Emissions Reductions from Solar Photovoltaic (PV) Systems

August 2005

MIT LFEE 2004-003 RP

Stephen Connors, Katherine Martin,
Michael Adams, Edward Kern
and Baafour Asiamah-Adjei

Analysis Group for Regional Energy Alternatives
Laboratory for Energy and the Environment
Massachusetts Institute of Technology

http://lfee.mit.edu/
Publication No. LFEE 2004-003 Report

Emissions Reductions from Solar Photovoltaic (PV) Systems

Estimating potential reductions across the United States by looking at the combined dynamics of solar resources and fossil unit dispatch

LFEE Report No.: 2004-003 RP *August 2004*

by:

The Analysis Group for Regional Energy Alternatives (AGREA)
Laboratory for Energy and the Environment (LFEE)
MASSACHUSETTS INSTITUTE OF TECHNOLOGY (MIT)

Stephen Connors
Director, AGREA
Katherine Martin
Graduate Student, M.I.T. Technology and Policy Program
Michael Adams
Graduate Student, M.I.T. Technology and Policy Program
Edward Kern
Irradiance, Inc.
Baafour Asiamah-Adjei
Undergraduate Student, M.I.T Dept. of Mechanical Engineering

This research was conducted for:
Air Pollution Prevention and Control Division
National Risk Management Research Laboratory E305-02
U.S. ENVIRONMENTAL PROTECTION AGENCY
Research Triangle Park, NC 27711

Under the Title: NATIONAL ASSESSMENT OF EMISSIONS REDUCTION OF PHOTOVOLTAIC (PV) POWER SYSTEMS
U.S. EPA Project No.: PR-C1-01-12087
U.S. EPA Contract No.: 68-C-02-008

National Assessment of Emissions Reduction of Photovoltaic (PV) Power Systems

Table of Contents

List of Figures

List of Tables

Executive Summary

Project Motivation

Electricity generated from renewable resources, especially sun and wind, are attractive since they are non-polluting, particularly on an air emissions basis. However, the amount of pollutant emissions they avoid by reducing centralized fossil generation is highly variable. This project focused on the determination of avoided emissions resulting from solar photovoltaic (PV) generation across the contiguous forty-eight United States, using historical PV and/or solar insulation data, coupled with hourly electricity demand and fossil unit operation and emissions data.

The majority of PV systems deployed in the USA in recent years are grid-connected, customer sited systems. There are significant daily and seasonal variations in the solar resource, and therefore how much electricity is generated by a PV system varies by time of day, time of year, and weather conditions (cloudiness, temperature, and wind). Additionally, different power systems have different mixtures of coal, oil, natural gas and other centralized generation sources. Individual fossil generators may be used more during different times of day or year, and may use different fuels in certain seasons. Therefore, avoided emissions from PV must be calculated on both an hourly and regional basis, consistent with both solar resource and power system fossil unit control and dispatch.

Results

The emissions reduction potential of a grid-connected PV system depends more on the characteristics of the regional electricity system than on the available solar resource. A detailed analysis of historical PV generation, fossil generation, and fossil emissions data for each region reveals that it is characteristics of a regional electricity system, like fuel portfolio and demand pattern, that determine the magnitude of emission reductions.

The use of PV systems lowers the electricity demand seen by a regional grid. Broadly speaking, the units that are affected by PV generation are those units that are following variations in regional load. To quantify the PV systems' emission reductions, the question that must be asked is: Which specific fossil generating units are affected by the reduction in demand and what are the emissions characteristics of those units? Another question is: Does PV generation in a particular region reduce generation from the above average or below average polluting fossil units (i.e. the coal-fired units or the natural gas-fired units), and how does that change from season to season, when natural gas prices are high, or when less non-fossil generation (nuclear and hydro power) is available?

This analysis empirically determined the fossil units that were offset by PV generation in each region and in each hour for the years 1998 through 2002. PV systems only generate power during daylight hours and the analysis found that PV systems often reduced emissions from natural gas peaking units because they are used in many regions to meet peak (usually daytime) electricity demand.

Some higher level conclusions regarding avoided emissions from PV, and avoided emissions in general, include:

- PV systems installed in the regions where higher emitting units follow changes in demand during the daytime hours will reduce more emissions than PV systems installed where there is more solar resource but where fossil units with lower emissions (natural gas units) follow changes in demand.
- Grid-connected photovoltaic systems do not generally affect the fossil generating units with the highest emission rates (e.g. coal-fired baseload generation). Economic dispatch dictates that the highest cost units are dispatched last and in many regions these are natural gas peaking units. PV systems do not offset power production from baseload units that are often large, coal-fired generation units.
- The emissions rates of units that follow demand in the evening and nighttime hours are higher than the emission rates of units that follow demand during the day. Strategically, stored non-emitting generation (pumped storage), targeted demand side management, and possibly wind generation, might affect these units more than PV generation that only produces power between sunrise and sunset.
- In most regions, a number of fossil units operate at inefficient output levels (between 5% and 55% of seasonal capability) for a significant portion of all operating hours. Thermal inertia (large fossil power plants take time and to turn on and off), and grid stability and contingency support are the primary reasons. Operation at these "sub-optimal" load levels leads to higher emission rates. Small penetration of renewable generation, especially PV, can do little to alleviate these aspects.

Summary

Introduction

The emission reduction potential of photovoltaic systems is dependent on the amount of solar resource in a given geographic location, as well as on the PV system's configuration, orientation, and performance. A lesser-studied relationship is the role of PV systems in regional electricity grids and how the system as a whole determines emission reductions from PV. Emission reductions depend on characteristics of the regional electricity grid to which the PV system is connected. Regional fuel portfolios, electricity demand, and operation rules and procedures all influence a PV system's impact on emissions. This report assesses the emission reduction potential of grid-connected PV systems by considering them as a part of the electricity system to which they are connected.

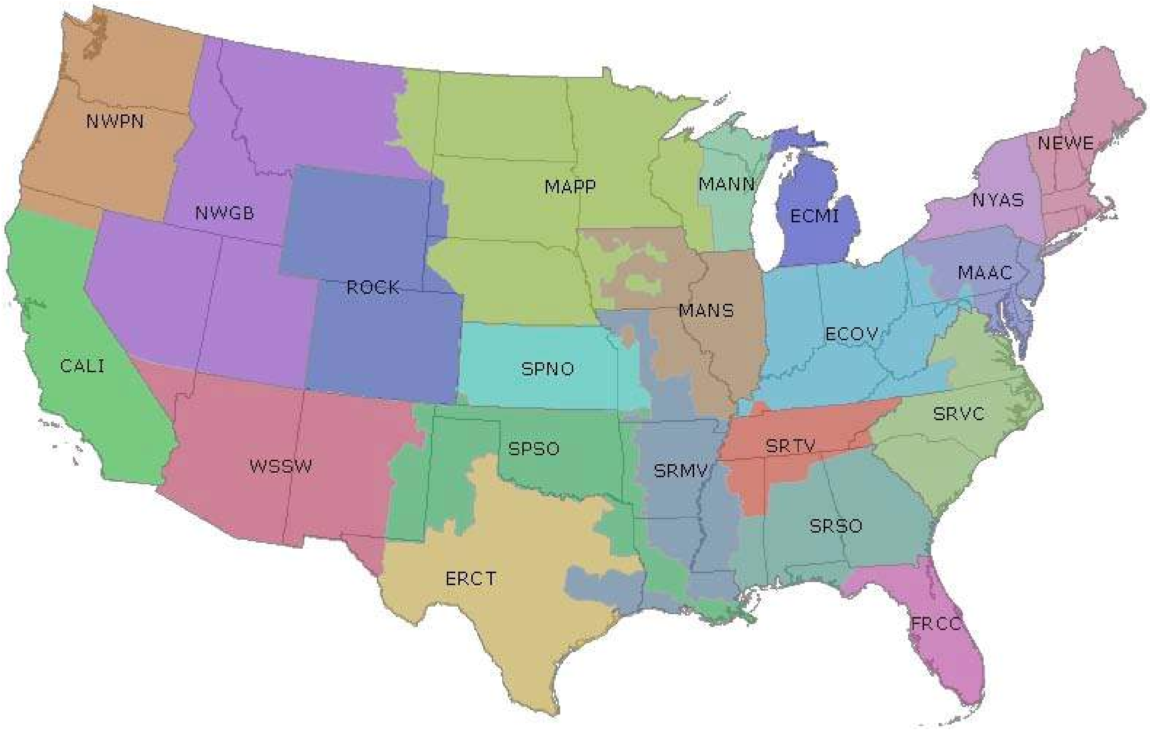
The project was undertaken following US EPA Solicitation No. PR-CI-01-12087. The analysis utilized the EPA's Acid Rain/Ozone Transport Commission (OTC) Program Hourly Emissions Data and the EPA's eGrid summarization data and documents. Information on solar resource and PV system performance came from Solar Electric Power Association (SEPA) and Schott Applied Power (formerly Ascension Technology) installations, which include several EPA-sponsored sites.

Methodology

In order to understand the emissions reductions from grid-connected PV systems this project's analysis sought to empirically determine which individual generating units within power plants were most likely affected by the PV generation. Distributed grid-connected PV systems are on the demand-side of the electricity system, so the centralized power systems sees them as a reduction in demand. A number of difference methods are used by the grid operators to respond to changes in demand. Automatic generation control (AGC) responds to small changes. Central generators are turned up and on (or down and off) in response to larger, slower changes.

In the absence of an hourly historical record of system operation (e.g. which units were running AGC in each hour) for every region in the country, we used empirical methods to identify units that were "following load" in any given hour and therefore likely to be affected by PV generation in that hour. We used the North American Electric Reliability Council's (NERC) definition of subregions as our load following, dispatch regions. These twenty-one regions, and their letter code abbreviations, are given in Figure ES.1. Due to the relative small size of PV systems in relation to overall electricity demand and the size of conventional power plants, we assume fossil units are not turned *off*, but turned *down* in reaction to PV generation.

Figure ES.1. NERC Subregions and Their Abbreviations



	Code	Region		Code	Region		Code	Region
(1)	CALI	California	(8)	SPNO	Kansas	(15)	MANN	Wisconsin
(2)	NWPN	Pacific Northwest	(9)	SPSO	Oklahoma	(16)	MANS	Illinois
(3)	NWGB	Great Basin	(10)	SRMV	Mississippi Valley	(17)	ECMI	Michigan
(4)	WSSW	Southwest	(11)	SRTV	Tennessee Valley	(18)	ECOV	Ohio Valley
(5)	ROCK	Rockies (CO, WY)	(12)	SRVC	Virginia-Carolinas	(19)	MACC	Mid Atlantic (PJM)
(6)	ERCT	ERCOT (Texas)	(13)	SRSO	Southeast	(20)	NYAS	New York
(7)	MAPP	Northern Plains	(14)	FRCC	Florida	(21)	NEWE	New England

Analyzing the time-series of total regional demand and generation of the units in the region, a load following unit's generation should follow the shape of the regional demand. That is, if the total system demand is increasing so should the unit's load and similarly for decreasing system load. If a unit's output changes in the opposite direction of the regional demand, that unit is not following load. In this manner, explained in detail in Chapter 1, units in any given hour were designated as "load shape following" (LSF). The emissions rates of the load shape following units in each hour were used to determine the emissions reductions from PV generation.

The assessment showed large variations in the emissions reductions across regional power systems. Reasons for variations span many system characteristics including:

- Solar resource
- PV system upkeep
- Shape and size of daily electricity demand
- Seasonal electricity demand changes
- Quantity of units responding to demand changes
- Fossil unit dispatch patterns
- Operation patterns of likely "turned down" units
- Regional fuel use patterns
- Seasonal fuel use patterns
- Fuel use of load shape following units
- Generation portfolio changes due to competition

Understanding the actual and potential emissions reductions requires an understanding of these and other electric power system variations.

Conclusions

The benefits of this methodology lie in its straightforward and flexible application. Only an operator's knowledge of the system in each subregion, or an historical account, could determine which units were dispatched at what times in response to load. The load shape following logic estimates this dynamically from the generation and demand data themselves.

Generation and Demand

Regional electricity demand determines the units that are utilized in any given hour and the manner in which they are dispatched. Demand itself is shaped by geography, meteorology, demographics, and the economy of the region. Non-dispatchable renewable technologies, like PV, affect the system when their resources are available. Key questions such as whether a PV resource is available during times of peak demand in a regional power system can be answered through analysis of hourly regional generation, demand, and renewable resource data. Analysis of these data also reveals which types of non-emitting generation might be best utilized to reduce peak demand in a subregion. Trends in load-growth and emissions reductions can also be gleaned by inspecting the time-series data.

Emissions

Load shape following emission rates, the emission rates of those units that can be affected by PV generation, depend on a multitude of generation unit and power system characteristics. These include the fuel and technology types of the generators that follow load as well as their load levels, combustion temperatures and operating efficiencies, and pollution control devices. LSF emission rates are by no means consistent from day to day, month to month, or hour to hour. The use of natural gas peaking units, for example, affects the load shape following emission rates. Natural gas units are turned on during times of peak demand in many regional power systems; Texas (ERCT) and the Mississippi Valley (SRMV) are good examples. The amount of SO_2 in natural gas is significantly less than that in coal or oil and thus the SO_2 LSF emission rates during peak-demand hours in many power systems that utilize natural gas peaking units are significantly lower than the LSF emission rates at other times of day in the same power system. The LSF emission rates in these instances are also significantly different than the average emission rates of all the fossil units generating at the time.

Analysis of the hourly emission rate profiles of subregions also shows the effects of generator and pollution control technology choices. Emission rates in California, which is a heavily regulated region, are substantially lower than those in other regions. The least variation in pollutant emission rates among subregions is in CO_2 emission. The carbon contents of coal, oil, and gas vary only by a factor of two, contributing to the relatively small variability in CO_2 emission rates. Also, SO_2 and NO_x emissions, unlike CO_2 emissions, are regulated, so pollution control equipment on some units, but not others, can create large differences between generators' emissions rates. For SO_2, a range of 48 to 1 existed between the highest regional LSF emission rate (MAAC-Mid-Atlantic) and the smallest (CALI-California) in 2002. For NO_x LSF emission rates in 2002 this ratio is 4:1 and for 2002 CO_2 LSF emission rates it is 2:1 (both for the WSSW-Southwest and CALI-California).

PV Generation and Emission Offsets

Two types of analysis are necessary to understand the emissions reductions from PV systems and the regional variation in PV emissions reduction potential:

- Actual PV system analysis using hourly PV generation data
- Simulated PV system analysis using hourly solar resource data

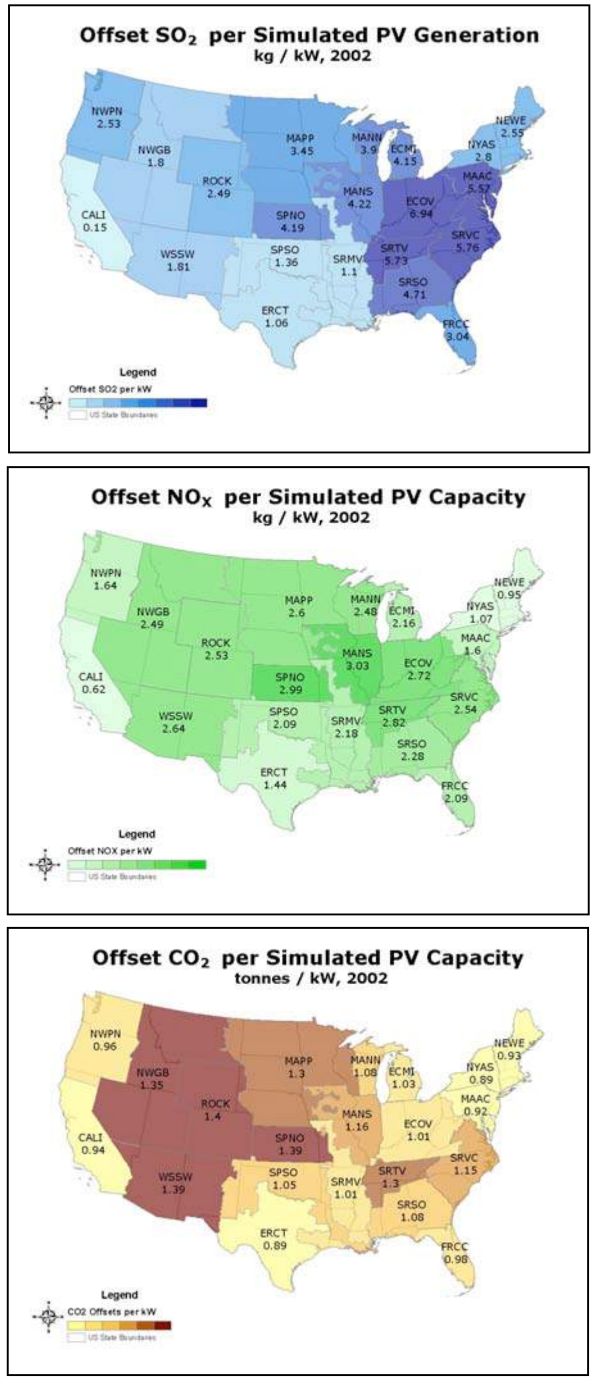
The solar resource available in a region and the performance (e.g. annual generation) of the PV systems are related, but PV system performance also depends on maintenance and upkeep. The upkeep and maintenance of PV systems is critical for emissions offsets: regardless of the resource in a subregion, if a PV system does not operate it cannot offset fossil unit emissions. The monitored (actual) PV sites in the Pacific Northwest were plagued with downtime during the five-year study period, and the emissions offsets in that region suffer as a result. Quantifying the emission reductions from actual grid-connected PV systems serves two purposes. First, it assesses the emissions impacts of the particular systems as they were installed and kept. Second, it informs a practical understanding of emissions reductions. *Real* systems break and they always will: how to the emissions reductions of real PV systems compare to ideal (simulated) PV systems?

Regional solar resources vary in magnitude and in seasonal and daily patterns. The patterns in weather and sunrise/sunset (diurnal and annual pattern) that contribute to the available solar resource also influence the demand for electricity and fossil generator utilization. It is important to analyze real PV systems and their impact in the electricity grid as it simultaneously responds to changes in weather. If this is unavailable, analysis of PV-related emissions reductions using simulated PV system generation *must* use solar resource data that are regionally and temporally coincident with demand, generation, and emissions data (as opposed to typical meteorological year (TMY) data).

Even so, we found the use of simulated PV systems to be necessary to obtain consistent regional comparisons. A region-to-region comparison using actual PV systems was not useful because of the inconsistent upkeep of installed PV systems, and its impact on avoided emissions calculations.

The maps in Figure ES.2 show annual emissions reductions per installed kW of PV using simulated PV systems. Because the simulated sites use hourly regional solar resource data the emissions reductions in the figures represent the emissions reductions expected from a kW of well maintained, and oriented, PV capacity[1].

Figure ES.2. Maps of 2002 SO_2, NO_X, and CO_2 annual offsets per kW of simulated PV capacity



[1] Baseline comparisons of monitored PV systems and simulated PV systems in the same region find that annual production for actual PV systems is about 10 to 20% lower than simulated systems for fairly well maintained actual sites. This difference is offset in the calculation of avoided emissions by comparing PV system generation with the gross power output of fossil generators. eGrid fossil unit power production is reported before taking into account electricity consumption at the generation unit (auxiliary power consumption), as well as additional losses in the transmission and distribution of electricity to the end-user. Higher

The darker regions on the maps indicate higher levels of emissions reductions per kW of installed PV. The maps emphasize the finding that PV installed in regions with less solar resource but higher LSF emission rates can have higher annual emissions reductions than PV systems in regions with better sun, but lower LSF emission rates. Table ES.1 ranks the subregions in order of decreasing annual PV production per installed kW (simulated) and compares annual avoided emissions per installed kW (simulated) for 2002.

Table ES.1. Annual PV production and avoided emissions per kW of Installed PV capacity (simulated).

NERC Subregion	***Photovoltaic Generation***		***Avoided SO2 LSF Emissions***		***Avoided NOx Emissions***		***Avoided CO2 Emissions***	
WSSW	**1784**	**1**	1808	16	2636	5	**1394**	**2**
ROCK	**1701**	**2**	2492	15	2534	8	**1404**	**1**
NWGB	1672	3	1805	17	2490	9	1351	4
CALI	1631	4	152	21	617	21	937	17
SPSO	1553	5	1355	18	2091	14	1053	11
SPNO	1553	6	4192	7	**2988**	**2**	1388	3
MANS	1438	7	4216	6	**3029**	**1**	1155	7
MAPP	1435	8	3453	10	2605	6	1295	6
SRMV	1397	9	1095	19	2178	12	1015	14
SRVC	1391	10	**5765**	**2**	2539	7	1150	8
SRSO	1384	11	4710	5	2283	11	1081	9
MANN	1352	12	3900	9	2479	10	1075	10
SRTV	1349	13	5730	3	2821	3	1302	5
ERCT	1330	14	1056	20	1438	18	892	21
FRCC	1309	15	3045	11	2087	15	984	15
ECOV	1271	16	**6943**	**1**	2715	4	1015	13
NYAS	1271	17	2799	12	1071	19	894	20
NEWE	1256	18	2549	13	946	20	930	18
MAAC	1254	19	5566	4	1602	17	921	19
ECMI	1242	20	4149	8	2160	13	1028	12
NWPN	1070	21	2532	14	1635	16	964	16
(2002)	(kWh/kW)	(Rank)	(g/kW)	(Rank)	(g/kW)	(Rank)	(kg/kW)	(Rank)

The solar resource and its correlation with demand and emission profiles is an influential factor on the emissions avoided by PV. The solar resource is generally well matched to times of peak demand, but times of peak demand are often characterized by the cleanest LSF emissions. The variation between regional power systems in this regard is significant especially for SO_2 and NO_X emissions that vary more by fuel type and technology type than do CO_2 emissions. The solar resource is intense in California (CALI) and Texas (ERCT), for example; but the annual SO_2 offsets are small because the load shape following emission rates in these regions during daylight hours are

simulated PV system generation is therefore offset by the conservative calculation of fossil unit avoided emissions rates. These factors are further explained in Chapter 2.

low. In this regard, the variability in fuels and technologies used in a subregion eclipse the variability in solar resource in determining the total emissions avoidable by PV systems. PV systems in the sunniest regions do not necessarily offset the most emissions per installed capacity; a subregion's LSF emission rate profile is considerably more influential.

With these factors in mind, access to detailed information regarding PV generation *and* electric system operation and emission is essential in order to get an accurate and informative picture of the emission reduction potential of PV (and other non-dispatchable options). Unless informed by this level of analysis, traditional more aggregate "slice of system" approaches will likely overestimate the emissions reduction benefits from PVs, and perhaps underestimate the emissions reduction potential of other renewables, such as windpower, which avoid higher emitting off-peak kWhs.

As the photovoltaic technology and industry continue to mature and grow, the case for PV (and other non-dispatchable technologies) as an emission reduction option, suitable for inclusion in emission trading markets or State Implementation Plans (SIPs) will strengthen. The ability to analyze power generator emissions down to the unit-hour level can provide greater insight into the effectiveness of a broad range of emission reduction policies and practices.

1 Research Approach and Overall Methodology

1.1 Overview

The emission reduction potential of photovoltaic (PV) power systems is known to be highly dependent on the amount of solar resource available in a given geographic location, as well as the PV system's technological configuration, orientation, and maintenance. However, its emission reduction potential also relies heavily upon the composition and operational characteristics of the regional electric power grid within which the PV system is located. This report, and the project it describes, assesses the emission reduction potential of PV systems considering their integration with the seasonal, diurnal, and geographical variations of both the PV systems and the region's equally dynamic power systems' emissions.

The project was undertaken following U.S. EPA Solicitation No. PR-CI-01-12087. The core of the analysis utilized the EPA's Acid Rain/OTC Program Hourly Emissions Data, the core fossil power plant data used in the EPA's eGrid summarization data and documents. Information on solar resource and PV system performance came from numerous EPA sponsored installations as well as Solar Electric Power Association and Schott Applied Power (formerly Ascension Technology) installations. The analysis was conducted on the basis of NERC (North American Reliability Council) subregions.

The project analysis was designed to seek out individual units within plants (facilities) that are most likely to be affected by PV generation. Due to the relative size of PV systems, we assume fossil units are not turned off, but turned down in reaction to the "net load reduction" of PV generation, as seen by the regional power grid. The assessment showed large variations in the emissions reduction potential across subregions. Reasons for variations span several system characteristics including:

- Shape and size of daily demand
- Seasonal demand changes
- Composition of fossil units responding to demand changes
- Operational patterns of likely "turned down" units
- Regional fuel use patterns
- Seasonal fuel use patterns
- Fuel use of likely "turned down" units
- Generation portfolio changes due to competition

Understanding the actual and potential emissions reductions requires an understanding of these and other electric power system variations.

The other key measure in evaluating reduction potential is the ability of PV systems to consistently convert solar resource into electric power. PV system monitoring data utilized in the analysis was from a diverse collection of photovoltaic system installations in terms of number, size, location, configuration, and upkeep. In some instances, the consistency of monitored data was poor. For some NERC subregions, monitored data was not available. To overcome these obstacles, the output of simulated PV systems was used. In these instances, solar resource information from several national networks was used. These include the National Oceanographic and Atmospheric Administration's (NOAA) Surface Radiation (SURFRAD) Network and Integrated Solar Information System (ISIS) Networks. This highly detailed hourly information was used so that simulated PV system performance could be benchmarked to actual PV system performance, increasing the confidence of using simulated PV system results where actual PV system operational data was unavailable.

The latter sections of this chapter cover in more detail the sources of data used and the analysis methodology.

- Chapter 2 of this report covers the demand and generation characteristics of the nation's subregions and their evolution over time.
- Chapter 3 looks at the methodology behind calculating avoided emission rates and analyzes results of such methods.
- Chapter 4 discusses the population of monitored PV systems and the performance relative to resource.
- Chapter 5 details the solar resource information used and outlines the solar site simulation process utilized in certain subregions.
- Chapter 6 assesses actual emission reductions from all subregions.
- Chapter 7 discusses the future of emission reduction from PV and how the methodology might change should PV achieve a larger market penetration.
- Chapter 8 offers conclusions and discussion of further uses of the data compiled as a result of this project.

1.2 Sources of Data

The analysis required matching up PV generation with associated changes in unit generation on an hourly basis. Given this need, a large openly available data source containing unit-level information on an hourly basis for all fossil plants and units across the nation was needed. The EPA's Acid Rain/OTC Program Hourly Emissions Data fit these criteria.[1] The hourly emissions are part of the 24 different sources aggregated to create the Emissions and Generation Integrated Resource Database (eGrid)[2]. The Acid Rain/OTC

[1] See the EPA website at http://www.epa.gov/airmarkets/emissions/raw/.

[2] Throughout this report the Acid Rain / OTC Program Hourly Emissions Data is referred to as the "eGrid hourly data" and the generation from plants participating in the program is referred to as "eGrid fossil generation." The widely distributed eGrid database is also used in the analysis and is referred to in this report as the eGrid summarization data. See also Chapter 1.2 and Appendix A.

Program began monitoring in the fourth quarter of 1997. This report is based on data from 1998 through 2002, analyzing five full years of hourly emissions data for the contiguous 48 states.

Information on solar resource and PV system performance came from numerous EPA sponsored installations as well as Solar Electric Power Association and Schott Applied Power (formerly Ascension Technology) installations. Each site had both a PV array generating power as well as varying pieces of solar radiation measuring equipment. In the data provided, some systems had information as far back as 1996. Only the data from 1998 through 2002 were used.

In addition to the core hourly emissions and solar generation information, several other data sources were utilized in the completion of this analysis. These included:

- Emissions and Generation Integrated Resource Database (eGrid, 2002 edition)
- FERC and region power pool total demand information
- Solar Resource Information
- ISIS, SURFRAD, and CONFRRM
- NERC Subregion Spatial Information
- National Emissions Inventory Information

Appendix A covers each data source in detail and describes the data utilized and the data management processes associated with the use of each source.

1.3 Analysis Methodology

The analysis has a unique perspective on the emissions reduction potential of PV power systems given the quantity and quality of the historical data. The ability to look retrospectively at system operation during times of top PV performance provides a unique insight in determining the fossil and other pollutant emitting units most affected by PV.

1.3.1 Alternative Approaches

It is common practice to predict emission reductions using market-based or simple average approaches. The market-based approach bases assumptions on the fact the PV is a “must-run” or “non-dispatchable” electric generator. Therefore in a competitive market, it will commonly offset electric power produced at the highest price, typically peaking units with low capacities, low capacity factors, and burning natural gas. This report challenges the market-based analysis approach on the grounds the PV is currently too small to effectively move the market, or affect centralized unit commitment. The units affected by PV are more likely to be units bid into market to respond to minor load variations, such as spinning reserve units and units in automatic generation control (AGC). These units’ capacities, capacity factors, and fuels can be quite diverse, thereby influencing actual avoided emissions from PV generation.

Alternatively, the simple averages approach takes an emissions rate for a given area (power pool) in units of emission per kilowatt-hour of generation (such as g/kWh) and simply multiplies it by the total solar generation in the desired time frame. This report also challenges the simple averages approach on the grounds that there is no evidence that average (Slice of System) emission rates occurring when PV is generating are representative of the fossil units that respond to changes in load, to be met by dispatchable generation. For example, in many parts of the country, times of peak demand are usually during daylight hours when PV generation is also at its peak production. Peak demand "marginal" emission rates are not equivalent to average emissions rates, as easy to start, often natural gas fired generation is brought on line to meet system peaks. Even if an average is taken for daylight hours only, including seasonal variations, the approach still makes assumptions that all units have an equal likelihood of, and ability to, adapt to hourly changes in electric demand, including demand changes reflecting consumer based PV generation.

1.3.2 Load Shape Following Logic

Addressing the alternative approaches focuses the questions asked in developing the analysis methodology used here: What operational characteristics will distinguish which units affected by PV in any given hour and how much are those units affected? The approach used was intended to find in the data those units that are responding to changes in total demand, understanding that the units responding to load will vary over time. Analyzing the time-series of total load demand and unit generation, the unit's generation should appear to follow the shape of the load. In such a manner, the unit in any given hour was designated as "load shape following."

In designating load shape following units, several logic rules were applied.

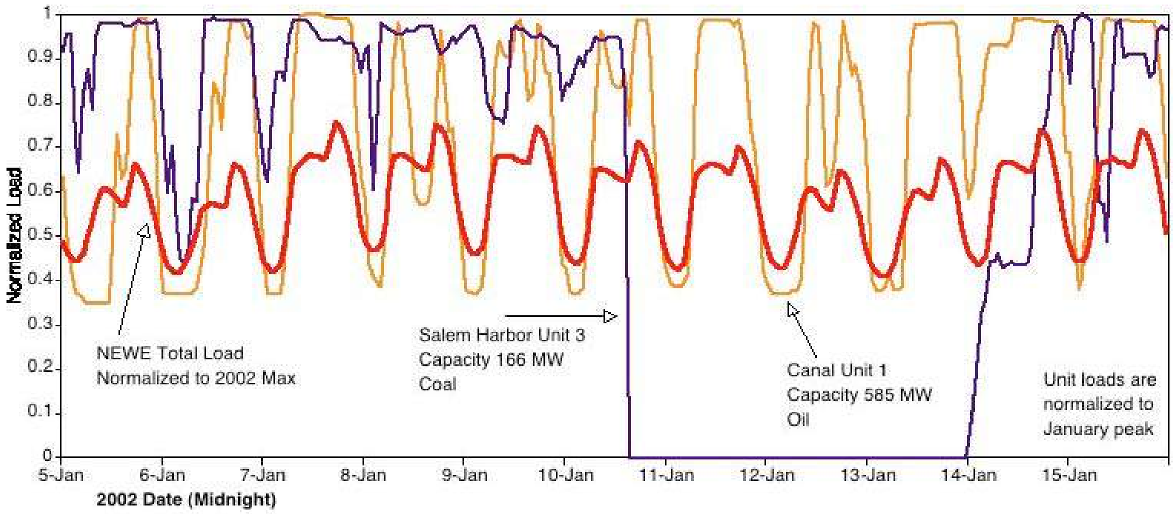
- ♦ If a unit's change in load from the previous hour is in the same direction as the change in total load from the previous hour (up or down), then the unit-hour is load shape following.

This logic alone will not always include units in spinning reserve or AGC that are generally primed to follow changes in demand, as these units are prone to sitting at constant levels of output for hours before being called on to respond. Therefore a second piece is needed:

- ♦ If a unit's change in load is small (+/- 2.5% of the 60 day rolling maximum load) and the unit's previous hour is load shape following, then the unit-hour is load shape following.

Below are some results of applying the above logic to given units.

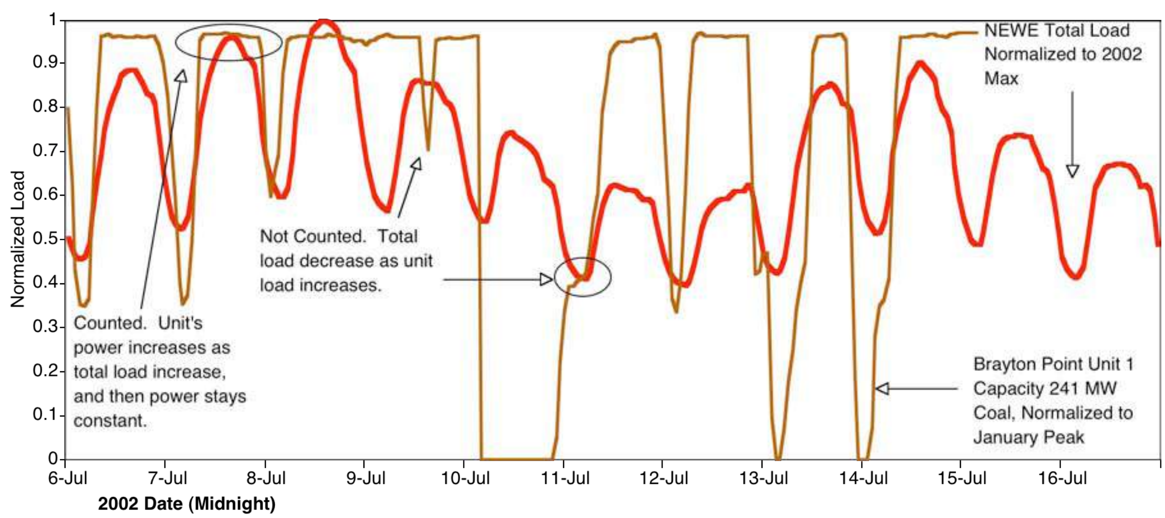
Figure 1.1. Example of Load Shape Following Units (Winter 2002)



In the above example, the Salem Harbor and Canal units are load shape following in nearly every hour during the selected week in the winter of 2002. For a unit just coming online or adapting to its operational pattern, the results vary.

In Figure 1.2, the unit shifts up and down upon restart on a day, creating variation hour to hour in its designation. Since the unit comes on in most days while the total load is increasing, the unit remains load shape following despite the slight load variations.

Figure 1.2. Example of Load Shape Following Units (Summer 2002)



The load shape following analysis is completed on an hourly basis. There are no rules regarding the size of units, the types of fuels used by the units, the location of the units, the technology type of the units, or the types of pollution control equipment on the units. The designation is assigned based on empirical observation of the operational data, and the assignment will vary hour to hour.

1.3.3 Operational Mode and the Load Shape Following Logic

In reviewing the operation of the entire population of units, it became apparent that there existed four main operating modes. These modes can be easily categorized according to the percent of capacity at which the unit was operating.

The modes were apparent across many different areas of the country. The varying modes were given the following names:

Table 1.1. List of Load State Definitions

Operational Mode Name	Percent of Capacity
Full Load	> 90
Spinning Reserve	> 55 and ≤ 90
Standby	> 5 and ≤ 55
Turning On / Off	> 0 and ≤ 5

Figures 1.3 through 1.5 show the frequency of occurrence of the various operational modes across all units in the subregion.

The California region (CALI) shows a region with a propensity of unit-hours in Standby mode. The Wisconsin region (MANN) also shows the Standby and Spinning Reserve divisions. The Tennessee Valley region (SRTV) shows a majority of unit-hours in Spinning Reserve or Full Load.

The modes are useful in understanding what purpose the unit might have been serving for the grid operator. Units in "Full Load" are typically the larger units that are part of the baseload. "Spinning Reserve" can include units in 30-, 60-, or 90- minute reserves or units in AGC. "Standby" units can be typified as units not needed for major load contribution, yet unwilling or unable to turn completely off due to the thermal inertia required to turn them back on.

In the interest of preserving the load shape following logical intention of capturing units responding to load changes, units given a mode of "Spinning Reserve" are automatically designated as load shape following units.

Figure 1.3. Frequency of Operational Mode, CALI 2002

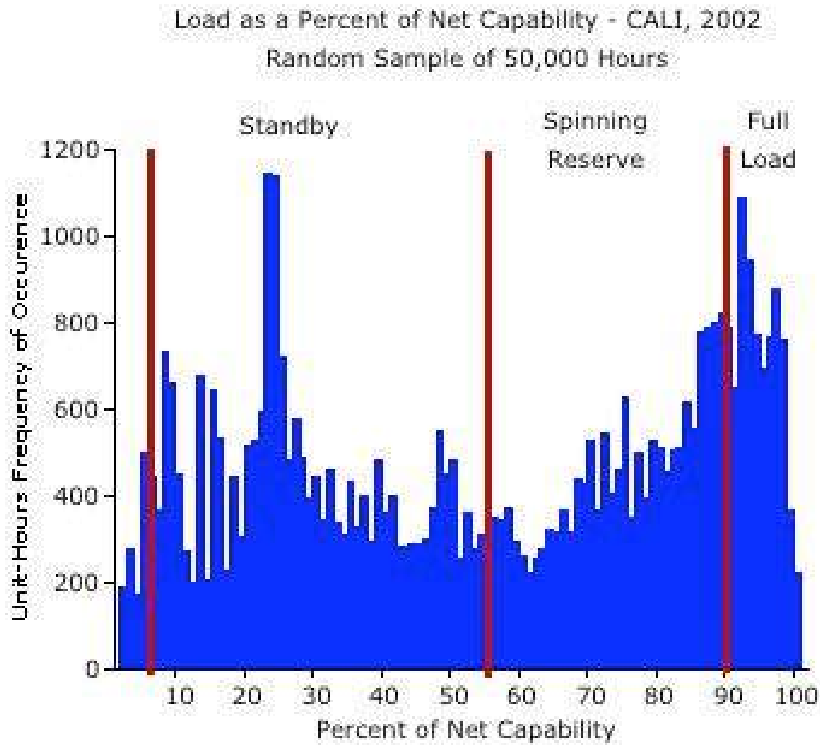


Figure 1.4. Frequency of Operational Mode - MANN, 2002

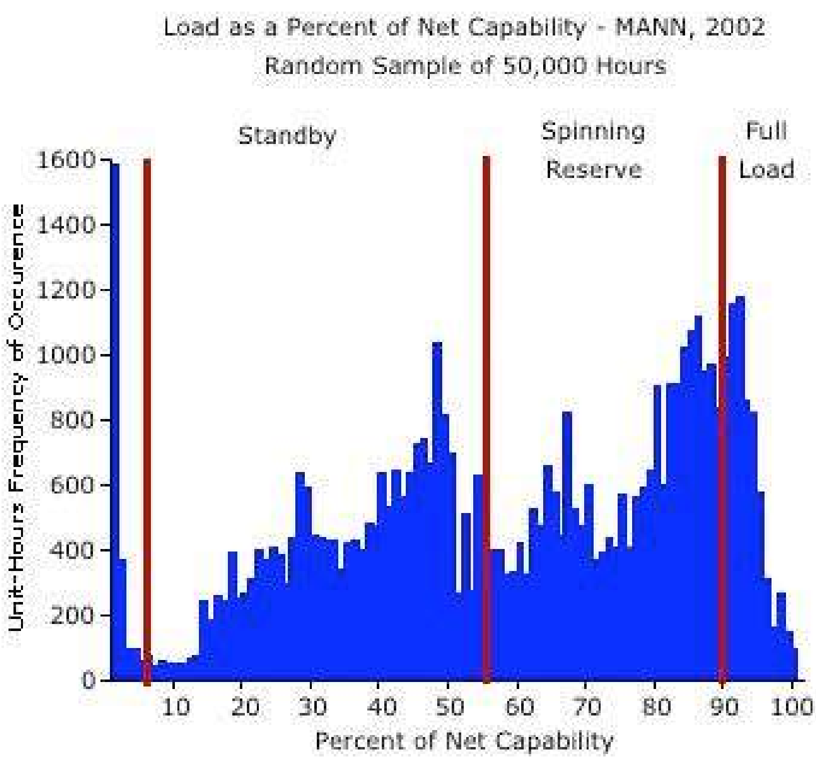
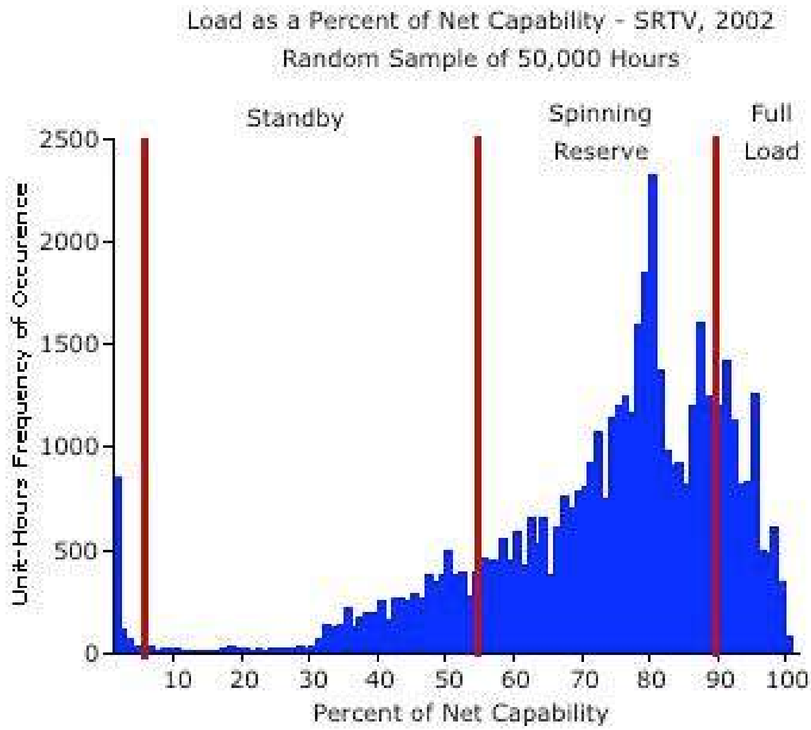


Figure 1.5. Frequency of Operational Mode - SRTV, 2002



1.3.4 Fuel Class Designation

An understanding of the types of fuels burned during any given hour is important to understanding regional emission variations. Many units across the nation are equipped to burn different fuels depending on fuel prices or season. In order to determine the fuel type burned in any given hour, the difference in the carbon content of fuels was utilized. Below, the histograms show the results of checking the carbon content on a hourly basis, accomplished by finding the ratio of carbon dioxide emissions to the hourly heat input rate. To obtain the carbon content on an hourly basis, the ratio CO_2 emitted to fuel heat rate input was calculated. The histograms in Fig. 1.6 – 1.8 show the results for various regions.

The ratios (kg/mmBTU) of most frequent occurrence are comparable to the Energy Information Administration data for fuel types carbon content.[3] The purple lines on the graph indicate the carbon content boundaries used to classify the fuel in this analysis. The New England (NEWE) and Florida (FRCC) regions show two regions with a sampling of the three fuel types. The Ohio Valley (ECOV) region is heavily coal.

---

3 See Energy Information Administration, Emissions of Greenhouse Gases in the United States 1998 , DOE/EIA-0573(98) (Washington, DC, October 1998), Table B-1.

Figure 1.6. Fuel Type Designation by Carbon Content, New England 2002

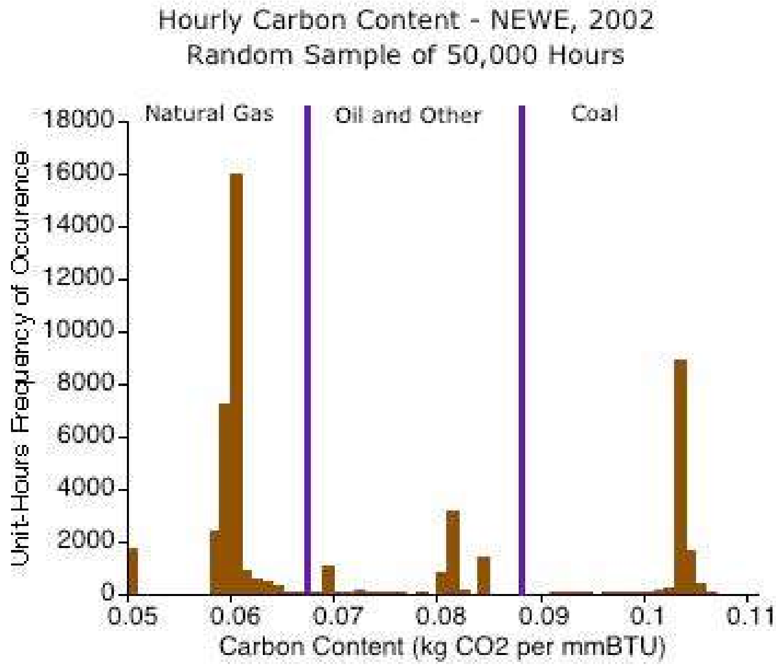


Figure 1.7. Fuel Type Designation by Carbon Content, Florida 2002

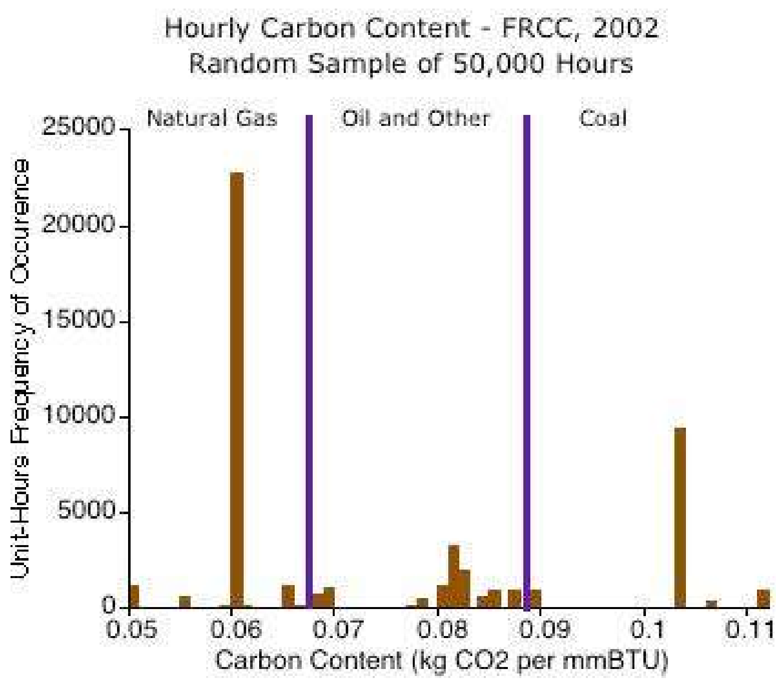
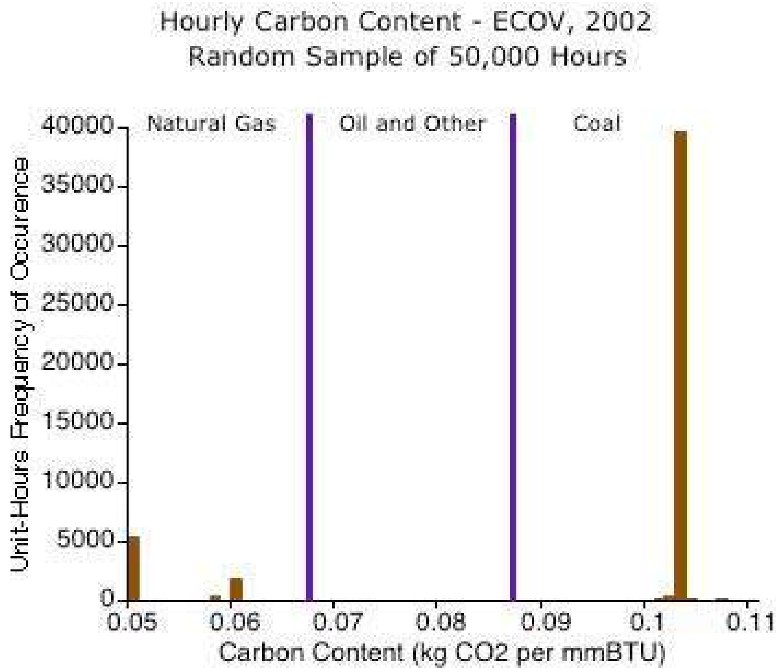


Figure 1.8. Fuel Type Designation by Carbon Content – Ohio Valley, 2002



1.3.5 Allotting PV

While the logic is robust, it is excessively inclusive. For example a large, baseload unit that typically operates at a consistent 95% of capacity may have been down for repairs or maintenance. If the unit happens to come back online during a time when total system load was increasing, the logic catches the unit as load shape following and will leave it in the designation until the system comes down again. To avoid counting these types of units as being affected by PV generation an additional step is taken when considering *how much* units are affected by PV.

Since the analysis is looking for units responding to changes in total system demand, the effect of PV on various units is weighted by the unit's change in load from the previous hour, or its $\Delta Load_{Unit}$. Therefore, a unit changing substantially in any given hour is allotted (or said to be affected more by) the PV generation in that hour. Baseload units will then have no PV allotted to them provided they have little or no $\Delta Load_{Unit}$. In this way, spinning reserve units, such as the unit demonstrated above in Fig. 1.2, were also allotted no PV until such hours when they *actually respond* to changes in demand. The Tables 1.1 and 1.2 demonstrate the allotment process for two different hypothetical operational time periods.

The model shows a representative sample of five units operating in a single hour in a subregion. The two sets of column totals show the difference between a normal emission rate calculation and a weighted emission rate calculation. The difference in the sulfur dioxide emission rates demonstrates the concept that a low sulfur fuel in natural gas responds more to changes in total load, and is therefore affected more by photovoltaic generation. An example of an overnight case in Table 1.3 demonstrates the opposite point.

Table 1.2. LSF Emissions Rate Allotment Model, Peak Load Case

Peak Load Case

LSF Unit	Fuel	Size	Operating Mode	Hourly Output	SO2 Emissions	Δ MW Prev.Hr.	Δ SO2 Emissions
1	Gas	75	Spinning	50	0.5	40	0
2	Gas	75	Spinning	50	0.5	20	0
3	Oil	350	Spinning	250	350	100	140
4	Coal	500	Full Load	475	900	25	47
5	Coal	550	Full Load	525	1400	25	67
		(MW)	**Total:**	1350	2651	210	255
				(MWh)	(kg)	(MWh)	(kg)
			LSF Unweigted Rate:		1.96	**Wgt.Rate:**	**1.21**
					(kg/MWh)		(kg/MWh)

Table 1.3. LSF Emissions Rate Allotment Model, Overnight Case

Overnight Case

LSF Unit	Fuel	Size	Operating Mode	Hourly Output	SO2 Emissions	Δ MW Prev.Hr.	Δ SO2 Emissions
1	Gas	75	Off				
2	Gas	75	Off				
3	Oil	350	Standby	150	450	25	75
4	Coal	500	Spinning	425	1100	25	65
5	Coal	550	Spinning	400	1600	75	300
		(MW)	**Total:**	975	3150	125	440
				(MWh)	(kg)	(MWh)	(kg)
			LSF Unweighted Rate:		3.23	**Wgt.Rate:**	**3.52**
					(kg/MWh)		(kg/MWh)

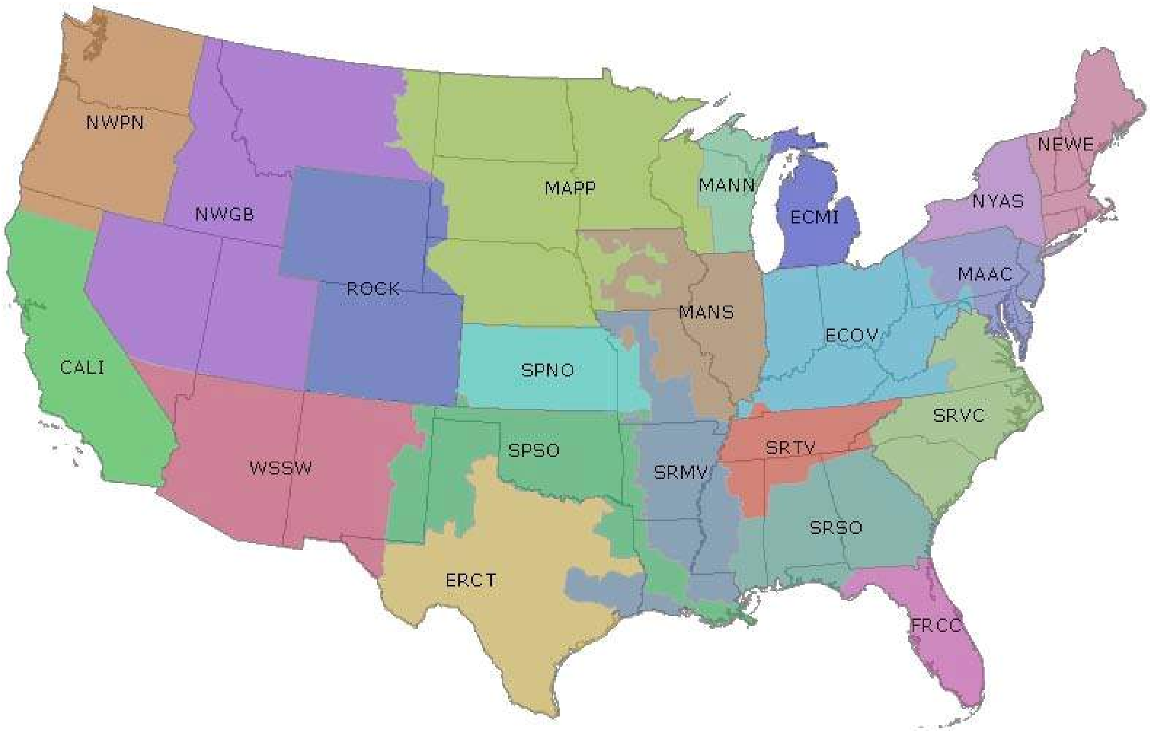
This "PV accounting" methodology along with the load shape following logic identifies and quantifies the generation, and therefore, emissions reduction, effects of PV generation on the unit and hourly level.

1.3.6 Using NERC Subregions

The analysis was also designed to preserve and display the regional variations in the emission profiles. Regional variations occur due to different fuel portfolios, fuel quality, emission control equipment, and regional air quality initiatives and regulations among other factors. Several region-designation options considered varied widely in size and definition. The reliance of emission reductions on variations in unit operations meant pursuing regions closely matched with electric power grid operation. The North American Electric Reliability Council (NERC) subdivides the grid into areas connected mainly through transmission lines. The NERC Regions represent these divisions. However, operation and dispatch of units occurs at a more granular level. NERC developed subregions to identify regions of coordinated dispatch. The next level of granularity would have been power control area (PCA). However, PCA's are often too small for use in this analysis, as dispatch of units must be coordinating between PCA's.

NERC subregions under went slight redefinition in 2002. These updated definitions are what is used in this analysis, with one exception. The New York ISO was subdivided into three subregions for Upstate New York, New York City, and Long Island. However, total load information required in the analysis had no clear way of subdividing load by the newly form subregions. Therefore, the New York ISO is treated as a single subregion. Chapter 2 further details the subregions nation-wide.

Figure 1.9. Map of NERC Subregions with Definitions



	Code	Region
(1)	CALI	California
(2)	NWPN	Pacific Northwest
(3)	NWGB	Great Basin
(4)	WSSW	Southwest
(5)	ROCK	Rockies (CO, WY)
(6)	ERCT	ERCOT (Texas)
(7)	MAPP	Northern Plains

	Code	Region
(8)	SPNO	Kansas
(9)	SPSO	Oklahoma
(10)	SRMV	Mississippi Valley
(11)	SRTV	Tennessee Valley
(12)	SRVC	Virginia-Carolinas
(13)	SRSO	Southeast
(14)	FRCC	Florida

	Code	Region
(15)	MANN	Wisconsin
(16)	MANS	Illinois
(17)	ECMI	Michigan
(18)	ECOV	Ohio Valley
(19)	MACC	Mid Atlantic (PJM)
(20)	NYAS	New York
(21)	NEWE	New England

2 Electricity Demand and Fossil Generation by NERC Subregion

As the load shape following methodology is central to the calculation of the avoided emissions potential of solar photovoltaics, an understanding of both hourly electricity demand, and fossil generator response, by NERC Subregion is needed. This chapter gives an overview of the NERC Subregions by both load and fossil contributions. But first, a discussion of where along the supply chain of electricity generation and consumption measurements are taken is needed.

2.1 Gross versus Net versus At-meter Generation

This analysis relies on hourly data from a number of sources. Details on the data sources from which fossil generation and emissions, total load data, PV generation, and solar resource data were derived can be found in Appendix A. This analysis depends on the interaction of all these sources so clarification of some of their characteristics is necessary.

The hourly eGrid fossil generation reported is gross generation on a generating unit basis. This should not be confused with net generation on a power plant basis measured at the plant busbar (e.g. electricity entering the grid), often referred to as busbar generation. Gross unit generation does not take in to account plant auxiliary power consumption for equipment like scrubbers, pulverizers, cooling fans, and turbine auxiliaries. The auxiliary power consumption for each participating plant in the eGrid database is not known. Examples of auxiliary power consumption for a selection of generation technologies are given in Table 2.1. In general, on site generator power consumption ranges from 2 to 10% of gross power output.

In contrast, PV generation is recorded at the meter. There is a disparity when comparing gross fossil unit generation to at-meter PV generation that is caused both by the auxiliary power consumption of the fossil plants, and the transmission and distribution losses incurred by transmitting power from the plant to the end-user. A given amount of demand reduction caused by PV generation at the end-user translates to a larger reduction in gross generation once auxiliary power consumption and transmission and distribution losses are taken into account. The Energy Information Association's "Electric Power Monthly" provides estimates of state-by-state net generation and retail sales of electricity. The difference between these provides an estimate of transmission and distribution losses that range from 5 to 12%.[1]

[1] Energy Information Association, "Electric Power Monthly – May 2003 Edition," Tables 1.6A and 5.4A. http://www.eia.doe.gov/cneaf/electricity/epm/epm_h_tabs.html

Table 2.1. Examples of Plant Auxiliary Power Consumption[2]

Generation Technology	**Auxiliary Load as Percent of Gross**
2 Natural gas-fired combustion turbines and 1 steam turbine generator	1.9
1 Natural gas-fired combustion turbine and 1 steam turbine generator	1.8
1 Coal-fired boiler and 1 steam turbine generator	10.4
Coal-fired supercritical steam plant	5.9
Conventional coal-fired ultra-supercritical steam plant	5.6
Advanced coal-fired ultra-supercritical steam plant	5.4

With all losses taken in to account, comparing at-meter PV and gross fossil-unit generation results in a 7 to 22% disparity. As a result, this analysis systematically underestimates the avoided emissions from actual, monitored PV systems by the same percentage range.

The hourly total load information, used to determine whether a fossil generator is load shape following or not, is electric utility and power control area demand, or net generation measured at busbar. These data were acquired through the Federal Energy Regulatory Commission (FERC). For details see Appendix A. As discussed in Chapter 1.3.2 the total load data is utilized in the load shape following logic to identify the units that follow the shape of the total load in any given hour.

Furthermore, this analysis assumes that power plant auxiliary power consumption, as a percentage of plant gross generation, is constant whether that unit is running at 40% or 80% of rated output. In other words, the auxiliary power consumption of a generation unit does not affect and is not affected by hourly changes in subregion total demand. In truth this may be an oversimplification as the busbar efficiency of a generating unit depends on its capacity factor and its operating level at any given time is not wholly dependent on total system demand. These possible changes in auxiliary power consumption is likely small compared to overall auxiliary power consumption, such as pulverizer or scrubber overall power-use.

Comparing NERC Subregion total demand (net generation) to gross unit generation also leads to apparent inconsistencies in regions such as the Ohio Valley (ECOV) where all generation is predominantly fossil. Total eGrid generation in 2002 in ECOV, for example is larger than the total demand reported for the region (see Table 2.2 below). The total subregion demand does not take into account the power exports (or imports) that create these

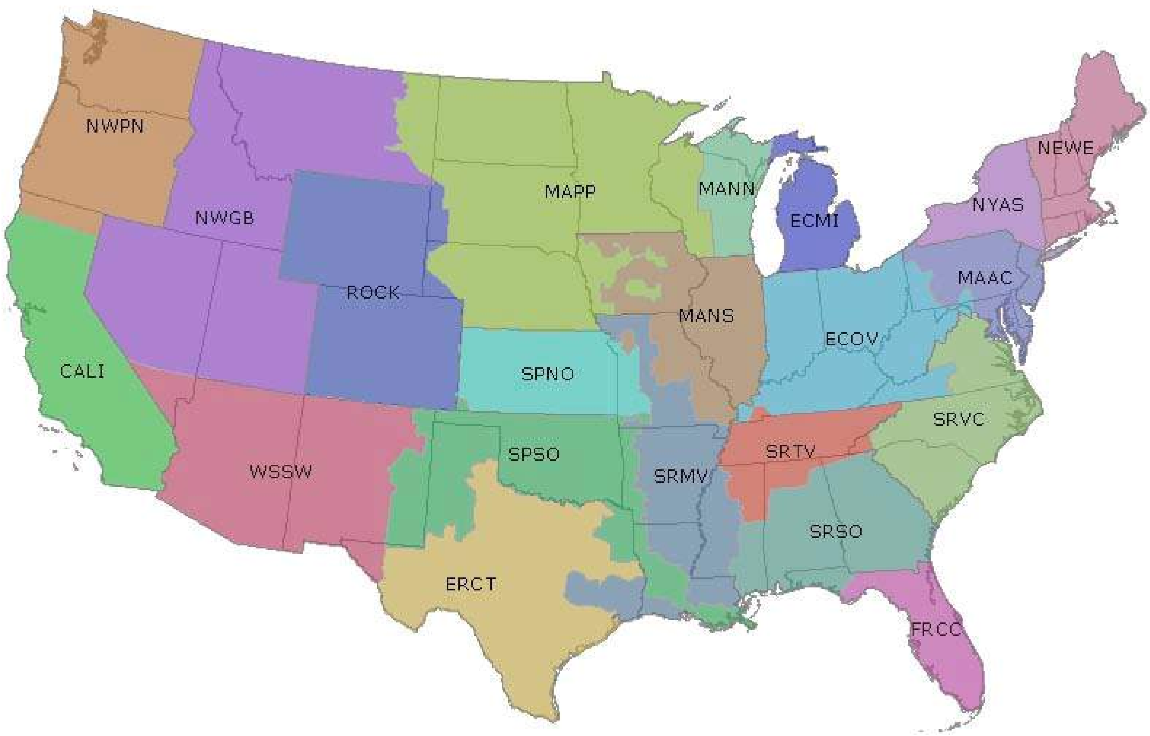
[2] Table 2.1 is adopted from "Handbook of Climate Change Mitigation Options (US Energy Association)," EPRI and DOE, June 1999, Chapter 4.4 Reducing loads from parasitic equipment. http://www.usea.org/Climatechange/chapter4/4.4.html. The auxiliary load of each plant is detailed in the report.

disparities. Fortunately, the load shape following approach doesn't require such information, as it is interested only in how generators located within a subregion respond to local perturbations in demand, and not scheduled, often baseload, inter-regional power trades.

2.2 NERC Subregion Statistics

The North American Electric Reliability Council's (NERC) regional reliability councils (NERC Regions) and the subregions within them divide the United States in to collections of power control areas that respond regionally to electricity demand (Fig. 2.1). The geographic, geologic, demographic, and political landscapes of these regions vary and, accordingly, so do important characteristics of their electric systems.

Figure 2.1. Map of NERC Subregions with Definitions



	Code	Region
(1)	CALI	California
(2)	NWPN	Pacific Northwest
(3)	NWGB	Great Basin
(4)	WSSW	Southwest
(5)	ROCK	Rockies (CO, WY)
(6)	ERCT	ERCOT (Texas)
(7)	MAPP	Northern Plains

	Code	Region
(8)	SPNO	Kansas
(9)	SPSO	Oklahoma
(10)	SRMV	Mississippi Valley
(11)	SRTV	Tennessee Valley
(12)	SRVC	Virginia-Carolinas
(13)	SRSO	Southeast
(14)	FRCC	Florida

	Code	Region
(15)	MANN	Wisconsin
(16)	MANS	Illinois
(17)	ECMI	Michigan
(18)	ECOV	Ohio Valley
(19)	MACC	Mid Atlantic (PJM)
(20)	NYAS	New York
(21)	NEWE	New England

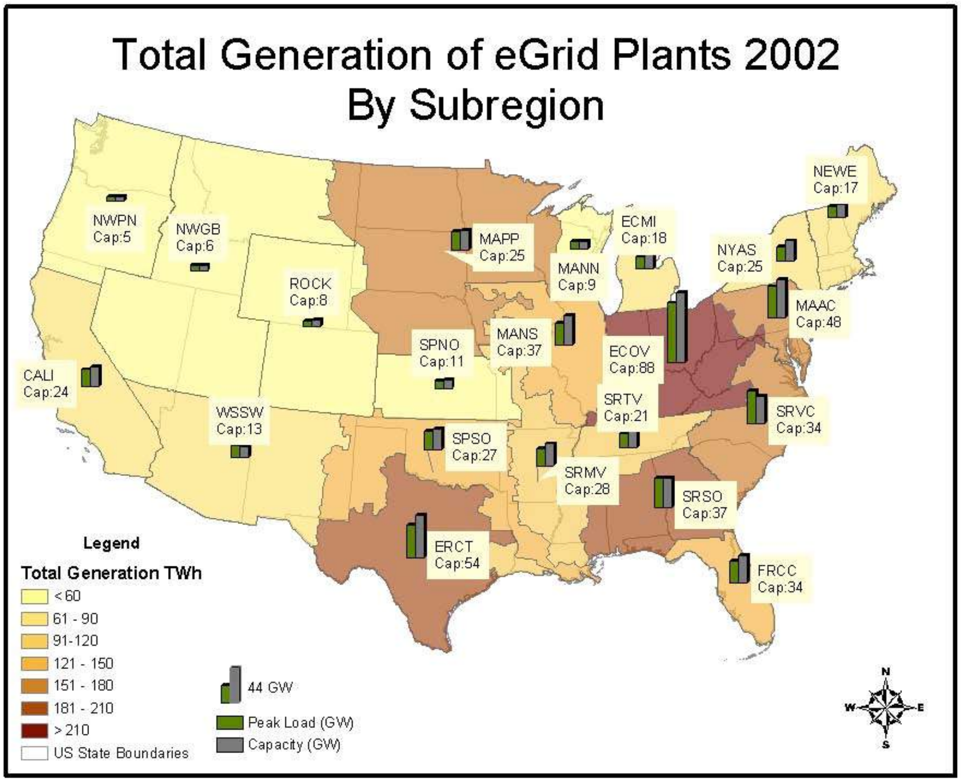
Electric system variations between subregions include magnitude of yearly demand, magnitude and temporal location of peak demand, shape of daily and seasonal demand, standard technologies and fuels used, and dispatch patterns. Table 2.2 shows subregional peak and total electricity demand, total generation capacity, and peak and total eGrid generation and capacity. The subregions are ordered by total eGrid fossil generation in 2002. Table 2.2 also serves as a reference for subregion names that are often referred to in this report by their four-letter abbreviations. Figure 2.2 plots the eGrid generation information on a map that is shaded by total 2002 eGrid generation. The Ohio Valley region (ECOV) is the largest in terms of eGrid fossil generation; its 2002-generation was more than double that of the next largest region, Texas (ERCT). Due to the large amount of hydropower in some subregions, such as the Pacific Northwest (NWPN), some of the larger total demand NERC Subregion appear well down the table.

Table 2.2. NERC Subregion Generation and Capacity

		eGrid			Total			
Subregion	**Subregion Description**	**Total Generation (TWh)**	**Peak Load (GW)**	**Capacity (GW)**	**Total Generation (TWh)**	**Peak Load (GW)**	**Total Capacity (GW)**	**eGrid % of Total Capacity**
ECOV	Ohio Valley	441	76	89	420	77	99	90
ERCT	Texas	208	42	54	280	56	74	73
SRSO	Southeast	191	37	37	196	37	51	73
MAAC	Mid-Atlantic	178	39	48	314	64	64	75
MAPP	Northern Plains	162	24	25	192	32	36	70
SRVC	Virginia/Carolinas	160	42	34	304	58	66	52
FRCC	Florida	137	28	34	194	37	44	78
MANS	Illinios	136	28	38	220	45	51	73
SPSO	Oklahoma	125	24	27	127	25	31	87
SRMV	Mississippi Valley	107	22	29	130	23	40	72
SRTV	Tennessee Valley	105	18	22	166	29	38	57
WSSW	Southwest	90	15	13	112	23	25	54
CALI	California	75	22	25	238	42	56	44
ECMI	Michigan	71	15	18	105	21	24	75
NEWE	New England	67	14	18	127	25	30	60
NYAS	New York	66	18	26	159	31	38	67
SPNO	Kansas	56	10	11	63	13	15	76
ROCK	Colorado	53	8	8	66	11	14	58
NWGB	Great Basin	45	7	7	99	17	22	30
MANN	Wisconsin	44	9	9	65	12	13	71
NWPN	Pacific Northwest	36	6	6	232	36	28	21

Table 2.3 shows subregion fossil fuel-use characteristics. It is ordered by total annual eGrid generation and shows the percentage of that generation by the coal, natural gas, and oil fuel classed discussed in Section 1.3.5, for 1998 through 2002. The percentages in the table do not always sum to one hundred percent because for some hours in those regions and years the fuel type could not be discerned using the carbon content method.

Figure 2.2. Total eGrid Generation in 2002



The difference in fuels used between subregions is notable although the majority of regions depend predominantly on coal for their fossil generation. A transition from coal to natural gas over the five years is evident in many subregions; this is particularly evident in California (CALI), which increases use of natural gas by almost 10% at the expense of coal. California's total eGrid generation also drops significantly between 2001 and 2002. A rise in the percentage of coal-fired generation and a drop in the natural-gas-fired-generation percentage accompany this drop revealing that natural gas units were turned off in response to decreasing overall demand.

The subregions are characterized to some extent by this summary data. The "size" of the subregion and its fuel portfolio play a significant role it its overall emission totals and emissions avoided by PV. The subtleties of a subregion's electric system, however, are masked by yearly totals and averages. For example, the total peak load and annual demand of the Northern Plains states (MAPP) and those of Florida (FRCC) are similar but the geographic and demographic characteristics are significantly different. Seasonal and daily demand patterns depend on these characteristics and cannot be distinguished from the annual totals.

Table 2.3. Fossil Fuel-use Characteristics of NERC Subregions

Subregion	Year	eGrid Total (TWh)	Coal (%)	Natural Gas (%)	Oil (%)	Subregion	Year	eGrid Total (TWh)	Coal (%)	Natural Gas (%)	Oil (%)
ECOV	**1998**	405	89	10	1	**CALI**	**1998**	60	41	58	1
	1999	410	87	13	0		**1999**	65	37	62	0
	2000	422	88	12	0		**2000**	93	27	72	0
	2001	399	86	14	0		**2001**	105	24	76	1
	2002	441	87	13	0		**2002**	75	33	67	0
ERCT	**1998**	216	51	49	0	**WSSW**	**1998**	73	96	4	0
	1999	213	53	47	0		**1999**	76	95	5	0
	2000	222	51	49	1		**2000**	86	89	11	0
	2001	209	52	48	1		**2001**	88	85	15	0
	2002	208	56	44	0		**2002**	90	83	17	0
SRSO	**1999**	169	94	6	0	**ECMI**	**1998**	72	87	13	0
	2000	173	91	9	0		**1999**	72	83	17	0
	2001	185	86	14	0		**2000**	80	92	7	0
	2002	182	83	17	0		**2001**	76	94	6	0
	1998	191	94	5	0		**2002**	71	90	10	0
MAAC	**1998**	146	86	6	8	**NYAS**	**1998**	52	43	37	20
	1999	141	76	14	10		**1999**	49	36	47	17
	2000	171	71	19	10		**2000**	56	36	51	13
	2001	164	71	20	8		**2001**	62	34	52	13
	2002	178	71	19	10		**2002**	67	35	56	9
MAPP	**1998**	151	97	3	0	**NEWE**	**1998**	56	34	19	46
	1999	150	97	3	0		**1999**	56	34	23	44
	2000	157	96	4	0		**2000**	65	36	38	26
	2001	160	97	3	0		**2001**	62	32	45	23
	2002	162	97	3	0		**2002**	66	41	40	19
SRVC	**1998**	146	91	7	2	**SPNO**	**1998**	45	93	7	0
	1999	147	90	8	2		**1999**	45	93	6	1
	2000	157	92	6	2		**2000**	47	92	7	1
	2001	152	90	7	3		**2001**	49	92	7	1
	2002	160	89	9	2		**2002**	56	91	8	0
MANS	**1998**	121	87	13	0	**ROCK**	**1998**	45	98	2	0
	1999	121	87	13	0		**1999**	46	95	5	0
	2000	133	87	12	0		**2000**	51	92	8	0
	2001	133	89	11	0		**2001**	53	89	11	0
	2002	136	90	10	0		**2002**	53	86	14	0
FRCC	**1998**	130	43	27	30	**MANN**	**1998**	45	86	14	0
	1999	124	41	30	28		**1999**	45	85	15	0
	2000	131	47	31	22		**2000**	48	91	9	0
	2001	134	48	29	23		**2001**	45	88	12	0
	2002	137	46	35	19		**2002**	44	85	15	0
SPSO	**1998**	112	65	34	0	**NWGB**	**1998**	44	91	9	0
	1999	112	66	34	0		**1999**	43	92	8	0
	2000	119	71	29	0		**2000**	46	90	10	0
	2001	117	70	29	1		**2001**	45	88	11	0
	2002	125	67	33	0		**2002**	45	91	9	0
SRMV	**1998**	103	55	44	1	**NWPN**	**1998**	35	85	15	0
	1999	109	54	46	0		**1999**	35	85	15	0
	2000	109	54	45	0		**2000**	37	84	16	0
	2001	107	56	43	1		**2001**	37	84	16	0
	2002	107	55	44	0		**2002**	36	82	18	0
SRTV	**1998**	97	98	2	0						
	1999	100	98	2	0						
	2000	107	98	2	0						
	2001	104	98	2	0						
	2002	105	97	3	0						

2.3 Analysis of Hourly Demand and Generation Data

2.3.1 Total Subregion Demand

As Fig. 2.3 shows, analysis of hourly data distinguishes important trends in a subregions' demand profiles. The graphs in Fig. 2.3 are representative of a type of analysis heavily relied upon in this report. Each graph plots a year of data (8760 hours) in a 365-day by 24-hour contour plot. These graphs will be referred to as 365x24 or 8760 graphs or plots throughout this report. In the case of total demand data, the data are normalized to the subregion's peak load in 2002. This allows the same color scheme to be utilized for all subregions even though the magnitude of peak and total generation vary greatly by subregion.

Patterns caused by weather and load growth are evident in the 365x24 plots of hourly demand. In summer-peaking regions like Texas (ERCT) demand is highest during the middle of the day in the summer while in winter-peaking regions like the Pacific Northwest (NWPN) demand is highest during winter mornings and evenings. Figure 2.3 shows the 365x24 total load graphs for 2002 for these and a few other regions. Appendix B shows contour plots for all subregions for the years 1998 through 2002. Figure 2.4 is an example of the figures shown in Appendix B. For these multi-year series of plots, demand is normalized to the subregion's 2002 peak. This allows load growth (or reduction) across the five years to be seen.

2.3.2 Analysis of Subregion eGrid Fossil Load

The eGrid hourly fossil generation can be analyzed in the same manner as the hourly demand. eGrid fossil generation is normalized to each subregion's 2002 maximum hourly eGrid generation. For subregions like SPSO (Oklahoma and surrounding areas) where generation is predominantly fossil-fuel based, the shape of the total load profiles are very similar to the shape of the eGrid fossil generation profiles (Fig. 2.5). In contrast, the Pacific Northwest (NWPN) utilizes a large amount of hydropower, and exports considerable generation to California, so its load and fossil generation plots are quite different. Notable in the Pacific Northwest's eGrid generation profile shown in Fig. 2.5 is the period between mid-April and July, when spring run-off supplies allows so much hydropower generation, that significant amounts of fossil generation is turned off.

Figure 2.3. Select Total Load Profiles Normalized to Subregion 2002 Peak

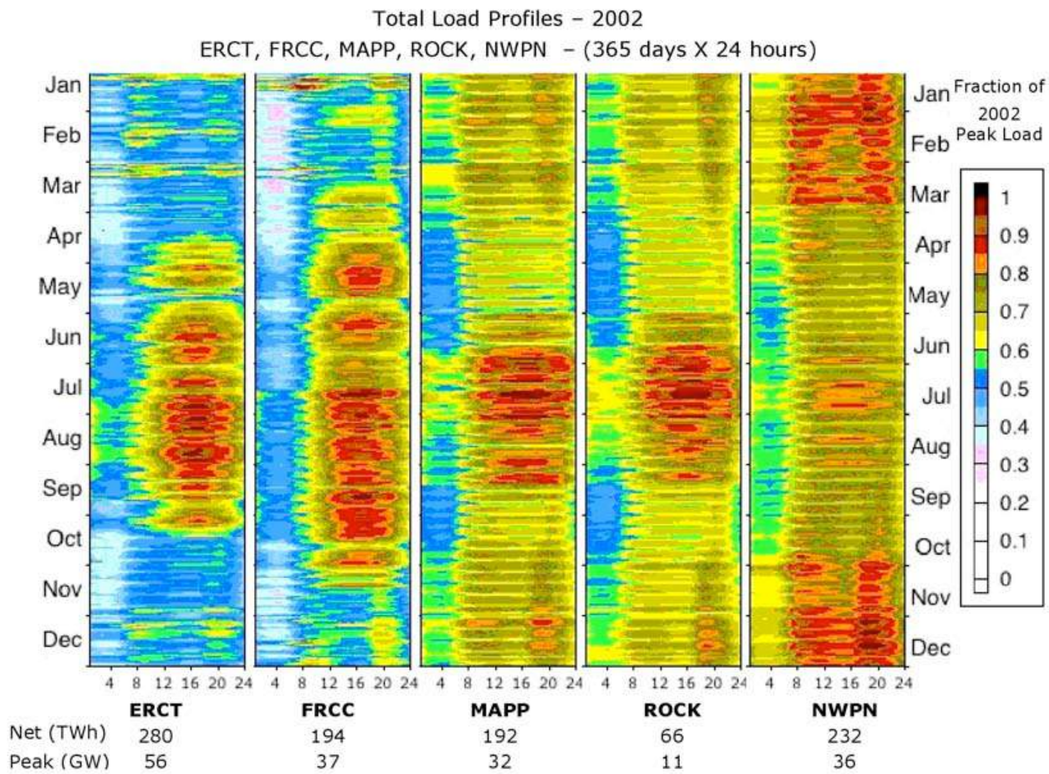


Figure 2.4. FRCC (Florida) Total Load Profiles Normalized to 2002 Peak

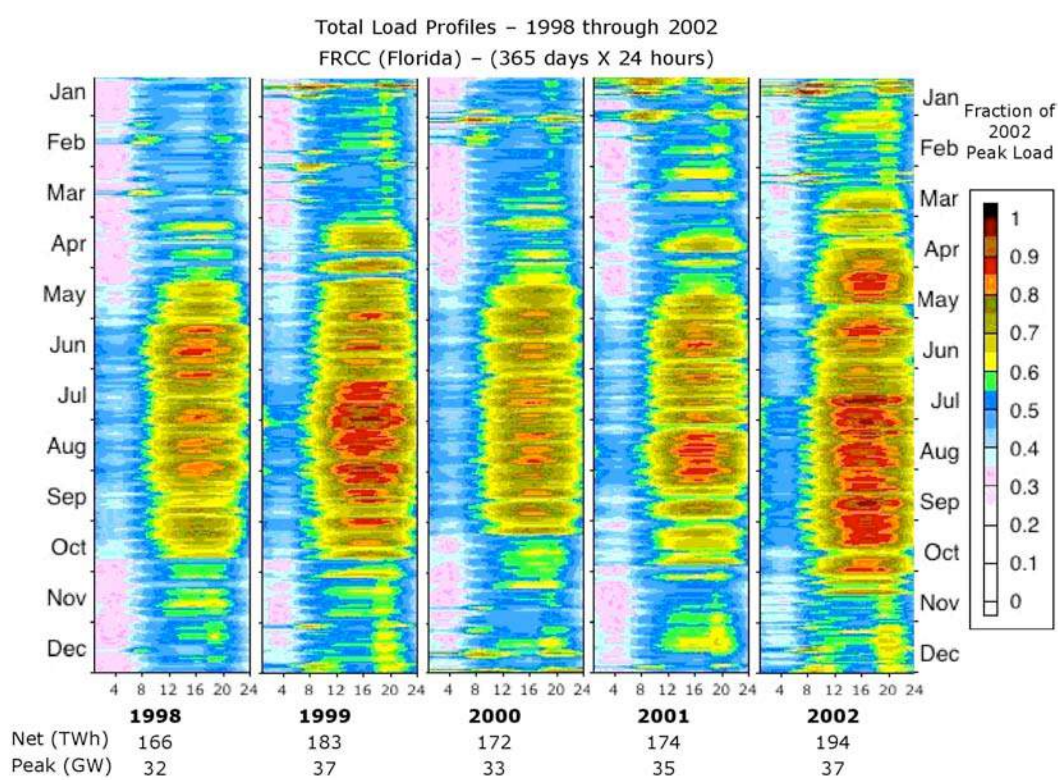
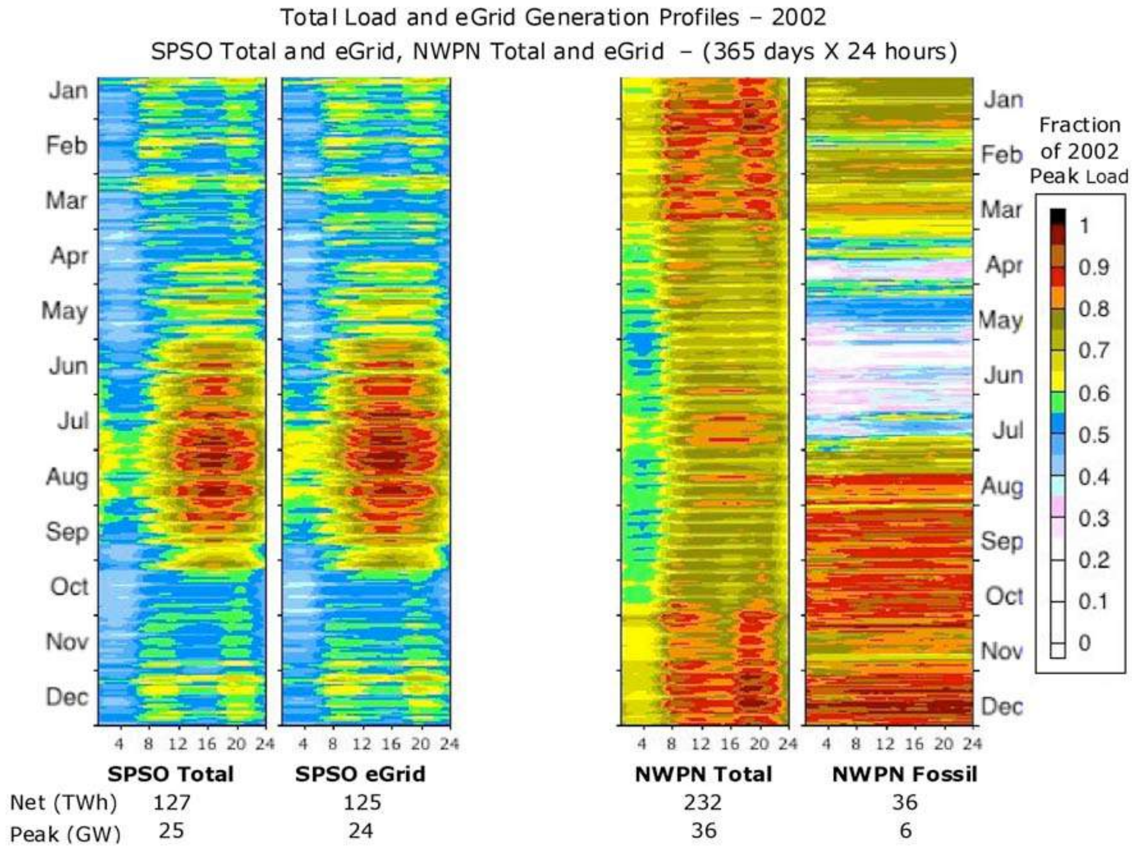


Figure 2.5. Total Load and eGrid Generation Comparison Illustrating Whether Fossil Generation Follows Regional Electricity Demand



2.4 Regional Demand and Load Shape Following

Analysis of the hourly data using the 365x24 plots clarifies the need for the load shape following logic. As discussed in Chapter 1.2, the main goal is to match PV generation with hourly fossil-unit generation to quantify its actual emissions reductions. PV is not going to offset emissions from units that respond little to changes in load, such as baseload generation (the blue regions on the plots in Fig. 2.4, for example). PV will offset units that are turned on to meet peak (mid-day) demand or units that increase their output in times of higher demand. The units offset by PV are those that follow the demand, as discussed in Chapter 1.3.4. These are the units that provide the power to fill peak demand, the yellow, orange, and red regions on the contour plots. The contour plots of demand and eGrid generation allow quick identification of the regions with peak demand that is coincident with times of largest PV generation potential: daytime hours although exact hours vary with factors like temperature and geography. An interesting nuance to the marginal units logic is hydropower's ability to respond to PV generation. This complexity and its effect on avoided emissions are discussed further in Chapter 3.

3 Emissions

3.1 Analysis of Hourly Data

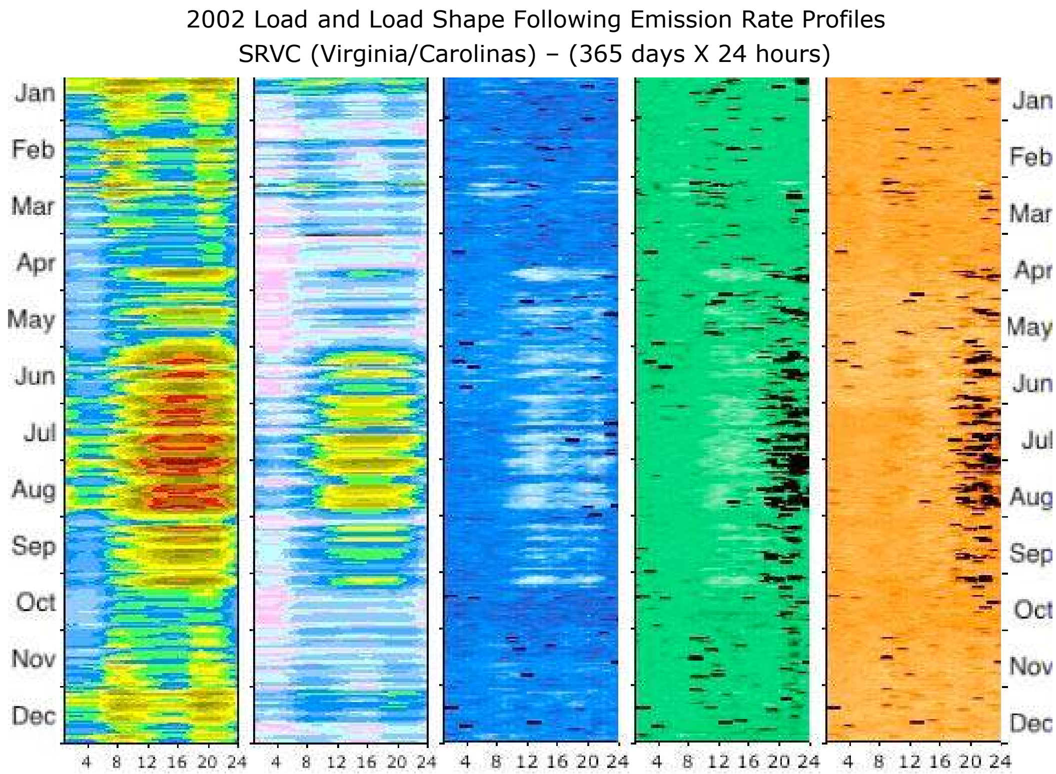
The addition of grid-connected PV to an electricity system results in a reduction in generation requirements by fossil and other units. Considerable amounts of PV generation might prevent a unit running in Spinning Reserve from moving to Full Load during times of peak demand. The emissions reductions from PV are those that would have been produced if the fossil unit had increased its power output. The efficiency of fossil fuel fired generators depends upon their load level, and output-based emission rates are often higher for units running in Standby or Spinning modes (lower load levels), than for those at Full Load. As a result, the avoided emissions from preventing a unit from increasing to full load are not proportional to a single emission rate. Analysis of the hourly unit-level data to calculate avoided emissions, rather than the use of regional and time averages, allows us to include these important complexities.

Larger amounts of PV or other non-emitting generation, greater than those generated by the SEPA PV site data used in this study, might prevent a peaking unit from turning on during times of peak load. Avoided emissions in this case could be more substantial. Analysis of this type would require an extension of the load shape following methodology, if fossil units were turned off as a result of non-dispatchable generation. Economic dispatch and transmission constraints would need to be included to determine which units would be turned on and off in certain circumstances.

The load shape following (LSF) logic identifies the units in a given hour and subregion that are affected by PV. To quantify the avoided emissions potential of PV in a given subregion the emissions of the load shape following units must be characterized. Again, the 365x24 contour plots lend themselves toward detailed inspection of the hourly data. The contour plots in Fig. 3.1 show the total demand, the eGrid hourly generation, and the avoided emission rates from one MWh of non-emitting generation in each hour of the year. This MWh of generation is allotted to units that are following load shape by weighting each unit's contribution by its change in load from the previous hour (this methodology is discussed in Chapter 1.3.3). The avoided emission rate graphs thus show the emissions from 1 MWh of generation from the units that are following load shape in the hour weighted by magnitude of change in output from the previous hour.

Figure 3.1 shows the total demand, eGrid fossil generation, and load shape following emission rates for the Virginia/Carolinas (SRVC) subregion in 2002. LSF SO2 emission rates are notably lower during times of peak demand (and accordingly peak eGrid generation). This trend is much more noticeable in the SO2 emission rate profile than in either the NOx or CO2 profiles. SO2 emission rates from natural gas fired units are significantly lower than those from coal and oil fired generators. The pattern of low load shape following emission rates during peak hours indicates the use of natural gas fired units to meet peak demand the subregion. These natural gas peaking units are load shape following during times of peak load since they are turned on only at these times.

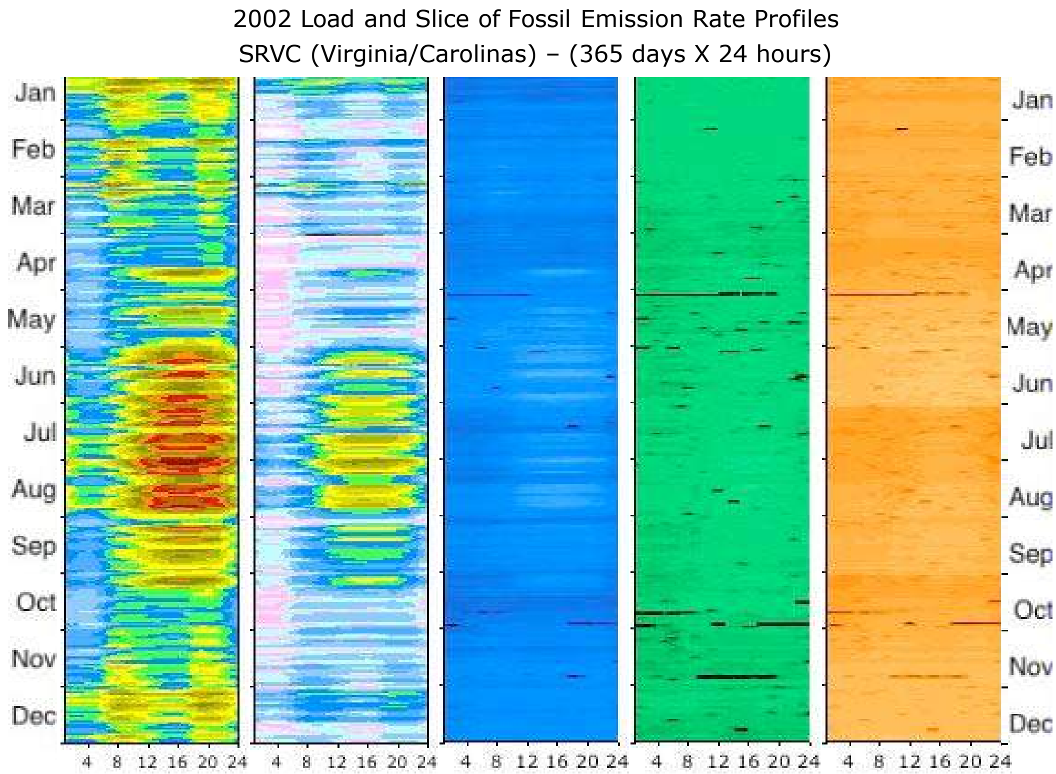
Figure 3.1. SRVC Demand, Generation, and Load Shape Following Emission Rate Profiles



	Total	Fossil	SO2	NOX	CO2	
Net (TWh)	304	160	4.6	1.9	845	Ave (kg/MWh)
Peak (GW)	58	42	40	17	7403	Total (t/8760MWh)

Figure 3.2 is a similar figure to Fig. 3.1 but it shows average emission rates from all eGrid units operating in each hour (e.g. Slice of Fossil (SOF) emission rates). It does not selectively show only the rates from those units that are load shape following in each hour. The difference between Fig. 3.1 and Fig 3.2 again stresses the importance of identifying marginal or LSF units for avoided emission calculations. PV generation will not affect the operation of all units so slice of fossil emission rates are not representative of the emissions that are avoided by the addition of PV generation to a subregion. In this case, the use of slice of fossil emission rates to calculate avoided emissions would have overestimated SO2 offsets and underestimated CO2 offsets.

Figure 3.2. SRVC Total Demand, eGrid Generation, and Slice of System Emission Rates

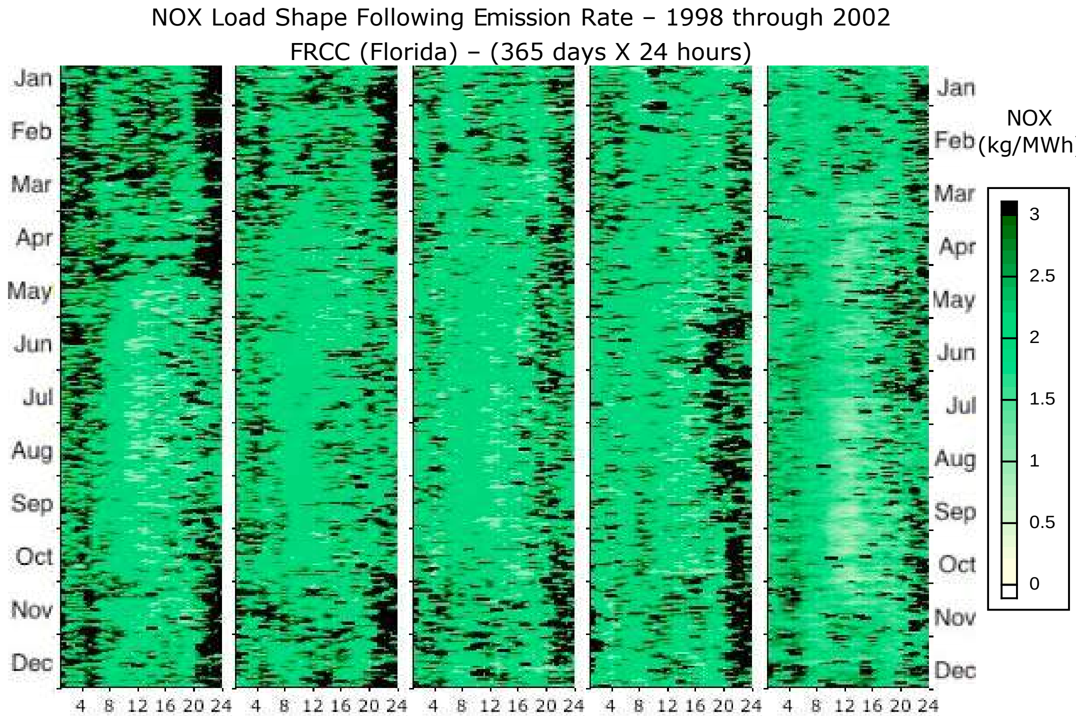


	Total	Fossil	SO2	NOX	CO2	
Net (TWh)	304	160	4.8	2.1	834	Ave (kg/MWh)
Peak (GW)	58	42	19	7	7303	Total (t/8760MWh)

The dark patches in the NOx and CO2 load shape following emission rate profiles (Fig. 3.1) that follow times of peak load are likely due to the inefficiency of running units at less than full load. As the units used to fill peak demand during the middle of the day are turned down and off, their emission rates are higher. These units are following the shape of the load and are therefore included in the load shape following logic. The units' outputs are increasing or decreasing rapidly in the direction of load so their emissions are weighted more heavily. These trends are not distinguished by a slice of system or average-emissions analysis.

Chronological trends from 1998 to 2002 are also apparent in the 365x24 graphs. Figure 3.3 shows all five NOx graphs for Florida (FRCC). The emission rates during times of peak demand decrease over the five-year period. This is likely the result of increased use of natural gas peaking units in Florida. Table 2.3 showed that the percentage of oil-fired generation decreased in the FRCC from 30 percent in 1998 to 19 percent in 2002 while that of gas-fired generation increases from 27 to 35 percent. The total eGrid generation grows in the FRCC by 7 TWh over this period with peak eGrid power increasing by 2 GW.

Figure 3.3. FRCC NOx Load Shape Following Emission Rates
for 1998 through 2002



	1998	1999	2000	2001	2002
Ave (kg/MWh)	2.2	2.2	1.9	1.9	1.8
Total (t/8760MWh)	19	19	17	17	16

The 365x24 graphs of load shape following emission rates for all subregions and years are shown in Appendices B.III through B.V. The compilation of the figures like Fig. 3.1 and 3.2 for all subregions are in Appendices B.VI and B.VII respectively.

3.2 Subregion Comparisons

The average LSF and SOF emission rates for 1998 through 2002 are compiled in Tables 3.1 through 3.3. The tables are sorted by subregion in order of decreasing average load shape following emission rate. This is the average for a single MWh per hour for every hour of the year, indicating the general emissions level of the subregion's fossil units, but not necessarily the avoided emissions from PVs or other non-dispatchable generation. The tables also include subregion rankings for both LSF and SOF emission rates. A ranking of one indicates the highest average emission rate of all the subregions; a bullet next to the LSF or SOF emissions rates indicates which is the higher of the two. The table of averages provides a quick reference for subregion to subregion and load shape following to slice of fossil comparisons, but the detail available from the hourly data is best analyzed using the graphs in the appendices. The maps shown in Fig. 3.4 and Appendix B are also useful in comparing subregion emission rates. The SO2 map clearly shows the regional fuel use patterns for coal: significantly more high sulfur coal is used in the Ohio Valley and surrounding subregions than in other areas of the country.

Figure 3.4. Maps of NERC Subregion Average Load Shape Following Emission Rates for 2002

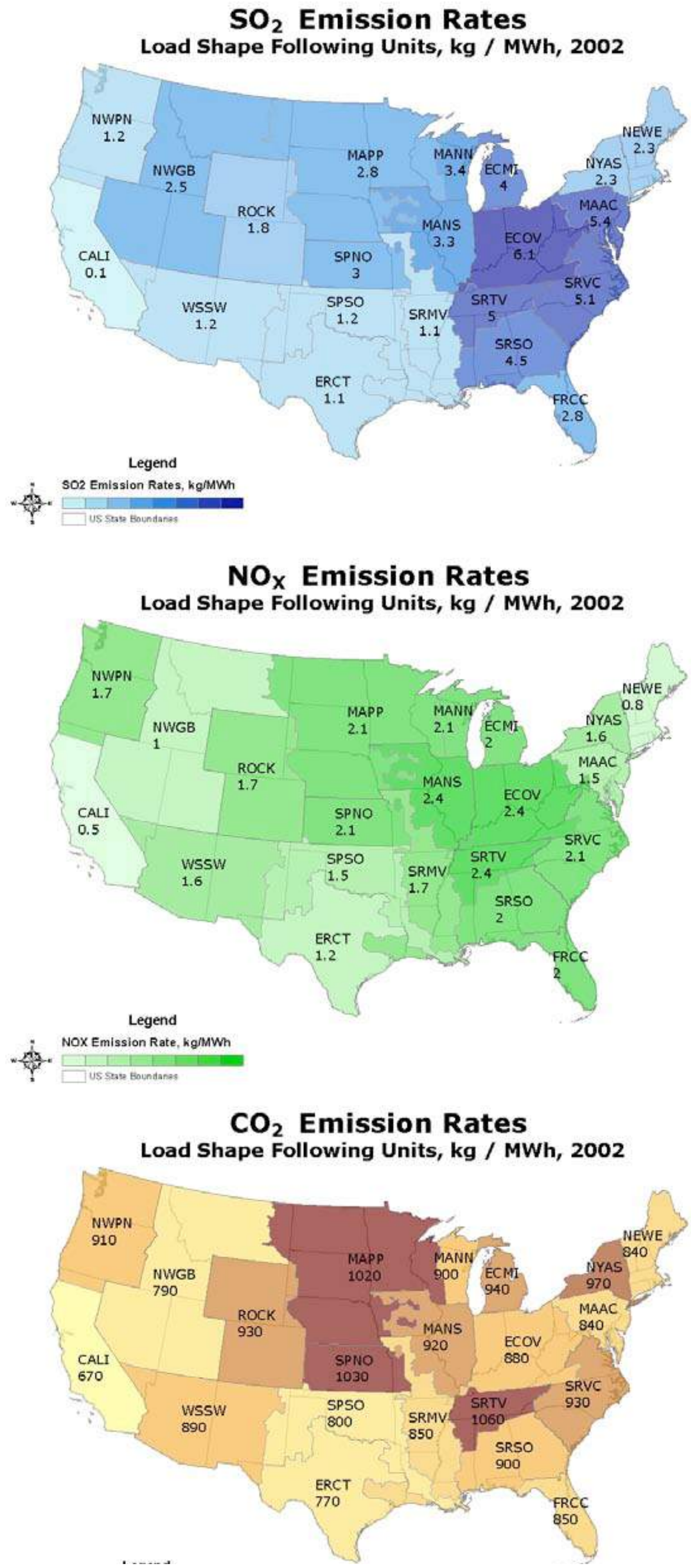


Table 3.1. Load Shape Following and Slice of Fossil Average Emission Rates for SO_2. *Bullets indicate which emission rate (LSF or SOF) is higher.*

Subregion	*SO2 LSF Emission Rates*			*SO2 SOF Emission Rates*		
ECOV		5.6	1	●	6.6	1
MAAC	●	4.9	2		3.5	8
SRVC		4.6	3	●	4.8	3
SRTV		4.6	4	●	5.5	2
SRSO	●	4.1	5		4.0	5
ECMI		3.6	6	●	3.8	6
MANN		3.1	7	●	3.7	7
MANS		3.0	8	●	4.1	4
SPNO		2.7	9	●	3.0	11
FRCC	●	2.5	10		2.4	12
MAPP		2.5	11	●	3.0	9
NYAS		2.3	12	●	3.0	10
NEWE	●	2.1	13		1.8	14
NWPN	●	2.1	14		1.8	15
ROCK		1.6	15	●	1.9	13
SPSO	●	1.1	16		1.0	17
NWGB		1.1	17	●	1.6	16
WSSW	●	1.0	18		0.9	18
SRMV	●	1.0	19		0.7	20
ERCT	●	1.0	20		0.8	19
CALI		0.1	21	●	0.1	21
		(kg/MWh)	Rank		(kg/MWh)	Rank

Table 3.2 Load Shape Following and Slice of Fossil Average Emission Rates for NOx. *Bullets indicate which emission rate (LSF or SOF) is higher.*

Subregion	*NOX LSF Emission Rates*			*NOX SOF Emission Rates*		
SRTV		2.2	1	●	2.3	5
ECOV		2.2	2	●	2.5	1
MANS		2.2	3	●	2.4	2
MANN		1.9	4	●	2.4	3
SRVC		1.9	5	●	2.1	6
SPNO		1.9	6	●	2.0	7
MAPP		1.9	7	●	2.3	4
ECMI	●	1.8	8		1.8	9
FRCC	●	1.8	9		1.8	11
SRSO		1.8	10	●	1.9	8
SRMV	●	1.6	11		1.5	14
NWGB		1.6	12	●	1.6	12
ROCK		1.5	13	●	1.8	10
WSSW		1.5	14	●	1.5	13
NWPN	●	1.5	15		1.2	16
SPSO		1.4	16	●	1.4	15
MAAC	●	1.3	17		1.1	17
ERCT	●	1.1	18		0.9	19
NYAS		0.9	19	●	1.0	18
NEWE	●	0.7	20		0.7	20
CALI		0.5	21	●	0.6	21
		(kg/MWh)	Rank		(kg/MWh)	Rank

Table 3.3. Load Shape Following and Slice of Fossil Average Emission Rates for CO_2. *Bullets indicate which emission rate (LSF or SOF) is higher.*

Subregion	*CO2 LSF Emission Rates*			*CO2 SOF Emission Rates*		
SRTV		961	1	•	973	3
SPNO		933	2	•	983	1
MAPP		928	3	•	974	2
NWPN	•	883	4		822	10
ECMI		858	5	•	954	4
ROCK		846	6	•	947	5
SRVC	•	845	7		834	9
MANS		832	8	•	906	6
NWGB		826	9	•	851	7
SRSO	•	820	10		777	14
MANN	•	814	11		803	13
WSSW		811	12	•	818	12
ECOV		801	13	•	841	8
SRMV	•	771	14		737	19
FRCC	•	769	15		755	16
MAAC	•	766	16		740	18
NEWE	•	763	17		760	15
SPSO		724	18	•	743	17
NYAS		721	19	•	818	11
ERCT		701	20	•	715	20
CALI		609	21	•	648	21
		(kg/MWh)	Rank		(kg/MWh)	Rank

3.3 Avoided Emission Rates for PM_{10}, $PM_{2.5}$, NH_3, VOCs, and Hg

The detailed analysis that the hourly emission data for SO2, NOx, and CO2 makes possible is not feasible for the other emissions in this report. For the emissions PM10, PM2.5, NH3, VOCs, and Hg only a single annual average input-based emission rate is available. Furthermore, this rate is only available on the plant-level, not the unit level. The rates were calculated by dividing 1999 emission totals by the 1999 annual heat input for the corresponding plant. Hg data is available from the eGrid summary data for all coal plants. Annual emissions totals for the other emissions are available through the EPA's National Emissions Inventory (NEI) database for 1999. Plants in the NEI database are organized by EPA's plant code. About 70% of these could be positively matched to the plant codes used in the eGrid data. This matching was necessary so that the emission totals could be used with heat rate data for 1999 from eGrid to develop average emission rates. The emission rates for these five emissions were then multiplied by the hourly heat rate data. These hourly estimates were used in conjunction with the load shape following logic to estimate load shape following emissions rates for PM10, PM2.5, NH3, VOCs, and Hg. The average annual load shape following rates for these emissions are shown in Table 3.4. The 365x24 contour plots were not used for analysis of these emissions because their hourly trends track heat rate exactly.

Table 3.4. Load Shape Following Emission Rates for PM_{10}, $PM_{2.5}$, NH_3, VOCs, and Hg

Average Load Shape Following Emission Rates (g/MWh)						
Subregion	Year	PM10	PM2.5	VOC	NH3	Hg
SRVC	1998	82	44	5	0.3	0.020
	1999	82	43	5	0.4	0.020
	2000	82	44	5	0.4	0.020
	2001	83	44	5	0.5	0.019
	2002	83	45	4	0.4	0.019
SRTV	1998	58	49	9	0.1	0.016
	1999	71	62	8	0.1	0.016
	2000	60	52	8	0.1	0.014
	2001	62	54	8	0.1	0.014
	2002	65	57	8	0.1	0.015
SRSO	1998	79	49	7	0.3	0.020
	1999	74	45	7	0.2	0.019
	2000	67	41	7	0.3	0.019
	2001	68	42	8	0.2	0.019
	2002	68	43	8	0.1	0.018
FRCC	1998	135	99	11	4.9	0.004
	1999	134	98	10	4.9	0.005
	2000	117	86	12	4.2	0.004
	2001	122	90	13	4.4	0.004
	2002	108	80	12	4.0	0.004
SRMV	1998	34	31	8	4.4	0.008
	1999	36	32	8	4.7	0.007
	2000	35	31	8	4.6	0.007
	2001	34	30	8	4.1	0.007
	2002	34	30	8	3.9	0.007

Average Load Shape Following Emission Rates (g/MWh)						
Subregion	Year	PM10	PM2.5	VOC	NH3	Hg
NEWE	1998	59	41	13	9.6	0.001
	1999	45	32	13	8.6	0.000
	2000	42	27	12	6.4	0.000
	2001	41	26	11	5.5	0.000
	2002	66	37	12	5.9	0.001
NYAS	1998	17	11	16	7.2	0.007
	1999	18	11	14	6.2	0.007
	2000	18	11	15	4.5	0.007
	2001	15	9	19	4.7	0.006
	2002	13	8	15	4.3	0.006
MAAC	1998	60	34	9	1.6	0.026
	1999	-	-	-	1.8	0.026
	2000	-	-	-	3.2	0.025
	2001	-	-	-	2.4	0.026
	2002	-	-	-	2.0	0.023
ECOV	1998	37	20	6	0.1	0.024
	1999	38	20	7	0.1	0.024
	2000	34	18	6	0.1	0.024
	2001	33	17	6	0.1	0.023
	2002	40	21	7	0.1	0.022
ECMI	1998	26	21	8	1.9	0.020
	1999	22	18	6	1.2	0.019
	2000	23	18	7	1.8	0.017
	2001	22	17	7	1.6	0.018
	2002	24	18	7	1.7	0.019

Average Load Shape Following Emission Rates (g/MWh)						
Subregion	Year	PM10	PM2.5	VOC	NH3	Hg
MANN	1998	34	30	7	0.1	0.017
	1999	21	17	7	0.1	0.019
	2000	25	21	6	0.1	0.017
	2001	20	15	7	0.1	0.018
	2002	23	18	6	0.1	0.017
MANS	1998	41	24	7	1.4	0.031
	1999	42	24	7	1.3	0.032
	2000	41	23	7	1.2	0.032
	2001	41	24	7	1.4	0.032
	2002	40	23	7	0.9	0.033
MAPP	1998	43	22	35	13.2	0.023
	1999	39	20	7	0.1	0.023
	2000	34	18	8	1.0	0.021
	2001	37	19	6	0.1	0.021
	2002	38	19	6	0.1	0.020
SPNO	1998	68	44	11	1.2	0.018
	1999	70	45	11	1.3	0.019
	2000	78	54	31	2.2	0.018
	2001	73	48	23	1.7	0.017
	2002	73	49	28	1.8	0.016
SPSO	1998	42	27	9	3.0	0.008
	1999	39	25	8	2.9	0.008
	2000	36	24	8	3.2	0.007
	2001	39	27	10	2.8	0.008
	2002	39	26	9	2.3	0.008
ERCT	1998	25	19	11	4.8	0.008
	1999	25	20	11	4.8	0.009
	2000	24	19	11	4.8	0.008
	2001	24	18	9	4.0	0.010
	2002	23	16	9	3.5	0.009

Average Load Shape Following Emission Rates (g/MWh)						
Subregion	Year	PM10	PM2.5	VOC	NH3	Hg
NWPN	1998	67	35	8	0.1	0.020
	1999	57	29	7	0.1	0.020
	2000	62	32	7	0.1	0.017
	2001	61	32	6	0.1	0.015
	2002	58	30	6	0.1	0.015
NWGB	1998	63	35	9	2.1	0.007
	1999	63	31	9	2.4	0.007
	2000	63	31	10	2.9	0.006
	2001	57	33	10	3.1	0.006
	2002	54	29	9	2.5	0.006
ROCK	1998	36	23	7	0.3	0.009
	1999	34	22	7	0.3	0.009
	2000	30	20	6	0.3	0.008
	2001	27	18	6	0.3	0.006
	2002	25	16	5	0.2	0.006
CALI	1998	37	35	6	3.4	0.001
	1999	36	34	6	3.6	0.001
	2000	32	31	5	3.7	0.000
	2001	29	28	5	3.1	0.000
	2002	27	26	5	2.9	0.000
WSSW	1998	72	47	8	1.4	0.019
	1999	67	45	9	2.1	0.016
	2000	57	40	9	2.4	0.013
	2001	54	37	9	2.3	0.011
	2002	53	35	7	1.4	0.012

(Data were not available for MAAC in 2000 through 2002.)

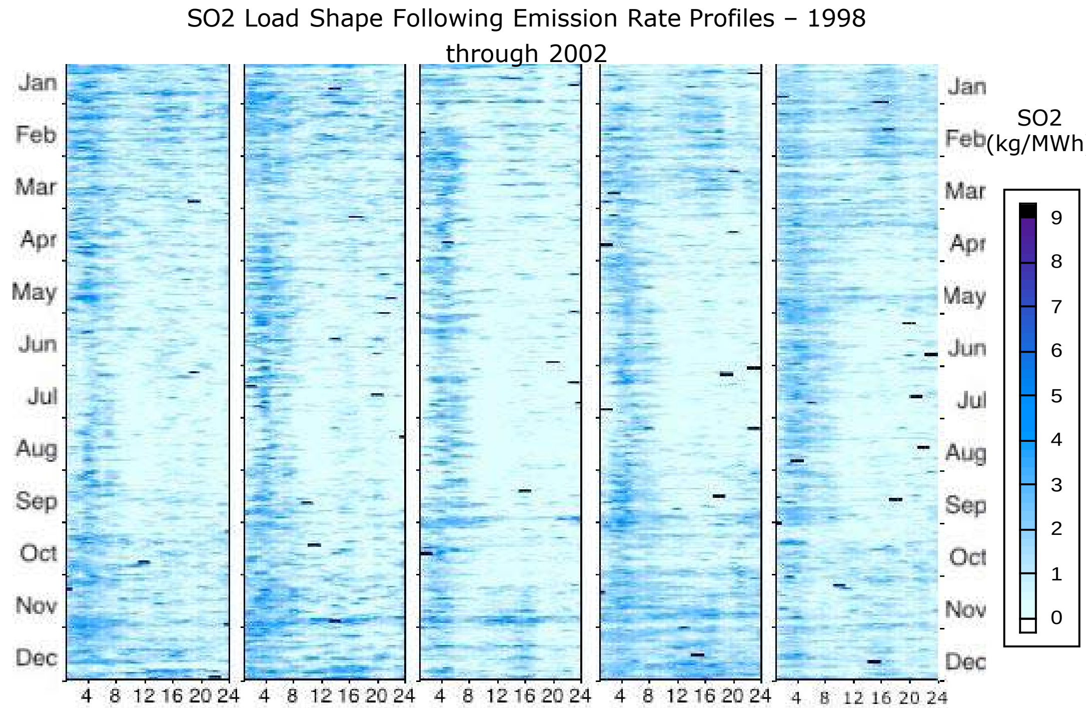
3.4 Outstanding Analysis Issues

3.4.1 Displaced Non-Fossil Generation

A complex issue that is difficult to quantify is the role played by hydropower in the load shape following logic. If hydropower is used in a subregion to meet peak demand there is the possibility that PV generation during the middle of the day will displace the use of that hydropower to later, instead of offsetting fossil generation exactly in that hour. The length of time the hydropower is displaced depends upon factors unique to the particular hydro-system (reservoir size, flow rate, etc.). Without specific knowledge of the hourly hydro generation for each subregion it is impossible to know exactly how much or for how long hydro generation might be displaced. In the case that such displacement did occur, however, there will still be an impact on the avoided emissions. The PV generation would not avoid the emissions released in coincident hours but instead during hours later in the day when the hydro generation was eventually used. In some subregions the marginal emission rates are worse later in the day or in the early mornings than they are during the middle of the day. In these cases the emissions avoided by use of PV would be greater than if the hydropower were not present.

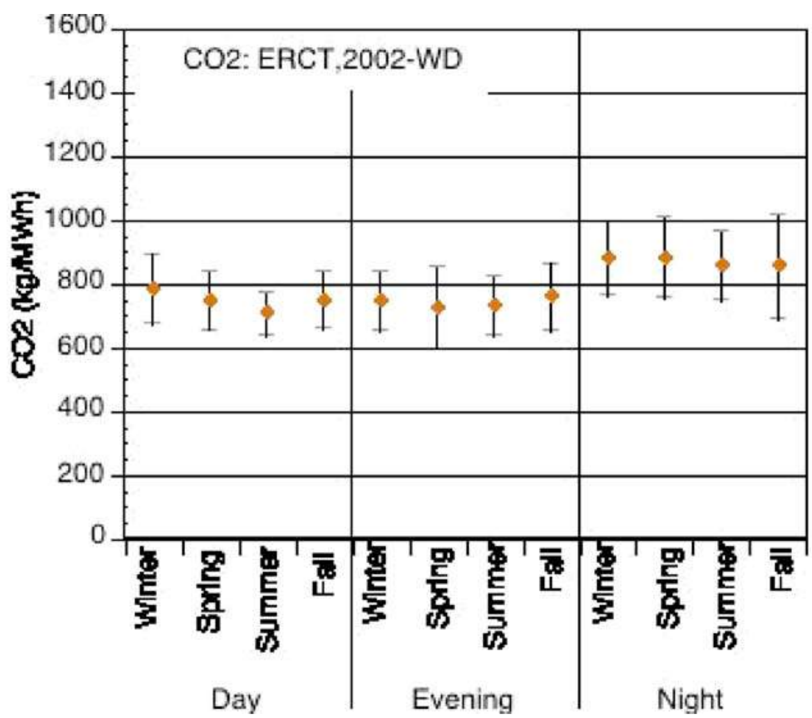
Texas (ERCT) is a good example. Figure 3.5 shows SO_2 emission rates for load shape following generation for 1998 through 2002 in ERCT. As seen in Fig. 3.5, the emission rates during the middle of the day in ERCT are often low while they are significantly higher during the early mornings. Figure 3.6 shows averages and standard deviations for load shape following emission rates in Texas in 2002. The daytime hours are from 6am to 7pm; evening hours are from 7pm to 11pm; and nighttime hours are from 11pm to 6am. The seasons are: summer – June through August, winter – November through February, and spring – March through May, and fall – September through October. The nighttime emission rates in all seasons are significantly higher than those in the daytime or evening. A similar phenomenon occurs in Florida (FRCC) in NO_x emission rates (Fig. 3.3) and in many of the other regions to varying extent (see Appendix B). This also presents an interesting opportunity for the strategic use of electricity storage to reduce emissions. Averages and standard deviations for all subregions are in Appendix B.

Figure 3.5. ERCT SO2 Load Shape Following Emission Rate Profiles



	1998	1999	2000	2001	2002
Ave (kg/MWh)	1.1	1.1	0.8	1.0	1.0
Total (t/8760MWh)	9	9	7	9	9

Figure 3.6. ERCT 2002 SO2 Load Shape Following Emission Rate Statistics (Average and Standard Deviation)



Another issue with non-fossil generation is the use of nuclear power. This concern, however, is not as complex as the hydropower situation. Nuclear power is almost exclusively used to fill baseload demand and it is therefore an assumption of this analysis that nuclear generation is not displaced by PV generation.

3.4.2 Interregional Power Flow

Interregional power flow across subregions is another complex issue that the data are not specific enough to unravel. As discussed at the beginning of Chapter 2, the eGrid generation is gross unit generation and the region in which it is actually consumed cannot be deciphered. If peak demand is always filled by generating units in the subregion in which that demand occurs then interregional power flow is not an issue. The transfer of baseload power is not a concern because we do assume that PV generation will not offset baseload generation. If this analysis were extended to other renewable generation technologies this complexity would become more of an issue.

4 Photovoltaic System Performance

4.1 Summary of Photovoltaic Power Systems

Information on solar resource and PV system performance came from numerous EPA sponsored installations as well as Solar Electric Power Association (SEPA) and Schott Applied Power (formerly Ascension Technology) installations. Each site had both a PV array generating power as well as varying pieces of solar radiation-measuring equipment. In the data provided, some systems had information as far back as 1996. Only the data from 1998 through 2002 were used.

The installations were dispersed over various subregions, as shown in Figure 4.1's map

4.2 Monitored PV Systems

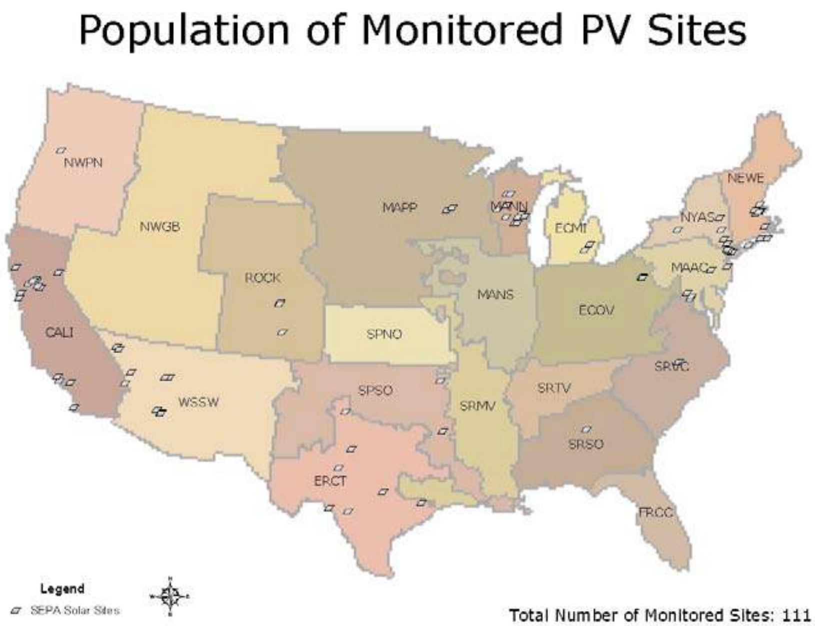
The actual emission reductions are from monitored PV systems. The PV systems were monitored following two earlier research reports completed by Daniel Greenberg and Edward Kern of Ascension Technologies for the EPA.[1] The data retrieval and quality assurance (QA) analysis for the monitored PV system generation and resource data was completed in accordance with the Quality Assurance Project Plans (QAPPs) described in these reports.

The population of monitored PV systems shown in Fig. 4.1 have varying dates of information available. Lack of data at specific dates can be due to later installation dates, system downtime, and other data loss not caused by system downtime. Since inoperative PV systems provide no data, it is assumed that degradation in PV system output is due mainly to meteorological and natural elements such as clouds, snow, shade, and debris. A summary of the PV systems and the associated available monitored dates can be found in Table 4.1 and 4.2.

The emissions offset assessment uses the generation data from these monitored sites. In the actual assessment, no estimations or projections are completed. The assessment estimates only the offsets from actual monitored generation. Chapter 5 discusses the solar resource data, which is used for a more thorough assessment of the variation in emission offset potential across subregions, including ones where there were no monitored PV systems available.

[1] EPA-600/R-96-130. "Demonstration of the Environmental and Demand-Side Management Benefits of Grid-Connected Photovoltaic Power Systems." November 1996; and EPA-600/R-99-061, "Demonstration of the Environmental and Demand-Side Management Benefits of Grid-Connected Photovoltaic Power Systems on Military Bases." July 1999.

Figure 4.1. Locations of All Monitored PV Sites



4.3 PV System Performance

The performance of the PV systems was tallied in several ways. First, the solar resource information was used to compare the relative fitness of different regions for PV generation, shown in Fig. 4.2.

Figure 4.2. Subregion Solar Resource Availability

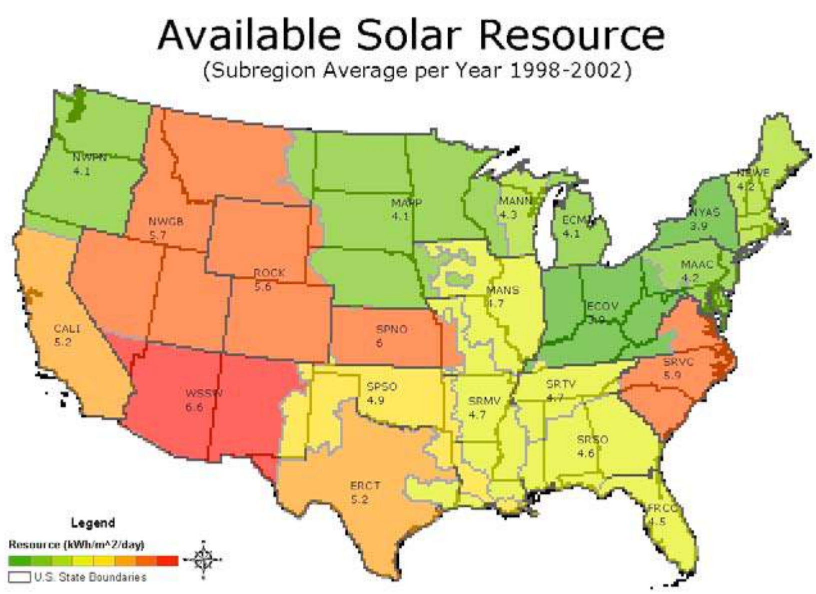


Table 4.1. Monitored PV Site Availability, CALI-MANN

System Characteristics						Availability Information % of Hours Data Available				
Sub-region	**Site Number**	**City**	**State**	**First Monitored Date**	**System Rating (kW)**	**98**	**99**	**00**	**01**	**02**
	1	Sacramento	CA	27-Jun-97	5.4	100	100	100	100	58
	2	Sacramento	CA	7-Jul-97	5.8	100	100	100	100	100
	3	Sacramento	CA	14-Jul-97	4.6	100	100	100	49	
	4	Sacramento	CA	22-Jul-97	6.1	100	50			
	5	Davis	CA	6-Aug-97	4.6	100	100	47		
	6	Sacramento	CA	2-Feb-98	409.2	66	100	13		
	7	Alameda	CA	22-Mar-98	5.0	78	100	100	100	79
	8	Sacramento	CA	30-Jun-98	141.8	50	100	100	15	
	9	Davis	CA	20-Oct-98	4.8	20	100	46		
	10	Chino Hills	CA	10-Nov-98	9.5	21	100	100	100	100
	11	Davis	CA	5-Jan-99	4.4		94	41		
CALI	12	Davis	CA	8-Jan-99	2.3	35	100	47		
	13	City of Industry	CA	1-Apr-99	127.7		82	100	100	55
	14	Belmont	CA	30-Apr-99	4.8		67	100	14	
	15	Vacaville	CA	30-Apr-99	4.6		67	84	100	100
	16	Hopland	CA	22-Jun-99	39.6		47	100	42	
	17	Buena Park	CA	2-Jul-99	34.7		50	16		
	18	Santa Monica	CA	2-Jul-99	41.3		50	33	9	
	19	Truckee	CA	28-Oct-99	2.2		27	100	100	89
	20	San Diego	CA	20-Dec-99	25.7		4	100	11	
	21	Carmichael	CA	23-Feb-00	5.6			86	76	
	22	Sylmar	CA	21-Sep-00	1.5			26	62	
	23	Sylmar	CA	26-Oct-00	1.5			7	100	100
	24	Ann Arbor	MI	1-Jun-96	34.2	100	100	100	95	73
ECMI	25	Southfield t	MI	16-Oct-97	15.8	97	99	100	97	
	26	Southfield f	MI	16-Oct-97	16.2	97	99	100	97	
	27	Pittsburgh	PA	29-Mar-99	2.6		51	79		
ECOV	28	Perryburg	OH	15-Aug-00	18.0					
	29	Pittsburgh	PA	17-Nov-00	31.9			12	100	100
	30	Abilene	TX	2-Jul-97	2.3	100	100	100	100	79
	31	Austin	TX	26-Aug-98	32.4	35	100	45		
	32	Austin	TX	6-Nov-98	10.8	16	100	100	100	100
	33	Austin	TX	11-Dec-98	111.6	6	100	100	100	67
	34	Childress	TX	5-Jul-99	4.6		52	100	24	
	35	Uvalde	TX	11-Aug-99	4.6		35	95	24	
ERCT	36	Del Rio	TX	13-Aug-99	4.6		38	100	24	
	37	San Angelo	TX	13-Aug-99	4.6		38	100	17	
	38	Abilene	TX	20-Aug-99	4.6		37	100	24	
	39	Austin	TX	27-Oct-99	7.2		18	100	100	23
	40	Austin	TX	3-Jan-00	1.8			100	70	
	41	Houston	TX	23-Sep-00	27.4					
	42	Houston	TX	9-Nov-00	8.4			18		
	43	Germantown	MD	12-May-98	3.3	64	100	100	100	100
	44	Lakewood	NJ	12-May-98	2.6		77	57		
	45	Arlington	VA	25-Oct-99	17.1		29	99	64	61
MAAC	46	Arlington	VA	25-Oct-99	18.2		16	99	64	61
	47	Plymouth Meeting	PA	25-Oct-99	61.2		20	100	100	100
	48	Suitland	MD	5-Oct-00	122.5			24	97	88
	49	Largo	MD	30-Oct-00	16.2			1	11	
	50	Antigo	WI	30-Jul-96	13.7	100	100	100	83	100
	51	Brussels	WI	8-Aug-96	13.7	100	100	100	100	34
	52	Green Bay	WI	23-Oct-96	13.7	100	93	100	100	100
	53	Mosinee	WI	10-Aug-98	4.6	33	100	100	100	62
	54	Waupaca	WI	10-Aug-98	4.6	42	100	47		
	55	De Pere	WI	10-Aug-98	4.6	42	100	100	100	23
	56	Crandon	WI	1-Oct-99	2.3		25	52		68
MANN	57	Pulaski	WI	1-Oct-99	2.3		25	100	100	100
	58	Oshkosh	WI	1-Oct-99	2.3		28	64	23	
	59	Laona	WI	3-Nov-00	2.9			22	26	69
	60	Oshkosh	WI	18-Oct-00	2.4			24	93	100
	61	Denmark	WI	10-Oct-00	2.4			23	100	100
	62	Green Bay	WI	11-Oct-01	2.4				22	78
	63	Wausaukee	WI	4-Oct-01	2.4				24	76
	64	Merrill	WI	9-Oct-01	2.4				8	92

Table 4.2. Monitored PV Site Availability, MANS-WSSW

System Characteristics						Availability Information % of Hours Data Available				
Sub-region	**Site Number**	**City**	**State**	**First Monitored Date**	**System Rating (kW)**	**98**	**99**	**00**	**01**	**02**
MAPP	65	Minnetonka	MN	10-Jun-96	2.9	100	100	100	100	100
	66	Rosemount	MN	1-Jul-96	2.3	100	100	100	18	
	67	White Bear Lk	MN	1-Jul-96	2.9	100	100	94	100	100
NEWE	68	Chelmsford	MA	2-Aug-97	2.3	100	100	16		
	69	West Newbury	MA	9-Sep-97	4.6	100	100	74	96	32
	70	Lynn	MA	3-Oct-97	4.6	100	100	100	100	100
	71	North Dartmouth	MA	14-Dec-98	1.1	5	100	100	100	100
	72	North Dartmouth	MA	14-Dec-98	1.0	5	100	100	100	100
	73	North Dartmouth	MA	14-Dec-98	13.7	5	100	100	100	100
	74	Medford	MA	23-Feb-99	2.3		61			
	75	Cambridge	MA	4-Oct-99	22.8		24	100	100	100
	76	Middletown	RI	31-Mar-00	63.8			75	100	100
	77	Boston	MA	31-May-00	37.1					
	78	Block Island	RI	22-Jun-01	5.7				53	100
	79	Waltham	MA		0.2					
NWPN	82	Portland	OR	7-Aug-00	2.4			32	14	
	83	Portland	OR	1-Sep-00	2.4			33	43	
NYAS	84	Vestal	NY	27-Sep-96	2.3	100	100	9		
	85	Dundee	NY	8-Oct-96	2.3	100	100	4		
	86	Tuckahoe	NY	12-Apr-98	23.2	72	81			
	87	Bronx	NY	20-Apr-98	331.8	71	81			
	88	Yonkers	NY	23-Apr-98	110.6	79	100	100	56	
	89	New Scotland	NY	30-Sep-98	130.2	26	100	100	98	
	90	Millwood	NY	1-Nov-98	7.6	12	100	94	25	
	91	New Paltz	NY	4-Mar-99	6.5		83	95	24	
	92	Old Westbury	NY	2-Nov-99	18.2		17	100	100	100
	93	Amsterdam	NY	4-Jan-00	7.6			98	100	100
	94	Jones Beach	NY	16-Feb-02	11.0				38	100
ROCK	95	Cherry Creek	CO	12-Jul-96	27.6	5				
	96	Pueblo	CO	9-Jul-99	3.8		48	100	93	
	97	Denver	CO	6-Aug-99	2.4		40	7		
	98	Denver	CO		2.4					
	99	Denver	CO		2.4					
	100	Golden	CO		2.4					
	101	Pine	CO		0.9					
SPSO	102	Texarkana	AR	27-Aug-99	4.6		35	100	24	
	103	Fayetteville	AR	3-Sep-99	4.6		33	100	24	
SRSO	104	LaGrange	GA	12-Mar-99	18.2		87	100	100	100
SRVC	105	Raleigh	NC	22-Jan-97	3.9	94	85			
WSSW	106	Las Vegas	NV	18-Sep-96	4.2	100	34			
	107	Phoenix	AZ	30-Jul-97	4.6	100	49			
	108	Kingman	AZ	23-Jan-98	5.4	94	100	23		
	109	Lake Havasu	AZ	23-Jan-98	4.6	92	95	100	100	1
	110	Flagstaff	AZ	23-Feb-98	94.5	70	99	47		
	111	North Las Vegas	NV	21-Mar-98	24.3	61	74			
	112	Tempe	AZ	11-Apr-98	94.5	71	100	97	36	
	113	Gilbert	AZ	1-Sep-98	113.4	20	97	70		
	114	Tempe	AZ	27-Jan-99	48.6					
	115	Phoenix	AZ	19-Aug-99	4.6		37	100	100	50
	116	Flagstaff	AZ	15-Sep-99	2.3		30	63		
	117	Gilbert	AZ	17-Nov-99	2.3		12	100	100	70

Note that resource measurements were taken from SEPA solar installations in every region except FRCC, MANS, NWGB, SPNO, SRMV, and SRTV where information from various solar resource monitoring networks was used. More details on the resource networks are in Chapter 5.

System performance was tallied using two separate metrics: the generation per monitored capacity (Gmc) (Fig. 4.3) and the effective system capacity factor (CFe) (Fig. 4.4). The generation per monitored capacity was tallied for each year and then averaged over the five years. The generation per monitored capacity was obtained by the following equation:

$$G_{mc} = \frac{\sum_{Years}\left(\sum_{Hours}\frac{\sum_{Systems} kW_{gen}}{\sum_{Systems} kW_{cap}}\right)}{Years}$$

The effective system capacity factor is much like the capacity factor for normal generating units:

$$CF_e = \frac{\sum_{Hours}\sum_{Systems} kW_{gen}}{8760 * kW_{rating}}$$

An excellent number for a PV system in terms of capacity factor is around 0.2 depending on the latitude.

A few selected regions are displayed here in 365x24 format used to analyze the load and emission rate in previous chapters. Four separate regions for 1998 through 2002 are displayed here: ERCT (Texas), MAPP (Northern Plains), WSSW (Southwest), and NWPN (Pacific Northwest). The generation and capacity are aggregated across all PV sites present in the subregion. Note that the capacity varies hourly as new sites come online and other sites fall off monitoring. In this sense, the total aggregate rating of all PV sites in a single subregion is called the "monitored PV capacity."

The generation numbers in the graph are normalized to the monitored PV capacity. Therefore, the equation for the generation on each hour (Gin hour) on the graph (represented by a 1x4 pixel area) is:

$$G_{\text{in hour}} = \frac{\sum_{Systems} kW_{gen}}{\sum_{Systems} kW_{cap}}$$

Texas is an example of a region with well-behaved and consistently operating PV systems. Most of the variations viewed in the figure are weather variations. Even though systems go in and out of monitoring (witnessed by the peak of PV production in 2000), the generation per monitored capacity of the remaining systems are consistent, as illustrated in Figure 4.5.

Figure 4.3. PV Generation per Monitored Capacity
(SEPA Sites: 1998-2002)

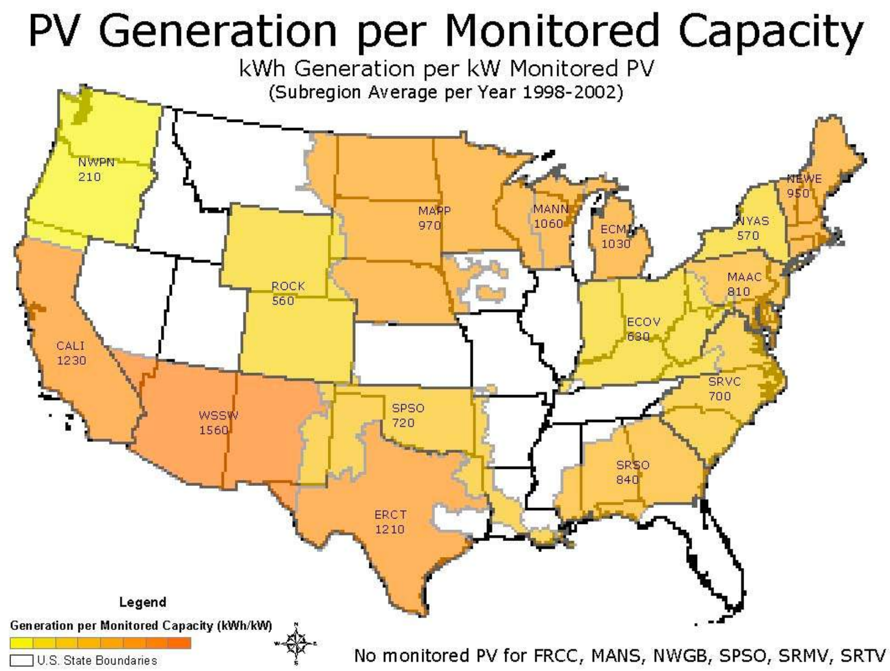


Figure 4.4. Effective PV Capacity Factor

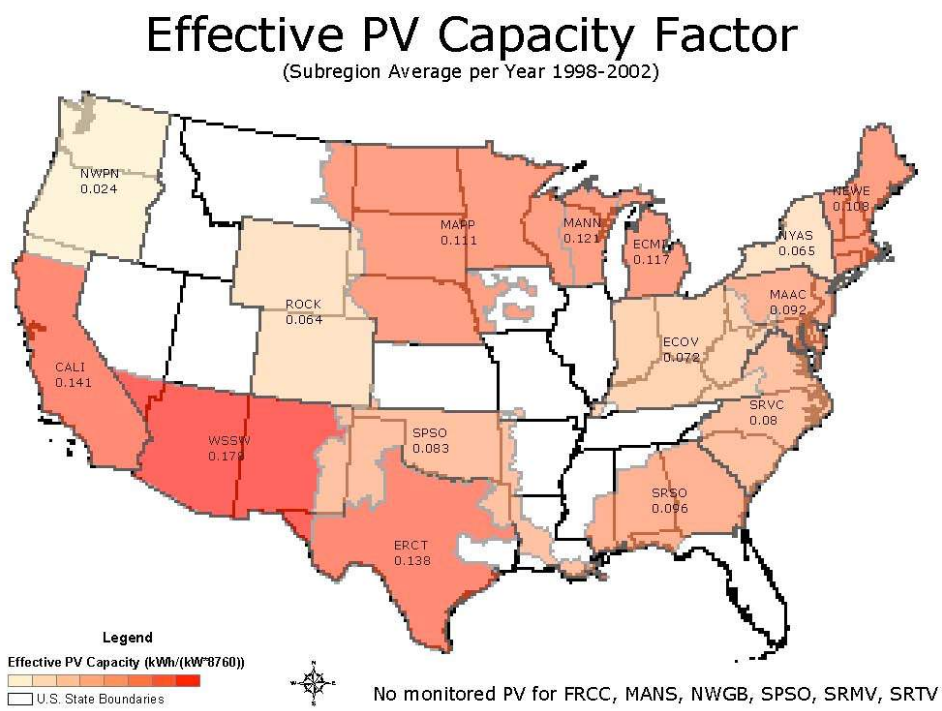


Figure 4.5. PV Generation per Monitored Capacity - ERCT (Texas)

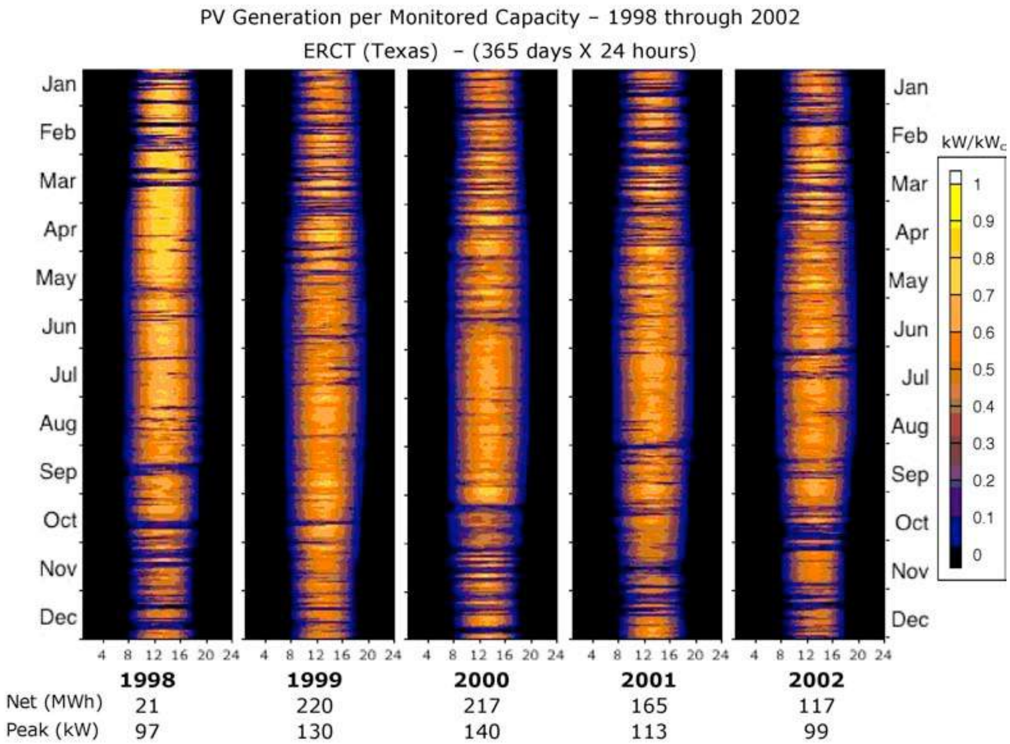
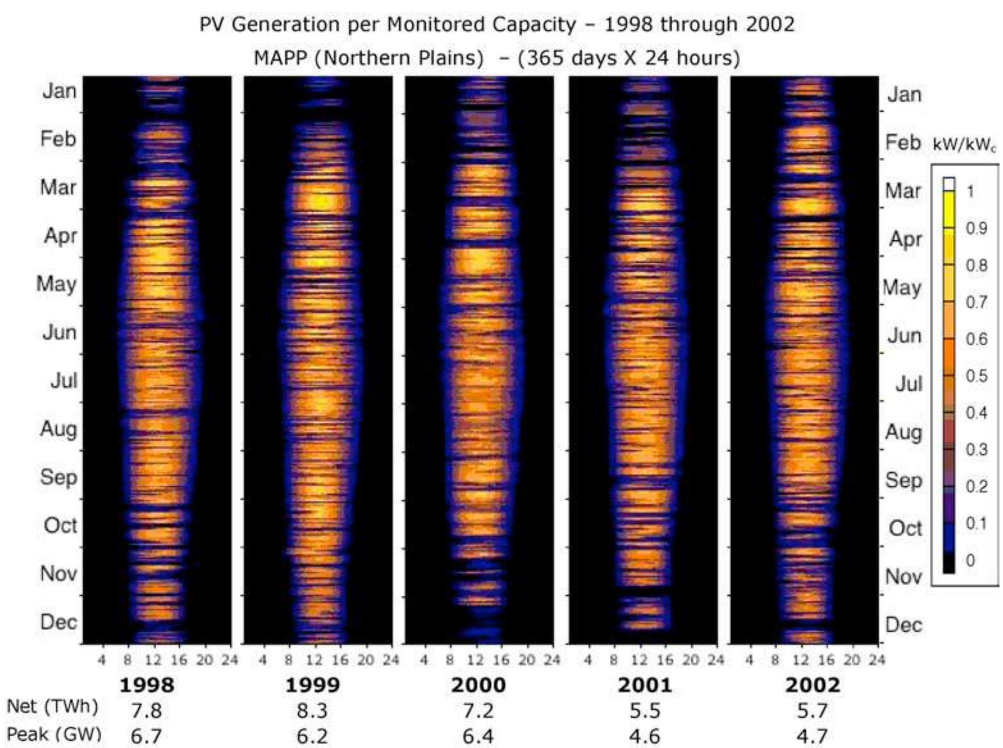


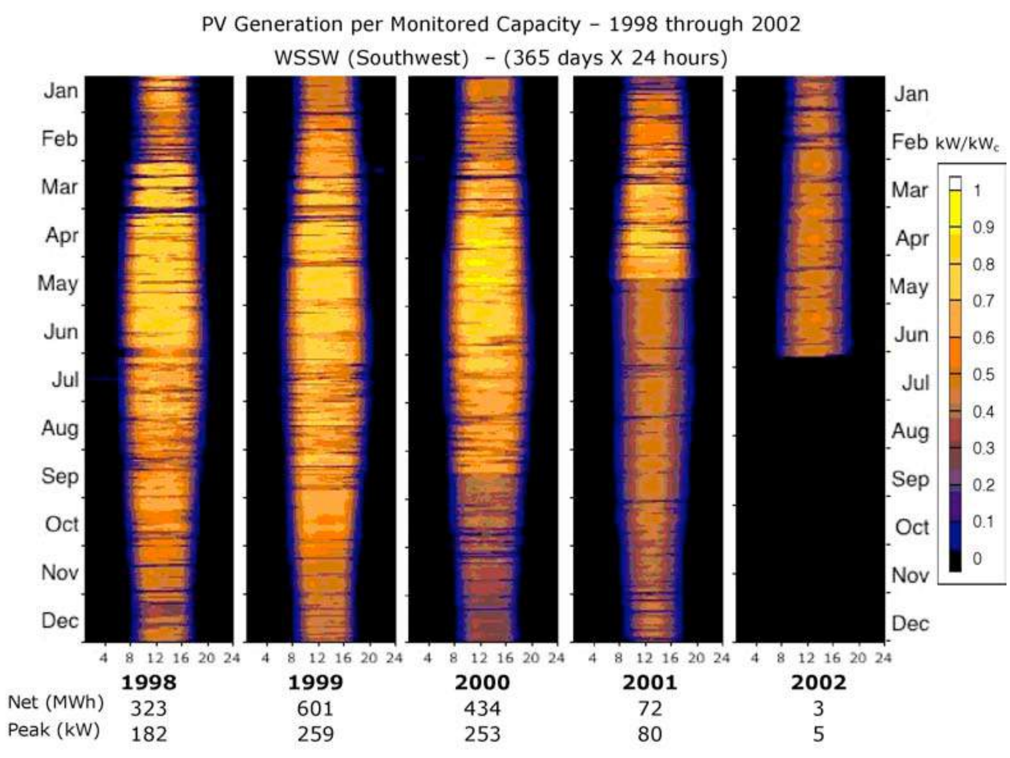
Figure 4.6. PV Generation per Monitored Capacity - MAPP (Northern Plains)



The Northern Plains sub-region is a demonstration of a region with much fewer PV modules installed, yet still maintaining strong overall system performance. Seasonal performance interruptions caused by snow can be seen in this region in the winter months (Figure 4.7)

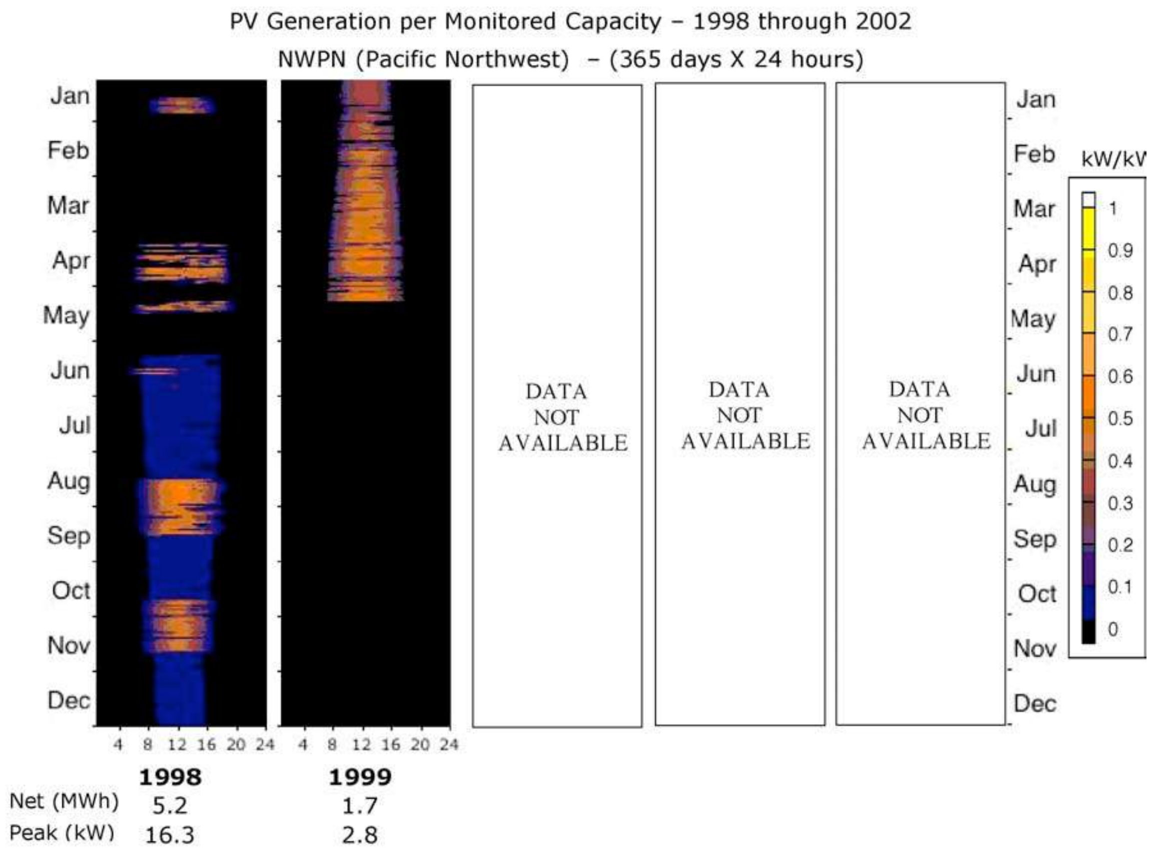
The Southwest contained the best performing systems in terms of both generation per monitored kW and capacity factor when aggregated over all years. The 365x24 graphs reveal this in the broad daily generation throughout the year and consistently vibrant generation in the spring and early summer. The Southwest is also an example of how the loss of systems can give deceiving performance results (Figure 4.8). In both 2000 and 2001, large systems drop off of monitored status mid-year, leaving only a small, underperforming system left in the subregion in 2002. Looking only at the single system available in 2002 might leave an observer believing performance of potential PV systems in the Southwest was poor.

Figure 4.7. PV Generation per Monitored Capacity - WSSW (Southwest)



The Pacific Northwest is an example of a sub-region where data was inconsistent throughout the time span analyzed (Figure 4.8). A few small systems come in and out of monitored status, providing only a patchwork glimpse of the seasonal and diurnal variations of PV generation.

Figure 4.8. PV Generation per Monitored Capacity – NWPN (Pacific Northwest)



The availability of data from the installed base of PV systems is an element of consideration when assessing the total emission reductions. In comparing subregions, it is more useful to compare offsets per monitored kW in the region, rather than total offsets. The disparity between actual offsets and offset rates is discussed further in Chapters 6 and 7.

5 Solar Resource Information

5.1 Purpose of Solar Resource Data

As demonstrated in Chapter 4, the SEPA PV system installations with monitoring ability are not evenly distributed across the nation. As a result, several NERC subregions are left without adequate PV system generation information in order to calculate potential avoided emissions. The availability of the systems throughout any given year was not consistent region to region. In order to provide a more significant comparison of the emission reduction potential region to region, solar resource information for each region was utilized in order to model PV generation output. The model, discussed further in section 5.3, allows for the analysis to remove the variability in PV system performance caused non-meteorological based events. Thus, the variability in solar resource and emission profiles are solely accountable for the emission reduction variations.

5.2 Overview of Solar Resource Networks

The comparison analysis required an entire year's worth of solar resource data for every subregion. In order to assure complete coverage, three solar resource networks were used, in addition to solar radiation data from several of the SEPA installations. Two networks, organized by the National Oceanic and Atmospheric Administration (NOAA), were:

- Surface Radiation Budget Network[1] (SURFRAD)
- Integrated Surface Irradiation Study[2] (ISIS)

An additional network, the Cooperative Networks For Renewable Resource Measurements (CONFRRM), overseen by the National Renewable Energy Laboratory (NREL), was also used. Table 5.1 lists the solar data sites used by NERC Subregion. Solar sites representing population centers, as opposed to geographic coverage, were used as it was felt that these better represent the likely deployment patterns of grid-connected PV systems on rooftops.

Each network had various sites that fulfilled the need for specific geographic locations and hourly radiation data. Data for 2002 was retrieved from these sources. Complete documentation of the retrieval methods and more details about each resource network is available in Appendix A.

---

[1] See also http://www.srrb.noaa.gov/surfrad/
[2] See also http://www.srrb.noaa.gov/isis/

Table 5.1. Solar Resource Sites Summary

Sub-region	Resource Network	Site
ECOV	CONFRRM	Bluefield State College, WV
ERCT	CONFRRM	Austin, TX
SPSO	CONFRRM	Canyon, TX
SRSO	CONFRRM	Savannah, GA
CALI	ISIS	Hanford, CA
FRCC	ISIS	Tallahassee, FL
MANN	ISIS	Madison, WS
NWGB	ISIS	Salt Lake City, UT
NWPN	ISIS	Seattle, WA
SRTV	ISIS	Oak Ridge, TN
SRVC	ISIS	Elizabeth City, NC
WSSW	ISIS	Albuquerque, NM
ECMI	SEPA	Ann Arbor, MI
NEWE	SEPA	Cambridge, MA
NYAS	SEPA	Old Westbury, NY
MAAC	SURFRAD	State College, PA
MANS	SURFRAD	Bondville, IL
MAPP	SURFRAD	Bismarck, ND
ROCK	SURFRAD	Boulder, CO
SPNO	SURFRAD	Boulder, CO*
SRMV	SURFRAD	Goodwin Creek, MS

* Note: No resource information was available for the SPNO region. The closest available site was used for resource information. See Appendix A for more details.

5.3 Solar Site Simulation

The resource information was used to simulate PV generation in select NERC subregions. A software package from the Maui Solar Energy Software Corporation called PV Design Pro was used for simulations.3 PV Design Pro takes as inputs various climate measurements, such as direct normal radiation, global horizontal radiation, and temperature, and PV system configuration settings, such as array rating, inverter rating, and orientation, and outputs the electric power generation from a site configured and experiencing the climate as specified. The process for completing the simulation is detailed in Appendix A.

To remove variations in non-climate induced system performance, a single set of PV system specifications were used for each model run. The system specifications are outlined in Table 5.2.

[3] See also http://www.mauisolarsoftware.com

Table 5.2. PV System Model Specifications

Specifications	
Array Model	Schott SAPC 165 2002 (E) mc-Si
Number of Modules	12
Array Area (m)	15.61
Rated Power (kW)	1.98
Fixed Slope	30
Fixed Azimuth	South (0)
Inverter Model	SunnyBoy 1800
Continuous Power Rating (kW)	1.8
Efficiency at 100% output	85%

The model is taken to be typical, but not necessary representative, of the currently installed systems. The objective in the modeling procedure was to draw out the regional resource and emission profile variations, not to make conjecture about what types of PV systems or system configurations are better for emission offsets.

5.4 Simulated System Output and Actual System Output

While the simulated systems do consider the meteorological variations desired in the analysis of emission reduction, they do not account for degradation of PV system performance from other natural externalities, such as snow or dirt and debris. This simulation shortcoming is demonstrated in the capacity factors of the various systems.

Table 5.3. Comparing Simulated vs. Actual PV Site Performance

Subregion	PV Site	PV System Rating	Annual PV Generation	Simulation Site	Simulated Generation	Percent Difference
CALI	Sylmar, CA	1.5	1390	Hanford, CA	1591	13
ERCT	Austin, TX	10.8	1130	Austin, TX	1296	13
ECOV	Pittsburgh, PA	31.9	949	Bluefield, WV	1239	23
MANN	Oshkosk, WI	2.4	999	Madison, WI	1318	24
SRSO	LaGrange, GA	18.2	925	Savannah, GA	1349	31
		(kW)	(kWh/kW)		(kWh/kW)	(%)

The capacity factors are routinely higher for the simulated sites than for monitored installations. This provides an idea of the over-estimate simulated sites will give when assessing emission reduction potential. For this reason, total emission reductions are not tallied using simulated PV generation information. The simulated information is used to compare relative offset rates.

Figure 5.1. Simulated PV Generation per Capacity (MANS, SPNO, NWGB)

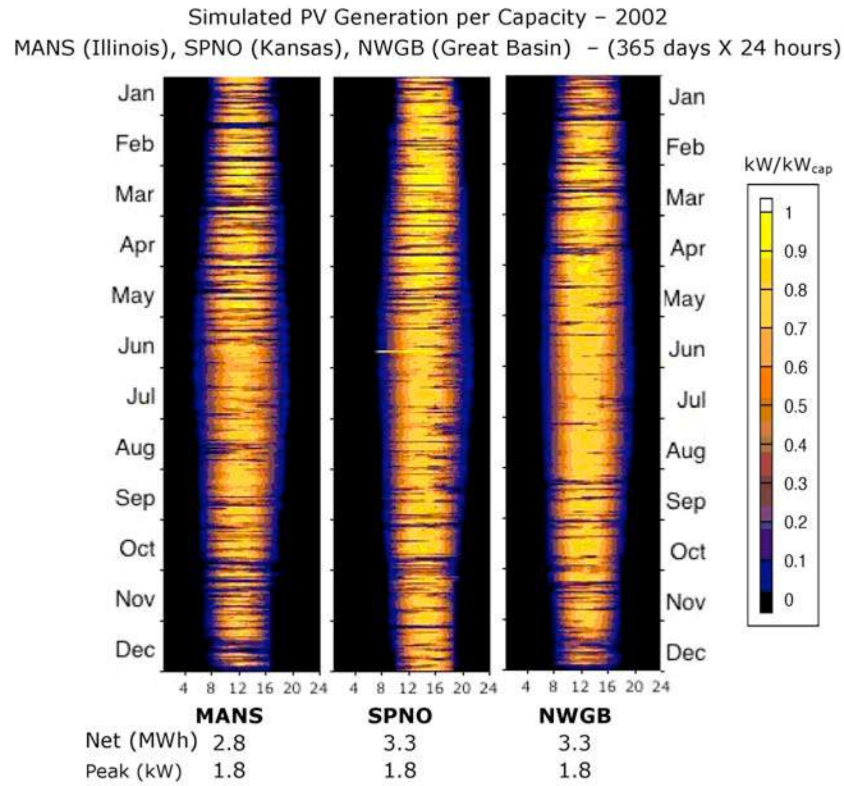
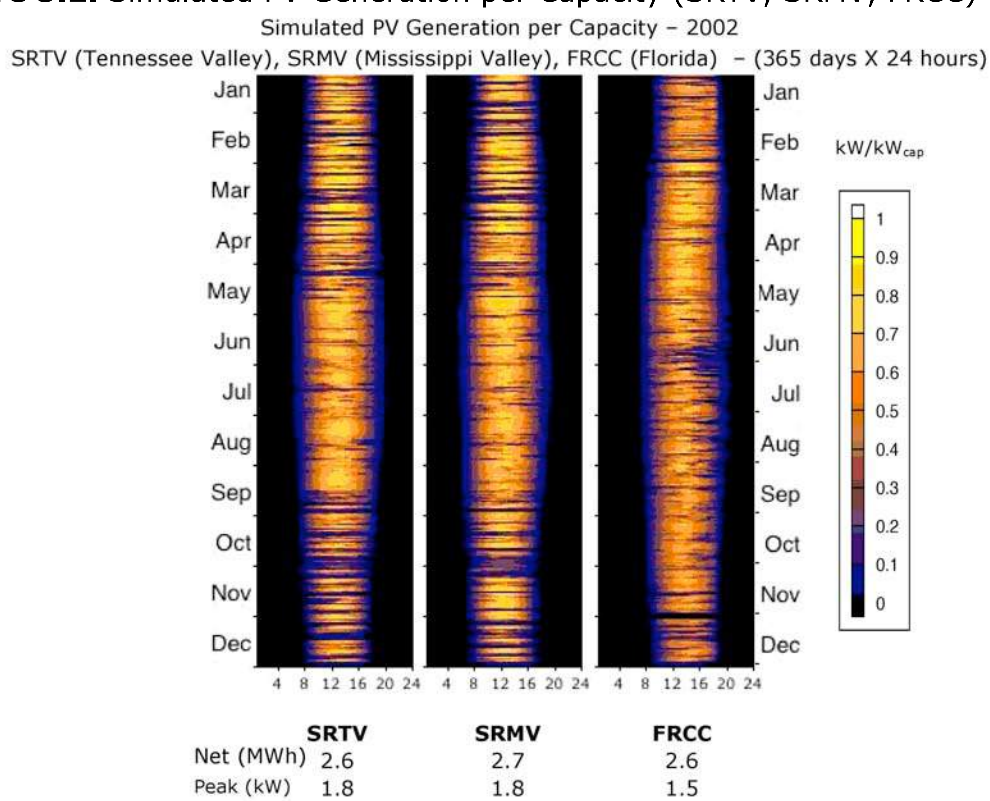


Figure 5.2. Simulated PV Generation per Capacity (SRTV, SRMV, FRCC)

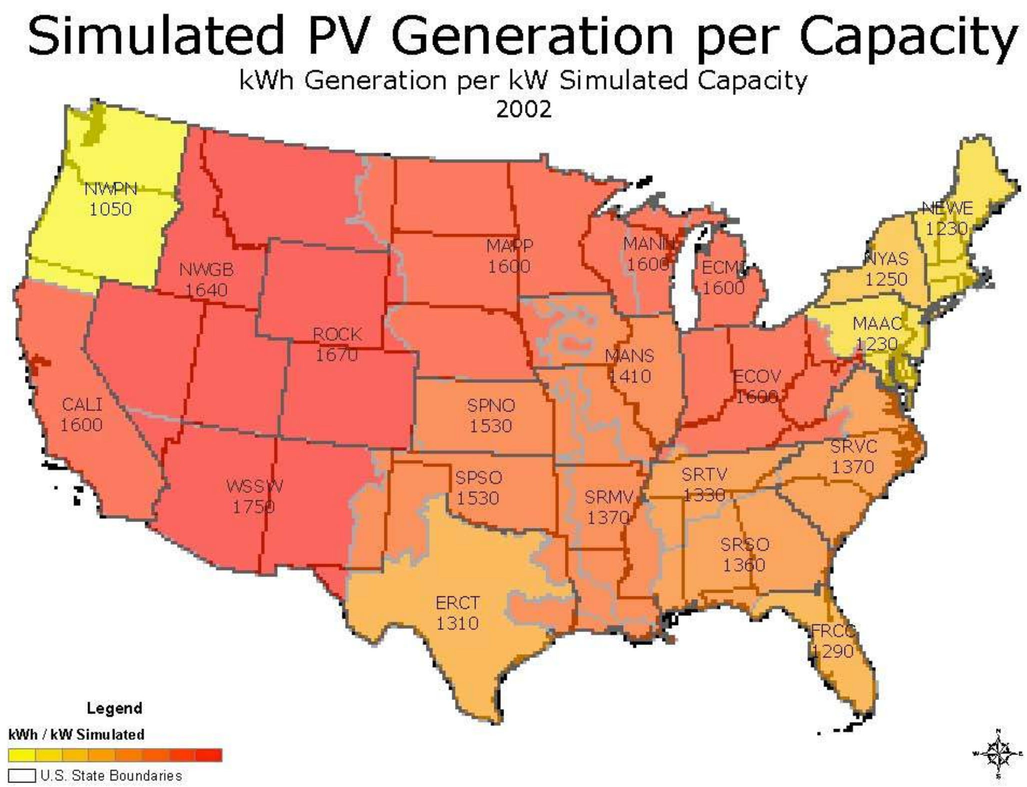


It should be noted that the percent overestimate the simulation gives relative to monitored PV sites is roughly equal to the underestimate of avoided fossil plant generation resulting from transmission and distribution losses and generation unit auxiliary power consumption as discussed in Chapter 1.

Note how consistent and vibrant the generation is throughout the year for the simulated sites, in contrast to the actual performance data viewed in Chapter 4.

Below is a map showing the photovoltaic generation per capacity for the simulated runs in all regions. This is analogous to Figure 4.3 that displays the actual, versus simulated PV system generation data.

Figure 5.3. Simulated PV Generation per Installed kW, 2002



6 Emission Reduction Assessment

Two complimentary emission reduction analyses are needed to quantify the emissions reductions from PV systems and to compare PV emissions reduction potential in different subregions. Quantifying the emission reductions of actual PV systems, using their historical generation is important because real PV systems break and this affects their ability to reduce emissions. The second type of analysis is that of simulated PV systems. The use of simulated PV systems is necessary for a consistent regional comparison. A region-to-region comparison using actual PV systems is not useful because the inconsistency in system upkeep greatly affects emissions offsets. The analysis of PV emissions reductions uses solar resource data that are regionally and temporally coincident with demand, generation, and emissions data to create simulated PV system generation.

The 365x24 contour plots in Figures 6.1 through 6.4 display the emissions reductions in each hour and subregion. The emissions reductions for an hour were calculated by multiplying the PV generation per installed capacity in that hour (kWh/kWc) by the load shape following emission rate in the same hour (g/kWh). This gives emissions reductions per installed PV capacity (g/kWc). The contour plots of emission reductions represent the results of performing this calculation for each hour of a year in a given subregion. Summing the 8760 data points results in the annual emission reductions from PV for a given subregion and year. (See Appendix B for the emission reduction contour plots for all subregions.)

6.1 Actual PV System Emission Reductions

Figures 6.1 through 6.4 show the 2002 emission reductions from PV in Texas (ERCT), California (CALI), Wisconsin (MANN), and the Southeast (SRSO). The emission offset from the Texas region provides a good example of higher winter emission rates. The lower rates in the summer could be due to seasonal fuel switching, increased emission control for the ozone season, or higher peak load and more utilization of natural gas peaking units. California, while having excellent solar resource availability, does not provide the best emission offsets per monitored PV capacity, especially for sulfur dioxide. The already stringent emission control laws in place in the state cause the low offsets. The Wisconsin region contained a large population of monitored PV sites. The profile from the Wisconsin area in Fig. 6.3 contains a distinct "hour-glass" pattern over the year, while the profile from the Southeast (Fig. 6.4) is more flat. Comparison of all the regions' total offsets for 2002 and for the entire timeframe of the analysis can be found on the maps in Figure 6.5.

Figure 6.1. 2002 Fossil & PV Generation, and PV Offset Emissions - ERCT

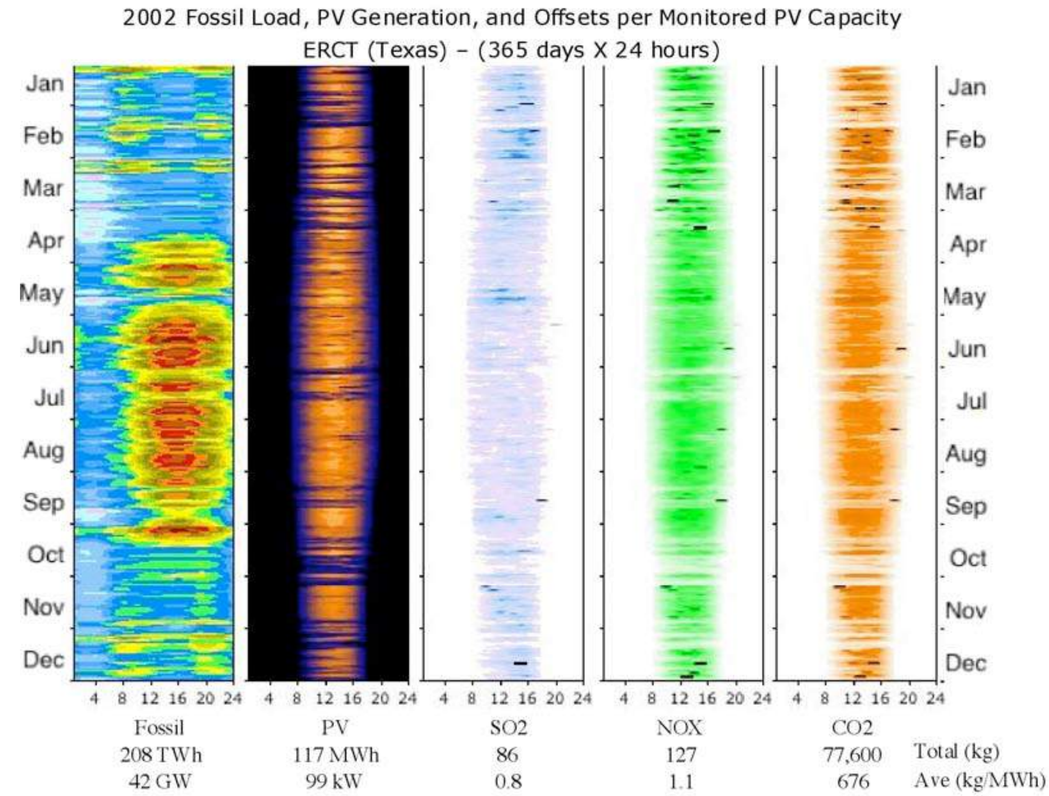


Figure 6.2. 2002 Fossil & PV Generation, and PV Offset Emissions - CALI

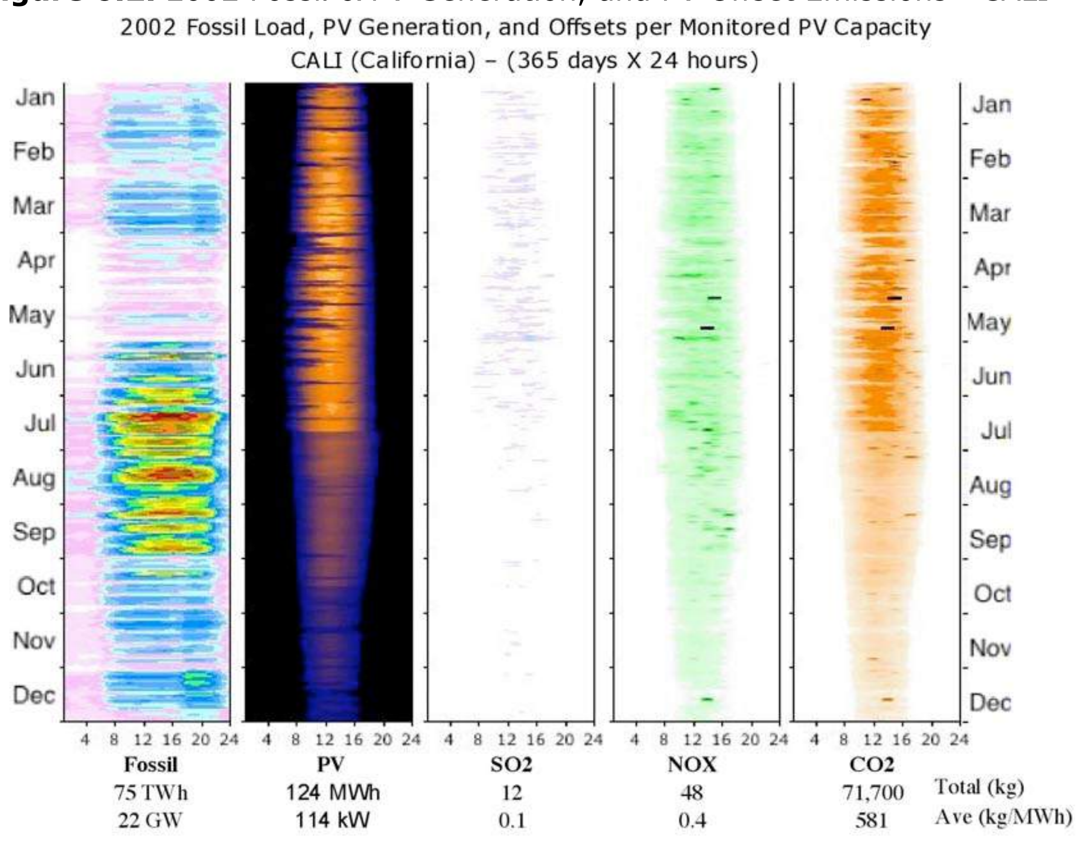


Figure 6.3. 2002 Fossil & PV Generation, and PV Offset Emissions - MANN

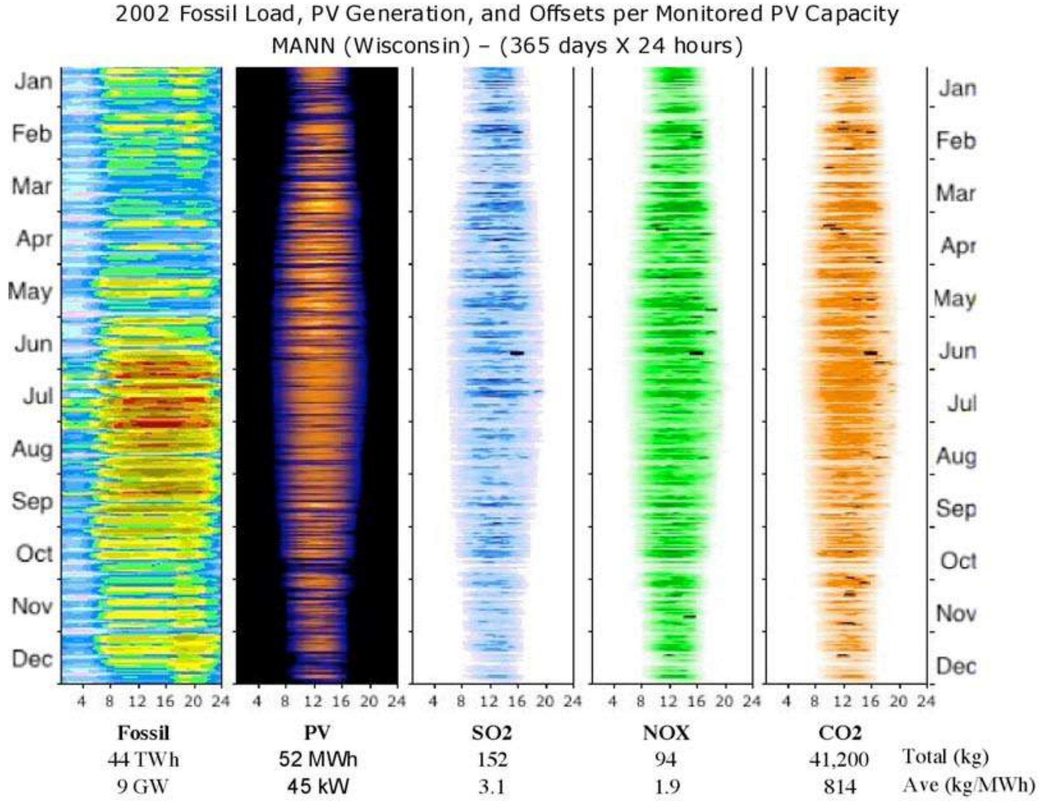
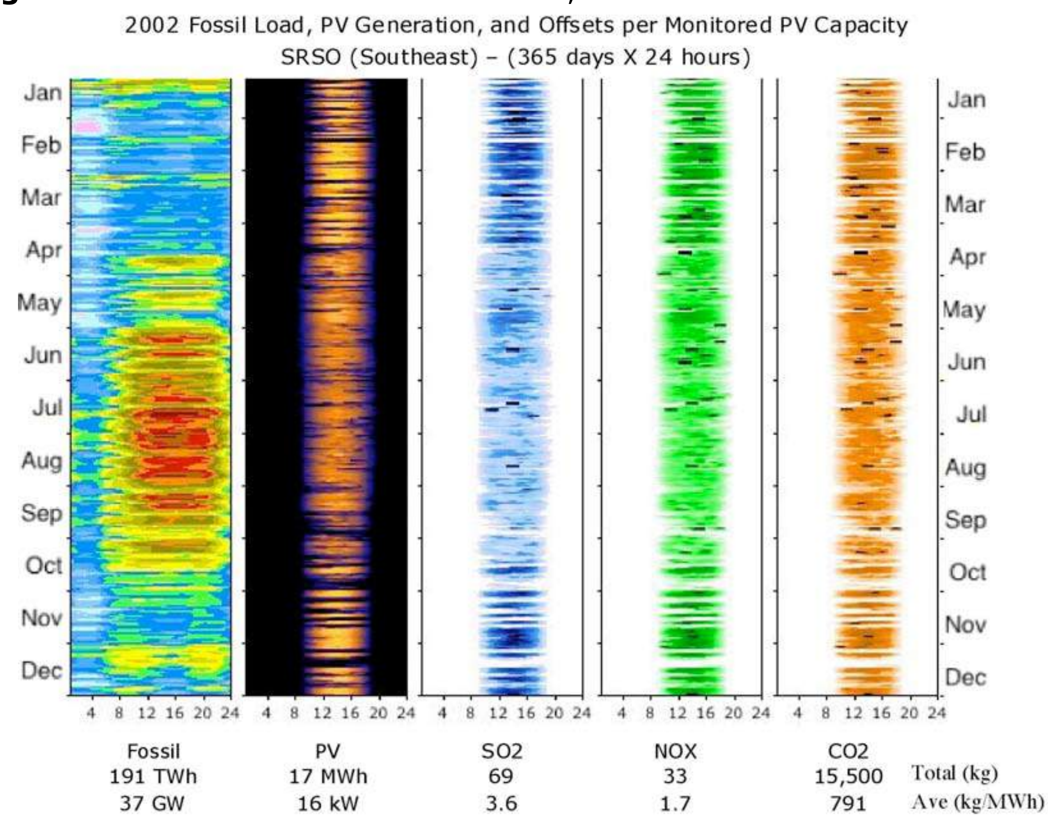
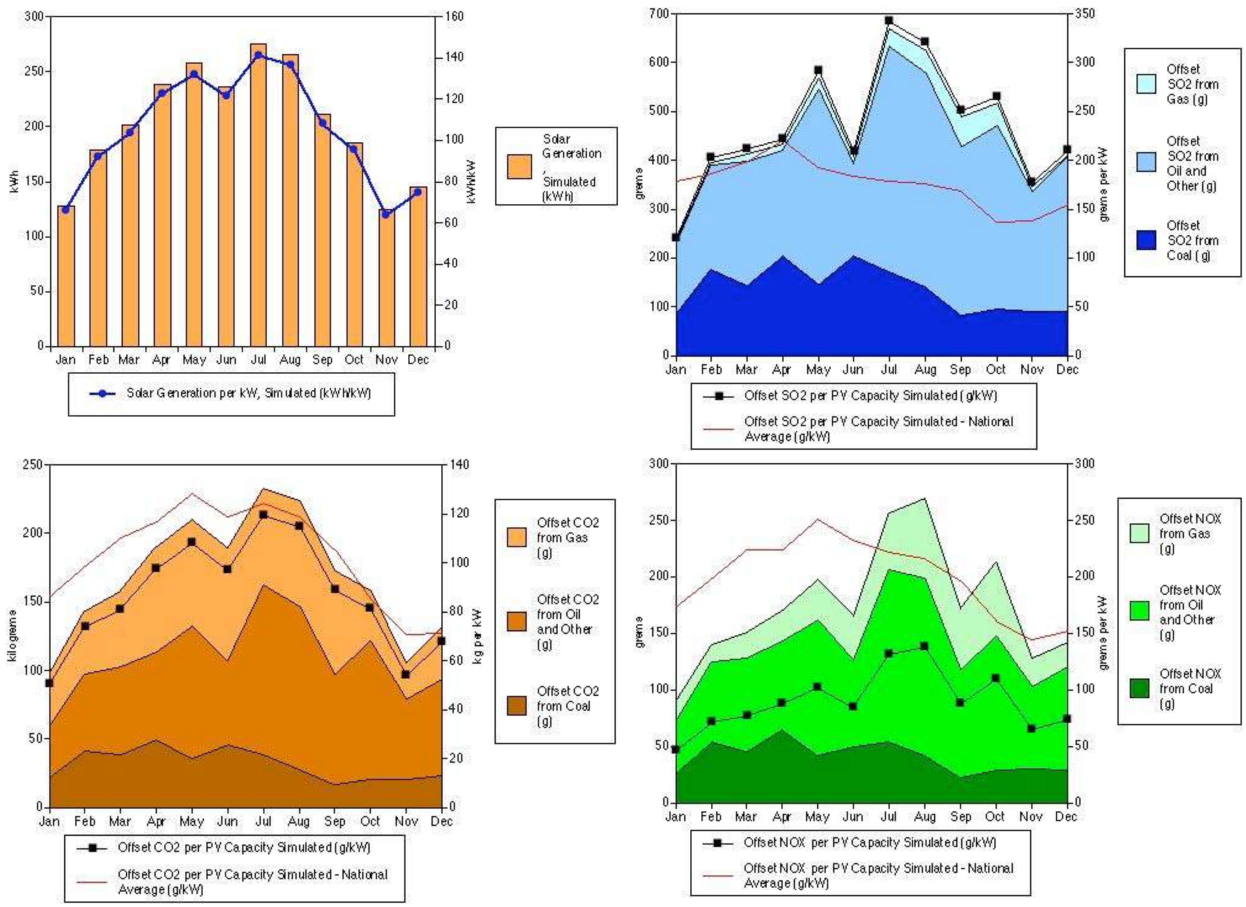


Figure 6.4. 2002 Fossil & PV Generation, and PV Offset Emissions - CALI



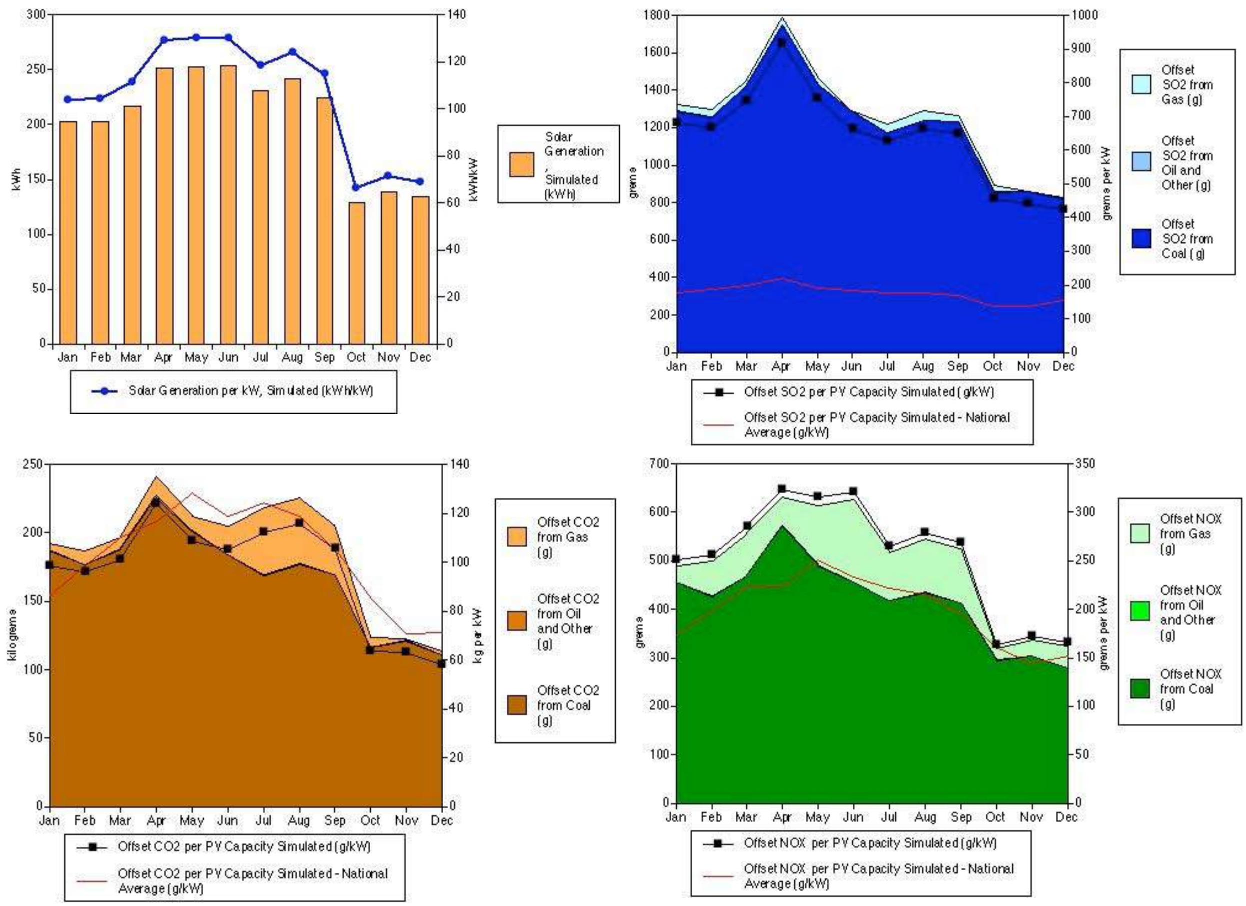
The graphs that follow show on four separate charts: the PV generation and the SO2, CO2, and NOx emission offsets per monitored PV capacity on a monthly basis for New England (NEWE), broken down by fuel class. Each graph also shows national averages of PV generation and offset per monitored PV capacity for comparison.

Figure 6.5. Monthly PV Generation and Offset Emissions Rates, NEWE (New England) 2002



In New England, monthly offsets are higher in the summer because PV production is better. The monthly offset plots show this because the monthly emission offsets track the monthly PV generation. In subregion like Texas (ERCT) this is not the case. Analysis of the monthly offsets by fuel type also shows that, in New England, offsets come from all of the various fuel types. This is contrary to the Ohio Valley shown in Figure 6.6. Coal-fired units dominate generation in the Ohio Valley (ECOV). Mainly due to the fuel mix offset by PV, the SO2 and NOx offsets per monitored PV capacity are higher than the national average for most of the year.

Figure 6.6. Monthly PV Generation and Offset Emissions Rates,
ECOV (Ohio Valley) 2002



A complete set of the monthly offset graphs for all regions, actual and simulated sites, is included in Appendix B.

6.1.1 Total Emissions Offsets from Actual PV Systems

The emissions offsets for SO2, NOx, and CO2 for 1998 through 2002 in each subregion are shown in Tables 6.2 through 6.4. The actual offsets reflect the installed PV capacity and whether or not the sites were maintained or broken during the year. The average monitored PV capacity for each subregion and year are shown in Table 6.1. As explained in Chapter 4, monitored PV capacity is the summed capacity of all PV sites in a subregion that report data for that hour. Sites that are installed or that break during the year are only counted when they report data. The inconsistency of maintenance and upkeep, which is captured in detail by the PV generation 8760 graphs in Appendix B, makes regional comparison of emission offsets extremely difficult. This is especially true for regions in which a PV site did not operate in each of the five years of analysis 1998 through 2002.

Table 6.1. Monitored PV Capacity

Average Monitored PV Capacity (kW)
(averaged over all hours in year)

	1998	1999	2000	2001	2002
CALI	377	769	461	214	100
ECMI	65	66	66	64	34
ECOV		3	6	32	32
ERCT	22	167	172	138	89
FRCC					
MAAC	3	25	130	207	194
MANN	46	56	59	57	52
MANS					6
MAPP	8	8	8	6	114
NEWE	12	34	95	114	
NWGB					
NWPN	19	26	4	3	
NYAS	380	547	280	223	37
ROCK	28	6	4	4	
SPNO					
SPSO		9	9	9	
SRMV					18
SRSO		18	18	18	
SRTV					
SRVC	4				
WSSW	169	312	229	45	6

Table 6.2. Annual SO2 Offsets from Real PV Sites

SO2 Annual Offsets (kg)

	1998	1999	2000	2001	2002
CALI	66	167	63	29	12
ECMI	313	235	229	204	96
ECOV		8	10	170	162
ERCT	25	172	116	125	86
FRCC					
MAAC	14	82	567	996	651
MANN	161	216	200	148	152
MANS					8
MAPP	23	25	18	13	14
NEWE	53	127	236	248	
NWGB					
NWPN	15	7	1	2	
NYAS	568	640	571	216	84
ROCK	8	7	6	5	
SPNO					
SPSO		5	9	3	
SRMV					2
SRSO		83	52	91	
SRTV					
SRVC	14				
WSSW	565	821	467	68	3

Table 6.3. Annual NOx Offsets from Real PV Sites

NOX Annual Offsets (kg)

	1998	1999	2000	2001	2002
CALI	177	441	197	83	48
ECMI	158	130	121	107	49
ECOV		3	4	68	65
ERCT	27	270	259	187	127
FRCC					
MAAC	4	23	162	268	185
MANN	98	133	115	105	94
MANS					6
MAPP	16	17	14	10	10
NEWE	16	37	76	85	
NWGB					
NWPN	10	3	1	2	
NYAS	205	220	216	83	29
ROCK	5	6	6	5	
SPNO					
SPSO		7	18	4	
SRMV					4
SRSO		36	25	38	
SRTV					
SRVC	5				
WSSW	603	1071	713	110	4

Table 6.4. Annual CO2 Offsets from Real PV Sites

CO2 Annual Offsets (kg)

	1998	1999	2000	2001	2002
CALI	256,500	596,800	321,100	140,700	71,700
ECMI	61,800	49,300	49,600	45,700	24,100
ECOV		1,000	1,400	24,200	24,100
ERCT	14,100	139,000	136,000	107,100	77,600
FRCC					
MAAC	2,000	12,000	86,700	142,900	105,700
MANN	42,500	52,200	49,100	42,800	41,200
MANS					2,300
MAPP	7,800	8,200	6,800	5,000	5,100
NEWE	10,500	27,800	65,300	75,100	
NWGB					
NWPN	5,300	1,700	400	900	
NYAS	131,700	161,900	143,700	57,900	24,400
ROCK	2,700	2,900	2,800	2,900	
SPNO					
SPSO		3,200	8,300	1,800	
SRMV					2,000
SRSO		14,300	11,100	17,200	
SRTV					
SRVC	2,500				
WSSW	286,100	502,500	337,800	55,000	2,100

Similar tables for the data from the National Emission Inventory Database (PM_{10}, $PM_{2.5}$, VOCs, NH_3, Hg) can be found in Appendix B. See Sec. 3.3 for more details on these emissions' calculation.

6.1.2 Total Emissions Offsets from Simulated PV Systems

Simulated PV systems are necessary because inconsistencies in monitored PV site operation makes regional comparison of PV emission offsets difficult. The method used to simulate PV sites is described in Chapter 5. Hourly solar resource data were used for each region for 2002 so that changes in weather that affect both PV generation and electricity demand were captured. Figures 6.7 through 6.9 provide a nice snapshot of the emissions offsets from simulated sites relative to monitored PV capacity. The annual PV generation per capacity of the simulated sites is also shown for each region. The regions are ordered by increasing PV generation per capacity.

The SO2 emission offsets vary significantly between regions, showing the reliance of some regions on coal for load following generation during daytime hours. The NOx plot also shows variation region-to-region. A few Southern regions (SRTV and SRSO) provide much better total offsets than other regions with comparable PV numbers (CALI and ERCT) because of the fuels used to follow load during daytime hours. California and Texas both use natural gas to follow load during the day and this is the generation PV offsets. CO2 emission offsets more closely follow the PV generation trend.

Table 6.5 shows the annual PV generation and emissions offsets with the regions ranked in order of decreasing PV generation.

Table 6.5. NERC Subregions ranked by 2002 simulated PV generation per kW of installed PV

NERC Subregion	***Photovoltaic Generation***		***Avoided SO2 LSF Emissions***		***Avoided NOx LSF Emissions***		***Avoided CO2 LSF Emissions***	
Southwest	**1784**	**1**	1808	16	2636	5	**1394**	**2**
Colorado	**1701**	**2**	2492	15	2534	8	**1404**	**1**
Great Basin	1672	3	1805	17	2490	9	1351	4
California	1631	4	152	21	617	21	937	17
Kansas	1553	5	1355	18	2091	14	1053	11
Oklahoma	1553	6	4192	7	**2988**	**2**	1388	3
Illinois	1438	7	4216	6	**3029**	**1**	1155	7
North Plains	1435	8	3453	10	2605	6	1295	6
Miss. Val.	1397	9	1095	19	2178	12	1015	14
Virg./Caro.	1391	10	**5765**	**2**	2539	7	1150	8
Southeast	1384	11	4710	5	2283	11	1081	9
Wisconsin	1352	12	3900	9	2479	10	1075	10
Tenn. Val.	1349	13	5730	3	2821	3	1302	5
Texas	1330	14	1056	20	1438	18	892	21
Florida	1309	15	3045	11	2087	15	984	15
Ohio Valley	1271	16	**6943**	**1**	2715	4	1015	13
New York	1271	17	2799	12	1071	19	894	20
New England	1256	18	2549	13	946	20	930	18
Mid-Atlantic	1254	19	5566	4	1602	17	921	19
Michigan	1242	20	4149	8	2160	13	1028	12
Pacific NW	1070	21	2532	14	1635	16	964	16
(2002)	(kWh/kW)	(Rank)	(g/kW)	(Rank)	(g/kW)	(Rank)	(kg/kW)	(Rank)

Figure 6.7. SO2 Annual offsets and PV generation per PV capacity for all subregions in order of increasing PV generation

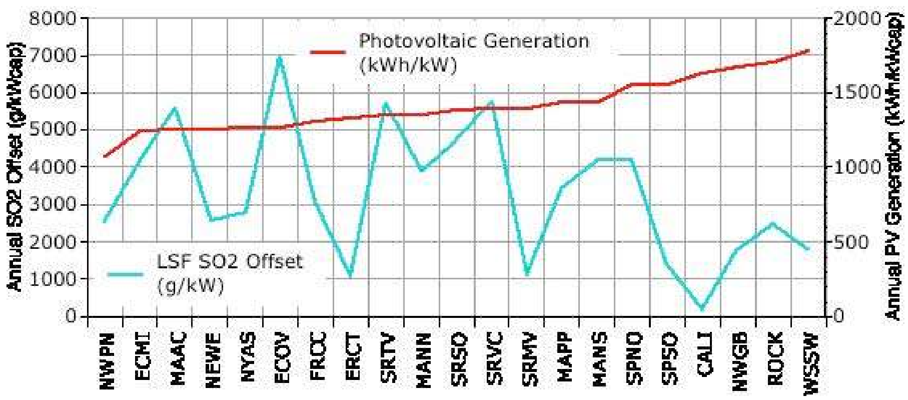


Figure 6.8. NOx Annual offsets and PV generation per PV capacity for all subregions in order of increasing PV generation

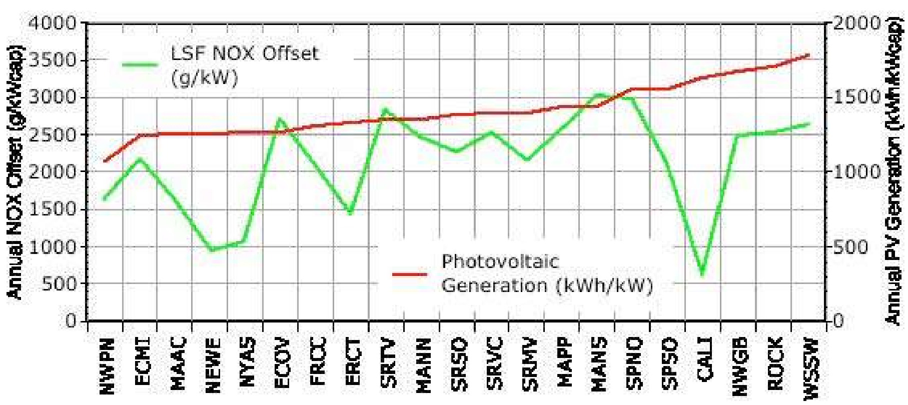
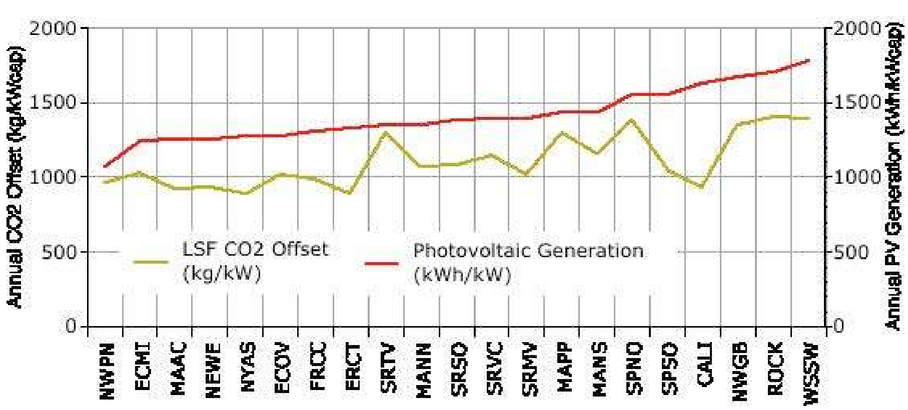


Figure 6.9. CO2 Annual offsets and PV generation per PV capacity for all subregions in order of increasing PV generation



7 Looking Forward

As discussed in Chapter 1, the emission reductions provided by photovoltaic power generation are dependent on two main factors: PV system productivity and electric power system emission profile. Each of these two main factors has their own uncertainties and indeterminacies.

7.1 Uncertainty in the Future of Photovoltaic System Productivity

As demonstrated over the past twenty years, photovoltaic power systems have shown significant growth both in terms of number of systems produced and installed as well as efficiency of power generation. While the rate of growth has been high, the relative size of the industry compared to the entire electric power generation industry is still notably small. Therefore, the number of future systems from which additional emissions might be avoided is very problematic.

Improvements in the performance and costs of photovoltaic technologies will likely affect different regions of the country equally in terms of power production per system kilowatt installed, meaning the current regional variations in photovoltaic generation will likely persist in the future regardless of technology changes and growth. However, regional technology penetration rates will vary depending on regional and state variations in public policy incentives (e.g. Renewable Portfolio Standards), market opportunities (e.g. Green Power Programs) as well as consumer education, environmental awareness, and affluence.

7.1.1 Effect of PV Installation Growth

PV production growth refers to the overall growth in the entire population of grid-tied photovoltaic power systems. The economics of PV systems is the largest contributing factor to the growth of installed PV capacity with overall cost of the system contributing a large piece to the economics. The cost of PV systems, on both a dollar per kWh production and dollar per kW installed has continually decreased over the past ten years with evidence that this trend is subsiding.[1] Growth of photovoltaic installations is also favored by the price gap between photovoltaic and fossil electric generation trend of growing smaller. Studies have shown the market for PV is nowhere near saturation. Growth of the overall installed capacity will have a positive effect on total emissions offset, but will have only secondary effects on increasing offset rates whether per installed capacity or per actual generation.

[1] See IEA Photovoltaic Power Systems Programme Annual Report 2002 (http://www.iea-pvps.org)

7.1.2 Effect of PV Efficiency Improvements

Efficiency improvements of PV systems translates to better conversion of solar resource energy into electrical power. Such an improvement would better the generation (kWh) to rating (kW) ratio and capacity factors (as shown in Table 5.2). Currently manufactured PV systems carry efficiencies of around 13-15%. Incremental efficiency gains can be expected from this range, but with theoretical limits around 25%, and actual limits likely to be lower, efficiency gains are unlikely to significantly improve the emission reduction potential. While emission reductions per kWh depend more on the subregion emission profile than the PV productivity, the more tangible number of emission reductions per system rating installed would be greatly enhanced as PV productivity increases. The emission reduction potential moving forward will be greater as the PV technology improves, even if incrementally so.

7.1.3 System Maintenance

The five years of PV system power production yielded a common theme for emission reductions: well-maintained systems provide better total emission offsets. The owner / operator of a PV system has financial incentives for maintaining the installed PV system since the amount of power production directly impacts the rate of return on initial investment. In many installation cases, this incentive was not enough to put the PV system on a regular maintenance schedule. The improvement of PV maintenance is a difficult metric to measure or predict, however such improvements certainly have a positive effect on emission reduction potential.

7.1.4 Potential Policy Impacts

Policy can affect each of the aforementioned factors contributing to the PV emission reduction potential. Many state and local municipalities have a production tax credit or equivalent incentive to promote the penetration of PV systems on residential and commercial buildings. An increase in these incentives would likely increase the overall PV system capacity. Inclusion of larger photovoltaic systems in emission trading markets or in State Implementation Plans (SIPs) provides opportunities for increasing the incentives for PV production and system maintenance. Both the emission trading systems and SIPs depend on having emission limitations set by federal or state statute. The reach, in terms of types of emissions and point sources affected, and the stringency, in terms of total emissions or rate of emission, are major uncertainties undermining accurate prediction of emission reduction potential.

7.2 Uncertainty in the Future of Electric Power System Emission Profiles

The second of the major uncertainties in the emission reduction potential equation is the characteristics of the electric power system. The key uncertainties moving forward are the regional and seasonal fuel use characteristics and the emissions control technology penetration.

7.2.1 Effects of Fuel Use Patterns

Fuel use patterns in various regions are affected by two main factors: fuel economics and response to emission control statutes. Fuel economics considers the price of fuel varying over time and over season and the cost of building new generation units designed to burn certain fuels. The current trend in new generation units is building units designed to burn natural gas, although this has shifted in the past year or two as natural gas prices have risen. This trends holds in many regions across the country, particularly in the South nearer to Gulf of Mexico sources of natural gas.

The effects of such a trend towards gas would mean a lower emission reduction potential for PV as natural gas represents a much cleaner burning fuel than the other fossil alternatives. However, fuel use economics is experiencing competing dynamics. As more natural gas units are built, the price of natural gas has risen. Economists now believe the price will remain at nearly 2 times the recent historical level. This competing dynamic suggests a possible future switch back to coal or coal-derived fuels, boosting the emission reduction potential. The competing fuel use system dynamics create an uncertain picture of the future reduction potential.

7.2.2 Emission Control Technology

The pervasiveness of emission control technology over time was clear in the reduction of emission rates over time in many regions. The continued adoption of such technology could decidedly change the regions where PV emission reduction is most effective. For example, if the New York region where to implement air quality laws parallel to those of California, the likely response of generation unit owners would be to install emission control technology. Thus, the emission reduction rates provided by PV systems will decrease in that region. The effect of carbon trading or other such CO2 control policies would likely result in emission control technology in the form of carbon sequestration, reducing the emission reduction effect.

7.3 Adapting the Analysis Methodology for Larger Penetrations of PV

A central assumption in the analysis methodology was that PV generation represented a small portion of the overall generation mix, and not affecting the amount or timing of fossil unit dispatch. Very large penetration of PV generation could cause select fossil units to turn on later, turn off earlier, or not turn on at all, instead of just operating at higher or lower levels.

If such an assumption were to be reevaluated, the analysis methodology also would need to be adapted. For instance, consideration would need to be given to the idea the PV systems aggregated together could feasibly prevent entire generating units off during certain hours of the day. Which units, as well as the timing of their use, will become more difficult to determine as more market-based unit commitment techniques are employed in regional grid operation. Also affecting these decisions are grid stability and reliability criteria, and the structure of grid reserves/capacity markets which may influence the amount of generation desired in each of the grid operating modes; full load, spinning reserve, and standby.

Even with the positive trends for PV installation growth, the apparent time when such an analysis would be warranted for PV is years ahead, if at all. A single 100 MW gas-fired peaking unit, on a capacity basis, would require the installation of 50,000 2 kW roof-mounted systems, presuming that gas fired unit is used mostly to meet mid-day peaks in electricity demand.

It is far more likely that other non-emitting generators, large wind farms in particular, will require such an enhanced methodology to assess their avoided emissions potential.

8 Conclusions

8.1 Results

The emissions reduction potential of a grid-connected PV system depends more on the characteristics of the regional electricity system than on the available solar resource. A detailed analysis of historical PV generation, fossil generation, and fossil emissions data for each NERC subregion in the contiguous 48 states reveals that it is characteristics of a regional electricity system, like fuel portfolio and demand pattern, that determine the magnitude of emission reductions. This does not mean, however, that issues related to the quality of the solar resource, and the installation and maintenance of PV systems is unimportant.

The use of PV systems lowers the demand seen by a regional grid. To quantify the PV system's emission reductions, the question that must be asked is: which fossil generating units are affected by a reduction in demand and what are the emissions characteristics of those units? Another question is: Does PV generation in a region reduce generation from the above average, or below average polluting fossil units (i.e. the coal-fired units or the natural gas-fired units)? Broadly speaking, the units that are affected by PV generation are those units that are following short-term variations in regional electricity demand.

This analysis empirically determined the fossil units that were offset by PV generation in each region and in each hour for the years 1998 through 2002. PV systems only generate power during daylight hours and the analysis found that PV systems often reduced emissions from natural gas-fired units because they are used in many regions to meet peak (usually daytime) demands.

8.2 Key Findings

- PV systems installed in regions where higher emitting units follow changes in demand during the daytime hours can reduce more emissions than PV systems installed where there is more solar resource but where load shape following units with lower emissions (e.g. natural gas units) follow changes in demand.

- Grid-connected photovoltaic systems do not generally affect the fossil generating units with the highest emission rates. Economic dispatch dictates that the highest cost units are dispatched last and in many regions these are natural gas peaking units. PV systems do not offset generation from base load units that are often older, coal-fired and higher emission rate plants.

- The emissions rates of units that follow demand in the evening and nighttime hours are often considerably higher than the emission rates of units that follow demand during the day. Strategically, stored non-emitting generation, targeted demand side management, or possibly wind generation might affect these units more than PV generation that is only possible during the day.

- In most regions, a large number of fossil units operate at inefficient output levels (between 5% and 55% of seasonal capability) for a significant portion of annual operating hours. While thermal inertia (power plants that are expensive to turn on and off), grid stability, and grid contingency are the likely reasons, inefficient operation means higher emission rates. Small penetration of renewable generation can do little to alleviate this inefficiency.

8.3 Methodology

The load shape following methodology plays a crucial role in this analysis. It determines which units are on the margin in any given hour using the historical hourly data and with no specific knowledge of how units are dispatched being required. The major assumption of the method is that those units whose output changes with the shape of the total demand are responding to that demand, and could therefore be offset by PV generation. The method also assumes that units running in 'Spinning Reserve' (or Automatic Generation Control) are load shape following because they are prepared to respond to changes in demand. These units only contribute to the avoided emissions calculated for the hour if they actually vary their output in accordance with demand changes in the hour.

The benefits of this methodology lie in its simplicity and its flexibility. The load shape following logic is intuitive. It is also not limited by the amount of penetration or the type of generation or demand management that is used to displace load and avoid emissions, whether PV, wind, or demand-side management. Only an operator's knowledge of the system in each subregion, or an historical account, could determine which units were dispatched at what times in response to load. The load shape following logic estimates this dynamically from the generation and demand data themselves.

8.4 Generation and Demand

An analysis of the generation and demand historical hourly data is a key part of the avoided emissions story. Demand determines the units that are utilized in any given hour and the manner in which they are dispatched. Demand itself is shaped by economics, demographics, and weather. Non-dispatchable renewable technologies, like PV, affect the system when resources are available. Key questions like if PV resource is available during times of peak demand in a subregion can be answered through analysis of hourly generation and demand data. Analysis of these data also reveals which types of non-emitting generation might be best utilized to reduce peak demand in a subregion. Trends like load-growth and reduction can also be gleaned from inspection of the data.

8.5 Avoided Emissions

Although trends and patterns in generation and demand data are an important aspect of the system and in understanding the emissions role of PV generation in a subregion, they are only part of the story. Marginal emission rates, the emission rates of those units that can be affected by PV generation, depend on a multitude of unit and system characteristics. These include the fuel and technology types of the generators on the margin as well as their capacity factors, combustion temperatures and operating efficiencies, and pollution control devices. Seasonal and diurnal load shape following emission rates are by no means consistent from day to day, month to month, or hour to hour. An excellent example is the effect of the use of natural gas peaking units on the load shape following emission rates. Natural gas units are turned on during times of peak demand in many subregions; ERCT (Texas) and SRMV (Mississippi Valley) are good examples. The amount of SO2 in natural gas is significantly less than that in coal or oil and thus the SO2 load shape following emission rates during peak-demand hours in subregions that utilized natural gas peaking units are significantly lower than the marginal emission rates at other times or in other subregions. The load shape following emission rates in these instances are also significantly different than the emission rates of the entire system.

Analysis of the hourly emission rate profiles of subregions also shows the effects of pollution control. Emissions rates in California, which is a heavily regulated subregion, are substantially lower than those in neighboring subregions. Inspection of Table 3.1 reveals the variations in emission rates across subregions. The least variation is seen in CO2 emission rates because, unlike SO2 and NOx emissions, they are not controlled. The carbon contents of coal, oil, and natural gas to not vary as drastically and this also contributes to the relatively small variability in CO2 emission rates. The ratio of largest (MAAC) to smallest (CALI) average SO2 LSF emission rates is 48:1 in 2002. For NOx LSF emission rates in 2002 this ratio is 4:1, and for CO2 it was 2:1 (both for WSSW and CALI).

8.6 PV and Emissions Offsets

The solar resource available in a region and the performance of the PV systems are related, but system performance also depends on maintenance and upkeep. The shape of the yearly generation profiles of PV systems in the Southwest, for example, vary significantly from those in Northeast or even the Southeast (see Figures in Appendix B) as does the available resource. The upkeep and maintenance of PV systems is critical for emissions offsets: regardless of the resource in a subregion, if a PV system does not operate it cannot offset emissions. The PV sites in the Pacific Northwest were plagued with downtime during the five-year period and the emissions offsets in that region suffer as a result.

The solar resource and its correlation with demand and emission profiles is an influential factor on the emissions avoided by PV. The solar resource is generally well matched to times of peak demand in many subregions, but times of peak demand are often characterized by the use of the cleanest and most expensive fuel–natural gas, diminishing avoided emissions.

The variation between subregions in this regard is significant especially for SO2 and NOx emissions that vary more by fuel type and technology type than do CO2 emissions. The graphs in Fig. 6.8 through Fig. 6.10 succinctly display this variation. Solar resource is intense in California (CALI) and Texas (ERCT), for example, and PV system performance is reliable; but, the annual SO2 and NOx offsets are small because the load shape following emission rates in these regions during daylight hours are low. In this regard, the variability in fuels and technologies used in a subregion outweigh the variability in solar resource in determining the emissions avoided by PV systems. PV systems in the sunniest regions do not necessarily offset the most emissions per installed capacity; a subregion's marginal emission rate profile is considerably more influential.