ASSESSMENT OF HIGH PENETRATION OF PHOTOVOLTAICS ON PEAK DEMAND AND ANNUAL ENERGY USE

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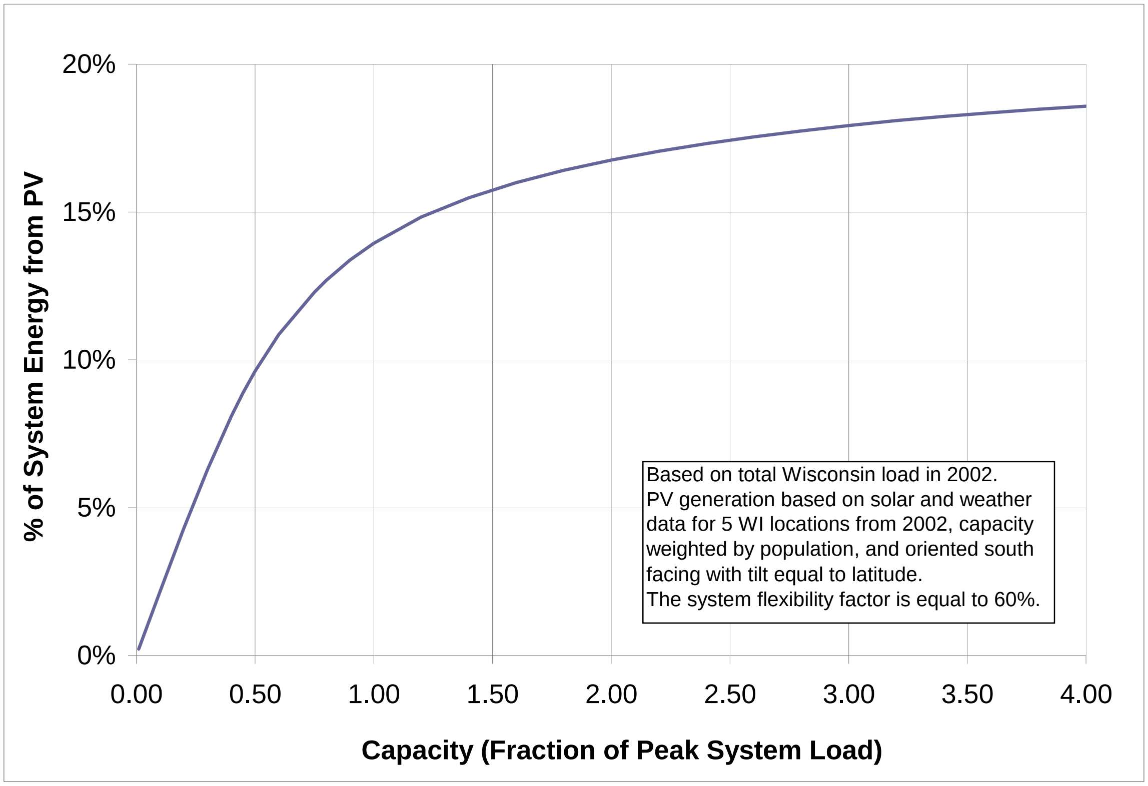
Executive Summary

The goals of the research were to provide an assessment of distributed solar photovoltaics in Wisconsin with regards to interaction with the utility grid, economics of varying levels of penetration, and quantify displaced emissions.

The first goal aimed to determine the impacts on the electric utility load with varying but high penetration rates of distributed solar photovoltaics. Analysis of distributed PV systems was carried out using TRNSYS. Within TRNSYS, the 5-parameter model for an individual solar PV system formed the basis for scale-up to simulate the performance of large numbers of distributed solar PV installations in Wisconsin. The simulations utilized measured hourly solar radiation and weather data from the National Solar Radiation Database. Hourly utility load data for each electric utility in Wisconsin for a complete year were used in combination with the simulated PV output to quantify the impacts of high penetration of distributed PV on the aggregate Wisconsin electric utility load.

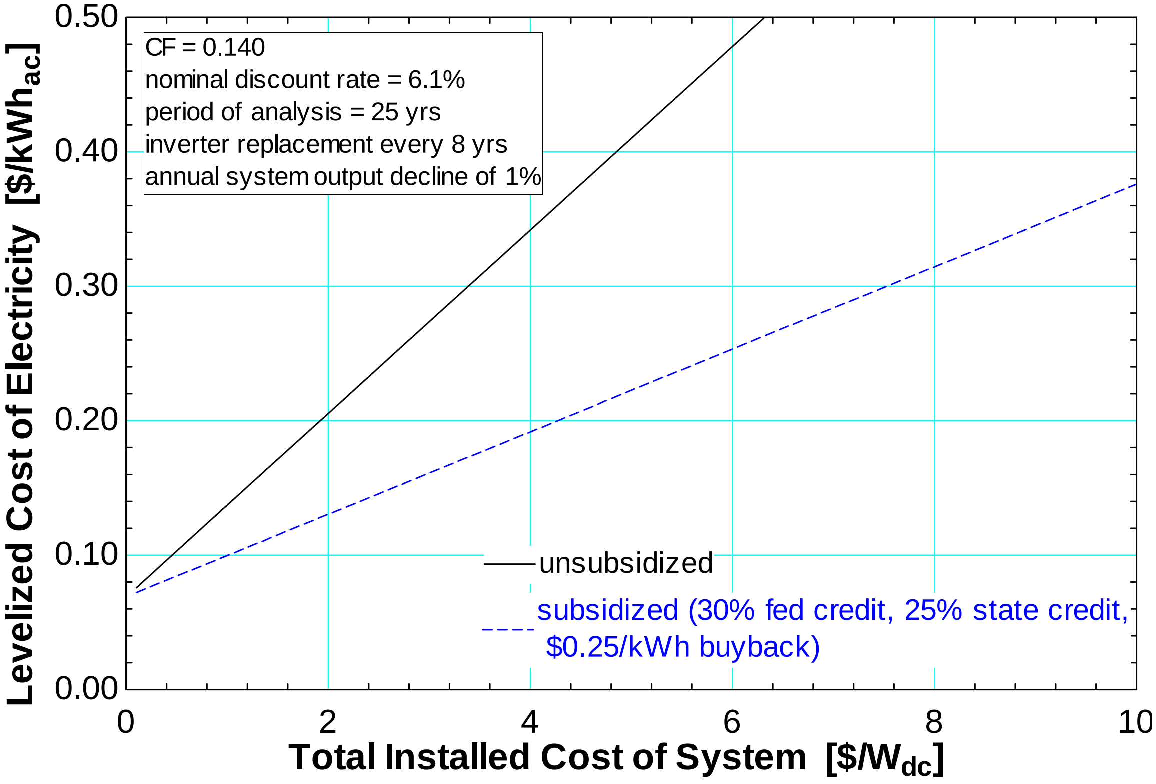
As the penetration rate of PV systems is increased, there are diminishing returns to further increasing the installed capacity of PV systems. At very high penetration rates, less of the energy generated from the PV system is useful and the contribution from PV and demand reduction both approach a limit. This limit is not affected by costs, but rather by the time-distribution of available solar radiation and the coincidence of aggregate utility electrical loads.



In Wisconsin, solar photovoltaics can contribute no more than 20% of the total electrical energy demand in the state based on a 60% flexibility factor, no short-term electrical storage, and a demand profile similar to the one experienced in calendar year 2002. A 20% contribution level would require a tremendous nominal capacity to be installed in the state; as such, it would not be cost-effective. The issues associated with minimum loading are not a concern at the current low penetration rates (installed capacity of 3.1 MW_{dc} – less than 0.025% of peak load). Minimum loading, and rejected power, become significant at penetration rates approaching 15% of peak load. Clearly, there is considerable room for growth in the installed base of solar PV capacity in the state of Wisconsin before minimum loading becomes a significant issue.

Distributed solar photovoltaics in Wisconsin will contribute only a small percentage of total electrical energy use in the near future, independent of economics. At an installed penetration rate of 15% of peak load (1980 MW_{dc}), solar PV will generate only 3% of the total electrical energy used in the state on an annual basis.

The second goal was to evaluate the economics of solar PV in Wisconsin. The economic analysis was accomplished by comparing the cost of electricity and a theoretical value of electricity generated from TRNSYS simulations of PV systems in Wisconsin. The cost of electricity was calculated based on the simulated performance of the PV system and current cost data for the PV panels, balance of system, installation, and inverter replacements. The value of electricity was calculated in two different ways, one approach assigned the utility's coincident marginal cost of generation to each unit of electricity generated by PV systems and the second assigned the coincident time-of-use rate to each unit of electricity generated by the PV systems.



The comparison, in Chapter 5, between the unit cost of solar PV electricity in Wisconsin and a theoretical value, based on generous time-of-use rates, indicates that the cost of electricity from PV is much greater than its value. The unsubsidized levelized cost of electricity for a typical residential solar PV installation in Wisconsin, under the conditions listed in Chapter 5, was calculated as $0.614/kWh ($614/MWh). The peak value of electricity from PV using the time-of-use rates was calculated as $138/MWh ($0.138/kWh). If subsidies were to close the difference of $476/MWh, production incentives totaling $0.476/kWh or initial investment subsidies totaling $7/$W_{dc}$, 87.5% of total installed cost, would be required based on the calculations in Chapter 5.

The third goal to evaluate the emissions impacts of the distributed solar PV systems was accomplished using the PV simulation data and a simplified dispatch. The emissions simulation estimated the reduction in six emission types based on average emissions rates derived from the EPA's eGRID2007 database. The procedure and results are presented in detail in Chapter 6.

The estimated emissions reductions from using solar PV to displace traditional electricity generation depended upon the capacity of solar PV. At low levels of installed capacity, solar PV primarily displaces electricity generation from lower emission natural gas plants that are on the margin. At high levels of installed capacity, solar PV begins to displace generation from coal (higher emissions) or biomass plants during times when the system load is low and PV generation is still high. At an installed capacity of 100% of annual peak load, the emissions were reduced by approximately 22% when compared with the base scenario. A potential tax on CO_2 emissions would need to be on the order of $460 per ton to justify solar PV based solely on the

emissions reductions. At such a high cost, nearly every other option for reducing CO_2 could be exhausted.

Wisconsin has a sufficient solar resource for solar photovoltaics to be a future source of electricity production. A very large level of capacity is required before this resource becomes a significant contribution to the total generation mix. On an economic basis, the investment in distributed solar photovoltaics in Wisconsin is not profitable at this time. With proper incentives, solar PV can be cost effective in Wisconsin.

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Variables

a	modified ideality factor (Eqn. 3.1-3.5); axial induction factor (Eqn. 3.9-3.10)
A_{bb}	annuity value of buyback payments (Ch. 5)
$A_{elecsav}$	annuity value of electricity savings (Ch. 5)
A_{fuel}	annuity cost of fuel
$A_{O\&M}$	annuity cost of operation of maintenance
A_R	swept area of wind turbine rotor
AtoP	annuity to present value conversion factor (Ch. 5)
BBRate	buyback rate (Ch. 5)
BtoC	benefit to cost ratio (Ch. 5)
Cap	capacity
CF	capacity factor
Chg_{usage}	usage charge
C_i	cost of inverter (Ch. 5)
Cost	cost of emissions reductions (Ch. 6)
C_P	power coefficient (Eqn. 3.8-3.9)
$Cred_{fed}$	federal investment incentive percentage credit (Ch. 5)
$Cred_{state}$	state and/or local investment incentive percentage credit (Ch. 5)
CRF	capital recovery factor
C_S	installed cost of the system (Ch. 5)
D	accumulated depreciation (Eqn. 2.16)
d	discount rate; depreciation component (Eqn. 2.16)
d_n	nominal discount rate (Ch. 5)
d_r	real discount rate (Ch. 5)
E	energy
E_c	mass of emissions from source c (Ch.6)
E_{gen}	energy generated
$E_{gen,elec}$	electrical energy generated

$E_{gen,nbb}$	energy generated at the end of the buyback contract period (Ch. 5)
E_{input}	energy input
$ElecRate$	retail electricity rate (Ch. 5)
$ElecRate_{nbb}$	retail electricity rate at the end of the buyback contract period (Ch. 5)
$E_{lifetime}$	energy generated over the lifetime
EM	total mass of emissions (Ch. 6)
ER_c	emissions rate from source c (Ch.6)
$ERed$	emission reduction rate (Ch. 6)
$E_{rejected}$	excess energy rejected from system
E_{system}	total energy load on the system
E_{useful}	useful energy generated
f	frequency
F	future value (Ch.5)
FF	flexibility factor
F_i	future value of inverter replacement (Ch. 5)
$FtoP$	future value to present value conversion factor (Ch. 5)
g_e	annual growth rate in electricity rates (Ch. 5)
g_i	annual growth rate in the cost of an inverter (Ch. 5)
$g_{i,n}$	nominal growth rate in the cost of an inverter (Ch. 5)
$g_{i,r}$	real growth rate in the cost of an inverter (Ch. 5)
g_{nm}	annual growth rate in value from net metering (Ch. 5)
G_{NOCT}	irradiance used to determine nominal operating cell temperature, W/m^2
G_T	irradiance on tilted surface, W/m^2
I	current
i_g	general inflation rate (Ch. 5)
I_L	light current
I_{mp}	maximum power current
I_o	diode reverse saturation current
I_{sc}	short circuit current
L	system load (Ch. 6)

LCOE	levelized cost of electricity
L_{loc}	longitude of location
L_{st}	standard meridian for the local time zone
n	length of discount period; lifetime
n_{bb}	length of buyback contract (Ch. 5)
n_i	lifetime of the inverters (Ch. 5)
NPV	net present value (Ch. 5)
oc	operating cost
P	power; present value (Ch. 5)
P_{bb}	present value of buyback rate (Ch. 5)
P_{buy}	power bought from the utility
P_{cap}	present cost of capital
$P_{cred,fed}$	present value of federal investment incentives (Ch. 5)
$P_{cred,state}$	present value of state and/or local investment incentives (Ch. 5)
$P_{elecsav}$	present value of electricity savings (Ch. 5)
P_{gen}	power generation
P_i	present value of inverter replacements (Ch.5)
P_{load}	power load
P_{loss}	power loss
$P_{minloadcond}$	minimum power loading condition
$P_{netload}$	net power load
$P_{O\&M}$	present cost of operation and maintenance
$P_{peakload}$	peak annual power load
$P_{rejected}$	excess power rejected from system
P_s	present value of cost of the system
P_{sell}	power sold to the utility
$P_{turbine}$	wind turbine power
$PV_{ElecOutput}$	present value of electricity output over the lifetime of the system (Ch.5)
P_{wind}	wind power
r	rate of return (Eqn. 2.16)

R	resistance
$Rate_{usage}$	usage rate
R_c	upper range of capacity for source c (Ch.6)
r_d	annual performance degradation rate (Ch. 3 and Ch. 5)
RelCap	relative capacity
$R_{inverters}$	integer number of replacement inverters (Ch. 5)
RR	revenue requirement
R_s	series resistance
R_{sh}	shunt resistance
Shift	shift in solar time
t	tax component (Eqn. 2.16)
T_a	ambient temperature, °C
tax_{CO2}	carbon dioxide tax
T_c	cell temperature, °C
T_{NOCT}	nominal operating cell temperature, °C
U	air velocity
U_o	free stream velocity of air
U_R	velocity of air at the rotor
v	speed
V	voltage; local wind speed in Eqn. 2.5; value of plant in Eqn. 2.16
V_{CO2}	added value from a CO_2 tax (Ch. 6)
V_{mp}	maximum power voltage
V_{oc}	open circuit voltage
VOE	value of electricity (Ch. 5)
z	height

Greek

▪	absorptance; shear component (Eqn. 3.11)
▪$_{Isc}$	temperature coefficient at short circuit current
▪$_{Voc}$	temperature coefficient at open circuit voltage

ût	length of timestep
$_c$	cell efficiency
$_{pp}$	average efficiency of power plants (Eqn. 2.7)
	wavelength; system lambda value (Ch. 5)
!	density
2	transmittance

Subscripts

B	benefits
C	costs
i	integer number (except for Ch. 5 and 6); inverter (Ch. 5); emission type (Ch.6)
j	time step
k	inverter replacement integer number (Ch. 5)
max	maximum
mp	maximum power
n	nominal
oc	open circuit
r	real
ref	reference
sc	short circuit

Abbreviations and Acronyms

AC	alternating current electricity
BOS	balance of system
CEC	California Energy Commission
CH_4	methane
CO_2	carbon dioxide
CPI	Consumer Price Index
CPV	concentrating photovoltaic
CST	Central Standard Time

DC	direct current electricity
DOE	U.S. Department of Energy
EES	Engineering Equation Solver
eGRID2007	Emissions & Generation Resource Integrated Database for the year 2007
EPA	U.S. Environmental Protection Agency
EPT (or EPBT)	energy payback time (Eqn 2.6)
EYR	energy yield ratio (Eqn 2.8)
FERC	Federal Energy Regulatory Commission
GhG	greenhouse gas
GOES	geostationary operational environmental satellites
GWP	global warming potential
Hg	mercury
IMBY	In My Backyard
ISIS	Integrated Surface Irradiance Study
LBNL	Lawrence Berkeley National Laboratory
MGE	Madison Gas and Electric
N_2O	nitrous oxide
NOAA	National Oceanic and Atmospheric Administration
NO_x	oxides of nitrogen
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
PSC	Public Service Commission
PV	photovoltaic
RPS	renewable portfolio standard
SAM	Solar Advisor Model
SO_2	sulfur dioxide
TMY	typical meteorological year (TMY2 and TMY3 are updates)
TOU	time-of-use
TRNSYS	TRaNsient SYstem Simulation
UTC	Universal Coordinate Time

Units Used

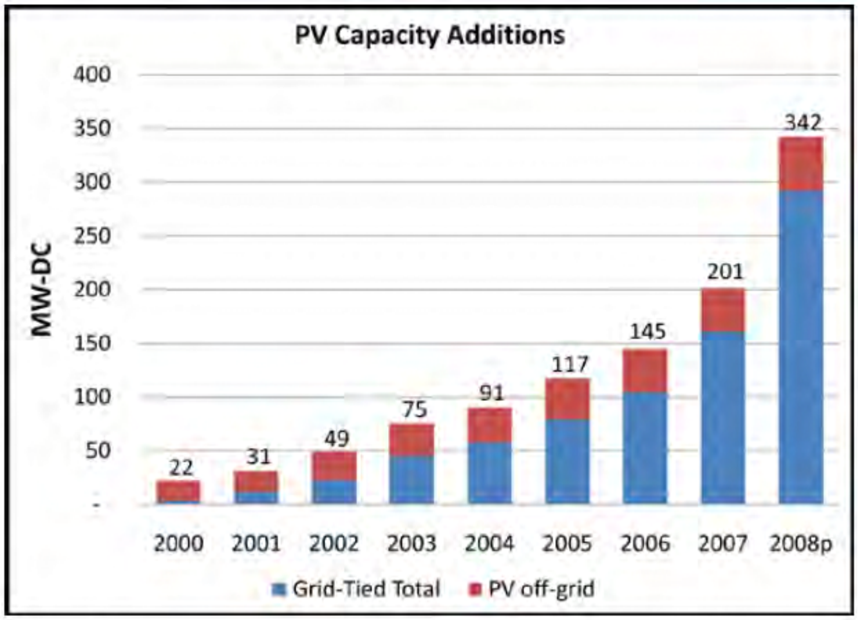
$	US dollars
°C	degree Celsius
eV	electron volt
GW	gigawatt (1x10^9 Watts)
kW	kilowatt (1x10^3 Watts)
kWh	kilowatt-hour
lb	pound
m	meter
MW	megawatt (1x10^6 Watts)
MWh	megawatt-hour
W	Watt
W_{ac}	Watt of alternating current
W_{dc}	Watt of direct current
W_p	Watt peak

Chapter 1

Introduction

1.1 Photovoltaic Systems

The number of installations of solar photovoltaic (PV) systems has increased dramatically in recent years. Figure 1.1 shows the growth in the capacity of PV installations in the United States since 2000. In 2008, the United States installed PV capacity grew by 342 megawatts (MW), including 292 MW of grid-integrated systems [1]. Grid-integrated PV installations in 2008 grew by 81 percent over the 161 MW of installations in 2007. PV manufacturers in the U.S. reported a 60 percent increase in production from year 2007 to 2008. In 2008, the cumulative installed PV capacity in the United States was over 1 gigawatt (GW). The United States is currently fourth in the world in solar electric installed capacity, as shown in Figure 1.2. The solar PV industry is experiencing a period of rapid growth in this country. This research is directed towards understanding the impacts of an increased portion of electricity generated through this renewable energy resource.



p = preliminary
Source: Larry Sherwood (IREC), SEIA

Figure 1.1: PV capacity additions [1]

Figure 1.2: Solar electricity capacity in 2008 by country[1]

The expansion of the market for photovoltaic systems can be attributed to efforts by federal and state governments to promote investment in renewable energy technology, public perception of the technology, and improvements in manufacturing processes. National goals of energy independence and a decreased reliance on fossil fuels have also contributed to a shift towards renewable energy sources. Within the electricity industry, the growing concern over emissions from traditional sources has been another key driver of growth in generation of electricity from renewable sources. This concern has led to the establishment of Renewable Portfolio Standards (RPS) in many states across the country [2]. The public acceptance of photovoltaic technology as a viable resource, the desire to become energy independent in their homes, the ability to scale down the size of the systems, and the incentives for investment have driven individual customers to purchase rooftop PV systems.

A typical grid-integrated photovoltaic system consists of a photovoltaic array and power conditioning equipment. A photovoltaic cell is the “basic building block of a PV system” [3]. A photovoltaic cell converts energy in the form of solar radiation into electrical energy. Cells are arranged in series to form a module, and multiple modules are arranged to form an array. The power conditioning equipment includes a maximum power tracker and an inverter. A maximum power tracker optimizes the current and voltage of the cell to yield maximum power output. An inverter converts the direct current electricity generated by the array into alternating current which is supplied to the utility grid. The technical details of photovoltaic systems are discussed in Chapter 2.

Grid-integrated PV systems eliminate the need for individual customers to have electricity storage. The electricity produced by the PV system is sent to the larger utility grid, which effectively acts as a large battery. The “storage capacity” of the electricity grid is finite and issues arise when a significant number of distributed generation units are connected to the grid. One goal of this research is to identify the limits of the quantity of photovoltaic systems connected to the electricity grid.

1.2 Motivation for Research

The motivation for this research stems from the growth of electricity generation from solar photovoltaic systems throughout the United States. As federal and state governments continue to subsidize the investment in photovoltaic systems and local utilities offer incentives for the generation from the systems, it is important to quantify the costs and benefits (to the system owner and the taxpayer) of generating an increased percentage of electricity from solar photovoltaic systems. The research is focused on the understanding the energy and environmental impacts that will be associated with increasing the market penetration of small-scale distributed photovoltaic electric energy generation in the state of Wisconsin.

Photovoltaic technology is a renewable energy generation technology that offers several advantages. PV technology provides a better match between generation and demand profiles for electricity than wind; the technology can easily be installed on a distributed basis; it is an increasingly familiar technology so that public awareness and acceptance of PV technology is high. Despite the advantages, the high unit cost has stunted the penetration of PV in the marketplace despite the fact that PV costs have been dropping over the last decade. A summary of some of the pros and cons of solar photovoltaic systems is shown in Table 1.1.

Table 1.1: Pros and cons of photovoltaics

Pros	Cons
No fuel cost (cost is stable and predictable; simplifies long-term planning)	High capital cost and subsequently high cost per unit of electricity generated
No emissions from operation	Non dispatchable (without storage)
Daily peak electricity production coincides relatively well with daily peak electricity demand	Short term transients (output varies over short time periods; requires other equipment to adapt)
Low maintenance costs	Intermittent resource
Distributable resource (rooftop installations)	Low capacity factor compared to other generation equipment (rated output not always available)
Seasonal output correlates with seasonal electricity demand	No dedicated maintenance (as compared to a centralized power plant)
Scalable (no efficiency reductions due to decreased size)	Significant energy input required to manufacture PV systems
Projects can be invested in increments	Disposal of materials at end of lifetime
Decentralized generation reduces impact of terrorist attack	Land resource for large centralized PV installations
Uninterruptible fuel supply	

1.3 Scope of Research

The scope of this research covers distributed grid-connected photovoltaic systems installed in the state of Wisconsin. Computer-based simulations of PV systems have been developed to determine the generation profile of PV systems. The computer simulations are based upon solar radiation and atmospheric temperature data and manufacturers' performance parameters for commercially available photovoltaic panels. The generation profile has been used in conjunction with electric utility load profile to evaluate the coincidence of electrical generation with utility peak loads, the value of electricity offset by PV generation, and the emissions offset by the PV generation.

The solar radiation and weather data sets used for the computer simulations are historical data chosen based upon the availability of utility load data. The attempt was made to use the most recent data available. In order to provide a forward looking evaluation, long-term average data sets were utilized as a predictor of output in the long-term. The long-term average data sets used represent the average radiation and weather data based on thirty (30) years of recorded measurements. The data sets are discussed in Chapter 3.

The objectives of the research are to quantify:

- the practical contribution limit of solar photovoltaics as a renewable energy resource in Wisconsin,
- the degree to which photovoltaic electrical energy generation coincides with utility peak loads,
- the effect of short-term transients in solar radiation on utility peak load,
- the impact (reduction) in emissions associated with solar photovoltaics, and
- the economics associated with achieving varying levels of market penetration.

The research will identify the current economics of distributed solar photovoltaics and the issues associated with achieving a large market penetration of distributed PV in Wisconsin. The goal of the research is not only to evaluate the current state of the photovoltaic market, but to establish guidelines for which photovoltaic technology will be competitive in the greater market under different scenarios. The cost targets will serve as a reference for policy decisions with regards to incentives for solar PV.

The research is intended to be used by Focus on Energy and other Wisconsin energy regulatory offices for its own analyses and as a mechanism for appropriately supporting PV systems incentive programs. The research determines whether PV systems should receive incentives in Wisconsin and if so, at what level.

1.4 Incentives for Photovoltaics

Energy policy plays an important role in the current market for renewable energy technology. Solar photovoltaic systems, in particular, rely heavily on subsidization from the federal government, state governments, and electric utilities to compete economically with traditional electricity generation technologies. The policies focused on promoting renewable energy technologies include renewable portfolio standards, purchase incentives, and production incentives. Purchase incentives offered by the federal and state governments in the form of tax credits encourage investment in renewable energy infrastructure. Capital purchase incentives reduce the apparent cost to a consumer. Net metering programs offered by electric utilities help those customers who wish to purchase PV systems but are discouraged by the purchase of expensive batteries or are concerned that they may not have power when they need it from the PV system. The net metering and buy-back programs are production incentives that encourage the best investment in terms of units of energy generated per dollar invested, or the technology which will yield the lowest cost of generated electricity.

A comprehensive and updated list of federal and state incentives for renewable energy technologies can be found in the Database of State Incentives for Renewables and Efficiency (DSIRE) available online at www.dsireusa.org. The Emergency Economic Stabilization Act of 2008 (EESA), enacted on October 3, extended the 30 percent solar investment tax credit (ITC) for eight years, lifted the $2,000 cap for residential PV installations, allowed application of the tax credits against the alternative minimum tax (AMT) and removed the prohibition against utilities' use of the ITC [1].

The Renewable Portfolio Standard (RPS) is a state policy that requires electricity providers generate a portion of their electricity from renewable energy sources by a specific date. The specifics of the RPS varies from state to state; states establish a percentage of total sales (energy, kilowatt-hours), a percentage of installed capacity (power, Watts), or absolute capacity.

The Wisconsin RPS, Wisconsin Statue 196.378, requires that a certain percentage of retail electricity sales from come from renewable sources, with the percentage increasing over time. This legislation was enacted on October 27, 1999 and became effective on December 31, 2001 [2]. The percentage of electricity sales from renewable energy sources for each year stated in the legislation is shown in Figure 1.3. The statute mandates that utilities raise the proportion of their electric generation portfolio derived from renewable source to 2.2% by 2011. The statewide target is 10 percent renewable electricity generation by 2015. The electricity providers may opt to purchase renewable energy credits in place of providing the renewable energy directly to its customers. The renewable energy technologies eligible for consideration towards the renewable portfolio standard are solar thermal electric, solar photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, tidal energy, wave energy, and fuel cells using renewable fuels. The legislation applies to investor-owned utilities, municipal utilities, rural electric cooperatives, and retail suppliers operating in Wisconsin. The authority to regulate and enforce the renewable portfolio standard was granted in Public Service Commission (PSC) Chapter 118 of Wisconsin's administrative code.

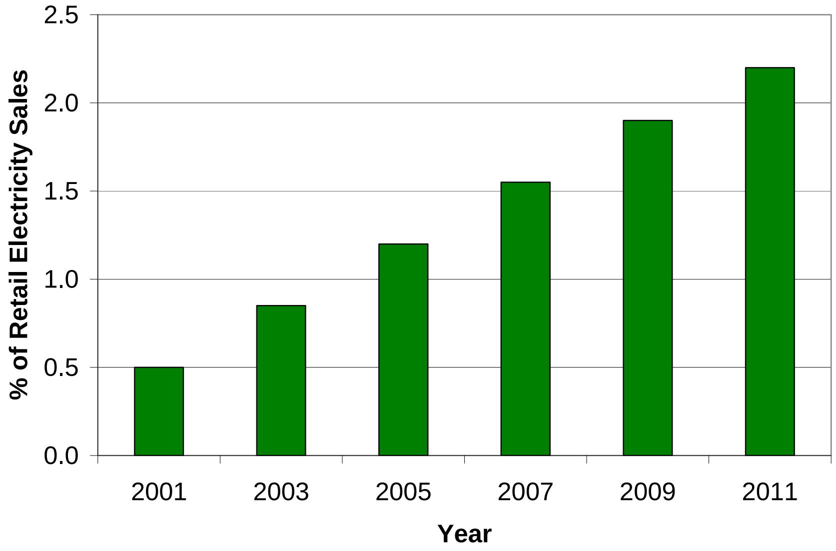


Figure 1.3: Wisconsin RPS percentage of retail sales from renewable sources

Electric utilities in the state of Wisconsin offer energy buy-back programs to customers who have grid-connected photovoltaic systems. The utilities who offer energy buy-back programs for photovoltaics in Wisconsin and the details of the programs are summarized in Table 1.2.

Table 1.2: PV electricity buy-back programs in Wisconsin

	Buy-back rate	Size of individual system	Program cap	Length of Contract	Additional Charges / Restrictions
Wisconsin Power & Light (Alliant Energy)	$0.25/kWh	1 kW - 20 kW	683 kW	10 years	Enrollment in Second Nature program: $0.005/kWh - $0.020/kWh depending on level. Fixed charges: systems 200 kW or less ($0.4176/day), systems >200 kW ($0.8352/day). Installation of second meter and necessary equipment.
Madison Gas & Electric	$0.25/kWh	1 kW - 10 kW	300 kW	10 years	$0.01/kWh for enrollment in Green Power Tomorrow; Valid for systems installed after March 6, 2007. Installation of second meter.
We Energies	$0.225/kWh	1.5 kW - 100 kW	1,000 kW	10 years	Facilities Charges for systems >20 kW. Metering charge: $2.50/month for Time-of-Use customers, $1.00/month for customers generating 40kW or less. Installation of second meter and necessary equipment.
Xcel Energy	Case-by-case	20 kW - 1,000 kW	Total subscriptions equal to 0.25% of previous year sales	10 years	Installation of a separate electric meter and all other associated equipment and installation costs. Service date after January 1, 2008.

Source: http://www.mge.com/Home/rates/CleanPower.htm
http://www.we-energies.com/business_new/altenergy/custgen_wisc.htm
http://www.dsireusa.org

1.5 Literature Review

The impacts of grid-connected photovoltaic electricity generation on electric utilities have not been studied as widely as the effects of wind generated electricity. This is likely due to proportion of electricity generated from the two sources. One study, performed at the National Renewable Energy Laboratory (NREL), attempted to evaluate the technical limit for electricity generated from photovoltaic systems as a portion of overall generation [4]. A second study published through the University of California Energy Institute evaluated the value and cost of electricity generated from photovoltaic systems [5]. These studies served as a guide for figures of merit in this research.

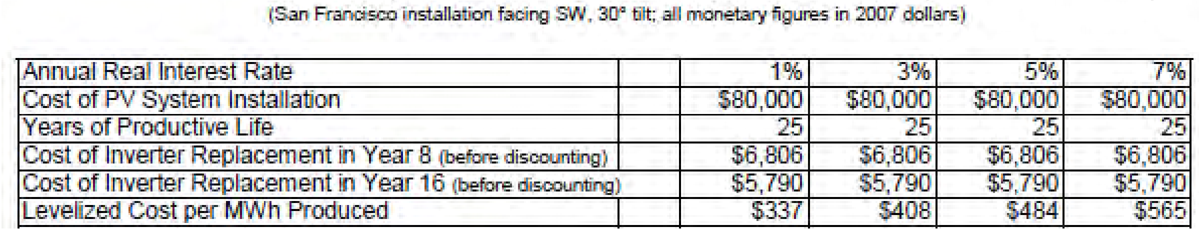
The study by Denholm and Margolis evaluated the limits of PV generated electricity for the state of Texas. The photovoltaic systems were evaluated based on nine (9) locations in Texas and averaged for spatially diverse generation with a mix of seven (7) different orientations. The performance of the PV systems was simulated using HOMER, a simulation software developed by the National Renewable Energy Laboratory (NREL). The data used in the simulation were hourly solar resource data from 2000.

The results of the study provide an upper bound on solar PV penetration constrained by minimum loading. The study defined a “system flexibility,” or flexibility factor, “as the fraction of peak load below which conventional generators can cycle.” The range for flexibility factors is 0%, in which the system is unable to cycle below annual peak, and 100%, in which the system could cycle down to zero load without significant penalties. The system flexibility is evaluated based on when the wholesale prices of electricity for the region drop below actual cost of generation. The system flexibility in the study was determined to be between 60-65%. The study evaluated the effects of three flexibility factors: 60%, 80%, and 100%. The study concluded that the technical limit of PV penetration was near 50% of a system’s energy for a system with 100% flexibility. A realistic limit for a system with 60% flexibility was a PV capacity of about 20% of peak load, or about 12 gigwatts (GW) for the evaluated system.

The second study by Severin Borenstein evaluated the economics of generating a significant portion of electricity from photovoltaic systems. The study utilized computer simulations of the performance of photovoltaic systems with the simulation program TRNSYS and typical meteorological year data (TMY2) for several locations in the state of California. The reduction in line losses added 1% to 2% to the value of PV generated electricity. Three different azimuth angles were used (S, SW, W). Upper and lower bounds for value of PV generated electricity were calculated due to not having coincident data; however, the bounds were found to vary little. The location of solar PV raises the value by an average of 1% due to reduction in line losses and the variation in output among different locations. PV cell performance degradation factor of 1% of original capacity per year, and degradation factor due to soiling of 5% of output were used. The system cost of $8/W installed was assumed. Maintenance costs were included, and the inverter lifetime was assumed to be 8 years. The life expectancy of the PV system was set at 25 years.

The results of the study were that with 1% real interest rate and 5% annual increase in real cost of electricity, the cost of solar PV is 80% greater than the value of the electricity that it will produce. A summary of the levelized cost of electricity generated by the PV system is shown in Table 1.3. Under moderate assumptions of interest rate and electricity cost increase, net present cost of solar PV built today is three to four times greater than the net present benefits of the electricity it will produce. Finally, for solar PV to be justified based on avoided CO2 emissions, the price would have to be over $300/ton CO2-equivalent for coal displacement, and $600/ton CO2-equivalent for natural gas displacement. The author concludes that solar PV cannot even compete with other renewable sources without heavy subsidies in California.

Table 1.3: Levelized cost per MWh from 10kW solar PV installation (Borenstein, 2008)



(San Francisco installation facing SW, 30° tilt; all monetary figures in 2007 dollars)

Annual Real Interest Rate		1%	3%	5%	7%
Cost of PV System Installation		$80,000	$80,000	$80,000	$80,000
Years of Productive Life		25	25	25	25
Cost of Inverter Replacement in Year 8 (before discounting)		$6,806	$6,806	$6,806	$6,806
Cost of Inverter Replacement in Year 16 (before discounting)		$5,790	$5,790	$5,790	$5,790
Levelized Cost per MWh Produced		$337	$408	$484	$565

A study by Curtright and Apt investigated the intermittency of solar photovoltaics [6]. The study looked at the intermittency of large-scale PV power for four locations in southwestern United States. The data used for analysis were real power output data with 10 second and 1 minute resolution from a single 4 MW site and 10 minute resolution data from three ~100 kW sites. The magnitudes of fluctuations in the 10 minute to several hour range are larger for PV than for wind, resulting in a compensation of intermittency of PV being more expensive than for wind. The researchers found that site diversity over a 280 kilometer (174 mile) range did not dampen PV intermittency sufficiently for substantial firm power or dispatchable demand response. This result implies than the costs associated with intermittency are non trivial.

There are several commercially available software tools to simulate the performance of photovoltaic systems. The software tools located in the literature were PVWatts, In My Backyard (IMBY), Solar Advisor Model (SAM), and the TRaNsient System Simulation (TRNSYS). PVWatts, IMBY, and SAM were developed at the National Renewable Energy Laboratory (NREL) and are publicly available. PVWatts is available online at http://www.nrel.gov/rredc/pvwatts/. IMBY is available online at http://www.nrel.gov/eis/imby/. SAM is available online at https://www.nrel.gov/analysis/sam/. The simulation tools are discussed further in Chapter 3.

1.6 Organization of the Thesis

Chapter 2 provides a review of the technology discussed in the research relating to solar photovoltaic systems and the electric utility grid. Chapter 3 covers the simulation tools used in the research, the data used in the simulations, and the simulation variables and their influence on the simulation results. Chapter 4 discusses the impacts of large scale PV generation on the electric utility grid and the contribution limit. Chapter 5 presents the economic analysis with regards to the cost of electricity from PV systems and the theoretical value of the electricity generated. Chapter 6 discusses the estimated emissions reductions from PV electricity generation. Chapter 7 summarizes the results of the research.

1.7 References

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Chapter 2

Technology Review

This chapter provides background for the technologies discussed in the research. The topics include the photovoltaic cell, the components that make up a distributed PV system, the costs associated with PV systems, and basic information relating to the electric utility grid.

2.1 Photovoltaic Basics

This section covers the basic operation of a photovoltaic cell, the types of PV, the components that make up a PV system, factors that influence performance, the rating of a PV system, and the costs associated with PV electricity generation.

2.1.1 Energy Conversion

Solar photovoltaic cells are electrical devices that convert solar radiation into electrical energy. Photovoltaic systems differ from traditional electricity generation equipment in that PV systems do not utilize thermal or mechanical energy conversion. Photovoltaic cells are semiconductor devices that convert part of the incident solar radiation directly into electrical energy [1].

Solar radiation is energy in the form of photons emitted from the sun. Radiation is emitted with a frequency (f) and wavelength ( ). The frequency and wavelength are related by the speed (v) at which the photon travels, $3.8\text{x}10^8$ m/s for light:

$$v \quad f\,\tilde{}\,\lambda \tag{2.1}$$

The energy (E) of a photon of solar radiation is a function of the frequency (f), represented in terms of Planck's constant (h) by

$$E \quad h\,\tilde{}f \tag{2.2}$$

The total spectrum of radiation is shown in Figure 2.1. The sun emits most of its radiation in a small band surrounding the spectrum of visible light, as illustrated in Figure 2.1. The spectrum of sunlight covers wavelengths of $2x10^{-7}$ m to $4x10^{-6}$ m, and energies of 0.5 eV to 2.9 eV. Each wavelength has a frequency and energy associated with it; the shorter the wavelength (in units of m), the higher the frequency (in units of Hz) and the greater the photon energy (in units of electron volts, or eV).

Figure 2.1: Radiation spectrum[2]

The photoelectric effect is created when a photon of solar irradiation is absorbed by an atom in the crystal lattice structure of silicon. If the energy of the photon is high enough, an electron from the outer shell of the silicon atom will be freed. The result is a hole-electron pair, in which there is a hole created by the vacant electron in the crystal structure. The electron is prevented from recombining to the hole by creating a potential barrier, across which a static charge exists. The static charge, or voltage, is the force that drives the flow of electrons through the cell. The barrier to recombination is created by doping the silicon on one side of the barrier with boron to form a p-silicon layer (positive charge) which has a deficiency of electrons. The other side of the barrier is doped with phosphorous to form an n-silicon layer (negative charge) which has an excess of electrons. The layers are connected by a circuit through which the electrons can flow (i.e. current). When the n-layer absorbs photons, the excess electrons flow to through the wire to the p-layer. A schematic of the construction of a single-crystal silicon cell is shown in Figure 2.2 [3]. The U.S. Department of Energy has a wealth of information on the operation of solar photovoltaic cells through its Solar Energy Technologies Program (SETP) available online at http://www1.eere.energy.gov/solar/photovoltaics.html.

Figure 2.2: n-layer and p-layer of a silicon cell[3]

Different photovoltaic materials respond in different ways to each wavelength of radiation. Photovoltaic cells are only able to utilize incident solar radiation over a relatively narrow wavelength range. The "'bandgap energy' is the amount of energy required to dislodge an electron from its covalent bond and allow it to become part of an electrical circuit" [4]. The bandgap energy is the minimum energy useable by the PV cell. The incident radiation energy must be greater than or equal to the bandgap energy of the photovoltaic material to create free electrons in the atomic structure. Crystalline silicon, with bandgap energy of 1.1 eV, can utilize the energy in the entire visible spectrum as well as part of the infrared spectrum [2]. Red light has energy of 1.7 eV, and blue light energy of 2.7 eV. Radiation below the bandgap energy is not useable by the cell, and is converted into heat. Likewise, energy in excess of what the cell can convert becomes heat. The bandgap energy for three different materials is shown in Figure 2.3.

Figure 2.3: Photovoltaic materials and bandgap energies [4]

Silicon PV cells can theoretically only convert about 45% of the energy of sunlight because the remaining 55% of the energy is either below or in excess of the bandgap energy [4]. Approximately 25% of terrestrial solar radiation is below the bandgap energy. The energy of the radiation in excess of the bandgap is wasted, accounting for the other 30% of incoming energy. Other materials have similar limitations.

2.1.2 Current-Voltage Relationship

The current-voltage (I-V) relationship represents the electrical characteristics of a photovoltaic cell. The relationship is expressed through an I-V curve. An I-V curve is developed by varying the resistance (R) of the electrical load on the PV cell (or array of cells), with a fixed temperature and constant level of radiation, then measuring the current produced by the cell. Ohm's law relates the current (I), voltage (V), and resistance (R) of an electrical circuit:

$$V \quad I \; R \tag{2.3}$$

Figure 2.4 illustrates an I-V curve for a monocrystalline silicon photovoltaic cell under solar radiation of 1,000 W/m^2 and a constant cell temperature of 25°C. The power output by a photovoltaic cell is the product of current and voltage at any point on the cell's I-V curve:

$$P \quad I \; V \tag{2.4}$$

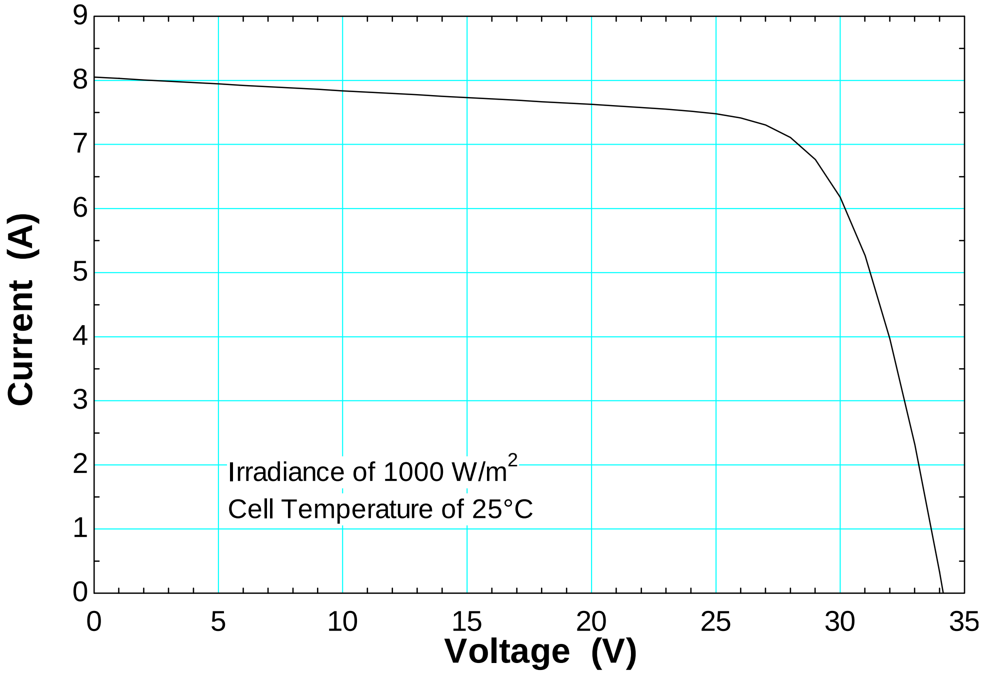


Figure 2.4: I-V curve for a photovoltaic cell

2.1.3 Maximum Power Point

The maximum power point on a current-voltage curve is the point at which the product of current and voltage is the highest. The maximum power point, on an I-V curve and a corresponding P-V curve, for a photovoltaic array under Standard Test Conditions (Section 2.1.7) is illustrated in Figure 2.5. Photovoltaic systems often have a maximum power point tracker, which adjusts the current and voltage load on an array to ensure that the maximum power point is always achieved under varying solar radiation and cell temperature conditions.

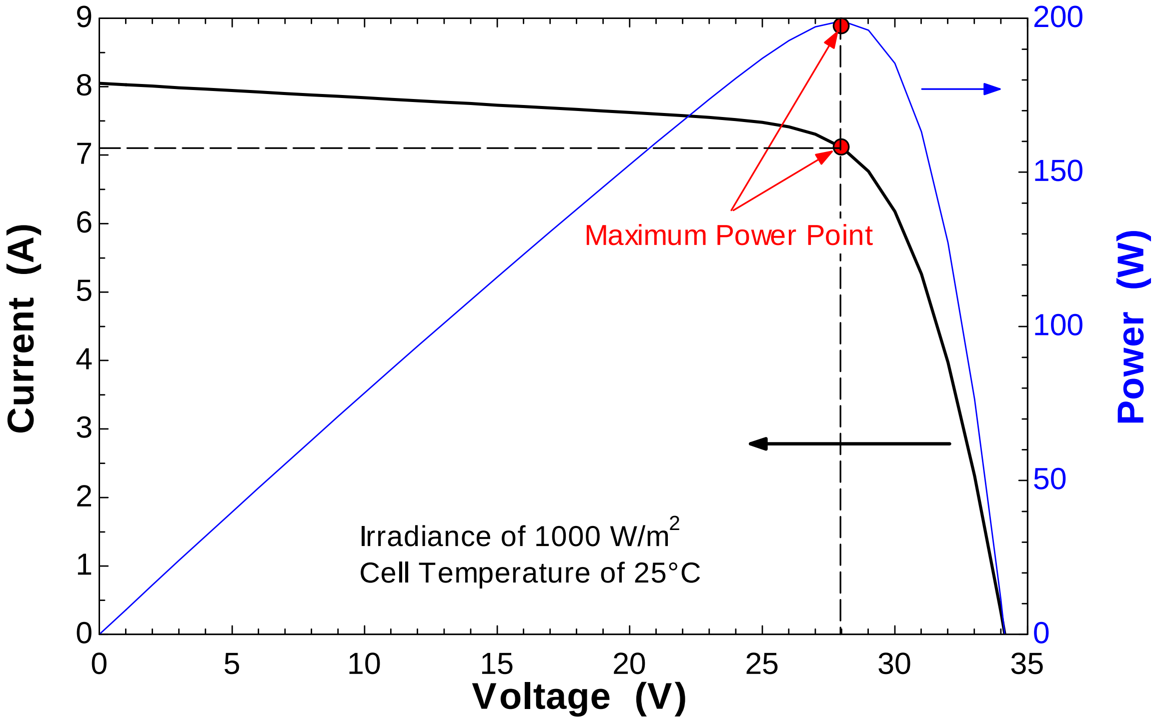


Figure 2.5: I-V and P-V curves with maximum power point

2.1.4 Types

The types of photovoltaic technologies discussed are crystalline silicon, thin-film, concentrating photovoltaics, and other developing technologies. Crystalline silicon (c-Si) is the most mature and widely used photovoltaic technology. Crystalline silicon cells have a 93 percent share of the PV market [5]. Crystalline silicon technology is the primary focus of the present research due to its widespread penetration into the marketplace. Crystalline silicon cells are available in two varieties: monocrystalline and polycrystalline. As the names indicate, monocrystalline PV cells are manufactured from a single, high-purity crystal of silicon and polycrystalline are made from multiple crystals. The maximum efficiency obtained by silicon cells is 23% based on the minimum energy level, and maximum wavelength, of photons that can cause the creation of a hole-electron pair [1]. The typical range of crystalline silicon cell efficiencies is 10 - 20%. The silicon used in PV cells requires an energy intensive manufacturing process to convert naturally occurring silica (i.e. quartz sand) into the high purity silicon required for PV cells. The energy inputs to PV systems are discussed further in Section 2.1.8.

Thin-film semiconductors were developed to address the high cost of silicon wafers. Thin-film solar PV cells can be manufactured at a lower cost because they are much thinner than silicon cells. Less material and cheaper materials result in lower costs for thin-film PV modules. The most common materials for thin-film cells are amorphous silicon (a-Si), cadmium telluride (CdTe), and copper indium (gallium) diselenide (CIS or CIGS). The thin-film manufacturer First Solar was able to reduce the cost to manufacture a PV module under $1 per Watt-peak [6]. Nanosolar, a thin-film manufacturer that uses a nanoparticle ink to “print” the semiconductor onto a conductive foil, promotes that its “thin-film solar films are more than 100x thinner than silicon-wafer cells” [7]. Nanosolar also reports an energy payback time (discussed in Section 2.1.8) of less than one month, versus three years for silicon-wafer. The highest cell efficiency for prototype thin-film cells is above 10 percent [5]. Advances in thin-film technology offer a promising future for reducing the cost of electricity generated from PV systems, making PV generated electricity competitive with fossil fuel based generation in traditional economics.

Concentrating PV collectors utilize lenses to collect and focus incident solar radiation onto a smaller area. This technology has the advantage of using less photovoltaic cell material which represents the most expensive component of a PV system on a per-area basis. Concentrator systems have additional advantages:

- an increase in the power output while reducing the size or number of cells needed;
- increased solar cell efficiency under concentrated light;

- a concentrator can be made of small, high-efficiency individual cells which are easier to manufacture than large, high-efficiency cells [8]

However, there are several disadvantages to concentrating collectors including:

- the concentrating optics (lenses) required are more expensive than the covers for flat-plate systems
- tracking equipment is required for the systems to be effective
- concentration increases the cell temperature (which degrades performance)
- concentrating PV can only utilize beam radiation, not diffuse radiation; thereby, limiting their effectiveness to locations with little or no cloud cover [8]

There are additional PV technologies in the developing stages such as silicon nanostructures, electrochemical PV cells, and organic photovoltaics. Each of these technologies is an attempt to lower the cost of the PV module while achieving high production yields. Organic photovoltaics have the benefit that they can be manufactured at low cost on flexible materials; however, the efficiency is much lower (less than 4 percent).

2.1.5 Grid-connected System

PV systems can either be stand alone systems, which have electrical storage and supply all the energy needed, or grid-connected, in which have no storage and electricity flows to and from the electricity grid. A grid-connected photovoltaic system consists of a photovoltaic array and the “balance of system” (BOS). The components in a typical grid-connected PV system are the PV module, power conditioning equipment, and electricity meter [9].

The photovoltaic array consists of one or more modules. Each module consists of multiple photovoltaic cells arranged in series (to increase the voltage of the module) and parallel (to increase the current of the module). An illustration of the build-up of a photovoltaic array is shown in Figure 2.6 [10].

Figure 2.6: Photovoltaic array construction (DOE)

The balance of system refers to the other components required to make the PV array functional for a given application. The BOS includes power conditioning equipment, wiring, mounting, and in most cases separate metering equipment. Power conditioning equipment includes the inverter and a maximum power point tracker. An inverter is an electrical device that converts the generated electricity from direct current to alternating current. A maximum power point tracker utilizes power electronics to adjust the current and voltage of the load to correspond to always correspond to the maximum power point on the I-V curve (which will change as the incident solar radiation and cell temperature changes. A photovoltaic system connected to the grid and enrolled in a buy-back program, or differential pricing for energy generated and energy used, will typically have two electricity meters. One meter will keep track of the energy generated by the PV system, while the second will keep track of the energy used by the customer. There are established electrical standards for connecting a PV system to the grid [11].

2.1.6 Factors that Influence Performance

There are several factors that influence the performance of a photovoltaic panel. The two discussed in this section are insolation and panel temperature. Other factors affecting the performance of a PV system are discussed in Chapter 3.

2.1.6.1Insolation

Insolation is the solar radiation incident on the photovoltaic panel. The energy output by a solar module is directly linked with the incident solar radiation. Figure 2.7 displays the effect of incident solar radiation on the I-V curve for a PV module. Figure 2.8 is a plot of the normalized maximum power output as a function of incident solar radiation for an Evergreen Solar model ES-190 (190 Watt rated) at a constant cell temperature of 25°C. The maximum power is normalized to the rated power (190 W). The output power is calculated using the 5-parameter model [12]. The reason the normalized power exceeds 1.0 under STC is because the manufacturer’s power rating (or guaranteed power output) is 190 W, whereas the maximum power point under STC is 194.9 W (Table 2.1). There is a direct linear relationship between maximum power output by a photovoltaic cell and incident solar radiation. Higher levels of incident solar radiation yield higher electrical power output.

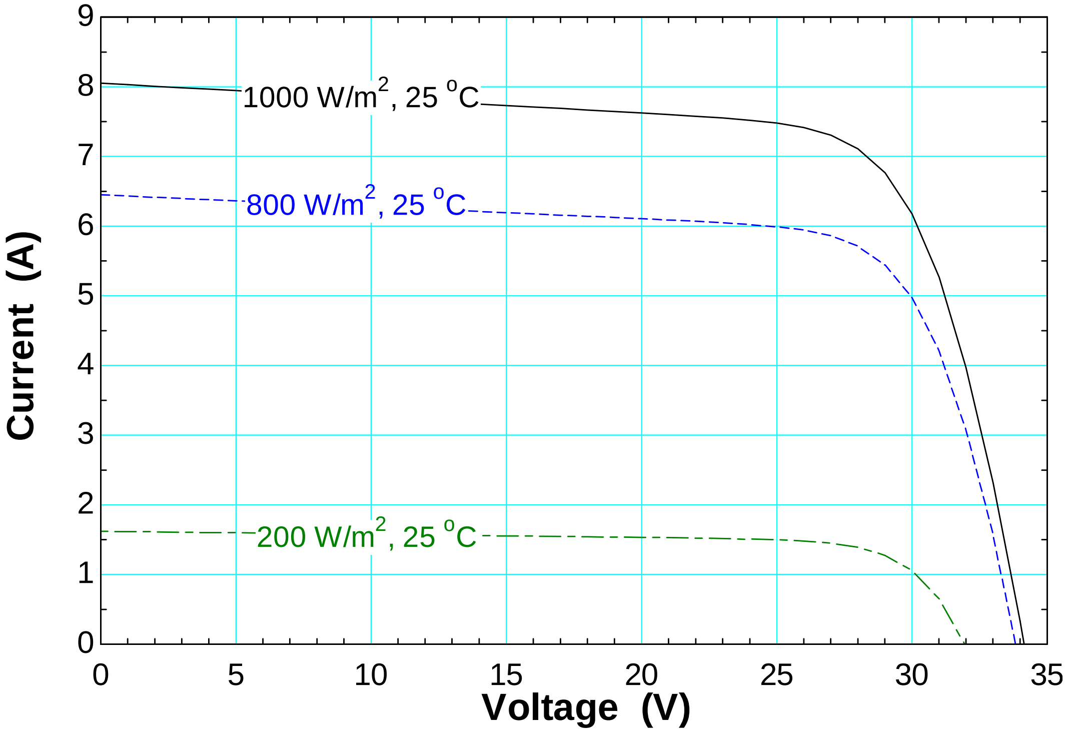


Figure 2.7: Effect of insolation on I-V curve

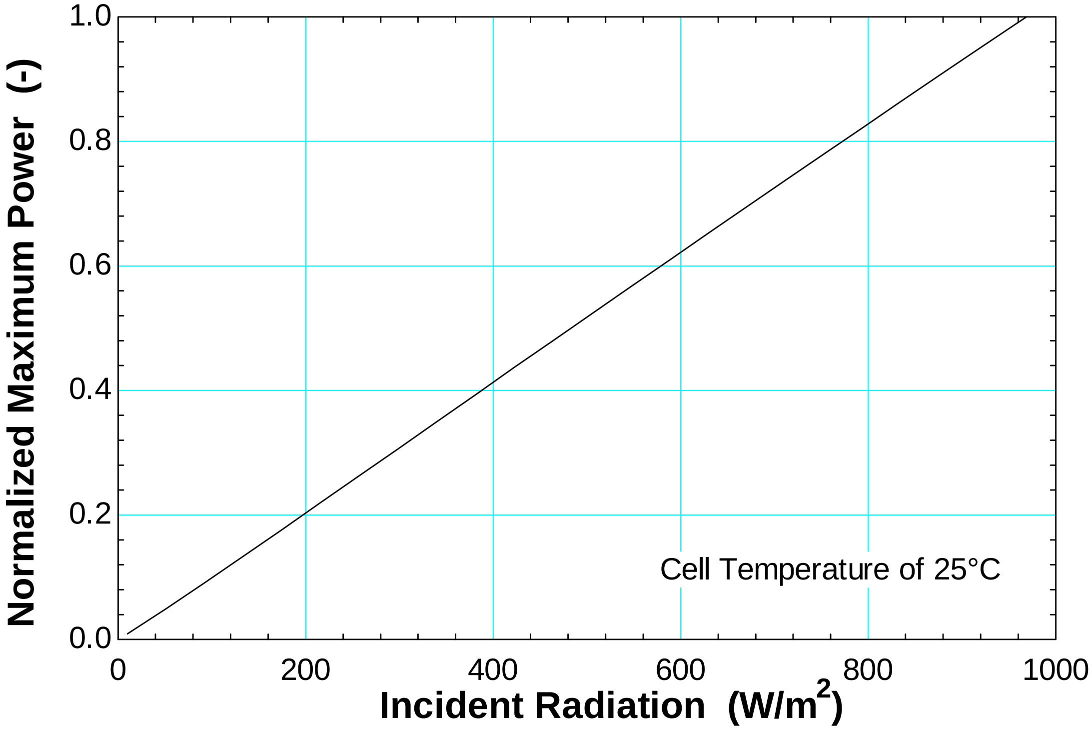


Figure 2.8: Normalized maximum power as a function of incident radiation

2.1.6.2 Panel Temperature

Panel temperature affects the performance of the photovoltaic panel. One approximation of the cell temperature (T_c) at any ambient temperature (T_a) is with the relationship [1]:

$$\frac{T_c - T_a}{T_{NOCT} - T_{a,NOCT}} = \frac{G_T}{G_{NOCT}} \frac{9.5}{(5.7 + 3.8V)} \left[1 - \frac{\eta_c}{(\tau\alpha)} \right] \tag{2.5}$$

where, T_{NOCT} is the nominal operating cell temperature (NOCT) in degrees Celsius under irradiance (G_{NOTC}) of 800 W/m^2, ambient air temperature ($T_{a,NOCT}$) of 20°C, wind velocity of 1 m/s, and open back-side mounting. G_T is the cell irradiance in Watts per square meter, V is the local wind speed in meters per second, η_c is the efficiency of the module in converting incident radiation into electrical energy, and $(\tau\alpha)$ is the effective transmittance-absorptance product, which can be estimated as 0.9. This estimation assumes the mounting is the same as used in the NOCT test. Panel temperature is heavily dependent upon the mounting. It is important that the panel be mounted according the manufacturer specifications to achieve the rated performance.

PV module performance decreases with increased panel temperature. Figure 2.9 is the normalized maximum power as a function of cell temperature at irradiance of 800 W/m^2.

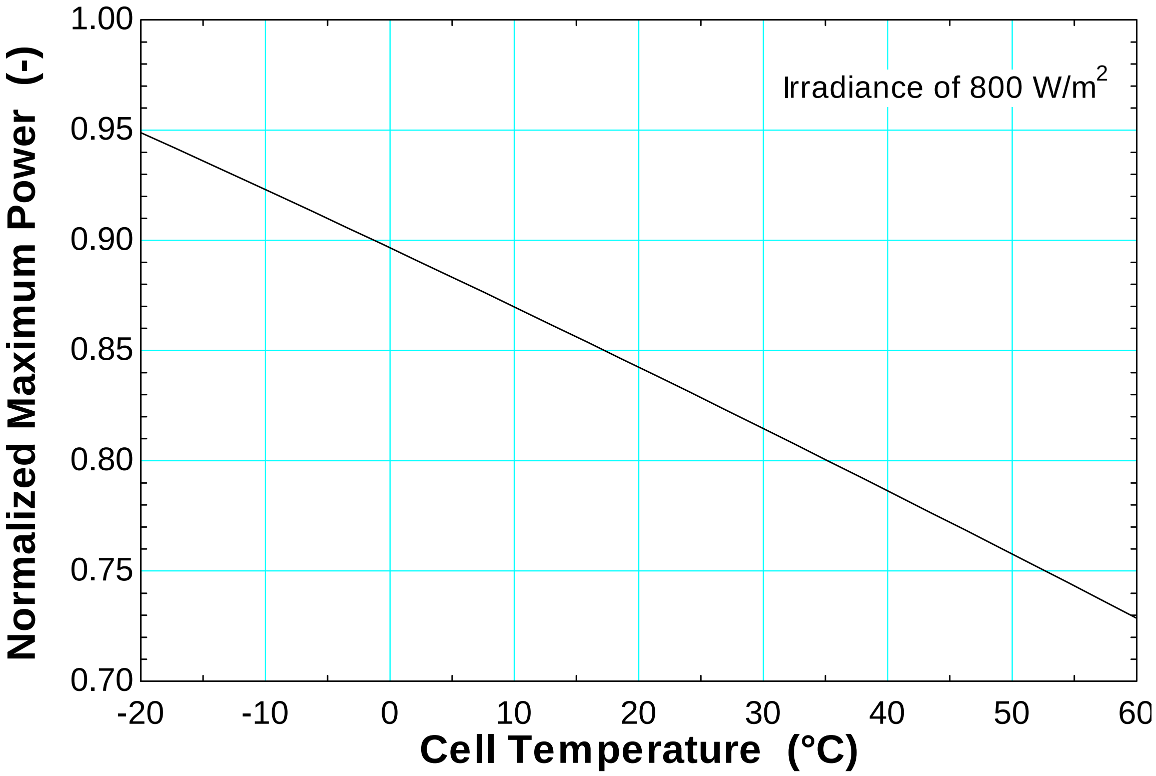


Figure 2.9: Normalized maximum poweras a function of cell temperature

There is an inverse relationship between maximum power and cell temperature. Decreasing the cell temperature increases the power output. High power output is achieved with high solar radiation and low cell temperature. However, high solar radiation and low cell temperature seldom coincide.

2.1.7 Performance Ratings

Since the power output from a PV cell depends on the level of radiation and cell temperature, a standard test method is used to compare the performance of different types of PV modules. PV modules are rated by the manufacturer based on Standard Test Conditions (STC) [13]:

- Irradiance of 1000 W/m^2
- Module temperature of 25°C
- Air mass equal to 1.5
- ASTM G173-03 standard spectrum

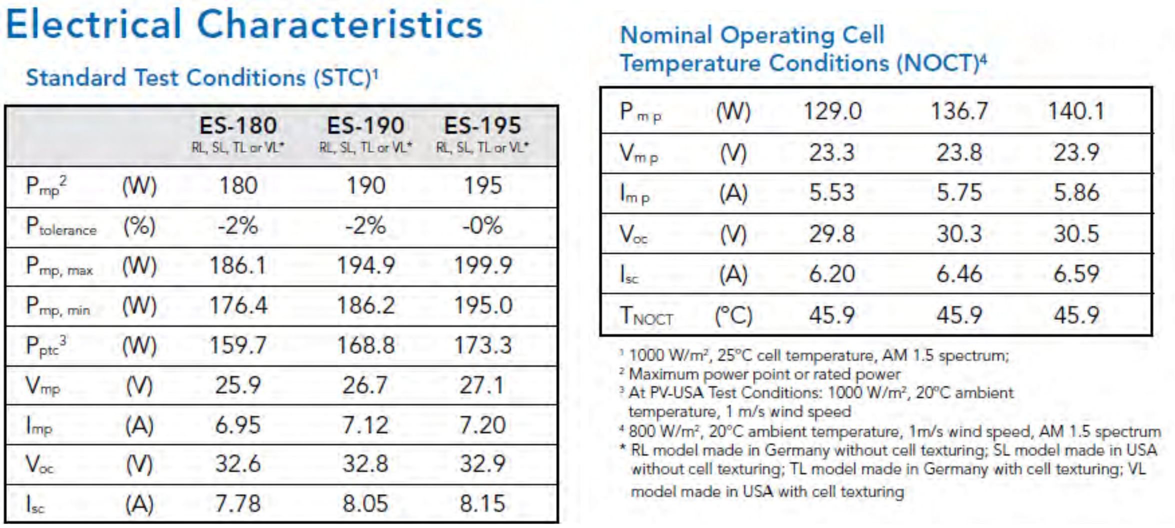
The maximum current and voltage are recorded under these conditions and multiplied to yield the maximum power. The maximum power (or peak power) is the value reported, in Watts of direct current, when referring to the rated output of a PV module. For example, a module rating of 210 Watts means that the panel is capable of generating 210 Watts of direct current power under irradiance of 1000 W/m^2 and a module temperature of 25°C. In reality, the module will operate over a range of irradiances and temperatures and rarely, if ever, achieve its rated maximum power. When configured in a grid-connected system, the overall output is reduced further due to the conversion by the inverter of direct current, output from the module, to alternating current.

Another rating provided by manufacturers is the Nominal Operating Cell Temperature (NOCT). The NOCT is the temperature of the module reached by open circuit cells under:

- Irradiance of 800 W/m^2
- Ambient air temperature of 20°C
- Wind velocity of 1 m/s
- Open back-side mounting

The performance ratings for a photovoltaic cell are shown in Table 2.1. The performance data at these two conditions can be used with other manufacturer's data to predict the performance of a PV module under any combination of irradiance and temperature. Several models are available to predict the performance of a PV module under varying irradiance and temperature. Four PV performance models are discussed in Chapter 3.

Table 2.1: Performance ratings for Evergreen Solar ES-180/190/195



Electrical Characteristics

Standard Test Conditions (STC)[1]

		ES-180 RL, SL, TL or VL*	ES-190 RL, SL, TL or VL*	ES-195 RL, SL, TL or VL*
P_{mp}[2]	(W)	180	190	195
$P_{tolerance}$	(%)	-2%	-2%	-0%
$P_{mp, max}$	(W)	186.1	194.9	199.9
$P_{mp, min}$	(W)	176.4	186.2	195.0
P_{ptc}[3]	(W)	159.7	168.8	173.3
V_{mp}	(V)	25.9	26.7	27.1
I_{mp}	(A)	6.95	7.12	7.20
V_{oc}	(V)	32.6	32.8	32.9
I_{sc}	(A)	7.78	8.05	8.15

Nominal Operating Cell Temperature Conditions (NOCT)[4]

P_{mp}	(W)	129.0	136.7	140.1
V_{mp}	(V)	23.3	23.8	23.9
I_{mp}	(A)	5.53	5.75	5.86
V_{oc}	(V)	29.8	30.3	30.5
I_{sc}	(A)	6.20	6.46	6.59
T_{NOCT}	(°C)	45.9	45.9	45.9

[1] 1000 W/m², 25°C cell temperature, AM 1.5 spectrum;

[2] Maximum power point or rated power

[3] At PV-USA Test Conditions: 1000 W/m², 20°C ambient temperature, 1 m/s wind speed

[4] 800 W/m², 20°C ambient temperature, 1m/s wind speed, AM 1.5 spectrum

* RL model made in Germany without cell texturing; SL model made in USA without cell texturing; TL model made in Germany with cell texturing; VL model made in USA with cell texturing

2.1.8 Lifecycle Analysis: Energy Payback Time and Greenhouse Gas Emissions

As with any manufactured good, PV systems require energy and raw materials during their manufacture. There have been several lifecycle studies performed on PV systems. These studies have analyzed the energy inputs to manufacture PV systems. The energy required to manufacture a PV system is often referred to as the "embodied" or embedded energy. This embodied energy is compared with estimates of the energy output by the PV system over its useful life in order to determine an "energy payback." In addition to the energy payback time (EPT or EPBT), the energy yield ratio (EYR) is another measure of performance applied to a PV system. The EPT represents the number of years required for the energy output of the system to recuperate the embodied energy of the system. The EPT is calculated as:

$$\mathrm{EPT} \quad \frac{E_{input}}{E_{gen}}. \tag{2.6}$$

The energy input (E_{input}) includes all the primary energy required for the raw material acquisition (mining), material processing (smelting, refining, purification), manufacturing of module and components, use (operation and maintenance), decommissioning, and disposal and/or recycling. The energy generated (E_{gen}) is defined as the primary energy savings (or energy "displaced" from conventional means) due to the annual energy generation by the PV module. The primary energy savings (E_{gen}) is calculated based on the actual electrical energy output ($E_{gen,elec}$) and the average efficiency of power plants ($_{pp}$) in the area in which the module is installed:

$$E_{gen} \quad \frac{E_{gen,\,elec}}{K_{pp}}. \tag{2.7}$$

There is a distinct difference between using the primary energy savings and the actual electrical energy generated by the system. Using the electrical energy output will yield an energy payback time approximately 3 times greater than using the primary energy savings, based on an average thermal power plant efficiency of 35%.

One argument against the EPT is that the calculation has no indication of the lifetime of the PV panel [14]. Richards and Watt argue that excluding the lifetime of the PV panel does not give any indication of which panel may generate more net energy over its operating life.

A second measure of the energy input relative to the energy output for a PV system is the energy yield ratio. The EYR, proposed by Richards and Watt, is the energy generated over the lifetime of the PV system (L_{PV}) and the input energy:

$$\mathrm{EYR} \quad \frac{E_{gen} L_{PV}}{E_{input}}. \tag{2.8}$$

This figure is intended to define “how many times the energy invested is returned or paid back by the system in its entire life” [14].

Table 2.2 lists the energy payback metrics and the lifecycle greenhouse gas emissions from different lifecycle analysis studies. Greenhouse gases (GhG) are heat trapping gases present in Earth’s atmosphere. Greenhouse gases include naturally occurring and anthropogenic (caused by human activity) gases, primarily carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases [15]. A low EPT is desirable, whereas a high EYR is desirable. The energy payback time from several studies range from 1 to 25 years depending of the on many factors [16]. The Nawaz and Tiwari study used the electrical energy output ($E_{gen,elec}$) instead of E_{gen} in the EPT calculation; the values based on primary energy savings are presented in brackets for comparison with the Richards and Watts study [17]. The Fthenakis and Kim study results for greenhouse gas emissions were remarkably lower than the results of other studies [18]. The Varun et al. study reviewed nine lifecycle studies of CO_2 emissions from a PV system dating from 1992 to 2006 for a variety of countries [19]. The differences with the Fthenakis and Kim study are accounted for by “country-specific parameters” and “outdated information” in the other studies. Several technological factors have contributed to the reduction in EPT (increase in EYR) and GhG emissions including: increased production yield of the PV manufacturing process, increased expected lifetime of system, and improved cell and system efficiency.

Table 2.2: Energy payback and greenhouse gas emissions reported by LCA studies

Study	Installation Type and Assumptions	EPT (years)	EYR (-)	GhG emissions ($g\ CO_2$-eq/kWh)
Nawaz and Tiwari (2006)	Rooftop PV system with BOS 35 yr lifetime 1 m^2 system electrical energy output [primary energy equivalent]	8 – 22 [3 – 8]*	1.6 - 4.4$^{\#}$ [4.4 - 11.2]$^{\#}$*	210 - 613
Richards and Watt (2007)	Rooftop on-grid PV system 2 kW_p system 20 yr (30 yr) lifetime primary energy equivalent	2.7 – 4.9	4.1 – 7.5 (6.2 – 11.2)	N/A
Fthenakis and Kim (2007)	30-year lifetime	N/A	N/A	17 - 49
Varun et al. (2009)	Review of other studies	N/A	N/A	53.4 - 250
* calculated based on power plant efficiency of 35% $^{\#}$ calculated based on 35 year lifetime				

The F&K study compared the GhG emissions from the nuclear fuel cycle and found the emissions ranged from 16-55 grams CO_2 equivalent per kWh. The Varun et al. study also reviewed the GhG emissions from other electricity generation technologies, summarized in Table 2.3. Although the lifecycle emissions from the renewable technologies (hydro, wind, biomass, solar thermal, and solar PV) can vary widely, as expected they are all well below the emissions of fossil-fuel based power generation.

Table 2.3: Lifecycle emissions comparison of electricity generation sources (Varun et al)

Type of System	GhG emissions from studies Range [Average] (g CO_2/kWh)
Hydro	3.7 - 237 [66]
Wind	9.7 - 123.7 [36]
Biomass	13.6 - 202 [75]
Nuclear	24.2
Solar thermal	35.0 - 178 [114]
Solar PV	53.4 - 250 [136]
Gas fired	607.6
Oil fired	742.1
Coal fired	975.3

2.1.9 Costs

The total installed cost of a photovoltaic system includes the module, inverter, mounting and electrical equipment, labor, and miscellaneous expenses. The miscellaneous expenses include overhead, regulatory compliance, and other expenses. According to the U.S Department of Energy's (DOE) Solar Energy Technologies Program (SETP) "Multi Year Program Plan 2008-2012" (MYPP 2008-2012), the installed cost for residential PV systems in 2006 was 7.87 US dollars per Watt peak ($\$/W_p$), and $\$7.23/W_p$ for commercial PV [20]. The levelized cost of energy (LCOE) over 30 years was calculated as \$0.30/kWh for residential, and \$0.186/kWh for commercial. The MYPP 2008-2012 benchmark cost and cost targets for PV systems for residential and commercial systems for 2010 and 2015 are shown in Figure 2.10, in terms of LCOE.

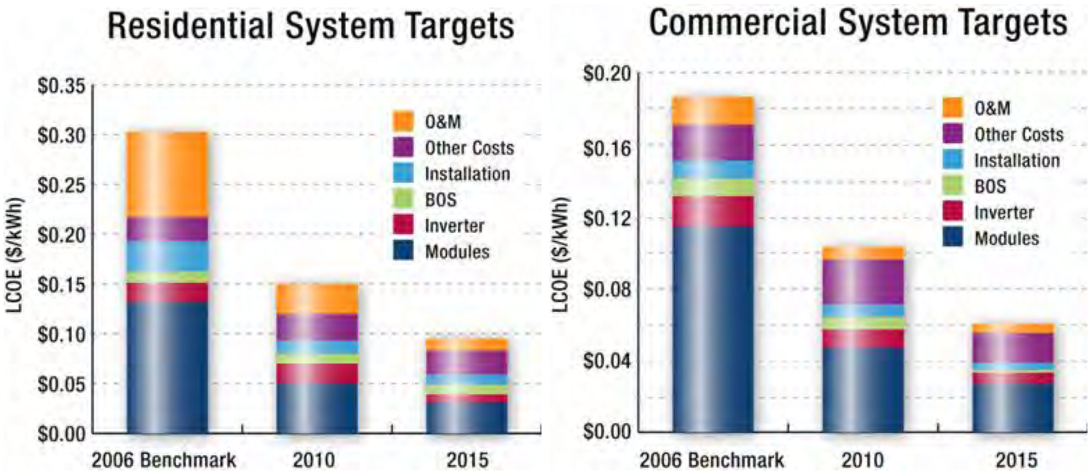


Figure 2.10: SETP cost targets for PV systems[20]

The levelized cost of energy represented in Figure 2.10 is calculated as prescribed [20]:

> The solar performance is based on NSRDB weather station closest to the center of the utility service territory, assuming a south facing array, at 25 deg tilt. An 82% derate factor is used to account for inverter and other PV system loses, but no performance degradation over life of the PV system is assumed. For the financial analysis, the installed system price is set at $\$8.5/W_p$ in the current case and $\$3.3/W_p$ in 2015. The system is assumed to be financed with a home equity loan or through mortgage (i.e., interest is tax deductible), with a 10% down payment, 6% interest rate, with the owner in the 28% tax bracket, and a 30 year loan/30 year evaluation period. Incentives included are the Federal ITC [Investment Tax Credit] worth $500/kW due to $2000 cap and individual state incentives as of December 2007 in the current case and no Federal ITC or state incentives in 2015.

A Lawrence Berkeley National Laboratory (LBNL) study of the market for photovoltaic systems encompassed the ten year period ending in 2007 and analyzed 76 percent of all grid-connected installations in the U.S. from 1998 to 2007 [21]. The average installed cost in 2007 for all systems was $\$7.6/W_p$. The installed cost of systems of varying size is shown in Figure 2.11.

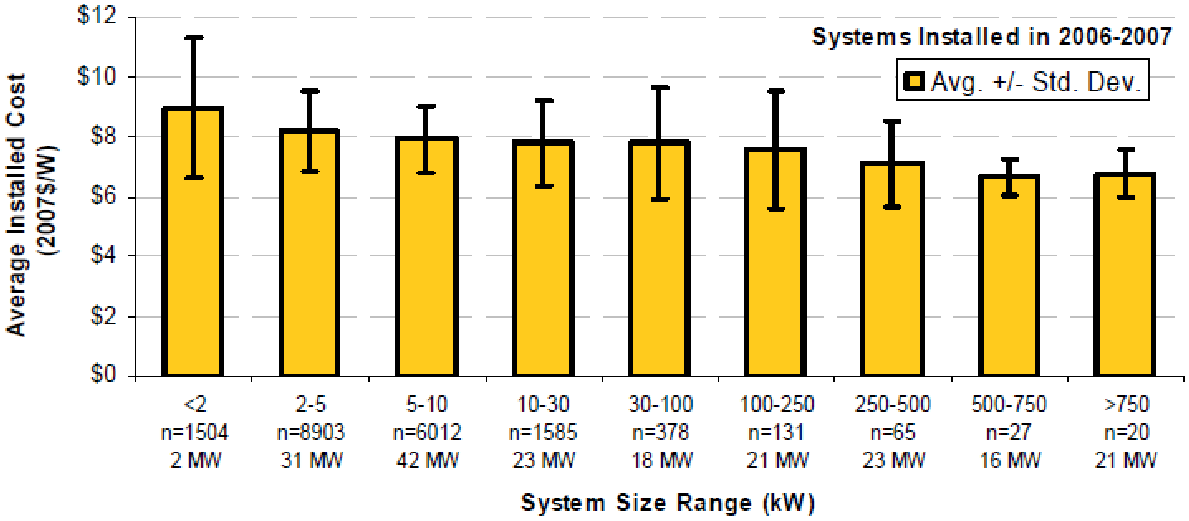
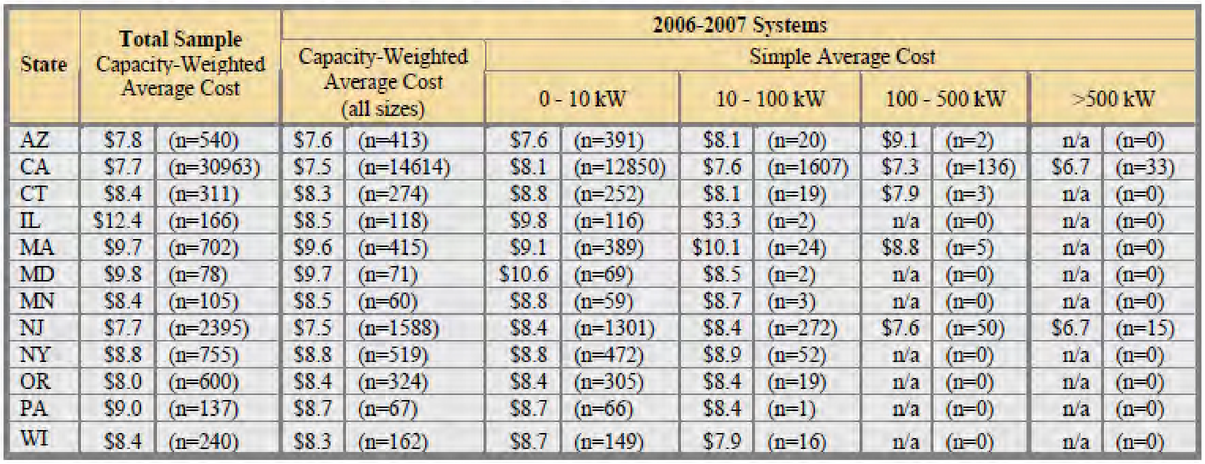


Figure 2.11: Installation cost for varying PV system size[21]

Table 2.4 lists the average installed cost by state and PV system size range from the Lawrence Berkeley National Laboratory study of the PV market. The average installed cost in Wisconsin for a system less than 10 kW, typical of a residential installation, for 2006-2007 was $8.7/W$_p$.

Table 2.4: Average installed cost by state and PV system size range[21]



State	Total Sample Capacity-Weighted Average Cost		2006-2007 Systems									
			Capacity-Weighted Average Cost (all sizes)		Simple Average Cost							
					0 - 10 kW		10 - 100 kW		100 - 500 kW		>500 kW	
AZ	$7.8	(n=540)	$7.6	(n=413)	$7.6	(n=391)	$8.1	(n=20)	$9.1	(n=2)	n/a	(n=0)
CA	$7.7	(n=30963)	$7.5	(n=14614)	$8.1	(n=12850)	$7.6	(n=1607)	$7.3	(n=136)	$6.7	(n=33)
CT	$8.4	(n=311)	$8.3	(n=274)	$8.8	(n=252)	$8.1	(n=19)	$7.9	(n=3)	n/a	(n=0)
IL	$12.4	(n=166)	$8.5	(n=118)	$9.8	(n=116)	$3.3	(n=2)	n/a	(n=0)	n/a	(n=0)
MA	$9.7	(n=702)	$9.6	(n=415)	$9.1	(n=389)	$10.1	(n=24)	$8.8	(n=5)	n/a	(n=0)
MD	$9.8	(n=78)	$9.7	(n=71)	$10.6	(n=69)	$8.5	(n=2)	n/a	(n=0)	n/a	(n=0)
MN	$8.4	(n=105)	$8.5	(n=60)	$8.8	(n=59)	$8.7	(n=3)	n/a	(n=0)	n/a	(n=0)
NJ	$7.7	(n=2395)	$7.5	(n=1588)	$8.4	(n=1301)	$8.4	(n=272)	$7.6	(n=50)	$6.7	(n=15)
NY	$8.8	(n=755)	$8.8	(n=519)	$8.8	(n=472)	$8.9	(n=52)	n/a	(n=0)	n/a	(n=0)
OR	$8.0	(n=600)	$8.4	(n=324)	$8.4	(n=305)	$8.4	(n=19)	n/a	(n=0)	n/a	(n=0)
PA	$9.0	(n=137)	$8.7	(n=67)	$8.7	(n=66)	$8.4	(n=1)	n/a	(n=0)	n/a	(n=0)
WI	$8.4	(n=240)	$8.3	(n=162)	$8.7	(n=149)	$7.9	(n=16)	n/a	(n=0)	n/a	(n=0)

2.1.9.1Module Cost

The LBNL study tracked the cost components of each installed PV system. The percentage of total installed cost for each of these expense categories, for different size systems, is shown in Figure 2.12.

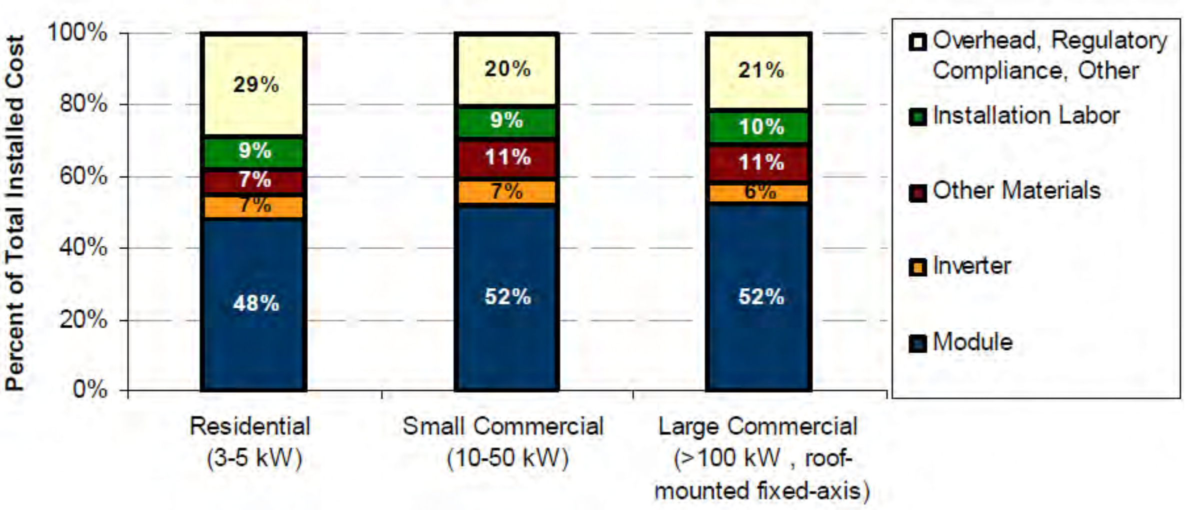


Figure 2.12: Breakdown of total installed cost of a photovoltaic system[21]

The PV module cost accounts for approximately 50 percent of the total system installed cost, and is therefore the most expensive component of a PV system. Combining the information in Figure 2.12 and Figure 2.11 for the range of residential installations, 3 kW to 5 kW, the average module cost for 2006-2007 was \$3.9/W_p. The LBNL study also found that the installation cost for thin-film modules for systems less than 10 kW, on average, was \$0.5/W_p more than crystalline silicon. The higher installation cost of thin-film modules is surprising due to the claims by thin-film manufacturers of low module manufacturing costs. The higher installed costs are attributed, by the authors, to the higher balance of system costs associated with lower module efficiencies of thin-film. This means that a lower-efficiency module will require a larger panel area to generate equivalent power; resulting in more mounting equipment for the larger panels. However, the authors note, there is not a significant difference in installed cost for larger systems (>10 kW).

Solarbuzz LLC maintains a Solar Module Retail Price Index that surveys the module costs from approximately 70 companies worldwide [22]. The index is the average retail price per Watt of rated power for PV modules rated above 125 W. The average retail price for a PV module available in the United States as of June 2009 was \$4.61/W_p. The lowest retail price for multi-crystalline silicon solar module was \$2.48/W_p, for monocrystalline silicon \$2.80/W_p, and for thin film module \$1.76/W_p.

2.1.9.2Inverter Cost

The inverter accounts for just below 10 percent of the total system installed cost, or an average of about \$0.53/W in 2007 dollars [21]. The inverter has an expected lifetime of 5 to 10 years, with warranties of 2 to 5 years [23]. A Navigant Consulting, Inc. survey of the price of residential inverters is shown in Figure 2.13. The study forecast an annual decline in inverter prices of 2 percent per year going forward [23]. The cost ranged, in 2004, from \$0.67/W to \$2.67/W and in 2005 from \$0.48/W to \$2.42/W. The average cost of an inverter as of June 2009 reported by Solarbuzz LLC was 0.721 US dollars per continuous Watt [24].

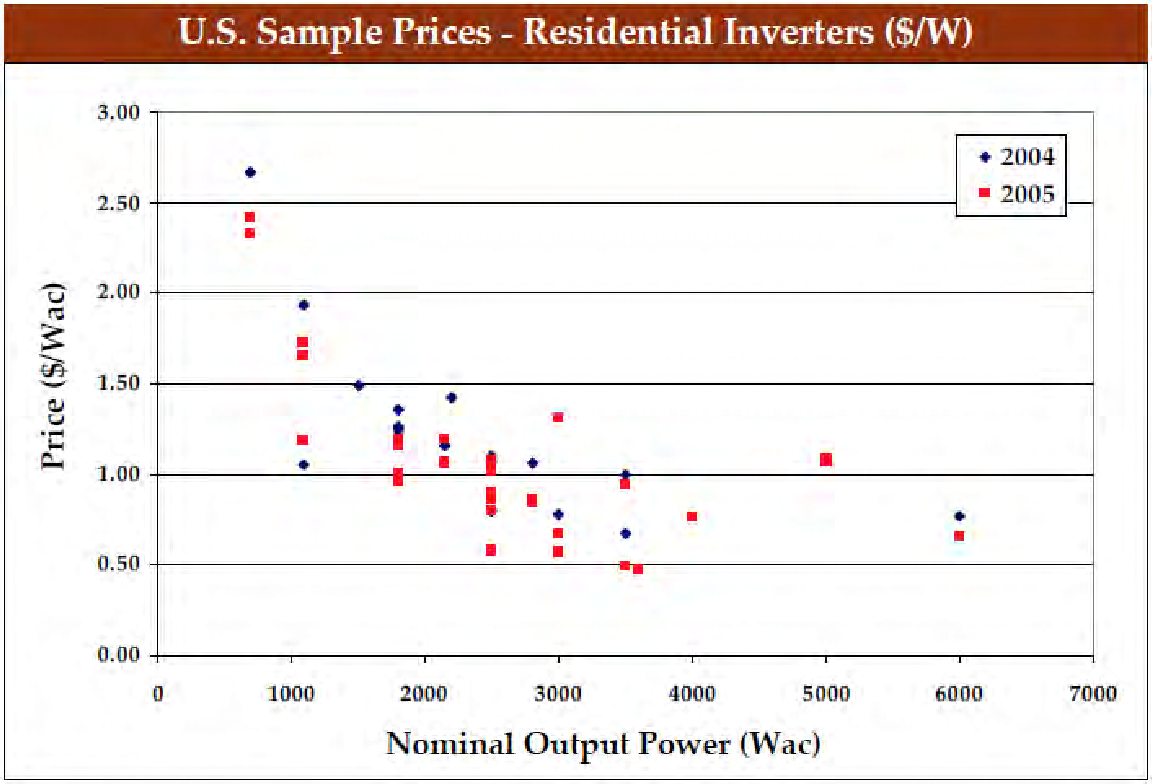
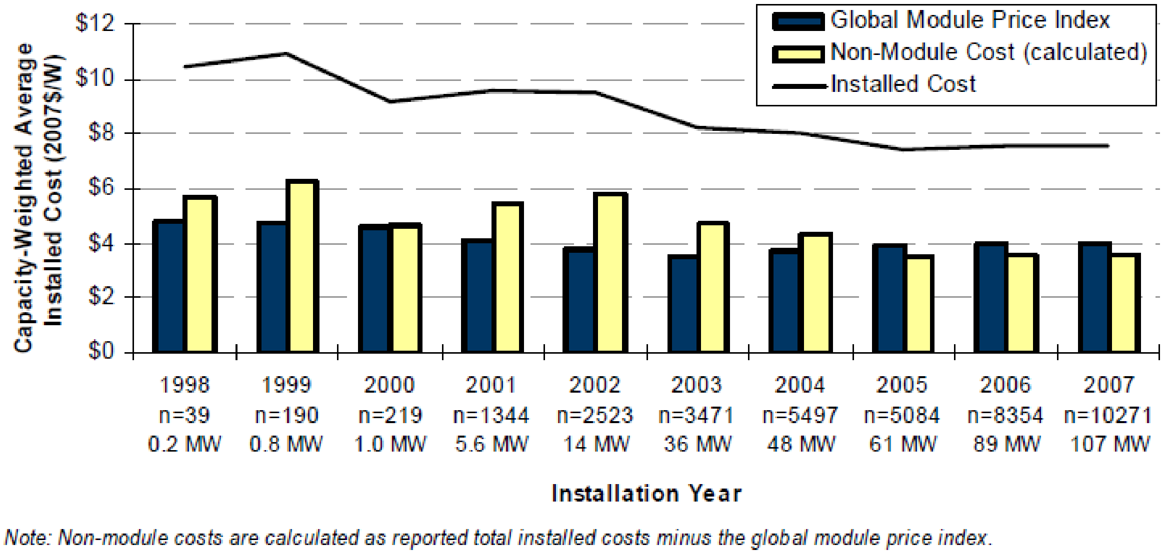


Figure 2.13: U.S. residential inverter prices (Navigant Consulting, Inc.)

2.1.9.3Price Trends

According to the 2009 LBNL study, the total installed cost of photovoltaics, in real 2007 dollars per watt of rated capacity before incentives, over the ten year period declined from \$10.5/W_p in 1998 to \$7.6/W_p in 2007. This decline equates to an average of \$0.3/W_p per year or 3.5 percent per year in real dollars. The reduction in installed cost was attributed to lower non-module costs, calculated as total installed cost minus an average module price index, which declined from \$5.7/W_p to \$3.6/W_p, or 73 percent of the decline in installed cost. The average installed cost, module index price, and non-module index cost for each year of the study are shown in Figure 2.14. Installed costs for systems less than 5 kW dropped from \$11.8/W_p in 1998 to \$8.3/W_p in 2007. Economies of scale existed for systems greater than 750 kW, which averaged \$6.8/W_p in 2007, over systems less than 2 kW, which averaged \$9.0/W_p.



Note: Non-module costs are calculated as reported total installed costs minus the global module price index.

Figure 2.14: Module and non-module cost trends over time[21]

Many studies have been performed to forecast future trends in PV prices. Some studies rely on a learning curve or experience curve, the “learning by doing” method, to reduce the costs of PV panels through increased capacity. While these studies are useful in the intermediate stages of a technology, once it has developed and the learning curve flattens, the results are less meaningful. There are other, more significant factors attributed to the cost reductions of PV over time including expected future demand, risk management, research and development, and knowledge spillovers [25]. As can be seen by Figure 2.14, the module costs have remained relatively flat over the ten-year period (decreasing initially then gradually increasing after 2003) even as the number of installations increases; installed capacity and number of panels is listed under the installation year. This would indicate that crystalline silicon PV is a mature technology and that any reductions in panel costs would come from a substitute material.

2.2 Electric Utility Basics

This section covers topics relating to the operation of an electric utility including electrical load, electricity generation, capacity factor, types of generation equipment, the electric utility grid and its importance in transporting electricity, and utility planning.

2.2.1 Electrical Load and Demand

The electrical load on a utility varies hourly over a day and over a season. Figure 2.15 illustrates the variation in load for a week in each of the four seasons. The load on the utility is normalized by the peak annual load. The utility profile is for Madison Gas and Electric, located in Madison, Wisconsin, for the year 2002. Utility load data from year 2002 was used because this was the year for which hourly load data from all Wisconsin utilities was available. The winter (January), spring (May), and autumn (October) week load were similar. The summer load (July) was the highest of all four seasons. The peak load occurred in July in the early afternoon.

The hourly load on an electric utility can be sorted from highest to lowest load and plotted to create a load duration curve Figure 2.16 is the load duration curve for the major electric utilities in Wisconsin for the year 2002 [26]. Each set of data was independently sorted in descending order, normalized by the maximum load for each set, and plotted serially. The load duration curve is interpreted as the number of hours at which a certain load was experienced by the system. There are three distinct regions of the load duration curve, approximated by the fraction of annual peak load: baseload (0-40% of annual peak), intermediate load (40-80% of annual peak), and peak load (80-100% of annual peak).

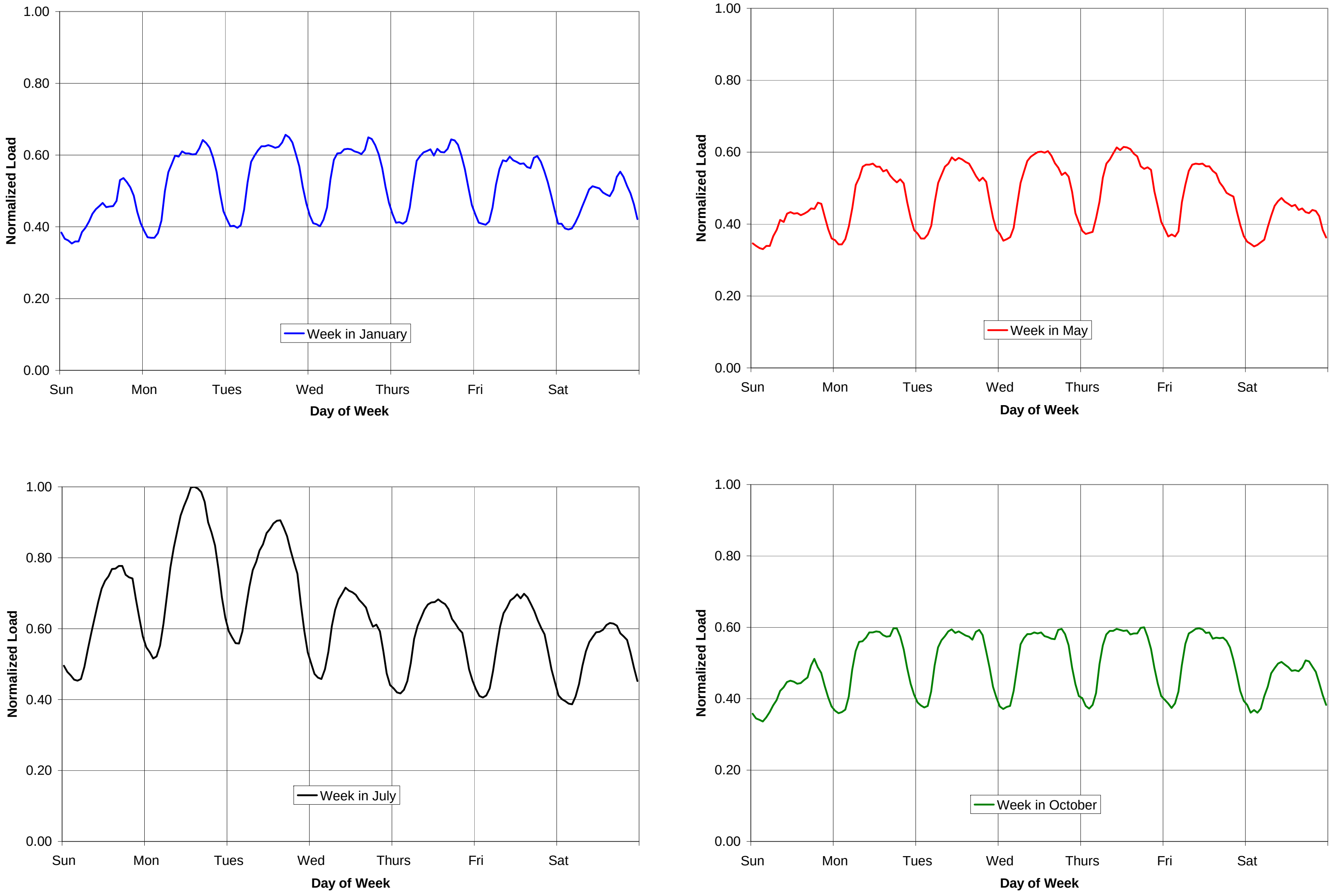


Figure 2.15: Seasonal and daily variation in load

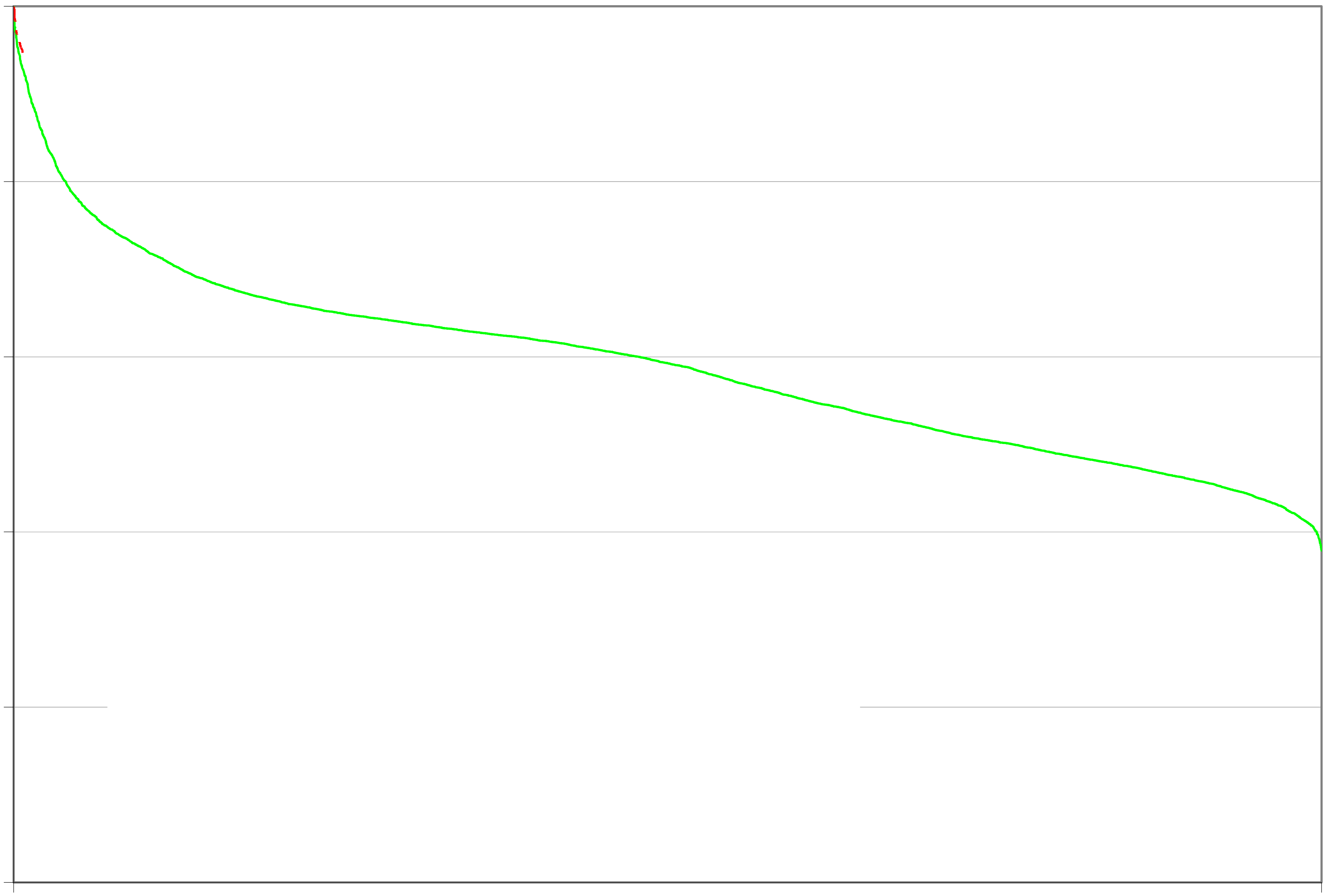


Figure 2.16: Load duration curve for major utility electric loads in Wisconsin (2002)

Public Service Commission of Wisconsin

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Environmental and Economic Research and Development Program

Final Report

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University of Wisconsin-Madison

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The power is within you.

This research project was funded through the FOCUS ON ENERGY Program.