

A DECISION MAKING TOOL FOR ASSESSING GRID ELECTRIFICATION  
VERSUS STAND-ALONE POWER SUPPLY OPTIONS FOR REMOTE USERS

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DECLARATION

I declare that this dissertation is my own, original work. It is being submitted in partial fulfillment for the degree of Master of Science in Energy Engineering at the University of Cape Town. It has not previously been submitted at any other university for degree or examination purposes.

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.27..day of *October*....., 19.89.

## ABSTRACT

The objective of this study is to compile a micro-computer based tool to aid in the evaluation of power supply options for remote sites. The options considered are stand-alone photovoltaic, diesel generation, and grid extension power supplies.

The basis on which the various options are compared is the unit cost of energy expected from the system. This is determined by combining all capital costs, running costs, and other payments on a present value basis over the project lifetime.

The comparison of the unit energy cost expected from each option is only meaningful if the reliability of each supply system is known. The Loss of Energy Probability of each option is therefore established to provide a common ground on which to compare these costs.

For each power supply option it was therefore necessary to establish a sizing methodology to result in a system of known reliability, and then to cost the system over the project life, to provide a unit energy cost supplied by the option.

Because of the variability in insolation patterns, sizing a stand-alone photovoltaic system to provide power of known reliability must include information on insolation distribution. A number of potentially suitable stand-alone photovoltaic system sizing methods were reviewed, and the method found to be most suited for use in the comparison tool was one developed at the University of Cape Town. The internationally available methods that were reviewed were found to either be based on flawed assumptions, or to contain assumptions not necessarily accurate in local conditions.

The diesel generation power supply sizing and costing methodology was established, and it was found necessary to include the average set capacity factor in the costing procedure, due to its significant effect on energy costs. A typical Loss of Energy Probability value for diesel generation was also determined.

The grid extension costing procedure and supply reliability was established, and the sizing and costing methodologies for the three options combined in the computer package.

Using the package it was then possible to establish the main energy cost determinants of each option, and therefore draw conclusions regarding the situations where each option is likely to provide an economical power supply. The package also was used to provide information on possible methods of optimizing energy costs from each option, and to examine the energy cost sensitivity to various factors such as component price changes and technological improvements.

Finally, the limitations of the comparison tool are pointed out. Amongst these are the inaccuracies resulting from the many generalizations made in the package, and the restriction of attention to the "cost of energy" criterion in power supply system assessment.

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GLOSSARY

AC - Alternating current

**Average Capacity Factor** - The average of the instantaneous capacity factors taken over a time period, typically one day. May also be expressed as the energy supplied by a power source divided by the energy able to be supplied by the source over the given time period.

**Autonomy** - Number of consecutive days of independent energy supply provided by a system without any energy input.

**Average Daily Energy Demand** - The total energy used per day, averaged over an extended time period

**Capacity Factor** - The actual power drawn from the power source divided by the power able to be supplied by it.

**Converter** - Unit that draws DC power at constant voltage and modifies voltage as required by the demand. Output to the demand is also DC.

DC - Direct current

**Diffuse Radiation** - solar radiation which is scattered in transmission through the atmosphere.

**ESKOM** - Electricity Supply Commission, the South African electricity supply utility.

**Genset** - Engine and generator set.

**Grid** - The national electricity distribution network.

**Insolation** - Solar radiation, usually measured in watts/sq.m

**Inverter** - Unit that converts DC supply at a range of voltages (typically from photovoltaic panels) to AC supply at the voltage required by the demand.

**kW** - Kilowatt, unit of power

**kWh** - Kilowatt-hour, unit of energy.  $1\text{kWh} = 3.6 \text{ MJ}$

**Life Cycle Cost** - an estimate of the total cost of owning and operating an energy supply system over the period of its useful life, usually expressed as a net present value.

Load - Power being demanded, measured in kW.

Load Factor - The average load divided by the peak load.

LOEP - Loss of Energy Probability

Loss of Energy Probability - The probability that the system will be unable to supply energy on a given day. A value of 0.01 therefore indicates that on a given day there is a 1 : 100 chance that the system will be unavailable, or that the system will be down 1 out of 100 days.

Maximum Power Point Tracker - Device that modifies the voltage-current relationship delivered by the array such that the array is continually operating at its maximum power output.

Optimum Power Loss Factor - A factor included in photovoltaic sizing procedures for systems without optimum power tracking, to include the effects of the array operating away from its optimum power point.

Optimum Power Tracking - A system that includes optimum power tracking uses a device such as the Maximum Power Point Tracker to maintain optimum array power output. See Maximum Power Point Tracker for further details

Peak Load - The highest load required of a power source

Peak Watt - The maximum power output of a photovoltaic module under standard conditions of 1000 W/sq.m and 25<sup>0</sup>C.

Photovoltaic - Device that converts solar radiation into DC electricity using the photo-electric effect

Photovoltaic Array - A set of photovoltaic modules or panels

Photovoltaic Module - A photovoltaic unit or panel

Power Factor - The dimensionless ratio of actual AC power (kW) to apparent power (kVA)

Power Tracking - See Optimum Power Tracking

PV - Photovoltaic

Radiation - Solar radiation, usually measured in watts/sq.m

Regulator - See voltage regulator

Run-time - (Used with respect to diesel generation) Time per day for which the diesel generator is run.

**SAPV - Stand-alone Photovoltaic system**

**SOC - State of charge, referring to storage batteries**

**Stand-alone Photovoltaic System -** A photovoltaic system, including energy storage and power conditioning, able to supply specified loads, either DC or AC, without any power being supplemented from another source.

**Tracking array -** Photovoltaic array that moves so as to keep its surface normal to the sun's rays

**Voltage Regulator -** Used in photovoltaic systems. Prevents excessive draining of the storage batteries by shedding the load at the set voltage, and prevents battery overcharging by disconnecting or regulating the supply at set voltages.

**Worst-month -** Month of worst average insolation. Array tilt angles are often set to optimize the worst-month insolation.



CHAPTER 1

INTRODUCTION

## 1 INTRODUCTION

At present, the national electricity supply grid, although extensive, has not reached a large proportion of the country's population. Eskom (1987) has recently estimated that over 20 million people live in non-electrified households throughout South Africa, and a survey carried out in 1987 (Williams, 1988,p7) indicates that there are about 15000 commercial farms not connected to the Eskom national electricity supply grid, many of which rely on an alternative electricity supply source. Another estimate, by Dingley (1988,p6), gives the number of un-electrified households in underdeveloped areas as 3.2 million, spread approximately evenly between peri-urban and rural areas. The overall situation, therefore, is that large numbers of people rely on a source other than grid electrification for their energy requirements.

The most desirable from amongst the choices of available energy sources has been found to be electricity in the majority of cases. It is also the best energy source in terms of expanding the productive opportunities of a society, and therefore stimulating its development. Having a reliable supply of electricity means having the ability to use the wide variety of electrical appliances and machinery available on the market. Electricity usually means improved lighting, presenting the opportunity for night study, TV, and other night-time recreational and educative activities. It can thus have a significant effect on the welfare of a community.

It can be expected that, as South Africa develops and its population increases, a growing number of individuals and communities will be seeking a reliable electricity supply source. Indeed Eskom is paying increasing attention to the electrification of rural areas, and is making its power more accessible in

presently off-grid situations. This has meant that users for whom it was previously too expensive to receive grid power, may now consider it as a viable option.

In un-electrified urban and peri-urban areas, grid electrification is likely to prove the most viable option for power. Here grid extension and connection fees are not as high as areas more remote from the grid, and grid electrification is inevitable at some stage in the future. Since other power options often only make economic sense if used for extended periods of time (as with photovoltaics), they may be uneconomic in areas where grid electrification is to be installed within their service life, as is the case for some peri-urban and urban areas.

The further one moves from the national grid, however, the more competitive other power supply options become. Thus rural schools, clinics and small businesses requiring electricity, may be in a situation where a number of alternative supply sources could be viable.

At present, large numbers of off-grid power users rely on diesel generation for electricity (such as commercial farms and rural hospitals), but rising fuel prices and the decreasing price of other power supply options, for example photovoltaics, has caused alternative energy sources to become more competitive. A potential power user is now faced with a choice between various alternative sources, including grid power, all of which may be feasible.

In general, as prices stand at present, stand alone photovoltaic systems tend to be more economic than diesel generation for smaller energy demands, while for large demands, diesel gensets become increasingly viable (E.R.I., 1989). This situation, however, may vary with a number of factors, such as

the peak demand, the genset capacity factor, and the shape of the demand profile. Grid extension power cost, on the other hand, depends on factors such as the distance from the grid, the type of terrain to be covered by the extension, and the demand characteristics.

Many factors, therefore, need to be considered in deciding on an appropriate power supply. However, persons needing to make the choice seldom have access to the information needed for the evaluation, and there are few advisers available in the field.

There is therefore a need to provide some kind of assistance to those wishing to evaluate power supply options to determine the most viable option in a specific situation. This project will provide this assistance by constructing a micro-computer based tool that will take into account as many as possible of the factors that influence the decision-making process, thereby enabling more accurate decisions to be made. The tool will be designed for use by those having only a basic knowledge of the supply options to be considered, and who have access to a micro-computer.

The various power supply options which may be compared include grid electrification, diesel generation, photovoltaic power, wind generation, micro-hydro power, and hybrid systems such as diesel/battery and diesel/photovoltaic. This thesis will only deal with grid electrification, diesel generation, and photovoltaic power, these being the most commonly used alternatives in South Africa.

To assess the viability of the various power supply sources, it is necessary to determine the cost of energy from each option. It is therefore first necessary to size each particular option according to the energy requirements of the user, and then the costs of each system can be assessed. To do this the initial

capital outlay must be combined with any operating and maintenance costs over the system lifetime to give an estimate of the average cost of power from each option.

Because the comparison procedure outlined above requires information to enable each particular system to be sized (including solar radiation data in the case of photovoltaics), and detailed information of the costs of the various components of each system, it is not the kind of operation that potential users, or those wishing to advise them, could be expected to carry out without considerable research. There is therefore a need to combine all of this information, together with compatible sizing techniques for the various options, into one easy-to-use package, accessible to, and usable by, those wishing to undertake the comparison, for example regional electrical utility officials or photovoltaic dealers.

The more detailed the information concerning the load demand characteristics, physical environment, and general power-user requirements, the more accurate will be the power costing procedure. However, detailed information may not be readily available to the person assessing the viability of the various options, and so it is necessary to restrict the information required to that which is more easily acquired by the assessor. Although this involves some sacrifice in the accuracy of the power cost estimates, it is necessary to maintain the general usefulness of the comparison package, and it would still fulfill its purpose of providing a reliable guide to the viability of the various options.

The comparison package, therefore, would be used by persons not necessarily having knowledge about system sizing procedures, and having basic information about the energy demand and physical environment of the site for which the comparison is being done. The person would then use this information to obtain an

estimate of the power costs for the alternatives being compared. Should the person then wish to see the effects of changing one of the input variables, for example the average energy demanded, the operation would then be repeated using the new demand data. Thus a sensitivity analysis could be performed.

To be able to compare these options realistically, it is necessary to have some basis on which to compare their reliability. The probability of diesel genset failure, for example, should therefore be comparable to that of Eskom power failure and PV system loss of power due to breakdown or insufficient insolation. This situation where the load demanded is unable to be supplied for one reason or another is called 'Loss of Energy'. The probability of this occurrence is the 'Loss of Energy Probability' (LOEP). The comparison procedure, therefore, should compare options of known LOEP in order that the costs of power determined for each option be an indicator of its viability.

In practice the determination and use of LOEP values is complex. The reliability of a diesel genset, for example, depends largely on how it is treated by its owner. Regular servicing will increase its reliability, as will careful management of the load drawn from the genset. The diesel genset LOEP therefore can only be an estimate based on common practice of genset owners. By changing the system size, photovoltaic power supply may be designed for a range of LOEP values, the larger the system to supply a given demand, the more reliable it will be. The reliability of grid power, on the other hand may be regarded as fixed, and is typically close to 100%.

To be able to design systems of the required LOEP it may be necessary to provide energy storage, as is the case with PV systems. Because the PV system output depends on the insolation level, which varies considerably, it is necessary to pro-

vide storage to be able to meet the energy demand at daytime when the insolation is insufficient, and at night. The storage would then absorb the excess energy when insolation levels are high, and be able to release it in times of poor or zero insolation. Thus if the PV array and storage sizes are chosen correctly, the system could provide the level of reliability desired.

There are various stand alone photovoltaic (SAPV) sizing methods which allow for the choice of array and storage sizes in order to provide a specified LOEP, but since such methods are of unproven reliability and untested in local conditions, it is first necessary to review them in order to assess their suitability for use in the comparison package. The first part of the thesis is therefore devoted to this analysis.

The comparison of the various power supply options is based on the cost of power from each option. To calculate this, it is necessary to know the size of each system necessary to meet the load demand for a certain level of reliability. Therefore to go about the compilation of such a comparison package, first a method of sizing the various alternatives for a specified level of reliability must be determined, and then the systems must be costed to find the overall price of power per kWh, and the systems compared on this basis. This, then, is the order in which the work in this thesis is undertaken :

CHAPTER 2 : The available photovoltaic sizing methods are reviewed, and their results compared, in order to find the one most suited for use in this project, and the chosen method adapted and extended as required.

CHAPTER 3 : A suitable diesel generator sizing and costing methodology is established.

CHAPTER 4 : The procedure for costing power from extending the grid is then determined.

At this stage the above sizing and costing methodologies are combined in a micro-computer program.

CHAPTER 5 : The computer package is briefly described.

CHAPTER 6 : The comparison program is then used to generate typical results for a variety of circumstances.

CHAPTER 7 : The results generated, and the comparison package in general, are then discussed. General trends in the viability of the various power supply options are examined, as are the limitations and uses of the package. Possible areas in which additional research is required are also mentioned.



CHAPTER 2

REVIEW OF STAND-ALONE PHOTOVOLTAIC

SIZING METHODOLOGIES

## 2 REVIEW OF STAND-ALONE PHOTOVOLTAIC SIZING METHODOLOGIES

### 2.1 INTRODUCTION

The purpose of reviewing various stand-alone photovoltaic (SAPV) system sizing methodologies, is to determine which is most suited to be used in this project under South African conditions. The method must also, therefore, be compatible with the sizing methodologies used for the other power alternatives considered; diesel generation and grid electrification. Since the intention is to develop a sizing aid to enable a realistic comparison of the power supply options being considered, the reliability of the various options to be compared must be compatible, as should be the levels of accuracy to which the different systems are sized.

Since the comparison package is intended for general use by persons not necessarily having detailed knowledge of the site in question, it cannot include sizing methodologies which require input of great detail, and this inevitably compromises the sizing accuracy, as mentioned in Chapter 1. The level of accuracy of the SAPV sizing method used in the project should, therefore, be as high as possible considering the limitations on the detail of input information. This should be borne in mind when the various SAPV sizing methods are reviewed.

Sizing of SAPV systems to result in a specified reliability (or LOEP) is relatively new, and available methods are largely unproven and may not be suitable for use in local conditions. It is therefore necessary to look in some depth at the various SAPV sizing methods to gain an understanding of the theory on which they are based, and thus their reliability and general suitability for use in this project.

In sizing SAPV systems to meet a certain energy demand, the problem of the variability in weather patterns arises, and thus the difficulty of predicting PV output. The simplest sizing methodologies determine the array output, using average monthly insolation figures, to match the average monthly energy demand (taking into account losses in the system). The battery storage is sized to provide power for a required number of days with zero insolation. The array and battery sizes may then be oversized by a certain percentage to give greater system reliability. These sizing techniques however, provide no indication of expected system reliability, of how many times in a year the system is expected not to be able to deliver the required energy. This not only provides no basis for comparison between these and alternative power sources, but often leads to system oversizing and thus designs which are not as cost-effective as they might be.

Hour-by-hour computer simulations of SAPV system performance using insolation data from a typical year are often used to provide a more complete model of system behavior. Many of the models for predicting the loss of energy probability (LOEP) - the probability that the system will be unable to supply the load demand at a given time - that are used in the sizing methodologies to be reviewed, have been developed using this kind of system simulation. These computer simulations are inappropriate for use in this project which needs quick but accurate estimates of system size and the optimization of system size with respect to power costs from the system.

A number of sizing methods have been developed which provide system designs for a required LOEP and allow for trade-off between battery storage size and array size to be made while maintaining the required LOEP. This provides an effective basis for the comparison of these systems with alternative power sources in that a system can be designed for the same

reliability (LOEP) as the alternative, and the storage and array size combination can be varied to achieve optimum costs for this LOEP, thus providing the cheapest power costs possible.

A review of one sizing method which does not use LOEP, and several that do, follows.

## 2.2 SIZING SAPV SYSTEMS USING "DAYS OF AUTONOMY"

This method does not use LOEP, but simply sizes the battery storage by a required number of "days of autonomy" - days without insolation, when the battery must supply all of the load. The Colorado Mountain College and the Florida Solar Energy Center are amongst those that use this method.

### 2.2.1 SUMMARY OF THE SIZING METHODOLOGY

(1) Electric load estimation: The average daily energy demand over the months of the year are used. If energy demands peak, for example seasonally, and these peaks are critical, then they should be used in place of the average energy demand in sizing the system.

(2) Battery sizing: The average energy demand per day (or peak energy demand) is multiplied by the required number of days of autonomy of the system (considering such factors as discharge limits on the battery and system efficiencies) to size the battery storage.

(3) Array sizing: The average daily energy requirement, battery efficiency, and insolation values for the month of design (the month of worst insolation to energy demand ratio) are used to determine the required array output and thus size. If insolation values on tilted surfaces provide a higher 'worst

month' insolation to energy demand ratio, these should be used and the array tilted.

### 2.2.2 DISCUSSION OF THE SIZING METHODOLOGY

Because this method uses "days of autonomy" rather than the required LOEP to size the storage, it provides no means of reliability comparison with other alternative power sources. It is thus not suited for use in this project. In addition the method appears generally coarse: The possibility of residue charge in the battery from previous months is not considered when designing the system, thus leading to probable oversizing. The fraction of the daily load supplied directly by the array is also not considered. This can lead to system oversizing of up to 25% (Borden et al., 1984, p2.11).

The sizing method is limiting in that it does not provide a range of storage size vs array size combinations and thus does not allow the designer to choose a most cost effective combination, but simply sizes the system from the 'average energy requirement' values.

The system is sized for the month of worst insolation to energy demand ratio, allowing some variation in average energy demanded over the year. Insolation data for tilted array surfaces can also be used, thus improving the design month array output.

### 2.3 R.N.CHAPMAN'S SAPV SIZING METHODOLOGY (1987)

This sizing technique can be used for any LOEP required. It is constrained to situations where the daily energy demand does not vary by more than 10% from month to month.

## 2.3.1 SUMMARY OF THE SIZING METHODOLOGY

(1) Define site and application parameters: Average daily energy demand, latitude, required LOEP, and average horizontal insolation in the design month (the month of lowest insolation - typically June in the southern hemisphere) are determined.

(2) Determine four sets of array sizes in terms of design insulations: Four different sets of nomograms and five different array tilt angles in each set ( $\text{lat}-20^{\circ}$ ,  $\text{lat}-10^{\circ}$ ,  $\text{lat}$ ,  $\text{lat}+10^{\circ}$ ,  $\text{lat}+20^{\circ}$ ) are used to determine twenty (four sets of five) different design insulations. Design insolation ( $\text{POA}_0$ ) is the average insolation necessary, per day, per square meter, to support the average energy demand (taking into account system losses). A nomogram for obtaining one design insolation in one of the four sets is shown in figure 2.1.

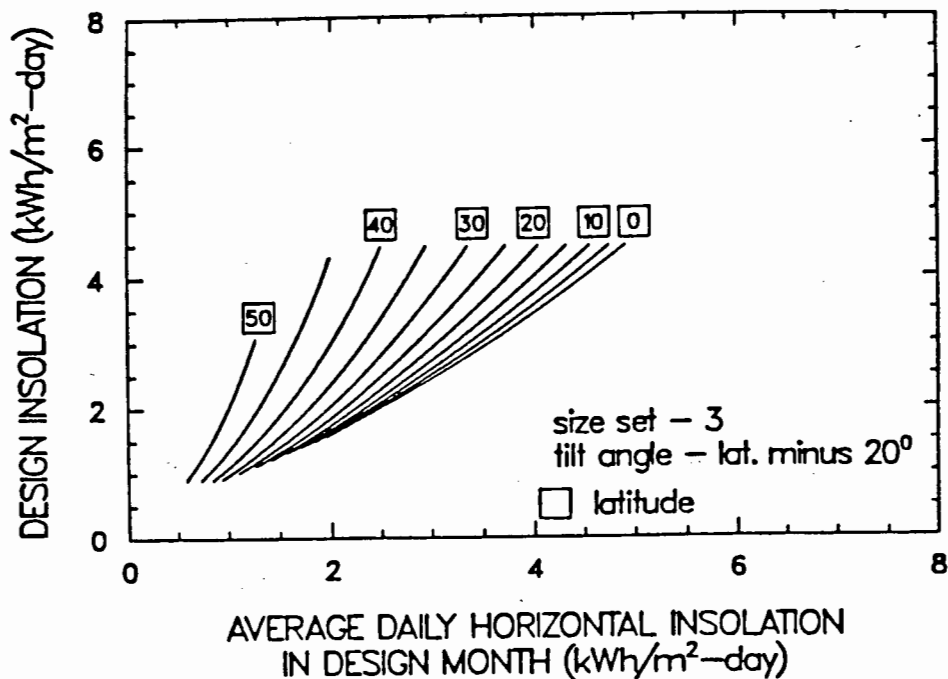


Figure 2.1 : An example of Chapman's nomograms used in system sizing. This one is for latitude minus  $20^{\circ}$  of size set 3. (Chapman, 1987, p29)

Each set of five tilt angle nomograms and one storage nomogram represent different array vs storage size combinations ranging from large array and small storage to small array and large storage, thus enabling the designer to choose the most cost effective combination for the required LOEP.

(3) Determine four storage capacities in terms of days of insolation : For each set of five tilt angle nomograms there is a LOEP vs days of storage nomogram. The one shown in figure 2.2 is for the second of the four sizing sets.

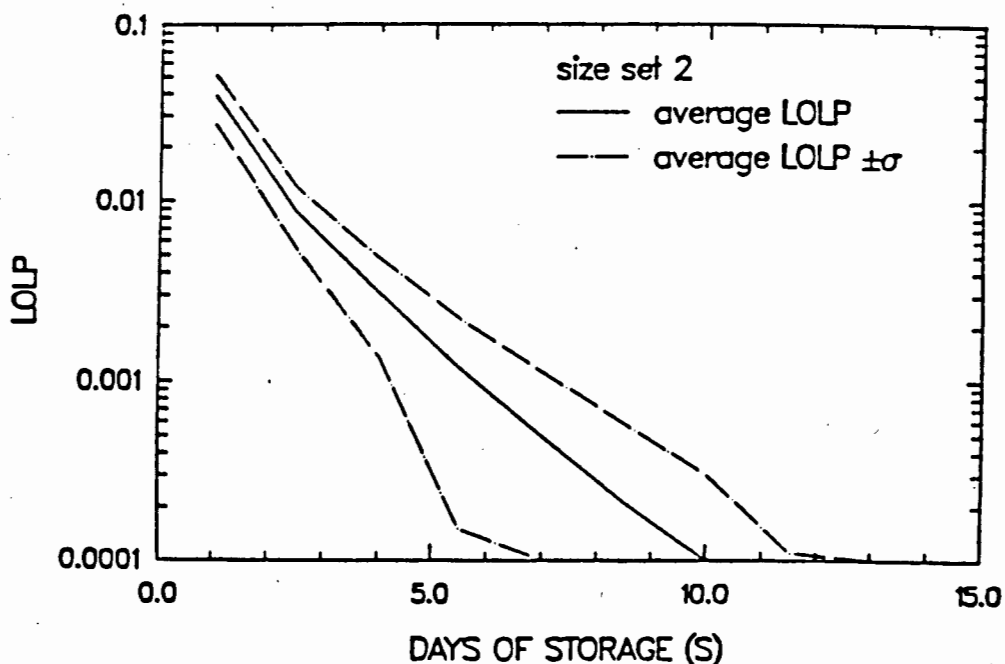


Figure 2.2 : One of the storage sizing nomograms used by Chapman (Chapman, 1987, p27)

Each set of five tilt angles will therefore have one corresponding "days of storage" value to achieve the required LOEP.

At this stage the tilt angle which yields the highest design insolation values may be selected.

(4) Determine array area and storage capacity : First it is necessary to know the insolation-to-storage efficiency ( $eff_{in}$ ), which comprises array, regulator, and battery charging efficiencies, and the storage-to-load efficiency ( $eff_{out}$ ) which comprises battery discharge and inverter efficiencies. Then the array area may be calculated for a specific design insolation using the following formula:

$$A = \text{demand} / (eff_{in} * eff_{out} * POA_0)$$

where A - array area  
 demand - energy demand (kWh)  
 $POA_0$  - design insolation (kWh/sq.m/day)

The storage capacity (CAP) may be calculated for a specific "days of storage" (S) value as follows:

$$CAP = (S * \text{demand}) / eff_{out}$$

### 2.3.2 DISCUSSION OF THE SIZING METHODOLOGY

This method results in a set of four design insolutions for the best tilt angle for the design month (the month of worst insolation) and a corresponding set of four "days of storage" values. From these, a curve may be plotted of design insolation vs "days of storage" for the required LOEP, and thus the most economical combination of array vs storage size found. Therefore, although values enabling the direct calculation of only four such combinations are found, by constructing a curve between these values a continuous range of combinations may be obtained.



By this method a SAPV system may be designed for any LOEP required, enabling the comparison between this and alternative power sources with various LOEP factors to be made.

Chapman shows that random average daily energy demand has only a small effect on system sizing, and that as long as the average daily energy use does not vary by more than 10% from month to month, the system may be accurately sized using the average daily energy demand over the year. This is a limiting constraint in that this may well vary by more than 10% over the course of the year, for example from mid-summer to mid winter, resulting in a misleading LOEP for the system. He is, however, working on a method which does away with this constraint.

It is now necessary to look at how Chapman derived the nomograms used in his sizing procedure. A SAPV hourly simulation model was developed and used as follows:

#### 2.3.2.1 The Loss of Power Simulation Model

Chapman's loss of energy (LOE) simulation model groups the PV system into three subsystems: the array, the storage, and the demand subsystems. To model the energy flow in and out of the storage subsystem he develops the equation :

$$S_i = S_{i-1} + (POA_i/POA_0) - LF_{hr}$$

where  $S_i$  - 'normalized' stored energy available for hour  $i$   
 $S_{i-1}$  - " " " " " from  
 previous hour  
 $POA_i$  - plane-of-array insolation for hour  $i$  (kWh/sq.m)  
 $POA_0$  - design insolation (kWh/sq.m)  
 $LF_{hr}$  - fraction of daily energy demand in hour  $i$

$S_i$  and  $S_{i-1}$  are fractional energy indicators and not energy quantities. They are therefore dimensionless.

One of the assumptions he makes in developing this model is that all the energy flows through the storage subsystem, enabling him to ignore the effect of hourly load variations on the system sizing (i.e. how much load is supplied directly by the array, and how much is cycled through storage). He maintains that this introduces no error into the LOEP. In practice, however, SAPV systems often demand large proportions of their load during daylight hours - when the array may supply the load directly without the energy being cycled through storage. This energy will therefore not incur battery charging and discharging losses, which can be as high as 30%. Since Chapman disregards this possibility, his sizing method can be expected to oversize systems in which the array supplies some of the load directly, and result in misleading LOEP values for such systems, contrary to his initial claim.

Running his LOE simulation model using twenty years of hourly insolation data for twenty sites, he is able to determine the number of times that the system cannot meet the load demanded, thus obtaining the long-term LOEP value for each  $POA_0$  and 'days of storage available' ( $S_0$ ) used. He is thus able to establish a relationship between  $POA_0$ ,  $S_0$ , and LOEP for each site. In other words he establishes the relationship  $LOEP = f(POA_0, S_0)$  for each site. He tests his results against the established "PVFORM" simulation program and finds the correlation between the two models to be  $\pm 50\%$ , which he regards as "within the uncertainty associated with the LOEP values given by this sizing technique" (p39). Cowan (1989), in an analysis of Chapman's work, regards this comparison with the PVFORM results as a dubious test of validity because "PVFORM was set to run for a typical residential load profile. This would increase the proportion of load outside daylight hours" (p152) and thus tend to

produce results more in line with Chapman, who assumes that all energy passes through storage. Also, both PVFORM and Chapman include the assumption of optimum power tracking, which is the control of array current and voltage output such that the power delivered is maximized. Such devices are, however, generally not justifiable in Southern Africa, and the PVFORM comparison can therefore not be regarded as testing the accuracy of Chapman's method with such systems. Chapman thus concludes that his model is accurate when correct average daily path efficiencies are used. However to obtain the correct efficiencies it may be necessary to perform a one day hourly simulation of the demand and thus obtain the average daily efficiency - a process which requires detailed system and demand knowledge which is unlikely to be at hand for the system designer, particularly in the context in which the sizing method is to be used in this project. In general, such accuracy appears inconsistent with the inaccuracies introduced by the various simplifying assumptions of the sizing technique : that all the array energy passes through storage, that the system may be sized using only a mid-winter average insolation value as sufficient an indicator of variability in insolation patterns, and that LOEP values from different sites may be approximated by one LOEP value (see later).

#### 2.3.2.2 The Generation of the Nomograms

The method used to generate the array sizing and storage sizing nomograms may be explained as follows :

For a fixed  $S_0$  value and tilt angle, the LOE simulation model is used to generate LOEP values for a range of  $POA_0$  values for each site, using the hourly SOLMET (insolation records for USA) data. For each site a function,  $LOEP = f(POA_0, S_0)$ , relating  $POA_0$ ,  $S_0$ , and LOEP, is determined using this data. Chapman then aims to find "a set of  $POA_0$  values, one for each site, so

that the deviation between LOEP curves from all twenty sites" becomes "very small" (40) using these  $POA_0$  values. He aims to correlate these  $POA_0$  values with the average mid-winter plane-of-array (POA) insolation values. The intention is to produce a storage sizing nomogram based on the  $LOEP = f(POA_0, S_0)$  relationship, that is independent of  $POA_0$  (i.e. the function effectively becomes  $LOEP = f(S_0)$ ).

To achieve this Chapman proceeds as follows: He relates the average daily plane-of-array insolation for the design month (mid-winter) to  $POA_0$  by the following polynomial:

$$POA_0 = a_0 + a_1(POA) + a_2(POA)^2 - a_3(POA)^3$$

- where POA is the average mid-winter plane-of-array insolation.

(Note: here Chapman actually uses average mid-winter horizontal insolation in order to eliminate the plane-of-array (POA) insolation as an input. This simply involves relating the average horizontal and POA insulations.)

The values  $a_0$  to  $a_3$  are chosen for each site so as to minimize the difference between all the LOEP curves between the sites - the LOEP values being derived from the  $POA_0$  values using the function  $LOEP = f(POA_0, S_0)$  established for each site. In other words, a relationship between  $POA_0$  and POA has therefore been established for each site, such that it produces a set of  $POA_0$  values from each site that result in similar LOEP curves for all the sites when these  $POA_0$  values are used.

Chapman has therefore correlated POA to  $POA_0$  in such a way that the LOEP varies significantly only with  $S_0$ , i.e.  $LOEP = f(S_0)$ . He thus produces array sizing curves ( $POA_0$  vs POA) for all sites on the same nomogram, with the different  $POA_0$  to POA cor-

relations (each for a different site) represented as sizing curves for locations of differing latitudes. He generates storage sizing curves (LOEP vs  $S_0$ ) using the function  $LOEP = f(S^0)$ .

According to Chapman, varying the tilt angle of the array had no effect on the storage sizing nomograms, therefore each set of five array sizing nomograms (for five different tilt angles) has only one storage sizing nomogram. He not only generates curves for different array tilt angles, but also gives different array vs storage size combinations for a system, so that the system designer may choose the most cost effective combination from these.

In producing such curves, however, Chapman does not state how closely he manages to fit the various LOEP curves from the different sites, he merely says that the deviation between them is "very small" (40), thus not indicating the sacrifice in accuracy necessary to generate these nomograms. Inspection of his LOEP curves does give some indication of accuracy however - the standard deviation of the fitted curves from the various sites is approximately equal to 25% of the days of storage value, 'S', given by Chapman's LOEP curves. In practical terms, this means that the LOEP curves for some of the sites could differ by about 50% (of the mean value) in days of storage required to achieve a certain LOEP - for example, one site may require 4 days storage to achieve a specific LOEP, while another site requires 6.5 days storage to achieve the same LOEP. This difference can hardly be termed "very small", and casts doubt on the accuracy of the method.

As has been shown, Chapman bases his system sizing on the insolation for the mid-winter month (June for the southern hemisphere), and has assumed that it is possible to correlate the variability of insolation to the average insolation of that

month. He bases this on evidence from, firstly, Liu & Jordan (1960), which suggests that the distribution of the daily insolation may be determined from the monthly average insolation only, irrespective of climate, and secondly, Klein & Beckman (1987), which implies that the persistence of weather patterns is not dependent on climate, and therefore location. Thus Chapman has assumed that climate and variability in insolation are independent, and he therefore includes no information on insolation distribution in his LOEP functions to accommodate the varying climates in which his technique may be used. Cowan (1989,152), however, shows that the evidence presented by Liu & Jordan is not sufficiently convincing to justify such assumptions. He also points out that it does not follow from Chapman's assumption that seasonal variations are also independent of climate. He refers to a case (Pretoria) where Chapman's method would provide maximum output for the mid-winter month (June), but significantly lower outputs would be achieved in other months (Cowan,1989,151). Thus the assumptions in Chapman's sizing method appear to result in the method not achieving optimum results at all locations, and cast doubt on the reliability of the LOEP values obtained from the sizing procedure. The poor correlation obtained between the LOEP curves for sites of differing climates further demonstrates the inaccuracies arising from the assumption that insolation variability and climate are independent, and illustrates the inaccuracy of the method in general.

#### 2.4 THE SAPV SIZING METHODOLOGY OF MACOMBER ET AL.(1981)

This sizing method uses LOEP as a reliability index. It is divided into two parts : In the first, the system is "quick sized" - i.e. an initial array and storage size determined, and in the second, the LOEP for this size combination is calculated. If the LOEP is not acceptable, the array and/or storage sizes are varied until it is. The optimum cost of the ar-

ray/storage size combination is then determined by varying their sizes until the optimum cost and acceptable LOEP is achieved.

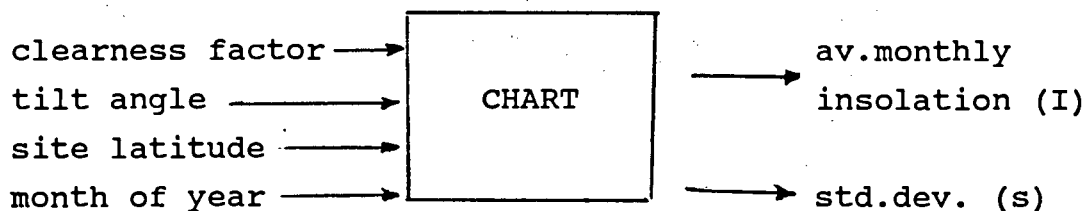
#### 2.4.1 SUMMARY OF THE "QUICK SIZING" METHOD

The following procedure is undertaken for each month of the year:

(1) Obtain the clearness factor - for which purpose clearness factor tables for many sites over the world are provided. This factor is the ratio of the average daily total radiation on a horizontal surface to the average daily total extraterrestrial radiation on a horizontal surface.

(2) Select an array tilt angle: Macomber et al. restrict this choice to latitude or latitude +  $10^{\circ}$ , but there appears to be no reason why other angles may not be chosen provided the standard deviation of the monthly average insolation can be found for the tilt angle. A method to compute these values is provided (11.2).

(3) Determine the average monthly insolation (I) and its standard deviation (s): Charts are provided for this purpose and are used as follows :



(4) Determine the average daily energy demand for the month

(5) Determine the system efficiency : It will be approximately equal to the product of the array efficiency, battery round-

trip efficiency (i.e. charge and discharge), and power conditioner efficiency.

(6) Select factor relating array & storage sizes : A factor used in relating array area to storage size, 'M', is selected and used to calculate an array area using the following formula:

$$\text{Area} = \text{av.energy demand} * \text{system eff.} * (I - M * s)$$

Because 'M' influences the array size vs storage size combination, it affects the cost of the system. A value of  $M = 0.33$  is suggested as a starting point to result in an economical design.

(NOTE: although 'M' is used here as a rather arbitrarily chosen factor, it is defined as  $M = (I - I_d) / s$ , where 'I<sub>d</sub>' is the average insolation required to meet the average energy demand for the month (comparable to Chapman's 'design insolation'), and is used in the second part of this sizing method. It relates the average insolation to the required insolation, and is therefore important in the LOEP statistical analysis explained later, and has been used to construct the nomogram for LOEP = 0.01 used in step 7 of this method. Because this quick-sizing section is carried out for a LOEP of 0.01 only, no LOEP calculations are necessary and 'M' is simply used as a factor in the equation.)

(7) Determine the "days storage" required: The nomogram shown in figure 2.3 is used for this.



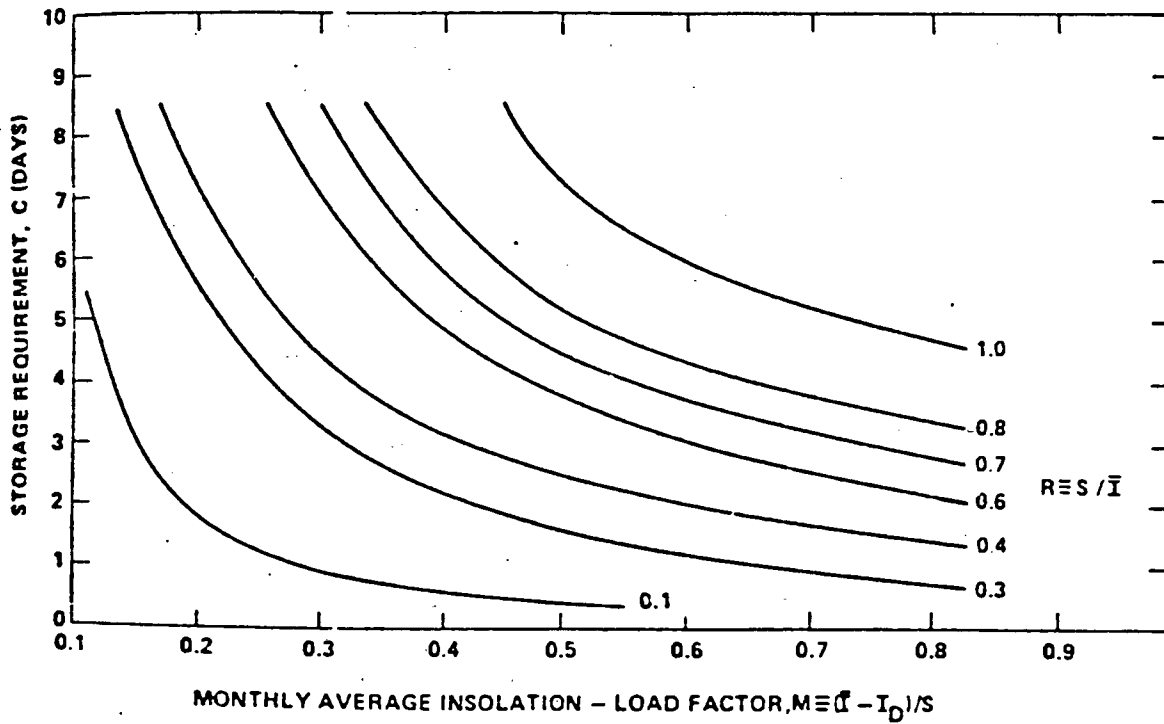


Figure 2.3 : Macomber's nomogram for determining the storage requirement for LOEP = 0.01. (Macomber et al, 1981, p6-11)

The nomogram relates storage and array area to give a LOEP of 0.01 only. Different LOEP's may be obtained by modifying the array/storage size combinations in the second part of this sizing method.

(8) Determine the design month: Once the above procedure has been carried out for all months of the year, the month resulting in the largest array area and storage size is chosen as the design month. If the largest array area does not coincide with greatest storage required, the array area is the deciding factor. In this case the storage size must be re-determined for each month from the nomogram, using the 'M' value that resulted in this array area. The month yielding the largest storage capacity determines the storage size.

The system has now been sized for a LOEP of 0.01. Macomber et al. now suggest that the life cycle costs of the system are calculated, and if either this or the LOEP of 0.01 is unacceptable, the array/storage size combination be varied. The resulting LOEP is then computed by the method shown below, as are the new life-cycle costs. If these are unacceptable the combination is further varied until the required results are obtained.

The method for computing the LOEP for the array/storage combination is now summarized:

#### 2.4.2 SUMMARY OF THE LOEP COMPUTATIONAL PROCEDURE (7.3)

The average insolation of the design month ( $I$ ), its standard deviation ( $s$ ), the array area ( $A$ ), and the storage in days ( $C$ ), have been determined for a LOEP of 0.01 by the "quick sizing" method. Now, a different LOEP is required, and so the array size or the storage size, or both, must be changed. The new LOEP resulting from these changes must now be calculated.

The insolation value required to meet the average energy demand for the month, ' $I_d$ ', is determined by  $I_d = \text{av. energy demand} / (\text{sys. eff.} * A)$  where "sys. eff" is system efficiency. Using the ' $I$ ' value as the mean insolation, the ' $I_d$ ' value as the required insolation, and ' $s$ ' as the insolation standard deviation, Macomber et al. embark on a probability analysis to establish the system LOEP. They assume that the probability distribution function of the insolation can be regarded as normal (7.5).

To establish the system LOEP, first the probability of losing the load is calculated for day  $C+1$  (i.e. the day after the maximum number of days that the storage can support the energy demand). Then for each subsequent day two possibilities are

considered: first that the insolation level will be low, and second that it will be "relatively high" (7.5). The probability of the system surviving without LOE is computed for each possibility. This is also done for subsequent days until enough days have been covered to result in an "adequate estimate" of LOEP. (Typically of the order of 200 values are considered necessary, i.e. the process is repeated for about 200 days.) all the LOEP values obtained for individual days are then combined using an expression to approximate the LOEP value that would have been obtained using an infinite number of values in the computational process.

At this stage, therefore, the LOEP has been established for that particular array/storage size combination. The life-cycle cost should then be calculated and should this or the LOEP found be unacceptable, the size combination must be varied until the desired results are obtained.

#### 2.4.3 DISCUSSION OF THE SIZING METHODOLOGY

The first shortcoming that becomes apparent with this sizing method is its awkwardness. It presents no easy way of sizing a system for a LOEP other than 0.01 and thus a process of trial and error must be undertaken. It would be possible, with some effort, to generate sizing nomograms for other LOEP values as Macomber et al. have done for LOEP=0.01, using the methodology presented here. This would streamline the process significantly. In fact Rosenblum (1982) has devoted much attention to doing just this (see section 2.5).

As has been mentioned, the probability density function of daily insolation has been assumed to be normal, and the statistical analysis, using the mean and standard deviation of the insolation in order to compute the LOEP, centre on this assumption. However, according to Klein & Beckman (1987,501), this

function can be "quite skewed", casting doubt on the accuracy of the results. Furthermore, in this LOEP computational procedure, only the monthly average insolation, standard deviation for that month, and 'Id' value for the month are used. On this basis a statistical analysis is undertaken to calculate what is regarded as the 'system LOEP'. Clearly the LOEP found is only for the design month and the authors present no way to convert this to, or to calculate separately, the long term LOEP. It is thus not possible, using this value, to compare the SAPV system reliability with that of other power systems.

Macomber et al. suggest using their pre-compiled charts to determine average monthly insolation and standard deviation of the insolation for the month. They suggest that these charts are applicable for any location in the world. In other words if the monthly clearness index is known, statistical information defining the distribution of the insolation for that month may be determined. This appears to be based on studies such as those done by Liu & Jordan (1960,9-12) which indicate that the insolation distribution is independent of location, and can be closely correlated with the clearness index in a particular month, although no mention is made of the source. This ability to correlate clearness index with insolation distribution has been criticized by Cowan as being unreliable (Cowan,1989,152).

The insolation value required to exactly meet the average energy demand for the month, 'Id', is given by the expression 
$$Id = \text{av. energy demand} / (\text{sys. eff.} * A)$$
. In determining 'sys. eff', the system efficiency, the authors suggest considering the efficiencies of the array, the battery (charging and discharging), and the power conditioner. This assumes that all the energy is to be cycled through storage, as does Chapman, and thus it is all assumed to incur battery charging and discharging losses. Systems that supply a partially daytime load, and could thus supply a portion of the load directly from the ar-

ray, would therefore be oversized, as is the case with Chapman's method. It would be an easy task to adapt the 'Id' equation to take such systems into account, but it means that the existing sizing nomogram, which uses 'Id', would have to be reconstructed.

This sizing method uses average monthly energy demand to establish array and storage size. According to Chapman (1987,2), this disregard for the short term demand profile results in negligible loss of accuracy in LOEP values.

In summary, then, the method appears to be generally inaccurate. The assumptions that the daily insolation distribution is normal, and that the distributional information of the insolation may be determined by using only the clearness index do not appear to be sound. For this specific project, the method is further unsuitable because it only yields a LOEP value for the design month and thus the value cannot be used when comparing reliability with other power options. The use of the sizing method is also awkward, although it is possible to streamline it, as has been done by Rosenblum (1982).

## 2.5 ROSENBLUM'S SAPV SIZING METHODOLOGY (1982)

Rosenblum has simply taken the method developed by Macomber et al. and streamlined it. What is presented here, therefore, has the same theoretical base as the Macomber method but has been extended and improved.

Where Macomber et al. have only provided one nomogram for system sizing, representing one LOEP, Rosenblum presents nomograms for LOEP values of 0.001, 0.01, and 0.1. Thus the prospective system sizer can choose between these LOEP values. This would still be of little help if the required LOEP was not

represented here, in which case the system would have to be sized using a LOEP value for which there is a nomogram available, and then the array and storage sizes would have to be modified and the resulting LOEP computed until the required value is obtained.

To facilitate the achievement of optimum system costs, Rosenblum presents a graph, which, for the LOEP value and the average insolation for the month (here again the LOEP choice is between 0.001, 0.01, & 0.1), gives the storage and array sizes which yield optimum costs. This graph was constructed using a cost algorithm with array size and storage size as the variables. Its use is valid for overall system efficiencies (array, battery charging & discharging, and power conditioner efficiencies) between 0.08 and 0.06 - which Rosenblum says covers "all operating conditions of practical interest" (12.16).

The author demonstrates how systems may be sized for average energy demands which vary from month to month, but the resulting LOEP is only valid for the design month (i.e. the worst month), as is the case with the Macomber et al. method. The only help Rosenblum provides in determining the long-term LOEP, is to state that it is observed to fall in the range of 20-40% of the value of LOEP for the design month (12.22).

In conclusion therefore, although Rosenblum's method is considerably less awkward than that presented by Macomber et al. it still may require a process of trial and error to achieve a specific LOEP value. As with Macomber et al., the LOEP value obtained is not a long term one but is only valid for the design month. The method is also subject to the same objection as that of Macomber's, which is that the assumption on which the LOEP computations are based, that the daily insolation distribution function is normal, is not necessarily true.

## 2.6 THE SAPV SIZING METHODOLOGY OF BORDEN ET AL. (1984)

This sizing method is not intended for detailed system design, but rather to estimate the required size and thus life-cycle costs of a SAPV system. The system is sized for the month of lowest insolation to energy demand ratio and provides a LOEP of 0.1 for this month. This is said to result in a long term LOEP of 0.02-0.04, approximately the same as that of a diesel or battery power source alternative, and thus the sizing is only carried out for this LOEP. The method, like that of Rosenblum, is based on the LOEP theory as developed by Macomber et al. and thus incorporates the same assumptions.

### 2.6.1 SUMMARY OF THE SIZING METHODOLOGY

(1) Calculate the energy requirements: The average energy demand for each month of the year is found. If the variation from month to month is large, and the periods of high energy demand are critical to the power user, these may be used in place of average energy demands.

(2) Determine local insolation: The average daily insolation values for each month of the year must be determined. The authors consider only three tilt angles; latitude  $-15^{\circ}$ , latitude, and latitude  $+15^{\circ}$ , but as long as the POA insolation values can be determined, the method is valid for any tilt angle. Here only these three tilt angles will be considered.

(4) Calculate "worst month" insolation and energy use: The system is sized to meet the energy demand during the month where the insolation to energy demand ratio is smallest. This ratio is determined for each month for the three tilt angles, and the month producing the smallest ratio (the "worst month") for each tilt angle established. The tilt angle resulting in

the highest insolation to energy demand ratio from amongst the three "worst months" is then selected as the design tilt angle - in other words the best tilt angle and the "worst month" of that angle are used in sizing the system.

(5) Determine array and battery storage sizing factors: Here, firstly, sizing factors which produce array and battery size combinations that satisfy the LOEP = 0.1 criterion are determined, and secondly that which is likely to be the most cost effective combination is found. The nomogram shown in figure 2.4 is used for this.

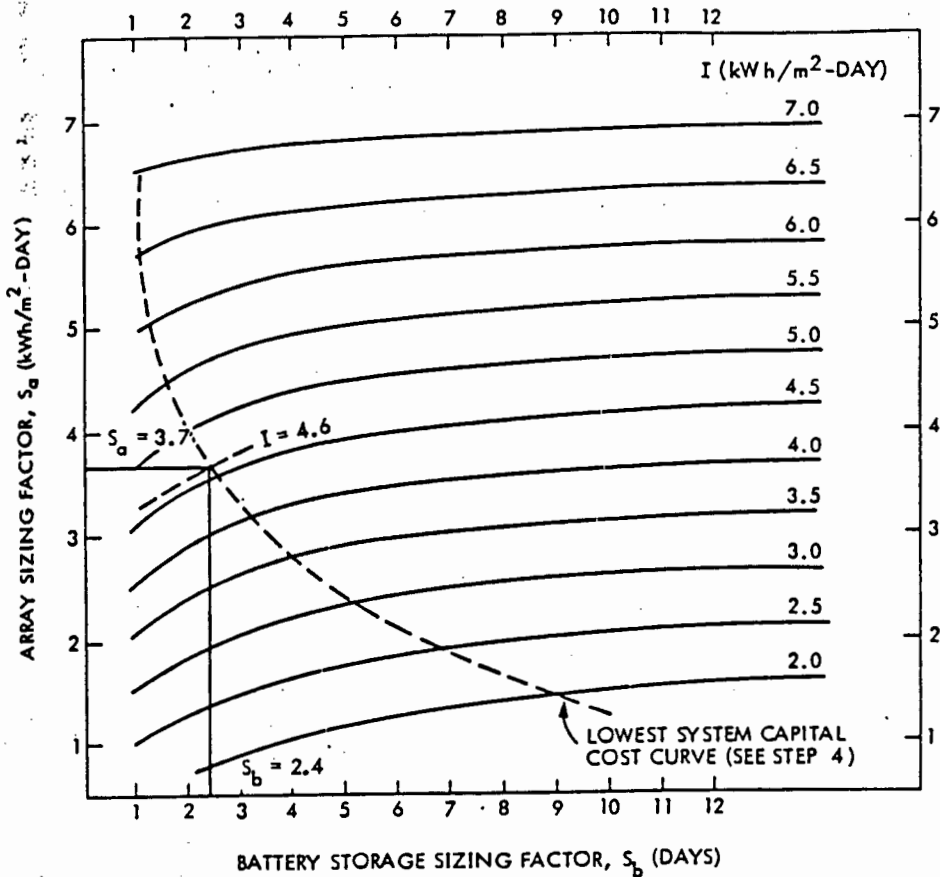


Figure 2.4 : The nomogram used in the sizing method of Borden et al. to determine array and storage size combinations that satisfy the worst-month LOEP of 0.1 requirement. (Borden et al., 1984, p2-9)

The nomogram is entered along one of the 'I' curves ('I' being the average daily worst month insolation), and the broken line



indicates the position on the curve likely to lead to the most cost effective design, as is shown for  $I' = 4.6$  kWh/sq.m/day.

(6) Estimate load fractions supplied by the array and by storage: A conservative approach would assume no load being supplied directly from the array, and the system would be sized so that all the load could be supplied by the batteries. This would oversize the system because the array usually supplies at least some of the load directly. Also, because of battery inefficiencies, the power supplied by the array has to be greater to satisfy the same load, than if it were supplied directly by the array. Oversizing due to this may range from 0 to 25%, but for a constant 24 hour/day load it is, according to the authors, typically less than 10%.

An alternative method of estimating these load fractions can be used: for each month of the year an idealized load and array output may be constructed as shown in figure 2.5, and the load fractions estimated from this. This would result in less oversizing.

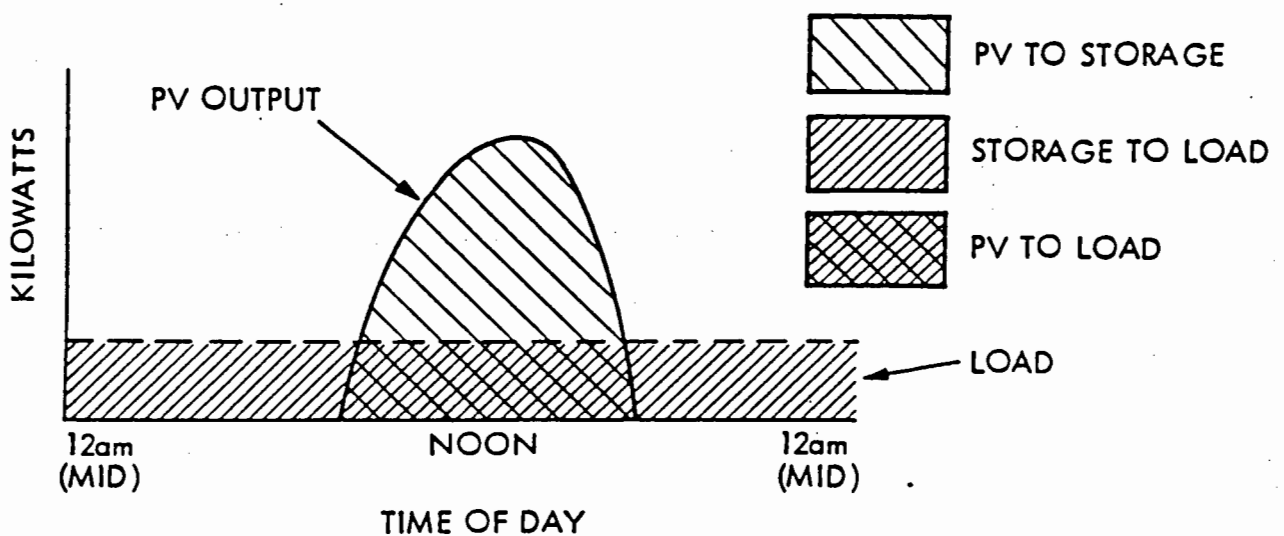


Figure 2.5 : An example of an idealized load and array output profile used to determine the proportion of energy cycled through storage. (Borden et al., 1984, pB-1)

(7) Calculate array power and area: The array is then sized taking into account the load fraction supplied directly by the array, the system efficiency, and the degradation of the array over time. The following equation is used to calculate the array power:

$$Pa = L / (Sa * F * e_{i/c} (fb(e_{vr} * e_b) + fa))$$

where Pa - array power  
 L - average daily energy demand in worst month  
 Sa - array sizing factor (from step 5)  
 $e_{i/c}$  - inverter or converter efficiency  
 F - factor to account for array degradation  
 $e_{vr}$  - voltage regulator efficiency  
 $e_b$  - battery efficiency  
 fa - load fraction supplied directly by array  
 fb - load fraction cycled through batteries

The equation used to calculate the array area is :

$$Aa = Pa / (e_m (1 + Ptc(Top - 28^{\circ}C)))$$

where Aa - array area  
 $e_m$  - module efficiency  
 Ptc - module temperature coefficient  
 Top - actual module operating temperature

(8) Calculate battery storage size: The battery size can now be determined, taking into account the load fraction supplied by the battery, the system efficiency, and the permissible

depth of discharge of the battery. The following equation is used :

$$E_b = L \cdot S_b / (d \cdot e_i / c)$$

where  $E_b$  - battery energy storage (kWh)

$S_b$  - battery sizing factor (from step 5)

$d$  - maximum allowable depth of discharge

## 2.6.2 DISCUSSION OF THE SIZING METHODOLOGY

This method sizes systems for a LOEP of 0.1 in the worst month, which is said to result in a long term LOEP of 0.02 to 0.04. According to the authors, this is approximately the same as that of a diesel or battery power source alternative, and thus provides a basis for comparing such alternatives. However, this approach is limited in that should one require a higher LOEP system, or wish to compare the system with alternatives of different LOEP's, for example wind generation, this method cannot be used (Although Rosenblum provides sizing nomograms for LOEP's of 0.01 and 0.001 (1982,12.10)).

This sizing method is not intended for detailed system design, but rather for estimating the required system size with a view to estimating the system life-cycle costs, and contains some simplifying assumptions which can lead to oversizing. One such assumption is that in sizing the system to be able to cope with the "worst month" energy demand, it is presumed that there is no 'residue' charge in the battery from previous months, which is often not the case. Also, limited load demand data may not enable the accurate estimation of the load fractions supplied by the array and storage, and it may thus be necessary to assume that no load is supplied directly by the array - an assumption which can oversize the system by up to 25%.

In introducing their array and battery sizing factor nomogram (see step 5), Borden et al. state : "These factors (and therefore the nomogram) have been derived from prior analyses of how photovoltaic system loss of energy probability depends on array and battery size" (2.8). Here they give Macomber et al. as a reference. It is thus possible that the nomogram already includes Macomber's assumption that all energy passes through storage and thus incurs storage losses, although it is not stated exactly how Macomber's work is used. If this is the case, it would tend to lead to further system oversizing, and less accurate and economic system design, although possibly still fulfilling the authors' aim of providing an estimate of system size and therefore life-cycle costs.

The method allows for variations in monthly energy demand over the year and the system sizer is also able to choose a tilt angle to optimize energy gain from the insolation.

Generally, however, the method contains simplifying assumptions which would tend to oversize the system, and in practice, therefore, the LOEP value for which the system is sized is likely to be conservative and unrealistic (although it must be remembered that the authors did not intend this as an accurate sizing method). The authors state that a LOEP of 0.1 for the worst month gives a long term LOEP of 0.02 to 0.04 without giving a reference. This may well be taken from Rosenblum (1982) on which this work is partially based. Rosenblum, however, presents only sketchy evidence to support this relationship between worst month and long term LOEP (12.22), and thus the long term LOEP figures of 0.02 to 0.04 given by the authors may well be unreliable.

As with Rosenblum's sizing method, this method incorporates the assumption of Macomber et al. (1981,7.5) that the daily insola-

tion distribution function is normal, and thus the LOEP values used in method would further tend to be unrealistic.

## 2.7 W.COWAN'S SAPV SIZING METHODOLOGY (1989)

Cowan has developed a method of sizing SAPV systems which uses empirical data from the region in which he was conducting a research project. It cannot therefore be applied to other sites in its present form, having been developed for use in one specific case, but the possibility exists of extending it to be more widely applicable. It also uses LOEP as a reliability measure, although the approach to determine the LOEP is unique.

### 2.7.1 SUMMARY OF THE SIZING METHODOLOGY

In system sizing, attention is restricted to periods where daily energy supplied by the array is less than that demanded by the load - i.e. when storage is being depleted from one day to the next. Because in such periods system characteristics tend to be more predictable (e.g. low module temperatures, low state of charge (SOC) of batteries), system efficiencies may also be predicted more accurately, resulting in more accurate sizing estimations.

First, Cowan develops an expression for the "required minimum average daily POA insolation" to support the load:

$$P = [(N - C/L) \times L / (A \times \text{sys. eff.})] / N$$

where P           - min. average daily POA insolation (kWh/sq.m/day)  
 N                - run length (of energy deficit days)  
 C                - installed battery capacity (kWh)  
 L                - average daily energy demand (kWh/day)  
 A                - area of array

sys.eff. - system energy efficiency (here Cowan takes into account the expected fraction of load passing through the storage and that being drawn directly from array to load)

Each value of N days run length, therefore has a corresponding P value for a certain system. Consider the following example: For N = 10 days, it is found from the expression that the corresponding P value is 1.0 W/sq.m/day for a certain array and storage size. This indicates that for any 10 day period, the minimum average insolation required to support the load on the PV system is 1.0 W/sq.m/day. As the run of days being considered increases, the total insolation required to support the load increases, as does the average insolation required. A curve of P vs N may thus be constructed for a particular PV system and particular energy demand. The demand curve shown in figure 2.6 is such a curve.

Ten years of insolation data from a site was analyzed as follows: Considering run lengths of 1 day to 20 days, the expected minimum POA insolation for that run length was determined - for example, when dealing with a run of 5 days, the hourly data was used to determine the minimum POA insolation that could be expected over a 5 day run by looking at POA insolation levels obtained for all possible sequences of 5 days in the 10 years insolation data. Because an expression for the minimum insolation required to meet the energy demand over a 5 day run has already been determined, the object of analyzing the hourly data is to determine what minimum insolation levels can be expected over a typical 5 day run period, and thus whether it would be sufficient to meet the load. The expected minimum insolation levels for various run lengths were determined for various probability levels - for example a probability level of 0.01 means that 99% of the insolation values observed would be above the final expected value used for the

particular run length. The results of run lengths and corresponding minimum expected POA levels were then modelled by the following function:

$$\text{min.POA } (p,N) = a + bN + c/N + d(\ln(N))$$

where  $p$  = probability level  
 $N$  = run length in days  
 $a, b, c, d$  are constants

(Note: 'p' is strictly speaking observed frequency, not probability, but for all practical purposes it may be regarded as a probability)

The coefficient of determination for the modelled fit to the observed data ranged from 0.999 (for  $p = 0.01$ ) to 0.996 (for  $p = 0.001$ ).

All the analysis of the insolation data was only done for one specific tilt angle which had previously been determined as the optimum angle for that site. The data would have to be re-processed to obtain results valid for another tilt angle.

To compensate for the possibility of the batteries not being fully charged at the beginning of an energy deficit run, periods of deficit which were interrupted by periods of energy surplus of comparable length are regarded as one continuous period of deficit. Cowan also adjusts the "installed battery capacity" term in his "required minimum average daily POA insolation" expression to account for the lower efficiencies that occur when the battery is approaching full state-of-charge

(SOC). This is done by assuming that the battery never exceeds 90% SOC. The expression thus becomes :

$$P = [(N - 0.85 * C/L) * L / (A * \text{sys. eff.})] / N .$$

where 0.85 is the factor used to derate battery capacity to cater for the 90% SOC ceiling. (This factor varies depending on the permissible depth-of-discharge of the battery in use, and 0.85 is used here as being representative of common depth-of-discharge limits)

At this stage two expressions have been derived, one for expected minimum POA insolation (as a function of probability level and energy deficit run length) derived from observed data, and another for "required minimum average daily POA insolation" to support the load (as a function of array area, battery capacity, and energy deficit run length). The curves of these two functions may be plotted on the same axes resulting in a graph as shown in figure 2.6. In the example plotted on this graph it can be seen that for all probability levels considered, the minimum expected POA levels are far above the minimum required POA levels, and thus the system has a negligible chance of failing, and the system is therefore significantly oversized.

The situation shown in the figure 2.7 - where the "required" curve converges on the "expected" curve for the different probability levels - indicate that the array and battery sizes used to generate the "required" curves would provide a level of certainty (of being able to support the load) equal to that of the probability level curve it converges on. This probability is the LOEP of the system used in this example.



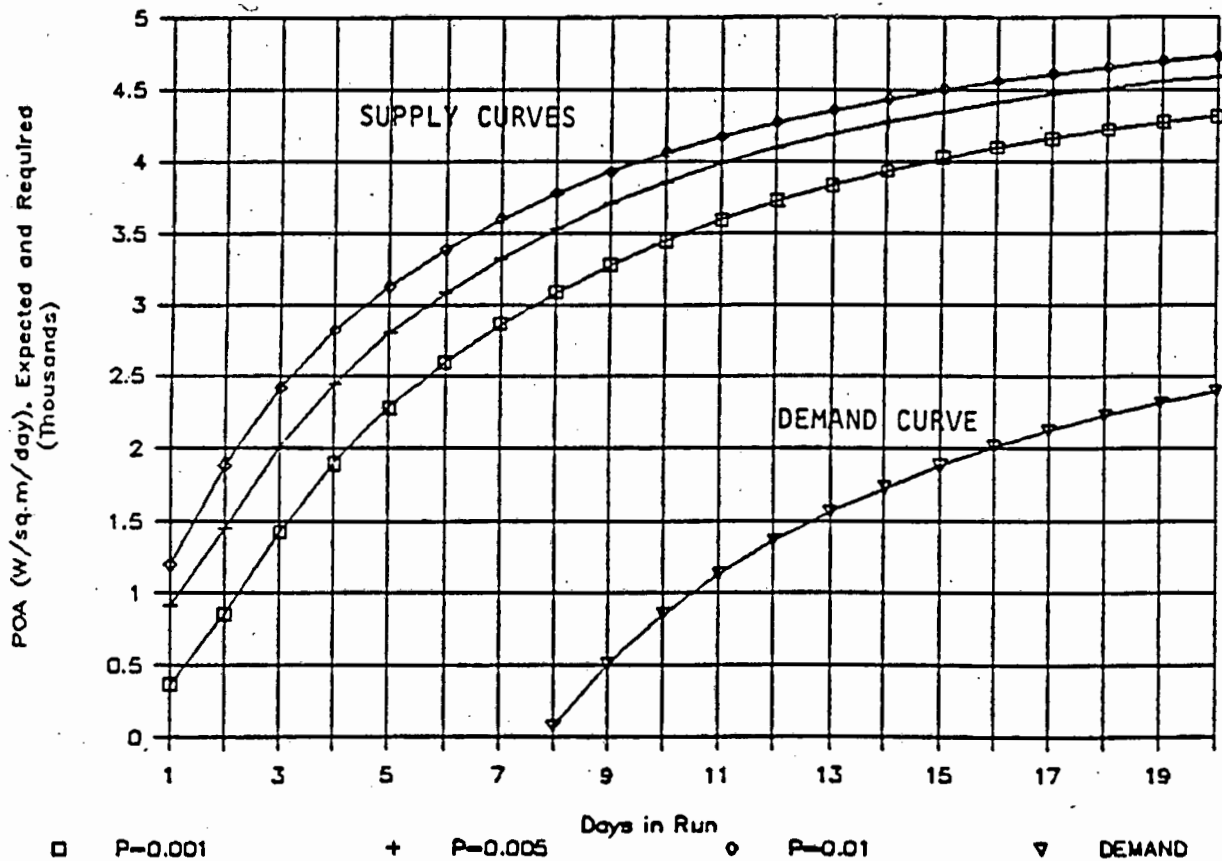


Figure 2.6 : Graph showing an example of "minimum required insolation" (demand) and "minimum expected insolation" (supply) curves generated by Cowan's SAPV system sizing method. The "expected" or supply curves are shown for a range of probability levels.

For any system, therefore, for the required energy demand and LOEP, a set of array and battery size combinations may be found (with the help of a computer) to satisfy them. Since the minimum expected POA curves are fixed for the location in question and the probability level required, the approach used to generate a set of array and battery size combinations is to hold for example battery size constant, and then find a set of array sizes each of which produces a curve convergence between the "expected" and "required" curves. This is carried out for various battery sizes until a suitable range of combinations is found. The most cost effective combination may then be selected from amongst these.

a seasonal adjustment function without shortening battery life. The question therefore revolves around which is the most economical: short-term or long-term cycling batteries with their corresponding array sizes necessary to fulfill the LOEP requirements.

Considering run-lengths of greater than 30 days does, however, further complicate the sizing procedure, since it is no longer clear which array tilt angle to use in the sizing. Normally, where systems are sized assuming average daily energy demands to be constant throughout the year, the sizing is done using the array tilt angle which optimizes the worst month insolation level. However, if run-lengths of greater than one month are used, it can no longer be assumed that this tilt angle will result in the optimum array and storage size combination. For example, if run-lengths of 50 days were being considered, the optimum tilt angle to use would be that which, for all 50 day periods considered over the year, resulted in the highest "worst-50-days", not the highest "worst-month" insolation.

To further examine the advantages of extending the run-lengths considered in system sizing is beyond the scope of this thesis, and it has been mentioned here simply to indicate an area of uncertainty in the method, and to point to possible future research should it be desired to refine the sizing method.

Although Cowan's sizing method has been dealt with here in more detail than the other sizing methods, it is felt that the extra attention is justified for the following reasons:

- (1) It has the obvious advantage over other methods in that it uses empirical data in system sizing, and as such may be tailored to local conditions and result in an accuracy unattainable by the quick-sizing methods dealt with.

(2) It is the only known non-simulation sizing method that attempts to reduce the inaccuracies caused by having to make sweeping assumptions concerning system efficiencies. This is done by restricting attention to energy deficit, or low insolation periods.

(3) It is particularly suited for use on a computer and is therefore compatible with this project, and because of its expected superior accuracy, is more fit for use in the comparison program than the other methods considered.

(4) Being a recently developed sizing method, and having been developed for use in one specific situation, there are still several areas of uncertainty about it, particularly when it is extended for use on a broader scale as this project requires. It therefore merits careful examination.

## 2.8 A LOOK AT SOME SYSTEM SIZING RESULTS PRODUCED BY THE VARIOUS METHODS

At this point it is interesting to look at some examples of system sizes produced by the various methods that have been reviewed. By doing this their degree of correlation will be established, and a feeling will be gained for the extent to which the assumptions included in the methodologies result in sizing inaccuracies. Because of the use of empirical insolation data in Cowan's method, and because of the expected superior accuracy of the system efficiencies used in his method, it is reasonable to expect that his results will be the most reliable in local conditions. Because the "correct" sizing results are unknown, Cowan's results will be used as a measure in this comparison, and results from the other methods discussed in relation to these.

The site used to generate results for all the sizing methods was Pretoria, and the site specific data is as follows :

Latitude	- 25.73° South
Worst month (Design month)	- June
Worst month horizontal global radiation	- 3900
Wh/sq.m/day	
Optimum worst month array tilt angle	- 25°
Optimum tilt worst month global radiation	- 5722
Wh/sq.m/day	

A maximum permissible depth-of-discharge of 0.5 was assumed for storage batteries in all the results shown. The required storage capacities given are therefore rated capacities.

## 2.8.1 RESULTS FROM COWAN'S METHOD

The results are set out in table 2.1.

Table 2.1 : Results from Cowan's SAPV sizing methodology for Pretoria conditions and an array tilt of 25 degrees..

LOEP	Average energy use (kWh/day)	% energy used in daylight	System efficiency	Array size (sq.m)	Stora (kW)
0.05	10	0.5	0.065	27.8	34.
0.01	1	0.5	0.065	2.8	5.
0.01	10	0.5	0.065	28.2	55.
0.01	100	0.5	0.065	285.0	557.
0.05	10	0.0	0.062	29.0	33.
0.01	10	0.0	0.062	29.8	57.
0.05	10	1.0	0.073	24.5	36.
0.01	10	1.0	0.073	25.5	55.
0.005	10	0.5	0.065	28.4	75.
0.001	10	0.5	0.065	29.0	89.

The results for the higher system efficiencies of 0.73 given above represent a situation where the energy demand is principally during daylight hours, and it has therefore been assumed that 70% of the energy demanded passes directly from the array to the demand, without being cycled through the batteries. The system efficiency of 0.065 represent a situation where the energy demand is spread equally between day and nighttime, and in this case 20% of the energy has been assumed to pass directly from the array to demand. Where no energy is supplied directly by the array, the system efficiency is 0.062. For more information concerning these assumptions refer to appendix D.

Results in rows 2,3 and 4 above, for LOEP of 0.01 and system efficiency of 0.065, show the linear relationship between in-

crements in average energy demand, and array and storage size increments, as would be expected.

Cowan's results will be further discussed in relation to the results of other methods, rather than here.

#### 2.8.2 TYPICAL RESULTS FROM THE "DAYS OF AUTONOMY" SIZING METHOD

Although this method can only be regarded as a "first estimate" method and does not give an indication of what system reliability may be expected, it is of interest to compare its results with those of other methods. As an example, consider a situation with an average energy demand of 10 kWh/day, and a system of 3 days autonomy (i.e. the storage is sized for 3x the average daily energy demand). Assuming the overall system efficiency to be the same as that used in Cowan's method above (0.065), using the worst month insolation on a 25° tilt (5.722 kWh/sq.m/day), and adding an arbitrary design margin to the results, say 10%, the following sizes are obtained :

Array area = 30 sq.m  
Storage = 66 kWh

Using Cowan's results as a measure, the system size obtained may be expected to result in a LOEP of approximately 0.002. The above example indicates that an experienced system designer, when using this method, may be able to choose the number of days of autonomy such that the system is not only economically sized, but it may also be possible to estimate system LOEP resulting from the design.

#### 2.8.3 RESULTS FROM CHAPMAN'S METHOD

Chapman's sizing method, for a 25° tilt, overall system efficiency of 0.065, and  $eff_{out}$  (battery discharging and inverter

efficiency) of 0.8, yields the range of results (numbered 1 to 4) shown in table 2.2 from which the most economical combination must be chosen. The an average energy demand used is 10kWh/day.

Table 2.2 : Results from Chapman's SAPV system sizing method for Pretoria conditions and an array tilt of 25<sup>0</sup>

Set No.	Array size (sq.m)	Storage size (kWh) for various LOEP values :			
		0.05	0.01	0.005	0.001
1	25.59	10.00	42.50	53.75	90.00
2	25.17	18.75	60.00	82.50	145.00
3	24.38	25.00	77.50	108.75	202.50
4	24.38	30.00	95.00	142.50	255.00

To obtain results for different energy demands, the above values may simply be multiplied by the relevant factor - for example the results would be multiplied by 1/10 to obtain sizes for an average energy demand of 1 kWh/day. Since Chapman's method has been developed such that Array size is independent of LOEP, only one array size set is given for all the LOEP values considered.

Looking at the above results, it can be seen that the method lacks definition, in that array and storage size combination sets numbered 3 and 4 have the same array sizes, but significantly different storage sizes. Yet both of these combinations are shown to result in the same system LOEP, which obviously cannot be the case.

Choosing the most economic combination for the LOEP requirements, in this case size set 1 for all LOEP values, Chapman's results can be compared with those of Cowan, as shown in table 2.3.

Table 2.3 : A comparison of Chapman's and Cowan's SAPV system sizing results.

LOEP	Array size (sq.m)	% difference frm Cowan's method	Storage size (kWh)	% difference frm Cowan's method
0.05	25.59	- 8%	10.0	-71%
0.01	25.59	- 9%	42.5	-24%
0.005	25.59	-10%	53.8	-29%
0.001	25.59	-12%	90.0	+ 1%

Significant differences between the two methods can be seen from the above table, particularly regarding storage capacity. Chapman's system sizes are generally smaller than Cowan's, and since Cowan's method is expected to yield more reliable results, it is suspected that Chapman's LOEP values given are not accurately related to the system sizes shown. Instead, the system reliability that could be expected from the sizes given is expected to be lower than indicated.

#### 2.8.4 RESULTS FROM THE METHOD OF ROSENBLUM

The difficulty in comparing the results of Rosenblum with those discussed above is that quick-sizing results from Rosenblum are only given for worst month LOEP, and long term LOEP must be estimated from this. The approach adopted here is to estimate the long term LOEP as 20-40% of the worst month LOEP, as suggested by Rosenblum (1982,p12.22). It must however be noted that this conversion may not be accurate.

Using the quick-sizing nomograms presented by Rosenblum (1982,p12.10-12), the range of results (sets 1 to 4) shown in table 2.4 may be obtained for an average energy demand of 10 kWh/day and tilt angle of 25<sup>o</sup>, and using an overall system efficiency of 0.065. The "% difference from Cowan's method" values below are from obtained from interpolating between Cowan's values to give a similar LOEP.



Table 2.4 : A comparison between Rosenblum's and Cowan's SAPV system sizing results.

Worst mnth LOEP	Approx.long term LOEP	Set No.	Array size (sq.m)	%diff frm Cowan	Storage (kWh)	%diff f Cowan
0.1	0.03	1	30.1	+ 8%	75.0	+66%
		2	31.3	+12%	50.0	+11%
		3	32.7	+17%	37.5	-16%
		4*	33.4	+19%	25.0	-40%
0.01	0.003	1	31.3	+9%	100.0	+21%
		2	32.0	+11%	75.0	-9%
		3*	34.1	+19%	50.0	-39%
		4	40.6	+41%	25.0	-70%

\* - most economic size set

Although, in his methodology, Rosenblum ignores the inverter efficiency in converting the "days of storage" values obtained from the nomograms into kWh of storage required, it has been included in determining the above results. This has the effect of increasing the required storage capacity, and is necessary to reflect the "days of storage required" value accurately in kWh. This is also consistent with all the other methods dealt with here.

As can be seen above, size sets may be chosen such that both the array and storage values are within approximately 10% of Cowan's results. However, if the most economical size set is chosen from the above options for each LOEP group, the results are less similar. For the LOEP of 0.03 group, the most economic combination is size set 4, and size set 3 is the most economic for the LOEP of 0.003 group. In both these cases the array size is about 20% greater than Cowan's, and the storage 40% smaller. Since these would be the final results obtained were the method used as suggested, it cannot be said to compare well with Cowan's results.

## 2.8.5 RESULTS FROM THE METHOD OF BORDEN ET AL.

(To facilitate readability, Borden et al. will simply be referred to as Borden.)

As with Rosenblum's method, this method does not allow for long term LOEP determination, and it must therefore be estimated from the worst month LOEP. Again worst month insolation values for a 25° tilt are used for system sizing. Other parameters used are :

F (factor to allow for array degradation)	- 1.0
$e_i$ (inverter efficiency)	- 0.8
$e_{vr}$ (regulator efficiency)	- 0.95
$e_b$ (battery cycling Wh efficiency)	- 0.8
$e_m$ (module efficiency)	- 0.12
Ltd (average energy demand in kWh)	- 10.00
Top (cell operating temperature)	- 55°C
Ptc (module temperature coefficient)	- -0.005/°C
Fb (fraction of energy supplied from battery)	- specified below
Fa (fraction of energy supplied directly from array)	- specified below

Borden's method only sizes systems for a worst month LOEP of 0.1. This is estimated to give a long term LOEP of 0.03. If Cowan's results are interpolated to give approximate system sizes for a LOEP of 0.03, Borden's results may be compared with Cowan's, as shown in table 2.5.

Table 2.5 : A comparison between Borden's and Cowan's SAPV system size results.

Fa	Fb	Set No.	Array size (sq.m)	% diff from Cowan's method	Storage size (kWh)	% diff fr Cowan's met
0.0	1.0	1	32.2	+10%	50	+10%
		2	33.2	+13%	38	-17%
		3*	34.0	+16%	25	-45%
0.2	0.8	1	30.4	+ 8%	50	+11%
		2	31.4	+12%	38	-15%
		3*	32.1	+15%	25	-44%
0.7	0.3	1	26.5	+ 6%	50	+ 8%
		2	27.3	+ 9%	38	-18%
		3*	27.9	+11%	25	-46%

\* - most economic size set

The 'Fa' values of 0.0, 0.2, and 0.7 have been chosen to result in the same proportion of energy being cycled through the batteries as for Cowan's "% of energy used in daylight" values of 0.0, 0.5, and 1.0 . The reason that all the energy demanded during daytime is not supplied directly by the array is discussed in appendix D.

The results for 'Fa' = 0.2 may be compared with Rosenblum's results, as the system efficiency obtained when this 'Fa' value is used is close to the efficiency used in obtaining Rosenblum's results. As can be seen, their results are within about 3% of one another, but since Borden et al. have founded their sizing method on the research of Rosenblum, it is not surprising that their results compare well.

As with Rosenblum, some of Borden's results are such that both the array and storage sizes given are within 10% of Cowan's values. However, choosing the most economic combinations from the above give array sizes 10 to 15% greater than Cowan's, and storage sizes of about 45% less. Here again, the method cannot

be said to correlate well with Cowan's if used as intended by the authors.

## 2.9 CONCLUSIONS AS TO THE SUITABILITY OF THE VARIOUS SIZING METHODOLOGIES FOR USE IN THIS PROJECT.

In SAPV sizing methodologies there is an inevitable play-off between accuracy, and speed and convenience of use. The detailed hourly SAPV simulation programs which track the system status using observed hourly insolation values, are the most accurate, but are relatively cumbersome to use, and are all of necessity run on computers. On the other hand to produce a sizing method which can size a system rapidly and without the aid of computers, demands that simplifying assumptions concerning insolation patterns, and therefore system status, be made, and the accuracy of the sizing suffers accordingly. These, then are the two extremes - accurate and relatively cumbersome, and convenient but of dubious accuracy. For the purposes of this project, neither extreme is desirable. The choice of method to be used in this project should be convenient to use, but result in a system size of acceptable accuracy within this constraint.

The review of the various sizing techniques has sought to point out their inaccuracies and other weaknesses, and to examine their general suitability for use in this project - i.e. to be used in conjunction with sizing techniques for other power supply options and provide some basis of comparison between them, notably LOEP. By comparing actual results generated by the various methods it was possible to determine the degree of correlation between them, and to gain some insight into the likely degree of inaccuracy instilled into the methods by their inherent assumptions. It is now necessary to choose between the methods, and a summary of the strengths and weaknesses of the various sizing methodologies follows.

### 2.9.1 THE "DAYS OF AUTONOMY" METHOD

This sizing method, although useful as a "field estimate" technique, has many drawbacks which render it unsuitable for use in this project: It provides no measure of system reliability and thus provides no basis of comparison between SAPV and other power supply options, it does not allow for a trade-off between array and storage size without affecting system reliability and would therefore lead to an uneconomical system design, and it incorporates assumptions which would tend to oversize a system.

### 2.9.2 CHAPMAN'S METHOD

Unlike the "days of autonomy" method, Chapman's method uses LOEP as an indicator of system reliability and so may be compared with other supply options, and allows the system designer to optimize the cost by varying the array vs storage size combinations without affecting the LOEP. There are, however a number of points on which the system may be criticized, the first being the constraint that the average daily load may not vary by more than 10% from month to month. This may well render the system unusable in many applications, as it is not uncommon for the average load to vary by at least this amount over the year. However, Chapman is working on sizing nomograms which do away with this constraint.

The sizing technique also assumes that all the energy passes through storage, which would be expected to result in oversized systems. Oversizing is, however, not apparent when the results obtained are measured against Cowan's.

The main criticism of Chapman's sizing method, however, stems from his assumption that climate and variability in insolation are independent, and therefore all the insolation information needed to size a SAPV system is contained in the average "worst

month" insolation value. Cowan has pointed out that, firstly, the evidence on which the assumption was based does not merit such an assumption, and secondly, seasonal variations in insolation are dependent on climate, a fact not taken into account, and therefore to base a sizing method on the above assumption would lead to inaccuracies. Inspection of Chapman's LOEP vs 'days of storage' curves shows that in fact he has not been able to correlate the LOEP curves for sites of varying climates as accurately as is implied, casting further doubt on the validity of his assumption that climate and variability of insolation are independent, and on the accuracy of the method in general.

The results found in the previous section using this method reinforce these doubts, in that, using Cowan's results as a measure, the LOEP's resulting from various system sizes do not appear to represent values that could be expected from the given sizes. In general, the system reliabilities that could be expected appear lower than is indicated.

While Chapman's method is easy to use, the dubious assumptions he makes regarding insolation variability dealt with above, and the resulting inaccuracies in sizing, render his method unreliable and unsuitable for use in this project.

### 2.9.3 THE METHODS OF MACOMBER ET AL. AND ROSENBLUM

Since Rosenblum has simply improved and extended Macomber's method, the methods will be treated as one.

Nomograms for sizing systems of LOEP values 0.001, 0.01, and 0.1 are provided by this technique. If other LOEP values are required, a process of trial and error must be undertaken by first varying the array and storage size, and then computing the LOEP that results from this combination. This must be

repeated until the desired LOEP is obtained. The optimum system cost combination for systems of LOEP 0.001, 0.01, and 0.1 may be obtained from a nomogram presented by Rosenblum, but should a different LOEP be required, the optimum cost curve must be calculated from scratch, and used when choosing array and storage size combinations in the LOEP calculation procedure.

While the complexity of the above calculations and trial and error process is daunting if tackled by hand, it would still provide answers relatively rapidly if programmed for use on a computer, and therefore this complexity cannot be regarded as a disadvantage. However, the method can be criticized for other reasons: Firstly, Macomber has assumed that the insolation distribution of any particular site may be determined from the site's clearness index only, and appears to base this on studies such as those done by Liu & Jordan. Like Chapman, therefore, this method assumes that climate and variability in insolation are independent, an assumption shown to be at best questionable. However, unlike Chapman, the method does take into account (if rather clumsily) the fact that the seasonal variations in insolation are dependent on the climate of the site in question, by initially quick-sizing the system for each month of the year.

Secondly, the LOEP computational procedure is based on the assumption that all insolation distributions are normal, which, according to Klein & Beckman, is not necessarily true, and therefore the LOEP computations are not necessarily accurate.

The method also only determines the LOEP for the design month (i.e. the worst month) and provides little help in converting this to the long-term system LOEP. It merely states, with little supporting evidence, that the long-term LOEP is observed to fall within 20-40% of the design month value.



The already questionable accuracy of the sizing method is exacerbated by its incorporating the conservative assumption that all the energy from the array passes through storage.

When results obtained using this method are compared with Cowan's results, the discrepancy between the two does nothing to instill confidence in the method. The results do not, however, indicate that Rosenblum's method oversizes due to the inclusion of the assumption that all energy passes through storage, as would be expected.

It can be concluded, therefore, that the method is rather course, and includes assumptions concerning the distribution of insolation which would result in an unreliable LOEP value for the design month. Converting this value to long-term LOEP is also done coarsely, and therefore the method can only be regarded as a rough sizing method, and is not suited for use in this project.

#### 2.9.4 THE SIZING METHOD OF BORDEN ET AL.

Although this method is dealt with separately here, it is based on the method developed by Macomber and is therefore subject to the same criticisms: It assumes that insolation distribution and climate are independent (although taking into account seasonal variability in insolation), and that insolation distribution is always normal. The long term LOEP is stated to be between 20-40% of the worst month LOEP, a relationship presumably taken from Rosenblum, who appears to base this observation on scant evidence, and is therefore to be viewed skeptically. The authors intend to size a system for a worst month LOEP of 0.01, a figure supposedly comparable to the LOEP of diesel and battery power supply systems. However, because of the assumptions on which the LOEP model is based, the LOEP value of 0.01 cannot

be regarded as an accurate indication of actual system reliability that could be expected.

The method appears to take into account systems that supply a portion of the load directly from the array, and so apparently increasing sizing accuracy, but Macomber has already included the assumption that all the energy passes through storage and so the system may already include the resulting inaccuracies, but the work of the authors is not referenced closely enough to confirm this.

Results obtained when using this method do not compare well with Cowan's results. These, rather than Cowan's results, are expected to be inaccurate. They do not, however, show the system to be noticeably oversized as would be expected from the inclusion of the assumption that all energy is cycled through storage.

Like the methods of Macomber et al. and Rosenblum, this method cannot be regarded as reliable. It must be remembered, however, that the authors only intended the method to give an estimate of system size to enable estimation of life-cycle costs.

#### 2.9.5 COWAN'S SIZING METHOD

Because this method restricts its attention to periods when the average insolation is less than is required to support the load, it is able to make more accurate assumptions concerning system efficiencies than do the other sizing methods dealt with in this review, and is therefore expected to be more reliable than the other methods, although not as accurate as the hour-by-hour simulation programs.

The main advantage that this system has over the others, however, is that it uses empirical insolation data from the site in question (or a representative site), and so avoids the generalizations concerning insolation distribution that the other methods have made, and therefore the inaccuracies arising therefrom.

With the use of observed insolation values, however, comes the problem of handling the large amounts of data, and so this method can only be used with the help of a computer. Hourly insolation data for a site (representing an area) would have to be processed for various tilt angles to give POA insolation probability curves - a process requiring extensive use of computers. However, this process has only to be undergone once for each site. The resulting set of POA probability curves could then be called up at will to size systems for varying load demands.

The methodology would result in a set of array vs storage size combinations that satisfy the required LOEP, and from these the most cost effective combination could be chosen, depending on the current costs of PV panels and batteries.

Because of the limited amount of hourly insolation data available in South Africa, it can be expected that some uncertainty will result in system sizing for low LOEP's. This is because, as Klein and Beckman point out (1987,501), to attain some stability in insolation distribution patterns for low probability levels (LOEP=0.01 and less), 50 years of hourly insolation records may be needed. It must nevertheless be remembered that the use of empirical data as done by Cowan, constitutes a significant improvement on the generalizations concerning insolation distributions used in the other methods reviewed.

Cowan's assumption that the batteries never exceed 90% state-of-charge in order to compensate for the possibility that the batteries will not be fully charged at the beginning of an energy deficit run, and for the lower system efficiencies that occur as the batteries reach full SOC, appears to be rather arbitrary and is expected to result in a degree of inaccuracy in the sizing procedure.

Further uncertainties in the method include the effects of assuming the module temperature to be in the region of 25°C for energy deficit periods, and the possible advantage of considering longer run-lengths in the sizing procedure.

Overall, however, the assumptions made by the method are considered safer than those of the other methods reviewed, and it is therefore expected to provide the most accurate sizing results. Its suitability for use on a computer is compatible with the purpose of this project, which is to establish a computer based tool for the comparison of various power supply alternatives. Cowan's method, therefore, will be used in this project.

The details regarding how this method is used in the program are included in chapter 5 and appendix A. This appendix also includes the SAPV system costing methodology used.

Information concerning the data processing undertaken to enable this method to be used in applications country-wide are given in appendix B.

CHAPTER 3

DIESEL POWER GENERATION SYSTEM

SIZING AND COSTING METHODOLOGY

### 3. DIESEL POWER GENERATION SYSTEM SIZING AND COSTING METHODOLOGY

#### 3.1 INTRODUCTION

##### 3.1.1 OBJECTIVES

This chapter will establish an acceptable genset sizing and costing methodology for use in the power option comparison package, which evaluates the suitability of various supply options for a particular site. The genset sizing should result in a system of known reliability in order that it may be compared with other options.

##### 3.1.2 DIFFICULTIES IN ESTABLISHING THE METHODOLOGIES

A survey carried out by Williams (1988) on current diesel generation practices in South Africa, has indicated that running costs and engine reliability and lifetimes vary greatly amongst users. Generation costs were estimated to vary from 85 c/kWh to 170 c/kWh at the time (1988), and this estimate included assumptions such as equal engine lifetimes and operation & maintenance costs, which would tend to narrow down the field of variation. In practice, therefore, the variation is very likely greater than indicated by these figures.

Kenna (1987), in his detailed survey of diesel gensets in rural Kenya, found generation practice, and therefore costs, to be equally varied amongst users.

The reasons for this large variation in generation costs may be largely explained by the great diversity in capacity factors and maintenance schedules of installed sets. The many different types and ages of gensets, different delivered fuel prices, and

variation in distance to support facilities also contribute to this large range of generation costs. In general, there is very little information available to enable the effects of each of the above on generation costs to be quantified accurately, but trends may be identified which allow reasonable assumptions to be made concerning their effects on power costs. Each of these factors will now be dealt with in more detail in order to extract these assumptions.

### 3.2 ESTABLISHING THE FACTORS TO BE USED IN THE METHODOLOGY

#### 3.2.1 CAPACITY FACTOR

Gensets are sized according to the peak load that must be met, and the average power demand is often significantly less than this. This low capacity factor results in expensive power generation since the genset efficiency (measured as electrical energy out / fuel energy in) increases with increasing capacity factor (Morris, 1988, p8). In addition, a low capacity factor results in engine damage due to carbonation and cylinder bore glazing, thus shortening the engine life (Williams, 1988, p30). It follows, therefore, that a high capacity factor results in improved generation costs due to more economic genset operation and longer engine life. Figure 3.1 by Paul (1981, p78) illustrates this point. Here it can be seen that, for the genset in question, the cost of power generation for a capacity factor of 10% (called 'percent of rated capacity' on graph) is about five times that for a factor of 100%. This relationship is supported by Morris (1988, p200), as is shown in figure 3.2, which represents a set of similar size to that used by Paul. Here the trend of falling unit energy cost for increasing capacity factor is once again clearly shown. Inspection of both the figures produced by Paul and Morris indicates that unit power costs may be kept to within 100% of their optimum if the capacity factor is 40% or higher. Williams (1988, p43) found

that typical capacity factors in South Africa ranged between 10% and 40% .

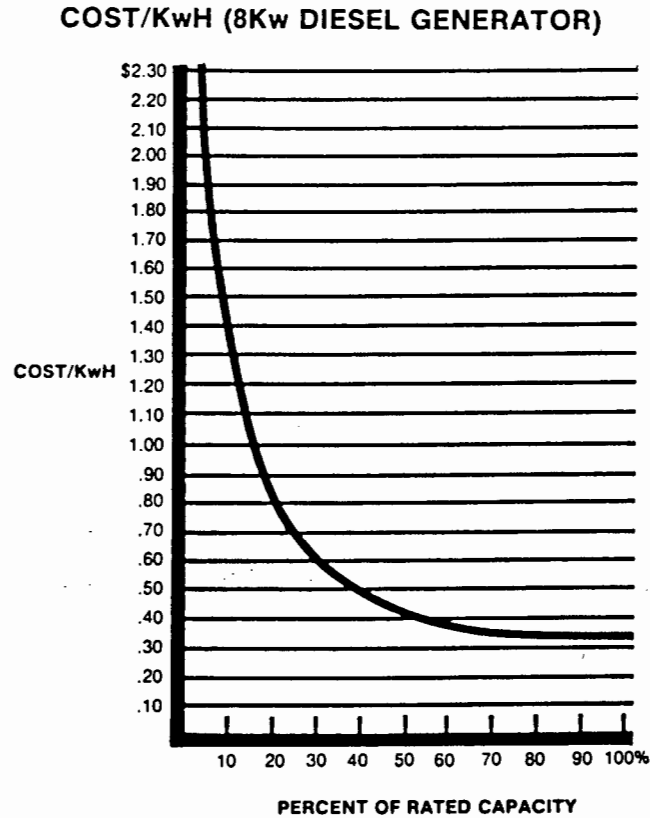


Figure 3.1 : The cost of energy from an 8kW diesel genset for different capacity factors as determined by Paul (Paul,1981,p78).

Various practices may be adopted to increase the capacity factor to avoid engine damage. Most users practice some form of load management - i.e. they use appliances demanding electricity during as short a period as is practical, thus providing a higher average load and so running the set at higher capacity. The effect of this is to decrease engine damage due to underloading, and to result in more efficient generation. Often, however, capacity factors remain lower than 40% even with load management. Another practice adopted to increase the capacity factor is to use "dummy loads". These are non-essential loads which are switched on as the total load varies,



to provide a better match between genset output and demand. Water heating or unnecessary lighting are amongst those loads used. While "dummy loads" help preserve the engine, they are often of little or no economic benefit to the genset owner, and thus result in expensive useful power generation costs. To fully assess the benefit of dummy loading it would be necessary to evaluate whether the savings resulting from the reduced engine maintenance and increased lifetime, outweigh the high useful power generation costs. This is beyond the scope of this thesis.

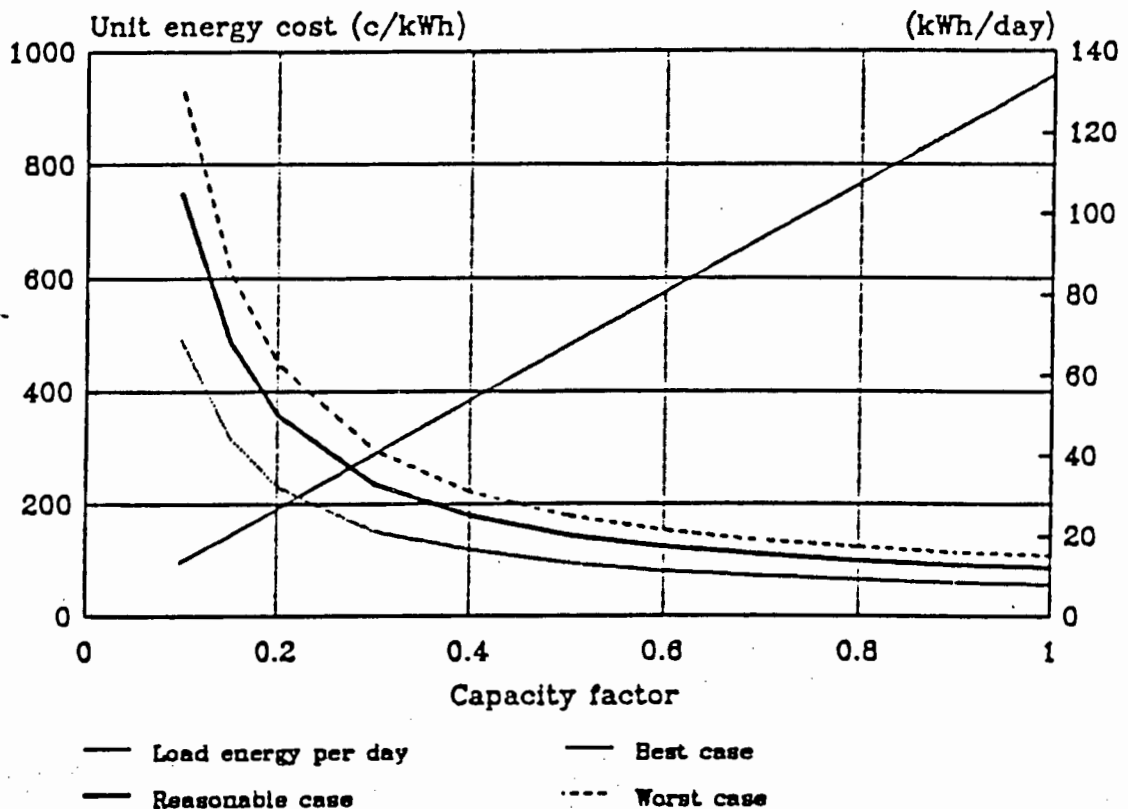


Figure 3.2 : The cost of energy from a 5.6kW genset for different capacity factors, as determined by Morris (Morris,1988,p200).

Where capacity factors are low, it may be economical to install a genset/battery hybrid system. This is a system whereby the genset capacity not being used directly for loads is used to

charge batteries which then supply the energy demand when the genset is not running. This will not be dealt with in this thesis.

In summary, therefore, the capacity factor has a large influence on engine life, maintenance costs, generation efficiency and thus fuel costs, and so is important in determining system life cycle costs and energy costs. Since the comparison package compares systems on the basis of these costs, the assumptions used in the package concerning capacity factor should be realistic, and thus based on current generation practices. It is therefore necessary to include the capacity factor effect in the diesel genset sizing and costing. The effect on engine life and maintenance costs will be dealt with in the relevant sections. Here only the set fuel efficiency will be examined in relation to capacity factor.

Morris, Paul, and Kenna have looked at this relationship between energy cost and capacity factor, and while Paul only produced the values shown in figure 3.1, the other two examine the relationship in more detail:

Morris (1988) has undertaken a detailed study of three well maintained gensets used in the Kruger National Park. The ratings of these sets were 7kVA, 225kVA, and 250kVA. For the 7kVA set, the generation costs related to capacity factor compare well with those found by Paul, as is shown by figures 3.1 and 3.2. The genset efficiency variation with differing capacity factor matches up well with those found by Kenna in his study of a similar sized genset (Morris, p149). While this lends credibility to Morris' results, no such analysis of the larger gensets is undertaken, and therefore he provides little help in establishing efficiencies for a range of gensets. The only helpful information given on the larger gensets is their average efficiency of 34.4% at average capacity factor of 0.58.

The high capacity factor is a result of the sets being used for the same power supply system, thus when demand is small only one set is used with resulting good capacity factors.

Kenna looks at seven relatively well maintained diesel engines in rural Kenya, three of which are used for generation, and the remainder for pumping. Tests were carried out to establish the system efficiencies on the engines, which vary greatly in capacity, age, condition, and method of use. This great variety of factors unfortunately has the result that no significant trends may be observed relating genset efficiency and capacity factor. Typical monitored capacity factors were around 10%, with the highest being 30% and the lowest 9%. The corresponding range of engine efficiencies was between 4% and 17%.

A clearer picture emerges when the fuel consumption figures are examined, as shown in figure 3.3. Here values from Morris, Paul, and Kenna are displayed, and, although there is a fair amount of scatter, a clear trend is visible in that higher capacity factors are consistently more economical in fuel consumption, and the best efficiencies are generally obtained by the larger sets, particularly for higher capacity factors.

Based on Morris' and Paul's curves for the smaller gensets (+-7kW), and Morris' curve for the larger sets (+-200kW), it was decided to divide the fuel consumption patterns for various sets into 3 groups: - up to 20 kW sets following the curve of Morris and Paul for small gensets; from 21 to 80 kW following an intermediate curve; and greater than 80 kW following the Morris curve for the 200kW sets. Although these curves are based on a small amount of data, it is felt that they provide sufficiently accurate consumption figures to fulfill the aims of the project, and greater accuracy would be out of context with other rather sweeping assumptions made regarding factors such as maintenance costs and engine lifetime.

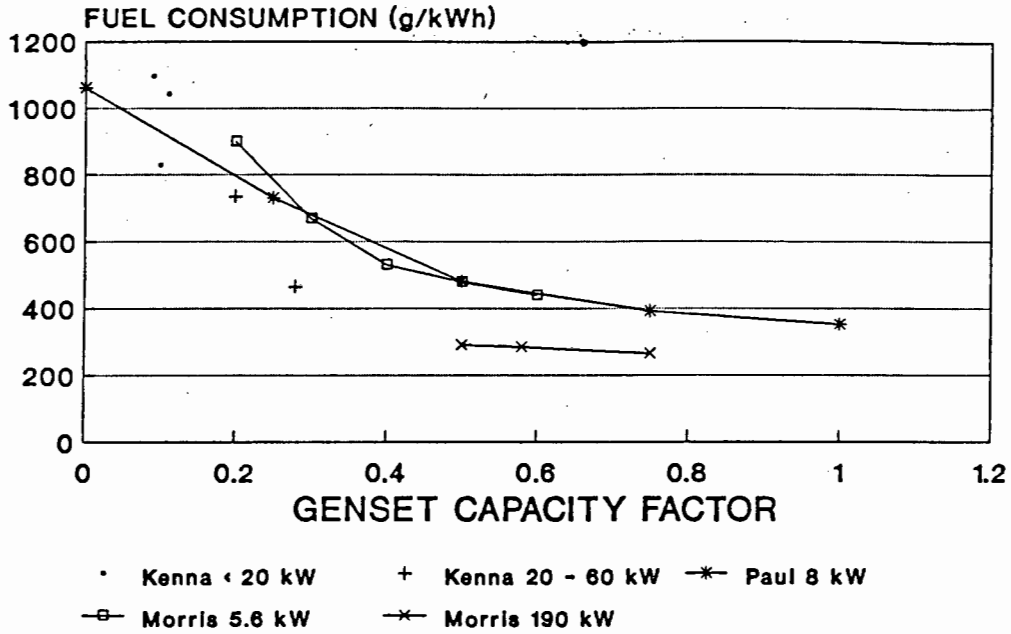


Figure 3.3 : Fuel consumptions for various genset capacity factors, for a range of different sets.

In practice, the number of start/stop cycles per day of the generator will also effect the fuel consumption of the genset since a cold engine is inefficient, and takes from 15 minutes to 1 hour to approach operating efficiency. However, the effect of this on overall energy costs is expected to be small, and will be ignored in this thesis.

The average capacity factor used for a particular genset sizing will simply be the average load divided by the maximum genset output capacity (after altitude derating). However, since the relationship between fuel consumption and capacity factor is not linear, the fuel consumption figure obtained from this average capacity factor will result in a lower value than is the case in practice, where the genset operates for various lengths of time at different load fractions. To overcome this problem, ten different load profiles were taken, representing six different capacity factors, and for each the average fuel

consumption was determined by integrating the different fuel consumptions for the changing instantaneous capacity factor of the load profiles. This average value was then compared with the original fuel consumption vs capacity factor curves, which were then adapted to give average fuel consumption figures for a given average capacity factor. This was performed for three different genset sizes. The average consumption figures obtained from the adapted curves were all found to be within 10% of the values found by integration, the majority of the values being within 3%. A difference of 10% was found to affect the cost of energy by at most 5%, an error considered acceptable for the purpose of this thesis.

Because the fuel consumption varies so greatly with changing capacity factor, the length of time for which the genset is run per day, and thus the average capacity factor, will substantially affect the cost of energy. Since capacity is a major determinant of diesel generation energy cost, the effect of genset run-time on energy costs will be discussed in more detail in Chapter 6, which deals with results produced by the comparison package.

### 3.2.2 MAINTENANCE

Another factor which contributes significantly to the cost of electricity generation is how the genset is maintained. Williams reports that maintenance as practiced in South Africa is varied and generally sub-standard, and gensets are commonly run from breakdown to breakdown - in other words completely lacking in scheduled maintenance. Poorly maintained sets not only run less efficiently and become expensive to maintain over the genset lifetime, but provide a less reliable source of power than those receiving regular maintenance.

Since maintenance practice is so varied, it is necessary to make some assumptions concerning typical maintenance costs. Williams, in his report, uses a maintenance cost of 50% of the initial genset capital cost spread over the system lifetime. He says "This factor was determined on the basis of discussions with diesel mechanics working in rural areas, and users and suppliers of diesel generating equipment"(1988,p36). He considers such a "high" figure justified considering the typically low load operation of diesel gensets. Paul assumes a maintenance cost of 25% of the initial capital cost spread over the system lifetime (1981,p79), but does not substantiate this figure.

Morris, however, undertakes a more detailed study of genset maintenance costs. He states that operating and maintenance costs "have been the most difficult factor of the life-cycle cost to estimate and have in the past been assumed to be much lower than appears to be the case in practice." (1988,p152). His estimates are substantially higher than those of both Williams and Paul. For the 7kVA genset studied, having an assumed lifetime of 7 years, operating for 11.15 hours/day, and incurring maintenance costs of R1.02/hr (which Morris considers to be inadequate maintenance), the present value of the maintenance costs over the system lifetime works out at about 130% of the initial capital costs of the genset system. The larger gensets studied, having assumed lifetimes of 15 years, operating for 12.15 hrs/day on average, and costing R4.13/hr in maintenance, result in present value maintenance costs of 113% of the initial capital investment for the system.

Since the maintenance figures of Paul are unsubstantiated and those given by Williams are based on scant evidence, Morris' figures must be considered the most accurate. Indeed, the detail in which Morris investigates the costs involved lends credibility to his results. A lifetime maintenance cost of

120% of the initial capital outlay for a genset system is therefore recommended for use in this project.

The effect of maintenance cost assumptions on the cost of energy generated for two different size gensets can be seen in figure 3.4. The figure was generated using the diesel genset sizing and costing package established in this thesis. For both gensets considered, a 50% difference in maintenance costs results in an energy cost difference of approximately 20%.

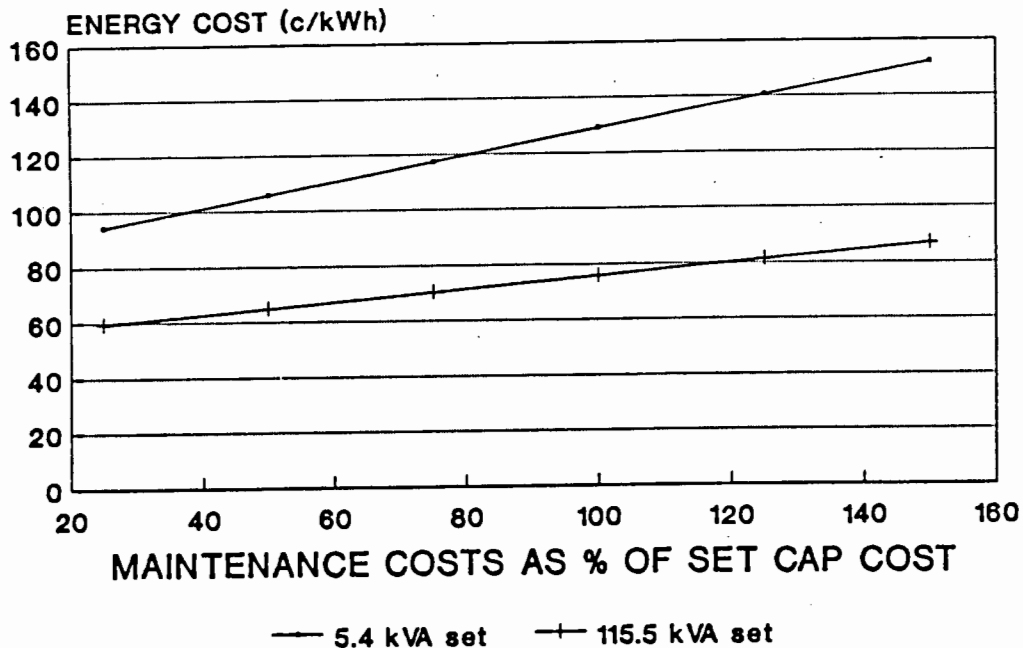


Figure 3.4 : The change in the cost of a unit of energy for different maintenance cost assumptions.

Although maintenance costs are expected to vary with sets used at different capacity factors due to engine damage at low capacity factors and increased wear at high capacity factors, no information was found which enabled this relationship to be quantified. This variation in maintenance costs will therefore be ignored.

### 3.2.3 LIFETIME

Genset lifetime is generally dependent on the engine, and is therefore strongly influenced by maintenance practice and average capacity factor at which the set is used. However, little information was found relating capacity factor and engine life, and for the purposes of this project, maintenance practices must be assumed to be uniform in all cases. Genset lifetime will therefore simply be based on the estimates and observations of Paul, Williams, Kenna, and Morris.

Paul (1981,p79) uses genset lifetimes ranging from 5000 hrs to 10 000 hrs depending on the capacity factor, but does not substantiate these. According to Williams (p34), genset suppliers estimate set life to be 15 000 hrs, but according to the results from his survey of South African genset users, many sets currently in use have over 20 000 hrs to their credit. Kenna's study of gensets in Kenya also suggests that lifetimes over 15 000 hrs are commonly attained. Of the 18 diesel gensets and pumps that he looked at, 10 had been in use for over 15 000 hrs, 7 for over 30 000 hrs, 5 over 50 000hrs, and 3 for over 60 000 hrs. These figures appeared to be independent of genset size. Morris estimates that, for the three gensets he examined, the 7kVA set could attain a life of 30 000 hrs (at the time of the study it had logged 13 000 hrs and was in good condition), and the larger sets could attain 60 000 hrs, judging by their excellent condition and logged hours of 16 000 and 24 000 respectively at the time of his examination.

Looking at existing genset logged hours and extrapolating this to result in an expected lifetime for sets in general, is of course deceptive in that no information on actual lifetimes is available since only working sets have been studied and "expired" sets are ignored. Ideally, a statistical analysis of



expired set lifetimes should be undertaken to establish the life that may be expected from a set, but since the required information is not available, assumptions based on the above data must be made.

Set lifetime is expected to vary with genset size. For example, a 500 kVA set is expected to last significantly longer than a 5 kVA set. However, the only information found relating set lifetime and size was the study done by Kenna, as mentioned above, and this indicates that, for gensets up to 100 kVA, size is not an important factor in determining set lifetime. For the range of gensets considered in this thesis, therefore, the variation of set lifetimes with size will be ignored.

From the above, it is reasonable to assume that most gensets would attain a life of between 20 000 and 30 000 hrs if maintained reasonably. Since the maintenance costs assumed in the previous section make provision for such maintenance, such lifetimes are consistent with these assumptions. A genset lifetime of 25 000 hrs is therefore recommended for use in the power supply option comparison package.

Figure 3.5, generated using the diesel genset sizing and costing package developed in this thesis, demonstrates the effect of set lifetime on unit energy generated costs. The energy cost sensitivity to set lifetime decreases significantly with increasing lifetime, and above about 23000 hours the energy cost decreases by less than 10% per extra 5000 hours of engine life.

#### 3.2.4 LOEP

Loss of Energy Probability for a genset can be based on observed failure frequency data. It is reasonable to assume that a low average capacity factor will increase the set LOEP

because of the resulting engine damage, as will poor maintenance practice, but information relating such factors is not available, and to generate such data is beyond the scope of this thesis. It is expected, however, that by using observed system failure rates taken from a number of independent sources, generalizations of acceptable accuracy may be made.

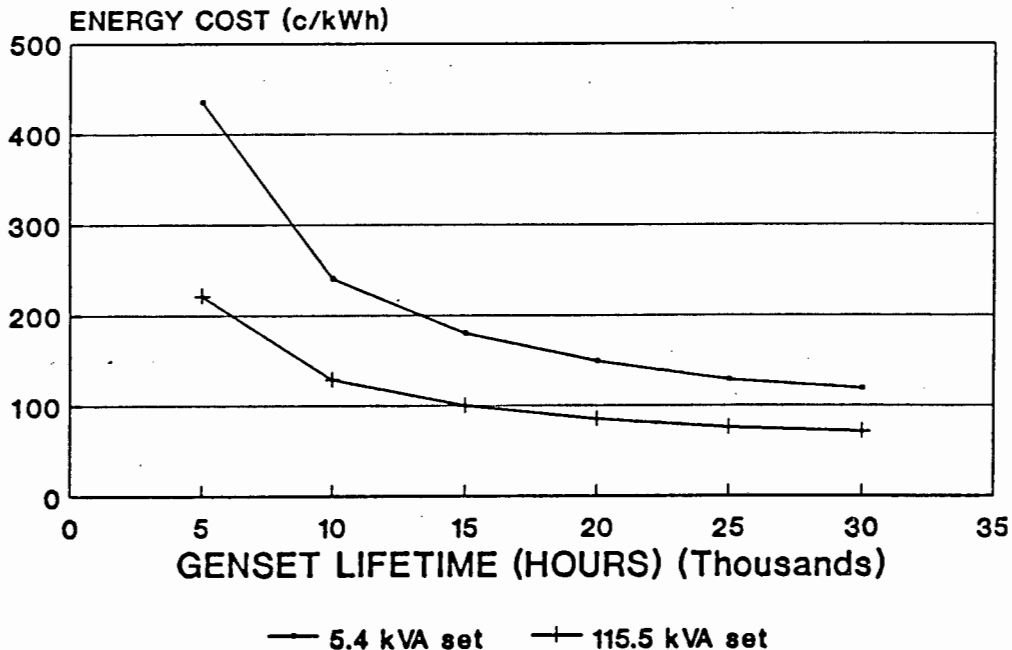


Figure 3.5 : The change in energy cost using different genset lifetime assumptions.

Rosenthal (1982) gives a genset availability figure of 95%, which he regards to be conservative. For the 7 sets monitored in some detail by Kenna (1987) over a 3 month period, the lowest recorded genset availability was 93%, and the average availability amongst the seven sets was 97%. Morris' study on the availability of the larger sets monitored by him resulted in a figure of approximately 99% availability. Borden et al. (1984, p2.8), in the presentation of his photovoltaic sizing method, regards the LOEP of a diesel generation system to be roughly 2% to 4%. All of the above figures indicate that

genset LOEP lies in the range of 1% to 7%. A LOEP of 5% (0.05) may thus be considered typical of diesel generation systems.

#### 3.2.5 ALTITUDE DERATING

It is necessary to derate the engine output power to account for the altitude at which the set operates where the site is not at sea level. Williams uses derating factor of 4% per 300m above sea level (1988,p32), and this value will be used in this project.

#### 3.2.6 OTHER FACTORS USED

A power factor of 0.8 was assumed, and a short term maximum generator power output of 90% of the rated kVA capacity was used in the system sizing.

#### 3.2.7 COSTING

The genset system costing was based on the method of Borden et al. (1984). Briefly, the initial system costs are combined with the present value operation and maintenance costs and any genset replacement costs over the project lifetime, to give a present value system life-cycle cost. From this the annualized unit energy cost is obtained. The costing methodology is explained in more detail in appendix A.

CHAPTER 4

GRID EXTENSION POWER

COSTING METHODOLOGY

## 4 GRID EXTENSION POWER COSTING METHODOLOGY

### 4.1 OBJECTIVES

Having already established sizing and costing methodologies for diesel and photovoltaic power supply systems, it remains to do the same for grid electrification so that the three supply alternatives may be compared. This chapter will therefore establish a sizing and costing methodology compatible in accuracy with the others, and resulting in a power supply of known reliability. This reliability will serve as a basis for the comparison and evaluation of the three options.

### 4.2 THE COSTING OF POWER FROM EXTENDING THE NATIONAL GRID

Unlike diesel generation, the cost of grid power is relatively easily determined. The monthly cost to the user is determined by the energy demand characteristics such as peak load and total demand, added to any extension charges levied. ESKOM has a comprehensive tariff schedule for users of various categories which is divided into large users (>100kVA), and small users (<100kVA), and grid extension charges are set according to the peak demand of the user, and distance and terrain to be covered from the existing grid to the site in question. The only uncertainties arise from the necessary simplification of demand profile to an average and peak demand, and the estimation of terrain type and ground hardness involved in grid extension.

The grid extension cost increases with hardness of ground and difficulty of terrain to be covered, and therefore in a general comparison package such as this, a range of terrain types and associated typical extension costs only can be given, from which the package user must choose the type most representative of that to be covered for the site needing power. This can

only be an estimate of actual extension costs which would normally be determined by an ESKOM inspection of the terrain. Since the least expensive extension cost was R16000/km (for level, soft ground) at the time of writing, and the most expensive R25000/km (mountainous terrain), it is reasonable to assume that the cost estimated by the package user would be within R2000/km of the actual cost of extension. Calculations show that this inaccuracy affects the cost of power per kWh by at most 15%, and this occurs for low energy demands (below 50 kWh/day). For demands of 50 to 100 kWh per day, the effect typically ranges from 5 to 10% , depending on the length of the extension. The shorter the extension, the less the effect. Extensions of greater than about 10km, however, would incur an inaccuracy of greater than 15% for a cost-per-kilometre estimate out by R2000. Since the cost of grid power tends to be prohibitive for such long extensions because of high extension charges, this would have little effect on determining the viability of various power supply options.

The other factor which results in inaccuracy of grid power costing, is the simplification of energy demand to an average and peak demand only. Although this simplification is common to all the power options being compared, here it has the added effect that user tariff category, which can depend on demand profile, may not be accurately determined from the simplified demand data in some cases.

Briefly, ESKOM's tariff categories are as follows (ESKOM 1989a):

Category "A" - The standard large user tariff.

Category "B" - Urban, low voltage, non-domestic, small user tariff.

Category "C" - Urban, low voltage, domestic supply tariff (available to small and large users).

Category "D" - Mainly rural, small user tariff.

Category "E" - Off-peak, large user tariff.

Category "F" - Low load factor, large user tariff (<20.5%).

It can be seen that tariff category "E" for example, is an off-peak tariff which applies to those that use >65% of their total energy demand during off-peak periods, and may be more economical than the standard large user tariff (category "A"), but whether the user qualifies for this cannot be determined from the simplified demand data.

The question therefore arises as to which categories should be used in the grid power costing procedure. For small users, the tariff that would apply to sites at present not connected to the grid, is category "D", and this will therefore be used. For large users the situation is more complex since remote sites may qualify for any or all of categories "A", "E", or "F". About tariff category "F", ESKOM says: "Customers with a variable demand and a low load factor will benefit from this tariff. The breakeven point between Tariffs A and F is at a load factor of approximately 20.5%." (1989a,p3). Since the load factor of the user may be determined from the program input data, this tariff may be used in the comparison package.

For large users, therefore, only tariffs "A" and "F" will be included in the costing procedure for power from grid extension. Since more detailed demand data is needed to determine

if the user qualifies for tariff "E", the off-peak tariff, it will not be considered.

#### 4.2.1 THE TARIFFS

Depending on whether the consumer is a large or small user, different tariff structures apply. These are summarized below.

##### ESKOM's Small User Tariff Structure (1989b):

- (1) Basic charge - due whether electricity is used or not.
- (2) Energy charge - charged per kWh used.

##### ESKOM's Large User Tariff Structure (1989b):

- (1) Basic charge - due whether electricity used or not.
- (2) Demand charge - charged per peak kVA supplied during the month.
- (3) Energy charge - charged per kWh used.
- (4) Transmission charge - dependent on the site distance from the centre of Johannesburg.

#### 4.2.2 THE EXTENSION CHARGE

These also vary depending on whether the user is a small or large consumer, and they apply where a new power supply point has to be installed by ESKOM to supply a particular site or community with electricity. They usually depend on the total cost of establishing the power supply point.

##### 4.2.2.1 Small User Extension Charges (ESKOM, 1989c)

To determine the small user extension charge, it is first necessary to establish the total cost of the extension. This involves adding the line extension costs, +-R18000/km for the 11 or 22kV lines used, to the transformer cost, which varies with the kVA needed by the user. The monthly extension charge



levied on the user is then set at 1.35% of the total extension cost, subject to a minimum monthly charge of R216/km of extension. At present ESKOM gives a rebate of R216/km for the first 2km of extension to users, but they are negotiating with the various bodies representing the users to whom this applies, to have this rebate removed. This is because ESKOM is apparently not recovering sufficient funds to pay for such extensions.

#### 4.2.2.2 Large User Extension Charges (ESKOM,1989c)

Here the monthly extension charge levied is also 1.35% of the total extension cost. With large users, however, metering costs become significant (+-R2000), and must be added into the extension cost. The cost per kilometer of the line extension is the same as for the small user lines, since for demands up to as high as 500kVA, the 11 or 22kV lines are still used. The monthly extension charge is subject to a minimum of R1.50 per kVA installed for the user. The rebate applicable to large users is R2.00 per peak kVA used by the customer during that month.

#### 4.2.3 THE TOTAL CHARGES LEVIED ON THE USER, AND THE FINAL ENERGY COST

The total monthly charge payable by the user is determined by the sum of the applicable tariffs and the extension charge levied per month. This total monthly charge may then be divided by the number of kWh used during the month to determine the cost of power per kWh. The result may then be used to compare the cost of energy from grid power to that of another supply alternative.

#### 4.3 POWER SUPPLY TO COMMUNITIES

Where communities are concerned, ESKOM normally supplies the governing municipality with a power point, either at high or low voltage, depending on the requirements of the municipality

and the layout of the community. For example, a spread out community would require high voltage to facilitate distribution. However, in South Africa there are few large communities without grid electricity. It may therefore be assumed that all new supply points established by ESKOM will be low voltage and therefore all extension costs will include the cost of a transformer. If the supply is to be divided amongst several households in the same area, for example, the supply may still be compared with other alternatives, since the cost of power from the supply point is given per kWh.

#### 4.4 GRID POWER SUPPLY LOEP

ESKOM has kept detailed records of incidents leading to the loss of installed Mega Volt-Amps (MVA) over the past two years for the Western Cape region. These records, however, only refer to the loss of installed MVA resulting in reduced supply capacity, and not to the actual loss-of-energy as experienced by the power user - which is the LOEP figure being used as a basis for comparing the various supply options in this package. For example, these loss of installed capacity incidents may occur in times of low demand, and thus have no effect on the consumer. These figures also refer only to ESKOM power supply, not to supplies that fall within municipal responsibility. This, however, does not present a problem for the comparing of various alternatives in an off-grid situation, since the majority of these cases will fall under ESKOM's wing.

The loss-of-MVAhr figures from January '87 to August '89, as supplied by ESKOM's Performance Division in the Western Cape, are summarized below (Distribution = >33kV, Reticulation = <33kV):

	<u>Distribution</u>	<u>Reticulation</u>
Average installed capacity (MVA):	3287.347	1496.988
Average hours in monitoring period:	731.143	731.143
Average MVAhrs lost during period:	219.283	693.971

Since lines of 33kV and over are usually installed for demands well in excess of 500kVA, the figures affecting this comparison package are the reticulation loss-of-MVAhrs. The reliability of the national grid, which would also affect users requiring grid power, may be regarded as 100 % . From the above figures, a supply availability may be calculated as follows :

$$\frac{(\text{installed MVA} * \text{hours in period}) - \text{MVAhrs lost during period}}{\text{installed MVA} * \text{hrs in period}}$$

which results in a supply availability of 99.937% . It must also be remembered that the loss-of-energy experienced by the user will be less than this figure, since the MVAhrs lost may not actually be in demand at that time. It may, however be the case that remote sites experience a greater loss-of-MVAhrs, since grid repair may be slower in these parts. No information is available to enable an estimate for such sites to be made. It seems reasonable, however, to assume that the loss of MVAhr figures found above provide an indication of the LOEP that may be expected for grid extension power. A LOEP value of 0.001 may therefore be assumed representative.

#### 4.5 POWER FACTOR OF GRID ELECTRICITY SUPPLY

According to the Power Marketing Division of ESKOM in the Western Cape (ESKOM,1989c), a power factor of 0.85 is representative of ESKOM power supplies.

CHAPTER 5

DESCRIPTION OF THE POWER SUPPLY

OPTION COMPARISON PROGRAM

## 5 DESCRIPTION OF THE POWER SUPPLY OPTION COMPARISON PROGRAM

This chapter will outline the program structure and content, and will briefly discuss how the program uses the sizing and costing methods dealt with in the previous chapters. More details of the program are given in appendix 'A'. This appendix provides the formulae used for sizing and costing, as well as information on system component efficiencies.

### 5.1 A GENERAL DESCRIPTION OF THE PROGRAM

The program comprises three main modules, each dealing with one of the options considered - photovoltaic, diesel generation, or grid extension power supply. Each module may be used independently or in conjunction with the others, and therefore the program may be used to evaluate a single option only if required, or more than one.

In order to remain flexible, as much data as possible may be changed by the user. This allows the general default data used by the program to be replaced with values more specific to a particular application, and thus increases the accuracy of the results. It also allows costing and technical data to be updated periodically. Because the program contains default values, it caters for those with a limited knowledge of the technical aspects, such as stand-alone photovoltaic (SAPV) system component efficiencies, while allowing the more knowledgeable user to input other values.

If it is required to undertake several runs for a particular option, the program allows the user to do this changing only specified groups of data, thus avoiding the monotony of re-entering identical values for each repeat run.

Because the comparison package is intended for application in a wide range of situations, it was necessary to cater for a broad spectrum of demand characteristics. The limits set on the program input data are as follows :

Minimum peak load	: 10 watts
Maximum peak load	: 400 kilowatts
Minimum average daily energy requirement	: 50 watt-hours
Maximum average daily energy requirement	: 10 000 kilowatt-hrs

It is felt that these limits cater for as broad a range of applications as possible without excessively straining the assumptions that must inevitably be made in the construction of such a package.

The program has been written in the "True Basic" language, and may be used on any micro-computer with graphics capabilities.

## 5.2 STAND-ALONE PHOTOVOLTAIC SYSTEM SIZING AND COSTING IN THE COMPARISON PROGRAM

The program uses Cowan's SAPV sizing method. Before the method could be applied on a national basis, it was necessary to establish the "minimum expected insolation" curves (explained in chapter 2) for all areas of the country. Because hourly insolation data is necessary for this, the twelve weather stations around South Africa and Namibia that keep hourly insolation records were used. Each site was assumed to represent a surrounding area, which was demarcated in order to limit variation in insolation levels and climatic characteristics within its boundaries. The "minimum expected insolation" curves were then established for various LOEP values, and for a tilt angle which optimized the worst-month insolation for that site. The LOEP values considered were 0.1, 0.05, 0.01, 0.005, and 0.001, which cover the range of practical interest. The data process-

ing methodology is explained in appendix B.

When sizing a SAPV system for a particular site, the program draws on the "minimum expected insolation" curves for the area in which the site is located, and establishes the "minimum required insolation" curves for a range on array and storage sizes, as described in chapter 2. A set of array and storage sizes are then found that satisfy the demand and LOEP requirements. The most economical combination is then selected from amongst these, and the system is costed using these sizes. The costing methodology has been taken from Borden et al. (1984), and involves determining the present value of all costs over the project lifetime to establish a present value life-cycle cost (LCC). Battery replacement, operation and maintenance, and installation costs, as well as initial component costs are all included in the LCC. The annualized unit energy cost is then determined (see appendix A for details).

The inputs required by the program are :

- Supply requirements AC or DC
- Area of the country in which site is located
- LOEP required
- Fraction of energy demanded during daylight
- Average daily energy use in kWh
- Peak load in kW

While the program is being run, the costing, component efficiency, and battery related data used are displayed, and may then be changed.

The results produced by the program include system component sizes and a cost breakdown as follows:

Component sizes - Array (in Wp and sq.m)

- Storage (in kWh)
- Regulator (specified by max. input watts)
- Inverter (if AC) or Converter (if DC),  
(specified by peak watts demanded)

Cost breakdown - Initial capital outlay

- Battery replacement costs (present value)
- Operation & maintenance costs (present value)
- System life-cycle cost
- Unit energy cost (in c/kWh)

The option of printing out the results is provided.

### 5.3 DIESEL GENERATION SYSTEM SIZING AND COSTING

Diesel gensets are sized according to the peak load that they are required to meet. However, gensets are generally able to deliver more power over a short period than they can on a sustained basis. If the peak demand is a short term load such as an induction load, therefore, a smaller set may be able to supply the requirements than if the same peak load is a sustained one. The program therefore considers this in set sizing. The sustained power output capability of gensets is taken as 80% of the set kVA rating, and the short term output as 90%.

The program compensates for changes in genset performance with increasing altitude by derating genset capacity by 4% per 300 meters above sea level.



After sizing, the program costs the genset for all daily run-times, from the minimum possible up to 24 hours. The minimum run-time considered is set by the average daily energy requirement and the peak load, because the set cannot be run for less hours than the daily energy requirement divided by the peak load. Since different run-times result in different average capacity factors and thus different fuel efficiencies, and higher run-times result in a shorter genset life in years, life-cycle costs vary considerably as run-time changes. The program user is shown these costs, and is then asked to choose a likely daily run-time for the site in question. Using the chosen value, the set life-cycle costs and unit energy cost are determined.

The genset life-cycle costing is also based on the method of Borden et al. (1984), and considers initial system costs, operation and maintenance costs, and set replacement costs over the project lifetime (see appendix A).

The program requires the following inputs :

- Average daily energy requirement in kWh
- Peak load in kW
- Nature of peak load (inductive or steady load)
- Site altitude in meters
- Daily genset run-time required

The fuel consumption and costing data used may be changed while the program is being run.

The results produced are as follows :

- Genset - kVA rating
  - Steady power output capacity (kW)
  - Short-term power output capacity (kW)

- Costs - Initial capital outlay
- Operation & maintenance costs (present value)
  - Set replacement costs (present value)
  - Life-cycle cost
  - Unit energy cost (in c/kWh)

If the set size required to meet the peak load specified is under the smallest set size available (3.5 kW), then the program informs the user that the resulting capacity factor will be poor and thus energy costs will be high.

The option is given of printing out the sizing and costing results.

#### 5.4 GRID EXTENSION POWER SUPPLY COSTING

There are two main parts to the costing of grid extension supplied energy : determining the extension charge, and computing the standard demand related tariffs. The charges applicable vary depending whether the user falls into the large or small user category, the dividing line being a peak demand of 100 kVA. For small users, the program sums the demand related tariffs, which include a basic charge and an energy charge, to the extension charge, which is a percentage of the total cost of the extension. The extension cost comprises the per kilometer line extension cost and the transformer cost. The program also subtracts the rebate due for the first 2km of extension from the extension charge.

For large users, the standard tariffs applicable are basic, energy, demand, and transmission charges. These are added to the extension charges, which, in addition to the line extension and transformer costs, also include metering costs. The rebate due per kVA used by the customer is also subtracted. The program

considers both tariff structures "A" and "F" as defined by Eskom (explained in chapter 4). While rate "A" is the standard large user category and is generally used, if the load factor is below 20.5%, the rates for category "F" are used since it is expected to prove more economical to the user.

All the applicable charges are then added together to result in a total monthly charge levied on the user, and using this, the unit energy cost from the supply is determined.

The program requires the following inputs :

- Terrain type covered by extension (chosen from a list)
- Average daily energy requirement in kWh
- Peak load in kW
- Site distance from the existing grid
- Site distance from Johannesburg (if a large user)

All costing data used is displayed while the program is being run, and may then be changed.

The results produced are as follows :

- Extension related - transformer cost
- line extension cost
  - total extension cost
  - rebate due on extension charge
  - final extension charge

- Standard tariffs - Basic charge
- Energy charge
  - Demand charge (for large users)
  - Transmission charge (for large users)

Final results - Total monthly charge  
- Unit energy cost (in c/kWh)

As with the other program modules, the results may be printed out if required.

#### 5.5 FINAL RESULTS OF THE COMPARISON

If all three of the options are being compared, the program produces a final results screen as a summary of the most important results from each option. The information given in this screen comprises system sizes, initial, running, and life-cycle costs where applicable, and the final unit cost of energy from each option. The information displayed may be sent to the printer.

CHAPTER 6

RESULTS OBTAINED FROM THE POWER

SUPPLY OPTION COMPARISON PROGRAM

## 6 RESULTS OBTAINED FROM THE POWER SUPPLY OPTION COMPARISON PROGRAM

Having established sizing and costing methodologies for the various power supply options, and having included various assumptions in these methodologies as discussed, the resulting power supply comparison package will now be used to establish the main energy cost determinants for each option. These results will be used to indicate situations where each option may be viable, as well as pointing to ways of reducing the energy cost from a particular supply source.

Each option will first be examined separately, to establish the most important energy cost determinants for the particular power supply source, and to provide information on possible methods of reducing energy costs. Although factors such as the energy charge for grid electricity, or the price of diesel fuel may also be considered energy cost determinants, those dealt with here will mainly be the location dependent determinants, rather than the time dependent ones such as these. The major determinants for the three options will then be combined in a graph for use in determining the viability of each option in various situations and for various demand characteristics. The three supply options will then be considered together in various examples to illustrate the use of the comparison package in practical situations.

Finally, the use of the package for sensitivity analyses will be demonstrated.

## 6.1 GRID EXTENSION ENERGY COST DETERMINANTS

### 6.1.1 DISTANCE FROM EXISTING GRID AND AVERAGE ENERGY DEMAND

The cost involved in extending the national grid is high, involving line extension, transformer, and possibly metering costs. The largest amongst these is, with few exceptions, the line extension cost, which is at present around R20 000 per kilometer. When this is carried over to the user, therefore, it forms a significant part of his monthly payments, and, depending on the energy demand, has a significant effect on the unit energy cost.

Figure 6.1 illustrates this relationship between extension distance and unit energy cost for various average energy demands. As can be seen, the extension cost has a more adverse effect on smaller average energy demands than for larger energy consumption. The figure was generated using a per kilometer extension charge of R18000, which may be considered average, and an arbitrary peak load of the average energy demand divided by 2 hours. The effect of both per kilometer extension charge and peak load on unit energy costs will be discussed later. The discontinuity evident at the 2 km extension mark is due to the Eskom extension charge rebate of R216/km for the first 2 km applicable to small users, and all but the 500kWh/day energy demand fall into this category.

It is apparent that grid extensions over approximately 10 km can only be considered viable for users with large average energy demands.

Figure 6.2 provides more detail on energy costs for shorter extensions, which is likely to be the area in which many small users would find grid electricity viable. The figure was generated using the same assumptions as for figure 6.1. The rea-

son that the 500kWh/day energy demand unit cost is marginally greater than that for the 100kWh/day consumption for distances under 2.5 km, is that the 500kWh/day user falls into the large user category, having a peak load of in excess of 100kVA. It is therefore subject to a different tariff structure.

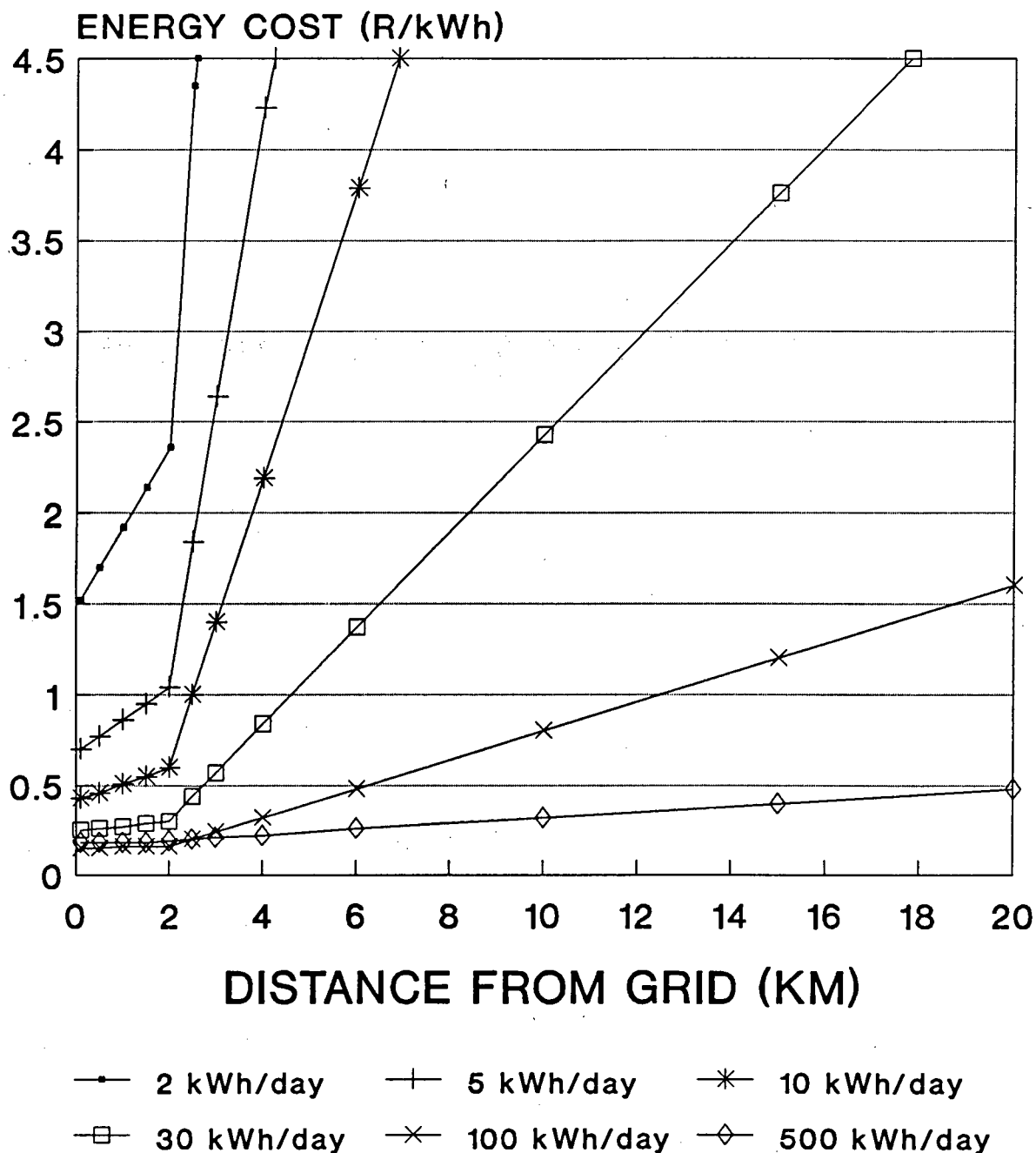


Figure 6.1 : Grid supplied energy costs for grid extension distances up to 20 km. The extension cost used is R18000/km.



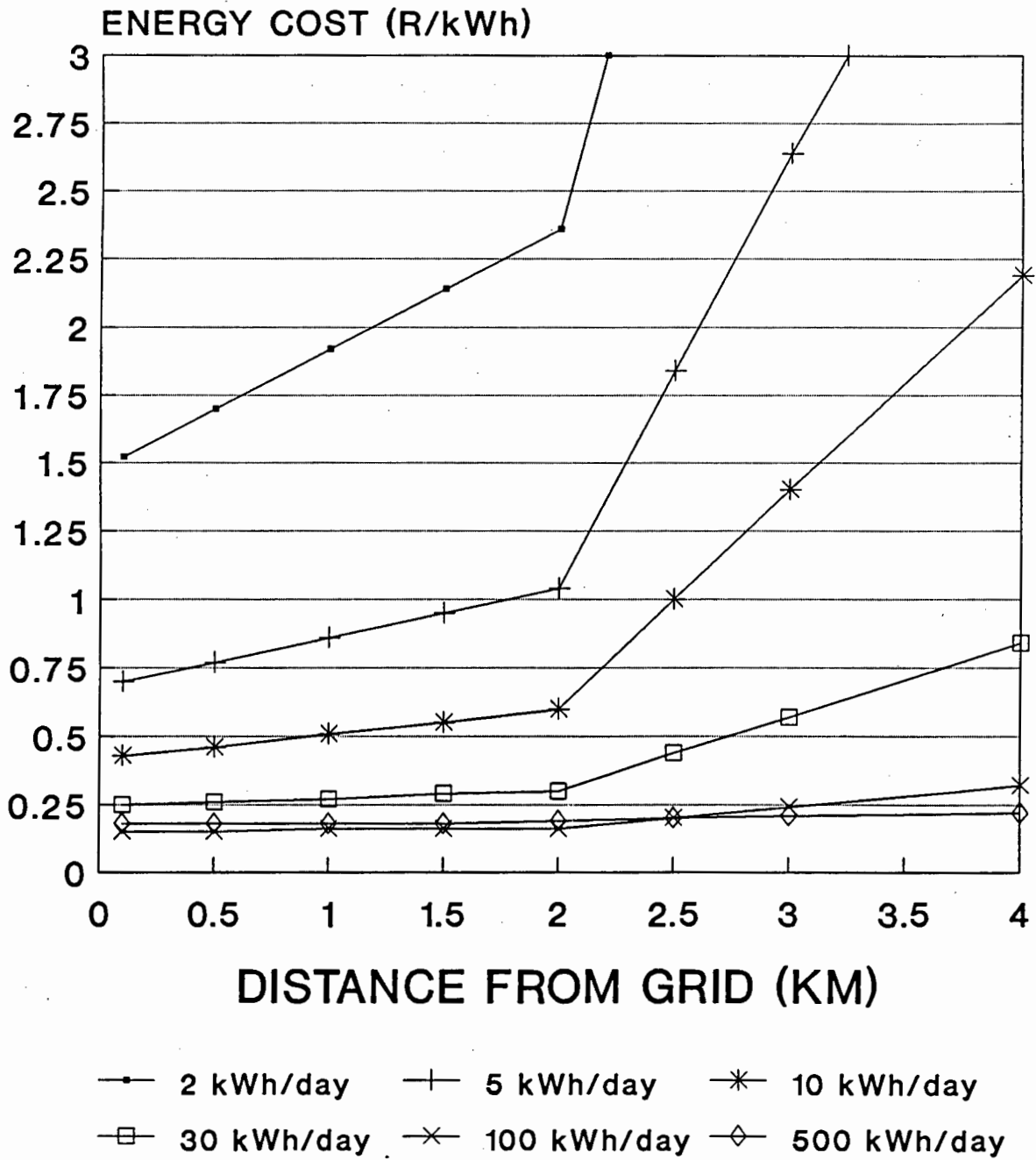


Figure 6.2 : Grid supplied energy costs for grid extension distances up to 4 km. The extension cost used is R18000/km.

## 6.1.2 TERRAIN TYPE OVER WHICH THE GRID IS EXTENDED

At the time of writing, possible line extension costs varied from R16000/km for level terrain with soft ground, to R25000/km for mountainous terrain. Figure 6.3 shows the effect that these costs may have on the unit energy costs for two different energy consumptions. It is evident that the effect is significant, particularly for smaller energy demands. For extensions of 2 km, terrain type could result in a 200% increase in unit energy costs for a 5kWh/day user, while it would affect the cost of energy for a 100kWh/day user by about 50%.

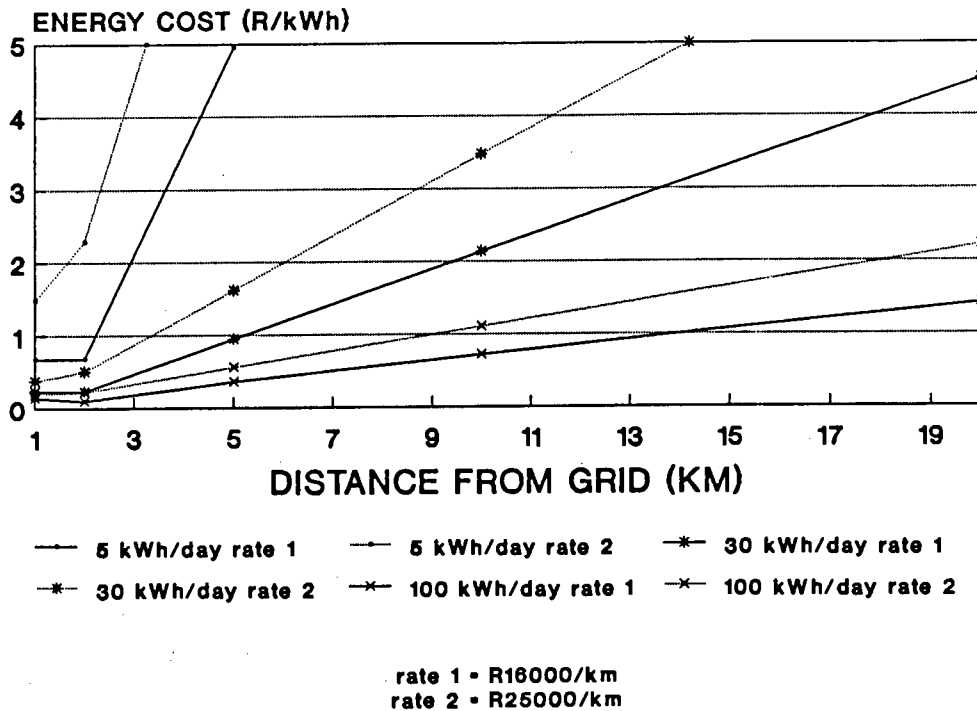


Figure 6.3 : Graph showing the difference in energy cost for two 'per kilometer' extension costs and various daily energy requirements.

### 6.1.3 MINOR DETERMINANTS OF GRID EXTENSION ENERGY COST

#### 6.1.3.1 Peak Loads

Since peak loads only affect the transformer costs and not the line extension costs in grid extension, their effect on unit energy costs is usually small and decreases with increasing extension distance. As an example, for an average energy demand of 30kWh/day and extension distance of 2 km, variation in peak load requirements by various users could be expected to affect unit energy costs by at most 5%.

#### 6.1.3.2 Transmission Charge (Large Users only)

Transmission charges are generally independent of grid extension distance, varying only with direct distance from Johannesburg. Their effect on unit energy cost is usually at most around 1.5%.

#### 6.1.3.3 Load Factor (Large Users only)

Since different tariffs may apply to users with load factors of greater than or less than 20%, energy costs can vary, by as much as 15% depending on the load factor. However, to qualify for the high load factor category the peak load must be in excess of 100kVA (i.e. must be a large user), which means that the average energy demand must be in excess of about 480kWh/day - a situation expected to be exceptional. The majority of users will therefore fall into the low load factor category, and thus load factor will not be regarded as an important determinant of energy cost.

## 6.2 DIESEL GENERATION ENERGY COST DETERMINANTS

### 6.2.1 CAPACITY FACTOR AND ENERGY COST

The major determinant of the unit energy cost produced by a diesel genset is the capacity at which the set is run. This is largely because of the large variation in fuel consumption per kWh produced at different capacity factors, and the inefficient use of genset running time at poor capacity factors, resulting in relatively low energy production over the set lifetime and thus high unit energy costs. In practical terms, capacity factors are adversely affected by oversized sets in relation to the peak load that they need to meet, running sets for excessive amounts of time to supply low demands, and a high load factor or peak load to average demand relationship required by the user. Figure 6.4 shows the effect that capacity factor has on the unit energy cost for various set sizes. It must be noted that the curves are a direct result of the assumptions made concerning fuel consumption at various capacity factors, maintenance costs, and set lifetimes.

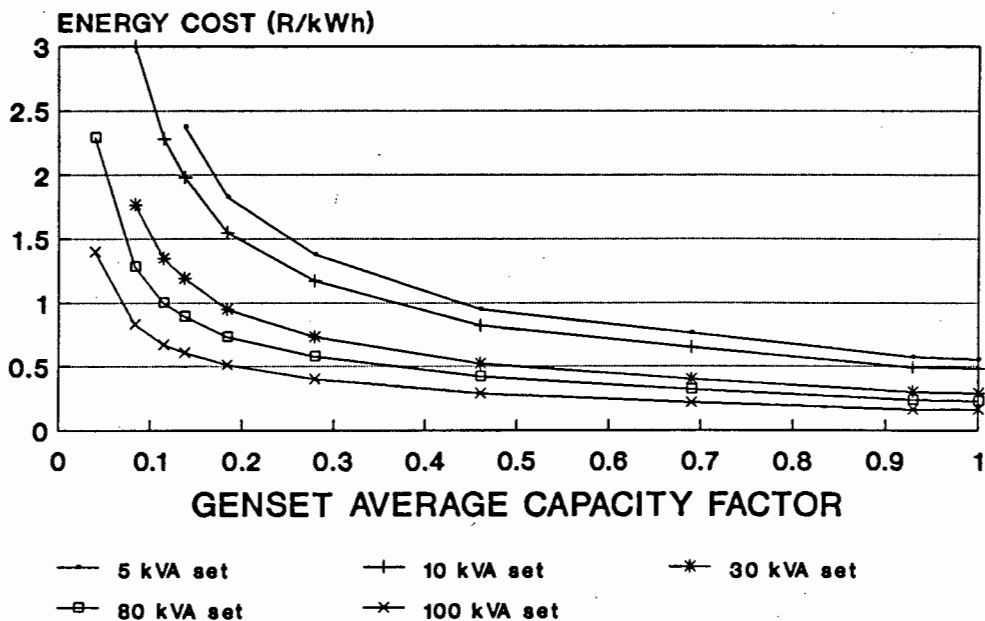


Figure 6.4 : Energy costs for varying capacity factors of different genset sizes.

It can be seen that the unit energy costs for different set sizes can differ greatly for a given capacity factor. For example, energy produced by a 400kVA set can be expected to be at most 30% of the cost of energy from a 5kVA genset. This difference would be increased were the difference in lifetime of different size sets considered. In practice, smaller sets generally last for shorter periods than do larger ones, and thus over a given costing period the smaller sets would require more frequent replacements, resulting in higher life-cycle costs, and thus unit energy costs. This effect, however, has not been included in the costing due to the lack of information needed to quantify it.

#### 6.2.1.1 Genset Run-time and its effect on energy cost

For a given peak load and daily energy requirement of a user, the length of time for which the genset is run to fulfill this requirement has a significant effect on the cost of the energy produced. This is as a result of the lower capacity factors that occur with longer daily run-times to supply a fixed energy requirement. It is therefore of practical interest to look at an example of the effect of run-time on energy cost. Figure 6.5 was generated using gensets sized to meet various peak load requirements, and average energy demands of the peak load multiplied by 3 hours. The graph corresponds to figure 6.4 as follows : the energy costs for a run-time of 24 hours corresponds to those for the lowest capacity factors in fig.6.4, while the 3 hour run-time corresponds to the highest capacity factor shown in fig.6.4.

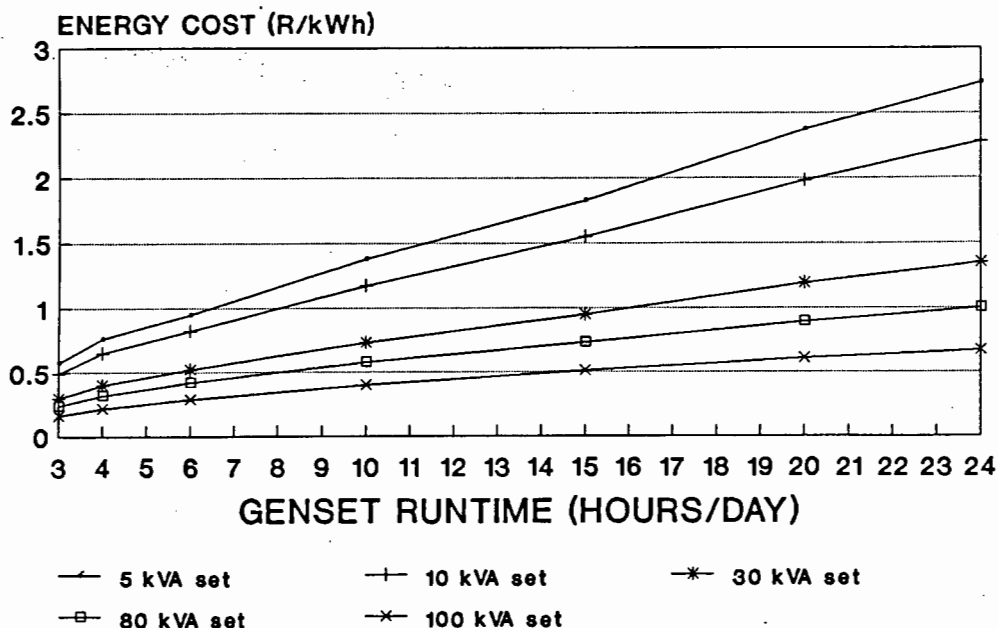


Figure 6.5 : Energy cost for various genset run-times (corresponding to the capacity factors in figure 6.4) and different set sizes.

The nearly linear relationship between run-time and energy cost is evident. This graph would be useful in predicting possible savings that would result from condensing energy consuming activities into shorter periods during the day.

#### 6.2.1.2 Peak Load requirements and Genset Size

Gensets are normally sized according to the peak load requirements. There are situations, however, when this is not the case, for example where the peak load is significantly less than the smallest diesel genset available, or where the user has a larger set because the required size is not available or because he wishes to accommodate future expansion. In such cases the resulting capacity factors will be lower than necessary, and figure 6.4 may be used to estimate the costs involved in the oversizing.

### 6.2.2 SITE ALTITUDE AND THE COST OF ENERGY

The altitude derating factor used in the diesel genset sizing and costing package is 4% per 300 meters. This typically results in an increase in energy cost of approximately 6% per 1000m ascent. The likely range of sites requiring gensets in Southern Africa would be between altitudes of 0 to 1500m, but it is conceivable that some applications could be at sites of up to 2000m above sea level. The maximum variation in energy cost due to altitude, therefore, is unlikely to exceed 12%.

### 6.3 PHOTOVOLTAIC ENERGY COST DETERMINANTS

#### 6.3.1 INSOLATION LEVELS AT THE PARTICULAR SITE

The approach adopted in this thesis was to take all the weather stations around the country for which hourly insolation data was available, and to assume these stations as being representative of the specified areas around them. All sites in the specified area would then use the data from these stations for photovoltaic system sizing. Details concerning these stations and their corresponding areas, and of how the insolation data was processed appear in appendix B. These stations, of which there are twelve, vary considerably in insolation characteristics, and also therefore in photovoltaic system requirements for a particular demand. Figure 6.6 provides an example of the different unit energy costs that may be expected from the different areas for the same demand characteristics. The figure was generated using a LOEP of 0.01, and a system efficiency of 6.51%. Since the daily energy demand magnitude has no effect on the energy cost for a particular site, it is not specified.

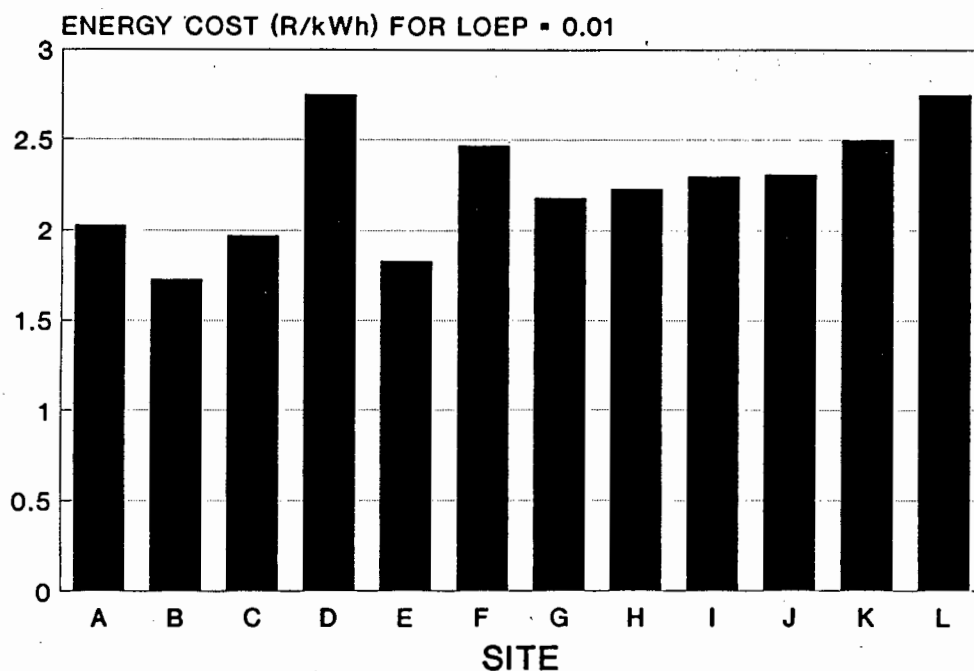


Figure 6.6 : SAPV energy costs from various sites for a LOEP of 0.01

The letters indicate that the following weather station's data was used :

A - Windhoek	G - Grootfontein (Cape)
B - Keetmanshoop	H - Bloemfontein
C - Alexander Bay	I - Pretoria
D - Cape Town	J - Roodeplaat
E - Upington	K - Nelspruit
F - Port Elizabeth	L - Durban

It is of interest to note the perhaps obvious trend, that the coastal sites have the highest unit energy costs, (sites D, F and L) while the inland sites in arid areas have the lowest (sites B and E). The variation between the lowest and highest energy costs is shown to be about R1.00/kWh.

### 6.3.2 LOSS OF ENERGY PROBABILITY AND ENERGY COST

The cost of energy from a stand-alone photovoltaic (SAPV) system varies greatly with the LOEP required by the user, as



shown in figure 6.7. The increase is most marked for the lower LOEP values. A system efficiency of 6.51% was used to generate these results.

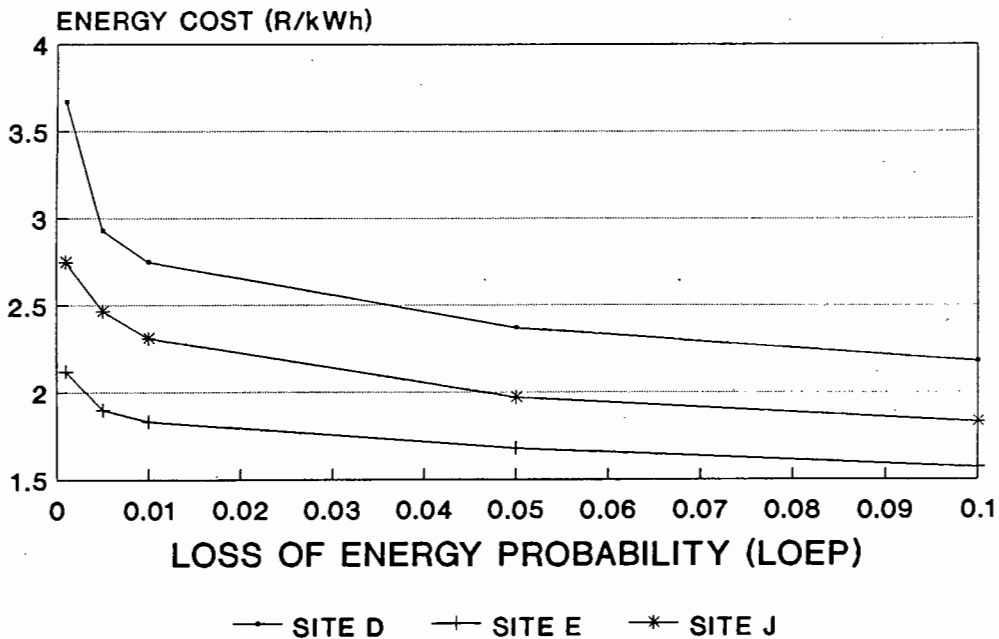


Figure 6.7 : Changes in SAPV energy costs for different LOEP levels at three different sites.

Using the LOEP = 0.01 system as a base value, the energy cost changes for various LOEP values may be estimated from the above results as follows :

LOEP	% change in energy cost		
	Site D	Site E	Site J
0.1	-21%	-14%	-21%
0.05	-14%	-8%	-15%
0.01	0%	0%	0%
0.005	+7%	+4%	+7%
0.001	+33%	+16%	+14%

The above table is merely intended to give an indication of change in energy costs that may be expected for differing system reliabilities, which is of practical interest to system

designers, rather than to provide a detailed study of the relationship. As can be seen, the percentage change in energy cost varies appreciably for different sites, pointing to a significant difference in their insolation distribution patterns.

### 6.3.3 ARRAY MODULE EFFICIENCY AND THE COST OF ENERGY

Since increasing the efficiency of photovoltaic modules is the most obvious way in which to make photovoltaic power more viable, it is worthwhile to look at the predictions of the comparison package with respect to module efficiency and its effect on the cost of energy. Figure 6.8 was generated using a constant module cost per square meter. In other words, an increase in module efficiency simply resulted in an increase in peak watts per square meter, but the unit area cost of the module was assumed unchanged. The insolation data used for system sizing in this example was that of Roodeplaat (site J).

At present, typical module efficiencies are between 0.08 and 0.12, and since efficiencies of 0.2 have been obtained in laboratory conditions, to examine such a range of efficiencies is not unrealistic. The package indicates that, for the site in question, and using the stated assumptions, unit energy costs can be expected to drop by 20% to 30%, depending on the system LOEP, with the use of modules with efficiencies of around 0.2. Since the increased module efficiency is reflected in the efficiency of the entire system, the drop in energy cost is not expected to vary significantly amongst sites.

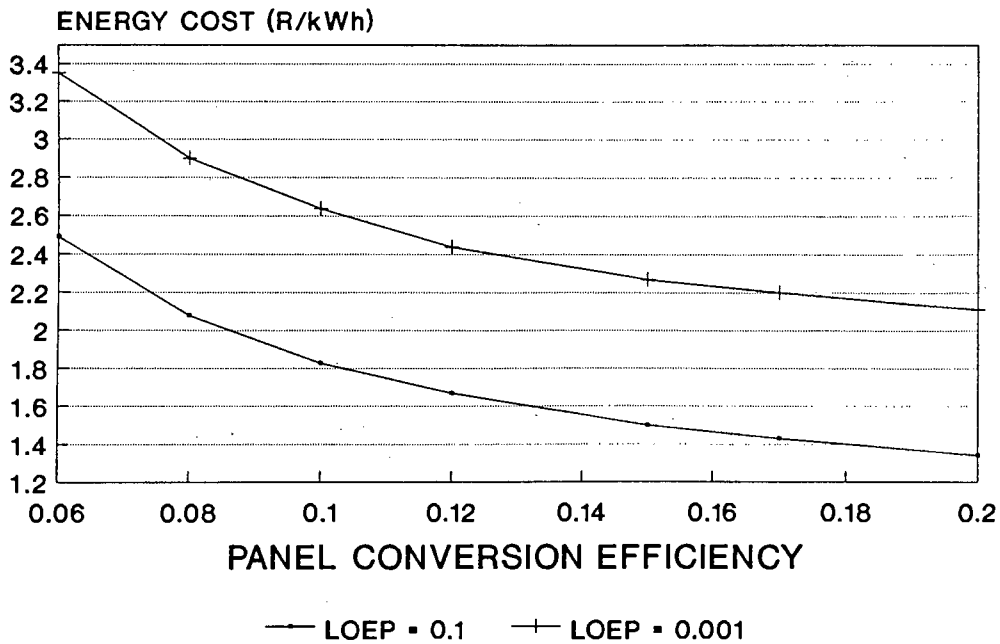


Figure 6.8 : An example of the change in energy cost with changing photovoltaic module efficiency.

#### 6.3.4 AC OR DC SYSTEMS AND THE COST OF ENERGY

A photovoltaic system designed to supply an AC demand must inevitably include an inverter. DC systems, on the other hand, use converters, which are more efficient than inverters. A typical converter (DC to DC) efficiency would be approximately 95%, while inverters (DC to AC) generally vary between 60% and 90% efficient, depending on the instantaneous energy demand. AC systems are therefore more wasteful of energy than DC ones, and this is reflected in the cost of energy produced by each system. Figure 6.9 demonstrates the likely energy costs for both systems. The insolation information used is once again from Roodeplaat (site J), and an inverter efficiency of 80%, and converter efficiency of 95% was used.

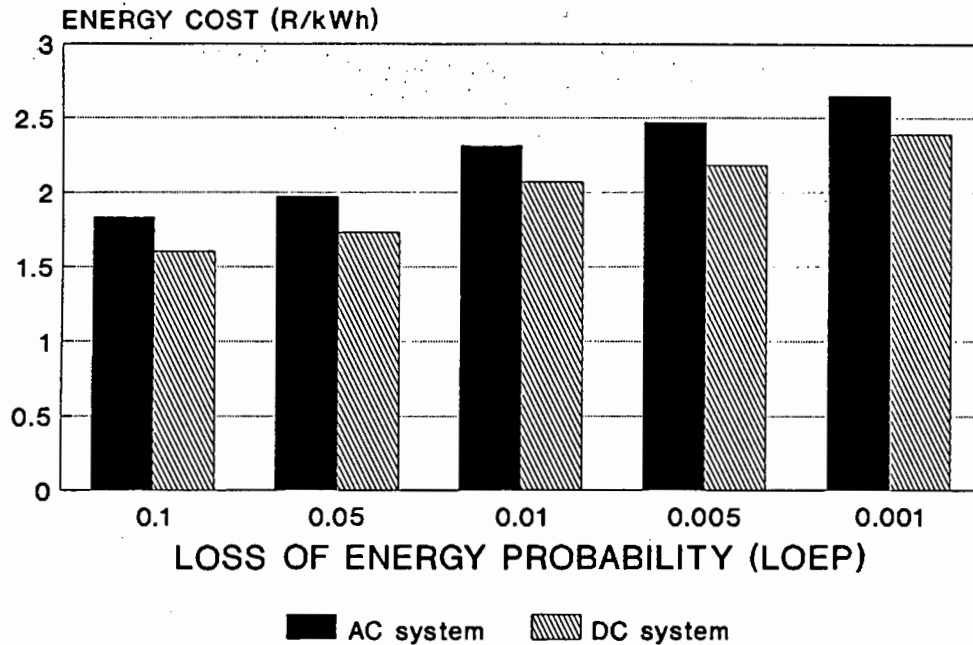


Figure 6.9 : Typical differences in SAPV energy costs for AC and DC systems.

The saving in energy cost by using a DC system is close to 12% for all LOEP values considered for this site. Here again, the drop in energy cost is not expected to be significantly site dependent, since the change in overall system efficiency resulting from the use of a converter or inverter is not site dependent.

#### 6.3.5 FRACTION OF ENERGY CYCLED THROUGH THE BATTERIES

The more energy that is cycled through the batteries before supplying the demand, the lower are overall system efficiencies because of battery charging inefficiencies. Figure 6.10 shows that the change in energy cost from systems where 30% of the energy is cycled through the batteries, which is the minimum allowed by the sizing procedure (see appendix D for details), to systems where all the energy is supplied via the batteries, is approximately 10% for all LOEP's considered. Since energy

cost changes because of a change in system efficiency, the trend is not expected to be significantly site dependent. Here the insolation data used was once again taken from Roodeplaat (site J).

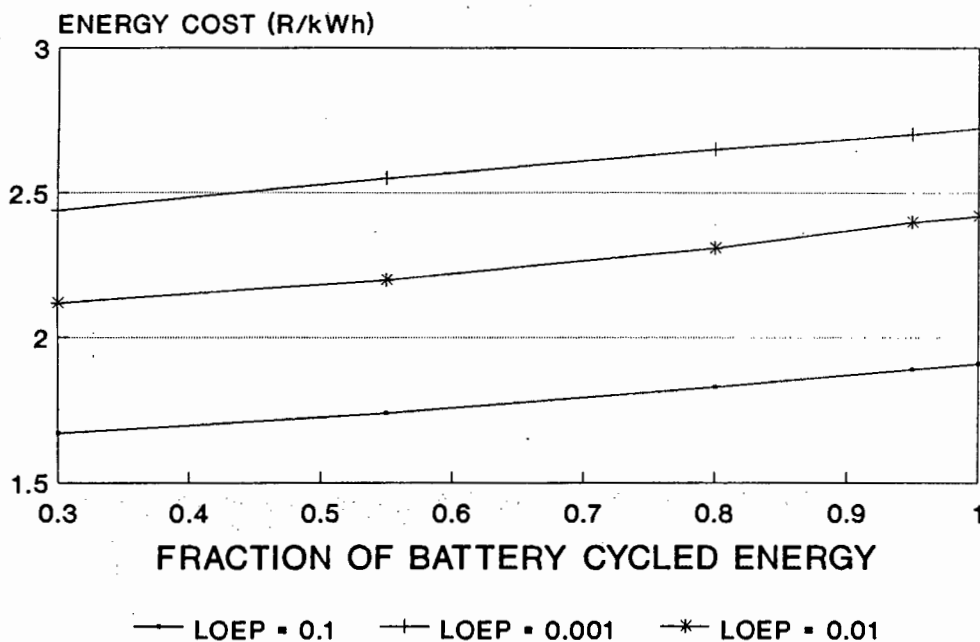


Figure 6.10 : Cost changes in SAPV supplied energy for systems where different average proportions of energy are cycled through storage.

#### 6.4 COMBINING THE MAJOR COST DETERMINANTS FROM EACH OPTION

This section is intended to indicate the general energy cost trends for various average daily energy demands from each power supply option considered. This will be done graphically. Since, in such a graph, it is not practical to include all the energy cost determinants for each option, only some of the major determinants will be considered. These are :

Photovoltaics : Insolation levels at the particular site  
 Diesel Generation : Capacity factor  
 Grid Extension : Distance from existing grid

The result is shown in figure 6.11. If more detail is required the effects of the various determinants not included in the graph may be examined in the relevant section, or the comparison package should be used to determine the likely resulting energy costs.

Figure 6.11 was generated using the following assumptions :

**Photovoltaics** - The LOEP was taken as 0.05, this being comparable with that of diesel generation. The upper limit of the photovoltaic energy cost was obtained using insolation data from the site with the poorest overall insolation levels (Cape Town), and the lower limit (cheapest energy cost) from Keetmanshoop, the site with the highest insolation levels. The system efficiency used was 6.51%, and the demand was assumed to be AC, since both diesel generation and grid power supply would provide AC supply.

**Diesel Generation** - The range of average capacity factors considered was between 0.1 and 0.4, since, according to Williams (1988,p43), this is the typical range to be found in South Africa. The genset sizes used in this exercise were determined according to the peak load specified by the average energy demand and the average capacity factor.

**Grid Extension** - The per kilometer extension cost was taken as R18000, which may be considered average, and the peak load requirement was taken as the average energy demand divided by 3 hours, giving a load factor of 0.33.

Figure 6.12 provides a detail of figure 6.11 showing energy costs for low daily energy consumptions.

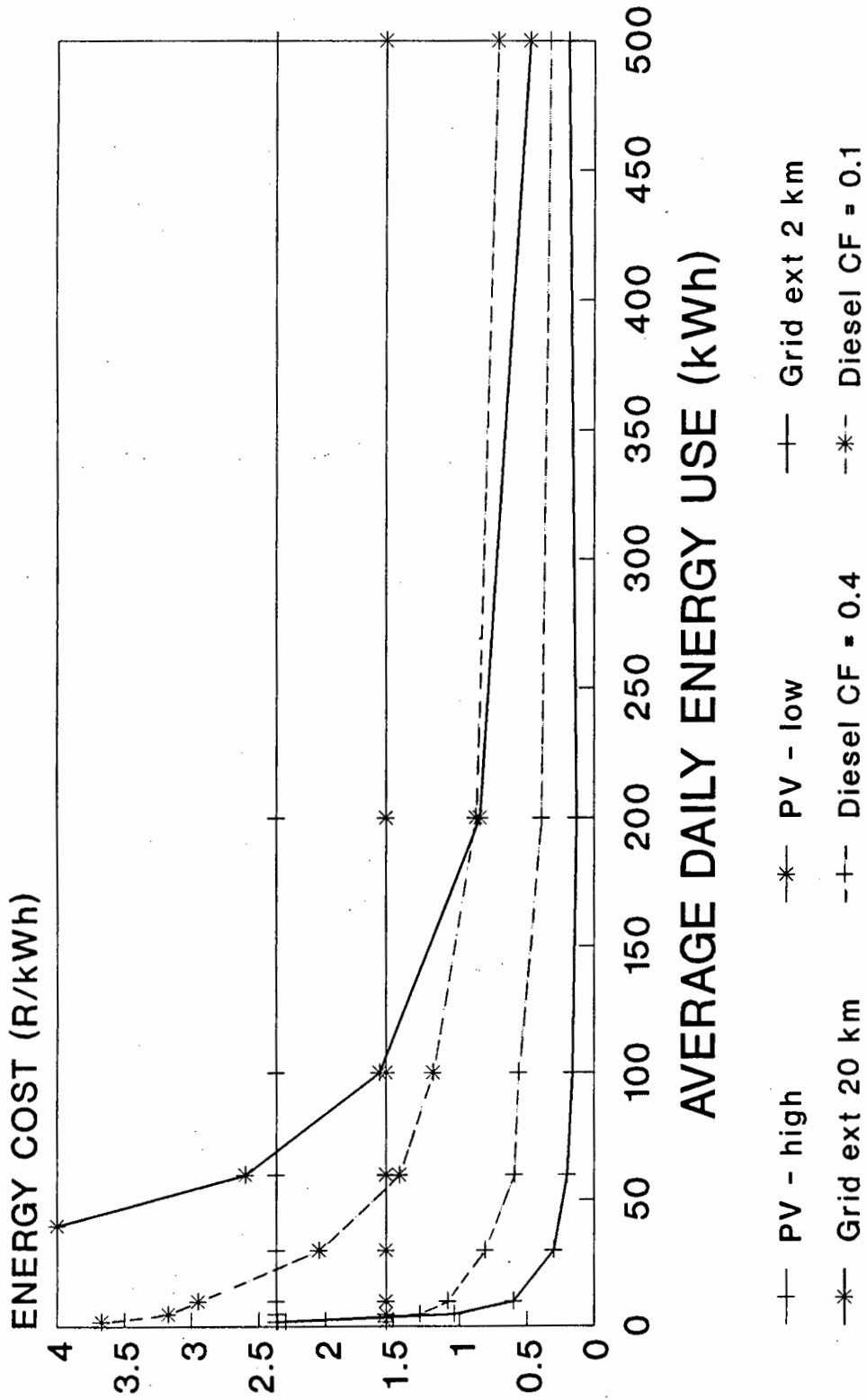


Figure 6.11 : Energy costs from the various power supply options for daily energy requirements of up to 500 kWh.

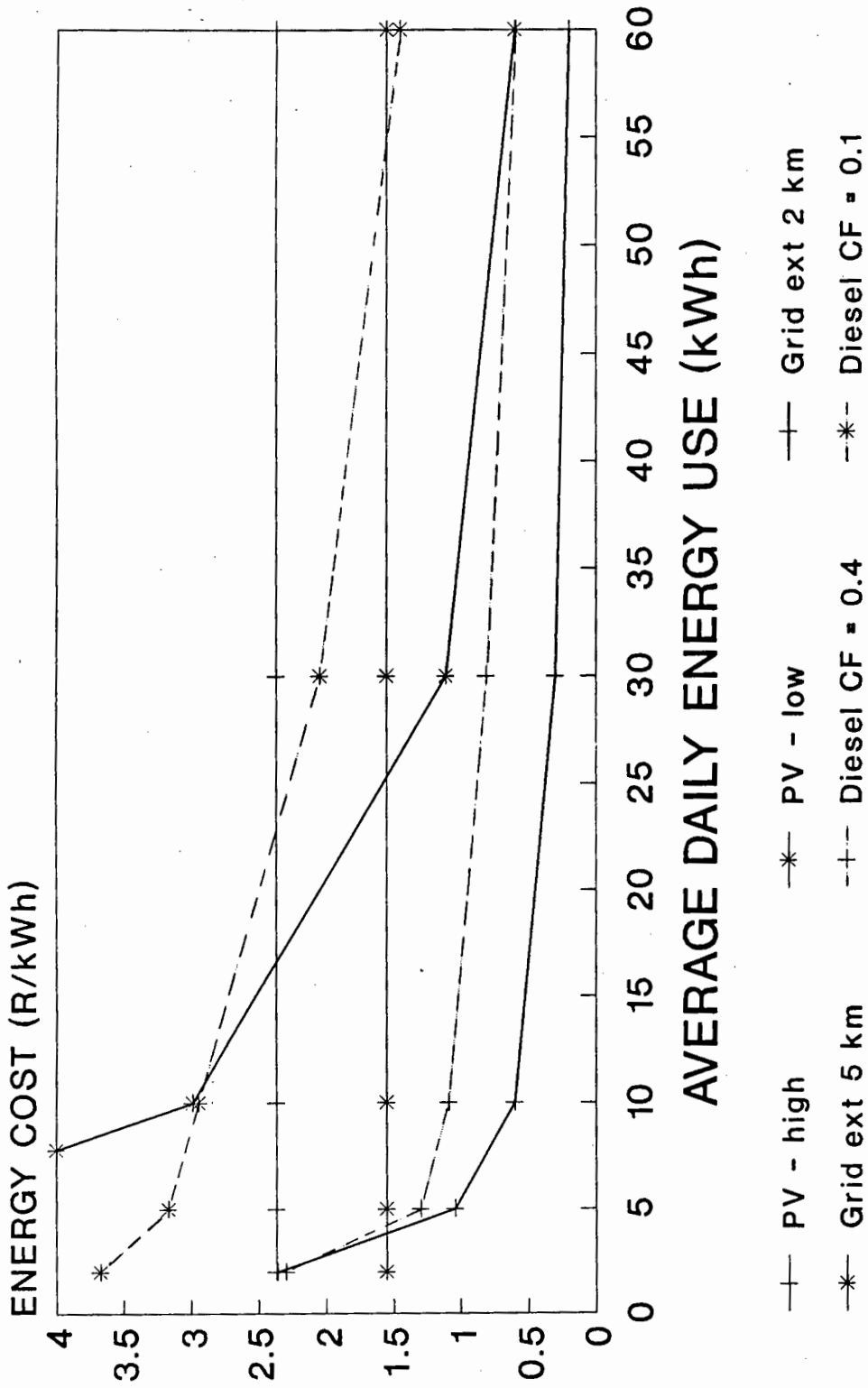


Figure 6.12 : Energy costs from the various power supply options for daily energy requirements of up to 60 kWh.



The figures indicate that for average daily energy consumptions in excess of about 100kWh/day, photovoltaics are seldom the most economical option. Grid extension power costs vary considerably with the extension distance, but it is evident that, for short extensions, resulting energy costs are very competitive. Where energy consumption is high, extensions of as much as 20km may provide an economical supply. For an energy consumption of over approximately 50 kWh/day diesel generation appears to provide a more viable option than photovoltaic supply, even for low genset average capacity factors.

## 6.5 EXAMPLES OF TYPICAL ENERGY COSTS FROM EACH OPTION AT SPECIFIC SITES

Now, some examples of the application of the power option comparison package in practical situations will be looked at.

### 6.5.1 EXAMPLE 1 - Arid inland site with small energy requirement :

For this example a hypothetical inland site was chosen in an arid area, and at an altitude of 900 meters. The daily energy consumption of 10kWh is used largely during the day, and the peak load is 6kW, which, for example, could be the starting requirement of a 1.5kW electric motor used at the site. The time over which the total daily energy requirement is used, is approximately 10 hours. The site is 15 km from the existing electricity grid.

Typical system sizes and resulting unit energy costs predicted by the package are summarized below :

PHOTOVOLTAIC : LOEP : 0.05  
 Array size : 21.0 sq.m  
 Storage capacity : 20 kWh  
 Energy cost : 1.73 R/kWh

DIESEL GENERATION : Set size : 8.5 kVA  
 Run-time : 10 hrs/day  
 Average capacity factor : 0.15  
 Energy cost : 1.96 R/kWh

GRID EXTENSION : User category : Small  
 Energy cost : 10.98 R/kWh

In this example, therefore, photovoltaics are predicted to provide the cheapest energy. The photovoltaic system was sized to provide a LOEP of 0.05, comparable to that of diesel generation. The high insolation levels found in arid inland areas result in relatively low photovoltaic energy costs. Since the

energy is required over 10 hours, and the genset size needed to provide the required peak load is large when compared with the total average daily energy demand, the average capacity factor of the diesel genset is low, resulting in relatively expensive generation. Grid extension power cost is excessive due to the small daily requirement and the site distance from the existing grid.

#### 6.5.2 EXAMPLE 2 - Coastal site with an average household energy usage

For this site near the coast, the daily energy consumption is 30kWh, and the peak load 10kW. The energy is required over a period of about 6 hours, and is used largely for domestic purposes such as heating, cooking and for use in appliances. Energy is required mainly during the evening. The site is 8km from the existing grid.

Typical system requirements and energy costs for this site are:

PHOTOVOLTAIC : LOEP : 0.05  
 Array size : 95.5 sq.m  
 Storage capacity : 93 kWh  
 Energy cost : 2.47 R/kWh

DIESEL GENERATION : Set size : 12.5 kVA  
 Run-time : 6 hrs/day  
 Average capacity factor : 0.50  
 Energy cost : 0.68 R/kWh

GRID EXTENSION : User category : Small  
 Energy cost : 1.90 R/kWh

Here diesel generation is expected to be the most viable power supply option. The high average capacity factor is the major contributing factor to the low energy cost from the genset, due to the favorable relationship between the set size and required run-time. Poor insolation levels at this coastal site require a large photovoltaic system to supply the necessary energy, and

therefore result in expensive unit energy supply. It can also be seen that the distance from the existing grid, although only 8km, is enough to give reasonably high utility supplied energy cost for such a daily requirement.

### 6.5.3 EXAMPLE 3 - An inland site requiring 50kWh/day

The site to be considered has an average daily energy demand of 50kWh and a peak load of 25kW, and is at an altitude of 600m. The energy is required over 10 hours, mostly during the day. The site is 5km from the existing grid.

Predicted system requirements and energy costs are :

PHOTOVOLTAIC : LOEP	:	0.05
Array size	:	111 sq.m
Storage capacity	:	164 kWh
Energy cost	:	1.92 R/kWh

DIESEL GENERATION : Set size	:	35 kVA
Run-time	:	10 hrs/day
Average capacity factor	:	0.184
Energy cost	:	0.93 R/kWh

GRID EXTENSION : User category	:	Small
Energy cost	:	0.71 R/kWh

With the increased energy requirement and decreased distance from the grid, grid extension is now expected to be the most economical power supply. Although the diesel genset capacity factor cannot be considered good, the relatively large energy requirement of the site is enough to bring expected genset produced energy costs down below R1.00/kWh. At such daily energy requirements, photovoltaics are seldom competitive, as is illustrated in this example.

## 6.6 SENSITIVITY ANALYSES

Since energy supply technology is continually changing, and prices are continually fluctuating, one of the uses of the comparison package is to predict the effects of possible future scenarios on the cost of energy from a particular option. This has already been demonstrated with respect to photovoltaics, where energy costs were examined with changing module efficiencies.

## 7 DISCUSSION ON THE CONSTRUCTION AND USE OF THE COMPARISON PACKAGE

This discussion will be handled in four main sections. The first will deal with the choice of power supply alternative, and will use results obtained from the comparison package to contrast general trends as to the situations where each option is likely to be viable. Other considerations apart from the energy cost criterion that affect the choice of option will also be discussed.

The comparison package provides useful information as to how energy costs may be optimized. CHAPTER 7 this will be dealt with in the second section.

In the third section, the limitations of the package will be discussed, and, with these in mind, the likely uses of the package.

### DISCUSSION ON THE CONSTRUCTION AND

USE OF THE COMPARISON PACKAGE to extend and improve the package.

### THE CHOICE OF POWER SUPPLY

#### SITUATIONS WHICH FAVOUR THE USE OF THE DIFFERENT OPTIONS

Results from the comparison package examined in chapter 6 will be used to derive some generalizations concerning the situations where one option is likely to provide the most economy. The more obvious cases are where the distance between the power source and the load is large and energy requirement is low, where nuclear power may be regarded as a viable option, and where energy requirements are high, where high voltages are unlikely to provide the most economical solution.

In order to look at these trends in more detail, it is useful to summarize the energy cost determinants examined in the previous chapter. This is done in table 7.1.

Table 7.1 : Summary of major and minor energy cost determinants for the various power supply options.

DETERMINANTS	PHOTOVOLTAIC	DIESEL GEN.	GRID EXT.
MAJOR	1 Local insolation levels 2 LOEP required	1 Capacity factor (established by run-time/day & genset size)	1 Distance fr grid 2 Energy reqd 3 Terrain btw grid & site
MINOR	1 Efficiency of array & other components 2 AC or DC system 3 % energy used during daylight	1 Site altitude	1 Peak Load. 2 Transmiss.c 3 Load factor

It should be remembered, however, that while conditions favorable to the different supply options are being discussed, these remain generalizations, and are not expected to be able to replace the more accurate information provided by the comparison package. The generalized trends are discussed in order to assist in a field assessment of a particular site, for example.

#### 7.1.1.1 Conditions that favour the use of photovoltaics

Photovoltaics are, in general, an expensive energy supply, with unit energy costs in excess of R1.30/kWh even at the most favourable sites and for high LOEP's, and commonly costs are around R2.00/kWh or higher. The situations where photovoltaics produce energy at competitive prices are, therefore, limited.

Such situations do, however, exist, and it is possible to establish a set of general conditions in which the use of photovoltaics would be viable. The most important condition is that of low energy use. Where energy requirements are above 10 kWh/day, the likelihood is that another supply option would be more economical. This is illustrated by figure 6.12 in chapter 6. However, for low energy demands, photovoltaics are competitive. For example, for a daily requirement of 2 kWh, only grid power requiring an extension of 1 km or less is likely to be able to provide power at a price comparable with photovoltaic energy. Since diesel gensets are only available in sizes of 3.5 kW or above, capacity factors for such low energy demands will inevitably be poor, and thus generation costs high.

Examples of low load applications are educational T.V. in rural areas, lighting for night-time study at un-electrified institutions, domestic or recreational lighting requirements, refrigeration for rural clinics or homes, and water pumping. The latter example is particularly suited to photovoltaics since a water storage tank is used in place of battery storage. The comparison package does not, however, accommodate such systems. Where heating requirements are to be met by the power supply option, however, energy use tends to be too great for the economical use of photovoltaics.

Other important factors influencing the energy cost from PVC systems are the local insolation levels and the system reliability, or LOEP, required. Areas such as the coastal regions of the Western Cape, for example, can be expected to have energy costs of as much as 40% higher than costs from stand-alone photovoltaic (SAPV) systems in the more arid inland regions due to typically poor insolation closer to the sea. The LOEP of the system, also, can change energy costs significantly. It is not uncommon for the cost per kWh for a LOEP of 0.1 to differ from a system of LOEP 0.001 by R1.00/kWh.



From the above it is evident that depending on the system LOEP and the site location, the cost of energy supplied could vary greatly, with systems in arid inland areas and of high LOEP having the lowest unit energy cost.

The higher the SAPV system efficiency, the lower the cost of the energy produced. For the likely range of system efficiencies, the difference in energy cost may be as great as 25%. Since DC systems, rather than AC ones, and systems that supply a largely daytime demand, have higher efficiencies, sites requiring power with these characteristics are more likely to be suited to SAPV systems.

#### 7.1.1.2 Conditions that favour diesel generation

With diesel gensets, the average capacity factor at which the set is run is the major energy cost determinant. In practical terms, this is determined by the genset size, and the time period over which it is required to produce energy. For example, a set sized to meet a peak load of 10 kW, and required to produce 20 kWh of energy per day, would have a high capacity factor if the energy was required over 2 hours only, and thus result in lower unit energy costs than would be the case if the set was run at a low average capacity factor caused by the energy being required over 10 hours. In this particular example the unit energy cost for the poor average capacity factor could be expected to be about three times that of the higher average capacity factor.

The following general observations may be made regarding the viability of diesel generation for different average capacity factors : Where the average capacity factor is around 0.1, diesel generated unit energy costs only drop below those of a SAPV system where daily energy requirements are about 30 kWh or greater. For average capacity factors of around 0.4, however,

diesel generation tends to be more economical than SAPV systems for daily requirements as low as 4 kWh. Since grid extension unit energy costs vary greatly with extension distance, it is not practical to compare diesel energy costs with this. Instead, figure 6.11 and 6.12 in chapter 6 should be used to compare the two.

As has been mentioned, because diesel gensets are only available in sizes of 3.5 kW or above, capacity factors for energy requirements under about 4 kWh will inevitably be poor, and thus generation costs will be higher, and other options are more likely to be able to supply the requirements more economically.

Diesel generation is therefore more likely to be viable where the set size is closely matched with the average load, or in other words where the load factor is close to unity. Situations where the set is oversized, because of the unavailability of the required size set for example, would lead to poor average capacity factors, and thus expensive generation. This would be the case where peak loads are less than 3.5 kW because smaller sets to match these peak loads are not available.

Typical average capacity factors in South Africa have been found to vary between 0.1 and 0.4 (Williams, 1988, p43), and the poorer capacity factors often occur where one set is used to meet a variety of demands, such as commonly occurs on farms. Where a genset is required to supply a low 24 hour load as well as meet other larger requirements, the capacity at which the set is run would typically be low for much of the time, and thus 24 hour diesel supplied power is commonly expensive. This is often the case where 24 hour refrigeration loads in addition to various other loads are to be met by the genset. Where a set is dedicated to a single non-inductive load, however, it can be run at a more optimum capacity and thus result in very

economical generation. Inductive loads, on the other hand, such as electric motors, may require starting currents of up to six times their running current, and thus require a set sized to cope with this starting peak, therefore reducing the load factor and increasing the unit energy cost.

The viability of diesel generation hinges, therefore, around the energy demand characteristics of a particular site, because this is what determines the average capacity factor at which the set is to be run.

The site altitude also has an effect on the cost of generated energy. High altitude sites require larger sets to meet specific demands, and thus tend to produce energy at a higher cost than for low altitude sites. The effect on the unit energy cost is not great, however, with energy cost increasing by about 6% for a 1000m increase in altitude.

#### 7.1.1.3 Conditions that favour grid connection as a power supply

The three major determinants of grid extension supplied power are distance of extension, terrain type over which the extension must run, and the energy requirement. Since extension charges are carried over to the user independent of the user's consumption, the unit energy cost of small consumers will inevitably be higher than for larger users. With extension costs averaging R 18 000 per kilometer, of which 1.35% or R250 per month is charged to the user, small energy consumers would often find all but the shortest extension prohibitively expensive. Users requiring 10 kWh/day and being as little as 4 km from the grid could find both photovoltaic and diesel power supplies more reasonable than grid power. If the terrain between the site and the grid is rugged and thus extension costs high, such a user may find the distance at which the other op-

tions become competitive reduced to less than 1 km.

Eskom has plans to remove the R216/km subsidy that presently applies to extensions of 2 km or under, and this will have the effect demonstrated in figure 7.1.

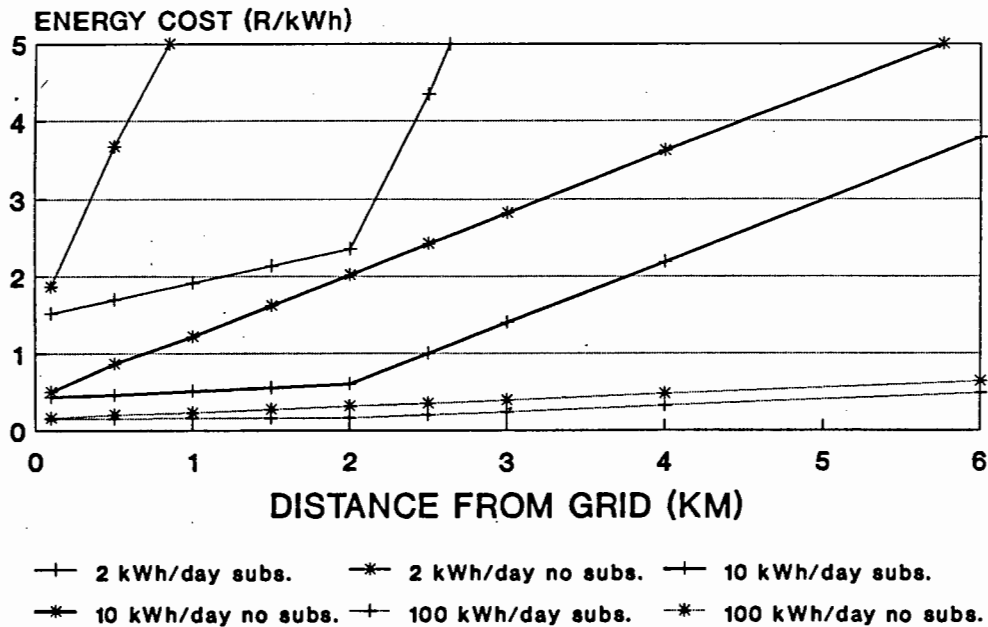


Figure 7.1 : Grid extension supplied energy costs with and without the subsidy of R216/km for the first two kilometers of extension.

It can be seen that the effects of removing the subsidy, while having little effect on large energy consumers, will have a great effect on the cost of grid power for smaller consumers. Figure 7.2 shows how this will affect energy costs in relation to the other supply options. This figure was generated using the same criteria as figure 6.12 except that grid extension charges are unsubsidized for the first 2 km.

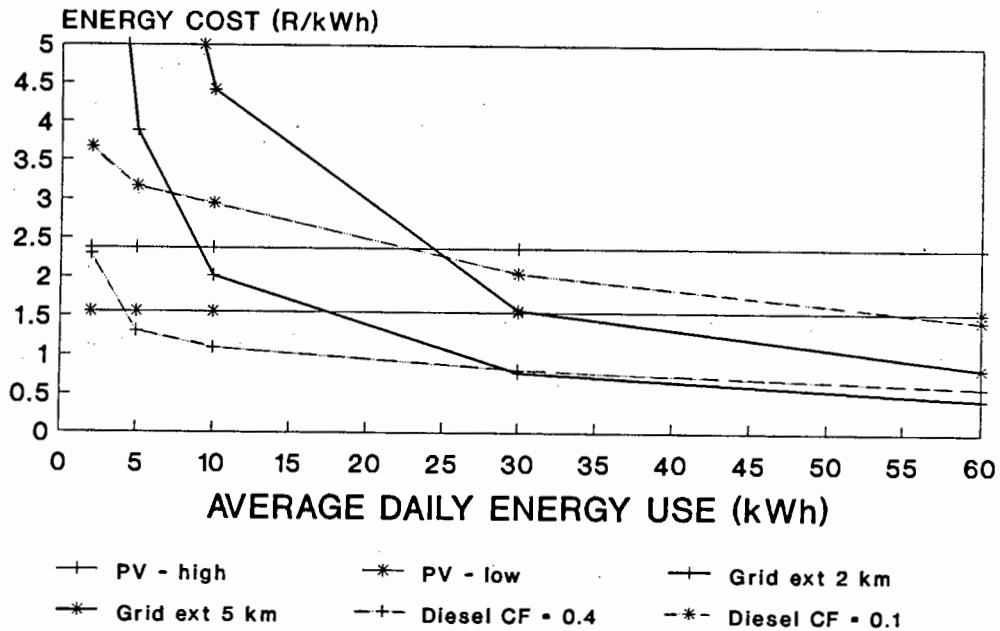


Figure 7.2 : Energy costs from the various power supply options as a function of daily energy requirement, where grid supply is not subsidized for the first two kilometers of extension.

The greater energy cost from grid extension supply on small users is apparent, with the result that diesel generation and photovoltaics will be economical in an increasing number of small demand situations.

Grid extension power supply therefore favours larger energy demands than smaller users, and with the removal of the present extension cost subsidy this tendency will be strengthened. The larger the daily energy requirement, the more competitive is grid supply. Users of around 100 kWh/day would typically be able to obtain power from a 10 km extension at under 90c/kWh, well below the cost of photovoltaic supply and comparable only with diesel genset supply with a good average capacity factor.

The peak load of the user generally has little effect on all but the shortest extensions since this only affects transformer

costs, which become a smaller proportion of the extension charge as extension distance increases. For extensions as little as 2 km, for example, changes in peak load would have an effect on energy costs of less than 5% for a user of 30kWh/day.

Transmission charges levied by Eskom depending on the site's direct distance from Johannesburg have a small effect on energy charges, typically below 1.5% for sites throughout the country.

In summary then, sites where grid extension is likely to provide the cheapest energy would typically not be small consumers of energy, would be close to the grid, and the terrain between the site and the existing grid would be reasonably accessible.

#### 7.1.2 GENERAL CONSIDERATIONS IN CHOOSING A POWER SUPPLY

The comparison package results in a cost per unit of energy produced for various supply options, and on this basis the user of the package may evaluate the viability of the various options. All discussion so far has been centered around this measure as an indicator of viability. There are, however, a host of other considerations which cannot practically be included in such a comparison package, and it must be remembered that the cost of energy is only one criterion amongst many that must be considered in such an evaluation. Factors that are less easily quantifiable may outweigh the "cost of energy" as a measure of viability. Since this thesis is concerned with evaluating the viability of various supply options, it would be incomplete without discussing these other considerations.

The comparison package costs diesel genset power supply systems and photovoltaic supply over a project life of 20 years. However, there are changes that could occur during this period that could influence the choice of power supply. Possible future increases in demand, for example, need to be considered

when making a choice. A diesel genset system is by nature not as easy to extend to cope with increases in peak loads as a photovoltaic system is. If the genset is oversized to cope with expansion plans, the average capacity factor will initially be low, resulting in expensive generation. Photovoltaic systems, on the other hand, are modular, and therefore expansion is relatively easy, which may make them more suitable for situations in which growth in demand is uncertain. Diesel gensets can, however, often cope with increases in total daily demand if the peak load is not increased, since sets are typically used at low capacity factors. This greater demand would then serve to reduce unit energy costs because of the resulting superior average capacity factor. If the average capacity factor is high, it may be possible to extend the daily run-time of the set to generate the extra energy required.

It is also necessary to consider any national grid expansion plans in assessing the power supply options. Eskom is paying increasing attention to the electrification of rural areas, and therefore extension distances from the national grid to the site in question may in future decrease significantly, with a corresponding decrease in grid supplied power cost. It may even be the case that there are plans to electrify the area in question within the project costing lifetime. Where future grid electrification of an area is a likelihood, the costing of an interim power supply becomes more complex, and the resale value of gensets or SAPV systems must be considered in making the choice. Here photovoltaic supply may be more suited to the situation, because of the reliability and long life of PV modules and thus good resale value.

Grid power has several points in its favour when weighed up against other options. It is highly reliable in comparison with diesel gensets, having a LOEP conservatively estimated at 0.001, while genset LOEP is around 0.05. Although

photovoltaics may be sized for a LOEP comparable to that of grid power, the cost of doing so is often prohibitive. Often expansion in grid power demand may be accommodated by the installed transformer, and involves minimal cost. If the transformer cannot manage the increase in demand, it will, at worst, have to be replaced with a larger one, and since transformers cost are at present in the range of R50/kVA, the cost of expansion is unlikely to be excessive. Expansion of energy needs do not generally require the line to be upgraded, since the standard 11 or 22kV lines are used for demands as high as 500 kVA.

The relative cost of energy from the various options is also likely to change over the project costing lifetime. Since running costs make up a significant proportion (typically 35%) of the life cycle cost of a diesel genset, changes in fuel price will change the unit energy cost supplied. With photovoltaics, however, the initial capital outlay forms the bulk of the life cycle cost (up to 90%), and therefore the unit energy costs are less changeable.

In terms of convenience to the user, diesel generation rates the lowest amongst the options considered here. Gensets require constant attention : the set must be started when power is required, fuel must be transported, services done at regular intervals, spares bought, mechanics called in or sets transported to workshops, and it may be necessary to monitor the engine load to prevent underloading. In addition, gensets are noisy and polluting. Photovoltaics, on the other hand require little maintenance : batteries must be purchased every few years, battery water levels monitored if required, and panels should be washed occasionally if rain is infrequent. Grid power is more convenient still, requiring negligible attention.



These, then, are some considerations other than the predicted price of energy that need to be kept in mind - ability to accommodate expansion of demand, future cost trends in equipment or fuels, utility plans for electrifying presently off-grid areas, and convenience of use. In addition, although it may not be of concern to the average small user, it may be preferred to use renewable energy sources such as the sun, rather than those that consume non-renewable and polluting fuels such as diesel generation and grid power.

The choice between options, therefore, is complex, and it should be remembered that the comparison package only deals with one measure of viability - the cost of energy resulting from the power supply system.

## 7.2 THE OPTIMIZING OF ENERGY COSTS

In establishing the major energy cost determinants for each supply option, the comparison package provides useful information on possible ways of optimizing the cost of energy produced from each option. This information will be of use to both present and potential power system users.

### 7.2.1 OPTIMIZING ENERGY COSTS FROM A SAPV POWER SUPPLY SYSTEM

As with all supply options, the ability to optimize energy costs depends on the particular requirements and limitations of the site in question. With SAPV systems, an obvious way to reduce costs per kWh is to install a system of high LOEP. Since the energy cost difference between power from systems of LOEP of 0.001 and 0.1 varies between 30% and 50% depending on the site, there is potential for considerable saving by decreasing the system size and increasing the LOEP. The LOEP is, however, limited by the requirements of the user. Here it is the responsibility of the system designer to inform the user

of the play-off between cost and LOEP, and let him decide. Using the comparison package this relationship is easily quantified.

Another method of decreasing energy costs is to improve the system efficiency. This may be done in various ways. Firstly, the components of the SAPV system should be of high efficiency. High efficiency inevitably means expensive components, but the resulting saving generally outweighs the added expense. Inverters of different quality may vary in efficiency by as much as 10%, for example, which would typically change energy costs by about 6% due to improved overall system efficiencies. If it is possible to utilize DC power at a site rather than AC, this would further improve system efficiency, since inverter efficiencies tend to be around 75% efficient while converters are around 95% efficient. This would result in a reduction in energy cost by over 10%. DC has the disadvantage that such systems are generally at low voltage, and therefore losses in wiring may become significant, depending on the length of wire involved. In general, applications require AC power, however, since appliances and other electrical equipment commonly use AC.

Since losses occur in battery charging, system efficiency may be improved by using power during the day, when more energy may be supplied directly from the array to the load, rather than have it cycled through storage. Here the user may be able to re-schedule some activities so that the proportion of energy used during the day is increased. The saving that can be expected by modifying a purely night-time demand profile to a purely daytime one is approximately 13%.

In addition to increasing the required system LOEP and improving the efficiency, energy costs may be reduced by reducing the peak load requirements. This reduces the inverter size re-

quired, but since inverter costs are generally well below 10% of the system life cycle costs, this is only worth considering in situations where load factors are poor.

#### 7.2.2 OPTIMIZING ENERGY COSTS FROM A DIESEL GENSET

Because genset energy costs revolve around the capacity factor at which the set is run, efforts at reducing costs must focus in this area. The factors that fix the average capacity factor are set size, peak load, average energy demand, and time over which the power is required. The only practical precaution to be taken regarding set size, is to ensure that it is not oversized with respect to the peak load that it is required to supply, which will avoid unnecessary reduction of the capacity factor.

If there is flexibility in the demand characteristics, the user could reduce energy costs by reducing the peak load or shortening the time during which the energy is demanded. Reducing the peak load will mean that a smaller genset is required to meet the requirements and therefore the running capacity of the set will improve while supplying the lower energy demands. This can result in a significant saving, particularly where the average capacity is low. For example, if a site requiring 10 kWh/day over 8 hours could reduce its peak load requirement from 5 kW to 3 kW, it would lower its unit energy cost by approximately 30%. Methods by which peak loads may be reduced would vary from user to user, but could include shuffling the larger demands so that they do not superimpose their loads on the genset, or modifying induction motor starters to "star-delta" configuration to reduce their starting currents.

A user may also be able to adapt his schedule so that all the power requiring activities are condensed into a shorter time period, and thus the average demand would be greater and capac-

ity factors higher. As an example, a user consuming 30 kWh/day and with a peak load of 10 kW could expect energy costs to drop by 20% if the genset run-time is reduced by 4 hours.

### 7.2.3 OPTIMIZING ENERGY COST FROM GRID EXTENSION POWER SUPPLY

Unlike with SAPV systems and diesel generation, little can be done to reduce grid power energy costs, since the largest proportion of the cost per kWh is typically the extension charge. However, where extensions are short and energy use high, there is potential for saving. Reducing the peak load would reduce the transformer requirements, however, with transformer costs in the region of 30 to 80 R/kVA, the reduction would have to be large to make a significant difference to the energy cost. Since transformers are only supplied in about seven standard sizes to cover the range up to 500 kVA, the peak load reduction would also have to be such that the required transformer size fell into a lower category. As an example, a user 2 km from the existing grid requiring 50 kWh/day of energy, if able to reduce the peak load requirement from 30 kW to 20 kW, would be able to reduce the transformer requirement from 50 kVA to 25 kVA, which would reduce the unit energy cost by about 4%.

If the site in question falls into the "large user" category, having a peak demand over 100 kVA (about 85 kW), there are additional opportunities to economize. Reduction in peak load will reduce the demand charge levied, but since this is a present R18.30 per kVA registered during a particular month, the reduction will have to be substantial to reduce the unit energy cost significantly.

Since different tariff structures are available to large users, it may prove worthwhile modifying the demand characteristics to benefit from another tariff. For example, it may be feasible to shift demand to off-peak periods to qualify for the off-peak

rate (Note: the off-peak rate is not included in the comparison package). Users with variable demand and low load factors, typically under 20.5%, may find it beneficial to apply for tariff 'F' rates. The possible savings resulting from such changes in tariff group, however, are dependent on the demand characteristics and flexibility of the site in question, and therefore require more detailed investigation.

Potential for reducing grid extension supplied energy costs, is, therefore, limited. For sites where extension charges are proportionally low, however, small savings may result from reductions in peak load requirements.

### 7.3 THE COMPARISON PACKAGE - USES AND LIMITATIONS

In establishing comparison package for the different power supply options, various simplifying assumptions, and generalizations were included in the sizing and costing methodologies used. While this was necessary to ensure the simplicity, wide applicability, and therefore the usefulness of the package, the results generated include certain limitations due to this, and these must be kept in mind when using the package. These limitations, therefore, will first be discussed, and in this light, the main uses of the package will be dealt with.

#### 7.3.1 THE LIMITATIONS OF THE PACKAGE

The sizing and costing methodologies from each option will first be dealt with in isolation, and thereafter the package in general will be discussed.

##### 7.3.1.1 The Photovoltaic Sizing and Costing Procedure

Because the photovoltaic sizing method does not make use of hourly system simulation, it inevitably must include some simplifying assumptions concerning system efficiencies.

Whereas full-scale simulation sizing procedures monitor hourly cell temperature, battery state of charge, and demand, all of which affect the system efficiency, the sizing procedure used in this package assumes efficiencies to be constant. If the efficiencies used are well chosen the results produced will be accurate, but inevitably less so than simulation program results. The system sizes produced by the program are, however, expected to be of superior accuracy to results from quick-sizing methods, since in this method program attention is restricted to energy deficit periods when efficiencies are more predictable.

The processing of the hourly insolation records for use Cowan's sizing method has only been done for the tilt angles which optimize the worst-month insolation for each station. The package therefore does not attempt to accommodate variations in energy demand over the year, which would be better served by array tilt angles which optimize peaking demand months rather than worst insolation months.

This sizing method also includes some uncertainty as to whether the results are optimized with respect to seasonal variation since it does not consider runlengths of greater than one month in system sizing. It may therefore be possible to optimize systems further by designing the storage for long term cycling to cope with seasonal variations, and sizing a corresponding array.

Because of the limited period for which weather stations in Southern Africa have been keeping hourly insolation records, there will be some uncertainty in the system sizes resulting from the use of Cowan's method for low LOEP values. Ideally, about 50 years of data is required to gain sufficient stability in insolation patterns for accurate sizing at such low probability levels (Klein & Beckman, 1987, 501), and South African data ex-

tends for 30 years at best. The extent of this uncertainty requires research that is beyond the scope of this project.

The program uses hourly insolation data to generate the curves used in sizing, and since there are only twelve sites in the that keep hourly records in South Africa and Namibia, only twelve sets of curves have been generated. The country has therefore been divided into twelve regions, and the insolation of station supplying the data in each region has been assumed to be representative of the entire region. Besides leading to obvious inaccuracies due to the differing micro-climates of specific sites in the region, there are variations in general insolation patterns within each region. In order to examine the extent of this variation, monthly horizontal global insolation records from 86 stations scattered throughout South Africa and Namibia were compared with the monthly records from the stations that keep hourly data records. The results are presented in appendix C. The standard deviations of the mean monthly radiation values of the sites within these areas is as high as 0.57 kWh/sq.m/day in some cases, which indicates a reasonable scatter in insolation levels. Examining average monthly data in order to obtain an indication of the similarity in isolation characteristics within a given region, is of limited value in that it includes no information on insolation distribution pattern diversity. It is merely undertaken here to provide some indication of differences in a particular region. The region boundaries were, however, chosen to limit climatic variation within them, and thus reduce differences in insolation distributional patterns.

The effect of differences in insolation characteristics within regions on system sizing accuracy is difficult to determine. Since full-scale simulation sizing programs also require hourly data, they cannot be used as a yardstick. It must therefore suffice to keep differences in average monthly average values

within a region to a minimum, and to limit the climatic variation within regions, as has been done.

It is, however, worth mentioning some of the obvious variations that would occur within regions. Where regions using hourly data from inland stations include stretches of coast, it can be expected that coastal insolation levels will generally be lower, and thus SAPV systems will be undersized. An example is the coastal area of Namibia, which is included in regions using data from Windhoek and Keetmanshoop. The opposite also applies, in that where coastal station's hourly data is used, the system sizes for inland areas included in that region would tend to be larger than required. Regions using the data from Alexander Bay, Cape Town, Port Elizabeth, and Durban are examples of this.

The main limitations in the photovoltaic sizing procedure, therefore, are the possible further optimization of system size by including long-term cycling storage to cater for seasonal variations in insolation levels, the generalizations concerning system component efficiency made, possible inaccuracies in sizing for low LOEP values, and the variations in insolation characteristics found within the chosen regions. It must be remembered, however, that the efficiencies used, and the use of local insolation data, are expected to result in a system sizing accuracy surpassing that of all other available sizing methods apart from the hourly simulation programs.

#### 7.3.1.2 Limitations in the Diesel Genset Sizing and Costing

The main cost determinants of diesel energy is the capacity factor at which the set is run, because of the large variation in fuel consumption per unit energy produced at different capacity factors. Since the set sizing and costing procedure only has average daily energy and peak load requirements as



program inputs, the average set capacity factor only can be determined, and on this basis the fuel consumption per kWh estimated. Because the fuel consumption per kWh and capacity factor relationship is not linear, the use of an average capacity factor to determine average fuel consumption per unit energy leads to inaccuracies. By comparing the average fuel consumption obtained in this way to values obtained using instantaneous capacity factors for a range of hypothetical demand profiles, it was possible to reduce the inaccuracies resulting from the use of average capacity factors to determine average fuel consumption. This was done by adapting the fuel consumption per unit energy curves, but, since these adapted curves cannot represent all possible demand profiles, some inaccuracy remains. A pilot study has shown that inaccuracies in fuel consumption estimates expected from this are at most 5%.

Other sources of uncertainty in the sizing and costing procedure for gensets revolve around the assumptions concerning set lifetime and maintenance costs. For both of these, the estimates found in the available literature vary greatly. Maintenance cost estimates vary from 25% of the capital cost of the genset spread over its lifetime, to 130%. The value recommended for use in the comparison package was 120% of the set capital cost, which was based on the estimates of Morris (1988,p152), whose work appeared to be the most reliable from amongst those reviewed. The package also ignores the effects of different capacity factors on maintenance costs. It is anticipated that the harmful effects of low capacity factors would lead to increased maintenance, but since insufficient information was found to enable this to be quantified, this effect was ignored.

As with maintenance costs, the variation in estimates concerning set lifetime were found to be great. The range found was from 10 000 hours to 60 000 hours, and appeared independent of

set size. It is reasonable to assume that large gensets would last for longer than smaller sets, but again, no information was found which enabled this relationship to be quantified. A study of gensets in rural Kenya by Kenna (1987) indicates that genset life is in practice not significantly dependent on its size, and thus omitting this effect from the package could result in negligible effect on the accuracy of results. Average capacity factor, also, could be expected to affect set life, but again, this was not able to be quantified.

The diesel genset LOEP value used in the package of 0.05, was based on information provided by various sources, and although this value is representative of these sources, the information provided was often sketchy and possibly unreliable. There is therefore a degree of uncertainty about this value.

In summary, it is felt that since the errors concerning fuel consumption estimates in relation to capacity factor have been minimized, and since assumptions concerning set lifetime, maintenance costs, and LOEP have been based what information is available, the resulting accuracy of the package is acceptable and could only be improved with considerable research.

#### 7.3.1.3 Limitations in Grid Extension Cost Estimates

Since the tariffs applying to Eskom power users are set, the major source of uncertainty in grid extension supply costing is related to the extension costs. In practice, a potential user requiring grid power would approach Eskom, who would give them a quote after an inspection of the situation including the terrain type. The package provides for four different types of terrain and gives typical costs per kilometer for extension over each. The accuracy of the results, therefore, would obviously vary with the accuracy of the user's choice.

The grid power costing procedure does not include the off-peak tariff option. Whether the user qualifies for this tariff depends on the proportion of the demand used in off-peak periods, and therefore its applicability cannot be determined without details of the demand profile beyond those used in the package. It is possible, however, that significant reductions in energy costs could result from the use of this tariff in certain cases. This should be kept in mind when using the grid extension costing procedure in cases where the demand is largely off-peak.

#### 7.3.1.4 Limitations of the Package in General

In such a comparison package there is an inevitable compromise between accuracy and usefulness. Requiring information not easily available, such as detailed demand profiles for the user in question, would automatically render the package less useful, but would enhance the accuracy of its results. The approach adopted here was to preserve its wide applicability by constructing a package that includes generalizations rather than highly specific inputs. This is the case with the demand information required. The package only uses the peak load and average energy required per day as inputs, and while this limits the accuracy obtainable, it does not restrict its usefulness as an assessment tool for various power supply options in presently off-grid situations.

In the package, prices are often given as Rand per Peak Watt, or Rand per kWh of battery storage. By generalizing the prices in this way, no account is taken of the actual equipment sizes available. This results in inaccuracies where a user must choose an item of equipment larger than required, for example PV storage batteries, because the required size is not available. It was, however, felt that to include details concerning

available equipment sizes from the various manufacturers of a particular component was not merited.

System component lifetimes are also generalized. The package uses typical values, but again, in practice different manufacturers products would last for varying periods, as would similar products in different climates. The program is, however, constructed so that all cost and system information that is variable may be changed by the user, and therefore if greater accuracy is required, more specific values may be used in place of the generalized ones.

Many of the limitations introduced into the comparison package by the generalizations discussed in this section, are, therefore, justifiable in terms of the objective of the project - to establish a comparison tool for general use to aid in the assessment of the various power supply options in presently off grid situations.

Because the package is computer based, its use is limited to those with access to a computer. This is an unavoidable limitation, however, since it is the only feasible way in which to access the large amounts of information involved in such an assessment, and the only practical way of processing the input information to give results in a short time. A set of graphs of likely energy costs for various daily energy requirements from the different supply options (fig 6.11 & 6.12) have been generated using results from the program, and for situations where there is no computer available, these may be used as a guideline. However, since these graphs were intended to be very general, the information obtained from them should be regarded as coarse.

### 7.3.2 USES OF THE COMPARISON PACKAGE

As stated in the previous section, the package is intended for use in situations where a site is in need of a power supply and the potential user wishes to assess the viability of the three options dealt with in this project. From the package, then, an estimate of the likely unit energy costs resulting from each option may be obtained. These results should be regarded as estimates rather than precise forecasts of energy prices because of the many generalizations and simplifications that have been included in the package, as has been discussed in previous sections. Factors other than the cost of energy should then be considered, such as convenience of use, adaptability of the supply to possible site expansion plans, and future utility plans to electrify presently off-grid areas. In the light of all the above considerations, then, a choice of power supply option can be made.

The package is therefore an aid in the above process, and enables a user to assess the options more fully, and thus avoid unnecessary expense.

Using results from the comparison procedure, graphs have been generated relating energy costs to daily energy requirements for the different options. These graphs may be used as indicators of which options are likely to be viable in circumstances where access to the computer package is not possible. They are also useful in presenting an overview of the viability of the options in different situations.

The use of LOEP as a system reliability measure enables the energy costs obtained from the package to be assessed on a common basis. The user therefore has the added dimension to assessing the options in that he may decide what he is prepared to pay for a specific reliability. If higher reliabilities than 0.05

are desired, for example, the choice is between a highly reliable SAPV system or grid power. If 0.05 is sufficiently reliable, diesel generation also can be considered as an option.

Because the package provides results quickly, it is possible to change a number of variables to determine the effect on power cost. In this way a large range of sensitivity analyses may be performed. By adjusting various input variables it may be determined, for example, whether a change in the time over which the energy is required during the day would have a significant effect on energy costs. In this way information may be gained regarding energy cost optimization strategies.

The effects of possible future cost trends or technology improvements may also be analyzed using this package, as has been demonstrated in chapter 6.

The package is therefore useful in a number of areas other than that for which it was principally intended, which is as an aid to the assessing of various power supply options for a specific off grid situation.

#### 7.4 SUGGESTIONS REGARDING FUTURE WORK IN THIS AREA

In undertaking this project, many areas were found where information was incomplete, or where there were uncertainties, and many of these shortcomings have not been pursued. Most such areas encountered have been mentioned in the relevant sections and in the section dealing with the comparison package limitations, and therefore here they will only be discussed briefly.

#### 7.4.1 PHOTOVOLTAICS

Since the SAPV system sizing method used in the comparison package has only recently been developed, there are several areas in which further research needs to be undertaken. These are listed below.

- (1) The effect of ambient temperature on the array efficiency and therefore system performance may have a significant effect on system sizing results. This effect should be clarified.
- (2) The possibility that, by considering run lengths of greater than 30 days in the sizing procedure, the array and storage size combinations could be further optimized with respect to cost needs to be investigated. This involves considering different tilt angles, and therefore establishing "expected insolation level" curves for these tilt angles, in each system sizing.
- (3) Cowan's assumption that batteries never exceed 90% state-of-charge to account for the reduced battery charging efficiencies at high state-of-charge, and to compensate for the possibility that batteries may not be fully charged at the beginning of a run, may be unnecessary, or may be a clumsy way to account for these factors. This should be clarified.
- (4) The "expected insolation level" curves for high LOEP values are more reliable than the low LOEP curves because, particularly for the LOEP = 0.001 (one day in three years) curve, large amounts of data are necessary to establish them with some certainty. It would therefore be useful to do a statistical investigation into the curve generation procedure in order to establish a confidence level for each curve. Since different amounts of data are available for different sites, this confidence level would vary amongst sites.

(5) Certain parts of the country are not particularly well represented by the data used in the system sizing procedure from the twelve weather stations. An example of this is the Namibian coastal region. SAPV system sizes will therefore not be as accurate as for other areas. The inaccuracies should be investigated and possible ways of reducing them looked into if it is merited.

(6) The sizing method would be enhanced if it could accommodate seasonally varying energy demands. This requires that array tilt angles other than those which optimize the worst insolation month be considered.

(7) It may be possible to hasten the SAPV sizing procedure by establishing "rules of thumb" of acceptable accuracy for sizing in each area.

#### 7.4.2 DIESEL GENERATION

Possible areas of further research with respect to diesel genset power supply are listed below.

(1) The relationship between set lifetime and set size should be clarified, since larger sets are expected to last longer than smaller ones.

(2) Genset maintenance cost estimates vary widely. Reasonable values should be determined.

(3) The LOEP value of 0.05 used in this package is based on limited information. It could therefore be established with more certainty.



#### 7.4.3 GRID EXTENSION POWER SUPPLY

Here, only one area of uncertainty worth further investigation was encountered :

The LOEP value of 0.001 used for grid power is based on figures from Eskom reflecting the percentage of total capacity lost, and not necessarily the total demand lost. This does not, therefore, indicate the reliability that the user can expect from the power supply. This information should be obtained, possibly by means of a survey of remote users.

#### 7.4.4 THE PACKAGE IN GENERAL

The range of power supply options considered was restricted to the three most common alternatives found in this country ; diesel generation, grid power, and SAPV systems. Ideally, the comparison package should be extended to include systems such as petrol generation, wind generation, micro-hydro supply, and hybrid systems such as photovoltaic/wind hybrids, micro-hydro/photovoltaic hybrids, and diesel genset/battery hybrids. The latter system is likely to prove economical in many circumstances, since the genset can be run at optimum capacity factors by supplying the demand and charging the batteries with any spare capacity. Its LOEP is also expected to be higher than that of a straight diesel generation system.

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**APPENDICES**

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APPENDIX A

SYSTEM SIZING AND COSTING METHODS AS USED IN THE PROGRAM

Note: This appendix outlines how the program uses the sizing and costing methods as described in chapters 2,3, and 4. It does not give details about the code itself.

A-1 : THE SAPV SIZING AND COSTING METHODOLOGY

Cowan's SAPV system sizing method is used in the program as described below.

**The minimum expected POA insolation level curves**

For the LOEP and site selected by the user, a curve of the minimum expected POA insolation level vs run length in days is set up using the 'expected POA insolation' equation described in chapter 2. The 'expected' curve for a LOEP of 0.01, for example, means that 99% of the observed hourly insolation levels used in establishing the curves are above this particular curve. Each site will have a different curve because of the different insolation characteristics of each area.

The data processing procedure used to generate the curves for the various sites is explained in appendix B.

**The minimum required POA insolation level curves**

The various array and storage size combinations that satisfy the energy demand for this expected insolation level curve are then determined. This is carried out by computing the minimum average required insolation curve (vs run length) for various array and storage size combinations (again refer to chapter 2 for the 'required' equation) until the 'required' curve converges on the 'expected' curve as explained in chapter 2. The array and storage size combination that results in this convergence is then saved as one of the combinations that satisfy the specified LOEP and average energy demand. By looping through a range of array and storage sizes, all such combinations that satisfy the specified LOEP and energy demand criteria are found and saved.

The program first fixes a storage size, and for this storage size determines the array size that produces a 'required' curve that converges on the 'expected' curve (if such an array size exists), by looping through a range of sizes. The storage size is then increased and the process repeated until the corresponding array size is found. The selection of the incre-

ments in the array and storage sizes that are taken for each subsequent loop, and the maximum array size considered, are dependent on the magnitude of the average energy demand. The smaller the demand, the smaller are the loop increments and maximum array size considered. This enables the program to find a satisfactory range of array and storage combinations in a reasonably constant time, independent of the magnitude of the demand, and results in a consistent level of accuracy for all demand magnitudes.

### Selection of final array and storage sizes

Once the range of combinations that satisfy the specified conditions has been found, the most cost effective of these combinations is found. This depends only on the current prices of array modules and storage batteries. This array and storage size combination, then, is the final result of the system sizing.

### Determining system efficiency (sys. eff.)

In determining the overall system efficiency, the following component efficiencies are considered:

- module conversion efficiency
- charge regulator efficiency
- inverter efficiency (if an AC system)
- converter efficiency (if a DC system)
- battery cycling Watt-hour efficiency

Module conversion efficiency - this is the efficiency at which the module converts the sun's energy into electricity. For Cowan's sizing method, attention is restricted to energy deficit periods, when module temperatures are likely to be relatively low, from 15 to 20 degrees C, and conversion efficiencies slightly higher than the specification values. In the comparison program, a module temperature of 25 degrees has been used, which is slightly conservative.

Charge regulator efficiency - in energy deficit periods losses across the regulator are expected to be low due to relatively high system energy demands when compared with available array power. Losses of less than 5% may be expected.

Inverter efficiency (for AC systems) - this depends on the current being drawn by the demand. If it approaches the full capacity of the inverter, the losses are reduced. The inverter is sized on peak energy demand expected, so the higher the peak demand compared to the average demand, the lower will be the average inverter efficiency. Also, inverter efficiencies vary greatly depending on the quality of AC signal produced and the quality of manufacture. It is therefore difficult to general-

ize concerning their efficiencies. Losses vary from between 15 to 40% typically.

Converter efficiency (for DC systems) - typical efficiencies vary from 80% to as high as 95% . Converters are also sized according to the peak energy demand expected.

Battery cycling watt-hour efficiency - the battery cycling efficiency is only applied to the fraction of energy being cycled through the batteries, and not to the energy demand being supplied directly from the array. The program user is expected to estimate the fraction of energy demanded during daylight hours (here assumed from 08h30 to 16h30) and so give an indication of the fraction of energy that will be supplied directly from array to demand. This user given fraction will, however, not take into account periods during daylight hours when insolation is insufficient to supply the demand, for example during over-cast conditions, or in the early morning and late afternoon. It is therefore necessary to include a factor in the user given fraction to account for these conditions. A preliminary study has shown 0.3 to be a suitable factor (see appendix D for details).

Since, in energy deficit periods, battery SOC is not expected to be high, and charge and discharge currents are low in relation to battery capacity, battery energy cycling efficiencies can be expected to be higher than average. Although this will vary for different types of battery, watt-hour efficiencies of between 80 and 90% are typical under these circumstances.

Deviation from optimum power point losses - In addition to the above considerations, a factor must be included in the system efficiency to account for deviations from array optimum power points. Briefly, during energy deficit periods, battery charging voltages are expected to be lowered, and modules are expected to be operating at a lower range of cell temperatures. The overall effect is a shift from array optimum power point conditions. A factor of 0.85 is used by Cowan (1988, 122).

The overall system efficiency

The system energy efficiency equation then becomes :

$$\text{SYS.EFF} = \text{module eff.} * \text{regulator eff.} * \text{inverter/converter eff.} * \text{optimum power loss factor} * (\text{battery cycling eff.} * \text{fraction of energy cycled through batteries}).$$

#### System costing methodology

The methodology used to cost the system has been adapted from that used by Borden et al. (1984). The steps used to compute the system costs are as follows :

(1) Initial cost - This includes all the initial capital outlay

for the system components (array, regulator, inverter, battery), and an array related "balance-of-system" cost multiplier (BOS), which accounts for wiring, array mounting, and any other installation costs. The equation for the initial cost is :

$$IC = [(1+BOS)*(MOD*Wp)] + (INV*Wac) + (REG*Wx) + (BAT*Cfinal)$$

Where IC - initial cost  
 BOS - array related balance of system cost multiplier  
 MOD - array module cost (R/peak watt)  
 Wp - array peak watts  
 INV - inverter cost per peak AC watt  
 Wac - Peak AC watts  
 REG - regulator cost per max. input power watt  
 Wx - max. regulator input power (watts)  
 BAT - battery cost per watt-hour  
 Cfinal - battery storage capacity (watt-hours)

The maximum regulator input watts are found by multiplying the array peak watts by a factor of 1.2. This factor was found to allow for array peak power increases caused by cell temperatures as low as 0 degrees C.

A typical value for BOS would be in the order of 0.05. The values of the other parameters depend on system size and current prices of the various components.

(2) Present value of sum of all battery replacement costs - The number of battery replacements, which depends on the system and the battery lifetimes, is computed and reduced to its present value. This step has the option of including the salvage value of the old battery in the system costing. The equations used here are :

$$BR = (BAT*Cfinal) * (1-SV)$$

where BR - cost of each battery replacement  
 SV - fractional salvage value of old battery

$$RPV = \text{Sum for number of replacements of: } \{BR*[(1-escB)/(1+dr)]^{(j*Byears)}\}$$

where RPV - present value of sum of all battery replacements  
 escB - real annual escalation of battery cost  
 dr - discount rate  
 j - counter for number of battery replacements  
 Byears - battery lifetime (years)

The fractional salvage value of batteries is commonly in the order of 10%. The real annual escalation of battery costs refers to the above inflation annual escalation, and is usually taken to be 0%.



(3) Present value of all operation and maintenance costs - Annual array and battery operation & maintenance costs are included as fractions of their initial costs. The total operation and maintenance costs over the system lifetime are then reduced to their present value to yield the system operation and maintenance cost. The equations used here are :

$$OM = [\text{Array}_f * (1 + \text{BOS}) * (\text{MOD} * \text{Wp})] + (\text{Batt}_f * \text{BR})$$

Where OM - annual operation and maintenance cost  
 Array\_f - fractional cost of array operation and maintenance  
 Batt\_f - fractional cost of battery operation and maintenance

$$\text{OMPV} = \text{OM} * (1 + \text{escOM}) / (\text{dr} - \text{escOM}) * \{1 - [(1 + \text{escOM}) / (1 + \text{dr})]^{\text{Nyears}}\}$$

where OMPV - present value of OM  
 escOM - real escalation of OM  
 Nyears - system lifetime (years)

Fractional costs of array operation and maintenance is the fraction of the initial array cost that is expected to be spent on operation and maintenance of the array during its lifetime. It tends to be negligible. The fractional cost of battery operation and maintenance may be taken as being in the order of 1% of the battery replacement cost. The system lifetime depends on the lifetime of the panels, and varies from 20 to 30 years.

(4) System life cycle cost - The initial cost, present value of operation and maintenance costs, and present value of all battery replacements are summed to yield the system life cycle cost. The equation used here is :

$$\text{LCC} = \text{IC} + \text{RPV} + \text{OMPV}$$

(5) Expected cost of electricity from system - The system life cycle cost is then divided by an "annualizing" factor (Morris, 1988, p53), and the total energy expected to be used over the year (in kWh), to give the expected annualized unit cost of electricity from the system. The total energy expected to be used is computed from the average daily energy demand. The equations used here are :

$$\text{PVann\_kWh} = 365 * \text{Load} / 1000$$

where PVann\_kWh - total energy used over the year  
 365 - days in year  
 1000 - conversion to kWh from Wh

$$\text{PVann\_factor} = (\text{disc\_fact} * \text{dr} / 100) / (\text{disc\_fact} - 1)$$

where disc\_fact =  $(1 + \text{dr} / 100)^{\text{Nyears}}$   
 dr - real discount rate  
 Nyears - project lifetime

$$\text{Elec\_cost} = \text{LCC} * \text{PVann\_factor} * 100 / \text{PVann\_kWh}$$
 where Elec\_cost - cost of electricity per kWh.  
 LCC - life-cycle cost

## A-2 THE DIESEL GENERATION POWER SUPPLY SIZING AND COSTING METHODOLOGIES

### The sizing methodology

The genset is sized according to the peak load required to be met. Genset capacity has been taken as 80% of the kVA rating for sustained loads, and 90% for short term loads. If the peak load is inductive for example, the short term capacity is used in sizing, and if it is a sustained load, the sustained capacity is used. An altitude derating of 4% per 300m ascent above sea level is included in determining the set capacity.

### The costing methodology

Once the genset capacity is established, the genset capital cost is read from a data file. This cost, together with the present values of all maintenance, operation, and set replacement costs over the project life, are summed to result in a final system life-cycle cost. Maintenance costs are estimated at around 100% of set capital costs spread over the set life, and operation costs are read from a data file and are dependent on the average capacity factor at which the set is run. Initially, the life-cycle cost are determined for all capacity factors corresponding to daily set run-times ranging from the minimum required to satisfy the demand inputs, to 24 hours. The minimum run-time required is calculated as the average daily energy required divided by the peak load.

The program user is then asked to choose a run-time from amongst these, depending on the site requirements, and using this choice the final costing is done.

The costing methodology has been taken from Borden et al.(1984). The costing equations used in the program are as follows :

To determine the genset capital cost ;

$$\text{Gencap} = \text{Rper\_kW} * \text{kW\_rating}$$
 where Gencap - genset capital cost  
 Rper\_kW - genset cost per kW rated (from data file)  
 kW\_rating - genset rating in kW

To find the total initial cost of the system ;

Totcap=Gencap+Gencap\*(Acc\_cost+Room\_cost+Trans\_cost+Inst\_cost)  
 where Totcap - total initial cost of system  
 Acc\_cost - accessories fractional cost (fuel tank, wiring, exhaust, etc)  
 Room\_cost - fractional cost of generator room  
 Trans\_cost - fractional cost of transporting genset to site  
 Inst\_cost - installation and commissioning fractional cost

To determine the genset replacement costs ;

Rep\_cost=Gencap\*(1-Salvage\_val)+Gencap\*(Trans\_cost+Inst\_cost)  
 where Rep\_cost - genset replacement cost  
 Salvage\_val - genset salvage value

To determine the present value of all genset replacements ;

Rep\_PV = Sum for no.of replacements of:  

$$\text{Rep\_cost} * \left( \frac{1 - \text{Esc\_rate}}{1 + \text{Disc\_rate}} \right)^{(r * \text{Gen\_years})}$$
  
 where Rep\_PV - present value of genset replacement costs  
 Esc\_rate - escalation rate  
 Disc\_rate - discount rate  
 r - counter for number of genset replacements  
 Gen\_years - genset life in years

To determine the present value of operation costs ;

Op\_PV = Op\_cost \*  $\left( \frac{1 - \text{Esc\_diesel}}{\text{Disc\_rate} - \text{Esc\_diesel}} \right) * \left( \frac{1 - \text{Esc\_diesel}}{1 + \text{Disc\_rate}} \right)^{\text{Proj\_life}}$   
 where Op\_PV - present value of operation costs  
 Op\_cost - annual operation cost  
 Esc\_diesel - escalation of diesel  
 Proj\_life - lifetime over which project to be costed

To determine the maintenance costs over the set lifetime ;

Maint\_cost=Gen\_maint\*Gencap\*count\_ratio  
 where Maint\_cost - maintenance cost of genset over lifetime  
 Gen\_maint - genset maintenance cost over lifetime as a fraction of the initial genset cost  
 count\_ratio - ratio of project life to genset life

To determine system life-cycle cost ;

Gen\_LCC = Totcap + Rep\_PV + Op\_PV + Maint\_cost  
 where Gen\_LCC - genset system life cycle cost

To determine the annualized unit cost of energy ;

Ann\_kWh = 365\*Load/1000  
 where Ann\_kWh - total energy produced over a year

$$\text{Ann\_factor} = \frac{\text{Disc\_rate}/100}{(1 + (\text{Disc\_rate}/100))^{\text{Proj\_life}} - 1}$$
 where Ann\_factor - annualizing factor

$$\text{Ann\_cost} = \text{Gen\_LCC} * \text{Ann\_factor} * 100/\text{Ann\_kWh}$$
 where Ann\_cost - annualized unit energy cost

### A-3 THE GRID EXTENSION POWER SUPPLY COSTING METHODOLOGY

The grid extension charges are combined with the demand related tariffs to give a total monthly charge to the user.

#### Determining the monthly extension charge

First the type of terrain over which the grid is to be extended is established, and from this the per kilometer extension cost determined. This is multiplied by the distance of extension to obtain a total line extension cost. To this is added the transformer cost, and metering cost if a large user. Since monthly extension charges are a percentage of the total extension cost, this may now be determined.

From the monthly extension charge is subtracted the rebate due. This varies with user size, large user rebates being dependent on the peak kVA demanded during the month, or the energy used during that month for "low load factor" users, and small user rebates being a fixed rate for the first two kilometers of extension (on 10/1989).

The form of the equations used to compute the extension charges is as follows :

$$\text{(Total extension cost)} = \text{(Line extension cost)} + \text{(transformer cost)} + \text{(metering cost if applicable)}$$

$$\text{(Total extension charge)} = \text{(Total extension cost)} * \text{(percentage rate)} - \text{(rebate due)}$$

#### Determining the monthly demand related tariffs

These tariffs also vary depending on whether the user is large or small. Small users are subject to a basic tariff, which is applicable whether energy is used or not, and an energy tariff, which is dependent on the energy used. Large users are subject to both basic and energy tariffs, as well as demand and transmission percentage charges. Demand charges are dependent on the peak kVA registered during the month, and transmission percentage charges on the site direct distance from Johannesburg, and apply to the demand, energy, and basic charges. In addition, large users may qualify for the "low load factor" tariff

structure, in which sets a ceiling on the following ratio:  
(demand+energy charge)/(kWh used during month).

The total monthly charge and the unit energy cost

The total monthly charge is then computed by summing the extension charge and the applicable tariffs :

$$\text{(Total monthly charge)} = [(\text{extension charge})+(\text{basic charge})+(\text{energy charge})+(\text{demand charge if applicable})]*(\text{transmission charge if applicable})$$

From this the unit energy cost is found as follows :

$$\text{(Unit energy cost)} = \frac{\text{(Total monthly charge)}}{\text{(Total monthly energy use)}}$$

-----

APPENDIX BTHE DATA PROCESSING METHODOLOGY USED TO ESTABLISH THE "MINIMUM EXPECTED POA INSOLATION" CURVES AS USED IN COWAN'S SAPV SYSTEM SIZING METHOD, FOR THE DIFFERENT WEATHER STATIONS AROUND THE COUNTRY

Because the comparison program must be applicable to the entire country, it is necessary to generate the "required POA insolation" curves needed for SAPV system sizing to cover the entire area. The generation of these curves requires hourly insolation records, and since only twelve weather stations around South Africa and Namibia keep hourly records, the curves have only been generated for these stations. The stations are well spread throughout the country, and have therefore been assumed to represent the insolation patterns of the entire country.

For each station, a tilt angle of array was chosen in order to maximize the worst month insolation levels. The data was then processed using this tilt angle.

The twelve stations, their latitude, the tilt angles used for each, and the worst month for that tilt angle are listed below. The letters refer to the regions as used in the comparison package.

<u>Letter</u>	<u>Station</u>	<u>Tilt angle</u>	<u>Worst month</u>	<u>Site Latitude</u>
D	Cape Town	60	Jun	-33.98
I	Pretoria	25	Jun	-25.73
F	Port Elizabeth	50	Jun	-33.98
G	Grootfontein (Cape)	45	Dec	-31.48
L	Durban	35	Sep	-29.97
H	Bloemfontein	35	Jun	-29.10
C	Alexander Bay	45	Dec	-28.57
E	Upington	40	Jan	-28.40
B	Keetmanshoop	35	Jan	-26.53
J	Roodeplaar	30	Jan	-25.58
K	Nelspruit	20	Nov	-25.43
A	Windhoek	20	Jun	-22.57

Since the sizing procedure allows for a choice of LOEP value, a curve for each LOEP level was generated at each station. The LOEP values used were 0.1, 0.05, 0.01, 0.005, and 0.001.

The data processing procedure to generate the curves for each site is explained below :

(1) For each day for a period of 20 years, 24 hourly diffuse and global insolation values were converted into hourly global insolation values using code extracted from the program PVFORM (Menicucci, 1985). The coding used to read the data from file,

input it into the tilt conversion program, and store the results in a file is listed in appendix F. The code extracted from PVFORM to convert horizontal data to tilted values is listed in appendix E.

(2) The hourly global insolation values on the tilt were converted to total daily global values.

(3) Then, for all runlengths of days, from 1 to 30 days, the average daily insolation for each runlength was determined. For example, when dealing with runs of 5 days, for all of these runlengths (the first starting on day one, the second on day two, etc.) the daily average is determined.

(4) For all LOEP values required, a value corresponding to that LOEP was then found from all the daily average values for each runlength. When dealing with a LOEP of 0.01, for example, from the range of average daily values obtained for each runlength, a value would be found such that 99% of all the values were above that value. In other words there is a 99% chance that the average daily insolation over any 5 day run will be higher than the value found. As Cowan points out, strictly speaking, observed frequency levels rather than probability levels are being dealt with, but practically, we may use the observed frequency levels as minimum expected insolation levels corresponding to that LOEP. If the above is done for all runlengths from 1 to 30 days, each run will have a corresponding minimum expected insolation level for the LOEP in question. The coding used to process the data as described in steps 3 and 4 is listed in appendix G.

(5) For each LOEP, the minimum expected insolation vs runlength data set was then curve fitted. The software used for this was the STATGRAPHICS nonlinear regression routine. The resulting curve fitting coefficients a, b, c, and d as used in the program, as well as the correlation coefficients obtained for each site, are listed on the following page. Each station is referred to by letter. The station corresponding to each letter is given in the table of site tilt angles used at the beginning of this appendix. The curve fitting equation used is :

$$\text{minimum expected insolation} = a + bN + c/N + d(\ln(N))$$

where N is the run length in days.

Site	LOEP	a	b	c	d	Corr coef. (
A	0.1	5256.17	-7.62	-20.85	376.63	0.999
A	0.05	4553.60	-9.05	-116.04	542.47	0.997
A	0.01	3017.17	-16.63	-296.72	962.82	0.998
A	0.005	2741.73	-11.34	-583.91	974.92	0.998
A	0.001	1693.78	-9.41	-369.31	1210.22	0.996
B	0.1	5526.38	-18.33	442.37	558.43	0.997
B	0.05	5159.17	-14.94	-34.43	608.72	0.999
B	0.01	3949.53	-22.19	-736.62	969.07	0.997
B	0.005	3153.92	-45.70	-555.09	1353.69	0.996
B	0.001	3104.42	-44.93	-2243.76	1341.35	0.993
C	0.1	5247.42	-7.72	-454.90	311.59	0.997
C	0.05	5054.52	-3.34	-1299.79	305.56	0.999
C	0.01	3252.77	-20.08	-1244.91	912.79	0.999
C	0.005	2228.87	-32.70	-643.57	1294.82	0.999
C	0.001	-656.95	-75.01	1700.33	2419.37	0.996
D	0.1	3693.42	-13.42	-943.33	358.12	0.998
D	0.05	2757.22	-24.19	-1118.85	658.22	0.999
D	0.01	313.89	-48.58	446.68	1458.27	0.999
D	0.005	-470.37	-45.49	1061.03	1628.78	0.998
D	0.001	-663.79	-1.92	959.98	1227.45	0.992
E	0.1	5124.35	-14.90	362.39	507.89	0.999
E	0.05	4833.48	-11.18	-434.41	523.29	0.998
E	0.01	3678.12	-30.37	-1402.65	907.86	0.999
E	0.005	3196.39	-41.67	-1506.59	1075.89	0.998
E	0.001	1073.09	-74.48	-132.35	1846.67	0.997
F	0.1	3972.47	-9.99	-1105.20	415.01	0.999
F	0.05	3008.13	-22.33	-1123.65	748.23	0.999
F	0.01	230.18	-55.76	664.84	1731.23	0.999
F	0.005	-473.61	-59.25	1101.99	1897.71	0.996
F	0.001	-1252.56	-33.67	1558.52	1788.30	0.975
G	0.1	4660.82	-8.54	-358.89	439.00	0.998
G	0.05	4042.16	-6.41	-1044.03	548.76	0.999
G	0.01	1270.68	-42.57	-71.77	1536.79	0.993
G	0.005	323.26	-47.44	-578.15	1817.46	0.999
G	0.001	-2563.47	-95.66	3098.09	2961.60	0.997
H	0.1	4373.86	-19.05	255.53	679.04	0.999
H	0.05	3350.92	-25.71	5.70	974.41	0.999
H	0.01	1802.58	-19.60	-434.21	1276.09	0.999
H	0.005	1424.37	-10.66	-474.85	1246.02	0.994
H	0.001	-625.85	-25.64	932.57	1758.23	0.980
I	0.1	4086.80	-16.12	-1.90	549.17	0.999
I	0.05	3416.31	-13.42	-361.88	677.63	0.999
I	0.01	1145.62	-36.42	255.07	1444.89	0.999
I	0.005	382.06	-34.63	597.86	1627.18	0.998
I	0.001	-1328.91	-50.08	1818.50	2180.02	0.996
J	0.1	4158.84	-13.17	38.09	543.44	0.999
J	0.05	3375.08	-18.40	-235.60	759.98	0.999
J	0.01	1642.40	-22.43	-245.06	1214.63	0.999
J	0.005	647.90	-31.14	385.22	1542.60	0.999
J	0.001	-1631.27	-54.97	2205.44	2335.48	0.998



Site	LOEP	a	b	c	d	Corr coef. (
K	0.1	3634.14	-10.00	-893.98	501.90	0.999
K	0.05	2826.87	-15.57	-1097.25	742.29	0.999
K	0.01	561.04	-48.97	369.59	1542.80	0.994
K	0.005	-105.67	-52.62	825.93	1723.56	0.994
K	0.001	-1152.17	-46.03	1581.21	1893.61	0.975
L	0.1	3578.31	-6.94	-1513.67	354.28	0.999
L	0.05	2303.88	-29.50	-908.93	851.68	0.999
L	0.01	-165.45	-56.40	950.97	1678.72	0.997
L	0.005	-899.75	-55.68	1591.75	1857.26	0.999
L	0.001	-2232.15	-58.61	2699.86	2156.70	0.984

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APPENDIX CA COMPARISON BETWEEN MONTHLY GLOBAL HORIZONTAL INSOLATION DATA FROM SITES WITHIN EACH SIZING AREA

This appendix examines the differences in mean monthly insolation between the major station used in each insolation region (which is the station which keeps hourly insolation records), and the various minor stations in the region for which monthly insolation data is available. The purpose of this is to gain some insight into the deviation in insolation characteristics within each region, and thus the possible error in assuming that the major station is representative of the entire region.

The table below summarizes the results of a comparison between horizontal monthly global insolation data from various minor stations within each sizing area, and the station keeping hourly records in that area used to generate the system sizing curves. The minor station numbers refer to the stations as listed in "A Solar Radiation Data Handbook for Solar System Designers in Southern Africa" (Eberhard et al., 1989, pp54-61). The insolation data used has also been taken from this source.

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Area using Alexander Bay as major station

Mean total daily insolation of major station : 6.01 kWh/sq.m

Minor stations in area by station number: 28, 43

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value from stations in area	Maximum value from stations in area	Mean from stations in area	Std.deviation of stn. mean
5.82	6.06	5.94	0.12

---

Area using Bloemfontein as major station

Mean total daily insolation of major station : 5.86 kWh/sq.m

Minor stations in area by station number: 57,53,36,48,62,52,60,38,61

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value from stations in area	Maximum value from stations in area	Mean from stations in area	Std.deviation of stn. mean
5.02	6.00	5.56	0.38

---

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 Area using Cape Town as major station

Mean total daily insolation of major station : 5.25 kWh/sq.m

Minor stations in area by station number: 3,4,7,15,5,1,4,11,12

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviati of stn. mea
4.60	5.84	5.19	0.36

---

 Area using Durban as major station

Mean total daily insolation of major station : 4.06 kWh/sq.m

Minor stations in area by station number: 40,33,68,54,64

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviati of stn. mea
4.50	5.16	4.71	0.23

---

 Area using Grootfontein as major station

Mean total daily insolation of major station : 5.38 kWh/sq.m

Minor stations in area by station number: 31,22,30,21,26,25,32,27,19,

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviati of stn. mea
4.70	5.97	5.36	0.43

---

 Area using Keetmanshoop as major station

Mean total daily insolation of major station : 6.13 kWh/sq.m

Minor stations in area by station number: 91,98,121

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviati of stn. mea
6.43	6.56	6.51	0.06

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 Area using Nelspruit as major station

Mean total daily insolation of major station : 4.59 kWh/sq.m

Minor stations in area by station number: 78,79,66,89,75,63,102,67,95

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
5.01	5.69	5.38	0.24

---

 Area using Port Elizabeth as major station

Mean total daily insolation of major station : 4.57 kWh/sq.m

Minor stations in area by station number: 9,10,18,14,16,17

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
4.86	5.01	4.91	0.05

---

 Area using Pretoria as major station

Mean total daily insolation of major station : 4.99 kWh/sq.m

Minor stations in area by station number: 77,82,72,73,83,84

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
4.83	5.46	5.25	0.20

---

 Area using Roodeplaat as major station

Mean total daily insolation of major station : 5.10 kWh/sq.m

Minor stations in area by station number:

97,105,103,113,104,81,93,88,100,

109,110,101,92

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
5.13	5.65	5.46	0.14

---

---

Area using Upington as major station

Mean total daily insolation of major station : 5.73 kWh/sq.m

Minor stations in area by station number: 71,44,65,35,59,34,70

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
5.63	6.07	5.83	0.13

---

Area using Windhoek as major station

Mean total daily insolation of major station : 5.82 kWh/sq.m

Minor stations in area by station number: 112,117,118,119,115,111

The following figures refer to the mean total daily insolation values from the minor stations in the area (units : kWh/sq.m) :

Minimum value frm stations in area	Maximum value frm stations in area	Mean frm stations in area	Std.deviasi of stn. mea
6.07	6.41	6.20	0.13

---

APPENDIX DDISCUSSION ON THE ESTIMATION OF THE SAFETY FACTOR TO BE INCLUDED IN THE 'DAYLIGHT FRACTION' OF ENERGY DEMAND USED IN COWAN'S SAPV SYSTEM SIZING METHODOLOGY FOR ESTIMATING THE SYSTEM EFFICIENCY.

Because of the losses that occur when energy is cycled through the batteries in a SAPV system, it is desirable to know what fraction of the energy is cycled through the batteries and what fraction is supplied directly to the demand from the array, in order to be able to estimate the overall system efficiency.

If the 'daylight fraction' is the fraction of energy used during daylight hours, when the array may be able to supply the demand directly without incurring storage cycling losses, and daylight hours are taken as from 08h30 to 16h30, then the fraction of energy incurring storage losses may be estimated as 1 - 'daylight fraction', or simply 'f'. This, however, is likely to underestimate the actual fraction incurring storage cycling losses, because, firstly, it does not account for overcast conditions when the insolation is insufficient to supply the load directly from the array and must therefore draw on storage, and, secondly, insolation levels in the early morning and late afternoon may not be sufficient to be able to supply the load directly (depending on the magnitude of the load of course) and it may again be necessary to draw on storage. It is therefore necessary to add a fraction onto 'f' to account for these conditions.

**Overcast conditions**

Although Cowan's sizing method takes into account the different insolation levels on various days, the overall system efficiency is still used to size the storage and array, and since the system efficiency includes the fraction 'f', it also includes the assumptions made in determining it.

One way of estimating this fraction is to estimate an array size, for example using an empirical rule-of-thumb such as the following :

$$\text{Energy demand} / \text{Array size} = 250$$

(which results in an array size of about 10% accuracy for Pretoria conditions, and may be adjusted for other regions), and then using hourly data over a number of years, establish the proportion of the daylight load that would not be able to be met because of overcast conditions. This would then be added onto 'f'.

It is, however, beyond the scope of this thesis to undertake such a detailed study. A factor of 20% will simply be added

onto 'f' to take this into consideration. This in effect allows for 1 in 5 days that the array will not be able to supply the load directly.

#### Lack of insolation in the early morning and late afternoon

Because the daylight hours have been limited to between 08h30 and 16h30, the proportion of the daylight energy demand that will not be able to be met directly by the array because of low insolation levels at the beginning and end of this period will be small.

As with the overcast conditions, this proportion could be accurately determined by comparing the hourly demand with hourly insolation levels during the defined hours, but this is also out of the scope of this thesis. However, a preliminary study done for Pretoria worst month conditions using a typical hourly insolation profile, indicates that, for all energy demands, the proportion of energy unable to be supplied directly by the array is less than 10% where the daylight energy fraction is 1.0 (i.e the entire energy demand occurs during daylight hours). This falls to 0% where the daylight energy fraction is 0.8 of the total energy demanded. It would therefore be conservative to add a fraction of 0.1 onto 'f' to account for these conditions.

#### The fraction 'f' as used in this thesis

The SAPV sizing program asks the user to input the fraction of energy demanded during daylight hours, and this gives an indication of the proportion of energy cycled through storage, or 'f'. Onto this is added a fraction of 0.2 to account for overcast days, and a fraction of 0.1 to account for low early morning and late afternoon insolation levels. The final fraction of energy expected to be cycled through storage is therefore :

$$(1 - \text{'daylight fraction'}) + 0.3.$$


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APPENDIX E

C\*\*\*\*\*  
 C ROUTINE TO CONVERT HOURLY HORIZONTAL GLOBAL AND DIFFUSE RADIATION  
 C VALUES TO TOTAL DAILY RADIATION ON A TILTED PLANE. THE CODING  
 C WAS ADAPTED FROM THE PVFORM PROGRAM.  
 C

-----  
 C  
 C INPUTS NEEDED: JLDATE (JULIAN DAY - TO BE CALCULATED)  
 C ----- TLAT (SITE LATITUDE - TERMINAL INPUT)  
 C TILT (ARRAY TILT ANGLE - TERMINAL INPUT)  
 C REFL (REFLECTIVITY - TERMINAL INPUT)  
 C + AN ARRAY OF  
 C HOR - 24 SEQUENTIAL HOURLY GLOBAL RADIATION  
 C VALUES FOR ONE DAY (HOR(1) TO HOR(24))  
 C (SAWB tapes in tenths kJ/hr - program  
 C accepts these units)  
 C DIFRAD - 24 SEQUENTIAL HOURLY DIFFUSE RADIATION  
 C VALUES FOR ONE DAY (DIFRAD(1) TO DIFRAD(24))  
 C (SAWB tapes in tenths kJ/hr - program  
 C accepts these units)  
 C  
 C OUTPUT: FTOTRD-ONE TOTAL DAILY RADIATION VALUE FOR TITED PLANE  
 C ----- (UNITS : WATT-HOURS)  
 C\*\*\*\*\*

C \*\*\*\*\*  
 C SUBROUTINE MODEL (FTOTRD, HOR, DIFRAD, JLDATE, TLAT, TILT, REFL)  
 C \*\*\*\*\*

C  
 C REAL DIFRAD(24), HOR(24), DIRHOR(24), FTOTRD  
 C  
 C DIFRAD - DIFFUSE RADIATION  
 C HOR - GLOBAL HORIZONTAL RADIATION  
 C DIRNRM - DIRECT NORMAL TO SUN RADIATION  
 C DIRHOR - DIRECT HORIZONTAL RADIATION  
 C  
 C  
 C DO 518 III=1,24  
 C  
 C FROM GLOBAL AND DIFFUSE RADIATION DETERMINE DIRECT COMPONENT  
 C  
 C DIRHOR(III)=HOR(III)-DIFRAD(III)  
 C IF (DIRHOR(III).LT.0.0) DIRHOR(III)=0.0  
 C  
 C CONVERT TO PROPER UNITS FROM SAWB TAPES (I.E. TO KJ/HR)  
 C -----  
 C DIRHOR(III) = DIRHOR(III)\*10  
 C HOR(III) = HOR(III)\*10  
 C DIFRAD(III) = DIFRAD(III)\*10



```

518      CONTINUE
C
C      CALL ROUTINE TO COMPUTE PLANE OF ARRAY INSOLATION FOR EACH HOUR
C
C          CALL INSOL(FTOTRD,HOR,DIFRAD,DIRHOR,JLDATE,TLAT,TILT,REFL)
C
C          RETURN
C          END
C
C*****
C      SUBROUTINE INSOL (FTOTRD,HOR,DIFRAD,DIRHOR,JLDATE,TLAT,TILT,REFL)
C*****
C      THIS ROUTINE ESTIMATES THE PLANE OF ARRAY INSOLATION GIVEN HORIZ
C      AND DIRECT NORMAL RADIATION. IT USES THE PEREZ MODEL TO ESTIMATE
C      THE TOTAL DIFFUSE RADIATION ON A TILTED SURFACE USING THE
C      TECHNIQUE DEVELOPED BY PEREZ AT THE STATE UNIV OF NY.
C
C      LOCAL VARIABLES :
C
C      AAT = COSINE OF INCIDENCE ANGLE
C      ABSAZM = ABSOLUTE VALUE OF SOLAR AZIMUTH
C      ARG = VALUE USED AS ARGUMENT IN ARC TRIG FUNCTIONS
C      ATANTT = ARC TANGENT OF ZENITH ANGLE
C      AZM = SOLAR AZIMUTH ANGLE
C      AZTEMP = TEMPORARY SOLAR AZIMUTH ANGLE
C      CA = COSINE OF ALTITUDE ANGLE
C      CB = COSINE OF TILT
C      CE = COSINE OF ELEVATION ANGLE
C      CST = SAME AS AAT
C      CT = COSINE OF ZENITH ANGLE
C      DCM = DIFFUSE PORTION ON SURFACE
C      DEC = DECLINATION
C      DH = DIFFUSE ON HORIZONTAL
C      DIR = DNI IN JOULES
C      DIRPOR = DIRECT PORTION ON SURFACE
C      DTOR = CONVERSION FACTOR FROM DEGREES TO RADIANS
C      ELV = ELEVATION ANGLE
C      HOR = HORIZONTAL RADIATION
C      HOURAN = SOLAR HOUR ANGLE
C      REFLCM = REFLECTED RADIATION COMPONENT FOR THIS CONFIGURATION
C      S = LATITUDE (RADIANS)
C      SA = SINE OF ALTITUDE ANGLE
C      SB = SINE OF TILT
C      SE = SINE OF ELEVATION ANGLE
C      SOLTME = SOLAR TIME
C      TA = INCIDENCE ANGLE
C      TILTNI = INTER STEP FOR REFL TILT ON POLAR MOUNT
C      TILTRF = HOURLY TILT OF ARRAY FOR GIVEN CONFIGURATION
C      TT = ZENITH ANGLE (RAD)
C      DIRNRM = DIRECT NORMAL RADIATION
C

```

```

DIMENSION DIFRAD(24),HOR(24),DIRHOR(24)
COMMON /PCOEF/ F(6,8)
DIMENSION DIRNRM(24)
TAZM = 0.0

```

C

```

DATA DTOR/.017453292/
TAZM = 0.0
TOTHR = 0
TOTDCM = 0
TOTDP = 0
TOTRFL = 0
FTOTRD = 0

```

C

C

C

```

LOOP TO COVER 24 HOURS IN THE DAY

```

C

C

C

C

```

DO 1000 I=1,24

```

```

CHECK THE HOR RADIATION FOR THIS HOUR. IF GT 0 COMPUTE POA
ELSE SET POA TO ZERO AND CONTINUE TO NEXT HOUR.

```

C

C

C

C

```

IF(HOR(I).GT.0)THEN

```

```

CALCULATE HOUR ANGLE (DEG) AND DECLINATION (RAD)

```

```

SOLTME=I-0.5

```

```

IF(SOLTME.LE.12.)THEN

```

```

    HOURAN=(12.-SOLTME)*15.

```

```

ELSE

```

```

    HOURAN=-(SOLTME-12.)*15.

```

```

ENDIF

```

```

ARG=.39795*COSD(0.98563*(JLDATE-173.))

```

```

IF(ARG.GT.1.)THEN

```

```

    ARG=1.

```

```

ELSEIF(ARG.LT.-1.)THEN

```

```

    ARG=-1.

```

```

ENDIF

```

```

DEC=ASIN(ARG)

```

C

C

C

```

CONVERT HOUR ANGLE TO RADIANS

```

```

HOURAN=HOURAN*DTOR

```

C

C

C

```

COMPUTE THE ELEVATION OF THE SUN (RAD)

```

```

ARG=COS(TLAT*DTOR)*COS(DEC)*COS(HOURAN)+
1 SIN(TLAT*DTOR)*SIN(DEC)

```

```

IF(ARG.GT.1.)THEN

```

```

    ARG=1.

```

```

ELSEIF(ARG.LT.-1.)THEN

```

```

    ARG=-1.

```

```

ENDIF

```

```

ELV=ASIN(ARG)

```

```

C
C
C
CHECK HOUR ANGLE AND COMPUTE AZIMUTH OF THE SUN (RAD)
ARG=COS(DEC)*SIN(HOURAN)/COS(ELV)
IF(ARG.GT.1.) THEN
  ARG=1.
ELSEIF(ARG.LT.-1.) THEN
  ARG=-1.
ENDIF
AZTEMP=ASIN(ARG)
IF(COS(HOURAN).GT.(TAN(DEC)/TAN(TLAT*DTOR))) THEN
  AZM=AZTEMP
ELSEIF(COS(HOURAN).LT.(TAN(DEC)/TAN(TLAT*DTOR))) THEN
  IF(AZTEMP.LT.0.) THEN
    AZM=-3.14159-AZTEMP
  ELSE
    AZM=3.14159-AZTEMP
  ENDIF
ELSEIF(HOURAN.LT.0.) THEN
  AZM=-3.14159265/2.
ELSE
  AZM=3.14159265/2.
ENDIF
C
C
C
INITIALIZE INPUT AND TRIG VARIABLES
CST=0.
DCM=0.
DH=0.
SE=SIN(ELV)
CE=COS(ELV)
SA=SIN(AZM)
CA=COS(AZM)
SB=SIND(TILT)
CB=COSD(TILT)
TT=(1.570796327-ELV)
CT=COS(TT)
DIRNRM(I)=DIRHOR(I)/SE
DH=HOR(I)-(SE*DIRNRM(I))
C
C
C
CONVERT TO PROPER UNITS (JOULES) FOR PEREZ MODEL
C
C
C
DIR=DIRNRM(I)
C
C
C
CALL PEREZ MODEL SUBROUTINE
C
C
C
COMPUTE THE DIFFUSE ON THE SURFACE, COMPUTE THE INCIDENCE ANGLE
AND ZENITH ANGLE. MAKE SURE ALL ARE IN PROPER UNITS FOR
PEREZ MODEL (KJ/MIN)
C
C

```

```
AAT=(SB*CE*COS(AZM-TAZM*DTOR)+CB*SE)
CST=AAT
TA=ACOS(CST)
```

```
COMPUTE THE TILT ANGLE -- USED TO COMPUTE REFLECTIVE
INSOLATION COMPONENT AND DIFUSE CALL. CONVERT TO RADIAN.
```

```
TILTRF=TILT*DTOR
S=TILTRF
```

```
CONVERT TO PROPER UNITS FOR PEREZ MODEL
```

```
CALL PEREZ MODEL
```

```
IF(DIFRAD(I).EQ.0.) THEN
DCM = 0.
ELSE
CALL DIFSE(DH,DIR,TT,TA,DCM,S,CST,CT,F)
IF(DCM.LT.0.)DCM=0.
ENDIF
```

```
IF INCIDENCE ANGLE IS LT 0.0 THEN SUN IS IN BACK OF COLLECTOR
AND SET DIRECT PORTION TO 0.0
```

```
DIRPOR=CST*DIRNRM(I)
IF(DIRPOR.LT.0.0)DIRPOR=0.0
TOTRAD=DIRPOR+DCM
GOTO 200
```

```
COMPUTE REFLECTED COMPONENT AND ADD TO POA (SUM OF BEAM AND
DIFFUSE)
```

```
200 CONTINUE
```

```
REFLCM=.5*(1-COS(TILTRF))*REFL*HOR(I)
IF(REFLCM.LT.0.)REFLCM=0.
TOTRAD=TOTRAD+REFLCM
IF(TOTRAD.LT.0.)TOTRAD=0.
```

```
ELSE
```

```
DCM=0.
DIRPOR=0.
REFLCM=0.
TOTRAD=0.
```

```
ENDIF
```

```
CONVERT FROM kJ TO WATT-HRS
```

```
DCM=DCM/3.6
DIRPOR=DIRPOR/3.6
```

```
REFLCM=REFLCM/3.6
TOTRAD=TOTRAD/3.6
```

```
TOTDCM = TOTDCM + DCM
TOTDP = TOTDP + DIRPOR
TOTRFL = TOTRFL + REFLCM
FTOTRD = FTOTRD + TOTRAD
```

```
1000 CONTINUE
```

```
C
  RETURN
  END

C*****
  SUBROUTINE DIFSE(DH,DIR,T,TA,DCM,S,CST,CT,F)
C*****
  DIMENSION F(6,8)
  PI=3.1415926

C
C
C  PEREZ MODEL
C
C  DH =DIFFUSE ON THE HORIZONTAL (KJ/HR)
C  DIR=DIRECT RADIATION
C  T  =SOLAR ZENITH ANGLE (RADS)
C  TA =SOLAR INCIDENCE ANGLE ON TILTING PLANE (RADS)
C  DCM=CALCULATED DFFUSE ON TILTED PLANE (KJ/HR)
C  S  =SLOPE ANGLE (RADS)
C  CST=COSINE(TA)
C  CT =COSINE(T)
C  F(LY,1) - F(LY,3)=PARAMETER F1
C  F(LY,4) - F(LY,6)=PARAMETER F2
C
C  PARAMETER EPSILON
C
C  EPS1=(DIR+DH)/DH
C  CSS=COS(S)
C  DELTA=(DH/CT)/4921.

C
C  HALF ANGLE OF CIRCUMSOLAR REGION
C
C  ALP=25.*PI/180.

C
400 IF(EPS1.LE.1.056) THEN
      LY=1
      GOTO 500
ENDIF
IF(EPS1.LE.1.253) THEN
      LY=2
      GOTO 500
```

```

ENDIF
IF(EPS1.LE.1.586) THEN
  LY=3
  GOTO 500
ENDIF
IF(EPS1.LE.2.134) THEN
  LY=4
  GOTO 500
ENDIF
IF(EPS1.LE.3.230) THEN
  LY=5
  GOTO 500
ENDIF
IF(EPS1.LE.5.980) THEN
  LY=6
  GOTO 500
ENDIF
IF(EPS1.LE.10.08) THEN
  LY=7
  GOTO 500
ENDIF
LY=8
500 F1=F(1,LY)+F(2,LY)*DELTA+F(3,LY)*T
    F2=F(4,LY)+F(5,LY)*DELTA+F(6,LY)*T
C
C
C
MODEL ALGORITHM
C
SAL=2.*(1.-COS(ALP))
TB=PI/2.-ALP
TC=PI/2.+ALP
CS=(1.+CSS)/2.
C
IF(T.LE.TB) THEN
  XH=CT
  YH=1.
ELSE
  YH=(PI/2.-T+ALP)/(2*ALP)
  XH=YH*SIN(YH*ALP)
ENDIF
C
IF(TA.LE.TB) THEN
  XC=YH*CST
ELSE
  IF(TA.LE.TC) THEN
    YC=(PI/2.-TA+ALP)/(2*ALP)
    XC=YH*YC*SIN(YC*ALP)
  ELSE
    XC=0.
  ENDIF
ENDIF
C
AA=SAL*XC

```

```

CC=SAL*XH
DCM=DH*(CS*(1-F1)+F1*(AA/CC)+F2*SIN(S))

```

C

```

RETURN
END

```

C

```

*****

```

```

FUNCTION COSD(X)
COSD=COS(X*3.1415926539/180.)
RETURN
END
FUNCTION SIND(X)
SIND=SIN(X*3.1415926539/180.)
RETURN
END

```

```

C *****

```

```

BLOCK DATA

```

```

COMMON /PCOEF/ F(6,8)

```

```

DATA F/

```

1	-0.011,	0.748,	-0.080,	-0.048,	0.073,	-0.024,
2	-0.038,	1.115,	-0.109,	-0.023,	0.106,	-0.037,
3	0.166,	0.909,	-0.179,	0.062,	-0.021,	-0.050,
4	0.419,	0.646,	-0.262,	0.140,	-0.167,	-0.042,
5	0.710,	0.025,	-0.290,	0.243,	-0.511,	-0.004,
6	0.857,	-0.370,	-0.279,	0.267,	-0.792,	0.076,
7	0.734,	-0.073,	-0.228,	0.231,	-1.180,	0.199,
8	0.421,	-0.661,	0.097,	0.119,	-2.125,	0.446/

```

END
-----

```

APPENDIX F

## PROGRAM GETFRD

\*This program is used to convert the hourly horizontal global and  
 \*and diffuse radiation values to total daily radiation on a  
 \*tilted plane. The subroutine model provided is called with good  
 \*daily data from this program.

\*INPUT: The program has two sources of data. The data files must  
 \*first be copied from the registered tape 0113AE to sys\$scratch.  
 \*The files are on the tape in backup save sets. The source data  
 \*type are:

- \*  
 \* 1. Diffuse Radiation Data for a station  
 \* 2. Global radiation data for the same station  
 \*

Data Source	Saveset Name	Files named as..
1	GLOB.BCK	GLOB<station-id>
2	DIFF.BCK	DIFF<station-id>

\*OUTPUT: A single file containing the daily radiation values on  
 \*a tilted plane. The format of the out put file is:

Field	Columns	Purpose	Format
STATID	1-4	Station id	A4
TYEAR	5-6	The year	I2
TMONTH	7-8	The month	I2
i	9-10	The day number in the month	I2
FTOTRD	11-18	The total radiation	F12.2

\* Author D.R. Franco  
 \* Date Aug 1989

Integer difnit  
 Integer glbnit  
 Integer outnit

Parameter (difnit = 9)  
 Parameter (glbnit = 10)  
 Parameter (outnit = 11)

Integer curday  
 Character\*24 curdif  
 Character\*24 curglb  
 Character\*4 dfdate  
 Real difrad(24)



Integer	dtstat
Logical	drpday
Logical	endofl
Character*4	fndate
Character*2	fnayer
Real	ftotrd
Character*4	gldate
Real	hor(24)
Integer	jldate
Integer	misval
Real	mthdif( 31, 24 )
Real	mthglb( 31, 24 )
Character*8	nowdat
Character*8	nowtim
Real	refl
Character*4	statid
Real	tilt
Real	tlat
Integer	tmonth
Integer	tyear

```

5 Format ( '1', 'Project: INSOLATION RUN LENGTHS' /
&      3x, 'Data conversion program GETFRD - version 1.0' /
&      3x, 'Date: ', A, 3x, 'Time: ', A //
&      3x, 'Conversion of Hourly Horizontal and Diffuse' /
&      3x, 'radiation to total daily radiation on a' /
&      3x, 'tilted plane.' / )

15 Format ( A4, 3I2, F12.2 )
25 Format ( A )
35 Format ( // ' The following parameters will be used for this
& run' /
&      / ' The data files are: GLOBAL radiation - ', A,
&      / '                               DIFFUSE radiation - ', A,
&      / '                               Station Latitude - ', F6.2,
&      / '                               Tilt - ', F3.0,
&      / '                               Reflectivity - ', f4.2,
&      / '                               Start Date (YYMM) - ', A4,
&      / '                               Max. No. of Missing values per day - ', I1 // )

*      Emit signon line
      call date( nowdat )
      call time( nowtim )
      write( *, 5 ) nowdat, nowtim

*      Get the run parameters.

      print *, 'Enter the station to be extracted and cleaned'
      read( *, 25 ) statid

      print *, 'Enter the station latitude'

```

```

read( *, * ) tlat
print *, 'Enter the tilt'
read( *, * ) tilt
print *, 'Enter the reflectivity'
read( *, * ) refl
print *, 'Enter the year (no century)'
read( *, 25 ) fndyer
print *, 'Enter the number of missing values to allow per
& day'
read( *, * ) misval

* Start at the beginning of the year
fndate = fndyer // ' 1'

curdif = 'diff'//statid//'.dat'
curglb = 'glob'//statid//'.dat'

Write( *, 35 ) curglb, curdif, tlat, tilt, refl, fndate,
& misval

* Open the required data files

Open( difnit, file='sys$scratch: '//curdif, status='old',
& form='formatted', recl=109, iostat=dtstat )
If( dtstat .gt. 0)then
  Print *, 'Error opening unit....', curdif
  Print *, 'please investigate.....'
  call lib$stop( dtstat )
Endif

*read forward to the first usable date month on or after the year
* entered - diffuse radiation
call readfw(dfdate, difnit, 'DIFF', endofl, fndate, statid)

Open( glbnit, file='sys$scratch: '//curglb, status='old',
& form='formatted', recl=109, iostat=dtstat )
If( dtstat .gt. 0)then
  Print *, 'Error opening unit....', curglb
  Print *, 'please investigate.....'
  call lib$stop( dtstat )
Endif

*read forward to the first usable date month on or after the year
* entered - global radiation
call readfw( gldate, glbnit, 'GLOB', endofl, fndate, statid )

Open( outnit, file='tilt'//statid//'.dat',
& status='new', form='formatted',
& recl=22, iostat=dtstat, carriagecontrol='list' )
If( dtstat .gt. 0)then

```

```

Print *, 'Error opening unit....', 'tilt'//statid//'.dat'
Print *, 'please investigate.....'
call lib$stop
Endif

```

```

10 If( .not. endofl )then

```

```

*   align the two input files on the month and year
20   If( gldate .ne. dfdate )then

       if( gldate .gt. fndate .and. dfdate .gt. fndate )then

           if( gldate .gt. dfdate )then
               call readfw( dfdate, difnit, 'DIFF', endofl, gldate,
               &                               statid )
           elseif( dfdate .gt. gldate )then
               call readfw( gldate, glbnit, 'GLOB', endofl, dfdate,
               &                               statid )
           endif

       else

           if( gldate .lt. fndate )then
               call readfw( gldate, glbnit, 'GLOB', endofl, fndate,
               &                               statid )
           elseif( dfdate .lt. fndate )then
               call readfw( dfdate, difnit, 'DIFF', endofl, fndate,
               &                               statid )
           endif
       endif

       goto 20
   endif

*   get the data for the current month
   if( .not. endofl )then
       call getmth( difnit, 'DIFF', endofl, mthdif, statid, tmonth,
       &                               tyear )
   endif
   if( .not. endofl )then
       call getmth( glbnit, 'GLOB', endofl, mthglb, statid, tmonth,
       &                               tyear )
   endif

*   get the total radiation for each day of the month
   if( .not. endofl )then
       do 30 i = 1, mthday( tmonth, tyear )
           drpday = .false.
           do 38 j = 1, 24
               hor( j ) = mthglb( i, j )
               difrad( j ) = mthdif( i, j )
38          continue

```

```

*      check the data for each day
      call chkday( drpday, misval, difrad, tmonth, tyear )
      if( .not. drpday )then
        call chkday( drpday, misval, hor, tmonth, tyear )
      endif

      if( .not. drpday )then
        curday = i
        call model(ftotrd,hor,difrad,jldate(curday,tmonth,tyear),
&          tlat, tilt, refl )
      write( outnit, 15 ) statid, tyear, tmonth, i, ftotrd
      else
        ftotrd = -1.
      write( outnit, 15 ) statid, tyear, tmonth, i, ftotrd
      endif
30    continue
      endif

```

```

*      get the next months date
      if( .not. endofl )then
        call getnxt( ddate, difnit, endofl, 'DIFF', statid )
        if( .not. endofl )then
          call getnxt( gldate, difnit, endofl, 'GLOB', statid )
        endif
      endif

```

```

goto 10
endif

```

```

Close( 9 )
Close( 10 )
Close( 11 )

```

```

stop
end

```

```

Integer function mthday( curmth, curyer )

```

- \* This function returns the number of days in a given month.
- \* There is a correction for february in a leap year.

```

Integer      curmth
Integer      curyer
Integer      daymth(12)

```

```

Data  daymth/ 31, 28, 31, 30, 31, 30, 31, 31, 30, 31, 30, 31/

```

```

If( mod( curyer, 4 ) .eq. 0 .and. curmth .eq. 2 )then
  mthday = 29
else

```

```

    mthday = daymth( curmth )
endif

```

```

Return
End

```

```

Integer function jldate( curday, curmth, curyer )

```

\* This function returns the julian date for the current day.  
\*There is a correction for february in a leap year.

```

Integer      curday
Integer      curmth
Integer      curyer
Integer      daymth(12)

```

```

Data daymth/ 31, 28, 31, 30, 31, 30, 31, 31, 30, 31, 30, 31/

```

```

    jldate = 0

```

```

    Do 10 j = 1, curmth-1

```

```

        If( mod( curyer, 4 ) .eq. 0 .and. j .eq. 2 )then
            jldate = jldate + 29
        else
            jldate = jldate + daymth( j )
        endif

```

```

10 Continue

```

```

    jldate = jldate + curday

```

```

    return
end

```

```

Subroutine readfw( datfnd, datnit, datatype, endofl, fndyer,
&                statid )

```

```

Character*(*)  datfnd      ! date found to be >= fndyer
Integer        datnit      ! data unit to read
Character*(*)  datatype    ! the type of data being read
Integer        datsta      ! the status of the read
Character*(*)  fndyer      ! the year to search for
Logical        found / .false./ ! true if year found
Character*(20) record      ! the first part of hourly record
Character*(*)  statid      ! the id of station being processed

```

```

5 Format( A )

```

```

    found = .false.

```

```

    Read( datnit, 5, iostat=datsta ) record

```

```

10  if( datsta .eq. 0 .and. .not. found )then
      if( record( 11:14 ) .ge. fndyer )then
          Found = .true.
          backspace( datnit )
          datfnd = record( 11:14 )
      endif

      If( .not. found )then
          Read( datnit, 5, iostat=datsta ) record
      endif

      goto 10
    endif

    call chkeof( datnit, datsta, datype, endofl, statid )

    return
  end

  Subroutine getnxt( datfnd, datnit, endofl, datype, statid )

Character*(*)  datfnd      ! date found to be >= fndyer
Integer       datnit      ! data unit to read
Character*(*)  datype      ! the type of data being read
Integer       datsta      ! the status of the read
Logical       endofl      ! true if end of input file being read
Character*(20) record     ! the first part of hourly record
Character*(*)  statid     ! the id of station being processed

  5 Format( A )

  found = .false.
  Read( datnit, 5, iostat=datsta ) record

  if( datsta .eq. 0 )then
      backspace( datnit )
      datfnd = record( 11:14 )
  endif

  call chkeof( datnit, datsta, datype, endofl, statid )

  return
  end

  Subroutine chkeof( datnit, datsta, datype, endofl, statid )

Integer       datnit      ! data unit to read
Character*(*)  datype      ! the type of data being read
Integer       datsta      ! the status of the read
Logical       endofl      ! true if eof encountered

```

```
Character*(*)  statid
```

```
if( datsta .ne. -1 .and. datsta .ne. 0 )then
  Print *, '**Error** Reading the file',
&      datatype//statid//'.dat'
  Print *, 'Program is terminating as a result'
  Print *, ''
  call lib$stop( datsta )
elseif( datsta .eq. -1 )then
  endofl = .true.
endif

return
end
```

```
Subroutine getmth( datnit, datatype, endofl, mthdat, statid,
&                tmonth, tyear )
```

```
Integer          curhor
Integer          datnit
character*(*)    datatype
Integer          dtstat
Logical          endofl
Real             mthdat( 31, 24 )
Character*(*)    statid
Integer          thour
Integer          tmonth
Integer          tyear
```

```
5 Format ( 10x, i2, I2, I2, 31F3.0 )
```

```
curhor = 1
Read( datnit, 5, iostat=dtstat) tyear, tmonth, thour,
&    (mthdat( i, curhor ), i = 1, mthday( tmonth, tyear ))
```

```
10 If( dtstat .eq. 0 .and. curhor .lt. 24 )then
  curhor = curhor + 1
  Read( datnit, 5, iostat=dtstat) tyear, tmonth, thour,
&    (mthdat( i, curhor ), i = 1, mthday( tmonth, tyear ))
  goto 10
endif
```

```
call chkeof( datnit, dtstat, datatype, endofl, statid )
```

```
return
end
```

```
Subroutine chkday( drpday, misval, datval, tmonth, tyear )
```

```
Real          badval
Parameter     (badval=999.)
```

```

logical      drpday
real         datval( 31 )
integer      misval
integer      numbad
integer      tmonth
integer      tyear

numbad = 0

Do 10 j = 1, mthday( tmonth, tyear )
  If( datval( j ) .eq. badval .and.
&    numbad .le. misval .and. .not. drpday )then

    If( datval( j-1 ) .ne. badval .and.
&      datval( j+1 ) .ne. badval )then
      datval( j ) = ( datval( j+1 ) +
&                    datval( j-1 ) ) / 2
      numbad = numbad + 1
      If( numbad .gt. misval )then
        drpday = .true.
      Endif
      Elseif( datval( j+1 ) .eq. badval )then
        drpday = .true.
      Endif
    Endif
  Endif
10 continue

return
end
-----

```



APPENDIX G

## PROGRAM RUNLEN

\*This program is used to calculate the insolation value for  
 \*specified run lengths corresponding to the probability level,  
 \*or LOEP required. The LOEP's considered are 0.1, 0.05, 0.01,  
 \*0.005, 0.001. The maximum run length is specified by the user.

\*INPUT: The program has one sources of data, The file produced  
 \*by the program GETFRD.

\*OUTPUT: A single file containing the insolation values at  
 \*prescribed probability levels, and a report to the  
 \*printer/screen or file.

\* Author D.R. Franco  
 \* Date Aug 1989

Real	drpval
Integer	inunit
Integer	lencut
Integer	maxval
Integer	maxrun
Integer	outnit
Integer	prunit

Parameter	(drpval = -1.)
Parameter	(inunit = 10)
Parameter	(outnit = 11)
Parameter	(prunit = 12)
Parameter	(lencut = 5 )
Parameter	(maxrun = 30 )
Parameter	(maxval = 7130 )

Integer	curend
Character*(40)	curfil
Integer	curlen
Integer	curval
Integer	curstr
real	cutdat(lencut)/0.1,0.05,0.01,0.005,0.001 /
Integer	dtstat
Real	ftotrd( maxval ) / maxval*0.0 /
Character*(8)	nowdat
Character*(8)	nowtim
Integer	numval / 0 /
Integer	runuse
Real	runavg( maxval ) / maxval*0.0 /
Real	insval( maxrun, lencut )
Character*4	statid
Real	trunav

```

5 Format ( '1', 'Project: INSOLATION RUN LENGTHS' /
&      3x, 'Data conversion program RUNLEN-version 1.0' /
&      3x, 'Date: ', A, 3x, 'Time: ', A //
&      3x, 'Calculate Insolation Run Lengths up to a ' /
&      3x, 'maximum run length specified. ' )

15 Format ( 10x, F12.2 )
25 Format ( 1h1, 20x, 'Project: INSOLATION RUN LENGTHS' //
&      20x, 'SITE: ', A, // )
35 Format ( 12x, 5( 2x, f5.2, '%', 4x ) )
45 Format ( 5x, I2, 5x, 5( f8.2, 4x ) )
55 Format ( 1x, I2, 1x, 5( f8.2, 1x ) )
65 Format ( A )

*      Emit signon line
      call date( nowdat )
      call time( nowtim )
      write( *, 5 ) nowdat, nowtim

*      Get the run parameters.

      print *, 'Enter the station to be extracted and cleaned'
      read( *, 65 ) statid

3      print *, 'Enter the maximum run length required'
      read( *, * ) runuse
      if( runuse .lt. 1 .or. runuse .gt. maxrun )then
        print *, '**Error** Max. run length specified is out of'
        print *, '          Range. Maximum allowed is ', maxrun
        Print *, 'Please re-enter:'
        goto 3
      endif

      curfil = 'tilt'//statid//'.dat'

      print *, curfil, statid, runuse

*      Open the required data files

      Open( inunit, file='tilt'//statid//'.dat',
&      status='old', form='formatted',
&      recl=18, iostat=dtstat )
      If( dtstat .gt. 0)then
        Print *, 'Error opening unit...', 'tilt'//statid//'.dat'
        Print *, 'please investigate.....'
        call lib$stop
      Endif

      numval = 1
      read( inunit, 15, iostat=dtstat ) ftotrd( numval )

```

```

10 If( dtstat .eq. 0 .and. numval .lt. maxval )then
    If( ftotrd(numval) .ne. drpval )then
        numval = numval + 1
    endif

    read( inunit, 15, iostat=dtstat ) ftotrd( numval )

goto 10
endif

If( dtstat .eq. 0 )then
    Print *, '**WARNING**More data available but could not'
    Print *, ' be accomadated. Re-run the GETFRD program'
    Print *, ' with a more recent starting date, and'
    Print *, '          then re-run RUNLEN.'
ElseIf( dtstat .ne. -1 )then
    Print *, 'Error reading file..', 'tilt'//statid//'.dat'
    Print *, 'please investigate.....'
    call lib$stop( dtstat )
Endif

numval = numval - 1
Do 20 curlen = 1, runuse

    curstr = 1
    do 22 j = 1, maxval
        runavg( j ) = 0.0
22    continue

26    if( curstr .lt. numval-curlen+1 )then
        curend = curstr + curlen - 1
        curval = 0
        do 30 j = curstr, curend
            curval = curval + ftotrd( j )
30    continue
        runavg( curstr ) = curval / curlen

        curstr = curstr + 1

goto 26
endif

curstr = curstr - 1
Do 40 j = 1, curstr-1
    Do 50 k = j+1, curstr

        If( runavg( k ) .lt. runavg( j ) )then

            trunav = runavg( j )
            runavg( j ) = runavg( k )
            runavg( k ) = trunav

```

```

        endif
50     continue
40     continue

        Do 60 j = 1, lencut
            insval(curlen,j) = runavg(int(curstr*cutdat(j)))
60     Continue

20 continue

    Open(prunit,file='insl'///statid//'.prn', status = 'new',
&     form='formatted', iostat=dtstat )
    Write( prunit, 25 ) statid
    Write( prunit, 35 ) ( cutdat(i)*100, i = 1, lencut )
    Do 70 j = 1, runuse
        Write( prunit, 45 ) j, ( insval(j, i), i = 1, lencut )
70 continue
    Close( prunit )
    Write(*,*)' '
    Write(*,*)'PLEASE NOTE: The insolation run length cutoff'
    Write(*,*)'data values have been written to a print file'
    Write(*,*) 'called: INSL', statid, '.PRN'
    Write(*,*) 'To print this file use the DCL Print com-
mand.'
    Write(*,*)'e.g. to print to the printer in the Computing'
    Write(*,*)' Centre User Area use the command:'
    Write(*,*)' PRINT /queue=rem_usr INSL', statid, '.PRN'
    Write(*,*) ' '

    Open(outnit,file='insl'///statid//'.dat', status = 'new',
&     form='formatted',iostat=dtstat,carriagecontrol='none')
    Do 80 j = 1, runuse
        Write( outnit, 55 ) j, ( insval(j, i), i = 1, lencut )
80 continue

    stop
    end

```

-----