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# The Value of Distributed Generation: The PVUSA Grid-Support Project Serving Kerman Substation

April 1994

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# THE VALUE OF DISTRIBUTED GENERATION: THE PVUSA GRID-SUPPORT PROJECT SERVING KERMAN SUBSTATION

Interim Report
April 1994

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## PROJECT PARTICIPANTS

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Many individuals and organizations deserve recognition for their efforts, support, and contributions relating to the PVUSA Grid-Support Project at Kerman. For the sake of brevity, those direct efforts resulting in the production of the Interim Test Results report are acknowledged with sincere thanks.

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Brian Farmer deserves special recognition for his contributions and steadfast guidance. We thank Dan Shugar for his work on the 1992 Case Study and for his exceptional efforts in the area of grid-support PV in general.

PVUSA members are gratefully recognized for their efforts and contributions resulting in the construction of the world's first grid-support PV demonstration plant. The 0.5 MW Kerman plant has enabled a greatly improved understanding of the value of distributed generation to utilities.

# EXECUTIVE SUMMARY

## BACKGROUND

A common practice of electric utilities experiencing transmission and distribution (T&D) system overloads is to expand the substation, add lines, or upgrade equipment, all of which are capital intensive options. In 1988, it was hypothesized that strategically sited photovoltaics (PV) could benefit parts of T&D systems near or at overloaded conditions. An evaluation methodology was developed and applied to a test case (Kerman Substation near Fresno, California). Analytical results, detailed in a 1992 Case Study,* suggested that the value of PV to the T&D system could substantially exceed its energy and generation capacity value.

The importance of this finding indicated the need for empirical validation. This led to the construction of a 0.5 MW PV demonstration plant by Pacific Gas and Electric Company (PG&E) at Kerman, California as part of the PVUSA (PV for Utility Scale Applications) project. PVUSA is a national public-private partnership that is assessing and demonstrating the viability of utility-scale photovoltaic electric generation systems. The Kerman PV plant, commissioned for commercial operation in June, 1993, is reported to be the first grid-support PV demonstration plant in the world.

## OBJECTIVE

This Interim Report focuses on validating the technical aspects of grid-support PV. It provides interim validation results for four of the eight identified value components that stack up to make the "value bar", and compares them to 1992 Case Study estimates. Results are based on improved technical evaluation methodologies, measured plant performance under a variety of conditions, and long-term plant performance estimated using a validated computer simulation program.

This report is not intended to be exhaustive in scope. It does, however, provide a thorough progress update of the validation project. Complete documentation of test procedures, data, and evaluation methods will be presented in the Final Report.

## ECONOMIC ASSUMPTIONS

The report uses the same economic methods and input assumptions as in the 1992 Case Study to facilitate comparison of results. For example, the interim test results use the same rates of inflation, cost of capital, and economic methods to compute value.

*Daniel Shugar, et. al., *Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation*, Pacific Gas and Electric Company, Report 007.5-92.9, November 1992.

## RESULTS SUMMARY

Figure ES-1 presents interim results in levelized ($/kW-yr) and net present value ($/kW) formats. The left bar presents the total economic value identified in the 1992 Case Study**; the right bar presents interim test results. For comparison purposes, the value components that have been technically validated are bordered by a bold line in both stacked bars.

> Validated interim test results equal about 84 percent of the 1992 Case Study estimates, based on initial data analyses. This significant interim result confirms that grid-support PV can provide measurable value to the local T&D system. The interim results indicate that substation and loss savings value can add about 45 percent to the sum of traditional energy and capacity value.

Table ES-1 presents the same information as in Figure ES-1, including 1992 Case Study estimates of value components that have yet to be validated. Approximately half of the value (from a dollar perspective) has been validated at this time.

## WHY DO THE STACKED BARS DIFFER?

A key difference between the interim test results and the 1992 Case Study results is attributable to plant performance and weather data assumptions. The differences are not due to under performance on the part of the PV plant. In fact, measured plant data compared to validated model results indicate that the Kerman PV plant is operating close to the PV system supplier's design.

Rather, the 1992 Case Study overestimated plant performance and thus value. This is principally due to the use of hourly weather data taken from San Benito, located about 60 miles southwest of Kerman at an elevation of 1500 feet. These data were used to calculate plant performance, impacting all 1992 Case Study calculations.

San Benito has a significantly better solar resource and a more moderate ambient temperature regime relative to the Kerman area. This explains a large part of the difference in results in this interim report as compared to the 1992 Case Study. Much of the remaining difference is due to plant design assumptions and improved technical evaluation methodologies.

**Qualifying Facilities (QF) Savings were identified in the 1992 Case Study but have been excluded from the analysis because they merely represent transfer payments, and the treatment of QF contracts in future resource planning is highly uncertain.

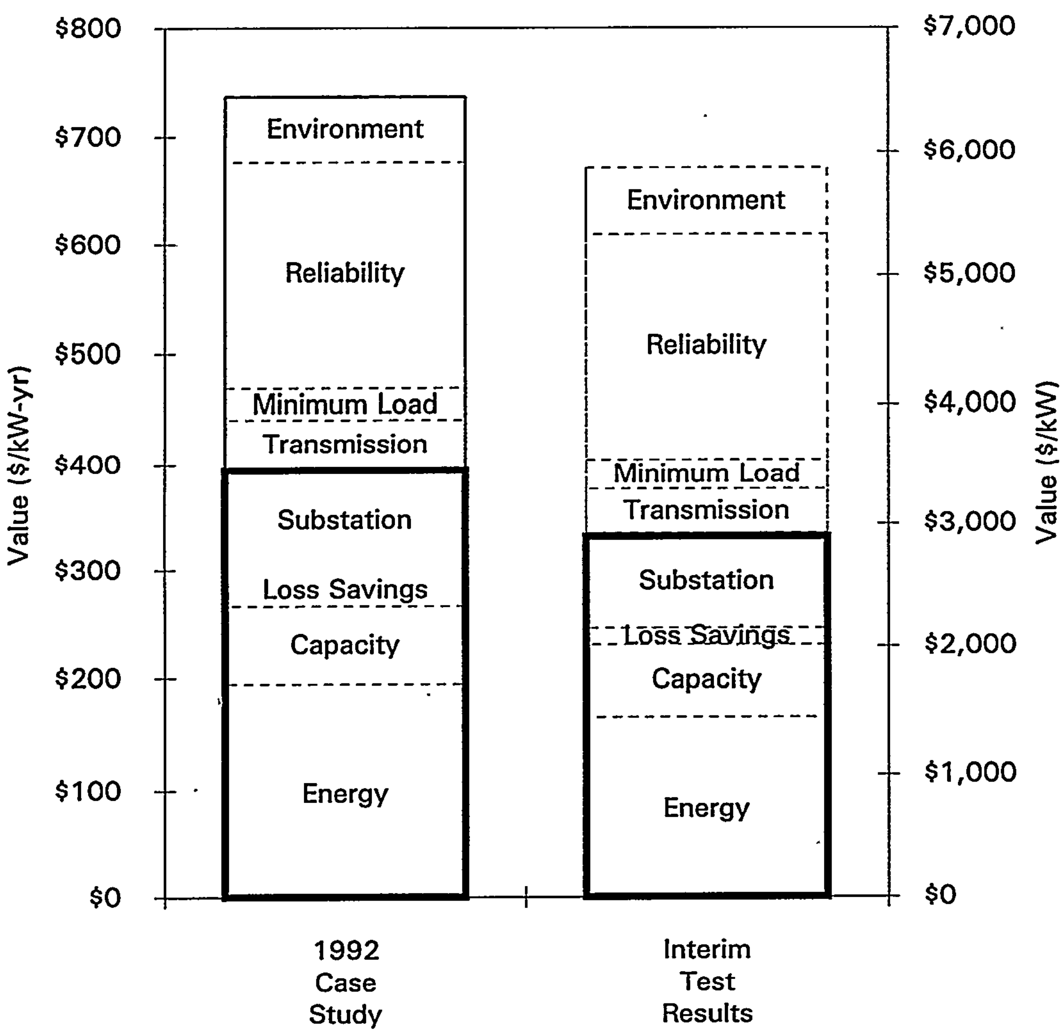


**Figure ES-1. 1992 case study and interim test results (year 1992 dollars).**

**Table ES-1**

**1992 Case Study and Interim Test Results (year 1992 dollars)**

| **Interim Value Components** | **1992 Case Study Estimates** ($/kW-yr) | ($/kW) | **Interim Test Results** ($/kW-yr) | ($/kW) | **Change** (%) |
|---|---|---|---|---|---|
| Substation | 99 | 861 | 88 | 765 | -11 |
| Loss Savings | 31 | 270 | 15 | 130 | -48 |
| Capacity | 72 | 626 | 65 | 565 | -10 |
| Energy | 194 | 1,687 | 166 | 1,443 | -14 |
| **Total Interim** | **396** | **3,444** | **334** | **2,903** | **-16** |
| **Remaining Value Components** | ($/kW-yr) | ($/kW) | | | |
| Environment | 62 | 539 | | | |
| Reliability | 205 | 1,782 | | | |
| Minimum Load | 28 | 243 | | | |
| Transmission | 47 | 409 | | | |
| **Total Remaining** | **342** | **2,973** | | | |
| **Grand Total** | **738** | **6,417** | | | |

**CAUTION: USE THE INTERIM RESULTS CAREFULLY**

The interim results are just that, interim. They must be used with caution for several reasons. First, the results are site- and utility-specific, and the economic methodologies have not yet been revisited. Second, data will be collected through testing and the site data acquisition system during 1994 allowing the reconfirmation of value components; therefore, the results are not final. Third, the results are not intended to project the break even price for economically viable grid-support systems.

Although the results are presented in net present value format, expressed in \$/kW, this does not reflect the PV break even price. In order to project the break even price, capital carrying charges (or cost of ownership) must be considered. Capital carrying charges account for such items as taxes, depreciation, and insurance.

These capital carrying charges vary depending on the utility's debt structure, accounting methods, and type of capital investment. For example, capital charges assumed in the 1992 Case Study increase cost (or reduce value) by about 13 percent. In addition, third party ownership will reflect much different capital carrying charges than most utilities, so the results are not universally applicable.

Finally, caution is urged since some evaluations in this report are performed using 1993 peak day data. No attempt to predict how close the 1993 peak day is to any long term average peak day is made. Variation in peak day may impact some results either positively or negatively. The 1993 peak load hour occurred on June 25 at 16:00 PST. The corresponding measurements at this peak hour are presented in Table ES-2.

**Table ES-2**

**Key Variables Corresponding to Kerman Peak Load Hour**

| | |
|---|---|
| Plant Output | 0.41 MW |
| Plane-of-Array Irradiance | 930 W/m$^2$ |
| Ambient Temperature | 42°C |
| Transformer Load | 9.53 MVA |
| Feeder Load | 4.52 MVA |

## UPDATED METHODOLOGIES

Updated and more rigorous methods were developed to evaluate several of the value components, including the transformer upgrade, transformer load tap changer, and real power loss savings. This was done because the methodologies in the 1992 Case Study were found to not be fully adequate.

The updated evaluation methods, described in the appendices, represent a valuable contribution to the field of grid-support PV in particular, and distributed generation in general, because they develop generic evaluation methodologies. By incorporating utility specific parameters, these methods can be used by other utilities. The reader is urged to study these appendices prior to applying the results from the Kerman analysis to other projects.

**FUTURE WORK**

The largest and most difficult value components that remain are reliability and environment. These are difficult to quantify because they do not directly accrue to the utility and there are presently no universally accepted evaluation methodologies. Identifying an acceptable methodology and determining the value will be a major area of focus in 1994. Also, the validation of 1992 Case Study economic evaluation methods will be completed, along with the technical validation of the remaining value components: Economic validation will be the second major area of focus. Finally, as a sensitivity, the value of modularity via an optimal investment approach will be investigated.

Several other activities are planned in 1994 relating to the Kerman project, including a full day review of Interim Test Results for the PVUSA Technical Review Committee, a two-day workshop on distributed PV generation, and publication of the Final Report in the fall.

Project Manager Brian K. Farmer

Brian K. Farmer

Research Director Jay H. Raggio

Jay H. Raggio

# CONTENTS

# FIGURES

# TABLES

Section 1

# INTRODUCTION

## BACKGROUND

A common practice of electric utilities experiencing transmission and distribution (T&D) system overloads is to expand the substation, add lines, or upgrade equipment, all of which are capital intensive options. In 1988, it was hypothesized that strategically sited photovoltaics (PV) could benefit (provide value to) parts of T&D systems near or at overloaded conditions. An evaluation methodology was developed and applied to a test case (Kerman Substation near Fresno, California). Analytical results, summarized in a report [1], suggested that the value of PV to the T&D system could exceed its energy and generation capacity value. This report is referred to as the 1992 Case Study.

The importance of this finding indicated the need for empirical validation. This led to the construction of a 0.5 MW PV demonstration plant by Pacific Gas and Electric Company (PG&E) at Kerman, California as part of the PVUSA (PV for Utility Scale Applications) project. PVUSA is a national public-private partnership that is assessing and demonstrating the viability of utility-scale photovoltaic electric generation systems. The Kerman PV plant, commissioned for commercial operation in June, 1993, is reported to be the first grid-support PV demonstration plant in the world.

## OBJECTIVE

This Interim Report focuses on validating the technical aspects of grid-support PV. It provides interim validation results for four of the eight identified value components that stack up to make the "value bar", and compares them to 1992 Case Study estimates. Results are based on improved technical evaluation methodologies, measured plant performance under a variety of conditions, and long-term plant performance estimated using a validated computer simulation program.

## ECONOMIC ASSUMPTIONS

The report uses the same economic methods and input assumptions as in the 1992 Case Study to facilitate comparison of results. For example, the interim test results use the same rates of inflation and cost of capital as well as the economic methods to compute value. All results are expressed in 1992 dollars. Validation of the economic evaluation methodologies and updating the results to the present will be included in the final report.

## PRESENTATION OF RESULTS

Economic results throughout the report are presented in two formats: levelized annual revenue requirements and net present value. Levelized annual revenue requirements, expressed as $/kW-yr, is an average of the actual year-by-year revenue requirements necessary to recoup all plant-related investments and expenses including a reasonable return. It represents the stream of equal annual payments equivalent to the actual revenues the company expects to receive. Net present value, expressed as $/kW, is the present value of the cash flows generated by the project. Based on the 1992 Case Study values of 11 percent cost of capital and 30 year life, it equals 8.694 times the levelized annual revenue requirement.

## REPORT STRUCTURE

Sections 2, 3, 4, and 5 of this interim report describe the four validated value components as they appear in Figure ES-1; namely the value to the substation, loss savings, generation capacity value, and energy generation value.

Each of these four sections is organized according to the following five-part format: first, a brief description of the value component is given; second, the 1992 Case Study and interim report evaluation methodologies are discussed and compared; third, actual tests performed at the plant and data collection requirements are described; fourth, results are presented; and fifth, interim tests results are compared to 1992 Case Study results and the differences are discussed.

Section 6 presents highlights of the computer simulation validation. Since the Kerman plant was interconnected in May and passed acceptance testing in June, 1993, there is not adequate measured data available to evaluate distributed generation value components that require a full year of plant performance data. For this reason, a computer model, PVGRID, is used to simulate plant performance for some of the value components. This section details the validation of the model using measured plant performance data, and provides an overview of PV plant performance.

Section 7 presents conclusions and Section 8 describes future activities.

## UPDATED METHODOLOGIES

In terms of the evaluation methodologies, updated methodologies were developed for several of the value components, including the transformer upgrade, transformer load tap changer, and real power loss savings. This was done because the methodologies in the 1992 Case Study were found to be not entirely adequate. Although extensive work has been invested in updating the methodologies, only highlights of the work are presented in the body of the report. Detailed descriptions of work performed are provided in the appendices.

These appendices represent a valuable contribution to the field of grid-support PV in particular, and distributed generation in general, because they develop generic evaluation methodologies. By incorporating utility specific parameters, these methods can be used by other utilities. The reader is urged to study these appendices prior to applying the results from the Kerman analysis to other projects.

## COMPARISON TO 1992 CASE STUDY RESULTS

A key difference between the interim test results and the 1992 Case Study results is attributable to plant performance and weather data assumptions. The differences are not due to under performance on the part of the PV plant. In fact, measured plant data compared to validated model results indicate that the Kerman PV plant is operating close to the system supplier's design.

Rather, the 1992 Case Study overestimated plant performance and thus value. This is principally due to the use of hourly weather data taken from San Benito, located about 60 miles southwest of Kerman at an elevation of 1500 feet. These data were used to calculate plant performance.

San Benito has a significantly better solar resource and a more moderate ambient temperature regime relative to the Kerman area. This explains a large part of the difference in results in this interim report as compared to the 1992 Case Study. Much of the remaining difference is due to plant design assumptions and improved technical evaluation methodologies.

Section 2
# VALUE OF DISTRIBUTED GENERATION TO THE SUBSTATION

The value of grid-support PV to the substation is defined to include the transformer upgrade deferral value as well as the value of the PV to voltage regulation devices. In the case of the Kerman Substation, voltage regulation devices include the transformer load tap changer and other voltage regulation devices on the feeder.

## EXTEND DISTRIBUTION TRANSFORMER LIFE

### Value Description

Grid-support PV can defer a substation transformer upgrade by supplying power on the low voltage side of a transformer during peak usage. The reduced transformer load results in decreased transformer temperatures, thus yielding longer life. A cooler transformer can accommodate additional load growth and enable the utility to defer purchase of a new transformer until fully needed.

### Evaluation Methodology

Although the 1992 Case Study performed preliminary analyses of the effect of PV output on transformer temperature using a transformer temperature model (see Appendix E.6.6 in the 1992 Case Study), the results were inconclusive. Rather, the transformer upgrade deferral value was based on the assumption that a "500 kW PV system could absorb load growth of 100 kW per year for a period of five years before a transformer upgrade would be necessary" (see page 4-5). This implies that PV plant output was expected to be 0.5 MW during the peak hour of the year. Thus, to obtain a five year deferral, one merely divides 0.5 MW of output by 0.10 MW per year of load growth. For simplicity, this is referred to as the peak load reduction method.

There are two short comings with this method. First, it does not account for the fact that, although rated at 0.5 MW, a PV plant may not produce 0.5 MW during peak conditions.[1] This is due to the high temperatures typically associated with peak load conditions as well as insolation conditions that may be lower than full sun. Second, this method fails to account for the fact that peak load is not the only factor affecting transformer temperature. That is, there is not a one-to-one relationship between peak load and transformer temperature.

[1] The Kerman PV plant is rated at 0.498 MW at PVUSA Test Conditions (PTC), based on plant output and site weather data measured over a pre-assigned rating period. PTC is defined as 1000 W/m$^2$ plane of array irradiance, 20°C ambient temperature and 1 m/sec windspeed.

To address the 1992 Case Study short comings, a new method was developed. It is called the allowable load increase method. It is based on the year's peak load day and on the reduction in transformer temperature as a result of a reduction in loads throughout the day on this peak day. It uses measured PV plant output and measured transformer load with the PV plant on-line; transformer load with PV off-line is determined by adding PV plant output (plus loss savings) to transformer load with the PV plant on-line.

Allowable load increase is determined by computing transformer hottest-spot temperature on the peak day of the year for transformer load with PV off-line using an IEEE transformer temperature model. This calculation is repeated for transformer load with PV on-line. The load with PV on-line is then increased until it has the same maximum hottest-spot temperature as the load with PV off-line. Allowable load increase is the amount that the load with PV on-line is increased. Allowable load increase is converted to years of deferral by dividing by an annual load growth estimate. The model, evaluation method, and results are presented in detail in Appendix A.

**Testing and Data Description**

As stated above, the allowable load increase method is based on transformer temperature. It is not sufficient, however, to simply turn the PV plant on and off and measure a temperature reduction because there is a long thermal time constant associated with substation transformers. Rather, the effect of PV output on transformer temperature must be estimated using a model. The IEEE has developed a detailed model for loading power transformers [2]. This model is referred to as the IEEE model.

The IEEE model simulates top-oil temperature and hottest-spot temperature rise over top-oil temperature. Top-oil temperature is the highest oil temperature in the transformer. Hottest-spot temperature rise over top-oil temperature is the greatest temperature rise anywhere in the transformer over the top-oil temperature. It is crucial that this model reflects reality as closely as possible since PV plant output is small (0.5 MW) compared to the transformer's rating (10.5 MVA).

Transformer top-oil temperature has been continuously monitored at the Kerman Substation since 1991. This extensive data base facilitates evaluation of the accuracy of the IEEE model. Simulated top-oil temperatures were compared to measured top-oil temperatures under a range of conditions. These conditions included seven peak days in 1991 and ten peak days in 1992. In addition, the PV plant was cycled on and off five times over the course of three hours on July 1, 1993, thus enabling the evaluation of how responsive the IEEE model is to load changes.

Results of the testing showed that the IEEE model needed slight modifications. First, the original model was modified to include a time lag in the effect of ambient temperature on top-oil temperature. Second, two of the transformer-specific parameters were altered. After these changes, it was found that simulated top-oil temperature was a good estimate of measured data. Figure 2-1 compares simulated with measured top-oil temperature for the 1991 peak day; results are similar for other peak days in 1991, 1992, and 1993. Details of the model validation are presented in Appendix A.

It is assumed that the model accurately simulates hottest-spot temperature rise over top-oil temperature because hottest-spot temperature data were inaccessible.

**Results**

The 1993 peak occurred on June 25. Figure 2-2 presents measured PV plant output and measured transformer load with the PV plant on-line on this peak day. The dashed line represents what the load would have been without the PV plant.

Measured data on the peak day of the year, including load, PV plant output, and ambient temperature, are input into the IEEE model to simulate transformer hottest-spot and top-oil temperatures. Figure 2-3 presents the transformer hottest-spot and top-oil temperatures with and without the PV plant. Results indicate that the PV plant reduced the maximum hottest-spot temperature by 4°C. Half of this reduction comes from a lower top-oil temperature (a result of decreasing the load throughout the day) while the other half comes from a reduction in hottest-spot temperature (a result of a lower peak load).

A 4°C temperature reduction corresponds to an allowable load increase of 0.41 MW. That is, as illustrated in Figure 2-4, the load with the PV plant on-line can be increased by 0.41 MW throughout the day and have the same maximum hottest-spot temperature as the load without the PV plant.[2]

Deferral value equals the cost savings due to postponing a capital investment. Neglecting the extra salvage value at the end of the study period, deferral value is the difference between the cost of a transformer today and the cost of a transformer at some point in the future (this assumes that the transformer needs to be upgraded immediately). Since the PV plant allows for an additional 0.41 MW of load growth at all hours throughout the day and load growth is assumed to be 0.1 MW per year as in the 1992 Case Study, the PV plant defers the transformer upgrade 4.1 years. This corresponds to an economic value of $75/kW-year ($651/kW).

[2]An alternative method to model load growth is to scale the load proportionately rather than having the same incremental load increase for all hours of the peak day. Both approaches will yield approximately the same result.

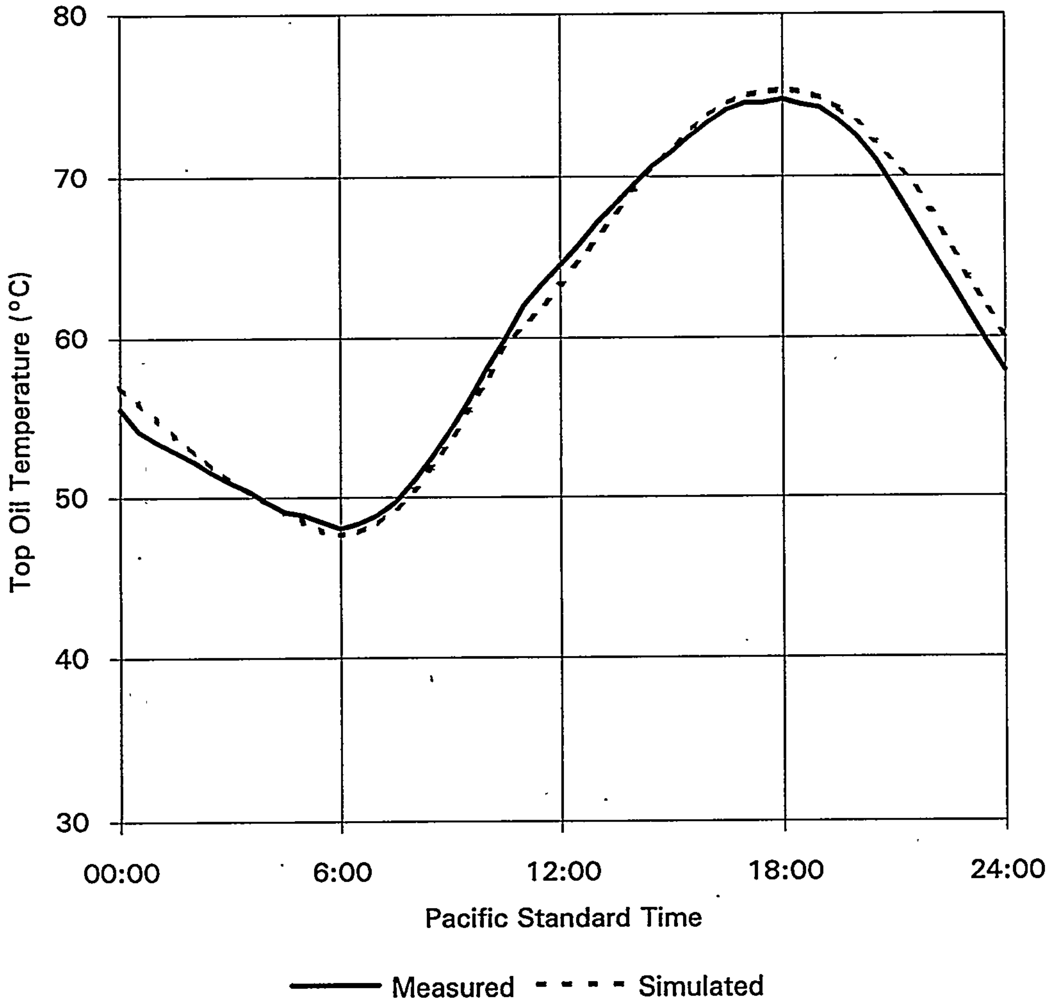


**Figure 2-1. Measured and simulated transformer top-oil temps. (July 3, 1991).**

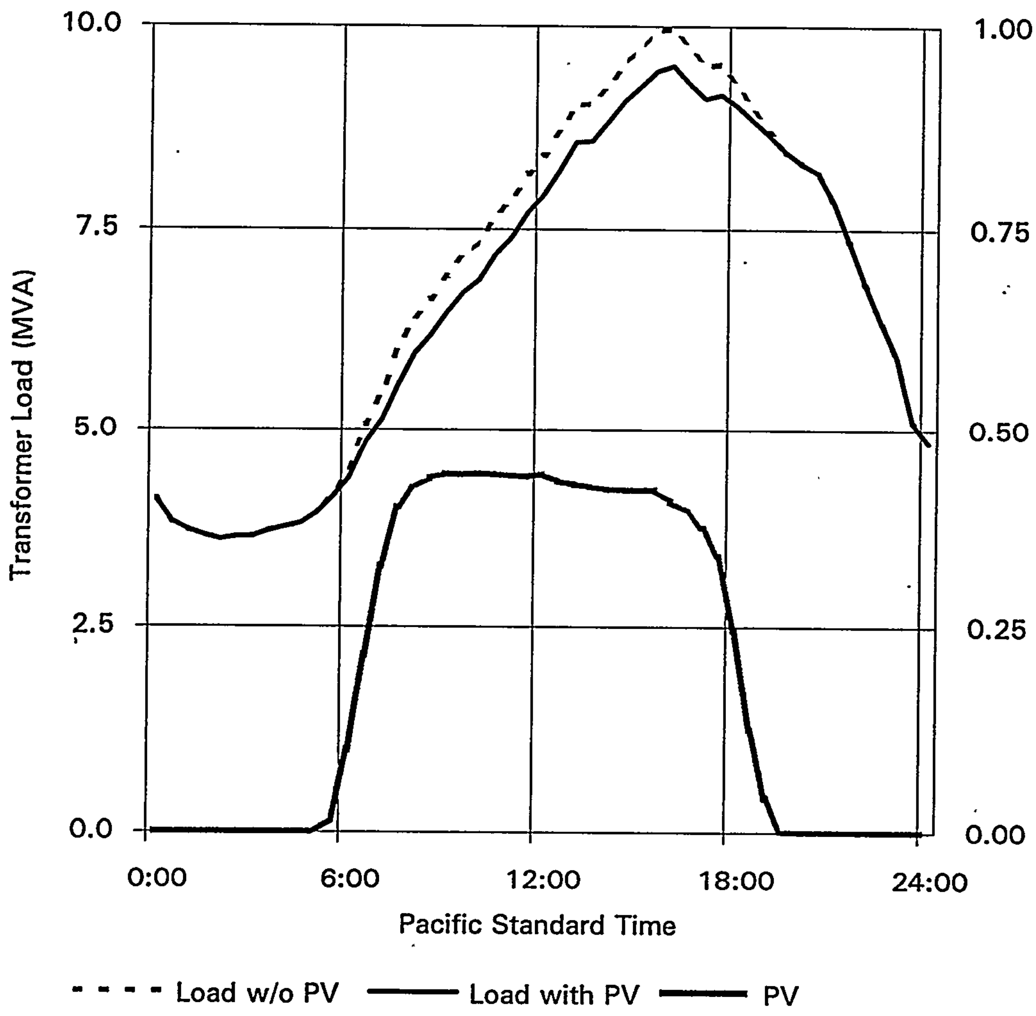


**Figure 2-2. Transformer load and PV output on 1993 peak day (June 25, 1993).**

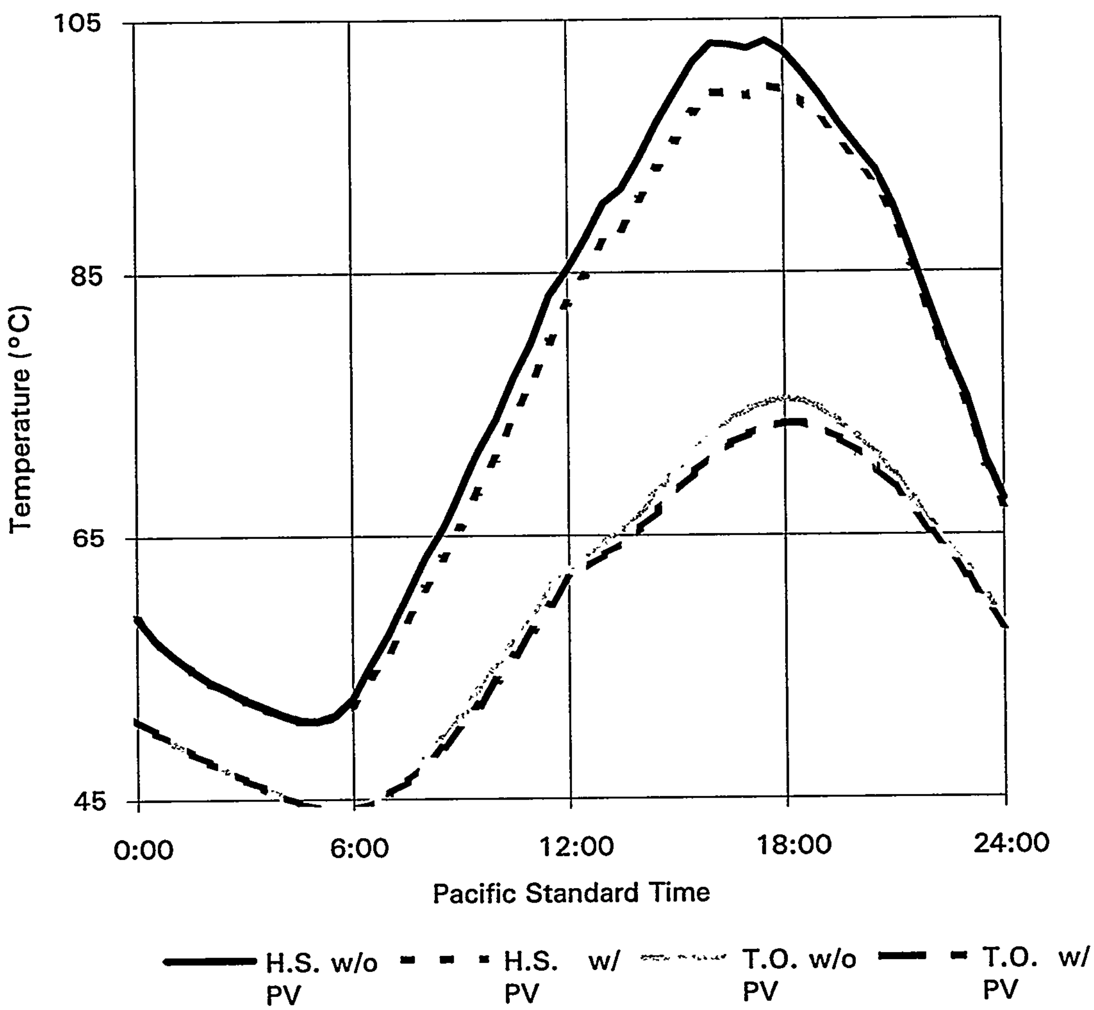


**Figure 2-3. Transformer temps. before allowable load increase (June 25, 1993).**

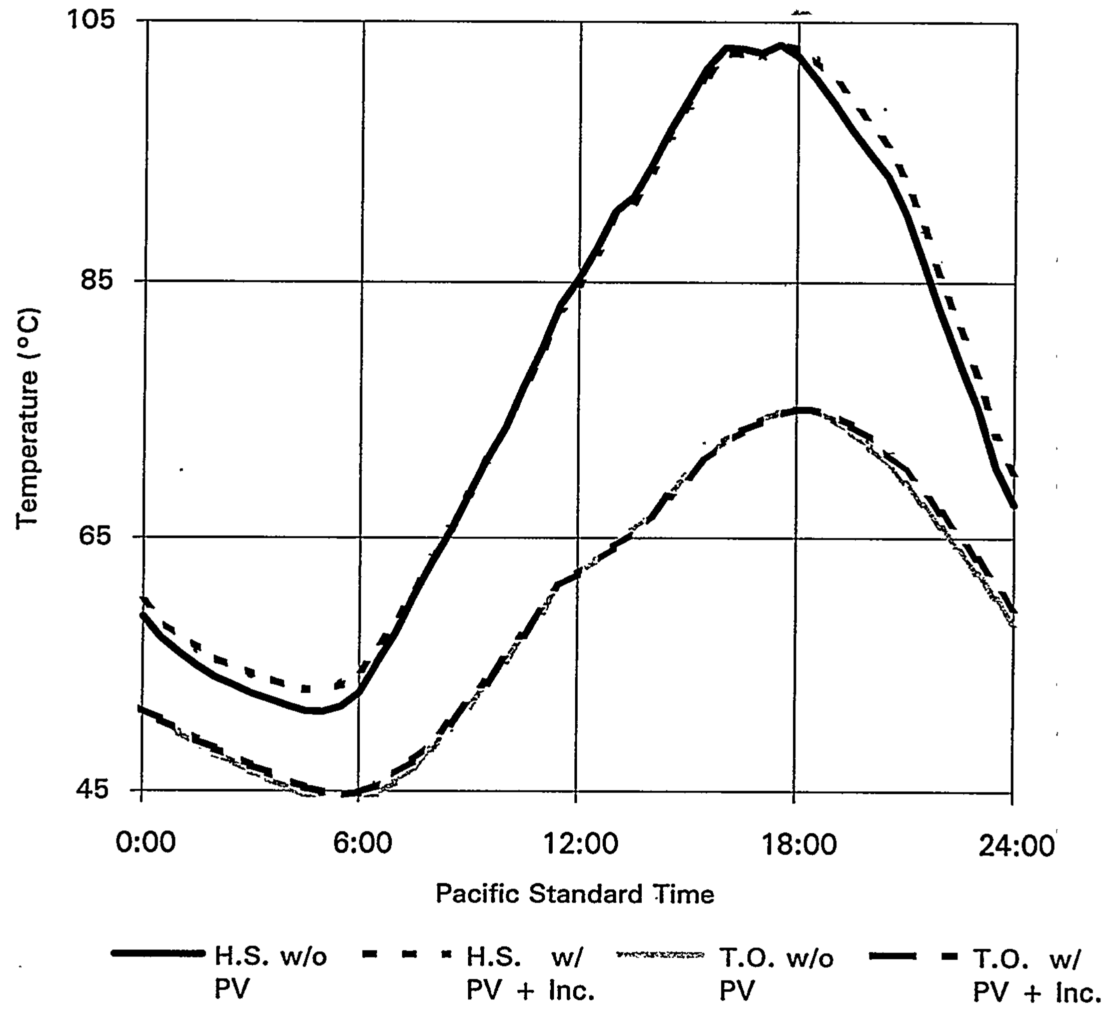


**Figure 2-4. Transformer temps. after allowable load increase (June 25, 1993).**

### Discussion

The 1992 Case Study estimated that the PV plant would defer the transformer upgrade for 5 years for a value of $89/kW-yr ($774/kW). Thus, the new estimate is 16 percent lower than the 1992 Case Study value. Although different methodologies are used, this is not the primary source of difference between the 1992 and current estimates. The primary difference is in PV plant output during the peak load. The 1992 Case Study assumed that the PV plant would produce 0.5 MW during the year's peak load. In reality, plant output was only 0.41 MW at the time of the 1993 peak (16:00 PST). This is due to a 42°C ambient temperature and 930 Watts/m$^2$ irradiance.

One of the important results of this section is that the allowable load increase method should be broadly applicable at other utilities. A substantial amount of effort has been invested in evaluating the IEEE transformer temperature model's ability to reflect reality. After slight changes, the model appears to be accurate in field conditions. This model, combined with the required transformer specific parameters, can be applied by other utilities to perform a similar analysis as performed for the Kerman Substation (see Appendix A for a detailed list of transformer characteristics required to perform the analysis. Default values for the Kerman transformer are included.) It is worth mentioning, however, that the peak load reduction approach is probably valid as a first order approximation for small sizes of PV plants. Accurate estimates of PV plant output on the peak day, however, are crucial to both methods.

## EXTEND LOAD TAP CHANGER MAINTENANCE INTERVALS

### Value Description

A load tap changer (LTC) is located on the low voltage side of a substation transformer. It regulates voltage for one or more distribution feeders to compensate for voltage drop on the worst feeder. Grid-support PV reduces the number of LTC operations (called LTC changes in this report) thus reducing LTC maintenance cost.

### Evaluation Methodology

LTC operation is based on LTC voltage, capacitor banks on the feeder, LTC voltage settings, and the variation in feeder load. The 1992 Case Study hypothesized that LTC changes are linearly related to transformer load variation and a PV plant reduces this variation. This hypothesis is evaluated by characterizing the relationship between LTC changes and load variation and calculating the PV plant's reduction in this variation.

Another hypothesis, which was developed during PV plant testing, is that LTC changes are a function of feeder voltage support requirements and a PV plant reduces these requirements by providing feeder voltage support. This hypothesis is evaluated by determining the voltage support provided by a PV plant and then calculating the impact of this support on LTC changes.

Evaluation of this second hypothesis is assisted by the development of two models. Both of these models are described in detail in Appendix B. The first model describes voltage support on a feeder. This model, which is based on engineering principals of voltage drop on a feeder (i.e., $\Delta V=IR$), predicts that voltage support at any particular feeder location is the product of PV plant output and conductor resistance between the transformer and the point at which the lateral is attached to the line between the transformer and PV plant. Most importantly, this means that voltage support is independent of feeder current. (Note that this does not mean that *voltage* is independent of feeder current). In addition, only a portion of the feeder's resistance (i.e., not all the way to the point of interest) is of consequence.

The second model describes the relationship between LTC changes and the voltage range settings of the LTC. This model was empirically derived and includes a non-linear relationship between LTC changes and LTC voltage range setting.

**Testing and Data Description**

Evaluating the first hypothesis required no special tests. The second hypothesis, however, required measuring voltage support provided by the PV plant at various locations on the feeder. These data were collected during testing for reliability data. Unfortunately, only voltage measurements were taken at these locations; current measurements were not taken.

Field tests of Kerman Feeder 1103 were performed on July 6, 1993, to quantify the voltage support provided by the 0.5 MW PV plant. Feeder voltage was measured under a variety of load conditions by having the distribution system operator transfer load to and from adjacent feeders to the Kerman Feeder 1103. Feeder load conditions got so high during this day that the peak load on July 6, 1993, was 20 percent greater than any other feeder load during normal conditions in 1993. Appendix B presents additional feeder load condition details.

Feeder voltage was measured manually at three critical feeder locations by field personnel. The distribution system operator took the PV plant off-line, field personnel measured three phase voltage, the distribution system operator put the plant back on-line, and field personnel remeasured the voltage. It took about 15 minutes between the first and last voltage measurements. Feeder current was not monitored at each location; rather, it was monitored every minute on only one phase at a location other than where the voltage measurements were taken.

In addition to the manual measurements, voltage was monitored automatically at the PV plant. Figure 2-5 presents the voltage support (measured and predicted by the model mentioned above) provided by the PV plant at the plant location as a function of plant output and feeder load. The figure includes data collected on July 1, 1993 (the plant was cycled on and off on this day) in addition to July 6, 1993. The figure suggests that voltage support is linearly related to PV plant output and is *independent of feeder load* as predicted.

Figure 2-6 presents the results of the voltage support measurements along the feeder. The single line diagram in the figure is drawn to scale and shows where the three manual and one automatic voltage measurements were made (they are marked with a box). The solid line is the predicted voltage support based on a 0.4 MW plant output.

As stated above, only voltages were measured at the various locations. Since it took 15 minutes to measure the change in voltage, feeder current could have changed in addition to the current change caused by switching the PV plant on and off. Current was measured, however, on only one phase at a location different than where the voltage measurements were made. For this reason, Figure 2-6 presents the results for only one phase. The phase was selected based on how well it correlated with the current measurements. Most of the measurements had a load reduction of about 0.4 MW when the plant was put on-line. The points corresponding to feeder loads of 4.4 MW and 5.9 MW had smaller load reductions; these data points are scaled up to reflect this.

Although not a perfect relationship,[3] the figure suggests that it is the location at which the lateral is connected to the line between the transformer and PV plant rather than the distance from the transformer to the point of interest that determines the level of voltage support provided by the PV plant. The analysis of these data are presented in greater detail in Appendix B.

The relationship between LTC changes and voltage support (and thus LTC voltage range setting) must be understood to translate PV voltage support to a reduction in LTC changes. Figure 2-7 presents the measured number of LTC changes for 1990 (voltage range setting of 3.8 volts), 1991 and 1992 (voltage range setting of 5.0 volts), and 1993 (voltage range setting of 2.5 volts). All points represent a year's worth of data except 1993, which is based on 40 percent of the year and scaled to an annual estimate. Notice that the measured points lie on a non-linear curve as suggested by model results.

[3] The differences may be explained by the lack of current (ampere) measurements at each voltage location to accurately determine the change in load between voltage measurements.

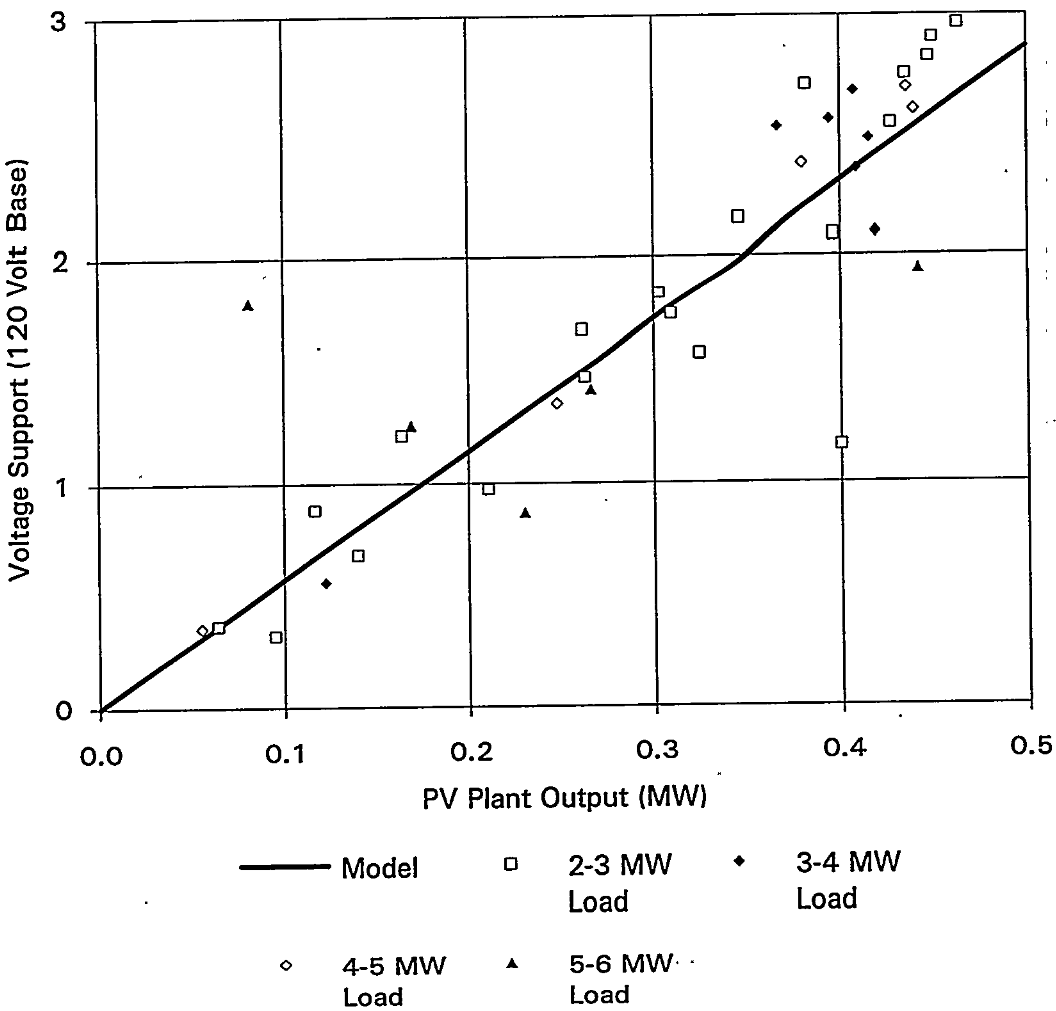


**Figure 2-5. Linear relationship between voltage support at PV plant and output.**

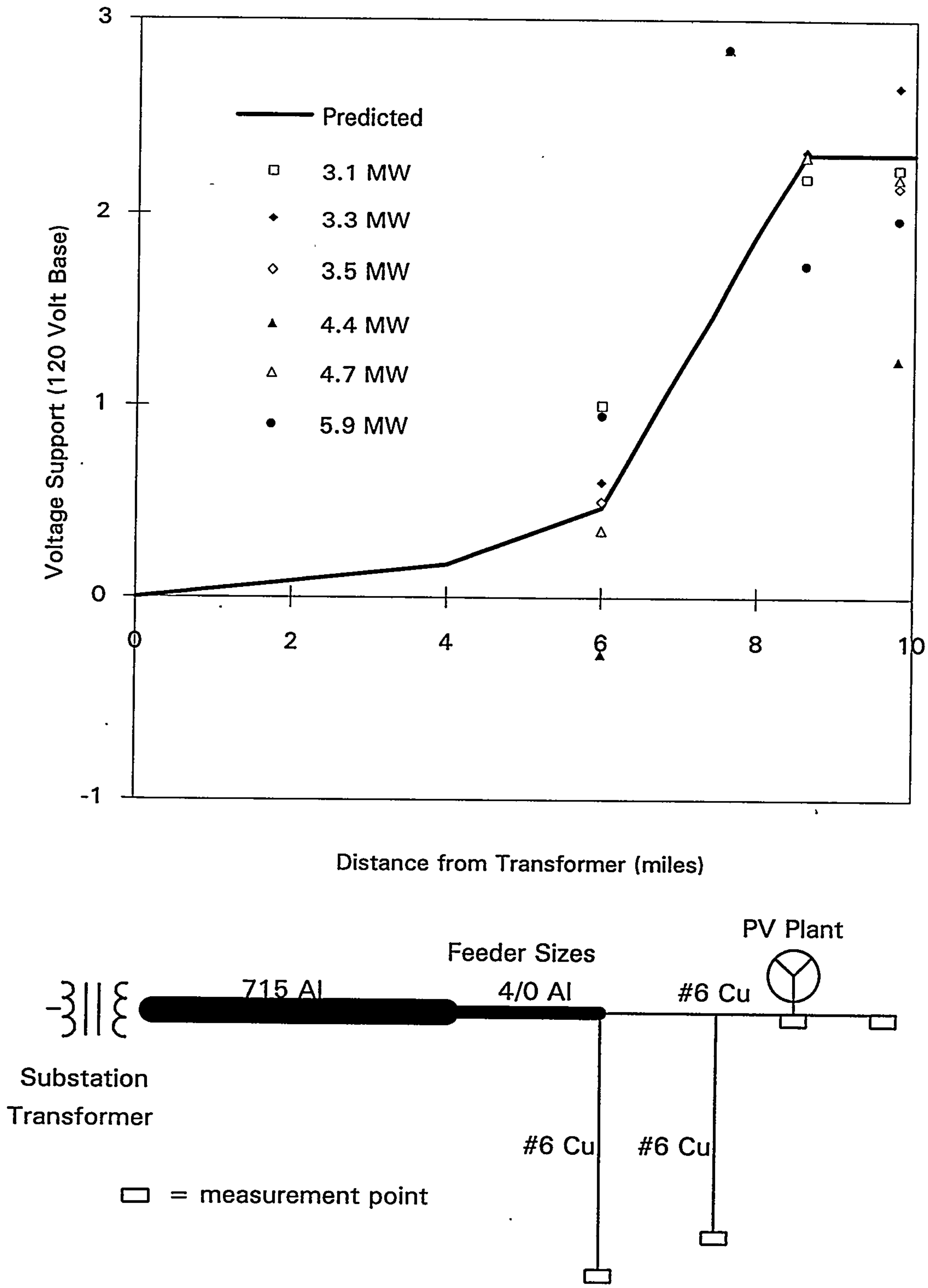


**Figure 2-6. Voltage support provided by PV is function of distance from substation.**

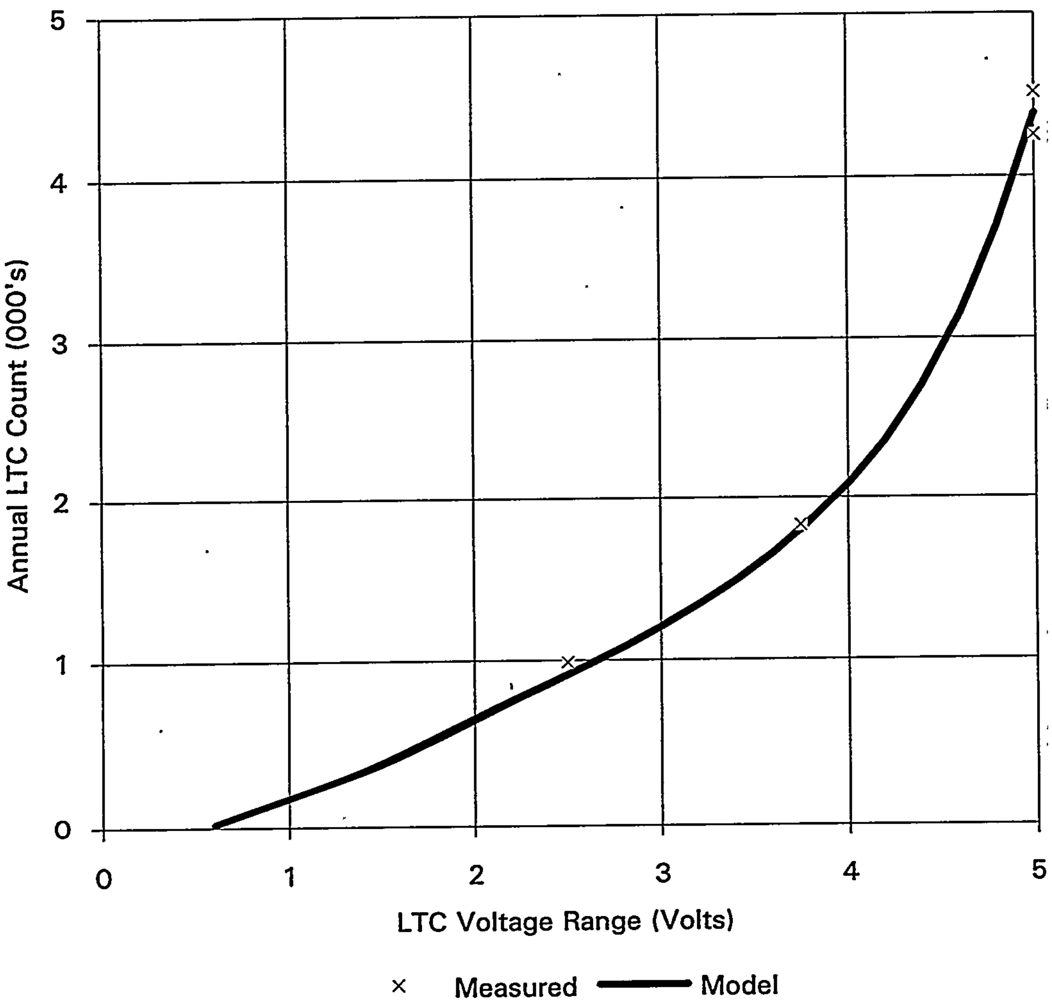


**Figure 2-7. Annual LTC changes as a function of LTC voltage range setting.**

## Results

The 1992 Case Study hypothesized that LTC changes are linearly related to transformer load variation and a PV plant reduces this variation. Measured transformer load data and historical LTC-changes data tend to confirm that LTC changes are linearly related to load variation. In terms of the PV plant's reduction in load variation, however, results indicate that the 0.5 MW PV plant only reduced load variation by about 2 percent. That is, the PV plant's reduction in load variation has an inconsequential affect on extending LTC maintenance intervals.

Measured data, however, did confirm the second hypothesis. As a result of the voltage support provided by the PV plant, the distribution planner for the Kerman area reduced the voltage support provided by the LTC from a 5 volt boost at full load to a 2.5 volt boost at full load.

The 1992 Case Study assumed that PG&E performs maintenance after 20,000 LTC changes and that the base case is a five year maintenance interval. Thus, as a result of the new LTC voltage setting and the non-linear relationship between the voltage setting and number of LTC changes, the frequency of the maintenance interval is changed from 5 years to 18 years. This translates to a new economic value of \$11/kW-yr (\$98/kW). It is assumed that the 1992 Case Study estimate of value to other line devices of \$2/kW-yr (\$19/kW)[4] is correct. Thus, the total value for voltage regulation devices is \$13/kW-yr (\$117/kW).

### Discussion

The 1992 Case Study estimated that the maintenance interval would increase from 5 years to 7 years. The economic value of this was estimated to be \$7/kW-yr (\$57/kW). This estimate, however, appears to have double counted inflation. Thus, the 1992 value is adjusted to \$4/kW-yr (\$38/kW) (or \$6/kW-yr when value to other line devices is included). Thus, the interim test results are 257 percent of the adjusted 1992 value.

The difference between these two values lies in the fact that the reason there is value to the LTC is different than initially anticipated. The 1992 Case Study anticipated that the PV plant would reduce the load variation and thus, the number of LTC changes. Although correct, the effect is minimal and has almost no value. Interim test results show that the PV plant is of value not because it reduces the load variation, but because it provides voltage support that the LTC no longer needs to provide.

[4] This value has been adjusted to reflect double counting of inflation.

## Section 3
# LOSS SAVINGS

Loss savings are divided into two parts: real power loss savings and reactive power loss savings. Real power loss savings are classified as either capacity or energy loss savings. Capacity loss savings lessen the need for capital upgrades by reducing peak loads on distribution, transmission, and generation system equipment. The value of capacity loss savings is the savings in finance charges that result from postponing a capital investment until a future date. The value of this loss savings is incorporated into the other value components, such as the deferral value of substation transformers. Energy loss savings reduce electricity generation requirements. Energy loss savings value is the cost savings realized by reducing operation and maintenance expenses of existing generation plants.

Reactive power loss savings are only of the capacity type. Specifically, they reduce a utility's need for capacitors.

## REAL POWER LOSS SAVINGS

### Value Description

Real power losses occur as current flows through conductors, transformers, and other transmission and distribution system devices. The magnitude of the losses is related to current flow and resistance of the devices. Grid-support PV can reduce losses because it reduces line current by serving some of the load locally.

### Evaluation Methodology

The 1992 Case Study based all loss savings results on loss savings estimates during one set of peak load conditions. That is, loss savings were only calculated for the peak hour of the year. Feeder loss savings were calculated using PG&E's FDRCAL program while transformer loss savings were estimated based on transformer resistance. Transmission system loss savings were determined using the General Electric Optimal Power Flow program maintained by PG&E's Transmission Planning Department. The 1992 Case Study states on page 2-10 that "the peak loss reductions are converted to annual energy savings using the system LDC [load duration curve]. Specifically, the peak loss reduction in kilowatts is multiplied by the square of the normalized load duration curve." It appears, however, that this conversion was not performed.

The 1992 Case Study approach can be improved in two areas. First, it bases all of the loss savings results on one set of peak load conditions. This fails to account for the potential that the PV plant may at times actually increase power losses on a feeder rather than reduce them. For example, PV output could increase the amount of current flowing through high resistance sections of the feeder during off-peak conditions. Second, since it uses all 8,760 hours worth of load data (i.e., every hour in the year) to scale peak loss savings to annual energy loss savings, times when the PV plant is not operating and thus has no impact on loss savings (e.g., night time) are included in the analysis. These hours have no effect on loss savings.

For these reasons, feeder and transformer loss savings were determined by developing a loss savings model; transmission system loss savings (both capacity and energy) were assumed to be the same as in the 1992 Case Study. The feeder and transformer loss savings model is based on the engineering principal of $I^2R$ losses. The model is a function of feeder load, distribution of load along the feeder, feeder resistance, and PV plant output.

There are two important characteristics of the model. First, the only condition when the distribution of load on the feeder has no impact on loss savings is when feeder load is zero. At this point, loss savings are negative and simply equal the square of the PV plant output current times feeder resistance. From a graphical perspective, this means that the y-intercept of a plot of loss savings versus feeder load is known with certainty. Second, loss savings are linearly related to feeder load given some distribution of load on a feeder at a constant PV plant output. The loss savings model development and application are presented in detail in Appendix C.

**Testing and Data Description**

The feeder loss savings model is validated as follows. Four sets of loss savings tests were performed (one on July 22, 1993 and three on August 24, 1993) by turning the plant on and off and measuring feeder load at the substation with the PV plant *on-line* and *off-line* (this was repeated at least eight times for each set of tests). Loss savings achieved over the entire distribution line is the difference between load with PV *off-line* and the sum of load with PV *on-line* and PV output.

Figure 3-1 presents the feeder load during one of the tests. Each horizontal line represents 10 kW; this is the magnitude of the expected loss savings at a 3.5 MW feeder load and 0.40 MW PV plant output. Notice that there was a one second delay between the time the PV plant was taken off-line and the time the load stabilized at its new value. This is due to the fact that the measurement device (transducer) required a half second to stabilize once the plant was turned off. In addition, the plant was turned off in two phases with a half second delay between phases.

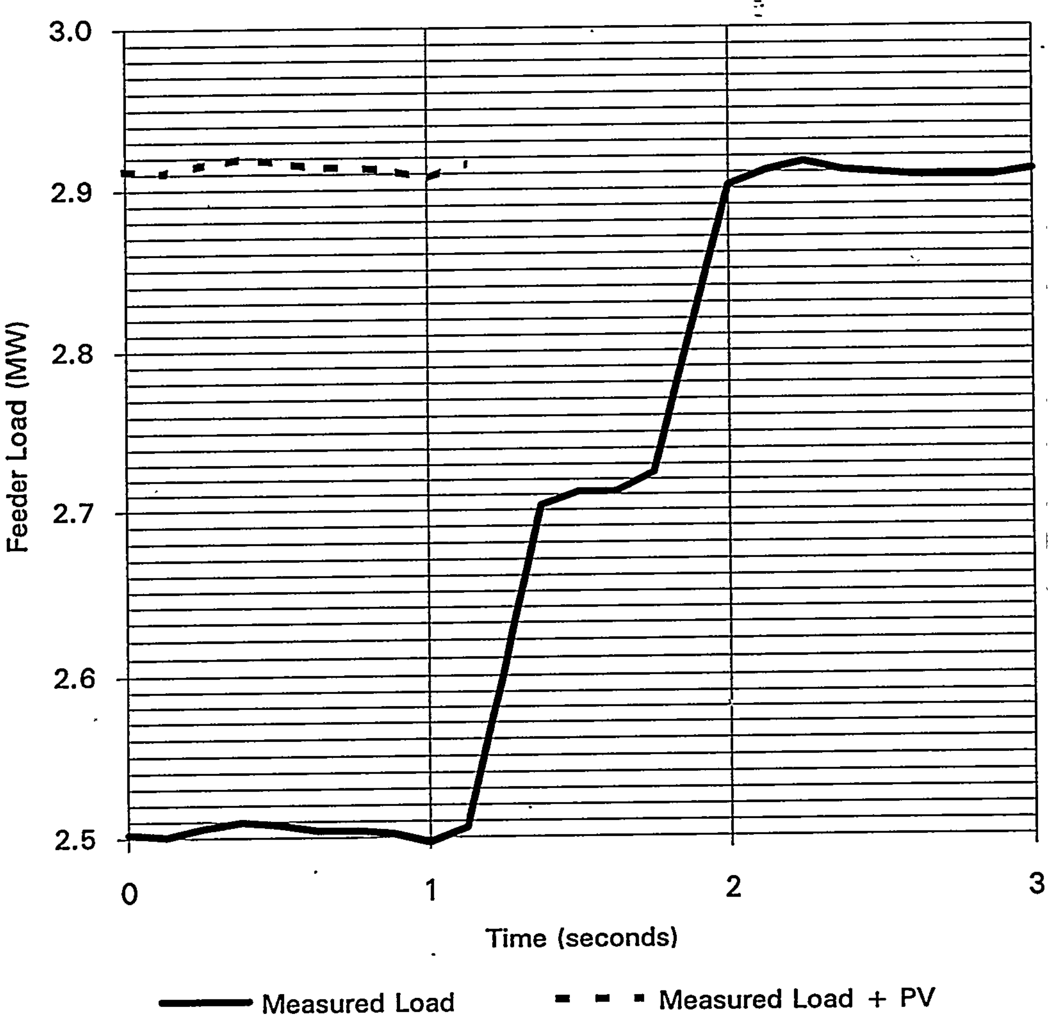


**Figure 3-1. Feeder load when PV plant is taken off-line.**

One observation from this data is that the loss savings are very small relative to feeder load and thus are difficult to measure. For example, using the loss savings model mentioned above, loss savings are anticipated to be about 5 kW (.005 MW) for a 2.9 MW feeder load and a 0.40 MW PV plant output. This represents a value that is less than 0.2 percent of feeder load.

Figure 3-2 presents the loss savings test results for all tests after screening out data that included obvious load instabilities. Each horizontal line represents 10 kW as in Figure 3-1; that is, Figure 3-2 spans a range of 60 kW while Figure 3-1 spans 500 kW. Since PV plant output was fairly constant at 0.40 MW during the testing, the solid line is the predicted loss savings for a plant output of 0.40 MW at various feeder loads; the x's are the average of the measured loss savings for each of the four sets of tests; the dots are the individual loss savings measurements. Data used to develop the "predicted line" in Figure 3-2 are specific to Kerman Feeder 1103. These data are presented in Appendix C.

As pointed out above, the y-intercept of the predicted loss savings line is known with certainty and, given a fixed distribution of feeder load and PV plant output, the predicted loss savings must be linear with feeder load. Considering the time delay required to perform loss savings measurements (more than one second) and the magnitude of the loss savings to be measured (between 0.2 and 0.3 percent of feeder load for the tests performed), measured data tend to validate the model.

**Results**

Capacity loss savings at the transformer equal the sum of feeder and transformer loss savings. The 1993 feeder and transformer peaks occurred coincidentally on June 25 at 16:00 PST. Using the validated model and feeder resistance, estimated load distribution on the feeder, and transformer resistance, feeder loss savings were estimated to be 17 kW and transformer loss savings were estimated to be 6 kW. Thus, total loss savings on the feeder and the transformer were 23 kW, or 5 percent of the PV plant rating. These savings are incorporated into other value components, such as the substation transformer and generation capacity values.

Annual energy loss savings equal the sum of feeder, transformer, and transmission system loss savings. Feeder and transformer loss savings were estimated using the validated model and measured transformer loads, measured feeder loads, and simulated PV plant output based on measured weather data for each hour of the year. That is, feeder and transformer loss savings were calculated for 8,760 hours using measured data. Note, however, that the model accounts for the fact that loss savings equal zero whenever PV plant output is zero. Thus, many of the 8,760 hours are zero and are effectively excluded from the analysis. Details of this calculation are presented in Appendix C.

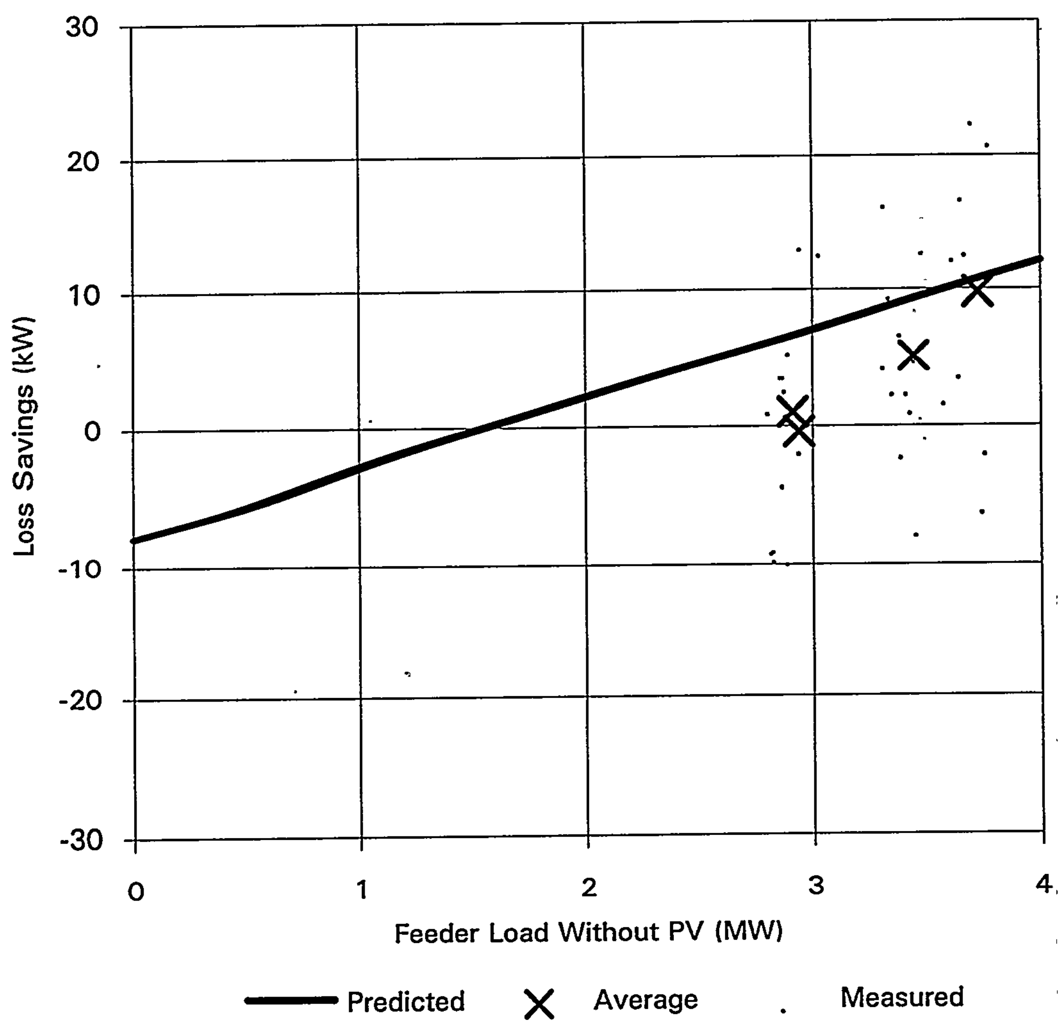


**Figure 3-2. Measured and predicted feeder loss savings.**

Feeder and transformer loss savings equal 28,500 kWh, or 2.6 percent of the plant's annual energy production. Transmission system loss savings were not verified but were based on the 1992 Case Study and are estimated to be 33,500 kWh. This is a total of 62,000 kWh/year for an economic value of $9/kW-yr ($76/kW).

**Discussion**

The 1992 Case Study estimated peak feeder and transformer loss savings to be 38 kW as opposed to the updated value of 23 kW. Most of the difference is due to the fact that the 1992 Case Study anticipated that the PV plant would be operating at 0.5 MW during the time of the peak as opposed to the actual value of 0.41 MW. In addition, the 1992 Case Study assumed that the peak loads would be 20 percent higher than they actually were. Some of the difference is due to a different plant location than was assumed in the 1992 Case Study.

The 1992 Case Study predicted annual energy loss savings of 96,000 kWh per year for a value of $21/kW-yr ($183/kW). Thus, the estimate for this interim report is 60 percent less than the 1992 Case Study. Part of the difference is that the 1992 Case Study anticipated that the PV plant would have a higher annual capacity factor. Another part of the difference is that the 1992 Case Study calculated loss savings based on a different plant location. Adjusting for both of these factors, however, it is still estimated that the loss savings would be 40 percent less than the 1992 Case Study value. Part of the remaining difference is probably because the peak results were not scaled to annual energy loss savings results using the LDC approach mentioned above. Another part is due to the difference in methodologies.

## REACTIVE POWER LOSS SAVINGS

**Value Description**

Utilities strive to maintain adequate voltage in the distribution system, often through the use of shunt capacitors. Used correctly, shunt capacitors bring power factors closer to unity. PV output that correlates well with peak loads can reduce reactive power losses (and thus shunt capacitors) because reactive power losses are related to current flow and device reactance.

**Evaluation Methodology**

The 1992 Case Study calculated feeder reactive loss savings using PG&E's FDRCAL program, while transformer reactive loss savings were estimated based on transformer reactance. Transmission system reactive loss savings were determined using the General Electric Optimal Power Flow program maintained by PG&E's Transmission Planning Department.

This report estimates feeder and transformer reactive power loss savings by developing a reactive power loss savings model similar to the real power loss savings model. This model employs the same approach as the PG&E FDRCAL model used in the 1992 Case Study.

**Testing and Data Requirements**

No special tests were performed specifically to evaluate reactive loss savings on the feeder. During the real power loss savings tests mentioned in the previous section, however, data were collected that could be used to evaluate reactive power loss savings on the feeder.

Data from the tests on August 24, 1993, were used to determine reactive loss savings on the feeder. The three sets of tests on this day showed average increases in the feeder of 30 kVARs (at a 2.9 MVA feeder load), 45 kVARs (at a 3.5 MVA feeder load), and 50 kVARs (at a 3.8 MVA feeder load). (Note: each of the measured numbers is increased by 20 kVAR based on an estimated increase in plant capacitance of 20 kVAR when the plant was turned off). These estimates match what the feeder reactive loss savings model mentioned above predicts.

**Results**

Using the validated model and peak load conditions, reactive power loss savings at the peak hour are estimated to be 50 kVARs on the feeder and 74 kVARs on the transformer. The 1992 Case Study estimate of 225 kVARs on the transmission system is assumed. This translates to an economic value of $6/kW-yr ($48/kW).

**Discussion**

The 1992 Case Study estimated the value of reactive power loss savings to be $10/kW-yr ($87/kW). (Three percent of the value is due to savings on the feeder, 48 percent to the transformer, and 49 percent to the transmission system). Twenty-five percent of the difference between the 1992 Case Study value and the interim test value is due to the fact that the 1992 Case Study anticipated that the PV plant would be operating at 0.5 MW (as opposed to the actual value of 0.41 MW) and that the peak loads would be 20 percent higher than they actually were. The remaining difference between the two values is that the 1992 Case Study attributed feeder kVARs to both the feeder and the transformer rather than just the feeder, thus double counting part of the value. The 1992 Case Study estimate and the interim test result are the same after adjusting for these conditions.

Section 4

# GENERATION CAPACITY VALUE

## VALUE DESCRIPTION

Adding PV generation to the utility system provides an incremental amount of reliability against capacity-related outages. This generation capacity value is calculated by assessing utility system reliability with and without the generation resource.

## EVALUATION METHODOLOGY

The 1992 Case Study and the interim report use the same methodology to evaluate generation capacity value.

A utility industry planning standard to ensure long-term reliability against bulk power outages is the 1-day-in-10-years loss of load probability (LOLP). LOLP is the amount of time that a utility estimates the installed generation capacity will not be able to meet all customer load. The 1-day-in-10-years criterion translates into a capacity shortfall of not meeting demand for 2.4 hours in one year or one day in 3,650 days, depending on whether hourly or daily peak load is used in the LOLP calculations. Utility investments in supply-side and demand-side resources are largely driven by meeting this criterion.

A standard utility proxy for evaluating cost-effective resource alternatives is the avoided marginal cost of a gas combustion turbine. This benchmark is used to evaluate the value of adding an incremental amount of PV generation capacity. Unlike a gas turbine, however, PV is not dispatchable and can not claim full generation capacity credit.

The Load Carrying Capability (LCC) of the plant must be calculated to establish the degree to which the PV plant provides the equivalent level of dispatchability to help meet peak loads. By adding PV capacity, the utility's LOLP is reduced. The LCC is the additional load, in MW, that can be added to the system until the LOLP returns to the same value without the PV resource. See reference [3] for LCC calculation details.

Once the LCC is calculated, the following four steps are executed to calculate the total generation capacity value:

1. Peak Power Availability (PPA) is determined by dividing the LCC by the PV plant's rating;

2. The PPA is then multiplied by the avoided marginal cost of installing a gas combustion turbine to obtain the generation capacity value;

3. The value obtained in step 2 is increased by the avoided O&M and general and administrative costs of operating a gas turbine; and

4. A line loss adjustment factor is applied to account for transmission system, substation transformer, and distribution feeder loss savings.

## TESTING AND DATA DESCRIPTION

A full year's worth of hourly system load and corresponding PV performance data from the same year are required to calculate the LCC. No testing is required. If actual PV performance data are not available, however, a validated PV simulation program is needed. This may require validation testing.

Since the Kerman plant has been running for less than one year, the PVGRID computer program is used to simulate 1993 hourly PV plant performance using 8,760 hours of 1993 Kerman site weather data.[5] The PV system simulation uses hourly direct normal and global horizontal irradiance values, ambient temperature, and wind speed measured on site. Corresponding hourly PG&E 1993 system load data are downloaded from PG&E's mainframe computer system.

Figure 4-1 presents the highest loads for PG&E's system and the corresponding PV plant output to illustrate data requirements and the match between 1993 system peak loads and PV output. The figure contains 25 of the year's 8,760 hours. The data are expressed as percentages of peak system load and PV plant rating. PV output during the top 25 hours is excellent, with three-quarters of the points exceeding 85 percent of the plant's rating.

## RESULTS

A load carrying capability of 0.41 MW is calculated based on 1993 PG&E system loads and 1993 simulated Kerman plant output. That means the 0.5 MW rated Kerman plant has an equivalent fully dispatchable generation capacity of 0.41 MW.

Dividing the LCC by the plant's 0.5 MW rating yields a PPA of 82 percent. As Figure 4-1 illustrates, it is not surprising that a high PPA results, since the top load hours factor most heavily into the PPA calculation.

[5] PVGRID model validation is discussed in Section 6.

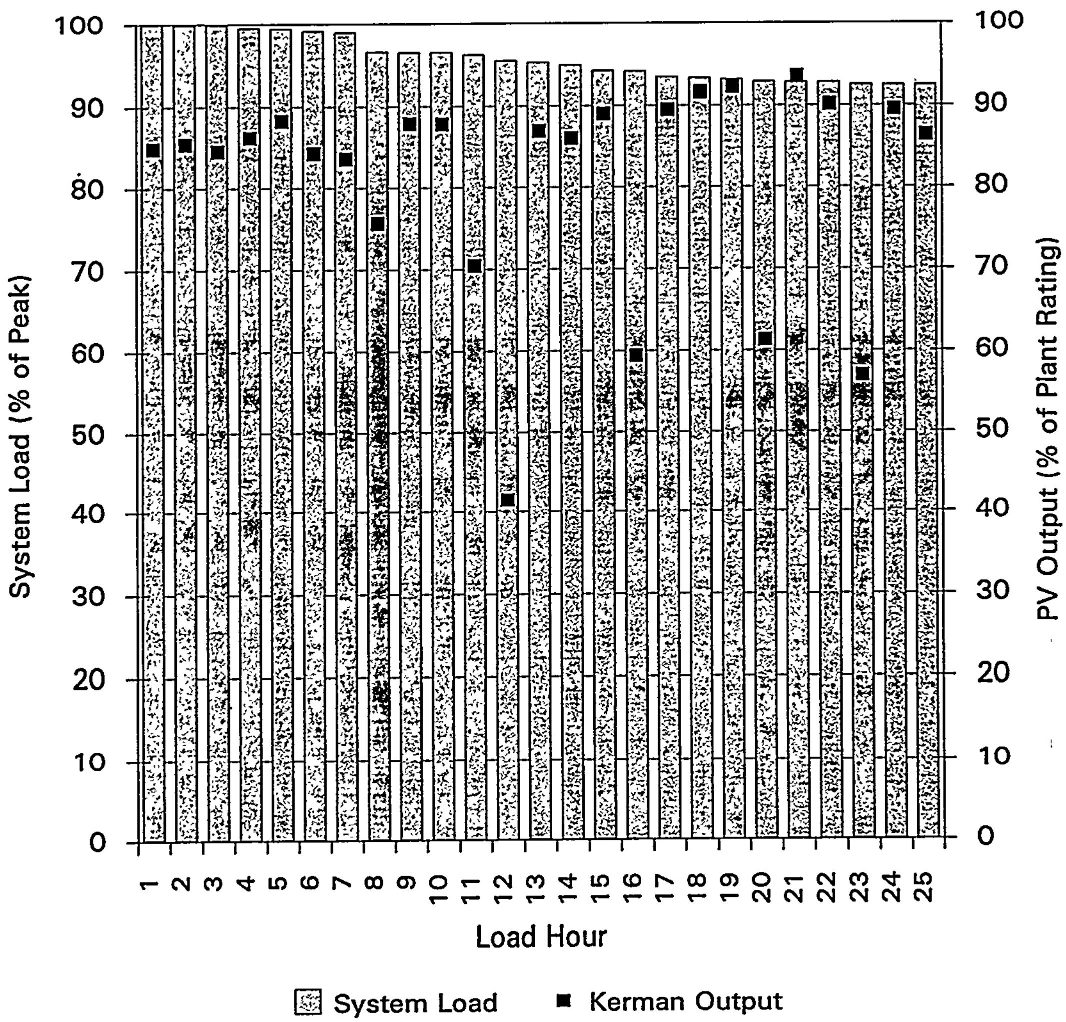


**Figure 4-1. Top 25 system load hours shows good correlation with plant output.**

The avoided cost of installing a gas combustion turbine is $65/kW-yr, to which avoided O&M and general and administrative costs are added, boosting this value to $74/kW-yr. The PPA is multiplied by $74/kW-yr to yield a generation capacity value of $60/kW-yr. Finally, the generation capacity value is modified upwards by a loss savings adjustment factor of 8 percent to yield a total generation capacity value of $65/kW-yr ($565/kW).

**DISCUSSION**

The updated interim test result is 10 percent less than the 1992 Case Study estimate of $72/kW-yr ($626/kW). The difference stems from variances in plant performance simulation assumptions and weather data. Also, a 12 percent loss savings adjustment factor was used in the 1992 Case Study, compared with an updated 8 percent adjustment factor.

The 1992 Case Study estimated a PPA of 87 percent, leading to a 6 percent over-prediction of generation capacity value. For a description of PV performance simulation differences, see Section 6.

The loss savings adjustment factor accounts for avoided transmission system, substation transformer, and distribution feeder losses. Interim test results, described in Section 3, found that peak transformer and distribution feeder loss savings are about 5 percent of the PV plant rating. Adding the same 3 percent transmission loss savings estimated in the 1992 Case Study brings the loss savings adjustment factor to 8 percent. This is a 35 percent reduction relative to the 1992 Case Study loss savings adjustment factor of 12 percent. The impact of this difference is a 5 percent overestimate of generation capacity value.

There are at least two items regarding the generation capacity value calculation that will be investigated for the Final Report:

- Technically, the loss savings adjustment should be calculated on an hourly basis for an entire year, and not on a peak loss savings basis; and

- PG&E and other utility planners are beginning to incorporate value-of-service (VOS) methods into reliability planning, where the economic value of reliability is measured in terms of customers' outage costs. For PG&E, meeting reliability planning standards for generation capacity-related outages has typically resulted in a planning reserve requirement of between 20 and 30 percent. Applying VOS concepts to generation system reliability planning appears to have actually lowered PG&E's planning reserve requirements, thereby lowering the value of adding incremental generation capacity to the system. This emerging planning concept will also be investigated.

Section 5

# ENERGY GENERATION VALUE

## VALUE DESCRIPTION

The PV plant's annual energy production reduces the utility's total (bulk) energy demand that would be satisfied by other resources. This energy generation value is calculated by totaling the avoided variable costs of production that the PV resource offsets.

## EVALUATION METHODOLOGY

The 1992 Case Study and the interim report use the same methodology to evaluate energy generation value.

The value of this production is captured using PG&E's System Power Values (SPVs). SPVs are long-term forecasts of the marginal value of energy and capacity at the generation level. SPVs are primarily driven by demand forecasts, resource availability, and fuel prices. They vary as a function of load demand; as demand increases, more expensive sources of electricity are used, thereby increasing the SPV. SPVs are used to evaluate the cost-effectiveness of supply- and demand-side resources, and are used in resource acquisition decision analysis.

Calculating energy value is a three step process: (1) Construction of a Load Duration Curve (LDC), which arranges the utility's total system load in descending order from the highest, or peak, load of the year to the lowest; (2) Construction of a PV output curve, which has a one-to-one chronological correspondence with the LDC; and (3) Multiplication of the total PV generation by the value of energy, which is a function of load duration curve interval.

## TESTING AND DATA REQUIREMENTS

The energy generation value data requirements are the same as those required to calculate generation capacity value, as described in Section 4. A full year's worth of hourly system load and corresponding PV performance data from the same year are required. If actual PV performance data are not available, a validated PV simulation program is needed. Model validation may necessitate verification testing.

Since the Kerman plant has been running for less than one year, the PVGRID computer program is used to simulate 1993 hourly PV plant performance using 8,760 hours of 1993 Kerman site weather data. The PV system simulation uses hourly direct normal and global horizontal irradiance values, ambient temperature, and wind speed measured on site. Corresponding hourly PG&E 1993 system load data are downloaded from PG&E's mainframe computer system.

**RESULTS**

Figure 5-1 illustrates the first two steps of the energy valuation; PG&E's 1993 system LDC and average 1993 Kerman plant output as a function of LDC interval are shown. For illustrative purposes, there is not a direct one-to-one correspondence between the points on the system LDC and the PV plant output curve. The system LDC contains 8,760 load points that are organized in descending order, while PV plant output is averaged over 50 hour intervals. The axes are referenced to a peak system load of 15,331 MW and the Kerman plant rating of 0.5 MW.[6] The PVGRID computer model is used to estimate the plant's hourly 1993 energy output.[7] The favorable correlation of system loads with PV output shown in Figure 5-1 is typical for solar installations in PG&E's service area.

Table 5-1 contains the third step of the energy value calculation. As a function of the system load duration curve interval, the corresponding amount of PV generation is multiplied by the SPV to yield energy value. For example, the 10 percent LDC interval represents the utility's highest 876 hourly loads out of a total of 8,760 hours per year. The PV plant generated a total of 281,022 kWh during this interval. This energy production yields a total value of $24,449 per year when multiplied by $0.087/kWh.

SPVs from the 1992 Case Study are used to yield a total annual energy value of $166/kW-yr ($1,443/kW). Since the Kerman plant is projected to produce 1,174,720 kWh per year, this translates to a levelized energy value of $0.07/kWh over the projected 30 year operating life.

**DISCUSSION**

The interim test result is about 14 percent less than the 1992 Case Study estimate of $194/kW-yr ($1,687/kW). This is solely due to differences in PV generation calculations.

The 1992 Case Study projected a 31.7 percent annual capacity factor (1,383,250 kWh/yr) compared to the 26.9 percent capacity factor (1,174,720 kWh/yr) validated for the Kerman plant. This variance, as noted earlier, is driven by different PV plant design assumptions and weather data used in the 1992

[6] The 1993 PG&E peak system, or customer, load of 15,331 MW does not include power transfers and exports. Although PG&E's peak 1993 load on its generators was closer to 20,000 MW, energy value calculations are based on system loads.

[7] PVGRID model validation is discussed in Section 6.

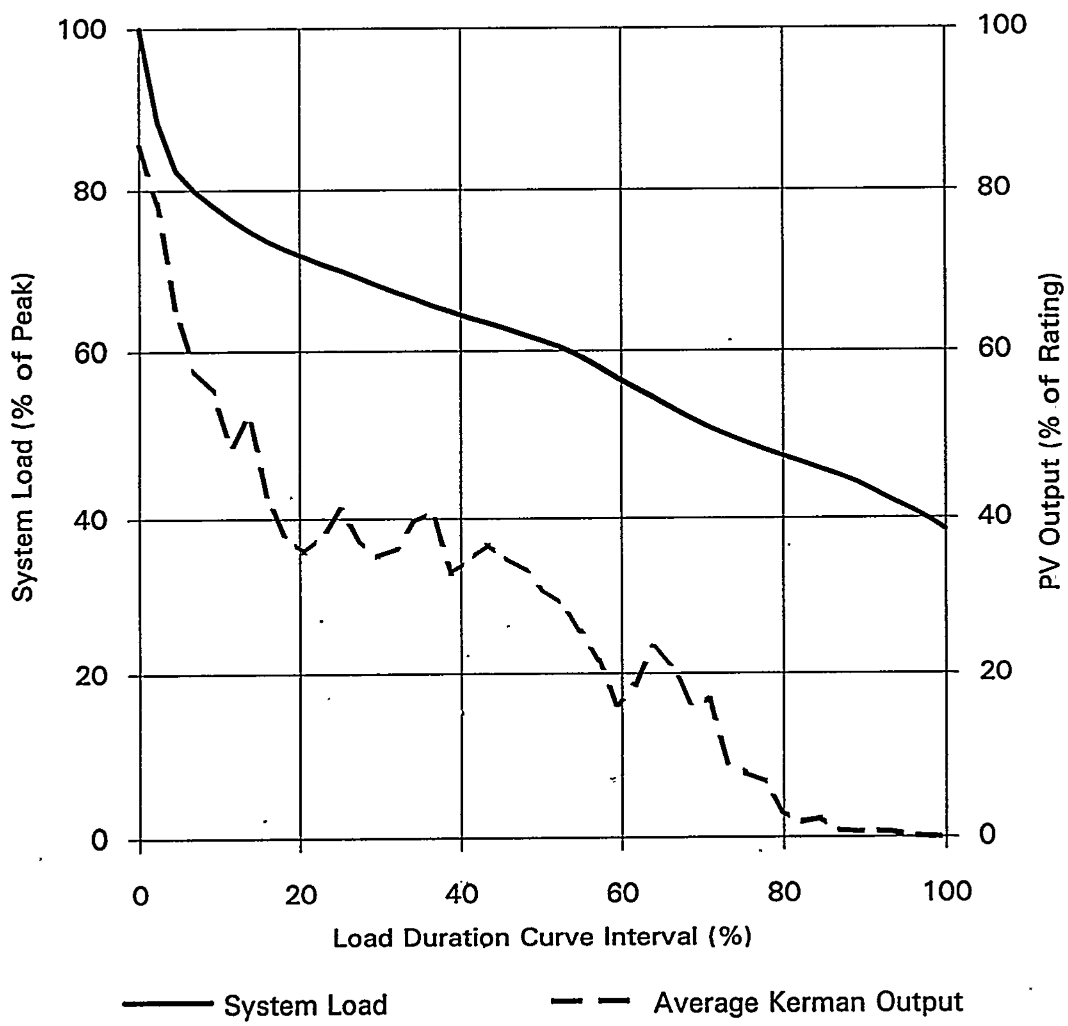


**Figure 5-1. First two steps of energy value calculation: LDC and PV output match.**

**Table 5-1**
**PV Plant Energy Generation Value ($1992)**

| LDC Interval (%) | PV Plant Generation (kWh) | SPV ($/kWh) | PV Energy Value ($/yr) |
|---|---|---|---|
| 10 | 281,022 | 0.087 | 24,449 |
| 15 | 103,964 | 0.081 | 8,421 |
| 20 | 83,946 | 0.077 | 6,464 |
| 25 | 85,786 | 0.078 | 6,691 |
| 30 | 80,767 | 0.076 | 6,138 |
| 40 | 163,270 | 0.065 | 10,613 |
| 50 | 150,426 | 0.057 | 8,574 |
| 60 | 98,979 | 0.055 | 5,444 |
| 70 | 88,642 | 0.049 | 4,343 |
| 80 | 31,274 | 0.043 | 1,345 |
| 100 | 6,644 | 0.034 | 226 |
| Annual | 1,174,720 | | 82,708 $/yr (166 $/kW-yr) |

Case Study calculations, and not by a deviation in Kerman plant performance per the system supplier's design. For a description of PV performance simulation differences, see Section 6.

Calculation of energy and capacity value can be somewhat complicated since SPVs contain embedded assumptions which are difficult to factor out, such as resource deployment and treatment of environmental externalities. PG&E's Electric Resources Planning department will be issuing "scenario SPVs" in 1994 to allow sensitivity analyses under uncertainty associated with key resource assumptions and environmental externalities.

Section 6

# PV PERFORMANCE AND COMPUTER MODEL VALIDATION

## PV PERFORMANCE ESTIMATION IN 1992 CASE STUDY

The 1992 Case Study utilized a simplified simulation program to estimate PV plant performance. Power output from a horizontal north-south axis tracking plant, nominally rated at 500 kWac at PVUSA Test Conditions, was simulated using hourly weather data measured in 1989. The weather data is from a PG&E solar resource monitoring station in San Benito, located about 60 miles southwest of Kerman at an elevation of 1500 feet. Out of 14 PG&E solar resource monitoring stations, San Benito is geographically closest to Kerman.

A solar monitoring station was installed at the Kerman Substation in 1990. The data reveal that San Benito has a significantly better solar resource and a more moderate ambient temperature regime relative to the Kerman area. The annual solar resource is approximately 7-10 percent greater than Kerman, with 7-10°C cooler temperatures during the summer. These factors alone account for about a 10 percent over-prediction of annual energy and peak power output in the 1992 Case Study report.

The PV performance simulation used in the 1992 Case Study was based on perfectly tracking arrays. Also, treatment of miscellaneous plant losses such as power conditioning efficiency, shading, dc wiring, mismatch, ac wiring, and transformers is not known. These factors probably contribute another 5 to 7 percent in performance over-prediction.

Use of a weather data set that is not representative of the Kerman climatic regime and modeling assumptions that do not reflect the characteristics of the installed Kerman plant result in an over-prediction of performance of about 15 percent (± 3 percent). The performance over-prediction applies to estimates of summer peaking capacity and total annual energy production.

The 1992 Case Study predicted power output at the time of the Kerman peak at approximately 0.5 MW. The interim test results show that power output during the peak is actually about 0.41 MW. Also the 1992 Case Study estimated an annual capacity factor of 31.7 percent (1,383,250 kWh/yr) compared to an updated capacity factor of 26.9 percent (1,174,720 kWh/yr) estimated using year 1993 Kerman site weather data.

## PV PERFORMANCE SIMULATION IN INTERIM TEST RESULTS REPORT

A computer model, PVGRID, is used to simulate plant performance to evaluate distributed generation value components requiring a full year of plant performance data [4]. Since the Kerman plant was interconnected in May and passed acceptance testing in June, 1993, there is not adequate measured data available for evaluating generation capacity, energy production value, and annual electrical loss savings. Weather data, measured on a half-hour averaged basis at the Kerman site, are used to predict plant performance.

Several enhancements made to the PVGRID model based on measured Kerman plant data have resulted in a highly accurate simulation program. These modeling enhancements include passive tracking as a function of summer and winter operation, power conditioning units 1 and 2 efficiency as a function of dc power input, and transformer losses as a function of ac current operating levels.

There are at least two factors motivating the use of the PVGRID model over other available simulation programs. First, the model is flexible and the evaluation team is familiar with the computer code, allowing sensitivity analyses and rapid modifications. And, second, a tailored model can be used as a diagnostic tool to confirm healthy plant operation, predict peaking and long-term performance, and investigate design features.

## PVGRID MODELING STEPS

The PVGRID model calculates power output via six major steps:

1. The array tilt angle is calculated based on the time of day and year;
2. The plane of array irradiance is determined based on the array tilt angle, relative position of the sun, and measured horizontal global and direct beam irradiance (interarray shading is also accounted for);
3. PV module temperature is estimated as a function of plane of array irradiance, ambient temperature, and wind speed;
4. Current-voltage curves are constructed and the maximum power point found (DC losses are accounted for);
5. Power conditioning unit efficiency is found (which includes air conditioning losses); and
6. AC power output at 12 kV is determined, subtracting transformer and other AC losses.

All of these modeling steps, with the exception of PV module temperature estimation, have been validated for the Kerman plant. PV module temperature modeling will be validated for the Final Report.

Highlights of the PVGRID validation process are discussed below.

## PASSIVE TRACKING

The Kerman plant has single-axis tracking arrays that track the sun about horizontal north-south axes using refrigerant R134 activated passive actuators. Figure 6-1 shows the layout of the Kerman plant. There are 9 rows of PV arrays, with two power conditioning units located in the center of the field. The arrays are mechanically ganged together (and electrically wired) to form 17 independently tracking source circuits. There are nine clinometers, one for each row, that measure the tilt angle of 9 of the 17 tracking source circuits.

Passive tracker performance impacts plant output and must be considered for accurate modeling. Figure 6-2 presents typical passive tracking performance for summer conditions.

The circles are measured half-hour averages from the nine clinometers. There is significant spread in array tilt angles in the early morning and late afternoon, but the arrays track very closely to one another during most of the day. The PVGRID model was modified to simulate actual tracker behavior; the modeled tracking angle is shown along with the optimum tilt angle. The optimum tilt angle is the tilt angle that minimizes the solar incidence angle and, generally, maximizes energy capture.

Two trends are evident from the clinometer data. First, most of the arrays back-track towards the horizontal position in the late afternoon as a result of inter-array shading. Second, the arrays consistently lag the optimum tilt angle by about 5° during most of the day. These trends appear to be independent of time of year.

The tracking pattern of Row 5 is noteworthy, since it is the location of a plane of array irradiance instrument (PSP). Row 5 is situated at the center of the field and has less afternoon shading because of the increased distance from Row 4 (see Figure 6-1). This causes Row 5 to have a markedly different tracking pattern in the late afternoon, causing the PSP measurements to not accurately reflect irradiance captured by the rest of the field. This becomes important if the measured POA irradiance data are used to predict late afternoon and long-term performance. Row 1 tracks similarly to Row 5, as it is also situated with no afternoon shading.

These tracking idiosyncrasies, and their effect on data collection, have been accounted for in the validation and adjustment of the PVGRID model.

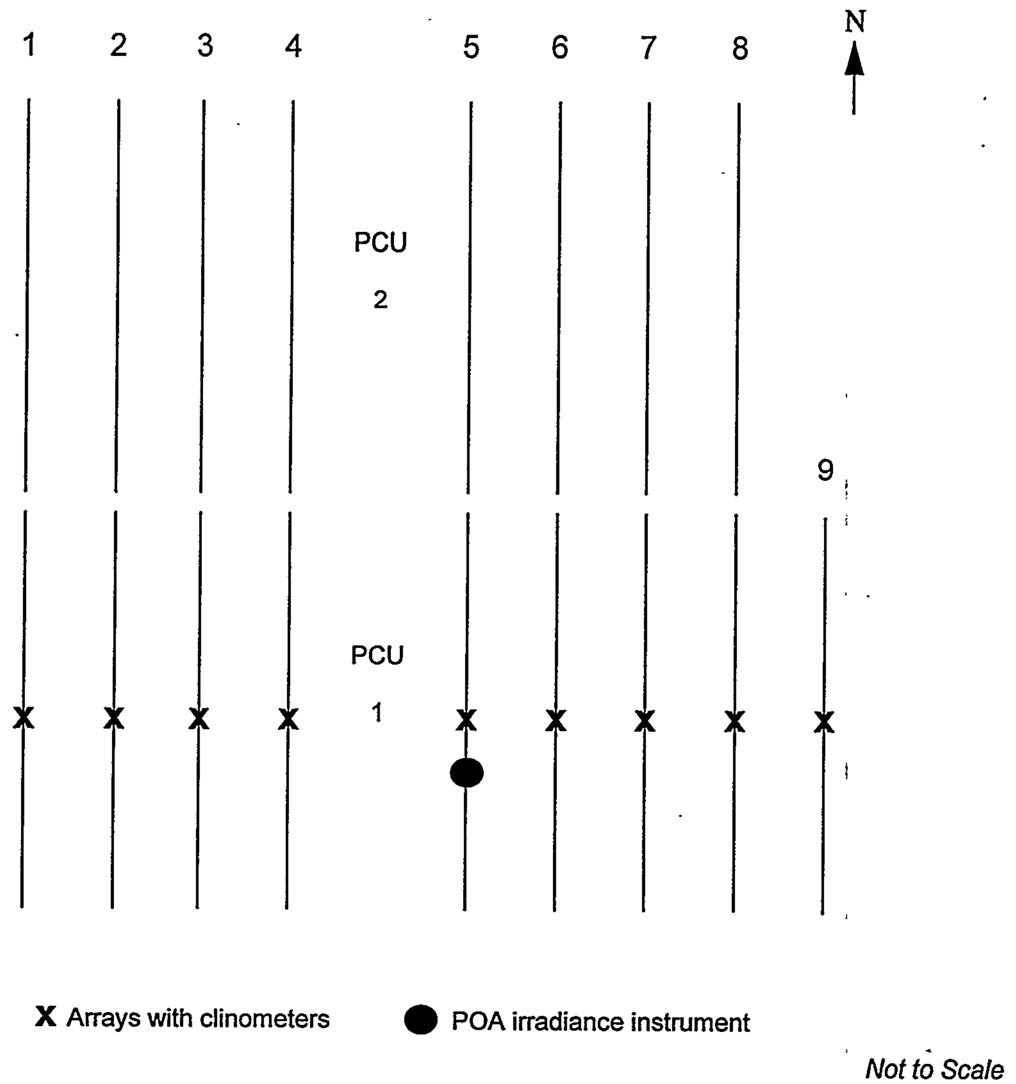


**Figure 6-1. Kerman PV plant layout and selected instrumentation.**

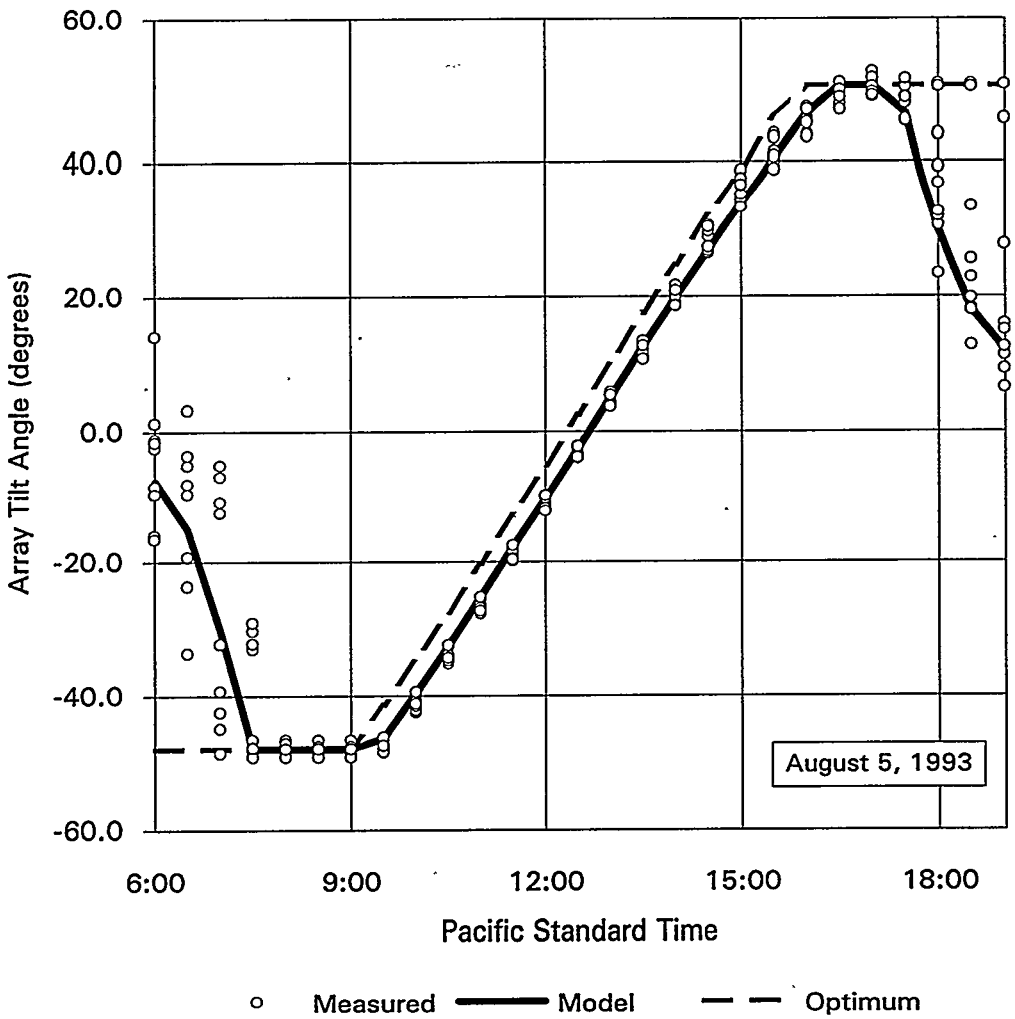


**Figure 6-2. Passive tracking performance: actual, modeled, and optimum.**

## POWER CONDITIONING UNITS

The Kerman plant has two 275 kWac power conditioning units (PCUs). PCU 1 is connected to 9 of the 17 source circuits, while PCU 2 is connected to the remaining 8 source circuits.

DC to AC conversion efficiency is measured by the PVUSA data acquisition system. A least squares regression is performed to construct an efficiency equation as a function of DC input to each inverter. Figure 6-3 presents the curve fit and measured data for PCU 1. Over 3000 data points are presented, spanning all months since the plant came on line.

Both PCUs demonstrate conversion efficiencies typically ranging from 91 to 94 percent, including air conditioning loads.[8] An air conditioning unit, rated at 15,000 Btu/hr (4.8 kW), serves each PCU enclosure. Air conditioning loads can contribute up to a 2 percent absolute reduction in PCU efficiency during peak conditions, depending on cooling load and compressor run time. This explains, to some extent, the range in PCU efficiency under full power conditions shown in Figure 6-3.

## PV POWER DELIVERED AT 12 KV

Current-voltage curves are constructed and all efficiency losses are taken into account to model PV power delivery at 12 kV. Isolation and 12 kV step-up transformer efficiencies are included, amounting to 4 to 10 kW depending on AC current levels.

Figure 6-4 presents actual versus modeled power levels for the local peak load day (June 25, 1993) and a representative winter day (November 18). The model exhibits close correlation compared with measured results, and typically predicts power output to within 1 percent on peak.

Figure 6-5 presents measured and predicted maximum monthly capacity factors, and a performance index. The maximum capacity factor is based on Kerman weather data which are continuously recorded. The performance index, defined as the ratio of measured to maximum capacity factor, is an indication of how well the plant operated. An index of less than 100 percent indicates plant downtime from such events as outages and testing, malfunctioning tracking devices, and electrical equipment failures.[9]

[8] PCU efficiency is calculated by dividing measured DC power input by AC power output. The AC power measurement is downstream of the air conditioning unit service, therefore the PCU efficiency includes air conditioning loads.

[9] The performance index should screen out all scheduled testing or maintenance-related outages. This will be done in the future.

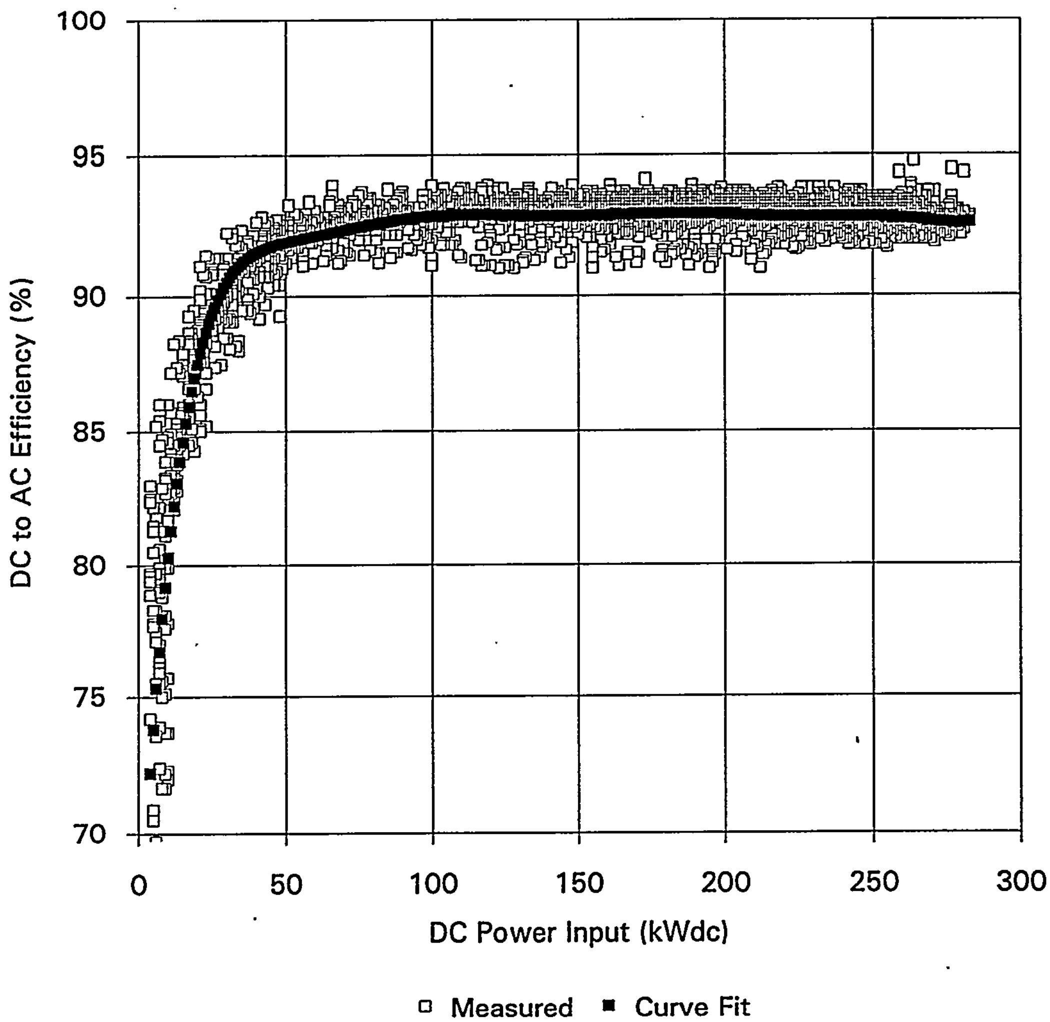


**Figure 6-3. PCU 1 efficiency curve (includes air conditioning load).**

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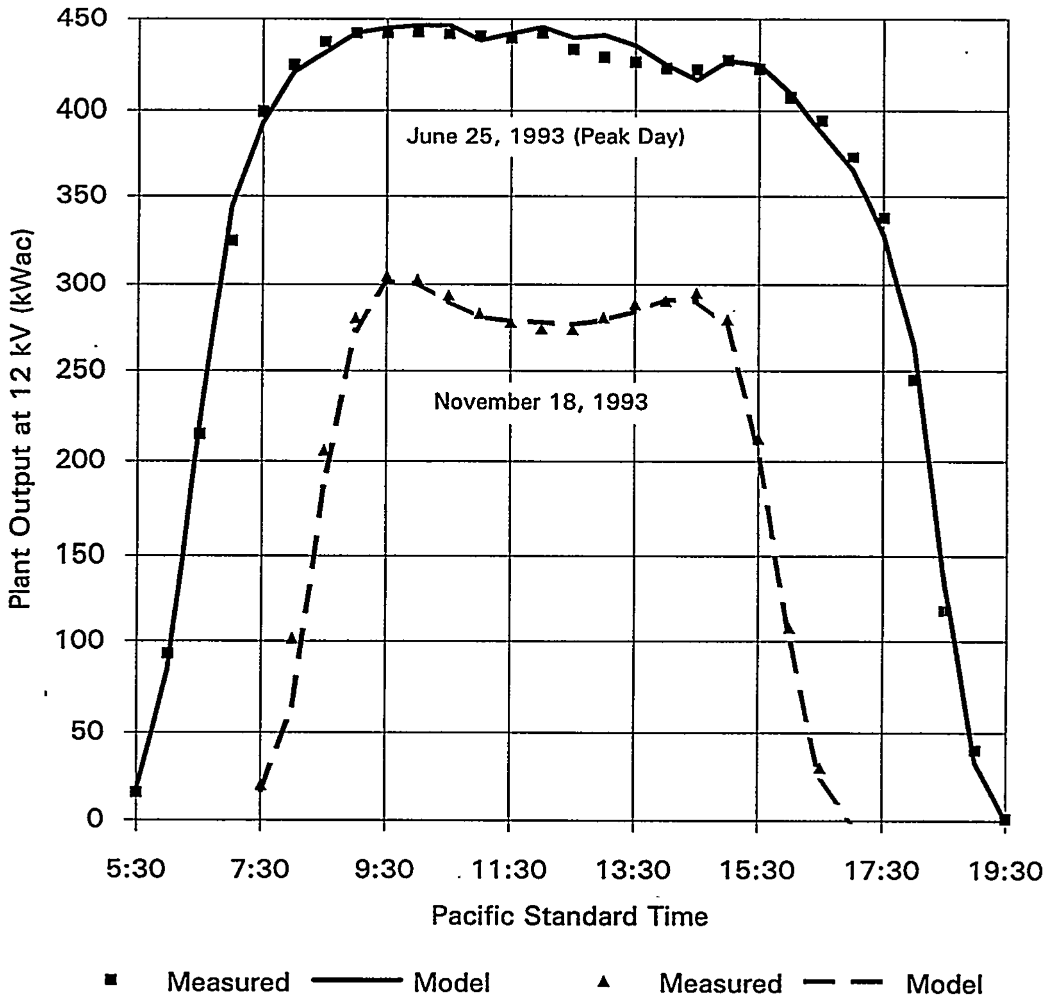


**Figure 6-4. PVGRID model shows close correlation with measured data.**

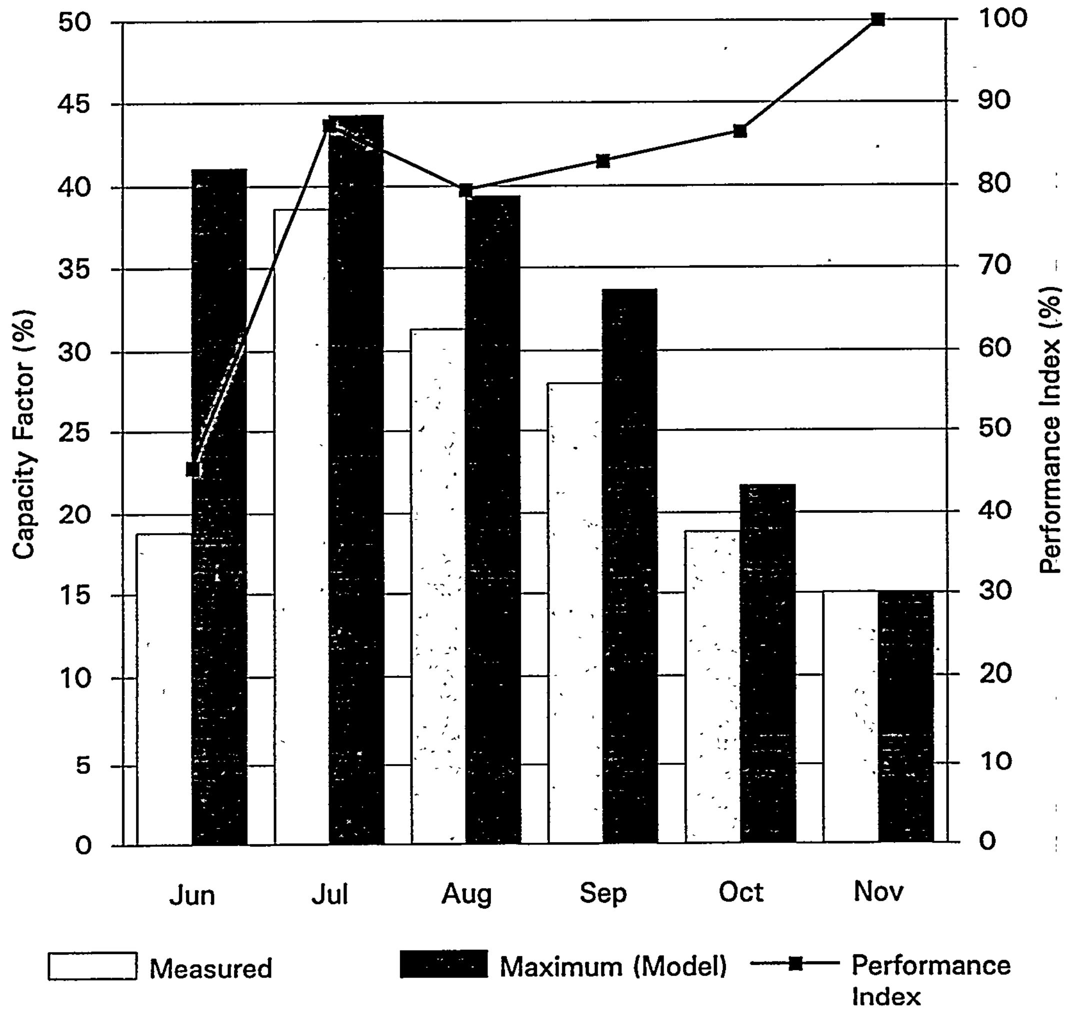


**Figure 6-5. Kerman plant performance, June-November, 1993.**

Because of testing and plant start-up activities, the index was between 80 and 90 percent during June-October. November was the first full month of uninterrupted plant operation, and the plant performed flawlessly with a performance index of 100 percent.

## IMPACT OF PASSIVE TRACKING ARRAYS

The validated PVGRID model can now be used to investigate plant design questions. One is the performance impact of passive versus active tracking arrays.

Figure 6-6 presents PV power output as a percentage of what the plant would have produced if it were equipped with perfectly tracking arrays[10]. Three typical days are shown for each season. This plot shows that the passive tracking arrays achieve nearly 100 percent of optimum performance during the crucial peaking times of the day, particularly during the summer. Therefore, distributed value components that rely on peaking capacity are fully captured with passive trackers.

Passive trackers, however, sacrifice energy capture during the early morning and late afternoon. Figure 6-7 presents monthly total PV energy production as a percentage of what the plant would have produced if it had perfectly tracking arrays.

This translates to an annual energy delivery impact of about 5 percent, the same reduction predicted by the system supplier[11]. In other words, if perfectly tracking structures were used, the projected 1993 Kerman plant capacity factor would increase from 26.9 percent to 28.2 percent. Distributed generation value components that rely on energy delivery rather than peaking capacity would, in turn, scale upwards by about 5 percent.

## MODELING CONCLUSIONS

A validated performance model provides confidence in the validation of the value of grid-support PV and allows for comparisons to the 1992 Case Study. The Kerman plant appears to be operating very close to the system supplier's design, following the initial 4 months of operation.

The sacrifice due to passive tracking is negligible during peaking conditions, from a power output perspective. From an energy production perspective, the passive trackers produce about 5 percent less

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[10]The perfectly tracking arrays are modeled with a maximum rotation angle of 50°; the same maximum angle as the Kerman passive trackers.

[11]Annual passive tracking losses break down to a 4 percent energy delivery reduction during summer, 6 percent during spring/fall, and about 3 percent during winter.

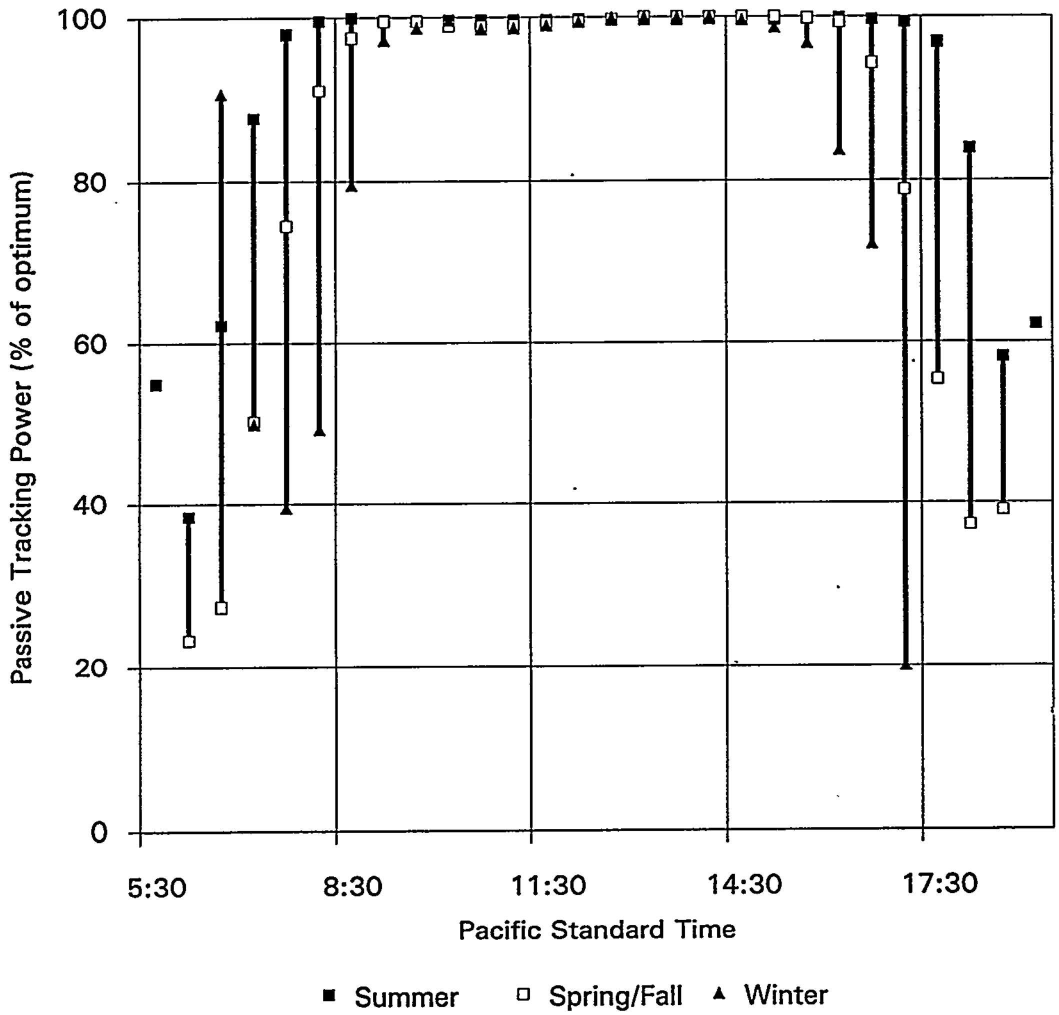


**Figure 6-6. Passive tracking performance is excellent for peaking power.**

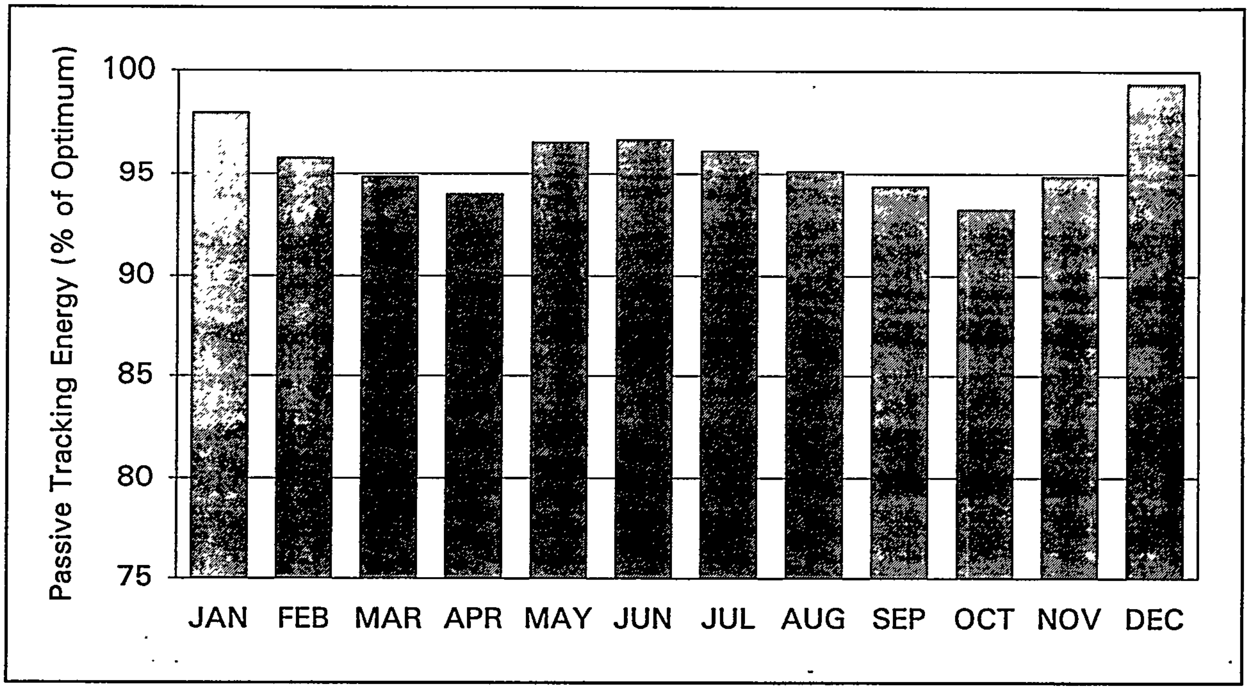


**Figure 6-7. Passive tracking sacrifices annual energy delivery.**

than perfectly tracking arrays on an annual basis. Grid-support values that rely on peaking capacity are fully captured with passive trackers, while benefits relying on energy production will scale downward.

Ancillary AC losses can be significant: 12 kV step-up transformer, PCU isolation transformer, and the two PCU air conditioning units add up to about 10 to 18 kW of additional load on peak, depending on air conditioning loading and cycling.

Plant output is sensitive to module temperature, with temperature-induced power output losses of about 50 kW during peak summer conditions when ambient temperatures typically rise above 40°C.[12] Future grid-support applications may consider sizing the power plant according to weather conditions coinciding with the local peak load. Ultimately, a benefit/cost trade-off must be performed to optimally design the plant.

Based on the validated model, the following annual capacity factors are estimated using measured Kerman site weather data:

[12]Temperature-induced power losses are relative to PVUSA Test Conditions of 20°C ambient temperature. These losses are solely attributable to module efficiency reductions from elevated temperatures, and do not include other plant losses.

**Table 6-1**

**Capacity Factors**

| Year | 1991 | 1992 | 1993 |
|---|---|---|---|
| Annual Capacity Factor (%) | 27.5 | 25.2 | 26.9 |

For reference, the system supplier projected a 1991 capacity factor of 28.0 percent, also using 1991 Kerman site weather data.[13]

## DISCUSSION

The 1992 Case Study did not use Kerman site weather data, nor did it utilize the PVGRID simulation program to evaluate distributed generation value. As a result, the 1992 Case Study projected a 31.7 percent annual PV plant capacity factor, causing over-prediction of energy-related value components. Capacity-related value components were also over-predicted, since San Benito has a better solar resource and a more moderate ambient temperature regime than Kerman during the summer peak.

This highlights the importance of using weather data that is representative of local conditions when evaluating PV grid-support, in addition to accurate performance modeling techniques and assumptions.

[13] The system supplier's annual capacity factor projection was 27.8% based on their projected 0.502 MW plant rating. This capacity factor is adjusted to 28.0% to reflect the PVUSA 0.498 MW plant rating which is the basis for PVGRID capacity factor estimates.

Section 7

# CONCLUSIONS

This Interim Report focuses on validating the technical aspects of grid-support PV. It provides interim validation results for four of the eight identified value components that stack up to make the "value bar", and compares them to 1992 Case Study estimates. Results are based on improved technical evaluation methodologies, measured plant performance under a variety of conditions, and long-term plant performance estimated using a validated computer simulation program. The report uses the same economic methods and input assumptions as in the 1992 Case Study to facilitate comparison of results.

## RESULTS SUMMARY

Figure 7-1 presents interim results in levelized ($/kW-yr) and net present value ($/kW) formats. The left bar presents the total economic value identified in the 1992 Case Study;[14] the right bar presents interim test results. For comparison purposes, the value components that have been technically validated are bordered by a bold line in both stacked bars.

> Validated interim test results equal about 84 percent of the 1992 Case Study estimates, based on initial data analyses. This significant interim result confirms that grid-support PV can provide measurable value to the local T&D system. The interim results indicate that substation and loss savings value can add about 45 percent to the sum of traditional energy and capacity value.

Table 7-1 presents the same information as in Figure 7-1, including 1992 Case Study estimates of value components that have yet to be validated. Approximately half of the value (from a dollar perspective) has been validated at this time.

## WHY DO THE STACKED BARS DIFFER?

A key difference between the interim test results and the 1992 Case Study results is attributable to plant performance and weather data assumptions. The differences are not due to under performance on the part of the PV plant. In fact, measured plant data compared to validated model results indicate that the Kerman PV plant is operating close to the PV system supplier's design.

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[14] Qualifying Facilities (QF) Savings were identified in the 1992 report but have been excluded from the analysis because they merely represent transfer payments, and the treatment of QF contracts in future resource planning is highly uncertain.

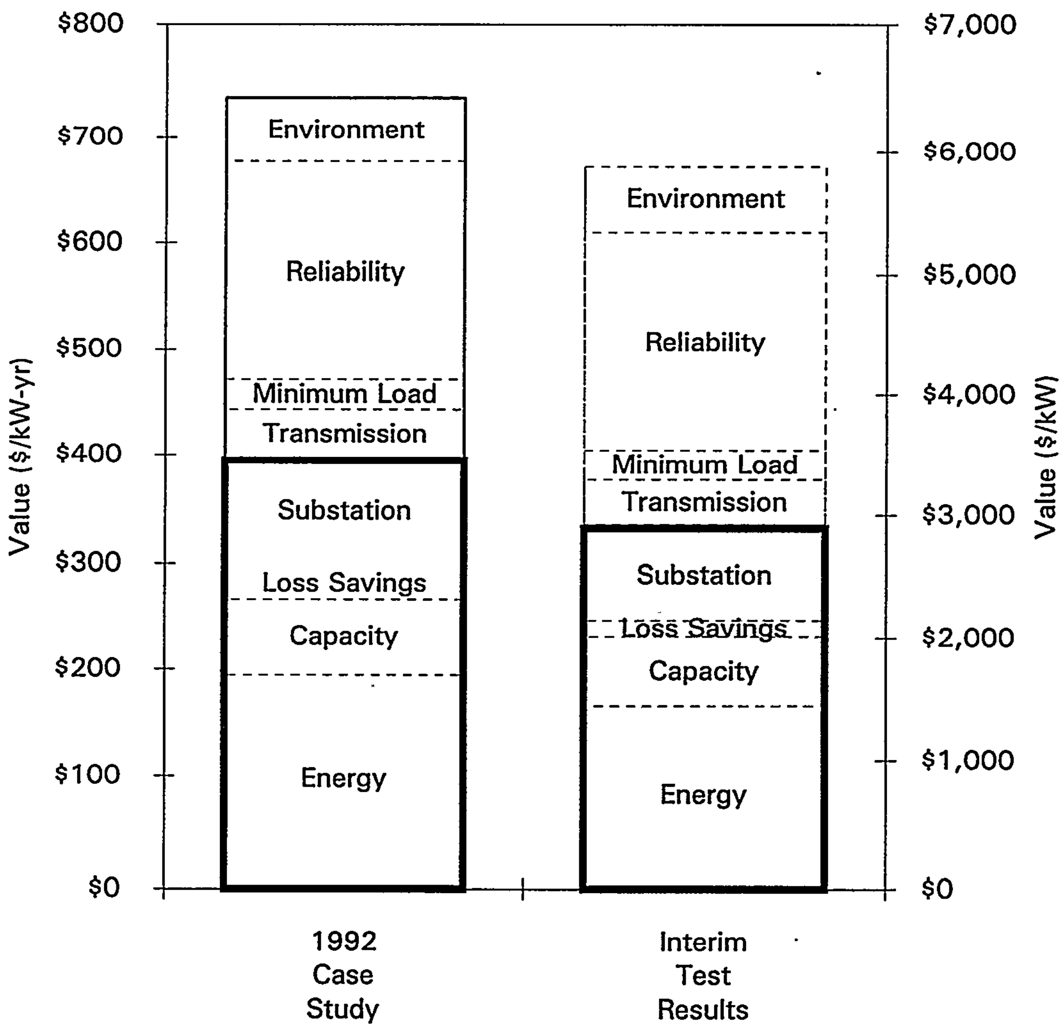


**Figure 7-1. 1992 case study and interim test results (year 1992 dollars).**

**Table 7-1**

**1992 Case Study and Interim Test Results (year 1992 dollars)**

| Interim Value Components | 1992 Case Study Estimates ($/kW-yr) | ($/kW) | Interim Test Results ($/kW-yr) | ($/kW) | Change (%) |
|---|---|---|---|---|---|
| Substation | 99 | 861 | 88 | 765 | -11 |
| Loss Savings | 31 | 270 | 15 | 130 | -48 |
| Capacity | 72 | 626 | 65 | 565 | -10 |
| Energy | 194 | 1,687 | 166 | 1,443 | -14 |
| **Total Interim** | **396** | **3,444** | **334** | **2,903** | **-16** |
| **Remaining Value Components** | ($/kW-yr) | ($/kW) | | | |
| Environment | 62 | 539 | | | |
| Reliability | 205 | 1,782 | | | |
| Minimum Load | 28 | 243 | | | |
| Transmission | 47 | 409 | | | |
| **Total Remaining** | **342** | **2,973** | | | |
| **Grand Total** | **738** | **6,417** | | | |

Rather, the 1992 Case Study tends to overestimate plant performance and thus overestimate value. This is principally due to the use of hourly weather data taken from San Benito, located about 60 miles southwest of Kerman at an elevation of 1500 feet. These data were used to calculate plant performance, impacting all 1992 Case Study calculations.

San Benito has a significantly better solar resource and a more moderate ambient temperature regime relative to the Kerman area. This explains a large part of the difference in results in this interim report as compared to the 1992 Case Study. Some of the difference is due to improved technical evaluation methodologies.

These results suggest that future grid-support applications need to carefully consider sizing the PV plant according to weather conditions during the local peak as well as the plant's annual capacity factor. Ultimately, a trade-off between maximizing value and minimizing cost must be performed to optimize plant design.

**CAUTION: USE THE INTERIM RESULTS CAREFULLY**

The interim results are just that, interim. They must be used with caution for several reasons. First, the results are site- and utility-specific, and the economic methodologies have not yet been revisited. Second, data will be collected through testing and the site data acquisition system during 1994 allowing the reconfirmation of value components; therefore, the results are not final. Third, the results are not intended to project the break even price for economically viable grid-support systems.

Although the results are presented in net present value format, expressed in $/kW, this does not reflect the PV break even price. In order to project the break even price, capital carrying charges (or cost of ownership) must be considered. Capital carrying charges account for such items as taxes, depreciation, and insurance.

These capital carrying charges vary depending on the utility's debt structure, accounting methods, and type of capital investment. For example, capital charges assumed in the 1992 Case Study increase cost (or reduce value) by about 13 percent. In addition, third party ownership will reflect much different capital carrying charges than most utilities, so the results are not universally applicable.

Finally, caution is urged since some evaluations in this report are performed using 1993 peak day data. No attempt to predict how close the 1993 peak day is to any long term average peak day is made. Variation in peak day may impact some results either positively or negatively.

**UPDATED METHODOLOGIES**

Updated more rigorous methods were developed to evaluate several of the value components, including the transformer upgrade, transformer load tap changer, and real power loss savings. This was done because the methodologies in the 1992 Case Study were found to not be fully adequate.

The updated evaluation methods, described in the appendices, represent a valuable contribution to the field of grid-support PV in particular, and distributed generation in general, because they develop generic evaluation methodologies. By incorporating utility specific parameters, these methods can be used by other utilities. The reader is urged to study these appendices prior to applying the results from the Kerman analysis to other projects.

Section 8

# FUTURE WORK

This report has presented the technical validation of substation, loss savings, generation capacity, and energy value components. The remaining value components that need to be validated include reliability, environmental, minimum load, and transmission system values. Validation of reliability and environmental value, and economic evaluation methods, will be areas of focus in 1994.

## RELIABILITY AND ENVIRONMENTAL VALUE

The largest and most difficult value components that remain are reliability and environment. These are difficult to quantify because they do not directly accrue to the utility and there are presently no universally accepted evaluation methodologies. Validating the environmental, minimum load, and transmission system values require data that are already being collected. The reliability value, however, requires further testing.

Grid-support PV improves service reliability by expanding the available options for switching distribution circuits following sustained local disturbances. This reduces customer outages. Two crucial factors distribution system operators consider when restoring service to customers during an outage are the additional load critical distribution system devices can carry and maintaining system voltage.

## ECONOMIC EVALUATION METHODOLOGY

Economic validations are required in addition to the technical validations described in this report. Specifically, these validations include re-examining the economic assumptions and methodologies used in the 1992 Case Study. One of the key areas where this will be an issue is the reliability value. The 1992 Case Study used a value of service approach. This assigned a very high $/kWh value to additional load served by the PV plant during outage conditions. Another example is that the 1992 Case Study utilized a feeder perspective in determining the deferral upgrade value of a substation transformer. The appropriateness of this perspective will also be evaluated and new methods will be used where appropriate.

## FUTURE WORK SUMMARY

In summary, the Final Report will include:

- Updated evaluation methods. New methodologies will be developed, including the adoption of best available practices of utilities examining distributed generation;

- Re-confirmation of all value components. A full year of plant operation data, including a second summer peaking season, will confirm the magnitude of each of the value components;

- Updated economic assumptions and values in 1995 dollars. This will bring the project up-to-date and provide a new benchmark;

- The value of modularity. As a sensitivity, an assessment of the value of modularity from an optimal investment perspective will be included; and

- Complete documentation of evaluation methods and test procedures.

Several other activities are planned in 1994 relating to the Kerman project, including a full day review of Interim Report Results for the next PVUSA TRC, a two day workshop on distributed PV generation, and the publishing of a Final Report in the fall.

Section 9

## REFERENCES


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# Appendix A

## THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS TO SUBSTATION TRANSFORMERS

Appendix B

## THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS IN PROVIDING DISTRIBUTION SYSTEM VOLTAGE SUPPORT

Appendix C

# THE VALUE OF GRID-SUPPORT PHOTOVOLTAICS IN REDUCING DISTRIBUTION SYSTEM LOSSES