry at those no-good door-to-door con-artists (or words to that effect), and launches into a sales pitch, not for the vacuum cleaner, but for a sign he pulled from his pocket that says "No Salesmen". The lady then buys a sign. Maybe I should get a sign; these solar panel guys are driving me nuts.

Solar panels have become an important business these days. Every few weeks I have solar panel salesmen ringing my doorbell and telling me how important it is to consider solar panels on my house. On two occasions I arranged to meet with their analysts, and in both cases they ran a model on their computers. After talking a little about how I set my thermostats and some history from my electric bills, the model run by the analysts produced some predictions about how much electricity a prospective solar system could generate and how much I could save over the next 25 years, especially since (they said) electricity rates are going to increase dramatically in the next few years. They did provide me with an estimate of the installation cost. But the curious thing is: nothing was put in writing, and no actual system specification was provided. I asked if I could obtain a formal quote and system layout with performance metrics, and I was told that I would first have to sign up to go ahead with the project.

On the second occasion, I was able to copy down a lot of the data being shown on the analyst's computer, and he had no objection to that. He explained that no written quote or specification could be made because he was only working from generic location data. It turns out that the data I acquired was enough to give me sense of how solar panel systems are specified and analyzed. I'm an incorrigible, cynical, sarcastic old buzzard, and am not about to sign up for a project before I have something in writing that tells me what I can reasonably expect out of the system. So, I decided to write my own model, a "Solar Energy Estimator", and this book is the documentation for it. Section 2.3 below contains instructions on how to obtain the free Estimator itself.

After looking around on the internet and investigating other available analytical models, I decided to develop this Estimator according to these generic requirements:

a. It is to be readily available for free to anyone who wants it.

b. It is to be entirely self-contained, and not require access to any external databases.

c. It should require a reasonably small number of inputs, with guidance to the user.

d. It is to be applicable to all locations in the 48 Continental United States.

e. The source data is to be fully traceable, and the internal equations fully documented.

f. It is to run on common PC's with a common application.

g. It is to be flexible enough to accommodate technological advances.

h. It is to provide the user with insight on how the solar panel characteristics and geometry lead to overall performance.

It is not necessary to read or understand everything in this book in order to run the Estimator. Chapter 1 gives a brief historical outline of the progress made in solar panel technology along with a description of the differences between this Estimator and the on-line tool call PVWatts, which was developed by the National Renewable Energy Laboratory (NREL). This Estimator is not intended to compete with PVWatts. It is another way of looking at the same problem, and (I believe) gives greater insight as to how these systems operate. Chapter 2 is a summary of how to obtain the Estimator, its goals and limitations, what assumptions went into its development, and a list of the profuse acronyms used throughout.

Chapter 3 gives guidance to the user on how to generate the necessary inputs in order to run the Estimator. It alludes briefly to some of the underlying logic behind it, which is more fully explained in Chapter 5. Chapter 4 shows the outputs from the Estimator.

Chapter 5 is the "theoretical" portion, showing the derivation of the internal data and equations.

Chapter 6 contains nine worked examples to demonstrate the capabilities of the Estimator, and how to interpret the results. It includes the one proposed by the second analyst noted above.

Chapter 7 is the "programmers guide", which shows how all the data is arranged within the Estimator worksheet, and how the various equations from Chapter 5 are implemented.

Chapter 8 contains a few closing remarks which I hope will prove valuable in any considerations about the use of solar energy. I should state up front that I am fully in favor of using solar panels, since they do serve to reduce pollution, and may enable the U. S. to partly become less dependent on foreign energy sources. But solar should be used only when economically feasible and when it provides a reasonable return on investment.

The casual user only needs to read chapters 3, 4, and 6 to become fully versed in the operation of the Estimator. Section 5.9 contains a useful guide on how to read and interpret a solar panel datasheet. The rest of Chapter 5 and Chapter 7 are of interest only to those who care about the underlying physics or who have recommendations on how to improve the Estimator.

1 Introduction

1.1 Historical Background

Solar panel technology has come a long way in the past 70 years or so and is now at the point where it is sometimes economically viable to convert the sun's energy directly into electricity. Paul M. Erlandson gave a review paper at the 1955 World Symposium on Applied Solar Energy in which he stated (with my explanatory comments in square brackets) in part [1.1-1]:

> "*The Photovoltaic effect in Boundary Layers*: A piece of crystalline material such as silicon which includes a junction between a lattice with an excess of electrons and a lattice with an excess of electron holes can absorb light at the junction, and can convert this light into an electrical voltage. … Early working models achieved efficiencies of approximately 6 percent, delivering power at the rate of about 60 watts per sq. meter of surface [illuminated with 1000 W/sq m at normal incidence]. Improvements to at least 12 percent have been announced."

Gerald L. Pearson also gave a paper at the same symposium, describing actual experiments made at the Bell Telephone Laboratories [1.1-2]; again I have added explanatory comments in square brackets:

> "Under these operating conditions [1000 W/sq m. irradiance directly onto the solar cells] the efficiency is about 11 percent. That is, the electrical power dissipated in the load is 11 percent of the total radiant energy subtended by the cross section of the cell. … Let us consider this efficiency figure. Although there is considerable room for improvement, this value of 11 percent is better, by a factor of 20, than the best previous photovoltaic device. We are optimistic that in time this value can be raised up to 15 or 20 percent."

Nearly all the other papers presented at that symposium addressed thermodynamic uses of solar energy: high temperature furnaces, direct home heating, growing algae, and distillation of water. Keep in mind that this was written during the vacuum-tube era, although advances in solid-state devices would accelerate in the next two decades.

Now fast forward to 1976, when A. B. Meinel and M. P. Meinel published their classic text on solar energy [1.1-3]:

> "The most widely used and technically developed type of solar cell is the silicon cells. Its popularity stems not from its scientific excellence but from the fact that it builds on the extensive solid-state technology and manufacturing experience of the semiconductor industry. … Most commercial cells yield 10% conversion efficiency; some now approach 15% in reliable quantities. The cost of solar silicon cells is, however, so high that their use as an energy supply for terrestrial applications is limited to specialized remote applications where the cost of power is minor compared to other costs …"

Here we are in 2022, having achieved great improvements in both cost reduction and efficiency. Installation costs now hover around $1,000 per sq. m., and efficiencies are between 18 and 22%. That means that direct-conversion of solar radiation to electricity is now viable under certain circumstances. But that does not mean that every door-to-door solar panel salesman is telling you the whole story. The "circumstances" vary a great deal, and without some attention to the details, it is easy to be led astray as to whether a solar panel installation is appropriate for you.

The purpose of the Estimator is to permit the user to determine if they fall into the proper circumstance for economic viability. It requires a small number of inputs and provides an assessment of power generated, utility cost avoided, and return on investment (ROI).

1.2 Comparison with Other Models

The National Renewable Energy Laboratory (NREL) has developed two solar panel models, PVWatts [1.2-1] and SAM [1.2-2]. The former is an on-line program and is intended to provide an approximate assessment of the utility of a solar installation; the latter is a more detailed model that encompasses a wide variety of possible applications.

The PVWatts program uses a different set of inputs than this Estimator. Figure 1.2-1 illustrates the differences. PV Watts uses the "nameplate" DC output power rating under STC conditions, which is a laboratory specification; whereas the Estimator uses the overall efficiency under nominal operating cell temperature (NOCT) conditions. The NOCT conditions provide a more realistic view of performance in the field, and the differences between these two laboratory conditions are explained further in section 5.9. The PVWatts user can specify the module type; "standard" designating older model with efficiencies between 0.14 and 0.17; "premium" designating modern systems with efficiencies of 0.18 to 0.20, and "thin film" designating the newer but low efficiency (0.11) types still in development. The Estimator requires an efficiency input directly and there is a Utilities page to assist the user in making the input; inputs up to the currently-demonstrated 0.34 are permitted.

Input Parameters	PVWatts Version 5	This Estimator
System sizing	DC output per the "nameplate" rating at STC conditions, kW	Physical area
Module Type	"Standard", "Premium", "Thin Film"	No corresponding input
System losses	Default = 14%	Calculated per temperature conditions and efficiency at NOTC conditions
Array Type	Fixed open rack, Fixed roof mount, 1-Axis, backtracked 1-Axis, 2-Axis; used to calculate effect of wind	No corresponding input; installtion is assumed to be a free-standing mount; no accounting for wind effects
Installation Geometry	Tilt Angle, Azimuth Angle	Tilt Angle, Azimuth Angle
Conversion from DC to AC	DC/AC ratio, inverter efficiency	One overall conversion efficiency input
Weather Conditions	No input	Cloud location
Location	Per latitude/longitude	Per approximate latitude
Other inputs		Performance degradation after 25 years, AR coating limit, ground cover type, installation cost, current electricty rates, annual escalation rate

Figure 1.2-1: Inputs for PVWatts and This Estimator

PVWatts permits the user to assign system losses; 0.14 is the default but the user may override it. It is intended to include miscellaneous losses due to shading, dirt, wiring, age, and a few other items. The Estimator does not require a corresponding input from the user. Any miscellaneous losses must be included in the DC-AC conversion efficiency. Otherwise, the Estimator only corrects the input NOCT efficiency for ambient temperature vs. laboratory test temperature. The PVWatts model also corrects for temperature in addition to the system losses entered here. PVWatts allows several installation types to be modeled, including tracking systems, and apparently accounts for temperature effects due to wind conditions. The Estimator only analyzes fixed systems, and there is no adjustment for wind.

The installation geometry is the same for both models; which includes approximate geolocation as well as tilt angle and orientation with respect to due north. The inputs for DC to AC conversion are similar, except in PVWatts there is an assumption of a 0.909 conversion efficiency plus a further degradation due to inverter efficiency. These are combined in the Estimator into a single overall DC-to-AC conversion factor.

The PVWatts model does not require any inputs for weather conditions; the specifics of annual solar irradiance are drawn from an internal database from which the overall performance is calculated on a daily basis. Both models use the same equation for determining the total angle between the sun and the normal vector of the solar panel. But the Estimator also requires the user to designate a "cloud location", which in turn is used to access an internal database of cloud cover fraction as a function of season. Cloud cover values derived from data collected by the U. S. Department of Energy is used to attenuate the amount of energy actually impinging on the solar panel per season. The Estimator uses internal data derived from the Air Force Geophysics Laboratory (AFGL) LOWTRAN7 model for solar irradiance, diffuse sky radiance, and diffuse cloud radiance. The Estimator permits the user to designate a ground cover type, for which pre-calculated effective reflectances are used to calculate the ground contribution. The PV Watts model assumes a ground reflectance of 0.2. The Estimator also requires inputs of the anti-reflection (AR) coating limit, which causes some attenuation of the incident radiation.

The Estimator requires inputs for current electricity rates, an annual escalation rate, the 25-year power degradation of the solar panels, and the installation cost as a way to estimate overall cost avoided and return-on-investment. A Utilities page and website references are provided to assist the user in making these inputs.

Figure 1.2-2 shows the outputs from the two models. PVWatts gives the totals on a monthly basis, whereas this model shows only seasonal averages. The Estimator also calculates return on investment based on installation cost, long-term degradation of solar panel performance, current electricity rates, and estimated escalation of utility rates, which are not outputs from the PVWatts model.

Parameter	PVWatts Version 5	This Estimator
Solar Radiation	Average solar radiation in kWh per sq m per day for each month	Average direct solar irradiance, diffuse sky radiance, and diffuse cloud radiance for each season
AC Energy	AC output from solar panel in kW-hr for each month	Averge daily power generated for each season (winter, spring, summer, and fall) segregated by type (direct solar, diffuse sky, diffuse clouds, and ground reflectsion).
Value	Monthly value of generated solar power, based on electricity rates based on input location	Average value per eason, total generated over 25 years, total cost avoided over 25 years, return-on-investment

Figure 1.2-2: Outputs from PV Watts and This Estimator

References

[1.1-1] Paul M. Erlandson, "Direct Conversion of Solar Energy", *Proceedings of the World Symposium on Applied Solar Energy*, Phoenix, AZ, 1955, Menlo Park, CA: Stanford Research Institute, 1956, pp. 269, 270

[1.1-2] Gerald L. Pearson, "Electricity from the Sun", *Proceedings of the World Symposium on Applied Solar Energy*, Phoenix, AZ, 1955, Menlo Park, CA: Stanford Research Institute, 1956, p. 285 Pearson was co-inventor of the Bell Solar Battery (cf. Proceedings, p. 303).

[1.1-3] Aden B. Meinel, Marjorie P. Meinel, *Applied Solar Energy: An Introduction*, Reading, MA: Addison-Wesley Publishing Company, 1976, p. 528

[1.2-1] Aron P. Dobos, *PVWatts Version 5 Manual*, National Renewable Energy Laboratory, Technical Report NREL/TP-6A20-62641, Sep 2014 The PVWatts calculator may be accessed at: https://pvwatts.nrel.gov/

[1.2-2] NREL System Advisor Model (SAM), http://sam.nrel/gov.2014

2
Description of the Estimator

2.1 Purpose

The purpose of the Estimator is to calculate the total power generated and cost benefit of a solar panel array based on a small number of inputs. The main goal is to permit the user to determine whether solar panels are an economically viable choice for the user's location, given the current properties of solar panel performance and the electricity rates prevailing in the user's area.

2.2 An Excel® Spreadsheet

The Estimator is contained on one Excel® [2.2-1] worksheet, and a second worksheet provides some utilities to aid in making inputs. It is self-contained: it does not contain any macros, external libraries, nor does it access any external databases. All of the cells requiring user inputs are colored in green, and output cells are colored in tan. There are a few constants that are colored in yellow.

All the cells are locked except for the user inputs. The Estimator and Utilities worksheets are password-protected.

2.3 Availability

The Estimator is available for free download at https://fremontvalleybooks.com. The file name is SolarEnergyEstimator_V1p0.xlsx.

2.4 List of Inputs

The inputs include: a) a pull-down menu for nearest latitude of the installation; b) a pull-down menu for nearest location in order to assign cloud cover metrics; c) panel physical area; d) panel orientation (azimuth from north, tilt from horizontal); e) panel performance metrics (nominal conversion efficiency, claimed output after 25 years, anti-reflection coating properties, coefficient of temperature, and DC-AC conversion efficiency); f) surrounding ground type; g) net installation cost after incentives; h) current electricity rates; and i) the annual rate at which electricity rates are expected to increase.

Section 3 of this book provides considerable guidance on developing the inputs.

2.5 List of Outputs

The scalar outputs include: a) total power generated in the initial year, b) total power generated in 25 years; c) cost avoided in the first year; d) total cost avoided after 25 years, and e) return on investment (ROI). ROI is defined here as the number of years it takes for the solar panels to generate enough electricity to cover the installation cost.

Several outputs are provided in chart form, showing: a) sun angles; b) conversion efficiency for directly sunshine; c) the amount of directly-transmitted irradiance; d) the power generated from each radiation component; and e) ROI.

2.6 Utilities

A Utilities worksheet provides assistance for: a) converting degrees:minutes:seconds coordinates to decimal degrees; b) converting sq. ft. to sq. m.; c) calculating the distance to the nearest cloud location applicable to the intended installation location; d) finding the properties of modern solar panels to aid in making the inputs cited in section 2.4; and e) calculation of efficiency from solar panel datasheet values.

2.6 Development Assumptions

The Estimator was developed under the following assumptions. First it is assumed that the solar panels are fixed, and there is no sun-tracking capability. This is the usual case for most installations. Secondly, the Estimator is valid only for Silicon solar cells, as they are the most common and most cost-effective at this time. Third, the Estimator is based on the assumption that the solar panels are connected to the utility power grid (i.e., it does not model standalone systems with battery storage). Most installations generate power during the day and any excess over immediate usage is provided to the electric grid in return for credits against the owners' electric bill.

2.7 List of Acronyms

AC	Alternating current
AFGL	Air Force Geophysics Laboratory
AOI	Angle-of-incidence
AR	Anti-reflection (refers to coatings on the outer glass surface of a solar panel)
C	Celsius (or Centigrade) temperature
DC	Direct current
DNI	Direct Normal Irradiance (referring to direct solar radiation)
FOR	Field-of-regard
kWh	Kilowatt-hour
LOS	Line-of-sight
MLS	Mid-Latitude Summer, a generic model within the LOWTRAN7 atmospheric code
MLW	Mid-Latitude Winter, a generic model within the LOWTRAN7 atmospheric code
MPH	Miles per hour
NM	Nautical miles
NMOT	Nominal Module Operating Temperature
NOCT	Nominal Operating Cell Temperature
NREL	National Renewable Energy Laboratory, a division of the U. S. Department of Energy
ROI	Return-on-investment
STC	Standard Test Conditions
USS	1976 U. S. Standard atmosphere, a generic model within the LOWTRAN7 atmospheric code

References

[2.2-1] Excel is a registered trademark and product of the Microsoft Corporation.

3
User Inputs

This chapter describes the required user inputs to the Estimator. All user inputs are shown in green cells as depicted on Figure 3-1. All the cell references in this chapter refer to the Estimator worksheet unless stated otherwise. Every change in an input automatically causes the Estimator to re-calculate the outputs. Don't be concerned with any of those intermediate results until you have entered all necessary inputs attendant to your proposed installation.

Inputs		Units	Symbol
Choose time zone, nearest latitude	C 30 New Orleans, LA		
Choose cloud location	Houston, TX		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	36	deg	epsilon
Panel Total Area	20	sq m	A_p
Panel Efficiency, NOCT	0.210	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	78	deg	A
Temperature Coefficient	-0.0034	%/100 °K	C_T
Ground Type, Winter	Beach Sand		
Ground Type, Spring	Beach Sand		
Ground Type, Summer	Beach Sand		
Ground Type, Fall	Beach Sand		
DC-AC Conversion efficiency	0.91		
Installation cost	15000	$	
Annual Electricity Escalation Rate	0.0186	%/100	
Constants			
Lab Temperature	298.15	K	

		Electricity Cost per kWh, dollars			
Local time	**24-hr**	**Winter**	**Spring**	**Summer**	**Fall**
Midnight to 1 AM	0.5	0.1206	0.1206	0.1206	0.1206
1 AM to 2 AM	1.5	0.1206	0.1206	0.1206	0.1206
2 AM to 3 AM	2.5	0.1206	0.1206	0.1206	0.1206
3 AM to 4 AM	3.5	0.1206	0.1206	0.1206	0.1206
4 AM to 5 AM	4.5	0.1206	0.1206	0.1206	0.1206
5 AM to 6 AM	5.5	0.1206	0.1206	0.1206	0.1206
6 AM to 7 AM	6.5	0.1206	0.1206	0.1206	0.1206
7 AM to 8 AM	7.5	0.1206	0.1206	0.1206	0.1206
8 AM to 9 AM	8.5	0.1206	0.1206	0.1206	0.1206
9 AM to 10 AM	9.5	0.1206	0.1206	0.1206	0.1206
10 AM to 11 AM	10.5	0.1206	0.1206	0.1206	0.1206
11 AM to noon	11.5	0.1206	0.1206	0.1206	0.1206
noon to 1 PM	12.5	0.1206	0.1206	0.1206	0.1206
1 PM to 2 PM	13.5	0.1206	0.1206	0.1206	0.1206
2 PM to 3 PM	14.5	0.1206	0.1206	0.1206	0.1206
3 PM to 4 PM	15.5	0.1206	0.1206	0.1206	0.1206
4 PM to 5 PM	16.5	0.1206	0.1206	0.1206	0.1206
5 PM to 6 PM	17.5	0.1206	0.1206	0.1206	0.1206
6 PM to 7 PM	18.5	0.1206	0.1206	0.1206	0.1206
7 PM to 8 PM	19.5	0.1206	0.1206	0.1206	0.1206
8 PM to 9 PM	20.5	0.1206	0.1206	0.1206	0.1206
9 PM to 10 PM	21.5	0.1206	0.1206	0.1206	0.1206
10 PM to 11 PM	22.5	0.1206	0.1206	0.1206	0.1206
11 PM to midnight	23.5	0.1206	0.1206	0.1206	0.1206

Figure 3-1: Input Section of the Estimator

3.1 Time Zone and Nearest Latitude Selection

Choose the best combination of time zone and latitude from the pull-down menu at cell D5. The first letter of the selections in the list are E, C, M, or P to denote the time zone (Eastern, Central, Mountain, and Pacific). The next portion of the label is the latitude in degrees, and the third is the name of a city and State. There are five or six selections for each time zone. Figures 3.1-1 through 3.1-4 [3.1-1] indicate the time zones and available selections as indicated by the red star. Choose the appropriate location based on the time zone and latitude of your solar panel installation.

There are two simple methods to obtain the latitude of your location. First, it can be looked up in Wikipedia; normally it will provide the latitude and longitude in degrees, minutes, and seconds (D:M:S). The decimal equivalent of D:M:S latitude coordinates can be calculated using the conversion system located in section 1 of the Utilities worksheet. Only the latitude is required for this selection. For example, suppose your location is Lordsburg, NM, located at N 32° 20' 49" latitude and W 108° 42' 26" W longitude. Select the Utilities page and enter the values in cells C4 to E5. Keep in mind that all longitudes in the U. S. are west of Greenwich, England, and therefore are negative. So the cell entries should be: C4 = 32, D4 = 20, E4 = 49, C5 = -108, D5 = 42, and E5 = 26. The result as shown in cells C8 and C9 is 32.34694° latitude and -108.70722° longitude. Only the latitude is necessary for the selection in cell D5 on the Estimator sheet. Since Lordsburg is in the Mountain Time Zone, Figure 3.1-3 indicates that Tucson, AZ is the correct selection in cell D5, since the 32.34694° is less than the 33.9° latitude of Socorro, NM.

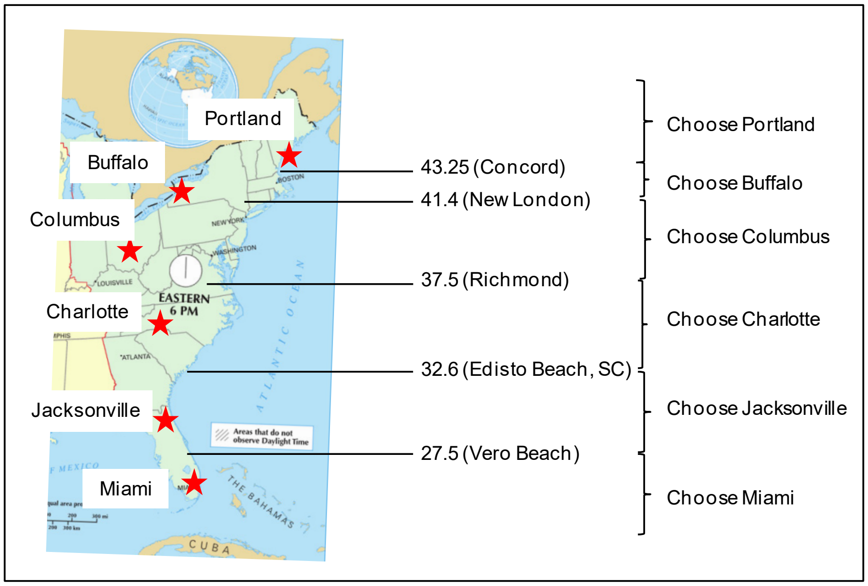


Figure 3.1-1: Latitude Selections for the Eastern Time Zone [3.1-1]

A second method is to use Google Maps® (https://www.google.com/maps) [3.1-2]. In the upper left box (where it says "Search Google Maps"), enter the name of your location. The map will shift to that area. Use the mouse to select a point on the map, and right-click. It will show the latitude and longitude in decimal coordinates. An alternate method is to right click a known point (such as your house) and select "What's here?"; it will show the decimal latitude and longitude coordinates at the bottom of the page. For example, the coordinates of the intersection of E. Honeoye St. and N. Stevens St. in Shinglehouse, PA are 41.96675, -78.18697. Referring to Figure 3.1-1, this latitude lies between that of New London and Concord; so Buffalo, NY is the correct latitude selection for Shinglehouse, PA.

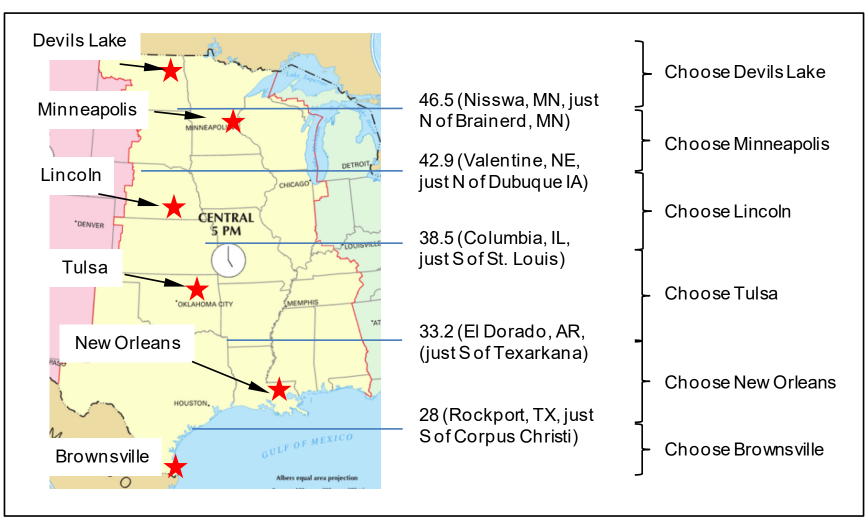


Figure 3.1-2: Latitude Selections for the Central Time Zone [3.1-1]

If the location lies on a boundary, choose either of the adjacent selections. For example, if the installation is in Valentine, NE, either Lincoln or Minneapolis is acceptable as the nearest latitude as shown on Figure 3.1-2.

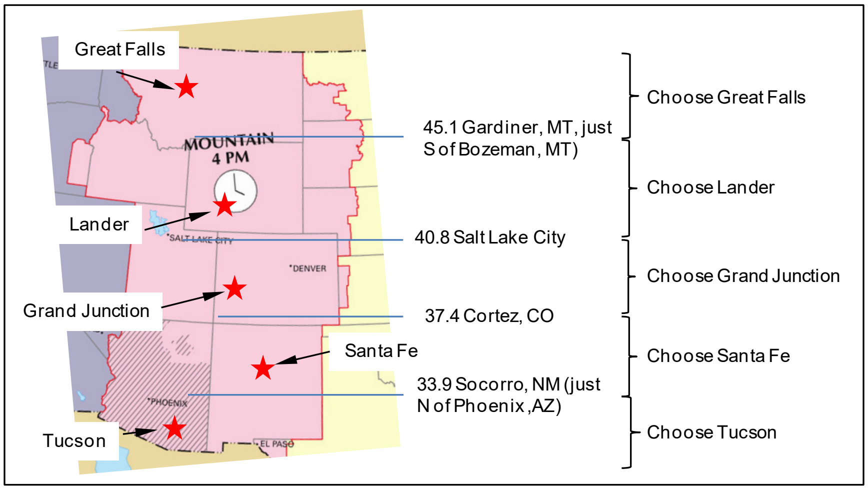


Figure 3.1-3: Latitude Selections for the Mountain Time Zone [3.1-1]

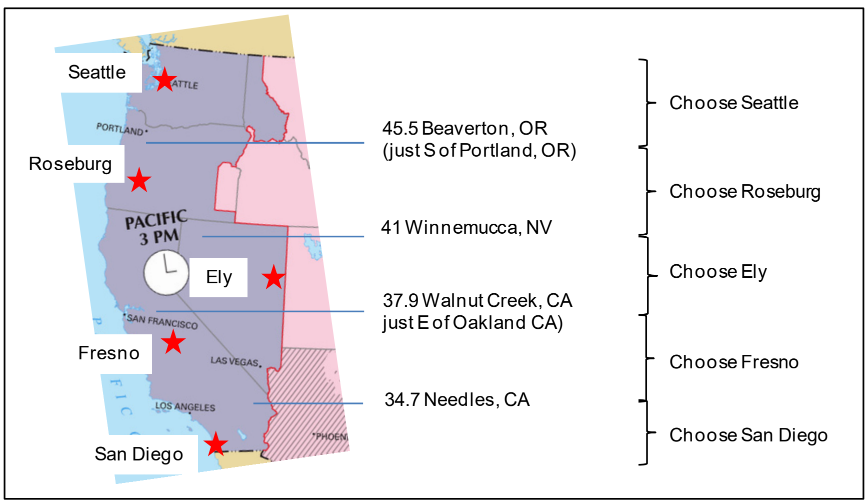


Figure 3.1-4: Latitude Selections for the Pacific Time Zone [3.1-1]

3.2 Nearest Cloud Location

The Estimator contains average cloud cover data for 188 locations in the continental U. S. Use the pull-down menu at cell D6 to select the one closest to the solar panel installation location. The cloud locations are listed alphabetically by city name and State name.

Section 3 of the Utilities page contains a calculator to determine the nearest distance between the solar panel location and a location with cloud data. Distances are calculated using Great Circle geometry. Select the 'Utilities' tab and enter the solar panel location in cells K4 and K5. For example, using Google Maps, suppose the solar panel is to be located in Baton Rouge, LA at coordinates 30.43067, -91.12559. Entering that location in cells K4 and K5 of the Utilities page, the spreadsheet calculates the distance to the nearest cloud location. For Baton Rouge, the closest cloud location is New Orleans, LA, at a distance of 59.95 nautical miles (NM) as indicated in cells K7 and K8. The Estimator does not calculate the second-closest location (in this case, Vicksburg, MS at 114.26 NM), and it is necessary to do a manual search in column T to obtain the next closest one.

Suppose the solar panel installation is to be in League City, TX at coordinates 29.50911, -95.13809. From the Utilities page, the closest cloud location is Galveston, TX at 20.95 NM, but the second closest is Houston, TX at 22.21 NM. Which one to choose is a matter of opinion or local knowledge (it turns out that Galveston is less cloudy than Houston). Once again, the Estimator makes no attempt to arbitrate these local differences.

Selection of the cloud location probably requires some discretion without relying solely on the closest location. Since New Orleans is on the Gulf of Mexico, its cloud statistics may well be very different than an inland point like Baton Rouge, and it may well be that Vicksburg, MS, another inland location, is a better choice. The Estimator does not attempt to arbitrate coastal vs. non-coastal considerations; it simply chooses the nearest point.

The cloud location selection also determines the atmosphere type utilized in LOWTRAN7 to calculate the direct solar irradiance and diffuse sky radiance. Two options are in the model: a) the 1976 U. S. Standard with desert, 70 km visibility; and b) the Mid-Latitude Summer, 23 km rural visibility atmosphere. Figure 3.2-1 [3.2-1] shows all the available cloud locations. The red markers indicate where a desert atmosphere is used to model the solar irradiance and sky radiance, and the violet markers indicate a Mid-Latitude atmosphere. If the solar panel installation in between a red and violet marker, then some judgment is required as to what cloud location is appropriate to describe the general atmospheric environment. The Estimator does not attempt to arbitrate these conditions. If the closest cloud location is inconsistent with the general atmosphere type, it may be necessary to choose another nearby cloud location. For example, choosing the cloud location for a solar panel installation located halfway between Austin, TX and San Antonio, TX is a matter of opinion to be decided by the user.

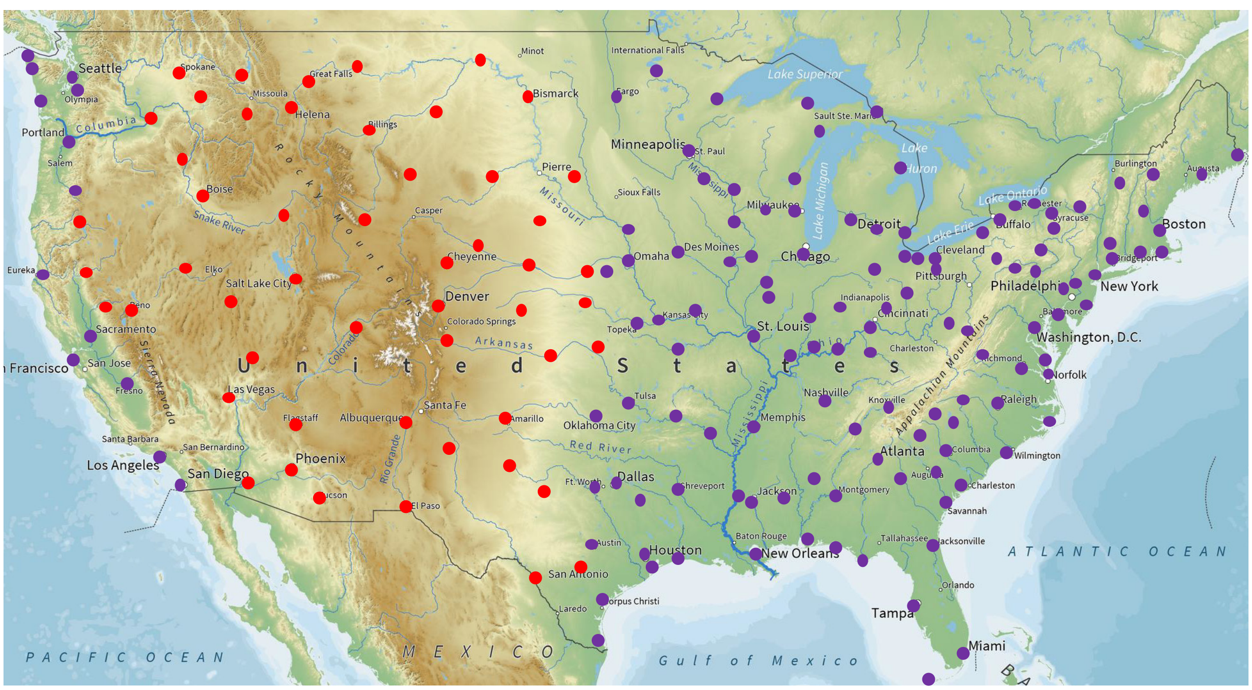


Figure 3.2-1: Cloud Locations and Desert vs. Mid-Latitude Atmosphere Type [3.2-1]

Some objection may be made to the use of single-value cloud statistics as a means to determine the fraction of direct sunlight that prevails over the long run. There are two interpretations that can be made. First, the fraction of cloud cover could be interpreted as the fraction of days during a given season in which the sky is completely overcast, and the rest of the days are entirely cloud-free. That is not usually the case, although it may be fairly close in places like Buffalo and Seattle in the winter months. It is approximately correct for all four seasons in Phoenix (i.e., usually it's either entirely clear or it's not). The second interpretation, the one used in the Estimator itself, is that the cloud fraction applies to partly cloudy conditions. Is what it says it is: the nominal fraction of the sky that is cloudy during daylight hours, averaged over the long term. However, it is not certain that, for any time of day, over the long run, the cloud fraction is the fraction of time that clouds block the direct LOS to the sun. For example, it is known that clouds are common throughout the morning in San Diego, but the afternoons are generally clear. The opposite is true in Vero Beach, FL. It was necessary to modify the raw cloud fraction data in order for the directly transmitted solar irradiance to match measurements, as described in Appendix A.

Warning: Any combination of nearest latitude and cloud location is permitted; one could select Portland, ME as the nearest latitude and Yuma, AZ as the cloud location, although doing so would clearly be illogical. The Estimator does not check for consistency between these two entries.

There is one additional choice that can be made in the cloud location: the every last one, called "Cloud Test Case". Changes to the cloud fractions for this selection are user-defined in cells CP227 to CS227. It is intended only as a test case to check against other models, and an example of its use is shown in a worked example in section 6.8.

3.3 Electricity Costs

Enter the cost of electricity on an hourly basis in dollars/kWh in cells J5 to M28. Eleven cents per kWh is entered as 0.11. Many utility companies charge higher rates for "peak usage" times, normally in the afternoon, and provision is made here in the Estimator to account for the rate changes. For average electricity costs, refer to https://www.electricitylocal.com, which gives the values for a wide variety of locations in the U. S.

The Estimator requires an input for every hour of the day not only for intra-day rate changes, but also to model cases in which there is a total or partial blockage of the direct sun. To handle blockages, simply zero out the electricity costs for the hours in which the sun is blocked by mountains, trees, adjoining structures, etc. The rationale is that zeroing the electricity cost out implies that there will be no economic benefit during those periods, and calculated power is made valid only for hours in which the electricity rates are non-zero. (Cloud blockage is handled automatically by the cloud location selection above). Typing in every value for every hour and season can be avoided if the electricity costs are the same for a series of hours by using the cut-and-paste feature in Excel®.

3.4 Solar Panel Geometry

Enter the solar panel azimuth angle β (East of North) in cell D7 and the panel tilt angle ε in cell D8 per the geometry on Figure 3.4-1. Angles are entered in degrees. For a panel oriented due east, the azimuth β is 90°; for due south; the azimuth β is 180°; for south-south-east, is 150°; for south-west, is 225°. Any value between 0° and 360° is permitted. For a panel lying flat, the tilt angle ε is 0°; for a vertical wall, the tilt ε is 90°; if the panel is tilted toward the ground, the angle would be greater than 90°. Only tilt values between 0° and 90° are permitted. In this convention, the tilt is the angle that the top of the panel is inclined toward the direction of the panel azimuth (the bottom of the panel is fixed). The example in Figure 3.4-1 shows a solar panel oriented at 150° azimuth and tilted at 25°.

Enter the area of the solar array in cell D9 in square meters. The exact orientation or configuration of the panels is not important, so long as all of them lie in the same plane. If the dimensions you have are in square feet, the Utilities page, section 2 contains a conversion routine (cf. Utilities page, cells C14 and C15).

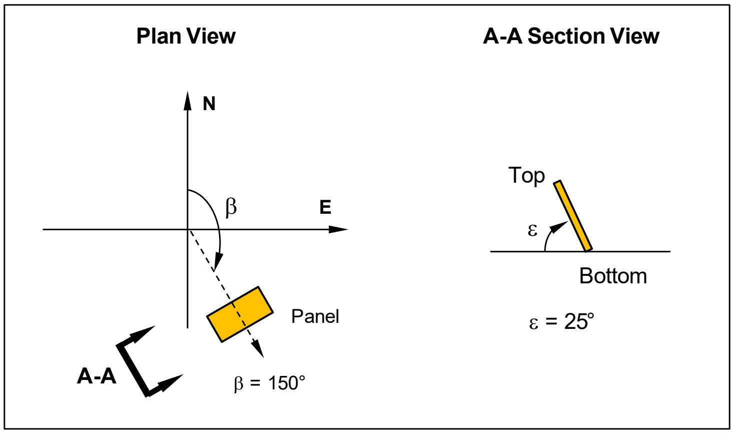


Figure 3.4-1: Solar Panel Orientation Geometry

3.5 Solar Panel Efficiency

Enter the nominal efficiency of the solar panel in cell D10. 'Nominal' efficiency is defined as the efficiency under 'nominal' operational conditions: a) 800 W/m^2 direct irradiance; b) 20° C ambient; and c) 1 m/s wind speed, also known as the NOCT conditions. NREL has published a paper [3.5-1] describing an experimental panel that has obtained an efficiency of 0.34. The ultimate theoretical efficiency is estimated at 0.40. Note that these values represent the efficiency of conversion from sunlight to direct current (DC) power; there is an additional efficiency factor discussed in section 3.10 that addresses the conversion from DC to alternating current (AC).

The nominal efficiencies are normally published in the manufacturer's datasheets, although occasionally they are omitted. It can be calculated as follows:
a. Find the power output in watts in the datasheet for the NOCT conditions stated above.
b. Calculate the area of the panel. Normally the dimensions are listed in mm, including the frame. Each frame dimension is normally about 25 mm unless stated otherwise. Then, the active area is [length - 50 mm] times [width - 50 mm]. This gives the active area in mm^2; divide by one million to obtain the area in square meters.
c. The nominal efficiency to be entered in cell D10 is then:

$$e = \frac{power\ output}{800 * area}$$

where the power output is in watts, and the area is in sq m. Section 5 of the Utilities page performs this equation.

Section 4 of the Utilities page shows the properties of several candidate solar panels. For example, cells W28 through AE28 show the properties called out in the VikramSolar Somera VSM H.78.475.05 datasheet. It cites a total length of 2288 mm x 1050 mm, and outputs 351.5 W under nominal (NOCT) conditions. Subtracting 50 mm from each dimension, the active area is then [(2238)(1000)]/1000000 = 2.238 sq m; and the efficiency is 351.5/[(800)(2.238)] = 0.196, as shown on the Utilities page, cell AA28.

The Utilities page, section 4 shows the efficiency calculations for a variety of commercial solar panels (cf. column AA). The mean value for this representative set is 0.208 as shown in cell AA44, although several of the larger formats claim efficiencies up to 0.225. A reasonable estimate for solar panel efficiency is 0.19 to 0.21. The Estimator uses only the NOCT efficiency values, although other efficiencies a different test condition, called STC, are also cited in most datasheets. Green et. al. [3.5-2] reported on solar cell efficiencies in 2013 under STC conditions; for Silicon, they ranged from 10.5% for thin-film to 25.0% for crystalline. STC (laboratory) vs. NOCT (operational) differences are discussed in section 5.9.

3.6 Power Fraction after 25 Years

Solar panels experience a decline in efficiency due to aging of components and long-term temperature cycling. Every manufacturer makes claims/guarantees about the resilience of their panels; typically they are stated as a certain fraction of maximum output power guaranteed after so many years (usually 20, 25, or 30). Enter in cell D11 on the Estimator page the fraction of power claimed by the manufacturer at the end of 25 years. The Utilities page, section 4, shows tabulated 25-year claims for a variety of commercial solar panels; the average is 0.847 as indicated in cell AD44. Reasonable values for this entry range from 0.82 to 0.90.

3.7 Anti-Reflection Coating Limit

Every solar panel consists of cells that convert the incident radiation to electrons, but they must be protected from the elements. Usually a thin sheet of tempered heat-resistant glass is used, varying in thickness from 2.0 to 3.2 mm (0.078" to 0.125"). Bare glass produces a reflection at normal incidence according to the relation:

$$r_G = \left[\frac{n-1}{n+1}\right]^2$$

where n is the refractive index of the glass. The reflections become greater at higher angles of incidence from normal. Most glass materials have a refractive index between 1.45 and 1.55 or so, and the reflection at normal incidence is therefore between 3.37% and 4.65%. This represents a direct loss to the solar panel. The remedy is to apply an anti-reflection (AR) coating designed to match the refractive index of the glass to the air in order to reduce the reflections down to a very low level (0.5% to 1%). However, the AR coating has the same problem as bare glass: the reflections become very large as the angle of incidence increases. In practice, the reflections become infinite at some definite angle off normal. Chhajed et al [3.7-1] has reported the development of a three-layer graded AR coating deposited on Silicon solar cells that is effective up to about 80°. Priyadarshini et. al. [3.7-2] has shown similar performance for the glass cover. Enter the maximum AR coating limiting angle in degrees in cell D12. Practical values range from a minimum of 60° to 85°; 87° is the maximum entry allowed.

3.8 Temperature Coefficient

Solar cells exhibit decreasing efficiency as they heat up, and the decline is expressed in the datasheets as a certain percent decline per degree C (or K). Enter the temperature coefficient in cell D13 as a decimal. Section 4 of the Utilities page (column AC) shows the temperature coefficient for a variety of commercial solar panels. The values here use the data from the datasheets divided by 100, as the Estimator uses decimal fractions instead of percentages. Notice that the temperature coefficients are all negative which means that the efficiency decreases with increasing temperature. The temperature coefficients for the panels studied range from -0.0029 to -0.0041 with an average of -0.0034 as shown on cell AC44 of the Utilities worksheet.

3.9 Ground Cover

Select the ground cover type using the pull-down menus for each of the four seasons in cells D14 to D17. Figure 3.9-1 shows the available selections and their associated effective reflectance. The effective reflectance was defined and calculated off-line from spectral data as described in section 5.13.

Material Type	Typical Location	Effective Reflectance
Beach Sand	All beach areas	0.239
Chernozem Soil	Midwest U. S. (Kansas)	0.132
Concrete		0.207
Conifer Meadow	Grassy areas in Western U. S.	0.120
Douglas Fir Forest	West of Rocky Mountains, esp. AZ, CA, ID, MT, NM, OR, WA, WY	0.071
Laterite Soil	Dark Soil (Eastern U. S. ~ North Carolina)	0.187
Lava		0.100
Leafy Spurge	Open areas in U. S. with high fraction of vegetation	0.139
Maple Forest	Northeastern and North Central U. S.	0.332
Marsh	Southeastern and Eastern U. S.	0.202
Oak Forest	East of Mississippi River, but including IA, MO, AR, LA	0.458
Pedalfer Soil 1	Southeast U. S. (Georgia)	0.228
Pedalfer Soil 2	Western U. S. (Colorado)	0.385
Pedocal Soil	Midwest U. S. (Nebraska)	0.369
Pine Forest	Pine forest in temperate regions	0.365
Populus Forest	Poplar, Aspen, Cottonwood	0.482
Rangeland Blue	Open areas in Eastern U. S. with sparse vegetation	0.152
Rangeland Sage	Open areas in Southwestern U. S. with sparse vegetation	0.123
Sand	High Desert in U. S. (New Mexico)	0.612
Seawater Coastal	All coastal areas	0.024
Snow		0.703

Figure 3.9-1: Ground Cover Types and Effective Reflectance

If the area surrounding the solar panel installation is bare soil or farmland, choose Chernozem, Laterite, Pedalfer, Pedocal, Rangeland Blue, Rangeland Sage, or Sand, depending on the geographical location. Most of the Northeastern U. S. bare soil is closest to the Laterite type. If the area has a large amount of green vegetation, choose either the Conifer Meadow (western States) or Leafy Spurge (eastern States). Other choices unique to specific geographical areas include Marsh (Southeast U. S.), Beach Sand (on lake or ocean coasts), or Coastal Seawater. Several forest options are available depending on geographical location. A selection is required for each season such that snow may be selected in wintry locations. Concrete is a suitable choice for most urban areas.

3.10 DC-AC Conversion Efficiency

Solar panels produce direct-current (DC) power, which has to be converted to alternating current (AC) before being connected to the commercial power grid. Enter the conversion efficiency in cell D18 as a decimal. Typical conversion efficiencies range from 0.88 to 0.93. This value is utilized by the Estimator to calculate the total net power provided either to the home or back to the power grid. This value should also include any miscellaneous losses such as dirt accumulation, which are usually around 3% (0.03) or so.

3.11 Installation Cost

Enter the net installation cost in dollars in cell D19 after all incentives and discounts are applied. This is the net cost to you, and the Estimator will utilize this value to determine the return-on-investment and the average cost of solar power per kWh. Currently, installation costs on rooftops run about $1,000 per sq meter, and there is in place a series of federal and State incentives. Several websites provide guidance on costs based on a per-watt basis. Keep in mind that these per-watt costs are rated against the "nameplate" panel ratings. For example, if your "nameplate" solar panel is 480 W (cf. Utilities page, cells W29 through AE29 for the Vikram Somera VSM H.78.480.05), the various websites [3.11-1] will quote on a per-watt basis. The current average in the U. S. is about $2.70 per watt, so this panel, as installed will run (2.70)(480) = $1,296. If you desire a rated 5.76 kW system, which would require 12 of these panels, the cost is (12)(1296) = $15,552 before any incentives, rebates, or tax credits. Suppose the total installation costs comes to $25,000, but there is a $7,500 combined and State incentive, the figure to be entered in cell D19 is 25000 - 7500 = 17500.

3.12 Annual Electricity Escalation Rate

Enter in cell D20 the amount by which the cost of electricity is expected to increase on an annual basis in your area, as a decimal. For example, if the local utility announces that the annual projected increase in electricity costs is estimated at 3.5%, enter 0.035 in cell D20. The Estimator assumes that this value is the average annual increase over the next 25 years. It utilizes this information to estimate the total value of the power produced by the solar system over that period, and from that, estimates the number of years before the solar system pays for itself by avoiding electric utility costs.

The U. S. Government has published a study [3.12-1, 3.12-2, 3.12-3] in which it found that average electricity costs have increased annually by 1.8% from 1994 to 2019 (thus would be entered as 0.018 in cell D20). That study was a nationwide average, but it did provide an analysis for each State. They range from a high of 0.0386 (3.86%) in Hawaii to a low of 0.0078 (0.78%) in Arkansas. The rate of past increase only gives approximate insight about future increases, and it would be best if local data could be found.

Average Residential Electricty Costs from Full-Service Providers, $/kWh [1]							
State	1990	1995	2000	2005	2010	2015	2020
Alaska	0.1011	0.1124	0.1145	0.1330	0.1626	0.1983	0.2257
Alabama	0.0659	0.0671	0.0705	0.0800	0.1067	0.1170	0.1257
Arkansas	0.0807	0.0798	0.0745	0.0800	0.0886	0.0982	0.1041
Arizona	0.0904	0.0909	0.0844	0.0886	0.1097	0.1213	0.1227
California	0.0998	0.1161	0.1085	0.1249	0.1474	0.1697	0.1984
Colorado	0.0702	0.0742	0.0731	0.0906	0.1104	0.1212	0.1236
Connecticut	0.1001	0.1195	0.1086	0.1364	0.1947	0.2038	0.2185
District of Columbia	0.0610	0.0762	0.0803	0.0909	0.1402	0.1230	0.1179
Delaware	0.0839	0.0909	0.0864	0.0901	0.1378	0.1329	0.1242
Florida	0.0777	0.0782	0.0777	0.0962	0.1144	0.1158	0.1127
Georgia	0.0746	0.0785	0.0760	0.0864	0.1007	0.1154	0.1202
Hawaii	0.1026	0.1332	0.1641	0.2070	0.2810	0.2960	0.3028
Iowa	0.0781	0.0824	0.0837	0.0927	0.1042	0.1163	0.1246
Idaho	0.0487	0.0533	0.0539	0.0629	0.0799	0.0993	0.0995
Illinois	0.0992	0.1037	0.0883	0.0834	0.1152	0.1255	0.1270
Indiana	0.0687	0.0674	0.0687	0.0750	0.0956	0.1157	0.1283
Kansas	0.0783	0.0792	0.0765	0.0790	0.1003	0.1234	0.1285
Kentucky	0.0569	0.0562	0.0547	0.0657	0.0857	0.1024	0.1087
Louisiana	0.0741	0.0723	0.0767	0.0887	0.0898	0.0933	0.0967
Massachusetts	0.0966	0.1126	0.1053	0.1325	0.1431	0.1940	0.2070
Maryland	0.0722	0.0843	0.0796	0.0844	0.1435	0.1343	0.1263
Maine	0.0930	0.1251	0.1292	0.0920	0.0547	0.1484	0.1643
Michigan	0.0873	0.0834	0.0853	0.0840	0.1246	0.1442	0.1626
Minnesota	0.0680	0.0717	0.0752	0.0828	0.1059	0.1212	0.1317
Missouri	0.0736	0.0725	0.0704	0.0708	0.0908	0.1121	0.1122
1. Source: U. S. Energy Information Administration, data per Reference 3.12-3							

Figure 3.12-1: Average Residential Electricity Costs, $/kWh, 1990-2020, Part 1

If you have an old bill and a recent bill, the average annual increase can be calculated using the equation:

$$Rate = \frac{\ln(recent) - \ln(old)}{number\ of\ years}$$

where ln is the natural log (available on most calculators). For example, if your bill from 2008 calls out 8.7 cents per kWh and the bill from 2021 calls out 12.7 cents per kWh, the rate to be entered in cell D20 is: [ln(12.7) - ln(8.7)]/13 = (2.54 - 2.16)/13 = 0.0292.

Figures 3.12-1 and 3.12-2 show the average residential electricity costs by State over the past 30 years in 5-year increments [3.12-3] in dollars per kW-hr. Notice that average electricity costs have actually decreased in some States in the past five years (cf. Delaware, Florida, Maryland, Mississippi, New Hampshire, Nevada, Ohio, Oklahoma, Pennsylvania, and Utah).

Average Residential Electricty Costs from Full-Service Providers, $/kWh [1]							
State	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**
Mississippi	0.0689	0.0699	0.0693	0.0871	0.0987	0.1127	0.1117
Montana	0.0545	0.0609	0.0648	0.0810	0.0916	0.1088	0.1124
North Carolina	0.0784	0.0812	0.0797	0.0865	0.1012	0.1128	0.1138
North Dakota	0.0626	0.0623	0.0644	0.0699	0.0813	0.0962	0.1044
Nebraska	0.0623	0.0637	0.0653	0.0714	0.0894	0.1060	0.1080
New Hampshire	0.1034	0.1350	0.1314	0.1351	0.1632	0.1862	0.1850
New Jersey	0.1036	0.1198	0.1029	0.1174	0.1658	0.1561	0.1595
New Mexico	0.0894	0.0893	0.0836	0.0913	0.1052	0.1247	0.1294
Nevada	0.0570	0.0711	0.0728	0.1020	0.1236	0.1276	0.1134
New York	0.1144	0.1390	0.1403	0.1586	0.1851	0.1780	0.1784
Ohio	0.0805	0.0860	0.0861	0.0819	0.1131	0.1277	0.1224
Oklahoma	0.0658	0.0682	0.0703	0.0795	0.0914	0.1014	0.1012
Oregon	0.0473	0.0549	0.0588	0.0725	0.0887	0.1066	0.1117
Pennsylvania	0.0922	0.0972	0.0935	0.0981	0.1268	0.1316	0.1289
Rhode Island	0.0984	0.1147	0.1128	0.1304	0.1593	0.1920	0.2175
South Carolina	0.0715	0.0753	0.0758	0.0867	0.1050	0.1257	0.1278
South Dakota	0.0695	0.0708	0.0742	0.0777	0.0897	0.1108	0.1175
Tennessee	0.0569	0.0591	0.0633	0.0698	0.0923	0.1030	0.1076
Texas	0.0720	0.0771	0.0796	0.1093	0.1160	0.1156	0.1171
Utah	0.0713	0.0694	0.0629	0.0752	0.0871	0.1088	0.1044
Virginia	0.0725	0.0784	0.0752	0.0816	0.1045	0.1137	0.1203
Vermont	0.0927	0.1052	0.1230	0.1296	0.1557	0.1709	0.1954
Washington	0.0439	0.0497	0.0513	0.0654	0.0804	0.0909	0.0987
Wisconsin	0.0663	0.0697	0.0753	0.0966	0.1265	0.1411	0.1432
West Virginia	0.0590	0.0650	0.0627	0.0621	0.0879	0.1008	0.1180
Wyoming	0.0597	0.0609	0.0650	0.0748	0.0877	0.1097	0.1111
1. Source: U. S. Energy Information Administration, data per Reference 3.12-3							

Figure 3.12-2: Average Residential Electricity Costs, $/kWh, 1990-2020, Part 2

Figures 3.12-3 and 3.12-4 show the average annual electricity rate increases from the year in the first row to 2020, based on the values in Figures 3.12-1 and 3.12-2. For example, the average increase in Colorado from 2005 to 2020 is 0.0207, and this is the type of value that is to be entered into cell D20. Use the starting year that you think is most appropriate for your location; for most locations, the values in the 1995 and 2000 columns are most suitable (for Colorado, is 0.0204 or 0.0263). There are some States (Idaho, Louisiana, Missouri, North Carolina, South Carolina, Texas, Wisconsin, and Wyoming) where the rate of increase was very low in the past five years.

Average Annual Rate Increases from Indicated Year to 2020 (decimal)						
State	1990	1995	2000	2005	2010	2015
Alaska	0.0268	0.0279	0.0339	0.0353	0.0328	0.0259
Alabama	0.0215	0.0251	0.0289	0.0301	0.0164	0.0143
Arkansas	0.0085	0.0106	0.0167	0.0176	0.0161	0.0117
Arizona	0.0102	0.0120	0.0187	0.0217	0.0112	0.0023
California	0.0229	0.0214	0.0302	0.0309	0.0297	0.0313
Colorado	0.0189	0.0204	0.0263	0.0207	0.0113	0.0039
Connecticut	0.0260	0.0241	0.0350	0.0314	0.0115	0.0139
District of Columbia	0.0220	0.0175	0.0192	0.0173	-0.0173	-0.0085
Delaware	0.0131	0.0125	0.0181	0.0214	-0.0104	-0.0135
Florida	0.0124	0.0146	0.0186	0.0106	-0.0015	-0.0054
Georgia	0.0159	0.0170	0.0229	0.0220	0.0177	0.0082
Hawaii	0.0361	0.0328	0.0306	0.0254	0.0075	0.0045
Iowa	0.0156	0.0165	0.0199	0.0197	0.0179	0.0138
Idaho	0.0238	0.0250	0.0307	0.0306	0.0219	0.0004
Illinois	0.0082	0.0081	0.0182	0.0280	0.0098	0.0024
Indiana	0.0208	0.0257	0.0312	0.0358	0.0294	0.0207
Kansas	0.0165	0.0194	0.0259	0.0324	0.0248	0.0081
Kentucky	0.0216	0.0264	0.0343	0.0336	0.0238	0.0119
Louisiana	0.0089	0.0116	0.0116	0.0058	0.0074	0.0072
Massachusetts	0.0254	0.0244	0.0338	0.0297	0.0369	0.0130
Maryland	0.0186	0.0162	0.0231	0.0269	-0.0128	-0.0123
Maine	0.0190	0.0109	0.0120	0.0387	0.1100	0.0204
Michigan	0.0207	0.0267	0.0323	0.0440	0.0266	0.0240
Minnesota	0.0220	0.0243	0.0280	0.0309	0.0218	0.0166
Missouri	0.0141	0.0175	0.0233	0.0307	0.0212	0.0002

Figure 3.12-3: Average Annual Rate Increases for Residential Electricity, 1990-2020, Part 1

Average Annual Rate Increases from Indicated Year to 2020 (decimal)						
State	1990	1995	2000	2005	2010	2015
Mississippi	0.0161	0.0188	0.0239	0.0166	0.0124	-0.0018
Montana	0.0241	0.0245	0.0275	0.0218	0.0205	0.0065
North Carolina	0.0124	0.0135	0.0178	0.0183	0.0117	0.0018
North Dakota	0.0170	0.0207	0.0242	0.0267	0.0250	0.0164
Nebraska	0.0183	0.0211	0.0252	0.0276	0.0189	0.0037
New Hampshire	0.0194	0.0126	0.0171	0.0210	0.0125	-0.0013
New Jersey	0.0144	0.0114	0.0219	0.0204	-0.0039	0.0043
New Mexico	0.0123	0.0148	0.0218	0.0233	0.0207	0.0074
Nevada	0.0229	0.0187	0.0222	0.0071	-0.0086	-0.0236
New York	0.0148	0.0100	0.0120	0.0078	-0.0037	0.0004
Ohio	0.0140	0.0141	0.0176	0.0268	0.0079	-0.0085
Oklahoma	0.0143	0.0158	0.0182	0.0161	0.0102	-0.0004
Oregon	0.0286	0.0284	0.0321	0.0288	0.0231	0.0093
Pennsylvania	0.0112	0.0113	0.0161	0.0182	0.0016	-0.0041
Rhode Island	0.0264	0.0256	0.0328	0.0341	0.0311	0.0249
South Carolina	0.0194	0.0212	0.0261	0.0259	0.0197	0.0033
South Dakota	0.0175	0.0203	0.0230	0.0276	0.0270	0.0117
Tennessee	0.0212	0.0240	0.0265	0.0289	0.0153	0.0087
Texas	0.0162	0.0167	0.0193	0.0046	0.0009	0.0026
Utah	0.0127	0.0163	0.0253	0.0219	0.0181	-0.0083
Virginia	0.0169	0.0171	0.0235	0.0259	0.0141	0.0113
Vermont	0.0249	0.0248	0.0231	0.0274	0.0227	0.0268
Washington	0.0270	0.0274	0.0327	0.0274	0.0205	0.0165
Wisconsin	0.0257	0.0288	0.0321	0.0262	0.0124	0.0030
West Virginia	0.0231	0.0239	0.0316	0.0428	0.0294	0.0315
Wyoming	0.0207	0.0240	0.0268	0.0264	0.0237	0.0025

Figure 3.12-4: Average Annual Rate Increases for Residential Electricity, 1990-2020, Part 2

References

[3.1-1] The maps shown on Figures 3.1-1 to 3.1-4 are derived from a time zone map called the United States Time Zone Map, public domain, de.wikipedia.org

[3.1-2] Google Maps, a product of Google LLC. None of the images in this document are from google maps.

[3.2-1] Figure 3.2-1 was derived from an image located at free maps of the world, https://mapswire.com

[3.5-1] F. Ahmad, A. Lakhtakia, P. B. Monk, "Double-absorber thin-film solar cell with 34% efficiency", Appl. Phys. Lett., 20 Jul 2020, DOI: 10.1063/5.0017916

[3.5-2] A. Green, K. Emery, Y. Hishikawa, W. Warta, E D. Dunlop, "Solar Cell Efficiency Tables (Version 42)", Prog. Photovolt: Res. Appl. 2013; 21:827-837; www.wileyonlinelibrary.com, DOI 10.1002/pip2404

[3.7-1] S. Chhajed, M. F. Schubert, J. K. Kim, E. F. Schubert, "Nanostructured multilayer graded-index antireflection coating for Si cells with broadband and onmidirectional characteristics", Applied Physics Letters 93, 251108 (2008)

[3.7-2] B. G. Priyadarshini, A. K. Sharma, "Design of multi-layer anti-reflection coating for terrestrial solar panel glass", Bull. Mater. Sci., Vol. 39, No. 3, June 2016, pp. 683-689

[3.11-1] For example, all the following websites offer some sense of per-watt costs referenced to the "nameplate" rating:
https://www.homedepot.com/c/cost_install_solar_panels
https://www.solar.com/learn/solar-panel-cost/
https://www.solarreviews.com/solar-panel-cost

[3.12-1] See https://www.solarreviews.com/blog/average-electricity-cost-increase-per-year for a summary.

[3.12-2] U. S. Energy Information Administration (EIA), U. S. Department of Energy, *Electric Power Annual 2020*, Oct 2021, available at https://www.eia.gov/electricity/annual/. Table 2.7 shows average electricity prices from 2010 to 2020.

[3.12-3] See https://www.eia.gov/electricity/data/state/; select the excel spreadsheet called "Average Price by State by Provider (EIA-861)"; spreadsheet = "avgprice_annual.xlsx"

4
Estimator Outputs

4.1 Charts

The Estimator produces eight charts, and each is shown on a separate sheet. The sheets are named: a) "sun_ch"; b) "COS_SIGMA_ch"; c) "P_D_ch"; d) "P_S_ch"; e) "P_C_ch"; f) "P_G_ch"; g) "P_HS_ch"; h) "ROI_ch"; and i) "DNI_ch". This section will show examples of each chart for the inputs shown on Figure 4.1-1.

Inputs		Units	Symbol
Choose time zone, nearest latitude	E 43 Portland, ME		
Choose cloud location	Portland, ME		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	44	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.220	decimal	e_TC
Power fraction after 25 years	0.85		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0034	%/100 °K	C_T
Ground Type, Winter	Maple Forest		
Ground Type, Spring	Maple Forest		
Ground Type, Summer	Maple Forest		
Ground Type, Fall	Maple Forest		
DC-AC Conversion efficiency	0.93		
Installation cost	17500	$	
Annual Electricity Escalation Rate	0.0200	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.16	0.16	0.16	0.16
1 AM to 2 AM	1.5	0.16	0.16	0.16	0.16
2 AM to 3 AM	2.5	0.16	0.16	0.16	0.16
3 AM to 4 AM	3.5	0.16	0.16	0.16	0.16
4 AM to 5 AM	4.5	0.16	0.16	0.16	0.16
5 AM to 6 AM	5.5	0.16	0.16	0.16	0.16
6 AM to 7 AM	6.5	0.16	0.16	0.16	0.16
7 AM to 8 AM	7.5	0.16	0.16	0.16	0.16
8 AM to 9 AM	8.5	0.16	0.16	0.16	0.16
9 AM to 10 AM	9.5	0.16	0.16	0.16	0.16
10 AM to 11 AM	10.5	0.16	0.16	0.16	0.16
11 AM to noon	11.5	0.16	0.16	0.16	0.16
noon to 1 PM	12.5	0.16	0.16	0.16	0.16
1 PM to 2 PM	13.5	0.16	0.16	0.16	0.16
2 PM to 3 PM	14.5	0.16	0.16	0.16	0.16
3 PM to 4 PM	15.5	0.16	0.16	0.16	0.16
4 PM to 5 PM	16.5	0.16	0.16	0.16	0.16
5 PM to 6 PM	17.5	0.16	0.16	0.16	0.16
6 PM to 7 PM	18.5	0.16	0.16	0.16	0.16
7 PM to 8 PM	19.5	0.16	0.16	0.16	0.16
8 PM to 9 PM	20.5	0.16	0.16	0.16	0.16
9 PM to 10 PM	21.5	0.16	0.16	0.16	0.16
10 PM to 11 PM	22.5	0.16	0.16	0.16	0.16
11 PM to midnight	23.5	0.16	0.16	0.16	0.16

Figure 4.1-1: Inputs for Example Output Charts

The "sun_ch" chart shows the sun position per time-of-day for the Time Zone/Latitude selection made on cell D5 of the Estimator worksheet (in this example, is E 43 Portland, ME). It shows both the azimuth (AZ in legend) and zenith (ZEN in legend) for 24-hour period for all four seasons (Julian day 35 (Winter), 126 (Spring), 217 (Summer), and 308 (Fall)). The source data was derived using the NREL sun position model as described in section 5.2. Figure 4.1-2 shows the result for this example. The zenith angles (solid lines) are read on the left side, and azimuth (dashed lines) on the right. Notice in this case that there is a large jump in the sun azimuth for Fall; this indicates that the computed azimuth is actually for the next day. All of these azimuth jumps occur outside the range where the zenith is less than 90°, and should be regarded as artifacts not affecting any calculations. (Keep in mind that zenith = 90° means the sun is at the horizon; zenith angles above 90° means the sun is below the horizon and thus cannot contribute to solar power generation.)

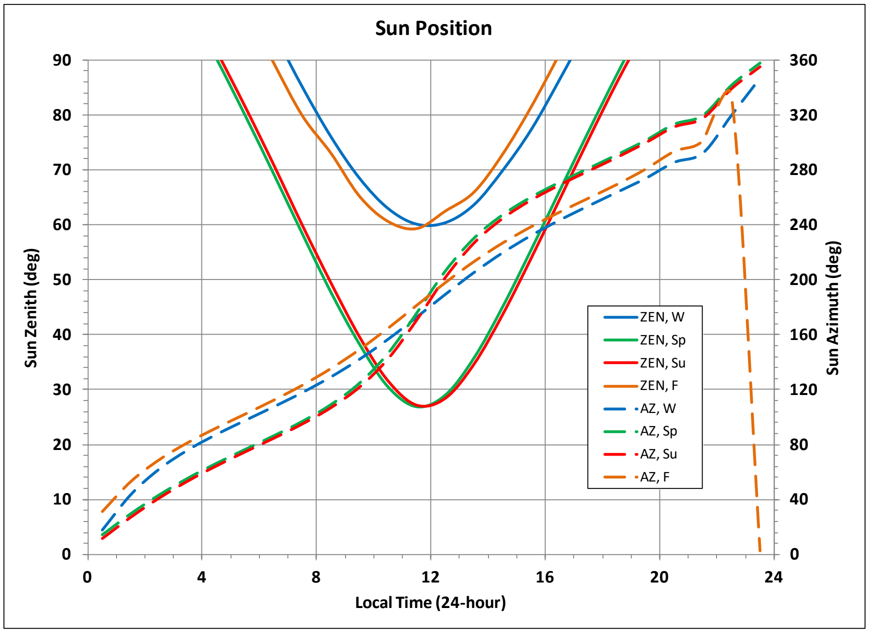


Figure 4.1-2: Sun Position Output Chart (sun_ch)

The "COS_SIGMA_ch" chart shows the cosine of the total included angle σ between the solar panel normal and the LOS to the sun as described in section 5.4. This angle determines what fraction of the incident direct sunlight can actually be captured by the solar panel. If the cosine is 1 (maximum), then the solar panel can utilize all of the incident sunlight; if zero, then none. Obviously the cos(σ) varies with time of day. Figure 4.1-3 shows the result for this case; it turns out that 44° at this location is approximately the optimum tilt angle, since cos(σ) is maximized near noon, and are close to unity at that time for all seasons. It is evident that the cos(σ) does not go to zero at the same times as the zenith angle approaches 90° as shown in the "sun_ch" chart per Figure 4.1-2 since the "COS_SIGMA_ch" shows the arbitrated σ values to account for the AR coating limitation (80° in this example).

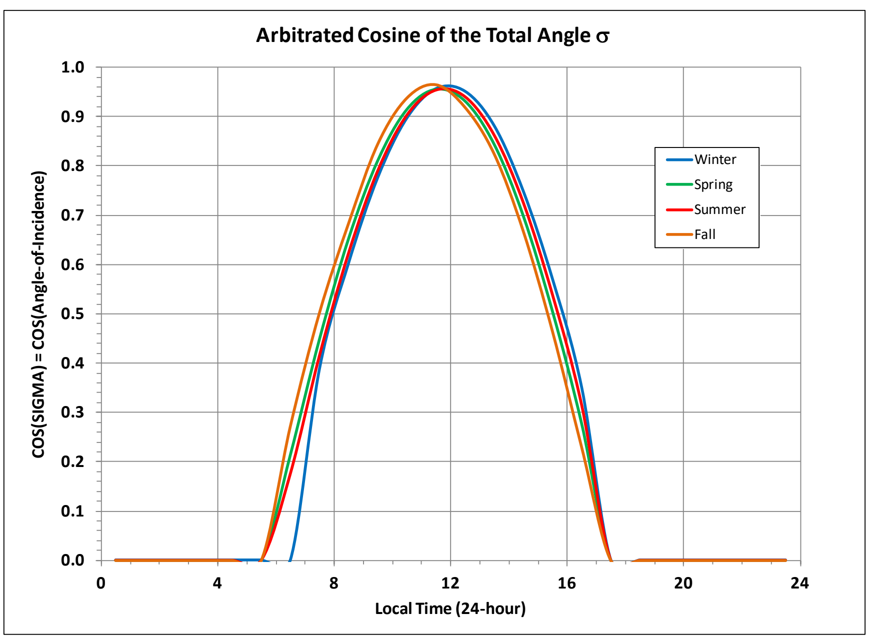


Figure 4.1-3: Cosine of the Total Included Angle Chart (COS_SIGMA_ch)

The "P_D_ch" chart shows the average power generated daily by the solar system per time-of-day during each season for the directly-transmitted solar irradiance component only. The results are shown as discrete points instead of a continuous line to indicate that these values are the amount generated during each hour. Notice also that the units are Watt-hours. Figure 4.1-4 shows the results for this case.

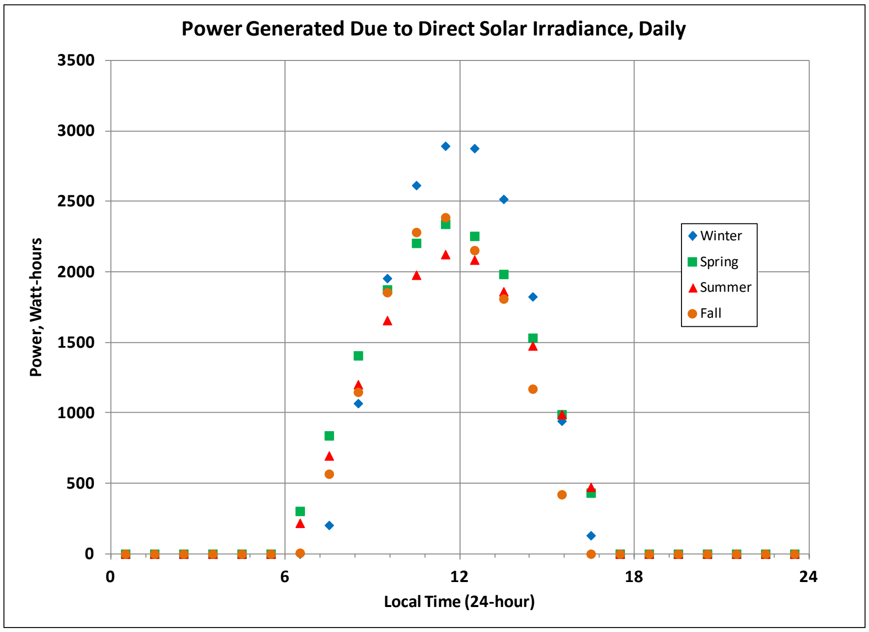


Figure 4.1-4: Power Generated from Directly-Transmitted Solar (P_D_ch)

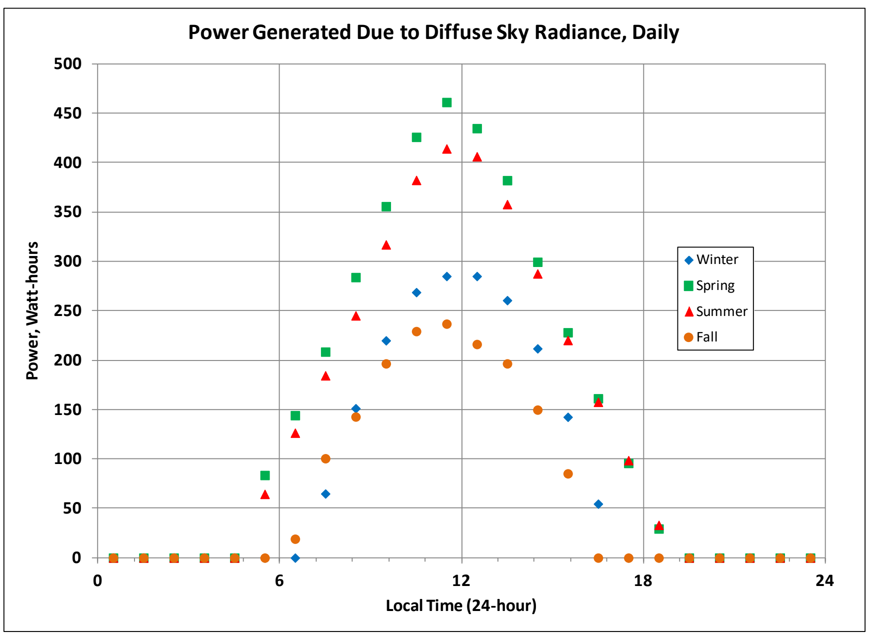


Figure 4.1-5: Power Generated from Diffuse Sky Radiance (P_S_ch)

The "P_S_ch" chart shows the average power generated daily by the solar system per time-of-day during each season for the diffuse sky radiance component only. The results are shown as discrete points instead of a continuous line to indicate that these values are the amount generated during each hour in Watt-hours. Figure 4.1-5 shows the results for this case. Notice that the diffuse sky radiation produces much less power than the direct solar irradiance. That is why the choice of cloud location in cell D6 (cf. section 3.2) is so important.

The "P_C_ch" chart shows the average power generated daily by the solar system per time-of-day during each season due to the diffuse cloud radiance component only. The results are shown as discrete points instead of a continuous line to indicate that these values are the amount generated during each hour in Watt-hours. Figure 4.1-6 shows the results for this case. Once again, the power due to diffuse cloud radiation is much less than the direct solar irradiance component.

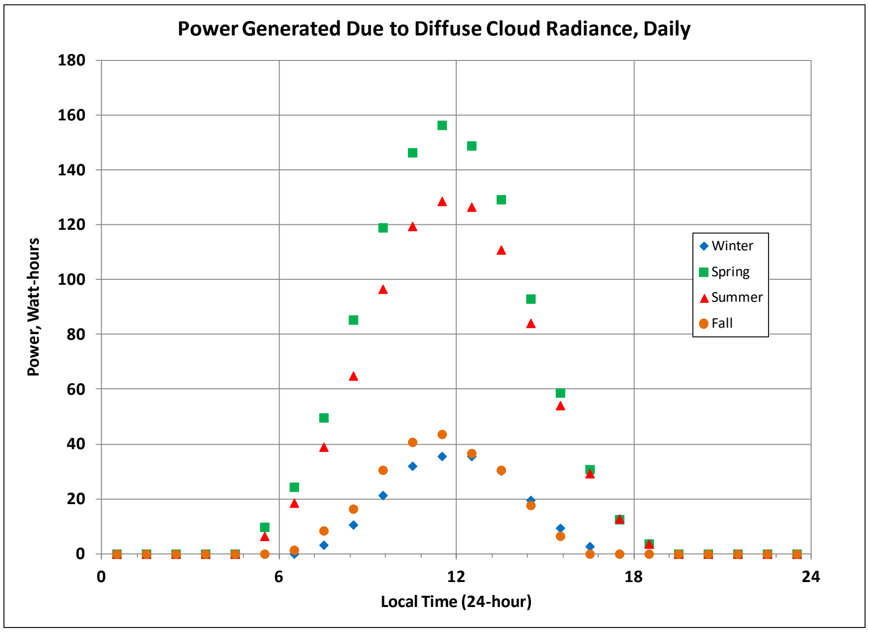


Figure 4.1-6: Power Generated from Diffuse Cloud Radiance (P_C_ch)

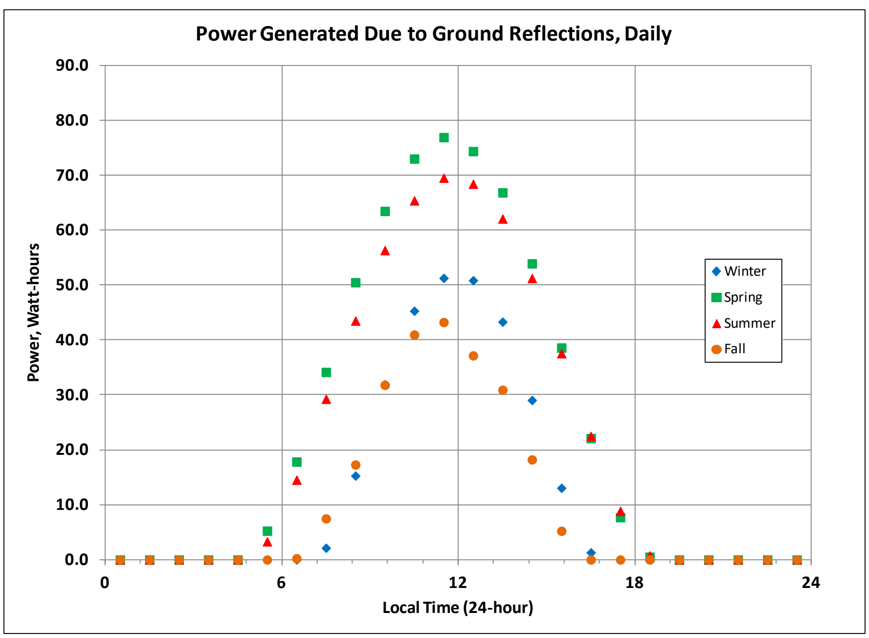


Figure 4.1-7: Power Generated from Ground Reflections (P_G_ch)

The "P_G_ch" chart shows the average power generated daily by the solar system per time-of-day during each season due to the ground reflection component only. The results are shown as discrete points instead of a continuous line to indicate that these values are the amount generated during each hour in Watt-hours. Figure 4.1-7 shows the results for this case. The ground reflections produce even less power than the diffuse components, at least for this ground type (Maple Forest, per Figure 4.1-1).

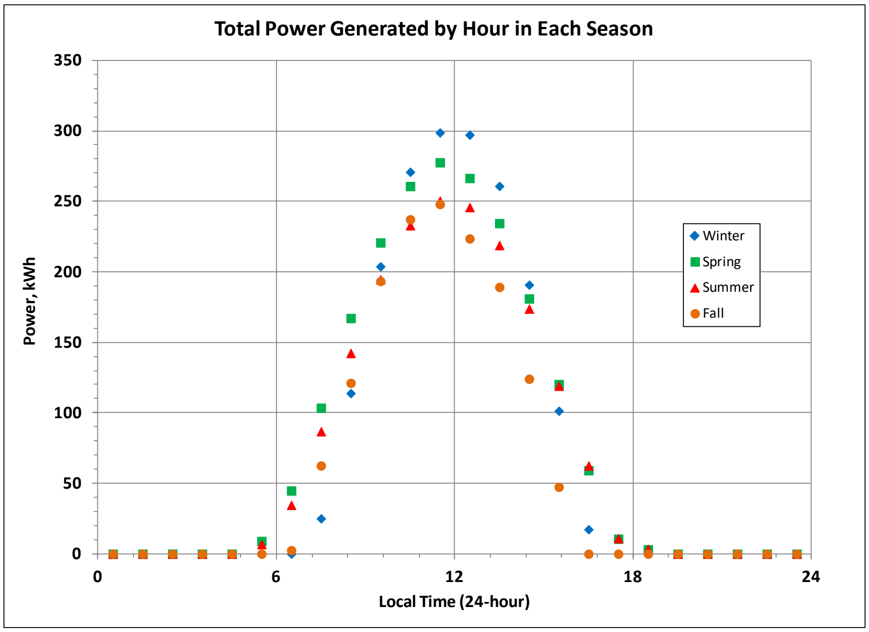


Figure 4.1-8: Total Power Generated from All Sources (P_HS_ch)

The "P_HS_ch" chart as shown on Figure 4.1-8 indicates the average power generated over an entire season by the solar system per time-of-day due to all sources (directly transmitted, diffuse sky, diffuse cloud, and ground reflections). The results are shown as discrete points instead of a continuous line to indicate that these values are the amount generated during each hour. These totals are shown in units of kWh's. This chart requires some clarification. It means, for the hour between 11:00 AM and 12:00 noon, the system will generate a total of 297 kWh for the entire winter season. It is not the amount generated every day in that hour during the winter season. The total power generated in each season is the sum of the hourly power in W-hr as seen on the previous charts, and then multiplied by 91.5, which is the number of days per season, then divided by 1000 to obtain kWh for the entire season. This particular system per the inputs on Figure 4.1-1 generates 1,780.3 kWh for the entire winter season, and 6,972.2 kWh for the entire year.

The "ROI_ch" chart compares the value of the energy generated by the solar system to the initial installation cost. It is called the "cost avoided", meaning money not paid to the electric utility due to the solar system. The point where these two lines cross is the return on investment (ROI); i.e., when the system has paid for itself by generating enough electricity (and avoid paying the local electric company) to equal the installation cost. The "cost avoided" includes two countering effects: a) the average annual increase in electricity rates (per cell D20), and b) the gradual decline in solar panel efficiency over time (per cell D11). It does not, however, include: a) any interest paid on the panels if financed; or b) any maintenance costs associated with the panels. Figure 4.1-9 shows the result for this example; the ROI for this installation in Portland, ME is about 14.2 years or so.

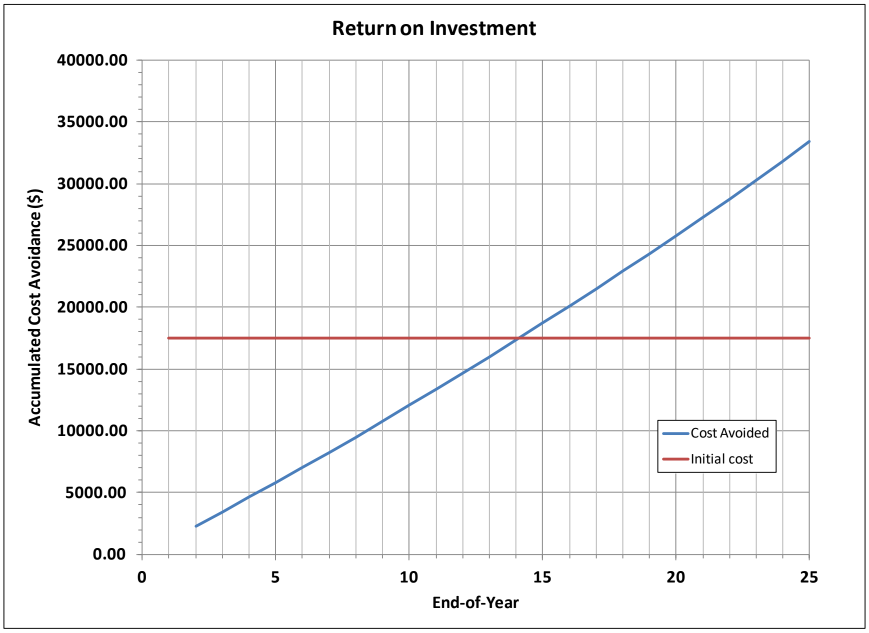


Figure 4.1-9: Return on Investment (ROI_ch)

Figure 4.1-10 shows the "DNI_ch" chart, which is the average daily directly-transmitted solar irradiance for a clear LOS in a plane normal to the line-of-sight (LOS) to the sun, referred to a direct normal irradiance (DNI). Keep in mind that these values represent the total incident irradiance in W/m^2 in a plane perpendicular to the sun LOS, not perpendicular to the solar panel normal vector. The amount actually available to the solar panel is modified by the average daily cloud fraction (cf. Appendix A, Figures A-15 to A-22) and the cosine σ of the total angle between the sun and the panel normal (cf. "COS_SIGMA_ch" per Figure 4.1-3). It is shown only for reference so that it may be compared to other data sources.

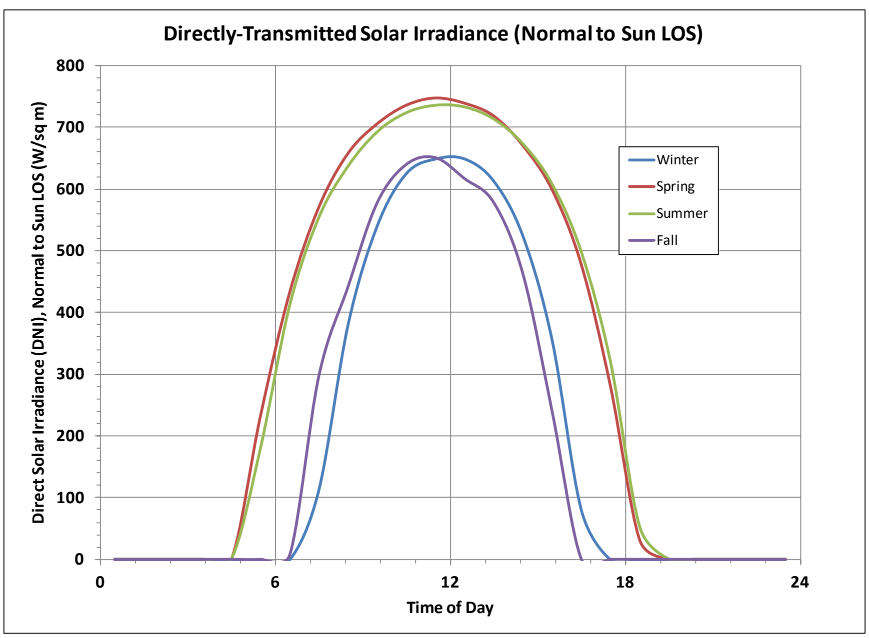


Figure 4.1-10: Average Daily Clear-Sky Directly-Transmitted Solar Irradiance Normal to Sun LOS

4.2 Scalar Results

Figure 4.2-1 shows the output section for the example input set shown on Figure 4.1-1. The scalar outputs on the left side include: a) the total power generated in each season in kWh; b) the total annual power generated in kWh; c) the initial value (i.e., cost avoided in the first year of operation) for each season; d) the total cost avoided for the first year; e) the accumulated dollar value of the electricity produced over 25 years, including the escalation in electricity rates and the decline in panel efficiency; f) the total power generated over 25 years including the decline in efficiency; and g) the average cost per kWh of the electricity produced by the solar panel system over 25 years. This particular system will produce 6,972.2 kWh during the first year with a first-year value (cost avoided) of $1,155.55. Adjacent cells show the monthly savings for each season ($94.95 in winter, etc.). The total cost avoided by using solar over 25 years is $33,379.00, and the total power generated during that period (including losses) is 161,231.0 kWh. The 25-year average cost of a kWh generated by the solar system is $0.109. The "ROI_ch" (cf. Figure 4.1-9) has already shown a return-on-investment of 14.2 years. The average cost of solar generation ($0.109/kWh) is 31.8% less than the initial electricity cost ($0.16/kWh) as seen on Figure 4.1-1. This block of outputs tells the most important story.

							W-hr/sq m	
							Clear Sky	CSDNI *
Outputs	Units		Symbol	Monthly			DNI	(1-Cld)
Power generated in Winter	1780.3	kWh				Winter	4521.40	3160.46
Power generated in Spring	1959.1	kWh				Spring	7589.17	4561.09
Power generated in Summer	1783.4	kWh				Summer	7533.93	4686.10
Power generated in Fall	1449.4	kWh				Fall	4510.83	2796.71
Total Initial Annual Power	6972.2	kWh	P_A					
Initial Value, Winter Season	284.84	$	C_S, W	94.95				
Initial Value, Spring Season	313.46	$	C_S, Sp	104.49			kWh/sq m	
Initial Value, Summer Season	285.35	$	C_S, Su	95.12		Annual	2210.21	1391.20
Initial Value, Fall Season	231.90	$	C_S, F	77.30				
Total Initial Annual Value	1115.55	$	C_A					
Dollar Value over 25 years	33379.00	$						
Total power, 25 years	161231.9	kWh	P_T					
Avg cost per kW-hr, 25 years	0.109	$						

Figure 4.2-1: Scalar Results

The scalar outputs on the right side show the average daily direct solar irradiance for each season, for clear sky and as modified by the cloud fraction. These are in W-hr/m^2, and only the cloud-modified ones are used in the Estimator to calculate cost savings and return on investment. Also shown at bottom right are the annual clear-sky DNI and true cloud-modified DNI in kWh/m^2. These are interesting, but do not tell much about system performance per se. They are mostly here for comparison to how direct solar is handled in other models, given that the dominant power production comes from the direct sunlight, and less so from the diffuse sky, diffuse cloud, and ground reflections, as already presented in Figures 4.1-4 through 4.1-7.

4.3 Utilities Page

The Utilities page contains five sections the aid the user in establishing the correct inputs to the Estimator.

The first one, located in cells B1 to F10 converts latitude and longitude in degree:minute:second (D:M:S) format to decimal degrees. The user inputs are made in the green cells, and the result is shown in the tan cells. Recall that all longitudes in the U. S. are west of Greenwich, England, and are negative. Likewise, all latitudes in the U. S. are north of the equator, and thus are positive. So if the D:M:S coordinates are N 34° 27' 45", W 104° 18' 5", the inputs in the green cells should be C4 = 34, D4 = 27, E4 = 45 and C5 = -104, D5 = 18, and E5 = 5. The decimal equivalent in cells C8 and C9 are 34.46250, -

104.30139, which is just west of Fort Sumner, NM. The two main purposes of this conversion are: a) determine the closest latitude when making the selection in cell D5 of the Estimator; and b) to provide decimal degree inputs to the third section of the Utilities page, which is used to calculate the distance to the nearest cloud location.

The second section is located in cells B11 to D16. It converts square feet to square meters; necessary because the area input in the Estimator (cell D9) must be in square meters.

The third section, located in cells J3 to T191, allows the user to determine the closest cloud location to be selected in the Estimator, cell D6. If the installation is not in one of the listed locations, the user can input the decimal degree coordinates in the green cells (K4, K5) and obtain the name and distance to the nearest cloud location. This list is identical to the one in the Estimator. For example, if the solar panel is located at 34.21155, -89.42683, (between Smith County Rd 577-2 and Smith County Rd. 583, just west of Mississippi Route 501 near Forest, MS), the nearest cloud location is Memphis, TN, at a distance of 62.52 NM. Memphis, TN is then the best choice for the cloud selection in cell D6 of the Estimator.

The fourth section, located in cells W2 to AE49 is a summary of the properties of some modern solar panels. It shows the manufacturer (column W), model number (column X), area in sq. m. (column Y), DC output in watts (column Z), the efficiency at NOCT conditions (e_NOCT, column AA), the cell temperature at NOCT conditions (T_NOCT, column AB), coefficient of temperature (C_T, column AC), and the warranted power output fraction after 25 years (column AD). These give an indication of reasonable values to be entered in cells D10 through D13 of the Estimator.

The fifth section in cells B18 to F24 calculates the efficiency of a solar panel based on data taken from datasheets (active area and output at NOCT conditions). For example, the LG Electronics LG380Q1C-V5 puts out 286 W at NOCT (cell Z40) and has an area of 1.621 sq. m. (cell Y40); and thus has a nominal (NOCT) efficiency of 0.221. The result here can be used as an input in cell D10.

4.4 Next Steps

Hopefully the last two chapters have provided sufficient guidance on how to use the Estimator and interpret the results. The worked examples in chapter 6 are recommended next in order to gain some further insight as to the use of the model. Otherwise, chapter 5 presents the theory behind the Estimator and how it was developed.

5
Theoretical Manual

5.1 Symbols and Conversions

Symbols

Note: The units called out below are the ones used in the equations, some user entries may be in different units.

α	alpha	Sun azimuth angle, radians
β	beta	Solar panel azimuth angle, East of North, radians
δ	delta	Total spherical angle used in calculating great-circle distance, radians
ε	epsilon	Solar panel tilt angle, top toward the panel azimuth, radians
η_p	eta	Quantum efficiency, peak value
λ	lambda	1. Wavelength, μm 2. Longitude for calculating great circle distance, radians
μ	mu	Multiplier for 10^{-6} (one-millionth)
ϕ	phi	Latitude for calculating great circle distance, radians
ρ	rho	Ground reflectance
σ	sigma	The total angle between the solar panel normal vector and the line-of-sight (LOS) to the sun, radians
θ	theta	Sun zenith angle, radians
Ω_S	Omega, S	Sky solid angle as observed by the panel, sr
Ω_G	Omega, G	Ground solid angle as observed by the panel, sr
Ω_T	Omega, T	Total solar panel solid angle, sr

A_P	Solar panel physical area, m^2
C_A	Total annual cost avoidance, initial year, $
C_C	Long-term average cloud cover
C_S	Cost avoided at each hour, $
C_T	Solar panel thermal efficiency coefficient, $°K^{-1}$
C_U	Cost of electricity in each hour, $
C_{25}	Total cost avoidance over 25 years, $
cm	centimeter (1/100th of a meter)
e_C	DC-AC conversion efficiency
e_g	Generic solar panel efficiency
e_{NOCT}	solar panel efficiency at NOCT conditions per a datasheet
e_{RC}	Reduced efficiency of diffuse cloud radiance conversion
e_{RS}	Reduced efficiency of diffuse sky radiance conversion
e_{TC}	Temperature-corrected solar panel efficiency
D	Great circle distance between two points, NM
E_A	Total annual direct solar irradiance, kWh/m^2
E_D	Direct solar irradiance, W/m^2

$E_{D,n}$ Normalized direct solar irradiance
$E_{D,S}$ Average daily solar irradiance for each season, W-hr/m^2
$E_{D,1.5}$ Direct solar irradiance under AM1.5 conditions
F Fill factor, the ratio of active collecting area to total area in the solar panel
F_C Fraction of power generated in a future year vs. initial year
F_T Integrated fraction of power generated over a number of years vs. initial year
hr hour
L_C Cloud radiance (diffuse), W/(sr-m^2)
L_{GC} Ground radiance due to reflection of cloud radiance, W/(sr-m^2)
L_{GD} Ground radiance due to reflection of direct solar irradiance, W/(sr-m^2)
L_{GE} Ground radiance due to emission from surface, W/(sr-m^2)
L_{GS} Ground radiance due to reflection of diffuse sky, (W/sr-m^2)
L_S Sky radiance (diffuse), W/(sr-m^2)
kW Kilowatt (1000 watts)
NM Nautical miles
m 1. meter
2. slope; used here for slope of long-term efficiency degradation
P_A Total power generated in the first year, W-hr
P_D Power from direct solar irradiance, W-hr
P_{DC} Power generated due to diffuse cloud radiance, W-hr
P_{DS} Power generated due to diffuse sky radiance, W-hr
P_G Power generated due to total ground reflections, W-hr
P_{HS} Total power generated at each hour, kW
P_T Total annual power, W-hr
P_{25} Total power generated over 25 years, W-hr
r Average annual electricity cost escalation rate, decimal
R Spectral responsivity (normalized)
R_E Earth radius, NM
sr Steradian, the unit of solid angle
T_{AMB} Ambient temperature (deg K)
T_{LAB} Laboratory ambient temperature (298.15° K)
W Watt

Conversions

Deg C = [0.5555][deg F - 32.0]
Deg K = deg C + 273.15
Deg F = [1.8][deg K] - 459.67
ft = 0.3048 meter
m = 3.28088 feet
m^2 = mm^2/1,000,000 = mm^2/1.0E+06
m^2 = cm^2/10,000 = cm^2/1.0E+04
radians = [degrees*π]/180
wavenumber (number of waves per cm)= 10,000/λ, where λ is wavelength in μm (1.0E-06 meters)
knots (NM/hour) = [m/s][1.943], where the 1.943 = [3600 s/hour][1 NM/1852 m]
MPH = [m/s][2.236], where the 2.236 = [3.2808 ft/m][1 M/5280 ft][3600 s/hour]

5.2 Seasonal Variations

The performance of solar panels depends in part on their orientation relative to the instantaneous sun position. As the sun moves across the sky, the amount of energy intercepted by the solar panel depends on the angle between the solar panel normal vector and the line-of-sight (LOS) from the solar panel to the sun. That LOS changes continuously, and is expressed by the sun azimuth relative to due North and zenith angle (i.e., the deviation from straight up).

In the Northern hemisphere, the sun zenith angle is lowest (closest to overhead) near mid-day in the spring and summer. It is higher (closer to the horizon) at mid-day during the fall and winter. The solar position was calculated for the main latitude locations using the NREL model [5.2-1]. The algorithm was coded (by the author) in FORTRAN, and a database was created for use in the Estimator. It is desirable for a simple model to minimize the number of days for which the azimuth and zenith is to be tabulated; at the same time, it is desirable to provide a fair representation of how the solar position changes with the seasons. The solar azimuth and zenith was calculated at one-hour intervals for four days out of the year. This Estimator utilizes the center day of each season as representative of each: a) 4 Feb (Julian day 35) for winter; b) 6 May (Julian 126) for spring; c) 5 Aug (Julian 217) for summer; and d) 4 Nov (Julian 308) for fall. Figure 5.2-1 shows the results for winter and spring in Charlotte, NC including data for the two equinoxes 21 Dec (Julian 355) and (20 Mar, Julian 79). The first thing to notice is that the 180° sun azimuths (dashed lines, read on the right) do not occur at noon. That is because there are 360° of longitude around the earth, and 24 hours in a day; therefore each hour subtends 15°. Standard time is measured from Greenwich, England which lies at 0° longitude. So, solar azimuth of 180° (due south) occurs at noon only in places that lie on a longitude that is an integer multiple of 15°. Since Charlotte lies at -80.84674°, the solar azimuth of 180° occurs later than it does at 75° longitude. Three of the latitude selections in cell D5 of the Estimator do in fact lie on or very close to longitudes that are multiples of 15°: New Orleans, Santa Fe, and Fresno. If those are selected in the Estimator, chart "sun_ch" will show that the solar azimuth of 180° (and the minimum zenith angle) occurs very close to noon.

The solid lines on Figure 5.2-1 indicate the solar zenith angle (measured from straight up). On the left side, showing winter conditions, the red line indicates the zenith on the beginning of winter on 21 Dec; the yellow line applies to the beginning of spring on 20 Mar; and the blue line applies to the mid-point on 4 Feb. Each of the lines represents the change in zenith occurring over the 45-day interval between these dates. The right panel of Figure 5.2-1 shows the situation during the spring: the red line indicates the earliest date (20 Mar), and the yellow line indicates the latest date (20 Jun), and blue is the mid-point (6 May). Notice that the yellow line on the winter chart is the same as the red line on the right chart; it is easy then to see how the zenith angle is changing by season. The data represented by the blue lines are used in the Estimator; these are nothing more than the median values for each season.

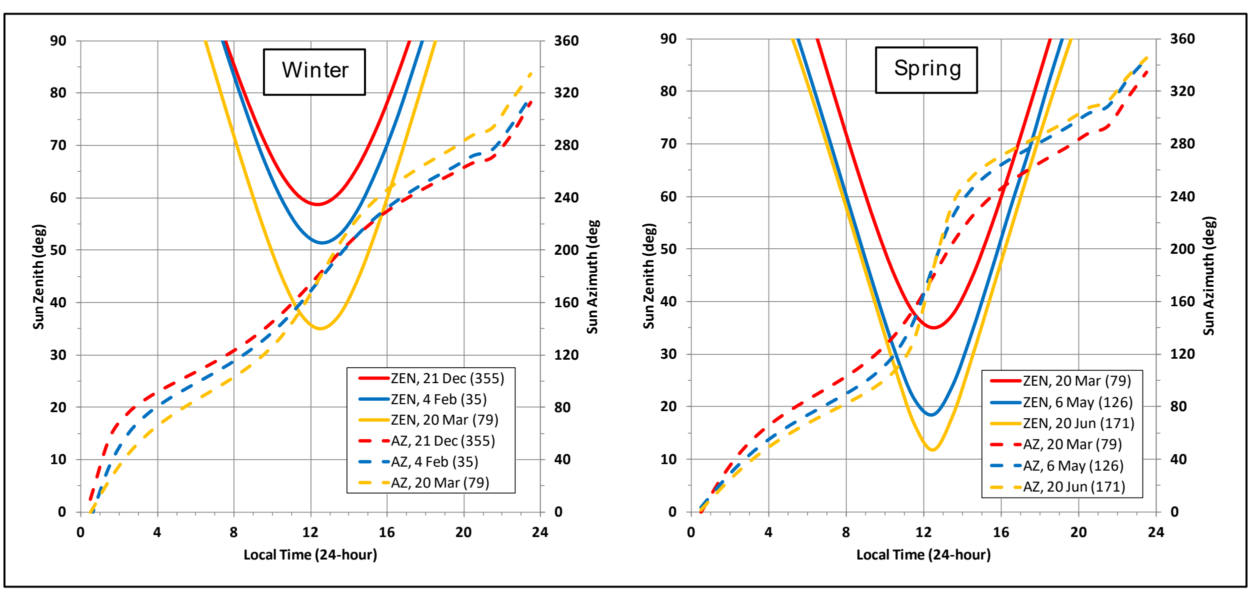


Figure 5.2-1: Sun Position During Winter and Spring in Charlotte, NC

Figure 5.2-2 shows the same thing for summer and fall along with the equinoxes at 20 Jun and 22 Sep. Once again, the Estimator utilizes the data from the median blue lines (5 Aug for summer, 4 Nov for fall) for calculation of the average zenith and azimuth angles for each season.

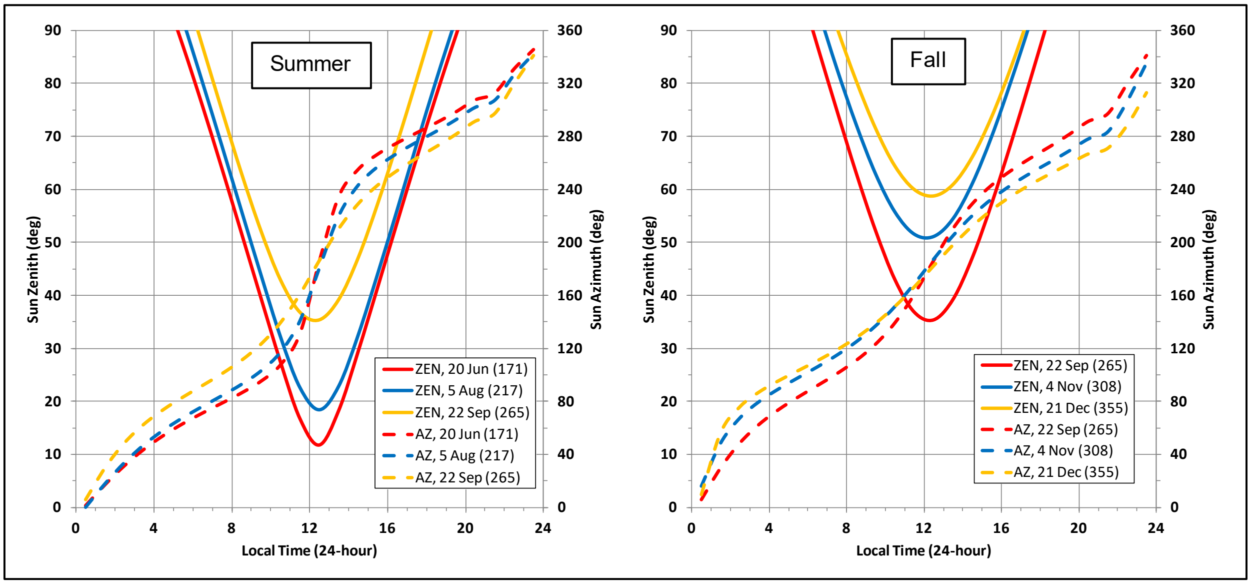


Figure 5.2-2: Sun Position During Summer and Fall in Charlotte, NC

5.3 Cloud Data

Average cloud coverage data was obtained from a U. S. Department of Energy document [5.3-1]. The data consists of percent cloud cover for about 195 locations (188 of which are used, excluding locations in Alaska and Hawaii). Most of the locations contain data from about 1900 to 1987, and some of them extend as far back as 1884.

% Cloud Cover by Month and Year for Charlotte, NC, 1898 - 1921													
Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	MEAN
1898	57	38	66	44	39	41	59	64	48	41	49	49	50
1899	63	56	47	57	60	46	60	53	39	49	36	47	51
1900	35	60	57	63	45	76	55	34	25	53	50	45	50
1901	47	40	51	51	58	66	48	69	44	18	35	58	49
1902	59	54	55	47	40	44	44	53	51	38	50	53	49
1903	61	56	66	57	54	50	39	45	38	40	55	37	50
1904	50	56	58	58	39	48	47	61	40	25	43	53	48
1905	54	61	54	45	59	56	60	54	37	48	50	60	53
1906	62	42	61	42	51	60	66	68	59	53	36	60	55
1907	55	58	48	60	55	58	52	62	42	37	56	56	53
1908	56	60	55	62	45	54	57	58	38	35	45	59	52
1909	59	52	56	55	54	61	56	48	54	24	36	47	50
1910	54	50	32	48	47	66	67	66	48	35	34	45	49
1911	70	57	49	62	33	54	53	55	57	58	59	64	56
1912	61	51	62	61	54	61	62	57	66	40	34	61	56
1913	68	57	59	45	47	52	60	53	59	38	39	56	53
1914	51	55	53	58	33	58	51	65	53	60	45	80	55
1915	62	54	54	40	69	58	53	51	51	47	34	40	51
1916	63	41	39	46	38	51	70	52	32	37	33	47	46
1917	64	47	51	36	52	53	65	57	65	28	42	48	51
1918	54	56	55	69	53	62	62	47	45	60	40	65	56
1919	49	54	54	49	61	62	67	70	35	69	54	50	56
1920	65	58	49	49	55	43	54	77	54	27	45	57	53
1921	65	60	56	50	62	54	57	62	46	31	60	50	54

Figure 5.3-1: Raw Cloud Data for Charlotte, NC, Part 1 (1898-1921)

Figures 5.3-1 through 5.3-4 show the data for Charlotte, NC which extended from 1898 to 1987. The percentage cloud cover for each month and year is as shown, along with an overall mean for each year. The annual mean data was not used.

% Cloud Cover by Month and Year for Charlotte, NC, 1922 - 1945													
Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	MEAN
1922	72	70	61	55	60	55	58	60	41	38	34	72	56
1923	59	61	56	55	67	52	61	65	57	41	49	61	57
1924	52	56	55	51	49	60	59	39	63	19	28	61	49
1925	64	55	45	48	45	58	54	41	46	57	56	54	52
1926	65	49	47	47	42	59	49	55	52	52	44	61	52
1927	57	64	61	61	60	69	58	65	48	25	56	51	56
1928	39	56	51	63	54	63	62	60	53	46	47	50	54
1929	57	64	55	49	61	56	61	52	62	39	66	48	56
1930	66	31	45	40	57	55	54	48	57	41	62	55	51
1931	51	51	54	58	54	45	53	59	31	32	44	67	50
1932	59	57	48	50	47	58	51	50	61	41	44	71	53
1933	62	65	44	51	49	41	53	63	41	33	36	62	50
1934	51	52	54	56	46	50	63	73	61	32	42	58	53
1935	65	52	64	61	60	51	71	60	53	36	53	51	56
1936	55	59	62	57	32	45	61	49	51	53	48	73	54
1937	92	62	38	48	42	62	62	67	47	57	42	61	57
1938	65	66	66	50	63	63	68	49	67	23	45	51	56
1939	53	67	55	48	62	63	64	60	46	43	50	51	55
1940	46	68	58	59	57	60	66	69	44	32	60	58	56
1941	52	49	60	54	34	70	76	58	43	51	34	52	53
1942	57	52	54	36	62	60	62	68	51	46	43	64	55
1943	58	44	58	53	62	60	67	52	41	39	36	54	52
1944	63	70	55	57	51	48	65	58	71	33	64	60	58
1945	60	70	56	58	54	58	73	59	66	45	51	70	60

Figure 5.3-2: Raw Cloud Data for Charlotte, NC, Part 2 (1922-1945)

% Cloud Cover by Month and Year for Charlotte, NC, 1946 - 1969													
Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	MEAN
1946	72	53	63	52	67	58	70	70	64	49	61	53	61
1947	70	41	56	70	54	63	55	66	57	60	64	61	60
1948	63	75	71	51	56	57	63	49	57	42	65	66	60
1949	77	73	62	61	55	67	67	73	62	62	38	64	63
1950	80	57	63	52	72	59	75	60	76	44	49	62	62
1951	60	57	71	56	45	61	57	56	56	49	58	70	58
1952	68	57	52	48	46	57	58	74	54	39	53	59	55
1953	62	59	63	48	59	61	56	44	44	33	40	57	52
1954	64	51	61	60	63	52	55	52	40	36	58	60	54
1955	63	65	66	58	61	54	60	55	67	41	40	54	57
1956	55	68	56	54	65	57	64	56	55	60	45	60	58
1957	80	73	64	50	67	66	46	44	74	60	63	59	62
1958	56	44	74	62	63	55	69	54	51	45	57	57	57
1959	52	77	52	65	67	56	77	61	64	69	53	61	63
1960	63	58	57	51	48	66	69	67	62	55	47	44	57
1961	46	70	71	54	62	67	59	72	44	26	64	60	58
1962	75	66	68	50	52	67	57	53	56	35	58	56	58
1963	58	55	51	55	70	67	59	49	55	18	55	53	54
1964	56	52	51	68	57	57	76	63	48	42	39	66	56
1965	47	59	66	62	51	66	69	54	57	38	57	55	57
1966	58	63	40	64	70	46	57	65	52	46	55	58	56
1967	54	58	52	52	66	66	75	71	50	48	43	62	58
1968	65	49	45	66	58	59	59	46	49	56	65	56	56
1969	73	58	49	58	46	66	55	59	66	48	49	51	57

Figure 5.3-3: Raw Cloud Data for Charlotte, NC, Part 3 (1946-1969)

The bottom four lines of Figure 5.3-4 indicate some statistics for this data set. The results calculated here were done for all locations. First, the median and means for each month are fairly close. Secondly, there is a fair amount of dispersion for all months (since the standard deviation/mean ranges from 0.127 in June to 0.28 in October). That should not be too surprising: this data was collected over 90 years by a wide variety of observers, and there are of course some natural variations from year to year and decade to decade. There were some corrections made to the data by the Department of Energy, mostly to fill in data that was missing. The description of the data reads in part:

> "In compiling the cloud amount data set, only monthly sunrise to sunset cloud amount averages (percentages) were used. This eliminated problems associated with nighttime measurements and also maintained consistency in any comparisons with the monthly sunshine data."

% Cloud Cover by Month and Year for Charlotte, NC, 1970 - 1987													
Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	MEAN
1970	56	55	68	63	48	58	62	62	57	62	53	57	58
1971	76	58	55	44	63	63	73	62	72	66	42	74	62
1972	69	63	58	56	75	52	62	59	53	55	55	70	61
1973	60	58	75	62	65	70	71	62	53	41	51	60	61
1974	84	50	69	52	70	69	62	73	67	33	46	75	63
1975	70	76	67	59	71	56	68	44	68	47	54	56	61
1976	47	48	67	34	63	70	62	54	67	52	47	47	55
1977	56	37	61	51	62	62	50	64	66	59	65	62	58
1978	56	56	60	61	61	47	54	62	59	32	73	60	57
1979	69	72	58	59	68	66	76	47	71	43	51	50	61
1980	77	58	67	50	59	53	48	42	55	48	46	52	55
1981	47	51	48	55	63	59	62	72	40	56	52	61	56
1982	69	71	68	65	56	64	66	59	60	60	64	69	64
1983	51	74	66	57	57	53	40	50	48	63	48	55	55
1984	55	57	58	66	53	46	73	55	44	61	52	69	57
1985	48	70	57	41	57	62	66	66	39	66	81	40	58
1986	53	74	46	38	70	58	46	75	61	52	85	64	60
1987	62	77	63	56	55	62	51	56	58	31	52	66	57
MEAN	60.3	57.8	56.9	53.9	55.7	57.9	60.4	58.2	53.1	44.1	49.9	57.7	
STDEV	9.7	9.7	8.4	7.8	9.8	7.3	8.4	9.1	10.6	12.4	10.8	8.3	
MEDIAN	59.5	57	56	55	57	58	60.5	59	53	43	49.5	58	
AVG		0.584			0.558			0.572			0.506		

Figure 5.3-4: Raw Cloud Data for Charlotte, NC, Part 4 (1970-1987)

The values shown in tan at the bottom of Figure 5.3-4 were modified for use in the Estimator, as described in Appendix A. They are the decimal averages of the mean values grouped by season (Jan-Mar, Apr-Jun, Jul-Sep, Oct-Dec), approximating the solar azimuth and zenith limits per season.

Section 3.2 mentioned a need to select a cloud location, and referenced the Utilities page section 3 to find the nearest tabulated cloud location to any point in the U. S. It uses great circle geometry to calculate the distance in NM:

$$\Delta\phi = \phi_2 - \phi_1 \qquad (5.3\text{-}1)$$

$$\Delta\lambda = \lambda_2 - \lambda_1 \qquad (5.3\text{-}2)$$

$$A = sin^2\left(\frac{\Delta\phi}{2}\right) + \cos\phi_1 \cos\phi_2\, sin^2\left(\frac{\Delta\lambda}{2}\right) \qquad (5.3\text{-}3)$$

$$\delta = 2tan^{-1}\left(\frac{\sqrt{A}}{\sqrt{1-A}}\right) \qquad (5.3\text{-}4)$$

$$D = R_E\delta \qquad (5.3\text{-}5)$$

where ϕ_1, ϕ_2 are the latitudes of the first and second points in radians; λ_1, λ_2 are the longitudes of the first and second points in radians; R_E is the radius if the earth (3437.9049 NM), and D is the distance between the two points (NM).

5.4 Sun-Panel Angle of Incidence

The angle of incidence between the solar panel normal vector and the LOS to the sun is given by [5.4-1]:

$$\cos\sigma = \cos\theta\cos\varepsilon + \sin\theta\sin\varepsilon\cos(\alpha - \beta) \quad (5.4\text{-}1)$$

where σ is the total angle of incidence from the panel normal, θ is the sun zenith angle, ε is the solar panel tilt angle, α is the solar azimuth angle, and β is the solar panel azimuth angle measured East of North. All the angles are in radians. Figure 5.4-1 shows the geometry.

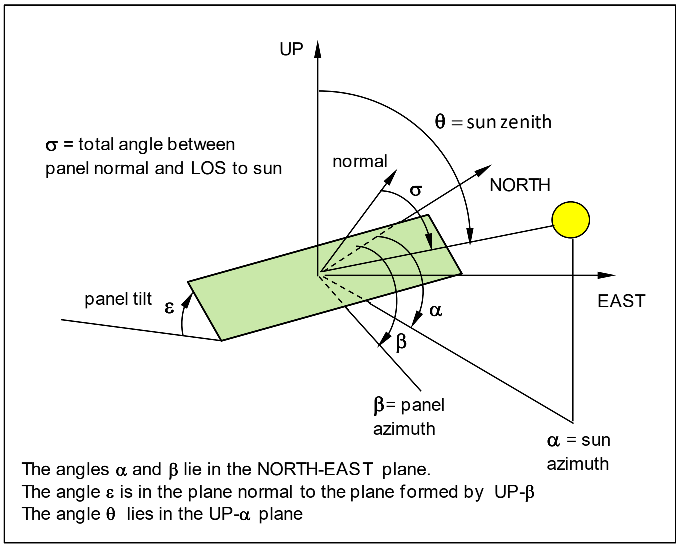


Figure 5.4-1: Panel Normal-to-Sun Angle of Incidence Geometry

5.5 Directly-Transmitted Solar Irradiance

The Estimator contains a database of directly-transmitted solar irradiances calculated off-line as a function of season and location using the LOWTRAN7 model. The cloud selection determines whether the LOWTRAN7 atmosphere type is 1976 U. S. Standard, desert environment with 70 km visibility; or Mid-Latitude Summer/Winter with 23 km rural visibility. The cloud location map on Figure 3.2-1 determines which is used: the red dots indicate the desert atmosphere, and the purple ones indicate the Mid-Latitude Summer/Winter type.

Figure 5.5-1 shows the solar irradiances as a function of zenith angle for the 1976 U. S. Standard model (used to model desert areas), and the Mid-Latitude Summer/Winter (used for non-desert areas).

The results shown in Figure 5.5-1 appear counter-intuitive: a) the irradiances in the winter and fall are larger than spring and summer for all three models; and b) the largest irradiances in the non-desert areas are always lower than the smallest desert case. If these are true, why is it cold in the winter, and is it really so much hotter in the desert than elsewhere? Irradiances are higher in winter and fall because the earth is closer to the sun due to its orbital eccentricity. In fact the solar irradiance at the top of the atmosphere on 1 Jan is about 7% larger than on 1 Jul. Secondly, Figure 5.5-1 shows the results for all possible zenith angles, even if they do not occur. Referring back to Figures 5.2-1 and 5.2-2, it is easy to see that the lowest zenith angle in Charlotte, NC in winter is 59° but is 18° in summer; thus the maximum irradiance in winter is about 660 W/m^2 and is about 760 W/m^2 in summer, consistent with the seasons. The same geometry would apply to a desert region at the same latitude: the maximum irradiance in winter is about 810 W/m^2 and the maximum in summer is about 920 W/m^2. So, although Figure 5.5-1 shows the complete picture, the low zenith angle conditions for winter and fall do not occur in the U. S., and the Estimator accounts for the true zenith conditions per Figures 5.2-1 and 5.2-2.

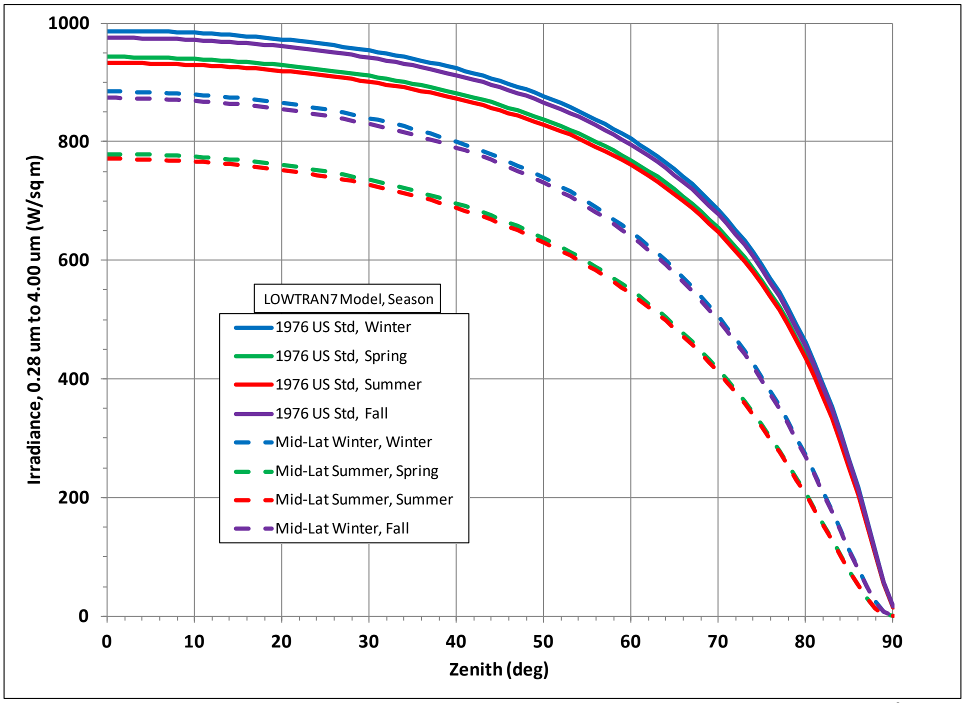


Figure 5.5-1: Directly Transmitted Solar Irradiances, 0.28 to 4.0 μm (W/m^2)

Third, the irradiances are lower for the Mid-Latitude models than the desert model due to the increased scattering in the atmosphere. The desert model uses a 70 km ground visibility, whereas the Mid-Latitude models use 23 km visibility. Ground visibility determines the properties of the haze layer within the LOWTRAN7 model. The haze layer extends up to 2 km altitude in the LOWTRAN7 model, and the ground visibility value affects the total transmitted through the lowest layers of the atmosphere. The same effect causes the irradiance to decline dramatically as zenith angle increases; it has to pass through a much longer path full of a greater density atmospheric scattering molecules.

Figure 5.5-2 shows the LOWTRAN7 inputs used to calculate the directly transmitted solar irradiance as a function of zenith angle.

LOWTRAN7 Inputs for Direct Solar Irradiance Calculations									
CARD 1		CARD 2		Alternate CARD 3		CARD 4		CARD 5	
Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value
MODEL	[1]	IHAZE	1	H1	0.001	V1	2500.0	IRPT	0
ITYPE	3	ISEASN	0	H2	0.000	V2	35720.0		
IEMSCT	3	IVULCN	0	ANGLE	[3]	DV	40.0		
IMULT	0	ICSTL	0	IDAY	[4]				
M1	0	ICLD	0	RO	0.0				
M2	0	IVSA	0	ISOURC	0				
M3	0	VIS	[2]						
M4	0	WSS	0.0						
M5	0	WHH	0.0						
M6	0	RAINRT	0.0						
MDEF	0	GNDALT	0.0						
IMULT	0								
NOPRT	0								
TBOUND	0.0								
SALB	0.0								
1. For Mid-Latitude Summer, Model = 2; for Mid-Latitude Winter, Model = 3; for US Standard, Model = 6.									
2. For Mid-Latitude Summer and Winter, VIS = 0.0 (defaults to IHAZE); for U. S. Standard with desert haze, VIS = 70.0. IHAZE = 1 means 23 km rural visibility at ground level.									
3. ANGLE (zenith) varies from 0 to 90.									
4. IDAY: 35 for winter, 126 for spring, 217 for summer, and 308 for fall.									

Figure 5.5-2: LOWTRAN7 Inputs for Direct Solar Irradiance Calculations

5.6 Diffuse Sky Radiance

The Estimator contains a database of diffuse sky radiances for the three main atmosphere types (1976 U. S. Standard, Mid-Latitude Summer, and Mid-Latitude Winter). LOWTRAN7 was utilized to calculate the diffuse clear-sky radiances in the 0.28 to 4.0 μm waveband at azimuths of 120°, 180°, and 240° as the sun zenith varied from 90° (horizon) to 0° (overhead). Figure 5.6-1 shows the azimuthal geometry; these three values were chosen since the sky radiance is not uniform in direction except when the sun is at 0° zenith. Since the solar panel installations in the Estimator are limited to the northern mid-latitudes, only points in the southern part of the hemisphere are relevant (for most installations). The exception occurs if the panels are oriented toward the north (rare) or are horizontal (i.e., if $\varepsilon = 0°$). In that case, there is a small error in the diffuse radiance.

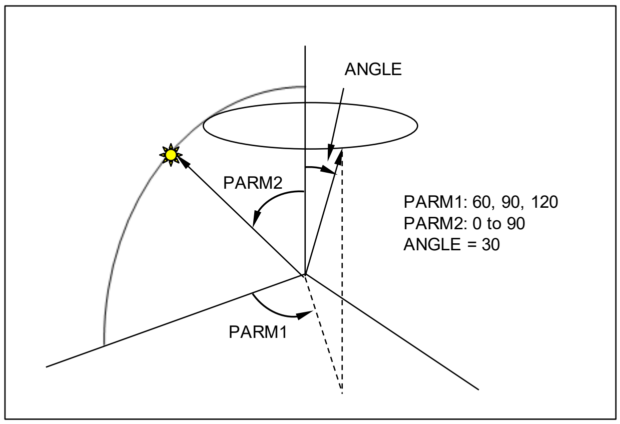


Figure 5.6-1: Geometry for Diffuse Sky Radiance

Figure 5.6-1 illustrates the LOWTRAN7 geometry utilized in calculating the diffuse sky radiances. The observer's zenith angle (ANGLE) is fixed at 30°, and the sky was sampled at three (60°, 90°, and 120°) sun-to-observer azimuth angles (PARM1) as the sun zenith angle (PARM2) varied from 0° to 90°.

Diffuse Sky Radiances for Desert: 1976 U. S. Standard Atmosphere, 70 km visibility, Desert Haze									
Winter (Julian Day 35, 4 Feb)					Spring (Julian Day 126, 6 May)				
	Azimuth Angle					Azimuth Angle			
Zenith	60	90	120	Average	Zenith	60	90	120	Average
0	43.24	43.24	43.24	43.24	0	41.31	41.31	41.31	41.31
10	49.04	41	35.51	41.85	10	46.85	39.17	33.92	39.98
20	49.26	35.62	28.55	37.81	20	47.06	34.03	27.27	36.12
30	43.46	29.45	23.05	31.99	30	41.53	28.13	22.03	30.56
40	35.1	23.88	18.88	25.95	40	33.54	22.82	18.03	24.80
50	27.2	19.28	15.65	20.71	50	25.98	18.42	14.95	19.78
60	20.54	15.35	12.92	16.27	60	19.63	14.67	12.35	15.55
70	14.9	11.77	10.35	12.34	70	14.23	11.25	9.89	11.79
80	9.04	7.52	6.93	7.83	80	8.63	7.18	6.62	7.48
90	1.45	1.24	1.2	1.30	90	1.38	1.19	1.15	1.24
Summer (Julian Day 217, 5 Aug)					Fall (Julian Day 308, 4 Nov)				
	Azimuth Angle					Azimuth Angle			
Zenith	60	90	120	Average	Zenith	60	90	120	Average
0	40.87	40.87	40.87	40.87	0	42.71	42.71	42.71	42.71
10	46.35	38.75	33.56	39.55	10	48.45	40.51	35.08	41.35
20	46.56	33.67	26.98	35.74	20	48.66	35.19	28.2	37.35
30	41.08	27.83	21.79	30.23	30	42.94	29.09	22.78	31.60
40	33.18	22.58	17.84	24.53	40	34.68	23.59	18.65	25.64
50	25.71	18.22	14.79	19.57	50	26.87	19.04	15.46	20.46
60	19.42	14.51	12.22	15.38	60	20.29	15.17	12.77	16.08
70	14.08	11.13	9.78	11.66	70	14.72	11.63	10.23	12.19
80	8.54	7.11	6.55	7.40	80	8.92	7.43	6.84	7.73
90	1.37	1.18	1.14	1.23	90	1.43	1.23	1.19	1.28

Figure 5.6-2: Diffuse Sky Radiances in 0.28 to 4.0 μm Band, Desert Environment, W/(sr-m^2)

Figures 5.6-2 through 5.6-4 show the results from the LOWTRAN7 calculation. Here zenith angles are in degrees, and radiances are in W/(sr-m^2) over the 0.28 to 4.0 μm band. The three results for azimuths of 120°, 180°, and 240° were averaged to obtain composite diffuse sky radiances as a function of zenith angle during the four seasons.

Diffuse Sky Radiances for Mid-Latitude Winter Atmosphere, 23 km visibility, Rural Haze									
Winter (Julian Day 35, 4 Feb)					Fall (Julian Day 308, 4 Nov)				
	Azimuth Angle					Azimuth Angle			
Zenith	60	90	120	Average	Zenith	60	90	120	Average
0	77.46	77.46	77.46	77.46	0	76.53	76.53	76.53	76.53
10	88.18	73.19	62.82	74.73	10	87.12	72.30	62.07	73.83
20	88.27	62.84	49.43	66.85	20	87.21	62.09	48.83	66.04
30	77.05	50.89	38.80	55.58	30	76.12	50.27	38.33	54.91
40	60.98	40.07	30.83	43.96	40	60.24	39.59	30.46	43.43
50	45.70	31.24	24.82	33.92	50	45.15	30.86	24.52	33.51
60	32.90	23.87	19.79	25.52	60	32.51	23.58	19.55	25.21
70	22.36	17.31	15.03	18.23	70	22.09	17.10	14.87	18.02
80	12.14	9.99	9.11	10.41	80	11.99	9.87	9.00	10.29
90	1.34	1.16	1.12	1.21	90	1.32	1.15	1.11	1.19

Figure 5.6-3: Diffuse Sky Radiances in 0.28 to 4.0 μm Band, Mid-Latitude Winter Environment, W/(sr-m^2)

Diffuse Sky Radiances for Mid-Latitude Summer Atmosphere, 23 km visibility, Rural Haze									
Spring (Julian Day 126, 6 May)					Summer (Julian Day 217, 5 Aug)				
	Azimuth Angle					Azimuth Angle			
Zenith	60	90	120	Average	Zenith	60	90	120	Average
0	77.01	77.01	77.01	77.01	0	76.19	76.19	76.19	76.19
10	87.74	72.79	62.62	74.38	10	86.54	72.02	61.95	73.50
20	87.47	62.57	49.37	66.47	20	86.53	61.90	48.85	65.76
30	76.34	50.07	38.81	55.07	30	75.53	50.16	38.40	54.70
40	60.42	39.93	30.86	43.74	40	59.77	39.50	30.53	43.27
50	45.23	31.09	24.81	33.71	50	44.75	30.76	24.55	33.35
60	32.45	23.67	19.71	25.28	60	32.11	23.42	19.50	25.01
70	21.87	17.01	14.84	17.91	70	21.63	16.83	14.68	17.71
80	11.64	9.63	8.80	10.02	80	11.52	9.52	8.70	9.91
90	1.26	1.10	1.06	1.14	90	1.24	1.09	1.05	1.13

Figure 5.6-4: Diffuse Sky Radiances in 0.28 to 4.0 μm Band, Mid-Latitude Summer Environment, W/(sr-m^2)

Only the values in the 'Average' column are used in the Estimator, and the values for intermediate angles are linearly interpolated since the average radiances are sufficiently monotonic with zenith.

Figure 5.6-5 shows the LOWTRAN7 inputs used in calculating the diffuse sky radiances. Multiple scattering was implemented (IMULT = 1) using the internal MIE scattering parameter database (IPH = 2).

LOWTRAN7 Inputs for Diffuse Sky Radiance Calculations													
CARD 1		CARD 2		CARD 3		CARD 3A1		CARD 3A2		CARD 4		CARD 5	
Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value
MODEL	[1]	IHAZE	1	H1	0.001	IPARM	2	PARM1	[4]	V1	2500.0	IRPT	0
ITYPE	3	ISEASN	0	H2	0.000	IPH	2	PARM2	[5]	V2	35720.0		
IEMSCT	2	IVULCN	0	ANGLE	30.0	IDAY	[3]	PARM3	0.0	DV	40.0		
IMULT	1	ICSTL	0	BETA	0.0	ISOURC	0	PARM4	0.0				
M1	0	ICLD	0	RO	0.0			TIME	0.0				
M2	0	IVSA	0	LEN	0			PSIPO	0.0				
M3	0	VIS	[2]					ANGLEM	0.0				
M4	0	WSS	0.0					G	0.0				
M5	0	WHH	0.0										
M6	0	RAINRT	0.0										
MDEF	0	GNDALT	0.0										
IMULT	0												
NOPRT	0												
TBOUND	0.0												
SALB	0.0												

1. For Mid-Latitude Summer, Model = 2; for Mid-Latitude Winter, Model = 3; for U. S. Standard, Model = 6.
2. For Mid-Latitude Summer and Winter, VIS = 0.0 (defaults to IHAZE); for U. S. Standard with desert haze, VIS = 70.0 km. IHAZE =1 means 23 km rural visibility at ground level.
3. IDAY: 35 for winter, 126 for spring, 217 for summer, and 308 for fall.
4. PARM1 (azimuth between observer-to-sun and observer LOS) set to 60, 90, and 120, and the results were averaged.
5. PARM2 (sun zenith angle) varied from 0 to 90 in 10 degree increments; other zenith angles calculated by linear interpolation.

Figure 5.6-5: LOWTRAN7 Inputs for Diffuse Sky Radiance Calculations

Figure 5.6-6 shows the overall diffuse sky radiances for the U. S. Standard, 70 km ground visibility (used as desert), Mid-Latitude Summer (MLS), and Mid-Latitude Winter (MLW) atmospheric models. In the legend, "U" indicates the LOWTRAN7 1976 U. S. Standard atmosphere model; the unmarked ones are MLS/MLW as appropriate.

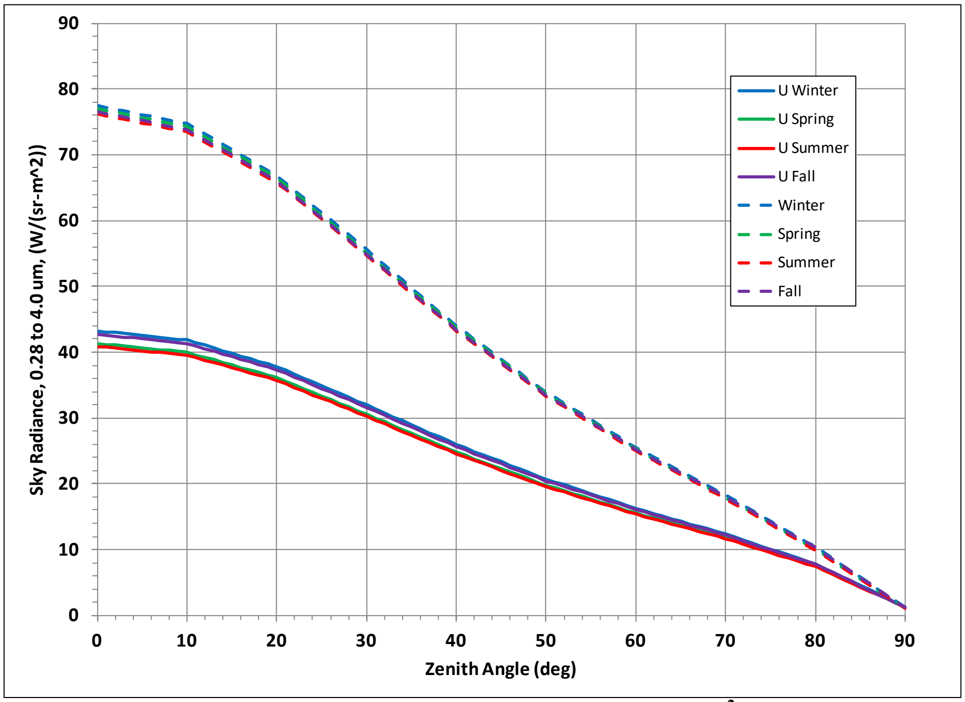


Figure 5.6-6: Diffuse Sky Radiances (W/(sr-m^2))

5.7 Diffuse Cloud Radiance

The Estimator utilizes diffuse cloud radiances as calculated by the LOWTRAN7 cumulus cloud model (ICLD=1), in which the base altitude is 0.66 km (4,010 ft.). Figure 5.7-1 shows the radiance in the 0.28 to 4.0 μm band for the desert and mid-latitude atmospheric environments as it varies with sun zenith angle. Cloud radiance is invariant with the azimuth difference between the observer LOS and the LOS to the sun (PARM1 in Figure 5.6-6) since LOWTRAN7 models clouds as a uniformly overcast sky.

Diffuse Cumulus Cloud Radiances									
	Mid_Lat Summer		Mid-Lat Winter			1976 U. S. Standard, Desert			
	Day 126	Day 217	Day 308	Day 35		Day 126	Day 217	Day 308	Day 35
Zenith	Spring	Summer	Fall	Winter	Zenith	Spring	Summer	Fall	Winter
0	31.18	30.85	33.43	33.84	0	32.19	31.85	33.28	33.69
10	30.23	29.91	32.42	32.82	10	31.22	30.89	32.28	32.68
20	27.55	27.26	29.54	29.90	20	28.46	28.16	29.43	29.79
30	23.53	23.28	25.21	25.52	30	24.32	24.06	25.14	25.44
40	18.03	17.84	19.30	19.53	40	18.65	18.46	19.28	19.52
50	11.88	11.75	12.67	12.82	50	12.31	12.18	12.72	12.87
60	7.01	6.94	7.42	7.51	60	7.27	7.19	7.51	7.60
70	3.58	3.54	3.71	3.76	70	3.70	3.66	3.82	3.87
80	1.35	1.34	1.30	1.23	80	1.37	1.36	1.41	1.43
90	0.27	0.27	0.14	0.14	90	0.22	0.22	0.22	0.22

Figure 5.7-1: Cumulus Cloud Radiances, 0.28 - 4.0 μm Band, All Environments, W/(sr-m^2)

The Estimator does not account for the bright edges of clouds as are often observed, since the LOWTRAN7 model does not accommodate them. But the error is probably small enough to ignore since the projected area of the bright cloud edges is generally small compared to the main body of the clouds. Figure 5.7-2 shows the LOWTRAN7 inputs used in calculating the cloud radiances.

LOWTRAN7 Inputs for Cloud Radiance Calculations [6]													
CARD 1		CARD 2		CARD 3		CARD 3A1		CARD 3A2		CARD 4		CARD 5	
Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value	Variable	Value
MODEL	[1]	IHAZE	1	H1	0.001	IPARM	2	PARM1	[4]	V1	2500.0	IRPT	0
ITYPE	3	ISEASN	0	H2	0.000	IPH	2	PARM2	[5]	V2	35720.0		
IEMSCT	2	IVULCN	0	ANGLE	30.0	IDAY	[3]	PARM3	0.0	DV	40.0		
IMULT	1	ICSTL	0	BETA	0.0	ISOURC	0	PARM4	0.0				
M1	0	ICLD	1	RO	0.0			TIME	0.0				
M2	0	IVSA	0	LEN	0			PSIPO	0.0				
M3	0	VIS	[2]					ANGLEM	0.0				
M4	0	WSS	0.0					G	0.0				
M5	0	WHH	0.0										
M6	0	RAINRT	0.0										
MDEF	0	GNDALT	0.0										
IMULT	0												
NOPRT	0												
TBOUND	0.0												
SALB	0.0												
1. For Mid-Latitude Summer, Model = 2; for Mid-Latitude Winter, Model = 3; for Desert, Model = 6.													
2. For Mid-Latitude Summer and Winter, VIS = 0.0 (defaults to IHAZE); for 1976 U. S. Standard with desert haze, VIS = 70.0.													
3. IDAY: 35 for winter, 126 for spring, 217 for summer, and 308 for fall.													
4. The radiance is invariant with azimuth between the LOS to the sun and the observer LOS; used PARM1 = 60.													
5. PARM2 (sun zenith angle) varied from 0 to 90 in 10 degree increments; other zenith angles calculated by linear interpolation.													

Figure 5.7-2: LOWTRAN7 Inputs for Cloud Radiance Calculations

Figure 5.7-3 shows the overall diffuse cloud radiances for the two classes of models ("U" designates the 1976 U. S. Standard model with 70 km visibility as before). The spring and summer values were calculated as before with the Mid-Latitude Summer model, and fall/winter with the Mid-Latitude Winter model.

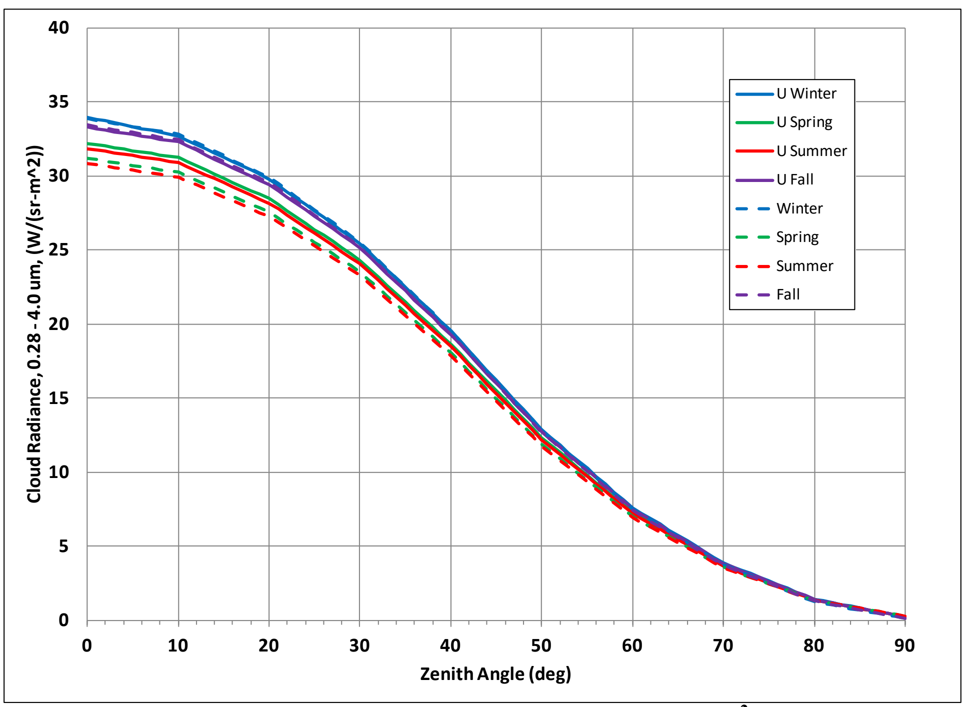


Figure 5.7-3: Diffuse Cloud Radiances ($W/(sr\text{-}m^2)$)

5.8 Solar Panel Efficiency

The efficiency of solar panels is calculated as the power output of the panel compared to a standard solar energy input at normal incidence. The "solar constant" is the irradiance at the top of the atmosphere (an altitude of 100 km), which varies slightly with time of year and averages about 1350 W/m^2. As the sunlight traverses through the air to the earth's surface, some of it is absorbed and some is scattered. One "atmosphere" is defined euphemistically as the amount of atmosphere that the solar energy passes through when the sun is directly overhead, i.e., zenith = 0°. The net result is a lower irradiance at the earth's surface as the sun moves away from zenith and the path includes a large length of scattering and absorbing atmosphere. A standard metric for solar energy is defined as the energy transmitted through 1.5 "atmospheres", which leads to an integrated irradiance of 800 W/sq m at the earth's surface [5.8-1]. The zenith angle that defines the number of "atmospheres" is given by:

$$\#\ atmospheres \sim \frac{1}{\cos\theta}$$

where θ is the sun zenith angle. This relation is valid for zenith angles less than about 80°; for larger angles, refractive bending becomes important and there is no simple formula. Fortunately, we are interested in only the one case, 1.5 atmospheres, denotes as "AM1.5".

The zenith angle θ corresponding to 1.5 atmospheres is 48.18°; and the atmospheric constituents are such that the irradiance at the earth's surface for normal incidence in the waveband from 0.28 to 4 µm is 800 W/sq m. There is nothing special about this definition; it is merely a convention by which all solar panels can be compared directly. The generic efficiency of a solar panel is defined as:

$$e_g = \frac{F\eta_p \int_{0.28}^{4.00} R(\lambda) E_{D,1.5}(\lambda) d\lambda|_{AM1.5}}{\int_{0.28}^{4.00} E_{D,1.5}\,(\lambda) d\lambda|_{AM1.5}}$$

where F is the fill factor of the detectors within the solar array, η_p is the peak spectral quantum efficiency, R is the normalized responsivity, and $E_{D,\,1.5}$ is the direct spectral irradiance at the earth's surface under 1.5 atmosphere conditions (800 W/sq m). This formula assumes the quantum efficiency of Silicon is constant [5.8-2]; although there is usually some roll-off with wavelength. This distinction is not important to the illustration. The importance of the above equation is that the solar panel does not convert all the incident energy to electrical power. There are four main sources of losses: a) the solar panel is not sensitive to all wavelengths contained in the AM1.5 definition; b) the conversion efficiency is always less than unity even under ideal conditions; c) the fill factor (the ratio of active conversion area to total area) is always less than unity; and d) there are thermal effects that reduce the quantum efficiency from the ideal state.

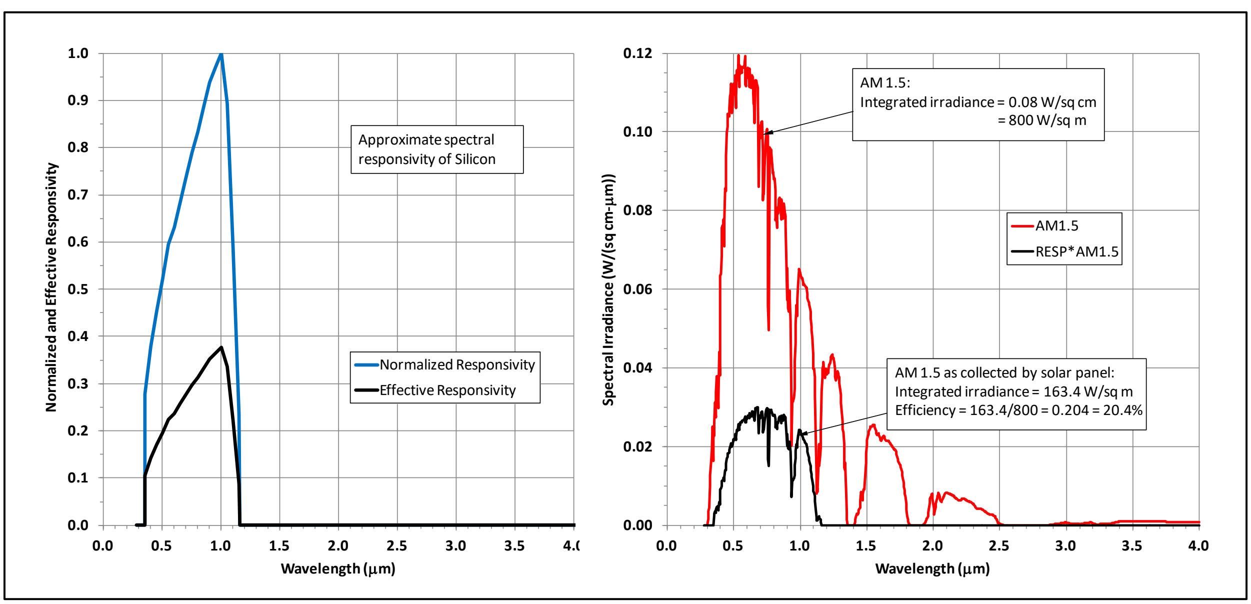


Figure 5.8-1: Illustration of Solar Panel Efficiency

Figure 5.8-1 shows the situation. On the left panel is shown an approximate representation of the normalized responsivity of silicon solar cells (in blue), and the effective responsivity (in black) that includes the actual quantum efficiency plus losses due to thermal effects and fill factor. (Quantum efficiency is a metric that defines what fraction of the incident photons are converted to electrons.) The right panel shows the spectrum of the solar irradiance under the AM1.5 condition (in red) and the black line shows the resulting converted spectrum owing to the properties mentioned above. The black line on the right panel is a result of the multiplication of the red curve on the right panel by the black curve on the left panel (the effective response). The area under the red curve is 800 W/sq m; the area under the black curve on the right panel is the amount actually converted to electrical power, and the ratio of these areas is the efficiency of the solar panel. In this notional example, the area under the black curve is 163.4 W/sq m; thus the efficiency of the panel is 163.4/800 = 0.204 = 20.4%.

Figure 5.8-2 is the input deck to LOWTRAN7 [5.8-3] that produces the AM1.5 spectrum shown on Figure 5.8-1. It uses the 1976 U. S. Standard atmosphere (MODEL = 6), with a 23 km rural haze (IHAZE = 1) visibility superseded by a ground visibility of 39.5 km (VIS = 39.5). The solar zenith angle is 48.18° (ANGLE = 48.18), the observer is at an elevation of 1 m (H1 = 0.001 km), and the day is 15 March (IDAY = 74). The geometry is a direct line-of-sight to the top of the atmosphere at 100 km (ITYPE = 3) and the calculation type is directly transmitted solar irradiance (IEMSCT = 3 and ISOURC = 0). Single atmospheric scattering is used (IMULT = 0). The waveband limits are 0.28 μm (V2 = 35720) and 4 μm (V1 = 2500). V1 and V2 are in wavenumbers, which is the number of wavelengths in 1 cm. Wavenumbers are calculated as 10000/λ, where λ is wavelength in μm. DV is the wavenumber increment, chosen to be 40 because the array length in LOWTRAN7 is limited to 1000: (35720-2500)/40 + 1 = 831.5, within the array limit. LOWTRAN7 uses 832 points in the array, thus extending the waveband to 25740 wavenumbers, which corresponds to 0.2797 μm. The difference between 0.28 μm and 0.2797 μm may be safely ignored. The calculated integrated solar irradiance (as shown by the red curve on Figure 5.8-1) using these inputs comes to 7.995E-02 W/cm^2 = 799.5 W/m^2, for an error of 0.0625%, close enough. Incidentally, the average transmittance from the top of the atmosphere along this LOS is 0.4461, and the irradiance at the top of the atmosphere is 1.3682E-01 W/cm^2 = 1368.2 W/m^2. This latter value is the so-called "solar constant", which varies slightly with time of year, and is commonly defined to be nominally 1353 W/m^2, -3.27/+3.42% [5.8-4].

CARD 1		CARD 2		Alt. CARD 3		CARD 4		CARD 5	
Variable	**Value**	**Variable**	**Value**	**Variable**	**Value**	**Variable**	**Value**	**Variable**	**Value**
MODEL	6	IHAZE	1	H1	0.001	V1	2500.0	IRPT	0
ITYPE	3	ISEASN	0	H2	0.000	V2	35720.0		
IEMSCT	3	IVULCN	0	ANGLE	48.18	DV	40.0		
IMULT	0	ICSTL	0	IDAY	74				
M1	0	ICLD	0	RO	0.0				
M2	0	IVSA	0	ISOURC	0				
M3	0	VIS	39.5	ANGLEM	0.0				
M4	0	WSS	0.0						
M5	0	WHH	0.0						
M6	0	RAINRT	0.0						
MDEF	0	GNDALT	0.0						
IMULT	0								
NOPRT	0								
TBOUND	0.0								
SALB	0.0								

Figure 5.8-2: LOWTRAN7 Inputs for AM1.5 Reference Spectrum

5.9 How to Read a Solar Panel Datasheet

There are seven general types of information contained in a typical solar panel datasheet: a) the physical dimensions; b) the window type; c) performance at standard test conditions (STC); d) performance at nominal operating cell temperature (NOCT), e) the overall panel efficiency at test conditions; f) the deviation in performance due to temperature effects; and g) the deviation in performance due to aging. There are other items, such as allowable mechanical stresses, connector types, and maximum fusing ratings, that are important for installation, but not for a general analysis. As usual, none of the data is presented in a manner that is directly useful, so some arbitration is necessary.

The physical dimensions are normally shown only as the outer dimensions, occasionally showing the dimension of the mounting frame. Sometimes the interior "active area" dimensions are shown, which is what is actually of interest. Figure 5.9-1 shows two main styles of how physical dimensions are shown and how to obtain the active area.

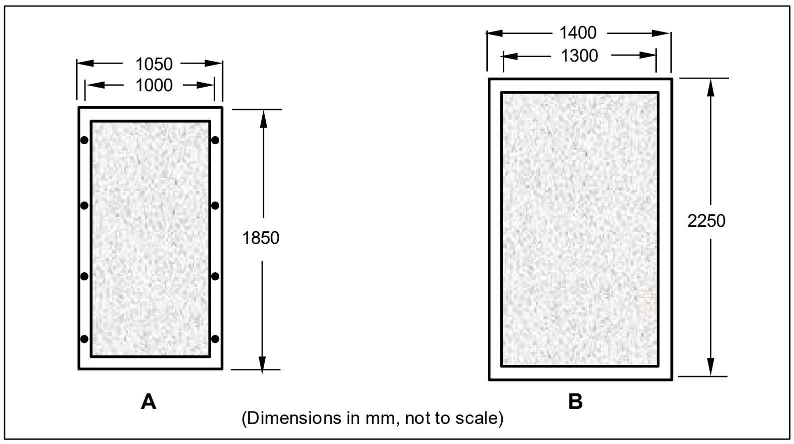


Figure 5.9-1: Typical Dimensional Styles

Panel A of Figure 5.9-1 shows the overall width and the width between mounting holes. If the mounting holes centered in the frame, then the width of the each side of the frame in the horizontal direction is 50 mm; therefore the horizontal dimension of the active area is 950 mm. The overall height is given as 1850 mm, and assuming the frame dimensions are symmetrical, the vertical active area is 1750 mm. The total active area shown by the shaded part is 950(1750) = 1,662,500 mm^2, which is 1.6625 m^2.

Panel B gives both the active and total horizontal dimensions and the total vertical dimension Again, if the frame is symmetrical, can assume that the total active area is 1300(2150) = 2,795,000 mm^2, which is 2.795 m^2.

The window type will nearly always be tempered glass of thickness between 2.8 and 3.3 mm, with an anti-reflection (AR) coating. The AR coating is necessary to reduce the reflections of sunlight off the front surface of the glass; without it, about 4% of the energy would be reflected back to the environment and not absorbed. With the AR coating, the total reflection is likely to be less than 1%. But, the AR coating cannot perform uniformly over all angles of incidence (AOI); typically they are optimized for normal incidence, and the performance falls off rapidly for AOI's a certain angle from normal incidence. Suppose a certain AR coating is limited to 70°; it means that reflections beyond that angle are very high, and the total field of regard (FOR) of the panel would then be 140° in every direction, measured from the panel normal vector. This fact will determine the solid angle observed by the panel when calculating the sky and ground irradiances.

Datasheets will always call out the performance at "standard test conditions" (STC). The standard conditions are: a) the panel is illuminated with 1000 W/m^2 of energy at normal incidence; b) the relative spectral content of the 1000 W/m^2 is the same as the AM1.5 as shown in section 5.8 (i.e., all the values in

Figure 5.8-1 are increased by 25%); and c) the solar cell temperature is maintained at 25° C (298.15° K). The maximum power output is generally called out in the part number (referred to as the "nameplate" rating) as the value obtained at STC conditions. But keep in mind that this rating applies to the total panel area, which is not usually 1 square meter. There are three problems with the STC conditions. First, the solar cells are held at a constant temperature of 298.15° K by adding cooling air and monitoring their temperature with thermocouples. This is not a simple task, and there is some variation in temperature at different points in the active area. Secondly, the laboratory source is engineered to produce the same spectral pattern as AM1.5, but it is difficult to do in practice, and there is a certain amount of spectral drift with temperature and duration. Third, somewhat related to the first, is that each solar cell in the array has a slightly different spectral response (i.e., the spectral quantum efficiency mentioned in section 5.8 is not uniform among the cells). In any case, these effects introduce slight variations in the open circuit voltage and short circuit currents, which lead to variations in power output. It is for these three reasons that the output power under STC conditions usually contains a tolerance ranging from ±1.5% to ±3%, depending on manufacturer. The module efficiency is quoted along with the power output. The formula for overall efficiency is:

$$e = \frac{P_{OUT}}{A_P P_{IN}}$$

where P_{OUT} is the DC power output in watts, A_P is the panel area in m^2, and P_{IN} is the incident solar energy in W/m^2. For example, the LG380Q1C-V5 panel calls out 380 W output under STC conditions, and its active area is 1.621 m^2. From the previous formula, the efficiency should be 380/(1.621*1000) = 0.234, but is quoted in the datasheet as 0.220, which amounts to a derating of [1 - (0.22/0.234)]*100 = 6%. The STC performance is all well and good and permits an easy comparison between manufacturer's panels, but is not much use for calculating as-installed performance. The reason of course, is that STC conditions apply only in test laboratories, not on your roof.

As-installed performance is more closely associated with the NOCT values in the datasheet. NOCT (also known as NMOT) is also a laboratory measurement under the following conditions: a) 800 W/m^2 irradiance at normal incidence; b) the spectral content the same as AM1.5; c) ambient air temperature is 25 ± 2° C (298.15 ± 2° K); and d) the wind speed is 1 m/s (1.943 knots or 2.236 MPH). These are more realistic because the temperature of the solar cells are permitted to float, and thus incur the losses associated with thermal effects. But it is still a lab measurement. The power output is called out under these conditions, and should be used to calculate the nominal efficiency. For example, the LG380Q1C-V5 panel calls out a NOCT power output of 286 W and its efficiency is then 286/(800*1.621) = 0.220. Section 4 of the Utilities page makes this calculation if datasheet values are available. The cell operating temperature is 44 ± 3° C (317.15 ± 3° K), which is 19° K above the ambient. It evident that the efficiency quoted for STC as above is the same as for NOCT in this particular datasheet, but is not generally the case. It is best to calculate the NOCT efficiency directly and not rely on the STC rating.

Solar cells become less efficient as the substrate temperature increases, and the variation is accounted for in the datasheet as the temperature coefficient of power. Values are typically around -0.30 to -0.35% per °C (= °K), negative because efficiency is decreasing with increasing temperature. The LG380Q1C-V5 datasheet calls out -0.30% per degree C (which is -0.003 in decimal). For a crude assessment (in the absence of thermal models), it is assumed for purposes of this simple Estimator that the panel substrate varies uniformly with ambient. In the above case, if the ambient was 308.15° K (95° F) as is common in many places in the summer, the panel substrate temperature would be 327.15° K (19° K above ambient), and the efficiency would be 0.220 + 10(-0.003) = 0.190. The multiplier of 10 comes from the difference between the ambient and the lab temperature, i.e., 308.15 - 298.15. The panel under these conditions would output 0.19*800*1.621 = 246.40 W vs. the 286 W under the NOCT test conditions. Keep in mind that the panel "nameplate" rating is 380 W at STC (1000 W/m^2 at normal incidence); for practical conditions turns out to be 246.4 W when irradiated at more practical 800 W/m^2

even at normal incidence; a very large difference. Since normal incidence is uncommon in practice, the actual output is even less.

The Estimator implements a thermal efficiency correction:

$$e_{TC} = e_{NOCT} + [\mathrm{T_{AMB}} - T_{LAB}]\left(\frac{C_T}{100}\right) \quad (5.9\text{-}1)$$

where e_{TC} is the efficiency corrected for temperature, e_{NOCT} is the generic efficiency calculated per NOCT conditions, T_{AMB} is the as-installed ambient temperature, T_{LAB} is the NOCT laboratory temperature (298.15 K), and C_T is the temperature coefficient of power per deg K called out in a datasheet. (A degree C has the same magnitude as a degree K; they are simply offset by 273.15.) This efficiency correction is a simple offset based on ambient temperature, since the e_{NOCT} term includes the effect of the elevated cell temperature at NOCT conditions. If the ambient temperature is below 298.15° K (77° F), then, since C_T is negative, the efficiency is higher than that reported in the datasheet. C_T is divided by 100 since the datasheets call it out as a percentage, whereas the efficiencies in the Estimator are expressed as decimals. The Estimator includes a database of nominal ambient temperatures for the four seasons assigned per the cloud location selection.

Solar panel efficiencies degrade with age. The datasheets normally will indicate the rate of aging by specifying: a) the percent degradation after the first year; b) the rate of degradation for each year afterward (so many percent per year); and c) a guaranteed minimum ratio of generated power to initial power rating after a certain number of years (usually 20 or 25). The initial rate of degradation in the first year or two is usually larger than the rate in ensuing years, but it is evident that the overall rate is approximately linear. The Estimator assumes it is entirely linear, and models the degradation with time as:

$$F_C(y) = (1 + my)P_A \quad (5.9\text{-}2)$$

where F_C is the fraction of power generated in year y compared to initial power, y is the number of years since installation, P_A is the power generated in the first year, and m is the slope of the degradation curve. The value of m can be determined from the datasheet:

$$m = \frac{Rating\ at\ n\ years - 1}{\#\ years} \quad (5.9\text{-}3)$$

where the rating after n years is the fraction that the manufacture guarantees after so many years, and the number of years is usually 25. If the guaranteed minimum power after 25 years is 0.85, then m = (0.85 - 1.0)/25 = -0.006. If the total power over a certain number of years is desired, it is a simple matter to integrate the above equation:

$$F_T(y) = \int_0^n (1 + my)dy = n + 0.5mn^2 \quad (5.9\text{-}4)$$

where n is the number of years since the initial installation, and y denotes years. F_T gives the integrated fraction of power including degrading effects due to aging. The total power generated by the solar panel system over any period is then:

$$P_T = P_A F_T \quad (5.9\text{-}5)$$

where P_A is the amount of power generated in the first year of operation. In the current example (0.85 fraction of initial power in the 25th year), after 13 years, $F_T(13) = 13 - 0.5(0.006)13^2 = 13 - 0.507 = 12.493$. If the total initial annual power generation of the system P_A is 10 kW-hr, the total power P_T generated during 13 years including the degradation is 124.93 kW-hr as opposed to 130 kW-hr. The Estimator sets n = 25 (and requires a user input in cell D11 for 25-year power fraction), and calculates P_{25}, the total power generated in 25 years, per equations 5.9-4 and 5.9-5, with F_T calculated using n = 25.

5.10 Overall Radiometry

Figure 5.10-1 shows a diagram of the various radiation contributors collected by a solar panel. The direct irradiance from the sun E_D is the most important source, but the solar panel also receives energy from the sky and clouds, denoted by L_S and L_C. In addition, it receives energy from ground reflections of those same three sources.

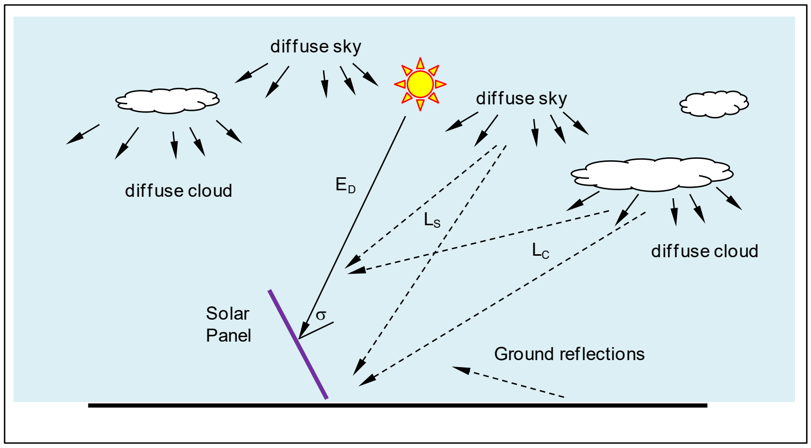


Figure 5.10-1: Radiation Sources

The overall radiometric equation for calculating the power generation is:

$$P = P_D + P_{DS} + P_{DC} + P_G \quad (5.10\text{-}1)$$

$$P_D = A_P e_{TC} e_C (1 - \mathrm{C_C}) \mathrm{E_D} \cos\sigma \quad (5.10\text{-}2)$$

$$P_{DS} = A_P e_{TC} e_C e_{RS} \Omega_S (1 - C_C) L_S \quad (5.10\text{-}3)$$

$$P_{DC} = A_P e_{TC} e_C e_{RC} \Omega_S C_C L_C \quad (5.10\text{-}4)$$

$$P_G = A_P e_{TC} e_C \Omega_G [L_{GD} + e_{RS} L_{GS} + e_{RC} L_{GC} + L_{GE}] \quad (5.10\text{-}5)$$

where P_D is the amount due to direct solar irradiance, P_{DS} is the amount due to diffuse sky radiance, P_{DC} is the amount due to diffuse cloud radiance, and P_G is the amount due to reflections off the ground from the incident direct solar, diffuse sky, diffuse cloud, and ground-emitted radiation. As for the terms on the right side of the equations, A_P is the physical active area of the solar panel array in m^2; e_{TC} is the thermally-corrected solar panel efficiency, C_C is the long-term fraction of cloud cover, σ is the total angle between the LOS to the sun and the solar array normal vector, E_D is the directly transmitted solar irradiance (W/m^2), e_C is the DC-to-AC conversion efficiency, e_{RS} is the reduced efficiency due to diffuse sky spectral content, e_{RC} is the same for cloud spectral content, Ω_S is the solid angle of the sky as observed by the solar array (sr); L_S is the sky radiance ($W/(sr\text{-}m^2)$), L_C is the cloud radiance ($W/(sr\text{-}m^2)$), Ω_G is the solid angle of the ground as observed by the solar array (sr), L_{GD} is the ground radiance due to reflected direct solar irradiance ($W/(sr\text{-}m^2)$), L_{GS} is the radiance of the diffuse sky reflected by the earth's surface ($W/(sr\text{-}m^2)$), L_{GC} is the radiance of clouds reflected by the earth surface ($W/(sr\text{-}m^2)$), and L_{GE} is the emitted ground radiance ($W/(sr\text{-}m^2)$). Radiances all have units of $W/(sr\text{-}m^2)$ whereas irradiances have units of W/m^2; efficiencies and cloud fractions are dimensionless. Since all the calculations are done on an hourly basis, all the power values are in units of W-hrs. The value of C_C is determined by the cloud location selection per sections 3.2, 5.3, and Appendix A, e_{TC} is calculated per section 5.9, σ is calculated per section 5.4, E_D is tabulated as described in section 5.5, L_S is tabulated per section 5.6, and L_C is as described in section 5.7. Sections 5.11 and 5.12 will address the ground terms and the solid angles Ω_G and Ω_S.

The equation for P_D applies to the direct sunlight. Since the solar panel does not track the sun, the fraction of the directly transmitted irradiance is reduced by the cosine of the angle between the solar panel normal vector and the LOS to the sun, as explained in section 5.4. But it is also scaled by the fraction of the time (1- C_C) that the direct sunlight is actually incident on the solar panel. Recall that the database described in section 5.3 noted that C_C is the average fraction of cloud cover during daylight hours. The Estimator assumes that the clouds obscure the direct sun randomly, and over long periods, the sun is obscured the same average fraction of the time as any other random portion of the sky. It is not necessary to be concerned as to whether clouds are moving or stationary; the point is that the area of the sky is obscured on average by some fraction C_C, and that the exact location and time of day is entirely random. The raw C_C data was arbitrated as described in Appendix A so as to make the average E_D values consistent with measured data.

The equation for P_{DS} applies to downwelling radiance L_S from the diffuse sky. Once again, the fraction of sky radiance that is actually received depends on the fraction of time that the sky is not obscured by clouds, that is, the term (1-C_C). The main distinction between the diffuse radiance and the directly transmitted irradiance is that the sky radiance occurs over the entire hemisphere that is not blocked by clouds. The diffuse sky and cloud radiance covers the entire hemisphere of the atmosphere, and totals to π steradians. However, the solar panel cannot receive sky and cloud radiation from all directions, and the fraction of the hemisphere (i.e., the solid angle viewed by the solar panel) that is available is denoted by Ω_S. The solid angle Ω_S is a property of the solar panel and its orientation, not any property of the sky or clouds. Since L_S has units of W/(sr-m^2), multiplying by Ω_S in sr gives the correct units of W/m^2 for this term. It turns out that L_S is actually a maximum at the horizon, and is larger for the higher scattering atmospheres than for the clear desert type. The horizon L_S is not used in the Estimator for two reasons: a) most solar panel installation do not have clear LOS to the horizon due to trees and other buildings; and b) the L_S is larger than the nominal sky only over a fairly small elevation above the horizon (maybe 10° or so). If the solar installation does view the horizon, the Estimator will slightly under-predict the diffuse sky contribution.

P_{DC} is the irradiance due to the downwelling radiance of clouds L_C. It is scaled by the fraction of the sky that is cloudy, C_C, and also by the portion of the sky that the solar panel can observe, Ω_S. The units of this term are W/m^2 for the same reason as the diffuse sky radiance.

The equation for P_G describes the irradiance incident on the solar panel due to radiation from the ground, reflected and emitted. The last term, L_{GE}, is the amount contributed directly by the ground due to the fact that it radiates as a greybody, characteristic of every object that is at a temperature above absolute zero. The other three terms, L_{GD}, L_{GS}, and L_{GC} are the contributions due to reflections of direct sun irradiance, diffuse sky radiance, and diffuse cloud radiance respectively. They are described in detail in section 5.11.

Atmospheric scattering causes the well-known "blue shift" that causes the sky to appear blue. The fact that the spectrum shifts slightly means that the efficiency of the solar panel for diffuse radiance is different compared to the efficiency calculated using the AM1.5 directly transmitted spectrum. Figure 5.10-2 shows the effect. It shows the typical spectrum of radiances for cloud and sky conditions in summer and winter for the two LOWTRAN7 models. Each of them is normalized, along with the responsivity of Silicon (in black) and the AM1.5 spectrum (in red). Notice that all the sky and cloud radiances are shifted toward "blue"; i.e., lower wavelengths. It is evident that the response of the solar panel to the diffuse sky and clouds will not be as efficient as the solar spectrum because the peak radiances are shifted toward the wavelengths where the responsivity is lower. The relative spectral efficiency e_{RS} and e_{RC} for sky and cloud are calculated by:

$$e_{RS} = \frac{\int_{0.28}^{4.0} L_{S,n}(\lambda)R(\lambda)d\lambda}{\int_{0.28}^{4.0} E_{D,n}(\lambda)R(\lambda)d\lambda} \qquad (5.10\text{-}6a)$$

$$e_{RC} = \frac{\int_{0.28}^{4.0} L_{Cn}(\lambda) R(\lambda) d\lambda}{\int_{0.28}^{4.0} E_{D,n}(\lambda) R(\lambda) d\lambda} \quad (5.10\text{-}6b)$$

where $L_{S,n}$ is either the normalized sky radiance, $L_{C,n}$ is the normalized cloud spectral radiance, λ is wavelength, R is normalized responsivity, and $E_{D,n}$ is the normalized directly-transmitted solar spectral irradiance. It is acceptable here to treat radiances and irradiances the same since the conversion from radiance to irradiance and vice-versa is done with non-spectral constants, including the ground reflectance, to be described in section 5.13.

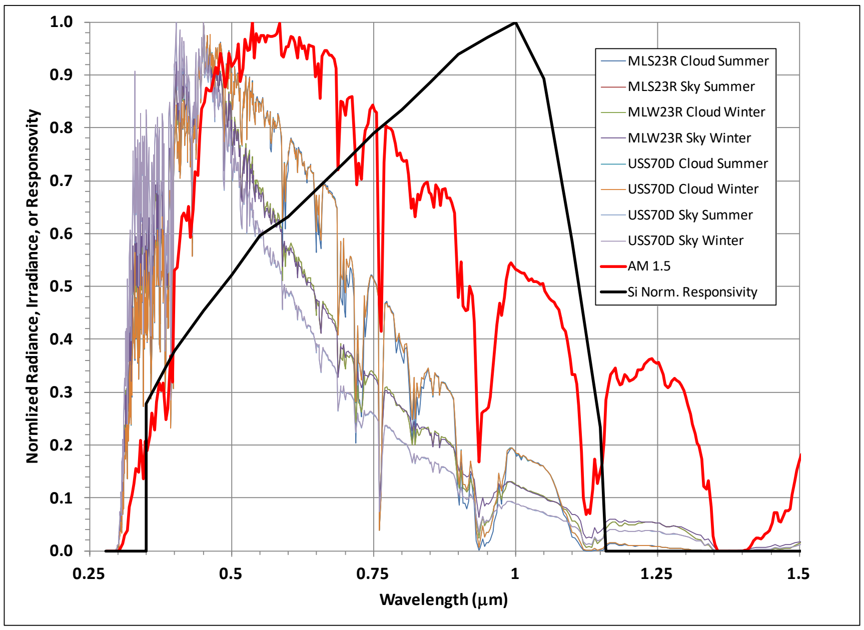


Figure 5.10-2: Spectral Shift Due to Scattering

Figure 5.10-3 shows the resulting relative efficiencies for the diffuse sky and cloud radiances. Keep in mind that these scaling factors are included as a way to avoid the inconvenience of spectral calculations within the Estimator.

Relative Efficiency vs. AM1.5 due to Spectral Differences for Silicon, %						
	Mid-Lat Summer		Mid-Lat Winter		1976 U. S. Std, Desert	
	Cloud	Sky	Cloud	Sky	Cloud	Sky
Summer	58.4	48.2			60.9	41.4
Winter			48.2	48.9	60.9	41.4

Figure 5.10-3: Relative Efficiencies for Sky and Cloud Radiances

5.11 Ground Radiance

The radiance of the ground has four components: a) reflected from the direct sunlight; b) reflected from down-welling cloud emission; c) reflected from diffuse sky emission; and d) self-emission from the ground itself. Figure 5.11-1 shows the geometry.

Since the directly transmitted solar irradiance is defined to lie in a plane normal to the LOS to the sun, the actual irradiance illuminating the earth surface is reduced by the cosine of the angle between the earth normal (straight up) and the LOS to the sun. It is clear that this angle for a locally flat earth is the zenith angle θ. Secondly, it is assumed that a portion of the energy is absorbed and part is reflected per the reflectance ρ. The reflected energy is spread uniformly in all directions into the hemisphere. The ground is assumed to be a Lambertian surface such that the intensity in W/sr scales with projected area. Thus the radiance of the reflected direct solar irradiance is reduced by a factor of π.

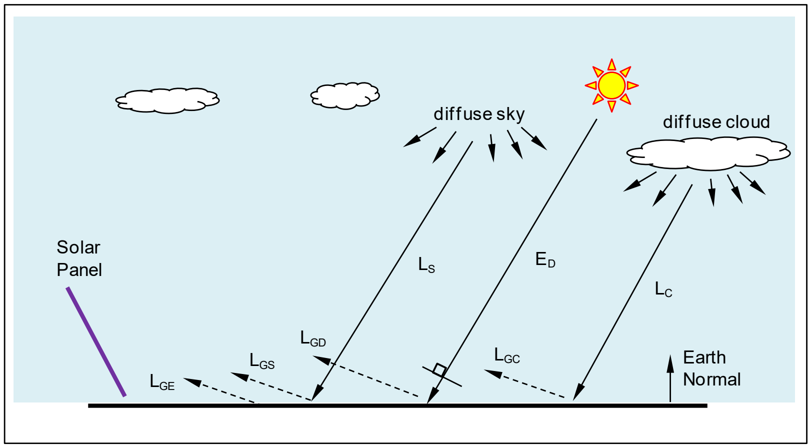


Figure 5.11-1: Geometry for Ground Radiance Terms

The overall equation for the ground radiance toward the solar panel arising from the reflected direct solar irradiance is:

$$L_{GD} = \left(\frac{\rho}{\pi}\right)\cos\theta(1 - C_C)E_D \qquad (5.11\text{-}1)$$

where ρ is the effective ground reflectance (unitless), π is the usual constant, θ is the solar zenith angle, and E_D is the directly transmitted solar irradiance as described in section 5.5. L_{GD} has units of W/(sr-m^2) and E_D has units of W/m^2; the steradian (sr) unit arising from the π in the denominator. Surface reflectance depends on the surrounding terrain type, and is selected by the user as described in section 3.9.

The Estimator makes an implicit assumption that the sky radiance is constant as represented by the average values in Figures 5.6-2 through 5.6-4. (The sky radiance is not actually constant; it varies by about 15% to 20% over the hemisphere.) If there were no clouds, every point in the sky hemisphere would radiate uniformly onto the ground; since the solid angle observed by the ground would then be π steradians, the total irradiance incident on the ground would be πL_S, where L_S is the downwelling sky radiance. But the ground is Lambertian; it re-radiates into π steradians after a reduction by the reflectance ρ. The result is:

$$L_{GS} = \frac{\rho}{\pi}\pi L_S = \rho L_S \qquad (5.11\text{-}2)$$

where L_S is the diffuse sky radiance; and this result applies only to a clear, uniform sky. If the sky is partly cloudy, then the only the clear-sky fraction would contribute to reflection of the sky radiance; in other words, the π hemisphere solid angle is replaced by $(1\text{-}C_C)\pi$, where C_C is the fraction of the hemisphere that is cloudy. The above equation is then:

$$L_{GS} = \frac{\rho}{\pi}(1 - C_C)\pi L_S = \rho(1 - C_C)L_S \qquad (5.11\text{-}3)$$

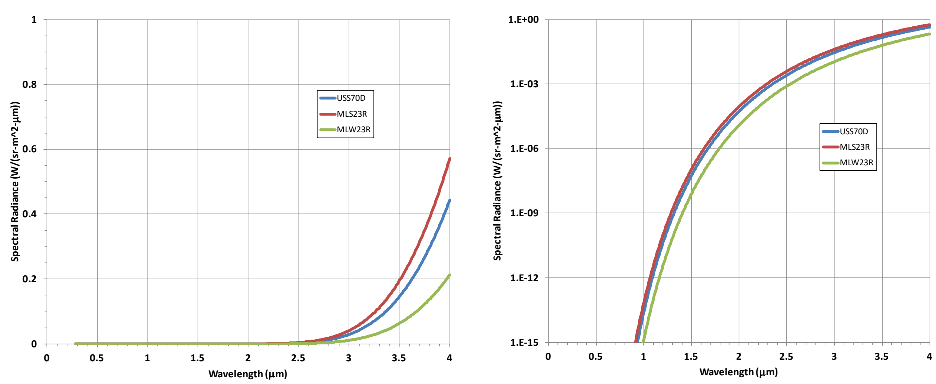
where ρ is the ground reflectance, C_C is the fraction of the sky covered by clouds, and L_S is the downwelling sky radiance.

The same logic applies to cloud radiance: if the sky were completely overcast, then the total cloud radiance incident on the ground would be πL_C, and the radiance toward the solar panel after reflection by the Lambertian ground would be ρL_C. For partly cloudy skies, the radiance from the ground attributable to cloud radiance is:

$$L_{GC} = \rho C_C L_C \qquad (5.11\text{-}4)$$

where ρ is the ground reflectance, C_C is the fraction of the sky covered by clouds, and L_C is the downwelling cloud radiance. All the values of ρ cited above refer to effective reflectance as described in section 5.13.

Ground temperatures are approximately the same as the air temperature at ground level. Ground temperatures for the 1976 U. S. Standard, Mid-Latitude Summer, and Mid-Latitude Winter models are 288.4° K, 294.2° K, and 272.2° K respectively. Figure 5.11-2 shows the spectral and integrated radiances for these temperatures, even if the emissivity of the ground were unity (i.e., zero reflectance). Even under these conditions, the table at the bottom of the Figure indicates that the total ground emitted radiance is very small over the 0.28 to 4.0 µm band, and is practically zero for the relevant Silicon response band at 0.4 to 1.15 µm. Therefore, the Estimator assumes the ground emitted radiance L_{GE} is zero. It may be objected that some places in the U. S. are so hot that the ground temperature is elevated to the point where an emission term would matter. Even if the air temperature in Phoenix is 120° F (322° K), and the ground temperature from absorbed sunlight were 50° K above that (377° K), the integrated radiance in the 0.28 mm to 4.0 µm band is 4.91 W/(sr-m^2) and in the 0.4 to 1.15 µm band is 9.99E-09 W/(sr-m^2), still insignificant.



Ground Radiance (W/sr-m^2)			
		Waveband (um)	
Type	Temp (K)	0.28 to 4.0	0.40 to 1.15
USS70D	288.4	0.1844	2.83E-13
MLS23R	294.2	0.244	6.99E-13
MLW23R	272.2	0.0826	2.10E-14

Figure 5.11-2: Ground Emitted Radiances

5.12 The Solid Angles Ω_G and Ω_S

It was mentioned in section 5.9 that every solar panel is equipped with a protective window that is in turn overlaid with an anti-reflection (AR) coating. Without such a coating, the outer surface of the window would reflect about 4% of the energy back to the environment, and would constitute a direct 4% reduction of collection efficiency. The AR coating is designed to match the refractive index of the air to the refractive index of the glass, and although cannot be done perfectly, can usually achieve a very low reflectance (0.5 to 1%) at normal incidence in the Silicon waveband. Typically coatings can be engineered to have the same low reflectance out to about 70° or 75° angle-of-incidence (AOI), beyond which the glass has a very high reflectance, far above the usual 4%. The reflectance of the window is included in the overall efficiency of the solar panel under the test conditions as cited in section 5.9, where the AOI is always zero. The Estimator contains the assumption that the AR coating permits the same efficiency out to some limiting AOI, after which the reflectance becomes infinite and consequently the conversion efficiency of the solar panel becomes zero. This limit is the user entry in cell D12. Figure 5.12-1 shows how this AR-driven limit determines the solid angles of the sky and ground as observed by the solar panel, using a 70° AR limit as an example.

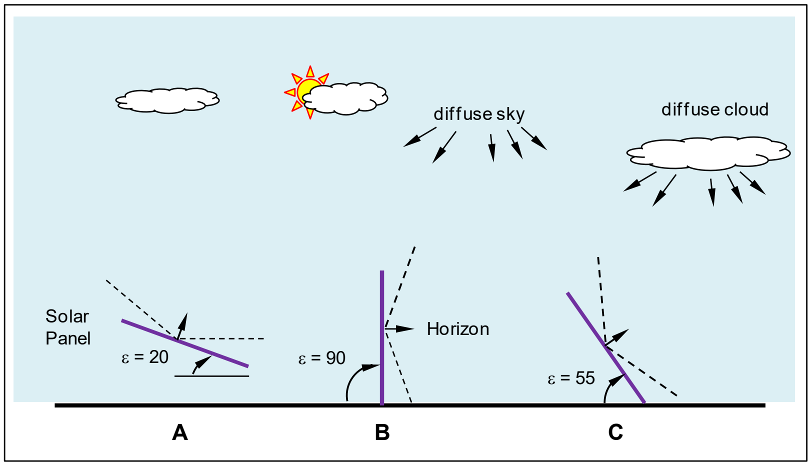


Figure 5.12-1: Solid Angles Determined by AR Coating Limits

The "A" installation at left with the AR limits indicated by the dashed lines shows that the solar panel receives no radiation from ground reflections since the lower limit is aligned with the horizon; the center "B" installation observes sky and ground equally since the centerline points to the horizon; and the installation at "C" receives mostly sky but also some ground reflections.

Figure 5.12-2 illustrates the means of calculating the solid angles Ω_S and Ω_G. On the left side is shown the standard formula for the solid angle of a right circular cone. Here the angular limits of the cone are the angular limits of an AR coating performance (70° as an example), but is shown as smaller for clarity. It is not necessary to utilize ray-tracing from the ground to the solar panel or vice versa in order to find the solid angle. Solar panels may be large and the array may be of irregular shape. However, there are two facts which permit a simplification: a) the AR coating performance is the same at every point on the surface of the solar panel array; and b) no matter how large the array is, it is small compared to the dimensions of the earth and sky. These two facts, uniformity and relative size, permit the solar panel to be modeled as a point source, and the solid angle can then be treated as the solid angle of a right circular cone. If the half angle A is 70°, the equation for the total solid angle observable by the solar panel is:

$$\Omega_T = 4\pi sin^2\left(\frac{1}{2}A\right) = 4\pi sin^2(0.61086) = 4.134\ sr \qquad (5.12\text{-}1)$$

since 70° = 1.22173 radians.

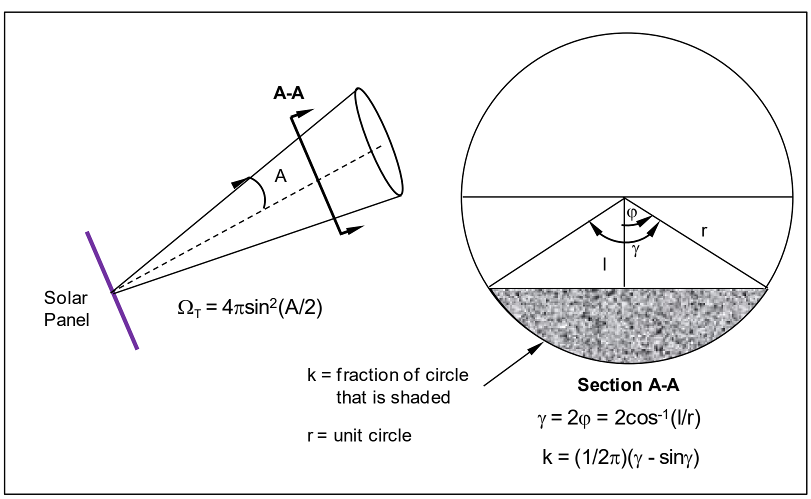


Figure 5.12-2: Geometry for Calculating Solid Angles Ω_S and Ω_G

The right side of the Figure shows the geometry looking outward from the apex of the cone. The shaded portion of the unit circle shows the fraction of the total solid angle that observes the ground and the unshaded portion applies to the sky. The fraction of the area that is shaded is:

$$k = \frac{1}{2\pi}[\gamma - \sin\gamma] \qquad (5.12\text{-}2)$$

where γ is the total included angle as shown. As an example, from panel A in Figure 5.12-1 it is evident that γ must be zero if ε is 20°, since in that case, none of the ground is visible to the solar panel. Likewise, from panel B of Figure 5.12-1, γ must be π if ε is 90°, since in that case the solar panel observes sky and ground equally. The angle γ is in turn related to the tilt angle ε by:

$$\gamma = \frac{\pi[\varepsilon-(90-A))]}{A} \qquad (5.12\text{-}3)$$

where A is the AR coating limit. Finally, the solid angle of the ground and sky is:

$$\Omega_G = k\Omega_T, \quad \Omega_S = \Omega_T - \Omega_G \qquad (5.12\text{-}4)$$

Recall that Ω_T is the total solid angle observable by the solar panel owing to the AR coating performance, and is not the 2π that would prevail if the solar panel could view an entire hemisphere.

The equations for L_{GD}, L_{GS}, and L_{GC} indicate that the radiance upon reflection into the entire hemisphere causes the incident radiance to be reduced by a factor of π. But, the paragraph above implies that a hemisphere consists of 2π steradians. Both are correct. The reason for the difference is that the solid angle calculation above is purely geometrical and there are 2π steradians in a hemisphere, whereas the factor of π in the radiance calculations also includes the fact that the radiance of a Lambertian surface varies with the cosine of the angle from normal (i.e., the projected area). Nearly all natural surfaces are Lambertian; the exceptions are still water, glaze ice, polished materials such as glass and metals, and mirrors. It is this cosine factor that causes the reflected radiance of a Lambertian surface to be reduced by π instead of 2π.

There is one other topic to be addressed. Referring back to Figure 5.11-1 and in view of the solid angle calculations above, it is clear that there may be a great deal of radiance that is reflected off the ground at points far away from the solar panel. The equations for L_{GD}, L_{GS}, and L_{GC} do not account for any additional scattering losses between all the possible ground points observed by the solar panel and the solar panel itself (i.e., no ray-tracing is done to obtain the reduced radiance from the foreground). At the same time however, keep in mind that while radiation may be scattered out of the path between distant points and the solar panel, the intervening atmosphere between the panel and those points also scatters some radiation into the path. No claim is made that the amount scattered in equals the amount scattered out, but there is some offsetting over the path. It is likely that the Estimator slightly overestimates the ground contributions.

5.13 Effective Ground Reflectance

Vegetation, soil, and building materials exhibit a wide range of spectral reflectance which will affect the amount of energy collected from ground reflections. Again it is desirable to permit user selection of the ground type surrounding the solar panel installation, but also desirable to avoid doing spectral calculations. The Estimator permits selection of a wide range of terrain types in cells D14 through D17, and the spectral calculations are avoided by pre-calculating the effective reflectance of materials using the equation:

$$\rho = \frac{\int_{0.28}^{4.0} \rho_S(\lambda) R(\lambda) E_{D,n}(\lambda) d\lambda}{\int_{0.28}^{4.0} R(\lambda) E_{D,n}(\lambda) d\lambda} \qquad (5.13\text{-}1)$$

where ρ_S is the spectral reflectance of a material, R is the normalized responsivity of Silicon, $E_{D,n}$ is a normalized spectral solar irradiance, and λ is wavelength. Any typical $E_{D,n}$ could have been used, but for clarity, the AM1.5 spectrum is utilized in this calculation (which determined the limits of the integration). Note also that it was not necessary to normalize $E_{D,n}$ since the same integrand appears in both the numerator and denominator. It was done this way only for clarity in the same way as shown on Figure 5.10-2. The resulting ρ is the effective reflectance of a material, given the response of Silicon and the dominant radiation contributor, the direct solar spectrum. A similar calculation was not performed for diffuse sky and cloud radiance, since the magnitude of those contributors is small compared to the direct component.

Figures 5.13-1 and 5.13-2 show the nominal spectral reflectance and effective reflectance results respectively for a wide variety of terrain types. The spectral data in Figure 5.13-1 only goes to 1.25 µm since the cutoff for Silicon is about 1.15 µm.

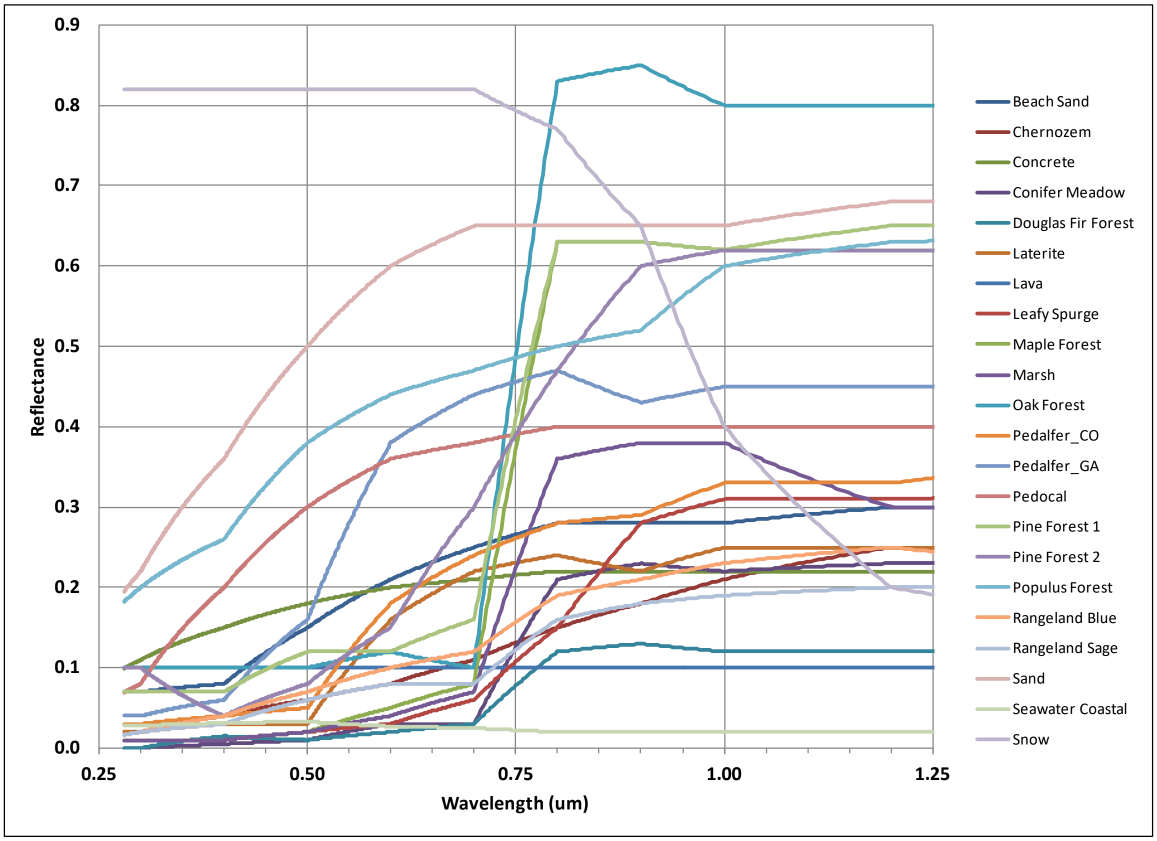


Figure 5.13-1: Nominal Spectral Reflectance for Various Terrain Types

Material Type	Source Data	Typical Location	Effective Reflectance
Beach Sand	[1], Figure 3.104i	All beach areas	0.239
Chernozem Soil	[1], Figure 3.101e	Midwest U. S. (Kansas)	0.132
Concrete	[1], Figure 3.114a		0.207
Conifer Meadow	[2], Record # 21046	Grassy areas in Western U. S.	0.120
Douglas Fir Forest	[2], Record # 21060	West of Rocky Mtns, esp. AZ, CA, ID, MT, NM, OR, WA, WY	0.071
Laterite Soil	[1], Figure 3.104x	Dark Soil (Eastern U. S. ~ North Carolina)	0.187
Lava	[1], Figure 3.110d		0.100
Leafy Spurge	[2] Record # 21469	Open areas in U. S. with high fraction of vegetation	0.139
Maple Forest	[2], Record # 21762	Northeastern and North Central U. S.	0.332
Marsh	[2], Record # 22717	Southeastern and Eastern U. S.	0.202
Oak Forest	[2] Record # 21769	East of Mississippi River, but including IA, MO, AR, LA	0.458
Pedalfer Soil 1	[1], Figure 3.104r	Southeast U. S. (Georgia)	0.228
Pedalfer Soil 2	[1], Figure 3.104y	Western U. S. (Colorado)	0.385
Pedocal Soil	[1], Figure 3.104m	Midwest U. S. (Nebraska)	0.369
Pine Forest	[2], Record # 21548	Pine forest in temperate regions	0.365
Populus Forest	[3]	Poplar, Aspen, Cottonwood	0.482
Rangeland Blue	[2], Record # 22998	Open areas in Eastern U. S. with sparse vegetation	0.152
Rangeland Sage	[2], Record # 24083	Open areas in Southwestern U. S. with sparse vegetation	0.123
Sand	[1], Figure 3.104t	High Desert in U. S. (New Mexico)	0.612
Seawater Coastal	[2], Record # 13630	All coastal areas	0.024
Snow	[1], Figure 3.150		0.703
[1] J. S. Accetta, D. L. Shumaker, eds., The Infrared and Electro-Optical Systems Handbook, Ann Arbor, MI: Environmental Research Institute of Michigan, Volume 1, (1993)			
[2] United States Geological Survey, Spectral Library Version 7, https://crustal.usgs.gov/speclab; "splib07a".			
[3] P. S. Roy, "Spectral reflectance characteristics of vegetation and ther estimating productive potential", Proc. Indian Acad. Sci., Vol. 99, No. 1 Feb 1989, pp. 59-81			

Figure 5.13-2: Effective Reflectance Values for Various Terrain Types

5.14 Value of Solar-Generated Electricity

Each of the power components per section 5.10 (P_D, P_{DS}, P_{DC}, and P_G) are added for each hour of the day in each season and converted to kWh:

$$P_{HS} = \frac{91.5}{1000}[P_D + P_{DS} + P_{DC} + P_G] \qquad (5.14\text{-}1)$$

where the 91.5 denotes the number of days in each season, and the 1000 converts W-hrs to kWhs. Likewise the cost avoidance at each hour of each season is:

$$C_S = \frac{91.5}{1000}\sum_{h=0.5}^{h=23.5}[P_D(h) + P_{DS}(h) + P_{DC}(h) + P_G(h)]C_U(h) \qquad (5.14\text{-}2)$$

where C_A is the first-year cost avoided by the use of the solar panel, h denotes the hour of the day, the P's are the power generated by direct, diffuse sky, diffuse clouds, and ground respectively (in W-hours) for each season, C_U is the cost of electricity for each hour from the local utility per cells J5 to M28, 91.5 is the number of days in each season, and 1000 converts W-hrs to kWhs. The total cost avoidance is the sum of the values for each season:

$$C_A = C_{S,Winter} + C_{S,Spring} + C_{S,Summer} + C_{S,Fall} \qquad (5.14\text{-}3)$$

The total accumulated electric utility cost avoidance of the solar panel system over 25 years is:

$$C_{25} = \sum_{y=1}^{y=25} C_A\,(1+r)^y(1+my) \qquad (5.14\text{-}4)$$

where C_A is the initial annual cost savings as above, r is the average annual increase in electricity costs, and m is the slope of the degradation over time of the performance of the solar system as described in section 5.9. The return on investment occurs where the value of C_{25} is equal to the installation costs. Note: This analysis excludes any interest costs if the system is procured on credit over a period of years.

5.15 Direct Solar Irradiance

The average daily direct solar irradiance for each season (in the plane normal to the LOS to the sun) in W-hr/m^2 is the sum of the hourly values:

$$E_{D,S} = \sum_{h=0.5}^{h=23.5} E_D(h) \qquad (5.15\text{-}1)$$

where $E_{D,S}$ denotes an average daily seasonal metric (winter, spring, summer, or fall). The total average annual direct solar irradiance in kWh/m^2 is:

$$E_A = \frac{91.5}{1000}\left[E_{D,Winter} + E_{D,Spring} + E_{D,Summer} + E_{D,Fall}\right] \qquad (5.15\text{-}2)$$

where 91.5 is the number of days per season, the 1000 converts W-hr to kWh, and the terms in the brackets are the seasonal terms from eqn. 5.15-1.

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6
Worked Examples

This chapter presents a few worked examples to illustrate the utility of the Estimator.

6.1 Utility Rate Escalation vs. Return on Investment

Example 1 will examine the effect of utility rate escalation in four different cities, Portland, ME, Grand Junction, CO, Lincoln, NE, and Seattle, WA. The same solar panel design and orientation will be used in all four: a) Panel azimuth = 180°; b) Tilt from horizontal = 35°; c) Total panel area = 24 m^2; d) Panel efficiency at NOCT = 0.20; e) Power fraction after 25 years = 0.87; f) Anti-reflection coating limit = 80°; g) Temperature coefficient = -0.0033 per °K; h) DC-AC conversion efficiency = 0.93; and i) Installation cost after rebates etc. = $18000. The ground cover is the same for all seasons in each location: a) Portland, Maple Forest; b) Grand Junction, Conifer Meadow; c) Lincoln, Rangeland Blue; and d) Seattle, Pine Forest.

The current electricity rates in $/kWh are from https://www.electricitylocal.com: a) Portland, ME, 0.0694; b) Grand Junction, 0.1105; c) Lincoln, NE, 0.0890; and d) Seattle, WA, 0.0775. It is assumed that the electric rates are the same for all daylight hours. In each case the corresponding cloud cover location for the four locations was selected.

The annual escalation rate was varied from 0.01 to 0.10 in 0.01 increments. Figure 6.1-1 shows some performance statistics for the panel design as above in the four locations. As expected, the cloudy locations (Portland, ME and Seattle, WA) have much worse performance and thus high average costs per kW-hr generated by the solar panel system.

Performance Statistics for Each Location					
		Portland, ME	Grand Junction, CO	Lincoln, NE	Seattle, WA
Input	Initial Electricity Cost, $/kWh	0.0694	0.1105	0.0890	0.0775
Outputs	Initial Annual Power, kWh	.6321.3	8425.1	6635.7	5023.3
	Initial Annual Value, $	438.70	930.98	590.58	389.31
	Dollar Value, 25 Years, $	13,287.32	28,197.57	36,567.93	24,105.53
	Power Generated over 25 years, kWh	147,760.1	196,937.6	155,109.9	117,420.6
	Average Cost of Solar Power, $/kWh	0.122	0.091	0.116	0.153

Figure 6.1-1: Summary Statistics, Example 1

Figure 6.1-2 shows the return-on-investment for each of the four locations. Note that an escalation rate of 0.02 means a 2% annual increase per year over 25 years; likewise 0.10 means 10% per year. It is evident that the U. S. public will not tolerate the higher rates shown here, and some locations end up with very long return-on-investment for practical rate increases (cf. Figures 3.12-3 and 3.12-4 for historical data).

Annual Escalation Rate	Return on Investment (Years) Portland, ME	Grand Junction, CO	Lincoln, NE	Seattle, WA
0.01	>25	18.5	>25	>25
0.02	>25	17.0	>25	>25
0.03	>25	15.7	22.6	>25
0.04	>25	14.6	20.7	>25
0.05	23.2	13.8	19.1	25.0
0.06	21.5	13.1	17.9	23.1
0.07	20.0	12.4	16.8	21.4
0.08	18.8	11.9	15.9	20.0
0.09	17.8	11.3	15.0	18.8
0.1	16.8	10.8	14.3	17.9

Figure 6.1-2: Return-on-Investment (Years) for Example 1

6.2 Optimum Tilt Angle

This example will examine the optimum tilt angle in Lander, WY for the same solar panel design as in Example 1, except: a) the tilt angle will be varied from 0° to 90°; b) two panel azimuths will be used, 180° and 240°; and c) the ground cover is Rangeland Sage for all four seasons. The escalation rate is 0.02, and the average cost of residential electricity in Lander per the above website is $0.105/kW-hr. Figure 6.2-1 shows the inputs with the tilt at 35° and orientation at 180°.

Inputs		Units	Symbol
Choose time zone, nearest latitude	M 43 Lander, WY		
Choose cloud location	Lander, WY		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	5	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.200	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0033	%/100 °K	C_T
Ground Type, Winter	Rangeland Sage		
Ground Type, Spring	Rangeland Sage		
Ground Type, Summer	Rangeland Sage		
Ground Type, Fall	Rangeland Sage		
DC-AC Conversion efficiency	0.93		
Installation cost	18000	$	
Annual Electricity Escalation Rate	0.0200	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.105	0.105	0.105	0.105
1 AM to 2 AM	1.5	0.105	0.105	0.105	0.105
2 AM to 3 AM	2.5	0.105	0.105	0.105	0.105
3 AM to 4 AM	3.5	0.105	0.105	0.105	0.105
4 AM to 5 AM	4.5	0.105	0.105	0.105	0.105
5 AM to 6 AM	5.5	0.105	0.105	0.105	0.105
6 AM to 7 AM	6.5	0.105	0.105	0.105	0.105
7 AM to 8 AM	7.5	0.105	0.105	0.105	0.105
8 AM to 9 AM	8.5	0.105	0.105	0.105	0.105
9 AM to 10 AM	9.5	0.105	0.105	0.105	0.105
10 AM to 11 AM	10.5	0.105	0.105	0.105	0.105
11 AM to noon	11.5	0.105	0.105	0.105	0.105
noon to 1 PM	12.5	0.105	0.105	0.105	0.105
1 PM to 2 PM	13.5	0.105	0.105	0.105	0.105
2 PM to 3 PM	14.5	0.105	0.105	0.105	0.105
3 PM to 4 PM	15.5	0.105	0.105	0.105	0.105
4 PM to 5 PM	16.5	0.105	0.105	0.105	0.105
5 PM to 6 PM	17.5	0.105	0.105	0.105	0.105
6 PM to 7 PM	18.5	0.105	0.105	0.105	0.105
7 PM to 8 PM	19.5	0.105	0.105	0.105	0.105
8 PM to 9 PM	20.5	0.105	0.105	0.105	0.105
9 PM to 10 PM	21.5	0.105	0.105	0.105	0.105
10 PM to 11 PM	22.5	0.105	0.105	0.105	0.105
11 PM to midnight	23.5	0.105	0.105	0.105	0.105

Figure 6.2-1: Inputs for Example 2

Figure 6.2-2 shows the initial annual power and initial annual value of the power generated as a function of tilt angle. It is easy to see that the 180° orientation is more efficient. The same results occur regardless of panel azimuth if the tilt angle is zero (since the AR coating limit is actually a projected circle). Also, the minimum cost per kWh generated by the solar panel system occurs at different tilt angles for the two azimuths; for azimuth = 180°, the lowest cost occurs near 40° tilt; for azimuth = 225°, it occurs between 30° and 35°.

	Panel Azimuth = 180			Panel Azimuth = 225		
Tilt (deg)	Initial Power, kW-hr	25-year Power, kWh	Avg Cost per kWh, $	Initial Power, kWh	25-year Power, kWh	Avg Cost per kWh, $
0	6,282.8	146,859.8	0.123	6,282.8	146,859.8	0.123
5	6,766.1	158,157.8	0.114	6,621.8	154,784.7	0.116
10	7,137.3	166,834.8	0.108	6,889.0	161,030.3	0.112
15	7,484.0	174,939.3	0.103	7,121.3	166,460.6	0.108
20	7,767.1	181,556.0	0.099	7,277.1	170,102.2	0.106
25	7,971.7	186,337.5	0.097	7,399.4	172,960.0	0.104
30	8,152.2	190,558.0	0.094	7,473.0	174,681.9	0.103
35	8,278.4	193,507.0	0.093	7,540.3	176,225.4	0.102
40	8,349.6	195,171.6	0.092	7,491.2	175,107.0	0.103
45	8,336.2	194,859.3	0.092	7,488.4	175,041.3	0.103
50	8,271.9	193,356.0	0.093	7,437.2	173,845.3	0.104
55	8,188.2	191,398.5	0.094	7,338.3	171,531.7	0.105
60	8,051.0	188,191.5	0.096	7,080.4	165,505.1	0.109
65	7,832.8	183,092.5	0.098	6,927.0	161,917.5	0.111
70	7,566.3	176,862.8	0.102	6,729.5	157,302.0	0.114
75	7,289.8	170,399.8	0.106	6,452.7	150,832.1	0.119
80	6,933.1	162,060.6	0.111	6,108.9	142,795.6	0.126
85	6,545.6	153,002.2	0.118	5,833.1	136,348.0	0.132
90	6,087.4	142,294.0	0.126	5,484.6	128,203.3	0.140

Figure 6.2-2: Initial Power, 25-Year Power, and Cost per kW-hr of Solar-Generated Power for Example 2

Figure 6.2-3 plots the 25-year power and average 25-year generation cost results of Figure 6.2-2. Power generated is read on the left, and average costs per kWh over 25 years on the right. It is not necessary to show the initial power since the degradation over time is the same in both cases and the ratio of total 25-year power to initial year power is therefore a constant, equal in this case to 23.375.

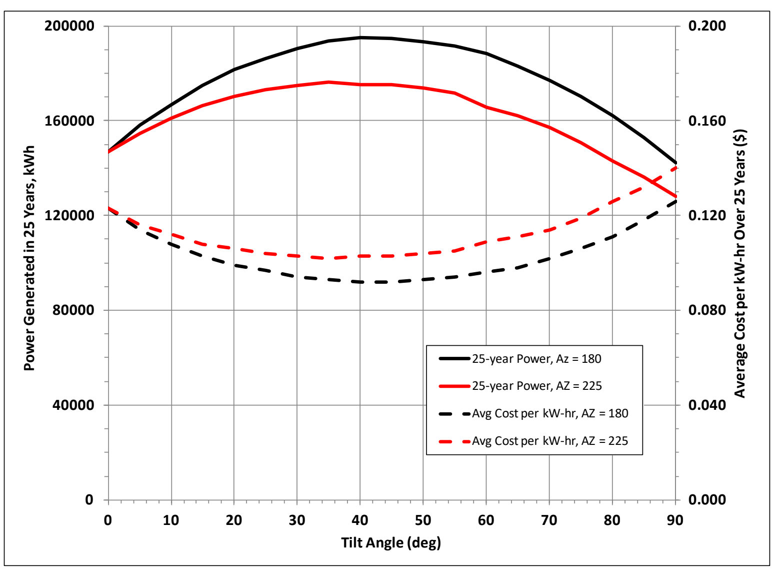

Figure 6.2-3: 25-Year Power and Cost per kWh of Solar-Generated Power, Example 2

6.3 Known Blockages

Billy Bob lives in Apache Junction, AZ, just west of the Superstition Mountains, and the sun does not appear over the mountains until about 10:00 AM every morning. Arizona does not observe daylight saving time, so the behavior is about the same all year round. The Estimator provides a means to deal with this situation by zeroing out the electricity costs in cells J5 through M28 for hours in which the sun is blocked. Note that this only affects the directly transmitted component; the diffuse sky, diffuse, cloud, and ground reflection components are unchanged.

Figure 6.3-1 shows the inputs for a system if there was no blockage. Tucson is the nearest latitude selection in cell D5 per section 3.1. There is no cloud location for Apache Junction, so section 3 of the Utilities page was used to find the nearest one. Apache Junction is located at latitude/longitude coordinates 33.40115, -111.53089, and is 27.97 NM east of Phoenix; thus Phoenix is the closest cloud location to be entered in cell D6. The total power generated by such a system over 25 years is 197,553.2 kWhs, having a dollar value over 25 years of $29,470.68; the return on investment occurs at 16.4 years, and the 25-year average cost of power generated by the solar panels is $0.091/kWh. Figure 6.3-2 shows the inputs for the blockage case; all the electricity costs are zero until 10 AM. Now the total power generated is reduced to 165,498.8 kWh, having a dollar value of $26,725.64 over 25 years, the return on investment occurs at 17.8 years, and the 25-year average cost of power generated is $0.109/kWh.

Inputs		**Units**	**Symbol**
Choose time zone, nearest latitude	M 32 Tuscon, AZ		
Choose cloud location	Phoenix, AZ		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	35	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.200	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0033	%/100 °K	C_T
Ground Type, Winter	Rangeland Sage		
Ground Type, Spring	Rangeland Sage		
Ground Type, Summer	Rangeland Sage		
Ground Type, Fall	Rangeland Sage		
DC-AC Conversion efficiency	0.93		
Installation cost	18000	$	
Annual Electricity Escalation Rate	0.0200	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	**24-hr**	**Winter**	**Spring**	**Summer**	**Fall**
Midnight to 1 AM	0.5	0.06	0.06	0.06	0.06
1 AM to 2 AM	1.5	0.06	0.06	0.06	0.06
2 AM to 3 AM	2.5	0.06	0.06	0.06	0.06
3 AM to 4 AM	3.5	0.06	0.06	0.06	0.06
4 AM to 5 AM	4.5	0.06	0.06	0.06	0.06
5 AM to 6 AM	5.5	0.06	0.06	0.06	0.06
6 AM to 7 AM	6.5	0.06	0.06	0.06	0.06
7 AM to 8 AM	7.5	0.06	0.06	0.06	0.06
8 AM to 9 AM	8.5	0.06	0.06	0.06	0.06
9 AM to 10 AM	9.5	0.06	0.06	0.06	0.06
10 AM to 11 AM	10.5	0.06	0.06	0.06	0.06
11 AM to noon	11.5	0.13	0.13	0.13	0.13
noon to 1 PM	12.5	0.13	0.13	0.13	0.13
1 PM to 2 PM	13.5	0.13	0.13	0.13	0.13
2 PM to 3 PM	14.5	0.13	0.13	0.13	0.13
3 PM to 4 PM	15.5	0.17	0.17	0.17	0.17
4 PM to 5 PM	16.5	0.17	0.17	0.17	0.17
5 PM to 6 PM	17.5	0.17	0.17	0.17	0.17
6 PM to 7 PM	18.5	0.17	0.17	0.17	0.17
7 PM to 8 PM	19.5	0.17	0.17	0.17	0.17
8 PM to 9 PM	20.5	0.06	0.06	0.06	0.06
9 PM to 10 PM	21.5	0.06	0.06	0.06	0.06
10 PM to 11 PM	22.5	0.06	0.06	0.06	0.06
11 PM to midnight	23.5	0.06	0.06	0.06	0.06

Figure 6.3-1: Inputs for Apache Junction, No Blockage from Superstition Mountains

Inputs		**Units**	**Symbol**
Choose time zone, nearest latitude	M 32 Tuscon, AZ		
Choose cloud location	Phoenix, AZ		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	35	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.200	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0033	%/100 °K	C_T
Ground Type, Winter	Rangeland Sage		
Ground Type, Spring	Rangeland Sage		
Ground Type, Summer	Rangeland Sage		
Ground Type, Fall	Rangeland Sage		
DC-AC Conversion efficiency	0.93		
Installation cost	18000	$	
Annual Electricity Escalation Rate	0.0200	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	**24-hr**	**Winter**	**Spring**	**Summer**	**Fall**
Midnight to 1 AM	0.5	0	0	0	0
1 AM to 2 AM	1.5	0	0	0	0
2 AM to 3 AM	2.5	0	0	0	0
3 AM to 4 AM	3.5	0	0	0	0
4 AM to 5 AM	4.5	0	0	0	0
5 AM to 6 AM	5.5	0	0	0	0
6 AM to 7 AM	6.5	0	0	0	0
7 AM to 8 AM	7.5	0	0	0	0
8 AM to 9 AM	8.5	0	0	0	0
9 AM to 10 AM	9.5	0	0	0	0
10 AM to 11 AM	10.5	0.06	0.06	0.06	0.06
11 AM to noon	11.5	0.13	0.13	0.13	0.13
noon to 1 PM	12.5	0.13	0.13	0.13	0.13
1 PM to 2 PM	13.5	0.13	0.13	0.13	0.13
2 PM to 3 PM	14.5	0.13	0.13	0.13	0.13
3 PM to 4 PM	15.5	0.17	0.17	0.17	0.17
4 PM to 5 PM	16.5	0.17	0.17	0.17	0.17
5 PM to 6 PM	17.5	0.17	0.17	0.17	0.17
6 PM to 7 PM	18.5	0.17	0.17	0.17	0.17
7 PM to 8 PM	19.5	0.17	0.17	0.17	0.17
8 PM to 9 PM	20.5	0.06	0.06	0.06	0.06
9 PM to 10 PM	21.5	0.06	0.06	0.06	0.06
10 PM to 11 PM	22.5	0.06	0.06	0.06	0.06
11 PM to midnight	23.5	0.06	0.06	0.06	0.06

Figure 6.3-2: Inputs for Apache Junction, With Blockage until 10 AM from Mountains

Figure 6.3-3 shows the difference in the arbitrated cos(σ) for the two cases, from which the difference in performance arises, since only the directly transmitted irradiance is affected.

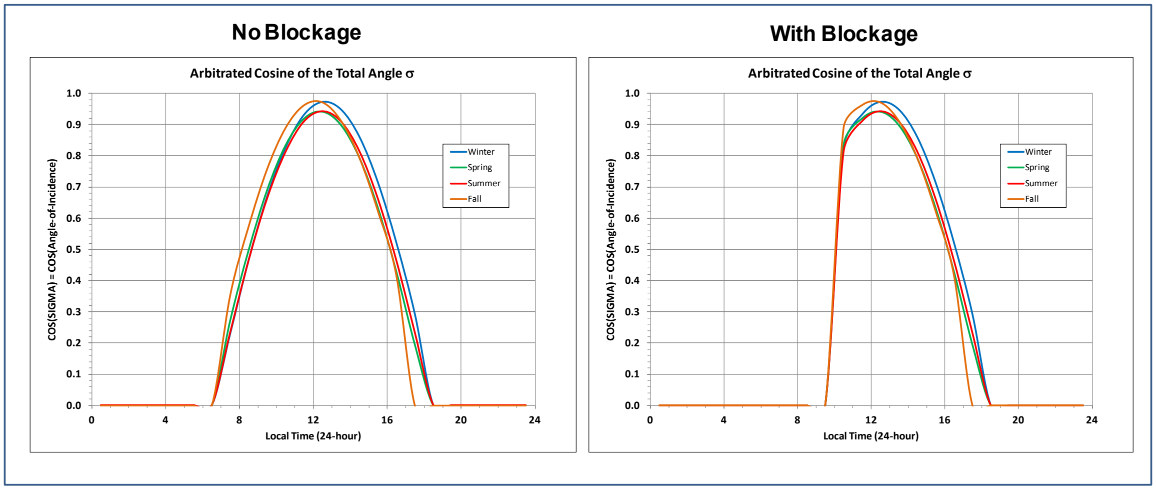

Figure 6.3-3: Arbitrated Total Angle for Two Cases in Example 3

6.4 Panel Efficiency

This example will examine the effect of NOCT panel efficiency for a system located in Topeka, KS. Figure 6.4-1 shows the basic inputs, with the efficiency at NOCT conditions at 0.17. The current electricity rate was obtained from the electricity local website, and the average rate of increase is from Figure 3.12-3. Notice that the panel azimuth is 135° and the tilt angle is set to its optimum for this azimuth and latitude (36°). Tulsa is the closest latitude point for Central Time in cell D5 and there is a cloud selection for Topeka in cell D6.

Inputs		Units	Symbol
Choose time zone, nearest latitude	C 36 Tulsa, OK		
Choose cloud location	Topeka, KS		
Panel Azimuth, E of North	135	deg	beta
Panel Tilt from Horizontal	36	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.170	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0033	%/100 °K	C_T
Ground Type, Winter	Pedalfer Soil 2		
Ground Type, Spring	Pedalfer Soil 2		
Ground Type, Summer	Pedalfer Soil 2		
Ground Type, Fall	Pedalfer Soil 2		
DC-AC Conversion efficiency	0.93		
Installation cost	18000	$	
Annual Electricity Escalation Rate	0.0250	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.107	0.107	0.107	0.107
1 AM to 2 AM	1.5	0.107	0.107	0.107	0.107
2 AM to 3 AM	2.5	0.107	0.107	0.107	0.107
3 AM to 4 AM	3.5	0.107	0.107	0.107	0.107
4 AM to 5 AM	4.5	0.107	0.107	0.107	0.107
5 AM to 6 AM	5.5	0.107	0.107	0.107	0.107
6 AM to 7 AM	6.5	0.107	0.107	0.107	0.107
7 AM to 8 AM	7.5	0.107	0.107	0.107	0.107
8 AM to 9 AM	8.5	0.107	0.107	0.107	0.107
9 AM to 10 AM	9.5	0.107	0.107	0.107	0.107
10 AM to 11 AM	10.5	0.107	0.107	0.107	0.107
11 AM to noon	11.5	0.107	0.107	0.107	0.107
noon to 1 PM	12.5	0.107	0.107	0.107	0.107
1 PM to 2 PM	13.5	0.107	0.107	0.107	0.107
2 PM to 3 PM	14.5	0.107	0.107	0.107	0.107
3 PM to 4 PM	15.5	0.107	0.107	0.107	0.107
4 PM to 5 PM	16.5	0.107	0.107	0.107	0.107
5 PM to 6 PM	17.5	0.107	0.107	0.107	0.107
6 PM to 7 PM	18.5	0.107	0.107	0.107	0.107
7 PM to 8 PM	19.5	0.107	0.107	0.107	0.107
8 PM to 9 PM	20.5	0.107	0.107	0.107	0.107
9 PM to 10 PM	21.5	0.107	0.107	0.107	0.107
10 PM to 11 PM	22.5	0.107	0.107	0.107	0.107
11 PM to midnight	23.5	0.107	0.107	0.107	0.107

Figure 6.4-1: Inputs for Topeka, KS Efficiency Variation

Figure 6.4-2 shows the results as the efficiency at NOCT conditions in increased from 0.17 to 0.22 (close to the current practical maximum). This system has long return-on-investment, mostly due to the fact that it does not face due south. It is very important, therefore, to examine the efficiency of the solar panels at NOCT conditions in order to accurately assess its performance.

Efficiency, NOTC	Initial Annual Value, $	25-year Cost Avoided	Total Power, 25 years, kWh	Average Cost per kWh	ROI (years)
0.17	599.95	19,446.00	131,064.1	0.137	23.5
0.18	632.66	20,506.02	138,208.6	0.13	22.5
0.19	665.36	21,566.05	145,353.1	0.124	21.6
0.20	698.06	22,626.08	152,497.6	0.118	20.8
0.21	730.77	23,686.11	159,642.1	0.113	20.0
0.22	763.47	24,746.13	166,786.6	0.108	19.2

Figure 6.4-2: Results for the Topeka, KS System, Efficiency Variation

6.5 AR Coating Limit

This example will illustrate the change in performance with the AR coating limit. The same system as in section 6.4 is modeled, except the efficiency at NOCT is fixed at 0.21 and the AR coating limit varied from 60° (a very poor one) to 85° (better than typical). Figure 6.5-1 shows the inputs.

Inputs		Units	Symbol
Choose time zone, nearest latitude	C 36 Tulsa, OK		
Choose cloud location	Topeka, KS		
Panel Azimuth, E of North	135	deg	beta
Panel Tilt from Horizontal	36	deg	epsilon
Panel Total Area	24	sq m	A_p
Panel Efficiency, NOCT	0.210	decimal	e_TC
Power fraction after 25 years	0.87		
Anti-reflection coating limit	60	deg	A
Temperature Coefficient	-0.0033	%/100 °K	C_T
Ground Type, Winter	Pedalfer Soil 2		
Ground Type, Spring	Pedalfer Soil 2		
Ground Type, Summer	Pedalfer Soil 2		
Ground Type, Fall	Pedalfer Soil 2		
DC-AC Conversion efficiency	0.93		
Installation cost	18000	$	
Annual Electricity Escalation Rate	0.0250	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.107	0.107	0.107	0.107
1 AM to 2 AM	1.5	0.107	0.107	0.107	0.107
2 AM to 3 AM	2.5	0.107	0.107	0.107	0.107
3 AM to 4 AM	3.5	0.107	0.107	0.107	0.107
4 AM to 5 AM	4.5	0.107	0.107	0.107	0.107
5 AM to 6 AM	5.5	0.107	0.107	0.107	0.107
6 AM to 7 AM	6.5	0.107	0.107	0.107	0.107
7 AM to 8 AM	7.5	0.107	0.107	0.107	0.107
8 AM to 9 AM	8.5	0.107	0.107	0.107	0.107
9 AM to 10 AM	9.5	0.107	0.107	0.107	0.107
10 AM to 11 AM	10.5	0.107	0.107	0.107	0.107
11 AM to noon	11.5	0.107	0.107	0.107	0.107
noon to 1 PM	12.5	0.107	0.107	0.107	0.107
1 PM to 2 PM	13.5	0.107	0.107	0.107	0.107
2 PM to 3 PM	14.5	0.107	0.107	0.107	0.107
3 PM to 4 PM	15.5	0.107	0.107	0.107	0.107
4 PM to 5 PM	16.5	0.107	0.107	0.107	0.107
5 PM to 6 PM	17.5	0.107	0.107	0.107	0.107
6 PM to 7 PM	18.5	0.107	0.107	0.107	0.107
7 PM to 8 PM	19.5	0.107	0.107	0.107	0.107
8 PM to 9 PM	20.5	0.107	0.107	0.107	0.107
9 PM to 10 PM	21.5	0.107	0.107	0.107	0.107
10 PM to 11 PM	22.5	0.107	0.107	0.107	0.107
11 PM to midnight	23.5	0.107	0.107	0.107	0.107

Figure 6.5-1: Inputs for Topeka, KS, AR Coating Variation

Figure 6.5-2 shows the results as the AR coating limit is varied. Note that row 5 of Figure 6.4-2 has results identical to row 5 of Figure 6.4-2 as expected (AR coating limit = 80°, efficiency at NOCT = 0.21).

AR Coating Limit, deg	Initial Annual Value, $	25-year Cost Avoided	Total Power, 25 years, kWh	Average Cost per kWh	ROI (years)
60	626.82	20,316.98	136,934.5	0.131	22.7
65	657.62	21,315.15	143,662.1	0.125	21.9
70	679.91	22,037.57	148,531.1	0.121	21.2
75	709.80	23,006.62	155,062.4	0.116	20.5
80	730.77	23,686.11	159,642.1	0.113	20.0
85	750.94	24,340.06	164,049.7	0.110	19.5

Figure 6.5-2: Results for the Topeka, KS System, AR Coating Limit Variation

6.6 Panel Azimuth Variation

Tom lives in a rural part of Warrenton, MO and has several options as to the orientation of his solar array. He knows that an azimuth of 180° is optimal, but his roofline and tree configuration indicate that other orientations may be more convenient. How much difference does panel azimuth make in practical terms? Suppose he uses one of the better panel designs, and has space for 30 m^2. Figure 6.6-1 shows the basic inputs with azimuth = 90°. The electricity costs are from the electricity local website. Lincoln, NE is the appropriate selection for the Latitude per Figure 3.1-2. The location of Warrenton, MO is 38° 48' 57" Latitude and -90° 8' 25" longitude. Recall that all longitudes in the U. S. are negative, since the U. S. is west of Greenwich, England. The corresponding decimal coordinates are 38.81583, -91.14028 per the conversion algorithm on the Utilities page. Inserting these into the Cloud Location section of the Utilities page, it turns out that the closest cloud location is St. Louis, MO (48.14 NM). Tom used the annual rate of increase from Figure 3.12-3 from 2000 to 2020.

Inputs		Units	Symbol
Choose time zone, nearest latitude	C 41 Lincoln, NE		
Choose cloud location	St. Louis, MO		
Panel Azimuth, E of North	90	deg	beta
Panel Tilt from Horizontal	35	deg	epsilon
Panel Total Area	30	sq m	A_p
Panel Efficiency, NOCT	0.220	decimal	e_TC
Power fraction after 25 years	0.85		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0034	%/100 °K	C_T
Ground Type, Winter	Pedocal Soil		
Ground Type, Spring	Pedocal Soil		
Ground Type, Summer	Pedocal Soil		
Ground Type, Fall	Pedocal Soil		
DC-AC Conversion efficiency	0.93		
Installation cost	22000	$	
Annual Electricity Escalation Rate	0.0233	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.1163	0.1163	0.1163	0.1163
1 AM to 2 AM	1.5	0.1163	0.1163	0.1163	0.1163
2 AM to 3 AM	2.5	0.1163	0.1163	0.1163	0.1163
3 AM to 4 AM	3.5	0.1163	0.1163	0.1163	0.1163
4 AM to 5 AM	4.5	0.1163	0.1163	0.1163	0.1163
5 AM to 6 AM	5.5	0.1163	0.1163	0.1163	0.1163
6 AM to 7 AM	6.5	0.1163	0.1163	0.1163	0.1163
7 AM to 8 AM	7.5	0.1163	0.1163	0.1163	0.1163
8 AM to 9 AM	8.5	0.1163	0.1163	0.1163	0.1163
9 AM to 10 AM	9.5	0.1163	0.1163	0.1163	0.1163
10 AM to 11 AM	10.5	0.1163	0.1163	0.1163	0.1163
11 AM to noon	11.5	0.1163	0.1163	0.1163	0.1163
noon to 1 PM	12.5	0.1163	0.1163	0.1163	0.1163
1 PM to 2 PM	13.5	0.1163	0.1163	0.1163	0.1163
2 PM to 3 PM	14.5	0.1163	0.1163	0.1163	0.1163
3 PM to 4 PM	15.5	0.1163	0.1163	0.1163	0.1163
4 PM to 5 PM	16.5	0.1163	0.1163	0.1163	0.1163
5 PM to 6 PM	17.5	0.1163	0.1163	0.1163	0.1163
6 PM to 7 PM	18.5	0.1163	0.1163	0.1163	0.1163
7 PM to 8 PM	19.5	0.1163	0.1163	0.1163	0.1163
8 PM to 9 PM	20.5	0.1163	0.1163	0.1163	0.1163
9 PM to 10 PM	21.5	0.1163	0.1163	0.1163	0.1163
10 PM to 11 PM	22.5	0.1163	0.1163	0.1163	0.1163
11 PM to midnight	23.5	0.1163	0.1163	0.1163	0.1163

Figure 6.6-1: Inputs for Warrenton, MO

Panel Azimuth, deg	Initial Annual Value, $	25-year Cost Avoided	Total Power, 25 years, kWh	Average Cost per kWh	ROI (years)
90	758.88	23,739.69	150,894.4	0.146	23.5
105	841.43	26,009.43	165,321.4	0.133	21.8
120	892.40	27,916.79	177,445.0	0.124	20.5
135	947.43	29,638.07	188,385.7	0.117	19.5
150	995.93	31,155.27	198,029.4	0.111	18.6
165	1018.95	31,875.35	202,606.4	0.109	18.2
180	1032.56	32,301.09	205,312.5	0.107	18.1
195	1017.75	31,838.04	202,369.2	0.109	18.2
210	995.93	31,155.40	198,030.2	0.111	18.6
225	951.81	29,775.28	189,257.9	0.116	19.4
240	897.40	28,073.03	178,438.1	0.123	20.4
255	836.63	26,172.12	166,355.4	0.132	21.7
270	763.50	23,884.20	151,813.0	0.145	23.3

Figure 6.6-2: Results for Warrenton, MO

Figure 6.6-2 shows the summary results as the panel azimuth is rotated from 90° (due east) to 270° (due west). Notice that the results are not exactly symmetrical (i.e., the result for 225° is not exactly the same as for 135°, even though both are 45° from due south at 180°). The reason is, from the sun_ch chart, the sun zenith angle is biased slightly past 12 noon, which leads to small deviations from symmetry. The average cost per kWh over the 25-year period is less than the initial utility cost ($0.1163/kWh) only for panel azimuths between 135° and 225°.

6.7 Northern and Southern Latitudes

In this example, the same solar panel design will be placed in locations along I-10 and I-90, which are east-to-west routes along the southern and northern U. S. respectively. The purpose is to examine the effect of latitude (sun zenith angle) and cloud cover. The I-10 route includes Jacksonville, FL; Pensacola, FL; New Orleans, LA; Houston, TX; San Antonio, TX; El Paso, TX; Tucson, AZ; and Santa Barbara, CA. The I-90 route includes Boston, MA; Buffalo, NY; Toledo, OH; Chicago, IL; Rochester, MN, Sioux Falls, SD; Rapid City, SD; Billings, MT; Missoula, MT; Spokane, WA; and Seattle, WA. As shown on Figure 3.2-1, there is a large variation in the general atmosphere (i.e., desert-type vs. mid-latitude summer/winter type) as well as the cloud cover. The basic inputs for the solar system are: a) panel azimuth = 180°; b) tilt angle = 36°; c) total area = 20 m^2; d) efficiency at NOCT = 0.21; e) power fraction after 25 years = 0.87; f) AR coating limit = 78°; g) temperature coefficient = -0.0034; h) DC-AC conversion efficiency = 0.91; and i) installation cost = $15,000. Figure 6.7-1 shows the other inputs, the cloud cover fraction, and the scalar outputs for each I-10 case. The current electricity rates are from the electricity local website (assumed to apply uniformly for all hours of the day); and the escalation rates are from Figure 3.12-3 and 3.12-4.

	Jacksonville, FL	Pensacola, FL	New Orleans, LA	Houston, TX	San Antonio, TX	El Paso, TX	Tucson, AZ	Santa Barbara, CA
Nearest Latitude	Jacksonville	New Orleans	New Orleans	New Orleans	New Orleans	Tucson	Tucson	San Diego
Cloud Location	Jacksonville	Pensacola	New Orleans	Houston	San Antonio	El Paso	Tucson	Los Angeles
Ground Cover, all seasons	Pedalfer 1	Beach Sand	Marsh	Leafy Spurge	R. Sage	Sand	R. Sage	Concrete
Ground Reflectance [1]	0.228	0.239	0.202	0.139	0.123	0.612	0.123	0.207
Electricity Cost/kWh [2]	0.1240	0.1206	0.0982	0.1098	0.0924	0.1111	0.1015	0.1598
Escalation rate [3]	0.0186	0.0186	0.0116	0.0193	0.0193	0.0193	0.0187	0.0302
Atmosphere Type	MLS/MLW	MLS/MLW	MLS/MLW	MLS/MLW	USS (desert)	USS (desert)	USS (desert)	MLS/MLW
Cloud fraction, winter [4]	0.270	0.300	0.331	0.362	0.246	0.100	0.124	0.210
Cloud fraction, spring [4]	0.315	0.291	0.328	0.363	0.364	0.100	0.100	0.261
Cloud fraction, summer [4]	0.420	0.378	0.399	0.330	0.352	0.270	0.311	0.172
Cloud fraction, fall [4]	0.324	0.282	0.307	0.308	0.250	0.100	0.100	0.193
Avg. Daily Solar DNI, winter, W/sq m	5967.62	6005.42	6005.42	6005.42	7660.61	7404.86	7404.86	5750.65
Avg. Daily Solar DNI, spring, W/sq m	7557.01	7518.50	7518.50	7518.50	10104.49	10116.67	10116.67	7489.90
Avg. Daily Solar DNI, summer, W/sq m	7455.77	7427.98	7427.98	7427.98	9974.75	10033.25	10033.25	7464.15
Avg. Daily Solar DNI, fall, W/sq m	5938.24	5962.47	5962.47	5962.47	7592.92	7373.62	7373.62	5754.17
(1-Cloud Fraction)*DNI, winter, W/sq m	4356.36	4203.79	4017.63	3831.46	5776.10	6664.37	6486.66	4543.01
(1-Cloud Fraction)*DNI, spring, W/sq m	5176.55	5330.62	5052.43	4789.28	6426.46	9105.00	9105.00	5535.04
(1-Cloud Fraction)*DNI, summer, W/sq m	4324.35	4620.21	4464.22	4976.75	6463.64	7324.27	6912.91	6180.32
(1-Cloud Fraction)*DNI, fall, W/sq m	4014.25	4281.05	4131.99	4126.03	5694.69	6636.26	6636.26	4643.62
Initial year power, kWh	5295.1	5654.1	5399.7	5324.9	6286.4	7801.3	7141.9	6580.8
Initial value, $	656.59	681.88	530.25	584.67	580.87	866.72	724.90	1051.61
25-year cost avoided , $	19516.12	20267.96	14360.95	17542.64	17428.47	26005.30	21575.55	36609.81
Power generated, 25 years	123772.5	132164.6	126217.1	124469.3	146945.7	182354.9	166942.0	153825.8
Avg. generation cost, $/kWh	0.121	0.113	0.119	0.121	0.102	0.082	0.090	0.098
Return on investment, years	19.9	19.2	>25	21.9	22.0	15.4	18.1	12.1

1. This is not an input; it is updated automatically by the model per the ground cover selection.
2. Per www.electricitylocal.com
3. Per Figures 3.10-3 and 3.10-4; annual increase from 2000 to 2020.
4. This is not an input; it is updated automatically by the model per the cloud location selection.

Figure 6.7-1: Remaining Inputs, Cloud Fraction, and Results for I-10 Cases

It is evident that the desert environment locations (San Antonio, El Paso, and Tucson) have better performance overall, since the atmosphere has less scattering and the direct solar irradiance is higher. But that does not necessarily mean that the solar panels in San Antonio are more attractive economically than in Pensacola which has the denser Mid-Latitude atmosphere; the big difference is that the cost of electricity in Pensacola is higher, and the escalation rate is about the same. Likewise, the Santa Barbara location is the most attractive economically (lowest ROI) because of both a high electric rate and high escalation rate, despite the fact that it lies in the denser Mid-Latitude environment. New Orleans is the worst case because it not only has the Mid-Latitude environment, but also has high cloud cover and a low escalation rate. There are only five locations (Jacksonville, Pensacola, El Paso, Tucson, and Santa Barbara) where the 25-year average cost of solar generation is less than the current electric cost.

It is evident that solar energy is most viable in places where: a) the cost of electricity is high (i.e., greater than about \$.12 per kWh); or b) the escalation rate is high (i.e., greater than about 0.025); and c) where there is a fairly low cloud fraction, at least in the summer (i.e., less than ~0.30 or so). Among the I-10 cases, El Paso, Tucson, and Santa Barbara have the lowest ROI's; El Paso and Tucson because of low cloud fractions, and Santa Barbara because of both high electric rate and high escalation rate.

Figure 6.7-2 shows the remaining inputs and results for the I-90 cases; the only change from the Figure 6.7-1 inputs is that the tilt angle at these nominal latitudes is 40° and ground cover as shown. There is no cloud data for Sioux Falls, SD. From the Utilities page, the closest cloud location is Sioux City, IA, 64.41 NM away.

	Boston, MA	Buffalo, NY	Toledo, OH	Chicago, IL	Rochester, MN	Sioux Falls, SD	Rapid City, SD	Billings, MT	Missoula, MT	Spokane, WA	Seattle, WA
Nearest Latitude	Buffalo	Buffalo	Columbus	Lincoln	Minneapolis	Minneapolis	Lander, WY	Great Falls	Great Falls	Seattle	Seattle
Cloud Location	Boston	Buffalo	Toledo	Chicago	Rochester, MN	Sioux City, IA	Rapid City	Billings	Missoula	Spokane	Seattle
Ground Cover, all seasons	Maple For.	Oak Forest	Oak Forest	Concrete	Pedocal	Pedocal	Pedocal	R. Sage	R. Sage	R. Sage	Douglas Fir
Ground Reflectance [1]	0.332	0.458	0.458	0.207	0.369	0.369	0.369	0.123	0.123	0.123	0.071
Electricity Cost/kWh [2]	0.1491	0.1174	0.0758	0.1044	0.1222	0.1083	0.1078	0.1164	0.1004	0.0571	0.0775
Escalation rate [3]	0.0338	0.0120	0.0176	0.0182	0.0280	0.0230	0.0230	0.0275	0.0275	0.0327	0.0327
Atmosphere Type	MLS/MLW	MLS/MLW	MLS/MLW	MLS/MLW	MLS/MLW	MLS/MLW	USS (desert)	USS (desert)	USS (desert)	USS (desert)	MLS/MLW
Cloud fraction, winter [4]	0.331	0.515	0.414	0.383	0.403	0.344	0.266	0.389	0.476	0.433	0.513
Cloud fraction, spring [4]	0.406	0.437	0.357	0.370	0.442	0.383	0.391	0.467	0.501	0.440	0.468
Cloud fraction, summer [4]	0.392	0.416	0.301	0.317	0.376	0.271	0.313	0.349	0.340	0.300	0.361
Cloud fraction, fall [4]	0.393	0.570	0.458	0.424	0.444	0.331	0.268	0.380	0.506	0.479	0.589
Avg. Daily Solar DNI, winter, W/sq m	4604.20	4604.20	5007.57	4868.09	4358.20	4358.20	6182.06	5629.48	5629.48	5593.62	4019.50
Avg. Daily Solar DNI, spring, W/sq m	7617.20	7617.20	7578.37	7603.34	7634.28	7634.28	10354.88	10527.27	10527.27	10493.01	7627.58
Avg. Daily Solar DNI, summer, W/sq m	7499.47	7499.47	7503.81	7425.94	7503.82	7503.82	10231.50	10410.04	10410.04	10346.40	7482.76
Avg. Daily Solar DNI, fall, W/sq m	4680.92	4680.92	4999.72	4894.42	4413.59	4413.59	6328.54	5723.43	5723.43	5675.07	4062.58
(1-Cloud Fraction)*DNI, winter, W/sq m	3080.21	2233.04	2934.44	3003.61	2601.85	2858.98	4537.63	3439.61	2949.85	3171.58	1957.50
(1-Cloud Fraction)*DNI, spring, W/sq m	4524.62	4288.48	4872.89	4790.10	4259.93	4710.35	6306.12	5611.03	5253.11	5876.09	4057.87
(1-Cloud Fraction)*DNI, summer, W/sq m	4559.68	4379.69	5245.16	5071.91	4682.39	5470.29	7029.04	6776.94	6870.63	7242.48	4781.49
(1-Cloud Fraction)*DNI, fall, W/sq m	2841.32	2012.80	2709.85	2819.19	2453.95	2952.69	4632.49	3548.53	2827.38	2956.71	1669.72
Initial year power, kWh	5219.7	4546.1	5319.1	5517.4	4938.9	5380.7	6798.3	5631.4	5182.0	5556.4	4225.4
Initial value, \$	778.26	533.71	403.19	576.02	603.53	582.73	732.86	655.49	520.28	317.27	327.47
25-year cost avoided , \$	28483.22	14530.99	11824.65	17029.75	20382.90	18380.52	23115.87	21986.17	17450.75	11435.09	11802.47
Power generated, 25 years	122011.0	106264.2	124334.2	128970.3	115446.6	125773.9	158910.5	131633.9	121129.9	129881.8	98768.0
Avg. generation cost, \$/kWh	0.123	0.141	0.121	0.116	0.130	0.119	0.094	0.114	0.124	0.115	0.152
Return on investment, years	15.2	~25.2	>25	22.4	19.6	21.1	17.3	18.4	22.2	>25	>25

1. This is not an input; it is updated automatically by the model per the ground cover selection.
2. Per www.electricitylocal.com
3. Per Figures 3.10-3 and 3.10-4; annual increase from 2000 to 2020.
4. This is not an input; it is updated automatically by the model per the cloud location selection.

Figure 6.7-2: Remaining Inputs, Cloud Fraction, and Results for I-90 Cases

Among the I-90 cases, Buffalo, Toledo, Spokane, and Seattle have ROI's greater than 25 years; for Buffalo and Toledo, is due to high cloud cover, for Seattle, is due to high cloud cover and low electric rates, and for Spokane, due to low electric rates. Among all the cases considered, the overall cost of solar energy generation is highest in Seattle (\$0.152/kWh), and the lowest is in Rapid City (\$0.094/kWh). That should be no surprise: Rapid City is in a desert atmosphere, and has generally less cloud cover. Seattle has the opposite conditions: high latitude (with higher zenith angles), the denser Mid-Latitude atmospheric environment, and high cloud cover.

There is a very large difference in the cost of solar generation between Rapid City, Billings, and Missoula, even though all are in a desert environment. The main difference is the level of cloud cover: least in Rapid City, worst in Missoula. Spokane and Seattle are nearly hopeless cases so far as ROI is concerned; they have low electricity rates and high cloud conditions, which overcome the high escalation rate. Buffalo and Toledo also have high enough cloud fractions and low enough escalation rates to make the ROI greater than 25 years.

It is easy to use this Estimator to determine what input variations are necessary to achieve some desired objective. For example, if escalation rates are as stated above, what panel efficiency would be required to obtain an ROI of 10 years; or conversely, given the efficiency as stated, what corresponding escalation rate is required. The Estimator shows that it is not always possible to obtain the desired solution. For Billings, MT, if the escalation rate remains at 0.0275 but the efficiency is increased to its current demonstrated maximum of 0.34, the ROI is still 12.8 years. If the efficiency remains at 0.21, an annual escalation rate of 0.15 (i.e., 15% per year) is required in order to obtain an ROI of 10 years. That would require a long-term conspiracy by the Federal Reserve, the politicians, the utility regulators, and the utilities to obtain that sustained level of electricity price increases.

6.8 Comparison to PVWatts Version 5

This example will compare the results from PVWatts version 5 to this Estimator. The inputs to PV Watts for Phoenix AZ are as follows: a) DC system size (kW) = 5.5; b) Module Type = Premium; c) Array Type = Roof Mount; d) System losses = 15%; e) Tilt = 35°; f) Azimuth = 180°; g) Residential rate type; and h) $0.12/kWh electric rate. The $.12 per kWh is the same as the electricity local website ($0.1196/kW-hr).

Recall from section 1.2 that PVWatts uses the "nameplate" DC rating for the DC system size. In order to make a reasonable comparison, the LG Electronics LG375Q1C-V5 has a 375 W DC "nameplate" (i.e., its DC output at 1000 W/m^2, normal incidence, with the cells held at 25° C). This solar panel has an area of 1.621 m^2, and an NOCT efficiency of 0.217. A "nameplate" system of 5,500 W using this panel equates to 5500/375 = 14.666 panels, and thus the active area is 14.666(1.621) = 23.77 m^2. This panel has a power coefficient of -0.0030, and its power rating after 25 years 0.908. Its' NOCT temperature is 317.15° K; implying a temperature difference of 19° K above ambient in operation. It is assumed that the AR coating limit is 80° and the surrounding ground cover is Rangeland Sage (reflectance = 0.123). The escalation rate in Arizona per Figure 3.12-3 is 0.0187. It is assumed that installation costs are about $1000 per m^2, but with incentives comes to about $700 per m^2; thus the installation cost is about $16,600. Figure 6.8-1 shows the inputs for this example.

Inputs		Units	Symbol
Choose time zone, nearest latitude	M 32 Tuscon, AZ		
Choose cloud location	Phoenix, AZ		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	35	deg	epsilon
Panel Total Area	23.77	sq m	A_p
Panel Efficiency, NOCT	0.217	decimal	e_TC
Power fraction after 25 years	0.908		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.003	%/100 °K	C_T
Ground Type, Winter	Rangeland Sage		
Ground Type, Spring	Rangeland Sage		
Ground Type, Summer	Rangeland Sage		
Ground Type, Fall	Rangeland Sage		
DC-AC Conversion efficiency	0.93		
Installation cost	16600	$	
Annual Electricity Escalation Rate	0.0187	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.12	0.12	0.12	0.12
1 AM to 2 AM	1.5	0.12	0.12	0.12	0.12
2 AM to 3 AM	2.5	0.12	0.12	0.12	0.12
3 AM to 4 AM	3.5	0.12	0.12	0.12	0.12
4 AM to 5 AM	4.5	0.12	0.12	0.12	0.12
5 AM to 6 AM	5.5	0.12	0.12	0.12	0.12
6 AM to 7 AM	6.5	0.12	0.12	0.12	0.12
7 AM to 8 AM	7.5	0.12	0.12	0.12	0.12
8 AM to 9 AM	8.5	0.12	0.12	0.12	0.12
9 AM to 10 AM	9.5	0.12	0.12	0.12	0.12
10 AM to 11 AM	10.5	0.12	0.12	0.12	0.12
11 AM to noon	11.5	0.12	0.12	0.12	0.12
noon to 1 PM	12.5	0.12	0.12	0.12	0.12
1 PM to 2 PM	13.5	0.12	0.12	0.12	0.12
2 PM to 3 PM	14.5	0.12	0.12	0.12	0.12
3 PM to 4 PM	15.5	0.12	0.12	0.12	0.12
4 PM to 5 PM	16.5	0.12	0.12	0.12	0.12
5 PM to 6 PM	17.5	0.12	0.12	0.12	0.12
6 PM to 7 PM	18.5	0.12	0.12	0.12	0.12
7 PM to 8 PM	19.5	0.12	0.12	0.12	0.12
8 PM to 9 PM	20.5	0.12	0.12	0.12	0.12
9 PM to 10 PM	21.5	0.12	0.12	0.12	0.12
10 PM to 11 PM	22.5	0.12	0.12	0.12	0.12
11 PM to midnight	23.5	0.12	0.12	0.12	0.12

Figure 6.8-1: Inputs for Comparison to PVWatts, Version 5 for Phoenix, AZ

The results from the Estimator are:

a) Total annual direct solar irradiance, including cloud effects = 2,792.81 kWh/m^2

b) Total initial annual power = 9,230.3 kWh;

c) Total annual initial value = $1,107.63;

d) Dollar value over 25 years = $33,721.20;

e) Total power generated over 25 years = 220,142.3 kWh,

f) Average cost of solar power generation = $0.075/kWh; and

g) Return on investment is about 13.5 years.

The results from the PVWatts model are:

a) Average power generated per year lies between 9,198 and 9,899 kWh (average = 9,683 kWh)

b) Total annual solar radiation = 6.64 kWh/m^2

c) Annual value (initial) = $1,158.00

Evidently the "total annual solar radiation" cited by PVWatts is different from the direct solar irradiance used in the Estimator; it likely includes the total from both direct and scattered sources [6.8-1].

The PVWatts model produces an initial estimate of power generation that is 4.9% higher than the Estimator; likewise the value of the power generated is also increased by the same ratio. It is evident that the main difference in the models is some combination of the total incident radiation (i.e., direct, diffuse sky, and diffuse cloud, and ground reflections) or the assumptions about cloud cover. The Estimator uses LOWTRAN7 to calculate the incident radiation, and it seems about right. If so, then the difference lies in the cloud cover estimates. For Phoenix, the cloud cover fractions are 0.100, 0.100, 0.191, and 0.100 for winter, spring, summer, and fall respectively.

If both models are re-run for Seattle, WA, the only two changes to the PVWatts and Estimator inputs are: a) tilt = 40°; and b) electricity cost = 0.078/kW-hr. The electricity local website calls out a nearly identical $0.0775/kW-hr. The results for the PVWatts Seattle case are:

a) Average power generated per year lies between 5,953 and 6,449 kW-hr (average = 6,238 kW-hr)

b) Total annual solar radiation = 4.12 kW-hr/m^2

c) Annual value (initial) = $484.00.

The corresponding Seattle inputs for the Estimator are shown on Figure 6.8-2. Here it is assumed that the ground cover is Douglas Fir (reflectance = 0.071) and the escalation rate for Washington per Figure 3.12-4 is 0.0327.

Inputs		Units	Symbol
Choose time zone, nearest latitude	P 48 Seattle, WA		
Choose cloud location	Seattle, WA		
Panel Azimuth, E of North	180	deg	beta
Panel Tilt from Horizontal	40	deg	epsilon
Panel Total Area	23.77	sq m	A_p
Panel Efficiency, NOCT	0.217	decimal	e_TC
Power fraction after 25 years	0.908		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.003	%/100 °K	C_T
Ground Type, Winter	Douglas Fir Forest		
Ground Type, Spring	Douglas Fir Forest		
Ground Type, Summer	Douglas Fir Forest		
Ground Type, Fall	Douglas Fir Forest		
DC-AC Conversion efficiency	0.93		
Installation cost	16600	$	
Annual Electricity Escalation Rate	0.0327	%/100	
Constants			
Lab Temperature	298.15	K	

		Electricity Cost per kWh, dollars			
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.0775	0.0775	0.0775	0.0775
1 AM to 2 AM	1.5	0.0775	0.0775	0.0775	0.0775
2 AM to 3 AM	2.5	0.0775	0.0775	0.0775	0.0775
3 AM to 4 AM	3.5	0.0775	0.0775	0.0775	0.0775
4 AM to 5 AM	4.5	0.0775	0.0775	0.0775	0.0775
5 AM to 6 AM	5.5	0.0775	0.0775	0.0775	0.0775
6 AM to 7 AM	6.5	0.0775	0.0775	0.0775	0.0775
7 AM to 8 AM	7.5	0.0775	0.0775	0.0775	0.0775
8 AM to 9 AM	8.5	0.0775	0.0775	0.0775	0.0775
9 AM to 10 AM	9.5	0.0775	0.0775	0.0775	0.0775
10 AM to 11 AM	10.5	0.0775	0.0775	0.0775	0.0775
11 AM to noon	11.5	0.0775	0.0775	0.0775	0.0775
noon to 1 PM	12.5	0.0775	0.0775	0.0775	0.0775
1 PM to 2 PM	13.5	0.0775	0.0775	0.0775	0.0775
2 PM to 3 PM	14.5	0.0775	0.0775	0.0775	0.0775
3 PM to 4 PM	15.5	0.0775	0.0775	0.0775	0.0775
4 PM to 5 PM	16.5	0.0775	0.0775	0.0775	0.0775
5 PM to 6 PM	17.5	0.0775	0.0775	0.0775	0.0775
6 PM to 7 PM	18.5	0.0775	0.0775	0.0775	0.0775
7 PM to 8 PM	19.5	0.0775	0.0775	0.0775	0.0775
8 PM to 9 PM	20.5	0.0775	0.0775	0.0775	0.0775
9 PM to 10 PM	21.5	0.0775	0.0775	0.0775	0.0775
10 PM to 11 PM	22.5	0.0775	0.0775	0.0775	0.0775
11 PM to midnight	23.5	0.0775	0.0775	0.0775	0.0775

Figure 6.8-2: Inputs for the Seattle Case

The results for Seattle from the Estimator are:
a) Total annual direct solar irradiance, including cloud effects = 1,140.69 kWh/m^2
b) Total initial annual power = 5,263.9 kWh;
c) Total annual initial value = $407.95;
d) Dollar value over 25 years = $15,057.92;
e) Total power generated over 25 years = 125,544.2 kWh,
f) Average cost of solar power generation = $0.132/kWh; and
g) Return on investment is about 27 years.

The disparity between the Estimator and PVWatts is considerably greater: the PVWatts model gives initial power as 18.5% higher than the Estimator, and the same ratio applies to the annual value of the power generated. It is necessary to set the cloud ratio to 0.400 for all four seasons using the "Test Case" cloud location (see cells CP227 to CS227) in order to reproduce the PVWatts result. Making this change in the cloud fraction leads to 6,295.3 kW-hr initial annual power generated and an initial year value of $487.88.

6.9 The Local Analysts' Case

I mentioned in the Preface that I had taken notes during the presentation made by one of the analysts' assessment of solar for my house. Figure 6.9-1 shows the corresponding Estimator inputs based on what he told me and what I could write down from his PC. My house only has east and west facing rooflines, and 270° is a better choice for me since one of the neighbors has fairly tall trees. Since I live in a suburban area, concrete was a logical choice for the surrounding ground cover. Notice that the electricity rates are different at different times of the day; he told me that the local utility is planning or already has adopted that scheme. I haven't noticed it yet on my bill. In any case, that is what he told me, and that is how I set up the inputs as shown. His configuration is a 5.5 kW system consisting of 14 each Hanwha Q Cell 395 panels (see Utilities, W37 through AE37), which has the properties of efficiency, thermal coefficient, guaranteed power after 25 years as shown. He also told me that the overall DC-AC conversion efficiency is 90% as shown. Figure 6.9-1 assumes 23.5 sq. m. area at $1,000 per sq. m. total cost, less 25% federal and state incentives; thus the installation cost in round numbers comes to $17,625 as shown.

Inputs		Units	Symbol
Choose time zone, nearest latitude	M 32 Tuscon, AZ		
Choose cloud location	Phoenix, AZ		
Panel Azimuth, E of North	270	deg	beta
Panel Tilt from Horizontal	35	deg	epsilon
Panel Total Area	23.53	sq m	A_p
Panel Efficiency, NOCT	0.220	decimal	e_TC
Power fraction after 25 years	0.86		
Anti-reflection coating limit	80	deg	A
Temperature Coefficient	-0.0034	%/100 °K	C_T
Ground Type, Winter	Concrete		
Ground Type, Spring	Concrete		
Ground Type, Summer	Concrete		
Ground Type, Fall	Concrete		
DC-AC Conversion efficiency	0.9		
Installation cost	17625	$	
Annual Electricity Escalation Rate	0.0600	%/100	
Constants			
Lab Temperature	298.15	K	

Electricity Cost per kWh, dollars					
Local time	24-hr	Winter	Spring	Summer	Fall
Midnight to 1 AM	0.5	0.06	0.06	0.06	0.06
1 AM to 2 AM	1.5	0.06	0.06	0.06	0.06
2 AM to 3 AM	2.5	0.06	0.06	0.06	0.06
3 AM to 4 AM	3.5	0.06	0.06	0.06	0.06
4 AM to 5 AM	4.5	0.06	0.06	0.06	0.06
5 AM to 6 AM	5.5	0.06	0.06	0.06	0.06
6 AM to 7 AM	6.5	0.06	0.06	0.06	0.06
7 AM to 8 AM	7.5	0.06	0.06	0.06	0.06
8 AM to 9 AM	8.5	0.06	0.06	0.06	0.06
9 AM to 10 AM	9.5	0.06	0.06	0.06	0.06
10 AM to 11 AM	10.5	0.06	0.06	0.06	0.06
11 AM to noon	11.5	0.13	0.13	0.13	0.13
noon to 1 PM	12.5	0.13	0.13	0.13	0.13
1 PM to 2 PM	13.5	0.13	0.13	0.13	0.13
2 PM to 3 PM	14.5	0.13	0.13	0.13	0.13
3 PM to 4 PM	15.5	0.17	0.17	0.17	0.17
4 PM to 5 PM	16.5	0.17	0.17	0.17	0.17
5 PM to 6 PM	17.5	0.17	0.17	0.17	0.17
6 PM to 7 PM	18.5	0.17	0.17	0.17	0.17
7 PM to 8 PM	19.5	0.17	0.17	0.17	0.17
8 PM to 9 PM	20.5	0.06	0.06	0.06	0.06
9 PM to 10 PM	21.5	0.06	0.06	0.06	0.06
10 PM to 11 PM	22.5	0.06	0.06	0.06	0.06
11 PM to midnight	23.5	0.06	0.06	0.06	0.06

Figure 6.9-1: Inputs for the Analyst's Case

Here are the results the analyst provided to me:
a. Power generated in the first year = 9,380 kWh.
b. The savings over 25 years would come to $45,000.

The results from the Estimator are (using the generic $1,000/sq. m. installation cost):
a. Power generated in the first year = 6,807.7 kWh.
b. The savings over 25 years would come to $49,312.85.
c. The average cost of solar generation over 25 years would be $0.111/kWh.
d. The return-on-investment is about 12.9 years.

The Estimator gave slightly better 25-year savings results than the analyst's model did (probably because he included interest charges on the solar system). Also, when I used the actual installation cost quoted by the analyst, the result for the long-term average solar generation cost per kWh came within the range he specified. But why is the power generated in the first year off so much? I believe the answer is: the Estimator calculates the actual power generated based on the radiometry, whereas the analyst's model performs the same calculation, but reports it out per the "nameplate" rating. Here is my logic. The Hanwha 395 (cf. Utilities page, cell Z37) calls out 296.3 W at NOCT conditions; 296.3/395 = 0.750. The Estimator uses efficiencies near the NOCT value (but also modified for temperature); the 6,807 kWh initial power from the Estimator divided by the 9,380 kWh per the analyst's model gives 0.725. I am at a loss for any other explanation. If my intuition is correct, it is important to verify the amount actually being generated, and not rely on laboratory rating scales. This would be a problem if you desired a system that actually generated 9,500 kWh per year and installed this system, only to find that it produces about 75% of it. But, the long-term savings and per-kWh generation rates would still be correct as shown above.

There is one last important point. Notice that the escalation rate is 6% per year (which is what the analyst told me the local utility had claimed), but is far above the historical norm as shown on Figure 3.12-3. Once again, make sure the projections are reasonable, otherwise the ROI will be too good to be true. Here is the proof. If the escalation rate is 0.0217 as shown in Figure 3.12-3 for Arizona from 2005 to 2020, then running this case again would lead to the following results:
a. Power generated in the first year = 6,807.7 kWh.
b. The savings over 25 years would come to $28,676.28.
c. The average cost of solar generation over the 25 years would be $0.111/kWh.
d. The return-on-investment is about 16.4 years.

The next step is to perform a parametric on total cost and examine the resulting return on investment. The inputs shown on Figure 6.9-1 are the same (including the 6% escalation rate), except the installation cost will vary from $4,000 to $24,000 in $2,000 increments. Figure 6.9-2 shows the results for ROI and average solar generation cost per kWh as a function of the initial installation cost. The dashed lines show the results for the initial case per Figure 6.9-1 (generic installation cost = $17,625).

Figure 6.9-2 shows that for the current level of technology (in which the efficiencies are about 20%) the installation costs must be fairly low to obtain an ROI less than 7 years for this particular case. It is evident from the Figure that this occurs when the net installation cost after incentives declines to about $8,000. That implies that either the cost of the panels and/or the cost of labor to install them has to decrease, or the government incentives must increase. On the other hand, if the panel efficiencies are increased, the ROI and average solar generation cost per kWh will come down (but not proportionally). The Estimator is designed to run these cases easily by changing efficiencies and installation costs as desired.

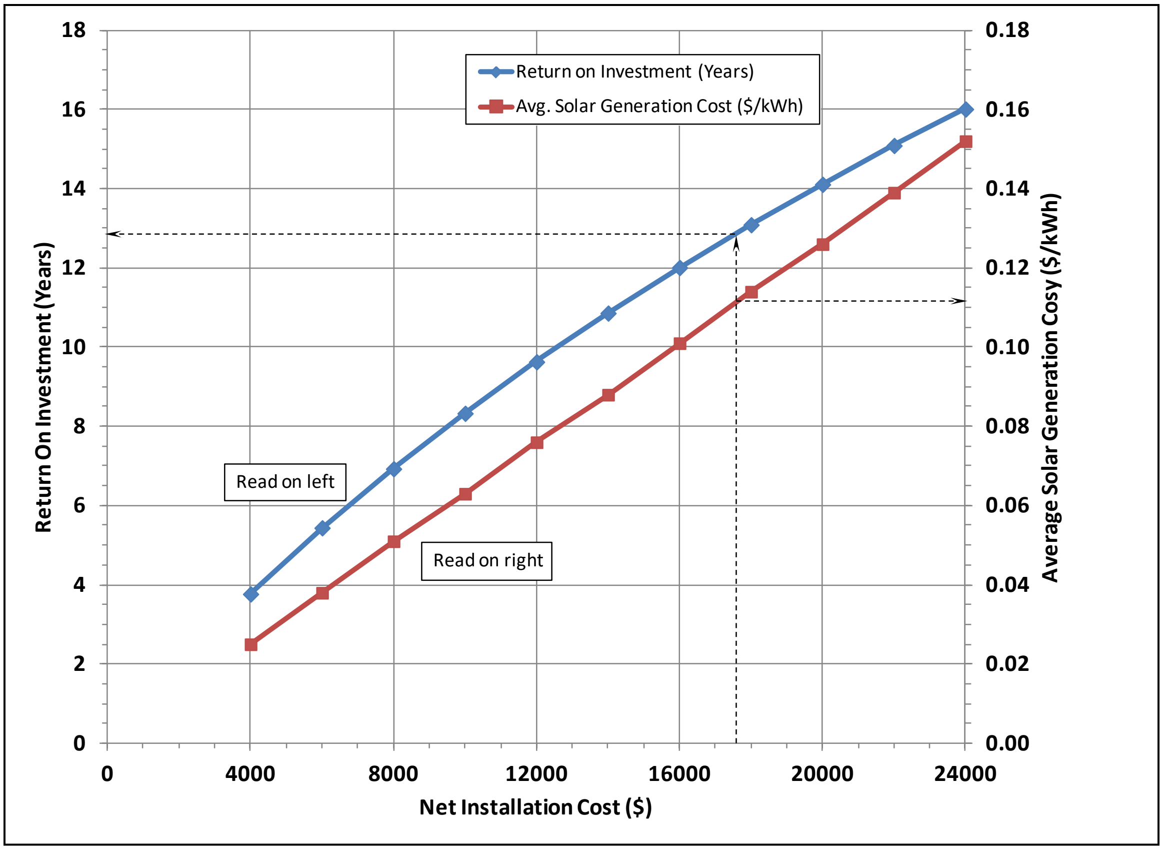

Figure 6.9-2: Parametric ROI and Solar Generation Cost vs. Initial Installation Cost

6.10 A Note on Installation Costs

These examples used a generic value of $1,000 per sq. m. as the installation costs. Normally the total installation costs are called out as $/watt (i.e., $/W), in which the referenced watt is per the "nameplate" rating (cf. the Utilities page, Col. Z). For example, the JA Solar model JAM72S30-525/MR has a "nameplate" DC output of 397 W. A 3.97 kW system would be called out at 10 of these panels, and the cost thereof would be quoted as 3,970 times the current $/W. NREL has published [6.10-1] an estimate of overall $/W for residential and commercial systems in the U. S. In 2020, the average total installation cost for residential systems was $2.71/W. But keep in mind that this is an average number for the entire nation, and costs vary widely by region (due mostly to labor and roof type). It is not clear if these are pre- or post-incentive values. In any case, ensure that you get an accurate cost number from your installer. If they are post-incentive, the 5.4 kW system in example 6.9 would come to 5,500($2.71) = $14,905, which is the value to be input in cell D19 of the Estimator. If so, Figure 6.9-2 indicates that the average solar energy cost per kWh is about $0.095, and the ROI would be about 11.4 years.

References

[6.8-1] Aron P. Dobos, *PVWatts Version 5 Manual*, Golden, CO: National Renewable Energy Laboratory, Technical Report NREL/TP-6A20-62641, Sep 2014, pp. 4, 5, There the author calls out direct normal irradiance (DNI) and diffuse horizontal irradiance (DHI) as "solar resources".

[6.10-1] https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html

7
Programmer's Guide

The cell references called out in this chapter pertain to the Estimator page, except for sections 7.36 and 7.37, which pertain to the Utilities page.

7.1 Source Data, Sun Location

Cells AO40 to CJ153 contain the results for the sun azimuth and zenith for the latitude selection on cell D5 per the NREL solar position model as described in section 5.2. The data is segregated as shown on Figure 7.1-1.

Sun Azimuth and Zenith Data Locations on Estimator tab, Excluding Headers				
Time Zone	**Season**	**Hour**	**Sun Azimuth and Zenith**	**Cities**
Eastern	Winter	AO40 to AO63	AP40 to BA63	Miami,FL; Jacksonville, FL; Charlotte, NC; Columbus, OH; Buffalo, NY; Portland, ME
	Spring	AO70 to AO93	AP71 to BA93	
	Summer	AO100 to AO123	AP101 to BA123	
	Fall	AO130 to AO153	AP131 to BA153	
Central	Winter	BB40 to BB63	BC40 to BN63	Brownsville, TX; New Orleans, LA; Tulsa, OK; Lincoln, NE; Minneapolis, MN; Devils Lake, ND
	Spring	BB70 to BB93	BC70 to BN93	
	Summer	BB100 to BB123	BC100 to BN123	
	Fall	BB130 to BB153	BC130 to BN 153	
Mountain	Winter	BO40 to BO63	BP40 to BY63	Tuscon, AZ; Santa Fe, NM; Grand Junction, CO; Lander, WY; Great Falls, MT
	Spring	BO70 to BO93	BP70 to BY93	
	Summer	BO100 to BO123	BP100 to BY123	
	Fall	BO130 to BO153	BP130 to BY153	
Pacific	Winter	BZ40 to BZ63	CA40 to CJ63	San Diego, CA; Fresno, CA; Ely, NV; Roseburg, OR; Seattle, WA
	Spring	BZ70 to BZ93	CA70 to CJ93	
	Summer	BZ100 to BZ123	CA100 to CJ123	
	Fall	BZ130 to BZ153	CA130 to CJ153	

Figure 7.1-1: Sun Azimuth and Zenith Data Locations

7.2 Source Data, Miscellaneous per Cloud Location

Figure 7.2-1 shows the location of source data for geolocation, percent cloud cover, ambient temperatures, radiometric index, and scaled efficiency for the "cloud locations" selectable in cell D6 as described in sections 3.2 and 5.3, and Appendix A. The location (latitude, longitude) data is provided for information only, and may be used by the user on the Utilities page to calculate great circle distances. It is not used otherwise. The fractional cloud cover (C_C) is used to scale the direct solar irradiance, sky radiance, and cloud radiances as described in section 5.10. The ambient temperatures are used to calculate the effective solar panel efficiency e_{TC} under as-installed seasonal conditions per section 5.9. The radiometric indices are utilized to select the direct solar, diffuse sky, and diffuse cloud radiances for either desert locations (these indices = 1, 2, 3, and 4 for winter, spring, summer, fall) or Mid-Latitude Summer/Winter (these indices = 5, 6, 7, and 8 for winter, spring, summer fall). The scaled efficiency index (1 for USS70D/desert, 2 for Mid-Latitude Summer/Winter) are used to index the reduced efficiency e_{RS} and e_{RC} for diffuse sky and diffuse cloud radiance as described in section 5.10.

Table Indicates Columns; Data is in Rows 39 to 226 on the Estimator tab, Excluding Headers					
City	Location	Fractional Cloud Cover	Ambient High Temp.	Radiometric Index	Scaled Efficiency
CM	Latitude: CN	Winter: CP	Winter: CT	Winter: CX	DB
	Longitude: CO	Spring: CQ	Spring: CU	Spring: CY	
		Summer: CR	Summer: CV	Summer: CZ	
		Fall: CS	Fall: CW	Fall: DA	

Figure 7.2-1: Cloud Location Additional Data Locations

7.3 Source Data, Effective Ground Reflectance

The effective reflectance data as described in section 5.13 for the ground types selectable in cells D14 through D17 is located in cells DD38 to DE58.

7.4 Source Data, LOWTRAN7 Direct Solar, Diffuse Sky, and Diffuse Cloud Results

The results for the direct solar irradiance from LOWTRAN7 calculations per section 5.5 are located in cells DU39 through EC129. There is a direct solar irradiance value for each zenith angle: column DU contains the zenith angles from 0° to 90°. Columns DW, DX, DY, and DZ contain the results from the LOWTRAN7 1976 U. S. Std (desert) environment in Winter, Spring, Summer, and Fall respectively. Columns DZ and EC contain the results for Winter and Fall as calculated by the Mid-Latitude LOWTRAN7 model, and columns EA and EB contain the results for Spring and Summer as calculated by the LOWTRAN Mid-Latitude Summer model.

The results for the diffuse sky radiance from LOWTRAN7 calculations per section 5.6 are located in cells EE39 through EM129. There is a sky radiance value for each zenith angle: column EE contains the zenith angles from 0° to 90°. Columns EF, EG, EH, and EI contain the diffuse sky results from the LOWTRAN7 1976 U. S. Std (desert) environment in Winter, Spring, Summer, and Fall respectively. Columns EJ and EM contain the results for Winter and Fall as calculated by the Mid-Latitude LOWTRAN7 model, and columns EK and EL contain the results for Spring and Summer as calculated by the LOWTRAN Mid-Latitude Summer model.

The results for the diffuse cloud radiance from LOWTRAN7 calculations per section 5.7 are located in cells EO39 through EW129. There is a diffuse cloud radiance value for each zenith angle: column EO contains the zenith angles from 0° to 90°. Columns EP, EQ, ER, and ES contain the diffuse cloud results from the LOWTRAN7 1976 U. S. Std (desert) environment in Winter, Spring, Summer, and Fall respectively. Columns ET and EW contain the results for Winter and Fall as calculated by the Mid-Latitude LOWTRAN7 model, and columns EU and EV contain the results for Spring and Summer as calculated by the LOWTRAN Mid-Latitude Summer model.

7.5 Source Data, Scaled Sky and Cloud Conversion Efficiency

The reduced efficiencies of a solar panel due to the altered spectral content of diffuse sky and cloud radiance were calculated off-line per equation 5.10-6, and are contained in cells EZ39 to FB40. The results for the 1976 U. S. Standard (desert) environment are in column EX, and the results for the Mid-Latitude Summer and Winter are in columns FA and FB respectively.

7.6 Intermediate Scalar Results, Cloud Cover

Cells D37 through D40 contain the fractional cloud cover results (C_C) for each season per the cloud location selection in cell D6. The values are extracted from the data described in section 7.2 by the formula: VLOOKUP($D$6, $CM$39:$CS$226, "X", FALSE), in which "X" is 4, 5, 6, or 7 for winter, spring, summer, and fall respectively.

7.7 Intermediate Scalar Results, Ambient Temperatures

Cells D41 through D44 contain the ambient high temperature results (T_{AMB}) in °K for each season per the cloud location selection in cell D6. These are utilized to correct the nominal solar panel efficiency per equation 5.9-1. The values are extracted from the data described in section 7.2 by the formula: VLOOKUP($D$6, $CM$39:$CS$226, "X", FALSE), in which "X" is 8, 9, 10, or 11 for winter, spring, summer, and fall respectively.

7.8 Intermediate Scalar Results, Thermal-Corrected Solar Panel Efficiency

Cells D45 through D48 contain the nominal conversion efficiency of the solar panel for each season per equation 5.9-1: $D$10 + ("X" - $D$25)*$D$13, in which $D$10 is the efficiency entered by the user per the solar panel datasheet, "X" is the ambient temperatures for each season per cells D41, D42, D43, and D44 (cf. section 7.7), $D$25 is the constant laboratory temperature (298.15 °K), and $D$13 is the user entry for the temperature efficiency coefficient from the datasheet.

7.9 Intermediate Scalar Results, Ground Reflectance

Cells D49 through D52 contain the effective ground reflectance for each season per the ground type selections in cells through D14 through D17. The values are extracted from the data described in section 7.3 by the formula: VLOOKUP("X", $DD$38:$DE$58, 2, FALSE), in which "X" is D14, D15, D16, or D17 for winter, spring, summer, and fall respectively.

7.10 Intermediate Results, Solid Angle Geometry

Cell D53 contains the AR coating limit in radians per the user entry in degrees in cell D12.

Cell D54 contains the total observable solid angle of the solar panel Ω_T per equation 5.12-1, using the result from D53.

Cell D56 contains the result of equation 5.12-3 for γ, using the user entries for tilt angle per cell D8 and AR coating limit per cell D12.

Cell D57 contains the result of equation 5.12-2 for k, using the result from cell D56 for γ.

Cell D58 contains the result (Ω_G) from equation 5.12-4, using the results in D54 (Ω_T) and D57 (k).

Cell D59 contains the result of equation 5.12-4 (Ω_S) using the results from D54 (Ω_T) and D58 (Ω_G).

7.11 Intermediate Scalar Results, Sky and Cloud Reduced Efficiencies

Cells D60 through D63 contain the lookup results for the reduced efficiency e_{RS} and e_{RC} of the solar panels due to the spectral content of diffuse sky and cloud radiances respectively per equation 5.10-6. The exact results were calculated off-line, and are contained in cells EX39 through FB40. They are accessed using the index contained in column DB (cf. section 7.2) using the formula:

IF(VLOOKUP($D$6, $CM$39:$DB$226, 16, FALSE)=1, "Y", "Z")

where $D$6 is the user-selected cloud location. If the result of the VLOOKUP is 1, then the cloud location uses a desert atmosphere. If so, then "Y" is: a) EZ39 in cell D60 for Sky/Winter-Fall; b) EZ39 in cell D61 for Sky/Spring-Summer; c) EZ40 in cell D62 for Cloud/Winter-Fall; and d) EZ40 in cell D63 for Cloud/Spring-Summer If the result of the VLOOKUP is not 1, then the chosen cloud location uses the Mid-Latitude Summer/Winter atmosphere model. If so, "Z" is: a) FB39 in cell D60 for Sky/Winter-Fall; b) FA39 in cell D61 for Sky/Spring-Summer; c) FB40 in cell D62 for Cloud/Winter-Fall; and d) FA40 in cell D63 for Cloud/Spring-Summer.

7.12 Intermediate Scalar Results, Geometry and Slope of Degradation

Cells D69 through D71 contain angle constants in order to make the geometry calculations simpler. Cells D69 and D70 are the cosine and sine of the tilt angle respectively as entered by the user in cell D8. Cell D71 is the solar panel azimuth angle entered by the user in cell D7 converted to radians.

Last, cell D71 implements equation 5.9-3 for the degradation slope m, using the user entry in cell D11.

7.13 Intermediate Array Results, Sun Azimuth and Zenith per Time Zone/Latitude Location

The basic sun azimuth and zenith data for each of the Latitude locations and seasons is located as described in section 7.1. When a user selects a location in D5, it is necessary to select the correct portion of this data so as to correctly calculate the total angle between the solar panel normal and the sun location. To do so, an indexing system is set up in cells AI40 to AK61. Column AI40 contains the names of the locations selectable in cell D5; column AJ contains an offset index for the sun azimuth, and column AK contains an offset index for the sun zenith. These column indices reference the columns cited in section 7.1, starting with column AO as an index of 1. For example, a selection of Jacksonville, FL in D5 references columns 4 and 5 offset from column AO (i.e., columns AR and AS), which contain the sun azimuth and zenith for Jacksonville.

Cells J37 through Q37 indicate the indices for Winter, Spring, Summer and Fall as contained in the indexing system above through the formula:

VLOOKUP($D$5,$AI40:$AK61, "X", FALSE),

where "X" is the sun azimuth offset or zenith offset referenced in cells AI40 to AK61. For example, if the user selects Jacksonville, FL in D5, cell J37 = 4 and K37 = 5, since those are the column offsets in the data cited in section 7.1 that contains the sun azimuth and zenith for Jacksonville.

The azimuth and zenith angles for the selected D5 location are loaded into cells J40 to Q63: a) column I40 to I63 is the local time; b) columns J and K are azimuth and zenith for winter; c) columns L and M are azimuth and zenith for Spring; d) columns N and O are azimuth and zenith for Summer; and e) columns P and Q are azimuth and zenith for Fall. The data is loaded in using the indexing system above through the formula:

OFFSET(AN40,0,$"X"$37),

where "X" denotes column J through Q. AN40 was selected as the reference for the offset, 0 denotes no offset in rows, and the column numbers in J37 through Q37, calculated by the VLOOKUP formula as above, contain the actual azimuth and zenith angles. These are loaded into cells J40 through Q63 for the 24-hour days and the four seasons.

7.14 Intermediate Array Results, Sines and Cosines of Angles

Cells S40 through AD63 contain 3 sets of data for each season: a) cosine of the zenith angle; b) sine of the zenith angle; and c) the sun azimuth converted to radians. The data in these columns reference the angles in columns J through Q. Columns S through U are for Winter (referencing J & K), V through X are for Spring (referencing L & M), Y through AA are for Summer (referencing N & O), and AB through AD are for Fall (referencing P & Q). These values are used to calculate the total angle between the solar panel normal and the LOS to the sun.

7.15 Intermediate Array Results, Total Angle Between LOS to Sun and Panel Normal

Cells J69 to M92 implement equation 5.4-1 ($\cos\sigma$) for the four seasons, per the time of day in column I.

Next, the raw cosσ is arbitrated to account for the angular limitation of the AR coating. The result is the angle σ and is contained in cells P69 through S92 for the four seasons, with column O containing the local time of day. The test is made with the formula:

IF((180/π)*acos(σ) <= $D$12, (180/π)*acos(σ), 90)

where $D$12 is the user entry for the AR coating limit. If the angle σ lies within the AR coating cone, then the angle is used, otherwise, is set to 90°.

Next, the arbitrated values of σ are converted back to cos(σ) in cells V69 through Y92,with column U containing the local time of day. Making σ = 90° in the last step if it lies outside the AR coating limit leads to cos(σ) values of zero in this block of data; this is how the power is set to zero for σ angles outside the AR coating limit. This section also accounts for cases in which the direct LOS to the sun is blocked during parts of the day (i.e., if the user enters zero for the cost of electricity in cells J5 to M28). The formula in cells V69 through Y92 is:

IF("X" > 0, COS("Y"*PI()/180), 0.0)

where "X" refers to the appropriate electricity costs (J5 to J28 for Winter, etc.) and "Y" refers to the corresponding σ angles in cells P69 to S92.

7.16 Intermediate Array Results, Directly Transmitted Irradiance per Atmosphere Type

Cells DH36 to DK36 contain an index that pulls directly transmitted solar irradiance from the source data as cited in section 7.4 (cells DU39 to EC129). Cells DH36 to DK36 contain the formula:

VLOOKUP($D$6, $CM$39:$DA$227, "X", FALSE)

where $D$6 is the user-selected cloud location, CM39 to DA227 contains the indexing data per section 7.2, "X" is the index within the VLOOKUP corresponding to directly-transmitted solar for Winter (X=12), Spring (X=13), Summer (X=14) and Fall (X=15). "X" values of 12 through 15 refer to columns CX to DA inclusive, and they contain either 1, 2, 3, 4 (to indicate the desert environment) or 5, 6, 7, 8 to indicate the MLS/MLW environment. Upon selection of the cloud location in D6, the indices per section 7.2 select either the desert or MLS/MLW environment; this in turn causes the directly transmitted solar irradiance source data to be inserted into columns DH through DK. For example, if Jacksonville FL is selected in D6, the indexing data per section 7.2, columns 12 through 15 contain the numbers 5 through 8; those are in turn used in columns DH through DK to select the source solar directly transmitted irradiance from the source data in columns DV through DY (cf. section 7.4). This is done using the formula:

OFFSET($DU39, 0, $"X"$36))

where DU36 is a reference cell, 0 means no row offsets, "X" is DH through DK, and $36 contains the value of the column offset as above. The irradiance results for zenith angles 0° to 90° are placed in cells DH39 through DK129, with column DG containing the zenith angles.

7.17 Intermediate Array Results, Directly Transmitted Irradiance per Location

Cells J98 through M121 contain the directly transmitted solar irradiance for the Latitude selection made by the user in cell D6. The zenith angles are contained in columns K40 to K63 for Winter, M40 to M63 for Spring, O40 to O63 for Summer, and Q40 to Q63 for Fall as described in section 7.13. The directly transmitted solar irradiances per the appropriate U. S. Standard to MLS/MLW model from LOWTRAN7 as a function of zenith angle is located in cells DH39 through DK129 as described in section 7.16, with the zenith angles from 0 to 90° in column DG. The directly transmitted solar irradiances are loaded from DG39 through DK129 using the zenith angles in K40 through Q63 with the formula:

IF(AND("X" ≥ 0, "X" ≤ 90),VLOOKUP(INT("X"),$DG$39:$DK$129,"Y",FALSE),0)

where "X" denotes the zenith angle in the K40 through Q63 block for each season, the INT("X") converts the zenith angle contained in that cell to an integer, the VLOOKUP accesses the solar irradiance data from the block in DG39 to DK129, and "Y" is 2 for Winter (column DH), 3 for Spring (column DI), 4 for Summer (column DJ), and 4 for Fall (column DK). This method uses the next lower integer value of the zenith angle rather than attempting to interpolate on the exact zenith angle.

7.18 Intermediate Array Results, Diffuse Sky Radiance per Atmosphere Type

Cells DL36 to DO36 contain an index that pulls diffuse sky radiance from the source data as cited in section 7.4 (cells EE39 to EM39). Cells DL36 to DO36 contain the formula:

VLOOKUP($D$6, $CM$39:$DA$227, "X", FALSE)

where $D$6 is the user-selected cloud location, CM39 to DA227 contains the indexing data per section 7.2, "X" is the index within the VLOOKUP corresponding to diffuse sky radiance for Winter (X=12), Spring (X=13), Summer (X=14) and Fall (X=15). "X" values of 12 through 15 refer to columns CX to DA inclusive, and they contain either 1, 2, 3, 4 (to indicate the desert environment) or 5, 6, 7, 8 to indicate the MLS/MLW environment. Upon selection of the cloud location in D6, the indices per section 7.2 select either the desert or MLS/MLW environment; this in turn causes the sky radiance source data to be inserted into columns DL through DO. For example, if Jacksonville FL is selected in D6, the indexing data per section 7.2, columns 12 through 15 contain the numbers 5 through 8; those are in turn used in columns DL through DO to select the sky radiance radiance from the source data in columns EE through EM (cf. section 7.4). This is done using the formula:

OFFSET($EE39, 0, $"X"$36))

where EE36 is a reference cell, 0 means no row offsets, "X" is DL through DO, and $36 contains the value of the column offset as above.

7.19 Intermediate Array Results, Diffuse Sky Radiance per Location

Cells J126 through M149 contain the diffuse sky radiance for the Latitude selection made by the user in cell D6. The zenith angles are contained in columns K40 to K63 for Winter, M40 to M63 for Spring, O40 to O63 for Summer, and Q40 to Q63 for Fall as described in section 7.13. The diffuse sky radiances per the appropriate U. S. Standard to MLS/MLW model from LOWTRAN7 as a function of zenith angle is located in cells DL39 through DO129 as described in section 7.18, with the zenith angles from 0 to 90° in column DG. The diffuse sky radiances are loaded from DL39 through DO129 based on the zenith angles in K40 through Q63 with the formula:

IF(AND(X≥0,X≤90),VLOOKUP(INT("X"),$DG$39:$DS$129,"Y",FALSE),0)

where "X" denotes the zenith angle in the K40 through Q63 block for each season, the INT("X") converts the zenith angle contained in that cell to an integer, the VLOOKUP accesses the solar irradiance data from the block in DL39 to DO129. "Y" is 6 for Winter (column DL), 7 for Spring (column DM), 8 for Summer (column DN), and 9 for Fall (column DO). This method uses the next lower integer value of the zenith angle rather than attempting to interpolate on the exact zenith angle.

7.20 Intermediate Array Results, Diffuse Cloud Radiance per Atmosphere Type

Cells DP36 to DS36 contain an index that pulls diffuse cloud radiance from the source data as cited in section 7.4 (cells EO39 to EW129). Cells DP36 to DS36 contain the formula:

VLOOKUP($D$6, $CM$39:$DA$227, "X", FALSE) where $D$6 is the user-selected cloud location, CM39 to DA227 contains the indexing data per section 7.2, "X" is the index within the VLOOKUP corresponding to diffuse cloud radiance for Winter (X=12), Spring (X=13), Summer (X=14) and Fall (X=15). "X" values of 12 through 15 refer to columns CX to DA inclusive, and they contain either 1, 2, 3, 4 (to indicate the desert environment) or 5, 6, 7, 8 to indicate the MLS/MLW environment. Upon selection of the cloud location in D6, the indices per section 7.2 select either the desert or MLS/MLW environment; this in turn causes the cloud radiance source data to be inserted into columns DP through DS. For example, if Jacksonville FL is selected in D6, the indexing data per section 7.2, columns 12 through 15 contain the numbers 5 through 8; those are in turn used in columns DP through DS to select the cloud radiance from the source data in columns EO through EW (cf. section 7.4). This is done using the formula:

OFFSET($EO39, 0, $"X"$36))

where EO36 is a reference cell, 0 means no row offsets, "X" is DP through DS, and $36 contains the value of the column offset as above.

7.21 Intermediate Array Results, Diffuse Cloud Radiance per Location

Cells J154 through M157 contain the diffuse cloud radiance for the cloud location selection made by the user in cell D6. The zenith angles are contained in columns K40 to K63 for Winter, M40 to M63 for Spring, O40 to O63 for Summer, and Q40 to Q63 for Fall as described in section 7.13 per the Latitude selection made in cell D5. The diffuse cloud radiances per the appropriate U. S. Standard to MLS/MLW model from LOWTRAN7 as a function of zenith angle is located in cells DP39 through DS129 as described in section 7.20, with the zenith angles from 0 to 90° in column DG. The directly transmitted solar irradiances are loaded from DP39 through DS129 based on the zenith angles in cells K40 through Q63 with the formula:

IF(AND(X≥0,X≤90),VLOOKUP(INT("X"),$DG$39:$DS$129,"Y",FALSE),0)

where "X" denotes the zenith angle in the K40 through Q63 block for each season, the INT("X") converts the zenith angle contained in that cell to an integer, the VLOOKUP accesses the solar irradiance data from the block in DP39 to DS129. "Y" is 10 for Winter (column DP), 11 for Spring (column DQ), 12 for Summer (column DR), and 13 for Fall (column DS). This method uses the next lower integer value of the zenith angle rather than attempting to interpolate on the exact zenith angle.

7.22 Intermediate Array Results, Power from Directly Transmitted Solar Irradiance (P_D)

Cells P98 through S121 contain the power generated during each day for each season due to directly-transmitted solar irradiance per the time of day in cells O98 to O121. The calculation implements equation 5.10-2, using: a) the user-entered panel area (cell D9); b) the computed efficiency due to ambient temperature (section 7.8, cells D45 to D48; c) the complement of the cloud cover fraction (section 7.6, complement of cells D37 to D40); d) the arbitrated cosine of the angle σ between the panel normal and LOS to the sun (section 7.15, cells V69 to Y92); e) the directly-transmitted solar irradiance (section 7.17, cells J98 to M121); and f) the user-entered DC-to-AC conversion efficiency (cell D18).

7.23 Intermediate Array Results, Power from Diffuse Sky Radiance (P_{DS})

Cells P126 through S149 contain the power generated during each day for each season due to diffuse sky radiance per the time of day in cells O126 to O149. The calculation implements equation 5.10-3, using: a) the user-entered panel area (cell D9); b) the computed efficiency due to ambient temperature (section 7.8, cells D45 to D48); c) the reduced efficiency of conversion of sky radiance due to the spectral shift (sections 7.5 and 7.11, cells D60, D61); d) the complement of the cloud cover fraction (section 7.6, complement of D37 to D40); e) the solid angle of the sky as viewed by the solar panel (section 7.10, cell

D59); f) the diffuse sky radiance (section 7.19, cells J126 to M149); and g) the user-entered DC-to-AC conversion efficiency (cell D18).

7.24 Intermediate Array Results, Power from Diffuse Cloud Radiance (P_{DC})

Cells P154 through S177 contain the power generated during each day for each season due to diffuse cloud radiance per the time of day in cells O154 to O177. The calculation implements equation 5.10-4, using: a) the user-entered panel area (cell D9); b) the computed efficiency due to ambient temperature (section 7.8, cells D45 to D48); c) the reduced efficiency of conversion of sky radiance due to the spectral shift (sections 7.5 and 7.11, cells D62, D63); d) the cloud cover fraction (section 7.6, cells D37 to D40); e) the solid angle of the sky as viewed by the solar panel (section 7.10, cell D59); f) the diffuse cloud radiance (section 7.21, cells J154 to M177); and g) the user-entered DC-to-AC conversion efficiency (cell D18).

7.25 Intermediate Array Results, Ground-Reflected Radiance Due to Direct Irradiance (L_{DG})

Cells V98 through Y121 contain the ground-reflected radiance for each season due to incident directly-transmitted solar irradiance per the time of day in cells U98 to U121. The calculation implements equation 5.11-1, using: a) the effective ground reflectance for each user-selected ground type (cells D49 to D52 and section 7.9); b) the cosine of the sun zenith angle (sections 7.1 and 7.13, cells K40 to K63, M40 to M63, O40 to O63, and Q40 to Q63); c) the complement of the cloud cover fraction (section 7.6, complement of cells D37 to D40); and d) the directly-transmitted solar irradiance (section 7.17, cells J98 to M121).

7.26 Intermediate Array Results, Ground-Reflected Radiance Due to Diffuse Sky (L_{DS})

Cells V126 through Y149 contain the ground-reflected radiance for each season due to diffuse sky radiance per the time of day in cells U126 to U149. The calculation implements equation 5.11-3 using: a) the effective ground reflectance for each user-selected ground type (cells D49 to D52 and section 7.9); b) the complement of the cloud cover fraction (section 7.6, complement of cell D37 to D40); c) the diffuse sky radiance (section 7.19, cells J126 to J149); and d) the reduced efficiency of sky radiance (section 7.5, cells D60, D61).

7.27 Intermediate Array Results, Ground-Reflected Radiance Due to Diffuse Clouds (L_{GC})

Cells V154 through Y177 contain the ground-reflected radiance due to diffuse cloud radiance per the time of day in cells U154 to U177. The calculation implements equation 5.11-4, using: a) the effective ground reflectance for each user-selected ground type (cells D49 to D52 and section 7.9); b) the cloud cover fraction (section 7.6, cells D37 to D40); and c) the diffuse cloud radiance (section 7.21, cells J154 to M177).

7.28 Intermediate Array Results, Power from Ground Reflections (P_G)

Cells P182 through S205 contain the power generated during each day for each season due to total ground reflections per the time of day in cells O182 to O205. The calculation implements equation 5.10-5, using: a) the user-entered panel area (cell D9); b) the computed efficiency due to ambient temperature (section 7.8, cells D45 to D48); c) the solid angle of the ground as viewed by the solar panel (section 7.10, cell D58); d) the ground-reflected radiance due to solar irradiance (section 7.25, cells V98 to Y121); e) the reduced efficiency of conversion of sky and cloud radiance due to the spectral shift (sections 7.5 and 7.11, cells D60 to D63); f) the ground-reflected diffuse sky radiance (section 7.26, cells V126 to V149); g) the ground-reflected diffuse cloud radiance (section 7.27, cells V154 to V177); and h) the user-entered

DC-to-AC conversion efficiency (cell D18). As explained in section 5.11, the emitted radiance of the ground L_{GE} is zero, and is excluded from the computations.

7.29 Final Array Results, Average Hourly Power per Season (P_{HS})

Cells P210 through S233 contain the power generated during each day for each season due to the total incident light per the time of day in cells O210 to O233. The calculation implements equation 5.14-1, adding the results for P_D, P_{DS}, P_{DC}, and P_G at each hour.

7.30 Final Array Results, Value of Generated Power per Season

Cells V210 through Y233 contain the power generated during each day for each season due to the total incident light per the time of day. The calculation implements equation 5.14-2, multiplying the total power generated at each hour in each season (section 7.29, in cells U210 to U233) by the user-entered cost of electricity (J5 to M28) cells at each hour. The total cost avoidance for each season is the sum of the per-season hourly values, and are shown in cells V234 to Y234. The overall cost avoidance for the initial year, C_A, is the sum of the seasonal totals per equation 5.14-3 and is shown in cell V235. Per-season totals from V234 to Y234 are copied into cells R10 through R13 and the overall annual total from cell V235 is copied into cell R14 in the Output section of the spreadsheet.

7.31 Final Array Results, Cost Avoidance by Year

Cells AC5 through AE29 implement equation 5.14-4 to calculate the overall cost avoidance over 25 years, accounting for both the user-input annual increase in electricity rates (cell D20) and the decline in solar cell performance over 25 years per the user input 25-year power fraction (cell D11). The individual yearly results are accumulated over 25 years and the result is cell AE29, which is copied into cell R15 as the total dollar value of the solar installation over 25 years. This is the total cost avoided from having solar power generate electricity instead of buying it from the utility at the rates entered in cells J5 to M28.

7.32 Final Scalar Results, Total Power by Season and Initial Year

The per-hour seasonal power generation levels per section 7.30 are summed in cells P234 to S234, and those seasonal totals are summed in cell P235 to establish the total power generated in the initial years. The seasonal results from cells P234 to S234 are copied into cells R5 to R8, and the annual total in P235 is copied into cell R9 in the Output section of the spreadsheet.

7.33 Final Scalar Results, Total Power over 25 Years and Average Cost Per kWh

Cell R16 implements equations 5.9-4 and 5.9-5 to provide the total power generated over the 25 year period. The average cost of power generation by the solar system is the ratio of the user-entered installation cost in cell D19 to total power in cell R16, and is shown in cell R17. Note that this assessment ignores any interest payments made on the solar system if it is purchased on credit, and also ignores any maintenance costs associated with it.

7.34 Final Scalar Results, Return on Investment

The chart in the Output section plots the installation cost and the progressive cost avoidance by year; the return-on-investment occurs where the two lines cross.

7.35 Final Scalar Results, Clear-Sky and Cloud Arbitrated Direct Solar Irradiance

Cells X5 through X8 contain the average daily clear-sky direct solar irradiance in W-hr/m^2 for the chosen latitude per cell D5, and per the atmosphere type implied in the selection of the cloud location in cell D6. The formula is per eqn. 5.15-1. These values are the sum of the hourly values in cells J98 through M121 (cf. section 7.17). Cells Y5 through Y8 contain the direct average daily direct solar irradiance in W-hr/m^2 as modified by the cloud fraction per the selection made in cell D6. Both of these metrics are the direct irradiance in a plane normal to the LOS to the sun; the useful portion thereof depends on the angle between the panel normal and the LOS to the sun as described in sections 5.4 and 7.15.

Cells X12 and Y12 indicate the annual totals for the directly transmitted clear-sky and cloud-affected irradiance per X5 to X8 and Y5 to Y8 respectively. These are in units of kWh/m^2 per equation 5.15-2.

7.36 Utilities Page, Section 3, Great Circle Distance

Rows P through T implement the great circle equations 5.3-1 to 5.3-5 using the observer latitude and longitude point in cells K4 and K5, and the latitude and longitude of each of the cloud locations as the endpoint. Cell K7 finds the minimum value in column T. Column L tests each value in column T for the minimum contained in cell K6; it is marked with a red "1", and the name of the location in column M is copied into cell K7.

7.37 Utilities Page, Section 5, NOCT Efficiency

Cells E21 and E22 accept user inputs for the NOCT power output and panel area in sq. m. Cell E23 implements the unnumbered equation in section 5.9.

8
Some Concluding Remarks

This Estimator is a simple first-order means to evaluate solar panel performance and economic viability, and is probably accurate to ±15% or so. The bigger question is: is direct conversion of sunlight to electricity the best option in the long term? After all, it only generates power during the day, atmospheric conditions permitting. Secondly, storing generated power in batteries for night or overcast day use requires considerable additional expense (not included in the Estimator).

My opinion, consistent with Estimator results, is that direct conversion of solar to electric power is beneficial under certain circumstances: a) electric rates are either very high or expected to increase rapidly in the future; b) the installation is located in fairly sunny places (mostly the desert southwest and high plains mid-west); and c) the installation costs can be reduced and/or conversion efficiency can be increased to a point where the return on investment is less than 15 years.

At the present time, only a few places in the nation meet all three criteria. The good news is that the semiconductor physics experts are hard at work improving the panel efficiencies; eventually they will probably increase from the current 0.18 to 0.22 to about 0.27 to 0.30 at reasonable costs. That will certainly improve the economic utility of solar panels.

As for installation costs, it seems to me that the best set of improvements include: a) convert to standardized physical sizes and connections; b) convert to standardized wiring and DC-to-AC converters; and c) develop a viable means to install residential solar on the ground instead of on rooftops. One of the big hurdles with rooftop solar is the increase in roof leaks after installation, and the difficulty of getting the installer to return and fix the leaks they caused (assuming they are still in business). I believe self-contained, standardized installation methods in the form of a ground-level gazebo or shed would serve to both reduce installation costs (since most of it could be built in a factory) and to increase residential customer confidence.

As efficiencies increase and installation costs (hopefully) decrease, solar, unlike windmills, will eventually become viable in all but the most cloudy locations or highest latitudes. Solar panels do reduce air pollution, and that is a good reason to use them where feasible. I myself have chosen not to use solar because there is not a sufficient payback to make it worth my while.

You should not install solar panels under some ideological notion that doing so is "saving the planet". Is the climate changing? Yes, same as it did in the last century, and the one before that, and the millennium before the current one, and in all the millennia before that. Is puny little mankind the cause of any of the climate variations? No. Has the earth been slowly getting warmer recently? Yes. Is the current warming trend permanent? No. If the Vikings could measure temperature, they would have discovered the same warming trend from the 900's to the 1400's, known as the "medieval warming period". Southern Greenland was then warm enough to support about 2,000 Norwegian colonists, and they vanished as soon as the cold weather returned [8-1]. As best the historians can determine, the Eskimo natives, who had vacated the area during the warming period, returned when the weather turned cold again. They apparently mounted a series of attacks on the Norwegians, contributing further to the collapse of the colonies.

You should investigate solar and use it if it benefits you and your family economically. Don't be intimidated or influenced by some "green" crusader with four 50-room mansions, three private jets, two yachts, and a fleet of Lamborghinis who shows up in a 15-limousine motorcade to lecture you about an obligation under some moral imperative to stop burning carbon. (He means that you are obligated, not him.) People living in the year 2100 will be able to look back on the current "man-made climate change" hysteria/hoax/cult and laugh it off the same as we currently laugh at the medieval Catholic Church's attempts to suppress the findings of Galileo and Copernicus.

Above all, if you do decide to install solar panels, make sure they are made in America. Otherwise you are likely to end up with cheesy Chinesium crap that will wear out long before their advertised lifetime, and with no hope of recovering your investment.

References

[8-1] Knut Gjserset, *History of Iceland*, NY: The Macmillan Company, 1925, pp. 94-96, 114-116

A
Arbitration of Cloud Data

The average cloud statistics are not sufficient to estimate the total direct irradiance for three reasons: a) there is likely some variability among the various observers, especially since some of the data was collected over a 100-year period; b) there is no indication of completely overcast vs. broken clouds; and c) the data applies to "daylight hours", but there is no indication as to whether clouds dominate in early morning, late afternoon, or during the prime mid-day when sunlight is most available for conversion.

A comparison was made between the calculated direct solar irradiance using the raw cloud fraction data vs. direct measurements per NREL [A-1]. Total daily solar irradiance for the 22 "latitude locations" (as selected in cell D5) were compared to the measurements of direct normal irradiance (DNI) for those same locations made by SUNY between 1998 and 2005. The Estimator lists the average seasonal DNI on an hourly basis as described in section 7.17. Keep in mind that these values are the direct solar irradiance in a plane normal to the LOS to the sun; not the "horizontal irradiance" on a level plane as is commonly referenced in solar panel performance predictions. Average as-measured daily DNI values for each season and year are shown on Figures A-1 through A-4; these apply to the four time zones per the latitude selections. These were al derived from the SUNY measurements. The last column shows the daily averages for each season for all eight years. The standard deviation/average values in the last column are fairly small, indicating that these results are fairly consistent from 1998 to 2005.

Measured Average Daily Solar Direct Normal Irradiance, W/sq m												
Location	**Season**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**Average**	**Std Dev**	**S. D./Avg**
Miami, FL	Winter	4036.28	5154.31	4828.51	4852.18	4500.68	4846.88	4176.82	4069.64	4558.16	423.93	0.093
	Spring	5471.04	4899.30	5040.73	4749.21	4730.26	4274.19	5123.12	4725.05	4876.61	351.55	0.072
	Summer	4213.28	3687.86	3727.75	3488.63	3573.36	3745.37	3732.86	3989.20	3769.79	230.81	0.061
	Fall	4214.95	3555.00	3942.14	3578.67	4024.34	3890.45	4103.76	3840.22	3893.69	234.09	0.060
Jacksonville, FL	Winter	4189.87	4964.81	4966.61	4145.04	4467.84	3862.31	4145.23	3987.40	4341.14	422.64	0.097
	Spring	5524.52	4862.78	5558.60	5031.15	4943.60	4686.54	5585.13	4836.43	5128.59	367.47	0.072
	Summer	3582.90	3999.75	3661.49	3934.84	3840.28	3565.82	3432.76	4115.96	3766.73	241.04	0.064
	Fall	3713.50	3873.56	4034.61	3569.26	3633.72	3926.74	3881.63	3697.42	3791.31	161.01	0.042
Charlotte, NC	Winter	3487.03	4276.13	4270.16	4293.25	4239.47	3648.48	3771.80	4101.53	4010.98	325.29	0.081
	Spring	4926.13	4904.19	5118.96	5104.02	5352.62	3885.82	5195.85	4719.43	4900.88	454.16	0.093
	Summer	5054.74	4536.31	3990.42	4002.43	4214.26	4348.70	3966.90	4458.59	4321.54	368.78	0.085
	Fall	3974.39	4223.84	4103.34	4582.78	2852.88	3822.22	3427.89	3887.16	3859.31	525.12	0.136
Columbus, OH	Winter	2036.13	2655.85	2929.74	2787.47	2480.22	2959.90	3034.86	2445.11	2666.16	335.28	0.126
	Spring	3824.97	4856.56	3844.51	4181.03	3816.99	3162.16	3883.13	3903.12	3934.06	469.80	0.119
	Summer	4582.71	4524.77	4015.33	4293.59	4816.34	4521.91	4140.96	4528.05	4427.96	260.13	0.059
	Fall	2701.44	3038.46	2393.74	2720.63	2207.39	2413.08	2459.03	2503.93	2554.71	256.74	0.100
Buffalo, NY	Winter	2249.00	2555.04	2677.92	2724.74	2553.21	2905.79	2713.53	2713.53	2636.60	191.84	0.073
	Spring	4654.30	5517.85	3624.78	4864.76	4095.25	3786.46	3969.59	3969.59	4310.32	644.39	0.149
	Summer	4462.19	4483.90	4311.81	4714.09	5298.70	4518.49	3894.81	3894.81	4447.35	452.22	0.102
	Fall	2136.96	2300.47	2123.20	2131.28	1737.76	2230.33	2358.97	2358.97	2172.24	201.30	0.093
Portland, ME	Winter	3617.53	3561.96	2710.20	3217.72	2589.81	3094.51	3985.61	3709.43	3310.85	493.88	0.149
	Spring	4477.34	5483.74	4051.42	5269.24	4481.33	3664.95	4599.40	4371.98	4549.93	593.44	0.130
	Summer	4787.27	4772.54	4471.29	5114.09	5368.69	4713.53	4582.62	5156.55	4870.82	310.01	0.064
	Fall	2745.93	2820.71	2944.00	2847.04	2501.58	2767.28	2911.71	2614.37	2769.08	149.15	0.054

Figure A-1: Measured DNI Values for Eastern Time Zone Locations

Measured Average Daily Solar Direct Normal Irradiance, W/sq m												
Location	Season	1998	1999	2000	2001	2002	2003	2004	2005	Average	Std Dev	S. D./Avg
Brownsville, TX	Winter	3363.70	4150.49	3508.98	2798.00	3288.85	2726.27	3304.79	3327.33	3308.55	439.57	0.133
	Spring	5197.56	4488.11	4462.91	4695.59	4756.14	4192.65	4282.83	4699.69	4596.94	315.84	0.069
	Summer	4890.10	4923.33	5589.99	5182.77	4827.16	4649.97	5187.71	5072.28	5040.41	287.66	0.057
	Fall	3529.00	4477.56	3266.03	3472.60	3646.54	3936.44	3650.40	3782.04	3720.08	366.18	0.098
New Orleans, LA	Winter	3369.28	4617.82	4336.49	3503.81	3802.44	3653.96	4207.63	3746.93	3904.80	436.28	0.112
	Spring	5305.84	5187.73	5286.91	4944.65	4939.45	4491.96	5166.49	5097.67	5052.59	264.86	0.052
	Summer	3680.60	4184.24	4326.89	3698.19	3418.86	3570.51	3977.23	4352.88	3901.18	359.17	0.092
	Fall	4099.57	4248.54	3835.08	4331.42	3283.57	4547.00	3827.61	4597.32	4096.26	436.48	0.107
Tulsa, OK	Winter	2554.85	3922.42	3736.22	3724.67	3768.72	3732.90	4420.82	4732.98	3824.20	636.04	0.166
	Spring	5431.14	4453.74	4779.30	4998.40	4791.41	5108.05	4429.46	4749.57	4842.63	333.44	0.069
	Summer	6253.31	5657.16	6158.16	5596.32	5628.19	5653.48	5415.18	6042.25	5800.51	305.52	0.053
	Fall	3531.99	4655.32	3359.68	3971.14	3546.21	3543.11	3343.12	4408.93	3794.94	498.04	0.131
Lincoln, NE	Winter	2590.81	4016.26	3349.49	3579.01	3667.92	3706.57	4372.41	4060.59	3667.88	540.21	0.147
	Spring	4529.37	4354.16	4956.28	4867.96	5144.47	5192.95	4947.57	4805.02	4849.72	286.89	0.059
	Summer	5370.10	5449.65	5578.10	5570.40	5821.66	6087.54	5294.45	5603.61	5596.94	255.49	0.046
	Fall	3370.38	4046.37	3361.21	4083.43	3449.90	3730.18	3358.90	3874.91	3659.41	313.42	0.086
Minneapolis, MN	Winter	2887.84	3097.60	2961.76	3168.97	3382.54	3592.19	3411.09	3365.23	3233.40	243.70	0.075
	Spring	4713.33	4230.96	4355.30	4337.17	4757.18	4661.33	4722.69	4291.89	4508.73	223.54	0.050
	Summer	5412.32	4763.35	4826.65	5263.52	5253.63	5252.53	4671.35	5284.46	5090.98	286.93	0.056
	Fall	2623.43	3487.54	2283.57	2672.50	2270.58	2678.84	2830.52	2818.41	2708.17	380.91	0.141
Devils Lake, ND	Winter	1998.30	1818.47	2909.19	2201.13	3173.73	2171.48	1555.42	2474.95	2287.83	543.47	0.238
	Spring	5487.27	5369.03	5375.14	5421.61	6054.27	5474.97	5557.62	5164.98	5488.11	256.72	0.047
	Summer	6072.67	5158.72	5512.17	5597.29	5560.73	5276.81	4640.90	5538.98	5419.78	413.29	0.076
	Fall	2590.76	2761.02	2185.13	3054.70	2487.82	2310.04	2795.11	2840.24	2628.10	290.57	0.111

Figure A-2: Measured DNI Values for Central Time Zone Locations

Measured Average Daily Solar Direct Normal Irradiance, W/sq m												
Location	Season	1998	1999	2000	2001	2002	2003	2004	2005	Average	Std Dev	S. D./Avg
Tucson, AZ	Winter	6195.90	7179.21	6775.86	5954.37	6442.42	5796.02	5970.58	5739.52	6256.74	508.74	0.081
	Spring	8666.49	8744.99	8504.49	8659.00	8917.12	8945.88	8427.77	8392.81	8657.32	208.58	0.024
	Summer	6828.66	6525.78	6883.31	6370.12	6774.86	7377.09	6801.65	7073.89	6829.42	309.27	0.045
	Fall	7036.77	7525.80	6138.38	6529.78	6723.03	6568.49	6611.67	6619.49	6719.18	408.64	0.061
Santa Fe, NM	Winter	6495.61	6340.85	5985.82	5581.36	7055.88	6171.48	6381.70	6308.86	6290.20	422.40	0.067
	Spring	8468.33	7927.06	7977.12	8054.85	8793.13	7452.51	8586.02	8150.57	8176.20	426.73	0.052
	Summer	7674.68	7121.77	7924.38	6806.18	7132.49	7731.61	7624.66	7327.67	7417.93	380.81	0.051
	Fall	6177.53	7129.56	5390.49	6286.76	6036.59	6933.32	6210.08	6614.94	6347.41	546.46	0.086
Grand Junction, CO	Winter	4478.02	5510.38	4371.74	4406.79	4879.67	4324.11	4709.17	5319.88	4749.97	453.19	0.095
	Spring	6524.43	6141.26	7370.38	7133.74	7549.19	6495.72	6878.94	6570.69	6833.04	485.58	0.071
	Summer	7226.23	6715.86	7073.82	6767.86	6823.97	7544.69	6844.60	7404.92	7050.24	313.24	0.044
	Fall	5041.33	5628.10	4879.82	5127.61	5158.93	4935.84	4345.48	5069.67	5023.35	355.61	0.071
Lander, WY	Winter	3794.73	5339.67	4742.87	3814.88	4353.31	3265.88	5219.82	5580.13	4513.91	841.65	0.186
	Spring	5941.43	5836.71	6559.63	7527.14	6888.82	6723.40	6933.10	7044.26	6681.81	564.54	0.084
	Summer	6863.10	6995.90	6975.70	6608.46	6545.22	6773.81	6231.04	6868.47	6732.71	258.48	0.038
	Fall	4407.44	5277.96	3582.54	4574.78	3962.94	5309.07	4263.94	5057.11	4554.47	626.38	0.138
Great Falls, MT	Winter	4079.44	4076.33	3618.10	3011.76	4108.38	3565.93	4142.66	4472.42	3884.38	458.47	0.118
	Spring	5359.94	5501.08	5206.30	5671.69	5330.95	4489.59	5542.16	5050.00	5268.96	370.74	0.070
	Summer	6803.75	6586.41	6511.37	6967.85	6254.78	6418.51	5902.60	6290.84	6467.01	333.26	0.052
	Fall	3390.68	2826.47	3545.77	3048.87	3651.19	3970.06	3911.94	3072.84	3427.23	418.30	0.122

Figure A-3: Measured DNI Values for Mountain Time Zone Locations

Next, the average values shown in Figures A-1 to A-4 were compared against the Estimator results using the raw cloud fraction data. Figures A-5 to A-8 show the results for DNI per the Estimator using the raw cloud fraction values and the error from the as-measured data. Column 1 of Figures A-5 to A-8 is the same as the Average column in Figures A-1 to A-4. Column 2 contains the DNI calculated by the Estimator as a function of the atmosphere type (Mid-Lat or USS Standard) and latitude. Columns 3 and 4 show the raw cloud fraction data and its complement; column 5 shows the initial model DNI multiplied by the complement of the cloud fraction. Column 6 shows the error between the initial model and the as-measured data. The errors are very large, indicating that the raw cloud fraction data must be arbitrated in order for the Estimator to be reasonably accurate. Notice that all the errors are negative, which indicates that the cloud fractions are too large, and this initial version thus under-predicted the DNI. Column 7 shows the cloud fraction that would cause the error to vanish. They vary widely per location and season. Column 8 (Delta) shows the difference between the raw cloud fractions and the values that would drive the error to zero (Column 3 less Column 7).

Measured Average Daily Solar Direct Normal Irradiance, W/sq m												
Location	Season	1998	1999	2000	2001	2002	2003	2004	2005	Average	Std Dev	S. D./Avg
San Diego, CA	Winter	4721.84	5228.39	4948.68	4424.55	5526.17	4930.26	5330.78	4166.45	4909.64	460.42	0.094
	Spring	5849.27	5401.97	6127.09	4753.39	5272.62	5247.67	5684.46	5525.72	5482.77	419.17	0.076
	Summer	6343.30	6343.01	6431.33	6093.88	6141.39	6223.30	6335.95	5932.65	6230.60	165.70	0.027
	Fall	5421.00	5581.03	4697.73	5069.74	4747.40	4359.24	5123.26	5347.86	5043.41	415.17	0.082
Fresno, CA	Winter	2424.43	3187.90	2915.66	3029.46	3518.09	3000.19	2403.67	2376.90	2857.04	418.05	0.146
	Spring	5510.35	7029.27	7171.49	7550.24	7412.87	6756.57	7748.38	6355.70	6941.86	729.97	0.105
	Summer	8128.42	7898.41	8091.24	8090.98	8043.71	7745.17	8037.70	8169.70	8025.67	138.98	0.017
	Fall	4186.30	4944.54	4174.71	4003.60	4113.93	4350.54	3586.91	4252.29	4201.60	378.42	0.090
Ely, NV	Winter	4769.39	5275.03	4787.68	4269.03	4690.69	4913.85	4840.18	4729.11	4784.37	277.30	0.058
	Spring	6090.68	6275.94	8071.86	7825.82	7942.94	7322.96	7355.54	7401.15	7285.86	737.66	0.101
	Summer	8035.80	7739.08	7815.95	8122.66	8425.08	7804.05	6921.77	8271.85	7892.03	459.91	0.058
	Fall	4972.56	6207.26	5176.21	5146.83	5063.79	5757.93	5011.00	5449.56	5348.14	434.57	0.081
Roseburg, OR	Winter	1732.49	1998.46	2180.36	2534.66	2377.33	2313.22	2600.06	3210.74	2368.42	442.49	0.187
	Spring	3851.67	4631.86	4649.48	5542.34	5290.10	4691.00	4919.35	3486.61	4632.80	683.37	0.148
	Summer	6726.71	6720.85	6808.24	6775.92	7200.67	7325.82	6563.60	7148.75	6908.82	275.70	0.040
	Fall	2186.70	2921.11	2841.10	2545.71	2806.78	2442.86	2053.13	2127.28	2490.58	344.18	0.138
Seattle, WA	Winter	1464.44	1377.73	1795.00	2264.76	1708.22	1567.64	1658.59	2430.31	1783.34	375.01	0.210
	Spring	3227.68	4108.00	3694.78	3951.01	3652.92	3897.73	4316.58	3159.70	3751.05	404.46	0.108
	Summer	5712.27	5133.89	5253.49	4983.57	5739.31	5957.66	4857.30	5404.53	5380.25	392.93	0.073
	Fall	1752.02	1760.20	2043.76	1405.11	1904.56	1873.19	1417.32	1504.82	1707.62	239.30	0.140

Figure A-4: Measured DNI Values for Pacific Time Zone Locations

		1	2	3	4	5	6	7	8
Location	Season	Measured DNI	Clear Sky Calc. DNI	Cloud Fraction	1 - Cloud Fraction	Clr Sky*(1-Cld Fract)	Error	C_C for error = 0	Delta
Miami, FL (MLS, Coastal)	Winter	4558.16	6375.54	0.511	0.489	3117.64	-31.603	0.285	0.226
	Spring	4876.61	7466.03	0.577	0.423	3158.13	-35.239	0.347	0.230
	Summer	3769.79	7412.53	0.638	0.362	2683.34	-28.820	0.491	0.147
	Fall	3893.69	6322.42	0.552	0.448	2832.44	-27.256	0.384	0.168
Jacksonville, FL (MLS, Coastal)	Winter	4341.14	5967.62	0.532	0.468	2792.85	-35.666	0.273	0.259
	Spring	5128.59	7557.01	0.511	0.489	3695.38	-27.946	0.321	0.190
	Summer	3766.73	7455.77	0.583	0.417	3109.06	-17.460	0.495	0.088
	Fall	3791.31	5938.24	0.519	0.481	2856.29	-24.662	0.362	0.157
Charlotte, NC (MLS, Interior)	Winter	4010.98	5494.86	0.584	0.416	2285.86	-43.010	0.270	0.314
	Spring	4900.88	7589.04	0.558	0.442	3354.36	-31.556	0.354	0.204
	Summer	4321.54	7491.94	0.572	0.428	3206.55	-25.801	0.423	0.149
	Fall	3859.31	5517.86	0.506	0.494	2725.82	-29.370	0.301	0.205
Columbus, OH (MLS, Interior)	Winter	2666.16	5007.57	0.708	0.292	1462.21	-45.157	0.468	0.240
	Spring	3934.06	7578.37	0.599	0.401	3038.93	-22.753	0.481	0.118
	Summer	4427.96	7503.81	0.52	0.48	3601.83	-18.657	0.410	0.110
	Fall	2554.71	4999.72	0.653	0.347	1734.90	-32.090	0.489	0.164
Buffalo, NY (MLS, Coastal)	Winter	2636.60	4604.2	0.777	0.223	1026.74	-61.058	0.427	0.350
	Spring	4310.32	7617.2	0.633	0.367	2795.51	-35.144	0.434	0.199
	Summer	4447.35	7499.47	0.579	0.421	3157.28	-29.008	0.407	0.172
	Fall	2172.24	4680.92	0.765	0.235	1100.02	-49.360	0.536	0.229
Portland, ME (MLS, Coastal)	Winter	3310.85	4521.4	0.563	0.437	1975.85	-40.322	0.268	0.295
	Spring	4549.93	7589.17	0.595	0.405	3073.61	-32.447	0.400	0.195
	Summer	4870.82	7533.93	0.541	0.459	3458.07	-29.004	0.353	0.188
	Fall	2769.08	4510.83	0.575	0.425	1917.10	-30.767	0.386	0.189

Figure A-5: Comparison of DNI with Raw Cloud Fraction vs. As-Measured, Eastern Time Zone

Location	Season	1 Measured DNI	2 Clear Sky Calc. DNI	3 Cloud Fraction	4 1 - Cloud Fraction	5 Clr Sky*(1-Cld Fract)	6 Error	7 C_C for error = 0	8 Delta
Brownsville, TX (MLS, Coastal)	Winter	3308.55	6329.45	0.65	0.35	2215.31	-33.043	0.477	0.173
	Spring	4596.94	7513.19	0.562	0.438	3290.78	-28.414	0.388	0.174
	Summer	5040.41	7407.5	0.481	0.519	3844.49	-23.727	0.320	0.161
	Fall	3720.08	6345.38	0.567	0.433	2747.55	-26.143	0.414	0.153
New Orleans, LA (MLS, Coastal)	Winter	3904.80	6005.42	0.593	0.407	2444.21	-37.405	0.350	0.243
	Spring	5052.59	7518.5	0.524	0.476	3578.81	-29.169	0.328	0.196
	Summer	3901.18	7427.98	0.562	0.438	3253.46	-16.603	0.475	0.087
	Fall	4096.26	5962.47	0.502	0.498	2969.31	-27.512	0.313	0.189
Tulsa, OK (MLS, Interior)	Winter	3824.20	5393.05	0.594	0.406	2189.58	-42.744	0.291	0.303
	Spring	4842.63	7557.77	0.579	0.421	3181.82	-34.296	0.359	0.220
	Summer	5800.51	7482.2	0.464	0.536	4010.46	-30.860	0.225	0.239
	Fall	3794.94	5420.22	0.531	0.469	2542.08	-33.014	0.300	0.231
Lincoln, NE (MLS, Interior)	Winter	3667.88	4868.09	0.588	0.412	2005.65	-45.319	0.247	0.341
	Spring	4849.72	7603.34	0.575	0.425	3231.42	-33.369	0.362	0.213
	Summer	5596.94	7425.94	0.461	0.539	4002.58	-28.486	0.246	0.215
	Fall	3659.41	4894.42	0.537	0.463	2266.12	-38.074	0.252	0.285
Minneapolis, MN (MLS, Interior)	Winter	3233.40	4358.2	0.626	0.374	1629.97	-49.590	0.258	0.368
	Spring	4508.73	7634.28	0.618	0.382	2916.29	-35.319	0.409	0.209
	Summer	5090.98	7503.82	0.524	0.476	3571.82	-29.840	0.322	0.202
	Fall	2708.17	4413.59	0.652	0.348	1535.93	-43.285	0.386	0.266
Devils Lake, ND (MLS, Interior)	Winter	2287.83	3978.28	0.618	0.382	1519.70	-33.575	0.425	0.193
	Spring	5488.11	7603.67	0.578	0.422	3208.75	-41.533	0.278	0.300
	Summer	5419.78	7518.27	0.48	0.52	3909.50	-27.866	0.279	0.201
	Fall	2628.10	3984.62	0.624	0.376	1498.22	-42.992	0.340	0.284

Figure A-6: Comparison of DNI with Raw Cloud Fraction vs. As-Measured, Central Time Zone

Location	Season	1 Measured DNI	2 Clear Sky Calc. DNI	3 Cloud Fraction	4 1 - Cloud Fraction	5 Clr Sky*(1-Cld Fract)	6 Error	7 C_C for error = 0	8 Delta
Tucson, AZ (USS)	Winter	6256.74	7404.86	0.452	0.548	4057.86	-35.144	0.155	0.297
	Spring	8657.32	10116.67	0.281	0.719	7273.89	-15.980	0.144	0.137
	Summer	6829.42	10033.25	0.422	0.578	5799.22	-15.085	0.319	0.103
	Fall	6719.18	7373.62	0.362	0.638	4704.37	-29.986	0.089	0.273
Santa Fe, NM (USS)	Winter	6290.20	7081.71	0.472	0.528	3739.14	-40.556	0.112	0.360
	Spring	8176.20	10248.26	0.401	0.599	6138.71	-24.920	0.202	0.199
	Summer	7417.93	10102.74	0.418	0.582	5879.79	-20.735	0.266	0.152
	Fall	6347.41	7043.74	0.382	0.618	4353.03	-31.420	0.099	0.283
Grand Junction, CO (USS)	Winter	4749.97	6700.54	0.564	0.436	2921.44	-38.496	0.291	0.273
	Spring	6833.04	10317.29	0.478	0.522	5385.63	-21.183	0.338	0.140
	Summer	7050.24	10195.65	0.388	0.612	6239.74	-11.496	0.309	0.079
	Fall	5023.35	6779.15	0.461	0.539	3653.96	-27.260	0.259	0.202
Lander, WY (USS)	Winter	4513.91	6182.06	0.537	0.463	2862.29	-36.589	0.270	0.267
	Spring	6681.81	10354.88	0.549	0.451	4670.05	-30.108	0.355	0.194
	Summer	6732.71	10231.5	0.417	0.583	5964.96	-11.403	0.342	0.075
	Fall	4554.47	6328.54	0.497	0.503	3183.26	-30.107	0.280	0.217
Great Falls, MT (USS)	Winter	3884.38	5629.48	0.738	0.262	1474.92	-62.029	0.310	0.428
	Spring	5268.96	10527.27	0.694	0.306	3221.34	-38.862	0.499	0.195
	Summer	6467.01	10410.04	0.495	0.505	5257.07	-18.709	0.379	0.116
	Fall	3427.23	5723.43	0.69	0.31	1774.26	-48.230	0.401	0.289

Figure A-7: Comparison of DNI with Raw Cloud Fraction vs. As-Measured, Mountain Time Zone

		1	2	3	4	5	6	7	8
		Measured	Clear Sky	Cloud	1 - Cloud	Clr Sky*(1-Cld		C_C for	
Location	Season	DNI	Calc. DNI	Fraction	Fraction	Fract)	Error	error = 0	Delta
San Diego, CA (MLS, Coastal)	Winter	4909.64	5750.65	0.477	0.523	3007.59	-38.741	0.146	0.331
	Spring	5482.77	7489.9	0.493	0.507	3797.38	-30.740	0.268	0.225
	Summer	6230.60	7464.15	0.382	0.618	4612.84	-25.965	0.165	0.217
	Fall	5043.41	5754.17	0.392	0.608	3498.54	-30.632	0.124	0.268
Fresno, CA (MLS, Interior)	Winter	2857.04	5327.06	0.576	0.424	2258.67	-20.944	0.464	0.112
	Spring	6941.86	7590.31	0.279	0.721	5472.61	-21.165	0.085	0.194
	Summer	8025.67	7499.76	0.124	0.876	6569.79	-18.140	-0.070	0.194
	Fall	4201.60	5325.73	0.448	0.552	2939.80	-30.031	0.211	0.237
Ely, NV (USS)	Winter	4784.37	6726.91	0.633	0.367	2468.78	-48.399	0.289	0.344
	Spring	7285.86	10263.52	0.545	0.455	4669.90	-35.905	0.290	0.255
	Summer	7892.03	10247.04	0.371	0.629	6445.39	-18.330	0.230	0.141
	Fall	5348.14	6710.17	0.536	0.464	3113.52	-41.783	0.203	0.333
Roseburg, OR (MLS, Interior)	Winter	2368.42	4570.35	0.741	0.259	1183.72	-50.021	0.482	0.259
	Spring	4632.80	7594.12	0.563	0.437	3318.63	-28.367	0.390	0.173
	Summer	6908.82	7529.52	0.326	0.674	5074.90	-26.545	0.082	0.244
	Fall	2490.58	4645.65	0.711	0.289	1342.59	-46.093	0.464	0.247
Seattle, WA (MLS, Coastal)	Winter	1783.34	4019.5	0.775	0.225	904.39	-49.287	0.556	0.219
	Spring	3751.05	7627.58	0.664	0.336	2562.87	-31.676	0.508	0.156
	Summer	5380.25	7482.76	0.524	0.476	3561.79	-33.799	0.281	0.243
	Fall	1707.62	4062.58	0.784	0.216	877.52	-48.612	0.580	0.204

Figure A-8: Comparison of DNI with Raw Cloud Fraction vs. As-Measured, Pacific Time Zone

After some experimentation, it appeared that the best arbitration was a simple offset to the cloud fraction, a constant to be subtracted from the raw values. But it turned out that a single set of offsets per season did not produce a reasonably uniform error reduction. It was necessary to segregate the locations by atmosphere type and for the MLS/MLW atmosphere locations (i.e., the violet locations on Figure 3.2-1), with the MLS/MLW ones further segregated by coastal or interior location. Those designations are shown under the place manes in Figures A-5 to A-8. The procedure then was simple: for each season and atmosphere/location type, average the Delta cloud fraction values and apply them as offsets to the raw cloud fractions per the atmosphere type. Figure A-9 shows the results of this calculation; these are to be subtracted from the raw cloud fraction values.

Cloud Fraction Correction Terms (Subtract from Raw Values)				
	Winter	Spring	Summer	Fall
MLS/MLW, Coastal	0.262	0.196	0.193	0.195
MLS/MLW, Interior	0.266	0.204	0.194	0.240
USS Standard (desert)	0.328	0.187	0.111	0.266

Figure A-9: Summary Cloud Fraction Correction Terms

Figures A-10 through A-13 show the new calculated DNI per the Estimator compared to the as-measured data. Columns 1 and 2 show the as-measured average and initial Estimator-calculated clear-sky DNI as before. Columns 3 through 5 show the old cloud fraction, correction term, and new cloud fraction respectively. Columns 6 and 7 show the complement of the new cloud fraction and the product with the clear-sky DNI per the Estimator. Column 8 shows the error for each season between the Estimator with the new cloud fractions and the as-measured data in Column 1. Column 9 shows the annual error, combining the results for each season. It is evident that there is still some wide variation among the seasonal errors, but the overall annual values (which are the main interest) are a great improvement over the original results. Only Columbus has a significant annual error (whereas the other MLS/MLW interior points have fairly small errors). No claim is made that this correction will produce like errors for all the other cloud location selections, but the errors should be fairly similar if the raw cloud cover data is consistent. Notice that the summer cloud fraction for Fresno had to be altered from 0.124 to 0.214 in order to avoid a negative cloud fraction. There were a few other cases in which this was necessary, as will be shown presently.

Location	Season	1 Measured DNI	2 Clear Sky Calc. DNI	3 Old Cloud Fraction	4 Correction Term	5 New Cloud Fraction	6 1 - New Cloud Fraction	7 Clr Sky*(1-New Cld Frac)	8 Seasonal Error (%)	9 Annual Error (%)
Miami, FL (MLS, Coastal)	Winter	4558.16	6375.54	0.511	0.262	0.249	0.751	4788.03	5.04	1.57
	Spring	4876.61	7466.03	0.577	0.196	0.381	0.619	4621.47	-5.23	
	Summer	3769.79	7412.53	0.638	0.163	0.475	0.525	3891.58	3.23	
	Fall	3893.69	6322.42	0.552	0.195	0.357	0.643	4065.32	4.41	
Jacksonville, FL (MLS, Coastal)	Winter	4341.14	5967.62	0.532	0.262	0.270	0.730	4356.36	0.35	4.96
	Spring	5128.59	7557.01	0.511	0.196	0.315	0.685	5176.55	0.94	
	Summer	3766.73	7455.77	0.583	0.163	0.420	0.580	4324.35	14.80	
	Fall	3791.31	5938.24	0.519	0.195	0.324	0.676	4014.25	5.88	
Charlotte, NC (MLS, Interior)	Winter	4010.98	5494.86	0.584	0.266	0.318	0.682	3747.49	-6.57	1.56
	Spring	4900.88	7589.04	0.558	0.204	0.354	0.646	4902.52	0.03	
	Summer	4321.54	7491.94	0.572	0.194	0.378	0.622	4659.99	7.83	
	Fall	3859.31	5517.86	0.506	0.240	0.266	0.734	4050.11	4.94	
Columbus, OH (MLS, Interior)	Winter	2666.16	5007.57	0.708	0.266	0.442	0.558	2794.22	4.80	13.17
	Spring	3934.06	7578.37	0.599	0.204	0.395	0.605	4584.91	16.54	
	Summer	4427.96	7503.81	0.52	0.194	0.326	0.674	5057.57	14.22	
	Fall	2554.71	4999.72	0.653	0.240	0.413	0.587	2934.84	14.88	
Buffalo, NY (MLS, Coastal)	Winter	2636.60	4604.20	0.777	0.262	0.515	0.485	2233.04	-15.31	-4.81
	Spring	4310.32	7617.20	0.633	0.196	0.437	0.563	4288.48	-0.51	
	Summer	4447.35	7499.47	0.579	0.163	0.416	0.584	4379.69	-1.52	
	Fall	2172.24	4680.92	0.765	0.195	0.570	0.430	2012.80	-7.34	
Portland, ME (MLS, Coastal)	Winter	3310.85	4521.40	0.563	0.262	0.301	0.699	3160.46	-4.54	-1.91
	Spring	4549.93	7589.17	0.595	0.196	0.399	0.601	4561.09	0.25	
	Summer	4870.82	7533.93	0.541	0.163	0.378	0.622	4686.10	-3.79	
	Fall	2769.08	4510.83	0.575	0.195	0.380	0.620	2796.71	1.00	

Figure A-10: DNI Results for Arbitrated Cloud Fractions, Eastern Time Zone

Location	Season	1 Measured DNI	2 Clear Sky Calc. DNI	3 Old Cloud Fraction	4 Correction Term	5 New Cloud Fraction	6 1 - New Cloud Fraction	7 Clr Sky*(1-New Cld Frac)	8 Seasonal Error (%)	9 Annual Error (%)
Brownsville, TX (MLS, Coastal)	Winter	3308.55	6329.45	0.65	0.262	0.388	0.612	3873.62	17.08	6.05
	Spring	4596.94	7513.19	0.562	0.196	0.366	0.634	4763.36	3.62	
	Summer	5040.41	7407.50	0.481	0.163	0.318	0.682	5051.92	0.23	
	Fall	3720.08	6345.38	0.567	0.195	0.372	0.628	3984.90	7.12	
New Orleans, LA (MLS, Coastal)	Winter	3904.80	6005.42	0.593	0.262	0.331	0.669	4017.63	2.89	4.20
	Spring	5052.59	7518.50	0.524	0.196	0.328	0.672	5052.43	0.00	
	Summer	3901.18	7427.98	0.562	0.163	0.399	0.601	4464.22	14.43	
	Fall	4096.26	5962.47	0.502	0.195	0.307	0.693	4131.99	0.87	
Tulsa, OK (MLS, Interior)	Winter	3824.20	5393.05	0.594	0.266	0.328	0.672	3624.13	-5.23	-3.34
	Spring	4842.63	7557.77	0.579	0.204	0.375	0.625	4723.61	-2.46	
	Summer	5800.51	7482.20	0.464	0.194	0.270	0.730	5462.01	-5.84	
	Fall	3794.94	5420.22	0.531	0.240	0.291	0.709	3842.94	1.26	
Lincoln, NE (MLS, Interior)	Winter	3667.88	4868.09	0.588	0.266	0.322	0.678	3300.57	-10.01	-4.54
	Spring	4849.72	7603.34	0.575	0.204	0.371	0.629	4782.50	-1.39	
	Summer	5596.94	7425.94	0.461	0.194	0.267	0.733	5443.21	-2.75	
	Fall	3659.41	4894.42	0.537	0.240	0.297	0.703	3440.78	-5.97	
Minneapolis, MN (MLS, Interior)	Winter	3233.40	4358.20	0.626	0.266	0.360	0.640	2789.25	-13.74	-5.72
	Spring	4508.73	7634.28	0.618	0.186	0.432	0.568	4336.27	-3.83	
	Summer	5090.98	7503.82	0.524	0.190	0.334	0.666	4997.54	-1.84	
	Fall	2708.17	4413.59	0.652	0.225	0.427	0.573	2528.99	-6.62	
Devils Lake, ND (MLS, Interior)	Winter	2287.83	3978.28	0.618	0.266	0.352	0.648	2577.93	12.68	-4.19
	Spring	5488.11	7603.67	0.578	0.204	0.374	0.626	4759.90	-13.27	
	Summer	5419.78	7518.27	0.48	0.194	0.286	0.714	5368.04	-0.95	
	Fall	2628.10	3984.62	0.624	0.240	0.384	0.616	2454.53	-6.60	

Figure A-11: DNI Results for Arbitrated Cloud Fractions, Central Time Zone

		1	2	3	4	5	6	7	8	9
Location	Season	Measured DNI	Clear Sky Calc. DNI	Old Cloud Fraction	Correction Term	New Cloud Fraction	1 - New Cloud Fraction	Clr Sky*(1-New Cld Frac)	Seasonal Error (%)	Annual Error (%)
Tucson, AZ (USS)	Winter	6256.74	7404.86	0.452	0.328	0.124	0.876	6486.66	3.67	2.70
	Spring	8657.32	10116.67	0.281	0.187	0.094	0.906	9165.70	5.87	
	Summer	6829.42	10033.25	0.422	0.111	0.311	0.689	6912.91	1.22	
	Fall	6719.18	7373.62	0.362	0.266	0.096	0.904	6665.75	-0.80	
Santa Fe, NM (USS)	Winter	6290.20	7081.71	0.472	0.328	0.144	0.856	6061.94	-3.63	-3.14
	Spring	8176.20	10248.26	0.401	0.187	0.214	0.786	8055.13	-1.48	
	Summer	7417.93	10102.74	0.418	0.111	0.307	0.693	7001.20	-5.62	
	Fall	6347.41	7043.74	0.382	0.266	0.116	0.884	6226.67	-1.90	
Grand Junction, CO (USS)	Winter	4749.97	6700.54	0.564	0.328	0.236	0.764	5119.21	7.77	6.79
	Spring	6833.04	10317.29	0.478	0.187	0.291	0.709	7314.96	7.05	
	Summer	7050.24	10195.65	0.388	0.111	0.277	0.723	7371.45	4.56	
	Fall	5023.35	6779.15	0.461	0.266	0.195	0.805	5457.22	8.64	
Lander, WY (USS)	Winter	4513.91	6182.06	0.537	0.328	0.209	0.791	4890.01	8.33	4.36
	Spring	6681.81	10354.88	0.549	0.187	0.362	0.638	6606.41	-1.13	
	Summer	6732.71	10231.50	0.417	0.111	0.306	0.694	7100.66	5.47	
	Fall	4554.47	6328.54	0.497	0.266	0.231	0.769	4866.65	6.85	
Great Falls, MT (USS)	Winter	3884.38	5629.48	0.738	0.328	0.410	0.590	3321.39	-14.49	-4.34
	Spring	5268.96	10527.27	0.694	0.187	0.507	0.493	5189.94	-1.50	
	Summer	6467.01	10410.04	0.495	0.111	0.384	0.616	6412.58	-0.84	
	Fall	3427.23	5723.43	0.69	0.266	0.424	0.576	3296.70	-3.81	

Figure A-12: DNI Results for Arbitrated Cloud Fractions, Mountain Time Zone

		1	2	3	4	5	6	7	8	9
Location	Season	Measured DNI	Clear Sky Calc. DNI	Old Cloud Fraction	Correction Term	New Cloud Fraction	1 - New Cloud Fraction	Clr Sky*(1-New Cld Frac)	Seasonal Error (%)	Annual Error (%)
San Diego, CA (MLS, Coastal)	Winter	4909.64	5750.65	0.477	0.262	0.215	0.785	4514.26	-8.05	-6.63
	Spring	5482.77	7489.90	0.493	0.196	0.297	0.703	5265.40	-3.96	
	Summer	6230.60	7464.15	0.382	0.163	0.219	0.781	5829.50	-6.44	
	Fall	5043.41	5754.17	0.392	0.195	0.197	0.803	4620.60	-8.38	
Fresno, CA (MLS, Interior)	Winter	2857.04	5327.06	0.576	0.266	0.310	0.690	3675.67	28.65	1.08
	Spring	6941.86	7590.31	0.279	0.204	0.075	0.925	7021.04	1.14	
	Summer	8025.67	7499.76	**0.214**	0.194	0.020	0.980	7349.76	-8.42	
	Fall	4201.60	5325.73	0.448	0.240	0.208	0.792	4217.98	0.39	
Ely, NV (USS)	Winter	4784.37	6726.91	0.633	0.328	0.305	0.695	4675.20	-2.28	-6.18
	Spring	7285.86	10263.52	0.545	0.187	0.358	0.642	6589.18	-9.56	
	Summer	7892.03	10247.04	0.371	0.111	0.260	0.740	7582.81	-3.92	
	Fall	5348.14	6710.17	0.536	0.266	0.270	0.730	4898.42	-8.41	
Roseburg, OR (MLS, Interior)	Winter	2368.42	4570.35	0.741	0.266	0.475	0.525	2399.43	1.31	-0.85
	Spring	4632.80	7594.12	0.563	0.204	0.359	0.641	4867.83	5.07	
	Summer	6908.82	7529.52	0.326	0.194	0.132	0.868	6535.62	-5.40	
	Fall	2490.58	4645.65	0.711	0.240	0.471	0.529	2457.55	-1.33	
Seattle, WA (MLS, Coastal)	Winter	1783.34	4019.50	0.775	0.262	0.513	0.487	1957.50	9.77	-1.23
	Spring	3751.05	7627.58	0.664	0.196	0.468	0.532	4057.87	8.18	
	Summer	5380.25	7482.76	0.524	0.163	0.361	0.639	4781.48	-11.13	
	Fall	1707.62	4062.58	0.784	0.195	0.589	0.411	1669.72	-2.22	

Figure A-13: DNI Results for Arbitrated Cloud Fractions, Pacific Time Zone

Figures A-14 to A-22 show the original, correction terms, and arbitrated cloud fractions for each cloud location and season. The arbitrated values are used in the Estimator to calculate the direct solar irradiance. The cloud fractions were further subject to a minimum value of 0.100, as indicated in red. The values shown in the last four columns of Figures A-14 to A-22 are used in the Estimator in cells CP39 to CS226 as described in section 7.2.

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Birmingham	AL	0.606	0.541	0.549	0.518	2	0.266	0.204	0.194	0.240	0.340	0.337	0.355	0.278
Mobile	AL	0.588	0.523	0.566	0.500	1	0.262	0.196	0.163	0.195	0.326	0.327	0.403	0.305
Montgomery	AL	0.582	0.509	0.528	0.492	2	0.266	0.204	0.194	0.240	0.316	0.305	0.334	0.252
Fort Smith	AR	0.577	0.533	0.448	0.505	2	0.266	0.204	0.194	0.240	0.311	0.329	0.254	0.265
Little Rock	AR	0.592	0.540	0.480	0.513	2	0.266	0.204	0.194	0.240	0.326	0.336	0.286	0.273
Flagstaff	AZ	0.522	0.373	0.471	0.404	3	0.328	0.187	0.111	0.266	0.194	0.186	0.360	0.138
Phoenix	AZ	0.408	0.238	0.302	0.316	3	0.328	0.187	0.111	0.266	0.100	0.100	0.191	0.100
Tuscon	AZ	0.452	0.281	0.422	0.362	3	0.328	0.187	0.111	0.266	0.124	0.100	0.311	0.100
Yuma	AZ	0.285	0.137	0.180	0.217	3	0.328	0.187	0.111	0.266	0.100	0.100	0.100	0.100
Blue Canyon	CA	0.650	0.469	0.179	0.542	3	0.328	0.187	0.111	0.266	0.322	0.282	0.100	0.276
Eureka	CA	0.696	0.620	0.616	0.659	1	0.262	0.196	0.163	0.195	0.434	0.424	0.453	0.464
Fresno	CA	0.576	0.279	0.124	0.448	2	0.266	0.204	0.194	0.240	0.310	0.100	0.100	0.208
Los Angeles	CA	0.472	0.457	0.335	0.388	1	0.262	0.196	0.163	0.195	0.210	0.261	0.172	0.193
Red Bluff	CA	0.585	0.365	0.153	0.496	3	0.328	0.187	0.111	0.266	0.257	0.178	0.100	0.230
Sacramento	CA	0.565	0.299	0.300	0.462	2	0.266	0.204	0.194	0.240	0.299	0.100	0.106	0.222
San Diego	CA	0.477	0.493	0.382	0.392	1	0.262	0.196	0.163	0.195	0.215	0.297	0.219	0.197
San Francisco	CA	0.565	0.413	0.366	0.485	1	0.262	0.196	0.163	0.195	0.303	0.217	0.203	0.290
Denver	CO	0.520	0.544	0.453	0.452	3	0.328	0.187	0.111	0.266	0.192	0.357	0.342	0.186
Grand Junction	CO	0.564	0.478	0.388	0.461	3	0.328	0.187	0.111	0.266	0.236	0.291	0.277	0.195
Pueblo	CO	0.483	0.494	0.421	0.420	3	0.328	0.187	0.111	0.266	0.155	0.307	0.310	0.154
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-14: Arbitrated Cloud Fraction Data, Part 1

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Hartford	CT	0.616	0.625	0.587	0.613	2	0.266	0.204	0.194	0.240	0.350	0.421	0.393	0.373
New Haven	CT	0.564	0.559	0.511	0.541	1	0.262	0.196	0.163	0.195	0.302	0.363	0.348	0.346
Washington	DC	0.600	0.564	0.530	0.559	2	0.266	0.204	0.194	0.240	0.334	0.360	0.336	0.319
Apalachicola	FL	0.552	0.480	0.569	0.472	1	0.262	0.196	0.163	0.195	0.290	0.284	0.406	0.277
Jacksonville	FL	0.532	0.511	0.583	0.519	1	0.262	0.196	0.163	0.195	0.270	0.315	0.420	0.324
Key West	FL	0.425	0.476	0.573	0.480	1	0.262	0.196	0.163	0.195	0.163	0.280	0.410	0.285
Miami	FL	0.511	0.577	0.638	0.552	1	0.262	0.196	0.163	0.195	0.249	0.381	0.475	0.357
Pensacola	FL	0.562	0.487	0.541	0.477	1	0.262	0.196	0.163	0.195	0.300	0.291	0.378	0.282
Tampa	FL	0.506	0.502	0.608	0.491	1	0.262	0.196	0.163	0.195	0.244	0.306	0.445	0.296
Atlanta	GA	0.598	0.543	0.567	0.517	2	0.266	0.204	0.194	0.240	0.332	0.339	0.373	0.277
Augusta	GA	0.563	0.516	0.549	0.490	2	0.266	0.204	0.194	0.240	0.297	0.312	0.355	0.250
Macon	GA	0.577	0.532	0.570	0.503	2	0.266	0.204	0.194	0.240	0.311	0.328	0.376	0.263
Savannah	GA	0.556	0.520	0.582	0.504	1	0.262	0.196	0.163	0.195	0.294	0.324	0.419	0.309
Burlington	IA	0.657	0.627	0.518	0.607	2	0.266	0.204	0.194	0.240	0.391	0.423	0.324	0.367
Des Moines	IA	0.611	0.594	0.482	0.572	2	0.266	0.204	0.194	0.240	0.345	0.390	0.288	0.332
Dubuque	IA	0.624	0.600	0.512	0.616	2	0.266	0.204	0.194	0.240	0.358	0.396	0.318	0.376
Sioux City	IA	0.610	0.587	0.465	0.571	2	0.266	0.204	0.194	0.240	0.344	0.383	0.271	0.331
Boise	ID	0.710	0.538	0.301	0.620	3	0.328	0.187	0.111	0.266	0.382	0.351	0.190	0.354
Lewiston	ID	0.763	0.619	0.369	0.724	3	0.328	0.187	0.111	0.266	0.435	0.432	0.258	0.458
Pocatello	ID	0.698	0.550	0.365	0.615	3	0.328	0.187	0.111	0.266	0.370	0.363	0.254	0.349
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-15: Arbitrated Cloud Fraction Data, Part 2

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Cairo	IL	0.639	0.585	0.498	0.558	2	0.266	0.204	0.194	0.240	0.373	0.381	0.304	0.318
Chicago	IL	0.645	0.566	0.480	0.619	1	0.262	0.196	0.163	0.195	0.383	0.370	0.317	0.424
Moline	IL	0.620	0.581	0.485	0.583	2	0.266	0.204	0.194	0.240	0.354	0.377	0.291	0.343
Peoria	IL	0.625	0.563	0.464	0.587	2	0.266	0.204	0.194	0.240	0.359	0.359	0.270	0.347
Springfield	IL	0.642	0.586	0.486	0.582	2	0.266	0.204	0.194	0.240	0.376	0.382	0.292	0.342
Evansville	IN	0.660	0.584	0.498	0.587	2	0.266	0.204	0.194	0.240	0.394	0.380	0.304	0.347
Fort Wayne	IN	0.707	0.615	0.529	0.674	2	0.266	0.204	0.194	0.240	0.441	0.411	0.335	0.434
Indianapolis	IN	0.689	0.611	0.518	0.631	2	0.266	0.204	0.194	0.240	0.423	0.407	0.324	0.391
Terre Haute	IN	0.662	0.597	0.487	0.592	2	0.266	0.204	0.194	0.240	0.396	0.393	0.293	0.352
Concordia	KS	0.551	0.548	0.437	0.494	3	0.328	0.187	0.111	0.266	0.223	0.361	0.326	0.228
Dodge City	KS	0.508	0.490	0.395	0.440	3	0.328	0.187	0.111	0.266	0.180	0.303	0.284	0.174
Goodland	KS	0.569	0.531	0.419	0.490	3	0.328	0.187	0.111	0.266	0.241	0.344	0.308	0.224
Topeka	KS	0.570	0.555	0.446	0.517	2	0.266	0.204	0.194	0.240	0.304	0.351	0.252	0.277
Wichita	KS	0.541	0.528	0.416	0.483	3	0.328	0.187	0.111	0.266	0.213	0.341	0.305	0.217
Covington	KY	0.686	0.595	0.507	0.617	2	0.266	0.204	0.194	0.240	0.420	0.391	0.313	0.377
Lexington	KY	0.675	0.566	0.499	0.600	2	0.266	0.204	0.194	0.240	0.409	0.362	0.305	0.360
Louisville	KY	0.660	0.577	0.494	0.590	2	0.266	0.204	0.194	0.240	0.394	0.373	0.300	0.350
New Orleans	LA	0.593	0.524	0.562	0.502	1	0.262	0.196	0.163	0.195	0.331	0.328	0.399	0.307
Shreveport	LA	0.588	0.510	0.445	0.488	2	0.266	0.204	0.194	0.240	0.322	0.306	0.251	0.248
Boston	MA	0.593	0.602	0.555	0.588	1	0.262	0.196	0.163	0.195	0.331	0.406	0.392	0.393
Nantucket	MA	0.632	0.589	0.565	0.628	1	0.262	0.196	0.163	0.195	0.370	0.393	0.402	0.433
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-16: Arbitrated Cloud Fraction Data, Part 3

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Baltimore	MD	0.586	0.556	0.519	0.542	1	0.262	0.196	0.163	0.195	0.324	0.360	0.356	0.347
Eastport	ME	0.635	0.655	0.610	0.677	1	0.262	0.196	0.163	0.195	0.373	0.459	0.447	0.482
Portland	ME	0.563	0.595	0.541	0.575	1	0.262	0.196	0.163	0.195	0.301	0.399	0.378	0.380
Alpena	MI	0.697	0.587	0.544	0.750	1	0.262	0.196	0.163	0.195	0.435	0.391	0.381	0.555
Detroit	MI	0.703	0.590	0.513	0.690	1	0.262	0.196	0.163	0.195	0.441	0.394	0.350	0.495
Escanaba	MI	0.627	0.560	0.521	0.680	1	0.262	0.196	0.163	0.195	0.365	0.364	0.358	0.485
Grand Rapids	MI	0.760	0.615	0.544	0.754	2	0.266	0.204	0.194	0.240	0.494	0.411	0.350	0.514
Lansing	MI	0.723	0.606	0.535	0.723	2	0.266	0.204	0.194	0.240	0.457	0.402	0.341	0.483
Marquette	MI	0.747	0.636	0.601	0.784	1	0.262	0.196	0.163	0.195	0.485	0.440	0.438	0.589
Sault Ste Marie	MI	0.713	0.606	0.595	0.801	1	0.262	0.196	0.163	0.195	0.451	0.410	0.432	0.606
Duluth	MN	0.605	0.605	0.554	0.668	1	0.262	0.196	0.163	0.195	0.343	0.409	0.391	0.473
Minneapolis	MN	0.626	0.618	0.524	0.652	2	0.266	0.204	0.194	0.240	0.360	0.414	0.330	0.412
Rochester	MN	0.669	0.646	0.570	0.684	2	0.266	0.204	0.194	0.240	0.403	0.442	0.376	0.444
Columbia	MO	0.608	0.570	0.466	0.548	2	0.266	0.204	0.194	0.240	0.342	0.366	0.272	0.308
Kansas City	MO	0.573	0.553	0.441	0.519	2	0.266	0.204	0.194	0.240	0.307	0.349	0.247	0.279
Springfield	MO	0.572	0.505	0.415	0.507	2	0.266	0.204	0.194	0.240	0.306	0.301	0.221	0.267
St. Louis	MO	0.610	0.556	0.464	0.549	2	0.266	0.204	0.194	0.240	0.344	0.352	0.270	0.309
Jackson	MS	0.640	0.555	0.530	0.539	2	0.266	0.204	0.194	0.240	0.374	0.351	0.336	0.299
Meridan	MS	0.596	0.522	0.525	0.512	2	0.266	0.204	0.194	0.240	0.330	0.318	0.331	0.272
Vicksburg	MS	0.594	0.512	0.490	0.496	2	0.266	0.204	0.194	0.240	0.328	0.308	0.296	0.256
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-17: Arbitrated Cloud Fraction Data, Part 4

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Billings	MT	0.717	0.654	0.460	0.646	3	0.328	0.187	0.111	0.266	0.389	0.467	0.349	0.380
Great Falls	MT	0.738	0.694	0.495	0.690	3	0.328	0.187	0.111	0.266	0.410	0.507	0.384	0.424
Harve	MT	0.621	0.570	0.426	0.602	3	0.328	0.187	0.111	0.266	0.293	0.383	0.315	0.336
Helena	MT	0.692	0.644	0.450	0.655	3	0.328	0.187	0.111	0.266	0.364	0.457	0.339	0.389
Kalispell	MT	0.749	0.616	0.443	0.760	3	0.328	0.187	0.111	0.266	0.421	0.429	0.332	0.494
Miles City	MT	0.578	0.539	0.382	0.520	3	0.328	0.187	0.111	0.266	0.250	0.352	0.271	0.254
Missoula	MT	0.804	0.688	0.451	0.772	3	0.328	0.187	0.111	0.266	0.476	0.501	0.340	0.506
Asheville	NC	0.582	0.557	0.582	0.516	2	0.266	0.204	0.194	0.240	0.316	0.353	0.388	0.276
Cape Hatteras	NC	0.574	0.517	0.542	0.522	1	0.262	0.196	0.163	0.195	0.312	0.321	0.379	0.327
Charlotte	NC	0.584	0.558	0.572	0.506	2	0.266	0.204	0.194	0.240	0.318	0.354	0.378	0.266
Greensboro	NC	0.606	0.582	0.585	0.537	2	0.266	0.204	0.194	0.240	0.340	0.378	0.391	0.297
Raleigh/Durham	NC	0.569	0.535	0.552	0.504	2	0.266	0.204	0.194	0.240	0.303	0.331	0.358	0.264
Wilmington	NC	0.541	0.510	0.558	0.476	1	0.262	0.196	0.163	0.195	0.279	0.314	0.395	0.281
Bismarck	ND	0.611	0.576	0.456	0.593	3	0.328	0.187	0.111	0.266	0.283	0.389	0.345	0.327
Devils Lake	ND	0.618	0.578	0.480	0.624	2	0.266	0.204	0.194	0.240	0.352	0.374	0.286	0.384
Fargo	ND	0.619	0.579	0.478	0.627	2	0.266	0.204	0.194	0.240	0.353	0.375	0.284	0.387
Williston	ND	0.618	0.573	0.459	0.591	3	0.328	0.187	0.111	0.266	0.290	0.386	0.348	0.325
Grand Island	NE	0.630	0.572	0.453	0.560	3	0.328	0.187	0.111	0.266	0.302	0.385	0.342	0.294
Lincoln	NE	0.588	0.575	0.461	0.537	2	0.266	0.204	0.194	0.240	0.322	0.371	0.267	0.297
North Omaha	NE	0.594	0.573	0.455	0.548	2	0.266	0.204	0.194	0.240	0.328	0.369	0.261	0.308
North Platte	NE	0.559	0.544	0.423	0.494	3	0.328	0.187	0.111	0.266	0.231	0.357	0.312	0.228
Scottsbluff	NE	0.640	0.596	0.436	0.561	3	0.328	0.187	0.111	0.266	0.312	0.409	0.325	0.295
Valentine	NE	0.580	0.556	0.419	0.515	3	0.328	0.187	0.111	0.266	0.252	0.369	0.308	0.249
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-18: Arbitrated Cloud Fraction Data, Part 5

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Concord	NH	0.570	0.582	0.548	0.606	2	0.266	0.204	0.194	0.240	0.304	0.378	0.354	0.366
Mount Washington	NH	0.770	0.785	0.786	0.768	2	0.266	0.204	0.194	0.240	0.504	0.581	0.592	0.528
Atlantic City	NJ	0.598	0.581	0.541	0.560	1	0.262	0.196	0.163	0.195	0.336	0.385	0.378	0.365
Trenton	NJ	0.609	0.605	0.573	0.579	2	0.266	0.204	0.194	0.240	0.343	0.401	0.379	0.339
Albuquerque	NM	0.472	0.401	0.418	0.382	3	0.328	0.187	0.111	0.266	0.144	0.214	0.307	0.116
Roswell	NM	0.434	0.380	0.391	0.376	3	0.328	0.187	0.111	0.266	0.106	0.193	0.280	0.110
Ely	NV	0.633	0.545	0.371	0.536	3	0.328	0.187	0.111	0.266	0.305	0.358	0.260	0.270
Las Vegas	NV	0.466	0.304	0.248	0.371	3	0.328	0.187	0.111	0.266	0.138	0.117	0.137	0.105
Reno	NV	0.566	0.419	0.216	0.470	3	0.328	0.187	0.111	0.266	0.238	0.232	0.105	0.204
Winnemucca	NV	0.626	0.496	0.264	0.520	3	0.328	0.187	0.111	0.266	0.298	0.309	0.153	0.254
Albany	NY	0.643	0.600	0.552	0.661	2	0.266	0.204	0.194	0.240	0.377	0.396	0.358	0.421
Binghamton	NY	0.746	0.668	0.624	0.746	2	0.266	0.204	0.194	0.240	0.480	0.464	0.430	0.506
Buffalo	NY	0.777	0.633	0.579	0.765	1	0.262	0.196	0.163	0.195	0.515	0.437	0.416	0.570
New York City	NY	0.604	0.593	0.557	0.578	1	0.262	0.196	0.163	0.195	0.342	0.397	0.394	0.383
Oswego	NY	0.779	0.563	0.498	0.758	1	0.262	0.196	0.163	0.195	0.517	0.367	0.335	0.563
Rochester	NY	0.756	0.595	0.548	0.759	1	0.262	0.196	0.163	0.195	0.494	0.399	0.385	0.564
Syracuse	NY	0.759	0.626	0.582	0.757	2	0.266	0.204	0.194	0.240	0.493	0.422	0.388	0.517
Akron	OH	0.772	0.663	0.585	0.725	2	0.266	0.204	0.194	0.240	0.506	0.459	0.391	0.485
Cleveland	OH	0.756	0.603	0.530	0.732	1	0.262	0.196	0.163	0.195	0.494	0.407	0.367	0.537
Columbus	OH	0.708	0.599	0.520	0.653	2	0.266	0.204	0.194	0.240	0.442	0.395	0.326	0.413
Dayton	OH	0.710	0.620	0.531	0.653	2	0.266	0.204	0.194	0.240	0.444	0.416	0.337	0.413
Sandusky	OH	0.700	0.570	0.478	0.668	1	0.262	0.196	0.163	0.195	0.438	0.374	0.315	0.473
Toledo	OH	0.676	0.553	0.464	0.653	1	0.262	0.196	0.163	0.195	0.414	0.357	0.301	0.458
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-19: Arbitrated Cloud Fraction Data, Part 6

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Oklahoma City	OK	0.541	0.513	0.405	0.466	2	0.266	0.204	0.194	0.240	0.275	0.309	0.211	0.226
Tulsa	OK	0.594	0.579	0.464	0.531	2	0.266	0.204	0.194	0.240	0.328	0.375	0.270	0.291
Baker City	OR	0.673	0.551	0.330	0.620	3	0.328	0.187	0.111	0.266	0.345	0.364	0.219	0.354
Medford	OR	0.773	0.569	0.264	0.729	3	0.328	0.187	0.111	0.266	0.445	0.382	0.153	0.463
Portland	OR	0.781	0.666	0.475	0.762	1	0.262	0.196	0.163	0.195	0.519	0.470	0.312	0.567
Roseburg	OR	0.741	0.563	0.326	0.711	2	0.266	0.204	0.194	0.240	0.475	0.359	0.132	0.471
Erie	PA	0.753	0.572	0.518	0.753	1	0.262	0.196	0.163	0.195	0.491	0.376	0.355	0.558
Harrisburg	PA	0.637	0.608	0.558	0.613	2	0.266	0.204	0.194	0.240	0.371	0.404	0.364	0.373
Philadelphia	PA	0.611	0.597	0.561	0.576	2	0.266	0.204	0.194	0.240	0.345	0.393	0.367	0.336
Pittsburgh	PA	0.740	0.633	0.563	0.692	2	0.266	0.204	0.194	0.240	0.474	0.429	0.369	0.452
Reading	PA	0.619	0.593	0.552	0.596	2	0.266	0.204	0.194	0.240	0.353	0.389	0.358	0.356
Wilkes-Barre	PA	0.691	0.617	0.577	0.680	2	0.266	0.204	0.194	0.240	0.425	0.413	0.383	0.440
Block Island	RI	0.567	0.547	0.514	0.565	1	0.262	0.196	0.163	0.195	0.305	0.351	0.351	0.370
Providence	RI	0.578	0.589	0.552	0.560	1	0.262	0.196	0.163	0.195	0.316	0.393	0.389	0.365
Charleston	SC	0.555	0.517	0.576	0.494	1	0.262	0.196	0.163	0.195	0.293	0.321	0.413	0.299
Columbia	SC	0.562	0.519	0.547	0.490	2	0.266	0.204	0.194	0.240	0.296	0.315	0.353	0.250
Greenville	SC	0.572	0.558	0.567	0.501	2	0.266	0.204	0.194	0.240	0.306	0.354	0.373	0.261
Huron	SD	0.598	0.557	0.442	0.571	3	0.328	0.187	0.111	0.266	0.270	0.370	0.331	0.305
Rapid City	SD	0.594	0.578	0.424	0.534	3	0.328	0.187	0.111	0.266	0.266	0.391	0.313	0.268
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-20: Arbitrated Cloud Fraction Data, Part 7

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Chattanooga	TN	0.628	0.561	0.545	0.543	2	0.266	0.204	0.194	0.240	0.362	0.357	0.351	0.303
Knoxville	TN	0.637	0.557	0.532	0.552	2	0.266	0.204	0.194	0.240	0.371	0.353	0.338	0.312
Memphis	TN	0.607	0.533	0.467	0.509	2	0.266	0.204	0.194	0.240	0.341	0.329	0.273	0.269
Nashville	TN	0.641	0.553	0.498	0.549	2	0.266	0.204	0.194	0.240	0.375	0.349	0.304	0.309
Abilene	TX	0.531	0.479	0.427	0.456	3	0.328	0.187	0.111	0.266	0.203	0.292	0.316	0.190
Amarillo	TX	0.462	0.439	0.401	0.408	3	0.328	0.187	0.111	0.266	0.134	0.252	0.290	0.142
Austin	TX	0.600	0.564	0.459	0.529	2	0.266	0.204	0.194	0.240	0.334	0.360	0.265	0.289
Brownsville	TX	0.650	0.562	0.481	0.567	1	0.262	0.196	0.163	0.195	0.388	0.366	0.318	0.372
Corpus Christi	TX	0.627	0.563	0.452	0.537	1	0.262	0.196	0.163	0.195	0.365	0.367	0.289	0.342
Dallas	TX	0.557	0.514	0.411	0.480	2	0.266	0.204	0.194	0.240	0.291	0.310	0.217	0.240
Del Rio	TX	0.520	0.510	0.422	0.485	3	0.328	0.187	0.111	0.266	0.192	0.323	0.311	0.219
El Paso	TX	0.385	0.285	0.381	0.326	3	0.328	0.187	0.111	0.266	0.100	0.100	0.270	0.100
Fort Worth	TX	0.548	0.502	0.406	0.479	2	0.266	0.204	0.194	0.240	0.282	0.298	0.212	0.239
Galveston	TX	0.587	0.475	0.443	0.477	1	0.262	0.196	0.163	0.195	0.325	0.279	0.280	0.282
Houston	TX	0.628	0.567	0.524	0.548	2	0.266	0.204	0.194	0.240	0.362	0.363	0.330	0.308
Lubbock	TX	0.513	0.464	0.430	0.439	3	0.328	0.187	0.111	0.266	0.185	0.277	0.319	0.173
Palestine	TX	0.583	0.522	0.455	0.494	2	0.266	0.204	0.194	0.240	0.317	0.318	0.261	0.254
Port Arthur	TX	0.637	0.550	0.531	0.539	1	0.262	0.196	0.163	0.195	0.375	0.354	0.368	0.344
San Antonio	TX	0.574	0.551	0.463	0.516	3	0.328	0.187	0.111	0.266	0.246	0.364	0.352	0.250
Milford	UT	0.603	0.462	0.357	0.497	3	0.328	0.187	0.111	0.266	0.275	0.275	0.246	0.231
Salt Lake City	UT	0.635	0.489	0.340	0.542	3	0.328	0.187	0.111	0.266	0.307	0.302	0.229	0.276
Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).														

Figure A-21: Arbitrated Cloud Fraction Data, Part 8

		% Cloud Cover, Original Data					Cloud Fraction Correction Terms				New % Cloud Cover			
City	State	Winter	Spring	Summer	Fall	Type	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Cape Henry	VA	0.570	0.509	0.499	0.504	1	0.262	0.196	0.163	0.195	0.308	0.313	0.336	0.309
Lynchburg	VA	0.571	0.544	0.519	0.514	2	0.266	0.204	0.194	0.240	0.305	0.340	0.325	0.274
Norfolk	VA	0.583	0.546	0.548	0.529	1	0.262	0.196	0.163	0.195	0.321	0.350	0.385	0.334
Richmond	VA	0.583	0.548	0.542	0.527	2	0.266	0.204	0.194	0.240	0.317	0.344	0.348	0.287
Burlington	VT	0.711	0.667	0.616	0.760	2	0.266	0.204	0.194	0.240	0.445	0.463	0.422	0.520
North Head	WA	0.746	0.697	0.654	0.739	1	0.262	0.196	0.163	0.195	0.484	0.501	0.491	0.544
Quillayute	WA	0.820	0.780	0.661	0.783	1	0.262	0.196	0.163	0.195	0.558	0.584	0.498	0.588
Seattle	WA	0.775	0.664	0.524	0.784	1	0.262	0.196	0.163	0.195	0.513	0.468	0.361	0.589
Spokane	WA	0.761	0.627	0.411	0.745	3	0.328	0.187	0.111	0.266	0.433	0.440	0.300	0.479
Tacoma	WA	0.748	0.624	0.526	0.789	2	0.266	0.204	0.194	0.240	0.482	0.420	0.332	0.549
Tatoosh Island	WA	0.767	0.722	0.670	0.777	1	0.262	0.196	0.163	0.195	0.505	0.526	0.507	0.582
Walla Walla	WA	0.738	0.523	0.322	0.704	3	0.328	0.187	0.111	0.266	0.410	0.336	0.211	0.438
Green Bay	WI	0.657	0.635	0.579	0.694	1	0.262	0.196	0.163	0.195	0.395	0.439	0.416	0.499
La Crosse	WI	0.625	0.598	0.512	0.638	2	0.266	0.204	0.194	0.240	0.359	0.394	0.318	0.398
Madison	WI	0.655	0.629	0.538	0.655	2	0.266	0.204	0.194	0.240	0.389	0.425	0.344	0.415
Milwaukee	WI	0.652	0.594	0.508	0.647	1	0.262	0.196	0.163	0.195	0.390	0.398	0.345	0.452
Elkins	WV	0.752	0.672	0.637	0.693	2	0.266	0.204	0.194	0.240	0.486	0.468	0.443	0.453
Parkersburg	WV	0.687	0.573	0.515	0.640	2	0.266	0.204	0.194	0.240	0.421	0.369	0.321	0.400
Cheyenne	WY	0.574	0.600	0.483	0.508	3	0.328	0.187	0.111	0.266	0.246	0.413	0.372	0.242
Lander	WY	0.537	0.549	0.417	0.497	3	0.328	0.187	0.111	0.266	0.209	0.362	0.306	0.231
Sheridan	WY	0.635	0.593	0.436	0.592	3	0.328	0.187	0.111	0.266	0.307	0.406	0.325	0.326

Types: 1 = Mid-Lat Summer/Mid-Lat Winter, Coastal; 2 = Mid-Lat Summer/Mid-Lat Winter, Interior; 3 = 1976 U. S. Standard (used as a desert environment).

Figure A-22: Arbitrated Cloud Fraction Data, Part 9

References

[A-1] S. Wilcox, W. Marion, Users Manual for TMY3 Data Sets, NREL Technical Report NREL TR/TP-581-43156, May 2008. It is part of the National Solar Radiation database, 1991-2005, available at https://nsrdb.nrel.goc/data-sets/archives.html

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