PERFORMANCE OF A GRID-CONNECTED PHOTOVOLTAIC SYSTEM USING ACTUAL AND KRIGED HOURLY SOLAR RADIATION

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ABSTRACT. *In this article the performance of a grid-connected PV system supplying a farmstead was evaluated using a commercially available energy balance simulation model, Hybrid2. By performing annual hourly simulations, the influence of system size, actual radiation data, and estimated radiation data on economic and energy production were assessed. The estimated radiation data were developed from kriging actual radiation data from 16 weather stations in western Nebraska. The results indicated that the capital costs associated with a PV system dictate the economic performance of the overall system. The energy costs associated with the grid-connected PV system were six times the retail price of electricity. The use of actual or estimated data had little effect on the simulated performance of the system.*

Keywords. *Photovoltaic, Grid-connected, Kriging.*

This work was part of a study at the University of Nebraska to assess the appropriateness of applying solar and wind energies to farm activities. There are a variety of topics, which could be addressed in such a study. Results from two topics are reported in this article: (1) energy costs of a grid-connected photovoltaic system supplying power to a farmstead; and (2) evaluation of a model to extrapolate hourly solar radiation to be used in the simulation of photovoltaic systems.

Engineers use monthly mean values of daily solar irradiation for preliminary sizing and estimation of solar energy system productivity (Markvart, 1994). The use of monthly means of daily values limits the accuracy of estimates because most solar energy systems exhibit a nonlinear dependence upon weather variables. The use of daily or monthly averages of solar radiation and electric load in the design does not take into account non-coincidental occurrence of solar radiation and electric load. Thus, computer simulations are used to accommodate the complexity involved with design optimization of solar energy systems (Fiksel et al., 1995). These simulations require hourly climatic and load variables as input data.

Engineers and researchers often do not have hourly or even daily solar radiation data available at the site under study. One alternative is to extrapolate solar radiation data measured at other locations. Extrapolation methods that take into account spatial variability can be evaluated in terms of the errors that they generate and the influence of these errors on the solar system performance, and the energy cost associated with the system. This work evaluated kriging as a tool to extrapolate solar radiation data measured at other locations where such data were needed to assess the performance and economics of a PV grid-connected system.

Many authors have studied the extrapolation and interpolation of daily and hourly solar radiation (e.g., Hubbard, 1994; Hay and Hanson, 1985; Suckling, 1985; Long and Ackerman, 1995). Merino et al. (1999) addressed the problem of extrapolation of hourly and daily solar radiation from a new perspective. These authors found that kriging was an effective method to estimated solar radiation data at sites where solar radiation was not measured. Kriging is a linear estimator—an estimated value of solar radiation in a particular site can be calculated from solar radiation measured in other sites using a linear combination of the measured radiation values. The weights used in this linear combination are determined by the semivariogram model used to describe the spatial structure of the solar radiation. Good presentations of the kriging theory and applications can be found in Gunst (1995) and Isaaks and Srivastava (1989). Merino et al. (1999) determined generic spherical semivariograms models to perform kriging of hourly solar radiation. These spherical models as well as the errors associated with them in the extrapolation of the radiation field were used for the research reported in this article.

A residential (in this case a farmstead) grid-connected photovoltaic system consists of an array of photovoltaic modules, an inverter, the balance of system (including wiring and mounting structure) and means of connecting to the electric grid (typically by back-feeding the main electric service distribution panel). Some systems also include batteries and charge controllers. The sizes of the photovoltaic array and inverter are rated in terms of their peak output power (i.e., in watts peak, or Wp).

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During daytime, direct current (DC) electricity from the photovoltaic modules is converted to AC by the inverter, and directed into the residential power distribution system to supply the residential electric loads. Any excess solar power is sold to the utility power grid. On the other hand, when the solar power is below the load demand, the electric grid supplies power to make up that deficit. During non-sun hours, the residential loads are supplied by the utility alone.

There are many advantages of grid-connected PV systems over stand-alone PV systems or utility-backed PV systems. As reported by Strong and Scheller (1993) the installed cost of a grid-connected PV residential systems is considerably lower for grid-interactive systems than for the other alternatives. Another important issue is that the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that independent grid-connected power producers be paid at the rate of the utility's avoided cost of electricity. Some states, including Massachusetts, Maine, Oklahoma, Wisconsin, Texas and Minnesota, mandate what is called "net metering", that is, small renewable power producers below a certain power limit (typically 30 to 50 kW) have the same rate for both buying and selling electric power (Wills, 1998). Finally, since most of the electric power supply is via a centralized electric grid, it is highly probable that widespread use of photovoltaic energy will be in the form of distributed power generation interconnected with these grids.

In 1998, it was estimated that there were about 300 grid-connected PV systems operating in the U.S. (Wills, 1998). The cost of generated electricity was about 20-40 ¢/kWh in locations with favorable solar irradiation (Wills, 1998). On the other hand, the residential electric utility rates varied from 6 to 11 ¢/kWh (Strong and Scheller, 1993). It is obvious that the costs for PV modules, power conditioning, and the balance of system must significantly decrease to compete economically with conventional electric power generation. Despite the higher costs, utilities and private consumers are investing in PV systems because they are environmentally friendly.

Solar radiation and electric rural residential demands fluctuate greatly with time (Stetson et al., 1988). To assess the effect of these fluctuations on the economics of a grid-connected PV system, the system simulations were conducted with time steps of an hour or shorter. The reason for this is that the economics of the system depends on the flow of energy from the PV modules into the grid, the on-site load, and the flow of energy from the grid to offset any deficits. These energy flows will change with time according to fluctuations in both solar radiation and the load.

In accordance with the issues presented above, the following objectives were undertaken: (a) to determine the cost of energy in a grid-connected PV system supplying a farmstead in Nebraska; and (b) to assess the influence of using kriged values of hourly solar radiation on the energy output and economics of a grid-connected PV system.

Materials and Methods

Grid-Connected PV System Design

Farmstead electrical loads were determined in a study conducted by Stark and Stetson (1986). These authors gathered electric demand and electric energy use data from 83 rural residential customers in Kansas from May 1982 to May 1984. Randomly selected rural residential customers fell into one of three energy use categories: 0 to 750, 751 to 1500, and greater than 1500 kWh/month. The watt-hour meter for each customer was replaced with a Westinghouse WR-31 load research-recording package. These recording packages recorded average 5-min demands. The demands recorded in this process were produced only by residential electrical appliances and do contain any contribution from other farm activities (Stark and Stetson, 1986). The load data used for this study were for a typical customer in the second category (751 to 1500 kWh) from August 1982 to July 1983.

For a preliminary sizing of the system the annual average of daily load (L = 23.12 kWh) and the annual average of daily irradiation (H = 4.7kWh/m^2) on a tilted surface were used. To calculate H, monthly averages of horizontal daily irradiation were obtained for the period 1984 to 1998 from the McCook weather station in western Nebraska. The horizontal average daily irradiation was transformed to irradiation on a tilted surface using the isotropic sky model described by Duffie and Beckman (1991). The surface tilt angle used in this process was equal to the latitude angle since the system was designed to maximize the production of energy through the entire year.

The possible PV array configurations were determined following the method presented by Markvart et al. (1994). The input voltage range allowed by the inverter limits the output voltage from the PV array. In this case an inverter with a maximum power output of 5.5 kVA and an input voltage range of 34 to 75 V was assumed since the farmstead power load rarely surpassed 5 kW during the period August 1982 to July 1983.

The PV module selected for the PV array had a peak rated power of 110W (Wp), with a maximum voltage (Vp) of 16.7 V and a maximum current of 6.6 A. Considering the above maximum voltage and the inverter input voltage range, the number of PV modules connected in series (Ns) was three. The number of strings of modules in the PV array (Np) was limited by the maximum power output of the inverter (5.5 kVA). Thus, Np fluctuated between 1 and 16 depending on the desired peak rated power of the system. Using a greater number of strings would exceed the inverter output power.

On the other hand, Np was also calculated using the equation:

$$Np = \frac{L}{\eta \times PSH \times Ns \times Wp} \qquad (1)$$

where PSH is the average daily number of peak sun hours (with irradiation equal to 1000 W/m^2), and η is the inverter efficiency. Given the above value for H, PSH = 4.7 h and considering an inverter efficiency of 0.9, we calculated Np to be 17. Therefore sizing the system to supply the average daily load with the average daily irradiation resulted in a larger system than when the system was sized taking into account the maximum power output of the inverter. This conflict was resolved by limiting the number of strings (Np) to 16 thereby complying with the limitations of the selected inverter.

GRID-CONNECTED PV SYSTEM SIMULATIONS

Due to the rapid time fluctuations of solar irradiation and the electric load, the way of estimating the actual energy flows in the system was through a time series simulation of the system. In this study, the program Hybrid2 (Manwell et al., 1996), developed by the University of Massachusetts and NREL, was used to simulate the system. These simulations were performed using hourly averages of solar radiation and farmstead load data for one year. The outputs obtained through this process were the annual energy produced by the PV array, the fraction of this energy that was used to meet the farmstead load, the annual energy produced by the PV array that went into the electric utility grid, and the annual energy demand of the farmstead.

The Hybrid2 model included both a time series and statistical approach to determining the operation of a PV system. This allowed the model to determine long term system performance while considering the effect of short-term variability of the solar irradiation and electric load. An essential feature of the time series method used by the model is that it employed an energy balance approach within each time step. This assured that energy is conserved throughout the entire simulation. In this case the source energy (photovoltaic) must equal the sum of all the sinks (load, losses, unmet load, and excess).

During each time step in the simulation process, Hybrid2 calculates the power output from the photovoltaic array based on an analytical model that defines the current-voltage relationships based on the electrical characteristics of the panels that form the array. A one-diode model (Duffie and Beckman, 1991) forms the basic circuit model used to establish the current-voltage curve specific to a PV panel. This model is able to include the effects of solar radiation level and cell temperature on the output power.

To calculate the incident solar radiation on the PV module surface, Hybrid2 uses the Hay, Davies, Klucher, Reindl (HDKR) anisotropic model (Duffie and Beckman, 1991). The model first calculates the extraterrestrial radiation based on the Julian day of the year, hour, site latitude and longitude and then establishes a clearness index, which is the ratio of global horizontal radiation to extraterrestrial radiation. Then the clearness index is used to determine the beam and diffuse components of the global radiation via empirical correlation. Finally, the program determines the radiation on the tilted surface of the modules, based on the incident direction of the beam and diffuse solar radiation components and the ground albedo.

Two types of simulations using Hybrid2 were performed in this study. In simulations for the first objective the same solar radiation data, electric load data, and temperature data for the period from August 1982 to July 1983 were used, but the number of strings of solar modules in the PV array (Np) was varied. In that manner, the effect of different system sizes on the cost of energy was assessed. In simulations for the second objective system size and temperature data were kept constant, but solar radiation data were changed by using actual measured values at a station and then kriged values for the same station. This procedure was performed for 16 stations in western Nebraska. In that manner, the effect of using estimated values of solar radiation on the energy flows was assessed.

HOURLY FARMSTEAD ELECTRIC LOAD USED IN SYSTEM SIMULATIONS

The Hybrid2 software simulated hourly energy balances for the grid-connected PV system. To that end, hourly load information was required. The work presented by Stark and Stetson (1986) does not explicitly report this information, but it is implied and can be estimated or inferred. An explanation follows of how the hourly energy demand for the entire year was determined.

Stark and Stetson (1986) reported the typical daily load profile for the farmstead of interest in this study. The typical daily load profile is the monthly average hourly load for each day of each month of the year. Therefore, there are 12 (one for each month of the year) typical daily load profiles. As an example, the typical daily load profile for July 1983 is shown in figure 1.

Also available from Stark and Stetson (1986) was the daily average load profile for every month of the year. The daily average load profile is the daily average load for each day within a month. Therefore, there are 12 (one for each month of the year) daily average load profiles. As an example, the daily average load profile for July 1983 is shown in figure 2. Also shown in figure 2 is the monthly average of daily average load for July 1983. There are 12 (one for each month of the year) monthly averages of daily average loads.

A weight factor for each day of the year was determined by dividing the daily average load by the

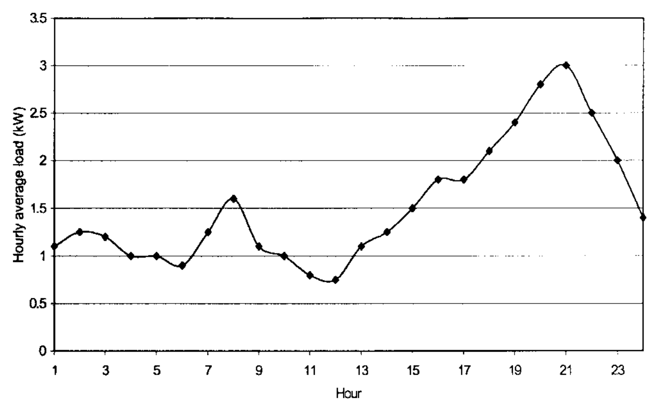

Figure 1–Typical farmstead load day in July 1983.

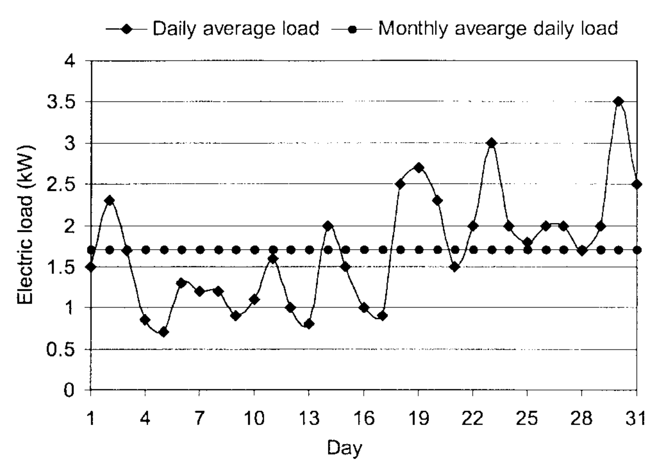

Figure 2–Farmstead daily average load for July 1983.

corresponding monthly average of daily average load. This weight factor reflected the deviation of each daily load from the monthly average. The weight factor was then multiplied by the corresponding typical daily load profile. The result was an inferred hourly load, which was then used by the Hybrid2 software.

Solar Radiation Data Used in System Simulations

Hourly values of global solar radiation on a horizontal surface were utilized in this study. The data were from 16 weather stations in western Nebraska. These stations form part of the High Plains Climate Center's (HPCC) Automated Weather Data Network (AWDN).

At these stations, a silicon photodiode detector, the Licor200 (Li-Cor, Lincoln, Nebraska), is used to measure solar radiation. The sensors are calibrated periodically with an Eppley Precision Pyranometer. This yields an absolute accuracy of about 5% (Barnett et al., 1998). Maintenance is performed by the HPCC. Data are downloaded, quality controlled, and archived by the HPCC.

A map of the weather stations used is shown in figure 3, and distances between stations are presented in table 1. The latitude and longitude differences between stations were not greater than 2.5 and 4.5°, respectively, and the distances fluctuate between 10 and 375 km.

The solar radiation data used in simulations depended on the simulation purpose. To assess the cost of energy as a function of the system size for the first objective, it was necessary to use solar radiation and temperature data from the same year and period as the electric load (August 1982 to July 1983) because, as reported by Stetson and Stark (1987), there are relationships between daily energy use for rural residents and climate variables. The nearest weather station to where the load data were taken (Kansas), in the same time period was McCook, Nebraska. Therefore, hourly solar radiation and temperature data from McCook were used in these simulations.

To assess the errors associated with using kriged solar radiation values for the second objective, simultaneous radiation data from many stations were required. Therefore,

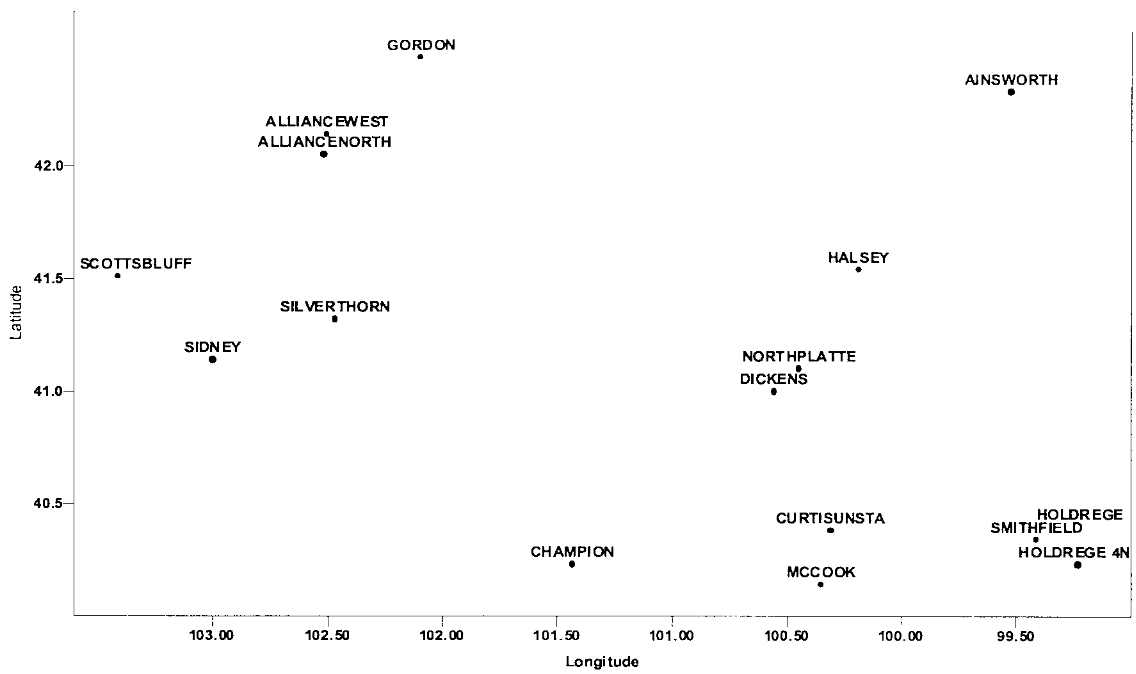

Figure 3–Map of weather stations in western Nebraska.

Table 1. Straight-line distances (km) between weather stations

Station	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
(1) Ainsworth															
(2) Aliance North	250.1														
(3) Aliance West	248.0	10.0													
(4) Champion	283.2	222.0	230.7												
(5) Curtisunsta	226.9	262.4	268.9	96.7											
(6) Dickens	171.6	201.1	206.3	112.9	72.1										
(7) Gordon	213.3	59.0	50.7	256.2	277.3	208.6									
(8) Halsey	104.1	202.0	204.0	179.3	129.4	67.7	189.7								
(9) Holdrige	220.7	334.8	339.6	188.7	92.8	133.9	337.1	154.7							
(10) Holdrige 4n	235.0	342.6	347.8	187.5	93.5	141.5	346.9	166.8	14.5						
(11) McCook	253.4	279.9	286.9	92.6	26.9	97.2	298.5	156.3	99.4	96.1					
(12) North platte	163.2	206.1	210.9	122.4	74.4	10.3	210.8	59.7	128.7	137.2	100.4				
(13) Scottsbluff	335.6	95.2	102.4	219.3	289.8	245.6	152.9	268.9	375.5	380.2	299.8	253.5			
(14) Sidney	318.5	108.7	118.3	166.9	242.4	205.8	166.6	239.5	331.0	334.6	250.3	214.6	53.6		
(15) Silverthorn	269.8	81.2	91.1	149.6	210.1	164.3	132.4	192.3	294.4	299.4	222.0	172.4	81.4	48.8	
(16) Smithfield	221.7	323.0	328.2	172.4	76.7	121.9	327.5	148.9	16.3	19.6	83.1	117.6	361.4	316.2	280.4

hourly solar radiation data for the period August 1995 to July 1996 for 16 stations in the region were used in system simulations. Thus, two sets of data were available for each of the 16 locations. The first one was the actual solar radiation data measured at that station. The second data set was generated using kriging by cross validation. That is, the estimated value of solar radiation for a given hour was obtained by discarding the actual value temporarily from the data set and then estimating (kriging) that value using the data from the rest of the stations. This procedure was repeated for all the stations. Thus, lists of actual and estimated values were obtained for the 16 stations. The semivariogram models used in the kriging process were generated by Merino et al. (1999).

ECONOMIC ANALYSIS

The objective of the economic analysis was to determine the cost per kWh of energy consumed by the farmstead when that unit of energy is produced by a grid-connected PV system. This cost can be compared with the cost per kWh when the only source of energy is the utility. With that information, the marginal cost associated with the use of renewable solar energy can be determined.

To the above end, annual simulations of the grid-connected PV system using Hybrid2 were performed. The outputs of such simulations were: (1) the energy produced by the PV array throughout the year; (2) the portion of the energy produced by the PV array that was not used to meet the on-site load (excess energy); (3) the portion of the energy produced by the PV array used to meet the on-site load; and (4) the annual electric energy use of the farmstead.

In this grid-connected PV system the electric energy produced by the PV array is transformed by the inverter and the fraction of this energy that is not used by the on-site electric load is sold to the electric utility (excess energy). On the other hand, unmet energy demand is bought from the utility to offset any deficit.

Simulations to obtain outputs 1, 2, 3, and 4 were performed for different peak rated power of the PV array where the peak rated power was determined by the number of modules in the array multiplied by the peak power of the PV modules that form the array.

The cost per unit of energy (COE) in \$/kWh consumed by the farmstead was calculated with the equation:

$$COE = \frac{CGPV - R}{ED} \qquad (2)$$

where CGPV is the annualized cost in US\$ of the grid-connected PV system, R is the annual revenue in US\$ that is generated from the energy excess (produced by the PV array) sold to the utility, and ED is the annual energy in kWh consumed by the farmstead (annual electric energy use). To calculate CGPV, the following items were considered:

1. Annualized capital cost—the costs of the PV array, power conditioning, and installation.
2. Annual operating and maintenance costs—annual inspection and energy purchased from the electric utility to supply any deficits.
3. Replacements cost—replacement of the power conditioning.
4. Salvage value—salvage for the PV modules and power conditioning.

To calculate R, the avoided electric cost from the utility was multiplied by the energy sold to the utility. The parameters used to calculate the above quantities are presented in table 2.

DATA ANALYSIS AND RESULTS

PHOTOVOLTAIC ENERGY PRODUCTION VERSUS SYSTEM PEAK RATED POWER

Using hourly data for the typical customer load, hourly solar radiation, and hourly temperature for the period August 1982 to July 1983, sixteen one-year-long simulations of the grid-connected PV system were performed. Each of the simulations was for a different system peak rated power ranging from 330 to 5280 Wp.

The outputs from the Hybrid2 model of these simulations are shown graphically in figure 4. The farmstead annual electric energy use calculated by Hybrid2, from the hourly load averages, was 8458 kWh. This energy used was independent of the PV peak rated power and was covered by part of the energy produced by the PV array, plus the energy purchased from the utility. From figure 4 it is evident that the annual PV energy produced increased linearly with the PV peak rated power. On the other hand, the PV load coverage (amount of on-site demand supplied by the PV array) reached a plateau of about 2500 kWh at a peak rated power of about 3300 Wp. This amount of energy represented only 30% of the

Table 2. Economic parameters used to calculate the per unit cost of energy

Economic Parameter	Value
Project life	20 years
Interest rate	4.5 %/year
Retailed electric price	7 ¢/kWh
Utility electric avoided cost	1 ¢kWh
Balance of System (BOS) cost	\$1/Wp
PV module cost	\$6/Wp
Installation and labor	\$1/Wp
Salvage value for PV modules and power conditioning	20%
Maintenance	130 \$/year

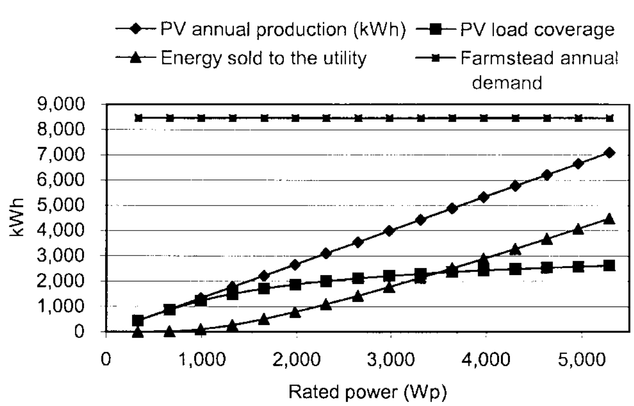

Figure 4–Annual PV energy produced, annual load coverage, annual energy use, and energy sold to the utility from grid-connected PV systems of different sizes for a typical farmstead at McCook, Nebraska.

farmstead annual electric energy use. This implies that no matter how large the PV array in the grid-connected PV system is, its capacity to meet the demand was limited because of the portion of the load that occurred during non-sun hours when the PV array could not produce energy. The peak rated power at which this upper limit is reached may serve as a criterion for the system sizing process depending on the interest of the PV system's owner.

An explanation for the asymptotic behavior of the PV load coverage curve can be determined from figure 5. This graph shows the typical hourly load and solar radiation regime for 15 July 1983. Similar patterns were observed for most of the year. Since the solar radiation and load curves are far from being coincident, as the PV array peak rated power increased linearly above the 3300 Wp level, the only energy component that grew almost linearly with the PV rated power was the energy sold to the utility through the inverter.

ECONOMIC ANALYSIS

The economics of the system was evaluated in terms of the cost per unit of energy consumed by the farmstead. This cost was calculated as a function of the PV system peak rated power (Wp). This function was determined under two scenarios, net metering and avoided cost, in relation to the PV energy sold to the utility. These scenarios affected the system's annual revenue, which is determined by the PV energy that goes into the utility grid and the price that the utility pays for that energy.

Shown in figure 6 is the cost per unit of energy provided to the farmstead as a function of PV peak rated power. There is a linear relationship between the cost per unit of energy and the system peak rated power. An optimum system size cannot be determined based upon economic performance. Even for large system sizes, where the fraction of sold energy becomes more significant, there is a small difference between the cost of energy under the avoided cost scenario and the cost of energy under net metering (about half of the retail utility price). The energy cost was six times the utility retail price when the PV array was sized at 5330 Wp to supply the average daily load (23.12 kWh) with the average daily irradiation (4.7 kWh/m^2). It is clear that economic motivations for installing this kind of system do not exist.

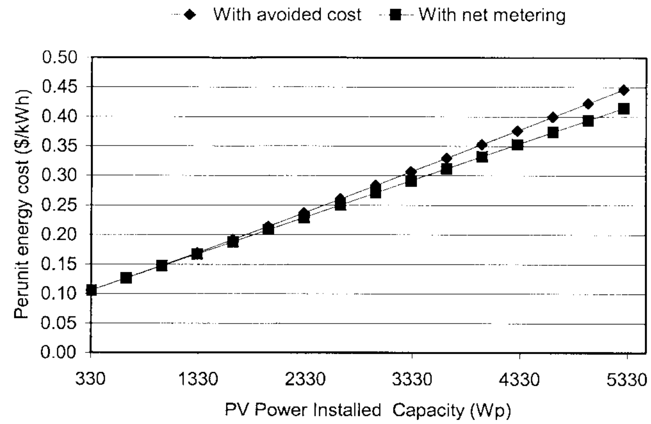

Figure 6–Cost per unit of energy as a function of system's peak rated power.

KRIGED VERSUS ACTUAL SOLAR RADIATION DATA

The annual simulations of the grid-connected PV system used hourly solar radiation data. The results from using actual data and estimated data were compared. The mean and standard deviation of the actual and estimated values at each of the 16 locations are compared in figure 7. These parameters were calculated from the two sets of 8760 values, at every station, corresponding to the total number of hours in a year. Differences in the means of estimated values with respect to the actual values are less than 20 W/m^2 for every station, and differences in standard deviations among stations are also less than 20 W/m^2. Considering the effect that such differences may have in the output of a PV module, it is reasonable to consider, for this analysis, the actual and estimated values as being identical. This view is reinforced by the mean error and mean absolute error calculated for every station, where the error was defined as the difference between the estimated value and the actual value of solar radiation at a given hour. As can be seen from figure 8, the mean error fluctuated between –15 to 15 W/m^2 with a rather even distribution between negative and positive values; this indicates that the semivariogram models used were not producing a tendency to overestimate or underestimate. From the same figure we also see that the mean absolute errors fluctuated between almost 20 to 40 W/m^2 which led us to conclude that the statistics of actual solar radiation and estimated radiation were very similar.

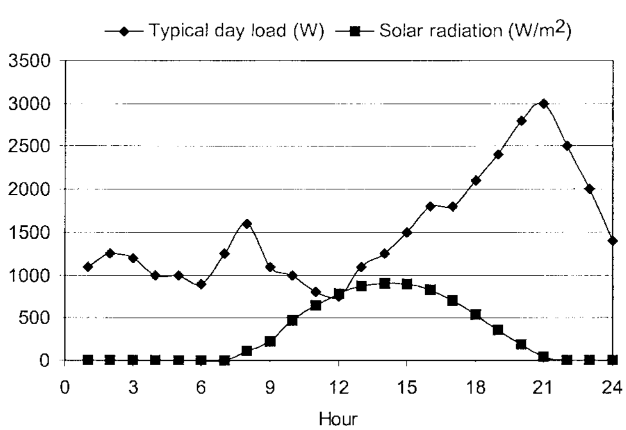

Figure 5–Typical hourly load and solar radiation for 15 July.

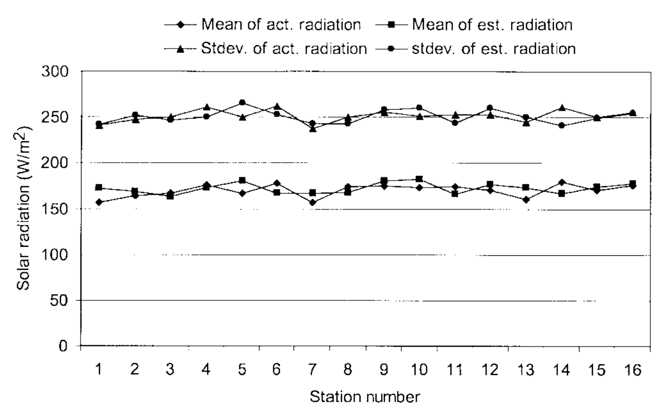

Figure 7–Mean and standard deviation of actual and estimated radiation data at 16 locations.

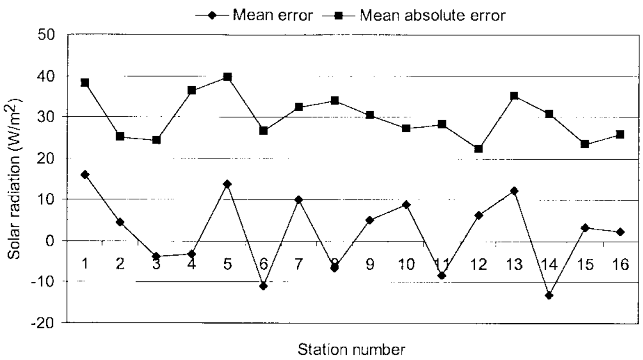

Figure 8–Mean error and mean absolute error at 16 stations for solar radiation data.

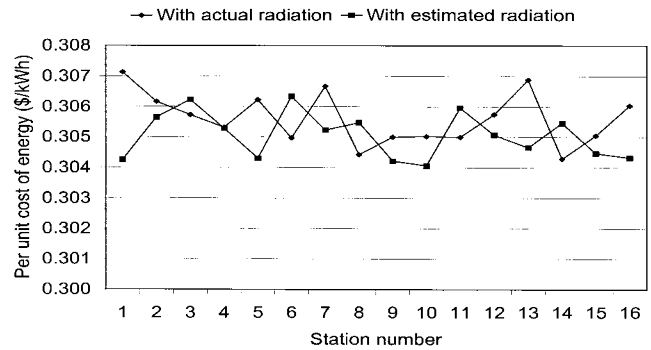

Figure 10–Cost of energy using actual and estimated radiation data.

INFLUENCE OF KRIGING ON THE PV ANNUAL ENERGY PRODUCED AND COST OF ENERGY

The effects of using kriged values of solar radiation in the grid-connected PV system may be analyzed under two perspectives. First, it is important to consider the differences obtained when using kriged solar radiation versus actual data in the annual energy produced by the PV array regardless of the fraction of this energy used to meet the load. In this way the conclusions achieved can be used to predict the performance of other kinds of PV systems. Second, it is important to assess the effect of using kriged radiation relative to using actual radiation on the economics of the system.

To satisfy these objectives, system simulations were performed with the kriged data and actual data at the 16 locations described. The hourly temperature data used in such simulations were the same in each of the simulations and corresponded to hourly averages at station 12 (North Platte, Nebraska) for the period August 1995 to July 1996. In this way differences due to the effect of temperature on the PV output were removed. Figure 9 shows the annual PV energy produced by the PV array with estimated and actual data at the 16 locations. The PV peak rated power for these simulations was 3300 Wp. The differences fluctuated between almost 150 to 720 kWh, but were less than 500 kWh for 11 of the 16 stations. On the other hand, the effect of these differences on the cost per unit energy consumed by the farmstead is shown in figure 10. This cost was determined using the utility avoided cost scenario in the analysis. As shown in figure 10, the influence of using kriged solar radiation versus actual radiation data is less than 0.5 ¢/kWh in all the locations. This is obviously due to the small contribution that the PV energy makes toward meeting the demand and also to the elevated capital cost of the PV array.

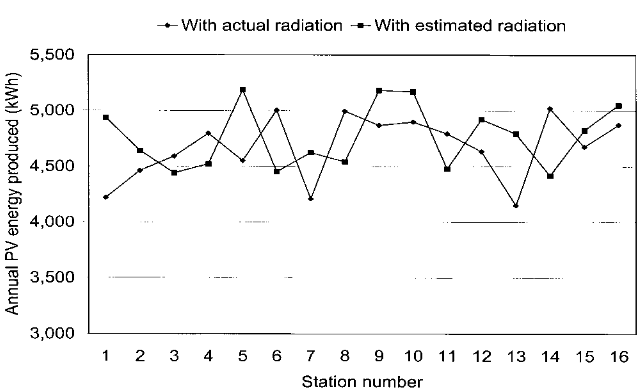

Figure 9–Annual PV energy production using actual and estimated radiation data.

SUMMARY AND CONCLUSIONS

In this article, the economic performance of a grid-connected PV system supplying power to a farmstead, was analyzed in relation to the system size, and in relation to the manner in which the PV system interacted with the grid, i.e., under the net metering scenario or under the avoided cost scenario. Also, semivariogram models for kriging solar radiation, generated in a previous work, were tested by assessing the influence of using estimated (by kriging) solar radiation data on the annual energy production and economic performance of the grid-connected PV system.

The economic performance was evaluated by computing the cost per unit of energy consumed by the farmstead. That cost depended on the annual PV energy produced and used by the farmstead, the annual energy purchased from the utility and the annual PV energy sold to the utility. These energy flows were determined by using Hybrid2 to perform annual system simulations in which hourly averages of solar radiation, temperature and electrical load were used.

Based on the energy flows obtained from the year-long simulations, a linear relationship between the PV energy produced and the PV array size was observed. Nevertheless, the PV energy that met load did not show a linear relationship to the PV array size, but approached a maximum value for installed power capacities of about 3300 Wp and higher. On the other hand, the cost per unit of energy for any size of grid-connected PV system was greater than the cost per unit of energy for a grid system supplying the same load alone. In fact, if the PV array was sized at 5290 Wp to supply the average daily load with the average daily irradiation, the cost per unit of energy was six times the retail utility energy price. The reason for this high cost was mainly the capital cost involved in the PV modules, which dominates the economics of the system.

The above results suggest that there must be other motivations besides the economic performance that have led to the use of grid-connected PV systems to supply farmstead electric demands. If such a decision is adopted, system simulations must be performed prior to installation

in order to determine the maximum PV installed capacity beyond which not more PV energy generated is used to meet the on-site load.

The semivariogram models generated from previous work performed satisfactorily for the network of weather stations in western Nebraska. These models produced hourly solar radiation estimates (kriged) with very similar statistical properties to the actual data. This similarity was reflected in differences less than 500 kWh for the simulated PV annual energy production for most of the 16 stations considered. When these differences were converted to cost per unit of energy, differences less than 0.5 ¢/kWh were observed at every station. These results increased our confidence with respect to using kriging to estimate solar radiation at places without weather stations.

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