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PHOTOVOLTAIC CENTRAL POWER PLANTS

Some New Evaluations on the Basis of Revised Insolation Data

By
S. L. Leonard

July 1978

Work Performed Under Contract No. EY-76-C-03-1101-008

The Aerospace Corporation
Energy and Resources Division
El Segundo, California

U.S. Department of Energy

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Solar Energy

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THE AEROSPACE CORPORATION
El Segundo, California

July 1978

Prepared for

THE UNITED STATES DEPARTMENT OF ENERGY
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PROJECT AGREEMENT 8

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FOREWORD

This report documents the results of one of several analytical investigations conducted under Contract No. EY 77-C-03-1101, Project Agreement 8, "Photovoltaic Mission Analysis", for the U.S. Department of Energy, Division of Distributed Solar Technology. The analyses described here were carried out as part of Task 4: Photovoltaic Solar Energy Program Technical and Management Support.

The work was accomplished by the Energy Systems Directorate of the Energy and Resources Division of The Aerospace Corporation. Dr. Harold Macomber of the Silicon Technology Programs Branch is the DOE Program Manager for this contract, and Dr. M. B. Watson, Principal Director of the Energy Systems Directorate, is the Principal Investigator. Dr. S. L. Leonard, Director, Photovoltaic Projects, has provided the day-to-day program management.

This document was prepared by Dr. S. L. Leonard.

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I. INTRODUCTION

In a number of recent studies (Refs. 1-5), analyses have been made of the expected performance of photovoltaic central station power plants of varied design in different climatic regions of the United States. The central element of these analyses has been detailed computer simulation of the operation of the plant under consideration, usually carried out on an hour-by-hour basis for at least a full year of operation.

A critical input to such simulations is an appropriate representation for the hourly insolation at the presumed location of the plant. In the case of plants using either flat-plate photovoltaic arrays or concentrator systems of low concentration ratio ($x < 5$), these input data must include information about both the direct normal (unscattered) component of the radiation and the diffuse (scattered) component. For systems of moderate-to-high concentration ratio ($x > 20$), only the direct component is of importance.

The requisite insolation inputs are provided to the simulation model in the form of an insolation data base containing hourly values for the output of a normal-incidence pyrheliometer (whose 5.7° field of view accepts a small amount of diffuse radiation from the immediate circumsolar region of the sky, in addition to the direct normal radiation) and the output of a hemispheric pyranometer (which records the total radiation, direct plus diffuse, that falls on a horizontal surface). The pyrheliometer output can be used with adequate precision to represent the direct normal insolation, and the diffuse component can be determined by subtracting the direct-insolation component from the total radiation, as recorded at the same site by a pyranometer.

The analyses mentioned above (Refs. 1-5) employed an insolation data base (Data Base I or "old data base") that was developed in 1974-75 by The Aerospace Corporation (Refs. 6,7) on the basis of historical National Weather Service (NWS) records for the years 1962 and 1963. Very recently, Aerospace has constructed (Ref. 8) a revised insolation data base (Data Base II or "new data base") that is based on a substantially greater body of measurements and takes into account some recent NWS corrections to the raw data. For a given location, the average values of total insolation represented in the new data base are in fairly good agreement (typically to within 6%) with the corresponding average values in the old data base. The average values of the direct normal insolation in the new data base, however, are substantially lower than those in the old base, especially for locations outside the Southwest. The differences are greater than 40% in some cases.

These indicated differences between the old and new data bases are sufficiently large that, if the new base is adopted as a better representation of insolation at the sites in question, conclusions drawn from the earlier analyses of photovoltaic plant performance may no longer be valid. In particular, judgments about the relative economic viability of flat-plate and concentrator systems in various parts of the U.S. may be affected. It was, therefore, decided to make a direct comparison between plant performance and cost effectiveness as computed with Data Base II and the corresponding performance and cost-effectiveness as computed with Data Base I for both flat-plate and concentrating photovoltaic plants at each of a representative set of U.S. locations. For the purposes of this comparison, three different collector/concentrator concepts (flat plate, north-south parabolic trough, and central receiver) were considered, and operation at four locations (Phoenix, AZ; Dodge City, KA; Miami, FL; and Sterling, VA) was evaluated. In addition, correlations between plant performance and average insolation were used to provide approximate evaluations of the cost-effectiveness of photovoltaic plants at 21 other locations. The criterion used to establish

cost-effectiveness was a comparison of the busbar cost of energy generation by a photovoltaic plant with the busbar cost of energy from an "equivalent" (same capacity and capacity factor) coal-fired or oil-fired plant serving the intermediate portion of the load of a utility system. The cost of enough backup (conventional) capacity to maintain utility system reliability was included in the cost of the solar plant in each case.

The remaining sections of this report contain a discussion of the methods used and the results obtained in this comparative analysis. The old and new insolation data bases and their differences are described in the next section, Section II. Following that, in Section III, a discussion is given of the methodology used in evaluating plant performance and of the technical and economic assumptions that were made in the course of the analysis. The results of the evaluations that were carried out are presented in Section IV, and the last section, Section V, contains a discussion of these results and of the tentative conclusions that may be drawn from them.

II. INSOLATION DATA BASES

1. Data Base I

The old insolation data base was developed by The Aerospace Corporation in 1974-5, largely for its own use in mission analysis studies of both solar thermal and photovoltaic electric power generation. The data base was constructed in stages to match the changing needs of the mission studies. In the initial version (Ref. 6), seven Southern California sites plus Yuma, AZ, and Albuquerque, NM, were represented. Because of limitations of time and resources, only two years of data for each site were included. The years selected for inclusion, 1962

and 1963, were chosen because they were the most "typical" years, with respect to Southern California meteorology, for which all the desired data were available for all the chosen sites.

As the scope of the mission studies enlarged, the data base was expanded to include, first (Ref. 7), data from a total of 20 sites in the U.S. Southwest (plus Omaha, NE) and, later (Ref. 1), data from 34 locations, with representation for all of the important climatic zones of the continental U.S. Since each expanded version incorporated the data from the earlier versions, of course, the Southwest and, particularly, Southern California were greatly over-represented in the final data base. Furthermore, the need to compare simulation results for different sites on a common basis dictated that the same two years of data, 1962 and 1963, be used for all sites. (Resources were never adequate during this period to justify expanding the data base to include more than two years of data from each site, with the single exception of Columbia, MO. For that site, the need of a separate program led to the incorporation of 18 years of data, 1952-1969, in the data base.)

The data on total hemispheric insolation (pyranometer readings) in the final version of Data Base I were obtained from four principal sources. For 22 of the 34 sites, the total insolation data came from magnetic tape records (in Card Deck 280 format) obtained from the National Climatic Center (NCC) in Asheville, NC. For four of the sites, the data were transcribed from manuscript records that were also archived by the NCC. For one site (Los Angeles Civic Center) data in printed tabular form were obtained from a cooperating agency (the Los Angeles Air Pollution Control District). For the remaining seven locations, the "data" were estimated on the basis of a correlation (in the form of a

least-squares best-fit polynomial of third degree) between total insolation and "opaque sky cover" as recorded by National Weather Service observers. In one case (the manuscript data for Inyokern, CA), the recorded data were corrected for a known instrument drift, but all the other measured data were copied into the data base as received.

The origins of the data on direct normal insolation in Data Base I are quite different. Only a very small fraction of these data are the products of actual measurements, principally because routine pyrheliometer measurements have been made at only a handful (typically four or five in any given year) of sites in the U.S. Furthermore, even at these sites, the measurements were not recorded at hourly intervals but rather at times corresponding to certain air-mass ratios (i.e. to certain standard values of the angular distance of the sun from zenith). The amount of recorded data is still further limited by the fact that, apparently, measurements were frequently omitted when the sun was even partially obscured. As a result, for several of the stations, the missing data far outnumber those that were recorded in tabular form (as reported in the NCC publication, Climatological Data National Summary).

For the above reasons, the great majority of the direct normal insolation values in Data Base I are estimates, based on an observed correlation between direct normal insolation and values for the percent of possible total insolation (the ratio of the ground-level total hemispheric insolation to the corresponding value just outside the earth's atmosphere, expressed as a percent) at the same hour. The correlation relation used in making these estimates was a linear least-squares best-fit regression line derived from the measured data for Albuquerque, NM, and Blue Hill, MA. (Actually, the "hourly" direct normal insolation values used in deriving the correlation were obtained from the printed record by interpolating between values measured at times corresponding to specific air mass ratios.)

2. Data Base II

The revised data base, Data Base II, differs from the older one in a number of important respects: a) the values for total hemispheric insolation have been adjusted by the NCC in a manner designed to correct for calibration error and instrument drift, b) the values for direct normal insolation have been estimated in the basis of an improved correlation algorithm, c) many more years of data (typically covering the 1952-1975 period) are provided for each location, and d) only 21 of the 27 locations represented in Data Base II are common to both old and new data bases.

Data Base II is, in part, the outcome of a NCC effort to provide from its archives a body of total hemispheric insolation data that is uniformly of fairly high quality and reliability. From the more than 60 stations at which such measurements were made, the NCC selected 27 for which the data were believed (on the basis of station records, internal consistency, etc.) to be of above-average quality. These data were then adjusted by a procedure which began with the selection from the original chart records of observed values of total hemispheric insolation at solar noon on clear days. Values for the insolation that would be expected at those times and locations were then computed on the basis of climatic data for the seasons and locations in question. The ratio of computed value to observed value for a given day was then used as a correction coefficient to be applied to the insolation data for the other hours of that day. Correction factors for other days were obtained by interpolating between values for clear days. The resulting insolation values are designated as Standard Year Corrected (SYC) values in the NCC archives.

The new procedure used in estimating the hourly direct normal insolation values in Data Base II is based on more than 20,000 simultaneous observations of direct normal and total hemispheric insolation.

These data were collected after September, 1974, with carefully calibrated instruments at four different U.S. locations (Livermore, CA; Raleigh, NC; Ft. Hood, TX; and Maynard, MA) with widely different climates. The estimation procedure takes into account statistical variations in estimated direct normal insolation values for a given total hemispheric insolation value and yields estimates of annual mean values of daily direct insolation that are believed to be accurate to within 4%. In constructing Data Base II, however, this procedure was used to generate direct normal insolation values on the basis of the NCC Standard Year Corrected values of total hemispheric insolation. Because of uncertainties in the SYC procedure, the annual mean values of daily direct insolation in Data Base II have a $\pm 10\%$ uncertainty associated with them.

The differences between the insolation data in the old and new data bases are illustrated in Table 1 and Fig. 1. In Table 1 are listed the average values of the daily amount of direct normal and total hemispheric insolation at each of the 21 sites that are common to the two data bases. (For Data Base I, with the single exception of the Columbia, MO, data, these are averages over the two year period, 1962-1963, while for Data Base II they are averages over, typically, the 24-year period from 1952 through 1975.) It is evident from the table that, except in the case of Fresno, the Data Base II total hemispheric data are uniformly lower than the corresponding data in the other data base. The differences are in general fairly small, however, exceeding 10% in only a few cases.

The differences between new and old estimates of direct normal insolation are quite a different story, ranging as high as 40% or more in some cases (when expressed as a percentage of the old, larger value). The origin of these large differences is two-fold: a) the direct normal values are estimated on the basis of the somewhat lower SYC total insolation values and b) the non-linearities of the new estimation procedure.

Table 1

Insolation Data Base Comparison

	Direct Normal Insolation			Total Hemispheric Insolation		
	New	Old	% Diff	New	Old	% Diff
Albuquerque	7.13	8.41	15.2	5.76	5.96	3.4
Bismarck	4.49	6.35	29.3	3.94	4.14	4.8
Boston (Blue Hill)	3.29	5.66	41.9	3.51	4.05	13.3
Charleston	3.74	5.95	37.1	4.24	4.80	11.7
Columbia	4.29	6.20	30.8	4.19	4.45	5.8
Dodge City	5.77	7.19	19.7	4.92	5.05	2.6
El Paso	7.26	8.47	14.3	5.98	6.26	4.5
Ely	6.52	7.99	18.4	5.15	5.48	6.0
Fort Worth	4.72	6.56	28.0	4.68	5.11	8.4
Fresno	6.13	6.86	10.6	5.40	5.18	-4.2
Great Falls	4.39	6.10	28.0	3.97	4.00	0.8
Lake Charles	3.67	5.64	34.9	4.27	4.62	7.6
Madison	3.72	5.91	37.1	3.75	4.23	11.3
Medford	4.32	5.89	26.7	4.27	4.41	3.2
Miami	3.81	6.35	40.0	4.65	5.28	11.9
Nashville	3.59	4.96	27.6	4.00	4.11	2.7
North Omaha	4.47	6.29	28.9	4.17	4.47	6.7
Phoenix	6.91	8.05	14.2	5.88	5.88	0
Santa Maria	5.41	7.41	27.0	4.98	5.47	9.0
Seattle	2.82	4.82	41.5	3.26	3.51	7.1
Sterling (Washington, D. C.)	3.45	5.94	41.9	3.74	4.41	15.2

Figure 1
Average Daily Direct Normal and Total Hemispheric Insolation
Data Base I vs. Data Base II

are such that the multiplying factor to convert total hemispheric insolation values to direct normal values is smaller at the lower end of the total insolation scale, thereby magnifying the effect of reductions in total insolation values.

Figure 1 provides a graphical illustration of these differences for five sites whose insolation values span the range from highest to lowest. (The abscissa scale in the graph has no quantitative or geographical significance; displacements along this axis merely provide, for clarity, separation between the points for the various locations.) The graphical format illuminates the important point that the relative magnitudes of total hemispheric and direct normal insolation in the two bases are quite different. In Data Base I, the total hemispheric insolation value is smaller than the direct normal value at every site. In Data Base II, on the other hand, the total hemispheric value is the larger one at 14 of the 27 sites (and at 8 of the 21 sites that are represented in both data bases), these being, in the main, the relatively low-insolation locations outside the Southwest. The clear implication of this difference between the two data bases is that use of the newer data to evaluate system performance can be expected to lead to a much less favorable assessment of concentrating systems in comparison with flat-plate systems for locations outside the Southwest. As will be seen, the results of the analyses reported later in this document fully confirm this expectation.

III. METHODOLOGY AND ASSUMPTIONS

The basic approach that was used in the analyses reported here is the same as that used in the earlier studies (Refs. 1 and 2). The central element was computer simulation of the operation of the photovoltaic system at the assumed location. Hour-by-hour computations of system performance were carried out with the aid of a mathematical model of the system and an hourly representation for the insolation to be expected at

the site. The computations were carried out for a full year of simulated operation and yielded, as a figure of merit, the capacity factor for the photovoltaic plant at the location. (The plant capacity factor, PCF, is the ratio of the total amount of electric energy generated annually to the amount that would be produced if the plant operated at rated capacity during all 8760 hours of the year.)

The insolation representations that were used consisted of one selected year of data from Data Base I and one from Data Base II for each of the four sites that were chosen for study: Phoenix, AZ; Dodge City, KA; Miami, FL; and Sterling, VA. (Originally five sites were selected for study, these four plus Seattle, in order to provide reasonable representation for the full range of insolation values observed in the U.S. Initial runs made it clear that photovoltaic plant performance at Seattle would be so poor as to be of virtually no interest, and it was decided to drop this site in the interest of economy.) The data used from Data Base I were those for 1963, since most of the earlier analyses had been based on the insolation of that year. From Data Base II the years selected were: Phoenix, 1973; Dodge City, 1973; Miami, 1953; and Sterling, 1955. In each case the insolation data year was chosen to provide the best available match between a) the average values of daily total hemispheric and direct normal insolation for the chosen year and b) the annual averages of these same quantities over all the years of record (typically 24 years) for the site in question.

As in the previous work, it was recognized that a photovoltaic power plant will, in general, contribute less to the overall reliability of power generation in a utility system than will a nominally equivalent (i.e. same rated capacity and capacity factor) conventional plant. This difference is a result of the fact that photovoltaic plants experience weather-related outages and, therefore, are not always able to generate power at times of peak demand. The analytical methodology, therefore, included a determination of the amount of backup (standby) conventional

capacity that would have to be provided along with a photovoltaic plant in order that it be completely equivalent to the conventional plant with which it was being compared. The capital cost of this backup capacity was then included in the capital cost of the photovoltaic plant.

The determination of the backup capacity requirement was accomplished by a methodology that includes a) a model for the utility system into which the photovoltaic plant is to be inserted, including a representation for the total system demand and a generation model (i.e., a model for the generation capacity of the system, including the individual capacity, annual maintenance time requirement, and probability of unscheduled outage for each plant in the system) and b) a procedure for calculating the loss-of-load probability of the system (the annual number of hours during which the available generation capacity of the system is less than the overall demand). Computations were first made of the loss-of-load probability for the system in the absence of photovoltaic capacity. One or more photovoltaic plants were then introduced into the generation model in place of nominally equivalent conventional plants and the loss-of-load probability was recomputed (and, in general, found to be increased). Incremental additions of conventional capacity were then made to the generation model until the loss-of-load probability was reduced to the original value. The amount of conventional capacity so introduced represented the required amount of backup capacity. The results of such an analysis are sensitive, of course, to the assumed degree of photovoltaic penetration into the generation mix. In all the cases discussed in this paper, it was assumed that the amount of photovoltaic capacity introduced was approximately equal to 5% of the total capacity of the utility system.

Three different photovoltaic plant configurations were considered: a) systems with flat-plate arrays tilted, about an east-west axis, to an angle equal to the local latitude, b) systems with parabolic trough concentrators (concentration ratio = 20) with single axis tracking

about a horizontal north-south axis, and c) central receiver systems (concentration ratio = 600). The central receiver configuration is one in which an assembly of steerable mirrors (heliostats) reflects incident sunlight onto a photovoltaic array mounted on a tower. It was assumed in the analysis that the flat-plate and parabolic trough systems incorporated single-crystal silicon arrays or cell assemblies with nominal efficiency, at 20°C, of 13.5% (cell efficiency of 15%, packing factor 90%). The cell assemblies in the central receiver plants were assumed to be fabricated of AlGaAs/GaAs cells, with an efficiency of 22% at 20°C (cell efficiency 24.5%, packing factor 90%). It was also assumed that in the first two cases the cells were passively cooled (with the assistance of fins to increase the effective cooling surface in the parabolic trough case); the simulation model calculated the cell temperature on the basis of the solar energy input, the ambient temperature, and an assumed convective heat transfer coefficient. In the central receiver case, it was assumed that the cell temperature (averaged over the receiver surface) was kept at 80°C by water cooling. The power consumed in circulating the water to the cells and to the heat exchanger was treated as a parasitic load and subtracted from the calculated system output.

In every case, it was assumed that the rated capacity (i.e., the rated AC output of the plant, as determined by the rating of the power conditioning system) was 100 MW. In the simulation computations, collector area and electric storage capacity were treated as variable parameters, and the zero-storage case was included. (Only storage dedicated to the photovoltaic plant, i.e., accepting only energy from the photovoltaic arrays, was considered.) The power conditioning efficiency was assumed to be 95%, independent of output level, and the overall output/input efficiency of the storage system was taken to be 70%. Ohmic losses of approximately 5%, largely in the DC portions of the system, were also taken into account.

The results of the performance calculations were then used as inputs to the economic analysis. For the purposes of this study, the standard EPRI/ERDA levelized fixed charge approach (Ref. 9) was used, and the levelized busbar energy cost was taken as the economic figure of merit. All inputs and results were expressed in terms of 1975 dollars. The fixed charge rate was set at 15%, a figure which is consistent with an after-tax discount rate of about 8%, a general inflation rate of about 5%, and a plant service life of 30 years. It was assumed that the levelized operation and maintenance cost is a flat 3 mills/kWh.

The total investment cost of each plant was determined by adding together estimated values for the installed costs of the different plant subsystems and then multiplying the total by appropriate factors to account for spares and contingencies, for indirect costs (construction equipment, facilities, and services plus architectural and engineering services, etc.), and for interest during construction. The cost of the silicon arrays used in the flat-plate system was treated as a variable parameter with values ranging from \$100/kW_{pk} to \$500/kW_{pk}. In the case of the parabolic trough systems the cell assembly cost was kept fixed at \$100/kW_{pk}, while the AlGaAs/GaAs cell assemblies in the central receiver system were assumed to cost \$10,000/m². The assumed values for the installed cost of the structural parts of the collector systems were (still in 1975 dollars):

Support structure for flat plate arrays	\$15.2/m ²
Parabolic trough collectors	\$64/m ²
Heliostats	\$60/m ²

In determining the cost of another element of the collector system, the DC wiring, it was assumed that the average DC voltage is 1000 V; wire size was then selected on the basis of a trade-off between increasing wire diameter to reduce ohmic losses and increasing collector or array area to compensate for these losses. The resulting figures ranged from a low of about 2% to a high of about 5% of the total cost of collector plus array or cell assembly. In the case of the central receiver

plants the purely solar part of the plant contained two other elements: the cell cooling system and the central tower. The former was assumed to cost \$10 per rated kW of plant output, while the cost of the latter was computed from the scaling relation

$$\text{Tower cost (1975 dollars)} = 20.5 h^2$$

where h, the tower height (in meters), is related to A, the total collector area (in meters²), by the equation

$$h = 0.368 A^{1/2}$$

These relationships were developed in the ERDA/DOE Solar Thermal Electric Program. (See, for example, Refs. 6 and 7).

The remaining elements of the system are common to all three photovoltaic plant configurations. The assumed values for the capital cost of these elements, including installation, were (in 1975 dollars):

Land and land preparation	\$500/acre
Structure and facilities	\$10.85/kW _{rated}
Power conditioning system	\$70/kW _{rated}
Electric storage system	\$40/kWh
Electric plant equipment	\$16.30/kW _{rated}
Miscellaneous plant equipment	\$5.97/kW _{rated}

The sum of the capital costs of the various required subsystems was taken to be the basic plant cost. To this was then added a) an allowance for spares and contingencies, assumed to be 8% of the basic plant cost, b) an allowance for indirect costs, 10% of the cost of the solar elements plus 52% of the cost of the conventional elements of the plant, and c) an allowance of 12.8% for interest during construction. The indirect cost figures were based on estimates of indirect costs for conventional plants (52%) and an assumption that the modularity of solar plants would sharply reduce this expense for the solar elements. The interest during construction allowance was based on an assumed annual interest rate of 8%, an assumed total construction time of 4 years, and a

construction schedule leading to capital cost expenditures of 5%, 15%, 65% and 15%, respectively, in the four years of construction. Examples of this investment cost computation for the three different system configurations are given in Table 2. After the total investment cost of the photovoltaic plant was determined by the above procedure, the capital cost of the required amount of backup (conventional) capacity was added. It was assumed that this backup capacity would be in the form of gas turbine generators at \$140/kW (1975 dollars).

The measure of cost effectiveness that was adopted for use in this study was a comparison of the busbar cost of energy from a photovoltaic plant with the cost of energy from a conventional plant serving the same intermediate portion of the utility load. The type of conventional plant used as the main standard of comparison in this case was a coal-fired steam boiler plant having a total capital cost (in 1975 dollars) of \$550/kW, an average plant capacity factor of 0.4, and an average heat rate of 9200 Btu/kWh. The levelized operation and maintenance cost, exclusive of fuel, was assumed to be a flat 3 mills/kWh. The figures used for the levelized cost of fuel (over 30 years of service) were based on fuel-price projections prepared, under sub-contract, by Sherman H. Clark Associates (Ref. 10). In levelizing these projected values (which are expressed in constant 1977 dollars), a discount rate of 8% and a general inflation rate of 5% were assumed. The resulting levelized values were then converted to 1975 dollars by dividing by the factor 1.109. Although the Sherman Clark projections of the cost of coal for use in electricity generation are listed by state, there are actually only 10 different sets of values for 10 U.S. regions: New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont); Middle Atlantic (New Jersey, New York, Pennsylvania); East North Central (Illinois, Indiana, Michigan, Ohio, Wisconsin); West North Central (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota); South Atlantic (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia); East South Central

Table 2

Investment Cost Computation:
Photovoltaic Power Plants

	Flat Plate	NS Parabolic Trough	Central Receiver
Collector Area ($\text{m}^2/\text{kW}_{\text{rated}}$)	10	12.5	10
Storage Capacity ($\text{kWh}/\text{kW}_{\text{rated}}$)	3	3	3
Capital Accounts ($\$/\text{kW}_{\text{rated}}$)			
Collector Structure	152	800	600
Cell Assemblies/Arrays	135	8	167
DC Wiring	8	16	25
Tower	--	--	28
Total Solar	<u>295</u>	<u>824</u>	<u>820</u>
Structure/Facilities	11	11	11
Power Conditioning	70	70	70
Storage	120	120	120
Electric Plant Equipment	16	16	16
Misc. Plant Equipment	6	6	6
Cooling Equipment	--	--	10
Land	6	12	4
Total Conventional	<u>228</u>	<u>235</u>	<u>237</u>
Total Basic Plant	524	1059	1057
Spares, Contingencies	42	85	85
Indirect Costs	148	204	205
Interest During Construction	91	172	172
Total Investment Cost	<u>805</u>	<u>1520</u>	<u>1519</u>

(Kentucky, Tennessee, Alabama, Mississippi); West South Central (Oklahoma, Arkansas, Louisiana); Texas; Mountain (Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming); and Pacific (California, Oregon, Washington). The corresponding figures for the levelized cost of fuel, $\overline{FL}$, (in 1975 dollars per million Btu), and the levelized busbar cost of energy, $\overline{BBEC}$ (in mills/kWh), from an intermediate-load coal-fired plant are given in Table 3. Figures are shown both for plants going on line in 1990 and those starting in the year 2000.

Since it is by no means certain that coal-fired generating plants will be the dominant type of fossil-fuel plant for intermediate-load service in the future, the busbar cost of photovoltaic electricity was also compared in each case with the busbar cost of energy from new oil-fired plants (capital cost, in 1975 dollars, \$350/kW; average heat rate 9600 Btu/kWh). The Sherman Clark projections (Ref. 10) of the cost of heavy fuel oil for use in generating electricity are not the same from state to state within larger regions, as was the case with coal. It was therefore necessary to compute the levelized cost of fuel separately for each state in which a solar plant was assumed to be located. The resulting figures for the levelized cost of fuel and the associated levelized busbar cost of electricity (plant capacity factor = 0.4) are given in Table 4. The Sherman Clark report does not contain projections of the price of heavy fuel oil for power plants for five states that are of interest: Tennessee (Nashville), New Mexico (Albuquerque), Montana (Great Falls), Oregon (Medford), and Washington (Seattle). The values given in Table 4 for these five states are based on Sherman Clark projections of the price of heavy fuel oil for general industrial use.

Table 3

Levelized Fuel and Busbar Energy Costs:
Coal-Fired Intermediate-Load Power Plants

	$\overline{FL}$ (\$/10 ⁶ Btu)		$\overline{BBEC}$ (mills/kWh)	
	<u>1990</u>	<u>2000</u>	<u>1990</u>	<u>2000</u>
New England	4.31	5.56	66.2	77.6
Middle Atlantic	4.06	5.18	63.8	74.2
East North Central	3.40	4.32	57.8	66.3
West North Central	2.95	3.89	53.6	62.3
South Atlantic	3.89	4.98	62.3	72.3
East South Central	2.95	3.68	53.7	60.4
West South Central	2.48	3.23	49.3	56.2
Texas	2.30	3.10	47.6	55.0
Mountain	1.90	2.66	43.9	51.0
Pacific	3.13	4.10	55.3	64.2

Table 4

Levelized Fuel and Busbar Energy Costs:
Oil-Fired Intermediate-Load Power Plants

	<u>FL</u> (\$/10 ⁶ Btu).		<u>BBEC</u> (mills/kWh)	
	<u>1990</u>	<u>2000</u>	<u>1990</u>	<u>2000</u>
Massachusetts	7.08	7.44	86.0	89.5
New York	7.05	7.41	85.7	89.1
Wisconsin	6.88	7.25	84.1	87.6
North Dakota	7.11	7.47	86.2	89.7
Missouri	7.21	7.58	87.3	90.8
Kansas	6.96	7.33	84.8	88.4
Nebraska	7.19	7.55	87.0	90.5
Florida	7.16	7.52	86.7	90.2
North Carolina	7.03	7.40	85.5	89.0
South Carolina	6.87	7.23	84.0	87.4
Virginia	7.16	7.52	86.7	90.2
Tennessee	(7.14)	(7.51)	(86.5)	(90.1)
Louisiana	6.99	7.34	85.1	88.5
Texas	7.22	7.58	87.3	90.8
New Mexico	(7.36)	(7.71)	(88.6)	(92.0)
Nevada	7.05	7.42	85.7	89.2
Montana	(7.21)	(7.57)	(87.2)	(90.7)
Arizona	7.21	7.57	87.2	90.7
California	7.22	7.58	87.3	90.8
Oregon	(7.11)	(7.47)	(86.3)	(89.7)
Washington	(7.09)	(7.46)	(86.0)	(89.6)

IV. RESULTS

1. Flat-Plate Photovoltaic Plants

The effect of using Data Base II rather than Data Base I in computing the performance of a 100 MW flat-plate photovoltaic plant in Miami is displayed in Figure 2. The graphs in the figure illustrate, in "carpet plot" format, the dependence of the plant capacity factor on two major system parameters: array area and storage capacity. In this format, distances in the horizontal (abscissa) direction do not represent a single specific variable but serve as a linear horizontal scale for use in interpolating between the curves that comprise the quasi-three-dimensional surface displayed in the figure. Along a given constant array-area curve, for example, points corresponding to different amounts of storage are spaced horizontally in direct proportion to the amount of storage. Correspondingly, along a given constant storage curve, the horizontal separations between points for different array area are proportional to the differences in array area. The reason for the decreasing slope of the constant storage capacity curves, as array area is increased, is that at higher array areas more energy is collected than can be handled by the power conditioning system (with its 100 MW limit). Any collected energy in excess of the amount that can be stored must simply be wasted and cannot, therefore, contribute to the plant capacity factor. The constant array area curves, for increasing storage, level off when the storage capacity becomes large enough to accommodate all solar energy in excess of the handling capability of the power conditioning system.

As is indicated by the curves in Fig. 2, the differences between the PCF values computed with the aid of the two data bases are not large. In the Miami case, the differences amount to at most 15%, a percentage that, not surprisingly, agrees fairly closely with the percentage

LOCATION: MIAMI, FLORIDA
 RATED CAPACITY: 100 MW
 ARRAY EFFICIENCY: 13.5% (20°C)
 ARRAY TILT ANGLE: LOCAL LATITUDE

Figure 2

Performance in Miami of a Flat-Plate Photovoltaic Plant: Old Insolation Data
 (Data Base I) vs. New Data (Data Base II)

difference in the average total hemispheric insolation values in the two data bases for the two years in question (1963 for Data Base I, 1953 for Data Base II).

Similar results were obtained for the other three sites (Phoenix, Dodge City, and Sterling), with the differences in PCF values roughly proportional to the differences in average total hemispheric insolation. This linear relationship between PCF and hemispheric insolation is illustrated graphically in Fig. 3 for the particular case of flat-plate plants with array area of $1.0 (10^6) \text{ m}^2$ (or $10 \text{ m}^2/\text{kW}_{\text{rated}}$) and zero storage. (These parameter values, as will be seen, are approximately those leading to minimum busbar energy cost.) The straight line shown in Fig. 3 provides a least-squares best fit to the eight computed data points.

The effect of the performance (PCF) differences portrayed in Fig. 2 on the resulting levelized busbar cost of energy is shown, for the same Miami plant, in Fig. 4. The assumed array price used in computing the energy cost in this case was $\$100/\text{kW}_{\text{pk}}$. The minima in the curves occur because a) in the small array-area region, the annual energy production decreases with array area while several significant elements of the capital cost of the plant (e.g., power conditioning) remain fixed and b) in the large array-area region, collected energy in excess of the handling capability of the power conditioning system is wasted when storage is full. The curves in Fig. 4 illustrate again that the effect of using the revised data base rather than the original one is to produce only a modest change in evaluations of the economics of flat-plate photovoltaic power plants. The horizontal lines in Fig. 4 correspond to the levelized busbar cost of energy from a new coal-fired intermediate load plant that goes on line in the South Atlantic region (which includes Miami) either in 1990 or 2000. (See Table 3). It is evident from the figure that at this location flat-plate photovoltaic plants with $\$100/\text{kW}_{\text{pk}}$ arrays can be expected to compete successfully with

Figure 3
Correlation of Computed Capacity Factors of Flat-Plate Photovoltaic
Plants with Average Daily Total Hemispheric Insolation

Figure 4

Levelized Busbar Cost of Energy From a Flat-Plate Photovoltaic Plant in Miami: Old Insolation Data (Data Base I) vs. New Data (Data Base II)

coal-fired plants even before 1990. The effect of varying the assumed array price is shown, for the zero-storage case, in Fig 5. This figure indicates that, if Data Base I is used, the year 2000 breakeven array price (the array price at which a flat-plate photovoltaic plant provides electricity at the same busbar cost as does a coal-fired plant) is greater than $\$300/\text{kW}_{\text{pk}}$. If the newer data base, Data Base II, is used, Fig. 5 indicates that the breakeven array price is somewhat greater than $\$250/\text{kW}_{\text{pk}}$.

The same economic evaluation methodology that was used in constructing Figures 4 and 5 was also applied in direct computations of the breakeven array cost, in both 1990 and 2000, for a total of 25 locations, including the 21 that are common to Data Base I and Data Base II. For the 21 sites for which detailed computations were not carried out, PCF values were deduced on the basis of the correlation relation of Fig. 3 and values for the average daily total hemispheric insolation for the site, as recorded both in Data Base I and in Data Base II. (For these additional 21 sites also, approximate values for the required amount of backup conventional capacity were estimated on the basis of correlations between backup capacity and PCF that were recognized in the data for the more completely analyzed cases.) The results are displayed in Figs. 6 and 7. For each location, two values are given, one (in parentheses) computed on the basis of Data Base I and the other on the basis of Data Base II. A comparison of these two values again supports the general conclusion that the effect of the insolation data base revision on evaluation of flat-plate photovoltaic power plants is relatively slight.

Since the revised data base is almost certainly a better representation for the actual insolation at the various sites, it is the numbers outside parentheses in Figs. 6 and 7 that should be used in drawing any additional conclusions. These values indicate that flat-plate photovoltaic plants with $\$100\text{--}200/\text{kW}_{\text{pk}}$ arrays will be competitive with coal-fired plants in many U.S. regions by the year 1990; by 2000, plants

Figure 5

Levelized Busbar Cost of Energy From a Flat-Plate Photovoltaic Plant in Miami as a Function of Array Price

Figure 6

Year 1990 Breakeven Array Prices for Flat-Plate Photovoltaic Plants
 vs. Coal-Fired Power Plants

Figure 7

Year 2000 Breakeven Array Prices for Flat-Plate Photovoltaic Plants
 vs. Coal-Fired Power Plants

with arrays costing more than \$250/kW_{pk} will be competitive in favored regions. The highest breakeven array prices in the figure are for locations in the South Atlantic region and in California, rather than in the desert Southwest, largely as a result of higher coal prices outside the Southwest. (El Paso is an exception because Texas coal prices were used in the analysis, rather than the coal prices prevailing in the nearby Mountain region.)

Similar computations were also made of the breakeven array prices for flat-plate photovoltaic plants in competition with oil-fired intermediate-load power plants at the same 25 sites. The results are displayed in Figs. 8 and 9. These breakeven prices differ from those obtained when coal-fired plants were the competitors in three important respects. In the first place, the allowable array prices are substantially greater in all parts of the country, because of the higher price of oil. In the second place, because the Sherman Clark oil-price projections (Ref. 10) are very nearly uniform over the entire U.S., the highest breakeven array prices, in excess of \$500/kW_{pk}, are found in the regions of best photovoltaic plant performance: the desert Southwest and southern California. Finally, because oil prices are projected to level off, in constant-dollar terms, after 2000, the breakeven array prices for plants going on line in 1990 and 2000 are not very different.

2. Concentrating Photovoltaic Plants

The effect of the insolation data base revision on computations of the performance (PCF) of concentrating photovoltaic plants can be considerably more dramatic, as is indicated by the carpet plots of Figs. 10 and 11. These figures portray the variation of plant capacity factor with array area and storage capacity for the cases of Miami plants incorporating either NS-oriented parabolic trough concentrators or the central receiver concentration configuration. The difference in PCF as

INSOLATION DATA SOURCE
 REVISED DATA BASE (Data Base II)
 - NO PARENTHESES
 OLD DATA BASE (Data Base I)
 - PARENTHESES

Figure 8

Year 1990 Breakeven Array Prices for Flat-Plate Photovoltaic Plants
 vs. Oil-Fired Power Plants

Figure 9

Year 2000 Breakeven Array Prices for Flat-Plate Photovoltaic Plants
 vs. Oil-Fired Power Plants

Figure 10

Performance in Miami of a Photovoltaic Plant with NS Parabolic Trough Concentrators

Figure 11

Performance in Miami of a High-Concentration Photovoltaic Plant
 in Central Receiver Configuration

calculated on the basis of the two different data bases is as large as 40-45% (expressed in terms of the larger PCF values determined from Data Base I).

These results, plus the corresponding ones for the other three sites, display the expected high degree of correlation between concentrator plant performance and average direct normal insolation. Since the direct normal insolation values in the two data bases are much more nearly equal for locations in the Southwest, for example, it is to be expected that the differences in the computed PCF values would be correspondingly small. The carpet plots in Fig. 12, representing the performance of a plant with NS parabolic trough collectors in Phoenix, confirm this expectation. More direct demonstrations of the very good linear correlation that exists between concentrator plant PCF and direct normal insolation are provided in Fig. 13, for the particular case of NS parabolic trough plants with collector area equal to $1.25(10^6)\text{m}^2$, i.e., $12.5\text{m}^2/\text{kW}_{\text{rated}}$, and no storage, and in Fig. 14, for the case of central receiver plants with collector area of $1.0(10^6)\text{m}^2$, or $10\text{m}^2/\text{kW}_{\text{rated}}$, and no storage. The straight lines shown in these figures again represent least-squares best fits to the data.

Examples of the effect of the insolation data base revision on computations of the economics of concentrator photovoltaic plants are presented in Figs. 15 and 16. The curves in these figures illustrate the dependence of busbar energy cost on array area and storage capacity for the same two Miami plants that are represented in Figs. 10 and 11. It is clear from the graphs of Figs. 15 and 16 that, at least for Miami, the change in the data base leads to quite substantial increases in the projected cost of service from concentrator photovoltaic plants. The horizontal straight lines represent the busbar cost of electric energy from a new coal-fired intermediate-load plant that goes into service in the same geographic region in 1990 or 2000; their presence dramatizes the

Figure 12
 Performance in Phoenix of a Photovoltaic Plant with NS Parabolic
 Trough Concentrators

Figure 13

Correlation of Computed Capacity Factors of NS Trough Photovoltaic Plants with Average Direct Normal Insolation

Figure 14

Correlation of Computed Capacity Factors of Central Receiver
Photovoltaic Plants with Average Direct Normal Insolation

Figure 15
Levelized Busbar Cost of Energy From a NS Parabolic Trough
Photovoltaic Plant in Miami

Figure 16
Levelized Busbar Cost of Energy From a Central Receiver
Photovoltaic Plant in Miami

negative impact of the data base revision on the ability of concentrator photovoltaic systems to compete economically with the coal-fired alternative.

Results of the type presented in Figs. 15 and 16 were also obtained for each of the other three sites for which detailed computations were carried out. In addition, the linear correlations illustrated in Figs. 13 and 14 were used, along with average values for direct normal insolation, to obtain good estimates of the performance of both NS trough and central receiver photovoltaic plants at the other 21 locations that were considered in the flat-plate analyses. (These include the 17 other sites that are represented in both data bases.) On the basis of these estimated PCF values, plus estimates of backup capacity requirements (as discussed above in connection with flat-plate systems), busbar energy cost values were computed. In this manner two sets of busbar energy cost values, one for each insolation data base, were obtained for each of the two types of concentrator plant considered in this study. A sort of inverse figure of merit was then obtained for each case by dividing the photovoltaic busbar energy cost by the busbar cost of energy from a new coal-fired plant going into service in the same geographic region either in 1990 or in 2000. The values for this busbar energy cost ratio for the year 2000 are presented in Figs. 17 and 18, with the ratios obtained on the basis of Data Base I placed in parentheses.

These figures reveal that the effect of the data base revision is to sharply increase the busbar energy cost ratio in all regions of the U.S. except in the Southwest, where the effect is significantly less pronounced. If the new direct normal insolation data are accepted as more reliable, Figs. 17 and 18 indicate that, in much of the U.S., electricity from the concentrator photovoltaic plants considered here will still cost

Year 2000 Busbar Energy Cost Ratios: NS Parabolic Trough
Photovoltaic Plants vs. Coal-Fired Intermediate-Load Plants

INSOLATION DATA SOURCES
 REVISED DATA BASE (Data Base II)
 - NO PARENTHESES
 OLD DATA BASE (Data Base I)
 - PARENTHESES

Figure 18

Year 2000 Busbar Energy Cost Ratios: Central Receiver Photovoltaic
 Plants vs. Coal-Fired Intermediate-Load Plants

twice as much as electricity from nominally equivalent coal-fired generation plants in the year 2000. Even in favorable southwestern locations, photovoltaic electricity from such concentrator plants will cost 40% more than coal-generated power.

One way of reducing the apparent disadvantage of concentrating photovoltaic systems would be to find a revenue-producing use for the large amount of thermal energy that is also collected (and must be disposed of in some way, in any case). In order to determine a set of rough upper-limit values for the possible economic impact of the sale of this thermal energy, new computations of the economics of central receiver photovoltaic plants were made on the basis of the assumptions that a) all of the thermal energy is sold at a price equal (on a $\$/10^6$ Btu basis) to the price of coal for industrial uses in the region where the photovoltaic plant is located and b) the revenue generated in this way is all applied against the costs of generating electricity, thereby reducing the effective busbar energy cost. The Sherman Clark projections (Ref. 10) were used in computing the levelized amount of revenue generated annually by the sale of the thermal energy. The new busbar energy cost figures were then used to compute new values for the ratio of the photovoltaic busbar cost to the busbar cost for coal-fired plants going on line in 1990 or 2000. The year 2000 results are shown in Fig. 19, where again the values obtained on the basis of Data Base I are placed in parentheses.

The results shown in Fig. 19 indicate that, for this most-favorable-case scenario, high-concentration systems like the central receiver plant analyzed in this study would be competitive with coal in the year 2000 throughout the Southwest (including California) and Middle Atlantic regions and in several other locations, as well, even if the revised data base is used. Although the case considered here is an optimistic one, the results suggest that in the most favorable locations the sale of the thermal energy could bring such high-concentration systems

INSOLATION DATA SOURCE
 REVISED DATA BASE (Data Base II)
 - NO PARENTHESES
 OLD DATA BASE (Data Base I)
 - PARENTHESES

Figure 19

Year 2000 Busbar Energy Cost Ratios: Central Receiver Photovoltaic
 Plants vs. Coal-Fired Plants, 100% Credit for Thermal Energy

near to or into the competitive range with respect to coal-fired plants. Prospects for lower-concentration configurations, such as the NS trough systems also analyzed above, are less promising because of the increased cost and greater thermal losses associated with transport of the heat over much greater distances than would be required in the central receiver case.

The competitive position of concentrating photovoltaic plants with respect to oil-fired power plants is, of course, considerably better than it is with respect to the coal-fired plants considered above. Figs. 20 and 21 present the results of an investigation of this competition, for the case of plants going on line in the year 2000. The numbers in each figure represent the ratios of the busbar cost of electricity from concentrating photovoltaic plants (NS parabolic trough systems in Fig. 20, central receiver in Fig. 21) to the busbar cost of energy from nominally equivalent oil-fired steam generating plants built to serve the intermediate portion of the utility load. The data in Figs. 20 and 21, unlike those presented earlier, are all based on analyses using the revised data base, Data Base II. The numbers in parentheses correspond to plants going on line in 1990, while those outside parentheses correspond to plants going on line in the year 2000. These results show that concentrating photovoltaic plants of either type, if located in the Southwest, may well be able to compete effectively with oil-fired plants as early as 1990. Furthermore, the busbar energy cost ratios are small enough in a number of other regions of the country to suggest that profitable use of even part of the thermal energy might be enough to make such concentrating systems competitive with oil in those regions also.

V. CONCLUSIONS

The major purpose of the investigation reported in this document was to determine the effect of the recent revisions in the insolation data base on technical and economic evaluations of photovoltaic central

Figure 20
Year 1990 and 2000 Busbar Energy Cost Ratios: NS Parabolic Trough
Photovoltaic Plants vs. Oil-Fired Power Plants

Figure 21

Year 1990 and 2000 Busbar Energy Cost Ratios: Central Receiver
Photovoltaic Plants vs. Oil-Fired Power Plants

station (utility) power plants using either flat-plate or concentrating collectors. The results discussed above clearly indicate that the data base revisions do not require any significant changes in earlier evaluations of flat-plate photovoltaic plants. On the other hand, the changes in direct normal insolation values result in significantly less optimistic projections of the cost-effectiveness of concentrator photovoltaic systems--at least concentrator systems of the two specific types that were studied--for locations outside the Southwest. This result implies that deployment of concentrator photovoltaic power plants may be much more regionally constrained than had previously been believed.

In view of the many assumptions and estimates that were required in order to generate the results discussed in Section IV, any more general conclusions drawn from the results must be considered somewhat tentative, subject to significant change if the assumptions prove unrealistic. In spite of this element of uncertainty, however, the analyses discussed in this paper do support the following generalizations strongly enough to justify a degree of confidence in their general correctness:

a) By 1990, flat-plate photovoltaic plants with $\$100\text{--}200/\text{kW}_{\text{pk}}$ arrays will be able to compete economically with conventional coal-fired generation in many regions of the U.S.; by 2000, such plants will be competitive in most of the U.S. and, in some areas, plants with $\$200\text{--}300/\text{kW}_{\text{pk}}$ arrays will be able to compete.

b) In competition with oil-fired power plants, flat-plate photovoltaic plants with $\$500/\text{kW}_{\text{pk}}$ arrays will be cost-effective as early as 1990 throughout the Southwest; breakeven array prices will be greater than $\$300/\text{kW}_{\text{pk}}$ in much of the remainder of the country.

c) Photovoltaic plants using high or medium concentration and producing only electricity are unlikely to be competitive with coal-fired plants even in the Southwest until after 2000.

d) High-concentration photovoltaic plants may be able to compete with coal-fired plants in the Southwest (including California) and Middle Atlantic regions by the year 2000 if a substantial portion of the thermal energy can also be profitably used.

e) Concentrating photovoltaic plants will probably be competitive with oil-fired power generation in the Southwest by the year 1990, even without profitable use of thermal energy.

It is also important to note that any of these conclusions with respect to concentrating systems is subject to modification if substantially higher conversion efficiencies can be achieved without prohibitive cost increases and without excessive increases in optical losses in collector systems.

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