Chapter 5 SOLAR PHOTOVOLTAICS

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5 SOLAR PHOTOVOLTAICS

5.1 Photovoltaic Systems Overview

5.1.1 Introduction

A photovoltaic (PV) system is able to supply electric energy to a given load by directly converting solar energy through the photovoltaic effect. The system structure is very flexible. PV modules are the main building blocks; these can be arranged into arrays to increase electric energy production. Normally additional equipment is necessary in order to transform energy into a useful form or store energy for future use. The resulting system will therefore be determined by the energy needs (or loads) in a particular application. PV systems can be broadly classified in two major groups:

1) **Stand-Alone:** These systems are isolated from the electric distribution grid. Figure 5.1 describes the most common system configuration. The system described in Figure 5.1 is actually one of the most complex; and includes all the elements necessary to serve AC appliances in a common household or commercial application. An additional generator (e.g., bio-diesel or wind) could be considered to enhance the reliability but it is not necessary. The number of components in the system will depend on the type of load that is being served. The inverter could be eliminated or replaced by a DC to DC converter if only DC loads are to be fed by the PV modules. It is also possible to directly couple a PV array to a DC load when alternative storage methods are used or when operating schedules are not of importance. A good example may be water pumping applications were a PV module is directly coupled to a DC pump, water is stored in a tank through the day whenever energy is available.

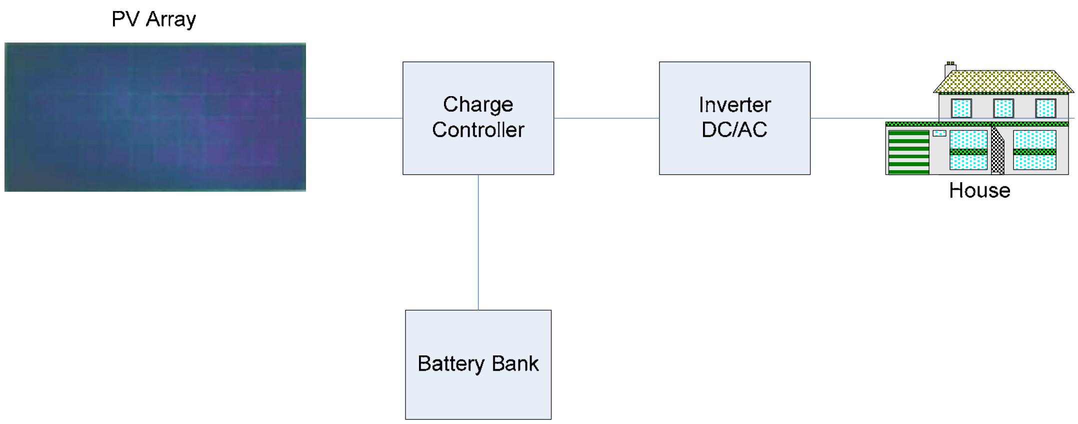

Figure 5.1 Stand-Alone Photovoltaic System

2) **Grid-Tied:** These systems are directly coupled to the electric distribution network and do not require battery storage. Figure 5.2 describes the basic system configuration. Electric energy is either sold or bought from the local electric utility depending on the local energy load patterns and the solar resource variation during the day, this operation mode requires an inverter to convert DC currents to AC currents. There are many benefits that could be obtained from using grid-tied PV systems instead of the traditional stand-alone schemes. These benefits are [2],[3],[17]:
   - Smaller PV arrays can supply the same load reliably.
   - Less balance of system components are needed.
   - Comparable emission reduction potential taking advantage of existing infrastructure.
   - Eliminates the need for energy storage and the costs associated to substituting and recycling batteries for individual clients. Storage can be included if desired to enhance reliability for the client.
   - Takes advantage of the existing electrical infrastructure.
   - Efficient use of available energy. Contributes to the required electrical grid generation while the client's demand is below PV output.

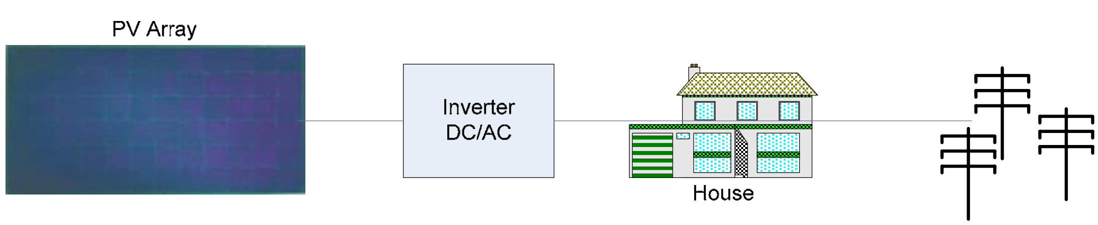

Figure 5.2 Grid-Tied Photovoltaic System

Hybrid systems may be possible were battery storage or a generator (or both) can be combined with a grid connection for additional reliability and scheduling flexibility (at additional cost). Most of the installed residential, commercial and central scale systems use pre-fabricated flat plate solar modules, because they are widely available. Most available reports on PV system costs are therefore related to this kind of technology and shall be our focus in this chapter. Other specialized technologies are available (e.g., concentrating PV systems), but not as commercially available as the traditional PV module.

5.1.2 Electricity Generation with Solar Cells

The photovoltaic effect is the basic physical process through which a PV cell converts sunlight into electricity. Sunlight is composed of photons (like energy accumulations), or particles of solar energy. These photons contain various amounts of energy corresponding to the different wavelengths of the solar spectrum. When photons hit a PV cell, they may be reflected or absorbed. Only the absorbed photons generate electricity. When this happens, the energy of the photon is transferred to an electron in an atom of the cell (usually silicon atoms). The electron is able to escape from its normal position associated in the atom to become part of the current in an electrical circuit.

To produce the electric field within a PV cell, the manufacturers create a junction of two different semiconductors (types P and N). The most common way of making P or N type silicon material is adding an element that has an extra electron or has a deficit of an electron. Silicon is the most common material used in manufacturing process of photovoltaic cells. Silicon atoms have 14 electrons, where the four electrons in the last layer are called valence electrons. In a crystal solid, each silicon atom normally shares one of its four valence electrons in a covalent junction with another silicon atom. The silicon crystal molecule is formed of 5 silicon atoms in a covalent junction.

The process of doping introduces an atom of another element into the silicon crystal to alter its electrical properties. The element used for doping has three or five valence electrons. Usually Phosphorus is used to make the N type (Phosphorus has 5 valence electrons) and Boron the P type (Boron has 3 valence electrons). In a polycrystalline thin-film cell the top layer is made of a different semiconductor material than the bottom semiconductor layer [56].

5.1.3 Photovoltaic Systems Total Costs Overview

The PV industry is rapidly maturing because of worldwide environmental concerns and its energy production potential due to the widely available free solar resource. The industry is in a race to achieve grid parity (PV energy costs equal to conventional utility costs) and increase competitiveness in the energy markets. PV system installed costs range from 4,600 to 19,500 $/kW (typically the size of the PV array is used to determine the kW or W rating of the system when complete system costs are considered). Common figures are 8,000 $/kW for grid-tied systems, and 14,000 $/kW for stand-alone systems. Energy production costs are typically estimated above 0.18 $/kWh in the United States, yet these energy costs are highly dependent on the available solar resource at the location under study and cannot be used as a general reference. Table 5.1 summarizes available cost information for PV systems (stand-alone and grid-tied) in the US and Europe. It is important to understand the factors that directly and indirectly affect system costs and viability, to properly identify the potential of this technology in a particular market. Table 5.2 summarizes some of these factors.

Table 5.1 Summary of Installed PV System Cost information

Study	$/kWp	$/kWh	Year of Report
NREL [12]	7,400-14,000	-	2001
IEA [11]	7,180	-	2003
EPV Industry Association and Greenpeace [11]	7,866-11,144	0.33-1.30	2004
Komor [8]	4,500-8,000	0.20-0.50	2004
BP Solar UK [11]	9,745-19,490	-	2005
NREL[# presentacion]	6,000-25,000	-	2005
NREL [13]	7,560	-	2006
San Francisco Environment [11]	9,500	-	2007
EIA [11]	8,000-12,000	0.21-0.82	2007
NREL [14]	9,000	-	2008
Solarbuzz [6]	6,000-10,000	0.20-0.40	June 2008

*Some of the reports may include system data for several years; in these cases the year of publication is included. Cost information is therefore affected by time span, data set size and system variety.

Table 5.2 Summary of Factors Affecting PV System Costs and Feasibility

Factors	Facts
Grid connection	• Grid-connected systems do not need batteries which reduces considerably initial capital costs and energy costs. • For a comparable load, grid-tied systems use smaller PV arrays than stand-alone systems. • Grid-Tied systems are estimated to cost ~$4,800/kW less than stand-alone systems including inverters and batteries according to the study in [12] for systems built in the US between 1997-2000.
Distance to nearest	• Stand-alone systems tend to become feasible in

utility grid	locations which are far from electrical distribution networks. • Grid extensions can cost thousands of dollars per mile of transmission line.
Solar resource	• Solar resource will not affect capital costs but the availability of solar energy does affect the cost of producing energy, hence the payback period for the investment. • According to [12], location is considered the second largest factor affecting PV system costperformance. • Location can have influence on shading patterns, soiling, operating temperature and solar resource variations.
BOS (tracking)	• Balance of system components is estimated to represent 30-50% of the total costs of a PV System [8]. • Most cost reductions for PV systems over the last decade are in BOS components including inverters [13]. • Local safety codes or regulations can require additional balance of system costs for the installation.
Type of installation , Mounting, size and Space	• When flat roofs are considered, 10^{o} tilt uses 30% more roof area when flat roofs are considered [9]. Commercial and industrial clients prefer horizontal installation to maximize flat roof utilization and to lower mounting expenses. • Retrofit installations tend to be more expensive than those planned for new buildings. According to [13]: → Large residential projects are ~$1.2/W$_{ac}$ less expensive. → Affordable Housing projects are ~$1.9/W$_{ac}$ less expensive. → Custom New House ~$0.18/W$_{ac}$ more expensive. • Large Scale systems tend to be less expensive on a per watt basis. Due to the volume or the purchases, developers take advantage of wholesale prices or discounts. This is also true for large residential projects as discussed above. • Due to capital cost restrictions, stand-alone systems tend to be smaller or used for smaller loads. • Grid-tied systems tend to be larger because they provide lower capital costs and energy costs for larger loads.

	• Typically larger systems tend to have lower cost per kW. According to [12] costs diminish ~$40 for every additional kW.
Module technology	• Modules account for 40-50% of total system costs, according to [6] and [8]. • Module efficiency determines the total area needed to install the system. Less area per watt is desired to maximize roof or land use. • PV modules that require less material, energy and time to develop have lower costs (details below).
PV production	• Supply and demand laws have been slowing the cost of PV modules in the last years. Market shortage of PV modules has been particularly driven by high demand and silicon supply shortage. • US production of both silicon and PV modules is constantly increasing to satisfy the demand. • Many research efforts today seek to reduce the quantity of materials used per module, one example is thin-film cell technology. • A doubling in PV production results in ~20% module price reduction [13].
Time and Learning Curve	• According to [12], next year cost reduction for systems built in the US between the years 1997 and 2000 is ~ $600/kW. • According to [13], a 7.3% annual decline has been observed on small scale system costs since 1998. Large scale systems showed lower reductions, yet these tend to be less expensive for each watt of capacity. • Lower component costs are complemented by the acquired knowledge by system designers and installers who can perform their jobs more efficiently as they gain experience, reducing overall costs as well.
O&M	• Most PV systems do not have notable O&M costs especially grid-tied systems. • The study in [9] suggests $11/kW/yr. for small residential and commercial systems and $27/kW/yr. • According to [8], O&M costs may range between 0.4 to 9.5 cents/kWh although most tend to the lower limit. • Most small scale grid-tied systems do not have moving parts and therefore maintenance is minimal. • Large-scale systems may use tracking systems and therefore may require more work.

	• Battery assisted systems may require acid refills when valve regulated batteries are not used. • Some arrays will require regular cleaning. This could represent additional costs especially for large scale systems. • Tree branch trimming may be also considered O&M costs were applicable. • Batteries, inverters and charge controllers will probably require at least one replacement during project lifetime, it is therefore important to consider equipment lifetime and replacement cost as part of O&M costs during a projects lifetime. Insurance and inspection should also be considered.
Energy Use and Cost	• System size depends mostly on energy use, solar resource and component efficiency. • Reducing energy consumption greatly reduces the initial capital cost investment necessary. • The average energy use for the US is ~10W/ft^2 [14]. • Average residential energy use in Puerto Rico is ~800kWh/month. • PV systems can be cost competitive in locations with high energy prices and Net metering programs. The assumption that PV is expensive is therefore relative to the solar resource and utility energy prices in a location.
Indirect benefits (home value, GHG reduction, etc.)	• Home appraisal is estimated at ~$20 for every $1 reduction in annual utility bills [14]. • Customers would pay 10% more for a solar equipped residence [14]. • Emissions reductions provide a wide range of economical, environmental and health benefits. These are difficult to quantify, yet they cannot be ignored.
Available grants or Incentive Programs	• PV technology is considered very expensive in most applications; therefore several strategies have been implemented to jumpstart the widespread use of the technology. Some of these are: → Tax Deductions → Renewable Energy Credits → Emissions Reduction Credits → Net Metering Programs → Accelerated Depreciation → Grants • Not all have positive effects; therefore incentive programs should be carefully tailored.

Financing and economic variables	• Debt term, debt ratio, interest rate and project life have market effect on payback time and energy costs. • Small systems (residential or commercial) can be financed at 7-8.5% interest rates [9], these numbers coincide with local financing institutions. • Larger systems can be financed at lower rates. • Project specific financial parameters are not the only factors having effect on PV system economic performance. The economic performance is also affected by external parameters like inflation and energy escalation rates. • Energy costs in Puerto Rico are currently between \$0.21 and \$0.25, and rising due to the heavy dependence on petroleum derived fuels (June 2008). • In Puerto Rico inflation is 8%, energy cost escalation rate is 14% [28]. • Utilities generally use MARR values between 3 and 18%. The 6 to 11% range is most common [26], [27]. • According to [29], average MARR values for private investment (big money) or corporations are: → 40% for high risk investments (new products, new business, acquisitions, joint ventures). → 25% for medium risk investments (capacity increase to supply forecasted sales). → 15% for low risk investments (Cost improvement, make v.s. buy, capacity increase to meet existing orders). • MARR values for individuals are not commonly available and are difficult to calculate. • 20 year debt terms are common for utilities. • 12 year debt terms are common for developers. • Residential systems can be financed with debt terms in the range of 5 to 15 years. Is systems are financed as part of residential mortages, debt terms would tend to the upper limit. Personal loans tens to the lower limits. • 5 year MACRS depreciation methods are common in many incentive programs.

*Reference [13] reports price indexes in $\$/W_{ac}$, the authors suggest a 0.84 conversion factor for $\$/W_{dc}$ ($W=W_{dc}$). All \$/kWh are reported on the AC side.

5.1.4 Photovoltaic Energy Equipment: General Characteristics and Costs

Cost information on individual components and labor affecting the overall cost of grid-tied PV systems is compiled below along with a brief description of each item. The data for individual components represents the estimated average unit cost for an individual unit, not considering bulk or wholesale special prices. The information found agrees with the total costs information compiled in the previous section.

1) **Photovoltaic (PV) Modules:** The basic building block of a photovoltaic module is the photovoltaic cell; these convert solar energy into electricity. The power output will depend on the amount of energy incident on the surface of the cell and the operating temperature of the photovoltaic cell. The power output of a single cell can supply small loads like calculators or watches, but in order to be useful for high energy demand projects these cells must be arranged in series and parallel connections. A photovoltaic module is an array of photovoltaic cells pre-arranged in a single mounting mold. The type of module is therefore determined by the cells that compose the module itself. There are three dominating cell technologies:

    - **Monocrystalline**: As the name implies, these are cells that are grown from a single crystal. The production methods are difficult and expensive. These tend to be more efficient (more power in less area) and more expensive.
    - **Multicrystalline:** The production process allows multiple crystalline structures to develop within the cell. It is easier to implement in a production line. It is relatively cheaper than mono-crystalline at the expense of lower efficiency.
    - **Thin-film:** Uses less silicon to develop the cell (hence the name thin film) allowing for cheaper production costs (silicon is in high demand). It tends to be less expensive but has also lower efficiency.

    The overall efficiency of the module will depend on the cell efficiency and placement within the module, and on the laminating materials used. The standard testing condition (STC), defined as a total irradiance of 1000W/m^2 and an ambient temperature of 25^{o}C, is used to define module ratings. Typical module efficiencies range between 11% and 17% for crystalline technologies at STC; most of the commercially available modules are in the lower bound of this range. Thin-film module efficiencies range between 6% and 12% [57]. Since 2003 total PV production grew in average 50%, whereas the thin film segment grew almost 80% and reached 196 MW or 8% of total PV production in 2006. About 90% of the current production uses wafer-based crystalline silicon technology. The main advantage of this technology was that complete production lines could be bought, installed and manufactured within a relatively short time. This predictable production start-up scenario constitutes a low-risk placement with high expectations for return on investments [52].

Figure 5.3 displays the trend of the price index for photovoltaic modules over the last year. The price index represents the average price per watt of photovoltaic modules in the market. The information used to generate the graph only considers individual modules with ratings over 125Wp; the price index might be lower if modules are purchased in larger quantities at wholesale price [6]. Table 5.3 summarizes the lowest prices recorded for each technology type. New thin film photovoltaic modules are expected to be available for as low as $2/$W_p$ during the year 2009 [19]. Most PV manufacturers extend warranties for 20 to 25 years for their PV modules.

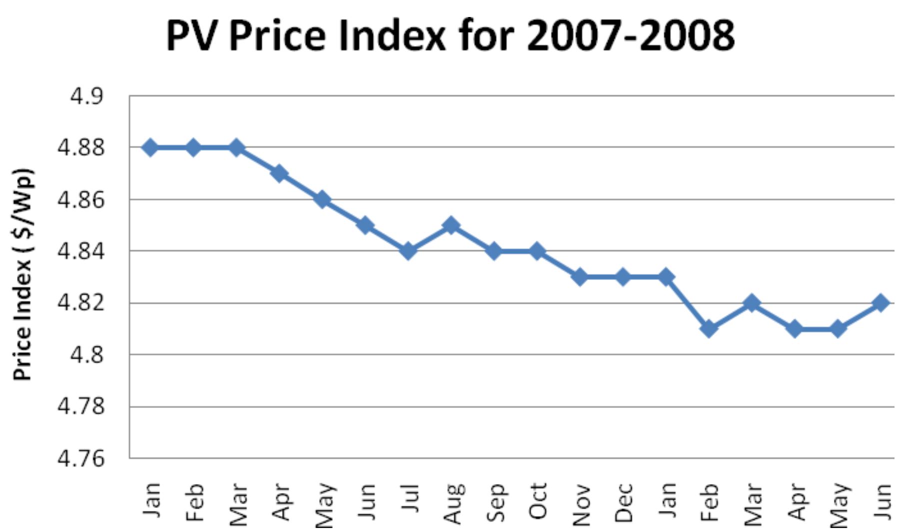

Figure 5.3 PV Module Price Index for 2007-2008

Table 5.3 Lowest for PV Price Index Recorded Technologies

Technology	Price (January)	Price (June)
Multicrystalline	$4.28/$W_p$	$4.17/$W_p$
Monocrystalline	$4.35/$W_p$	$4.35/$W_p$
Thin-film	$3.66/$W_p$	$3.74/$W_p$

The technology is receiving much benefit from research that strives to make existing technologies cheaper and more accessible. The Energy Information Administration (EIA) reports that 26 companies were expected to introduce new photovoltaic products in the market in the year 2007 [1]. Recent years have presented new alternatives to the way solar modules are built and implemented.

Examples of creativity include shingles and windows that use photovoltaic cells as part of their design. Architects and engineers have developed ways to use PV modules in building facades substituting them for regular building materials, hence reducing the net cost of the PV generated energy. The approach is known as building integrated photovoltaic (BIPV) architecture.

2) **Inverters**: Inverters are used to transform DC current into AC currents. In the photovoltaic industry, inverters can be classified into two broad categories:

- **Stand-Alone Inverters**- These inverters are meant to operate isolated from the electrical distribution network and require batteries for proper operation. The batteries provide a constant voltage source at the DC input of the inverter. Inverters can be classified briefly as:

  → Square Wave Inverters
  → Modified Sine Wave Inverters
  → Sine wave inverters (quasi-sine wave).

  Voltage and current waveforms produced by inverters are never perfect sinusoids (even for sine wave inverters); therefore some harmonic currents are expected during normal system operation. Total harmonic distortion (THD) is a measure of the harmonic content in current and voltage waveform. The type of inverter used will depend on the load that it will serve. Resistive loads could tolerate square wave inverters which are cheaper and easier to develop. Motors and sensitive electronics will need inverters that are able to produce almost perfect sinusoidal voltage and current waveforms in order to operate correctly. These tend to be more expensive and difficult to design. The designer should choose inverters according to load types and power requirements. Modern stand-alone inverters have software applications embedded that monitor and control equipment operation.

- **Grid-Tied Inverters**- These inverters operate coupled to the electric distribution network and therefore must be able to produce almost perfect sinusoidal voltages and currents. The operating requirements for these types of inverters are in most cases determined by the local utilities, yet most utilities rely on existing standards to determine feasible technologies. The most referenced standards in the United States are the IEEE1547 and the UL 1741. These standards include the minimum requirements that manufacturers should include into their inverter designs in order to prevent adverse effects in the distribution grid [20]-[24]. Normally, embedded software applications monitor and control equipment operation to comply with standard requirements. There are two main categories of grid-tied inverters. Line-commutated inverters derive their switching signals directly from the grid line currents. The low switching frequencies produce harmonic currents that need to be filtered out. In the case of small single-phase inverters the bulky and expensive filtering networks are not practical. In the case of large three phase inverters, multiple units could be connected through a multi-phase isolation transformer at the utility output, filtering any unwanted currents [21]. Self-commutated inverters derive their switching frequencies from internal control units as they monitor grid conditions, in particular frequency and voltage. High switching frequencies (3 – 20 kHz) are used and therefore lower current harmonic content is possible without the need of using large filtering networks. Self-commutated inverters can be either voltage source inverters or current source inverters. PV modules behave like voltage sources; therefore our interest will be in voltage source type inverters. Voltage source type inverters can yet again be subdivided into current control and voltage control types. In applications where there is no grid reference, voltage control schemes are used and the inverter behaves as a voltage source. Where a grid connection is used the current control scheme is used and the inverter behaves as a current source. These inverters use the utility voltage as reference to provide the current available from the PV, and are not able to operate as an island. The advantages of current control voltage source inverters are [23]:

- → Power Factor (PF) ~ 1 (employing a simple control scheme).
- → Transient Current Suppression: The fault current is limited in the range of 100% to 200% rms rated current. The fault contributions of these inverters are limited by their control and protection system. The fast switching frequencies these inverters use, allow them to detect large currents that may exceed their semiconductor ratings and stop operation within 0.5 cycles [25].

Some stand-alone inverters can also be operated as grid-tied inverters or in combination with other renewable energy sources as part of hybrid power systems. Modern inverters can achieve efficiencies higher than 95% (especially grid-tied inverters) and are warranted for 5 to 10 years in most cases. Most inverters have efficiencies above 85%. Figure 5.4 describes the price trend of inverter technologies on a per watt basis for the year 2007. The statistics do not separate existing technologies.

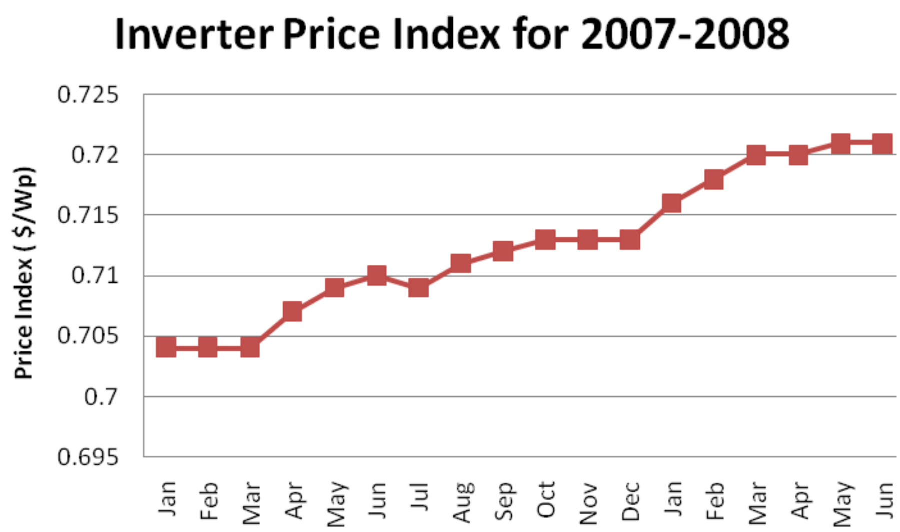

Figure 5.4 Inverter Price Index for 2007-2008

3) **Batteries:** These are most commonly used to store energy in stand-alone applications for use at times when no irradiance is available (e.g. night, rainy day). Batteries are also used for a diverse number of applications including stand-by power and utility interactive schemes. PV batteries require tolerance to deep discharges and irregular charging patterns. Some applications may require the batteries to remain at a random state of charge for a prolonged time. The most common technology used in PV systems is the lead-acid battery. These batteries are available in two major categories:
   - Flooded (Vented)- This is the regular battery technology most people are used to. It tends to be the cheapest option when only initial costs are of interest. In this battery, overcharge results in the conversion of water into hydrogen and oxygen gases. The gases are released into the atmosphere; hence the batteries require that the water is replaced adding a maintenance cost to the system.
   - Valve Regulated- The chemical characteristics of these batteries allow for maintenance free operation because the oxygen is allowed to recombine with the hydrogen within the battery. The recombination has a maximum rate which depends on the charging current. If excess pressure builds up, it is vented through valves to the atmosphere, proper charge control can limit this effect. These batteries tend to allow deeper discharge cycles resulting in smaller battery banks and are expected to have longer life times. There are two main technologies available: Absorbed glass mat (AGM) and Gel. Another advantage of these sealed batteries is that most are spill proof.

Nickel-Cadmium batteries can also be used in PV applications, especially where extreme temperatures are expected that could lower the battery life of lead-acid batteries. Some batteries of this technology allow discharges of 90% or more of rated capacity and tolerate prolonged periods at sub-optimal state of charge without damage or memory effect. Nickel-Cadmium batteries are 3 to 4 times more expensive per stored kWh and are highly difficult to dispose off due to their toxic potential. Battery technology is relatively old, and is often regarded as the weakest link in photovoltaic systems. Improper care of the batteries can seriously affect battery lifetime. Figure 5.5 displays the price trends for battery technologies within the lead-acid type.

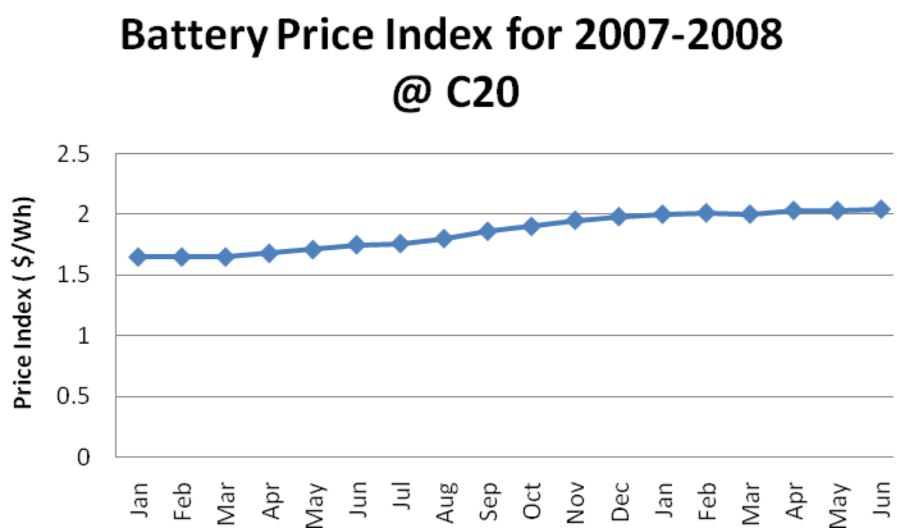

Figure 5.5 Battery Price Index for 2007-2008

4) **Balance of System Components (BOS) and Charge Controllers**: BOS components typically constitute 30-50% of total system costs. They are all the additional elements necessary in order to properly install the PV system. The minimum requirements are regulated in the 2005 NEC (the 2008 version is now available as well) [7]. A comprehensive overview can be found in [18] BOS components may include:

→ Conductors, conduits and boxes
→ Overcurrent Protection (e.g. Fuses and Breakers)
→ Ground Fault Protection
→ Mounting Gear (support structure)
→ Disconnects
→ Metering Equipment
→ Maximum Power Point Trackers
→ Charge Controllers
→ Battery Enclosures

The cost of the support structure could vary considerably depending on whether the system is to be mounted on the building wall, or roof, or whether it is to be ground mounted. For an array installed flush into a ceiling, support structure costs are negligible. More complicated structures may cost ~$200/m^2. Tracking system costs are in the $300 to $1,200 per m^2. Large or simple structures are in the lower boundary region of this range. Small complicated tracking systems are in the upper boundary region of this range [26]-[27].

System installation is in the $900 to $2,500 per kW [26]-[27]. Installation costs depend on system size, location and complexity. Larger systems could require heavy machinery and larger crews. Land based systems could require terrain preparation and trench digging.

Electrical equipment could cost ~$700/kW for simple or residential systems and ~$1,500/kW for industrial systems [26]-[27]. Costs are determined by system complexity and system size. Stand-alone systems generally have higher costs than grid-connected systems on a per watt basis.

Charge controllers are part of the electrical equipment costs. These control the current flow from the PV array to the battery in order to ensure proper charging. These controllers disconnect the PV array from the battery whenever produced energy exceeds battery storage capacity or the load whenever charge levels are dangerously low or reach a certain threshold. It is common for charge controllers to monitor battery voltage, temperature, or a combination of both to determine depth of discharge. The controllers extend battery life and are a safety requirement of the National Electrical Code (NEC) for residential and commercial installations. It is important to select a proper charge controller and controller settings for the battery type selected for the system. Some controllers can be adjusted to accommodate different battery types; some are built for specific battery technologies exclusively. Today, commercially available controllers can achieve efficiencies as high as 95%. Most charge controllers currently available rely on solid state technology to control current flowing into the battery bank; still some electromechanical relay versions available. Electromechanical relays can only perform classic on/off control (therefore little flexibility is possible), this control strategy can still be rough on the battery. Solid state controllers are more varied or flexible in terms of control strategies. Some of the possibilities are:

- → On-off
- → Constant Voltage
- → PWM, constant voltage and with current regulation
- → MPPT

Figure 5.6 displays the price trends of charge controllers over the last year. The price index for charge controllers is described in terms of the current rating. Price information does not distinguish between the different controller technologies, but most products available in the market today are based on solid state technologies and dominate the cost trends for this report.

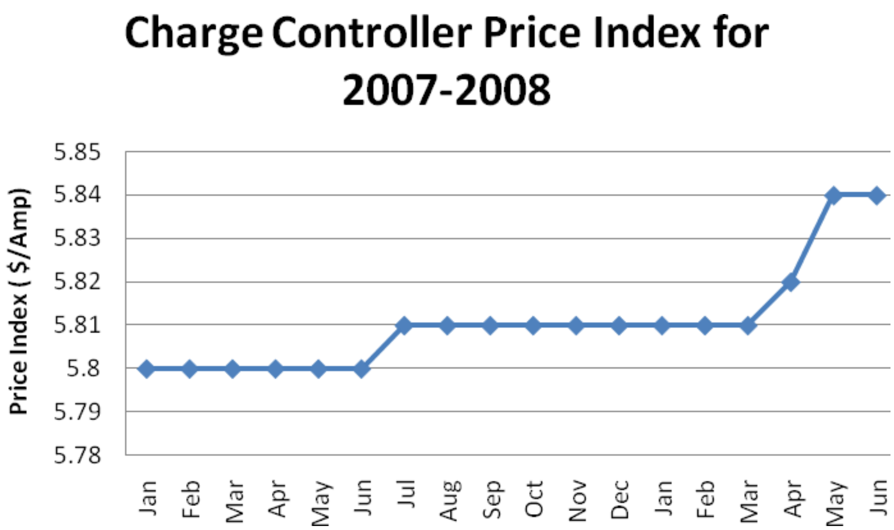

Figure 5.6 Charge Controller Price Index for 2007-2008

The PV industry is relatively new. The industry has space for small companies which specialize in specific equipment, or large corporations which have expanded their product range to include PV related equipment. A list of component manufacturers has been compiled in Table 5.4.

Table 5.4 PV System Component Manufacturers

PV Modules	Inverters	Batteries	Charge Controllers
Air Therm	Advanced Energy Systems	Akku Solar	Apollo Solar
Aten Solar	Advanced Electronic Supply (AES)	Banner Batterien	Blue Sky Energy
Atersa	Beacon Power	Bären Batterie GmbH	BZ Products
Atlantis	Cherokee Electronics	C&D Batteries	DIREC
BP Solar	Exeltech	Concorde	Enermaxer
Canrom	Fronius	Crown Battery Manufacturing	ETA Engineering
Conergy	Go Power! Electric Inc.	Deka	Flexcharge
Duravolt	Heart Interface	Delco	GeoSolar
Energie Bau, Koln (EBK)	Omnion	Deta Batteries UK Ltd	Heliotrope
Eurosolare	Outback	Douglas	ICP Solar
Evergreen Solar	PowerPro (Tumbler Technologies)	Dyno	Lyncom
GPV	PowerSine	East Penn-Deka Manufacturing	Outback Power
GE Energy	PV Powered	Exide	Pico Electronics Inc
GPV	Sharp Electronics	General Battery Corporation (GBC)	Plasmatronics
Heliodinamica	SMA Regelsysteme	GNB	Morningstar Corporation
Helios Technology	Solarix	Hoppecke Batterien	Pulse Energy Systems Inc
IBC	Solsum	HUP Solar One	SES Flexcharge USA
ICP Solar	Soltek	Industrial Battery Engineering (IBE)	Specialty Concepts Inc
Isofoton	Statpower	MK Batteries	Sunwize Steca
Kaneka Corporation	Studer	Moll Batterien	Sun Selector
Kurzsolar	Xantrex Technology Inc	Northern Battery	SunAmp Power
Kyocera Solar		Optima	SunWize Technologies Inc
Mitsubishi Electric		Prevailer	Trace Engineering
Mitsubishi Heavy		Rolls Battery Engineering	Uhlmann Solarelectronic GmbH
MSK Corporation		Resource Commander	Vario
Matrix Photowatt		SEC Industrial Battery Co	
Schott Solar		Solar Electric Specialties	
Sanyo Solar		Sonnenschien	
Sharp Corporation		Surrette Battery Co	
Solara		Trojan Battery	
Solar-Fabrik		US Battery	
Solarwatt		Varta AG	
SolarPort		Yuasa	
Solarwerk			
SolarWorld			
Solon AG			
SunPower, Spain			
SunPower Corporation			
SunSet			
Suntech Power			
Sunware			
Total Energie			
Webasto			
Solmec			

Uni-Solar			
Yingli Solar			

5.1.5 PV Modules

A number of solar cells electrically connected to each other and mounted in a support structure are called a photovoltaic module. Modules are designed to supply electricity at a certain DC voltages such as 12, 24 or 48 volts. The current produced is directly dependent on how much light hits the module. Multiple modules can be wired together to form an array. A larger area of a module or array will produce more electricity. PV modules are rated on the basis of the power delivered under Standard Testing Conditions (STC) of 1 kW/m^2 of sunlight and a PV cell temperature of 25 degrees Celsius (°C). Their output measured under STC is expressed in terms of “peak Watt” or Wp nominal capacity [54]. A typical crystalline silicon module consists of a series circuit of 36 cells, encapsulated in a glass and plastic package for protection from the environment. Although PV modules are warranted for power output for periods from 10-25 years, they can be expected to deliver amounts of energy (voltage and current) for periods of 40 to 50 years [53]. Typical electrical information supplied by the manufacturer includes:

- Polarity of output terminals or leads
- Maximum series fuse for module protection
- Rated open-circuit voltage
- Rated operating voltage
- Rated operating current
- Rated short-circuit current
- Rated maximum power
- Maximum permissible system voltage

Table 5.5 and Table 5.5 summarize characteristics of various PV cell technologies.

Table 5.5 Photovoltaic categories by semiconductor selection [56].

Crystalline silicon solar cells Market Share: 93%	• Monocrystalline, produced by slicing wafers (up to 150 mm diameter and 350 microns thick) from high-purity single crystal. • Multicrystalline
Thin Film Solar Cells Market Share: 7%	• Amorphous silicon • Pollycristalline materials: Cadmium Telluride (CdTe), Copper indium (gallium) Diselenide (CIS or CIGS).

Table 5.5 Advantages and Disadvantages by solar cell technologies [57].

Cell Type	**Advantages**	**Disadvantages**
Single Crystal Silicon	• Well established and tested technology • Stable • Relatively efficient	• Uses a lot of expensive material • Lots of waste in slicing wafers • Costly to manufacture • Round cells can't be spaced in modules efficiently
Polycrystalline Silicon	• Well established and tested technology • Stable • Relatively efficient • Less expensive than single Crystalline Si • Square cells for more efficient spacing	• Uses a lot of expensive material • Lots of waste in slicing wafers • Fairly costly to manufacture • Slightly less efficient than Single Crystalline Si

Ribbon Silicon	• Does not require slicing • Less material waste than single and polycrystalline • Potential for high speed manufacturing • Relatively efficient	• Has not been scaled up to large-volume production • Complex manufacturing process
Amorphous Silicon	• Very low material use • Potential for highly automated and very rapid production • Potential for very low cost	• Pronounced degradation in power output • Low efficiency

5.1.6 Inverters

Inverters are electronic solid-state devices used to transform electric energy from DC to AC, as shown in Figure 5.7. The simplest inverter can be accomplished with a circuit similar to that shown in Figure 5.8. The ideal switches in the circuit may represent MOSFETs, IGBTs or bipolar transistors (depending on the power and voltage requirements). If the switches are turned on and off at the required AC frequency (S1&S3 and S2&S4), a square wave voltage can be obtained as shown in Figure 5.9. This is a simple control strategy, yet no control of load voltage is possible and high harmonic currents and voltages are present. High frequency pulse width modulation techniques are used to diminish harmonic distortion and provide load voltage control. Harmonic content may cause overheating in motor loads due to higher copper losses as well as uneven magnetic fields affecting overall operation. Sensitive electronic loads may also display erratic operation. Today, advanced control schemes and creative topologies allow the creation of AC with very low harmonic distortion; three phase designs are also possible by incorporating additional switches.

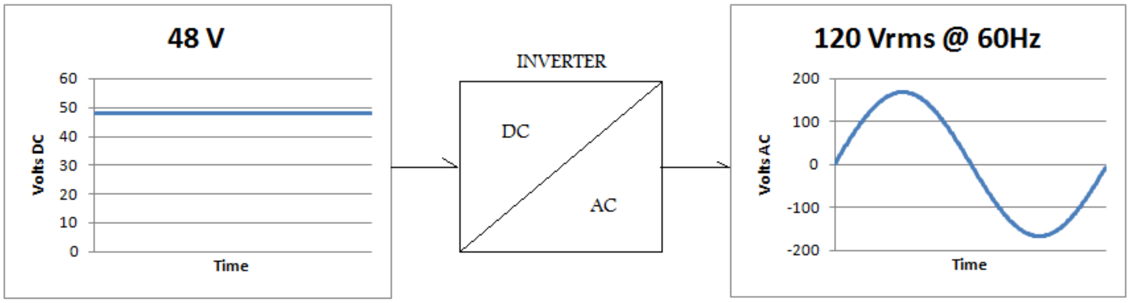

Figure 5.7 Representation of DC to AC conversion Process

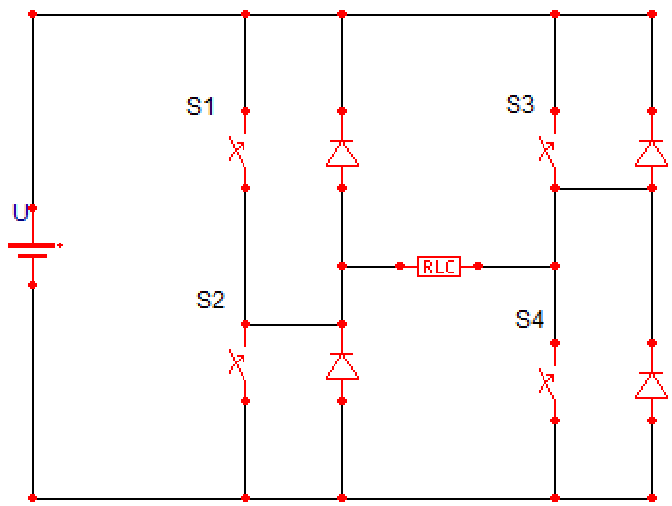

Figure 5.8-Single Phase Inverter Conceptual Circuit

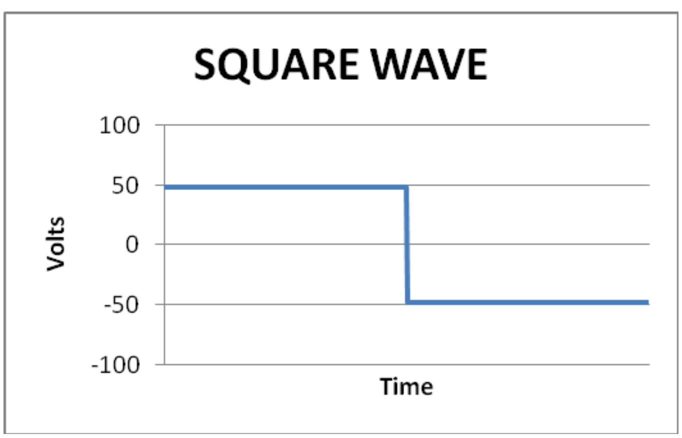

Figure 5.9- Example Voltage Square Wave

Many industries have found applications for inverters; hence design requirements tend to be specific to the needs of a particular application. A whole new industry has evolved around the need of a proper inverter to accommodate the needs of the relatively new solar industry, with both big and small manufacturers entering the market. PV modules produce DC outputs which are dependent on the irradiance, temperature and load operation. Stand-alone inverters operating with energy storage or batteries need a small DC voltage operating range to allow for voltage differences due to battery state of charge, and surge capacity to allow for safe and uninterrupted transient event operation. Grid-tied systems do not normally incorporate energy storage; hence larger DC voltage operating ranges are needed to accommodate both the varying operating conditions and module configurations. Maximum power point tracking control algorithms are normally included to take full advantage of the PV module energy production capabilities. Advanced protection functions are normally also included in order to guarantee safe operation in parallel with the distribution grid. These are just examples of specific requirements for PV inverters in their specific applications. The following section shall summarize current PV inverter characteristics, industry status and trends, especially in the grid-tied market, which is currently of most public interest. The industry challenges attended include:

1. Reliability
2. Inverter lifetime improvements
3. Higher inverter efficiencies
4. Production cost reduction
5. System and installation cost reduction
6. Unreliable or inadequate components or parts
7. Safety
8. Grid connection issues
9. Optimal circuit topologies, etc.

Grid-Tied inverters operate coupled to the electric distribution network and therefore the operation requirements are quite different from those of stand-alone inverters. Figure 5.10 shows a simple block diagram of a grid-connected PV system. Energy Storage is not considered in most grid-connected applications, hence it is not included in the diagram, but it could be an option depending on the reliability needs of the owner. In general terms the system can be divided into the solar panels and the power conditioning equipment, which includes: the maximum power point tracker, the inverter, the galvanic isolation (optional), and protection and control features. These components are commonly integrated in the same enclosure or unit as a way to reduce production and installation costs; hence it has been customary in the PV industry to refer to the combination of all these elements as the inverter. We shall adopt this practice.

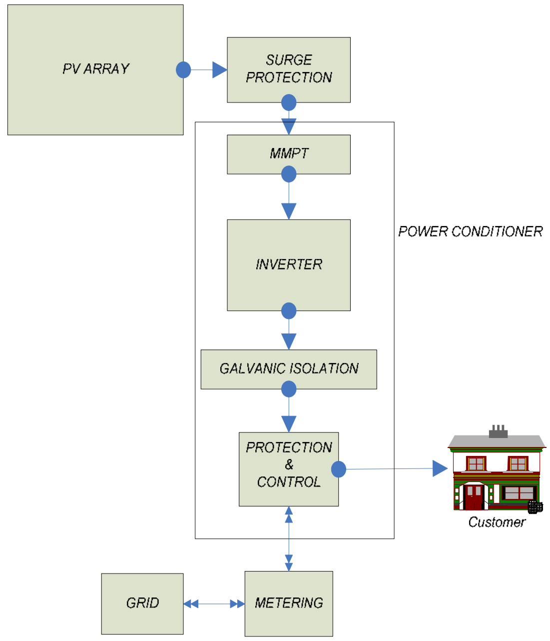

Figure 5.10-Grid-Connected PV System Block Diagram

It is commonly said that grid connected PV systems are as good as their interfaces between the DC and AC power segments. As an example, the best solar modules in the industry will not be of great use if the power is not transformed efficiently and safely to useful levels at the load side. For the utilities it is of no use to allow the integration of DG systems that could degrade the quality of the electric power in the distribution network. Inverter failure will prevent any useful energy being produced. Proper inverter systems should include or consider the following:

- **Maximum Power Point Tracker (MPPT)** - Nominal voltage and current conditions will not be available from the PV array at all times due to constant changes in solar irradiance. Figure 5.11 displays the I-V curves for a PV module at different operating characteristics. The MPPT guarantees optimum power is always obtained from the PV modules at any given operating condition. Different algorithms have been developed to achieve MPPT control, some achieving more than 98% of the PV array output capacity. The most popular is the Perturb and Observe (P&O) algorithm, this algorithm increases or decreases voltage in small steps and monitors the power output until maximum power point is found. A summary of available literature is available at [61].

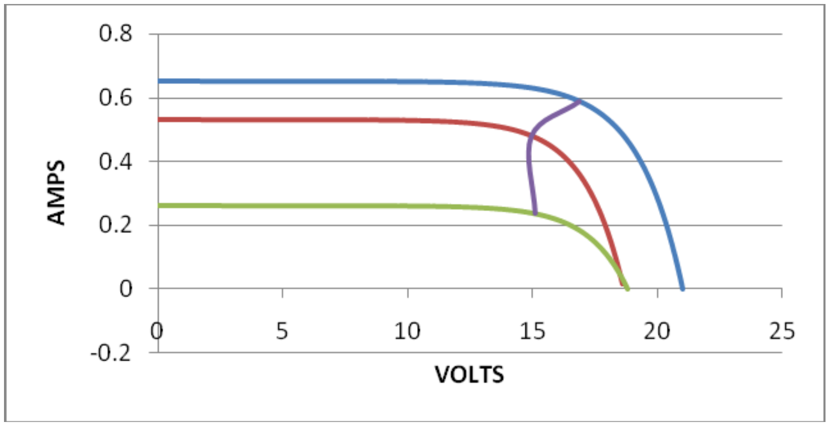

Figure 5.11- I-V Curves for a PV Module at different operating conditions

- **Inverter-** Inverters have the task of DC/AC conversion. There are two main categories of grid-tied inverters. Line-commutated inverters derive their switching signals directly from the grid line currents. The low switching frequencies produce harmonic currents that need to be filtered out. In the case of small single-phase inverters the bulky and expensive filtering networks are not practical. In the case of large three phase inverters, multiple units could be connected through a multi-phase isolation transformer at the utility output to filter any unwanted currents; the transformers should be rated to withstand additional heating due to harmonic current copper losses [20]. Self-commutated inverters derive their switching frequencies from internal control units as they monitor grid conditions, in particular frequency and voltage. Self-commutated inverters can be either voltage source inverters or current source inverters. PV modules behave like voltage sources; therefore our interest will be in voltage source type inverters. Voltage source type inverters can yet again be subdivided into current control and voltage control types. In applications where there is no grid reference, voltage control schemes are used and the inverter behaves as a voltage source. Where a grid connection is used the current control scheme is preferred and the inverter behaves as a current source. Operating the inverter under current control limits the possibility of active voltage regulation, a high power factor can be obtained with simpler control circuits (usually the power factor is kept as near to unity as possible), and transient current suppression is possible when disturbances as voltage fluctuations occur. Another advantage is that current related power quality disturbances related to inverter operation, like harmonics, can be controlled with ease and independence from voltage quality which then depends entirely on the utility. Problems caused by unusual utility voltages should be the responsibility of the utility because they are commonly associated to more complicated problems. It is important to understand that customer compliance to any standard should be independent to utility compliance to the same issue; the utility should not assume that the customer has total responsibility. The disadvantage of operating using current control is that it cannot operate as an isolated power source. Some inverters are able to handle both control functions to operate as grid connected and also provide conversion for storage batteries working as a backup.

- Table **5.6** summarizes the characteristics of voltage source inverters under different control strategies [23]. According to a survey from the IEA for inverters under 50kW, 19 % of inverters in the market use voltage control and while 81% use current control. High switching frequencies (3 – 20 kHz) are used in some designs; therefore lower current harmonic content is possible without the need of using large filtering networks. The only problem is that higher switching frequencies result in higher losses reducing the efficiency of the inverter. Designers must find a balance between efficiency, power quality and size. Table 5.7 summarizes some of the tradeoffs associated with high efficiency according to [62].

Table 5.6 Voltage vs. Current Control

	Voltage Control	Current Control
Inverter main circuit	Self-commutated voltage source inverter (DC voltage source)	
Control objective	AC voltage	AC current
Fault short circuit current	High	Low (limited to rated current)
Stand-alone operation	Possible	Not Possible

Table 5.7 High Efficiency Design Tradeoffs

Higher Conversion Efficiency via	Semiconductor Costs	Magnetic Costs	Heat Removal Costs	RFI Generation	Size to Weight	Circuit Complexity
Lower Switching Frequency		Increase	Decrease	Decrease	Increase	
Lower Semiconductor Conduction Losses	Increase		Decrease			
Natural Convection Cooling vs. Forced Convection			Increase		Increase	Decrease
Switching Auxiliary Power Supply vs. Linear	Increase	Decrease		Increase	Decrease	Increase
Lower Dissipation Snubbers				Increase		Increase

- **Voltage and Frequency Synchronization**-Inverters should operate without problem for normal fluctuations of voltage and frequency at the utility grid side. The controllers must include protection devices that continuously monitor the grid voltage and frequency. If these go outside of the tolerable ranges established the unit should trip within an acceptable time frame, while permitting inverter operation through instantaneous voltage sags or swells. Inverter must inject current in phase with utility voltage (Power Factor=1).
- **Islanding Protection-** Islanding occurs when a DG continues to energize a distribution network that would otherwise be de-energized for any reason (e.g. Breaker opens because of a fault). It has been determined that this is a low probability event and the probability of continued operation of DG's is also very low, especially for residential grid tied PV systems which would not be able to perform load following. Yet in the event that load balance occurs, islanding represents a safety hazard.

Islanding protection is a requirement for all grid-connected distributed generation (DG).

- **Inverter Reaction to Faults-** Inverters rely on solid state technology for its operation and, unlike generators and motors; they have no inertia or considerable amounts of energy stored within them which means that they can react to faulted conditions almost instantly. The reaction of the inverter will depend on what it "sees" as terminal voltage and apparent load impedance during a fault. In event that the detection scheme takes longer than the anticipated or simply does not work, fault contributions, if any, will still be quite low, compared to utility short circuit currents, since inverters cannot supply currents much larger than the rated load current, the condition will cause the device to disconnect. Most grid-tied inverters are designed to operate under current control. These inverters use the utility voltage as reference to provide the current available from the PV, and are not able to operate as an island. The advantages of current control voltage source inverters are [23].
    - → PF~1 (employing a simple control scheme).
    - → Transient Current Suppression: The fault current is limited in the range of 100% to 200% rms rated current. The fault contributions of these inverters are limited by their control and protection system. The fast switching frequencies these inverters use, allow them to detect large currents that may exceed their semiconductor ratings and stop operation within 0.5 cycles [25].
- **Power Quality-**The concerns are mainly harmonic and DC current injection into the local distribution grids. A report of the IEA found that most PWM inverters can keep harmonic injection levels below 5% [8]. Harmonics cannot be eliminated completely due to the switching process involved in PWM, but high switching frequencies and filtering are used to lower THD at the AC output. Flicker problems should not be a major concern in the approval of inverters because voltage fluctuations on the DC side depend on solar irradiance, and have proven to be quite slow; also these inverters will operate as current sources and at unity power factor and reactive power demand in residences is not considerable.
- **DC Isolation (Galvanic Isolation) –** The early low power inverter designs incorporated a low frequency transformer at the output of the inverter; these are still present in most of the larger three phase inverters. In some cases an external transformer is used. The transformers could be regular Δ-Y distribution transformers in case of a three phase output or a single phase isolation transformer with a 1:1 ratio for low voltage single phase a connection. The transformers are used to prevent possible by product DC currents produced by semiconductor switching from being injected into the distribution network (DC currents may cause saturation of distribution transformers) and are commonly used as part of the

harmonic filtering network within the inverter. The transformer also provides a safe grounding point while maintaining electrical isolation. The isolation transformer was a requirement in many electrical codes and utility regulations, yet most codes are no longer requiring galvanic isolation (including the NEC). Inverter designers have found ways to mitigate the problems mentioned before into acceptable levels. It is possible to use high frequency (HF) transformers embedded in an internal high frequency conversion stage, these are small, lightweight, and provide the electrical isolation Line Frequency (LF) transformers provide. Common line frequency transformers used in inverter outputs cause losses of around 2% and are the larger part of the inverter's weight and cost. Transformerless designs are also possible, yet a regular full-bridge inverter cannot be used as a suitable grid-connection if both sides are to be grounded (the NEC requires PV arrays with operating voltages over 50V to be grounded), hence special circuit topologies are used. The Transformerless designs are cheaper, more efficient, and lighter. Modern power electronic devices tend to use more silicon and less iron.

The operating requirements for these types of inverters are in most cases determined by the local utilities, yet most utilities rely on existing standards to determine feasible technologies. The most referenced standards in the United States are the IEEE1547 and the UL 1741. These standards include the minimum requirements that manufacturers should include into their inverter designs in order to prevent adverse effects in the distribution grid [20]-[25]. Normally, embedded software applications monitor and control equipment operation to comply with standard requirements. Table 5.8 summarizes the disconnection requirements for grid-tied inverters operating under abnormal system conditions. The disconnection requirements are meant to protect the inverter and surrounding equipment as well as maintenance personnel servicing utility lines. Some inverters have better response than the minimum established by standards. The inverters are required to have a 5 minute wait time until they reconnect after normal grid operation is resumed. Table 5.9 displays harmonic current injection limits (even harmonics are limited to 25% of the limits in the table). DC current injections are limited to 0.5% of the rated current.

Table 5.8 Disconnection Requirements According to IEEE 1547

Condition	**Trip Time**
Islanding	6-120 cycles
V < 50%	6 cycles
50% < V < 88%	120 cycles
88% < V < 110%	Normal Operation
110% < V <137%	120 cycles
137% < V	2 cycles
98.8%>f>101%	6 cycles

Table 5.9 Harmonic Limits According to IEEE 1547

Odd Harmonic Order	H<11	11≤h<17	17≤h<23	23≤h<35	35≤h	TDD
%	4	2	1.5	0.6	0.3	5

A brief discussion on circuit topologies for grid-tied inverters will help to understand the efficiency and power quality issues discussed before. Central grid-tied PV systems were the first to be installed. A single stage inverter is commonly used which handles all functions including: current control, MMPT and inversion. These centralized installations suffered from severe limitations. Power losses were considerable due to the centralized MPPT and mismatches between PV modules. The earliest designs were line commutated using thyristors; therefore power quality was seriously deteriorated at the point of connection. Three phase AC outputs were directly coupled into the distribution network, normally through a distribution transformer. Figure 5.12 displays such a system. Generally Central inverters should be avoided unless high voltage is guaranteed. Large PV systems in the 5kW to +1MW range are currently becoming more common due to the incentives provided by government agencies (e.g. REC, GHG reduction credits, grants, etc). Modern central inverters use IGTB semiconductor technology and are self-commutated enhancing power quality. A common MPPT is still used in many designs, yet several central inverters can be arranged in master slave configurations in order to use the most efficient combination of inverters according to total PV array output.

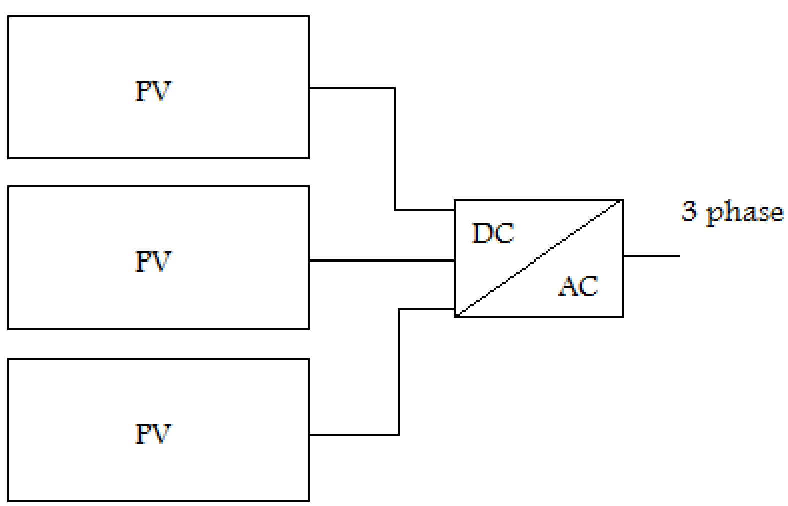

Figure 5.12 Central Inverter

Currently, the most successful technology is the string inverter. Most of these inverters use either Metal Oxide Field Effect Transistors (MOSFET) or Insulated Gate Bipolar

Transistor (IGTB) semiconductors instead of thyristors to perform self-commutated switching actions. PWM high frequency switching is used providing high power quality. According to IEA 62% of inverters under 50kW use IGTB switches using 20 kHz switching frequencies, while 38% uses MOSFETs with switching frequencies in the range of 10 to 20 kHz [23]. MOSFETs can operate with frequencies as fast as 800 kHz, yet power capacity is compromised as the frequency is increased. High input voltages are possible to avoid voltage amplification stages, yet smaller voltages are possible (e.g. AC module) by incorporating additional dc-dc conversion or line frequency transformers at the output. Figure 5.13 displays a simple representation of a string inverter, yet it is possible to have multiple conversion stages within the same inverter enclosure.

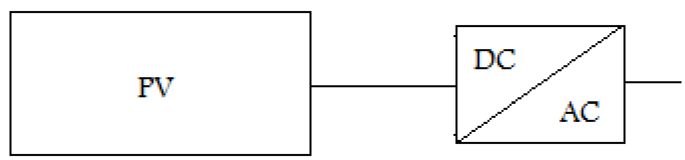

Figure 5.13 String Inverter

Single stage inverters may perform MPPT, inversion and other control functions in the same stage. The benefits include simplicity, yet only a limited voltage range. Single stage inverters can use either four or six switch structures. Four switch structures commonly incorporate (or require) LF transformers in the AC output. Six switch structures facilitate grounding in transformerless designs when PV arrays and AC grids need to be grounded. Multiple stage inverters offer a wider input voltage range, more power capacity and the opportunity to incorporate HF transformers in the design to reduce weight while providing adequate isolation. Circuit structures are more complicated than single stage inverters. Figure 5.14 shows a single stage inverter LF transformer arrangement. Figure 5.15 and Figure 5.16 display different transformer location options in multi-stage transformers, different configuration options include:

1) DC-DC-AC
2) DC-AC-DC-AC
3) DC-AC-AC, etc.

The selection between single-stage and multiple stage topologies is a tradeoff between weight, cost, efficiency, complexity, size, power rating, power quality, etc. The use of transformers will depend on regulatory requirements in the area and safety.

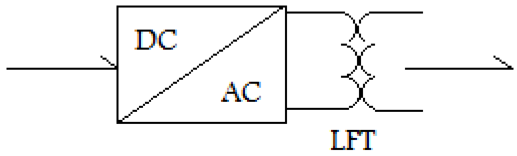

Figure 5.14 Single-Stage Inverter with LF Transformer

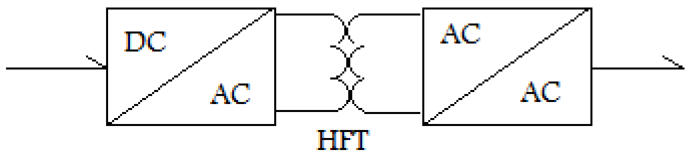

Figure 5.15 Multi-Stage Inverter with HF Transformer in AC Converter

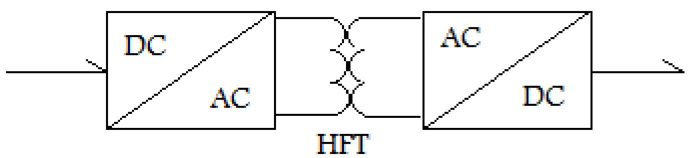

Figure 5.16 Multi-Stage Inverter with HF Transformer in DC Converter

Multi-string inverters are a further development of the string inverter. Each PV string has an individual maximum power point tracking DC-DC conversion stage with a common inversion stage. Each string could be at very different operating points (e.g. orientation, shading, module brand) without affecting the operation of the other string, while energy is transformed through the same inversion stage. Multi-string technology provides an alternative for future installations, especially large scale types. Multi-string technology is still not used in the majority of residential and small commercial inverters today.

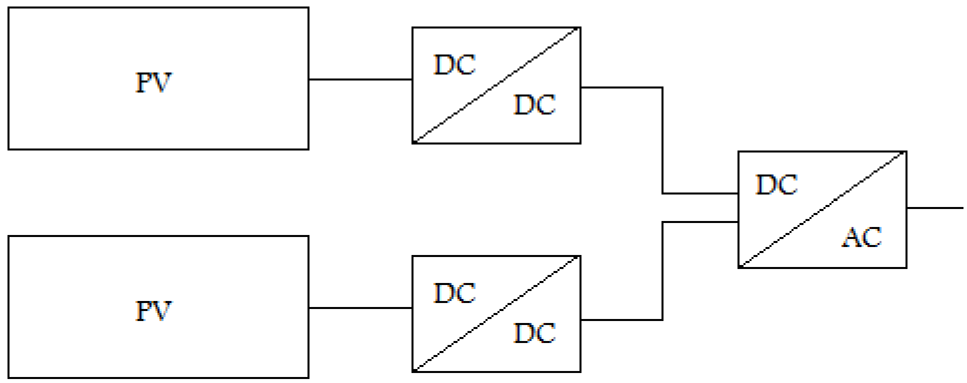

Figure 5.17 Multi-String Inverter

The PV inverter technology is constantly improving, motivated by the rapid growth the PV market has been experiencing in the last decade due to:

→ Environmental Awareness
→ Increasing Fuel and Energy Costs
→ Government Subsidies for system equipment, etc.

In the US most growth has been experienced in California, due to the aggressive government involvement. New Jersey holds the second place, even with its somewhat lower solar resource, due to its recent incentive programs. More than 85% of the cumulative system installations in the US have occurred in California, yet this scenario would be very different if the subsidy programs were not present. According to [63], the PV inverter industry needs to reduce average inverter prices to the \$0.25-0.30 W_p range by 2020 (this represents a cost reduction of 50-75%), in order to reduce average PV levelized cost of energy to \$0.06/kWh and allow the technology to be competitive with conventional electrical energy generation in the US. These requirements are not that extreme in Puerto Rico were energy costs are currently >\$0.22/kWh, yet cost reductions will certainly provide additional incentives to local customers. Capital costs are not the only factor affecting PV energy costs; inverter reliability issues also need attention. Currently inverters represent 10-20% of initial PV system costs; therefore a client expects it to operate correctly for a reasonable amount of time before needing a replacement. Reliability issues could damage the image of PV technology, therefore slowing installation growth and long-term adoption of the technology.

The inverter industry is rapidly maturing driven by the race for grid parity. Various participants have entered the market, large and small, benefitting from government support programs (DOE, SNL, NREL, etc.), advancements in power electronics and semiconductor technology, and interest from academia. Figure 5.18 displays the market shares for different market participants in the year 2006. Reliability, ease of installation, user friendliness, efficiency, size and weight, etc. have all improved significantly since

the birth of the industry. Table 5.10 summarizes inverter evolution in the last three decades, providing proof of the technical capacity of the industry to respond to client necessities. As it has been mentioned before, PV generation has not yet achieved cost competitiveness in most regions of the US, although the requirements are greater in some places than others. PV systems have been proved cost effective were remote loads need a reliable energy source, and it is evident that the situation in Puerto Rico is not as challenging as in the US (considering the high energy costs in the island and the total dependence of foreign fuels).
Table **5.11** summarizes the current challenges and trends for the PV inverter industry during the next 5 to 10 years.

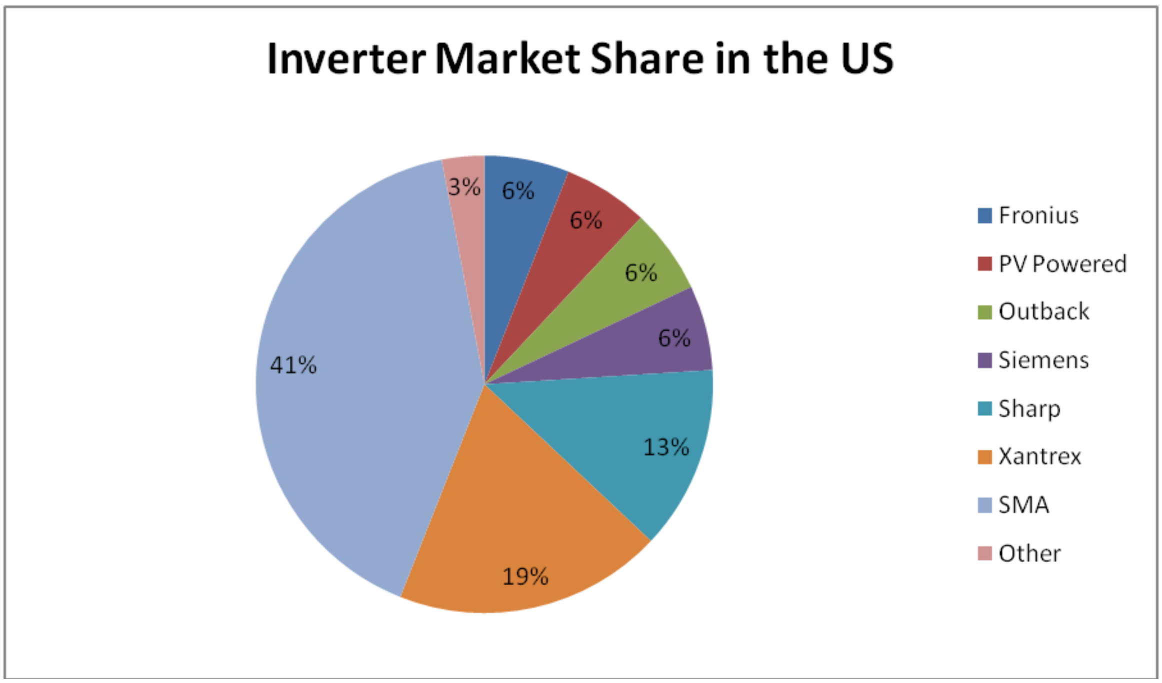

Figure 5.18 Inverter Company Market Shares in the US.

Table 5.10 Time Table for Inverter Evolution

1980's	▪ Inverters were bulky, heavy, difficult to install, unreliable, and their efficiency was in the 85-90% range. ▪ They were strictly devices for converting DC to AC.
1991	▪ The early 1990s saw the first large-scale series production of PV inverters (SMA PV-WR).
1995	▪ First PV string inverter (SMA SB 700). ▪ Allows connection of modules in series, modular systems, higher system efficiency, and reliability. ▪ String inverter becomes most common on the market.
Late 1990's	▪ Basic data-acquisition system, "plug-and-play" installation. ▪ Transformerless and high frequency (HF) designs reach efficiencies above 95% ▪ Reliability improves. Warranties (2-5 years) offered.
2000's	▪ Data logging and communication capabilities. ▪ User adjustable parameters. ▪ Master slave configuration for multiple inverters. Only the necessary inverters are kept operating to achieve higher efficiencies. ▪ Multi-string technology allows multiple series arrangements of PV modules under different conditions featuring separate Maximum Power Point Tracker (MPPT) for each string and a common inverter. The most popular residential inverters in the US still do not have this feature, yet it is becoming an important one as system sizes increase. ▪ 10 year warranties are being offered by some manufacturers.

Table 5.11 PV Inverter Industry Challenges and Trends

Inverter Capital Cost	▪ Inverter costs have been falling approximately 5-10% a year since 1999. The general price level of inverters fell by about 40% from 1998 to 2002. ▪ Targeted cost reductions for 2020 are not expected to be fulfilled with current market growth and learning-rate levels. Most companies agree that sales volume is the determinant factor in order to lower costs. ▪ Inverters have a slower learning curve than the PV module industry, which implies that cost and performance

	improvements for inverters will lag behind PV modules. Inverter prices have been dropping by about 10% with every doubling of cumulative production, compared to 20% for PV modules. ▪ It is difficult to determine or rate inverters using a price one-dimensional price index ($/kW). It is important to consider the evolution of inverter features to establish appropriate comparisons, especially if the design and performance improvements in the last couple of years are considered. Inverter prices depend on: → Rated Power → Manufacturer → Efficiency → Size → Weight → Reliability → Displays → Data Monitoring → Communication Capabilities → DG and Operation Flexibility → Plug-and-Play Capabilities ▪ Inverter size has an important impact on cost. A 3kW inverter could cost half than a 1kW inverter on a per watt basis. Therefore manufacturers are trying to identify optimal inverter sizes based on installation trends, efficiency and cost information. ▪ The most common installation size for residential systems is in the 4-5 kW range; commercial installations over the 10kW range are also becoming common. Inverter manufacturers are increasing the size of inverters above 2 kW for residential and small commercial applications.
Reliability	▪ Inverter mean time between failures (MTBF) is currently in the range of 5 to 10 years, whereas modules and other system components have a life of 25 years or more, requiring investment in a new inverters 3-5 times over the lifetime of the project. ▪ Consumers tend to consider first costs above all other requirements. Short payback periods are expected. These characteristics suggest the use of high discount rates. Manufacturers today are focused on lowering first cost over improving reliability. Some manufacturers suggest that higher lifetimes for inverters would not represent savings for consumers because cheaper more efficient inverters will be available in the future.

	▪ The manufacturers offering 10 year warranties claim they have gained a better understanding of inverter technology reducing part count, incorporating higher quality components and modifying product design to lessen component stress. Other manufacturers claim these warranties are mere marketing tools. ▪ Some manufacturers are evaluating offering extended warranties for an additional cost to reduce the risks of near-term failures.
Manufacturing and Design Issues	▪ Most inverter designs are highly dependent on electrolytic capacitors. Manufacturers have identified capacitors as the component needing most improvement in terms of cost and lifetime in order to improve both inverter costs and reliability. Capacitors available on the market are not well-suited to PV inverter applications. It is necessary to include decoupling capacitors between the PV array and the dc-dc conversion stage, or between internal dc-dc stages within the power conditioning unit in order to limit the voltage fluctuations caused by irradiance fluctuations. The electrolytic capacitors used for this purpose and are normally kept as small as possible. Film capacitors. Are only an option when small capacitors are needed. ▪ Many manufacturers are small startups therefore lacking the capital and the internal processes needed for: → Quality control of product development and manufacturing. → Adequate product-improvement processes. → Training. → Sophisticated testing and manufacturing equipment. → Experiment with alternative inverter topologies. → Proper development time (products rushed to market). → The capacity and need to buy components in large quantities or bulk (due to low sales volume). ▪ Regulations differ across PV markets. US regulations for grid-connection and installation greatly increase costs. ▪ In the near-to medium-term, an MTBF of >10 years is likely to be achievable through improving quality control, better heat dissipation, and reducing complexity. ▪ Some inverter manufacturers have incorporated other protection and installation feature. These add complexity to the manufacturing process, yet it reduces overall system and installation costs. Some of the features include: → Ground Fault Circuit Interrupt (GFCI).

	→ Disconnect Switches, etc. ▪ Some considerations that could help lower inverter related costs are: → Universal Communication Standards. → Inverters Compatible with various DG technologies (economies of scale). → Uniform interconnection and installation requirements. → Government incentive programs. ▪ Manufacturers use analog or analog/micro-processor hybrid control systems for the inverters. These are prone to aging, exhibit temperature drift, increase component count and create noise and EMI.

5.1.7 Energy Storage

In a PV system the energy produced by PV modules does not always coincide with energy demanded. A PV array that it is not grid-connected needs to store the energy excess produced by solar cells. Electrical storage batteries are often employed in Stand Alone PV systems. The primary functions of a storage battery in a PV system are [31]:

1. Energy Storage and Autonomy: Store electrical energy produced by PV modules and supply energy as needed for the load.

2. Voltage and Current stabilization: To supply power to electrical loads at stable voltages and currents.

3. Supply Surge Currents: Supply high peak operating currents to electrical loads or appliances.

In PV systems, lead-acid batteries are most common due to their wide availability in many sizes, low cost and well known characteristics. Electrical storage batteries can be divided into Primary and Secondary Batteries. Table 5.12 shows secondary batteries charge characteristics.

Table 5.12 Secondary battery types and maintenance characteristics.

Battery Type	Cost	Deep Cycle Performance	Maintenance
Flooded Lead-Acid			
Lead-Antimony	Low	Good	High
Lead-Calcium Open Vent	Low	Poor	Medium
Lead-Calcium Sealed Vent	Low	Poor	Low
Lead Antimony/Calcium Hybrid	Medium	Good	Medium
Captive Electrolyte Lead-Acid			
Gelled	Medium	Fair	Low
Absorbed Glass Mat	Medium	Fair	Low
Nickel-Cadmium			
Sealed Sintered-Plate	High	Good	None
Flooded Pocket-Plate	High	Good	Medium

Primary batteries can store and deliver electrical energy, but cannot be recharged. Then primary batteries are not used in PV systems. Table 5.13 shows the advantages and disadvantages of each battery type.

Table 5.13 Battery Types Characteristics [31].

Battery Type	Advantages	Disadvantages
Flooded Lead-Acid		
Lead-Antimony	low cost, wide availability, good deep cycle and high	high water loss due to required overcharge, high maintenance, high self-

	temperature performance, can replenish electrolyte, high discharge rate performance, antimony limits the shedding of active material, ability to take abuse, greater mechanical strength than pure lead grids	discharge rate,
Lead-Calcium Open Vent	low cost, wide availability, low water loss due to reduced gasification, can replenish electrolyte, greater *mechanical strength* than pure lead grids, *low self-discharge rate,*	poor deep cycle performance, intolerant to high temperatures and overcharge, short PV life-span,
Lead-Calcium Sealed Vent	low cost, wide availability, low water loss	poor deep cycle performance, intolerant to high temperatures and overcharge, cannot replenish electrolyte, short PV life-span unless carefully charged,
Lead Antimony/Calcium Hybrid	medium cost, low water loss, good deep cycle performance, low water loss and long life	limited availability, potential for stratification and sulfating,
Captive Electrolyte Lead-Acid		
Gelled	medium cost, little or no maintenance, less	fair deep cycle performance,

	susceptible to freezing, install in any orientation	intolerant to overcharge and high temperatures, limited availability
Absorbed Glass Mat	medium cost, little or no maintenance, less susceptible to freezing, install in any orientation	fair deep cycle performance, intolerant to overcharge and high temperatures, limited availability
Nickel-Cadmium		
Sealed Sintered-Plate	wide availability, excellent low and high temperature performance, maintenance free	only available in low capacities, high cost, suffer from 'memory' effect
Flooded Pocket-Plate	excellent deep cycle and low and high temperature performance, tolerance to overcharge, long lifetime	limited availability, high initial cost, water additions required

Nickel-Cadmium Charge/discharge characteristics and high cost make them impractical for most PV systems. Flywheels, hydrogen, and other gas storage also have limited applicability in residences.

5.1.8 Charge Controllers

The charge controller is a DC to DC converter whose main function is to control the current flow from the photovoltaic modules array with the purpose of charging batteries. Most of these devices can maintain the maximum charge of the battery without overcharging or reaching the minimum design charge. The main functions of a Charge Controller are:

- **Overcharge Protection:** The purpose is to prevent the damage in the batteries when they are charged and the PV array still supplies energy. This protection interrupts or restricts the current flow from the modules to the batteries and regulates the batteries voltage.
- **Over discharge Protection:** During periods of excessive use of energy or little solar irradiation the charge of the batteries could be affected approaching to the point of minimum discharge. The charge controller disconnects the batteries or stop the current flow from the batteries to the load (Load Management) to prevent batteries damage.

There are two basic methods for controlling the charging of a battery from a PV module array:

Shunt Controller: Since PV cells are current-limited the basic operation of shunt controller is short-circuiting the PV modules and arrays. For this reason most shunt controller require a heat sink to dissipate power. The regulation element of these controllers typically is a power transistor or MOSFET.

Shunt Interrupting: The shunt interrupting controllers completely disconnect the array current when the batteries reach the voltage set point. When the batteries voltage decreases, the controller reconnects the array to resume charging the batteries.

Shunt Linear: When the batteries become nearly fully charged, the controller maintains the battery near a set point voltage by gradually shunting the array through a semiconductor regulation element.

Series Interrupting: This is the simpler of series controller (on-off type). The charge controller constantly monitors the batteries voltage and disconnects the arrays once the batteries reach the set point. When the batteries voltage drops this controller reconnect the array to charge the batteries.

Series interrupting, 2 step, Constant Current: The 2 step, constant current controller is similar to the series interrupting but when the voltage reaches the set point, instead of totally interrupt the array current, a limited constant current remains flowing to the batteries. This continues either for a pre-set period of time, or until the voltage drops to the cycle repeats.

Series interrupting, 2 step, Dual Set Point: This type of series charge controller has two distinct voltage regulation set-points. During the first charge cycle of the day, the controller uses a higher regulation voltage to maximization of the charge and in the other cycle uses a voltage lower voltage set-point. The purpose is minimizing the battery gassing and the water loss for flooded lead-acid type.

Series Linear, Constant Voltage: The linear constant voltage controller maintains the battery voltage at the voltage regulation set-point. The regulation element acts like a variable resistor controlled by the battery voltage sensing circuit of the controller, and dissipates the excess of charge.

Series Interrupting, Pulse Width Modulated: The PWM uses algorithm with a semiconductor switching element between the array and the batteries. The algorithm switches on-off the charge of the batteries with a variable frequency and variable duty cycle to maintain the voltage of the batteries very close to the set-point voltage.

Table 5.14 Controllers Design for Particular Battery types.

Controller Design	**Type of Batteries**
Shunt Interrupting	All battery types, but recommended by gel and AGM lead-acid battery manufactures.
Shunt Linear	Sealed VRLA batteries.
Series Interrupting	Flooded batteries rather than the sealed VRLA types.
Series Interrupting, 2 step, Constant Current	
Series Interrupting, 2 step, Dual Set Point	Flooded lead-acid types.
Series Linear, Constant Voltage	All battery types.
Series Interrupting, Pulse Width Modulated	Preferred use with sealed VRLA.

Table 5.15 Charge Controllers manufacturers.

Apollo Solar	**GeoSolar**	**Morningstar Corporation**	**Trace Engineering**
Blue Sky Energy	Heliotrope	Pulse Energy Systems Inc	Uhlmann Solarelectronic GmbH
BZ Products	ICP Solar	Ses Flexcharge USA	Vario
DIREC	Lyncom	Specialty Concepts Inc.	
Enermaxer	Outback Power	Sunwize Steca	
ETA Engineering	Pico Electronics Inc.	Sun Selector	
Flexcharge	Plasmatronics	SunAmp Power	

5.2 Photovoltaic Generation Potential in Puerto Rico

Puerto Rico's geographic location provides a generous solar resource that should be exploited to its maximum potential. The use of photovoltaic technology could allow the local community to take advantage of this resource without sacrificing land resources by using the unused portions of building rooftops and facades as energy collection fields. The analysis presented in this section uses only the available roof resource in the island to accommodate the proposed PV generation. This is the most efficient way to use the island's limited natural resources. Using roof areas is more economical due to the current value of real estate in the island. Other possibilities were considered during the study which included the use of highways and lighting poles to accommodate additional PV capacity. Using highways would require additional electrical infrastructure. The losses due to long electrical distances to the loads would probably diminish the feasibility of these projects. The lighting loads are probably best serviced by systems with batteries since no correlation exists between the resource and the loads. Special cases may exist which require individual attention. The following is a gross theoretical estimate of the electric energy production potential using photovoltaic technology in Puerto Rico.

To estimate the available rooftop area we have collected data for three mayor customer groups: residential, commercial and industrial. It was found that the island has 1,254,318 occupied residences with an average size of 152 m^2 [68]. To account for multiple dwelling buildings, only single unit (994,754 units) and contiguous unit

(194,813 units) types were considered. These add up to 1,189,567 residences. The total estimated available area for this sector is 180,814,185.00 m^2. The estimated commercial and industrial rooftop areas in the island are 7,300,000.00 m^2 and 2,702,545.45 m^2 respectively [69],[70]. Only half of the area will be assumed as available in order to account for uncertainties in how this area is distributed within the facilities.

We shall assume that all PV generating capacity is directly coupled to the utility grid by means of an inverter and no battery storage is utilized. Energy production over any period can be estimated using:

$$E_{PV} = E_{solar} * \eta_{PV} * (Module\ Area) * \eta_{inv} * \eta_{loss}$$

$$\eta_{PV} = \eta_{rated} * \eta_{T_c}$$

$$\eta_{T_c} = 1 - TC\,\eta(T_c - T_N)$$

For monthly average conditions:

$$\bar{T}_c - \bar{T}_a = (219 - 832 \cdot \bar{K}_t) \cdot \frac{NOCT - 20}{800}$$

A correction factor is introduced to the right side of the last equation to account for mounting angles different from optimal tilt angle:

$$C_f = 1 - 1.17 \cdot 10^{-4}(s_M - s)^2$$

where:

$T_c = Operating\ PV\ Module\ Temperature\ (^\circ C)$

$T_a = ambient\ temperature\ (^\circ C)$

$T_N = Operating\ PV\ Module\ Temperature\ at\ STC\ (25^\circ C)$

$TC\eta = \eta\ temperature\ coefficient\ (usually\ in\ \%/^\circ C)$

$\overline{K}_t = monthly\ clearness\ index$

$NOCT = nominal\ operating\ cell\ temperature$

$s_M = optimum\ tilt\ angle$

$s = mounting\ angle$

The peak power rating of a photovoltaic system can be estimated using the following equation:

$$W_p = 1000 * \eta_{rated} * A$$

Typical characteristics for specific PV cell technologies are shown in Table 5.16. The generation potential estimate for Puerto Rico is based on the typical characteristics for mono-crystalline PV modules. System related performance assumptions are summarized in Table 5.17.

Table 5.16 Typical PV Module Characteristic Values

PV module type	η_{rated}(%)	NOCT (^{o}C)	TCη ($\%/^{o}C$)
Mono-Si	13	45	0.4
Poly-Si	11	45	0.4
a-Si	5	50	0.11

Table 5.17 PV Energy Yield Assumptions

Inverter Efficiency (η_{inv})	0.9
Efficiency for Losses (η_x =1-%loss)	0.95
Mounting Angle	0^o
Optimal Tilt Angle	~18^o

Solar resource data for the Metro region of the island was downloaded from Surface Meteorology and Solar Energy: A Renewable Energy Resource web site [75]. The dataset was derived from satellite observations performed by NASA over a 10 year period. This set is assumed representative of the whole island in order to perform one global energy production potential estimate. Figure 5.19 displays the estimated yearly daily average solar resource distribution within the island. According to the figure, our data set corresponds to the largest average daily solar insolation region within the island (18.5-20 MJ/day). The "roof resource" can be assumed to be distributed similarly to the island's population. The data from the latest census was processed to distribute the population within the different insolation areas [68]. The vast majority of the population within the island (~50%) is distributed through areas with average insolation of 18.5 MJ/day or above. Approximately 20% of the island's population is distributed within the 17-18.5 MJ/day region. The remaining population is distributed within regions that receive less than 17 MJ/day. The selected dataset is within the predominantly dominating insolation range. It is therefore reasonable to assume that the selected dataset is representative of the whole island.

The PV modules are assumed to be mounted flat to simplify the solar geometry and to maintain a conservative result. It is well understood that module mounting angle can increase the available energy on the surface of the module. The energy incident on a PV module's surface can be maximized by choosing a mounting angle equal to the location's latitude with a mounting azimuth angle equal to zero. Table 5.18 displays the measured solar resource on the horizontal plane and the estimated resource at an 18^{o} mounting angle [26],[27]. The estimated total annual difference is less than 3%. This small difference is particular to south facing collecting surfaces in Puerto Rico. The difference would be more pronounced at locations with higher latitude angle magnitudes where the difference between the optimum angle and horizontal mounting is greater.

Using the stated assumptions, the average yearly energy generation potential in Puerto Rico can be estimated. Figure 5.20 to Figure 5.22 display the estimated energy production for each sector as a function of the percent of available roof area utilized. Any estimate attempted for such a large region is always subject to some uncertainty. A 10% uniform monthly resource variation margin was included in these figures. Figure 5.23 to Figure 5.25 displays the percentage of energy displaced assuming the annual electric energy production reported for Puerto Rico on the year 2005, which amounts to 24,960,000,000 kWh [76].

Table 5.18 Mean Daily Solar Resource per Month in Metro Area in kWh/m^2

	K_t	0° (Data)	18° (estimated)	Temperature (°C)
January	0.55	4.28	4.993062	24.7
February	0.56	4.91	5.438881	24.7
March	0.59	5.72	5.977196	25.2
April	0.58	6.1	5.993504	26
May	0.53	5.78	5.441539	26.7
June	0.56	6.05	5.566634	27.5
July	0.56	6.09	5.655229	27.8
August	0.56	5.96	5.743623	27.8
September	0.55	5.53	5.627517	27.6
October	0.55	4.92	5.327874	27.2
November	0.54	4.31	4.943017	26.3
December	0.53	3.97	4.628908	25.3
Average	0.56	5.301667	5.444749	26.4

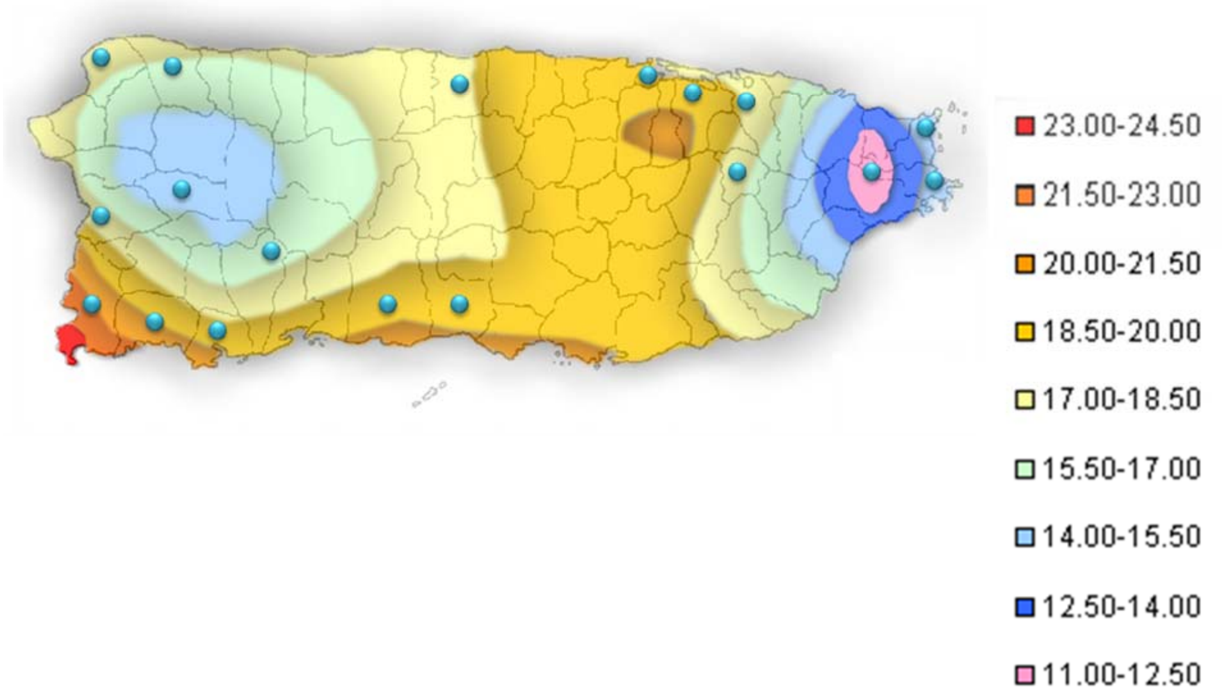

Figure 5.19 Puerto Rican Solar Resource Map

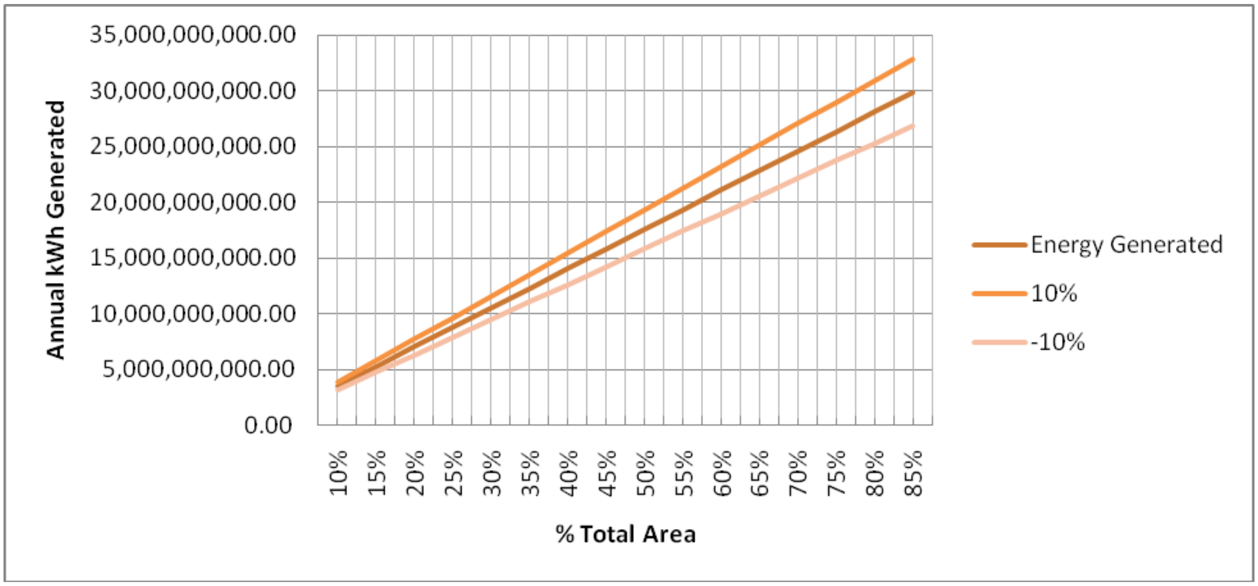

Figure 5.20 Annual Residential Generation Potential

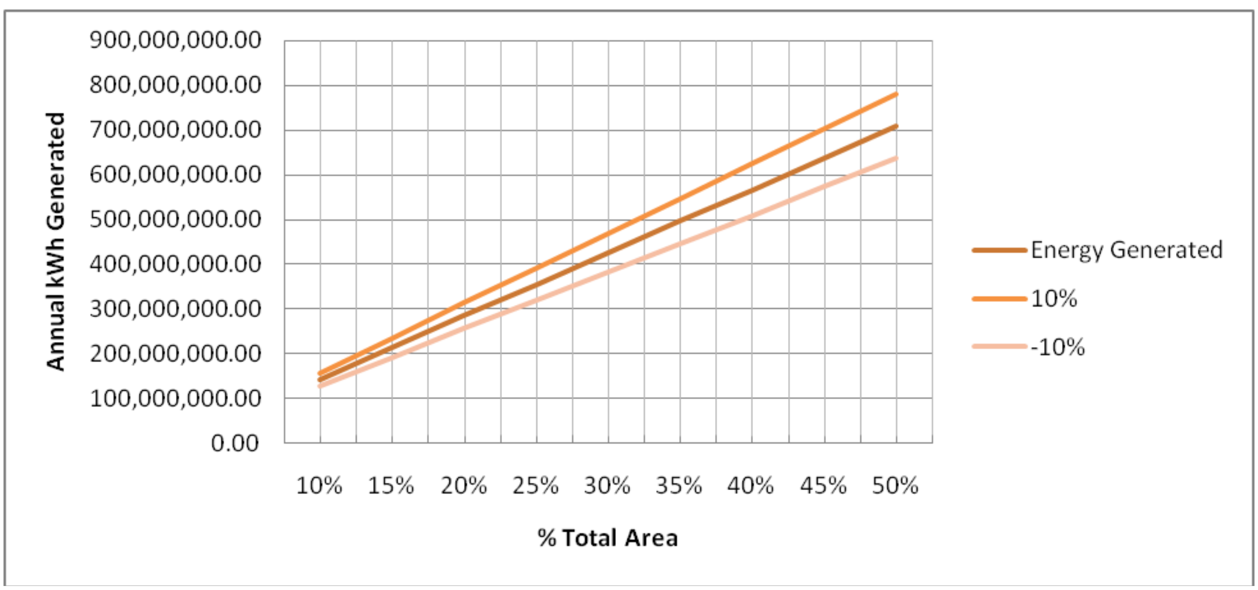

Figure 5.21 Annual Commercial Generation Potential

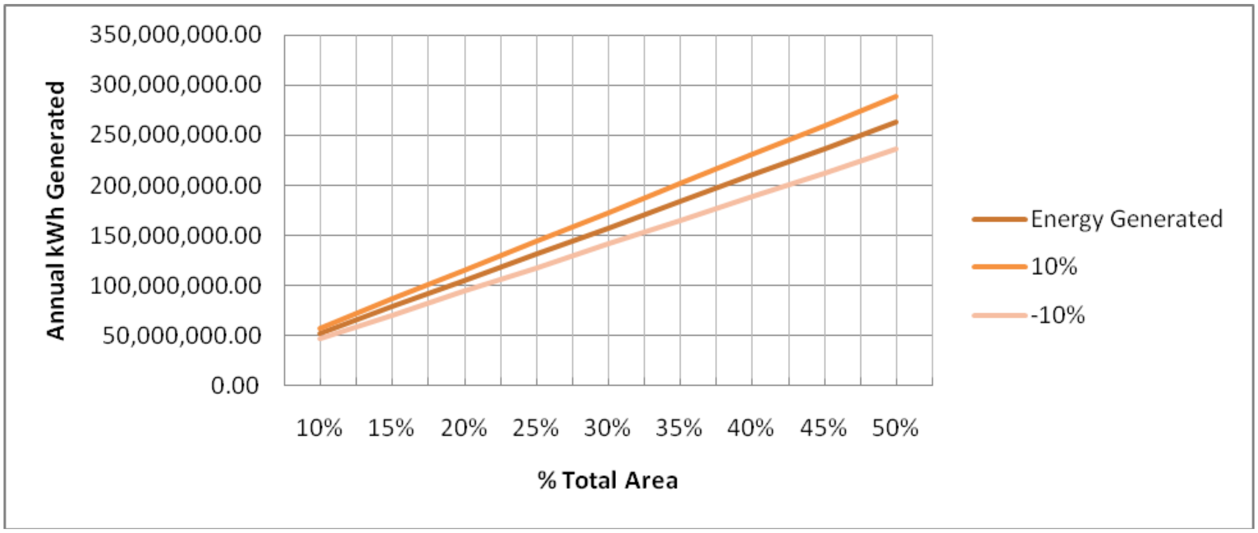

Figure 5.22 Annual Industrial Generation Potential

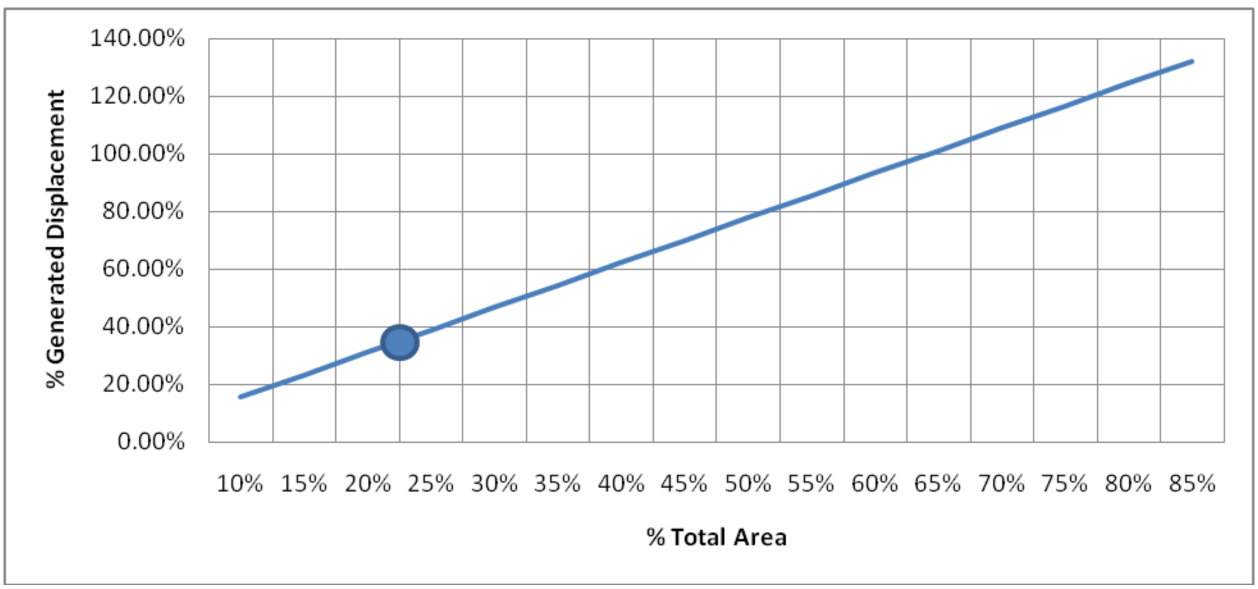

Figure 5.23 Annual Residential Generation Displacement Potential

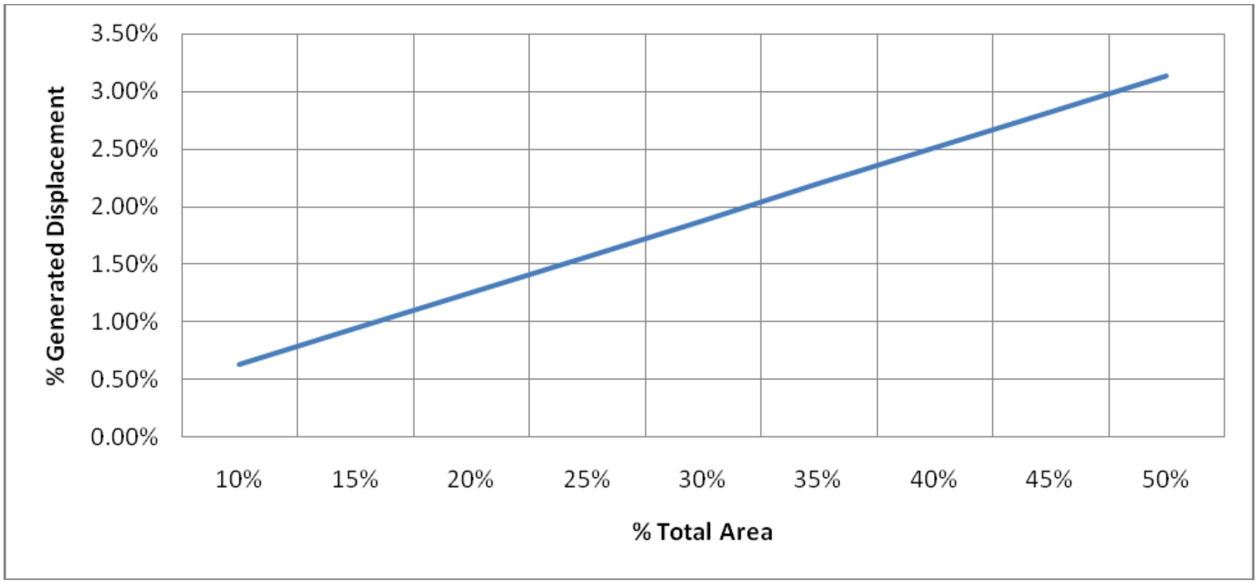

Figure 5.24 Annual Commercial Generation Displacement Potential

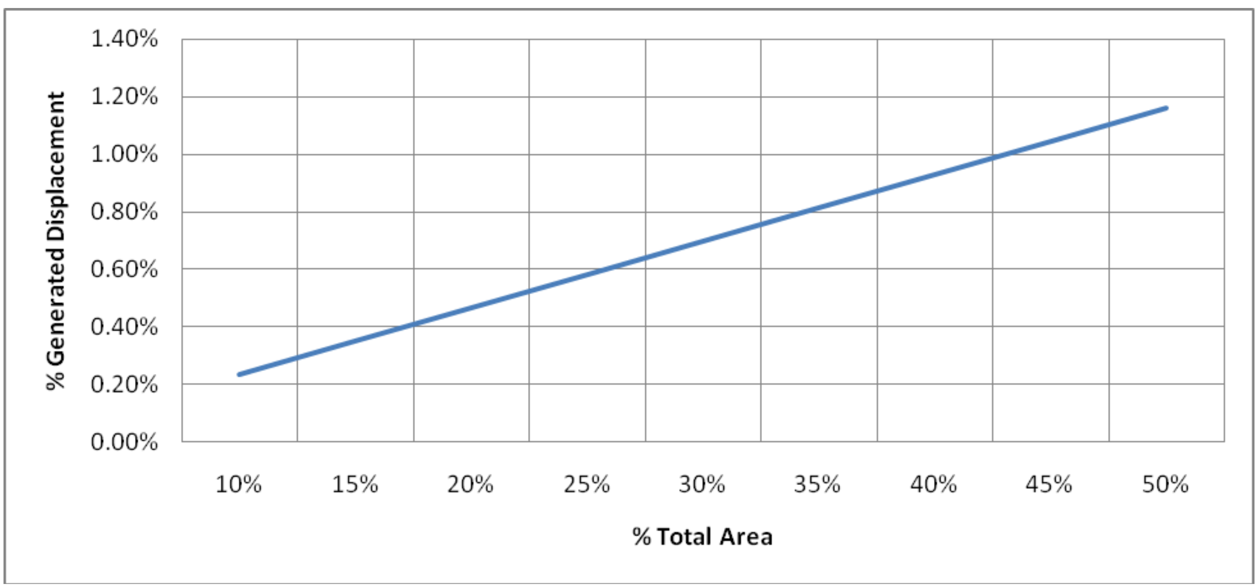

Figure 5.25 Annual Industrial Generation Displacement Potential

According to the available data, preliminary penetration limits could be established based on the energy requirements of each sector (36%, 43% and 21% of total generation respectively for residential, commercial and industrial customers). The residential penetration could be estimated at ~25% of the available rooftop translating to ~23,506 MW of peak capacity. In the case of industrial and commercial spaces the whole available area could be used without displacing the whole energy consumption of each sector. An estimated 949 MW could be installed in commercial rooftops and 351 MW in industrial rooftops if the whole available estimated rooftop resource is used.

Fuel use and emissions reductions can be estimated based on average operating characteristics of generators similar to those in the Puerto Rican electric grid. Detailed simulations are too complex for the scope of this evaluation; it would at least require the specific output functions of each active generator during the year under study and a record of the electric output of each generator during each dispatch period. We can provide ballpark estimates using simplified methods. The simplifying assumptions are presented in Table 5.19 [1], [77], [78].

Table 5.19 Fuel and Emissions Reduction Assumptions

	natural gas	coal	oil #6	Hydro
Average Generator Efficiency (η_g)	45%	35%	30%	Very Small fraction. Not considered in our analysis.
Heating values (HV)	1030 BTU/ft3	12000 BTU/lb	153000 BTU/gal	
Unit Price	$10/1000ft3	$56/short ton	$135/barril	
CO_2 Emissions Factor	56.1 kg/GJ	95.6 kg/GJ	77.4 kg/GJ	
CH_4 Emissions Factor	0.0030 kg/GJ	0.0020 kg/GJ	0.0030 kg/GJ	
N_2O Emissions Factor	0.0010 kg/GJ	0.0030 kg/GJ	0.0020 kg/GJ	
T&D Losses	10%	10%	10%	
Generation Mix Percentage (GM%)	17%	15%	68%	

The Fuel reductions can be easily estimated using the following equation:

$$\Delta F = \frac{E_{offset} * GM\% * (1 + T\&D_{loss})}{\eta_g * HV}$$

The fuel use reduction as a function of the percent of available roof area is displayed in Figure 5.26 to Figure 5.28. Similarly, estimated fuel savings ($) are displayed in Figure 5.29 to Figure 5.31.

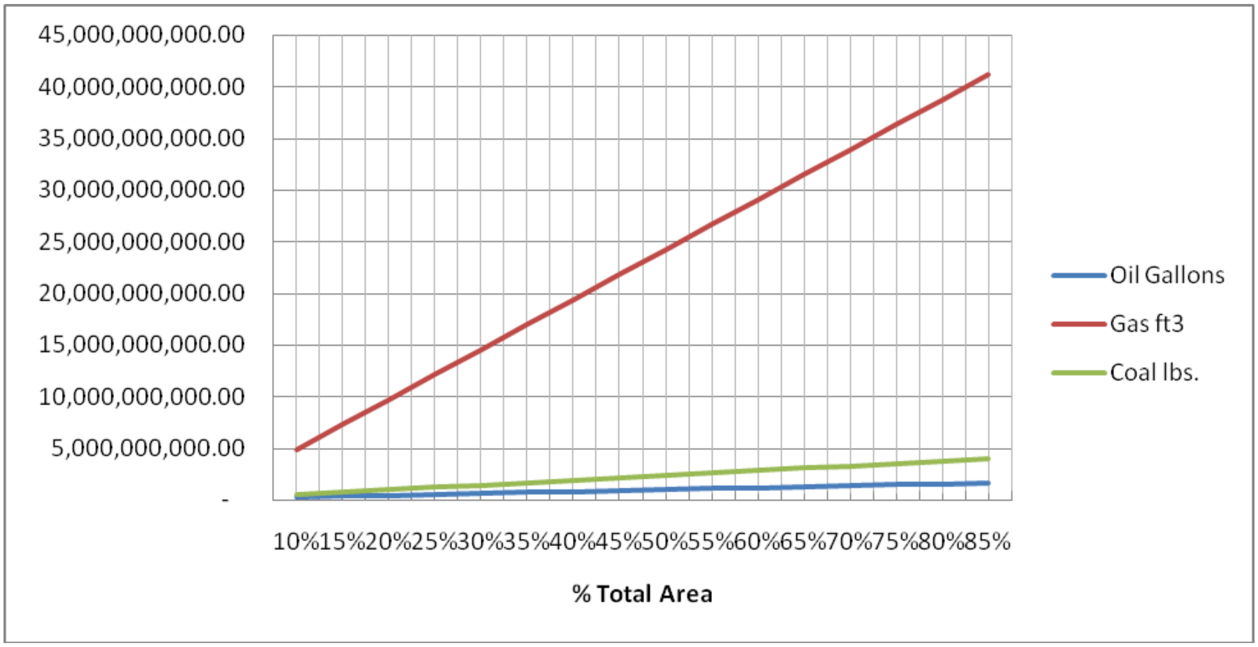

Figure 5.26 Annual Residential Fuel Use Reductions

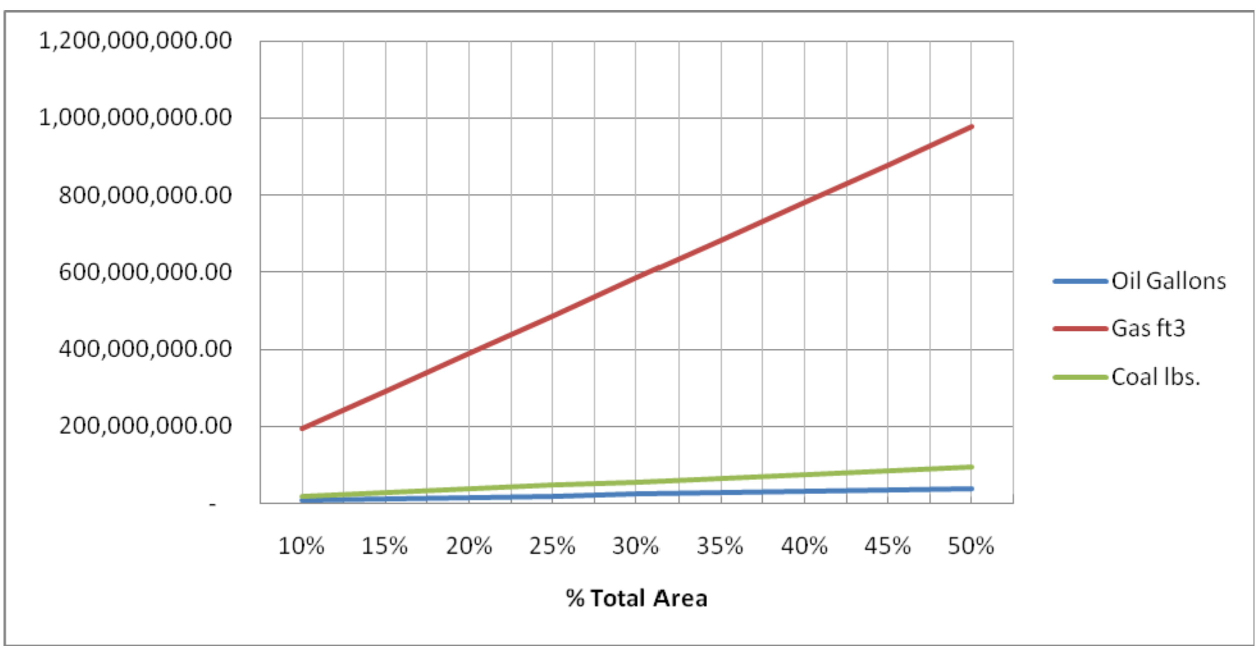

Figure 5.27 Annual Commercial Fuel Use Reductions

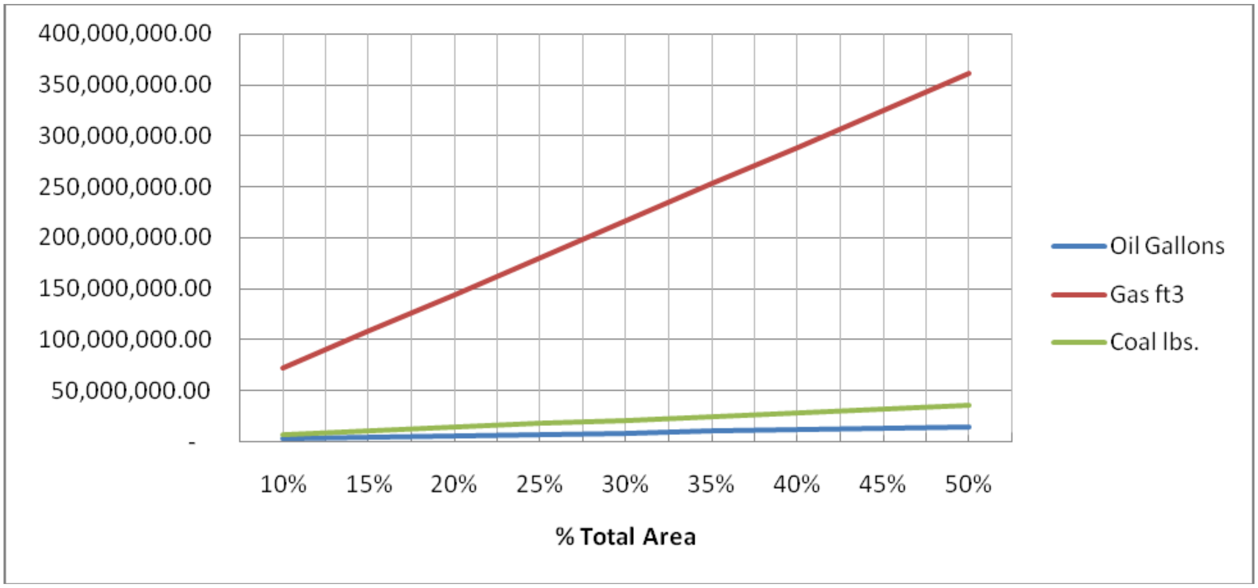

Figure 5.28 Annual Industrial Fuel Use Reductions

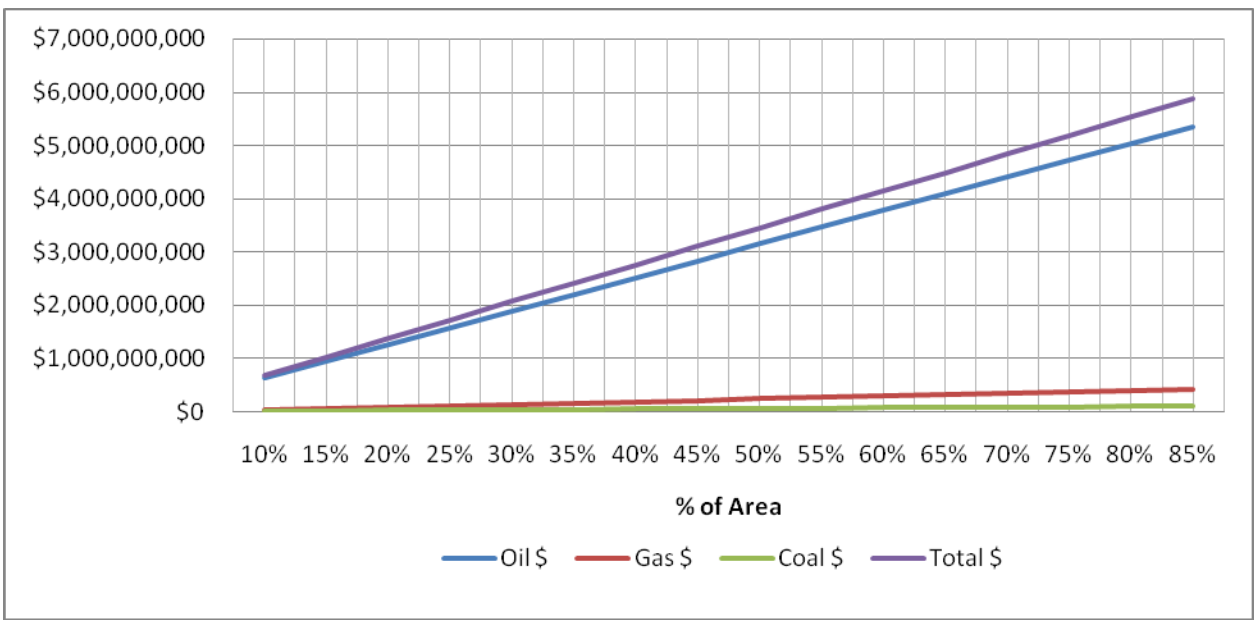

Figure 5.29 Estimated Residential Fuel Savings

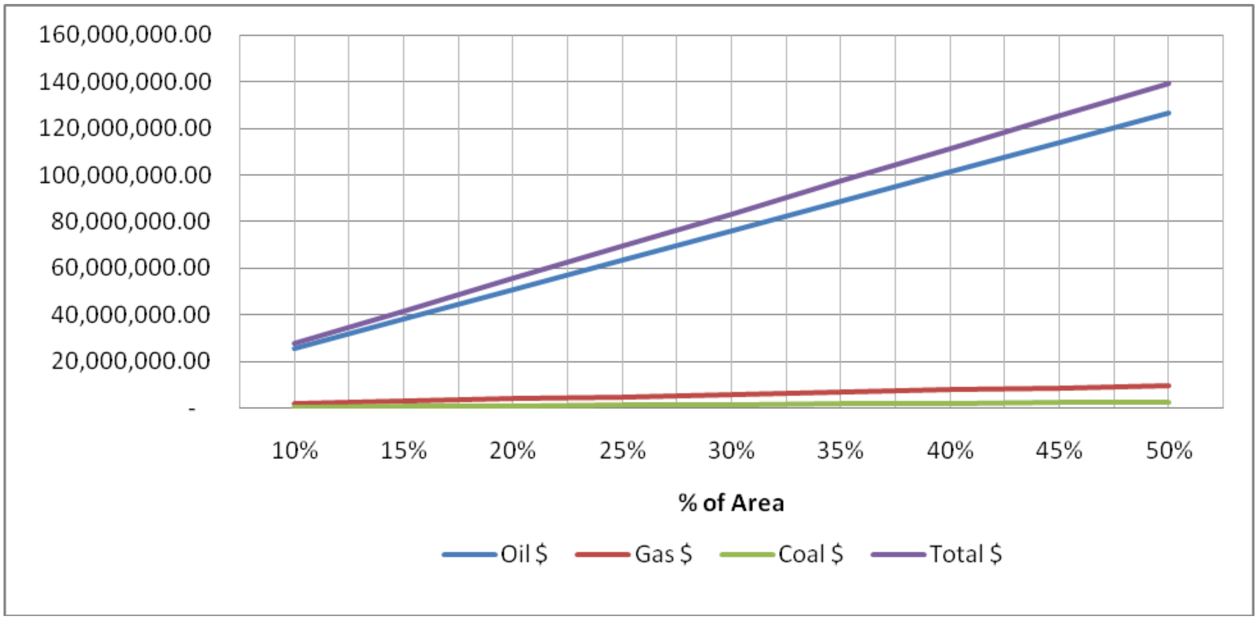

Figure 5.30 Estimated Commercial Fuel Savings

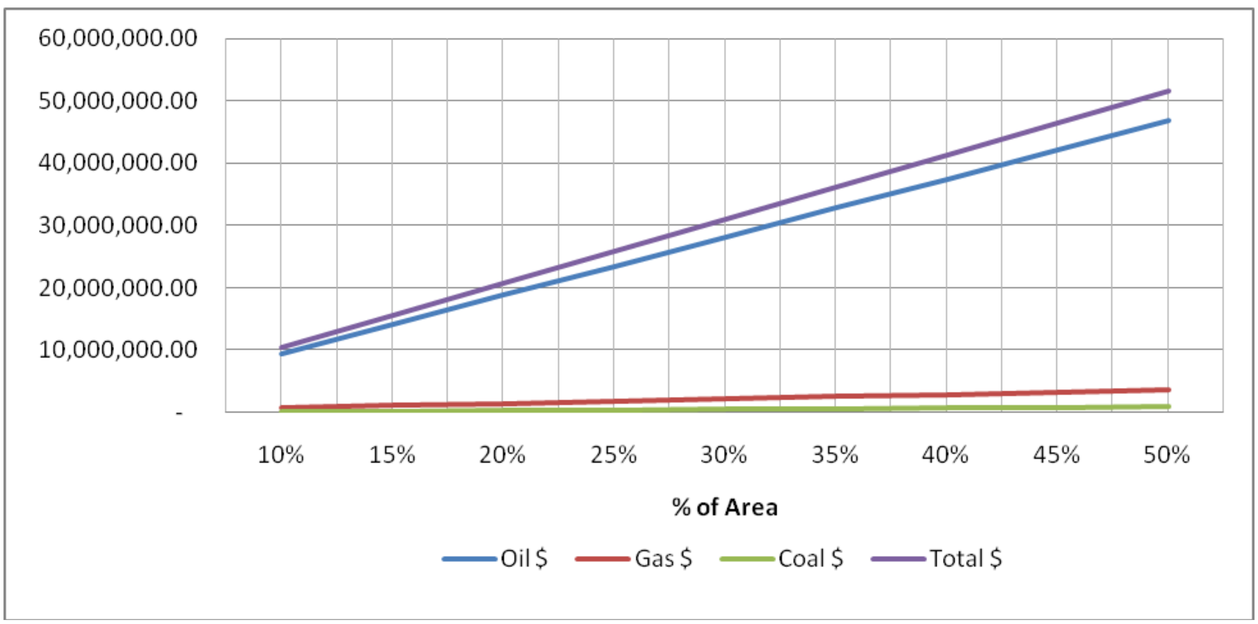

Figure 5.31 Estimated Industrial Fuel Savings

The system equivalent emissions reduction factors and GHG emission factor can be easily obtained using the RETScreen software package and are displayed in Table 5.20 [26],[27]. The corresponding emissions reduction potentials are displayed in Figure 5.32 to Figure 5.34. These transform all emissions into a CO2 equivalent in terms of global warming potential. The conversion factors are displayed in

Table 5.21.

Table 5.20 System Emission Factors

	CO_2 emission factor	CH_4 emission factor	N_2O emission factor	T & D losses	GHG emission factor
	kg/GJ	kg/GJ	kg/GJ	%	**(t_{CO2}/MWh)**
Electricity mix	263.5	0.0098	0.0069	10	0.957

Table 5.21 Global Warming Potential of GHG (IPCC 1996)

	Equivalency
1 tonne CH4	21 tonnes CO2
1 tonne N2O	310 tonnes CO2

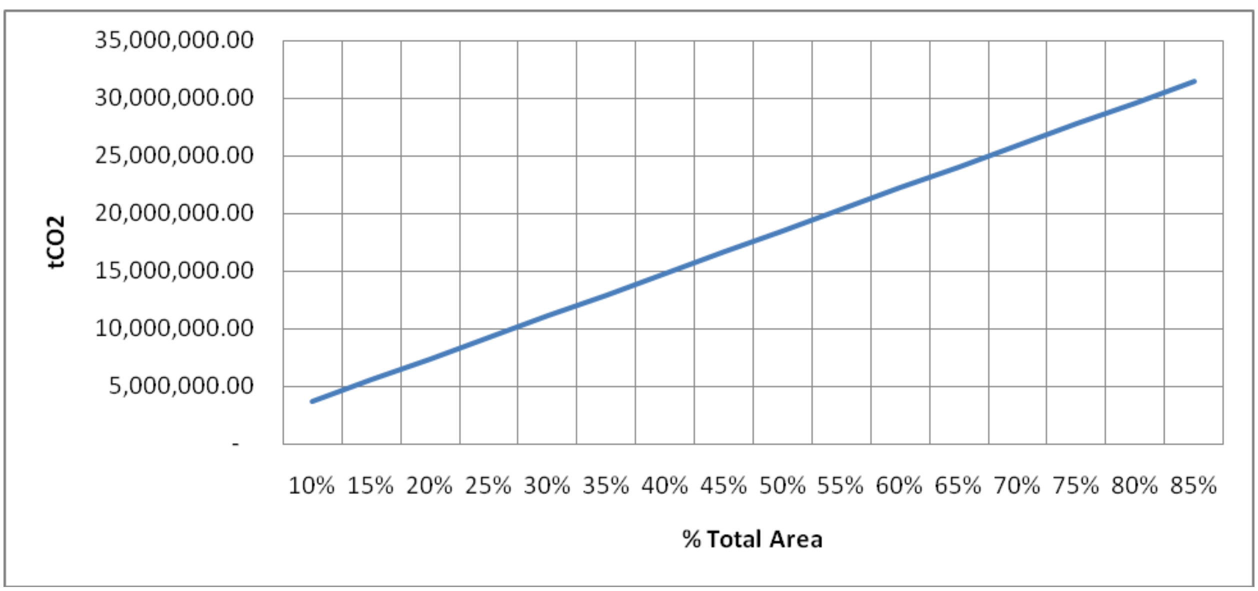

Figure 5.32 Estimated GHG Reduction Potential for the Available Residential Roof Area

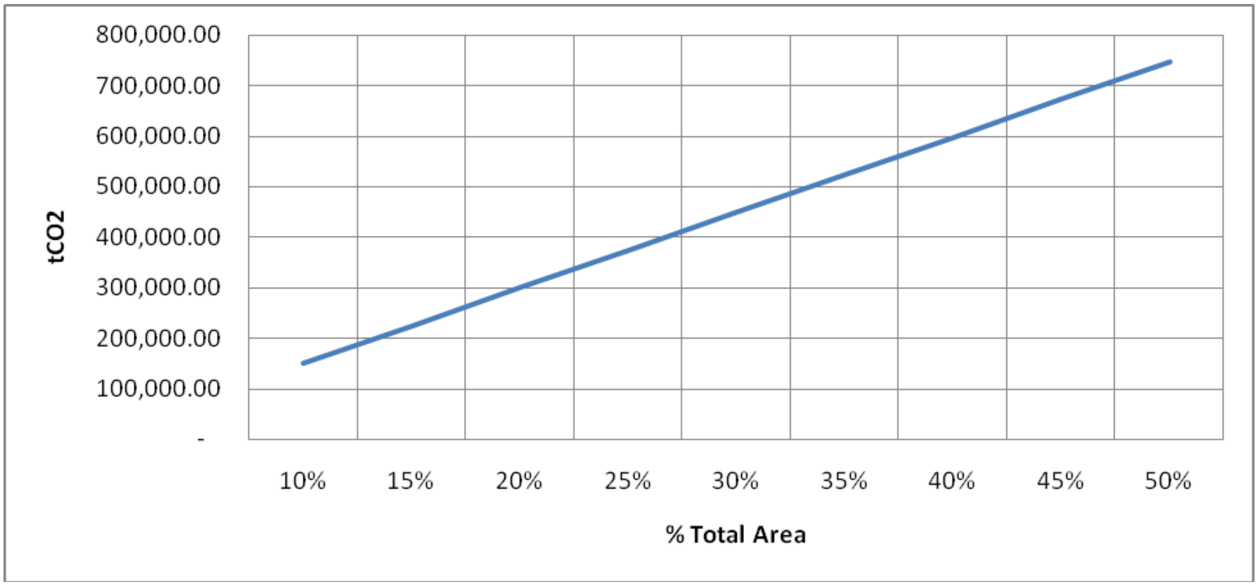

Figure 5.33 Estimated GHG Reduction Potential for the Available Commercial Roof Area

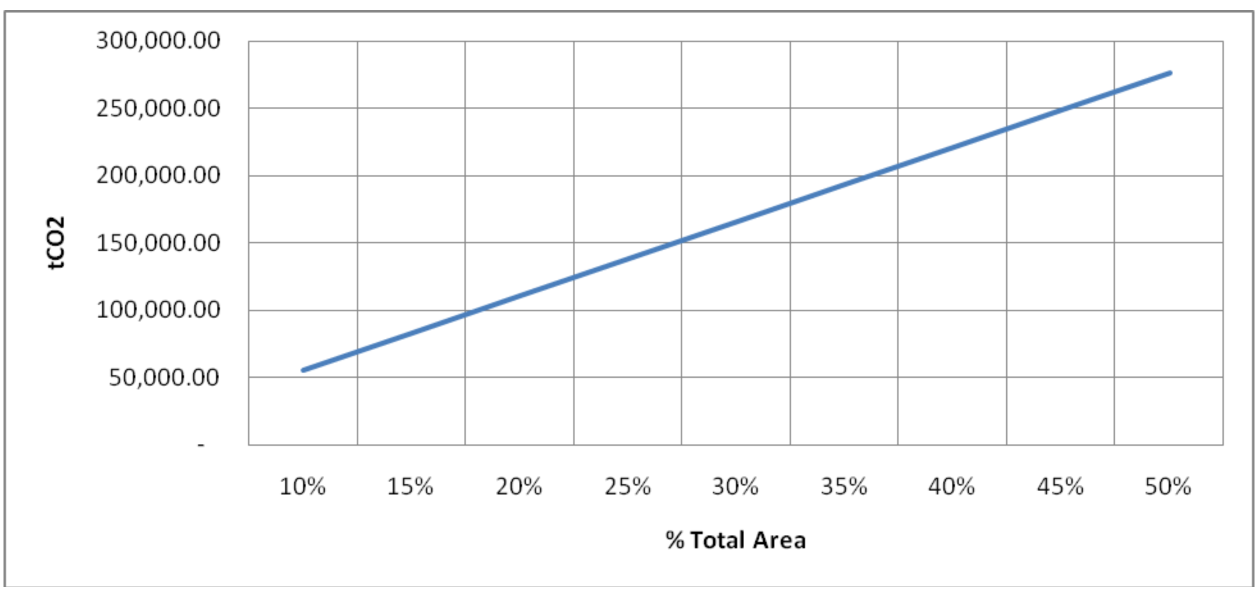

Figure 5.34 Estimated GHG Reduction Potential for the Available Industrial Roof Area

This section has attempted to estimate the theoretical PV generation potential and the associated benefits of using this technology in combination with the Puerto Rican electrical distribution grid. The real benefits of incorporating this renewable energy source will depend on the methods and supplemental technology used to make the transition from the traditional generation and distribution schemes. The authors recognize the possibility of stand-alone PV systems as an alternate method of incorporating the technology in the island, yet they strongly believe this to be a secondary option when a utility connection is readily available and inexpensive (see section 5.1.1). The next sections shall attempt to discuss the possible benefits and problems of large scale penetrations of PV generation by taking a closer look at the economic feasibility of these systems in the island and the possible issues associated to the integration of this technology to the available transmission and distribution systems.

5.3 Grid-Tied PV Economic Feasibility

The economic feasibility for PV technology as an alternative to fossil fuel generation will depend on a combination of capital cost investment, expected energy yield and the financial scenario on which the debt is to be repaid. Recently there has been active legislation in favor of incentivizing PV technology as an alternative source of energy. Table 5.22 summarizes the currently available incentives applicable to PV technology.

Table 5.22 PV Incentive Guidelines in Puerto Rico

Type	Incentive	Terms
Tax Exemptions	All PV and Auxiliary Equipment are free from all sales tax. Exempt from taxes over property.	• Auxiliary equipment has to be proved necessary for the installation and operation of the PV system. • Equipment must have at least a 5 year warranty. • Equipment must be approved by AAE.
Tax Credits	75% of Total Capital Costs (2007-2009)	• $5,000,000/yr. available for natural persons. • $15,000,000/yr. for juridical

<table>
<tr><td rowspan="2"></td><td>50% of Total Capital Costs (2009-2011)</td><td rowspan="2">persons.
The credit can be divided or retained for a period of 10 years.
The credit can be sold or transferred. The revenues from selling the credit are tax exempt.
Equipment must have at least a 5 year warranty.
Equipment must be approved by AAE.</td></tr>
<tr><td>25% of Total Capital Costs (2012+)</td></tr>
<tr><td>Net Metering</td><td>Customers having grid-tied PV energy generation systems are only charged for the Net Energy consumption over a billing period. If more energy is generated than consumed in a billing period, the surplus energy is available for the next billing period.</td><td>25kW maximum PV array size for residential customers.
1MW maximum PV array size for industrial, commercial and other customers.
If customers with systems larger than 300kW have surplus energy at the end of the fiscal year, the utility will pay only $0.10/kWh for 75% of the surplus. The remaining 25% will be credited to AAE.
If customers with systems smaller than 300kW have energy surplus at the end of the fiscal year, the utility will pay the customer for this surplus at the current retail price.
A daily maximum energy production of 300kWh for residential customers and 1MWh for other customers is allowed.
The PV system will be used</td></tr>
</table>

		only to displace in whole or in part the client's energy demand.
Industrial Incentive Program	50% credit for energy generation equipment bought by an industrial organization.	• Wheeling is allowed. • Maximum $8,000,000 limit per organization for equipment meant for energy retail. • Maximum 25% of annual contributions will be granted if the equipment will be used to exclusively supply the organization's load. • $20,000,000/yr.

The feasibility of PV systems in Puerto Rico will be examined performing a cash flow analysis on a 1kW system; this will allow us to extrapolate the performance of systems of other sizes. Our main interest is to verify the yearly additional costs or savings that PV systems could provide to their owners and in the investment is recuperated during the system's life. The base case assumptions are described in

Table **5.23**. The cost per kW was determined using the average unit cost for each system component and labor. The data gathered in section 5.1.4 shows that system costs can be lower on a kW basis than the estimated value used, yet the author believes this value represents a realistic estimate for the worst case situation in which a trained engineer or system installer will buy the equipment through a non-affiliated distributor. The case we shall study shall assume that the capital costs are completely financed and the payments shall be equally distributed throughout the project life span. The debt interest chosen is considered typical for personal loans and the inflation rate was chosen according to the available information in [80]. The energy cost for 2008 was calculated using the data found in [79], which is summarized in Table 5.24. The current energy escalation rates and energy rates are higher than those used in the table. The author has chosen to use the average calculated energy price for the three main client classes and fixed the energy escalation rate to the inflation rate. Lower energy escalation rates will slow down the system payback, assuming the escalation rate to be equal to the inflation will assume that the energy escalation rate has been slowed to theoretical minimum yielding conservative results. The analysis assumes that the proposed PV system will be used to displace the owner's energy consumption in whole or in part in order to take advantage of the possible energy savings when determining system pay-back. Systems meant for the production of energy for the wholesale market could not be as beneficial to the owner unless the energy is sold in a wheeling contract, otherwise PREPA will buy energy at a price below $0.08/kWh (the avoided cost of energy). The project life has been chosen to agree with the typical warranty periods offered by PV module manufacturers, yet modules could last more than 50 years. The annual expected energy yield for a 1kW system was estimated using the same assumptions used in section 5.2. The O&M costs were calculated using an estimated cost of 0.4 cent/kWh (see Table 5.2) and an annual insurance cost contribution according to the preliminary interconnection guidelines published by PREPA [81]. The worst case cost per kW situation will be for residential customers who shall pay an estimated cost of $124 for annual insurance and the average installation size is about 5kW. The expected cash flows for the scaled base system are displayed in Figure 5.35 to Figure 5.39. The future costs or savings were adjusted to account for inflation effects. The cash flows were determined neglecting all taxes as is permitted by the current available incentives, yet the allowed credits are not considered. One inverter replacement was considered at the half of the project life, current average unit costs were used as reference to provide conservative results, yet inverter cost should be expected to be lower [63]. The base case will be used to evaluate sensitivity to variation in some of the economic performance parameters including:

1. Capital Cost
2. Energy Escalation Rate
3. Debt Period
4. Debt Interest
5. Cost of Energy/Energy Yield

The proposed analysis methodology allows us to examine the effects of different variables on the economic feasibility of grid-tied PV technology. We shall not attempt to quantify externalities associated with the operation of PV systems (e.g. emissions reduction potential). Table 5.25 to Table 5.39 display the cash flows and cumulative cash flows for each case studied. The colored cells indicate values equal or greater than cero.

Table 5.23 Base Case Economic Assumptions

Capital Costs	$9,090.00
% to be Financed	100.00%
Financed Costs	$9,090.00
Debt Term (yr)	25
Debt Interest	8.50%
Inflation	8.00%
Project Life (yr)	25
Energy Price ($/kWh)	0.22
Energy Escalation Rate	8.00%
Expected Annual Yield (kWh)	1,512.00
Yearly O & M Costs	$30.8

Table 5.24 Energy Cost Data for Puerto Rico

Customer	Average Energy Rate 2006 ($/kWh)	Average Annual Increment	Average Energy Rate Projection 2008 ($/kWh)
Residential	0.177	14%	0.23
Commercial	0.19	11.4%	0.236
Industrial	0.156	12.2%	0.196
Average	0.174	27%	0.221

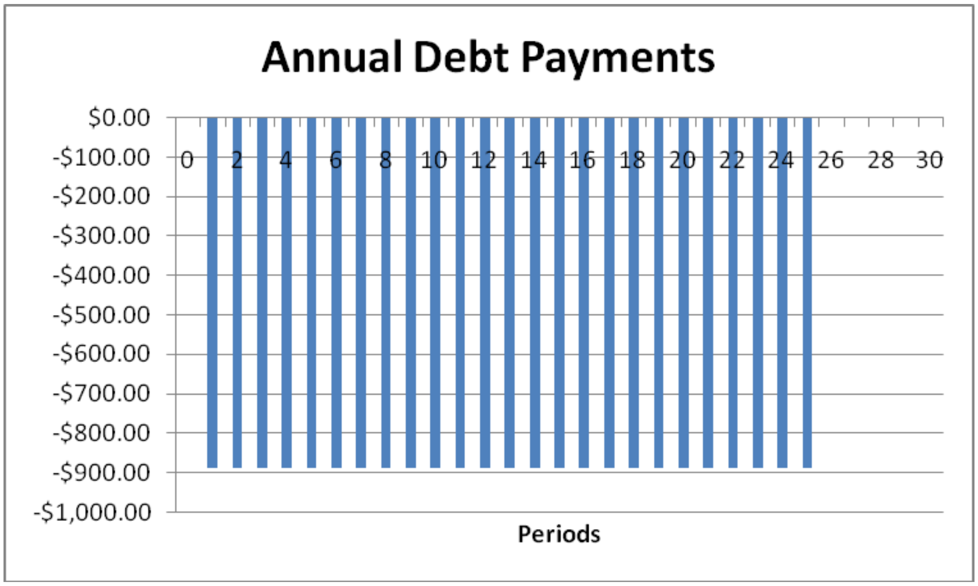

Figure 5.35 Annual Debt Payments for Base Case

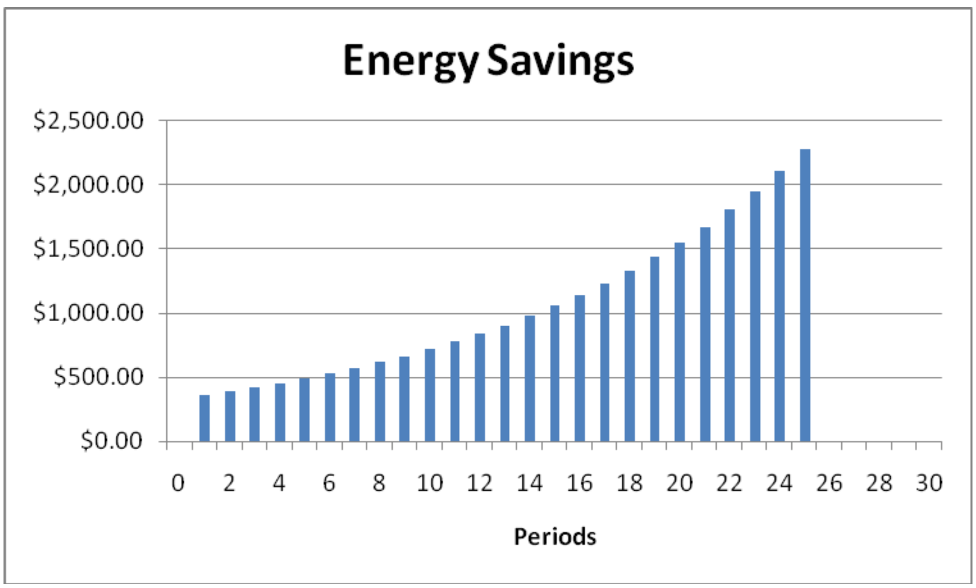

Figure 5.36 Projected Yearly Energy Savings for Base Case

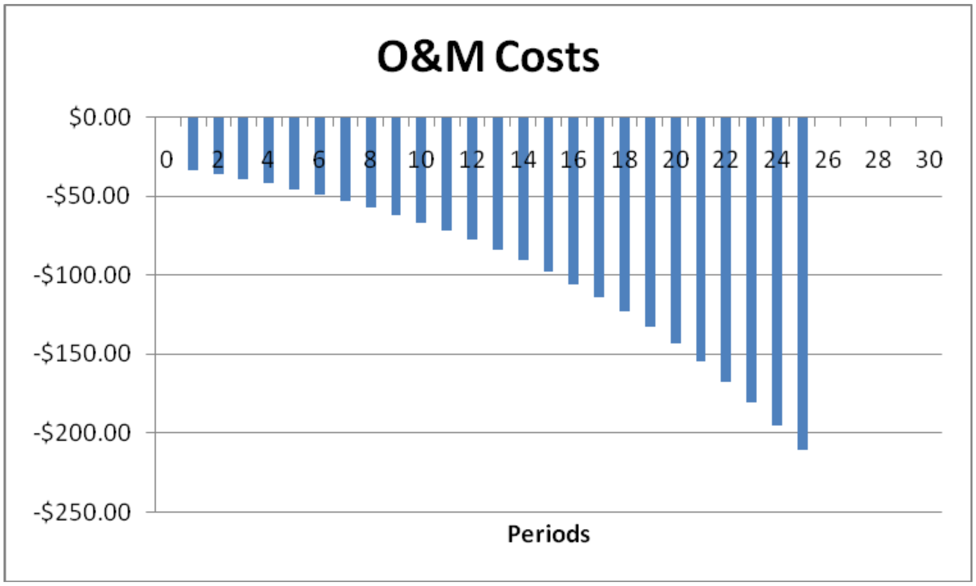

Figure 5.37 Projected Yearly O&M Costs for Base Case

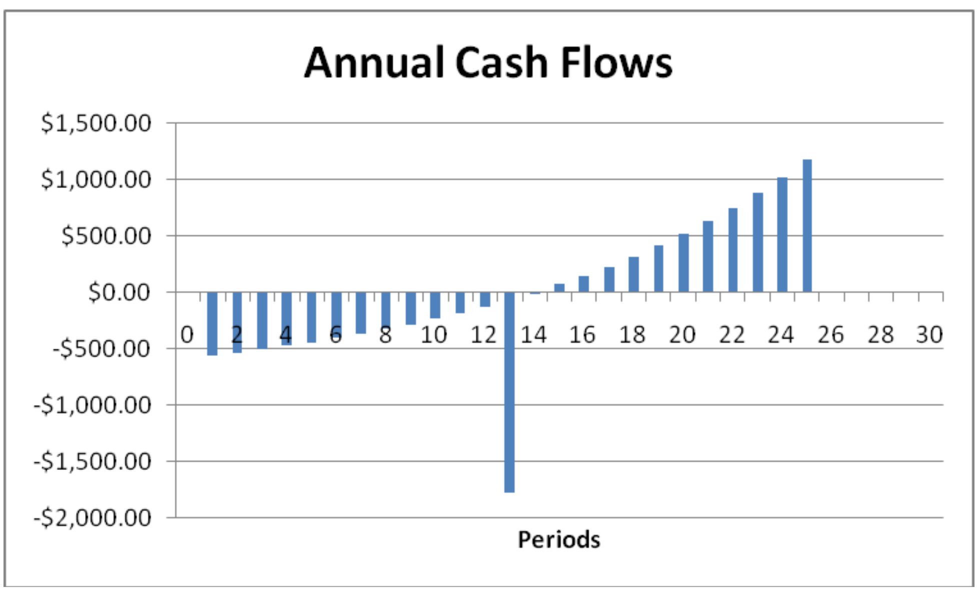

Figure 5.38 Annual Cash Flows for Base Case

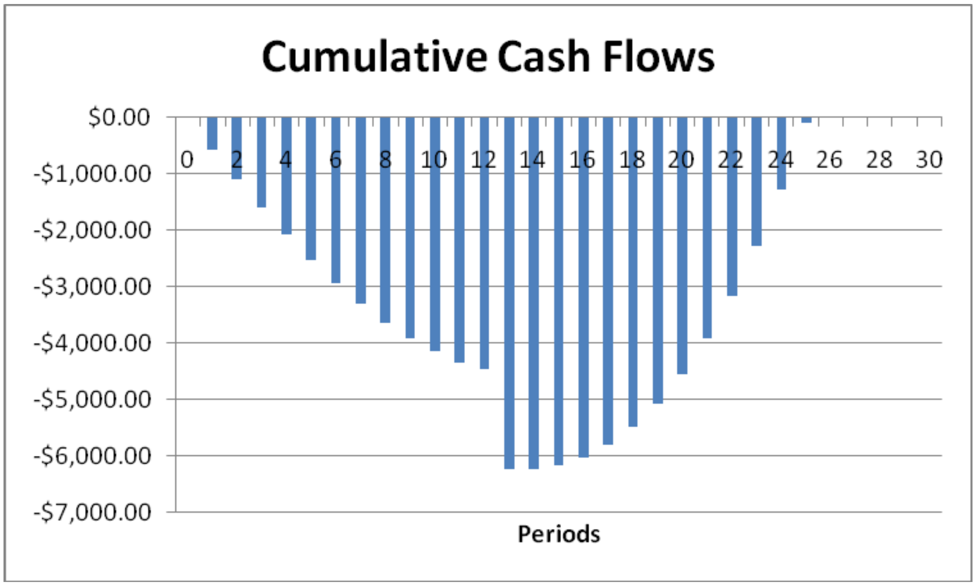

Figure 5.39 Cumulative Cash Flows for Base Case

Table 5.25 Annual Debt Payments Assuming Variations in Capital Costs

	Annual Payments due to Variation of Capital Costs										
yr.	50.00%	40.00%	30.00%	20.00%	10.00%	0.00%	10.00%	20.00%	30.00%	40.00%	50.00%
0	0	0	0	0	0	0	0	0	0	0	0
1	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
2	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
3	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
4	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
5	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
6	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
7	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
8	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
9	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
10	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
11	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
12	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
13	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
14	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
15	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
16	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
17	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
18	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
19	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
20	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
21	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
22	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
23	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
24	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3
25	-444.1	-532.92	-621.739	-710.559	-799.379	-888.199	-977.0191	-1065.84	-1154.66	-1243.48	-1332.3

Table 5.26 Cash Flows Assuming Variations in Capital Costs

	Cash Flows due to Variation of Capital Cost										
yr.	50.00%	40.00%	30.00%	20.00%	10.00%	0.00%	10.00%	20.00%	30.00%	40.00%	50.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-118.112	-206.932	-295.752	-384.572	-473.392	-562.212	-651.032	-739.852	-828.672	-917.492	-1006.31
2	-92.0334	-180.853	-269.673	-358.493	-447.313	-536.133	-624.953	-713.773	-802.593	-891.413	-980.233
3	-63.8681	-152.688	-241.508	-330.328	-419.148	-507.968	-596.788	-685.608	-774.427	-863.247	-952.067
4	-33.4496	-122.27	-211.09	-299.91	-388.73	-477.55	-566.37	-655.19	-744.01	-832.83	-921.65
5	-0.59761	-89.4175	-178.237	-267.057	-355.877	-444.697	-533.517	-622.337	-711.157	-799.977	-888.797
6	34.88255	-53.9374	-142.757	-231.577	-320.397	-409.217	-498.037	-586.857	-675.677	-764.497	-853.317
7	73.20112	-15.6188	-104.439	-193.259	-282.079	-370.898	-459.718	-548.538	-637.358	-726.178	-814.998
8	114.5852	25.76526	-63.0547	-151.875	-240.694	-329.514	-418.334	-507.154	-595.974	-684.794	-773.614
9	159.28	70.46004	-18.3599	-107.18	-196	-284.82	-373.64	-462.459	-551.279	-640.099	-728.919
10	207.5503	118.7304	29.91049	-58.9094	-147.729	-236.549	-325.369	-414.189	-503.009	-591.829	-680.649
11	259.6823	170.8624	82.04248	-6.77744	-95.5974	-184.417	-273.237	-362.057	-450.877	-539.697	-628.517
12	315.9849	227.165	138.345	49.52511	-39.2948	-128.115	-216.935	-305.755	-394.574	-483.394	-572.214
13	-1336.57	-1425.39	-1514.21	-1603.03	-1691.85	-1780.67	-1869.49	-1958.31	-2047.13	-2135.95	-2224.77
14	442.4629	353.643	264.8231	176.0032	87.18325	-1.63667	-90.4566	-179.277	-268.096	-356.916	-445.736
15	513.3879	424.568	335.7481	246.9282	158.1083	69.28833	-19.5316	-108.352	-197.171	-285.991	-374.811
16	589.9869	501.167	412.3471	323.5272	234.7073	145.8873	57.06741	-31.7525	-120.572	-209.392	-298.212
17	672.7139	583.8939	495.074	406.2541	317.4342	228.6143	139.7943	50.97442	-37.8455	-126.665	-215.485
18	762.0589	673.239	584.4191	495.5992	406.7793	317.9593	229.1394	140.3195	51.49957	-37.3203	-126.14
19	858.5516	769.7317	680.9118	592.0919	503.2719	414.452	325.6321	236.8122	147.9923	59.17234	-29.6476
20	962.7637	873.9438	785.1239	696.3039	607.484	518.6641	429.8442	341.0243	252.2044	163.3844	74.56451
21	1075.313	986.4929	897.6729	808.853	720.0331	631.2132	542.3933	453.5733	364.7534	275.9335	187.1136
22	1196.866	1108.046	1019.226	930.406	841.5861	752.7662	663.9462	575.1263	486.3064	397.4865	308.6666
23	1328.143	1239.323	1150.503	1061.683	972.8633	884.0434	795.2235	706.4036	617.5836	528.7637	439.9438
24	1469.922	1381.102	1292.283	1203.463	1114.643	1025.823	937.0029	848.183	759.363	670.5431	581.7232
25	1623.044	1534.224	1445.404	1356.584	1267.764	1178.945	1090.125	1001.305	912.4848	823.6649	734.845

Table 5.27 Cumulative Cash Flows Assuming Variations in Capital Costs

	Cumulative Cash Flows due to Variation of Capital Cost										
yr.	50.00%	40.00%	30.00%	20.00%	10.00%	0.00%	10.00%	20.00%	30.00%	40.00%	50.00%
0	0	0	0	0	0	0	0	0	0	0	0
1	-118.112	-206.932	-295.752	-384.572	-473.392	-562.212	-651.032	-739.852	-828.672	-917.492	-1006.31
2	-210.146	-387.786	-565.425	-743.065	-920.705	-1098.35	-1275.98	-1453.62	-1631.26	-1808.9	-1986.54
3	-274.014	-540.474	-806.933	-1073.39	-1339.85	-1606.31	-1872.77	-2139.23	-2405.69	-2672.15	-2938.61
4	-307.464	-662.743	-1018.02	-1373.3	-1728.58	-2083.86	-2439.14	-2794.42	-3149.7	-3504.98	-3860.26
5	-308.061	-752.161	-1196.26	-1640.36	-2084.46	-2528.56	-2972.66	-3416.76	-3860.86	-4304.96	-4749.06
6	-273.179	-806.098	-1339.02	-1871.94	-2404.86	-2937.78	-3470.7	-4003.62	-4536.53	-5069.45	-5602.37
7	-199.977	-821.717	-1443.46	-2065.2	-2686.94	-3308.67	-3930.41	-4552.15	-5173.89	-5795.63	-6417.37
8	-85.3923	-795.952	-1506.51	-2217.07	-2927.63	-3638.19	-4348.75	-5059.31	-5769.87	-6480.43	-7190.99
9	73.88764	-725.492	-1524.87	-2324.25	-3123.63	-3923.01	-4722.39	-5521.77	-6321.15	-7120.53	-7919.91
10	281.438	-606.761	-1494.96	-2383.16	-3271.36	-4159.56	-5047.76	-5935.96	-6824.16	-7712.35	-8600.55
11	541.1203	-435.899	-1412.92	-2389.94	-3366.96	-4343.98	-5320.99	-6298.01	-7275.03	-8252.05	-9229.07
12	857.1052	-208.734	-1274.57	-2340.41	-3406.25	-4472.09	-5537.93	-6603.77	-7669.61	-8735.45	-9801.29
13	-479.466	-1634.13	-2788.78	-3943.44	-5098.1	-6252.76	-7407.42	-8562.08	-9716.74	-10871.4	-12026.1
14	-37.0032	-1280.48	-2523.96	-3767.44	-5010.92	-6254.4	-7497.88	-8741.36	-9984.83	-11228.3	-12471.8
15	476.3847	-855.914	-2188.21	-3520.51	-4852.81	-6185.11	-7517.41	-8849.71	-10182	-11514.3	-12846.6
16	1066.372	-354.747	-1775.87	-3196.98	-4618.1	-6039.22	-7460.34	-8881.46	-10302.6	-11723.7	-13144.8
17	1739.085	229.1468	-1280.79	-2790.73	-4300.67	-5810.61	-7320.55	-8830.48	-10340.4	-11850.4	-13360.3
18	2501.144	902.3859	-696.373	-2295.13	-3893.89	-5492.65	-7091.41	-8690.17	-10288.9	-11887.7	-13486.4
19	3359.696	1672.118	-15.4609	-1703.04	-3390.62	-5078.2	-6765.77	-8453.35	-10140.9	-11828.5	-13516.1
20	4322.46	2546.061	769.6629	-1006.74	-2783.13	-4559.53	-6335.93	-8112.33	-9888.73	-11665.1	-13441.5
21	5397.772	3532.554	1667.336	-197.882	-2063.1	-3928.32	-5793.54	-7658.76	-9523.97	-11389.2	-13254.4
22	6594.638	4640.6	2686.562	732.5236	-1221.51	-3175.55	-5129.59	-7083.63	-9037.67	-10991.7	-12945.7
23	7922.781	5879.923	3837.065	1794.207	-248.651	-2291.51	-4334.37	-6377.23	-8420.08	-10462.9	-12505.8
24	9392.704	7261.026	5129.348	2997.669	865.9914	-1265.69	-3397.36	-5529.04	-7660.72	-9792.4	-11924.1
25	11015.75	8795.25	6574.752	4354.254	2133.756	-86.7421	-2307.24	-4527.74	-6748.24	-8968.73	-11189.2

Table 5.28 Variations in Annual Energy Costs at Different Energy Cost Escalation Rates

	Annual Energy Savings at Different Energy Cost Escalation Rates										
yr.	0.00%	1.40%	2.80%	4.20%	5.60%	7.00%	8.40%	9.80%	11.20%	12.60%	14.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	332.64	337.30	341.95	346.61	351.27	355.92	360.58	365.24	369.90	374.55	379.21
2	332.64	342.02	351.53	361.17	370.94	380.84	390.87	401.03	411.32	421.75	432.30
3	332.64	346.81	361.37	376.34	391.71	407.50	423.70	440.33	457.39	474.89	492.82
4	332.64	351.66	371.49	392.14	413.65	436.02	459.29	483.49	508.62	534.72	561.82
5	332.64	356.59	381.89	408.61	436.81	466.54	497.88	530.87	565.59	602.10	640.47
6	332.64	361.58	392.58	425.78	461.27	499.20	539.70	582.89	628.93	677.96	730.14
7	332.64	366.64	403.58	443.66	487.10	534.15	585.03	640.02	699.37	763.38	832.35
8	332.64	371.77	414.88	462.29	514.38	571.54	634.17	702.74	777.70	859.57	948.88
9	332.64	376.98	426.49	481.71	543.19	611.55	687.45	771.61	864.80	967.88	1081.73
10	332.64	382.26	438.44	501.94	573.61	654.35	745.19	847.22	961.66	1089.83	1233.17
11	332.64	387.61	450.71	523.02	605.73	700.16	807.79	930.25	1069.37	1227.15	1405.81
12	332.64	393.03	463.33	544.99	639.65	749.17	875.64	1021.42	1189.14	1381.77	1602.63
13	332.64	398.54	476.30	567.88	675.47	801.61	949.19	1121.51	1322.32	1555.87	1827.00
14	332.64	404.12	489.64	591.73	713.30	857.72	1028.93	1231.42	1470.42	1751.91	2082.78
15	332.64	409.77	503.35	616.58	753.24	917.76	1115.36	1352.10	1635.11	1972.65	2374.36
16	332.64	415.51	517.45	642.48	795.42	982.01	1209.05	1484.61	1818.24	2221.21	2706.77
17	332.64	421.33	531.93	669.46	839.96	1050.75	1310.61	1630.10	2021.88	2501.08	3085.72
18	332.64	427.23	546.83	697.58	887.00	1124.30	1420.70	1789.85	2248.33	2816.21	3517.72
19	332.64	433.21	562.14	726.88	936.67	1203.00	1540.04	1965.26	2500.15	3171.06	4010.21
20	332.64	439.27	577.88	757.41	989.13	1287.21	1669.40	2157.85	2780.16	3570.61	4571.63
21	332.64	445.42	594.06	789.22	1044.52	1377.32	1809.63	2369.32	3091.54	4020.51	5211.66
22	332.64	451.66	610.69	822.36	1103.01	1473.73	1961.64	2601.51	3437.79	4527.09	5941.30
23	332.64	457.98	627.79	856.90	1164.78	1576.89	2126.41	2856.46	3822.83	5097.50	6773.08
24	332.64	464.39	645.37	892.89	1230.01	1687.27	2305.03	3136.39	4250.98	5739.79	7721.31
25	332.64	470.89	663.44	930.40	1298.89	1805.38	2498.66	3443.76	4727.09	6463.00	8802.29

Table 5.29 Annual Cash Flows Considering Variations in Energy Cost Escalation Rate

	Cash Flows at Different Energy Cost Escalation Rates										
yr.	0.00%	1.40%	2.80%	4.20%	5.60%	7.00%	8.40%	9.80%	11.20%	12.60%	14.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-588.82	-584.17	-579.51	-574.85	-570.20	-565.54	-560.88	-556.22	-551.57	-546.91	-542.25
2	-591.48	-582.11	-572.60	-562.96	-553.19	-543.28	-533.25	-523.09	-512.80	-502.38	-491.83
3	-594.36	-580.19	-565.63	-550.66	-535.29	-519.50	-503.29	-486.67	-469.61	-452.11	-434.18
4	-597.46	-578.44	-558.61	-537.96	-516.46	-494.08	-470.81	-446.62	-421.48	-395.38	-368.29
5	-600.81	-576.87	-551.56	-524.84	-496.64	-466.91	-435.58	-402.59	-367.87	-331.36	-292.98
6	-604.43	-575.50	-544.49	-511.30	-475.80	-437.87	-397.38	-354.18	-308.14	-259.11	-206.94
7	-608.34	-574.34	-537.41	-497.33	-453.88	-406.84	-355.95	-300.97	-241.61	-177.60	-108.63
8	-612.57	-573.43	-530.33	-482.92	-430.83	-373.67	-311.03	-242.47	-167.51	-85.64	3.68
9	-617.13	-572.79	-523.27	-468.06	-406.58	-338.22	-262.32	-178.16	-84.96	18.11	131.96
10	-622.05	-572.44	-516.26	-452.75	-381.09	-300.34	-209.50	-107.47	6.97	135.13	278.48
11	-627.37	-572.41	-509.30	-436.99	-354.29	-259.86	-152.23	-29.76	109.35	267.13	445.80
12	-633.12	-572.73	-502.43	-420.77	-326.11	-216.59	-90.12	55.66	223.38	416.01	636.87
13	-2352.69	-2286.79	-2209.02	-2117.45	-2009.86	-1883.72	-1736.13	-1563.81	-1363.01	-1129.46	-858.33
14	-646.02	-574.55	-489.02	-386.94	-265.37	-120.94	50.26	252.76	491.76	773.25	1104.11
15	-653.26	-576.13	-482.55	-369.32	-232.66	-68.14	129.45	366.20	649.21	986.75	1388.46
16	-661.08	-578.21	-476.27	-351.24	-198.30	-11.71	215.33	490.89	824.52	1227.49	1713.06
17	-669.52	-580.83	-470.23	-332.70	-162.19	48.59	308.45	627.94	1019.72	1498.92	2083.56
18	-678.64	-584.05	-464.45	-313.70	-124.27	113.02	409.42	778.57	1237.06	1804.94	2506.45
19	-688.48	-587.92	-458.98	-294.25	-84.45	181.88	518.91	944.13	1479.02	2149.93	2989.08
20	-699.12	-592.48	-453.88	-274.35	-42.63	255.46	637.64	1126.09	1748.41	2538.85	3539.88
21	-710.60	-597.82	-449.18	-254.02	1.28	334.08	766.39	1326.08	2048.30	2977.26	4168.42
22	-723.00	-603.99	-444.95	-233.28	47.37	418.08	905.99	1545.87	2382.15	3471.44	4885.65
23	-736.40	-611.06	-441.25	-212.14	95.74	507.85	1057.37	1787.42	2753.79	4028.46	5704.04
24	-750.87	-619.11	-438.14	-190.61	146.50	603.76	1221.53	2052.89	3167.48	4656.28	6637.80
25	-766.49	-628.24	-435.69	-168.74	199.76	706.25	1399.52	2344.63	3627.96	5363.87	7703.16

Table 5.30 Cumulative Cash Flows Considering Variations in Energy Cost Escalation Rate

	Cumulative Cash Flows at Different Energy Cost Escalation Rates										
yr.	0.00%	1.40%	2.80%	4.20%	5.60%	7.00%	8.40%	9.80%	11.20%	12.60%	14.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-588.82	-584.17	-579.51	-574.85	-570.20	-565.54	-560.88	-556.22	-551.57	-546.91	-542.25
2	-1180.31	-1166.27	-1152.10	-1137.81	-1123.38	-1108.82	-1094.14	-1079.32	-1064.37	-1049.29	-1034.08
3	-1774.67	-1746.46	-1717.73	-1688.47	-1658.67	-1628.32	-1597.43	-1565.98	-1533.97	-1501.40	-1468.26
4	-2372.13	-2324.90	-2276.34	-2226.43	-2175.12	-2122.40	-2068.24	-2012.60	-1955.46	-1896.78	-1836.54
5	-2972.94	-2901.77	-2827.91	-2751.27	-2671.77	-2589.31	-2503.82	-2415.19	-2323.32	-2228.14	-2129.53
6	-3577.38	-3477.27	-3372.40	-3262.57	-3147.57	-3027.18	-2901.19	-2769.37	-2631.47	-2487.25	-2336.47
7	-4185.72	-4051.61	-3909.81	-3759.89	-3601.45	-3434.02	-3257.15	-3070.34	-2873.08	-2664.85	-2445.10
8	-4798.29	-4625.05	-4440.14	-4242.81	-4032.27	-3807.69	-3568.18	-3312.81	-3040.59	-2750.49	-2441.42
9	-5415.42	-5197.84	-4963.41	-4710.87	-4438.86	-4145.92	-3830.50	-3490.97	-3125.55	-2732.38	-2309.46
10	-6037.47	-5770.28	-5479.67	-5163.62	-4819.94	-4446.26	-4040.01	-3598.44	-3118.59	-2597.25	-2030.99
11	-6664.85	-6342.68	-5988.97	-5600.62	-5174.23	-4706.11	-4192.23	-3628.20	-3009.23	-2330.11	-1585.18
12	-7297.97	-6915.41	-6491.40	-6021.39	-5500.34	-4922.70	-4282.35	-3572.55	-2785.85	-1914.10	-948.32
13	-9650.65	-9202.20	-8700.42	-8138.84	-7510.20	-6806.42	-6018.49	-5136.36	-4148.86	-3043.56	-1806.65
14	-10296.68	-9776.75	-9189.44	-8525.77	-7775.57	-6927.36	-5968.22	-4883.60	-3657.10	-2270.31	-702.54
15	-10949.94	-10352.87	-9672.00	-8895.09	-8008.23	-6995.50	-5838.77	-4517.40	-3007.90	-1283.56	685.93
16	-11611.02	-10931.08	-10148.27	-9246.33	-8206.53	-7007.21	-5623.44	-4026.51	-2183.38	-56.08	2398.98
17	-12280.54	-11511.91	-10618.49	-9579.03	-8368.72	-6958.62	-5314.99	-3398.57	-1163.65	1442.84	4482.55
18	-12959.17	-12095.97	-11082.94	-9892.73	-8492.99	-6845.59	-4905.57	-2620.00	73.40	3247.78	6988.99
19	-13647.66	-12683.88	-11541.93	-10186.98	-8577.44	-6663.72	-4386.66	-1675.86	1552.43	5397.71	9978.08
20	-14346.77	-13276.37	-11995.81	-10461.33	-8620.07	-6408.26	-3749.02	-549.77	3300.83	7936.56	13517.95
21	-15057.37	-13874.19	-12444.99	-10715.35	-8618.79	-6074.19	-2982.63	776.31	5349.13	10913.83	17686.38
22	-15780.38	-14478.17	-12889.94	-10948.63	-8571.42	-5656.10	-2076.64	2322.18	7731.28	14385.27	22572.03
23	-16516.78	-15089.23	-13331.19	-11160.77	-8475.68	-5148.25	-1019.26	4109.60	10485.07	18413.73	28276.06
24	-17267.65	-15708.35	-13769.32	-11351.38	-8329.18	-4544.49	202.26	6162.48	13652.54	23070.01	34913.87
25	-18034.14	-16336.58	-14205.01	-11520.12	-8129.42	-3838.24	1601.79	8507.11	17280.50	28433.88	42617.02

Table 5.31 Annual Debt Payments Considering Variations in Debt Term

	Anual Payments at Different Debt Terms										
yr.	0	2.5	5	7.5	10	12.5	15	17.5	20	22.5	25
0	-9090	0	0	0	0	0	0	0	0	0	0
1	0	-4187.88	-2306.73	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
2	0	-4187.88	-2306.73	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
3	0	0	-2306.73	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
4	0	0	-2306.73	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
5	0	0	-2306.73	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
6	0	0	0	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
7	0	0	0	-1688.29	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
8	0	0	0	0	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
9	0	0	0	0	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
10	0	0	0	0	-1385.39	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
11	0	0	0	0	0	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
12	0	0	0	0	0	-1208.56	-1094.622	-1016.47	-960.549	-919.302	-888.199
13	0	0	0	0	0	0	-1094.622	-1016.47	-960.549	-919.302	-888.199
14	0	0	0	0	0	0	-1094.622	-1016.47	-960.549	-919.302	-888.199
15	0	0	0	0	0	0	-1094.622	-1016.47	-960.549	-919.302	-888.199
16	0	0	0	0	0	0	0	-1016.47	-960.549	-919.302	-888.199
17	0	0	0	0	0	0	0	-1016.47	-960.549	-919.302	-888.199
18	0	0	0	0	0	0	0	0	-960.549	-919.302	-888.199
19	0	0	0	0	0	0	0	0	-960.549	-919.302	-888.199
20	0	0	0	0	0	0	0	0	-960.549	-919.302	-888.199
21	0	0	0	0	0	0	0	0	0	-919.302	-888.199
22	0	0	0	0	0	0	0	0	0	-919.302	-888.199
23	0	0	0	0	0	0	0	0	0	0	-888.199
24	0	0	0	0	0	0	0	0	0	0	-888.199
25	0	0	0	0	0	0	0	0	0	0	-888.199

Table 5.32 Cash Flows Considering Variations in Debt Term

	Cash Flows for Different Debt Terms										
yr.	0	2.5	5	7.5	10	12.5	15	17.5	20	22.5	25
0	-9,090.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	325.9872	-3861.89	-1980.74	-1362.3	-1059.4	-882.572	-768.635	-690.486	-634.562	-593.315	-562.212
2	352.0662	-3835.81	-1954.66	-1336.22	-1033.32	-856.493	-742.556	-664.407	-608.483	-567.236	-536.133
3	380.2315	380.2315	-1926.5	-1308.06	-1005.15	-828.328	-714.391	-636.242	-580.318	-539.071	-507.968
4	410.65	410.65	-1896.08	-1277.64	-974.736	-797.909	-683.972	-605.824	-549.899	-508.652	-477.549
5	443.502	443.502	-1863.23	-1244.78	-941.884	-765.057	-651.12	-572.972	-517.047	-475.8	-444.697
6	478.9821	478.9821	478.9821	-1209.3	-906.404	-729.577	-615.64	-537.491	-481.567	-440.32	-409.217
7	517.3007	517.3007	517.3007	-1170.99	-868.085	-691.259	-577.321	-499.173	-443.248	-402.002	-370.898
8	558.6848	558.6848	558.6848	558.6848	-826.701	-649.875	-535.937	-457.789	-401.864	-360.618	-329.514
9	603.3796	603.3796	603.3796	603.3796	-782.006	-605.18	-491.242	-413.094	-357.17	-315.923	-284.82
10	651.6499	651.6499	651.6499	651.6499	-733.736	-556.91	-442.972	-364.824	-308.899	-267.653	-236.549
11	703.7819	703.7819	703.7819	703.7819	703.7819	-504.778	-390.84	-312.692	-256.767	-215.521	-184.417
12	760.0845	760.0845	760.0845	760.0845	760.0845	-448.475	-334.538	-256.389	-200.465	-159.218	-128.115
13	-892.472	-892.472	-892.472	-892.472	-892.472	-892.472	-1987.09	-1908.95	-1853.02	-1811.77	-1780.67
14	886.5625	886.5625	886.5625	886.5625	886.5625	886.5625	-208.059	-129.911	-73.9866	-32.7399	-1.63667
15	957.4875	957.4875	957.4875	957.4875	957.4875	957.4875	-137.134	-58.986	-3.06163	38.18508	69.28833
16	1034.087	1034.087	1034.087	1034.087	1034.087	1034.087	1034.087	17.61297	73.53737	114.7841	145.8873
17	1116.813	1116.813	1116.813	1116.813	1116.813	1116.813	1116.813	100.3399	156.2643	197.511	228.6143
18	1206.159	1206.159	1206.159	1206.159	1206.159	1206.159	1206.159	1206.159	245.6094	286.8561	317.9593
19	1302.651	1302.651	1302.651	1302.651	1302.651	1302.651	1302.651	1302.651	342.1021	383.3488	414.452
20	1406.863	1406.863	1406.863	1406.863	1406.863	1406.863	1406.863	1406.863	446.3141	487.5609	518.6641
21	1519.412	1519.412	1519.412	1519.412	1519.412	1519.412	1519.412	1519.412	1519.412	600.1099	631.2132
22	1640.965	1640.965	1640.965	1640.965	1640.965	1640.965	1640.965	1640.965	1640.965	721.6629	752.7662
23	1772.243	1772.243	1772.243	1772.243	1772.243	1772.243	1772.243	1772.243	1772.243	1772.243	884.0434
24	1914.022	1914.022	1914.022	1914.022	1914.022	1914.022	1914.022	1914.022	1914.022	1914.022	1025.823
25	2067.144	2067.144	2067.144	2067.144	2067.144	2067.144	2067.144	2067.144	2067.144	2067.144	1178.945

Table 5.33 Cumulative Cash Flows Considering Variations in Debt Term

	Cumulative Cash Flows for Different Debt Terms										
yr.	0	2.5	5	7.5	10	12.5	15	17.5	20	22.5	25
0	-9090	0	0	0	0	0	0	0	0	0	0
1	-8764.01	-3861.89	-1980.74	-1362.3	-1059.4	-882.572	-768.635	-690.486	-634.562	-593.315	-562.212
2	-8411.95	-7697.7	-3935.41	-2698.52	-2092.72	-1739.07	-1511.19	-1354.89	-1243.04	-1160.55	-1098.35
3	-8031.72	-7317.47	-5861.91	-4006.57	-3097.87	-2567.39	-2225.58	-1991.14	-1823.36	-1699.62	-1606.31
4	-7621.07	-6906.82	-7757.99	-5284.21	-4072.61	-3365.3	-2909.55	-2596.96	-2373.26	-2208.27	-2083.86
5	-7177.56	-6463.32	-9621.22	-6529	-5014.49	-4130.36	-3560.67	-3169.93	-2890.31	-2684.08	-2528.56
6	-6698.58	-5984.33	-9142.23	-7738.3	-5920.9	-4859.94	-4176.31	-3707.42	-3371.88	-3124.4	-2937.78
7	-6181.28	-5467.03	-8624.93	-8909.29	-6788.98	-5551.2	-4753.63	-4206.6	-3815.12	-3526.4	-3308.67
8	-5622.6	-4908.35	-8066.25	-8350.6	-7615.68	-6201.07	-5289.57	-4664.38	-4216.99	-3887.02	-3638.19
9	-5019.22	-4304.97	-7462.87	-7747.22	-8397.69	-6806.25	-5780.81	-5077.48	-4574.16	-4202.94	-3923.01
10	-4367.57	-3653.32	-6811.22	-7095.57	-9131.43	-7363.16	-6223.79	-5442.3	-4883.06	-4470.59	-4159.56
11	-3663.78	-2949.54	-6107.44	-6391.79	-8427.64	-7867.94	-6614.63	-5754.99	-5139.82	-4686.11	-4343.98
12	-2903.7	-2189.45	-5347.35	-5631.71	-7667.56	-8316.41	-6949.16	-6011.38	-5340.29	-4845.33	-4472.09
13	-3796.17	-3081.93	-6239.82	-6524.18	-8560.03	-9208.88	-8936.26	-7920.33	-7193.31	-6657.1	-6252.76
14	-2909.61	-2195.36	-5353.26	-5637.61	-7673.47	-8322.32	-9144.32	-8050.24	-7267.3	-6689.84	-6254.4
15	-1952.12	-1237.88	-4395.77	-4680.13	-6715.98	-7364.83	-9281.45	-8109.22	-7270.36	-6651.66	-6185.11
16	-918.035	-203.789	-3361.69	-3646.04	-5681.9	-6330.75	-8247.36	-8091.61	-7196.82	-6536.87	-6039.22
17	198.7786	913.0249	-2244.87	-2529.23	-4565.08	-5213.93	-7130.55	-7991.27	-7040.56	-6339.36	-5810.61
18	1404.937	2119.183	-1038.72	-1323.07	-3358.92	-4007.78	-5924.39	-6785.11	-6794.95	-6052.51	-5492.65
19	2707.588	3421.835	263.9349	-20.4176	-2056.27	-2705.13	-4621.74	-5482.46	-6452.85	-5669.16	-5078.2
20	4114.452	4828.698	1670.798	1386.446	-649.409	-1298.26	-3214.88	-4075.6	-6006.53	-5181.6	-4559.53
21	5633.864	6348.11	3190.211	2905.858	870.0036	221.1505	-1695.47	-2556.19	-4487.12	-4581.49	-3928.32
22	7274.829	7989.076	4831.176	4546.823	2510.969	1862.116	-54.5005	-915.221	-2846.15	-3859.82	-3175.55
23	9047.072	9761.318	6603.419	6319.066	4283.212	3634.358	1717.742	857.0215	-1073.91	-2087.58	-2291.51
24	10961.09	11675.34	8517.441	8233.088	6197.234	5548.38	3631.764	2771.043	840.1108	-173.56	-1265.69
25	13028.24	13742.48	10584.58	10300.23	8264.377	7615.524	5698.908	4838.187	2907.255	1893.584	-86.7421

Table 5.34 Annual Debt Payments Considering Variations in Interest Rate

	Annual Payments at Different Interest Rates										
yr.	0.00%	1.70%	3.40%	5.10%	6.80%	8.50%	9.80%	11.10%	12.40%	13.70%	15.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
2	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
3	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
4	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
5	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
6	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
7	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
8	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
9	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
10	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
11	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
12	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
13	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
14	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
15	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
16	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
17	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
18	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
19	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
20	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
21	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
22	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
23	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
24	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22
25	-363.60	-449.36	-545.56	-651.44	-766.02	-888.20	-986.07	-1,087.24	-1,191.26	-1,297.71	-1,406.22

Table 5.35 Annual Cash Flows Considering Variations in Interest Rate

	Cash Flow Variations at Different Interest Rates										
yr.	0.00%	1.70%	3.40%	5.10%	6.80%	8.50%	9.80%	11.10%	12.40%	13.70%	15.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-37.61	-123.37	-219.57	-325.45	-440.03	-562.21	-660.08	-761.25	-865.27	-971.72	-1,080.23
2	-11.53	-97.29	-193.49	-299.37	-413.95	-536.13	-634.00	-735.17	-839.19	-945.64	-1,054.15
3	16.63	-69.13	-165.33	-271.21	-385.78	-507.97	-605.83	-707.01	-811.03	-917.48	-1,025.99
4	47.05	-38.71	-134.91	-240.79	-355.37	-477.55	-575.42	-676.59	-780.61	-887.06	-995.57
5	79.90	-5.86	-102.06	-207.94	-322.51	-444.70	-542.56	-643.74	-747.76	-854.21	-962.72
6	115.38	29.62	-66.58	-172.46	-287.03	-409.22	-507.08	-608.26	-712.28	-818.73	-927.24
7	153.70	67.94	-28.26	-134.14	-248.72	-370.90	-468.77	-569.94	-673.96	-780.41	-888.92
8	195.08	109.33	13.13	-92.75	-207.33	-329.51	-427.38	-528.55	-632.57	-739.03	-847.53
9	239.78	154.02	57.82	-48.06	-162.64	-284.82	-382.69	-483.86	-587.88	-694.33	-802.84
10	288.05	202.29	106.09	0.21	-114.37	-236.55	-334.42	-435.59	-539.61	-646.06	-754.57
11	340.18	254.42	158.22	52.34	-62.23	-184.42	-282.28	-383.46	-487.48	-593.93	-702.44
12	396.48	310.73	214.53	108.65	-5.93	-128.11	-225.98	-327.15	-431.17	-537.63	-646.13
13	-1,256.07	-1,341.83	-1,438.03	-1,543.91	-1,658.49	-1,780.67	-1,878.54	-1,979.71	-2,083.73	-2,190.18	-2,298.69
14	522.96	437.20	341.00	235.13	120.55	-1.64	-99.50	-200.68	-304.70	-411.15	-519.66
15	593.89	508.13	411.93	306.05	191.47	69.29	-28.58	-129.75	-233.77	-340.22	-448.73
16	670.49	584.73	488.53	382.65	268.07	145.89	48.02	-53.15	-157.17	-263.62	-372.13
17	753.21	667.46	571.26	465.38	350.80	228.61	130.75	29.58	-74.45	-180.90	-289.40
18	842.56	756.80	660.60	554.72	440.14	317.96	220.09	118.92	14.90	-91.55	-200.06
19	939.05	853.29	757.09	651.21	536.64	414.45	316.59	215.41	111.39	4.94	-103.57
20	1,043.26	957.51	861.31	755.43	640.85	518.66	420.80	319.63	215.60	109.15	0.65
21	1,155.81	1,070.05	973.85	867.98	753.40	631.21	533.35	432.17	328.15	221.70	113.19
22	1,277.37	1,191.61	1,095.41	989.53	874.95	752.77	654.90	553.73	449.71	343.26	234.75
23	1,408.64	1,322.88	1,226.68	1,120.81	1,006.23	884.04	786.18	685.00	580.98	474.53	366.03
24	1,550.42	1,464.66	1,368.46	1,262.58	1,148.01	1,025.82	927.96	826.78	722.76	616.31	507.80
25	1,703.54	1,617.79	1,521.59	1,415.71	1,301.13	1,178.94	1,081.08	979.91	875.89	769.43	660.93

Table 5.36 Cumulative Cash Flows Considering Variations in Debt Interest Rate

	Cumulative Cash Flow Variations at Different Interest Rates										
yr.	0.00%	1.70%	3.40%	5.10%	6.80%	8.50%	9.80%	11.10%	12.40%	13.70%	15.00%
0	0	0	0	0	0	0	0	0	0	0	0
1	-37.6128	-123.371	-219.571	-325.45	-440.029	-562.212	-660.079	-761.251	-865.271	-971.723	-1080.23
2	-49.1466	-220.662	-413.063	-624.821	-853.979	-1098.35	-1294.08	-1496.42	-1704.46	-1917.37	-2134.38
3	-32.5152	-289.789	-578.389	-896.027	-1239.76	-1606.31	-1899.91	-2203.43	-2515.49	-2834.85	-3160.37
4	14.53483	-328.497	-713.297	-1136.81	-1595.13	-2083.86	-2475.33	-2880.02	-3296.1	-3721.91	-4155.94
5	94.43682	-334.352	-815.353	-1344.75	-1917.64	-2528.56	-3017.89	-3523.75	-4043.86	-4576.11	-5118.65
6	209.819	-304.728	-881.929	-1517.2	-2204.68	-2937.78	-3524.98	-4132.01	-4756.13	-5394.84	-6045.89
7	363.5197	-236.785	-910.186	-1651.34	-2453.39	-3308.67	-3993.74	-4701.95	-5430.09	-6175.25	-6934.8
8	558.6045	-127.458	-897.059	-1744.09	-2660.72	-3638.19	-4421.12	-5230.5	-6062.66	-6914.28	-7782.34
9	798.384	26.56329	-839.238	-1792.15	-2823.36	-3923.01	-4803.81	-5714.36	-6650.54	-7608.61	-8585.17
10	1086.434	228.8553	-733.146	-1791.94	-2937.73	-4159.56	-5138.23	-6149.95	-7190.15	-8254.67	-9339.74
11	1426.616	483.2794	-574.922	-1739.59	-2999.96	-4343.98	-5420.51	-6533.4	-7677.63	-8848.59	-10042.2
12	1823.1	794.006	-360.396	-1630.95	-3005.89	-4472.09	-5646.49	-6860.56	-8108.8	-9386.22	-10688.3
13	567.0286	-547.824	-1798.43	-3174.85	-4664.38	-6252.76	-7525.03	-8840.27	-10192.5	-11576.4	-12987
14	1089.991	-110.619	-1457.42	-2939.73	-4543.83	-6254.4	-7624.54	-9040.94	-10497.2	-11987.5	-13506.7
15	1683.879	397.5108	-1045.49	-2633.68	-4352.36	-6185.11	-7653.11	-9170.69	-10731	-12327.8	-13955.4
16	2354.365	982.2394	-556.963	-2251.03	-4084.29	-6039.22	-7605.09	-9223.84	-10888.2	-12591.4	-14327.5
17	3107.579	1649.695	14.29283	-1785.65	-3733.49	-5810.61	-7474.35	-9194.27	-10962.6	-12772.3	-14616.9
18	3950.137	2406.496	674.8934	-1230.93	-3293.35	-5492.65	-7254.25	-9075.35	-10947.7	-12863.8	-14817
19	4889.188	3259.789	1431.987	-579.718	-2756.72	-5078.2	-6937.67	-8859.93	-10836.3	-12858.9	-14920.5
20	5932.452	4217.294	2293.292	175.7085	-2115.87	-4559.53	-6516.87	-8540.31	-10620.7	-12749.7	-14919.9
21	7088.264	5287.349	3267.146	1043.684	-1362.47	-3928.32	-5983.53	-8108.13	-10292.6	-12528	-14806.7
22	8365.629	6478.956	4362.554	2033.212	-487.523	-3175.55	-5328.63	-7554.41	-9842.86	-12184.8	-14572
23	9774.272	7801.841	5589.238	3154.017	518.703	-2291.51	-4542.45	-6869.4	-9261.87	-11710.3	-14205.9
24	11324.69	9266.505	6957.702	4416.602	1666.709	-1265.69	-3614.49	-6042.62	-8539.11	-11093.9	-13698.1
25	13028.24	10884.29	8479.288	5832.309	2967.837	-86.7421	-2533.42	-5062.71	-7663.23	-10324.5	-13037.2

Table 5.37 Annual Energy Savings Considering Variations in Energy Cost or Energy Production

	Effects of Energy Cost or Energy Production Variations										
yr.	25.00%	20.00%	15.00%	10.00%	5.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	269.44	287.40	305.36	323.33	341.29	359.25	377.21	395.18	413.14	431.10	449.06
2	290.99	310.39	329.79	349.19	368.59	387.99	407.39	426.79	446.19	465.59	484.99
3	314.27	335.22	356.18	377.13	398.08	419.03	439.98	460.93	481.89	502.84	523.79
4	339.41	362.04	384.67	407.30	429.93	452.55	475.18	497.81	520.44	543.06	565.69
5	366.57	391.01	415.44	439.88	464.32	488.76	513.20	537.63	562.07	586.51	610.95
6	395.89	422.29	448.68	475.07	501.46	527.86	554.25	580.64	607.04	633.43	659.82
7	427.56	456.07	484.57	513.08	541.58	570.09	598.59	627.10	655.60	684.10	712.61
8	461.77	492.55	523.34	554.12	584.91	615.69	646.48	677.26	708.05	738.83	769.62
9	498.71	531.96	565.21	598.45	631.70	664.95	698.20	731.44	764.69	797.94	831.19
10	538.61	574.52	610.42	646.33	682.24	718.14	754.05	789.96	825.87	861.77	897.68
11	581.70	620.48	659.26	698.04	736.82	775.60	814.38	853.16	891.94	930.72	969.50
12	628.23	670.12	712.00	753.88	795.76	837.64	879.53	921.41	963.29	1,005.17	1,047.06
13	678.49	723.72	768.96	814.19	859.42	904.66	949.89	995.12	1,040.35	1,085.59	1,130.82
14	732.77	781.62	830.47	879.33	928.18	977.03	1,025.88	1,074.73	1,123.58	1,172.43	1,221.29
15	791.39	844.15	896.91	949.67	1,002.43	1,055.19	1,107.95	1,160.71	1,213.47	1,266.23	1,318.99
16	854.70	911.68	968.66	1,025.65	1,082.63	1,139.61	1,196.59	1,253.57	1,310.55	1,367.53	1,424.51
17	923.08	984.62	1,046.16	1,107.70	1,169.24	1,230.77	1,292.31	1,353.85	1,415.39	1,476.93	1,538.47
18	996.93	1,063.39	1,129.85	1,196.31	1,262.77	1,329.24	1,395.70	1,462.16	1,528.62	1,595.08	1,661.54
19	1,076.68	1,148.46	1,220.24	1,292.02	1,363.80	1,435.57	1,507.35	1,579.13	1,650.91	1,722.69	1,794.47
20	1,162.82	1,240.34	1,317.86	1,395.38	1,472.90	1,550.42	1,627.94	1,705.46	1,782.98	1,860.50	1,938.03
21	1,255.84	1,339.56	1,423.29	1,507.01	1,590.73	1,674.45	1,758.18	1,841.90	1,925.62	2,009.35	2,093.07
22	1,356.31	1,446.73	1,537.15	1,627.57	1,717.99	1,808.41	1,898.83	1,989.25	2,079.67	2,170.09	2,260.51
23	1,464.81	1,562.47	1,660.12	1,757.78	1,855.43	1,953.08	2,050.74	2,148.39	2,246.05	2,343.70	2,441.35
24	1,582.00	1,687.46	1,792.93	1,898.40	2,003.86	2,109.33	2,214.80	2,320.26	2,425.73	2,531.20	2,636.66
25	1,708.56	1,822.46	1,936.37	2,050.27	2,164.17	2,278.08	2,391.98	2,505.88	2,619.79	2,733.69	2,847.60

Table 5.38 Cash Flows Considering Variations in Energy Cost or Energy Production

	Cash Flows due to Energy Cost or Energy Production Variations										
yr.	25.00%	20.00%	15.00%	10.00%	5.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	-652.02	-634.06	-616.10	-598.14	-580.17	-562.21	-544.25	-526.29	-508.32	-490.36	-472.40
2	-633.13	-613.73	-594.33	-574.93	-555.53	-536.13	-516.73	-497.33	-477.93	-458.53	-439.14
3	-612.73	-591.77	-570.82	-549.87	-528.92	-507.97	-487.02	-466.06	-445.11	-424.16	-403.21
4	-590.69	-568.06	-545.43	-522.80	-500.18	-477.55	-454.92	-432.29	-409.67	-387.04	-364.41
5	-566.89	-542.45	-518.01	-493.57	-469.14	-444.70	-420.26	-395.82	-371.38	-346.95	-322.51
6	-541.18	-514.79	-488.40	-462.00	-435.61	-409.22	-382.82	-356.43	-330.04	-303.65	-277.25
7	-513.42	-484.92	-456.41	-427.91	-399.40	-370.90	-342.39	-313.89	-285.39	-256.88	-228.38
8	-483.44	-452.65	-421.87	-391.08	-360.30	-329.51	-298.73	-267.95	-237.16	-206.38	-175.59
9	-451.06	-417.81	-384.56	-351.31	-318.07	-284.82	-251.57	-218.32	-185.08	-151.83	-118.58
10	-416.09	-380.18	-344.27	-308.36	-272.46	-236.55	-200.64	-164.73	-128.83	-92.92	-57.01
11	-378.32	-339.54	-300.76	-261.98	-223.20	-184.42	-145.64	-106.86	-68.08	-29.30	9.48
12	-337.53	-295.64	-253.76	-211.88	-170.00	-128.11	-86.23	-44.35	-2.47	39.41	81.30
13	-2,006.83	-1,961.60	-1,916.37	-1,871.14	-1,825.90	-1,780.67	-1,735.44	-1,690.21	-1,644.97	-1,599.74	-1,554.51
14	-245.89	-197.04	-148.19	-99.34	-50.49	-1.64	47.21	96.07	144.92	193.77	242.62
15	-194.51	-141.75	-88.99	-36.23	16.53	69.29	122.05	174.81	227.57	280.33	333.09
16	-139.01	-82.03	-25.05	31.93	88.91	145.89	202.87	259.85	316.83	373.81	430.79
17	-79.08	-17.54	44.00	105.54	167.08	228.61	290.15	351.69	413.23	474.77	536.31
18	-14.35	52.11	118.57	185.04	251.50	317.96	384.42	450.88	517.34	583.81	650.27
19	55.56	127.34	199.12	270.89	342.67	414.45	486.23	558.01	629.79	701.57	773.35
20	131.06	208.58	286.10	363.62	441.14	518.66	596.19	673.71	751.23	828.75	906.27
21	212.60	296.32	380.05	463.77	547.49	631.21	714.94	798.66	882.38	966.10	1,049.83
22	300.66	391.08	481.50	571.93	662.35	752.77	843.19	933.61	1,024.03	1,114.45	1,204.87
23	395.77	493.43	591.08	688.74	786.39	884.04	981.70	1,079.35	1,177.01	1,274.66	1,372.31
24	498.49	603.96	709.42	814.89	920.36	1,025.82	1,131.29	1,236.76	1,342.22	1,447.69	1,553.16
25	609.43	723.33	837.23	951.14	1,065.04	1,178.94	1,292.85	1,406.75	1,520.66	1,634.56	1,748.46

Table 5.39 Cumulative Cash Flows Considering Variations in Energy Cost or Energy Production

	Cumulative Cash Flows due to Energy Cost or Energy Production Variations										
yr.	25.00%	20.00%	15.00%	10.00%	5.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
0	0	0	0	0	0	0	0	0	0	0	0
1	-652.025	-634.062	-616.1	-598.137	-580.175	-562.212	-544.249	-526.287	-508.324	-490.362	-472.399
2	-1285.16	-1247.79	-1210.43	-1173.07	-1135.71	-1098.35	-1060.98	-1023.62	-986.259	-948.897	-911.534
3	-1897.88	-1839.57	-1781.25	-1722.94	-1664.63	-1606.31	-1548	-1489.69	-1431.37	-1373.06	-1314.74
4	-2488.57	-2407.63	-2326.69	-2245.74	-2164.8	-2083.86	-2002.92	-1921.98	-1841.04	-1760.1	-1679.16
5	-3055.46	-2950.08	-2844.7	-2739.32	-2633.94	-2528.56	-2423.18	-2317.8	-2212.42	-2107.04	-2001.66
6	-3596.64	-3464.86	-3333.09	-3201.32	-3069.55	-2937.78	-2806	-2674.23	-2542.46	-2410.69	-2278.92
7	-4110.06	-3949.78	-3789.5	-3629.23	-3468.95	-3308.67	-3148.4	-2988.12	-2827.85	-2667.57	-2507.29
8	-4593.49	-4402.43	-4211.37	-4020.31	-3829.25	-3638.19	-3447.13	-3256.07	-3065.01	-2873.94	-2682.88
9	-5044.55	-4820.24	-4595.93	-4371.63	-4147.32	-3923.01	-3698.7	-3474.39	-3250.08	-3025.77	-2801.47
10	-5460.64	-5200.42	-4940.21	-4679.99	-4419.77	-4159.56	-3899.34	-3639.13	-3378.91	-3118.7	-2858.48
11	-5838.95	-5539.96	-5240.96	-4941.97	-4642.97	-4343.98	-4044.98	-3745.98	-3446.99	-3147.99	-2849
12	-6176.48	-5835.6	-5494.72	-5153.85	-4812.97	-4472.09	-4131.21	-3790.33	-3449.46	-3108.58	-2767.7
13	-8183.31	-7797.2	-7411.09	-7024.98	-6638.87	-6252.76	-5866.65	-5480.54	-5094.43	-4708.32	-4322.21
14	-8429.21	-7994.25	-7559.28	-7124.32	-6689.36	-6254.4	-5819.44	-5384.47	-4949.51	-4514.55	-4079.59
15	-8623.72	-8136	-7648.27	-7160.55	-6672.83	-6185.11	-5697.39	-5209.67	-4721.94	-4234.22	-3746.5
16	-8762.73	-8218.03	-7673.33	-7128.63	-6583.92	-6039.22	-5494.52	-4949.82	-4405.12	-3860.41	-3315.71
17	-8841.81	-8235.57	-7629.33	-7023.09	-6416.85	-5810.61	-5204.37	-4598.13	-3991.89	-3385.65	-2779.41
18	-8856.16	-8183.46	-7510.76	-6838.05	-6165.35	-5492.65	-4819.95	-4147.24	-3474.54	-2801.84	-2129.14
19	-8800.6	-8056.12	-7311.64	-6567.16	-5822.68	-5078.2	-4333.72	-3589.23	-2844.75	-2100.27	-1355.79
20	-8669.54	-7847.54	-7025.54	-6203.54	-5381.53	-4559.53	-3737.53	-2915.53	-2093.53	-1271.52	-449.522
21	-8456.94	-7551.22	-6645.49	-5739.77	-4834.04	-3928.32	-3022.59	-2116.87	-1211.14	-305.42	600.3047
22	-8156.28	-7160.13	-6163.99	-5167.84	-4171.7	-3175.55	-2179.41	-1183.26	-187.117	809.0283	1805.174
23	-7760.51	-6666.71	-5572.91	-4479.11	-3385.31	-2291.51	-1197.71	-103.911	989.8889	2083.688	3177.488
24	-7262.02	-6062.75	-4863.48	-3664.22	-2464.95	-1265.69	-66.4207	1132.845	2332.111	3531.377	4730.643
25	-6652.59	-5339.42	-4026.25	-2713.08	-1399.91	-86.7421	1226.428	2539.598	3852.767	5165.937	6479.107

The following observations correspond to the results shown above:

1. The base case assumptions do not reflect immediate savings or grid parity. The yearly costs associated with the PV system are more than the expected savings during the first half of the project life. The annual savings are considerably greater on the second half of the project. It is interesting to notice that in base case conditions the cumulative cash flows are not far from reaching zero before the end of the project lifetime, even when conservative assumptions have been made. Cumulative cash flows would be shifted one year in favor of the owner if inverter replacements costs are halved, current projections indicate that this could be the case by the time the inverter replacement is needed. The results could be much better if system size is increased hence reducing the estimated annual O&M costs per kW which are dominated by the required insurance. We have chosen to use a 25 year life for the project to match typical manufacturer warranties. PV modules can have life times of over 50 years, the potential long range benefits are evident from the results provided in this analysis. Under the base case conditions the use of PV technology could be considered a better choice over regular utility service on the long term. The lack of immediate savings or grid parity suggest that only wealthier clients that are able to overcome the additional operational expenses during the first half of the project life will invest in such technology. The allowed tax credits could help shift the possible market for this technology. The current law governing PV tax credits allows the flexibility of dividing the allowed tax credits over a period of up to ten years, allowing the owner to use the credit in a manner that best suits its interests. The credit has the potential to completely damp the additional yearly costs associated with the PV system for approximately five years of operation and reducing the energy payback period by 4 years if a 25% credit is awarded. Cost damping for ten years is possible if a 50% credit is awarded; in this case cumulative cash flows would only be negative for eight years after the inverter is replaced (unless inverter costs are successfully lowered).

2. The effects of capital cost variations are considered in Table 5.25 to Table 5.27. The effects of deviations of up to 50% in initial capital costs have been determined. Capital costs up to 20% less than those used in the base case analysis could be expected for small systems (e.g. residential or small commercial). Capital costs below 20% of the base case costs could be expected for large systems or large volume clients (e.g. industrial, large commercial, utility and developers). Capital costs larger than the base case capital costs could represent installations using energy storage or custom modules or installations. According to the results, a reduction of 50% of base case initial capital costs will still require the system owner to incur in excess annual costs for the first 5 years of system operation. In this case the 25% tax credit could damp all excess costs. It is interesting to notice that systems in the residential/small commercial capital cost range have payback periods smaller than the project life span although a conservative energy cost escalation rate has been used.

3. The energy cost escalation rate has a very marked effect on the economic feasibility of grid-tied PV systems. This determines the possible energy related savings a system owner will have while operating a PV system within his facilities. A larger escalation rate will improve the system's payback period by increasing the annual potential savings for the system owner. As can be seen in Table 5.28 to Table 5.30, a small increment in the escalation improves considerably the energy payback period. The energy cost escalation rate was chosen to be equal to the actual inflation rate to obtain conservative results, current energy escalation rates are much larger and lower capital costs per kW could be expected for all installation types hence improving the feasibility of the project. Table 5.24 displays energy cost escalation rates for customers in the island. If the current escalation rates are maintained PV systems should become a very attractive option in the island. Residential customers suffer from the worst energy escalation rate and have the largest roof resource available. Commercial and industrial customers have the capital cost advantage and an almost equally impressive energy cost escalation rate. It is interesting to notice that if energy escalation rates are maintained, the current allowed tax credits will no longer be necessary for potential customers to find PV systems in parity to utility service during the whole project life span in less than 10 years for some customers.

4. Debt Term has effects on both the annual cash flows and the cumulative cash flows. Shorter debt terms improve the payback period of the investment yet annual debt payments increase. Long debt terms have longer payback periods and annual payments decrease, hence potential system owners might prefer long debt terms to maintain annual payments lower. The allowed tax credits would easily damp the net payments during a portion of the system's lifetime before savings are larger than payments. Long term debt payments are typical for energy generation systems at a large scale. Residential customers could take advantage of house mortgages. Government offices could establish special financing programs as well. Smaller systems may be easily financed in short terms, where capital costs are comparable to those of an automobile, yet the allowed tax credits will not be able to damp system costs. As has been previously discussed, PV systems are a good investment when long term operation is expected. The tax credits could allow customers to operate close to grid parity during the net cost period of the project's life, yet the required financial commitment limits the potential market for these systems in the island.

5. The future of energy price in Puerto Rico is quite uncertain. Table 5.40 summarizes the electrical energy generation mix distribution for the local electrical grid. Until very recently, fossil fuels dominated the past, present and future electrical energy supply. PREPA recently announced plans of incorporating 20% of renewable energy generation in the island. This new generation capacity is expected mostly in wind parks. The expected effect of adding the new renewable generation capacity on the price of energy has not been published,

yet a sharp decrease in energy prices should not be expected in the following 7 years. The worst case for system payback has energy cost escalation rate slowing down as the generation moves away from petroleum based fuels, yet the fists years of operating costs will still be damped by a higher initial energy cost escalation rate and the allowed tax credits (if applicable).

Table 5.40 Puerto Rican Generation Mix

Fuel	Pre-2007	2007	2010	2015 (spring 2008)	2015 (summer 2008)
Petroleum Derivates	68%	73.1%	49.7%	32%	-
Coal	15%	13.6%	12.3%	32%	-
Natural Gas	17%	12.8%	37.5%	33%	-
Renewable	<1%	<1%	<1%	2%	20%

This section has attempted to investigate the financial feasibility of grid-tied PV systems. The current financial and climatic conditions in the island may permit this technology to become a competitive option in the island for client owned systems. PV systems are a long term commitment, and may be feasible in the island without the need of additional incentives. The available tax credits combined with the current energy escalation rates allow owners to operate at or near grid parity during the first years of debt improving the feasibility of these systems in the island, yet the technology costs have not lowered enough to permit a general market entrance. Utility systems may require additional incentives in order for this technology to become feasible. The analysis presented in this section does not consider externalities such as the social and environmental costs incurred in the use of fossil fuel technologies because the Puerto Rican society lacks a standardized method to study these variables. Potential system owners may be influenced by these variables in the future due to recent climate concerns and the possibility of creating a positive corporate image. Some countries have adopted emissions reduction markets which allow customers to obtain and trade emissions reduction credits. The creation of such a market in the island provides would have interesting effects on the way energy systems are planned and managed. PV systems have the potential to limit the cash flows to foreign oil interests and to limit the global warming potential in the island, while creating permanent employment for Puerto Ricans.

5.4 Grid-Interconnection Issues

It is commonly said that distributed generation (DG) in all its forms can have very positive effects on a distribution network, yet it could completely change the way distribution networks are operated and designed. Distribution networks are commonly designed for radial operation, hence power flows are only expected in one direction and the voltage profile can be easily described (lower voltages are expected as the electrical distance from the source increases). The incorporation of a new technology into a utility grid will always introduce new challenges for distribution engineers, yet countries like Germany and Denmark have already proved it is possible to integrate 20% of renewable capacity (mainly wind and solar) into their electrical grids in a safe manner. PV systems are of particular interest because of the random nature of irradiance patterns and the lack of rotating parts which allow almost instantaneous response to network events or irradiance variations. Among the possible DG benefits we may find:

→ Demand Reduction

→ Reduced Equipment Loading

→ Higher Efficiency

→ Economic Savings

→ Fuel Savings

→ Emissions Curtailment

→ Efficient Use of Space

The real benefits obtained will depend on the proper planning and incorporation of the new technology. It is therefore of great importance to understand the characteristics of a renewable resource in order to predict the possible effects that different renewable energy technologies will have on distribution networks. The effects of PV generation on a distribution system can be divided broadly in two categories:

1. **Issues related to irradiance variations**: One of the most challenging aspects of PV distributed generation is the proper management of the intermittent solar resource. PV output capacity will depend on the available solar resource at a given instant which depends on a number of stochastic

parameters like cloud cover, dust and contamination and it will also depend on the patterns established by the earth's orbit around the sun and the rotation on its own axis. Irradiance variations will affect the effective demand (or load) on a distribution feeder hence affecting the voltage profile, power flows and generator outputs. The effects of irradiance variations are really a concern when large amounts PV penetration are present in a single area; otherwise power output variations have similar effect to normal system load variations and can be ignored. Determining the threshold for PV penetration is not a trivial task and will depend on the expected correlation between load and solar resource, the installed PV capacity, the geographic dispersion of PV systems within the system, and the dynamic response capabilities of network components including generation control equipment. Limits are usually expressed as a ratio between maximum load and installed PV capacity. This practice is correct as long as the system planner understands that the PV rated capacity is not always available, and in some cases never reached. The system area extension is determined depending on the problem that needs to be addressed. Usually limits can be established at the feeder level to reduce the probability of overvoltage conditions and unwanted reverse power flows, while avoiding investment in network improvements. Overvoltage conditions will arise when low effective load conditions are present (PV injected power reduces feeder load below its minimum design limit). This problem could be of more importance in highly loaded feeders or rural feeders which are serviced by a multiple tap substation transformer whose tap has been set to raise the feeder voltage at nominal condition. In these cases the tap can only be set manually and would require the disconnection of the transformer to reset the tap. Resetting the transformer is not a practical solution, because it means a possible service interruption and it only solves the problem during periods of high solar irradiance. Some feeders may also have equipment like voltage regulators and capacitor banks to improve voltage quality. These devices have mechanical systems which permit the modification of operating conditions, usually using automated monitoring systems. These mechanical devices could expect an increase in operations decreasing their lifetime due to the mechanical stress associated with each operation. DG systems are also required to disconnect when abnormal voltage conditions are present, hence an over voltage or under voltage condition in the feeder might cause the disconnection of generation capacity that is operating properly limiting system output and creating sudden considerable load increments in a feeder. The daily variations in solar irradiance could also create reverse flows in sub-transmission networks that could cause the miss operation of protection relays. Limits established at the system level will usually be determined by the ability of generator control equipment to follow sharp variations in solar irradiance. The generator control equipment will sense these variations as sudden variations in load and will try to increase or decrease their rotor speeds. If these load variations are very large and not properly followed by the generators they may cause system stability issues. The ability of a generator to follow these load changes is called the ramping rate. The ramping rate will depend on the generators size and the fuel used to move the rotors. Currently natural gas generators with very fast ramping rates are available but are more expensive to operate hence only used by utilities at certain times when large system load peaks are expected. With fast machines present, a large amount PV penetration could be permitted as long as the ramping rates allow the worst case load change. It has been shown that PV systems can lower utility operating costs while the generators are able to follow the effective load changes. Utilities prefer to limit penetration at the point that operational costs are increased. Clear and overcast sky conditions tend to have less effect on system conditions than partly cloudy days where irradiance may dramatically increase or decrease almost instantaneously. The effects of resource variations will not have significant effects unless a large amount of PV penetration is installed in a given system. Central PV systems make distribution network conditions more dependent on the specific irradiance conditions at the facility's location, a sharp decrease or increase in irradiance will mean a sharp increase or decrease of injected power at the point of common coupling between the generation facility and the distribution network. Dispersed central PV systems of similar aggregated capacity will have less effect on the distribution network because a damping effect is created by the cloud conditions at different locations. Small residential and commercial distributed PV DG systems can be installed with great flexibility in almost any location; the resulting dispersion effect could help increase the maximum allowable capacity within a system. An alternative to limiting PV penetration in a feeder is energy storage. Storage technology could be used to damp the effects of instantaneous variation in solar irradiance intensity, hence permitting increased PV penetration levels in a given feeder or system.

2. **Issues related to Power Conditioning or Grid Interconnection Device** – It is often said that the success of a distributed energy resource will depend mostly on the power conditioning used. The DC output current of the solar module array has to be transformed to AC current and synchronized to grid conditions in order to be useful and safe to the distribution system. Most of the available devices rely on high power semiconductor technology to perform this task. It is important to understand that no device is able to perfectly convert energy from one form to another, yet a set of minimum requirements can be pre-determined to guarantee compatibility between the PV system and the local distribution network. Standards have been created that specify the minimum operational requirements for grid interconnection equipment. The IEEE 1547 is one such standard. This standard unifies the requirements for different interconnection technologies in one universal document. Following standard guidelines guarantees system designers that the equipments chosen will not have negative impact on the distribution system (or will at least maintain negative impacts within a tolerable margin).

The most important requirements are discussed in detail in the PV inverter section of this document. The issues to consider from a distribution system operation perspective are:

→ Harmonics- These are parasitic currents and voltages at frequencies different than the fundamental system frequency (50Hz in Europe or 60Hz in America) that are commonly created by non-linear loads or power electronic equipment such as the inverters used to convert DC currents to AC currents in PV systems. The frequencies are typically multiples of the fundamental frequency, hence the term harmonics. These are a normal and necessary by-product of power electronic energy conversion equipment, yet the harmonic content of equipment output currents can be minimized using appropriate switching frequencies and filtering networks.

→ Islanding- This happens when a section of the distribution network is disconnected from the utility network due to abnormal operating conditions, but a DG continues to unintentionally feed current to the network. This can cause a safety hazard to maintenance personnel servicing the faulted section and could cause damage to DG and sensitive loads. The probability that an event like this happens for an extended period of time with PV inverters is quite small due to the required protection functions for these devices, and the ideal load to generator conditions that must exist for the island to remain energized.

→ Fault Current Contribution- The IEEE 1547 sets the operational requirements for grid-tied inverters under fault conditions, yet inverters that follow the standard may still contribute fault currents to the distribution network for small time frames. Fault contributions by inverters are typically of very short duration and limited to twice the rated current capacity due to internal protection functions. These currents could increase the required instantaneous short-circuit withstand capability of some distribution equipment and may interfere with reclosing protection schemes and protection device coordination time.

→ Synchronization-The DG system should not actively regulate the voltage profile, hence power factors close to 1 are necessary. The DG should act as a current source hence the operating voltage must match the grid voltage in phase and magnitude.

The development and use of proper system planning techniques is of great importance to guarantee the safe and reliable operation of a power system, yet it is equally important to follow proper methods when designing and constructing the PV system. The incorrect use of PV equipment could tarnish the reputation of renewable energy technology; hence only qualified engineers or technicians should design and install them. The improper matching of PV components could cause the malfunction of otherwise good components. Often grid-tied inverters are matched with undersized or oversized PV arrays reducing or impeding the expected power outputs. Inverters should be sized considering the loading and fault current limits of distribution system equipment like: transformers, cables, switches and fuses. The behavior of grid-tied inverters under fault conditions is discussed in the PV inverter section of this document.

5.5 Concluding Remarks

Photovoltaic systems can have a dramatic impact at the residential level in Puerto Rico. During the day, enough electrical energy can be generated to displace fossil-fuel based generation equivalent to the residential load using dispersed residential PV systems. Irradiance variations not a big issue for dispersed PV systems. However, due to stringent land use limitations, it is not recommended to use land in PR for large PV arrays.

PV grid interconnection issues are a widely studied field. Several references regarding the operational characteristics of PV DG equipment have already been provided throughout this chapter. A sample of literature dealing with some PV DG grid-interconnection issues at a system level is provided in [85]-[89]. The operational limits are dependent on the utility's particular operating region. In Puerto Rico, where we have an abundant solar energy resource, the question should be not how to best integrate that resource into the existing energy infrastructures, but how the latter should change or transition in order to make way for the maximum penetration possible (technologically, economically and socially) of solar and other renewable sources.

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