Photovoltaic System Grounding
And Fault Protection Guidelines

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Abstract
This document addresses grounding and fault protection aspects of photovoltaic power systems. It is intended to serve as a reference for system designers and others working with photovoltaics. The emphasis is on large systems, such as central stations (>1 MW), with commercial and industrial-sized systems (20 kW to 1 MW) also addressed. Design criteria and requirements are presented for grounding and fault protection subsystems. Details of grounding subsystems are discussed in terms of subsystem configurations, integration with other subsystems, the use of foundations as ground electrodes, corrosion, and other factors. Fault protection details include representative configurations, fault detection alternatives and economics, power conditioning aspects, protection against nearby lightning strikes, and other factors. Transformerless power conditioners and isolation transformers are discussed for commercial/industrial applications. Appendices include representative lists of suppliers of relevant equipment and equations for the resistance to earth of various electrode configurations.
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Section 1

INTRODUCTION

Under contract to Sandia National Laboratories, the Research and Engineering Operation of Bechtel Group, Inc. has conducted a study of grounding and dc fault protection in photovoltaic (PV) power systems. The final report on this effort is offered in the form of a design manual which investigates grounding and dc system fault protection methods for PV systems. The manual includes a listing of design criteria, recommended procedures, typical grounding system design approaches, an analysis of system fault protection, fault detection economics and an analysis of protection against nearby lightning strikes. The material in this manual is not intended to restrict design choices for individual systems. However, it is essential to note that the grounding and fault protection subsystems must act in concert in order to provide a safe environment for personnel. These subsystems should also act jointly to limit potential damage to equipment. The guidelines presented herein are intended to reinforce and implement this concept.

In broad terms, the functions of grounding and protection subsystems are to:

- Protect people from electrical shock hazards by using measures that are in compliance with applicable codes and standards, and that are demonstrably effective.

- Limit equipment damage and prevent injuries that might be caused by internal electrical faults, equipment malfunctions, human error, or by unusual conditions imposed from outside.

- Provide access to suitable grounding points for other components of the PV plant electrical system, such as lightning protection and instrumentation ground leads.

It is not immediately clear which grounding subsystem configuration is best suited for a given PV system. Nor is it clear which arrangement of circuits and complement of protective devices is best. Further, there
are overlapping functions which make grounding and protective design interdependent. This report provides an approach to determine suitable grounding and fault protection for PV systems on a case-by-case basis.

In developing an overall approach to grounding and fault protection through the design process, it is important to consider all electrical states and transients that can be anticipated within the system. These states and transients include normal operation, switching, faults, fault-clearing, and reclosing. In addition, testing, startup, shutdown, and various maintenance modes must be considered. Similarly, infrequent but possibly damaging external influences must be considered. These include lightning (direct strokes or induced surges), weather extremes, and faults or mis-operations on adjacent electrical facilities (e.g., a utility grid).

1.1 SCOPE OF STUDY

The overall scope of this study encompasses investigation of PV system grounding and dc system fault protection methods. Emphasis is placed on large (1 to 1,000 MW) systems, with medium-sized (20 kW to 1 MW) systems also addressed. The study consisted of two phases and included seven tasks:

- Review existing requirements and establish grounding criteria.
- Select and analyze grounding systems for representative PV systems.
- Investigate system fault protection, particularly in dc circuits. Additionally, evaluate the need for isolation transformers in medium-sized systems.
- Define recommended grounding and fault protection procedures, and hardware development, and identify code impacts.
- Evaluate the need for ground mats in concentrator array subfields.
- Assess fault detection alternatives and economics.
- Evaluate means of protecting against nearby lightning strikes.
The work on the configuration, grounding, and fault protection power conditioners was conducted by United Technologies Corporation (UTC) as a subcontractor to Bechtel.

1.2 APPROACH

The ranges of plant ratings considered in this study are 20 kW to 1 MW for commercial and industrial-type plants, and 1 MW to 100 MW for utility-type central power stations. The extension of central plant ratings toward 1,000 MW is treated as a future possibility.

Two baseline alternative solar PV collector structures are considered: fixed flat plate and concentrator arrays. Flat plate designs included are the JPL Buried Anchor Plate, the Bechtel Torque-Tube, the Hughes Building Block, and roof-mounted fixed rack assemblies (Refs. 1-1, 1-2, 1-3). The concentrator design is a Martin-Marietta two-axis concentrator assembly (Ref. 1-4).

In addition to defining the bounds of this study, the above plant ratings and array types are used as the bases for developing several PV plant layouts and some alternative circuit connections. These designs are used to illustrate some proposed grounding and fault protection solutions.

The plant layouts and power circuitry arrangements are deemed realistic, workable, and reasonably efficient in use of equipment and materials. However, they should not be regarded as validated or optimized designs, or as conforming to all current recommendations of the respective PV array suppliers and system designers.

1.3 REPORT FORMAT

The following sections of this report present guidelines for grounding and fault protection design development, supplemented by important related matters.

Section 2 introduces the factors that must be considered early in the design process in order to set a proper basis for more detailed work.
which follows. These include statements of the functions required, criteria for evaluating plant designs, equipment benefits of an integrated approach, and a description of the plant layouts and schematics used for purposes of this study. Also included is a discussion of PV array electrical modeling, and a listing of pertinent site parameters.

Section 3 highlights the major steps to be taken in the design of grounding and fault protection subsystems for PV plants. Both utility- and commercial/industrial-type plants are addressed.

Section 4 discusses several topics that must be considered in developing a grounding subsystem design. These include selection of the method for grounding source circuits, configuration of plant grounding, evaluation of earth electrodes, special problems posed by large areas, and lightning protection. This section also includes a review of the major causes of deterioration in equipment and materials typically used in grounding and protection subsystems.

Section 5 contains a general discussion of fault protection for PV plants, followed by a recounting of applicable fault protection techniques and an example showing a case-by-case fault analysis. A review of applicable hardware is also included. The economics of alternate fault detection and maintenance scenarios are evaluated. An analysis of protection against nearby lighting strikes is presented. The section also addresses the technical and economic feasibility of omitting isolation transformers in power conditioning systems for medium-sized PV systems.

Section 6 is a recapitulation of selected code requirements that influence PV grounding and fault protection design. There is also a discussion of hardware that would be useful in PV plant protection, but which is not known to be commercially available at present.

In addition to references, the report includes an annotated Bibliography which lists relevant codes, standards and guides; reports; technical
papers and articles; books; and computer programs. Appendix A contains a brief list of terms that may otherwise be unclear, or that are used in special ways in this report. Comprehensive glossaries are available in other publications listed in the Bibliography. Appendix B contains a summary of PV plant ratings, layout drawings, and electrical schematics. Appendix C provides expressions to evaluate resistance to earth for a variety of buried electrodes. Appendix D describes a method for analyzing faulted source circuits, considering modules and blocking diodes. Appendix E contains a listing of manufacturers and suppliers of equipment for fault protection systems. Appendix F presents an illustrative example of the design steps outlined in Section 3 for a central station PV plant. Appendices G and H contain data supporting the fault detection/maintenance economics and lightning protection analyses, respectively.
Section 2
REQUISITES FOR DESIGN

Since PV plant design procedures are not well established by prior use, it is necessary to provide a firm basis for a detailed design. This includes defining functions, developing criteria, assessing comparable technologies, postulating alternatives that may lead to lowest life-cycle cost, and determining the system and site characteristics.

Listings of design guidelines, and other background information on PV plants, are presented in this section. This type of material, updated and directed to the plant being designed, should be collected and developed at the start of design work on a PV power plant project.

There is a degree of overlap between the provisions that must be made for grounding and those for fault protection in PV plants. Because of this, classification of functions and criteria are interdependent in some areas, and in these areas the two subsystem designs must be closely correlated.

A few terms and definitions that may not be intrinsically clear or the meanings of which may be specific for PV grounding and fault protection designs and applications are listed in Appendix A.

2.1 FUNCTIONS OF GROUNDING AND PROTECTION

The functions of grounding and fault protection subsystems for any PV plant include the following:

- Prevent injury to personnel imposed by ground voltage differences or by high-current arcs and heating.
- Prevent damage to equipment due to insulation breakdown or fault current arcs and heating.
2.2 CRITERIA FOR DESIGN

This section presents both grounding and fault protection criteria developed for the design of PV systems. The design requirements for PV plants were derived from a variety of sources (see Section 2.3). These include review of published material (including relevant portions of codes and standards), experience from specific PV or similar field installations, and examination of expected site and plant characteristics.

2.2.1 Grounding Criteria

- Provide a low impedance ground path to allow for rapid dispersal of surges.

- Provide effective return paths for fault current flow, so that relays, fuses, and similar devices will perform predictably.

- Protect equipment against mis-operation caused by excessive voltage or current coupling with foreign sources.

- Provide proper paths for small leakage currents, so that they will be less likely to cause corrosion than by flowing in stray paths.

- Provide return fault current paths that meet National Electric Code (NEC) requirements or intents:
  - Design and install strictly according to NEC, OSHA, IEEE 80, ANSI and state codes for all areas and structures outside the PV plant secure area.
  - Examine the intent of NEC requirements and design accordingly for dc and other circuits that are unique to PV technology.
  - Design a system that is safe when operated and maintained according to stated procedures.

- Coordinate with utility requirements and practices in the design of grounding facilities at the plant substation.

- Where possible, consider integration of the grounding subsystem with other subsystems in order to obtain effective grounding with minimum costs of material and installation (e.g., use of array structures as part of the ground wire system, use of foundation and other excavations to bury ground conductors, etc.)
• Provide earthing points that will accommodate a lightning protection arrangement chosen for specific sites.

• Provide grounding connections that will prevent build up of static electric charges on any element.

• Limit leakage currents from PV arrays, to the extent possible.
  - If leakage currents cannot be reduced to negligible levels, provide defined paths where they may flow without causing deterioration or hazard.
  - Provide means for testing or monitoring the status of predictable leakage currents.

• Limit the step, touch, and similar hazardous voltages to acceptable values: (See Appendix A for terminology)
  - Step voltage ($E_s$) versus shock-duration time ($t$) for a 60 hertz source should not exceed:
    \[
    E_s = \frac{116 + 0.7 \, r_s}{\sqrt{t}} \text{ volts}
    \]
    \[
    r_s = \text{resistivity near surface, ohm-meters}
    \]
    \[
    t = \text{time duration, seconds}
    \]
  - Touch voltage ($E_t$) versus shock duration time for a 60 hertz source should not exceed:
    \[
    E_t = \frac{116 + 0.17 \, r_s}{\sqrt{t}} \text{ volts}
    \]
  - Step or touch voltage versus time for a dc source should not exceed 2.0 times $E_s$ or $E_t$ above, and for an impulse (lightning excepted) it should not exceed 1.5 times $E_s$ or $E_t$. (Some references [e.g., Ref. 2-1] show a permissible dc voltage of as much as 5.0 times the ac value. The more conservative limit of 2.0 is suggested herein).
  - These values are considered valid only in the range of 0.008 to 5.0 seconds. (This range of times is typical of the time required to clear most faults. Single lightning strokes have much shorter durations than this.)

• Limit the surge voltage on auxiliary shielding and control cable circuits to levels that will not cause flashover or damage to equipment, by use of beneficial layout and circuit shielding.
• Use surge arresters on all incoming ac circuits, on high-voltage and low-voltage sides of transformers, and on dc circuits at all vulnerable locations.

• Provide grounding or earthing points for all surge suppression devices, relays, and other devices that depend on an effective ground for proper operation.

• Design ground wire connection routes to earthing points to be as straight and short as possible in order to limit transient voltage buildup and reflection. Consider the possibility of side flash on connections and cable runs that are expected to carry lightning surge currents.

• Ground all exposed metal structures, enclosures, panels, trays, conduits, and similar parts.

• Mark grounding cables and connections so that they are clearly identifiable.
  - All bare wires (except inaccessible wires such as enclosed or overhead conductors) must be part of the ground system.
  - Insulated ground wires must be green, or marked or tagged green.
  - Green jackets or markers must not be used for other than ground circuitry.

• Size ground wires to accommodate fault current levels and energies expected in each area of use. The sizing and design of the grounding system must also anticipate plausible mechanical damage and the effects of corrosion.

• Provide ground connections that will not become progressively less effective because of loosening bolts, corrosion or other long-term effects.
  - Ground wires and connections must be protected from mechanical damage.
  - Structural connections that are also used for grounding must be designed to be effective and remain so over the life of the plant. Separate ground straps must be provided where structural connections might possibly become electrically ineffective.

• Provide flexible ground straps or similar conductors between movable conductive surfaces, such as in tracking array drive assemblies or fence gates.

• Arrange equipment and connectors so that ground is the first connection made during installation, and the last connection broken during removal or other maintenance procedures.
• Provide separate wires and cables for grounding in dc systems that operate with one polarity grounded, or that have a designated neutral conductor. (Codes generally prohibit using any line conductor for the grounding function.)

• Consider worst case circumstances, such as increased soil resistance due to low water table, dried-out soil, or low soil temperature, when designing earth electrodes and buried grids. For large plants, the possible variation of soil resistance over the site area must be taken into account.

• Use grounding or guarding techniques, as each is best suited, to provide a safe environment. (All codes recognize "guarding" as an acceptable way to safeguard personnel in the vicinity of live circuits or equipment. It is often an efficient way to solve safety problems).

• Design so that grounding subsystem equipment and materials are repairable or replaceable, as required.

• Examine materials, configuration, and grounding for fences and gates to provide for personnel safety.

• Evaluate less costly alternatives or adaptations of the conventional ac substation grounding grid concepts, while still providing safe conditions within array fields.

• Design so that grounding system elements will not impede necessary movement of operating and maintenance personnel or vehicles on prescribed routes within the array field.

• Avoid configurations that would invite continual electrical energy loss in the grounding networks or equipment. For example, midpoint grounding resistance in a certain range would absorb substantial power from unbalanced source circuits.

• Provide connections to the building structural steel ground via the most direct route practical when designing roof-mounted array installations.

• Provide insulated walkways and working surfaces around roof-mounted arrays.

  - Design to consider the effect of metallic roof membranes, structural members, pipes, ducts, and other conductors which may create hazards in the array area.

  - Consider the possibility of otherwise non-injurious voltages causing a person to fall. Extra barriers and guard rails may be required to counter this possible hazard.
2.2.2 Fault Protection Criteria

- Configure power and grounding circuits to facilitate detection of faults and other malfunctions in the plant.
- Provide means to connect sensors at selected points in the grounding and protection circuitry, so that the state of the system may be tested or monitored.
- Use remote or automatic switching of safety clearing and grounding devices where this would contribute to safety or operating effectiveness.
- Limit the possibilities of exposure to dc power current arcs which can cause injuries, damage, or fires.
- Configure circuits and wiring routes to reduce the opportunity for dc line-to-line faults and to limit the magnitude of predictable fault currents.
- Limit the use of mechanical or complex protective devices, particularly those distributed throughout the array field. (Such devices will tend to require periodic servicing and thereby raise O&M costs.)
- Include suitable dc fuses wherever they can be effective in protecting cables, other devices, and arrays against high-current faults.
- Consider the use of high-speed "resistance" or "conductance" sensors to detect high-current dc line-to-line faults. These sensors would respond to abnormally low ratios of voltage to current. They would be analogous to the impedance or admittance relays used on ac power lines. They could solve the problem of positively identifying faults in PV array circuits in which maximum load current (under normal operation at full insolation) can exceed minimum fault current (at minimum insolation). No dc protective devices of this type are known to be commercially available at present. Such devices could be fabricated with commercially available components.
- Use solid-state relays and microprocessors, where they would enhance protective functions, provide backup protection, broaden the scope and benefits of monitoring, or reduce costs.

2.2.3 Generic Criteria

- Limit deterioration due to corrosion, ultra-violet radiation (UV) effects, pollution, heating and cooling, freezing, and general weathering.
- Select equipment and materials that will retain their functional characteristics for the design life of the plant, based on reasonable scheduled maintenance efforts.

- Provide shields or enclosures for materials and devices that cannot withstand weathering and sunlight.

- Specify field assembly procedures such that cutting, drilling, threading, welding or similar disruptions to factory-applied protective coatings will be rarely necessary, and which will not produce vulnerable points for corrosion in the final work.

• Provide means to connect devices required to control electrolytic corrosion of buried conductors, electrodes, and/or structural parts.

• Consider the use of non-metallic raceways and structures to improve safety, avoid corrosion, and control costs.

• Design to utilize commercially available materials, equipment, and subsystems in order to minimize costs.

• Avoid requiring construction steps that would slow the project schedule, damage the environment in any substantial way, or be unnecessarily costly.

• Design to limit access to the array area by persons who have no specific skills in PV plant operation and maintenance (applicable to industrial-type PV plants, and especially with roof-mounted arrays).

• Verify that the design will protect against fire hazards within the PV plant, especially in plants to be mounted on roofs or adjacent to industrial buildings.

• Avoid plant layouts that have overhead ac distribution or transmission lines routed over or near the array field.

2.3 SOURCES OF CRITERIA

Some of the foregoing criteria items have been adapted from practice in other industries where grounding problems are difficult, and for which some analyses and solutions are well documented (refer to the Bibliography). Examples are electric utility substations, surface mines, electrolytic reduction plants, electric rail systems, and aviation ground electronic installations.
Other criteria have been taken from available reports that describe PV plants which have been built or proposed. In some of these reports, the criteria (or equivalent) listings are specific and lengthy; in others, hardware and installation details are not provided. With a few exceptions, operating experiences and later modifications are not generally available.

Finally, certain criteria have been adapted from codes and standards, including changes recently proposed for inclusion in the National Electric Code and in U. L. Standards.

2.4 BENEFITS FROM DUAL USAGE

All of the components in a PV plant that provide effective paths for the flow of current into ground return networks or into earth must be integrated into a grounding subsystem by specific design efforts. This is necessary not only to ensure proper electrical performance but also to economically adapt certain intrinsic plant components to grounding functions in addition to their primary functions. For example, excavations for array foundations can also be used for burying ground conductors. Worthwhile cost savings, particularly in large plants, can be anticipated if attention is directed to these matters in the preliminary design phase. In some instances, PV plant operation may be improved as well.

2.4.1 Buildings

Steel framing for buildings is conventionally used for shielding the interior from lightning stroke currents, and for providing safety ground points for equipment and electrical installations inside or near the buildings. Lightning air terminals, cable runs, bonding jumpers, and other hardware details must be added as required to provide an acceptable subsystem, but many of the grounding functions can be provided inherently by a building's structural members.

Similarly, the steel or aluminum structures required in outdoor substations or switchyards should be included as an essential part of the
grounding and shielding configuration. At power conditioning system (PCS) locations in a PV array field, any structures required to accommodate equipment needs should be adapted to perform shielding and grounding functions.

2.4.2 Arrays and Source Circuits

Any metal structural members of the arrays (such as frames, beams, and supports that are required in the physical assembly) should be adapted to perform or enhance grounding functions and meet code requirements for equipment grounding. Exceptional cases may arise where integration of structural and grounding functions should be avoided. Such cases may include insufficient net cost benefit or a special problem with electrolysis. However, safety grounding of metal parts must still be addressed. Some parts are grounded at only a single point in order to block current flow through the part under non-fault conditions.

Flat plate arrays provide significant area that is shaded from direct sunlight. Where feasible, terminal and equipment enclosures should be mounted under the panels to reduce heating and UV aging effects. Shading would be provided to some extent by mounting enclosures on the north side (in northern latitudes) of two-axis tracking array support pedestals.

2.4.3 Equipment

Equipment assemblies ranging from power transformers to array terminal boxes each have their individual grounding requirements. These requirements are prescribed by codes, manufacturers, current magnitude/duration calculations, and by the worst-case touch voltage predictions for each application. This equipment may provide junction points for additional "foreign" grounding circuits (e.g., for tracking drive, instrumentation, etc.). In such cases, ground current duties must be checked, a safe procedure for removing and replacing equipment must be prescribed, and code restrictions must be complied with, including bonding requirements.
2.4.4 Electrodes and Conductors

Buried ground conductors, buried grids, and vertical ground rods are the conventional and most-used configurations for earthing electrodes. Where feasible, buried conductors should be arranged to function as earth electrodes, and also as interconnections among other electrodes.

2.4.5 Foundation Structures

Foundation structures, especially reinforced concrete members, are important to consider thoroughly for adaptation to serve also as earthing electrodes. Although this cost-saving choice would be desirable to pursue for buildings, substations, and PCS locations, its greatest potential benefit would likely arise by adapting array support footings and piers to serve as earthing electrodes throughout the array field. This is because the below-grade concrete shapes are required for structural reasons, and little if any extra earth preparation would be required to incorporate the grounding subsystem. Trenching and backfill work needed for certain foundation types (such as the JPL buried plate concept) and for burial of dc power, tracking drive power, ac power, control or instrumentation wiring may also be used to advantage to install buried ground grids.

2.5 SYSTEM DESCRIPTION

The overall layout of PV plants will primarily depend upon the physical and electrical characteristics of array assemblies, the dc voltage rating selected for source circuits, and the power rating selected for PCS units. These three important parameters will in turn establish the number of arrays in each source circuit and the number of source circuits that must be connected to each PCS input bus. The sizing process is not simple and deterministic because the relative capabilities of the PCS unit and array subfield must be optimized as functions of solar insolation, life cycle PV cell efficiency, and equipment costs.

Further steps in the layout of a large plant include configuring the standard subfield to minimize the length of dc cable connections to the
PCS and using trenching patterns that will allow joint usage by all types of cables to the extent possible. Also, plant layout should provide space to install and service PCS units, and space for vehicle maintenance parking.

Layout of roof-mounted arrays will be constrained by some additional factors, such as the outline and slope of the available space, structural loading limits, access routes, safety measures, and security requirements.

2.5.1 System Definition

The configuration parameters that define the essentials of any particular plant are listed below. Refer to Appendix A, Figure A-1, for definitions of PV plant terminology.

- **Plant layout**
  - Arrangement of source circuits, subfields, and all ancillary areas
  - Number of PCS units
  - Location and outline of a typical PCS area
  - Location and outline of the ac substation
  - Location and outline of buildings and other support facilities

- **Plant operating characteristics**
  - Load characteristics at stated insolation levels (usually maximum output, nominal full-load, and minimum plant operating level)
  - Array voltage and current
  - Source circuit voltage and current
  - Subfield dc power, optimized for the most efficient cyclical utilization of insolation projected for the plant life span
  - PCS unit full-load power output
  - Substation full-load power output

- **Physical characteristics of arrays and source circuits**
- Size and configuration of one complete array assembly
- Number of arrays in one source circuit
- Spacing between arrays in the plant as required to minimize shadowing, provide access lanes, and accommodate structural parts
- Number of source circuits in a source circuit group and in a subfield

- Cabling and grounding
  - Circuit schematics
  - Configuration and layout of grounding grids and electrodes
  - Routes and raceways for all cable types

- Fault characteristics
  - Maximum short-circuit current values at all significant points on the dc and ac circuits
  - Minimum short-circuit current values at the same circuit points, based on the lowest plant operating level.

2.5.2 Characteristics of PV Plants Studied

In order to provide a basis for discussions of the plant subsystems, the essentials of the five representative types of PV arrays considered in this study are described. The baseline descriptions are for 2000 volt (±1000) source circuits. Alternative 800 volt (±400) source circuit configurations are also addressed in sections of this report.

Bechtel Torque-Tube. The Bechtel array is shown in Figure 2-1 and is based on an 8-by-36-foot panel, containing a 2-by-9 matrix of 4-by-4-foot modules. The support structure is a horizontal steel box beam (torque-tube), slightly longer than 36 feet, to which transverse module support rails are affixed at 4-foot intervals. The beam rests on cylindrical reinforced concrete piers, spaced 36 feet apart, and extending above and below grade.
For a large plant, each source circuit was assumed to comprise 32 series-connected arrays, which produce about 111 kW at 2,000 Vdc nominal. One subfield contains 48 source circuits, to drive one 5.0 MWac PCS unit.

JPL Buried Plate. The JPL array assembly is shown in Figure 2-2 and is based on an 8-by-20-foot panel, containing a 2-by-5 matrix of 4-by-4-foot modules. The support structure, extending above and below grade and including the anchor plate, is made of treated wood. Modules and arrays are framed with galvanized steel channel and angle members. For a large plant (e.g., 100 MW) each source circuit was assumed to comprise 58 series-connected arrays, which produce about 112 kW at 2000 Vdc nominal (at 1.0 kW/m² insolation). One subfield contains 48 source circuits, to drive one 5 MWac PCS unit.

Hughes Building Block. The Hughes assembly, shown in Figure 2-3, is based on an extended array, 8 feet high by 80 feet long in one version. Modules are each 2 by 4 feet, assembled into panels that measure 4 feet.
NOTE:
PLACE TRUSS STRUCTURE IN
1.5-ft-WIDE x 3.5-ft-DEEP x 9-ft-LONG TRENCHES
REFILL AND TAMPER TRENCHES
USING REMOVED EARTH.
SHADEd PORTION OF STRUCTURE IS BELOW GROUND LEVEL.

Figure 2-2. JPL Buried Plate Array (Ref. 2-3)

Figure 2-3. Hughes Array (Ref. 2-4)
wide by 8 feet high. The support structure is of galvanized steel angle and channel members extending above and below grade. The array in this design is extendable to any length desired, becoming, in effect, a continuous source circuit. Array output voltage in one version is 420 Vdc, and plant sizes of 10 kW (the "building block") and 100 kW (ten blocks) have been proposed.

Rack-Mounted Arrays. Generally these assemblies would be based on 4-by-4 or 2-by-4-foot modules. They may be mounted on a roof or on the ground. The array structure would be specially designed or adapted to fit each situation. It is likely that existing roofs will require structural and finish improvements to accommodate the weight, wind loading, and roof penetration problems imposed by PV arrays. However, these arrays would generally resemble the arrays shown by the preceding three figures, except for the lower portions and attachment (foundation) details on roof-mounted arrays. Two methods of roof attachment are shown in Figure 2-4 (Ref. 2-5). The pitch pocket design illustrates attachment directly to a building metal frame member, which offers a means of grounding the array structure. The curb design illustrates attachment via an insulating wood beam. For this design, a separate conductor must be used to provide the ground connection. This would also be the case for wood frame buildings and wood array structures. For industrial-type PV plants, whether mounted on a roof or on grade, dc output voltage from source circuits are specified to range from 300 to 600 Vdc for purposes of this study.

Concentrator Arrays. The Martin-Marietta array is shown in Figure 2-5 and is an integrated assembly containing sixty 1.41-by-4.82-foot modules, supported on a 44.3-foot horizontal tube and drive mechanism. The preassembled array is supported at its center by a reinforced concrete pier extending above and below grade. The tube assembly rotates on two axes in order to track the sun. For a large plant, each source circuit was assumed to comprise five series-connected arrays that are arranged in a cluster. Each source circuit produces about 21 kW at 978 Vdc nominal. One subfield contains about 250 source circuits to drive one 5.0 MWac PCS unit.
Figure 2-4. Typical Roof Attachments (Ref. 2-5)

Figure 2-5. Martin Marietta Fresnel Lens Array
2.5.3 Plans of PV Plants Studied

Drawings and electrical diagrams for a 100 MW plant, prepared for purposes of this study only, are shown in a set of figures in Appendix B.

For plants smaller than 100 MW (to 5.0 MW), the 5.0 MW PCS unit remains a good technical and economic choice. If subfield redundancy is a requirement, then 500 kW would be a logical next smaller PCS unit rating. Similarly, the still lower range of PV plant sizes could be covered by two more PCS unit ratings, 100 KW and 20 KW.

The multiple-of-five MW progression in ratings is only a suggestion; there are currently no commercial equipment families offered on this basis.

For PV plants larger than 100 MW, no clear advantages arise by postulating PCS ratings above 5.0 (or, possibly, 10.0 MW). For example, a 50.0 MW unit would require 25,000 A input circuits at 2,000 Vdc, which would pose difficult problems in switching and protection. Plants larger than 100 MW should, however, be arranged and developed so as to require only one ac substation.

2.6 MODELING TYPICAL ARRAY PARAMETERS

A knowledge of typical array and source circuit voltages and currents under varying operating conditions is required for effective photovoltaic grounding and fault protection system design. In this section, typical array voltages and currents are developed for two array designs (JPL Buried Anchor Plate and Bechtel Torque Tube) as an example of the design process. The results are used to make predictions of maximum source circuit voltages and currents as a function of annual temperature fluctuations in Albuquerque, N.M. The results are also used to develop a typical I-V curve for an array panel. The equations for the I-V characteristics are given and these may be used for modeling array behavior under various fault conditions (see Appendix D).
2.6.1 Maximum Array Voltages and Currents

Generally, array voltage and current are determined by individual cell characteristics, array electrical configurations (i.e., number of cells in series and parallel), amount of insolation, cell operating temperature and cell operating point. The cell operating point is typically the maximum power point for the given conditions of insolation and cell temperature. However, calculations of the maximum voltage and current experience require consideration of the open-circuit and short-circuit operating points for given conditions of insolation and temperature. Maximum voltage across the cell (or source circuit, which consists of a series string of cells) occurs when there is an open circuit. This is the condition when there is no load applied or when a fault occurs which opens the circuit. Maximum current in a cell or source circuit occurs when a fault condition (such as a ground fault) exists at some point of the circuit.

Cell voltage, current, and power output at three operating points (maximum power point, open circuit, and short circuit) are normally specified by cell manufacturers for nominal operating conditions (e.g., 1 kW/m² insolation and 20°C ambient temperature). In addition, temperature coefficients for cell voltage and current may be determined from the manufacturer's literature. For a flat-plate array, the nominal operating cell temperature (NOCT) may be approximated from ambient temperature by

\[ \text{NOCT} = T_{\text{cell}} = T_{\text{air}} + 0.3 Q \]

where \( Q \) is the insolation expressed in mW/cm², and \( T_{\text{air}} \) is the nominal ambient air temperature. Open circuit voltage \( (V_{\text{oc}}) \) varies inversely with cell temperature and thus will be greatest for most locales in the winter. Short-circuit current \( (I_{\text{sc}}) \) increases somewhat with cell temperature.

Source circuit voltages and currents were developed assuming a 100 MW plant sited in Albuquerque, N.M. Array dimensions and the subfield configuration were as described in Section 2.5.2 for the two designs.
chosen. The subfield source circuits were postulated to produce a nominal 5 MWac at 2,000 Vdc at the input terminals of the PCS.

The subfield bus voltage is nominally ± 1,000 V with respect to the array ground. Typical source circuit voltages and currents at the maximum power point (V\text{mp} and I\text{mp}) were calculated using panel dimensions for the two designs. Array efficiency was postulated to be 13 percent at 1 kW/m\(^2\) insolation and 20°C ambient air temperature (50°C NOCT). The results are shown in Table 2-1. Also shown in Table 2-1 are typical values of the source circuit open-circuit voltage (V\text{oc}) and short-circuit current (I\text{sc}), for both NOCT and annual temperature extremes expected in Albuquerque.

Average values of the ratio of open-circuit voltage to maximum power point voltage (V\text{oc}/V\text{mp}) and of short-circuit current to maximum power point current (I\text{sc}/I\text{mp}) were determined from manufacturers' literature for several currently available solar cells. Multiplying V\text{mp} and I\text{mp} by these ratios yields maximum voltage and current at NOCT. Average values of the temperature coefficients for cell voltage and current were also obtained from manufacturers' data. These were used to calculate the maximum open-circuit voltage and short-circuit current for the annual temperature extremes experienced by an array sited in Albuquerque, N.M. The voltage and current ratios and temperature coefficients used are summarized in Table 2-2.

Weather data compiled by the Engineering Meteorology Section of the U.S. Air Force Environmental Technical Applications Center (cited in Ref. 2-6), records the annual temperature extremes over a 12-year period in Albuquerque. During the hours 9 a.m. to 4 p.m. (approximately the hours of array operation), the lowest temperature recorded was in the range 5° to 9°F (10° to 18°C), occurring in the month of January. The highest recorded temperature occurred in the month of July and was in the range 100° to 104°F (35° to 43°C). Nominal values of 14° and 39°C for the lowest and highest temperatures, respectively, were used for the present calculations.
### Table 2-1

**SOURCE CIRCUIT VOLTAGES AND CURRENTS FOR TWO ARRAY DESIGNS SITED IN ALBUQUERQUE, NEW MEXICO**

<table>
<thead>
<tr>
<th>Array Design</th>
<th>Nominal Subfield Output</th>
<th>Nominal Subfield Voltage</th>
<th>Source Circuit at NOCT(50°C) 1kW/m² Insolation</th>
<th>Source Circuit at the Annual Temperature Extremes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MWac Vdc Vmp Voc Imp Isc</td>
<td></td>
<td>V oc max</td>
<td>I sc max</td>
</tr>
<tr>
<td>Torque Tube</td>
<td>5</td>
<td>2,000 1,977 2,530 56.3 63.1</td>
<td>2,883 63.6</td>
<td></td>
</tr>
<tr>
<td>Buried Plate</td>
<td>5</td>
<td>2,000 1,991 2,548 56.3 .63.1</td>
<td>2,903 63.6</td>
<td></td>
</tr>
</tbody>
</table>

where

- \(V_{mp}\) = Source circuit voltage at the maximum power point (at NOCT)
- \(V_{oc}\) = Source circuit voltage for open-circuit conditions (at NOCT)
- \(V_{oc\, max}\) = Maximum source circuit voltage for open-circuit conditions (at annual temperature extremes)
- \(I_{mp}\) = Source circuit current at the maximum power point (at NOCT)
- \(I_{sc}\) = Source circuit current for short-circuit conditions (at NOCT)
- \(I_{sc\, max}\) = Maximum source circuit current for short-circuit conditions (at annual temperature extremes)

### Table 2-2

**AVERAGE SOLAR CELL ELECTRICAL CHARACTERISTICS (FROM MANUFACTURER’S SPECIFICATIONS)**

<table>
<thead>
<tr>
<th>Temperature Coefficients (at 25°C)</th>
<th>Temperature Coefficients (at 25°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(V_{oc}/V_{mp})</td>
<td>(V_{mp}/V/V^°C)</td>
</tr>
<tr>
<td>(I_{sc}/I_{mp})</td>
<td>(V_{oc}/V/V^°C)</td>
</tr>
<tr>
<td>(V_{oc}/V_{mp})</td>
<td>(I_{mp}/A/A^°C)</td>
</tr>
<tr>
<td>(I_{sc}/I_{mp})</td>
<td>(I_{sc}/A/A^°C)</td>
</tr>
<tr>
<td>1.28</td>
<td>-0.004</td>
</tr>
<tr>
<td>1.12</td>
<td>-0.004</td>
</tr>
<tr>
<td>(+0.04)</td>
<td>(-0.001)</td>
</tr>
<tr>
<td>(+0.04)</td>
<td>(+0.001)</td>
</tr>
<tr>
<td>(+0.001)</td>
<td>(+0.003)</td>
</tr>
<tr>
<td>(+0.0005)</td>
<td></td>
</tr>
</tbody>
</table>
From the data presented in Table 2-1, it may be concluded that source circuit electrical insulation must be designed for voltages exceeding the maximum power point voltage by about 46 percent. On the other hand, ground and bus conductors must carry about 13 percent more current than the rated maximum power point current.

2.6.2 Typical Panel I-V Characteristics

Based upon the source circuit electrical parameters given in Table 2-1, a typical I-V curve was constructed for the Bechtel torque tube array design. The curve is shown in Figure 2-1 for two cell temperatures. The equation for the I-V characteristic has the form

\[ I = I_{sc} \left[ 1 - \exp \left( \frac{V-V_{oc}}{V_{o}} \right) \right] \]

where the subscripted parameters refer to the array panel rather than the source circuit. It is assumed that each cell operates as a current source in parallel with an ideal diode with a very large shunt resistance and negligible series resistance. It is also assumed that all cells have identical I-V characteristics, and that there are no internal losses resulting from mismatches between cells or cell interconnections. For a more detailed analysis in which the effects of these assumptions are considered, the reader is referred to References 2-7, 2-8, and 2-9. No assumptions about individual cell size or the specific electrical configuration of the cells within the array panel are made.

The parameters \( V_{oc} \), \( I_{sc} \), and \( V_{o} \) are dependent upon temperature and insolation. For the I-V curves shown in Figure 2-1, these parameters were assumed to obey the following approximate relationships:

\[
\begin{align*}
I_{sc} &= 62.26 \ Q + 0.03822 \ Q \ (T_{cell} - 28) \\
V_{oc} &= 85.28 - 0.2854 \ (T_{cell} - 28) + 3.373 \ln \ Q \\
V_{o} &= 0.02470 \ (T_{cell} + 273)
\end{align*}
\]
In the above equations $T_{\text{cell}}$ is the cell operating temperature, °C, and $Q$ is the incident insolation, kW/m$^2$. At $T_{\text{cell}} = 50^\circ$C (NOCT) and $Q = 1$ kW/m$^2$, $I_{sc} = 63.1$ A and $V_{oc} = 79.0$ V. These results are in close agreement with the numbers shown in Table 2-1 for the torque tube array source circuit. (The source circuit voltage must be divided by 32 to obtain the array panel voltage.) The parameter $V_o$ is the thermal voltage of the solar cells and is usually given by

$$V_o = (nkT/e) \times \text{(correction factor)}$$

where $k$ is Boltzman's constant, $e$ is the charge on the electron, $T$ is the absolute temperature and $n$ is the number cells in series. The correction factor has been chosen to approximately model the data presented for the torque tube in Table 2-1. $V_o$ is assumed to be dependent only upon cell temperature. At $T_{\text{cell}} = 50^\circ$C, $V_o = 7.978$ Vdc.

Given $V_o$, $V_{oc}$ and $I_{sc}$ for the I-V characteristic in Figure 2-1, the corresponding values of $V_{mp}$ and $I_{mp}$, the maximum power point voltage and current, may be obtained analytically by

$$V_{mp} = V_{oc} - V_o \ln(1 + V_{mp}/V_o)$$

$$I_{mp} = I_{sc} \left[1 - \exp \left(\frac{V_{mp} - V_{oc}}{V_o}\right)\right]$$

The expression for $V_{mp}$ may be solved iteratively using Newton's method and the result used to calculate $I_{mp}$. At $T_{\text{cell}} = 50^\circ$C and $Q = 1$ kW/m$^2$, the above expressions give $V_{mp} = 61.7$ Vdc and $I_{mp} = 55.9$ A, which are in agreement with the data in Table 2-1 for the torque tube.

2.7 SITE CHARACTERISTICS

It is important to make an early determination of the site characteristics that will affect design of PV grounding facilities. The items considered pertinent to the design of grounding equipment, circuits, and structures are listed below. Several of the characteristic parameters may be non-uniform if examined over a large area. Therefore,
mapping would be required to obtain correct information (as is current practice for conventional installations occupying similarly large areas).

- Type of earth surface and types of subgrade soil (to a depth of ten feet, for example, or greater, if the soil resistivity is high near the surface)

- Soil resistivity at the surface and in one or more discrete layers; including wet or dry conditions at the surface, and seasonal variations

- Chemical composition of the soil, as it would affect corrosion, conductivity, and water retention
- Feasibility of making shallow excavations, boring holes, and driving rods; and type of backfill
- Character of underlying rock layers
- Frost line depth predictions
- Water table and moisture level projections for future years
- Bacteriological and fungicidal conditions in the soil
- Rodent population, existing and predicted
- Lightning stroke frequency, current peak and duration probabilities, and seasonal and daily patterns
- Contours of the PV area, after site preparation
- Drainage characteristics of the improved site
- Contours of the terrain and profiles of foreign structures outside the PV site
- Natural or man-made conducting features on the surface or below grade within the PV area (e.g., buried pipes)
- Ambient temperatures (seasonal and daily variations)
- Rainfall, snow, icing, and hailstorm patterns
- Airborne pollutants, existing and predicted

2.7.1 **Major Parameters**

After review of previous work, and based on design experience, several characteristics are judged to be major or critical parameters that will govern the design of PV grounding systems and their costs. These include:

- **Site characteristics**
  - Soil resistivity governs the quantity of ground grid conductors or rods to be buried or driven
  - Freezing depth dictates the minimum depth of burial for grounding grid conductors (and structure foundations)
  - Soil physical properties influence the feasibility and cost of trenching and backfill for grounding grid conductors (as well as for other subsystems)
- Lightning stroke characteristics, as the most likely source of very high current surges, may govern design of the PV field ground mat

- **System characteristics**

  - Array efficiency, array size, and interarray spacing set the land packing density and thereby influence ground mat design

  - Foundation design impacts the method of ground grid installation, as well as being a potential contributor to lowering ground resistance and mesh potential

  - Array structure and/or module construction and materials impact the grounding system design, because exposed metal parts must be grounded or guarded

2.7.2 **Soil Resistivity**

Soil resistivity is a direct factor in determining the potential rise of a buried grid when fault current is imposed from an outside source. It will have less influence in determining the magnitude of various fault currents, and of the differential voltages that could develop across a very large-mesh grid.

In calculating grid rise voltages to be expected at a specific site, local measurements of resistivity at that site are essential because general tables or maps cannot provide sufficiently accurate data. The best procedure is to prepare a resistivity "contour" map of the PV field area. Layering of the soil at moderate depths may be encountered. If so, this requires investigation and further mapping at selected depths because of its possibly significant effects in very large fields.

To illustrate the possible range of resistivities, some published values are shown in Table 2-3, and a map is shown in Figure 2-2.
Figure 2-7. Resistivity Map of the United States (Ref. 2-11)
Table 2-3

TYPICAL VALUES OF EARTH RESISTIVITY

From IEEE Standard 80-1976 (Ref. 2-10):

<table>
<thead>
<tr>
<th>Type of Ground</th>
<th>Resistivity (ohm-meters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wet organic soil</td>
<td>10</td>
</tr>
<tr>
<td>Moist soil</td>
<td>$10^2$</td>
</tr>
<tr>
<td>Dry soil</td>
<td>$10^3$</td>
</tr>
<tr>
<td>Bed rock</td>
<td>$10^4$</td>
</tr>
</tbody>
</table>

From EPRI Report EL-2699 (Ref. 2-11):

<table>
<thead>
<tr>
<th>Material</th>
<th>Resistivity (ohm-meters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loams, garden soils</td>
<td>5 to 50</td>
</tr>
<tr>
<td>Clay, chalk</td>
<td>10 to 70</td>
</tr>
<tr>
<td>Clay, sand, gravel mixtures</td>
<td>40 to 250</td>
</tr>
<tr>
<td>Peat, marsh soil, cultivated soil</td>
<td>50 to 250</td>
</tr>
<tr>
<td>Diabase, shale, limestone, sandstone</td>
<td>100 to 500</td>
</tr>
<tr>
<td>Sand, cambrian limestone, sandstone</td>
<td>$1 \times 10^3$ to $3 \times 10^3$</td>
</tr>
<tr>
<td>Moraine, quaternary surface coarse sand and gravel</td>
<td>$1 \times 10^3$ to $1 \times 10^4$</td>
</tr>
<tr>
<td>Igneous rocks, granite</td>
<td>$3 \times 10^5$ to $4 \times 10^7$</td>
</tr>
<tr>
<td>Wet concrete</td>
<td>50 to 100</td>
</tr>
<tr>
<td>Dry concrete</td>
<td>$2 \times 10^3$ to $1 \times 10^4$</td>
</tr>
</tbody>
</table>
Section 3

OUTLINE OF DESIGN STEPS

This section highlights the major steps to be taken in the design of grounding and fault protection subsystems for PV plants. The numbers in parentheses following the steps refer to sections of the report or references where further details can be found. Both utility- and industrial-type plants are addressed. An example of these steps is presented in Appendix F.

3.1 UTILITY-TYPE PLANT

The criteria presented in Section 2.2 should be reviewed and incorporated into the design process.

- For an A/E designing and constructing the plant, the grounding practices of the client utility should be reviewed and incorporated. On any items where such utility practice may deviate from special practice that may benefit the PV plant (and yet be safe), the deviation would likely have to be justified to utility personnel and client approval obtained before proceeding with the design.

- Determine the soil chemistry for all parts of the proposed site, including the site for the remote substation, if this option is contemplated. (Sect. 4.2.5)
  - Decide whether the soil is compatible with buried copper cables by soil analysis and examination of older facilities in the same area. (Sect. 4.6.1, 4.6.2)

- Measure the soil resistivity for all parts of the proposed site, including any layers that have distinctively different values. (Ref. 3-1)

- Determine the depth at which the soil can be considered an effective conducting medium under worst-case conditions of drying and freezing. (p. 4-64)

- Determine whether the underlying geology or any prior man-made installations would introduce special grounding problems.
- Look for underlying rock layers, relatively close to the surface, that would tend to isolate the PV site electrically from true remote earth.

- Look for man-made features, such as pipelines or buried cable lines, that would distort the soil conductivity or transfer foreign voltages (including true remote earth potential) into the array field area. (p. 4-41)

- Determine soil composition and workability of the soil.
- Assess whether trenching, backfilling, driving ground rods, and/or drilling small vertical holes would be feasible operations.

- Decide whether any of the foregoing site characteristics would pose unacceptable electrical problems at the proposed site.

- Establish the layout of array foundations for the PV field. (Sect. 2.5)

- Establish the general cabling routing for dc, ac, instrumentation, and ground cables in the PV field and subfields. (Sect. 4.2)
  - Decide whether the array foundations can be used as grounding electrodes. (Sect. 4.3.4)
  - Define a trial design for a reinforced concrete electrode, and calculate resistance to earth for one unit. (App. C)
  - Define the layout and connections for grounding cables in the field and subfields. (Sect. 4.2)
  - Calculate resistance to earth for the matrix of interconnected array foundations and buried ground wires. (App. C, Sect. 4.4.3)

- Estimate leakage current and any stray currents due to module or source circuit unbalances. Calculate corrosion rates for the system configuration selected to assure compatibility with a 30-year plant life. (Sects. 4.6.3, 4.6.4)

- Determine the maximum ground fault current and backup clearing time imposed by the utility network for faults on the high-voltage circuits at the substation. (Sects. 4.2.5, 4.5.2)
- Calculate the grounding grid configuration and surface treatment required in the substation area, using IEEE Standard 80. (Sect. 4.4.3)

- Calculate resistance to earth and maximum voltage rise and duration for the substation grounding grid.

- Determine the level to which the low voltage (34.5, 13.8, or 4.16 kV) circuit ground fault current should be limited.

- By making trial calculations and considering other constraints, decide whether the substation should be close to and tightly coupled with the PV field grounding matrix, or whether it should be moved some distance away and decoupled. (Sect. 4.4.3, Ref. 3-2)

- Define the high-voltage and low-voltage (34.5, 13.8, or 4.16 kV) circuits, buses, and major equipment required in the substation, including auxiliary power and grounding transformers.

- Establish lightning protection design. (Sect. 4.5)

- Make provisions to clear array field area of personnel upon impending storms, or

- Provide shielding or air terminal protection for array field area.

- Determine governing current (lightning, ac or dc fault) and calculate maximum step, touch, and reach potentials. (Sect. 4.4.2)

- Use fault-induced potentials to specify fault protection system backup clearing times.

- Interactively modify ground and fault protection system designs to bring potentials within allowable limits.

- Make a trial design for the dc power circuits in a typical subfield. (Sect. 5.1, 5.2)

- Establish the dc performance and protective characteristics of the PCS. (Sect. 5.3)

- Define tentative dc protective devices and performance specifications for the entire subfield, including the PCS. (Sects. 5.3, 5.6)

- Make a fault effects and fault clearance tabulation for the trial design. (Sect. 5.5)
- Rework the dc circuitry, the device selections, and performance specifications until a workable design is developed. (Sect. 5.5, 5.6)

- Complete the definition of PCS protective devices, including both ac and dc circuits. (Sect. 5.3)

- Complete the design of ac substation grounding and protective devices verifying that these correlate with the PCS units, the utility transmission circuits, and the safe clearing time requirements in PV field and substation. (Sect. 4.25, 5.1.1, Ref. 3-3)

- Complete the specifications for ac and dc circuits and equipment in the subfields and field. (Sect. 4.2.7)
  - Define the configuration of termination equipment enclosures. (Sect. 5.6)
  - Prescribe design review and prototype testing for all apparatus of new or modified commercial types. (Refs. 3-4, 3-5)

- Establish bonding details
  - Ground wires, bonds, and jumpers should be sized to resist mechanical and corrosion damage as well as to carry fault currents. (Ref. 3-6)
  - Field connections should not destroy factory-applied protective coatings on structures, etc. Where they do, apply new coatings after the ground connections are made.
  - Ground connections and risers should be routed to resist mechanical damage. (Ref. 3-6)
  - Exposed metal parts should be joined and connected to ground in ways that will provide a corrosion-free, secure path by means of inherent structural detail or by separate ground connections. (Refs. 3-6, 3-7)
  - Flexible jumper cables should be used around bearings and gearboxes on tracking arrays and on fence gates.
  - Connections between ground or earth and lightning protective devices should be as short and straight as possible to minimize transient voltage rise. The potential for sideflash should also be considered. (Refs. 3-6, 3-7)
3.2 INDUSTRIAL-TYPE PLANT

Design of the grounding and fault protection subsystems for commercial/industrial-type PV plants would generally follow the design steps outlined for utility plants. These steps are listed for ground-mounted arrays in Section 3.2.1. Changes required for roof-mounted arrays are presented in Section 3.2.2.

3.2.1 Ground-Mounted Arrays

As for the utility plant, the criteria presented in Section 2.2 should be reviewed and incorporated into the design steps:

- The local utility should be contacted regarding interface requirements for the PV system and its converter. The need for an isolation transformer should be examined during these discussions. (Sect. 5.4)

- Similarly, state and local codes should be reviewed for requirements and their impact on postulated design details. Although such codes generally follow the National Electric Code, variations abound.

- Particular attention should be paid to who may have access to the PV system area and its equipment. This item also includes assessing the skills and training of the owner's staff if they are to perform maintenance on the system.

- Determine the soil chemistry for the proposed site. Decide whether the soil is compatible with buried copper cables by soil analysis and examination of facilities existing at the site and other facilities in the same area. (Ref. 3-1)
• Measure the soil resistivity at several areas of the proposed site, including any layers that have distinctively different values. Fewer measurements would be required for this size plant than for the larger utility-type plant. (Ref. 3-1)

• Determine the depth at which the soil can be considered an effective conducting medium under worst-case conditions of drying and freezing. (p. 4-64)

• Determine whether the underlying geology, or any prior man-made installations by man would introduce special grounding problems.
  - Look for man-made features, such as buried pipe or cable lines, that would distort the soil conductivity or transfer voltages out of the array field into areas accessible by the public. Checking with the local gas, water, and electric utilities and records of existing plants would be a good starting point but would not be sufficient to detect unrecorded pipes, etc. (p. 4-41)
  - Any existing pipes, etc. that cannot be removed must be integrated into the PV system. The possibility of such buried metal being subject to electrolytic corrosion by PV system leakage currents must be assessed. (Sect. 4.6.2)
  - Look for underlying rock layers, relatively close to the surface, that would tend to isolate the PV site electrically from true remote earth.

• Determine soil composition and workability of the soil.
  - Assess whether trenching, backfilling, driving ground rods, and/or drilling small vertical holes would be feasible operations.

• Decide whether any of the foregoing site characteristics would pose unacceptable electrical problems at the proposed site.

• Establish the layout of array foundations for the PV field. (Sect. 2.5)

• Establish the general cabling routing for dc, ac, instrumentation, and ground cables in the PV field and subfields. (Sect. 4.2)
  - Decide whether the array foundations can be used as grounding electrodes. (Sect. 4.3.4)
- Define a trial design for a reinforced concrete electrode, and calculate resistance to earth for one unit. (App. C)

- Define the layout and connections for grounding cables in the field and subfields. (Sect. 4.2)

- Decide whether a layer of crushed rock will be used on the array field for aesthetic, dust control, and/or electrical reasons.

- Calculate resistance to earth for the matrix of interconnected array foundations and buried ground wires. (App. C, Sect. 4.4.3)

- Consider in detail the fence area separating the array field from areas of public access. Additional buried ground grid may be required outside of the fence if metal fences are to be used. (p. 4-41)

- Estimate leakage current and any stray currents due to module or source circuit unbalances. Calculate corrosion rates for the system configuration selected to assure compatibility with a 30-year plant life. (Sects. 4.6.3, 4.6.4)

- Determine the maximum ground fault current and backup clearing time imposed by the utility network for faults on the ac circuits at the plant substation or utility interface point. (Sects. 4.2.5, 4.5.2)

- Calculate the grounding grid configuration and surface treatment required in this area by using IEEE Standard 80. (Sect. 4.4.3)

- Calculate resistance to earth and maximum voltage rise and duration for the grounding grid in this area.

- Determine the level to which the ac voltage circuit ground fault current should be limited. (p. 2-3) Such levels may be lower for most industrial plants compared to utility central stations, but they cannot be ignored.

- Establish lightning protection design. (Sect. 4.5)

- Make provisions to clear array field of personnel upon impending storms, or

- Provide shielding or air terminal protection for array field.
- Determine governing current (lightning, ac or dc fault) and calculate maximum step, touch, and reach potentials. (Sect. 4.4.2)
  - Use fault-induced potentials to specify fault protection system backup clearing times.
  - Interactively modify ground and fault system designs to br limits.
- Make a trial design for the dc power circuits in a typical subfield. (Sects. 5.1, 5.2)
- Establish the dc performance and protective characteristics of the PCS. (Sects. 5.3, 5.4)
  - Include provisions for utility personnel to remove and lock out this active source from their lines for maintenance or other reasons.
  - Assess the fault contribution capability of the PCS and coordinate protection with the utility.
  - Incorporate utility system requirements regarding harmonic or dc injection, metering, and other requirements, as necessary.
- Define tentative dc protective devices and performance specifications for the entire subfield, including the PCS. (Sects. 5.3, 5.6)
  - Make a fault effects and fault clearance tabulation for the trial design. (Sect. 5.5)
  - Rework the dc circuitry, the device selections, and performance specifications until a workable design is developed. (Sects. 5.5, 5.6)
- Complete the definition of PCS protective devices, including both ac and dc circuits. (Sects. 5.3, 5.6)
  - Submit the proposed design for approval of the local utility.
- Complete the specifications for ac and dc circuits and equipment in the subfields and field. (Sect. 4.2.7)
  - Define the configuration of termination equipment enclosures. (Sect. 5.6)
Prescribe design review and prototype testing for all apparatus of new or modified commercial types. (Refs. 3.4, 3.5)

- Establish bonding details.

- Field connections should not destroy factory-applied protective coatings on structures, etc. Where they do, apply new coatings after the ground connections are made.

- Ground wires, bonds, and jumpers should be sized to resist mechanical and corrosion damage as well as to carry fault currents. (Ref. 3-6)

- Ground connections and risers should be routed to resist mechanical damage. (Ref. 3-6)

- Exposed metal parts should be joined and connected to ground in ways that will provide a corrosion-free, secure path by means of inherent structural detail or by separate ground connections. (Refs. 3-6, 3-7)

- Flexible jumper cables should be used around bearings and gearboxes on tracking arrays and on fence gates.

- Connections between ground or earth and lightning protective devices should be as straight as possible to minimize transient voltage rise. The potential for sideflash should also be considered. (Refs. 3-6, 3-7)

- During the course of the design, submit proposed and final designs for the approval of cognizant local code authorities and the interconnecting utility.

- Define the procedures to be used for installation of all grounding and protective materials and equipment including safety precautions. (Ref. 3-8)

- Define the procedures, tools, devices, and instruments to be used for ongoing maintenance of all grounding and protective facilities. The maintenance requirements specified by the manufacturers of the equipment should be incorporated.

- Define the safety procedures to be used for ongoing operations and maintenance. (Ref. 3-8)
3.2.2 **Roof-Mounted Arrays**

Roof-mounting of the arrays necessitates several obvious changes to the design steps outlined in Section 3.2.1 for ground-mounted arrays in a commercial/industrial type application. These changes are given below.

- Measurements of soil resistivity are not necessary. However, the adequacy of the existing (or planned) building ground must be determined.

- Determine whether the building has a ground conductor and earthing system adequate for addition of a PV plant, or whether the existing grounding system must be augmented.

- Building structural metal, pipes, conduits, and other metal parts on or immediately below the roof must be evaluated with respect to their effect on step, touch, and reach potentials. The conventional equations used to calculate ground voltage differentials (generally) will not apply. Special analyses would be required to evaluate potentials through and along the roof materials. Since roof construction may vary from metal decking (conductor) to tar and gravel over a wooden structure (insulator), no general solution is possible.

- The possible inherent connection of the array structure with the building structural ground should be considered during the array design (see Figure 2-4).

- Conduit and raceways should be used for the wiring. Local code requirements will govern whether these may be plastic or must be metal.

- The architecture of the roof area and array layout should be considered to determine the possible need for a guard rail or fence to prevent an otherwise nonhazardous voltage from causing a worker to recoil and fall from the building.

- Locate a sheltered and accessible position for mounting the PCS unit, switchgear, transformer, and control panels.

- Lay out a configuration for catwalks that may be required to support inspection and maintenance activities.

- Determine how grounding and power cable routes and penetrations can be installed to connect the external components to the interior apparatus (PCS, switchgear, transformer, etc.).

- Design a network of roof-top conductors and down-leads that will meet code requirements for installation of lightning air terminals.
Section 4

GROUNDING

The design and installation of grounding subsystems for PV plants embrace both conventional and unique methods. The design choices with which the PV system designer is faced are presented in this section. The emphasis is on how conventional utility and industrial practices must be modified or dispensed with and upon the coordination of the grounding subsystem design with the overall plant design. Specific approaches for implementing the grounding criteria presented in Section 2 are provided. The role of the grounding subsystem in lightning protection is also discussed.

4.1 ALTERNATIVE METHODS FOR SOURCE CIRCUIT GROUNDING

Most of the design steps required to define grounding subsystems for PV plants can be adopted directly from codes, regulations, and industrial/utility practices. However, there are some areas where conventional methods and prior experience do not provide clear design directions.

One of these special areas is the selection of a grounding concept for the active dc circuits in an array subfield (e.g., floating, midpoint ground, etc.). This is analogous to selecting the form of neutral grounding in three-phase power circuits, a subject which has been analyzed exhaustively over many decades. Also, there is relevant precedent in the connection options long used for rotating dc generators. But the lessons learned from these older technologies are not all directly transferable to PV source circuits and PCS inverters.

At an early stage in design, one of the several alternative methods for providing a ground reference level in array and PCS dc circuits must be selected. This is essential because many details of subfield layout, protective functions, and cable routing depend upon this choice.
4.1.1 Large Plants

For utility-type plants where the subfield circuits may operate at 2000 Vdc or higher between output terminals, strong justification exists to hold the electrical midpoint of each source circuit at or near ground potential during normal operation. This design imposes the least electrical stress on cable and equipment insulation, it provides a convenient tie point (at low potential) where monitoring sensors may be installed, and it produces an overall network symmetry that is beneficial. An alternate possibility is to have no ground reference. This and mid-point ground methods are discussed in the following paragraphs.

Ungrounded Subfield Circuits. The possibility of operating the dc circuits with no intentional ground reference has several disadvantages, including showing little effort to meet code intents. Sensing abnormal circuit conditions would be more difficult and vulnerability to arcing ground faults might be greater. However, grounding dc circuits through very high resistance may be practical and beneficial in some respects. If specific advantages could be found for the dc floating source circuit configuration, then precedent could be cited and certain escape clauses could likely be invoked to permit installation of such a design. For example, 2400 and 4800 Vac ungrounded power distribution systems have been used for years, and are still the norm in many areas. But the trend in codes, guides, and practice is toward some type of grounded circuitry.

If a definite fault should occur in a completely ungrounded PV subfield from either polarity to earth, it could be detected by unpolarized or bi-polar voltage relays connected from mid-point to earth. Such relays could be connected to trip or alarm. However, it is not clear that such relays would be available in a sufficiently rugged design for this service, nor that voltage symmetry with respect to ground of the dc circuits would remain sufficiently stable for this method to work reliably.
Partial or intermittent faults to earth might be more difficult to handle. Examples of this would be a fault path through a carbonized track on an insulating board or fixture, or a path through a pin-hole puncture in insulation. After initial breakdown at operating voltage, (e.g., 1000 volts dc plus contributions from switching transients or lightning impulses) voltage on the line conductors would be unbalanced with respect to earth and current would flow through the shorting path. Current flow would continue until the dc system capacitances that are not blocked by diodes have discharged to a low voltage. At some point the current might decrease to extinction level, and become zero for awhile. This sequence could occur so rapidly that a relay would not have time to detect the fault. Thus the fault might recur and recycle for a long time before being discovered.

If a second fault on the other polarity should develop before the first fault is repaired, a high-current line-to-line fault would probably result. Back-up relays or fuses would be required to protect against this type of fault. However, a line-to-line fault involving two separate locations is difficult to deal with in typical relay design.

The floating ground method would probably be improved by adding a surge suppressor at the neutral point of each branch circuit.

At this writing, there seem to be no strong incentives to pursue the totally ungrounded system. Capital costs might be lower, but a third conductor (ground) would probably still be required. All exposed metal parts in the array field must be grounded. Also, the maximum electrical stress across the module insulation in ungrounded systems is twice that of center grounded systems. Monitoring and protection functions would be required and would, in general, be more difficult to implement for ungrounded systems.

**Solid Midpoint Grounding of Each Array.** This method is probably closest to the general intent of NEC and similar codes. Pertinent Code paragraphs are reproduced below because of their importance:

4-3
NEC 81 250-1:

"Scope. This article covers general requirements for grounding and bonding of electrical installations, and specific requirements in (a) thru (f) below.

(a) Systems, circuits, and equipment required, permitted or not permitted to be grounded.

(b) Circuit conductor to be grounded on grounded systems.

(c) Location of grounding connections.

(d) Types and sizes of grounding and bonding conductors and electrodes.

(e) Methods of grounding and bonding.

(f) Conditions under which guards, isolation, or insulation may be substituted for grounding."

NEC 81 250-3:

"B. Circuit and System Grounding


(a) Two-Wire Direct Current Systems. Two-wire dc systems supplying premises wiring shall be grounded. Exception No. 3: A system operating at over 300 volts to ground.

(b) Three-wire Direct Current Systems. The neutral conductor of all 3-wire dc systems supplying premises wiring shall be grounded."

"C. Location of System Grounding Connections


(a) Arrangement to Prevent Objectionable Current. The grounding of electric systems, circuit conductors, surge arresters, and conductive noncurrent-carrying materials and equipment shall be installed and arranged in a manner that will prevent an objectionable flow of current over the grounding conductors or grounding paths.

(b) Alterations to Stop Objectionable Current. If the use of multiple grounding connections results in an objectionable flow of current, one or more of the following alterations shall be made:

(1) Discontinue one or more such grounding connections.
(2) Change the locations of the grounding connections.

(3) Interrupt the continuity of the conductor or conductive path interconnecting the grounding connections.

(4) Take other suitable remedial action satisfactory to the authority having jurisdiction.

(c) Temporary Currents Not Classified As Objectionable Currents. Temporary currents resulting from accidental conditions, such as ground-fault currents, that occur only while the grounding conductors are performing their intended protective functions shall not be classified as objectionable current for the purposes specified in (a) and (b) above.

250-22. Point of Connection for Direct-Current Systems. DC systems to be grounded shall have the grounding connection made at one or more supply stations. A grounding connection shall not be made at individual services nor at any point on premises wiring."

Proposed Addition to NEC 81:

"E. Grounding

6XX-41 System Grounding. For a photovoltaic power source, one conductor of a two-wire system and a neutral conductor of a three-wire system shall be solidly grounded.

Exception: Other methods which accomplish equivalent system protection and which utilize equipment listed and identified for the use shall be permitted."

"6XX-42 Point of System Grounding Connection. The direct-current circuit grounding connection shall be made at any single point on the photovoltaic output circuit.

FPN - Locating the grounding connection point as close as practicable to the photovoltaic source will better protect the system from voltage surges due to lightning."

"6XX-44 Common Grounding Electrode. Exposed noncurrent-carrying metal parts of equipment and conductor enclosures of a photovoltaic system shall be grounded to the grounding electrode that is used to ground the direct-current system. Two or more electrodes that are effectively bonded together shall be considered as a single electrode in this sense."

The foregoing paragraphs allow flexibility and options in circuit layout, especially for utility PV installations. The truly important sense of
the NEC code is conveyed in the fine print note that follows

Article 250-1:

"Systems and circuit conductors are grounded to limit voltages due to lightning, line surges, or unintentional contact with higher voltage lines, and to stabilize the voltage to ground during normal operation. Systems and circuit conductors are solidly grounded to facilitate overcurrent device operation in case of ground faults.

Conductive materials enclosing electrical conductors or equipment, or forming part of such equipment, are grounded to limit the voltage to ground on these materials and to facilitate overcurrent device operation in case of ground faults. See Section 110-10."

Most partial ground faults will quickly progress into solid faults to ground, and can be detected by current sensors in the neutral. The high currents possible with solid grounding would be a disadvantage because of possible damage at the fault location, and because abnormal stray voltages would be higher. But there may be circuit, diode, and relay configurations where this could be turned to advantage in detecting and isolating faults quickly. All potential fault locations on source circuit conductors, dc feeders, and the PCS dc bus would have to be evaluated to resolve this question in specific designs.

Unbalanced voltage output from the positive and negative halves of a source circuit would also produce current flow in the neutral. Random cell or module failures would not likely produce enough current to be troublesome. But array failures, or shading of arrays in one row only, could cause current flow of the same order as ground fault conditions.

One advantage of solid midpoint grounding is that the dc voltage to ground appearing at any module would not exceed half the maximum dc line-to-line voltage. Another advantage of solid grounding at the midpoint of each array is that in-line sensor shunts could be installed around the wye point, where they would operate close to ground potential. Thus, the need for insulated transducers (Hall effect, dc-to-dc, dc-to-frequency, etc.) can be avoided with the solid grounding alternative.
Midpoint Grounding Through Resistor. Resistance grounding at midpoints would provide the following advantages, some of which are also found in the solid grounding method:

- The magnitude of dc ground fault current would be limited to a chosen level, for single ground faults.
- Some of the energy in impulse or harmonic voltages to ground appearing at the midpoint of each branch would be absorbed. These voltages might arise from intermittent ground faults, switching, inverter harmonics, or electromagnetic coupling.
- It would provide a convenient and protected point to connect neutral current sensors.
- An appropriately high resistor would provide "decoupling" between normal load currents and ground fault currents, thus facilitating fault detection.

With resistance grounding a solid ground fault on one line conductor will impose twice the normal voltage on the other conductor, and on all equipment connected to it. This is not a severe problem for cables and for the UTC PCS. It might pose more difficulty for the PV modules themselves and for protective devices. These possibilities require consideration during plant design and equipment specification efforts.

Other design factors are to select resistors of moderate cost that will survive in the service environment, and to choose a resistance value that will require only a moderate power rating for the resistors, yet will be reasonably favorable for fault detection. Excessive power loss in resistors during reasonably normal operation is not likely. Severely unbalanced source circuits could produce substantial power loss, but may have to be repaired in any case. The effect of nominal unbalance currents on the ability of the protection system to detect fault currents must also be considered.

4.1.2 Small and Medium Plants

For PV plants that will operate in an industrial environment, design goals should be to choose an operating voltage in the 600 V (or less)
class, to use a dc circuit configuration that is simple and closely resembles conventional low-voltage ac distribution circuits, and to conform as closely as possible to existing electrical codes.

For low voltage (250 Vac or less) systems on customers' premises, existing principal codes give little option but to install circuits having one conductor (or a midpoint) solidly grounded. For circuits above 600 Vac, exception is granted if relay protection is provided. For 480 Vac systems, exception is more or less understood if relaying is provided.

The best approach to meeting the above goals is to design for a nominal source circuit of about 400 Vdc, a two-wire dc network having the negative polarity grounded at the PCS input, and an isolation transformer at the PCS output. This approach will provide compatibility with familiar maintenance procedures and conventional protective measures, to the extent possible.

For example, in the dc circuits all positive cables that normally operate above ground potential could be coded red, and all negative cables that might float or become energized after protective switching occurs could be coded blue. All negative or neutral cable sections solidly tied to ground could be coded gray, and all ground conductors would necessarily be bare or coded green.

Midpoint (or neutral) grounding is also an option for industrial type plants. It might be justifiable for the upper range of PV plant ratings, if dc subfield voltages above 600 V are contemplated. However, it is not clear that substantially higher dc voltage levels would be advantageous, because many commercial products (contactors, switches, fuses) could not then be used.

4.2 OVERALL PLANT GROUNDING

PV array design and overall plant layout provide unique opportunities as well as special problems for the implementation of the grounding criteria discussed in Section 2. Specific grounding requirements and implementation
techniques are discussed in this section for each of the major elements of a PV plant. These elements include arrays, source circuits, PCS units, fields and subfields, ac substations, and buildings. In addition, particular design and construction practices for the PV plant installation as a whole which must be coordinated with the design and operation of the grounding subsystem are reviewed. Specifically, the design choices related to the cable circuit configuration and the means of running cables in a PV field are analyzed. The section concludes with a discussion of several issues of importance to grounding including the design of cables and shields, safety bonding, signal reference grounds, and testing of grounding system components.

4.2.1 Arrays

Flat plate PV modules may be assembled onto either metallic or non-conducting array frame members. If the framing is conductive, has substantial cross-section, and forms an electrical path along the entire length of each array, it should be adapted to serve as a grounding path as well as a structural member. This would also fulfill the requirement that all exposed metal parts be connected to the ground system. This adaptation will require adding ground connectors at the ends of all arrays, so that jumpers may later be installed between arrays, and earthing connections may be added wherever required. Additional grounding bonds may have to be added from the module to the panel or array structure, depending upon the assembly details of particular designs.

Single-axis tracking concentrator arrays that include extended support arms and flat plate arrays supported by torque tubes have an intrinsic grounding path through their large structural members. To adapt these for grounding service may require adding terminals at ends, and possibly other ground bonds to ensure that frames are electrically bonded to the longitudinal beams or tubes. Flexible ground straps would be necessary at bearings and motor drive points.
Two-axis concentrator arrays can provide more or less direct paths to earth at points along the array support arms. Surge arresters connected to the power circuit and bonded to the support arm might be required for transient overvoltage protection. Flexible ground straps or jumper cables would be required at the horizontal and vertical bearings to accommodate the maximum displacement angles.

All connecting devices should be attached to arrays and modules at the time of assembly. Attention to design and workmanship is important to ensure connections that will remain tight and resist corrosion for the plant lifespan.

Some flat plate array structure designs do not provide adequate intrinsic ground paths. In some array assemblies, the framing may be too small in cross-section to serve as a grounding path, be discontinuous, or be made of wood or other nonconductor. Also, frameless self-supporting modules and panels have been postulated. In all of these cases, a longitudinal grounding conductor would very likely have to be added to each array. One method is to install a small bare stranded cable (e.g., #1 AWG) supported at intervals above the upper horizontal edge of the completed rows of arrays. In this position, the grounding conductor would also furnish a degree of protection against lightning. Providing physical support points would require additional structural details and consideration of the effects of shadowing, as well as electrical design. The support points could be metal poles to earth grounding electrodes below the arrays.

4.2.2 Source Circuits

As a minimum, flat plate array source circuits should be provided with access to buried ground grid conductors at every physical end point of the array rows. Depending upon the electrical configuration of source circuits, physical end points of row sections may correspond to positive, negative, or midpoint terminals (two-wire subfield, Figure 4-1), or to half-voltage points (three- and four-wire subfields, Figures 4-2 and 4-3).
Figure 4-1. Schematic of DC Power Circuitry, Two-Wire PV Subfield
Figure 4-2. Schematic of DC Power Circuitry, Three-Wire PV Subfield
Figure 4-3. Schematic of DC Power Circuitry, Four-Wire PV Subfield
on the source circuits. (The half-voltage point refers to half the voltage between one terminal and ground.) In all cases, two kinds of connection to the buried ground grid should be made. The first is a solid connection from each end array frame, torque tube, beam, or cable ground. The second is a connection (direct, through a midpoint resistor, or through a surge arrester) from each circuit midpoint; or a connection through only a surge arrester from each half-voltage point.

One purpose served by providing connections to the earth at each physical row end on every source circuit is to allow an intended path for traveling wave surge currents to flow into the earth, thus not forcing them to reverse direction and reflect into the adjacent arrays. Also, connection of row end points by a single conductor appears to be a logical and convenient way to run ground conductors across a PV field.

With concentrator arrays arranged in a roughly circular source circuit configuration (see Figure B-3), there is no obvious physical end point. The solution is to make a grounding loop which includes each of the arrays in the source circuit. A single ground connection is provided for the loop. Ground connections from every source circuit are then linked together by a single conductor.

Power, control, instrumentation, and grounding links may be run above grade for concentrator source circuit layouts, where several arrays are connected in a series pattern. Access lanes for maintenance vehicles can be mapped such that direct access to any central pedestal apparatus is possible without crossing the cabling routes. Also, if arrays can be rotated on their vertical axis by local control or hand cranking, then all parts of array assemblies would be accessible.

4.2.3 PCS Units

Grounding facilities for PCS units should follow utility and industrial practices, codes, and standards applicable to electric substations for the following reasons:
The high concentration of energy and circuits at these locations

- The presence of high-voltage metal-clad electric apparatus

- The need to stabilize instrumentation and communication circuits (for some source circuit configurations)

- The need to provide a single point dc neutral grounding connection for the subfield

Grounding facilities would generally include site preparation to assure drainage, a dense buried ground grid with multiple risers, reinforced concrete foundation slabs, crushed rock surfacing over the subgrade, and aerial shielding structures, conductors, or air terminals bonded to the ground grid.

4.2.4 Fields and Subfields

The major component of the subfield grounding facilities is the interconnected matrix of array foundation structures, provided the foundations are adapted to function effectively as electrodes. Interconnecting links between arrays may be provided partially by longitudinal grounding circuits in the array rows. Other links may be provided by buried grounding conductors that run linearly under the end points of array rows, or that run as shield wires in the same trenches with power, control, or instrumentation cable. By thus adapting circuits and structures that already exist in the field, costs and disruptions otherwise incurred in providing a full pattern of intersecting buried grid conductors may be avoided.

If the array structural foundation members cannot function as electrodes, or if a design choice is made not to adapt them for this role, then an alternative must be provided. The preferable alternative is to drive vertical ground rods throughout the subfield, in a pattern that will accommodate downleads from the arrays and from source circuit longitudinal grounding conductors or members.
Supplementary driven ground rods may be required if dry soil conditions do not provide sufficient conduction to earth from horizontal grid conductors buried at a reasonable depth.

4.2.5 Substations

A conventional grounding grid should be designed for the substation. The grid should meet technical and code requirements based on ac fault conditions and lightning protection measures appropriate for the location. Substation grounding design should follow IEEE Standard 80-1976, or a newer version that may supersede it. (A substantially revised standard is reportedly being readied for publication in 1984).

Grounding grids for PV plant substations should probably be installed in a rectangular mesh pattern as shown in Figure 4-4 with buried bare cables situated below the frost line and in moist earth. The lighter lines in Figure 4-4 illustrate an optional second circuit. (See Appendix B, Figures B-9 through B-11 for substation layout drawings.) Ground rods are installed to lower the resistance to earth of the grid, and to insure that direct paths to earth exist at particular points. The decisive design factors are earth volume resistivity and earth surface resistivity.

4.2.6 Buildings and Control Rooms

Grounding for administrative buildings and adjacent areas should be conventional and according to codes and practices appropriate for the location. The building and local area grounding subsystem should be tightly coupled to the PV field grounding subsystem.

The main control room should be provided with a "quiet" ground connection (see Section 4.2.10), using a large shielded insulated single-conductor cable that rises directly into the room from a point in the buried ground grid. This would be in addition to the safety grounds normally provided in equipment rooms. A similar quiet ground may be required at each PCS, depending on the sensitivity of the electronic components used.

Special attention should also be paid to ground grid design around gates, entrances, and metallic fences.
Figure 4-4. Grounding Grid for Substation
4.2.7 Routing of Cable Circuits

Two of the important choices in PV plant design will be the cable circuit configuration and the physical means to accommodate and secure cable runs. In the on-grade PV plants that are within the scope of this study, there will be dc cables (600 to 2000 V), ac cables (2.4 to 34.5 kV), instrumentation/control cables, and grounding cables traversing the array subfields.

Grounding cables may function as connecting links, earthing electrodes, or both. When used for earthing, the cables must be uninsulated and buried directly in the soil at a depth of 2 to several feet as determined by soil resistivity characteristics and the frost line limit. If the grounding cables are intended only as connecting links between earthing points, they should be insulated against random contact with metallic parts, and physically protected against damage if the runs are exposed. In order to minimize costs, grounding cables used only for linking earthing points should normally be run together with other cables.

Flat Plate Arrays. Internal roadways must be provided in large array fields to facilitate washing, inspection, and maintenance. Some of these roadways are natural corridors for power, control/instrumentation and ground cable runs (Figure 4-5). There are several viable methods available for carrying wire and cable circuits, including wood pole lines, concrete-encased conduit banks, accessible cable trays, direct buried prefabricated cable and conduit, and direct burial cable. These are discussed below.

The least costly conventional method to carry wire and cable circuits along a roadway would be overhead on wood pole lines, probably using one or more messenger wires. Aside from initial low cost, this method would keep the cables away from physical, chemical, and bacteriological damage in the soil, away from burrowing rodents, and place them in a visible and easily maintained position. In PV applications, the following disadvantages may preclude the use of this method:
Figure 4-5. Five Megawatt Flat Plate Subfield — Fixed Torque-Tube Arrays
- Poles, cables, and fittings would shade the arrays.
- There would be added risks from high winds and ice storms.
- Cables would be more vulnerable to direct lightning strokes, unless a shield wire were run several feet higher, and connected to earth with out-rigger type down leads.
- Errant high vehicles or crane booms could foul the cables.

Another conventional method is to route cables in concrete-encased conduit banks buried below the frost line. Several non-metallic conduit types are named and approved for use underground in the NEC, Article 347-1. Steel conduits are not justified in this application because of cost and possible corrosion. Also, steel conduit systems must be electrically continuous and securely grounded, or they could transfer hazardous voltages around the field. They also could carry random leakage currents in undefined paths. Whatever the conduit material, a concrete encased conduit design is comparatively expensive, and not well adapted to circuits requiring frequent risers. All cables must be pulled in, point to point, which partially accounts for the higher installed cost typical of this method.

For circuits requiring frequent low-current risers, an accessible cable tray seems to offer much more convenience and a lower life cycle cost than buried conduit. The best non-conducting material to assure 30-year life would be concrete, reinforced with a non-conducting material. Cable trays, whether of concrete or other non-metallic material, can and should be shop-fabricated in modules (10 or 12 feet long) that fit together so as to prevent misalignment. The covers should also be concrete or other non-metallic material. Figure 4-6 shows some typical configurations.

Three options exist for placing these trays in an array field: (1) above grade, resting on small buried prefabricated concrete stanchions; (2) with top of cover more or less flush with grade; and (3) buried 1 to 2 feet below grade.
ONE SUBGROUP, COMPRISING 8 SOURCE CIRCUITS:

CROSS-SECTION OF ROADWAY:

Figure 4-6. Power, Control, and Ground Cabling — Flat Plate Arrays
The first option affords best protection to wires and cables, is least disruptive to install, and convenient to maintain. But it cannot be used where vehicles must cross; although walking traffic could be accommodated with stepping blocks.

The second option is a compromise to accommodate vehicle crossing. However, more disruption of the field is required to prepare a shallow trench and the cables will be wet some of the time. Freezing and thawing cycles may shift a shallow tray. This last effect would be very much site dependent. A drainage system might be required to prevent major problems from this cause.

The third option might be attractive if very heavy vehicles must circulate throughout the array field or if the field or a portion of the field has soft subsoil that would not support the tray satisfactorily. But accessibility to the tray, particularly for ongoing maintenance, would be more difficult.

An alternative to the accessible cable tray is the use of direct-buried preformed conduit sections. This method employs pre-formed non-metallic conduit/cable assemblies, and preformed concrete crossing blocks wherever vehicles are to cross. The method seems to solve some of the problems with conventional conduit banks and tray assemblies as described above. It would require less disruption to the field surface, it can be installed in convenient stages, and it provides easier accessibility for repair.

Another possibility is to use cable in non-metallic conduit, which is available as a manufactured product and shipped on cable reels. This assembly may be directly buried, and in some environments may resist the underground hazards, though each of the potential hazards should be reviewed for specific sites. This method permits replacing cable runs easily, provided the conduit is unharmed.
Another alternative is direct buried cable of the type used in industrial installations similar to PV fields, and for underground utility distribution circuits in recent years. Overall results have been acceptable, though not without some troublesome experience. The vulnerabilities of direct buried cable include subsequent digging into the cable by others (unlikely in a PV plant), corrosion of outer shields or strands, and attack by rodents or insects. Specially jacketed, armored, or rodent-proof cable assemblies have been used successfully to counter anticipated problems. Currently, cable wrapped with hardened bronze tape and covered with a plastic outer jacket is offered by some major suppliers.

Concentrator Arrays. Cable runs and connections to the source circuit terminals in a 2-axis concentrator array would be generally similar to those in a flat plate array. For these portions of the cabling, similar solutions would apply.

However, individual concentrator array assemblies must also be connected together in groups to form source circuits. In one configuration postulated for this study, there are five assemblies connected in a loop layout as shown in Figure 4-7. The cable links around this loop are mostly point-to-point, connecting adjacent array foundations.

The loop cables may be installed by direct burial if conditions permit. For raceways, the best alternatives for this application appear to be:

1. A prefabricated cable harness with terminals attached that is preassembled inside a formed length of non-metallic conduit. The completed assembly is sized to reach from foundation to foundation in a narrow trench.

2. A prefabricated cable harness with terminals attached which would be laid into a non-metallic sectionalized cable tray extending from pier to pier above grade.

Cost and immunity from damage would likely favor the first alternative except in locations where ground freezing is severe.
Figure 4-7. Five Megawatt Concentrator Subfield with Martin-Marietta Arrays
Roof-Top Arrays  Cable runs in roof-top arrays should be pulled into conventional conduit runs, designed and installed strictly according to NEC, and state and local requirements. The preferred material for outside use is aluminum conduit (and fittings), because it is easier to handle, would provide a low resistance ground return path everywhere, and will not corrode if properly installed. However, there are certain contaminants that will attack aluminum, with dramatic effect. Aluminum conduit should not be in direct contact with concrete or with dissimilar metals. All joints in the conduit system should be watertight and physically strong, and electrically conductive. This could be done with threaded fittings and bonding jumpers, or some equivalent method.

Other choices generally less appropriate for roof-top arrays are epoxy-coated steel (not galvanized), glass fiber reinforced polyester, or black heavy-wall PVC non-metallic conduits. The latter is the only type mentioned for exposed outdoor use in the current issue of the NEC; some local codes do not allow this use.

4.2.8  Cables and Shields

Cables that are to be buried and serve as grounding electrodes should be copper. Stainless steel would resist some soil chemicals better than copper, but is generally available as wire rope, not electrical cable. Stranding should be coarse, to provide better resistance to chemical attack.

Power cables for dc circuits in large utility-type array fields that operate at 2,000 Vdc nominal should be of the 5 kV class, with 133 percent insulation thickness. This conservative rating is recommended to provide a coordinating margin for voltage surge protection devices, and to make it more likely that cable system life span will meet the 30-year requirement. Such cables generally contain shields of some sort to control the internal corona effects.
Power cables for lower voltage industrial-type systems operating in the range of 300-600 Vdc should be the 1.0 kV class. Cables in this class generally do not require shields, which simplifies termination. Use of direct-buried cables requires consideration of attack by rodents and other living organisms. This site-dependent variable is discussed in Section 4.6, along with other possible deterioration effects. Alternatively, the cables may be run in conduits or raceways selected to provide the level of protection dictated by the site environment.

Color coding for cables is important to control the installation work, to facilitate use of prefabricated cable harnesses, and to make ongoing maintenance safer. The suggested identifications are as follows:

- Positive dc power - red (or red, dashed)
- Negative dc power - blue (or black, dashed)
- Neutral dc power - gray (or white, dashed)
- Grounding, all - green or bare
- Phase and hot leg ac - black (phases to be identified by cable tags)
- Neutral ac - white
- Instrumentation - yellow

The use of the green, black, and white colors for outer cable jackets is mandatory in U.S. codes.

4.2.9 Safety Bonding

Electrical bonding will be required at many places in a PV plant. A bond is typically a critical component because it must be present to provide a safe electrical relation between two nearby points, or to provide an essential return path for fault current. Bonds must be sized with careful attention to the worst-case current and duration that will be imposed on them.

Usually a bond is a short jumper cable that connects two metal assemblies together, connects two ground conductors together, or connects a metal
assembly to a ground conductor. This is a conventional practice, and several proven techniques and hardware details can be applied at many of the typical places in a PV plant where bonding is required. Electric welding, exothermic welding, bolting and crimping are conventional means of installing bonding jumpers.

There are several places on the typical array or source circuit assembly where special design attention to bonding is essential. The concerns are with the current capacity of the bond and the method of attachment at each end. Requisites are that the contact be electrically solid and physically firm, so that heating/cooling cycles, vibration in the wind, and occasional impacts will not affect the connection. Also, the connection must withstand chemical and electrolytic corrosion for the design life of the plant. These factors are important because there can be many bonding connections on the arrays and source circuits in a large PV plant.

4.2.10 Signal Reference

In communication and electronic installations it is frequently required that a "low-level" or "signal reference" grounding circuit be provided at each equipment room. One method of establishing such a ground point is to install a large, single-conductor, fully-shielded power cable from a signal reference ground bus near the equipment to a nearby junction (node) in the buried ground grid. This junction point should not be one that also serves to terminate power circuit neutrals or equipment safety grounds. This method provides a connection to earth reference that has a fair immunity to electromagnetic interference originating above ground, and it provides some decoupling (depending upon grid design) from the effects of fault currents originating in nearby power distribution circuits.

In PV plant design, a signal reference ground would likely be required in the main control room, and may also be desirable at each PCS location, depending on the sensitivity of the electronic components.
4.2.11 Testing

All prefabricated assemblies such as terminal boxes, equipment boxes, cable harnesses, and connectors should be fully tested electrically and mechanically in a shop environment. Burn-in and non-destructive limit tests should be included in the procedures where applicable.

Design qualifications tests should be applied to all items that are new, or are being applied outside their proven service range.

As field installation proceeds, tests or inspections of grounding electrodes, buried grid sections, cabling, jumpers, bonds, and terminations should be made and recorded.

Tests for resistance to earth of the grounding electrodes are particularly important to verify that the electrodes will perform as calculated. A difficulty will arise if installing is not done during the dry season. In this case it may be necessary to retest sample electrodes later, during the dry (or freezing) season. In case of poor performance, additional ground rods may have to be added.

4.3 EARTHING ELECTRODES

The various grounding circuits throughout a PV plant area must be connected together to form a common network so that indeterminate differential voltages will not develop. This network must in turn be connected to earth through paths (earthing electrodes) that have sufficient combined conductance to limit potential rise of the entire system with respect to true (remote) earth potential. Further, the earthing electrodes must be arranged in a pattern that is sufficiently dense to limit step and touch potentials, and also to offer multiple local paths to earth for direct or induced lightning currents. Various electrodes are described in Appendix C. Methods for providing earth connections are discussed in the following paragraphs.

4.3.1 Ground Rods

Vertical ground rods are commonly used as electrodes because of simple installation and adaptability (by selecting length) for various soil
conditions. Rods may be installed in clusters to provide lower resistance to earth or lower surge impedance. They may also be used to enhance buried grids in areas of high soil resistivity or unfavorable soil layering.

Installation of ground rods causes minimum disruption to the earth surface and can be easily mechanized with existing machines. Also, ground rod electrodes may permit contact with moist soil in dry zones where trenching to that depth would be impractical. In extreme cases, deep hole electrodes might be required to reach a conducting earth layer, or to augment the conductivity to earth in a relatively small PV field.

4.3.2 Buried Cable

Bare copper cable is the electrode most widely used for industrial and utility facilities. It serves as the interconnecting network as well as a continuous earth electrode. Also, it provides an electromagnetic shield when installed over or next to insulated cable circuits.

It is estimated that for the quantities involved in central stations, the price of 2/0 and 4/0 grounding cable is approximately $0.81 and $1.19 per foot (first quarter 1983 dollars). It must be remembered that the ground wire risers add about 40 percent to the lengths of buried cable runs (typical for flat-plate array configuration shown in Figure 4-5). The costs of installation labor and connections (exothermic weld assumed) bring the field cost to about $0.95/m² (m² of aperture area) for 4/0 and $0.65/m² for 2/0. For the lower area density two-axis concentrator array configurations, the costs are estimated to be on the order of $2 to $3/m². These costs exclude the cost of trenching, which is assumed to be included with power wiring. (The field cost of trenching and backfilling for moderately easy soil conditions is estimated to range from $0.75 to $1.30 per foot for typical depths and widths.)

4.3.3 Other Electrode Shapes

Buried metal shapes of any sort may be used as grounding electrodes. Plates (such as may be part of array foundations), horizontal rings,
cylinders, or any other shape may be used. Each will have a characteristic resistance to earth which is a function of shape and soil resistivity.

4.3.4 Concrete Foundations as Electrodes

The use of concrete caissons, blocks, or linear footings as electrodes would save material, field work and further disruption of the surface compared to the use of buried cables or even driven ground rods.

Review of the reported experiences with reinforcing members in concrete foundation as grounding electrodes shows this method to be effective in many circumstances. Structural deterioration, though plausible if aided by severe electrical conditions or substandard fabrication, is probably avoidable in a PV plant.

Typically, steel electrodes buried in the earth deteriorate faster than comparable electrodes made of copper, bronze or stainless steel. However, it is reported that steel rebars encased in uniformly dense, void-free concrete will last longer than non-ferrous rods driven directly into the earth. This subject is discussed further in Section 4.6. Typical PV array caissons are shown in Figures 4-8 and 4-9.

Electrically, rebar in concrete foundations may provide resistances to earth that are lower than would be provided by driven rods of equal length. This favorable situation exists for sites where the soil has higher resistivity than moist concrete, typically from 3000 to 5000 ohm-cm. Expressions to calculate the resistance to earth of reinforced caissons are shown in Appendix C.

Concrete equipment pads may be comparatively ineffective as electrodes if their contact plane with the soil is too shallow. Also, they would very likely be constructed on gravel or porous subgrade material which would further reduce their effectiveness. Installation of a cable grid buried well below the pad would be preferable in soils of high resistivity.
Figure 4-8. Flat Plate Array Foundation
Figure 4-9. Concentrator Array Foundation
4.4 PV FIELD GROUNDING DESIGN

In PV plants there are two quite different sources of fault currents of principal concern in grounding subsystem design. One is the high-voltage ac power system, which can contribute the maximum fault capacity of the utility network, plus a smaller amount from the PCS output circuits. The other source is any subfield dc power subsystem, which can contribute the combined fault capacities of all source circuits within one subfield, plus substantial momentary backfeed through the associated PCS unit.

The potential for high current faults requires the design of an earthing method for use in large array fields that is effective and safe. At the same time, the method chosen must not impose the initial cost and ongoing maintenance penalties that would result from installing conventional grids and crushed rock surfacing throughout a PV field of several square kilometers. As with source circuit grounding, conventional methods and prior experience do not provide clear design directions.

4.4.1 Effects of Major Faults

Exclusive of lightning, line-to-ground ac faults involving the substation high-voltage circuits are likely to pose the worst and governing conditions of ground grid potential rise and step/touch potentials in a PV plant. Three-phase or line-to-line ac faults on these circuits could also produce high fault currents, but normally such currents would flow only in very localized fault paths until cleared.

For dc faults, line-to-ground faults in the subfield or PCS input circuits would pose the worst conditions of ground grid rise and step, touch, and mesh potentials. As a rule, assuming reasonably rapid clearing and allowing for exceptions at local points, shock hazard from dc ground fault currents would be less than from ac currents for the following reasons:

- Permissible step and touch voltage limits are higher for dc.
• The voltage of the entire grid system is not raised above remote earth potential by dc faults, as would be the case for ac substation faults. Rather, there would be local voltage peaks and profiles within the field grounding system, whose magnitude would depend upon internal conductivity of the grid system as modified by parallel paths through the local earth.

• By layout and circuit design, likely locations for high-current dc faults that require coordinating time delays to clear can be restricted to zones in the interior of each subfield, thus lessening voltage differentials at the edges and corners of a complete field.

If two dc ground faults were to occur simultaneously at different locations, one from each polarity, the total fault current across the grid would include the momentary inverter backfeed.

High-current dc faults in a subfield (whether line-to-ground or line-to-line faults) are nonetheless a serious matter because of the flash and burn hazards that they pose. Line-to-line dc faults will draw current from all source circuits, plus more current as a momentary backfeed through the inverter (perhaps five times the PCS rated dc current).

4.4.2 Surface Voltages Caused by Ac Faults

If a solid single-line-to-ground fault should occur on any main high-voltage circuit in the substation, the current that flows to the grounding grid and local earth under the substation would raise the potential of the grid with respect to remote earth reference. The potential of all things connected or coupled to the grid would rise correspondingly.

For example, assume a typical 100 meter square transmission substation, isolated from all other grounding structures, that has a resistance to earth of 0.56 ohm. If a 5000 A ground fault occurs within the substation, the voltage rise of the grid would be 2800 Vac. Mesh potential (a type of touch potential) for such a substation, built with
1000 meters of grid cable buried in soil having a 100 ohm-meter resistivity, would be approximately 200 Vac (Ref. 4-1). The highest step, touch and mesh potentials typically develop in corner areas of the grid, and at perimeter structures including metallic fences.

The permissible touch voltages (see Section 2.2.1), assuming fault clearing time of one-half second, for three different assumed values of soil surface resistivity ($r_s$) are as follows:

- $r_s = 0$ (realistic for very wet loam)
  
  $$E_m = \frac{(116 + 0)}{(0.5)^{1/2}}$$
  
  $$= 164 \text{ Vac}$$

- $r_s = 100$ ohm-meters (a "natural" soil)
  
  $$E_m = \frac{(116 + 0.17 \times 100)}{(0.5)^{1/2}}$$
  
  $$= 188 \text{ Vac}$$

- $r_s = 3000$ ohm-meters (crushed-rock)
  
  $$E_m = \frac{(116 + 0.17 \times 3000)}{(0.5)^{1/2}}$$
  
  $$= 721 \text{ Vac}$$

One indication from the above example is that crushed-rock surfacing would be required within the substation area and around the perimeter fence. This feature is found in most actual substation yards, unless they are built on a site where crushed rock would not enhance the wet surface resistivity.

Another indication is that when working with an unimproved surface, the assumption of zero resistivity may lead to a touch voltage limit that is not significantly more burdensome than for a natural surface. For PV
array fields where surface treatment (e.g., installation of a layer of crushed rock) is generally not contemplated, using \( r_s = 0 \) is suggested as the prudent course, because local ponding or silted areas would likely develop during the life of the plant.

Finally, and again referring to the example, a question arises as to whether or not such a substation, if intended to serve a PV plant, should be located directly adjacent to the PV field and solidly interconnected with the PV grounding grid system. Locating the substation close to the PV field, and tying the ground systems together, would clearly reduce the ground grid voltage rise of the combined systems for the same ac fault conditions, but it is not clear that ac step, touch, and mesh potentials around the PV field and fencing would then be acceptable (e.g., all below 164 Vac, assuming \( r_s = 0 \)).

In consideration of the above, there are two options for locating the typical transmission (or distribution) substation serving a PV utility-type plant. One is to locate it close to (or even within) the PV field perimeter and couple the grounding subsystems tightly together so that differential voltages cannot develop. The other is to locate it far enough away so that ground fault voltages coupled into the PV field by mutual earth conduction paths will be below the ac step, touch and mesh voltage limits. If the substation is located apart from the PV field to isolate fault effects, then no conducting ground paths may be permitted between the two areas. Therefore, no utility pipelines, fences, continuous overhead ground wires, cable shields, or low-voltage circuits of any type could be installed that would connect the two areas electrically. Fiber-optic or optically coupled communication and control links would serve well in this situation.

4.4.3 Analysis of PV Field Grounding

Four alternative ways to calculate resistance to earth and maximum ac mesh voltage for PV fields are discussed in this section. The first two are comparatively easy, and are widely used for buried cable grids laid in regular patterns; but their suitability for combinations of electrodes...
In unique patterns may be questioned. The other two methods should be accurate for any configuration, but require considerably more effort to execute. These four methods are discussed in the following paragraphs.

**IEEE Standard Method.** The current standard (IEEE 80-1976) provides a simple and generally verified equation to calculate voltage rise of a large rectangular buried grid layout. Also, it provides some more lengthy equations to calculate step, touch, and mesh voltages. The difficulty in applying these to PV fields is that the derivations and check measurements apply particularly to buried grids. Adaptation to situations where other electrodes might predominate is not addressed. Also, the step and touch voltage calculation methods may lead to values that are too low, based on more recent studies (Ref. 4-1).

Answers obtained from this standard would likely suffice for early estimates, but not as the documented final design.

**Vertical Electrodes in Groups.** Another way to calculate resistance to earth of a large number of similar interconnected vertical electrodes (such as array foundations) would be to first calculate the resistance of one isolated electrode, then to estimate its effect in an area having many electrodes by using the methods shown in two AIEE Transactions Papers (Refs. 4-2 and 4-3). However, the references extend only to areas having 80 or so ground rods, far short of the number of caissons proposed for a 5.0 MW subfield.

More accurate estimates for step, touch and mesh potentials can be obtained by applying the methods shown in a recent IEEE Technical Paper (Ref. 4-4), where the voltage contributions of all electrode elements in a field are summed to produce a voltage profile along any chosen line on the earth's surface. A computer program is required to execute this method, because contributions of a large number of elements, each less than a meter in length, must be considered to produce accurate voltage profiles. Even using a computer, it would be realistic to model only the critical corner of a large PV field in detail, or to establish bounds on
the critical voltage profiles by analyzing a sample field considerably simpler than the actual one. Bechtel has a proprietary program of this type that presently can accept up to 200 electrodes, partitioned (by the program) into 2000 conducting elements. Sample results from this program are shown in Figures 4-10 and 4-11.

The program calculates the potentials at points on the surface of the soil in the array field (earth surface potential) and the potential of the ground grid. Calculations are based on input values of soil resistivity, fault current to ground, and the configuration of the ground grid, including spacings and depths of buried wires, rods, etc. Although the potential can be calculated for all points in the field, each of the two figures show potentials along two lines to simplify the illustrations. Actual calculations may also make use of symmetry to reduce the cost of computer runs. The potentials in the illustrative figures are shown without an absolute scale since the potential is linearly proportional to fault current. This is the normal assumption for power plant design work. However, the analysis is not valid for areas immediately adjacent to lightning strikes where soil ionization occurs.

The difference in potentials are, of course, the voltages of interest in evaluating personnel safety and electrical insulation. The difference in potential between the ground grid (to which array framework and exposed metal are bonded) and the earth's surface is the voltage that a person would be exposed to when standing at that point and touching the array framework during a fault. For example in Figure 4-10, this "touch potential" is 0.11 volts per amp of fault current at the worst point. Thus a person could be exposed to a possibly lethal voltage of 110 volts if standing between the rows of arrays and touching the array framework when a 1000 amp fault occurs. Similarly, the difference in earth surface potential at two points 3 feet apart would give the "step potential." This is the voltage to which a person would be exposed when
Figure 4-10. Sample Plot of Surface Voltage Based on Layout of Proposed SMUD Plant
Figure 4-11. Sample Plot of Surface Voltage for Ground Rod Array
walking through an array field (with a 3-foot stride) during a fault. The highest of these voltages for the site's soil resistivity and maximum expected fault current would be used to set fault clearing times required for personnel safety (see equations on page 2-3).

The illustrative example shown in Figure 4-10 is for an initial design of the Sacramento Municipal Utility District's (SMUD) Phase 1, 1MW installation. Symmetry is used to model only one quarter of the array field. Two potential profiles are shown, along the central roadway and along an interarray "road" near the center of the field. Due to a lack of details available and to simplify calculations, additional ground grid elements in the control building/substation area were neglected. The potentials plotted are illustrative of the effects previously discussed. Additionally, it should be noted that the potential plots extend beyond the site's perimeter fence. This points out the need to consider the existence of buried pipes or other metal extending beyond the fence and connected to the plant ground grid. Not illustrated are possible special ground grids adjacent to the fence exterior which are sometimes used to mitigate possibly hazardous potentials. Figure 4-11 shows a second example, which is representative of two axis array foundations. The potentials are plotted for areas along the two lines indicated, Sections AA and BB. Although not clearly evident with the reduced scale of the figure, the original (larger) computer printout shows the variations in earth surface potential caused by the individual foundations.

**EPRI Analysis Programs.** Two electric utility programs have been developed at the Georgia Institute of Technology, for EPRI. These are capable of modeling the essentials of an entire PV plant, including remote or closely coupled substations. The capacity of the program is quite large, but again, a reasonable limit on input data handling and computer run time would probably require representing only the critical corner and edge of a large PV field (Refs. 4-1 and 4-5).
Analysis by Scale Models. Some recent work has been done with scale models of grounding electrode systems (Ref. 4–6). This approach might prove effective and less costly than computer analysis. However, it should be performed by individuals who have actually done this previously to ensure efficiency and credibility. A physical model may be the only practical way to analyze a site that has some severe irregularities in resistivity of layers that underlie the PV field. At most, the computer models can handle two-layer soil where the interface between layers is a plane.

4.5 PEDESTAL-SUPPORTED ARRAYS

The grounding of pedestal-supported arrays was investigated in further detail during the second phase of this study in order to assess the need for a ground mat in the array field. Three basic dc subsystem configurations of source circuit midpoint grounding for these arrays were evaluated both with and without a ground mat. These configurations were (1) solidly grounded, (2) grounded through an insulated neutral, and (3) resistance grounded.

The effects of electric currents on personnel govern the safety aspects of grounding system design. These effects are less severe for the dc currents in a photovoltaic plant subfield than for conventional 60 Hertz currents as indicated by Table 4–1. Although this study was primarily directed at dc fault protection and grounding, the complete plant design process must also consider the presence of 60 Hertz ac at the PCS outputs, the plant substation and other areas such as tracking subsystem drives.

The footnote to Table 4–1 indicates a degree of uncertainty in the data. Also, as previously discussed, there is less than a consensus on the differences between dc and 60 Hertz currents. Existing practice is to generally design to the let-go current level. This current must be considered with other factors in assessing step, touch and similar potentials. These factors include variations in physiology and conditions of the environment. Internal body resistance is on the order
Table 4-1  
EFFECTS OF ELECTRIC CURRENTS

<table>
<thead>
<tr>
<th>Effect</th>
<th>Direct (Milliamperes)</th>
<th>60 Hertz (Milliamperes)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Men</td>
<td>Women</td>
</tr>
<tr>
<td>Slight sensation on hand</td>
<td>1</td>
<td>0.6</td>
</tr>
<tr>
<td>Perception threshold</td>
<td>5.2</td>
<td>3.5</td>
</tr>
<tr>
<td>Shock—not painful, muscular control not lost</td>
<td>9</td>
<td>6</td>
</tr>
<tr>
<td>Shock — painful, muscular control not lost</td>
<td>62</td>
<td>41</td>
</tr>
<tr>
<td>Shock — painful, let-go threshold</td>
<td>76</td>
<td>51</td>
</tr>
<tr>
<td>Shock — severe, muscular contractions,</td>
<td>90</td>
<td>60</td>
</tr>
<tr>
<td>breathing difficulty</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shock — ventricular fibrillation possible</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>from 3-second shock</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: The data is based on limited experimental tests and is not intended to indicate absolute values.

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of 500 ohms. Skin contact resistances are the order of 1000 ohms (wet) and $5 \times 10^5$ ohms (dry). Resistance through both feet, shoes and the earth is on the order of 6 times the surface soil resistivity (in ohm-meters) for step potentials and 1.5 times for touch potentials. Since some conservation regarding personnel safety is indicated, the IEEE recommends using a total resistance of 1000 ohms (Ref. 4-1). For a let-go current of 50 milliamperes, the lower value of let-go voltage would be 50 volts for the dc case.

This value is also consistent with present design practice. In designing rapid transit systems using dc power, the maximum voltage between the platform and train car bodies is generally limited to about 25 volts in the U.S. A 50 volt limit is more common in Europe. In cases
where the limit cannot be met directly due to track resistance and other factors, "indirect" means have been employed (such as insulating mats or granite platform surfaces). This would be analogous to the gravel surface treatment commonly used in switchyards.

Such measures are not affordable for photovoltaic plants. Plant personnel could be required to wear linemen's gloves when in the array field. This would still not reduce step potential hazards. Thus, the 50 ma/50 volt limit is used herein.

4.5.1 Ground Mat Included

For the case with a ground mat, the three dc subsystem configurations are shown in Figure 4-12. The figure shows the voltages and currents flowing through power wiring, ground wiring and array frames for a short between a cell and the array frame. The subfield is a nominal 400 volt, 5 MW system of 450 parallel source circuits. The illustrative numbers on the figure are for a solid short located 6 modules from one pole in a source circuit with 120 modules in series.

The major point to be seen is that the currents are confined to metallic paths and no appreciable current flows through the earth. Thus, there are no hazardous step and touch potentials generated for this type of fault in the case with a ground mat. It can also be seen that with the resistance grounded configurations there is a voltage drop across the grounding resistor and the physical midpoint is no longer at ground potential. For the illustrative fault location, the voltage across the insulation between the last cell and the grounded array structure is 429 volts. For a fault at the pole and an open circuited source current, this voltage would be the full system voltage.

4.5.2 No Ground Mat

For the case without a ground mat, current flows and voltages must be similarly defined. For a solidly grounded configuration, connection of the source circuit physical midpoint to "ground" is used as in the case with a ground mat. In this case the midpoint ground connection is
Figure 4-12. Voltages And Currents During A Fault
to the array foundation. For a fault to ground on the array adjacent to
the one on which the midpoint ground connection is made, a current will
flow through the earth between the two array foundations. This current
flow sets up a surface potential as shown by Figure 4-13. This figure is
for a +400 volt subfield. The surface potential profile for a +1000 volt
subfield is similar with the two peaks separated further corresponding to
the greater spacing resulting from more arrays being used to attain the
higher dc system voltage. Although not visible at the scale of the
figure, the minor effect of adjacent array foundations can be seen in the
original computer output. The relative voltage profile shown must be
scaled by consideration of the soil resistivity and available fault
current.

The resistance \( R \) between two adjacent ground rods is given by:

\[
R = \frac{R_e}{2\pi L} \ln \left( \frac{S - r}{r} \right)
\]

where

- \( R_e \) = soil resistivity in ohm-cm
- \( L \) = depth of ground rod in cm
- \( r \) = radius of ground rod in cm
- \( S \) = spacing between ground rods in cm

For the typical concentrator array foundations and spacings used herein,
the rod-to-rod resistance is approximately equal to 0.0019 \( R_e \). The fault
current for an open source circuit be approximated by scaling the module
characteristics shown by Figure 2-6. The worst case touch voltages
(fault at one pole and a person at the edge of the array at the noontime
alignment) are shown in Figure 4-14 as a function of soil resistivity.
At the lower soil resistivities the earth and array foundations tend to
effectively short out the array. It can also be seen that the 50 volt
limit (for let-go threshold) is exceeded for almost all soil types. The
curves are mathematically extended to soil resistivities typical of rock
and rocky areas. However, it is likely that in such areas, the
foundation used may be different than the one assumed (see Figure 4-9).
Figure 4-13. Surface Voltage Profile for Solidly Grounded Array
As discussed, this limit was somewhat conservatively set due to an uncertainty in the data relating to human tolerance to electric currents. Doubling the limit would still not render this configuration safe for most soil types. A nominal \(+400\) volt dc subsystem may not result in a fatal touch potential even for dry soil conditions. Touch potentials under worst case fault conditions are likely to be fatal for the nominal \(+1000\) volt dc subsystem. However, present practice is to generally design for let-go thresholds. Thus, center grounding of a source circuit to the array foundation without a ground wire interconnecting the arrays would not be acceptable for most soil resistivities.
Step potentials can also be hazardous, but for this configuration the governing effect is the touch potential. This is due to the array structure reaching some 22 feet beyond the point where the ground rod (foundation) is embedded in the earth.

The second dc subsystem configuration considered is midpoint grounding via an insulated neutral. Figure 4-15 shows the relative surface voltage profile for a fault at one pole with the faulted source circuit open circuited. As before, this relative voltage profile is scaled by considering the resistance to earth and source circuit characteristics. The insulated neutral is assumed to be tied to a low resistance ground at the PCS which is sufficiently distant from the fault location to give the profile shown by Figure 4-15. For the concentrator foundations used herein (see Figure 4-9), the resistance to earth is $11.4 + 0.00142 \ Re$ ohms and the resulting touch potentials are given by Figure 4-16. In this instance, the touch potentials exceed the safe let-go threshold for all practical ground resistivities.

The third configuration is similar to the first, except that the midpoint ground is made through a grounding resistor. The shape of the surface voltage profile would be similar to that shown in Figure 4-15. The fault current can be limited to safe values by the ground resistor. The resistance required to limit the fault current to a let-go threshold of 50 ma is 22,000 to 24,000 ohms for $\pm 1000$ volts and 7,000 to 9,000 ohms for $\pm 400$ volts, depending (slightly) on soil resistivity. The power dissipated by these resistors is about 25 and 60 watts for the $\pm 400$ and $\pm 1000$ volt systems respectively. Incorporation of a proper midpoint grounding resistor can limit fault currents to safe values for a short between a cell and the array frame without the need for a ground mat connecting the arrays. However, it should be pointed out that this configuration can also double the voltage to ground across the insulation of the last modules in all of the parallel-connected source circuits.
Figure 4-15. Surface Voltage Profile For Grounding Via Neutral

Figure 4-16. Touch Potential Versus Soil Resistivity
For above circuits, the step and touch potentials would be lower with the faulted source circuit connected in parallel with other source circuits to an operating PCS. However, disconnecting a faulted source circuit is expected to occur for maintenance or repair work and therefore must be considered as a credible event in designing the ground system.

4.5.3 Ground Mat Costs

Several alternatives are available to connect the arrays, PCS and other equipment. Connections are required for dc power, tracking drive power, signaling, and, where used, grounding. The alternatives include: direct buried, buried in conduit, and on-grade conduit or raceways. In general, the conduit for the latter two alternatives may be either conducting or nonconducting.

If there is a conducting metallic path between the array structures, then the currents from a fault from a cell or other power wiring to the array structure will essentially be confined to this metallic path, as discussed for Case 1 above. The metallic path may be a ground mat, conduit (surface or buried) raceway or similar equipment. Such paths must be designed to provide the needed integrity over the life of the plant in order to be safe.

If there is to be no ground connection between arrays (Case 2), then conducting conduits, raceways can not be used (otherwise this would revert to Case 1, ground included). With this configuration, the only safe design appears to be use of a midpoint grounding resistor to limit fault currents.

For direct buried wiring, a single trench is assumed to be shared by dc, tracking drive and signal wiring. If a ground mat is to be used, its wires would share this trench and in doing so provide a shielding effect for the other wires. With this configuration, the trench would be partially backfilled after installation of the other wiring, the ground wire would then be installed and the backfilling completed. The added direct field costs and wire run lengths involved for this ground system are presented in Table 4-2 for a system using 2/0 wire.
Table 4-2
GROUND SYSTEM COSTS - 5 MW (NOMINAL) SUBFIELD

<table>
<thead>
<tr>
<th>Nominal System Voltage (volts)</th>
<th>+400</th>
<th>+1000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical parameters</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interarray wire runs (feet)</td>
<td>21150</td>
<td>33840</td>
</tr>
<tr>
<td>Group bus and PCS wire runs (feet)</td>
<td>9225</td>
<td>3690</td>
</tr>
<tr>
<td>Risers (feet)</td>
<td>7200</td>
<td>7200</td>
</tr>
<tr>
<td>Total (feet)</td>
<td>37,575</td>
<td>44,730</td>
</tr>
<tr>
<td>Cost items</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Materials</td>
<td>$30,436</td>
<td>$36,231</td>
</tr>
<tr>
<td>Installation</td>
<td>62,750</td>
<td>74,700</td>
</tr>
<tr>
<td>Direct field costs</td>
<td>$93,186</td>
<td>$110,931</td>
</tr>
<tr>
<td>Normalized cost</td>
<td>$2.81/m²</td>
<td>$3.35/m²</td>
</tr>
</tbody>
</table>

It is difficult to estimate the total cost impact of the grounding resistor. For the quantities required, the price for the resistor itself is $1 to $2 for the +400 and +1000 volt dc systems, respectively. The system voltage requires that the resistor be enclosed. A NEMA 3R box for this purpose would cost approximately $25 to $35, installed (for +400 and +1000 volts, respectively). Hardware and mounting of the resistors would bring the midpoint grounding resistor costs to $0.45/m² and $0.23/m² for the +400 and +1000 volt dc systems. If there were room to mount the resistor in the existing array junction box the cost would be a few cents per square meter. However, increasing the size of a large box by only a few inches can increase its cost by several hundred dollars (if standard sizes are procured). Also, it may be less than desirable to add the heat load of the resistor (25 to 60 watts) to the array junction box. Most important, however, is the fact that the electrical insulation capability of the modules and dc wiring system must essentially be doubled over that of a solidly grounded configuration. This is because of the voltage drop across the midpoint grounding resistor. This voltage drop is only affected slightly by practical soil resistivities. In addition, increased electrical insulation on the concentrator module.
would tend to increase cell operating temperature and thereby lower plant output. It is beyond the scope of the present effort to calculate the dollar value of these effects produced by the grounding resistor.

4.5.4 Conclusions and Recommendations

Three source circuit configurations were evaluated with and without a ground mat for a nominal 5MW subfield made up of pedestal-supported arrays. These configurations were solidly grounded, grounded via an insulated neutral and resistance grounded. This evaluation has led to the following conclusions and recommendations.

Conclusions

- For expected values of soil resistivity, the flow of fault currents in the soil can result in voltages harmful to plant personnel. This is in part due to the configuration of the pedestal-supported array which transfers potentials from its foundation area, along the structure, to its extremities some 24 feet away.

- Use of a ground mat system generally confines PV fault currents to metallic paths and prevents harmful voltages from being set up in the soil. This is true for all practical soil resistivities and all three source circuit configurations.

- Without a ground mat, potentials resulting from the flow of fault current through the soil exceed normal design limits (i.e., let-go threshold) for the solid and neutral grounded source circuits at $\pm 400$ volts and may be fatal with $\pm 1000$ volt circuits.

- Incorporation of a proper value midpoint grounding resistor can limit fault potentials to safe levels. However, this configuration can also double the voltage to ground across the last modules in all of the parallel-connected source circuits and equipment in the subfield.

Recommendations

- It is recommended that a ground mat system be used to interconnect the array structures and foundations. In addition to its more inherent safety and lower dc system insulation requirements, this approach has advantages with regard to maintenance (see Section 5.7.1) and lightning surge protection (see Section 5.8).
If a midpoint ground resistor is used in place of a ground mat, careful consideration must be given to specifying the voltage insulation levels for the modules and other dc equipment.

### 4.6 LIGHTNING PROTECTION

There are very close ties between lightning protection and grounding design, and some areas of overlap where grounding facilities perform lightning protection functions. In all cases the lightning protective measures require connection to an adequate ground system. To provide protection for outdoor facilities against the effects of lightning requires attention to four principal measures that can usually reduce the risks to an acceptable level. These measures are:

- Intercept direct stroke currents and secondary streamers
- Shield against induced surge voltages and currents
- Bypass surge voltages and currents whenever they appear on ungrounded working conductors
- Provide multiple metallic paths to earth that are configured to contain and conduct the expected impulse currents

The extent and cost of measures that are realistically necessary at a particular installation depend upon stroke frequency and severity typical for that site. Specific requirements are difficult to quantify because stroke characteristics are statistical and not completely known. Also, the permissible limits on peak voltage caused by lightning are difficult to define because little has been reported concerning the effects on people exposed to very fast impulses (durations less than 0.008 second). Further, calculating the propagation of steep wave transients through PV field structures and wiring networks is complicated. However, this topic is addressed with regard to protection of the modules in Section 5.8.
4.6.1 Limitation of Scope and Working Assumptions

Selection of equipment and design of facilities that will intercept lightning strokes to photovoltaic plants are tasks not included in this study. The specific work items which impact PV grounding system design but which are outside the scope of the current effort are:

- Estimated probabilities of receiving direct or induced lightning surges at a given or typical site, and estimated probability distributions of the incident impulse characteristics (peak magnitude, wave front, wave tail, single or multiple, total duration).
- Type and extent of lightning protection equipment judged appropriate to "match" the degree of exposure.
- Assessment of need for air terminals or overhead shield wires in the PV array field, and definition of their specific locations and best configurations.
- Provisions required to protect people and vehicles circulating in various areas of the PV plant, again based on degree of lightning exposure at a specific site.

These items must be addressed as part of the overall plant electrical design effort.

In order to proceed logically with grounding design examples, some assumptions will be made to postulate reasonable and workable lightning protection criteria. At several locations within a PV plant which are apart from the arrays in subfields it is assumed that conventional shields and arresters will be installed. These protective measures should conform with practices that have proven acceptable in the same geographical area. PV plant equipment locations of this type are:

- Substation
- Power conditioning systems
- Administrative and control buildings
- Warehouses and storage areas
- Emergency engine-generator and fuel storage facilities

4.6.2 Substation

A conventional design based on IEEE Standard 80 provides a buried grid with low resistance to earth (e.g., less than 1.0 ohm) to which various lightning protection devices may be connected. These devices would include:
- Transmission line shield wires (overhead ground wires)
- Overhead shield wires, masts or air terminals within the substation area
- Buried counterpoise wires on the line right-of-way
- Lightning arrester and surge suppressor tails
- Cable shields and raceways
- Buried shield wires over cable runs
- Equipment enclosures and tanks
- Structural members

When installed according to codes and practice (NFPA, NEC, UL), the above measures would meet the general requirements for substation lightning protection. One improvement in grid layout in this respect would be to insure that a three- or four-way grid intersection is located near each connection point, so that ground risers can conveniently be connected to such nodes in the grid. Another improvement would be to locate a cluster of ground rods (3 or 4) around the intersections that will serve high exposure high-energy connection points (overhead ground wires, lightning arresters, masts, etc.).

4.6.3 Power Conditioning Systems

Each PCS area should be protected with conventional shielding and grounding measures as used in a substation. Operating and maintenance personnel would be able to seek shelter in these areas more quickly and
conveniently than at buildings. Also, the PCS power, control, and instrumentation equipment is both expensive and vulnerable. Thus, this concentration of costly equipment also warrants increased lightning protection on an economic basis.

The characteristics wherein the PCS differs from the substation include a smaller occupied area, ac fault currents limited by design to very much lower values, and utility overhead transmission lines not present. Otherwise, the same substation design procedures and installation practices would apply to PCS areas.

4.6.4 Buildings and Storage Areas

All the requirements that govern commercial/industrial building protection apply here. The requirements would likely be more stringent than for PV field secured areas because any of the administrative and control buildings may be occupied by non-technical employees and the public. Warehouses and storage areas would generally be treated the same as the administrative buildings, but with special attention to any facilities containing hazardous materials. There are special code and regulation requirements governing the protection of fuel storage and transfer zones.

4.6.5 Array Subfields

To proceed with an analysis of alternative grounding facilities in the vicinity of arrays, it is necessary to postulate a number of possible lightning protection concepts. Possible (though not necessarily acceptable) approaches for dealing with lightning strokes include:

- Intrinsic protection using existing structural members (No shield wires, masts, air terminals, or buried counterpoises added for lightning protection)

- Horizontal ground wires mounted above the arrays (either close to the array frame or high above)

- Air terminals, supports, and down leads mounted on the array structures
- Overhead ground wires (shield wires) installed on poles or towers, with downleads at selected locations
- Free-standing poles or towers erected on grade at selected points throughout the subfields

The following paragraphs describe grounding facilities that would complement each of the above cases. The cost impact of lightning protection is not addressed.

**Intrinsic Protection.** Structural metal frames around modules and panel frames on flat plate arrays would tend to intercept direct lightning strokes, and conduct the stroke current to earth at foundation caissons, at other types of buried foundation members, or at ground rods. Heat sinks and structural members on two-axis concentrators would also be likely intercept points.

The shielding effect and the current conduction paths for direct strokes would not be ideal. It is possible that strokes would hit the flat surface of an array. Side flashes or streamers could develop across the array surface, from array to array, from row to row, or from array to ground.

The intrinsic shielding effect against induced currents and voltages would be somewhat better, because proper layout of longitudinal ground conductors would provide loop current paths, perhaps in the horizontal as well as vertical plane (or inclined plane). These loops, of low resistance for properly connected panel frameworks, would conduct current and produce counter emf's that would significantly reduce the net effects of high-intensity incident magnetic fields. Such fields could be produced by nearby strokes to earth or to grounded objects, or by cloud-to-cloud strokes.

In this and all concepts of lightning protection, attention should be given to providing complete loop current paths that will lessen the magnitude of voltages that might otherwise be induced by nearby strokes.
Connections to ground should be as straight as possible to reduce inductance and the accompanying transient voltage rise. Conductive straps should be used to provide a path around gearboxes and bearings in concentrator arrays.

**Horizontal Ground Wires.** Horizontal ground wires mounted a foot or two above the top edge of the array frame would provide an intended path to earth for direct stroke currents. The shielding at such modest elevations would not be exemplary, but it would be continuous along the rows and might furnish a worthwhile degree of protection.

The wires should be grounded at intervals, such as at each foundation pier or at ground rods.

Physical support for ground wires could be a problem. Wind, ice, and static loading require attention during design. The wires could be carried on poles anchored in the earth and stabilized by the array structure. However, poles used to support the wires may shadow the arrays.

**Air Terminals on the Arrays.** Air terminals are an alternative way to intercept direct strokes and provide an intended path to earth. To be more effective than the horizontal wire, terminals would have to extend higher above the arrays, be fairly close together, and be connected to earth by a direct path.

**Overhead Ground Wires on Towers.** Excellent shielding and isolation from direct stroke effects can be provided by ground wires strung high overhead. These ground wires must be connected to earthing points at appropriate intervals. Support of these wires requires high towers or poles, using utility construction practices. This sort of system would likely shade the arrays. However, with careful layout, the degree of shading might be acceptable.
Free-Standing Poles and Towers. An alternative to the high ground wire is the use of free-standing poles or towers of considerable height, located in a regular pattern throughout the array field. These structures can provide any degree of protection desired, depending upon height and spacing. They would shade the arrays more than long-span overhead wires.

The total number of strokes to an array field would likely be increased by the addition of poles or towers, or aerial shield wires. Also, the peripheral structures in a large field might attract more strokes than the interior structures of comparable height. However, if the higher structures are designed to contain and conduct most of the possible direct strokes, overall protection against hazards and damage could be substantially improved. Nevertheless, induced currents would remain a problem.

4.7 DETERIORATION EFFECTS

All components and materials proposed for use in the grounding and protection subsystems must be evaluated for the degree of deterioration to be expected over a plant's life span. For this study, a plant life of 30 years is taken as the basis for judging materials and components.

Life expectancy and long-term availability are especially important matters when considering the array, source circuit, subfield cabling, and field termination assemblies in a large plant. System-wide maintenance or retrofit programs would have large negative cost impacts, probably at a time when the plant might otherwise be approaching its payoff years.

4.7.1 Chemical Corrosion

Corrosion of the surfaces of enclosures, fixtures, and uninsulated conductors can occur directly by weathering and chemical attack. Materials which will probably resist these non-electrolytic effects for a thirty year span when exposed above ground include concrete, stainless
steel, aluminum, copper, and treated wood. For burial below grade, the materials would be likely restricted to concrete and treated wood having oversized cross-sections.

The use of bare copper grounding cable has generally proven to give acceptably corrosion free life during many years of application in the electric utility industry. However, a degree of uncertainty exists concerning the actual lifespan of buried copper grounding cable in some soils. There have been a few examples of serious early deterioration (e.g., within months) in soil containing certain natural or manmade compounds that react with copper. Chlorides are particularly damaging. Data concerning the integrity of copper cable at specific sites where it has been buried for 20, 30, or 40 years are not available.

Stainless steel might be considered an alternative to copper for locations with severe corrosion problems. Based on comparative electrode tests it would have roughly 1.5 or 2.0 times the lifespan of copper, but it would certainly be much more expensive. Another alternative, discussed in greater detail in Section 4.6.4, is the use of concrete-encased rebar as earthing electrodes.

It has been found that it is generally acceptable to bury large copper cable (e.g., 2/0 or 4/0 AWG) for ground grids. While this size may be larger than needed for expected fault currents, it is needed to resist corrosion and mechanical damage. When using copper, certain precautions should be taken to insure that premature failures do not occur due to concentrations of harmful soil types:

- Before installation of the grounding system a chemical analysis of the soil should be performed. This analysis can make use of the soil samples which are routinely gathered as part of the foundation investigation.
- The soil tests should be taken to determine the following: ammonia, ammonium compounds, sulfides, sulfates, chlorides, sulphur, mercury, mercury salts, pH, resistivity.
On long runs of ground cable in areas where the cable would be inaccessible, insulated ground cable can be used. Insulated cable should also be used in areas where the ground cable crosses a steel pipe (5 feet on each side of the crossing) or closely parallels a steel pipe (less than 10 feet separation) to reduce corrosion problems on the steel pipe.

If an analysis of the soil conditions in a particular area indicates that copper may be adversely affected, but the issue is not clear cut, an alternative to the use of stainless steel or concrete encased grounding electrodes may be to install sections of the ground grid that can conveniently be disconnected and tested. These test sections would be installed so that the overall integrity of the grounding network would not be affected. Monitoring of these test sections over time would reveal whether significant corrosion of the ground cable was occurring.

4.7.2 Electrolytic Corrosion

Four principal sources of electrolytic action can be anticipated in a PV field. Three of these are due to the formation of a natural electrolytic cell in the soil by the buried structural members which are affected. The fourth is similar to these except that the driving potential (source of current) is external to the corroding parts. These are discussed briefly in this section. A detailed presentation of corrosion control design and construction techniques may be found in Reference 4-8.

Dissimilar Metals. Classical electrolytic cell corrosion occurs when two dissimilar metals are in contact with a common electrolyte (e.g., soil or water) and are electrically connected. The two metal structures, common electrolyte and external electrical connection form a simple electrolytic cell. One of the two metals will become an anode (i.e., positive current emitter) and will be corroded by electrolytic action. The other metal collects current from the soil electrolyte and is thus a cathode. Which of the two will become anodic depends upon their relative location in the electromotive force series. For example, in a copper-steel pair the steel is anodic with respect to the copper and will be corroded in a cell comprising these two metals.
For this reason the practice of installing unprotected steel members below grade in proximity to buried copper electrodes is considered imprudent. If the soil at a particular site is known to be very inactive as an electrolyte, problems may not develop. But for general use in various possible areas, this practice would invite trouble.

Control of electrolytic corrosion is commonly attained in three ways: (1) coating the metallic surface to be protected, (2) electrically insulating the dissimilar metals from each other, and (3) the use of some form of cathodic protection.

The effectiveness of the coating method derives from the ability of the coating to electrically and chemically isolate the metal structure from the surrounding electrolyte (soil). An example of this method is the use of a bituminous coating on steel. However, life expectancy of the bituminous coating may not approach 30 years, especially for coating on irregular shapes.

The encasement of steel in concrete has been found to provide effective protection in corrosive environments, particularly saltwater (Ref. 4-9). In the case where a copper conductor is buried adjacent to a steel structural member to which it is electrically connected, encasing the steel member in concrete may afford effective protection. According to Reference 4-8, mild steel encased in concrete has about the same natural electromotive force potential as does copper with respect to a common neutral soil. Thus, there would be little or no potential difference to drive this cell and to cause corrosion of the steel.

Insulating dissimilar metals from each other is limited in its application to grounding systems. A continuous electric circuit from above-ground circuits to below-ground earthing electrodes is, by definition, necessary to an effective grounding system.

Cathodic protection is achieved when the buried metal structures to be protected are made to collect current from the soil electrolyte environment (i.e., become cathodes). As current collectors they do not
corrode. This may be implemented in different ways, the most important of which are the use of an external dc current source (e.g., a battery or rectifier), and the use of sacrificial anodes (e.g., magnesium or zinc) which more readily go into solution in the soil than do iron and steel.

Dissimilar Soils. An electrolytic corrosion cell may also be set up with only one metal present when that metal passes through dissimilar soils. The natural electromotive force potential established between a metal and the surrounding soil depends somewhat upon the chemical composition of the soil. Thus, two different regions of the same metallic structure can become anode and cathode with respect to each other due to their different soil environments. The result is an electrolytic cell, similar to that formed by dissimilar metals, in which the region that is anodic will corrode.

The conditions in a PV plant grounding system under which this type of corrosion may occur are related to the large land areas which are traversed by electrically conductive structures. Soil type in one part of an array field may differ substantially from soil type in another part. Also, if different soil types are found in horizontal layers at the site then the action of trenching and backfilling may create local conditions of soil dissimilarity, leading to corrosion.

The natural difference in potential between adjacent and different soil types can be measured and this fact used in assessing the need for protecting PV plant structures from this type of corrosion. Protection methods are the same as those discussed above for dissimilar metals.

Differential Aeration. Another type of corrosion cell is formed when a metallic structure passes through soils having different degrees of aeration. That portion of a structure in well aerated soil will be cathodic with respect to an adjacent portion in poorly aerated soil. In such circumstances an electrolytic cell is set up. This is sometimes called an "oxygen cell" because it is the relatively free access to oxygen which renders a portion of the structure cathodic.
This type of corrosion is common where pipelines pass under roadways or riverbeds where the soil is less well aerated. In a PV plant, trenching and backfilling can create the conditions for an oxygen cell by differentially aerating the soil around parts of buried structures.

Prevention methods include proper design to avoid unnecessary aeration of soil where that would lead to formation of an oxygen cell. Protection is obtained by the methods outlined for dissimilar metals.

**Array Leakage Currents.** In the above described sources of electrolytic corrosion the source of corrosion current was due to electrochemical action at the surfaces of exposed metal(s). Another source of dc corrosion current is the PV array itself. Due to the finite, though high, resistivity of array encapsulation materials some leakage of dc current from the high voltage ends of source circuits will occur. The path for this normally expected current would generally be from PV cells in the panels toward the positive bus end of the source circuit, through the encapsulating material to metallic support structures, and thence to ground via buried supports or ground wires. The circuit is completed through the earth to the negative bus end of a source circuit where currents from the ground flow through the support structure and encapsulant and back to the cells. This is less likely to be a problem in concentrator arrays where the leakage current is less than that of flat plate arrays by a factor approximately equal to the concentration ratio.

Array-fed dc leakage currents which pass to ground through embedded foundation structures or earthing electrodes are a potential source of corrosion. As with other types of electrolytic corrosion, only the anode is corroded. Thus, it is the structures associated with array modules at positive voltages with respect to ground that will be affected. The leakage current corrosion of concrete-encased rebar in foundation structures used as earthing elements is discussed further in Section 4.7.4.
If metallic array support structures are to be direct grounded (as recommended here) designers should consider the effects of array-fed leakage currents for the reasons described above. Estimated leakage currents should be calculated and compared with corrosion rates for the metals to be used for earthing conductors. Protection methods, if warranted, could include some form of cathodic protection in which the flow of leakage currents through vulnerable structures is neutralized by an external current source (e.g., a sacrificial anode).

The effect of array leakage current is quantified by the following sample calculations. Specifications for the "Block V" solar cell modules prepared by the Jet Propulsion Laboratory require that module dc leakage currents be less than 50 microamps at NOCT when subjected to a 3000 V dc hi-pot test for one minute duration (Reference 4-10). Actual leakage during such tests is reported to be generally in the range of 20 microamps. (Reference 4-11). Recent tests of one manufacturer's "Block IV" module indicated leakage currents of greater than 50 microamps with a strong temperature dependence (Reference 4-12). However, subsequent communications with JPL indicate that the manufacturer has reduced the problem by at least a factor of 10 (Reference 4-13). A solar cell module meeting the JPL leakage current specification at 3000 Vdc would have an encapsulant electrical resistance of $6 \times 10^7$ ohms $(3000 \text{ Vdc} / 50 \times 10^{-6} \text{ A})$. An array comprising 18 modules in one metallic array support frame (such as the Bechtel Torque Tube array) would have an equivalent resistance of $3.33 \times 10^6$ ohms $(6 \times 10^7 \text{ ohms} / 18)$. Operating at an average voltage of 1000 Vdc (as would the end array in a typical source circuit in a large PV plant) the leakage current to ground would be 0.3 mA. The degree of corrosion to be expected in concrete encased rebars from currents of this magnitude is discussed in Section 4.7.4.

4.7.3 Other Forms of Deterioration

PV plant grounding system components are subject to forms of deterioration other than direct chemical or electrical corrosion. Some of these, such as electrical tracking or dirt accumulation, may act in
concert with the chemical and electrical corrosion mechanisms already discussed. The major sources of non-corrosive deterioration are briefly assessed in this section.

**Ultra-Violet Effects.** Metals are not affected by ultra-voilet (UV) radiation in sunlight, and treated wood structures would not be affected significantly in 30 years of exposure.

All coatings and polymeric materials exposed to direct sunlight would be affected to a degree that might require maintenance within 30 years. Some polymers such as polyethylene (not filled with carbon black) would be damaged within months.

It is difficult to estimate how UV testing per UL746C, Section 27, would correlate with actual life expectancies of polymeric. Determining the outdoor life expectancy of any material is difficult, partly because there are related factors, other than simply UV stability, to be considered. One of these is physical stress, which almost always exists in field installations but is typically not imposed on laboratory samples. Accelerated testing procedures can provide comparisons of durability among materials, but cannot supply an accurate prediction of one material's life expectancy.

Based on incomplete experience gained to date in service and test conditions, glass-fiber reinforced polyester is regarded as the structural polymeric composite material with longest life expectancy. If fabricated into electrical enclosures, cable trays, or conduit, its estimated life while fully exposed to weather and sunlight would be 15 years. If shaded from direct sunlight, by installation under a flat plate array for example, estimated life would likely approach 30 years.

**Electrical Tracking.** Destructive carbonized tracks can develop progressively in non-metallic plates, panels, supports, or other shapes that are subjected to voltage stress. Both off-the-shelf and custom designed electrical enclosures, terminal cabinets, and similar items must
be evaluated very carefully to avert catastrophic failures from this cause. The nominal operating voltage of 2,000 Vdc is in a range where tracking could cause a type of damage several years into the operating plant life that would be most expensive to repair.

Whether electrical enclosures are metal or polymeric, energized internal parts should be mounted on standoff insulators, or on separate insulating plates with proven characteristics, so that high electrical stress will appear only on materials designed and proven for that duty. Glass and ceramics are highly resistant to tracking; there are certain composite polymeric materials that have proven acceptable in switchgear assemblies if properly applied.

**Dirt Deposits.** Large PV plants will be installed on partially improved field sites, so there will likely be substantial exposure to blowing dirt and dust.

Dirt collecting on exterior parts can affect grounding and protection equipment in three ways. First, it can pack into ventilation and heat radiating fixtures on electrical enclosures, causing internal components to overheat. Second, it can collect in crevices, joints, and fasteners where it will retain contaminated water and hasten corrosion at those points. Third, it can drift inside equipment enclosures, which at some point will cause problems.

Design of enclosures, heat dissipating details, hardware fittings, bonds, and other fittings must be evaluated for their non-vulnerability to airborne dirt. Many existing outdoor electrical devices can be thoroughly washed by rainstorms or by maintenance crews using washing equipment. But this capability has to be designed into the devices, and verified by test.

**Attack by Living Organisms.** Because of their intrinsic outdoor nature, photovoltaic plants have a special risk that some of their components may be attacked or affected by animals and insects.
The most frequently reported type of damage in installations similar to PV plants is from rodents chewing into cable jackets. Other risks include termites attacking cables, insects nesting in enclosures or blocking air intake/exhaust openings, fungus attacking buried cables or plastic parts and bacteriological corrosion of buried metal.

Priorities of concern should be determined during the survey of a proposed site, based on direct inspection and inquiries of existing facilities in the same area. However, these efforts might not provide a totally accurate prediction of the problems that might develop in the years after the PV plant becomes operational. Conditions might change because of migrations or population cycling, or the new structures and shade in a PV field might attract concentrations of certain animals. During preliminary design, advice should be sought from wildlife biologists who are familiar with these problems, and are conducting ongoing research. The Denver Wildlife Research Center, U.S. Department of Interior, is an important center for this activity.

Rodents. The three rodents most likely to damage wires, cables, and conduits in continental U.S. are the Gray Squirrel, the Pocket Gopher, and the Norway Rat. These animals can exert biting pressures of 22,000 psi, 17,000 psi, and 7,000 psi, respectively. The gopher can attack most buried materials because its incisor teeth operate outside of its mouth. No material has been found that will repel gophers, and yet be safe to manufacture and install. Attack by gophers must be thwarted by a barrier that is hard enough to resist the pressure or large enough to force an unworkable biting angle.

Measures that have been found to be effective against gopher attacks on buried cables include the following:

- Steel conduits, usually encased in concrete for protection against corrosion
- Non-metallic conduits encased in concrete
• Non-metallic conduits of diameter larger than two inches, and made of a hard polymer. One estimate is that 2 inch hard plastic conduit will repel 99 percent of attacks.

• A cable wrap of hardened stainless steel or hardened bronze tape

• A cable or wire covering of specific polymer composites (this method is in development and early stages of application)

For protecting the many small cables required in PV fields, the last approach named above appears to offer the best prospect for a generally applicable solution. But it is not yet generally available nor proven in service. For larger cable raceways, 4-inch rigid non-metallic conduits with large-radius fittings appear to be the most appropriate.

Termites. Less specific information on countermeasures is available for termites than for rodents. Metal barriers will stop them, unless the metal is thin and becomes pitted by corrosion. Hard plastic utility pipes and conduits are now approved by many building codes, which must reflect their adequate resistance to termites. Cable jackets and the softer plastics, however, are known to be vulnerable.

Insects. Flying and crawling insects would probably be more of a nuisance than a damaging effect on PV plant equipment. But they could enter or nest in any enclosures or raceways that are not closed off or screened adequately. It would be particularly important to provide effective screens for all enclosures that house protective devices. Otherwise invading insects could cause malfunction by overheating, mechanical blocking, or short-circuiting. This is a hazard that has been countered in the past by proper attention to design details.

Fungus and Bacteria. Serious impacts from fungus and bacteria are rarely reported in the continental U.S. For PV plants, the best preventative would be to avoid any site where these would be potential problems. All facilities in a plant would suffer if the site were highly infested with microscopic organisms.
4.7.4 Array Foundations as Earthing Electrodes

With little or no modification, array (and building) foundations may themselves be used as earthing electrodes in addition to their primary structural function. In some cases this would tend to lower plant costs. Further, some array foundation designs are such that foundation members necessarily become part of the grounding subsystem unless specific measures are taken to provide electrical isolation. Corrosion is addressed here specifically for array foundations.

Reinforced Concrete Caissons. The Martin-Marietta concentrator array, the Bechtel Torque Tube flat-plate, and other array designs each use cylindrical reinforced concrete caissons. The Martin-Marietta design is for one 18-inch diameter caisson per array, with about 12 feet below grade and 5 feet above. The Bechtel design is for a line of 16-inch diameter caissons, one per array plus one extra at the end of each row. The depth is about 5 feet below grade and 3 feet above.

In such foundation designs, the rebar itself may be bonded electrically so that it would function as an earthing electrode. For this, a significant portion of the concrete caisson and rebar cage must be in moist soil and below the frost line. However, there is concern that in serving as buried electrodes, the strength of caisson might be affected, through corrosion of the rebar over a 30-year plant life. It is expected that structural design of array foundations will be fairly close to the wind loading requirements. This would tend to increase the possibility of corrosion induced failures in later years.

Factors that might cause corrosion of the rebar cage in a caisson are:

- Leakage currents (dc) to earth from modules via the array structure
- Electrolytic action - steel rebars forming an electrolytic couple with direct buried copper grid cables and/or ground rods.
- Poorly compacted concrete
- Highly corrosive soil
Array-fed leakage currents have been described in Section 4.6.2. These currents would be greatest toward the high-voltage (plus or minus) ends of source circuits. As mentioned, current flowing from the structure to earth near each positive terminal will be more damaging than current leaving earth near each negative terminal.

Review of the available literature on the corrosion of grounding electrodes indicates that this may be a significant problem when electrodes are subject to continuous dc currents. An example of this is the observed corrosion of grounding electrodes used in underground mines (Ref. 4-14). In this case, the corrosion reaction is driven by the presence of stray dc current from electric haulage track. Laboratory tests of the response to dc currents of various types of grounding electrodes (including concrete-encased rebar) have shown measured rates of corrosion of .03 to 1.33 gm/A-hr (Ref. 4-14).

Conversely, corrosion due to ac currents has not been a problem. Reported experience with the use of concrete-encased rebar as earthing electrodes for structures subjected to ac fault currents is generally positive. Field and laboratory experience with ac currents in the safety ground system have shown no significant corrosion of the rebars or the anchor bolts (Refs. 4-15, 4-16).

It is concluded that the nature of the fault or stray currents (i.e., whether they are ac or dc) in the safety grounding system is a key factor in the corrosion problem.

Leakage currents from array structures to earth may be reduced by providing metallic interconnection among all adjacent arrays. In this case, module leakage currents would find a low-resistance direct metallic path for these short distances, and the proportion of current entering and leaving the earth would be reduced. This should also permit monitoring the magnitude of leakage currents, either continually or by spot check.
Since stray dc currents of sufficient magnitude can cause corrosion of concrete-encased rebars used for earthing electrodes, study of this subject is warranted. Because of the high dc potentials at each end of an array source circuit, some dc leakage current from the cells to ground via the array support structure may be expected. As mentioned, electrical bonding of the adjacent support structures would reduce but not eliminate currents to earth. According to Reference 4-14, steel rebars encased in concrete corrode at a rate of about 0.73 gm/A-hr when subjected to continuous dc currents. While corrosion occurs over the entire length of the rebar, the effect is more pronounced at the point where the rebar exits from the concrete into open air. Galvanized steel buried in moist sand corrodes at a rate of 0.44 gm/A-hr. It may be assumed that the latter rate also applies to the corrosion of a galvanized steel anchor bolt at the point where it exits from the top surface of a concrete caisson. With this assumption, calculations show that for a caisson employing two 3/4-inch diameter galvanized steel anchor bolts bonded electrically to the rebar cage (as in the Bechtel Torque Tube design), a dc current of 0.22 mA per caisson over a 30-year plant life (8 hours per day and 365 days per year) would cause the corrosion loss of 10% of the metal from each of the anchor bolts over a 3/4-inch zone above the point of entry into the concrete. In these calculations it is assumed that all of the corrosion current passes through a 3/4-inch zone above the concrete.

If the corrosion of the anchor bolts were somehow prevented (e.g., by coating) and the corrosion current distributed uniformly over four vertical rebars, each 9 feet in length, then a similar calculation shows that the same dc current would cause the corrosion loss of about 0.08% of the rebar metal. A test in which 33% of the metal of a single concrete-encased rebar was removed by corrosion resulted in the splitting apart of the concrete casing (Ref. 4-14). Similar results could be projected for buried concrete caissons for levels of corrosion of that magnitude. However, it is doubtful that corrosion induced metal loss in the range of a few tenths of a percent would produce these catastrophic results.
If corrosion should be a problem, one approach to the control of stray current corrosion is to shield the rebar cage with an exterior electrode assembly. For reasons discussed above, the cage material should not interact as an electrolytic cell with the rebars. Stainless steel material in the outer shield should accomplish this to a degree. The proper alloy to use, and the percent effectiveness as a shield will have to be determined.

The most practical shield shape is probably an assembly of 2 or 3 narrow upright U-shaped rods, bent to the shape of the bore-hole vertical cross-section. These are welded together at the bottom of the U, and probably prefabricated with one or more rings to permit handling the completed unit. This outer cage would be dropped into the bore-hole first, then the rebar cage. Afterwards the concrete encasement is poured. The shield rods would lie on or close to the concrete surface, thus enhancing conductivity to the earth. Effectiveness of the shield could be estimated by a mapping of equipotential lines and current flow lines, representing the rebar cage by a cylinder and the shield by four discrete rods.

This structure would provide protection around the bottom face of the pier which other methods would not provide. Corrosion in experimental electrodes subject to stray currents occurs increasingly toward the bottom of the rods, except for a zone right at the grade line (Ref. 4-14). With this construction it would be possible, if pre-arranged in the hardware, to spotcheck the integrity of shield rods. With a shield cage in place, the rebar assembly can be insulated so that virtually all leakage current flows through intended metallic paths and the outer shield, not through rebars. This insulation could be accomplished by coating the completed rebar cage assembly with epoxy paint or by insulating hold-down bolts from the metal assembly that is bolted onto them.

A second possible problem associated with the flow of stray currents through concrete-encased rebar used for grounding purposes is the
physical deterioration of the concrete (Ref. 4-15). This may occur when the concrete is dried out by the heating effect of the current. However, high current densities are required, and these may be easily avoided through proper design. Explosive destruction of the concrete due to lightning surge current has not been observed in the concrete footings used for grounding structures exposed to lightning strikes (e.g., transmission line towers).

A third area of concern is the possible galvanic corrosion of the steel rebar when connected to copper. This has been discussed in Section 4.7.2. Some observers have concluded that this is not a problem for steel encased in concrete (Ref. 4-15).

As discussed in Section 4.7.2, with copper and iron in the same area, iron will tend to be sacrificed. The remedies for this situation include using no grounding electrodes other than the caisson rebars, or some form of cathodic protection as discussed above.

Concrete with fissures or breaks will allow the rebar to be exposed to the corrosive soil and will tend to promote the formation of oxygen cells and the subsequent corrosion of the rebar. Control of work quality during installation is the principal remedy for poorly compacted concrete. Quality would likely be better if piers were prefabricated.

Finding a remedy for corrosive soils is difficult; costs will be higher and risks to all plant facilities will remain. Measures to protect rebars in foundations are to keep the concrete dense and uniform, and to provide a minimum of 4-inches of concrete between the rebar and the soil, rather than the conventional 2-inches. This would increase somewhat the expected resistance to earth but only in soil whose resistivity is less than that for moist concrete. Rebars could be coated with epoxy paint, which has been proposed for reinforcing in bridge decks, but this would make the rebar cage ineffective as an electrode. If required, the latter method could be applied more readily to two axis
concentrators where sufficiently low ground resistance may be provided by
the burial of ground wires to connect the individual arrays. However,
the buried wire must still be protected, perhaps by encasement in
concrete, or be designed as a replaceable element.

Buried Wood or Steel Structural Parts. The JPL buried-plate foundation
assembly is mostly wood, with some galvanized metal fittings and
fasteners (see Figure 2-2). The wood parts pose no special problem with
regard to stray currents, and electrolytic or (presumably) chemical
corrosion.

The most efficient way to utilize the buried plate foundation for
earthing would be to prefabricate a copper or stainless steel loop, with
or without cross links. The loop could be stapled or tied to the bottom
plate during fabrication. Risers could also be attached in the shop,
using flexible cable leads. Thus, the field work required to place an
earthing electrode would be minimal. The depth of this design would be
about 42 inches. This is deeper than necessary for most grounding
network conductors, but in some cases it may be shallower than the soil
moisture level. (It should not to be shallower than the frost line,
otherwise the structural design would be in question.)

The Hughes design uses buried structural steel parts, with some encased
in concrete footings and others not (see Figure 2-3). The "metal foot"
front foundations form a long horizontal buried electrode. The rear,
concrete-encased structural members act as vertical (albeit shallow)
ground rods. Effective and longterm use of such inherent structural
characteristics as an earthing system requires that consideration be
given to the electrical, as well as the structural, bonding at the array
members. Additionally, as with other array types, there is a need to
electrically connect these electrodes by crossties. The use of copper
wire may be questionable here, because it would lie very close to a
succession of bare steel footings. Hughes used buried stainless steel
crossties for the installation of their arrays at the Sandia Albuquerque
test facility to avoid possible corrosion problems.
Many passive and active protective measures are available, or may be devised, to safeguard people and equipment in a PV plant. These measures include limiting the magnitude of fault currents, detecting faults and limiting their duration, enclosing or guarding energized equipment, grounding or guarding exposed metallic parts that could develop voltages during faults or normal operation, and providing isolating switches or similar devices as required.

Most of the techniques and hardware described herein are based on designs for certain types of existing installations, such as utility and industrial power systems, underground and surface mines, and electrolytic reduction plants. Other techniques are unique to photovoltaic installations. For example, intentionally short-circuiting a power source for several hours, or deferring remedial action until after sunset are possible safety measures for a PV plant which are not generally contemplated in other types of installations.

5.1 FAULT PROTECTION

Fault protection methods on the dc circuits in PV plants must be specialized because of the unique voltage-current characteristics of PV cells, modules, and source circuits. Fault protection for the ac circuits in a PV plant can be based on the conventional application of relays, circuit breakers, and fuses.

5.1.1 Predictable Faults

The first step in the design of protective subsystems is to identify the specific faults that are to be suppressed or nullified in order to limit the potential for damage to equipment and hazard to personnel. In this study only reasonably predictable faults were defined. Designing for
highly unlikely faults would lead to overcomplicated and expensive protective measures. However, the designer will not be absolved from using reasonable caution in the area of personnel safety, regardless of cost.

Cells. A PV cell may fail in service by cracking or by defects in internal connections. This may cause an open-circuit, or a leakage path from positive to negative or to ground. Some of these faults could be intermittent or arcing faults. Another type of fault is a marked degradation in the I-V output characteristics (see Figure 2-1) caused by internal changes or contamination of the cell surface. Symptoms of faults include:

- Distortion of the normal I-V curves for source circuits
- Relatively hotter or cooler operation, overall or in spots
- Transients or electrical noise on dc busses caused by intermittent or arcing faults

Modules. A module may fail by open-circuit or poor connection at its terminals, by line-to-line short-circuit, or by short-circuit to the module frame, backplane, or heat sink. Symptoms of such faults would include those listed above for cells, plus stray currents to ground through the module frame, either steady-state or transient. Arcing faults may lead to visible damage to modules. If the module assembly includes bypass diodes, these could fail open, short, or to ground.

Arrays. Array wiring may fail by open-circuit or poor connections at terminals, or by short-circuit to array frames or support structures. Also, an array may fail by an open, short, or ground in a bypass diode if diodes are components of the array assembly.

Symptoms of such faults would include those listed above for cells and modules, plus:

- Stray currents to ground through the array frame, and to earth through the supporting structure
• Unbalanced or circulating currents in the source circuit containing the faulty array, and possibly in other dc circuits
• Visible damage caused by arcing faults

Source Circuits. Source circuits will be affected by any of the possible faults in arrays, and also by failure of cables, connectors, blocking diodes, or other protective and switching devices. Failure of a blocking diode, triggered by an internal fault might initiate high reverse current that would have to be interrupted by a fuse.

Cable Circuits (dc). Cabling and terminations in the PV subfield may fail by short-circuit from either polarity to ground or earth, and by any short or cross involving the dc neutral circuit if it exists. Also, the dc network may fail at random points. All of these faults may be solid, intermittent, or arcing.

Symptoms of such faults would be abnormal voltage, current, or power flow, and distorted I-V curves. Arcing faults might produce abnormal wave forms or high-frequency radiation.

In addition, the above dc faults may cause operation of fuses, relays, circuit breakers, alarm circuits, or other elements of the dc fault protection system.

PCS. At the PCS, external thyristors in the collecting circuits may fail to block the inverse voltage, or they may fail to conduct forward current. Filter or commutating capacitors may fail by short-circuit. Transformers and reactors may fail by short-circuit, including turn-to-turn shorts. All components and circuits are subject to ground and open-circuit faults.

The control and protection circuitry itself may malfunction, which poses a need for backup protection or supervisory monitoring. Typically, backup protection is provided by ac circuit breakers and dc isolation and protective devices within the PCS.
Three-phase Output Circuits (ac). Failures in the ac three-phase plant output circuits (connecting the PCS units to a plant substation) will likely be of familiar types; phase-to-ground, phase-to-phase, three-phase, and various open-circuit situations.

Most of these can be dealt with, to a degree, by the use of conventional power system relays, circuit breakers, switches, and fuses. However, two characteristics of the typical PV plant must be recognized in order to apply these protective devices correctly:

- Current into an ac three-phase or phase-to-phase fault from the PV field may be only about 20 percent higher than full rated load current, even for maximum insolation.
- Current into an ac fault will come both from the PV subfields and from the utility transmission circuits. To clear an ac fault will require opening both paths, together or independently.

Substation. Transmission line relays located at a PV substation must be coordinated with the overall line and network protective scheme. Usually these requirements are defined rather specifically by the electric utility company, including makes and models of relaying equipment that will interface properly with existing installations at line terminals in other substations.

Within the substation, transformers and busses should be protected by differential, phase overcurrent, ground overcurrent, and directional relays. Each protected zone or equipment item should have primary and backup relay protection.

5.1.2 Recommended Measures

Personnel. The nature of large PV plants, where many thousands of virtually identical arrays would be attended by a small number of personnel, suggests that protective measures be provided for all people who have access to the field rather than for all arrays installed in the field.
There are of course limits and conditions in pursuing this goal but the benefits in cost should be worthwhile. By considering each point carefully the overall effectiveness in protecting people could be enhanced. There is precedent for this approach in electric utilities, electrified transportation systems, electrolytic reduction and similar industrial processes, and at high-power radio transmitter sites. A very necessary condition is that the array field be sufficiently secure to discourage access by unauthorized personnel, whether public or members of the plant or utility staff.

Industrial PV plants (and some utility plants) probably could not meet this security condition. This point would have to be established during preliminary design. Failure to meet this condition would dictate that in typical industrial PV plants, all judicious and code-prescribed safeguards be built into the arrays and source circuits to the extent feasible.

Structures. Protective measures applicable to structures are not extensive. In addition to effective earthing and bonding, they include the following:

- Limiting the magnitude and duration of faults
- Guarding any particularly hazardous zones (such as high-voltage cable runs in open trays)
- Posting cautionary signs as required

One special measure applicable to roof-mounted industrial arrays is to provide railings around the maintenance catwalk, so that an involuntary muscular reaction from a minor shock could not cause a person to fall from the roof.

Equipment. Depending upon their nature and application, equipment items may be protected by several techniques. Active measures include:

- Clearing faults
- Shorting faulty PV arrays or source circuits until repairs can be made
• Blocking any reverse flow of dc current
• Alarming upon the occurrence of any abnormal conditions
• Interlocking (electrical and key types) to prevent gross operating errors
• Shutting down equipment or circuits that might aggravate the fault

Passive measures include:

• Guarding access to energized equipment
• Guarding exposed metal parts that might develop a voltage
• Posting cautionary signs as required

Circuits. Point-to-point circuits running in wires, cables, or buses are protected by surge arresters or suppressors to prevent overstressing the conductor insulation, and by fault clearing devices to limit excessive conductor heating, or to prevent further damage if the fault is internal.

PCS Units. Power conditioning systems have many internal components and circuits to protect. Such protection would be provided as an integral part of the PCS, but it must be related to the ac and dc plant design so that all protective functions will be coordinated.

Active protective measures inside a typical PCS should include the following:

• Circuit interrupters in the main dc positive and negative busses
• Fuses in capacitor, filter, and inverter leg circuits
• A three-phase circuit breaker on the ac output leads
• Conventional relays on the ac side (i.e., overcurrent and differential current types)
• A control center with various sensors to provide fast shutdown of the inverter bridge whenever abnormal conditions are detected in any part of the PCS
circuitry (These would include peak current, reverse current, overvoltage, undervoltage, off frequency and out of phase detectors.)

5.2 DETECTION OF FAULTS

The following paragraphs describe general ways that faults thought to be typical of PV plants might be detected and located. Reference to Figures B-11, B-12, B-13, 4-1, 4-2, and 4-3 is suggested at this point.

5.2.1 Electrical Characteristics

The dc circuits of PV plants are unique in their load and fault characteristics. They perform generally in a constant-current mode (at a given level of insolation). So many of the application rules and practices developed for conventional dc networks supplied by batteries, rotating machines, or rectifiers do not apply. Thus it is necessary to identify the characteristics of electrical faults or malfunctions in PV plant circuits with the objective of developing detection methods.

Voltage Level. The voltage appearing at the dc terminals of a normal PV source circuit may vary from zero in darkness to about 150 percent of nominal at no load on a very cold bright day. Therefore, the absolute dc voltage level alone cannot be used as an indicator of a fault. There is no reasonably predictable type of fault that would produce a reverse voltage or a voltage significantly greater than 150 percent of nominal across the source circuit terminals.

The voltage appearing at the midpoint to ground terminals of an ungrounded source circuit would, in theory, be indeterminate. In practice however, leakage currents would tend to make this voltage float around zero volts dc. Any substantial deviation of this voltage from zero (or from its settled out level) would be an anomaly. The causative difficulty might be a lowered output from a malfunctioning module, or a fault to ground at some point in the source circuit. However, this is not a very helpful fault indicator because of its vacillatory normal state and its indiscriminate response to ground fault location.
Voltage levels on ac circuits, whether at the PCS outputs, at the substation, or on auxiliary power circuits within the plant, are expected to stay within the range of ±15 percent of nominal. Thus, deviation of the absolute ac voltage value greater than 15 percent can correctly be used as an indicator of fault or malfunction.

Voltages appearing at the neutrals of ac circuits, particularly on ungrounded wye transformer windings, might be used to indicate ground faults. But this is rarely done in practice, because easier alternatives exist.

**Current Level.** Direct current flowing from the terminals of a normal PV source circuit may vary from zero in darkness to about 25 percent above nominal with terminals shorted at full insolation. This provides little or no basis to use increased forward current flow as an indicator of a fault.

However, there may be some fault conditions in dc subfield circuitry that can effectively be detected by simple overcurrent as a fault indicator. One of these is a fault in one source circuit that pulls current from parallel connected circuits. This condition indicates two simultaneous failures, a ground fault, and a shorted blocking diode. Still, all overcurrent level indicators have a bounded effectiveness because they depend, directly or indirectly, upon the level of insolation existing when a fault occurs.

As part of an off-line test procedure, short-circuit current from an array or source circuit could be measured and compared with previous values for the same element.

Overcurrent is widely used to detect faults in ac circuits and identify their locations more or less specifically. These conventional methods can be used for most of the ac circuits found in a PV plant.
Power Level. Power and volt-ampere levels in themselves do not provide further fault indicators beyond those derivable from current levels. Power values are generally more difficult to measure. PCS control usually requires a power output level indicator, but this is used for the power optimizing function, not for fault detection.

Reversals (Current, Power). Current flow in several of the typical links within a dc subfield network will reverse if solid faults occur. At source circuit terminals, this reversal is such a hazard to all affected internal PV cells that diodes are universally used to block reverse current. Thus, actual reversal of dc at source circuit terminals requires an internal fault together with a shorted blocking diode.

At other points in a dc subfield network, current reversal may result from only a single fault.

If midpoints of the source circuits were connected to ground directly or through resistors or neutral circuits, then dc current flow in any midpoint connection would be a definite indicator of a fault in that source circuit. This current would also flow in a definitive direction, depending on which leg of the source circuit is faulted. This topic is discussed further in Section 5.4.

In three-phase ac circuits, direction of power flow may be quite significant as a fault indicator. Since the PCS is designed to always supply power toward the utility, and since auxiliary power is taken from the substation bus, then any power reversal at the PCS output terminals is a definite fault indicator.

Comparisons (Voltage, Current). Because of the repetitive nature of circuits and components in large PV plants, many possibilities exist for comparison between a particular circuit's operating value and that of other contiguous or essentially identical circuits. This is a powerful method; it is used in input-vs-output differential relaying, in parallel-path differential relaying, and in ground fault interrupter devices.
The comparison technique can be considerably extended in large PV plants, compared with the limited opportunities in most other kinds of electric power installations. Output of a particular PV source may be compared with any other, or with several others sampled in sequence, or statistically with a group of others. Further, output of a particular source may be compared to its performance a few moments earlier, or to any previously measured output under comparable insolation and temperature.

Window transducers can be used to compare current flow in positive and negative leads at the PV source circuit dc terminals. Any difference would indicate a ground fault (if the subfield is referenced to ground at some central point).

This expanded capability, beyond local comparison of in-out current flow, would be unrealistically complex if implemented by wired relay devices. However, by use of a microprocessor-based data acquisition system, comparisons of a fast sequential, statistical, or historical nature are feasible. Also, this would permit the use of simpler field devices. Additionally, comparisons executed by a computer could remain workable to quite low insolation levels.

**I-V Curves.** The measurement of source circuit I-V curves can be used to indicate faults. However, this method appears more suited as a troubleshooting tool to determine the location and nature of suspected faults rather than as a means of active fault protection. Determining whether or not a source circuit is performing as specified usually involves knowing the incident insolation. For purposes of fault identification, the shape of the curve could be measured and evaluated for irregularities indicative of faults. Measurement equipment could be a portable I-V curve tracer and capacitive load. This equipment is currently available for power levels up to 20 kW, but at voltages about one-fourth those postulated for central station source circuits. Alternatively, the PCS may be used to measure I-V curves (discussed further in the next section and in Section 5.3.3).
5.2.2 Use of the PCS as Test Equipment

One method of determining whether failed cells or cell strings exist in a given solar array is to operate the array over its open-circuit to short-circuit range and record the I-V characteristic. Discontinuities in the I-V characteristic may then be used to identify module or source circuit failures. The power conditioner is normally operated to deliver array power to the utility line; it might be desirable to utilize it in a reverse test mode to generate the open-circuit to short-circuit source circuit I-V characteristics. That would require the power conditioner to accommodate dc input voltages ranging from the open-circuit level to essentially zero. This test mode is discussed in detail in Section 5.3.3.

5.2.3 Non-Conventional Methods

PV cells, cell strings, or modules that are performing poorly might be difficult to detect and locate by in-circuit fault detectors. This is because, assuming no ground fault were involved, they would cause only a small percentage change in source circuit output or balance. Examples of such faults would be bypassed strings, high resistance cells, arcing faults, or high-resistance joints or terminals.

There are some new or unconventional methods, applicable to the above circumstances, that should be considered for fault detection in PV subfields. Products are available to implement these possibilities but development and prototyping would be required to assemble and evaluate a functioning system.

Radio Interference Detection. Typical arcing faults on PV arrays, or on cabling and terminals, might be found to radiate significant electro-magnetic interference. Radio frequency receivers that would respond to these interference fields and locate their source could be a valuable adjunct to other in-circuit fault indicators.

Installing receivers, or remote pickup devices, on source circuits or arrays becomes unattractive in large plants because of initial cost, maintenance, and extra cabling. Also, this approach would not provide a
good resolution of the fault location. It appears that a better solution would be to mount the receiver on a vehicle that would patrol the subfield roadways and access lanes. The vehicle operator could detect and track the significant radio noise signals down to their point of origin by using directional and portable pickups.

Local radio and television signals and radiation from PCS units might complicate this approach, or make it unworkable. However, PCS inverters will have to be specifically shielded to meet FCC regulations. The potential benefits of this technique suggest that it is worthwhile pursuing.

**Infra-Red Detectors.** Another alternative, applicable to flat plate arrays, would be to scan the infra-red image of each array, with sufficient resolution to detect cells that are warmer or cooler than the norm for that panel and for adjacent panels. The optics on concentrator arrays make this approach unworkable for scanning cells in these types of arrays. However, the approach may be viable for scanning the heat sinks normally visible on the backs of point focus concentrators. The method appears unsuited for most line focus concentrator array configurations.

Visual scanning could be a difficult task for people to perform with the speed, sensitivity, and acceptance of boredom that would be required. An automated optical imaging, scanning, detecting, and recording system could be developed to flag and locate anomalies of a prescribed degree.

Further, the system (or important parts of it) would likely be mounted on an automated vehicle that would continually move itself along the array rows in accurately controlled traverses. This, too, would be a repetitive task not suited for people, except during an experimental phase. Such a vehicle could be checked out, repaired, and calibrated in a central shop.
The benefit of this approach would be gained only in large plants, and even there it would depend on whether cell and module malfunctions prove to be a minor or major problem. It is also possible that if such equipment is developed, it may be shared (or leased) by several large plants on a rotational basis.

5.3 ROLE OF THE PCS IN FAULT PROTECTION

The PCS in a PV system provides the interface between the dc source circuits and the ac utility line. Both self-protection for the PCS and the protection afforded by it to connected circuits are discussed in this section for typical self- and line-commutated inverter designs.

5.3.1 Self-Commutated Inverter Protection Features

UTC's self-commutated inverter (SCI) design provides an effective buffer between the dc source and the ac utility line. The built-in control center and protection equipment, coupled with the paralleling impedance, make the dc source immune to any detrimental effects from ac line faults. In the same way, the ac line is prevented from contributing significantly to dc source faults. In addition, the power conditioner protection minimizes any disturbances to the ac line or dc source should the power conditioner suffer an internal failure or fault.

The self-commutated power conditioner provides two basic levels of protection:

- Direct protection equipment such as fuses or circuit breakers
- Sensing circuits for critical parameters such as current or voltage, which detect fault situations and initiate proper protective action via a control center within the system

Isolation and Protection Device (IPD). The IPD provides a no-load-break, motor-operated isolating switch and a high-speed current-limiting fault interrupter. The motor-operated switch isolates the power conditioner from the dc source during periods of non-use and for maintenance. The
fault interruptor consists of a pyrotechnic element that cuts the main current carrying conductor and shunts the current through a small (100 A) current-limiting fuse which completes the circuit interruption and quenches the arc. Specific operating features of the fault interruptor and its control assembly are that it:

- Provides two-pole interruption, for ungrounded or center-grounded dc sources
- Operates if dI/dt exceeds adjustable level of 10 to 60 amperes per microsecond
- Operates on instantaneous trip if the current level exceeds 3000 to 10,000 amperes (adjustable)
- Operates on inverse time ($t^2$) with curve selectable
- Operates via command from remote location such as system site controller
- Is easily adaptable to operating on any desired parameter (such as low-level reverse current flow) to improve protection of dc source

**Inverter Input Filter Capacitor Fuses.** Input filter capacitor cans are individually fused (F1) as shown in Figure B-12. Fuse coordination is such that the rated energy of each can may be stored or discharged in all operating modes at any rate without opening the fuse, but a short in any one can will open the fuse before the shorted can ruptures. The instantaneous fault energy (fuse clearing) is provided from the other parallel capacitors which are all close-coupled. Thus, the dc source sees very little disturbance.

**Inverter Bridge Semiconductor Fuses.** As shown in Figure B-12, the power bridge semiconductor elements are short-circuit (shoot-thru) protected by current limiting semiconductor fuses (F2). As is the case with the input filter capacitor fuses, the instantaneous fuse clearing energy for faults is provided by the input filter capacitors, so that disturbance to the dc bus is small.
Inverter Bridge Output Fuses. Also shown in Figure B-12, each of the six inverter output lines is fused with a current limiting semiconductor fuse. These are coordinated to protect the power rectifier diodes from utility fed current if an inverter bridge fault occurs.

Series Reactors. Although the series reactors are passive elements with no interrupting capability, they are included as a protective feature for three reasons:

- Coupled with the output transformer's 0.05 per unit impedance, they provide a total of 0.22 per unit impedance which limits fault current from the ac utility line to about 4.5 times rated current.

- They provide a defined rate of rise of fault current. This allows proper coordination of pole overcurrent protection (discussed in next section) to account for minimum turn around time for main thyristor switching and maximum commutation capability requirements.

- Their impedance integrates utility line voltage switching or lightning surges into current wave shapes that pole overcurrent protection can evaluate. Thus, all powerpoles can be commutated off prior to current surges exceeding the commutation capability. The voltage surge is not seen by the bridge semiconductors or by the dc bus; therefore overvoltage failures are essentially eliminated. Extreme lightning surges may cause semiconductor fuse blowing (commutation failure) because it is usually not justifiable to design for such worst case conditions.

AC Breaker. A standard utility type circuit breaker is utilized in the three-phase output circuit. It operates from standard relay protective sensing for instantaneous and inverse time overcurrent, as well as trip signals from output transformer differential current protection. It is also opened upon command by the power conditioner logic for dc source start/stop sequencing and other sensed protective functions that would dictate a system shutdown.

Lightning Arresters. Two levels of lightning arresters are provided, one set on each side of the ac breaker. These arresters provide clamping action for voltage surges on the ac line caused by lightning.
Distribution class arresters are provided on the line side of the ac breaker; station class arresters are used on the power conditioner side of the ac breaker.

**Overvoltage/Undervoltage Sensing (dc).** Should the dc bus voltage level move outside the inverter minimum or maximum dc operating levels, the inverter is immediately commutated off (in about 200 microseconds). It remains off until the voltage returns within limits, and then automatically restarts. For PV applications, programming is added to prevent excessive on/off cycling due to low insolation at dawn or dusk.

**Pole Overcurrent Sensing.** Output current from each of the six powerpoles in the inverter is sensed, and if it exceeds a specified peak value the inverter bridges are immediately commutated off (in about 200 microseconds). The peak current trip value is about 1.3 times the rated peak output load current. This feature limits the inverter contribution to an ac line fault to less than 1.1 per unit on an rms basis for one cycle. For dc bus faults, the inverter turns off, but the fault current can still flow through the rectifier diodes. The inverter automatically restarts when the current is no longer out of limits, provided no other limit functions prevent the restart.

**Utility Voltage Out of Limits.** At present, standards are being developed for the operation of megawatt-sized PCS units in parallel with utility systems (Ref. 5-1). Utility line voltage regulation can be expected to be better on most transmission line circuits (e.g., the interface point for central stations) than on distribution lines (e.g., the interface point for intermediate power level systems). Any of four parameters of the ac utility line voltage being out of limits can cause the inverter to immediately commutate off. For distribution and transmission line systems, the postulated limits of inverter operation include:

- **Ac Overvoltage** - more than 110 percent of nominal
- **Ac Undervoltage** - less than 80 percent of nominal
• Line unbalance - 5 percent line to line
• Line frequency - outside the range of 57 to 61 hertz

Supplementary Protective Functions. In addition to the above described protective functions (where parameters are sensed, and if out of limits the inverter is commutated off), the list below shows fault conditions for which the inverter is not only commutated off, but the ac breaker and the dc isolating switches are opened. Automatic restart is not allowed; manual action must be taken before a restart can be attempted.

• Loss of inverter bridge cooling fans
• Loss of line synchronization
• Loss of ac power source for logic
• Loss of logic dc power supply
• Loss of communication with site controller
• Incorrect status of ac breaker or dc switch
• Blown fuse (input capacitor, semiconductor, or bridge output)

5.3.2 Line Commutated Inverter Protection Features

In the conceptual design of the line-commutated inverter (LCI) system, source circuit dc power is fed through two three-phase line-commutated bridges. One bridge ac output is connected wye-wye in the output transformer, and the other is connected wye-delta as shown in Figure B-13. On the dc side, the bridges are connected to the source circuits through a center-tapped interphase transformer. This configuration results in 12-pulse system operation. The fundamental frequency component of the dc side voltage is 720 hertz. The ac side harmonic multiples are 11, 13, 23, 25, etc. Multiples 5, 7, 17, 19, etc. are cancelled out by the transformer connections. The uncanceled current harmonics delivered to the ac line are reduced by the use of filters. The higher-order, lower-magnitude harmonics (ripple) on the dc side are controlled by the dc series inductance which is connected between the source circuits and the bridges.

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Power flow and voltage of the line-commutated inverter are controlled by the point at which the SCR's are turned on compared to the zero voltage crossing of the ac line; this is referred to as the firing angle. Since the inverter firing leads the line voltage crossing, the line-commutated inverter appears inductive to the line. Direct current sources with wide voltage regulation require large firing angles, thus increasing the reactive power consumed by the inverter. Two basic approaches are used to ease this problem. The first approach attacks the problem by regulating dc voltage with a boost, a buck, or a buck/boost stage to allow the converter to operate at close to unity power factor. The second approach employs power factor correction capacitors or a static var generator on the ac side of the inverter to correct power factor, thus compensating for the wide power factor requirements operation of the converter. Both approaches increase parts count and may have significant cost impact for small inverters (i.e. tens to hundreds of kilowatts). For small inverters, it may be more economical to correct the power factor with a power factor correction capacitor on the utility line.

Contributions to ac fault currents by LCI power conditioning systems will be dependent on the type of high speed dc interrupter used. With one type, the fault current contribution will be reduced to zero in less than one cycle. Because ac breakers generally do not begin opening in less than one cycle, it can be argued that the converter makes no contribution to system fault interrupting currents. If the contribution disappears before the breaker begins arcing, it will have added nothing to breaker interrupting duty. However, these very short-time currents may contribute to momentary duty on breakers, busses, and other components of the system.

Power Conditioner Fault Protection Equipment. The line-commutated inverter provides two basic levels of protection:

- Direct protection equipment such as fuses or circuit breakers
- Sensing circuits for critical parameters such as current or voltage which command proper protective action via a control center within the system

**Isolation and Protection Device (IPD).** The IPD in an LCI provides the same functions as in the SCI, previously discussed.

**DC Reactors.** Reactors in the dc input circuitry perform the following functions:
- Decrease harmonic voltages and currents in the dc line
- Smooth the ripple in the direct current sufficiently to prevent the current from becoming discontinuous at light loads

**High Speed Interrupter.** The effects of dc side faults on the ac system are dependent on the fault location. Three possibilities are considered:
- Shorted SCR string: If one SCR in a string becomes shorted, the entire string may cascade into shorted SCRs when a large ac voltage surge occurs due to overvoltage. Operation may continue for appreciable periods in some instances before this occurs. A shorted string must be replaced before normal operation can resume. The ac system will be cleared from the inverter bridges by opening the ac breaker. The dc side current will be commutated off by the high speed interrupter.
- Short circuit at the dc bridge input: The bridges will commutate off and open up the ac side. Hence, the ac system will see a very small disturbance which disappears very quickly. The dc current will be commutated off by the high speed interrupter backed up by the dc source (or sink) fault protection.
- Short circuit at the source circuit end of the dc inductor: The ac system will see a decaying set of ac currents until the energy stored in the dc inductor is dissipated into the ac system. At this time, ac side conduction will cease. The dc side fault will be removed by the dc source fault protection.
Inverter Bridge Controls and Snubber Circuits. In order to avoid SCR overvoltage and dv/dt failures, snubber circuits are required to limit the rate of rise of forward voltage. Such circuits are required across thyristors to prevent their breaking down on forward voltage that exceeds the rated value.

A short circuit in the ac system may cause a commutation failure. If a commutation failure occurs, the high speed interrupter will open in less than one cycle and the bridges will shut down. The inverter restarts automatically when the line voltage returns to normal.

Firing angle control can be designed to enable the inverter to ride through most lightning and switching surges. If a commutation failure occurs, the firing angle initiating the next commutation will advance sufficiently to prevent further failures. In the event of persistent commutation failures, the high speed interrupter will open to shut the bridges down and restart will take place when line voltages return to normal.

In the event of commutation failures due to abnormal line voltage unbalance, the high speed interrupter will shut the bridges down. The inverter will restart when the voltage unbalance is within normal levels.

Inverter Bridge Output Fuses, Circuit Breakers, and Lightning Arresters. These protective devices in the ac circuitry perform the same functions as described for the SCI power conditioner.

5.3.3 Diagnostic Capabilities of the PCS

In addition to providing protective functions, the PCS may be able to be operated in a diagnostic mode to identify source circuits with failed cell strings or modules by measuring I-V characteristics. This is discussed for SCI and LCI equipment.

Self-Commutated Inverter. A self-commutated type of inverter (SCI) generally does not provide a sufficiently extended voltage range for it
to have a test capability. Ideally it is designed to operate over a defined input voltage ratio of between 1.0/1.0 and 1.5/1.0. It is nominally designed for a 1.3/1.0 ratio for this solar application. This ratio equals maximum design operating voltage divided by minimum design operating voltage. If the minimum design operating voltage corresponds to a peak power point for a given insolation level, then an SCI can operate to only 86 percent of the open circuit voltage at that condition.

Inverter operation towards the short-circuit end of the source circuit characteristic is limited by the reactive power flow that occurs due to the decrease in dc input voltage. Thus, the inverter commutation capability decreases with decreasing dc input voltage. The typical SCI inverter design is such that its current commutation capability decreases linearly with dc input voltage. An inverter designed for maximum power (1.0 per unit commutation capability) at the 1.3 per unit voltage level is rated at 0.77 per unit power (commutation capability) at the 1.0 per unit voltage level.

Furthermore, the inverter is designed such that its ac output voltage can be preset to deliver rated power at the 1.0 per unit voltage point at unity power factor (zero reactive power). At dc voltages below 1.0 per unit, the reactive power consumption will increase. The inverter ac output voltage will drop linearly with the dc input voltage, and the resulting delta voltage between the inverter and the utility line is impressed across the 0.22 per unit paralleling reactance of the inverter, producing reactive power flow increasing at $1/0.22 = 4.5$ times the per unit dc voltage decrease. The lowest dc voltage at which that inverter design can operate is 0.86 per unit. At that level, all the commutation capability is required to handle the reactive load alone.

The above analysis does not account for the real power that must be handled by the inverter to traverse the source circuit I-V characteristic. This effect is to increase the lowest dc voltage at which the inverter can operate. Obviously, with all source circuits in a subfield connected, the lowest operating voltage is at 1.0 per unit.
because the maximum real power equals the commutation capability. Any reduction in the dc input voltage would add reactive loading, increasing the kVA and thus the inverter current, and would exceed the commutation rating. If tests were performed on smaller connected portions of the subfield, operation down to dc voltages approaching the 0.86 per unit lower limit of operating voltage would be possible.

Enlarging the commutation capability is not a practical way to achieve lower voltage operation. Thus, the SCI does not provide a means of obtaining open-circuit to short-circuit I-V characteristics.

One other method does exist that utilizes the power conditioner equipment and requires minimal additional system components. However, its use is dependent upon being able to obtain the necessary I-V information during a transient condition. If the dc isolation switch is rated for load closure, the open circuit source circuits may be switched into the uncharged capacitors in the input filter capacitor bank (through an appropriate charging resistor). The I-V charging characteristic may be captured with fast recorders. This is also a method of determining when a subfield has sufficient capacity to warrant startup in the morning or on heavily overcast days.

**Line Commutated Inverters.** The line commutated inverter (LCI) may be used over a wide range of dc voltage input from virtually zero to about 1.3 times the magnitude of the rms line voltage. This type of inverter is essentially current fed, with sufficient inductance in series with the dc source to produce continuous current even at minimum load for normal operation.

Usually, at least two bridges are used to eliminate the 5th and 7th harmonics from the ac output. Traps are used on the output line to remove interaction between the bridges due to gaps in the waveform during commutations. The resultant 12 step current wave is almost in phase with the line at full power and at 90° for zero dc input. The reactive power of the line is constant for constant dc current, but the power factor drops with decreasing the dc voltage.
In using the line commutated inverter to obtain a load profile of a source circuit, several problems arise:

- At light loads the current may be discontinuous, thus limiting the minimum operating point.
- The ripple voltages at low dc voltage inputs to the bridges are of maximum values, requiring much higher dc inductance than needed for normal running conditions.
- Control of the dc voltage at close to short-circuit conditions for the array adds control complexity since the effective control angle is a function of impedance and load current.
- It is necessary to prevent the operating point from passing to the rectifier mode as this produces a voltage polarity reversal which could force high currents through the array and damage the solar cells. However, existing blocking diodes should prevent this.
- Instrumentation accuracy may be a problem at low dc voltage levels because of the ripple content.

The line commutated inverter can, with the conditions noted above, be used to obtain most of the points on a source circuit I-V curve between 10% voltage and 10% current. Both the open-circuit and short-circuit points, and the adjacent low-scale points, may have to be obtained by special methods and circuitry that exclude the inverter.

5.4 PCS ISOLATION TRANSFORMERS

This section presents a discussion of the need for an isolation transformer between the PCS inverter bridges and the utility for medium-sized applications. If used, such a transformer would logically be a component of the PCS unit in order to provide coordination of its protection and load requirements.

The choice of including or omitting an isolation transformer is more likely to arise in small or medium power low-voltage industrial-type PV installations. The specific question addressed is whether an additional
transformer is required to isolate the PV plant from all other ac power circuits.

5.4.1 Guidelines and Assumptions

The following guidelines and assumptions have been used as a basis for this evaluation:

- Systems under consideration are solar photovoltaic, as would be used in industrial plant or similar cogeneration applications.

- Utilization system ratings range from 20 kVA to 1000 kVA and all are connected to three-phase utility distribution circuits.

- Solar array output voltage (power conditioner dc input voltage) is between 300 and 600 Vdc, nominal.

- Utility interface is at the customer load utilization voltage level; the utility transformer used at that interface is a standard distribution feeder transformer with a four-wire grounded neutral low side connection.

- Power conditioning equipment is solid state only, comprising either line- or self-commutated inverters; rotating machine generators are not considered.

- Typical SCI and LCI interfaces are taken from UTC's DOE contract study entitled "Investigation of a Family of Power Conditioners Integrated into the Utility Grid" (Ref. 5-3).

5.4.2 Institutional Factors

The position of the electrical utility industry regarding whether an isolation transformer is required is not well defined at this time. Individual utility companies that are structuring interconnect requirements for customer-owned generators vary greatly in their position on this matter, from specifically requiring such a transformer to no mention of it at all. However, reviews of utility requirements and discussions with individuals conversant with utility requirements have uncovered no statement that a transformer may be omitted.
Preliminary guidelines and requirements for the interconnection of customer-owned generators issued by five utilities have been reviewed:

San Diego Gas & Electric
Pacific Gas and Electric Company
Southern California Edison Company
Baltimore Gas and Electric Company
Georgia Power Company

One of these utilities specifies that a separate transformer is required, one implies that it may be required, and the other three take no position either way. Two of them require that customer-owned generators and their utilization level loads be serviced by a dedicated utility distribution feeder transformer; that is, such a customer must be serviced by a utility transformer that services no other customers.

There are several groups and committees addressing these interface issues under the auspices of organizations such as the utility companies, SERI, JPL, EPRI, DOE and others. Many of the resulting interface specification documents that these groups have produced contain nonexplicit references to the transformer issue. Isolation transformers are mentioned as a means to accomplish certain requirements such as isolation or to block dc at the interface but is not stated to be an absolute requirement. For example, the "IEEE Trial Use Standard Utility Interface for Terrestrial Photovoltaic Systems" prepared by the Photovoltaic Systems Subcommittee of the IEEE Standards Coordinating Committee for Photovoltaics contains the following statement:

"514 DC Isolation

The PV system shall not inject dc into the ac interface under normal or abnormal conditions. (As an example, an isolation transformer connected between the PCS and ac interface is one way of satisfying this requirement.)"
It should also be noted that Article 250-3 of the 1981 National Electrical Code, which discusses two wire dc systems, states that two wire direct current systems shall be grounded, but Exception No. 3 exempts systems operating at over 300 volts between conductors. That article can be interpreted to mean that commercial (300 to 600 Vdc) systems do not require grounding of the dc array source.

Another example is document "82 (Secretariat) 5, Draft, Interface of Residential and Intermediate Size Terrestrial Photovoltaic Power Systems with an Electric Utility System" which was prepared mainly from a joint JPL-EPRI draft document "Interim Working Guidelines and Discussion Concerning the Interface of Small Dispersed Photovoltaic Power Producers with Electric Utility Systems." Figure 2 in that document is the "PV System/Utility Interface Diagram" (shown as Figure 5-1 herein). Between the PCS and the utility interfacing subsystem there is an isolation transformer shown in dotted lines with an asterisk. The asterisk explanation states: "These protective functions should (may) be incorporated into the PCS."

The answer to the transformer requirement question is clearly an institutional as well as technical problem. Utility companies and various study committees are evaluating the technical details of grounding, circuit isolation, and the potential for dc current injection at the PCS/utility interface of photovoltaic systems, as well as other dc systems such as fuel cells and batteries. Experience in these areas has led to the subjective judgement that more of them are tending towards the conclusion that an isolation transformer be mandatory.

5.4.3 Techno-Economic Factors

Interrelated technical and economic factors affect the need for isolation transformers. Several of these factors have bases traceable to institutional requirements but the following discussions are primarily on technical and economic aspects.

The principal alternatives are shown in Figure 5-2 and 5-3. The PCS schematics shown in Figures B-12 and B-13 are also pertinent here.
Figure 5-1. PV System/Utility Interface Diagram
Figure 5-2. Schematic of Ac and Dc Circuitry for Transformerless PCS
Figure 5-3. Schematic of Ac and Dc Circuitry for PCS with an Isolation Transformer
Figure 5-2 illustrates a transformerless PCS connection in parallel with a dedicated, utility-owned distribution transformer. This configuration has restrictions on the manner in which the dc side (arrays) can be grounded. The restrictions are discussed in further detail in a later subsection, Impact on System Grounding and Isolation. Figure 5-3 illustrates four possible alternative configurations for interfacing the PCS and utility line through an isolation transformer. Figure 5-3A illustrates an isolation transformer with a delta-connected secondary. With this configuration, the PCS cannot supply unbalanced loads on a four-wire plant distribution system independently from the utility line (i.e., cannot operate in a standalone mode). Figure 5-3B shows the equivalent configuration with a wye-connected secondary, which can supply unbalanced loads on a four-wire system. Both of these configurations utilize a conventional distribution transformer, which may be either utility- or customer-owned. Figure 5-3C shows a configuration with the isolation transformer and distribution transformer windings combined into a single unit. This combined transformer scheme requires only three sets of windings, as opposed to four with the preceding two configurations. The configuration shown in Figure 5-3D is similar except that it includes a wye-delta primary to provide harmonic cancellation for a two-bridge PCS. Both of the latter configurations require special transformers which would very likely be customer-owned.

Dedicated Versus Customer-Owned Distribution Transformers. The significance of a dedicated utility transformer is that it serves only the customer who operates the generating source. Therefore, any detrimental effects from the customer's system are buffered from the rest of the utility by that transformer. In addition, for new installations incorporating customer generation, the dedicated utility transformer could be designed to provide special isolation or operating requirements such as multiple windings for multi-bridge inverters. This would invite a cost penalty, but probably would be less expensive than a standard utility transformer plus a separate inverter isolation transformer. As noted earlier some utilities are already requiring that customer-owned generators be served by a dedicated utility transformer.
A customer-owned distribution transformer (by implication dedicated to that customer only) has significance beyond that of the dedicated utility transformer. The customer can take the position that any detrimental effects of his generating are seen only by his load system and his transformer, and that no problems of isolation or dc unbalance are imposed on the utility.

The validity of that position is somewhat dependent on whether the customer-owned transformer is designed and protected accordingly. For example, generation of excessive dc unbalance could saturate the customer-owned transformer, and the utility would see the resulting malfunction. If the transformer is designed to withstand expected levels of dc generation (and the power conditioner designed to shut down beyond that level) and it is properly fused to clear a malfunction due to saturation, impact on the utility is minimized in that only that customer is disconnected from the utility in the event of a problem.

Either configuration (dedicated and dedicated/customer-owned) of course, only has significance at potential installations where they exist. Discussions with utility transformer manufacturers indicate that the percentage of customer-owned transformers is a function of KVA service rating. With installed ratings of 500 KVA and up, less than 30% of the transformers are customer-owned; below 500 KVA the percentage is probably less than 20%. Dedicated transformer statistics, being inclusive of the customer-owned, are higher and probably vary considerably from utility to utility, and within the service area of any given utility.

The utility-owned dedicated transformer situation will be governed by whatever regulations are established for interfacing customer-owned generating systems and reflects back to the previous discussion on utility company requirements regarding interfacing transformers. For new installations, use of a properly designed dedicated transformer may satisfy both the utility requirements and the customer's needs. Specific definitions of the requirements are needed, along with establishment of who incurs any additional costs for the transformer designed for a customer-owned generator interface.
For the customer-owned transformer situation, the fundamentals of the problem are the same. Until the interface requirements are established it cannot be resolved what transformer configuration is acceptable.

In summary, it would appear that present day statistics on dedicated and customer-owned transformers are really not significant. What is significant is the establishment of the interface requirements. Once that is accomplished, customer-owned generating systems can be grid connected in a manner that meets interface requirements in the most economic manner.

Voltage Levels. The typical medium-sized photovoltaic systems evaluated were specified as being 20 to 1000 kVA at 300 to 600 Vdc, which immediately places some restrictions on the PCS that can be considered for a transformerless configuration.

A PCS without a transformer requires the operating input dc voltage range to directly match the secondary voltage (no step-up or down via a transformer). The specified dc voltage range of 300 to 600 volts therefore places system ac interface restrictions on the power conditioner. These restrictions are somewhat different in LCI and SCI systems. The power conditioners are assumed to be single-stage types, with no internal dc to dc converter. Such two-stage converters can provide voltage matching and are discussed in a subsequent subsection, Impacts on System Grounding and Isolation.

The dc input voltage of a PCS must vary over about a 1.5:1 range to enable tracking of array maximum power operating points for nominal variations in temperature and insolation. Energy losses incurred by reducing this range have been quantified in several studies (Refs. 5-2, 5-4). A study by Bechtel (Ref. 5-2) considering PCS and energy costs concluded that maximum power tracking will not necessarily be economic for mature PV module costs in central station plants. This is not the case for present day module costs. For the present evaluation, a 1.3:1

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PCS voltage range is assumed. The characteristics of SCI systems are such that the minimum dc voltage (lower end of range) is equal to about 1.4 times the line-to-line rms ac output voltage, if no transformers are used. LCI system characteristics dictate that the maximum dc input voltage (upper end of range) be equal to about 1.4 times the line-to-line voltage. The impact of these characteristics is summarized in Table 5-1. The table shows the dc input voltage ranges needed for SCI and LCI systems to interface with 208 Vac and 480 Vac utility circuits without a transformer.

Table 5-1

<table>
<thead>
<tr>
<th>Utility Line 3-Phase Voltage (Vac)</th>
<th>Minimum dc Input Voltage (Vac)</th>
<th>Maximum dc Input Voltage (Vac)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCI 208</td>
<td>* 291</td>
<td>**378</td>
</tr>
<tr>
<td>LCI 208</td>
<td>**224</td>
<td>* 291</td>
</tr>
<tr>
<td>SCI 480</td>
<td>* 672</td>
<td>**873</td>
</tr>
<tr>
<td>LCI 480</td>
<td>**516</td>
<td>* 672</td>
</tr>
</tbody>
</table>

* Required in power conditioner design to meet ac interface.
** Due to 1.3/1 voltage operating range of PV source circuits.

As Table 5-1 shows, strict adherence to the 300 to 600 volt dc criteria would allow an SCI to be transformerless at 208 Vac only (ignoring 120 Vac single phase which would not be likely at the power levels being considered), and would allow an LCI to be transformerless at only 480 Vac. Increasing the high limit by 45 percent (600 Vdc to 873 Vdc), and decreasing the low end by 25 percent (300 Vdc to 224 Vdc), would allow use of either the LCI or SCI transformerless design at utility ac levels of 208 Vac or 480 Vac.
Power Levels. As part of its on-site fuel cell powerplant technology development program, UTC has reviewed building electrical characteristics to ascertain the relationship between utilization (customer) voltage levels and service levels demand.

Building or plant demands up to about 500 kVA are typically serviced at 120/208 or 120/240 volts ac. Demands up to 1000 kVA typically require 277/480 volts ac, with the two voltage levels overlapping in the 100 kVA to 500 kVA range.

Those ac voltage level requirements are consistent with earlier comments on voltage levels at which SCI or LCI power conditioners can be interfaced without a transformer, provided the wider range of dc input (source circuit) voltages can be made available (244 to 873 Vdc rather than 300 to 600 Vdc). These levels are also consistent with typically available electrical power equipment (such as switchgear and breakers). At 500 kVA, a 120/208 Vac three-phase service requires circuits rated at about 1400 amperes per phase. Typically, the capabilities of 208 Vac rated equipment (such as main breakers) do not exceed 1000 amperes, thus 400 or 500 kVA appears to be the practical limit on systems interfacing directly at 208 Vac. Since 480 Vac main breaker equipment is rated as high as 2000 or 3000 amperes, 1000 kVA at 480 Vac is not a problem because the current is only about 1200 amperes.

The above considerations indicate that systems between 20 and 1000 kilowatts can be grid connected directly without a transformer at either 208 Vac or 480 Vac, with 500 kVA being a practical limit for 208 Vac systems. The significance in cost and efficiency of the PCS power rating versus ac or dc voltage levels will not be addressed here, because this is a generic study of the need for an isolation transformer based on functional issues such as utility requirements, safety aspects, advantages/disadvantages of transformer, alternative transformer types and grounding considerations. However, the expanded dc input (source circuit) voltage required to service these system ranges may increase costs. For a fixed power level, decreasing the dc voltage will result in
higher current. This would require larger size conductors, connectors, switches, diodes, etc., and would thereby tend to increase costs. Increasing the voltage would, at some level, require the next highest class of insulation on switchgear and wiring, and would also tend to increase insulation thickness on the modules (assuming the thickness is not set by mechanical considerations, Ref. 5-5).

Introduction of Dc Components Into Utility Circuits. One of the most significant issues in determining whether or not an isolation transformer is required is the concern over PV generation systems injecting dc components into utility lines. By their nature, solid-state inverters generate some level of dc circulating current due to the fact that power-handling components and switching times cannot be exactly matched. Thus, upper and lower portions of their output waveshapes are not exactly identical. This unbalance results in a dc component being generated. The dc component will appear as a circulating current, which in a transformerless system will flow through the windings of the utility distribution-feeder secondary transformer that services the customer's plant. As will be shown below, excessive levels of dc current will result in saturation of the transformer. The level of dc generation can be controlled by active control of thyristor firing angles. Additional protection can be offered by a protection scheme that turns off the inverter if the dc current exceeds some predetermined level.

Use of an isolation transformer as part of the power conditioner alleviates the problem of injecting the dc current directly into the utility transformer. An isolation transformer can be designed to handle normally expected dc levels without saturation. If coupled with a protection scheme that turns off the inverter when the dc current exceeds the transformer saturation threshold, PCS systems can be designed so that the utility is not affected or exposed to dc components from a customer-owned grid connected generator.
Successfully employing transformerless systems requires determining the level of dc current that can be imposed on a typical utility transformer. The power conditioner must be designed to control the dc current below that level and to shut down before the current reaches the saturation level of the connected distribution transformer. Where dc content is generated by the source circuit grounding configuration (e.g., unbalanced, center-grounded arrays), adequate control range will probably not be obtainable, and an isolation transformer will be required.

Table 5-2 shows characteristics and derived characteristics for distribution transformers in the 15 kVA to 1,000 kVA range. The basic characteristics were obtained from the center section of Table 16-16 in The Standard Handbook for Electrical Engineers (Ref. 5-6). Impedances, resistances, reactances, no-load losses, and the approximate magnetizing current \(I_{\text{mag}}\) were derived from Table 16-16. The magnetizing currents shown are based on the ratio of magnetizing kVA to core loss (approximately equal to no load loss). This ratio for many transformers lies between 3.5 and 5.0; the average of which was used in Table 5-2 to compute \(I_{\text{mag}}\).

### Table 5-2
DISTRIBUTION TRANSFORMER CHARACTERISTICS

<table>
<thead>
<tr>
<th>Rated kVA</th>
<th>Impedance (% of Rated kVA)</th>
<th>No Load Loss (%)</th>
<th>Magnetizing Reactance (%)</th>
<th>Magnetizing Current*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Magnitude</td>
<td>Phase</td>
<td>Resistance</td>
<td>Reactance</td>
</tr>
<tr>
<td>15</td>
<td>2.3</td>
<td>13.5°</td>
<td>2.10</td>
<td>0.54</td>
</tr>
<tr>
<td>30</td>
<td>1.7</td>
<td>17.7°</td>
<td>1.62</td>
<td>0.52</td>
</tr>
<tr>
<td>45</td>
<td>1.6</td>
<td>20.3°</td>
<td>1.50</td>
<td>0.56</td>
</tr>
<tr>
<td>75</td>
<td>1.4</td>
<td>17.2°</td>
<td>1.34</td>
<td>0.41</td>
</tr>
<tr>
<td>112.5</td>
<td>1.4</td>
<td>30°</td>
<td>1.21</td>
<td>0.70</td>
</tr>
<tr>
<td>150</td>
<td>1.8</td>
<td>49.7°</td>
<td>1.16</td>
<td>1.37</td>
</tr>
<tr>
<td>225</td>
<td>1.6</td>
<td>46.5°</td>
<td>1.10</td>
<td>1.16</td>
</tr>
<tr>
<td>300</td>
<td>1.4</td>
<td>44.4°</td>
<td>1.00</td>
<td>0.98</td>
</tr>
<tr>
<td>500</td>
<td>2.2</td>
<td>60°</td>
<td>1.10</td>
<td>1.91</td>
</tr>
<tr>
<td>1,000 (Est)</td>
<td>3.1</td>
<td>70.1°</td>
<td>1.05</td>
<td>2.90</td>
</tr>
</tbody>
</table>

* Percent of rated full load current
Hysteresis loops, as shown in Table 5-3, were examined for a transformer at three different ac voltages with and without a dc current equal to 0.33 times the magnetizing current at rated voltage. Selection of this dc current level is based on flux margins typical of utility transformers. Based on empirical methodology from a rather limited set of test conditions, the following effects were noted:

- The main body of the hysteresis loop remained essentially constant over the ac voltage range, whether dc current was present or not. The changes due to ac voltage level and dc current merely affected the length of the tails on the hysteresis loop.

- The area enclosed by the loop is representative of the hysteresis loss. Since the areas enclosed by the tails are small, the tails may be shifted without affecting that component of core loss very greatly. Thus, at rated voltage where addition of dc current merely decreases the negative tail and increases the length of the positive tail (deducted a small area from the negative half cycle and added a small area to the positive half cycle), the change in this component of loss is small. In general, $I_{dc}$ can be large enough to reduce one of the tails to zero without incurring much penalty. If this level be exceeded and the main body of the loop is altered, the penalties grow rapidly.

- Somewhat similarly, the eddy current loss increases little when this dc current flows. Again, the increase on the positive half cycle is partially offset by the decrease on the negative half cycle, if $I_{dc}$ is not too large compared to $I_{mag}$.

- As seen in Table 5-2, $I_{mag}$ lies between about 4% of full load rated current at 15 kVA to about 1.2% at 1,000 kVA. This means that the allowable $I_{dc}$ can be as large as 1.33% of full load rated current at 15 kVA but should decrease as the rating increases to allow an $I_{dc}$ of only 0.4% of rated at the 1,000 kVA level.

At 20 kVA with a 120V/208 system, $I_{dc}$ should be constrained to about 0.74 amperes (the system rated current is 56 amperes). At 1000 kVA with a 277/480 Vac system, $I_{dc}$ of about 5 amperes is allowable.
Another way to approach the analysis is based on the transformer's designed flux density. Typically, a utility-type transformer is designed to operate at a flux level of 18 kilogauss, but in actuality only operates at about 13 or 14 kilogauss. That effectively leaves a flux margin of about 30 percent that can be added due to dc circulating current; roughly one third of the magnetizing current level can occur in the form of dc current. As Table 5-2 indicates, the magnetizing current as a percentage of full load current, decreases with increasing transformer size. This is because the smaller transformers typically employ more turns (fewer volts per turn) than larger transformers. However, the change in number of turns with increasing transformer size occurs at a slower rate than the increase in kVA rating, resulting in less dc current being allowed in the smaller transformers.

If $I_{dc}$ allowed = 0.33 $I_{mag}$

At 15 kVA, $I_{mag}$ = 3.9% of $I_{full \ load}$

$$I_{dc} = 0.33 \times (3.9\%) \times I_{full \ load} = 1.3\% \times I_{full \ load}$$

### Table 5-3

<table>
<thead>
<tr>
<th>Ac Voltage</th>
<th>Dc Current</th>
<th>Fundamental $I_{mag}$</th>
<th>Second Harmonic $I_{mag}$</th>
<th>Hysteresis Loops</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.63 Rated</td>
<td>0.33 $I_{mag}$</td>
<td>0.58 $I_{mag}$</td>
<td>0.15 $I_{mag}$</td>
<td>60 Hz Only</td>
</tr>
<tr>
<td>1.00 Rated</td>
<td>0.33 $I_{mag}$</td>
<td>1.00 $I_{mag}$</td>
<td>0.16 $I_{mag}$</td>
<td>with $I_{dc} = 0.33 \times I_{mag}$</td>
</tr>
<tr>
<td>1.27 Rated</td>
<td>0.33 $I_{mag}$</td>
<td>3.67 $I_{mag}$</td>
<td>0.07 $I_{mag}$</td>
<td></td>
</tr>
<tr>
<td>1.00 Rated</td>
<td>0.33 $I_{mag}$ (with air gap)</td>
<td>2.87 $I_{mag}$</td>
<td>0.12 $I_{mag}$</td>
<td></td>
</tr>
</tbody>
</table>
At 1,000 kVA, $I_{\text{mag}} = 1.19\%$ of $I_{\text{full load}}$

\[ I_{dc} = 0.33 \times (1.19\%) \times I_{\text{full load}} = 0.39\% \text{ of } I_{\text{full load}} \]

For 120/208 Vac Systems

At 15 kVA, $I_{\text{full load}} = 41.6$ amps

\[ I_{dc} = (41.6 \text{amps}) \times (0.013) = 0.54 \text{ amps} \]

At 1,000 kVA, $I_{\text{full load}} = 2,775$ amps

\[ I_{dc} = (2,775) \times (0.0039) = 10.8 \text{ amps} \]

To qualitatively state the case, the basic hysteresis characteristic of the utility transformer is established and stabilized by the ac utility line voltage as a function of the transformer ac magnetizing current. The effects of flowing dc current through the transformer windings are not detrimental, provided the dc current level is maintained well below the ac magnetizing current level. Dc current levels of about 1.3 to 0.4 percent of rated full load current can be tolerated by typical utility distribution feeder secondary transformers for ratings that range from 20 kVA to 1,000 kVA. Power conditioners can be designed to control the dc circulating current to within acceptable levels, and protection can be employed to shut down the PCS if the dc current is not held within acceptable levels. Thus, considering only the inverter-generated component of the dc current, it appears technically possible to eliminate the problem of injecting dc into the utility transformer. What remains is the institutional issue of achieving general acceptance that interface specifications may stipulate allowable levels, rather than allowing no dc current.

Impact On System Grounding and Isolation. Power conditioning systems that do not utilize an isolation transformer in their output to four-wire grounded ac distribution systems are limited as to allowable dc source ground configurations, and they require sensing and protection for ground
faults in the dc or ac portions of the system. One-pole grounded configurations cannot be used with a transformerless PCS. Neither the plus nor minus pole from the dc array can be solidly grounded without effectively shorting out either the upper or lower PCS bridge half. The remaining configurations for grounding of the dc source (solar array) are:

- Center ground
- No ground
- Resistive ground
- Capacitive ground

Details of alternate grounding configurations are also discussed in Section 4.2.2 and are illustrated in Figures 4-1 through 4-3.

Solid center grounding results in any voltage unbalance between the two halves of the source circuit (positive half and negative half) becoming a dc offset, which drives dc circulating current through the utility transformer windings. The dc resistance of the circuit is very low, so very little dc offset voltage is required to drive significant amounts of dc current. Typically, the circuit dc resistance is less than 0.10 per unit, where 1.0 per unit impedance (in ohms) is equal to rated line-to-neutral voltage (i.e., line-to-line voltage \( \sqrt{3} \)) divided by rated line current. For a 200 kVA system with a line-to-line voltage of 208 volts:

\[
I_{\text{line}} = \frac{\text{200,000 VA}}{\sqrt{3} (208 \text{ V})} = 555 \text{ amps}
\]

Therefore

\[
1.0 \text{ per unit impedance (Z)} = \frac{208 \text{ V}}{\sqrt{3} (555 \text{ A})} = 0.216 \text{ ohms}
\]

and

\[
0.1 \text{ per unit Z} = 0.1 (0.216) = 22 \text{ milliohms}
\]
Thus, it follows that only 22 millivolts of dc voltage unbalance is required to drive 1 amp of dc current through a dc resistance of 0.1 per unit.

Power conditioner controls can be designed to compensate for the small amounts of dc offset voltage that are generated internally as a function of the inverter circuit and differences in its components. These offsets are typically less than one volt. However, greater dc voltage differences between the two array halves can be generated, primarily due to three causes:

- Performance differences among array cells
- Differences in array cell aging/failure characteristics
- Differences in insolation within a subfield due to random shadowing (clouds) phenomena or dust/dirt coverage

Cell voltage matching does not appear to be a viable technique, leaving transformer isolation as the most straightforward technique to eliminate this dc offset problem for systems designed with both array and utility transformer grounding. For this purpose, high-frequency link PCSs (discussed below) are considered to have an effective isolation transformer. Other techniques (also discussed below) generally involve disconnecting the PCS when a predetermined current level is sensed.

Operating the source circuit without a midpoint ground eliminates the principal problem of dc offset and allows a straightforward application of a transformerless system. It also has the advantage of requiring two ground faults to produce a short circuit or ground loop in the subfield. On the negative side, the array may then be subject to static charge buildup, and the personnel safety issue becomes a matter of contention, as does the possibility of RFI/EMI generation. However, module leakage currents will tend to aid in removal of static changes to some degree. Similarly, stray capacitances between the modules and ground will tend to filter EMI/RFI currents. Consideration of array design characteristics indicates that these latter two effects would be more significant for flat plates than for concentrator arrays.
Resistance grounding of the source circuit midpoint through a high resistance offers several features, including: limiting of dc ground fault currents and circulating currents, providing a path to ground for EMI/RFI currents and static charges, and aiding in the detection of ground faults. However, with this method of grounding, consideration must be given to the power rating of the resistor, as discussed in Section 5.5.2 and illustrated by Figure 5-5.

Capacitive grounding is similar to resistive grounding, using a capacitor instead of a resistor. This configuration provides filtering for higher frequency EMI/RFI and transient currents. As for the ungrounded configuration, some degree of static charge dissipation is provided by module leakage current paths.

Dc to ac (array to utility) isolation can also be accomplished by two-stage PCS designs that incorporate a high-frequency link transformer, rectification, and a second inverter. With this design, dc from the arrays is inverted to high-frequency ac (e.g., 1,500 Hz) and fed into a transformer, which provides isolation. The transformer output is rectified and fed into an output inverter stage. The efficiency of the stages preceding the output inverter stage would typically be 94 to 96 percent at full load. Their cost would be at least 60 percent of that of the output stage. Thus it would appear that the high-frequency link approach could be more costly and less efficient than approaches using a single-stage inverter with an output isolation transformer. However, low-power, high-frequency link systems (e.g., ≤100 kW) may be able to use advanced semiconductors (e.g., MOSFETs) and advanced material (e.g., metglass). It may be possible to develop a two-stage, high-frequency link PCS that has little or no cost and efficiency penalties compared to a single-stage design. The output stage would still be an inverter. Thus, it can still introduce dc currents into the connected utility system if waveshape asymmetries are present due to mismatched bridge components or switching patterns. As discussed for other types of inverters, it should be possible to keep such dc currents within acceptable limits by proper design of the output inverter stage.
Commercial equipment is available for sensing ac-side ground currents (e.g., Ground-Censor from the Square D Company). Such equipment senses deviations from zero current summed over the wires fed through the device and can be used on three- and four-wire systems. The sensor can be installed around the ac output power leads within the PCS enclosure. The relay can be interconnected to the PCS shutdown circuits which also will open dc and ac switchgear (see Figure 5-2). However, most PCS designs inherently sense the output currents necessary to provide ground fault protection and the relaying function can be performed in the PCS logic by simplistic electronic summation of the sensed currents. This logic can command the PCS to turn off and open the dc and ac switchgear whenever the summation deviates from zero by a specified amount.

Magnetic amplifiers, second harmonic sensing, and other means can also be used to sense dc currents. However, the basic approach does not reduce the dc current from an operating PCS/array system. Rather, the injected dc current and all PV power are eliminated by disconnecting the PCS.

Ac sensing for ground faults or leakage at the PCS output has limited effectiveness in solar photovoltaic systems as it is sensitive only to problems occurring in the ac output power wiring and load system. Better protection is provided by sensing on the dc side, as near the array output terminals as possible (see Figure 5-2). A review of commercially available equipment revealed very little ground fault detecting equipment designed specifically for two-wire dc systems. However, Hall Effect sensors (such as available from American Aerospace Controls, Inc.) could be used to provide this function. The function could also be built into the PCS by sensing and comparing the currents in the positive and negative array output lines.

Due to the large exposure of array and its interconnecting dc power cabling, photovoltaic systems are most likely to have ground faults or leakage paths develop within the array structure itself. Therefore, the most effective system protection is afforded by sensing the current in the array ground connection. It can be simply done with a single shunt.
or Hall Effect sensor if the array grounding is done at a single point. Multiple ground lead current sensing requires multiple sensors and summing logic to ascertain total ground current. Several alternative configurations of this type are illustrated in Figures 4-1 through 4-3.

In summary, if both the source circuit and the distribution transformer must be solidly grounded, the PCS will probably require an isolating transformer to eliminate the dc circulating current flow rather than disconnect the PCS when such currents are detected. This may be the major factor in determining whether or not an isolation transformer is required.

In addition to the limitations described above, sensing of ground current levels is required to indicate when leakage currents to ground in the array increase above a specified level. System action required would be to shut off the inverter and open up the ac and dc contactors to provide ground fault isolation. Systems employing an output isolation transformer escape these grounding problems by isolating the system ac output from the dc source input.

Harmonic Cancellation or Reduction - Single-Bridge PCS. For the transformerless system discussed above with the inverter ac output lines connected to a four-wire grounded neutral utility transformer, and with source circuits solidly grounded, triplen (3rd, 9th, etc) harmonics will be present in the line-to-neutral output voltage, and will require a means for elimination or reduction. With a delta/delta isolation transformer in the system, the triplen harmonics do not appear in the line-to-line ac output voltage.

Transformerless PCS systems can be designed to eliminate or reduce the triplen harmonics. The switching frequency can be increased to achieve required harmonic reduction in SCI systems employing high-frequency pulse width modulation for harmonic control. LCI systems can employ additional brute force filtering (this requires very sharply tuned filters to shunt 3rd harmonic without substantial fundamental VAR loading), or they can
employ two half-bridges and an interphase transformer. In either case, the means employed to handle the triplen harmonics (which would be cancelled by an isolation transformer) are not as expensive or as inefficient as using a full isolation output transformer, but they do detract from the advantages of a transformerless system.

Harmonic Cancellation or Reduction - Multibridge PCS. Many power conditioner designs employ multiple three-phase bridges which are operated phase-displaced to take advantage of harmonic cancellation schemes, or to allow use of advanced semiconductors which are not rated sufficiently to handle the system power in one bridge. These multibridge systems (assumed to be a maximum of two bridges for systems between 20 kVA and 1,000 kVA) combine the bridge outputs via a transformer with two primary windings. In a two-bridge system, one delta and one wye winding are usually employed. In this arrangement, if the two bridges are phase displaced by 30 electrical degrees, the 5th and 7th harmonics and their conjugate pairs are eliminated via flux cancellation in the transformer. (Cancelled harmonics are defined as $6N + 1$, where $N$ equals the progression of odd numbers. Thus, the 5th and 7th harmonics are cancelled ($N = 1$), the 17th and 19th are cancelled ($N = 3$), etc).

With standard utility distribution feeder secondary transformers, in this study consisting of single-winding secondaries types only (grounded neutral wye), two-bridge power conditioners, which require two transformer secondary bridge windings, cannot utilize the utility transformer alone. Such a power conditioner would require an integral or closely coordinated special transformer.

The conclusion is that two-bridge inverter designs cannot be used in "transformerless" systems.

Safety Aspects. Properly designed and installed transformerless systems do not increase the risk of injury to owners, installers, or service personnel. For either a transformerless PCS or those with an isolation transformer, PCS components must be enclosed in properly designed
cabinetry that prevents people from coming into direct contact with high voltages. Also, as with other types of electrical equipment, exposed metal surfaces should be properly bonded and grounded to prevent internal faults from raising the voltage of the enclosure above ground. Further safety may be provided by door or other interlocks that act to turn off or disconnect the PCS when its cabinet is opened. As always, safe servicing requires strict procedures, such as assuring isolation from the dc source and the ac line, and discharging energy storage elements (e.g., capacitors). Similarly, a properly designed transformerless system need not be more potentially damaging to internal or external equipment.

Efficiency. As shown by Table 5-4, between 1 and 2.5 percent of the PCS power at full load is consumed by losses in the transformer. These loss estimates are based on utilization of transformers designed for an 80°C rise above ambient at full load. Transformers in the 20 to 1000 KVA range could have losses as high as 5 percent at their rated power. Within the accuracy of the study, the estimates in Table 5-4 apply to both LCI and SCI designs.

Economics. As shown by Table 5-5, 10 to 18 percent of the PCS FOB cost is attributable to the isolation transformer. The table also shows that the transformer constitutes a substantial fraction of the total PCS weight. This weight translates into PCS shipping and installation costs. The data in Table 5-5 applies to both LCI and SCI PCS.

The economic advantages of a transformerless system is that eliminating the separate isolation transformer can reduce the power conditioner cost by ten to twenty percent. On an overall PV plant basis, that may not seem overly significant; if the power conditioner represents only about twenty percent of the total PV plant system cost, then total system cost is reduced only two to four percent. However, elimination of the transformer also reduces the system losses by one to two and one-half percent. This in turn reduces the quantity and cost of the dc arrays required to provide a given system ac output power. With the same assumption that the dc source accounts for 80 percent of system cost,
Table 5-4
TRANSFORMER LOSSES
(percent of system rating)

<table>
<thead>
<tr>
<th>Rating (kVA)</th>
<th>Core</th>
<th>Winding</th>
<th>Full Load Losses</th>
<th>Total Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>30</td>
<td>.78</td>
<td>1.80</td>
<td>2.58</td>
<td>1.23</td>
</tr>
<tr>
<td>45</td>
<td>.78</td>
<td>1.80</td>
<td>2.58</td>
<td>1.23</td>
</tr>
<tr>
<td>112.5</td>
<td>.60</td>
<td>1.50</td>
<td>2.10</td>
<td>0.975</td>
</tr>
<tr>
<td>225</td>
<td>.60</td>
<td>1.50</td>
<td>2.10</td>
<td>0.975</td>
</tr>
<tr>
<td>500</td>
<td>.45</td>
<td>1.00</td>
<td>1.45</td>
<td>.70</td>
</tr>
<tr>
<td>750</td>
<td>.43</td>
<td>.70</td>
<td>1.13</td>
<td>.605</td>
</tr>
<tr>
<td>1000</td>
<td>.43</td>
<td>.70</td>
<td>1.13</td>
<td>.605</td>
</tr>
</tbody>
</table>

Table 5-5
TRANSFORMER COST, WEIGHT, AND SIZE

<table>
<thead>
<tr>
<th>PCS Rating (kVA)</th>
<th>Isolation Transformer</th>
<th>Percent of PCS System</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cost ($/kW)</td>
<td>Weight (pounds)</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------</td>
<td>-----------------</td>
</tr>
<tr>
<td>30</td>
<td>36</td>
<td>369</td>
</tr>
<tr>
<td>45</td>
<td>31</td>
<td>590</td>
</tr>
<tr>
<td>112.5</td>
<td>22</td>
<td>1050</td>
</tr>
<tr>
<td>225</td>
<td>20</td>
<td>2000</td>
</tr>
<tr>
<td>500</td>
<td>18</td>
<td>4600</td>
</tr>
<tr>
<td>750</td>
<td>18</td>
<td>6500</td>
</tr>
<tr>
<td>1000</td>
<td>17.8</td>
<td>7700</td>
</tr>
</tbody>
</table>

5-47
these savings are about one to two percent of the system cost. Thus, total system cost savings (due to elimination of the transformer cost and reduction in the quantity of arrays for lower PCS losses) are about three to six percent. In addition, the decrease in size and weight of the transformerless power conditioner results in decreased shipping and installation costs, as well as a reduced footprint. But, as previously discussed, compensation for the disadvantages of a transformerless system can detract from the three to eight percent in savings, possibly to the point where the overall evaluated cost difference is a minor factor.

5.4.4 Conclusions

The potential advantages of a transformerless power conditioning system include (see Tables 5-4 and 5-5):

- Ten to twenty percent less initial cost
- One to two and one-half percent better efficiency at full load
- About fifteen percent reduction in volume and forty percent reduction in weight

Potential disadvantages of a transformerless power conditioning system include:

- Constraints on system grounding
- Introduction of dc components into the utility line currents
- Limitations on system design options and flexibility, including:
  - Power rating and voltage matching restraints
  - Increased harmonic generation

In addition there are the institutional issues of whether or not the utilities or regulatory bodies will require a separate isolation transformer by contract or code.
The principal design factors appear to be the grounding and dc component issues. If the solar array must be solidly grounded, and the PCS output connects to a four-wire grounded distribution transformer, in all likelihood the interface with the utility will have to be via a full isolation transformer connection for which there are two or three alternative forms. In systems where the array does not require solid grounding or the utility distribution feeder transformer does not have a grounded neutral, transformerless designs can be utilized. It is anticipated however, that both array and utility transformer grounding will be required.

The dc circulating currents, with proper control and protection, can be maintained at acceptable levels only for systems with a single ground as discussed above. Of course the institutional conclusion might be that no dc component can be introduced into the utility system at any interface level.

The other disadvantages of a transformerless system have lesser significance in the overall system, and do not appear to outweigh the earlier mentioned advantages.

For array outputs between 224 Vdc and 873 Vdc, transformerless PCS units can interface with the utility only in the range of 208 Vac and 480 Vac. However, most commercial facilities in the 20 to 1000 kVA range are typically serviced at a utilization voltage within that range in any case.

Any increased harmonics generated by the transformerless designs can be eliminated or reduced to acceptable levels by higher frequency switching, or with brute force passive filters, or a combination of the two.

In general, personnel and equipment safety would not be jeopardized by proper design of transformerless PCS.
The major issue remains one of source circuit grounding requirements. If one assumes that the array must be solidly grounded, and if the utility transformer has a four-wire wye low side with the neutral grounded, transformer isolation becomes almost a necessity. Without isolation, any voltage unbalance between the two halves of the source circuit produces an unsymmetrical waveform at the bridge output which causes dc circulating currents. Solar cell performance differences and potential random partial shadowing of the array can make these voltage differences too large to be compensated by active control circuits; thus isolation becomes necessary.

In summary, it is possible to design a safe intermediate-sized PCS (20 kW to 1 MW) without an isolation transformer. The removal of this transformer would reduce the cost of the PCS and increase its efficiency. However, meeting PV system requirements such as harmonic levels and grounding may increase the PCS costs to the point of greatly reducing or eliminating any economic advantage of transformerless designs. Also, such designs would likely be precluded from applications with solidly center-grounded source circuits or a multi-bridge PCS. Although generally allowing transformerless designs at present, utilities and ad hoc standards committees are tending toward requiring incorporation of an isolation transformer in the PCS.

5.5 FAULT ANALYSIS

To develop an effective fault protective system it is necessary to assume a tentative configuration of circuits and devices, and then calculate (case by case) the responses to a set of postulated faults and operating conditions. This process is not likely to provide, on the first pass, a solution that is acceptable in all respects. Both the network and the complement of devices may have to be recast more than once before a workable combination is developed.
5.5.1 Problems Unique to PV Circuits

In the application of conventional protective relaying to industrial or utility plant ac power networks, the supply circuits can be regarded as constant-voltage sources of comparatively low internal impedance. The ratio of maximum to minimum generation is generally not more than three or four to one. However, PV sources pose special protective problems in these two areas.

Constant-Current Sources. PV cells, modules, arrays, and source circuits operating at constant insolation generate output currents that increase comparatively little (about 30 percent) if an optimum load impedance unexpectedly changes to a solid short circuit. This characteristic makes simple overload fusing and overcurrent relaying virtually impossible. It also leads to unfamiliar results when two output paths (e.g., normal load path and fault bypass through other circuit elements) are offered to a PV source. Appendix D contains an equivalent circuit and expressions which may be used to calculate some of the responses in PV branch circuits.

Dependence on Insolation. For PV sources, minimum generation is so low that no conventional protective or monitoring devices will perform. But as a practical necessity, all protective measures should be designed to operate throughout a range corresponding to the PCS operating window. Some devices, such as reverse current detectors and computer comparison techniques could sustain their protective functions into quite low power levels.

5.5.2 Faults in Source Circuits

Using the methods and the computer program described in Appendix D, values were calculated for current flow in a typical subfield, assuming faults to ground at different locations in a source circuit or along an array row. Figure 5-4 shows three curves of current magnitude versus fault location for source circuits grounded through zero, 100, and 1,000 ohm midpoint resistors, respectively. Figure 5-5 shows power dissipated in midpoint resistors for four different resistance values.
Figure 5-4. Currents in a Faulted Source Circuit
CURRENT AND POWER THRU MIDPOINT GROUNDING RESISTOR,
WITH LOAD REMOVED (OPEN CIRCUIT)
AND FAULT TO GROUND
LOW RESISTANCES

HIGH RESISTANCES

Figure 5-5. Power Dissipated in a Faulted Source Circuit
Proper coordination of fault detection devices, and proper interpretation of outputs from monitoring sensors, would depend upon similar precalculation of performance for a specific proposed source circuit under 1) ideal, 2) acceptably unbalanced, and 3) faulted conditions.

5.5.3 Sample Fault Analysis

A type of fault effects and corrective action analysis is shown in Table 5-6. This sample is based on a typical 5 MW flat plate subfield, but analysis of any other PV plant would be similar. A complete set of fault cases, patterned after this sample, should be prepared showing all reasonably predictable faults in the dc subfield, PCS unit, ac circuitry, and major ac equipment. Further, each case should be extended through a series of reduced insolation levels.

5.6 HARDWARE FOR FAULT DETECTION AND PROTECTION

5.6.1 Hardware Devices

Various hardware devices are available for implementing fault protection and safety measures in a PV power plant. The most important of these are described below. Factors which determine the applicability of each device are discussed, including availability, rating, and cost.

Surge Suppressors. Semiconductor devices are likely to be the most vulnerable components in PV subfield circuits and thus will require surge limiting. These devices require metal-oxide varistor or symmetrical diode suppressors snubber assemblies which are specifically intended for this service. The insulation in flat-plate modules would also be vulnerable. One study indicates that some modules may have substantial intrinsic immunity to voltage surges; experience is required to verify this. The use of terminal protection devices to protect module insulation is addressed in detail in Section 5.8. Transducers, auxiliary power devices, and all low-level voltage leads are next in order of vulnerability, followed by high-voltage power cables, busses and the direct connections to array output terminals.

5-54
## Table 5-6
### SAMPLE ANALYSIS OF FAULTS IN 5 MW SUBFIELD

(All Source Circuits Solidly Grounded at Midpoints)
(Cases Shown Here Are Illustrative Only)

<table>
<thead>
<tr>
<th>CASE</th>
<th>FAULT DESCRIPTION</th>
<th>EVIDENCE OF FAULT</th>
<th>MEANS OF DETECTION</th>
<th>MEANS OF CLEARING</th>
<th>PROTECTIVE DEVICES</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Solid pos to neg short at PCS input bus when insolation is high</td>
<td>Pos to neg voltages at dc buses drop to very low values</td>
<td>Sense the very low dc voltage/current ratio in major dc circuits</td>
<td>Open subfield dc circuits after coordinated time delays</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Forward dc currents increase moderately in all subfield circuits</td>
<td>Difficult to detect small increases; use computer to compare with other subfields and to locate fault</td>
<td>Open subfield dc circuits closest to the fault</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Current in PCS internal dc circuits reverse; ac power flow reverses</td>
<td>Sense the reverse current in PCS input circuits, and the reverse power in output circuits after coordinated time delays</td>
<td>Switch off the inverter bridge thyristors; open the PCS dc and ac circuits</td>
<td>Solid state switches, pyrotechnic fuses, circuit breakers</td>
</tr>
<tr>
<td>2</td>
<td>Solid pos to gnd (or neg to gnd short at PCS input bus when insolation is high)</td>
<td>Voltages from pos to gnd and neg to gnd become unequal</td>
<td>Sense the unbalance in pos and neg voltages at gnd at PCS bus</td>
<td>Switch off the inverter bridge thyristors</td>
<td>Solid state switches</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Forward dc current in pos (or neg) circuits increases moderately</td>
<td>Difficult to detect small increases; use computer to compare with other subfields and to locate fault</td>
<td>Open subfield dc circuits closest to the fault</td>
<td>Solid state switches, mechanical switches</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Currents in pos and neg dc subfield circuits become distinctly unequal</td>
<td>Sense the unbalance in pos and neg dc currents</td>
<td>Switch off the inverter bridge circuits</td>
<td>Solid state switches</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Current flow in source circuit midpoint grounds increases substantially</td>
<td>Sense the increase and direction of ground current at midpoint of each circuit; use computer to locate fault</td>
<td>Open subfield dc circuits closest to the fault</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td>3</td>
<td>Solid pos to neg short at a subfield group bus when insolation is high</td>
<td>Pos to neg voltages at all dc buses drop to very low values</td>
<td>Sense the very low dc voltage/current ratio in major dc circuits</td>
<td>Open subfield dc circuits after coordinated time delays</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Current in output circuit of faulted group bus reverses and increases</td>
<td>Sense the reverse current flow in the faulted bus collecting circuit</td>
<td>Open the collecting circuit to the faulted bus, after a coordinating time delay</td>
<td>Overcurrent fuses, solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Forward dc current in unfaulted groups and source circuits increases moderately</td>
<td>Difficult to detect small increases; use computer to sense reverse current flow and to locate fault</td>
<td>Open subfield dc circuits closest to the fault</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td>4</td>
<td>Solid pos to neg short at a subfield group bus when insolation is very low</td>
<td>Current in output circuit of faulted group bus reverses, but its magnitude is low</td>
<td>Sense the reverse current flow in the faulted bus collecting circuit</td>
<td>Open the collecting circuit to the faulted bus, after a coordinating time delay</td>
<td>Solid state switches, mechanical switches</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Forward dc current in unfaulted groups and source circuits increases moderately, but from a very low level</td>
<td>Use computer to sense reverse current flows and locate fault</td>
<td>Open subfield dc circuits closest to the fault</td>
<td>Solid state switches, mechanical disconnects</td>
</tr>
<tr>
<td>5</td>
<td>Solid fault to ground at connection between two adjacent series arrays when insolation is high</td>
<td>Current thru short in midpoint grounding connection increases substantially, and becomes 4 to 6 times larger than midpoint currents in any other source circuit in the subfield</td>
<td>Use computer to discover change in midpoint currents, and to locate faulted row in source circuit</td>
<td>Open pos and neg leads to faulted source circuit; locate fault and isolate array</td>
<td>Portable bypass device, with built-in circuit interrupter, quick-disconnect connectors in source circuit leads</td>
</tr>
<tr>
<td>6</td>
<td>Solid fault to ground at midpoint of a source circuit when insolation is high</td>
<td>No apparent change in current thru short in midpoint grounding connection</td>
<td>On scheduled basis, apply test ground to one subfield, polarity at low insulation; use computer to locate non-responsive output from faulted source circuit</td>
<td>Locate fault and isolate array</td>
<td>Quick-disconnect connectors in source circuit leads; open at right time</td>
</tr>
</tbody>
</table>
Effectiveness of voltage clamping and energy absorption capability for metal oxide varistors and diodes differ considerably, requiring selection for each application (see Section 5.8). Costs for a range of capabilities, and quantities, are shown in Figure 5-6, which is taken from Reference 5-2.

Disconnect Switches. Mechanical switches rated for no-current break duty are available for dc service in the 3 kV, 800 A range. For quantity orders, switches rated 100 A could be developed. Such switches should be certified for safe closing onto faulted circuits (for example, 4,000 Adc at the 800 A rating, or 800 A at the 100 A rating, in a 5.0 MW subfield).

Mechanical load break dc disconnect switches are not commercially available in greater than 100 A sizes, but their development appears feasible.

Circuit Breakers. Mechanical circuit breakers are available in dc ratings up to 3500 V and 2000 to 6000 A from European manufacturers. Their fault interrupting capability is higher than would be required in the subfields proposed here. Due to massive construction and limited production volume, large dc circuit breakers of this type are expensive and cost on the order of $15,000 to $50,000 each.

Vacuum circuit breakers are not available for 3 kV dc service, but their development would be feasible as an extension of current technology.

Solid-state switching assemblies also appear feasible, either as thyristors with voltage reversal circuits, or (looking further ahead) as power transistors or gate turnoff thyristors.

Contactors. Contactors rated for dc service are available at voltages below 1000V. They appear quite appropriate for industrial-type PV plants.
Figure 5-6. Metal-Oxide Varistor Cost Curves
Pyrotechnic Fuses. Circuit interruptors that can open dc circuits on command are available from one U.S. manufacturer. They must be replaced after each operation, but cost much less than circuit breakers.

Fuses. Conventional power fuses are available to cover the ratings required. Some fuses are designed specifically to protect solid-state devices and are dc rated or ac rated. Each proposed use must be approached as a special problem, to ensure coordination with the protected device or cable, and to be certain that ac to dc derating is considered, if applicable. Some fuses may be equipped with visible or electrical indicators, which would be a useful feature in most PV plants.

Sensors. Conventional current shunts are directly applicable in any circuit lead that is permanently connected to ground, or to a grounded neutral circuit. These sensors are passive, and their output can be connected to metallic instrumentation pairs that run to a PCS instrumentation cabinet, or directly to the plant control room. The most likely application for current shunts is in the midpoint connection to symmetrical source circuits.

Active dc transducers designed to measure current, differential current in two leads, voltage, or power are applicable in either grounded or line voltage circuits. Current transducers are easiest to apply, because cable leads can be run through window-type transducer pickups, thus providing the major insulation to ground, and requiring no extra power terminations. These devices all require auxiliary power, and thus would best be located in the PV group bus or PCS input bus enclosures.

Thermal sensors might also perform important functions in remote enclosures, PCS enclosures, and in major equipment housings (e.g., power transformer tanks). They can be used to monitor interior temperatures of the heat sink modules of solid state elements, or other important elements, and of cooling fluids. Application would probably be limited to locations where the sensing element could operate at ground potential, and where the auxiliary equipment could be accommodated.
Cable Connectors. Quick-disconnect connectors rated up to 5 kV, 500 A are commercially available. Both cable-to-cable and cable-to-panel types can be furnished. These have zero current interrupting rating, which would prohibit opening such connections under load. Recognizing this limitation, such connectors would provide a reasonable way to connect dc circuits initially, to isolate source circuits for maintenance, and to permit series or tee connections for testing or protection. Special configurations could be ordered, if desired, to permit operations with special insulated tools. Connectors of this type are best located inside the terminal boxes, or in other ways that would protect them against sunlight.

5.6.2 Small Electrical Enclosures

Terminal boxes and equipment cabinets of relatively small sizes will likely be required at points throughout each PV subfield for termination, protection, and instrumentation of the dc circuits. Cost savings could be envisioned by mounting circuit devices in the open, but most of them would not survive to function correctly in typical outdoor environments.

Field enclosures will typically be located at source circuit output terminals, at group collection busses, and possibly at source circuit neutral terminals.

These enclosed equipment assemblies will generally be unique for PV plant applications. Except for those that might serve auxiliary ac circuits, none is known to be presently available completely outfitted as a catalog item. Provisioning of these items for any particular plant project thus requires using recognized specification, design, prototype, and controlled production techniques. This procedure is essential to achieving the plant safety, availability, and life cycle cost requirements. Until proven commercial product lines become available, the unit quantities required to equip a large plant clearly justify use of a development/verification/production cycle for each type of enclosure assembly.
Non-metallic Enclosures. The use of non-metallic electrical enclosures throughout the array field is believed to be a beneficial design direction. The use of a polymeric composite material is not without problems and unverified aspects, but on balance it appears preferable for the relatively small, numerous and distributed enclosures. The advantages of non-metallic enclosures for a PV plant are:

- To resist corrosion by chemical action, dissimilar material junctions, and dc leakage currents
- To reduce exposure to stray touch voltages and to inadvertent arcs involving enclosure bodies
- To avoid the need for field touch-up or scheduled refinishing programs

The principal disadvantage of polymeric materials is that they tend to deteriorate in sunlight. But materials and methods seem to be at hand to achieve a life expectancy approaching 30 years, and industry developments are continuing because of demand in other industries.

Design Requirements. Enclosure assemblies must be able to perform the electrical functions prescribed, and also to meet other requirements derived from project criteria. Some of the essential capabilities are:

- Heat transfer from internal components
- Quick way to inspect and test components
- Provide quick disconnect fittings
- Immunity to insects, dirt, rain, washing, and internal condensation
- Convenient cable entrance details
- Space, mounting and connecting points for shunts and transducers
- Integral ground bus or metal backplane
- Internal guards for live terminals and ground bus
- Provisions for lifting and mounting
Heat Transfer Methods. Typically, several hundred watts of heat loss from diodes and fuses would have to be transferred out of group bus enclosures. The possible methods are: (1) forced air cooling, (2) metal or fluid-filled heat sinks with external cooling fins, (3) conduction through beryllia panel inserts, or (4) convection through fluid/vapor heat pipes. Forced-air cooling is the least costly method, but would require ongoing maintenance to counter the problems of dust, moisture, contamination, and insects. The other methods could be designed to survive with only occasional external washing.

Condensate Drain. A screened drain fitting will be required, because no reasonable enclosure for this application could be made air tight. This must be corrosion proof, equipped with a fine stainless steel screen, insulated on the outside if used in non-metallic boxes, and easy to replace.

5.6.3 Readiness

All of the safety grounding and protective measures that are built into a PV plant must be maintained in a ready condition, to a quite high confidence level. Otherwise the safeguard functions expected from such devices may in fact be absent. This will tend to cancel the benefits of extensive safety measures, or worse, to convert them into hidden hazards. The need for assurance of the readiness of safety grounding and protective devices is particularly acute, since these devices may sit idle and unused for long periods of time (e.g., 10 years). Yet, when needed they must operate without malfunction. Without a specific program of regular and frequent maintenance, it is easy to lose track of devices that are seldom used but which are nevertheless very necessary for the proper operation of the systems of which they constitute a part.

In a large PV field, economics dictate that maintenance be held to a very low per unit level for each source circuit. Thus, maximum use of passive components and of the simpler active devices is clearly a preferable design direction since the maintenance requirements of these components are often significantly less than for complete devices.
5.7 MAINTENANCE ECONOMICS

From an economic point of view, faults are undesirable in that they reduce plant revenue. Revenue losses result from capital expenditures for fault detection equipment; annual expenditures for maintenance labor, equipment and replacement parts; and from reductions in plant energy output. In the second phase of this study, several fault detection schemes were evaluated in conjunction with alternate maintenance scenarios. Economic analyses were performed which considered tradeoffs among these factors in order to maximize net plant revenue. The analyses also considered no-repair scenarios to determine if the energy saved by the repair of failures, as illustrated by Figure 5-7, would pay for the requisite maintenance equipment and labor. The results of the analyses also indicate allowable breakeven costs for improvements in module reliability.

Several types of failures in the dc electrical subsystem were evaluated in the economic analyses. These include:

- Module shorts to ground
- Module failures to open circuit
- Diode failures
- Cable failures

5.7.1 Module Shorts To Ground

Computer modeling of module shorts to ground for several alternate 5 MW subfield configurations indicated that the resulting currents would not be particularly damaging. This is based on the circuit configurations evaluated which include blocking diodes and midpoint grounding (solid or resistive). Also, the grounding subsystem is assumed to be adequately designed so that fault currents are generally confined to low-resistance metallic paths and do not pose a personnel hazard. It is also assumed that the faults are solid grounds and are not arcing, intermittent or high resistance. Under these conditions there does not appear to be a need for immediate action from the point of view of personnel safety. It should also be noted that opening the poles of a midpoint-grounded source
circuit which has a faulted module does not eliminate ground fault currents in that source circuit. It would keep such currents from unfaulted, parallel source circuits in the subfield. However, the magnitude of these currents is not too much greater than circulating currents which might be expected from unbalanced source circuits. Therefore it is postulated that the faulted source circuits are left in service until a repair action is undertaken for economic reasons. With this scenario, the subfield output power is reduced by an amount which depends on the location of the fault as illustrated by Figure 5-8. For the economic analysis the average reductions in subfield power were used. This corresponds to about 43 percent of the source circuit for the solid ground, 17 percent for a low resistance ground (1000 ohms) and 2 percent for a high resistance ground (40 kohms).

In evaluating no-repair scenarios, multiple faults must be considered for the resistance grounded cases in particular. With the first fault in a subfield, the power is reduced by a small amount (e.g., 2 to 17 percent average) depending on value of the grounding resistor and the fault.
location within the source circuit. With the second solid fault there is a metallic current path through the array structure and/or ground system which bypasses the ground resistors in the affected source circuit(s). When this second fault occurs the circuit can resemble the solid grounded cases and the power is reduced by anywhere from near zero (two faults near the midpoints) to 200 percent of the source circuit power (faults at opposite poles of two source circuits). Predicting the probability and power loss of multiple ground faults at all locations within a subfield was considered beyond the scope of the present effort. For purposes of the analysis it was assumed that after the first fault each subsequent fault would, on the average, reduce the subfield output by the power of one source circuit.

Module and subfield characteristics used for the economic analyses are summarized in Table 5-7. The four system configurations are presented in order of increasing number of parallel source circuits per subfield. This parameter has a major effect on fault detection equipment costs because the number (and cost) of current sensors increases with the
Table 5-7

PLANT CHARACTERISTICS

<table>
<thead>
<tr>
<th>Array Type</th>
<th>Flat Plate</th>
<th>Concentrator</th>
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</thead>
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<tr>
<td>Nominal System Voltage</td>
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<td>+400</td>
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<tr>
<td>Configuration</td>
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<td></td>
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<tr>
<td>Modules per Array</td>
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<td>18</td>
</tr>
<tr>
<td>Arrays per Source Circuit</td>
<td>32</td>
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<tr>
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<td>Group Buses per Subfield</td>
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<tr>
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<td>Subfields per plant</td>
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Aperture Areas (m²)

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<td>Subfield</td>
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<td>821,947</td>
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Voltage (volts)

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</thead>
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</tr>
<tr>
<td>Source Circuit</td>
<td>61.8</td>
<td>61.8</td>
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<td>1976</td>
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Current (amps)

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</thead>
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<td>Array, Source Circuit</td>
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<tr>
<td>Group Bus</td>
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<tr>
<td>Subfield, PCS</td>
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<td>450</td>
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<td>2,702</td>
<td>7,206</td>
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Efficiency (%)

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<th>Module</th>
<th>Flat Plate</th>
<th>Concentrator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance of Plant</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td></td>
<td>85</td>
<td>85</td>
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</tbody>
</table>

Insolation (kWh/m²)

<table>
<thead>
<tr>
<th>Module</th>
<th>Flat Plate</th>
<th>Concentrator</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2400</td>
<td>2400</td>
</tr>
</tbody>
</table>
number of source circuits. As noted in Table 5-7, the economic analyses were carried out for insolation typical of Albuquerque and included balance of plant efficiency in determining the plants' energy outputs.

Several alternative fault detection systems were developed for the four circuit configurations and array types being evaluated. All of the monitoring methods utilize Hall effect current sensors. Commercially available units were selected based on the magnitudes of changes in currents predicted by the computerized circuit analyses of module faults. The electrical locations of the sensors for the alternative monitoring methods are shown by Figure 5-9.

Estimates were developed for the total installed costs of these fault detection systems. The costs are summarized in Table 5-8. Details are presented in Appendix G. It should be noted that the costs in Table 5-8 (in thousands of dollars) are for a nominal 100 MW plant, while the cost tables in Appendix G (in dollars) are for one of the plant's 5MW subfields.

The cost of fault detection is directly related to the number of circuits monitored. Monitoring group bus circuits will be much less expensive than monitoring individual source circuits and fewer source circuits or group buses will reduce detection and protection costs.

Monitoring group buses provides the least expensive method of fault detection and reducing the number of group buses would lower costs accordingly. However, reducing the number of group buses increases the number of source circuits per group until a point is reached where detection is impaired. The limit is in the order of 8-10 source circuits per group bus.

Monitoring source circuits is more costly than monitoring group buses but provides more information on fault location. Again, reducing the number of source circuits reduces the cost of detection. With fewer source circuits, either system voltage or source circuit current must be increased or both.
Figure 5-9 Fault Detection Sensor Locations
Table 5-8

SUMMARY OF EQUIPMENT COSTS AND MANHOURS TO LOCATE MODULE FAULTS

<table>
<thead>
<tr>
<th>Case</th>
<th>Monitoring Method</th>
<th>Equipment Costs ($1000)</th>
<th>Manhours per Fault</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Flat Plate</td>
<td>Concentrator</td>
</tr>
<tr>
<td></td>
<td></td>
<td>+1000</td>
<td>+400</td>
</tr>
<tr>
<td>1</td>
<td>Group Bus Differential Current at PCS</td>
<td>83</td>
<td>155</td>
</tr>
<tr>
<td>2</td>
<td>Group Bus Pole Currents at PCS</td>
<td>128</td>
<td>270</td>
</tr>
<tr>
<td>3</td>
<td>Source Circuit Differential Current at PCS</td>
<td>311</td>
<td>678</td>
</tr>
<tr>
<td>4</td>
<td>Source Circuit Pole Currents at PCS</td>
<td>585</td>
<td>1,499</td>
</tr>
<tr>
<td>5</td>
<td>Source Circuit Differential Current at Group Bus</td>
<td>726</td>
<td>2,450</td>
</tr>
<tr>
<td>6</td>
<td>Source Circuit Pole Currents at Group Bus</td>
<td>1,387</td>
<td>4,777</td>
</tr>
<tr>
<td>7</td>
<td>Source Circuit Neutral Current at Group Bus</td>
<td>2,967</td>
<td>4,912</td>
</tr>
<tr>
<td>8</td>
<td>Source Circuit Neutral Current at Midpoint</td>
<td>2,967</td>
<td>4,912</td>
</tr>
<tr>
<td>9</td>
<td>Group Bus Differential Current at PCS</td>
<td>149</td>
<td>309</td>
</tr>
<tr>
<td>10</td>
<td>Source Circuit Differential Current at PCS</td>
<td>378</td>
<td>833</td>
</tr>
</tbody>
</table>
Another factor which can directly affect cost is the location of sensing equipment. The signals from various sensors need to be collected at a central location (e.g., PCS) by a data acquisition system. The amount of wiring and its associated costs is reduced as the sensors are moved closer to the central terminal location. Signal conditioners would not be required if sensors are sufficiently close (less than 300 ft for the equipment used herein) to the data acquisition equipment. These costs might be reduced by using multiplexing equipment at remote locations. A tradeoff study of equipment versus wiring cost would be required.

Scenarios were developed to estimate the number of manhours required to locate faulted modules for each of the ten cases and four array type/system voltages summarized in Table 5-8. Each scenario takes into account the information available from the fault detection equipment installed in the plant, additional measurements needed and the layout of the subfield. For example, the activities and times for Case 1, Monitoring Group Bus Differential Current at the PCS (Flat Plate, +1000 volts), consist of the following:

- Obtain and evaluate computer trouble report - 2 minutes
- Drive to the group bus junction box (an average distance of 0.5 miles and 10 mph is assumed) - 4 minutes
- Unload equipment, open junction box and measure source circuit currents - 3 minutes plus one minute per source circuit
- Drive to the faulted source circuit - 4 minutes
- Walk to the center of the affected half of the source circuit and measure current. Walk half the distance toward the determined direction of the fault. Repeat the process until the faulted module is located. The number of these measurements required will average 0.69 ln N, where N is the number of modules per source circuit. Four minutes is allowed for the first measurement, 2 minutes for the second and one minute for each additional measurement.

Since the above are estimates for clock time, the manhours required are twice the estimate for the two-man crews postulated.
The *± 400 volt Case 1 is similar but the arrays are shorter for the lower voltage and require fewer measurements and walking. The concentrator arrays require even less time and walking.

Case 2, Monitor Pole Current At PCS, requires the same actions as Case 1. The instrumentation equipment in Cases 3 through 8 convey more information about the fault and therefore less time is required for maintenance field measurements. Cases 9 and 10, Resistance Grounded, give the approximate location of a faulted module within the source circuit, thus requiring the least amount of fault location labor.

It is not known what the module failure rates will be for future designs. One tenth of one percent per year was taken as the base case, with higher and lower failure rates addressed parametrically. It is likely that overall economics will dictate failure rates of less than 1 percent per year. The set of module failure rates used was 1.0, 0.1, 0.01 and 0.001 percent per year. Figure 5-10 puts these rates into perspective with regard to the number of failures per day and days/weeks between failures for a nominal 100 MW PV plant. The difference between the flat plate and concentrator plants is due to the concentrator plant having a larger number of smaller modules and failure rate being considered on a per module rather than on an aperture area basis.

The data in Table 5-8 was used as an input for economic analyses to determine approaches to maximize net plant revenue. The data in the table also shows that some proposed systems (i.e., cases) can increase capital equipment costs without reducing the labor required to locate a faulted module. That is, the same information on fault location can be obtained with less equipment. Such cases were eliminated from the economic analyses and consequently only cases 1, 3, 9 and 10 were analyzed. The first two cases show increasing capital equipment cost with decreasing labor costs. This is also true of cases 9 and 10 which in addition have decreased energy losses due to the resistance grounding. One additional version of case 10 was run for a very high value of ground resistance to determine the effects of further reduced energy losses.
A number of periodic repair period intervals would be feasible for the larger range in failure rates. To add consistency to the analysis, the periodic repair interval was selected to be the number of days required (including weekends) to accumulate 8 hours of repair work. A minimum of one repair event per year is included at the low failure rates. The highest failure rate requires full-time (or near full-time) repair crews.

The economic analyses include:

- Alternate fault detection schemes
- Flat plate and concentrator arrays
- System voltages of ±400 and ±1000 volts
- Periodic, immediate and no-repair scenarios
- Module failure rates of 1.0, 0.1, 0.01 and 0.001 percent per year
- Values of energy of $0.10/kWh and $0.05/kWh

A representative output of the economic analyses is shown by Table 5-9. The complete data set of 20 tables and further details are included in Appendix G.
### Table 5-9

**REPRESENTATIVE OUTPUT OF ECONOMIC ANALYSES**

<table>
<thead>
<tr>
<th>FLAT PLATE ARRAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>821947 m² Aperture Area (nominal 100MW plant)</td>
</tr>
<tr>
<td>$100/m² Module Cost</td>
</tr>
<tr>
<td>0.30 mh to Replace Failed Modules</td>
</tr>
<tr>
<td>$27.00/mh Cost of Labor</td>
</tr>
<tr>
<td>$0.10/kWh Value of Energy</td>
</tr>
<tr>
<td>$21.80 million Annual Revenue of Fault-Free Plant</td>
</tr>
</tbody>
</table>

#### FLAT PLATE ARRAY

<table>
<thead>
<tr>
<th>MODULAR FAILURES (%/year)</th>
<th>1.0</th>
<th>0.1</th>
<th>0.01</th>
<th>0.001</th>
</tr>
</thead>
<tbody>
<tr>
<td>1000 VOLT CASE</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.50 mh to Locate Failed Modules</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Scenario</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Period (days)</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Replacement Modules</td>
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<td>0.07</td>
<td>5.87</td>
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<tr>
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<td>22395</td>
<td>59720</td>
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<tr>
<td>Replacing Failed Modules</td>
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<td>44790</td>
<td>4479</td>
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<tr>
<td>Detection Equipment</td>
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<td>14900</td>
<td>14900</td>
<td>14900</td>
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<tr>
<td>Subtotal</td>
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<td>1105586</td>
<td>123969</td>
<td>31481</td>
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<tr>
<td>Value of Lost Energy</td>
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<td>20518</td>
<td>20518</td>
<td>20518</td>
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<tr>
<td>Total Costs</td>
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<td>1176105</td>
<td>165345</td>
<td>32186</td>
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<tr>
<td>% of Fault-Free Plant Revenue</td>
<td>94.60</td>
<td>94.60</td>
<td>99.44</td>
<td>99.91</td>
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#### 400 VOLT CASE

<table>
<thead>
<tr>
<th>MODULAR FAILURES (%/year)</th>
<th>1.0</th>
<th>0.1</th>
<th>0.01</th>
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<tr>
<td>1.50 mh to Locate Failed Modules</td>
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<tr>
<td>Replacement Scenario</td>
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<td>Replacement Period (days)</td>
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<td>Replacement Modules</td>
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5-72
Several important aspects of the results are summarized by Figure 5-11. The figure shows the ranges of 30-year net present value (at 12 percent) of plant energy outputs as functions of module failure rates. The present value is shown as a percent of the net present value of energy from an ideal, fault-free plant (with the characteristics given in Table 5-7, e.g., Albuquerque insolation). For the concentrator array design, this is equal to $186 million. It is $176 million for the flat plate plant design. Both of these revenues are for a $0.10/kWh value of energy. At $0.05/kWh, they would, of course, be half as much. Due to the close spacing of the data points and crossing of curves, the "with repair" data are shown by ranges rather than by individual labeled curves as for the "no repair" cases. The ranges for the two "with-repair" curves ($0.10/kWh and $0.05/kWh) represent the most economic options available. That is for each given array type, system voltage and failure rate, the data points are for the detection method and repair scenario which results in the highest revenue. The resistance grounded data set is excluded from Figure 5-11 for reasons discussed in a subsequent paragraph.

The vertical scale of the figure (probability) tends to exaggerate values near 100 percent. However, small differences are significant in that each percentage point corresponds to almost $2 million (at a $0.10/kWh value of energy).

The most immediately noticeable result is that for all of the scenarios evaluated it is more economic to repair faulted modules than it is to let plant power continue to decrease without repair. The range of no-repair values shows the effects of continuing for 30 years without repairing module failures. These effects are not as readily apparent with the first year revenue values presented in Table 5-9 and similar tables in Appendix G.

Figure 5-11 also shows that lower module failure rates result in higher plant revenues, as would be expected. This result is quantified in
Figure 5-11 Present Value of Plant Revenue Versus Module Failure Rate
further detail in Table 5-10. The table shows increases in plant net present value of revenue over 30 years which result from the indicated order of magnitude decreases in module failure rates. These increases represent the breakeven amounts which could be spent to improve module reliability. As can be seen, this breakeven amount decreases substantially as module reliability increases. Based on current experience, it would appear that failure rates of 0.1 percent per year or less are attainable (and likely will be economically necessary). It can also be seen that, within the accuracy of the analysis, the results are independent of the value of energy.

Table 5-10

<table>
<thead>
<tr>
<th>Module Failure Rate Decrease (%/year)</th>
<th>1.0</th>
<th>0.1</th>
<th>0.01</th>
<th>0.001</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value of Energy</td>
<td>Array Type</td>
<td>System Voltage</td>
<td>Breakeven Value ($/m^2$)</td>
<td></td>
</tr>
<tr>
<td>$0.10$/kWh</td>
<td>Flat Plate</td>
<td>$+1000$</td>
<td>9.61</td>
<td>1.30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$+400$</td>
<td>9.46</td>
<td>1.05</td>
</tr>
<tr>
<td></td>
<td>Concentrator</td>
<td>$+1000$</td>
<td>13.69</td>
<td>1.38</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$+400$</td>
<td>13.18</td>
<td>1.32</td>
</tr>
<tr>
<td>$0.05$/kWh</td>
<td>Flat Plate</td>
<td>$+1000$</td>
<td>9.47</td>
<td>1.11</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$+400$</td>
<td>9.40</td>
<td>.97</td>
</tr>
<tr>
<td></td>
<td>Concentrator</td>
<td>$+1000$</td>
<td>13.55</td>
<td>1.35</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$+400$</td>
<td>13.13</td>
<td>1.31</td>
</tr>
</tbody>
</table>

The value of resistance grounding is shown by Figure 5-12. The figure shows the increase in net present value of plant revenue (in $/m^2$) for resistance grounding over the next most economic solid grounded option. It can be seen that resistance grounding does not appear to be economically attractive from a fault maintenance point of view for module failure rates of 0.1% per year or less. As previously discussed, it is believed that such failure rates are attainable and economically necessary. Further, resistance grounding requires that the modules and
Figure 5-12. Increase in Net Present Value of Plant Revenue with Resistance Grounding Over Next Most Economic Alternative
entire dc system be insulated for twice the voltage of its solid grounded counterpart (see Section 5.5.3). At most, $1.43 would be available to spend on increased insulation (flat plate, +1000 volts, 1% failure rate). For these reasons, resistance grounded cases were not included in Figure 5-11.

Figure 5-13 shows the value of periodic repair over immediate repair of faulted modules. The values shown (in $/m^2) are the increases in 30 year net present value of plant revenue. As mentioned, the repair period used is the length of time required to accumulate 8 hours of repair work. A full time repair crew is required for failure rates of 1% per year. As can be seen, there is an economic advantage of slightly more than $1/m^2 for periodic repair for concentrator arrays and failure rates of 0.1% per year. The advantage is less for flat plates. With lower failure rates, immediate repair offers an economic advantage. However, this advantage may not be significant within the accuracy of the present analysis.

An assessment was made of the value of installing more fault detection capital equipment to reduce the labor required to locate faulted modules. This is basically a comparison of Case 1 (Monitor Group Bus Differential Currents at the PCS) and Case 3 (Monitor Source Circuit Currents at the PCS). Figure 5-14 shows the savings of Case 1 (minimal equipment) over Case 3 (i.e., the net present value of plant revenue for Case 3 minus that for Case 1 with the same parameters). The parameters covered by this averaged curve include failure rates of 0.1 to 0.001 percent per year, values of energy of $0.05/kWh and $0.10/kWh, and all four combinations of array type and source circuit voltage. Data points for all of these parameters are within 13 percent of the averaged curve shown in the figure. The data points for the 1 percent per year failure rate are too scattered to be included on this one curve, but they generally exhibit the same trend. The results indicate that for the system configurations and parameters evaluated the most economic approach is to install minimal fault detection equipment. Since the selected approach involves monitoring currents, the economic advantage of minimal equipment increases with the number of source circuits in a subfield.
Figure 5-13. Value of Periodic Repair Over Immediate Repair of Faulted Modules
5.7.2 Open Modules

Module failures to an open circuit condition were also considered. It is assumed that each module is shunted by a bypass diode. Use of a computer model showed the power loss to essentially be equal to the loss of power from the one module plus the power dissipated by the bypass diode. The model also indicated the changes in source circuit voltages and currents to be very small and essentially unmeasurable by the previously discussed fault detection equipment or similar systems. For purposes of analysis, it is postulated that module failures to open could be easily detected by using an IR camera to sense the heat produced by an operating bypass diode and/or its heat sink. The failure repair/maintenance scenario includes periodically driving a small truck behind the rows of arrays. A two-man crew is used (a driver and a camera operator). Upon detection of an open module, the crew would replace the module with one carried in the truck. The repair procedure also includes disconnecting the source circuit while performing the replacement work.
As for failed modules, a computer program was used to calculate the annual costs for this maintenance and the net present value (30 years at 12%) of the plant's energy output, both with and without this maintenance. The analysis included the following parameters:

- Module failure rates of 1.0, 0.1, 0.01 and 0.001% per year
- Repair/maintenance intervals of 7, 30, 180 and 365 days
- Values of energy of $0.05 and $0.10/kWh
- Flat plate and concentrator arrays

In considering the array field layout and maintenance scenario, it can be seen that the results are not affected by system voltage.

The costs of the modules, manhours to replace a module, labor rates and similar factors are the same as used for the maintenance of faulted (shorted to ground) modules. A cost of $43,000 is included for the IR camera. The cost of the truck is excluded since it is assumed that it would also be used for other purposes. This latter assumption is perhaps not valid for the weekly maintenance scenario but does not materially affect the results of the analysis since the cost of replacement modules is two orders of magnitude more significant that equipment costs in cases where repair is economic. The diode losses were estimated by using a forward voltage drop of 0.8 volts and the module nominal operating current. For both the flat plate and concentrator, this loss turns out to be very close to 12% of the module power and 12% was used for both array types in the analysis.

Detailed results of the analysis are presented in Tables G-32 through G-35 in Appendix G. One typical result is also shown here as Table 5-11.

Under the postulated maintenance scenarios, it is generally not economic to replace modules that have failed to an open circuit (and are shunted by a bypass diode).
Table 5-11

REPRESENTATIVE ECONOMIC ANALYSIS OUTPUT

<table>
<thead>
<tr>
<th>FLAT PLATE ARRAY</th>
<th>7 Day Repair Interval</th>
<th>30 Day Repair Interval</th>
<th>180 Day Repair Interval</th>
<th>365 Day Repair Interval</th>
</tr>
</thead>
<tbody>
<tr>
<td>MODULE FAILURE RATE (%/year)</td>
<td>1.0</td>
<td>0.1</td>
<td>0.01</td>
<td>0.001</td>
</tr>
<tr>
<td>Module Failure Rate</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 Day Repair Interval</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>82195</td>
<td>8219</td>
<td>822</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>60538</td>
<td>60538</td>
<td>60538</td>
<td>60538</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
<td>448</td>
<td>45</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td>Subtotal</td>
<td>935015</td>
<td>154952</td>
<td>76945</td>
<td>69145</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>2234</td>
<td>234</td>
<td>22</td>
<td>2</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>937356</td>
<td>155186</td>
<td>76969</td>
<td>69147</td>
</tr>
<tr>
<td>30 Year Net Present Value (% of fault-free plant revenue)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With Replacement</td>
<td>95.70</td>
<td>99.29</td>
<td>99.65</td>
<td>99.68</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>99.54</td>
<td>99.95</td>
<td>100.00</td>
</tr>
<tr>
<td>30 Day Repair Interval</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>82195</td>
<td>8219</td>
<td>822</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>14126</td>
<td>14126</td>
<td>14126</td>
<td>14126</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
<td>448</td>
<td>45</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td>Subtotal</td>
<td>888603</td>
<td>108539</td>
<td>30533</td>
<td>22732</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>1003</td>
<td>1003</td>
<td>100</td>
<td>10</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>937030</td>
<td>109543</td>
<td>30633</td>
<td>22742</td>
</tr>
<tr>
<td>30 Year Net Present Value (% of fault-free plant revenue)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With Replacement</td>
<td>95.88</td>
<td>99.50</td>
<td>99.86</td>
<td>99.90</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>99.54</td>
<td>99.95</td>
<td>100.00</td>
</tr>
<tr>
<td>180 Day Repair Interval</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>82195</td>
<td>8219</td>
<td>822</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>2354</td>
<td>2354</td>
<td>2354</td>
<td>2354</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
<td>448</td>
<td>45</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td>Subtotal</td>
<td>876831</td>
<td>95575</td>
<td>19364</td>
<td>11021</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>6020</td>
<td>6020</td>
<td>6020</td>
<td>6020</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>937030</td>
<td>102788</td>
<td>19364</td>
<td>11021</td>
</tr>
<tr>
<td>30 Year Net Present Value (% of fault-free plant revenue)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With Replacement</td>
<td>95.70</td>
<td>99.53</td>
<td>99.91</td>
<td>99.95</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>99.54</td>
<td>99.95</td>
<td>100.00</td>
</tr>
<tr>
<td>365 Day Repair Interval</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>82195</td>
<td>8219</td>
<td>822</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>1161</td>
<td>1161</td>
<td>1161</td>
<td>1161</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
<td>448</td>
<td>45</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td>Subtotal</td>
<td>875638</td>
<td>95575</td>
<td>17568</td>
<td>9768</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>12207</td>
<td>12207</td>
<td>1221</td>
<td>122</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>997977</td>
<td>107786</td>
<td>16789</td>
<td>9890</td>
</tr>
<tr>
<td>30 Year Net Present Value (% of fault-free plant revenue)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With Replacement</td>
<td>95.42</td>
<td>99.51</td>
<td>99.91</td>
<td>99.95</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>99.54</td>
<td>99.95</td>
<td>100.00</td>
</tr>
</tbody>
</table>
The exception is for high failure rates (1% per year) and a high value of energy ($0.10/kWh). The analysis also shows that for this latter case, monthly maintenance is the most economic repair interval for the flat plate array. The net present value of energy over 30 years shows a savings of $1.13/m². For the concentrator plant, weekly repair is more economic and shows a savings of $1.77/m².

For failure rates of 0.1% per year and less (and $0.10/kWh), it is not economically attractive to replace modules failed to open. Similarly, module replacement is not economic for a $0.05/kWh value of energy at any failure rate (of 1%/year or less).

A second economic factor that can be derived from the results of the analysis is the worth of increasing module reliability. For the baseline assumptions and a $0.10/kWh energy value, it would be worth $10/m² for the concentrator and $7.82/m² for the flat plate to decrease module failure rates from 1% to 0.1% per year. Decreasing the failure rate from 0.1% to 0.01% is worth $1.15/m² and $0.88/m² for the concentrator and flat plate, respectively. With a $0.05/kWh value of energy, the worth of increasing module reliability is approximately half that of the $0.10/kWh case.

5.7.3 Diode Failures

The probability and cost of diode failures were investigated. In electronic applications, a diode is considered to have failed when its reverse leakage current increases from tens of microamperes to tens of milliamperes. A catastrophic failure implies leakage currents of hundreds to thousands of milliams (i.e., amps). A typical diode failure curve is shown by Figure 5-15 (Ref.5-7). Catastrophic failures have one-tenth the rate indicated and were used for the present analysis.

To estimate failure rates it was assumed that the blocking diodes will be conducting 12 hours per day on average. It is further postulated that failures are a temperature related aging effect. An average daytime temperature of 24°C is combined with a calculated 40°C rise on a heat sink to give a junction temperature of 64°C. This, with a design of
75 percent of rated voltage, indicates an annual failure rate of $7.4 \times 10^{-5}$. The number of blocking diodes and failures per year are shown in Table 5-12 for the four circuit configurations evaluated.

Blocking diode failures (to high reverse leakage) are not a problem by themselves. The diodes are a means of protection and not necessary for subfield operation if there are no other types of failures. However, as discussed in Section 5.7.1, module faults are a likely event. With a simultaneous diode failure and module fault in a solidly grounded circuit, there would be the possibility of damaging almost half of the
Table 5-12

BLOCKING DIODE FAILURE MAINTENANCE COSTS

<table>
<thead>
<tr>
<th>Array Type</th>
<th>Flat Plate</th>
<th>Concentrator</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Voltage</td>
<td>+1000</td>
<td>+400</td>
</tr>
<tr>
<td>Number of Diodes</td>
<td>1920</td>
<td>5920</td>
</tr>
<tr>
<td>Cost Per Repair</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Labor to Locate</td>
<td>$18.90</td>
<td>$18.90</td>
</tr>
<tr>
<td>Labor to Replace</td>
<td>5.40</td>
<td>5.40</td>
</tr>
<tr>
<td>Replacement Diode and Fuse</td>
<td>21.50</td>
<td>8.50</td>
</tr>
<tr>
<td>Total</td>
<td>$32.80</td>
<td>$32.80</td>
</tr>
<tr>
<td>Failures per Year</td>
<td>.14</td>
<td>.44</td>
</tr>
<tr>
<td>Expected Annual Cost</td>
<td>$7</td>
<td>$14</td>
</tr>
</tbody>
</table>

modules in the affected source circuit. Since replacing half the modules in a source circuit (even one) is quite expensive compared to installing a fuse, it is assumed that the blocking diodes are backed up by a fuse to prevent damage to the modules. Thus, the maintenance costs consist of locating and replacing the diode and fuse for the purposes of this analysis. An open fuse would be detectable by the fault protection systems previously discussed. The time required to locate the failure is dependent on the fault detection system used (e.g., see Table 5-8). Following the results of Section 5.7.1, the minimal equipment - maximum labor approach is assumed. As with the other cases, a two-man crew was assumed. A slightly longer time to locate failures in the concentrator subfield was used because of the lower power density and longer distances involved. The costs of the replacement fuse and diode depend on the system voltage and current. The above labor and equipment costs were multiplied by the probabilities of failure to give the annual maintenance costs presented in Table 5-12. These costs do not include the costs of locating and replacing the faulted module (which are addressed in Section 5.7.1). Further, the above analysis assumes that a module fault occurs at (or almost at) the same time as the diode failure. This is indeed very likely for the higher module failure rates. At the lower module failure rates this becomes less likely and would therefore make the diode failure maintenance costs presented somewhat pessimistic. However, even for the worst case, the diode failure maintenance costs do not appear to be significant.

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It has been assumed there are bypass diodes shunting each module. Except when the adjacent module fails open or is shaded, these diodes would be at ambient air temperature (assuming they are not in the sunlight and they do not receive any heat from the module or its heat sink). From Figure 5-15 it can be seen that the bypass diode failure rate could therefore be expected to be about two orders of magnitude lower than that of the blocking diode. This is about the same as the increase in number of bypass diodes over blocking diodes. Thus, bypass diode failures were estimated to also have insignificant maintenance costs and were not evaluated further.

5.7.4 Cable Failures

Some failures of the dc wiring subsystem can be expected to occur during the life of the plant. An average rate of 0.84 failures per year per 100 miles of cable is postulated for purposes of economic analysis. This failure rate is based on data for direct buried (ac) cables at 35 utility companies (Ref. 5-8). The data was adjusted to remove failures due to dig-ins since it is believed that this would not be a likely cause of failures in operating PV plants. In addition, one data point showing an inordinately high failure rate was assumed to be due to poor cable selection for the site conditions and was discarded. The highest (remaining) rate was 6.5 failures per year per 100 miles of cable. Of the 34 data points remaining, seven utilities reported no failures in a year.

Initial detection of cable failures would be accomplished by the instrumentation previously discussed. This will also identify the general location of the fault. Precise location of the fault would be accomplished by use of conventional cable tracing equipment. At this point the cable area would be dug up to locate and repair the failed cable using conventional methods, including the care that would be exercised for several cables in a common trench. The costs for such repairs was estimated and multiplied by the expected number of failures per year to determine an expected annual maintenance cost. The results are presented in Table 5-13. As can be seen from the table, the estimated annual maintenance costs for dc cable failures are insignificant, with the highest costs still well under 1¢/m²/year.
Table 5-13

DC CABLE FAILURE ANNUAL MAINTENANCE COSTS

<table>
<thead>
<tr>
<th>Array Type</th>
<th>Flat Plate</th>
<th>Concentrator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal System Voltage</td>
<td>+1000</td>
<td>+400</td>
</tr>
<tr>
<td>With Group Buses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miles of cable</td>
<td>50</td>
<td>226</td>
</tr>
<tr>
<td>Failures/year</td>
<td>0.42</td>
<td>1.9</td>
</tr>
<tr>
<td>Annual maintenance cost</td>
<td>$109</td>
<td>$495</td>
</tr>
<tr>
<td>With Single Feeders</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miles of cable</td>
<td>102</td>
<td>622</td>
</tr>
<tr>
<td>Failures/year</td>
<td>0.85</td>
<td>5.2</td>
</tr>
<tr>
<td>Annual maintenance cost</td>
<td>$225</td>
<td>$1435</td>
</tr>
</tbody>
</table>

5.7.5 Maintenance Economics Conclusions and Recommendations

Several conclusions and recommendations follow from the foregoing analyses of maintenance scenarios.

Conclusions

Faulted Modules

- It is economic to repair faulted modules for all conditions and parameters evaluated. This is primarily due to the short removing half the power of a source circuit (on the average).

- Correspondingly, it pays to increase module reliability with regard to faults. The breakeven value of doing so can be as high as $13/m² (+400 volt concentrator 1 percent failure rate decreased to 0.1 percent). This value decreases (approximately) by a factor of 10 for each decade decrease in failure rate and is independent of the value of energy.

- Resistance grounding does not appear to be attractive from a maintenance economics point of view.

- At failure rates of 0.1 percent per year, there is an economic advantage for periodic repair over immediate repair. At higher failure rates a full time repair crew would be needed. At lower failure rates there is a slight advantage for immediate repair.
Open Modules

- For practical failure rates (e.g., 0.1 percent or less) it would not be economic to replace modules failed to an open circuit provided that they are shunted by a bypass diode.

- The value of increasing module reliability with regard to open circuits is slightly less than that with regard to shorts to ground (e.g., as high as $8 to $10/m^2 at 1 percent per year). This value of further increasing the reliability of module with a practical failure rate (e.g., 0.1 percent per year) is about $1/m^2.

Other

- The contribution of failed diodes (blocking and bypass) and dc power cables to annual O&M costs is likely to be insignificant. However, care must still be taken in the specification of these subsystem elements.

Recommendations

- Minimal monitoring equipment and portable test equipment for repair crews are recommended over permanent installation of more complex monitoring systems to precisely locate failures.

- For the anticipated low rate of failures and a large plant (e.g., 100 MW), it is recommended that modules with a ground fault be repaired by the dispatch of a repair crew upon indication of a fault by plant monitoring equipment. If module failure rates exceed 0.1 percent per year, repairs should be made on a periodic basis.

- Modules failed open should not be repaired, provided that they are shunted by a bypass diode and failure rates are less than 0.1 percent per year.

- Design modification should be undertaken for modules with failure rates (to short or open) greater than one percent per year. Redesign of modules to decrease failure rates to less than 0.1 percent per year should be implemented if the cost of doing so is less than $1/m^2.

- Solid midpoint grounding of source circuits is recommended as being more economical than resistive grounding.

- Blocking and bypass diode specification should consider use of both higher than minimal voltage ratings and thermal design to maximize diode life.
5.8 PROTECTION AGAINST NEARBY LIGHTNING STRIKES

Subsequent to initial efforts, a further investigation was conducted to assess means of protecting against voltage surges caused by nearby lightning strikes. Direct strikes were excluded from the investigation by the scope of the work. The results of the assessment are presented in this section. Details of the methodology used are presented in Appendix H. Briefly, the methodology consisted of using computer programs to solve for transient voltages and currents in equivalent circuit models of the arrays.

Following general comments in the next section, flat plate and concentrator arrays are addressed in detail in Sections 5.8.2 and 5.8.3, respectively. Several additional topics, including costs, are presented in Section 5.8.4 and the results are summarized in Section 5.8.5.

5.8.1 General

As mentioned, the assessment was limited to the effects of nearby lightning strikes. Both magnetic field and ground current effects were included. Initial calculations showed coupling to electric fields could be neglected.

The coupling of ground currents into the arrays is illustrated by Figure 5-16. As the lightning current enters the earth, it diffuses radially outward. This current and the resistance of the soil causes a potential gradient (voltage) in the soil. As is conventional, the resistivity of the soil is assumed to be uniform and ionization of the soil near the point of entry is neglected. This results in hemispherical equipotential surfaces, with voltages decreasing inversely with distance to the strike. A portion of the current is intercepted by the array foundations. For the flat plate array, the current is conducted into the torque tube structure and, by inductive and capacitive coupling, into the modules. For the concentrator configuration, this effect is much smaller since adjacent array foundation are only connected by a ground wire. This ground wire is much smaller than the flat plate torque tube and its path is not near the modules.
Figure 5-16. Ground Current Effects

Figure 5-17. Magnetic Effects - Flat Plate

Figure 5-18. Magnetic Effects - Concentrator
Magnetic fields result from the lightning current. These fields induce a voltage in loops formed by the array structure according to Lenz's law. For the flat plate array, energy is coupled into the loops formed by the torque tube structure and ground plane, and the modules and ground plane, as illustrated by Figure 5-17. For the concentrator array, the magnetic fields couple to the loop(s) formed by the cells and array wiring as illustrated in Figure 5-18. In all cases, a worst case alignment of the lightning strike and arrays was assumed. Further details on these effects are presented in Appendix H.

As with any physical structure, photovoltaic arrays have capacitances associated with adjacent conductors and the conductors have a finite inductance. These capacitances and inductances are quite small and are negligible for the general design of array fields. However, they govern the response of the arrays to the very short duration (e.g., tens of microseconds) transients associated with lightning.

The capacitances and inductances of various portions of an array interact to form resonant circuits. This is illustrated by the representative response shown in Figure 5-19. The figure shows the voltage across the module insulation. Insulation breakdown due to high voltages is expected to be the major cause of failures due to nearby lightning strikes (Ref. 4-7). While specific cases are presented in subsequent sections, several general characteristics can be seen from the representative response presented in Figure 5-19. First, the voltage is oscillatory in nature as can be expected from the interaction of array capacitances and inductances. This oscillatory type of response to lightning strikes is also characteristic of other circuits such as household wiring (Ref. 5-9). A second characteristic is the build-up to the maximum voltage over several cycles. This response is typical of initially unexcited resonant circuits. Although not completely evident from this figure, the peak voltage across the module insulation is reached after the peak in the lightning surge driving voltage (1 to 2 microseconds). Several computer runs alternately eliminating magnetic and ground current effects showed that, in general, the major energy transfer effect is by
magnetic fields. This depends to some extent on the strike distance, soil resistivity, and array type. The figure also shows damaging voltages can be induced.

Terminal protection devices (TPDs) can be used to limit voltage surges induced between the modules and array structures. TPDs can generally be described as nonlinear devices whose resistance decreases with increasing applied voltage. Several types of TPDs are commercially available.

It is not totally clear that there would be sufficient sunlight during a lightning storm to cause the arrays to be at their normal voltage. However, even a small amount of sunlight on open circuited flat plate arrays can cause substantial voltage to be present. The presence of the normal dc voltage eliminates consideration of TPDs which rely on the current...
zero crossings found in ac circuits. Devices such as a spark gap, once fired by a transient voltage, would continue to conduct dc current (if present) and short the arrays. Dc follow-on current could destroy the device by exceeding its energy handling capability. This follow-on effect with spark gaps can be eliminated by including a series resistor. However, spark gaps seem to have several disadvantages, including wide tolerance or variation in firing voltage. Their major advantages are high power handling capability and high rated voltages.

Devices such as zener diodes are not available for applications over 50 to 100 volts.

One of the most commonly used TPDs is the metal oxide varistor. This basic type of device is available from several manufacturers (see Appendix E). The major comparative advantages of this type of device are low cost and reasonably adequate performance. Disadvantages include the possibility of aging with the constantly applied dc voltages of the array circuit and repetitive surge voltages. This type of device also tends to fail to an open circuit so that its failure may go unnoticed (until the next lightning storm). All factors considered, however, this was the device selected for baseline evaluation of TPDs on array circuits. Models are commercially available to protect dc systems of up to ±4,000 volts (but at a much higher cost than the baseline device selected).

A second device selected for evaluation is the silicon avalanche diode. In particular, the commercially available device selected includes two diodes (as required to limit positive and negative going transients) on a single wafer. Avalanche diodes generally have better performance characteristics than metal oxide varistors. That is, there is a more rapid decrease in resistance with increasing applied voltage. Their disadvantages include limited availability in the desired voltage range, lower power handling capability, and higher cost.

Further details on the two selected TPDs are presented in Section H.5. Factors important to the application of these and other TPDs are discussed in the following paragraphs.
In general, TPDs have a manufacturer-specified voltage at which they are rated, "fire", or turn on, etc. Below this voltage, their resistance is very high, and they draw negligible current and consume negligible power. Power consumption must be considered from the point of view of device rating. Power consumed from the point of view of PV plant output is miniscule. It is generally desirable to set the device voltage as close as possible to the operating voltage of the source circuit in order to more effectively limit the magnitude of surge voltages. However, selection of a TPD must consider the fact that the device will be exposed to "long term" high voltages. Long term in this context is several seconds or minutes, depending on the thermal characteristics of the device. The high voltage in this case is the maximum open circuit voltage of the source circuit which is present during startup, maintenance, etc. The effect of low temperatures on open circuit voltage must also be taken into account. A nominal +400 volt circuit may have a maximum open circuit voltage of +550 to +600 volts. A "600 volt" metal oxide varistor would have a nominal one milliamp flowing through it at 600 volts and dissipate 0.6 watts. A similar 500 volt device would have a current of 237 milliamps and dissipate 150 watts at 600 volts, which would destroy most such devices. Most source circuits could supply this quarter ampere even with low irradiance. It is important that consideration also be given to the voltage from the source circuit poles to ground in resistance grounded circuits which have a fault and are then disconnected for repair. Thus, the first step in applying a terminal protection device is to determine the maximum expected voltage between the dc terminals of the array and ground, i.e., the maximum long-term voltage across the TPD. Having determined the maximum voltage, most manufacturers' literature then offers guidance as to which model or device to select. A representative list of suppliers is included in Appendix E.

For the most part, manufacturers have a series of devices available which span the range of maximum voltages expected for PV source circuits. Unfortunately, however, the "rated" voltage of the device may have a considerable variation with manufacturing tolerances. The "varistor" voltage of the commercially available metal oxide varistor selected for the baseline evaluation is nominally 680 volts with a minimum of 610 volts and
a maximum 748 volts (Ref. 5-9). The avalanche diode evaluated has a nominal tolerance of ±25 volts, with a tolerance of ±60 volts for a slightly less expensive model (Ref. 5-10).

One final factor is the energy rating of the device. As previously indicated by Figure 5-6, the cost of TPDs is related to their energy rating rather than their voltage rating. No simple means was found to estimate the energy that a given device on an array would have to dissipate. High energy (and high cost) suppressors for dc applications are generally found on rail transit systems. Such applications involve coupling lightning magnetic energy into loops very much larger than those formed by arrays. In general, low energy devices (a few joules) were calculated to offer adequate protection on the two array types for very close lightning strikes. Details on these evaluations are presented in the next two sections for flat plate and concentrator arrays.

5.8.2 Flat Plate Arrays

This section presents the results of computer modeling of a flat plate array. In particular, the Bechtel torque tube array shown in Figure 2-1 (page 2-13) served as the basis for the computer modeling. Both solid and resistive midpoint ground circuit configurations were evaluated. Details of the model used are presented in Appendix H.2.

Solid Midpoint Ground. Induced transient voltages on the array vary with time and distance along the array. Figure 5-20 shows the voltage between the cells/dc system and structure at the ungrounded (pole) end of the array as a function of time. This voltage is for a strike distance of 200 feet and soil resistivity of 1,000 ohm-meters. This is the worst case strike distance and soil resistivity evaluated. Other cases are addressed in subsequent portions of this section. As can be seen, the voltage resembles a multiple frequency damped sinewave. The multiple frequencies are due to the interaction of the several resonant circuits formed by the modules and array structure. The damping is due to the induced energy being dissipated in the soil resistance. The figure shows that the voltage has decreased to about 10 percent of its peak value at

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the time (50 microseconds) that the driving lighting stroke current has decayed to 50 percent of its peak. This would tend to indicate that a majority of the energy has been coupled into the array via magnetic field effects which peak at approximately one microsecond, about the same as the array response. However, it will be shown that soil resistance is also a major factor for the flat plate array configuration evaluated (but not for the concentrator array).

The voltages across the module insulation at other points along the length of the array generally exhibit the same waveshape as that of the ungrounded end. Their highest peaks occur at different points in time and some peak on negative portions of a cycle. The magnitudes of the highest peak voltages along the array are shown in Figure 5-21. As can be seen, the voltage approaches zero at the grounded midpoint. The durations of these peak voltages may be a fraction of a microsecond but this can still be sufficient to cause insulation breakdown.
Figure 5-21. Peak Voltages along Array.

It was found that, in general, the maximum voltages induced along the array depend very little on the overall length of the array. Implicit in this is the fact that the distributions of maximum voltages along an array are nominally the same for a 216-foot long +400 volt source circuit flat plate array and a 576-foot long +1,000 volt array. Thus, the remainder of this discussion focuses on the +400 volt circuit and the distributions of maximum voltages along the array are shown normalized with regard to array length. This point is discussed further in Section 5.8.4. In Figure 5-21 and in all subsequent similar figures, the source circuit pole is at zero and the source circuit midpoint is at one.

Figure 5-21 also shows the computed effect of installing terminal protection devices at the ungrounded end. This significantly reduces the magnitudes of the peak voltages, as would be expected. The variation of these voltages along the array is shown in Figure 5-22 with an expanded vertical scale. The metal oxide varistor, MOV, is a General Electric VA420LA20A. Its current was modeled as $kV^{30}$ with $k$ calibrated to give
one milliamp at 680 volts. The avalanche diode is a Brown Bovari DSAS 07-2. Its current was modeled as kV\textsuperscript{a}. The diode has a steeper voltage characteristic than the MOV and a slightly lower voltage (625 versus 680 volts). Details of the models used are presented in Appendix H.3. Both models were adjusted to the center of their manufacturing tolerance ranges.

As can be seen in Figure 5-22, the computed voltage limiting capability of the diode is better than that of the MOV. Unfortunately, it is also significantly more expensive.

For the case illustrated, the computed voltage across the module insulation could still be considered high. An attempt was made to further reduce the voltage by placing additional MOVs on the array. The results are shown in Figure 5-23. The locations of the MOVs for the two cases evaluated are shown by arrows on the figure. For comparison, the
Figure 5-23. Voltages Along Array with Multiple MOVs

... voltage with one MOV at the ungrounded end of the array is also shown as a dashed line. Placing an additional MOV at the center of the array has little effect in lowering the peak voltages. Adding two MOVs, one at each penultimate foundation, does lower the voltage. However, it appears that the only way to limit the module insulation voltage to values significantly below that attained by one TPD at the end of the array is to install TPDs along the entire length of the array.

The waveshapes of the voltage across the module insulation at the ungrounded end and at the adjacent foundation are shown by Figures 5-24 and 5-25, respectively, for the case of an MOV installed at the ungrounded end. The voltage limiting effect of the MOV can be seen in Figure 5-24 and can be compared to the unprotected case (see Figure 5-20). The effect of the MOV at adjacent locations is evident in Figure 5-25. Essentially the same waveshapes are exhibited for the case of the diode.
Figure 5-24. Voltage Across Module Insulation and MOV

Figure 5-25. Voltage Across Module Insulation at Location Adjacent to MOV
The voltage across the MOV and the module insulation which it shunts is shown in Figure 5-26 with an expanded time scale. The current through the MOV is shown by Figure 5-27. The corresponding waveshapes with the diode are shown in Figures 5-28 and 5-29. (The slightly jagged appearance of the curve in Figure 5-29 is due to using too large a time increment for the sharp voltage characteristics of the diode. The 2 nanosecond time increment used requires 70,000 iterations per curve and a small amount of accuracy was sacrificed in favor of reduced computer run time.) As can be seen, the responses of the two TPDs are nearly identical. However, the diode does clamp to a lower voltage and has a slightly higher current. The overall effects of these two TPDs are better compared in Figure 5-22.

Integrating the voltage and current indicates that an energy of 8.4 joules will be dissipated by the MOV. Both this energy and the peak current for the pulse duration calculated are within the rated capabilities of the MOV selected. The diode will dissipate 8.0 joules. This energy and the peak currents are near the rated limits for the diode selected and are brought within the limits only by the fact that the pulses can be considered nonrepetitive in this application. As mentioned previously, avalanche diodes are more effective voltage clamps than metal oxide varistors, but they generally have lower power handling capabilities.

For the cases where multiple MOVs were installed along the length of the array, the MOV at the ungrounded end was found to dissipate the majority of the energy. With a second MOV at the center, the end device dissipates 8.3 joules (down from 8.4) and the center device dissipates 0.19 joules. With two additional MOVs located at the penultimate foundations, the end device dissipates 7.7 joules and the others dissipate approximately 0.17 joules.

Thus far, a somewhat worst case has been addressed. The voltages induced across the module insulation decrease with increasing distance to the lightning strike. This is illustrated by Figure 5-30. This figure shows the maximum voltage at any point on the array as a function of distance...
Figure 5-26. MOV and Module Insulation Voltage

Figure 5-27. MOV Current
Figure 5-28. Diode and Module Insulation Voltage

Figure 5-29. Diode Current
for both unprotected and protected cases. As can be seen, the TPDs have no effect for lightning strikes beyond about 750 feet. For very close strikes (e.g., 200 feet), the TPD can significantly reduce induced voltages across the module insulation. The nominal maximum power point voltage and maximum open circuit voltage for a ±400 volt source are indicated by arrows on the figure. Also indicated is a nominal protection voltage limit. This limit is discussed in Section 5.8.4.

Although not specifically calculated, it is expected that at a strike distance of about 150 feet the power handling capabilities of the selected MOV will be exceeded. This is based on extrapolation of the data plotted in Figure 5-31. Devices with higher power handling capabilities are available, but their performance (e.g., steepness of the voltage clamping effect) was not evaluated in this effort. As the distance to the strike decreases further, the possibility of direct
strikes to the array or perimeter fence becomes more likely. While the TPDs evaluated are not expected to protect against (or survive) direct strikes to an array, they would protect nearby arrays. It should also be pointed out that the peak lightning strike current used in these calculations was 140,000 amperes. This value is much higher than typical strike currents, but at the same time, one percent of the lightning strikes will have higher currents.

Another factor affecting the maximum voltages induced on the flat plate array modeled is the soil resistivity. The maximum voltages at any point on the array for a soil resistivity of 100 ohm-meters is shown in Figure 5-32. Comparing this figure with Figure 5-30 shows that the lower soil resistivity contributes to lowering the voltages on the array. The waveshapes of the array voltages are generally the same as for the 1,000 ohm-meter cases, except that they are reduced in magnitude and the duration of current flow through the MOV is reduced proportionately. The energy dissipated in the MOV is reduced by about two orders of magnitude to 0.1 joules for the worst case (i.e., a 200-foot strike distance). The voltage distribution along the length of the array is also different, as shown in Figure 5-33 for a 200-foot strike distance. This voltage distribution closely resembles that of the 1,000 ohm-meter case with a
Figure 5-32. Maximum Module Voltage Versus Strike Distance - 100 Ohm-Meter Soil

Figure 5-33. Peak Voltages Along Array - 100 Ohm Meter Soil
strike distance of 500 feet. At this distance the induced voltages for unprotected arrays are approximately the same, so that a similar response would be expected.

For these curves and those in preceding similar figures, it is possible that some of the fine structures have been lost with the limited number array sections modeled. These curves should exhibit a better-defined voltage undulation versus distance (i.e., standing wave pattern) as would be expected from a transmission line which the model resembles. The relatively high damping and multiple frequency oscillations make calculation of a standing wave pattern impossible, but multiple reflections of induced traveling waves on electrical transmission lines are known to occur. Using this viewpoint also tends to explain some of the shifts in the voltage patterns with various TPDs placed along the arrays. This point is discussed further in the next section for ungrounded source circuits.

Resistive Midpoint Ground. The effects of using a resistive rather than solid connection to ground in the source circuit were evaluated. A 40 kohm grounding resistor was used. This high resistance ground was found to produce the same results as an ungrounded circuit.

As can be seen in Figure 5-34, the waveshape of the voltage across the insulation of the end module is similar to previous cases. However, the voltage is noticeably less damped and slightly higher than the corresponding voltage for the solid grounded case (compare to Figure 5-20). The voltage distribution along the array is markedly different as shown by Figure 5-35 (compare to Figure 5-21). If use is made of the previously mentioned resemblance to a transmission line, this voltage distribution is what would be expected. In this case, the ends of the line are open-circuited and a voltage maximum would occur at these points. In the case of the solidly grounded source circuit, the midpoint end is short-circuited and a voltage minimum would occur at this point. The opposite end is essentially open-circuited and a voltage maximum occurs. This is also evident in Figure 5-35 for the case with an MOV.
Figure 5-34. Voltage at End of Array

Figure 5-35. Peak Voltages Along Array
added at one end and for the case with MOVs added at both ends (considering that the MOVs are a very low resistance at the voltages involved). Thus, the transmission line analogy seems to be borne out by the calculated distribution of voltages along the array.

The resistance grounded source circuit requires use of a higher voltage MOV. As previously discussed, a module ground fault at or near one of the source circuit poles will approximately double the "normal" module insulation voltage to ground at the opposite pole. That is, a +400 volt circuit can have 800 volts to ground on the last modules. When the faulted source circuit is opened (e.g., for repair), the voltage could be as high as 1200 volts on a cold, bright day. This high voltage from a ground fault is present very much longer than the microsecond transient times and the previously selected MOV would be destroyed. Ground faults must be considered a credible event, otherwise there would be no need for the midpoint grounding resistor. Thus, a higher voltage device was modeled for the resistive grounded case.

In the same series of MOVs, the manufacturer's literature recommends a V100LA80A for a continuous dc voltage of 1200 volts (Ref. 5-9). Based on the manufacturer's curves, the current of this device is $kV^{2/8}$. The factor $k$ was calibrated to give one milliamp at 1600 volts, the middle of the manufacturing tolerance range.

As can be seen in Figure 5-35, use of a single MOV at one end of the array does not provide adequate voltage limiting. Two MOVs, one at each end, provide significant reduction in the maximum voltage across module insulation along the array. The figure also shows a much higher voltage than the corresponding solid ground case. This would be expected with the higher voltage MOV made necessary by voltages that would be present with a ground fault.

Based on the similarity to the solid grounded cases, it is likely that four MOVs (one at each end and penultimate foundation) would further reduce the maximum voltage. Use of two diodes (one at each end) could
also be expected to reduce the maximum voltage. However, these cases were not run for the ungrounded source circuit.

The waveshapes of the voltage and current for the MOV are shown in Figures 5-36 through 5-38. These are for MOVs at the source circuit poles and midpoint, a soil resistivity of 1,000 ohm-meters, and a strike distance of 200 feet. As can be seen, they are similar to the corresponding waveshapes for the solid grounded case.

The variation of maximum voltage with strike distance is shown in Figure 5-39 for a 1,000 ohm-meter soil resistivity and in Figure 5-40 for 100 ohm-meter soil. The behavior of the ungrounded source circuit is similar to that of the solid midpoint ground with regard to these two factors.

The major difference is that the addition of the MOVs does not bring the maximum surge voltage below the selected limit of 2 Vmp + 1000 volts. The energy dissipated by the MOVs in the ungrounded circuit is also similar to the solid grounded cases. For two MOVs (one at each end), a strike distance of 200 feet, and 1,000 ohm-meter soil, each MOV is calculated to dissipate 4.4 joules. This compares with 8.4 joules in the single MOV for the equivalent solid grounded case. The variation of MOV energy dissipation with strike distance is similar to that previously shown in Figure 5-31.

In summary, the flat plate arrays, both the ungrounded and solid midpoint ground source circuit configurations, exhibit markedly higher module insulation voltages with increasing soil resistance and with decreasing distance to the lightning strike. It is believed that the former effect is due to ground potentials causing currents to flow through the foundation and torque tube. These are then coupled to the modules via mutual inductance. The use of terminal protection devices on source circuits with a solid midpoint ground can be effective over a range of strike distances. For soil resistivities of 1,000 ohm-meters, the power handling capabilities limit the effective range to 150 to 200 feet. For 100 ohm-meters, this may become as close as 20 to 30 feet. For resistive
Figure 5-36. MOV and Module Insulation Voltage

Figure 5-37. MOV and Module Insulation Voltage - Expanded Scale

Figure 5-38. MOV Current
Figure 5-39. Maximum Module Insulation Voltage - 1,000 Ohm-Meter Soil

Figure 5-40. Maximum Module Insulation Voltage - 100 Ohm-Meter Soil
midpoint grounded circuits, a higher voltage TPD is required because of the voltages present with a ground fault. This results in higher voltage stresses across the module insulation during nearby lightning strikes.

5.8.3 Concentrator Array

This section presents the results of computer modeling of lightning induced surges on the pedestal-mounted, two-axis tracking concentrator array shown in Figure 2-5 (page 2-16). Details of the model used are presented in Appendix H.3. As for the flat plate array, both solid and resistive midpoint grounds are addressed.

Unlike the flat plate array, the voltages induced across the module insulation on the concentrator array were found to be independent of soil resistivity. It is believed that this is because the individual arrays are not solidly connected by a torque tube between adjacent foundations as is the flat plate. There is a ground wire connecting adjacent foundations, but it does not carry current up into the array structure adjacent to the modules as does the torque tube. Thus, the major source of induced voltages across the module insulation is magnetic coupling of energy into the loops formed by the array wiring.

This leads to one additional factor for the two-axis tracking array, tilt angle. Coupling of the lightning strikes magnetic field varies directly as the sine of the tilt angle. Based on the assumption of perfectly horizontal magnetic field and no asymmetries, there would be no coupling to an array stowed in a horizontal position. It will be shown that stowing at 5 degrees from the horizontal results in relatively low induced voltages. Tilt angles of 35 and 90 degrees were used to evaluate the effects on arrays that were not stowed in a nominally horizontal position during a nearby lightning strike.

Solid Midpoint Ground. Figure 5-41 shows a representative module insulation voltage waveshape. This figure is for the end module on an array with a 35 degree tilt angle and 200-foot strike distance. Except for magnitudes, the waveshapes are generally the same for other points on
Figure 5-41. Voltage at Ungrounded End of Array

Figure 5-42. Peak Voltages Along Array
the array, tilt angles, and strike distances. As can be seen, there is relatively little damping compared to the flat plate cases discussed in the previous section.

The distribution of peak voltages along the one of the arrays is shown in Figure 5-42 for this case (i.e., 35 degree tilt angle, 200-foot strike distance). The voltage is plotted versus relative electrical length since the physical path of the dc wiring folds back and forth on the concentrator array structure. This voltage distribution is relatively the same as for the equivalent solid grounded flat plat array (see Figure 5-21) and its shape is generally what would be expected from the transmission line theory previously discussed. Some of the standing wave (i.e., reflection) fine structure has been lost because of the limited number of array sections in the equivalent circuit model (see Appendix H.3).

Figure 5-42 also shows the voltage distribution with a single MOV shunting the end module. (A second MOV is shunting the opposite dc pole on the adjacent array in the source circuit.) As can be seen, the resulting voltage distribution corresponds to that of the equivalent flat plate case (see Figures 5-21 and 5-22) with reflection effects missing due to fewer sections modeled.

The MOV voltages and currents are shown in Figures 5-43 through 5-45. Again, these are similar to the equivalent flat plate case (see Figures 5-26 and 5-27).

The waveshapes shown for the concentrator have lower magnitudes. Thus, the energy dissipated in the MOV is lower. For the case shown, the energy dissipated is 0.04 joules. With a 90 degree tilt angle, the energy dissipation is 0.12 joules. These energies are significantly lower than the 8.4 joule maximum value computed for the corresponding flat plate array case.
Figure 5-43. Voltage Across Module Insulation and MOV

Figure 5-44. Voltage Across Module Insulation and MOV - Expanded Scale

Figure 5-45. MOV Current
The variation of the peak induced voltages across the module insulation is plotted as a function of distance to the lightning strike in Figure 5-46. Array tilt angle is shown as a parameter. The computed variation of peak voltage with tilt angle corresponds almost exactly to the sine of the angle as would be expected. The slope of the lines for the unprotected cases is about the same as for the flat plate with a soil resistivity of 100 ohm-meters.

Figure 5-46 also shows the peak voltages for arrays protected by a single MOV per array. The slight difference between the 35 and 90 degree protected cases is due to the fact that actual MOVs are not a perfect voltage clamps. As can be seen, if the arrays can dependably be stowed in a horizontal position during lightning storms, there would appear to

Figure 5-46. Maximum Module Insulation Voltage Versus Strike Distance
be little need for terminal protection devices. This would require strict operating procedures to stow the arrays when lightning can be expected. Also, omitting the MOV would leave nearby arrays unprotected in the event of a direct strike to one of the arrays.

Resistive Midpoint Ground. As for the flat plates, the effects of using a high resistance midpoint ground source circuit were evaluated for the concentrator array.

The waveshape for the voltage across the insulation of the end module is shown in Figure 5-47. The waveshape is for a strike distance of 200 feet and a tilt angle of 35 degrees. The waveshapes for other strike distances and tilt angles are similar. The damping and multiple frequency effects are almost imperceptible in the time interval plotted.

![Voltage at End of Array](image.png)

Figure 5-47. Voltage at End of Array
The distribution of peak voltages along the electrical length of the array is shown in Figure 5-48. The general shape of this profile corresponds to that of the equivalent flat plate array (see Figure 5-35). As with the solid grounded case, the fine structure undulations due to reflections are missing because of the limited number of array sections modeled. Figure 5-48 also shows the voltage distribution with two MOVs, one at the pole end and one at the midpoint of the source circuit. As can be seen in the figure, the MOVs have little effect in this case.

The variations of peak induced voltage with strike distance and array tilt angle for the resistive midpoint grounded cases are shown in Figure 5-49. These parameters exhibit essentially the same behavior as the solid ground case but with a slightly lower voltage for the unprotected cases and a higher voltage for the cases with MOVs.

The voltages and currents for the pole end MOV are shown in Figures 5-50 through 5-52. Figure 5-50 shows very slight damping as in the unprotected case (see Figure 5-47). The current in the MOV is about an order of magnitude less than in the corresponding solidly grounded case (see Figure 5-45). The voltage and current in Figures 5-51 and 5-52 integrate to a MOV energy dissipation of about 0.005 joules.

In summary, the voltages induced on the concentrator array module insulation were found to be independent of soil resistivity. These voltages were also generally lower magnitude and less damped than those of the corresponding flat plate cases. The higher voltage MOVs required for resistance grounded source circuits offer limited protection compared to the solid grounded cases. Stowing the arrays in a horizontal position would virtually eliminate the voltages induced on the arrays by nearby lightning strikes. However, including TPDs would offer protection if the arrays were not stowed horizontally and, to some degree, protect adjacent arrays in the event of a direct strike to one array.
Figure 5-48. Peak Voltages Along Array

Figure 5-49. Maximum Module Insulation Versus Strike Distance
Figure 5-50. Voltage Across Module Insulation and MOV

Figure 5-51. Voltage Across Module Insulation and MOV - Expanded Scale

Figure 5-52. MOV Current

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5.8.4 Additional Topics

This section presents the results of evaluating several additional topics. These include:

- Array length and source circuit voltage
- Mitigating measures for the concentrator array
- Intercloud discharges
- Voltage protection level
- Strike probabilities
- Surge protection costs

Array Length. The foregoing results were calculated for a nominal + 400 volt source circuit. Higher voltage flat plate source circuits using the same basic subfield layout concept would have longer arrays. For the concentrator array, several arrays would be connected in series. That is, more sections would be modeled in both cases. It was found that the induced maximum voltages are relatively independent of length. This is illustrated in Table 5-14 which shows the voltages across the pole end MOV and the peak voltage for a flat plate array with a 100 ohm-meter soil resistivity, 250-foot strike distance and high resistance midpoint ground. The peak voltage occurs at the midpoint for this configuration and is also indicative of the maximum voltages induced on an unprotected array (see Figure 5-35). As can be seen from this example, the variations in voltage with the number of array sections modeled (i.e., array length or source circuit voltage) are less than a quarter of a percent. Since this is much less than the estimated accuracy of the parameters used in the model, higher voltage source circuits were not evaluated and the preceding graphs of distribution of voltages are shown normalized with regard to length.

For ± 1,000 volt source circuits, the postulated allowable voltage (e.g., 2 Vmp + 1,000) would be 3,000 volts. As indicated in Table 5-14, the maximum voltages induced on the array/module insulation do not increase with the increase in circuit length needed to attain the higher
nominal operating voltage. Thus, ±1,000 volt source circuits can be expected to exhibit the same general characteristics as their low voltage (i.e., ±400 volt) counterparts. However, the effective range for TPD protection would be shifted toward smaller strike distances. Also, a higher voltage TPD must be selected.

Concentrator Array. Calculations for the concentrator array were based on the wiring configuration shown in Figure 5-53A. Cells are connected in series to attain a module voltage and modules are, in turn, connected in series to attain the array or source circuit voltage. This dc wiring configuration also series connects the loops which couple to the magnetic fields of a nearby lightning strike. A possible alternative array wiring configuration is shown in Figure 5-53B. This alternative configuration essentially leaves the dc wiring unaffected, except for a slight increase in intermodule wire length. It may also require construction of two
types of modules (i.e., having the + pole either on the right or left side). However, adjacent loops are connected with opposing polarities with respect to coupled magnetic fields. This alternative wiring configuration would tend to reduce and cancel magnetically induced surges. From a simplified mathematical model point of view, the magnetically induced surges would be completely canceled for an even number of modules. Stowing the arrays in a perfectly horizontal position would have the same effect.

Intercloud Discharges. Lightning discharges occur between (and also within) clouds. The current paths for these discharges are generally considered to be horizontal. This current flow generates magnetic fields which couple to the loops formed by the modules, wiring, and arrays. However, intercloud discharge currents are much smaller that the vertical strike currents modeled herein and the distance to the strike is typically thousands of feet. Thus, the voltages induced in the arrays would be negligible and this phenomenon was not evaluated.

Voltage Protection Level. Maximum voltages induced across module insulations have been calculated for several parameters and protection measures. The question remains as to what voltage protection level to select. It could be expected that the module insulation would survive 3000 volts, the voltage level used to test for leakage current. However, this does not account for aging of the insulation over the life of the plant and that a dc voltage is called for the JPL Block V specifications (Ref. 5-11). Figure 5-54 (Ref. 5-12) illustrates the general decrease in voltage withstand capability of an insulator with time and frequency. Research in areas such as the cable industry has not been too successful in accurately predicting voltage breakdown levels. The industry conservatism engendered by aging effects and uncertainty are illustrated in Figure 5-55 (Ref. 5-12). This figure also indicates a much higher voltage withstand capability against short pulses (for new material) such as presently under consideration. Because of uncertainty in predicting the voltage breakdown of module insulation, a nominal value of twice the operating voltage plus 1000 volts was selected for purposes of the
Figure 5-54. Effects of Frequency and Time on Voltage Breakdown

Figure 5-55. Insulation Characteristics of Polyethylene
present study (e.g., 1800 volts for a ±400 volt source circuit). This voltage level includes a significant safety factor for the short duration transients caused by nearby lightning strikes.

The foregoing results indicate a limited range of strike distances over which a terminal protection devices effectively limit voltages induced on the arrays. For strike distances greater than about 750 feet, the TPDs would not have any significant effect. For distances greater than 500 feet, the induced voltages likely would not exceed the inherent withstand capabilities of the module insulation. For strike distances of less than about 150 feet, the energy dissipation capabilities of low cost TPDs would be exceeded. Higher energy TPDs could protect against closer strikes. However, the currently available high-energy metal oxide varistors have limiting voltages that are too high for a ±400 volt source circuit and, as previously indicated, are comparatively expensive. The aforementioned distances are somewhat for the worst case. The strike distances over which TPDs are effective depend on array type, soil resistivity (for the flat plate, fixed tilt array), magnitude of the lightning current, type and number of TPDs installed, and other factors. The generalized result is still valid; the TPDs would be effective only over a relatively narrow range of nearby strike distances. Further detailed analyses may shift and/or expand or contract this range of effectiveness. While not addressed in the analyses, it is believed that TPDs also offer some degree of protection for arrays adjacent to arrays hit by a direct strike.

Strike Probabilities. There are two basic types of storms that characterize lightning. Convection storms are relatively local events caused by heating of the air and therefore predominate in the summer. Frontal storms are caused by the meeting of an atmospheric cold front and warm moist front. Such storms generally include more severe lightning, but both storm types are incorporated into statistical databases without distinction. Thus, isokeranuic maps may tend to be pessimistic in this respect. Such maps generally report only the number of days on which thunder was heard in given areas and not the number or severity of
lightning strokes reaching the ground. Still these maps seem to have formed an adequate basis for most lightning protection design in the U.S.

The annual number of lightning strikes reaching the ground per square kilometer \(N\) is related to the isokeraunic level (i.e., number of thunderstorm days per year, \(T\)) latitude angle \(L\) at a plant site, and is given by (Ref. 5-13):

\[
N = 0.0007 T^{1.7} (1 + (L/30)^2)
\]

For a site such as Albuquerque \((T=50\) and \(L=35)\), approximately one lightning strike per square kilometer per year would reach the ground.

The area of attraction for lightning is larger than the physical area of a PV plant. This increase in area depends on the height of the structures over that of the surrounding terrain. For relatively low structures, an "attractive radius" \(R, \text{in meters}\) can be computed from the structure height \(h, \text{in meters}\) by (Ref. 5-13):

\[
R = 80 h (e^{-0.02h} - e^{-0.05h}) + 400 (1 - e^{-0.0001h^2})
\]

The attractive area is then given by:

\[
A = WL + \pi R^2 + 2R (W + L)
\]

where

- \(W\) is the physical width of the area and
- \(L\) is the length of the area.

For the 100 MW PV plant shown in Figure B-1 of Appendix B and an 8-foot high perimeter fence, the attractive area is about one percent larger than the physical area, which is not significant. However, this factor could become more significant for small installations with tall arrays.

Considering a somewhat worst case of a ±400 volt flat plate source circuit and 1,000 ohm-meter soil resistivity, module insulation failure might be expected for strikes closer than 500 feet (see Figure 5-30) for
an unprotected array. Including an MOV at each pole of the source
circuits decreases this distance to about 200 feet. For the Albuquerque
site and the plant shown in Figure B-1, there would be 0.6 strikes per
year in the site area protected by the MOVs. There would also be 0.4
strikes per year closer than 200 feet and 2.4 direct strikes to the
arrays per year.

Although not calculated, it is likely that the MOVs or other TPDs would
protect some of the arrays for these latter two events. If the soil
resistivity were 100 ohm-meters, it is estimated (from Figure 5-32) that
the MOVs would offer protection for strike distances ranging from 90 feet
to 295 feet, an area attracting 0.45 strikes per year. For the
concentrator, the number of protected strikes per year ranges from zero
(for arrays stowed horizontally) to 1.75 (for arrays at 90 degrees during
lightning events). It is estimated that the concentrator PV plant would
also receive 6.3 direct strikes per year, against which the MOVs would
offer protection to some of the arrays.

Surge Protection Costs. The purchase price of the MOV modeled
(VA420LA20A) is $2.15 (Ref. 5-14). The MOV is one-inch diameter, plastic
encapsulated disk with radial leads. In the foregoing analyses where a
TPD is used at the pole end of the array/source circuit, the device could
be installed in an array junction box along with items such as a blocking
diode, fuse, and feeder and panel wiring. In particular, it is
postulated that one lead of the MOV could be inserted under a terminal
bolt connection between the panel dc wiring and blocking diode. The
other lead would be connected to the junction box or other suitable
ground point via a screw terminal. (As previously mentioned, such
connections should be as short and straight as possible.) It is
estimated that this would add about five minutes to the installation time
for the dc wiring (corresponding to $2.25). An additional allowance of
fifty cents is included for ground lug. The installed field cost is
estimated to be $4.90 (in mid 1984 $). Referring to Table 5-7, it can be
seen that this MOV protects 161 m^2 (half a source circuit) for the ±400
volt source circuit flat plate. Thus, the normalized cost is $3/\text{m}^2$.  

5-127
For the ±400 volt concentrator, which has fewer square meters per source circuit, the cost is 13¢/m².

Although not modeled, the cost for ±1000 volt source circuits were estimated for purposes of comparison. As mentioned, a higher voltage device must be used to accommodate the higher source circuit voltage. A Panasonic C14DK182 varistor was selected. The price of this device is 92¢ (mid 1984$, in quantities of 1000, Ref. 5-15). The outward physical appearance of this device is similar to that of the MOV used for the ±400 volt source circuits. Thus, the same installation procedures and costs to install are assumed. The normalized field costs are estimated to be 0.42¢/m² for the flat plate and 2¢/m² for the concentrator array (with the source circuit aperture areas given in Table 5-7). The voltage exponent of this device is approximately 26 to 28. Thus, its voltage clamping effectiveness would be less than that of the device modeled.

The purchase price of the dual avalanche diode modeled is approximately $55 (Ref. 5-16). In addition, a short lead must be purchased or fabricated. The diode is stud mounted and, as with the MOV, is postulated to be located in an array junction box. Because the diode must be mounted and one more electrical connection made, the cost to install is higher and is estimated to be $6.40. The total installed field cost is $63. This translates to 39¢/m² for the flat plate and $1.71/m² for the concentrator with ±400 volt source circuits. The performance of the diode is better than that of the MOV, but its cost is also significantly higher.

With the high resistance or ungrounded source circuits, an additional TPD is required at the midpoint. This point would also be located in the array junction box for the concentrator ±400 volt configuration. One TPD can be shared between adjacent arrays (i.e., halves of the source circuit). The price of the higher voltage MOV (V1000LA80A) is $3.05. Thus, the estimated installed field cost is 23¢/m². For the flat plate, the midpoint is at the far end of the array. If there is a grounding resistor in a junction box, the MOV (shared between halves of
the source circuit) can be installed as previously indicated. The estimated field cost for the flat plate surge protection with high resistance grounding is $5d/m^2$. If the circuit is ungrounded, the midpoint may or may not have a separate junction box for the interconnecting dc cable. If an additional small junction box and terminal block must be installed, the estimated field cost becomes $14d/m^2$.

5.8.5 Conclusions and Recommendations

Conclusions. Based on the modeling of the arrays, nearby lightning strikes can induce potentially damaging voltages across module insulation. Due to the capacitances and inductances associated with the arrays, these voltages have oscillatory wave shapes which continue past the time of the lightning surge with degrees of damping that depend on the array type and other parameters. The analyses indicate that the arrays resemble lossy transmission lines with reflections causing a distribution of voltages along the length of the array. It is also indicated that the maximum induced surge voltages are independent of array length. These voltages are therefore independent of source circuit voltage attained by series connecting a number of arrays or array segments in the same basic physical configuration.

Commercially available terminal protection devices can limit the voltage induced across module insulation. These TPDs are effective over a limited range of distances between the arrays and lightning strike. Beyond the upper end of the range (e.g., 500 feet), the module insulation can withstand the voltages induced without TPD protection. At the near end of the range (e.g., 150 feet), the energy rating of the TPD will be exceeded and the device and array may be damaged. The exact range of protection depends on several parameters. The parameters include array type, soil resistivity (for flat plate fixed tilt arrays), array tilt angle (for the two-axis tracking concentrator), source circuit configuration (grounded or ungrounded), source circuit voltage and type of TPD. It also depends on the magnitude of the lightning current. Most lightning strikes will have currents much lower than the current used for the calculations. However, one percent of lightning currents can exceed this current.
Additionally, the above ranges of protection depend on the estimated breakdown voltage of module insulation, an item with some uncertainty.

Source circuits with a high resistance midpoint ground require TPD voltage ratings that can accommodate the voltage levels present with module ground faults. This results in the clamped transient voltage surges exceeding the selected voltage limit of 2 Vmp +1000 volts.

Two types of TPDs were evaluated, metal oxide varistors and avalanche diodes. The diode has a steeper voltage-current characteristic and therefore is a more effective voltage clamp. Unfortunately, it generally has a lower energy handling capacity and is significantly more expensive. The purchase price of the varistor modeled is about $2 and the price of the diode modeled is about $55. Considering installation costs and aperture areas, the installed field cost for the varistor ranges from 3$/m^2$ (flat plate) to 13$/m^2$ (concentrator) for +400 volt source circuits with a solid midpoint ground and protected by a metal oxide varistor at each pole. Ungrounded or high resistance grounded source circuits require an additional varistor at the midpoint. This increases the above costs to 5$/m^2$ and 23$/m^2$, respectively. High voltage source circuits (e.g., +1000 volts) have lower normalized costs because each TPD protects more square meters of aperture area.

Attracted lightning strikes depend on geographic location and plant area. For +400 volt source circuits and a 100 MW PV plant located in Albuquerque, the varistors would protect against 0.6 lightning strikes per year for the flat plate. Depending on whether the concentrator array tilt angle is zero or 90 degrees during the lightning, the varistors would protect against zero to 1.75 strikes per year. In addition, there would be 2.4 (flat plate) to 6.3 (concentrator) direct strikes per year to the above plant. Although not evaluated specifically, it is likely that the varistors would also provide protection for some of the arrays during direct lightning strikes to the plant.
Recommendations. Based on the analyses conducted, it is recommended that metal oxide varistors be installed to protect module insulation against the voltages induced by nearly lightning strikes. Such devices are available from a number of manufacturers (see Appendix E).

In selecting the particular device to use, the maximum continuous voltage must be determined (i.e., the maximum open circuit voltage on a cold day). The lowest voltage compatible device would then be selected.

The varistors should be installed between each pole of the source circuit and the array structure or suitable ground point. For ungrounded or high resistance grounded source circuits, an additional varistor should be installed at the midpoint. If a higher degree of protection is desired, additional varistors should be installed closer to the pole ends of the source circuit rather than the middle of the arrays. As with any lightning protection equipment, the wiring should be as short and straight as possible.
Section 6

SPECIAL PRACTICES, CODE IMPACTS, AND EQUIPMENT DEVELOPMENT REQUIREMENTS

There are several possible solutions to problems in grounding and protection of PV plants that would appear to be beneficial in an operating plant. However, it is not clear at this time whether certain of these designs would be approved by regulatory agencies, that other solutions would be practical in all respects, or that the necessary equipment could be developed to sell at reasonable costs. These matters are discussed in the following paragraphs.

6.1 WITHSTAND VOLTAGE OF MODULES

PV modules installed in some large-plant configurations may be subjected to comparatively high voltages to ground. For example, if source circuits are each grounded through a very high resistance at the midpoint, modules near the unfaulted terminal might have to withstand full dc line-to-line voltage for as long as a solid fault remains. In a utility-type plant this might range from about 2,000 volts (source circuits loaded on a normal day) to about 3,000 volts (source circuits unloaded on a very cold day).

Currently, the isolation test voltage for Block V flat plate modules, in new condition, is 3,000 Vdc for one minute. This test is prescribed to verify the ability of a working module to withstand a worst-case open-circuit system voltage of 1,000 Vdc.

Based on the above information on Block V modules, only solid midpoint grounding of each source circuit would come close to meeting the 1,000 Vdc design limit. Actually, voltage to ground on the unfaulted side of a disconnected source circuit would be about 1,250 V.
This leaves little or no margin to permit confident use of ungrounded or resistance grounded source circuit configurations. Thus, a higher voltage test would have to be specified for presently conceived PV central station designs.

6.2 INTERRUPTIBLE GROUND CIRCUITS

There are possible advantages in operation if midpoint ground or neutral circuits could be opened upon detection of an excessive current.

One example, in an industrial-type PV plant, would be contactor opening of both power leads (positive-hot and negative-neutral) to an internally grounded source circuit. Clearing both power leads by fuse or contactor action might block a fault current loop, thus averting further damage. But this action would violate a long-standing code provision that prohibits breaking the ground or neutral conductor of any circuit. Article 380-2 of the 1981 NEC grants exceptions if it can be assured that all live conductors are also disconnected.

The situation might be made more acceptable if the neutral contact is permanently tied to ground through a high resistance, so that at least static charges can be dissipated. However, this approach does not meet the real intent of NEC code requirements because in PV subfields the circuits on both sides of an opened contactor would remain live.

6.3 PROTECTIVE FUNCTIONS BY COMPUTER

There are some fault detection and clearing functions in PV fields that could be implemented more reasonably by using a microcomputer system than by equivalent hard-wired devices distributed throughout the subfields. There are other protective functions, such as making extensive comparisons of source circuit I-V or short circuit characteristics and providing backup protection, that would be technically impractical to attempt with wired devices. Also, a computer would be capable of
displaying additional information for analysis in borderline cases, and could perform certain self-checks of sensors, circuits, and of its own processing.

These advantages are expected to push the computer into becoming an essential element of protective subsystems in PV plants. To fulfill this role, computer systems must be designed, programmed, operated, maintained, and accepted as a critical safety component. Precedent exists in other industries, such as electric utility and transportation, for heavy dependence on computers being always available for correct response. Often, redundant equipment with switchover capability is proposed to achieve the necessary confidence level.

6.4 LOAD-BREAK DISCONNECT SWITCHES

A type of equipment that should find application in future PV plant projects is the dc load-break fused disconnect switch, with voltage/current ratings and optional features particularly chosen to fit projected systems.

Characteristics that would be beneficial in switch assemblies intended for use in dc subfield circuits are:

- Single-pole and double-pole designs
- Manual close-open with an external insulated handle
- Load break capability, with option for high-current break duty without requiring frequent maintenance
- Safe circuit isolation when open
- Remote trip circuit, with external indicator at the switch
- Capability of closing safely into a short circuit of specified current (high)
- Provisions to mount high-capacity dc fuse, with external indicator
• Insulated enclosures, with provisions to attach similar enclosures for blocking diodes, thyristors, transistors, sensors, or other auxiliaries

• Integral ground bus and external lead connector

• Provisions, in the switch enclosure or elsewhere, to mount MOV surge arresters so that their external leads can go directly to ground

• Service life of 30 years or more in outdoor environment
REFERENCES


1-3 Drawings for Hughes Building Block provided by H. N. Post of Sandia National Laboratories.


3-4 Standards for Industrial Control Devices, Controllers, and Assemblies, NEMA ICS 1-78, revised 2-80 (typical).

3-5 High Voltage Industrial Control Equipment, ANSI Standard 347-78.


4-2 Dwight, H. B., Calculation of Resistance to Ground, AIEE, Electrical Engineering, December 1936.

4-3 Jensen, C. H., Grounding for Substations, Electrical South, October and November 1960.


4-8 Peabody, A. W., Control of Pipeline Corrosion, Houston, Texas, National Association of Corrosion Engineers, 1967, pp. 5-8.


4-11 Private communication with H. N. Post, Sandia National Laboratories, October 14, 1982.


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5-1 Ferraro, R. J. (EPRI) and Roesler, D. J. (DOE), Integrating New DC Sources Into Utility Systems, 1982 draft document.


5-10 Brown Boveri Brochure Number CH-E 4.0347.1 E/F/D.


5-14 Telephone quotation from Kierulff Electronics, Palo Alto, CA.

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CODES, STANDARDS, AND GUIDES:

National Electrical Code, NFPA 70-1981; principally Articles 250-Grounding and 280-Surge Arresters. This edition does not address photovoltaic installations per se; the next revision will very likely do so (see next item). However, many Articles do address subjects that are quite germane to PV projects. This phrase in the introduction is worth noting: "This Code is purely advisory as far as the NFPA and ANSI are concerned but is offered for use in law and for regulatory purposes in the interest of life and property protection." Where cited by OSHA, for example, compliance with the NEC becomes a regulatory matter.

Proposed Article 6XX - Solar Photovoltaic System for the National Electric Code. The preliminary working document includes definitions and requirements for complete PV systems. Section E, Grounding, Article 6XX-41 through 44 pertains to grounding. PV dc systems over 300 volts are to be exempt in accordance with 250-3, exception 3, as long as they meet the fine print note to 250-1 to provide protection equivalent to solid grounding.


IEEE Guide for Safety in Substation Grounding, IEEE Standard 80-1976. This is the most widely used reference for design of grounding grids. This standard is scheduled for major updating in the next year or so.


Recommended Practice for Electric Power Systems in Commercial Buildings, IEEE Standard 241-1974. This is a comprehensive guide to electrical design of building power systems; Section 9 addresses protection.

Grounding Electric Shovels, Cranes, and Other Mobile Equipments, National Safety Council; Data Sheet 1-287-79, National Safety News, September 1979, p. 79. Provides a brief summary of the techniques and equipment used to safely ground mobile equipment in open-pit mines and quarries. Open-pit mines can involve electrical circuits in large areas and thus are similar to PV plants.


Underwriters Laboratories, Inc.; various standards, including:

UL 96-81, Lightning Protection Components
UL 198L-81, DC Fuses for Industrial Use
UL 467-72, Grounding and Bonding Equipment
UL 746A, Standard for Polymeric Materials
UL 1097-78, Double Insulation Systems for Use in Electrical Equipment

These standards do not address photovoltaic equipment, but they do cover equipment likely to be installed or used in array fields. A new standard, specific for PV installations, is being prepared. The draft proposed standard is comprehensive and detailed. It includes material, construction and installation specifications, as well as test procedures. Jet Propulsion Laboratory (JPL) module design and test specifications are incorporated. Although somewhat directed toward smaller PV systems, most of the items are also applicable to large systems. Title of the draft version is "Proposed Standard for Safety, Flat Plate Photovoltaic Modules and Panels."

California Administrative Code, and Register; various title numbers, including:

Title 8, Electrical Safety Orders
Title 24, Part 3, Building Standards, Basic Electrical Regulations

Currently this Code does not specifically address PV installations. But many sections would apply, as State regulations. Similar codes exist for other states. There are also local city and county codes. Many of these refer to and/or incorporate national codes.
REPORTS:

Analysis Techniques for Power Substation Grounding Systems, Vol. 1, by School of Electrical Engineering, Georgia Institute of Technology, for EPRI; Report EL-2682, October 1982. An important new reference for design of electrical grounding systems.

A Conceptual Design of a Photovoltaic Central Station Power Plant, Bechtel; January 1976. Provides a complete definition of design basis and all components in a proposed PV plant. The array described, however, is not one of the types to be included in this PV grounding study.

A Capacitive Load and Data Acquisition System for Photovoltaic Array Testing, Sandia Laboratories, SAND82-2547, January 1983.

Application of Solar Technology to Today's Energy Needs, Vols. I and II, Office of Technology Assessment, Congress of the U.S.


Commercial/Industrial Photovoltaic Module and Array Requirement Study, prepared for JPL; Report DOE/JPL 955698-81, December 1981. This is a design guide for medium-sized PV arrays that are to be mounted on or integrated with buildings.


Integrating New dc Sources into Utility Systems, R. J. Ferraro and D. J. Roesler; EPRI and DOE. This is an informal review of all important factors affecting power converter design and application. It is directed to battery and fuel cell sources, but applicable to PV systems.

Interim Performance Criteria for Photovoltaic Systems; Solar Energy Research Institute, December 1980. Presents an extensive listing of design and performance criteria, including a number of items on grounding, protection, and safety.


Mine Grounding Systems, Dept. of Electrical Engineering, West Virginia University, for U.S. Bureau of Mines, Grant GO144138, June 1979. Also see prior Annual Reports for same activity.


Photovoltaic Subsystem Optimization and Design Tradeoff Study, Bechtel for Sandia National Laboratories, Contract 46-0042, January 1982. This is a comprehensive design study, addressing grounding as well as array field layouts, cable sizing and routing, power conditioners, array supports, and other subjects.

Requirements Definition and Preliminary Design of a Photovoltaic Central Station Test Facility; Bechtel for Sandia Laboratories, SAND79-7012. Gives a detailed analysis and layout of a 10 MW test station, comprising a variety of array types.


Safety Analysis Report, Natural Bridges National Monument, 100 kW PV Power System, DOE/ET Report 20279-116, September 1981. Procedures designed to provide safe working conditions are described.


Terrestrial Central Station Array Life-Cycle Analysis Support Study, Bechtel for JPL, August 1978. This study presents designs for five central station concepts using different array types.


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Proceedings of The Fourth WVU Conference on Coal Mine Electrotechnology, West Virginia University, College of Engineering and IEEE Industrial Applications Society, Sections 7, 9, 11, and 13, August 1978.


**BOOKS:**


Optoelectronics Applications Manual; Staff of Hewlett - Packard Optoelectronics Div., 1977 and later.

Peabody, A. W., *Control of Pipeline Corrosion*, National Association of Corrosion Engineers.


**COMPUTER PROGRAMS:**

SGA and SMECC, Substation Grounding Analysis Programs developed at Georgia Institute of Technology for EPRI Report. Contact Prof. A. P. Meliopoulos, School of Electrical Engineering.

GRID, Ground Grid Calculation Program, EE 301, Bechtel.
GRIDVOLTS, Ground Voltage Profile Program, EE 300, Bechtel.

SYSCAP, Electronic Circuit Analysis (dc, ac, transients) Program, CDC Service Bureau.

Computer Program to Determine the Resistance of Long Wires and Rods to Nonhomogeneous Ground; Steve A. Arcone; Corps of Engineers, CRREL Report 77-2.

Appendix A

TERMINOLOGY

This listing of selected terms is not a complete glossary, because many familiar definitions used in electrical or photovoltaic work are not repeated here. Generally, the listing includes those for which usages or definitions are directed particularly to the purposes of this report.

**Grounding System**
Electrical facilities installed to provide all the required conductive paths to earth, whether direct or circuitous.

**Earthing Point**
Any location where circuits connect directly to earth via a buried or driven electrode, rather than via another conducting cable or member in the grounding system.

**Step Potential**
The voltage difference between any two points on a ground surface that a person can contact simultaneously, foot-to-foot. Distance separating the two points is usually assumed to be one meter.

**Touch Potential**
The voltage difference between any point on a ground surface where a person can stand, and any other point simultaneously accessible by either hand. This is usually assumed to be a one-hand to both-feet contact. Effective "electrical" separation of the two points must be determined for each case.

**Reach Potential**
The voltage difference between any two accessible points that can be bridged in any way by one person. Neither point may be on a ground surface. Effective "electrical" separation of the two points must be determined for each case. Hazardous levels of hand-to-hand potential must be calculated specifically for each case.

**Transferred Potential**
A local voltage difference appearing on a conductor that is normally grounded at some quite remote point. This situation may arise during fault conditions where very long "electrical" separations exist in the reach or mesh modes.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mesh Potential</td>
<td>The voltage difference from a conductor in a buried grounding grid to a point on the ground surface near the center of a grid mesh, or to a point equidistant from surrounding electrodes (in any case, a point of maximum voltage differential with respect to the conductor).</td>
</tr>
<tr>
<td>Guard</td>
<td>A supplementary protective component or structure, usually non-metallic, which is designed and installed around conducting parts that are energized, or that may assume hazardous potentials during abnormal conditions. Its purpose is to prevent inadvertent contact by personnel.</td>
</tr>
<tr>
<td>Isolation Transformer</td>
<td>A power transformer interposed at some point in the circuit between PCS inverter output and the first utilization circuit level, and connected so that ground currents will not flow across the interface.</td>
</tr>
<tr>
<td>Transformerless PCS</td>
<td>A PCS unit that does not include an isolation transformer between inverter bridge output and the industrial plant low-voltage ac distribution bus.</td>
</tr>
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</table>
MODULE - THE SMALLEST COMPLETE ENVIRONMENTALLY PROTECTED ASSEMBLY OF SOLAR CELLS/OPTICS AND OTHER COMPONENTS (EXCLUSIVE OF TRACKING), DESIGNED TO GENERATE DC POWER WHEN UNDER UNCONCENTRATED TERRESTRIAL SUNLIGHT.

PANEL - A COLLECTION OF ONE OR MORE MODULES, OPTICS AND OTHER COMPONENTS FASTENED TOGETHER, FACTORY PREASSEMBLED AND WIRED, FORMING A FIELD INSTALLABLE UNIT.

ARRAY - A MECHANICALLY INTEGRATED ASSEMBLY OF PANELS TOGETHER WITH SUPPORT STRUCTURE (INCLUDING FOUNDATIONS) AND OTHER COMPONENTS, AS REQUIRED, TO FORM A FREE-STANDING FIELD INSTALLED UNIT THAT PRODUCES DC POWER.

SOURCE CIRCUIT - A GROUP OF PANELS OR PARALLELED PANELS CONNECTED IN A SERIES TO PROVIDE DC POWER AT THE DC VOLTAGE LEVEL OF THE POWER CONDITIONING SUBSYSTEM. A SOURCE CIRCUIT MAY INVOLVE THE INTERCONNECTION OF PANELS LOCATED IN SEVERAL ARRAYS.

ARRAY SUBFIELD - A GROUP OF SOLAR PHOTOVOLTAIC ARRAYS ASSOCIATED BY THE COLLECTION OF SOURCE CIRCUITS THAT ACHIEVES THE RATED DC POWER LEVEL OF THE POWER CONDITIONING UNIT.

ARRAY FIELD - THE AGGREGATE OF ALL ARRAY SUBFIELDS THAT GENERATE POWER WITHIN THE PHOTOVOLTAIC POWER SYSTEM.

PHOTOVOLTAIC POWER SYSTEM - THE ARRAY FIELD TOGETHER WITH AUXILIARY SYSTEMS (POWER CONDITIONING, WIRING, SWITCHYARD, PROTECTION, CONTROL) AND FACILITIES REQUIRED TO CONVERT TERRESTRIAL SUNLIGHT INTO AC ELECTRICAL ENERGY SUITABLE FOR DELIVERY TO THE LOAD.

Figure A-1 Photovoltaic Power System Terminology
Appendix B

SUMMARY OF SYSTEMS STUDIED

This appendix highlights array characteristics and system designs developed as aids in conducting the study.

The baseline system configurations used in this study were:

- JPL buried anchor plate
  - Type: flat plate
  - Efficiency: 13 percent
  - Module size: 4 x 4 feet
  - Aperture width: 8 feet
  - Spacing: 2.5 times vertical height of panels at 35° tilt angle
  - Array size: 8 x 20 feet
  - Arrays per source circuit: 48
  - Source circuits per group: 8
  - Groups per 5.0 MW subfield: 6

- Bechtel torque-tube (same configuration as above, except):
  - Array size: 8 x 36 feet
  - Arrays per source circuit: 32

- Rack-type arrays, same as either of the above except:
  - Arrays per source circuit: 10 (JPL) or 6 (Bechtel)
  - Source circuits: determined by plant rating

- Martin-Marietta concentrator
  - Type: fresnel lens, 14 lenses per module
- Efficiency: 19.3 percent
- Module size: 0.42 x 1.46 m
- Modules per array: 60
- Array size: sweeps a 44 foot diameter circle
- Array spacing: 47 feet on centers
- Arrays per source circuit: 5
- Source circuits per group: 18
- Groups per 5.0 MW subfield: 14

Plans and schematics for the baseline plants are shown in the figures that follow. Figure B-1 is a composite of field layouts, Figures B-2 and B-3 are subfields, Figures B-4 through B-7 are PCS areas, Figures B-8 through B-10 are alternative substations, Figure B-11 is a substation electrical diagram, and Figures B-12 and B-13 are diagrams of PCS units.
Figure B-1. 100 Megawatt Photovoltaic Plant, Flat Plate Arrays
Figure B-2. 5.0 Megawatt Flat Plate Subfield, Fixed Torque-Tube Arrays, 48 Source Circuits
Figure B-3. 5.0 Megawatt Concentrator Subfield, Martin-Marietta Arrays
Figure B-4. 5.0 Megawatt PCS Unit Layout (Base Case), Self-Commutated Inverter
Figure B-5. 5.0 Megawatt PCS Unit Layout (Alternative A), Self-Commutated Inverter
Figure B-6. 5.0 Megawatt PCS Unit Layout (Alternative B), Self-Commutated Inverter
Figure B-7. 5.0 Megawatt PCS Unit Layout, Concentrator Arrays, Self-Commutated Inverter
Figure B-8. AC Substation, Breaker-Per-Line Layout
Figure B-9. AC Substation, Ring Bus Layout
Figure B-10. AC Substation, Breaker-and-a-Half Layout
Figure B-11. AC Substation, Single-Line Diagram
Figure B-12. 5.0 MW Power Conditioning System Schematic, Self-Commutated Inverter
Appendix C

RESISTANCE TO EARTH OF BURIED ELECTRODE CONFIGURATIONS

This appendix presents equations to calculate ground resistance for several electrode shapes and groupings applicable in approaches to PV plant grounding. The contents of this appendix are summarized by Table C-1. Each of the electrode configurations is addressed in further detail on the subsequent page indicated in Table C-1. The details include further definition of the equation for resistance to earth, simplified equations for some cases, and a numerical example. An attempt was made to address these configurations believed to be most applicable for PV plant grounding systems. Further information on other configurations and methodologies to develop equations may be found in the sources of the equations presented herein, References C-1, 2, and 3.

Soil resistivity is expressed in ohms across a centimeter cube (ohm-cm), in all cases shown here. References vary in this respect; some important sources use meter-ohms. Dimensions herein are expressed in centimeters. The same nominal values have been used for all of the dimensions in the example calculations, insofar as practical for the variety of configurations addressed. These nominal values appear in parentheses following each entry in the list of symbols given below.

Symbols Used:

- \( r_e \) Soil resistivity, ohm-cm \((1.5 \times 10^5 \text{ ohm-cm})\)
- \( r_c \) Concrete resistivity, ohm-cm \((5 \times 10^3 \text{ ohm-cm})\)
- \( L \) Length of rod, wire, etc. in contact with earth, cm \((300 \text{ cm})\)
- \( \ln \) Natural logarithm, base \(e\)
- \( d \) Diameter of rod, wire, etc., cm \((1.3 \text{ cm})\)
- \( d_n \) Diameter of foundations, rebar cages, etc., cm \((40, 50 \text{ cm})\)
D  Diameter of circular configuration for electrodes in a group, cm
s  Spacing between electrodes, cm (200, 1200 cm)
n  Number of vertical rods or similar electrodes (20)
h  Depth of buried electrode below grade, cm (50 cm)
R₁  Resistance to earth for one electrode, neglecting its internal resistance, ohms
Rₙ  Resistance to earth for n electrodes, ohms
### Table C-1

**RESISTANCE OF BURIED ELECTRODES**

<table>
<thead>
<tr>
<th>ELECTRODE TYPE</th>
<th>CONFIGURATION</th>
<th>EQUATION FOR RESISTANCE TO EARTH</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Driven Vertical Rod</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(2 \pi L\right)^{-1}\ln \left(\frac{4L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-5</td>
</tr>
<tr>
<td>N Driven Rods Arranged in a Straight Line with Equal Spacing Less than Rod Length</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = \frac{r_0}{2\pi} \left(2 \pi L\right)^{-1}\ln \left(\frac{4L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-6</td>
</tr>
<tr>
<td>Concrete Encased Fixed or Pile Electrode</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(2 \pi L\right)^{-1}\ln \left(\frac{4L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-7</td>
</tr>
<tr>
<td>N Driven Rods Equally Spaced on a Circle and with Spacing Less than Rod Length</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = \frac{r_0}{2\pi} \left(2 \pi L\right)^{-1}\ln \left(\frac{4L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-8</td>
</tr>
<tr>
<td>Two Driven Rods with Spacing Less than Rod Length</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-9</td>
</tr>
<tr>
<td>Two Driven Rods, with Spacing Greater than Rod Length</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-10</td>
</tr>
<tr>
<td>Buried Horizontal Rod or Wire</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-11</td>
</tr>
<tr>
<td>Combined Buried Bare Wire and N Driven Rods Arranged in a Straight Line</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = \frac{r_0}{2\pi} \left(2 \pi L\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-12</td>
</tr>
<tr>
<td>Circular Plate at the Surface of the Earth</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 / 2d$ ohms</td>
<td>C-13</td>
</tr>
<tr>
<td>Buried Circular Plate</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-14</td>
</tr>
<tr>
<td>Buried Ring of Wire</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-15</td>
</tr>
<tr>
<td>Buried Hemisphere</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-16</td>
</tr>
<tr>
<td>Buried Sphere</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-17</td>
</tr>
<tr>
<td>Acrete Encased Circular Pad Electrode</td>
<td><img src="image-url" alt="Diagram" /></td>
<td>$R = r_0 \left(4 \pi \frac{L}{d}\right)^{-1}\ln \left(\frac{8L}{d}\right) - \frac{1}{2} \left(\frac{d}{L}\right)^2$ ohms</td>
<td>C-18</td>
</tr>
</tbody>
</table>

where $r_0$ = mutual resistance between the rods and the wire as follows:

\[
R_{MT} = s \left(\frac{M}{2\pi}\right)^{-1} \ln \left(\frac{M}{2\pi}\right) + \frac{L}{2\pi} \ln \left(\frac{M}{2\pi}\right)
\]

and $s$ is:

- the mean distance between rebar and bottom of pad
- equivalent diameter of rebar

Reproduced from best available copy.
Resistance to Earth:

$$R_1 = r_e (2 \pi L)^{-1} \left[ \ln \left( \frac{(4L/d)[1 + (1 + (d/4L)^2)^{1/2}]}{d/4L - [1 + (d/4L)^2]^{1/2}} \right) \right] \text{ ohms}$$

If $L$ is much greater than $d$,

$$R_1 = 0.159 \frac{r_e}{L} \left[ \ln \left( \frac{8L}{d} \right) - 1 \right] \text{ ohms}$$

Example:

Let $r_e = 1 \times 10^5$ ohm-cm
$L = 300$ cm (nominal 10 ft)
$d = 1.3$ cm (nominal 1/2 in)

$$R_1 = 0.159 \times 1 \times 10^5 \times 300^{-1} \left[ \ln \left( 8 \times \frac{300}{1.3} \right) - 1 \right]$$

$$= 345 \text{ ohms}.$$
Figure C-2. N Driven Rods Arranged in a Straight Line with Equal Spacing Less than Rod Length

Resistance to Earth:

\[ R_n = \frac{1}{n} \left[ R_1 + r_e (2 \pi s)^{-1} \left( \frac{1}{2} + \frac{1}{3} + \frac{1}{4} + \ldots + \frac{1}{n} \right) \right] \text{ ohms} \]

where \( R_1 \) = Resistance of one rod as calculated previously.

For a large number of rods,

\[ R_n = r_e \left( n \pi L \right)^{-1} \left[ \ln 8Ld^{-1} - 1 + 2Ls^{-1} \ln 0.6553n \right] \text{ ohms} \]

(This expression has a 1 percent error for 20 rods)

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( L = 300 \text{ cm} \)
\( d = 1.3 \text{ cm} \)
\( s = 200 \text{ cm} \)
\( n = 20 \text{ rods} \)

\[ R_{20} = 1 \times 10^5 \left( 20 \pi \times 300 \right)^{-1} \left[ \ln 8 \times 300 \times 1.3^{-1} - 1 + 2 \times 300 \times 200^{-1} \ln 0.6553 \times 20 \right] \]
\[ = 76 \text{ ohms} \]
Figure C-3. Concrete Encased Pier or Pile Electrode

Resistance to Earth:

\[ R = r_c \left( \frac{2 \pi L}{L} \right)^{-1} \left[ \ln \left( \frac{d_1}{2} \right) - \ln \left( \frac{d_o}{2} \right) \right] + \]

\[ r_e \left( \frac{2 \pi L}{L} \right)^{-1} \left[ \ln \left( \frac{4L}{L} \right) - \ln \left( \frac{d_1}{2} \right) - 1 \right] \text{ohms} \]

Example: Concrete pier with rebar cage;

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( r_c = 5 \times 10^3 \text{ ohm-cm} \)
\( L = 300 \text{ cm} \)
\( d_1 = 50 \text{ cm} \)
\( d_o = 40 \text{ cm} \)

\[ R = 5 \times 10^3 \left( \frac{2 \pi 300}{300} \right)^{-1} \left[ \ln \left( \frac{50}{2} \right) - \ln \left( \frac{40}{2} \right) \right] + \]

\[ 1 \times 10^5 \left( \frac{2 \pi 300}{300} \right)^{-1} \left[ \ln \left( \frac{4 \times 300}{300} \right) - \ln \left( \frac{50}{2} \right) - 1 \right] \]

\[ = 150 \text{ ohms} \]
Resistance to Earth:

\[ R_n = \left(\frac{1}{n}\right) \left[ R_1 + r_e \left(2 \pi s\right)^{-1} \left[\frac{1}{2} + \frac{1}{3} + \frac{1}{4} \ldots + \frac{1}{n}\right]\right] \text{ohms} \]

where \( R_1 \) = Resistance of one concrete pier to earth
\( n \) = number of piers

If \( n \) is large, \( \left[\frac{1}{2} + \frac{1}{3} + \frac{1}{4} \ldots + \frac{1}{n}\right] \) approaches
\[ \ln \left(\frac{Gn}{e}\right) = \ln 0.6553n \]

where \( G = 1.781 \)
\( e = 2.718 \)

then \( R_n = \frac{1}{n} \left[ R_1 + r_e \left(2 \pi s\right)^{-1} \ln 0.6553n\right] \)

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( R_1 = 150 \text{ ohms} \) (refer to previous example, page C-7)
\( s = 1200 \text{ cm} \)
\( n = 20 \) piers

\[ R_{20} = \left(\frac{1}{20}\right) \left[150 + 1 \times 10^5 \left(2 \pi 1200\right)^{-1} \ln 0.6553 \times 20\right] \]
\[ = 9.2 \text{ ohms} \]
Figure C-5. N Driven Rods Equally Spaced on a Circle of Radius D/2 and with Spacing Less than Rod Length

Resistance to Earth for a large number of rods ($n \geq 20$) and with $(\pi D)$ approximately equal to $(ns)$:

$$R_n = r_e \left(2 \pi n L\right)^{-1} \left[\ln \left(\frac{8L}{d}\right) - 1 + 2L s^{-1} \left(\ln \left(\frac{2n}{\pi}\right)\right)\right] \text{ohms}$$

Example:

Let $r_e = 1 \times 10^5 \text{ ohm-cm}$
$n = 20 \text{ rods}$
$L = 300 \text{ cm}$
$d = 1.3 \text{ cm}$
$s = 1200 \text{ cm}$

$$R_n = 1 \times 10^5 \left(2 \pi \times 20 \times 300\right)^{-1} \left[\ln \left(\frac{8 \times 300}{1.3}\right) - 1 + 2 \times 300 \times \frac{1}{1200} \left(\ln \left(\frac{2 \times 20}{\pi}\right)\right)\right]$$

$$= 21 \text{ ohms}$$
Resistance to Earth:

\[ R = r_e \left(4 \pi L\right)^{-1} \left[ \ln \frac{8L}{d} + \ln \frac{4L}{s} - 2 + \frac{s}{2L} - \frac{s^2}{16L^2} + \frac{s^4}{512L^4} \cdots \right] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \) ohm-cm

L = 300 cm

d = 1.3 cm

s = 200 cm

\[
R = 1 \times 10^5 \left(4 \pi \times 300\right)^{-1} \left[ \ln \left(8 \times 300/1.3\right) + \ln \left(4 \times 300/200\right) - 2 + 200 \left(2 \times 300\right)^{-1} - 200^2 \left(16 \times 300^2\right)^{-1} + 200^4 \left(512 \times 300^4\right)^{-1} \right]
\]

= 200 ohms
Resistance to Earth:

\[ R = r_e \left(4\pi L\right)^{-1} \left[ \ln \left(8L/d\right) - 1 \right] + r_e \left(4\pi s\right)^{-1} \left[1 - L^2/3s^2 + 2L^4/5s^4 \ldots \right] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( L = 300 \text{ cm} \)
\( d = 1.3 \text{ cm} \)
\( s = 1200 \text{ cm} \)

\[ R = 1 \times 10^5 \left(4\pi \times 300\right)^{-1} \left[ \ln \left(8 \times 300/1.3\right) - 1 \right] + \]
\[ 1 \times 10^5 \left(4\pi \times 1200\right)^{-1} \left[1 - 300^2 \left(3 \times 1200^2\right)^{-1} + \right] \]
\[ 2 \times 300^4 \left(5 \times 1200^4\right)^{-1} \]
\[ = 180 \text{ ohms} \]
Resistance to Earth:

\[ R = r_e \left( \pi L \right)^{-1} \left[ \ln \left( 2L(dh)^{-1/2} \right) - 1 \right] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( d = 1.3 \text{ cm} \)
\( h = 50 \text{ cm} \)
\( L = 1200 \text{ cm} \)

\[ R = 1 \times 10^5 \left( \pi \frac{1200}{1200} \right)^{-1} \left[ \ln \left( 2 \times 1200 \left( 1.3 \times 50 \right)^{-1/2} \right) - 1 \right] \]
\[ = 69 \text{ ohm} \]
Resistance to Earth:

\[ R_t = \frac{R_w R_r - R_w^2}{(R_w + R_r - 2R_{wr})} \text{ ohms} \]

where \( R_w \) = Resistance of wire to ground as determined previously (page C-12)

\( R_r \) = Resistance of rods as determined previously (see page C-11)

\( R_{wr} \) = Mutual resistance between the rods and the wire as follows:

\[ R_{wr} = r_e (\pi L_w)^{-1} \ln \left( \frac{L_w}{L_r} \right) \]

Example:

Let \( r_e = 1 \times 10^5 \) ohm-cm

\( L_w = 1200 \) cm

\( R_w = 69 \) ohm (see example on page C-12)

\( L_r = 300 \) cm

\( R_r = 180 \) ohms (see example on page C-11)

\( N = 2 \)

\[ R_{wr} = 1 \times 10^5 (\pi \times 1200)^{-1} \ln \left( \frac{1200}{300} \right) \]

\[ = 55 \text{ ohms} \]

\[ R_t = (69 \times 180 - 55^2) / (69 + 180 - 2 \times 55) \]

\[ = 48 \text{ ohms} \]
Resistance to Earth:

\[ R = \frac{r_e}{2d} \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \) ohm-cm
\( d = 50 \) cm

\[ R = 1 \times 10^5 \left(2 \times 50\right)^{-1} \]

\[ = 1000 \text{ ohms} \]
Resistance to Earth:

\[ R = r_e \left( \frac{4d}{h} \right)^{-1} + r_e \left( \frac{8 \pi h}{h} \right)^{-1} \left[ 1 - \frac{7d^2}{192h^2} + \frac{33d^4}{10,240h^4} \ldots \right] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)

\( d = 50 \text{ cm} \)

\( h = 50 \text{ cm} \)

\[ R = 1 \times 10^5 \left( \frac{4 \times 50}{50} \right)^{-1} + 1 \times 10^5 \left( \frac{8 \pi \times 50}{50} \right)^{-1} \]

\[ \left[ 1 - 7 \times 50^2 \left( \frac{192 \times 50^2}{50^2} \right)^{-1} + 33 \times 50^4 \left( \frac{10,240 \times 50^4}{50^4} \right)^{-1} \right] \]

\[ = 580 \text{ ohms} \]
Figure C-12. Buried Vertical Circular Plate

Resistance to Earth:

\[ R = r_e (4d)^{-1} + r_e (8 \pi h)^{-1} [1 - 7d^2/384h^2 + 99d^4/81,920h^4\ldots] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( d = 50 \text{ cm} \)
\( h = 50 \text{ cm} \)

\[ R = 1 \times 10^5 (4 \times 50)^{-1} + 1 \times 10^5 (8 \pi \times 50)^{-1} \]
\[ [1 - 7 \times 50^2 (384 \times 50^2)^{-1} + 99 \times 50^4 (81,920 \times 50^4)^{-1}] \]
\[ = 580 \text{ ohms} \]
Figure C-13. Buried Ring of Wire

Resistance to Earth:

\[ R = r_e \left( \pi^2 \frac{D}{d} \right)^{-1} \ln \left[ 4D (dh)^{-1/2} \right] \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( D = 50 \text{ cm} \)
\( d = 1.3 \text{ cm} \)
\( h = 50 \text{ cm} \)

\[ R = 1 \times 10^5 \left( \pi^2 \times 50 \right)^{-1} \ln \left[ 4 \times 50 (1.3 \times 50)^{-1/2} \right] \]
\[ = 650 \text{ ohms} \]
Figure C-14. Buried Hemisphere

Resistance to Earth:

\[ R = \frac{r_e}{\pi d} \text{ ohms} \]

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)
\( d = 50 \text{ cm} \)

\[ R = \frac{1 \times 10^5}{\pi \times 50} \]
\[ = 640 \text{ ohms} \]
Figure C-15. Buried Sphere

Resistance to Earth:

\[ R = r_e (4 \pi)^{-1} \left[ \frac{2}{d} + \frac{1}{2h} \right] \text{ohms} \]

where \( h \) and \( d \)

Example:

Let \( r_e = 1 \times 10^5 \text{ohm-cm} \)
\( d = 50 \text{ cm} \)
\( h = 50 \text{ cm} \)

\[ R = 1 \times 10^5 (4 \pi)^{-1} \left[ \frac{2}{50} + \frac{1}{2 \times 50} \right] \]
\[ = 640 \text{ ohms} \]
Figure C-16. Concrete Encased Circular Pad Electrode

Resistance to Earth:

\[ R = r_c (4 d_o)^{-1} + r_c (4 \pi s)^{-1} \left[ 1 - 7d_o^2 (48s^2)^{-1} + 33 d_o^4 (640s^4)^{-1} \right] - \]

\[ \frac{1}{r_c (2 d_1)} + \frac{1}{r_e (2 d_1)} \text{ ohms} \]

where \( s \) = mean distance between rebar and bottom of pad

\( d_o \) = equivalent diameter of rebar

\( d_1 \) = diameter of concrete pad

Example:

Let \( r_e = 1 \times 10^5 \text{ ohm-cm} \)

\( r_c = 5 \times 10^3 \text{ ohm-cm} \)

\( d_o = 50 \text{ cm} \)

\( d_1 = 60 \text{ cm} \)

\( s = 50 \text{ cm} \)

\[ R = 5 \times 10^3 (4 \times 50)^{-1} + 5 \times 10^3 (4 \pi \times 50)^{-1} \left[ 1 - 7 \times 50^2 (48 \times 50^2)^{-1} + 33 \times 50^4 \right. \]

\[ \left. (640 \times 50^4)^{-1} \right] - 5 \times 10^3 (2 \times 60)^{-1} + 1 \times 10^5 (2 \times 60)^{-1} \]

\[ = 820 \text{ ohms} \]
REFERENCES


Appendix D

EQUIVALENT CIRCUIT ANALYSIS OF A TYPICAL PV SUBFIELD WITH A FAULTED SOURCE CIRCUIT

Grounding and fault protection subsystem designs depend upon the voltages and currents experienced in the subfield and at the PCS during a dc fault. For a given fault condition, the voltages and currents can be calculated from suitable circuit equations. These equations can be developed from a consideration of the equivalent circuit for a subfield (or group of source circuits) during a fault. Equivalent circuits for typical fault conditions are presented in this appendix. An example of the analysis is presented for one case. The computer program used to solve these equations is also listed.

D.1 BASELINE ARRAY SUBFIELD EQUIVALENT CIRCUIT

Typical subfield array group configurations and subfield bus connections are shown by the drawings in Appendix B. With respect to representing ground current for the large power station array groups, two categories of equivalent circuits are sufficient. These are solid and resistance grounded at the midpoint. A third category of circuit in which the array group is floating with respect to ground is not discussed. In that case, steady state ground currents would be non-existent except in the case of a double fault to ground. The transient effects of a fault were not considered.

Figure D-1 shows a typical subfield dc circuit consisting of N source circuits connected in parallel. Figure D-2 shows an equivalent circuit with one of the N source circuits shown explicitly and the other N-1 source circuits represented by a single equivalent source circuit. By symmetry, the effects of a single ground fault in any source circuit with M modules or panels in series can be studied with this model. As indicated on Figure D-2, blocks 1 and 2 each represent M/2 panels connected in series and N-1 such circuits in parallel. Block 3
Figure D-1. Resistance Grounded Two-Wire Subfields Circuit

1 & 2 = M/2 PANELS x (N-1) SOURCE CIRCUITS
3 = M/2 PANELS x 1 SOURCE CIRCUIT
4 = (M/2-F) PANELS x 1 SOURCE CIRCUIT
5 = F PANELS x 1 SOURCE CIRCUIT

R3 = \( \frac{R2}{N-1} \)

F = NUMBER OF ARRAYS BETWEEN NEGATIVE TERMINAL AND FAULT POINT

Figure D-2. Equivalent Circuit for Solidly Grounded Two-Wire or Grounded Neutral Three-Wire Subfields
represents a series connection of M/2 panels. Blocks 4 and 5 represent a series connection of M/2 panels total, with a fault to ground between them, F panels from the negative terminal of the Nth source circuit. The actual number of panels or cells represented by each group is immaterial so long as both blocks in a pair have the same number of panels or cells and are identical in their voltage and current characteristics, as is assumed here (i.e., balanced). Thus, analysis of fault conditions can be restricted to occurrences in one half of the source circuit with results applicable to either half by symmetry.

The figures show each source circuit grounded at its mid-point by a fixed resistor of specified value, represented as R₂. The equivalent resistance, R₃, accounts for the N-1 parallel resistances of value R₂ in each of the other paralleled source circuits, and is equal to R/(N-1) under the assumption of balanced source circuits. The value of the midpoint resistor may be varied from zero to infinity (within numerical limits of the computer program) to represent solidly grounded to floating ground configurations. This is the equivalent configuration for both two-wire circuits and single point grounded neutral three-wire systems. Assuming that the resistance of the neutral conductor is negligible, the currents for both systems will be the same.

In both figures the load resistor, R₁, represents the input resistance of the power conditioning system. For the purpose of the fault current calculations performed here, R₁ is assumed to be fixed. Thus, the currents calculated are those in the first instant after the fault occurs. If the PCS incorporates maximum power tracking capability, R₁ will change as the PCS equivalent load moves toward a new operating point to maximize the power from the arrays. If the time taken by the array protective devices to clear the fault is sufficiently long, the PCS will reach the new operating point. Solution of the circuit equations for the new maximum power point operation is difficult. A full treatment of this is outside the scope of this study. However, an evaluation by trial and error substitutions of incrementally changing values of R₁ for an array group having 6 parallel source circuits indicated that the
calculated fault currents for a fixed $R_l$ were within approximately 10 percent of what they were for an optimized value of $R_l$. The difference between fixed and optimized values of $R_l$ would decrease with a larger number of source circuits in parallel.

D.2 ANALYSIS OF TYPICAL FAULT CONDITIONS

The equivalent circuit and equations of Figure D-3 provides the baseline for the ground fault calculations. The circuit and currents are modified as appropriate to represent particular fault situations. This section presents a sample circuit for a typical fault situation as an example of how to model fault current calculations. The method of solution is outlined.

D.2.1 Equivalent Circuit for Interpanel Fault to Ground

The circuit shows a single ground fault occurring between two panels in the lower half of a source circuit. The fault divides the panels in the lower half of the source circuit into two groups, represented by the blocks labeled 4 and 5 in Figure D-3.

Currents $I_1$ and $I_2$ flow from the source circuits through the PCS, represented by $R_l$, as in the unfaulted case. However, the fault introduces additional loop currents, $I_3$ and $I_4$ in Figure D-3.

By the sign convention selected, $I_2$ and $I_4$ are in opposite directions. As long as $I_4$ is less than (or equal to) $I_2$ the circuit in Figure D-3 is the appropriate model. This represents a fault occurring such that the number of panels in series below the fault (Block 5) is substantially less than the number above the fault (Block 4). As the fault location approaches the mid-tap point the current $I_4$ increases while $I_2$ decreases until the blocking diode in the lower half source circuit "opens." That is, the diode does not permit $I_4$ to be greater than $I_2"
ITERATIVELY SOLVE FOR LOOP CURRENTS BY NEWTON'S METHOD:

\[
\begin{align*}
    i_1 R_1 + i_2 R_1 - V_1 - V_2 &= f_1 = 0 \\
    i_1 R_1 + i_2 R_1 - V_3 - V_4 - V_5 &= f_2 = 0 \\
    i_3 R_2 - V_4 &= f_3 = 0 \\
    i_4 R_3 - V_1 + V_5 &= f_4 = 0 \\
\end{align*}
\]

\[
f_{xy} = \frac{\partial f_x}{\partial i_y} \\
f_{11} = \frac{\partial f_1}{\partial i_1} \\
f_{12} = \frac{\partial f_1}{\partial i_2} \\
f_{21} = \frac{\partial f_2}{\partial i_1} \\
\text{etc.}
\]

\[
\begin{bmatrix}
    f_1 & f_{12} & f_{13} & f_{14} \\
    -f_2 & f_{22} & f_{23} & f_{24} \\
    -f_3 & f_{32} & f_{33} & f_{34} \\
    -f_4 & f_{42} & f_{43} & f_{44} \\
\end{bmatrix}
\]

\[
i_1' - i_1 =
\begin{bmatrix}
    f_{11} & f_{12} & f_{13} & f_{14} \\
    f_{21} & f_{22} & f_{23} & f_{24} \\
    f_{31} & f_{32} & f_{33} & f_{34} \\
    f_{41} & f_{42} & f_{43} & f_{44} \\
\end{bmatrix}
\]

Figure D-3. Currents and Equations for Fault Current Modeling
D.2.2 *Determination of Fault Currents*

Using Figure D-3 the loop equations for each current loop may be written. From Figure D-3, for a fault location such that $I_2 > I_4$, the equations are:

\[
\begin{align*}
I_1 R_1 + I_2 R_1 - V_1 - V_2 &= f_1 = 0 \\
I_1 R_1 + I_2 R_1 - V_3 - V_4 - V_5 &= f_2 = 0 \\
I_3 R_2 - V_4 &= f_3 = 0 \\
I_4 R_3 - V_1 - V_5 &= f_4 = 0
\end{align*}
\]

For fault locations such that $I_2 < I_4$, the equations are:

\[
\begin{align*}
I_1 R_1 + I_2 R_1 - V_1 - V_2 &= f_1 = 0 \\
I_1 R_1 + I_2 R_1 + I_2 R_3 - V_1 - V_3 - V_4 &= f_5 = 0 \\
I_3 R_2 - V_4 &= f_3 = 0
\end{align*}
\]

It is assumed that the voltage drop across the diodes can be neglected and that the resistance of the fault is zero. The voltages $V_1, V_2, \ldots$, are the voltages across the series of array panels represented by the numbered blocks in the figures. The voltage of an array panel may be determined from the equation for the panel I-V characteristic (see Section 2.6.2):

\[
V = V_{dc} + V_o \ln \left[1 - \left(I/I_{SC}\right)\right]
\]

For this study, a 0.7 fill factor is used. Initial values of $I_2 = I_{mp}$, $I_1 = (N-1)I_{mp}$ and small values for $I_3$ and $I_4$ are used and the set of loop equations is solved iteratively using Newton's method. The basic equations are illustrated in Figure D-3. The determinants are used to iteratively correct the values for the currents ($I_1$ illustrated) until a suitably small correction is obtained.

D.2.3 *Modeling of Other Fault Conditions*

The equivalent circuits of the previous sections may be used, with appropriate modifications, to model other fault or abnormal conditions...
which may occur. These may include other single faults such as an intrapanel short to ground and an imbalanced source circuit due to partial failure of the cells in a panel. Also, multiple faults may be analyzed using similar circuits. These include failure of the blocking diode to a shorted condition at the same time as a fault to ground, and removal of the PCS load during a fault. In each of these cases an equivalent circuit similar to Figure D-3 may be drawn and the loop currents specified. From these the loop equations may be written and solved using the methods outlined in Section D.2.2.

The effect of different values of the mid-point grounding resistor and of the number of parallel source circuits on fault currents may also be determined using the methodology outlined above.

D.3 LISTING OF BASELINE COMPUTER PROGRAM

The baseline computer code used during this study is listed on the following four pages. It was written to obtain answers to questions arising during the study and is not particularly optimized to reduce computation time or facilitate use by others. It should also be noted that the means used to obtain the determinant of the matrices by first inverting the matrix is an idiosyncracy of the Basic language on the computer used for the work.
ARRAY FAULT SIMULATION

1000 PRINT DAT.CLK
1010 'ARRAY FAULT SIMULATION'
1020 PRINT
1030 Q1=.00001
1040 N1=32
1050 N2=6
1060 N3=N1/2
1070 Q=1
1080 T1=20
1090 T=T1+30+Q
1100 R2=5
1110 IF R2<.001 THEN R2=.001
1120 PRINTINIMAGE'%%% PANELS PER BRANCH CIRCUIT':N1
1130 PRINTINIMAGE'%%% BRANCH CIRCUIT PER FEEDER':N2
1140 PRINTINIMAGE'%%% OHM BRANCH CIRCUIT GROUND RESISTORS':R2
1150 PRINTINIMAGE'%%% KW/M2':0
1160 PRINTINIMAGE'TEMP':T
1170 El=(1.366E-4*(T+273)+1.4)*79/0.609
1180 E2=(0.6574-0.0022*(T-28)+0.026*LOG(T)+79/0.609)
1190 X=0.5*79/0.609
1200 FOR M=1 TO 13 
1210 • SOLVE FOR VMP
1220 E3=X-(E1+LOG(1+X/E1)+X/E2)/(1/(1+X/E1)+1)
1230 X=X3
1240 NEXT M
1250 U2=1-(1-EXP((E3-E2)/E1)) • IMP BC
1260 P=E3+N1/J2/N2 • NORMAL MAX POWER LOAD
1270 R3=R2/(N2-1)
1280 PRINTINIMAGE'BRANCH CIRCUIT OPEN CIRCUIT VOLTAGE = VOLTS':E2+N1
1290 PRINTINIMAGE'BRANCH CIRCUIT SHORT CIRCUIT CURRENT = AMPS':J1

1300 '/
1310 MAT K=ZER(4,4)
1320 MAT F=ZER(4,4)
1330 MAT G=ZER(4,4)
1340 MAT H=ZER(4,4)
1350 MAT I=ZER(4,4)
1360 MAT J=ZER(4,4)
1370 D=J1
1380 C=J1*(N2-1)
1390 X1=U2*(N2-1)
1400 X2=U2
1410 X3=U2
1420 X4=0.001
1430 DEF FNC(X)=E2+E1*LOG(1-X/C)
1440 DEF FND(X)=E2+E1*LOG(1-X/D)
1450 K1=0
1460 GOSUB 10000
1470 IF X2<X4 THEN GO TO 1520
1480 GOSUB 12000
1490 N3=N3-1
1500 IF N3>=0 THEN GO TO 1450
1510 GO TO 1650
1520 K1=1
1530 X1=U2*(N2-1)
1540 X2=U2
1550 X3=U2
1560 MAT F=ZER(3,3)
1570 MAT K=ZER(3,3)
1580 MAT G=ZER(3,3)
1590 MAT H=ZER(3,3)
1600 MAT I=ZER(3,3)
1610 GOSUB 20000
1620 GOSUB 22000
1630 N3=N3-1
1640 IF N3>=0 THEN GO TO 1520
1650 STOP
10000 IF X2>ED THEN X2=D-1.E-3
10010 IF X1>C THEN X1=C-1.E-3
10020 IF X2*X3>D THEN X3=D-X2-1.E-3
10030 IF X2<X4<D THEN X4=D-X2-1.E-3
10040 IF X1*X4=C THEN X4=C-X1-1.E-3
10050 E(1)=X1*R1+X2*R1-FNC(X1+X4)+N1/2-FNC(X1)*N1/2
10060 E(2)=X1*R1+X2*R1-FNC(X2)+N1/2-FNC(X2)*N1/2-N3-FND(X2-X4)+N3
10070 E(3)=X3*R3-FND(X2+X3)*(N3/2-N3)
10080 E(4)=X4*R4-FNC(X1+X4)*N1/2+FND(X2-X4)*N3
10090 F(1, 1)=R1+El*N1/2/(C-X1+X4)+El*N1/2/(C-X1)
10100 F(1, 2)=R1
10110 F(1, 3)=0
10120 F(1, 4)=E1+N1/2/(C-X1-X4)
10130 F(2, 1)=R1
10140 F(2, 2)=R1+E1*(N1/2-N3)/(D-X2-X3)+E1*N3/(D-X2+X4)
10150 F(2, 3)=E1*(N1/2-N3)/(D-X2-X3) + E1*N3/(D-X2+X4)
10160 F(2, 4)=-E1*N3/(D-X2+X4)
10170 F(3, 1)=0
10180 F(3, 2)=E1*(N1/2-N3)/(D-X2-X3)
10190 F(3, 3)=R2+E1*(N1/2-N3)/(D-X2-X3)
10200 F(3, 4)=0
10210 F(4, 1)=E1+N1/2/(C-X1-X4)
10220 F(4, 2)=E1*N3/(D-X2+X4)
10230 F(4, 3)=0
10240 F(4, 4)=R3+E1*N1/2/(C-X1-X4)+E1*N3/(D-X2+X4)
10250 MAT K=INV(F)
10260 Y9=DET
10270 MAT G=F
10280 MAT H=F
10290 MAT I=F
10300 MAT J=F
10310 FOR N=1 TO 4
10320 G(N, 1)=-E(N)
10330 H(N, 2)=-E(N)
10340 I(N, 3)=-E(N)
10350 J(N, 4)=-E(N)
10360 NEXT N
10370 MAT K=INV(G)
10380 Y5=DET
10390 MAT K=INV(H)
10400 Y6=DET
10410 MAT K=INV(I)
10420 Y7=DET
10430 MAT K=INV(J)
10440 Y8=DET
10450 Y1=X1+Y5/Y9
10460 Y2=X2+Y6/Y9
10470 Y3=X3+Y7/Y9
10480 Y4=X4+Y8/Y9
10490 IF ABS(X1-Y1)<Q1 AND ABS(X2-Y2)<Q1 AND ABS(X3-Y3)<Q1 AND ABS(X4-Y4)<Q1 THEN GO TO 10570
10500 X1=Y1
10510 X2=Y2
10520 X3=Y3
10530 X4=Y4
10540 K1=K1+1
10550 IF K1>200 THEN GO TO 10560 ELSE GO TO 10000
10560 PRINTIMAGE 'CONVERGENCE LIMITS NOT REACHED WITH %%% ITERATIONS':K1
10570 X1=Y1
10580 X2=Y2
10590 X3=Y3
10600 X4=Y4
10610 V1=FNC(X1+X4)*N1/2
10620 V2=FNC(X1)+N1/2
10630 V3=FND(X2)+N1/2
10640 V4=FND(X2+X3)*(N1/2-N3)
10650 V5=FND(X2-X4)*N3
10660 X5=X1+X2
10670 P9=(V1+V2)*(X1+X2)
10680 V9=V1+V2
10690 RETURN
12000 PRINTIMAGE '%%% FAULT LOCATION NUMBER':N3
12010 PRINTIMAGE 'NORMAL BRANCH CIRCUIT VOLTAGE=%%% VOLTS':E3*N1
12020 PRINTIMAGE 'FAULT BRANCH CIRCUIT VOLTAGE=%%% VOLTS':V1+V2
12030 PRINT
12040 PRINTIMAGE 'NORMAL LOAD CURRENT=%%% AMPS':U2+N2
12050 PRINTIMAGE 'FAULT LOAD CURRENT=%%% AMPS':X1+X2
12060 PRINT
12070 PRINTIMAGE 'NORMAL LOAD POWER=%%% KW':E3*N1+U2+N2*1.1+1.1
12080 PRINTIMAGE 'FAULT LOAD POWER=%%% KW':(V1+V2)*(X1+X2)+1.1
12090 PRINT
12100 'VOLTAGES NORMAL FAULT',
12110 PRINTIMAGE 'V1=%%% VOLTS':E3*N1/2.V1

D-9
12120 PRINTINIMAGE'V2
12130 PRINTINIMAGE'V3
12140 PRINTINIMAGE'V4
12150 PRINTINIMAGE'V5
12160 'CURRENTS'
12170 PRINTINIMAGE'I1
12180 PRINTINIMAGE'I2
12190 PRINTINIMAGE'I3
12200 PRINTINIMAGE'I4
12210 PRINTINIMAGE'amps':J2*(N2-1),X1
12220 E(1)=X1*R1+X2*R1-FNC(X1+X4)*N1/2-FNC(X1)*N1/2
12230 E(2)=X2*(R1+R3)+X1*R1-FND(X2+X3)*(N1/2-N3)-FND(X2)*N1/2
12240 E(3)=X3*R2-FND(X2+X3)*(N1/2-N3)
12250 E(4)=X4*R3-FNC(X1+X4)*N1/2+FND(X2-X4)*N3
12260 PRINT E(1),E(2),E(3),E(4)
12270 ' '
12280 PRINTINIMAGE'LOAD=%%.%%OHMS POWER=%%.%.%.%.%.%.WATTS':R1,(V1+V2)*(X1+X2)
12290 ' '
12300 ' '
12310 ' '
12320 RETURN
20000 IF X1>C THEN X1=C-1,E-3
20010 IF X1+X2>C THEN X2=C-X1-1,E-3
20020 IF X2>D THEN X2=D-1,E-3
20030 IF X2+X3>D THEN X3=D-X2-1,E-3
20040 E(1)=X1*R1+X2*R1-FNC(X1+X2)*N1/2-FNC(X1)*N1/2
20050 E(2)=X2*(R1+R3)+X1*R1-FND(X2+X3)*(N1/2-N3)-FND(X2)*N1/2
20060 E(3)=X3*R2-FND(X2+X3)*(N1/2-N3)
20070 F(1,1)=R1*E1*N1/2/(C-X1-X2)+E1*N1/2/(C-X1)
20080 F(1,2)=R1*E1*N1/2/(C-X1)
20090 F(1,3)=0
20100 F(2,1)=R1*E1*N1/2/(C-X1-X2)
20110 F(2,2)=R1+R3+R1*(N1/2-N3)/(D-X2-X3)+E1*N1/2/(D-X2-X3)+(C-X1-X2)
20120 F(2,3)=E1*(N1/2-N3)/(D-X2-X3)
20130 F(3,1)=0
20140 F(3,2)=E1*(N1/2-N3)/(D-X2-X3)
20150 F(3,3)=R2+R1*(N1/2-N3)/(D-X2-X3)
20160 MAT K=INV(F)
20170 Y9=DET
20180 MAT G=F
20190 MAT H=F
20200 MAT I=F
20210 FOR N=1 TO 3
20220 G(N,1)=E(N)
20230 H(N,2)=E(N)
20240 I(N,3)=E(N)
20250 NEXT N
20260 MAT K=INV(G)
20270 Y5=DET
20280 MAT K=INV(H)
20290 Y6=DET
20300 MAT K=INV(I)
20310 Y7=DET
20320 Y1=X1+Y5/Y9
20330 Y2=X2+Y6/Y9
20340 Y3=X3+Y7/Y9
20350 IF ABS(X1-Y1)<Q1 AND ABS(X2-Y2)<Q1 AND ABS(X3-Y3)<Q1 THEN GO TO 20420
20360 X1=Y1
20370 X2=Y2
20380 X3=Y3
20390 K1=K1+1
20400 IF K1>200 THEN GO TO 20410 ELSE GO TO 20000
20410 PRINTINIMAGE'CONVERGENCE LIMIT NOT REACHED IN %%%% ITERATIONS':K1
20420 X1=Y1
20430 X2=Y2
20440 X3=Y3
20450 Y1=FNC(X1+X2)*N1/2
20460 Y2=FNC(X1)*N1/2
20470 Y3=FND(X2)*N1/2
20480 V4=FND(X2+X3)*(N1/2-N3)
20490 V5=E2+N3
20500 X5=X1+X2
20510 P9=(V1+V2)+(X1+X2)
20520 V9=V1+V2
20530 RETURN

D-10
22000 PRINTINIMAGE '%%% FAULT LOCATION NUMBER':N3
22010 'ZERO NET CURRENT THROUGH BLOCKING DIODE'
22020 PRINTINIMAGE 'NORMAL BRANCH CIRCUIT VOLTAGE: E3*N1'
22030 PRINTINIMAGE 'FAULT BRANCH CIRCUIT VOLTAGE: V1+V2'
22040 PRINT
22050 PRINTINIMAGE 'NORMAL LOAD CURRENT: J2*N2'
22060 PRINTINIMAGE 'FAULT LOAD CURRENT: X1+X2'
22070 PRINT
22080 PRINTINIMAGE 'NORMAL LOAD POWER: E3*N1*J2*N2*1.E-3'
22090 PRINTINIMAGE 'FAULT LOAD POWER: (V1+V2)*(X1+X2)*1.E-3'
22100 PRINT
22110 'VOLTAGES NORMAL FAULT'
22120 PRINTINIMAGE 'V1': E3*N1/2,V1
22130 PRINTINIMAGE 'V2': E3*N1/2,V2
22140 PRINTINIMAGE 'V3': E3*N1/2,V3
22150 PRINTINIMAGE 'V4': E3*(N1/2-N3),V4
22160 PRINTINIMAGE 'V5': E3*N3,V5
22170 'CURRENTS'
22180 PRINTINIMAGE 'I1': J2*(N2-1),X1
22190 PRINTINIMAGE 'I2': J2,X2
22200 PRINTINIMAGE 'I3': X3
22210 PRINTINIMAGE 'X1': K1
22220 E(1)=X1*R1+X2*R1-FNC(X1+X2)*N1/2-FNC(X1)*N1/2
22230 E(2)=X2*(R1+R3)+X1*R1-FND(X2+X3)*(N1/2-N3)-FND(X2)*N1/2-FNC(X1+X2)*N1/2
22240 E(3)=X3*R2-FND(X2+X3)*(N1/2-N3)
22250 PRINT E(1),E(2),E(3)
22260 '
22270 '
22280 PRINTINIMAGE 'LOAD= %.%% OHMS POWER= %.%% WATTS': R1,(V1+V2)*(X1+X2)
22290 '
22300 '
22310 RETURN
22320 END
Appendix E

MANUFACTURERS AND SUPPLIERS

Potential manufacturers and suppliers of components and equipment items for photovoltaic generating plant grounding and fault protection systems are listed in this appendix. The equipment categories listed focus primarily on the dc side of a generating plant. Certain ac equipment, which must be coordinated with dc equipment, is also included. Fault protection components and equipment which are integral with the PCS are not included here.

The list of companies under each equipment category is representative and should not be considered to be exhaustive. Also, listing herein should not be considered an endorsement of an equipment item or manufacturer. Certain trade magazines, such as CEE (Contractor's Electrical Equipment), publish product reference issues from which further supplier information may be obtained.

In most cases, representatives of the companies listed here were contacted to ascertain the availability of the denoted equipment. Some large companies prefer that product inquiries be made through local branch sales offices of the parent company. Entries in the following list which are preceded by an asterisk (*) have requested this. However, if difficulty obtaining product information is encountered, the parent company main office should be contacted.

Circuit Breakers, Dc (under 1500 Vdc)

- ASEA, Inc.
  Control Equipment Division
  1 Odell Plaza
  Yonkers, NY 10701
  (914) 969-1900, ext. 295
  Attn: Mr. John Gross
- Brown Boveri Electric  
  Route 309 & Norristown Road  
  Springhouse, PA  19477  
  (215) 628-7466  
  Attn: Al Filippone

- GEC Switchgear Ltd.  
  Trafford Park  
  Manchester, M17 1PR England  
  Tel. 061-872 2431

- ITE Electrical Products Division  
  2800 Golf Road  
  Rolling Meadows, IL  60008  
  (312) 981-5174  
  Attn: Greg Brown, Manager, Industrial Components

- The Ohio Brass Co.  
  Rectifier Division  
  P.O. Box 450  
  Oak Hill, WV  25901  
  (304) 465-5648  
  Attn: Tom Young  
  (415) 283-2363  
  Attn: Elmo F. Huston

- Pemco Corporation  
  Box 1338  
  Bluefield, WV  24701  
  (703) 326-2611

- Siemens-Allis  
  100 Wood Ave., South  
  Iselin, NJ  08830  
  (201) 321-8828  
  Attn: Max Deterding

Circuit Breakers, Dc (2000 Vdc and over)

- ASEA, Inc.  
  Control Equipment Division  
  1 Odell Plaza  
  Yonkers, NY  10701  
  (914) 969-1900, ext. 295  
  Attn: Mr. John Gross

- Brown Boveri Corporation  
  1460 Livingston Ave.  
  North Brunswick, NJ  08902  
  (201) 932-6116  
  Attn: Frank E. Klaus
• Wipp & Bourne, Ltd.
  Castleton, Lancashire, England
  Represented in USA by The Ohio Brass Co.
  (415) 283-2363
  Attn: Elmo F. Huston

Connectors (quick disconnect)

• Amerace Corp., Elastimold Div.
  Box 503, Newburg Road
  Hackettstown, NJ 07840
  (201) 852-1122
  Attn: Caron B. Anderson

• Brad Harrison Co.
  3411 Woodhead Drive
  Northbrook, IL 60062
  (312) 291-9260
  Attn: Michael Rakowski

• ITT Blackburn Co.
  1525 Woodson Road
  St. Louis, MO 63114
  (314) 993-9430

• Joy Manufacturing Co.
  La Grange, NC 28551
  (919) 566-3014

Contactors (under 1500 Vdc)

• ASEA, Inc.
  Control Equipment Division
  1 Odell Plaza
  Yonkers, NY 10701
  (914) 969-1900, ext. 295
  Attn: Mr. John Gross

• Automatic Switch Co.
  Florham Park, NJ 07932
  (201) 966-2000

• Brown Boveri Electric
  Route 309 & Norristown Road
  Springhouse, PA 19477
  (215) 628-7466
  Attn: Al Filippone

• *General Electric Co.
  Drive Systems Dept.
  1501 Roanoke Blvd.
  Salem, VA 24153
  (703) 387-7000
ITE Electrical Products Division
2800 Golf Road
Rolling Meadows, IL 60008
(312) 981-5174
Attn: Greg Brown, Manager, Industrial Components

Siemens-Allis
100 Wood Ave., South
Iselin, NJ 08830
(201) 321-8828
Attn: Max Deterding

Toshiba International Corp.
465 California St., Room 430
San Francisco, CA 94104
(415) 434-2340
Attn: Mr. H. Ohtsuka

Ward-Leonard Electric Co., Inc.
31 South St.
Mt. Vernon, NY 10550
(914) 664-1000

Contactors (2000 V dc and over)

ASEA, Inc.
Control Equipment Division
1 Odell Plaza
Yonkers, NY 10701
(914) 969-1900, ext. 295
Attn: Mr. John Gross

Current Limiting Protectors (dc-power)

Phoenix Electric Corp.
P.O. Box 53
Boston, MA 02137
(617) 821-0200
Attn: Mr. H. M. Pflanz

Enclosures (high voltage dc & noncorrosive)

Crouse-Hinds Co.
Wolf & Seventh N., PO Box 4999
Syracuse, NY 13221
(315) 477-7000
Attn: Norm Abbott

The English Electric Corporation
102 Midland Ave.
Port Chester, NY 10573
(914) 937-7450
Attn: Gary Quirk
• PEMCO Corporation  
PO Box 1338  
Bluefield, WV 24701  
(703) 326-2611

• Robroy Industries  
Electrical Products Division  
500 Maple St.  
Belding, MI 48809  
(616) 794-0700

Fuses (dc-power)

• Bussman Division, McGraw-Edison Co.  
PO Box 14460  
St. Louis, MO 63178  
(314) 394-2877  
Attn: Ronald Mollet

• Carbone-Ferraz, Inc.  
P.O. Box 324  
Rockaway, NJ 07866  
(201) 627-6200

• Gould Inc., Electric Fuse Div. (Gould-Shawmut)  
Newburyport, MA 01950  
(617) 462-6662

• International Rectifier  
233 Kansas St.  
El Segundo, CA 90245  
(213) 772-2000

Grounding and Bonding Hardware

• Burndy  
Richards Ave.  
Norwalk, CT 06856  
(203) 838-444

• Copperweld Bimetallics Div.  
Glassport, PA 15045  
(412) 664-7131

• ERICO Products, Inc.  
34600 Solon Road  
Cleveland, OH 44139  
(216) 248-0100

• ITT Blackburn Co.  
1525 Woodson Road  
Saint Louis, MO 63114  
(314) 993-9430
• TRW Nelson Division
  E. 28th St. & Toledo Ave.
  Lorain, OH 44055
  (216) 245-6931

Instrument Transformers

• *General Electric Co.
  Meter Business Dept.
  130 Main St.
  Somersworth, NH 03878
  (603) 692-2100
  Attn: Manager of Sales

• *Westinghouse Electric Corp.
  4300 Coral Ridge Drive
  Coral Springs, FL 33065
  (305) 752-6700

Protective Relays (ac)

• Brown Boveri Electric
  Route 309 & Norristown Road
  Springhouse, PA 19477
  (215) 628-7466
  Attn: Al Filippone

• *General Electric Co.
  Power Systems Management Business Dept.
  205 Great Valley Parkway
  Malvern, PA 19355
  (215) 251-7000

• Siemens-Allis
  100 Wood Ave.
  South Iselin, NJ 08830
  (201) 321-8828

• *Westinghouse Electric Corp.
  4300 Coral Ridge Drive
  Coral Springs, FL 33065
  (305) 752-6700

Semiconductors (blocking diodes, thyristors)

• Brown-Boveri Corporation
  North Brunswick, NJ 08902
  (201) 932-6210
  Attn: Willy Parolari
• General Electric Co.
  Semiconductor Products Dept.
  Auburn, NY 13201
  (315) 253-7321

• International Rectifier Co., Semiconductor Div.
  233 Kansas Street
  El Segundo, CA 90245
  (213) 772-2000
  Attn: Fred Ruby, Ed Chayet

• Motorola Semiconductor Products, Inc.
  Box 20912
  Phoenix, AZ 85036

• Siemens Components
  100 Wood Ave., South
  Iselin, NJ 08830
  (201) 321-4546
  Attn: Peter Winch

• Toshiba America, Inc.
  Electronic Components Division
  2441 Michelle Drive
  Tustin, CA 92680
  (714) 730-5000, ext. 534
  Attn: Mr. Matsubayashi

• Unitrode Corp.
  580 Pleasant Street
  Watertown, MA 02172
  (617) 926-0404

• Westinghouse Electric Corp.
  Semiconductor Division
  Hillis St.
  Youngwood, PA 15697
  (412) 925-7272

Surge Arrestors and Suppressors (dc)

• Brown Boveri Corporation
  1460 Livingston Ave.
  North Brunswick, NJ 08902
  (201) 932-6210
  Attn: Willy Parolari

• General Electric Co.
  Semiconductor Products Dept.
  Auburn, NY 13201
  (315) 253-7321
• Siemens Components
  100 Wood Ave., South
  Iselin, NJ 08830
  (201) 321-4546
  Attn: Peter Winch

• Toshiba America, Inc.
  Electronic Components Division
  2441 Michelle Drive
  Tustin, CA 92680
  (714) 730-5000, ext. 534
  Attn: Mr. Matsubayashi

Switches, Disconnect (dc)
• Pringle Electrical Manufacturing Co.
  425 Commerce Drive
  Fort Washington, PA 19034
  (215) 643-0100

(Also: See suppliers under Circuit Breakers and Contactors)

Test Instruments (grounding)
• Advanced Electrical Measurements & Controls
  99 Chauncy Street
  Boston, MA 02111
  (617) 451-0227

• Fluke Manufacturing Co. Inc.
  PO Box C9090, Stop 250C
  Everett, WA 98206
  (800) 426-0361

• James G. Biddle Co.
  Plymouth Meeting, PA 19462
  (215) 646-9200

Transducers (dc sensors)
• American Aerospace Controls Inc.
  570 Smith Street
  Farmingdale, NY 11735
  (516) 694-5100

• F. W. Bell, Inc.
  6120 Hanging Moss Road
  Orlando, FL 32087
  (305) 678-6900

• Ohio Semitronics, Inc.
  1205 Chesapeake Avenue
  Columbus, OH 43212
  (614) 486-9561
Appendix F

EXAMPLE OF DESIGN STEPS FOR A UTILITY-TYPE PLANT

This appendix presents an illustrative example of the salient design steps and logic that might be undertaken in designing PV plant grounding and protection subsystems. The example follows the procedures outlined in Section 3 for a utility-type plant. The example is for a 100 MW plant using flat-plate arrays. Site characteristics are assumed for purposes of illustration.

Analysis of samples indicates that the soil is fairly uniform and only mildly corrosive, except for one relatively small area (about 200 feet in diameter) where most samples were highly saturated with chlorides. This anomaly was apparently caused by prior disposal of industrial waste products. Discussions with utility personnel and industrial firms that have built grounding facilities within a few miles of the proposed site indicate no cause for special concern about corrosive soil in this region. The conclusion is to use bare, hard-drawn stranded copper conductors where buried ground wires are required. One exception is that insulated (cross-linked polyethylene) conductors will be used in all buried runs through the highly contaminated zone.

Resistivity measurements taken during the dry season average about 80,000 ohm-centimeters at the surface (day), based on soil sample tests. Other samples taken at several depths below grade show average resistivities ranging from 14,000 ohm-centimeters at two feet to 9,500 ohm-centimeters at five feet. Electrical measurements, using the four-electrode fall of potential method, show a fairly consistent average of about 10,000 ohm-centimeters over the entire area. Rock outcroppings and buried formations (scattered and relatively small) disturb this uniformity at several known locations; these are mapped on the site plan. Extensive rock formations underlie the site, but only at depths ranging from 25 to 60 feet.
No buried pipelines, tower lines, or other man-made metallic structures exist within the proposed area.

The soil composition is generally suitable for shallow trenching operations, although some sloughing can be expected from the trench sides. Battens will be required for some runs. The soil is generally suitable for back-filling of trenches, although rocks larger than one inch should be screened out to reduce the possibility of damaging cables, or of leaving voids around bare ground wires (a precaution against corrosion).

Holes for 16-inch diameter caissons can be drilled, except at the rock outcroppings. In some areas, the soil composition is such that follower casings will be required in the drilling operation.

Principal difficulties posed by the site characteristics are 1) the zone of highly corrosive soil, and 2) the rock outcroppings. In each case, buried cabling and foundation structures will have to be adapted to these special locations.

In the corrosive area, buried ground wires will be insulated, making them connecting runs rather than grounding electrodes. The trench backfill should be clean material taken from another area of the site. Concrete caissons for this area will be designed with several extra inches of concrete envelope over the rebars to compensate for possible deterioration at the soil interface.

In the rock outcrop areas, cable runs should be protected by being cut into the rock or by concrete, metal, or plastic raceways. Foundation structures may have to be redesigned to avoid the rock or so that they can be anchored directly to the rock. (In severe situations, a solution might be to omit one or several arrays entirely - few enough to have minimal effect on branch circuit power outputs.)
A subfield rating of 5 MW ac is prescribed for this project. This value is defined as the ac power output from the PCS with 1.0 kW/m$^2$ incident on the modules and an ambient air temperature of 20°. The dc input power to each PCS must supply about 5 percent more power to account for the dc wiring and PCS losses (about 5.26 MW$_{dc}$).

Each flat plate array (torque tube type), is 36 feet long by 8 feet wide. The modules are standard 4-foot square assemblies, arranged in a 2 x 9 configuration. The array will generate 61.78 volts. The source circuit operating voltage is designed to be 2000 Vdc, nominal. Thirty-two arrays per source circuit will produce a terminal voltage of 1977 Vdc. At 13 percent conversion efficiency, the power from each array will be:

$$8' \times 36' \times (0.3048)^2 \times 0.13 = 3.478 \text{ kW}$$

The power from each source circuit will be:

$$32 \times 3.478 = 111.3 \text{ kW}$$

Forty-eight source circuits per subfield will provide power just over the 5.26 MW proposed above, and is a number divisible into logical groups.

One of the logical groupings is 8 source circuits in each of 6 groups. This appears favorable for physical arrangement, efficient cabling, and circuit protection.

The output current from each source circuit will be

$$111.3 \text{ kW}/1.977 = 56.3 \text{ A}_{dc}$$

Output current from each group of 8 branch circuits will be:

$$56.3 \times 8 = 450 \text{ A}_{dc}$$

F-3
For efficient cabling, each source circuit will comprise two parallel rows of 16 arrays each. Source circuit output terminals (positive and negative) are located at one end of the paired row, and a short crossover connection will be made at the other end. All of the rows required to form a subfield (2 x 48 = 96 in all) will be arranged so that they extend to either side of a central access road, with all output terminals adjacent to the roadway. In this way, each group of 8 branch circuits (16 rows) can be connected by cable to a group junction point, and each group circuit can be connected to the PCS unit. This permits short power cable runs alongside the access roadway.

The 20 subfields required in a 100 MW plant are rectangular and can be arranged so as to fit the site. A 4 by 5 arrangement is postulated for this example.

Buried ground cables are installed parallel to and near the power cables, one running along each side of each access road. Their primary functions are to shield the power cables and to provide common tie points where all the inboard (roadway) ends of array rows can be jumpered to a buried grid (counterpoise) conductor. Buried ground cables are also installed along the outboard (remote from roadway) ends of array rows, to provide tie points for the remote ends of array rows.

Buried ground cables are installed along the periphery of the plant array field. This zone, especially at the outside corners, is the most critical for step and touch voltage hazards from voltage rise and voltage differential conditions. All structures and devices adjacent to the plant periphery are tied to these buried conductors. Each available ground electrode is also tied in to enhance the effectiveness. This is not to imply that the peripheral conductor is a sufficient measure, but that it is an essential first step.

Buried ground cables around the entire periphery of each subfield would probably not be justified, unless studies should show a need for more total length of active buried conductors or the plant were to be built.
and commissioned in several stages, so that some internal subfield boundaries would function for a while as external field boundaries.

The reinforced concrete caissons are to be used as earthing electrodes. The typical caisson in this soil is 16 inches in diameter, and extends 5 feet below grade. Effective length of the caisson as an electrode (rebar) is 4 feet. Resistivity of the concrete is approximately 5000 ohms-cm. Its resistance to earth is 287 ohms.

All caissons are to be tied into a common grounding network. For caissons that are not on the periphery of the field (or on a temporary periphery), the tie will be through the torque tube that the caissons support. Caissons along a periphery will be tied both to the torque tube and to the nearest accessible point on the buried ground conductor.

Current that leaks from the modules and arrays to earth through the concrete encasement are of such small magnitude that they should not affect useful life of the caissons. In design and fabrication, care must be taken to provide sufficient concrete thickness at the bottom of the assembly (e.g., 6 inches beyond the rebar metal), because this is a zone where current flow tends to concentrate. Also, all exposed metal and fittings at the top of the caisson should be coated or covered to reduce the leakage current flow over wet contaminated surfaces. Leakage currents will be highest near the positive and negative terminal ends of the source circuits. It is important to insure that direct metallic conducting paths exist (through copper cables, torque tubes, and jumpers) so that leakage currents are not forced to seek a path from positive to negative through foundation structures and earth.

The technically defendible way to calculate resistance-to-earth of large nonconventional buried configurations is by use of the EPRI, Georgia Tech, or equivalent computer programs. For a reasonably accurate quick estimate, the simplified equation in IEEE Standard No. 80 compares rather well with more recent, fully analytical methods.
For this tie point in the utility transmission network line-to-ground fault current is predicted to be 5,000 A, with backup clearing time of 30 cycles (decrement factor = 1.0). By using the procedures described in IEEE 80, a pre-final buried grid design was developed for the substation. This is a matrix 100 meters on each side, with 15 parallel conductors (equally spaced) running in each direction across the square. This design is based on use of a conventional crushed rock surface treatment over the entire substation yard. Step and touch potentials at the corner meshes should be verified by the EPRI or Georgia Tech programs if possible; IEEE 80-1976 results do not now seem sufficiently conservative in these matters.

The resistance to earth overall will be:

\[ R = \frac{r}{2d} + \frac{r}{L} \text{ ohms} \]

where

- \( r \) = resistivity in ohm-centimeters (10,000 for this example)
- \( L \) = total length of buried conductor in cm
- \( d \) = diameter (in cm) of circle whose enclosed area equals the area of the square matrix.

\[ R = \frac{10,000}{2 \times 11,280} + \frac{10,000}{300,000} \]
\[ = 0.477 \text{ ohms} \]

The calculated voltage rise for this substation, if it is isolated from other grounds, is thus 5,000 x 0.477 = 2380 Vac.

An ac output voltage of 34.5 kV is designed for the PCS output circuits and substation low-side circuits. This corresponds to a rated 3-phase ac line current of about 84 A. The need for high-speed clearing of ground faults on the 34.5 kV circuits can be avoided by limiting the fault current magnitude. This may be done by connecting grounding resistors in the neutral circuits of the 34.5 kV step up transformers. One rule of thumb is to limit the maximum ground current to about the rated load.
current in the circuits to be protected. In this case, 100 A is selected as the limit. This value will permit relatively low-speed clearing of 34.5 kV faults. Sensitive differential relaying will be required on the 34.5 kV busses, large tie cables, and step-up transformers, because their rated current is about 10 times that of the "collector" feeders.

For this example, a separated substation design is selected because connecting to the utility transmissions lines is made easier, and the substation voltage rise will affect the PV field to only a minor degree. The separation distance is selected as 1500 feet at the nearest points. This may be modified, based on later calculations of the mutual effects between two grids in the same area.

Conventional utility design practice is generally used in selecting the substation equipment. Switchgear for the twenty 34.5 kV "collecting" circuits is unique; electrically operated load-break switches are proposed because 34.5 kV power circuit breakers would be overrated and unnecessarily expensive. Protective relaying, particularly for phase-to-phase faults, must be correlated with the main 34.5 kV circuit breakers which would necessarily clear these higher current faults.

Conventional lightning protective measures are provided for the substation, the PCS units and immediate area, and for all buildings, work areas, and parking lots. The inherent capability of the array frames and supporting structures to protect themselves against damage to a degree will be used. The field and subfield areas (excepting the PCSD areas) will not be a safe zone for maintenance or construction workers to occupy during lightning storms. A warning system and procedure will be used to enable and require workers to move to a safe area, or to take refuge inside of a vehicle.

All lightning air terminals, shield wires, ground electrodes, surge arrester tails, and similar components will be tied to the main grounding grid conductors by short straight cables. All power, control, and communication conductors will be equipped with appropriate surge-limiting
devices. Particular attention will be given to protecting against the hazardous transfer of surge voltages along conductors. Fiber optic or optically coupled communication and control channels will be used between the substation and the plant control room.

The total resistance to earth for an entire PV field (or for the phased operating portion of a total plant) should be calculated by a currently accepted program, as mentioned before for substations. For an estimate, the IEEE method will serve moderately well, based on comparisons among various older and newer methods.

The area of the 100 MW field (4450' x 4900') is about 2.026 km$^2$. The equivalent diameter for this area is 1606 m. The total length of the buried and effective conductor is about 15,200 meters (total perimeter plus seven effective crossties along the row ends).

Using the IEEE 80 equation:

\[ R = \frac{r}{2d} + \frac{r}{L} \]

\[ = \frac{10,000}{2 \times 160,600} + \frac{10,000}{1,520,000} \]

\[ = 0.038 \text{ ohms} \]

For the 34.5 kV ground fault of 100 A, as limited by neutral resistance, no clearing time limit would exist. The worst case transferred ground rise voltage of about 4 volts (0.038 x 100) would be below the hazardous level; and below the let-go voltage, even for wet ground.

For a high-voltage transmission circuit ground fault of 5000 A, the voltage rise would be 189 volts. For wet ground, the maximum clearing time (for transferred voltage hazards) would be 0.38 seconds, just over the backup breaker clearing time assumed. Thus, from this aspect the ac substation could be located directly adjacent to the PV field. But if
the fault current were substantially higher, or if the PV plant were to be commissioned in several stages, such an arrangement would be unacceptable.

Direct-current faults can produce large currents, approaching 3000 A. But dc currents act on the buried grid in a different way than transmission circuit ground fault currents. All sources and return paths for dc fault currents (whether line-to-line direct, line-to-ground, or line-to-line via earth) are confined within the PV field area. Thus they tend to produce a voltage differential across the grid, rather than a voltage rise of the entire grid structure with respect to a remote point (or to true earth potential).

The worst location for high-current dc faults is in the central portion, where the power circuits converge and can thus deliver the highest current. The worst locations for dc fault differential voltages would generally be at the outer power junction boxes in those subfields occupying an exterior corner of the field layout.

A number of trial fault types and locations would have to be calculated to determine which cases govern and what their impact would be. The equivalent network to be solved for most of the foreseeable fault cases would involve the buried conductors, the torque tube ground paths, and the paralleling local earth paths. If every electrode and buried wire segment were to be represented, the equivalent network would be very extensive (over 1500 caissons in a subfield) and tedious to represent as input data to a computer program. Some combining approximations would be in order, such as converting each array row to a single "T" equivalent (two end terminals and one path to earth representing all caissons). Such a network could be simulated by a dc network program of reasonable capacity, or by a grounding analysis program such as the Georgia Tech model. The latter would provide a credible simulation of mutual current paths in the earth.
For calculation of worst case faults, two subcases should be considered for each type of fault assumed. One is where all blocking diodes survive and perform normally. The other is where the most critical diode fails, presumably permitting higher currents and voltages to develop, and also requiring some form of backup protection.

For a ground faults inside any source circuit's terminals, the program presented in Appendix D of this report (or an equivalent one) should be used to prepare tabulated answers for the various cases. General purpose network programs would be more difficult to adapt for this special situation.

For a 5 MW dc subfield that is divided into six groups, each group collection bus enclosure would accommodate eight source circuit incoming feeders and one outgoing feeder to the PCS input bus. The most effective location for source circuit blocking diodes and fuses would be at the group bus enclosure because this would protect the incoming feeder cables as well as the array rows.

The size of each source circuit feeder cable is chosen to be a No. 4 AWG stranded copper conductor with 5 kV insulation. This provides a margin for high ambient earth temperature and high thermal resistance (see Table 310-47 in the NEC).

The source circuit blocking diode assembly (two or more series diodes may be required at 2 kV) should be rated for reliable operation in high ambient temperatures, and for a favorable life-cycle energy loss evaluation. This could lead to a choice of a considerably overrated unit, say 200 A average current.

The source circuit fuse should also be rated for long life, high ambient temperature operation, and maximum forward current (to survive a short-circuit elsewhere in the subfield). But fuse clearing time must be acceptably short to protect people, equipment, and cables in pertinent fault situations. For example, if one group of source circuits is
temporarily disconnected from the PCS (group feeder to PCS switched open) and insolation is normal, any source circuit fuse must clear positively for a solid fault on a source terminal or line cable (if the diode should fail to block).

Normal load current in a group circuit is about 450 A, and maximum is about 540 A. A conductor site of 1000 kcmil would provide a margin for high ambient temperatures and high thermal resistance.

Blocking diode assemblies are available for this rating in standard ratings. Power thyristor (switching-type) or transistor assemblies may be found, but probably as custom designs. Either would require a forced cooling system. The other choice is to use a dc contactor (latching type), with relays set to trip it on reverse current in its own circuit, and also with a remote shunt trip circuit that may be energized manually, by monitoring computer, or by other sensors and relays. The contactor may be supplemented by blocking diodes, if considered necessary.

Power fuses in ratings above 500 A have a long thermal time constant, so their fusing time is probably more than sufficient to protect personnel. They may have a function in providing backup protection for equipment.

To provide primary or backup protection and annunciation for various fault conditions, a microcomputer monitoring and relaying system is recommended. This permits using balance, comparison, and reverse current sensing to trip various devices, both as a type of backup and as a system that will function at substantially reduced insolation. This computer may also be linked to PCS internal protective logic, and also to the ac relaying devices.

The time-current characteristics of grounding conductor segments, grounding jumpers, bonds, busses, and grounding paths in structures (e.g., the torque tube) must all be verified as adequate. The bases for this are the ac and dc fault studies, and the clearing time settings attainable on all protective devices proposed. Mismatches must be
corrected by changing the conductor capacity or the protective device. Ground paths that could burn open are quite hazardous; this could unground a part unexpectedly, or could initiate an exposed arc.

The dc electrical enclosures to be used at group circuit collecting points and at PCS convergence points for incoming subfield circuits must be developed and fabricated. These will most likely be custom devices, built to PV specifications and tested in a prototype phase.

A variety of disconnect devices must be provided in PV subfields, ranging from enclosed safety switches to quick-disconnect plug/socket devices. These will prove essential during construction to permit phased startup, and to facilitate maintenance during the life of the plant. Any PV array that is physically in place and connected internally will be generating about 1.2 times rated voltage during midday.

It will be prudent to keep arrays electrically isolated until all protective devices, including the computer system, have been installed and verified as ready to operate.

Then activation of source circuits can be done quite efficiently by coupling plug connectors and closing disconnect switches. Similarly, isolation of faulty arrays can be done much more rapidly if disconnects are provided at logical points.
Appendix G

FAULT DETECTION ECONOMICS DATA

This appendix contains further details to support the economic analysis of fault detection and maintenance presented in Section 5.7.

G.1 SYSTEM COSTS

Table G-1 shows the material quantities on which the fault detection costs are based. Tables G-2 through G-11 show details of the costs summarized in Table 5-8. It should be noted that the tables and costs in this appendix are for a 5 MW subfield and must therefore be multiplied by 20 to arrive at the total plant costs.

Dc current sensors are available from several manufacturers. For purposes of estimating costs, Hall effect sensors from Ohio Semitronics were used. The CT3KLT sensor selected requires a signal conditioner such as the CTA101 to supply operating current. Thus, these are listed as a single unit in the tables. For cable runs over 300 feet long, additional signal conditioning is needed (i.e., Cases 5 through 8). These are listed separately as signal conditioners in the tables. As mentioned, the tables in this appendix are for nominal 5 MW subfields. However, unit costs were obtained from discount schedules for 100 MW plant purchase quantities.

Power cables to supply 110 Vac to the signal conditioners are 2/C #14. Sensor cables between the Hall effect sensors and signal conditioners are shielded 2/C #18. Crimp lug terminations are used for the power and sensor cables.

Neutral cables for Cases 7 and 8 are 600 volt #2/0.
## Table G-1

### MATERIAL QUANTITIES LIST

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(1) FP = Flat Plate Array  
C = Concentrator Array  
(2) All cable lengths in feet
The resistance grounded cases include a ground resistor. This item consists of a resistor, NEMA 3R box, bulkhead fittings, mounting hardware and assembly of the unit.

The cost of the signal processor includes multi-channel remote processor units located within the subfields and a central data logging microcomputer unit. The costs of the processor equipment are based on the SBM-200 from Alber Engineering, Inc. and depend on the extent to which available data channel capabilities are used. For purposes of analyzing the forty cases, equipment costs were estimated for several designs and then approximated for all cases as $1150 per processor unit plus $22 per data channel. There is, of course, one channel per sensor. Thus, these items are not repeated in Table G-1. For each of the 20 subfields, this cost includes one-twentieth of the central computer cost.

Total field cost is the sum of tabulated direct costs for material and labor plus indirect cost which estimated at 50 percent of the direct labor costs. The total installed cost includes:

- Engineering at 8 percent of field cost
- A Contingency of 20 percent of field cost
- An Allowance for Funds During Constructions (AFDC) of 10 percent of the field cost and engineering and contingency
- Other Owner's Costs at 7 percent of the field cost and engineering and contingency
### Table G-2
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS

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<td>Normalized Cost ($/m²)</td>
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|                | CONCENTRATOR |              |            |              |             |            |
| Current Sensors| 2,268        | 408          | 5,670      | 1,020        |
| Power Cables   | 6            | 15           | 6          | 15           |
| Sensor Cables  | 99           | 270          | 248        | 675          |
| Connections    | 49           | 284          | 122        | 709          |
| Signal Processor| 1,546       | 126          | 2,140      | 254          |
|                | 3,968        | 1,103        | 8,186      | 2,693        |
| Direct Cost    |              |             | 5,071      | 10,879       |
| Indirect Cost  |              |             | 552        | 1,347        |
| Total Field Cost|            |             | 5,623      | 12,226       |
| Engineering & Contingency | 1,574 |           |             | 3,423        |
| AFDC & Owner's Costs | 1,223 |           |             | 2,660        |
| Total Installed Cost | 8,420 |           |             | 18,309       |
| Normalized Cost ($/m²) | 0.25 |           |             | 0.55         |

G-4
Table G-3
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR GROUP BUS POLE CURRENTS AT PCS

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CONCENTRATOR

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Table G-4
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS

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G-6
Table G-5

DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT POLE CURRENTS AT PCS

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<tr>
<td><strong>Indirect Cost</strong></td>
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<tr>
<td><strong>Total Field Cost</strong></td>
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<tr>
<td><strong>AFDC &amp; Owner's Costs</strong></td>
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</tr>
<tr>
<td><strong>Total Installed Cost</strong></td>
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<td><strong>Normalized Cost ($/m²)</strong></td>
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|                     |          |       |         |          |       |         |
| **+ 400 Volts**     |          |       |         |          |       |         |
| **CONCENTRATOR**    |          |       |         |          |       |         |
| Current Sensors     | 13,167   | 4,079 | 17,246  | 32,918   | 10,197| 43,115  |
| Power Cables        | 188      | 513   | 701     | 188      | 513   | 376     |
| Sensor Cables       | 9,335    | 25,458| 34,793  | 23,426   | 63,890| 87,316  |
| Signal Conditioners | 16,416   | 4,079 | 20,495  | 41,040   | 10,197| 51,237  |
| Cabinets            | 954      | 1,638 | 2,592   | 2,385    | 4,095 | 6,480   |
| Connections         | 972      | 5,670 | 6,642   | 2,430    | 14,175| 16,605  |
| Signal Processor    | 5,110    | 895   | 6,005   | 12,200   | 2,218 | 14,418  |
| **Direct Cost**     |          |       |         |          |       |         |
| **Indirect Cost**   |          |       |         |          |       |         |
| **Total Field Cost**|          |       |         |          |       |         |
| **Engineering & Contingency** |    |       |         |          |       |         |
| **AFDC & Owner's Costs** |     |       |         |          |       |         |
| **Total Installed Cost** |      |       |         |          |       |         |
| **Normalized Cost ($/m²)** | 4.96  |       |         |          |       |         |

G-8
Table G-7
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT POLE CURRENTS AT GROUP BUS J-BOX

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<th>(+ 400 Volts)</th>
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<td>Labor</td>
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<td>Material</td>
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<td>9,197</td>
<td>18,726</td>
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<td>764</td>
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<td>9,545</td>
<td>14,241</td>
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<td>2,175</td>
<td>10,930</td>
<td>23,347</td>
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<td>546</td>
<td>1,326</td>
<td>2,080</td>
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<td>3,542</td>
<td>1,382</td>
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<td>6,782</td>
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<td>66,774</td>
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<tr>
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<td>7,782</td>
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CONCENTRATOR

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<th>(+ 400 Volts)</th>
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<td>Material</td>
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<td>65,835</td>
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<td>188</td>
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### Table G-8
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT NEUTRAL CURRENT AT GROUP J-BOX
GROUND VIA INSULATED NEUTRAL

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<th>Labor</th>
<th>Totals</th>
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<td>12,263</td>
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<td>7,120</td>
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<td>58,180</td>
<td>27,344</td>
<td>36,564</td>
<td>63,908</td>
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<td>5,466</td>
<td>11,674</td>
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<td>14,574</td>
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<td>1,771</td>
<td>691</td>
<td>4,032</td>
<td>4,723</td>
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<td>3,966</td>
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<td>4,614</td>
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<td>78,347</td>
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<td>68,509</td>
<td>129,731</td>
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<tr>
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<td>9,363</td>
<td>2,900</td>
<td>12,263</td>
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<td>164</td>
<td>224</td>
<td>216</td>
<td>590</td>
<td>275</td>
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<tr>
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<td>4,772</td>
<td>7,120</td>
<td>19,419</td>
<td>26,541</td>
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<td>58,180</td>
<td>27,344</td>
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<td>63,908</td>
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<td>2,900</td>
<td>14,574</td>
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<tr>
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<td>864</td>
<td>848</td>
<td>1,456</td>
<td>2,304</td>
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<td>1,512</td>
<td>1,771</td>
<td>691</td>
<td>4,032</td>
<td>4,723</td>
</tr>
<tr>
<td>Signal Processor</td>
<td>2,205</td>
<td>268</td>
<td>2,473</td>
<td>3,966</td>
<td>648</td>
<td>4,614</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>36,903</td>
<td>41,444</td>
<td>78,347</td>
<td>61,222</td>
<td>68,509</td>
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<tr>
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<td>129,731</td>
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<tr>
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<tr>
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Table G-9
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT NEUTRAL CURRENT AT MIDPOINT
GROUNDED VIA INSULATED NETURAL

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</tr>
<tr>
<td>FLAT PLATE</td>
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</tr>
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<td>27,344</td>
<td>36,564</td>
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<td>1,088</td>
<td>11,674</td>
<td>2,900</td>
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<tr>
<td>Cabinets</td>
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<td>546</td>
<td>848</td>
<td>1,456</td>
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<td>Connections</td>
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<td>691</td>
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</table>

CONCENTRATOR |       |        |           |       |        |
<p>| Current Sensors | 13,167 | 4,079 | 32,918 | 10,197 |
| Power Cables | 1,235 | 3,369 | 2,591 | 7,065 |
| Sensor Cables | 15,414 | 42,038 | 39,523 | 107,790 |
| Neutral Cables | 26,316 | 35,190 | 29,025 | 38,813 |
| Signal Conditioners | 16,416 | 2,900 | 41,040 | 10,197 |
| Cabinets | 954 | 1,456 | 2,385 | 4,095 |
| Connections | 972 | 4,032 | 2,430 | 14,175 |
| Signal Processor | 5,110 | 895 | 12,200 | 2,218 |
| Direct Cost | 173,543 |       | 356,662 |
| Indirect Cost | 46,980 |       | 97,275 |
| Total Field Cost | 220,523 |       | 453,937 |
| Engineering &amp; Contingency | 61,746 |       | 127,102 |
| AFDC &amp; Owner's Costs | 47,986 |       | 98,777 |
| Total Installed Cost | $330,255 |       | $679,816 |
| Normalized Cost ($/m²) | 9.97 |       | 20.53 |</p>
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Table G-11
DETECTION EQUIPMENT TOTAL INSTALLED COSTS
MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS

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<th>Labor</th>
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|                |          |       |         |          |       |         |
| **CONCENTRATOR** |          |       |         |          |       |         |
| Current Sensors | 13,167   | 4,079 | 17,246  | 32,918   | 10,197| 43,115  |
| Power Cables   | 11       | 30    | 41      | 22       | 60    | 82      |
| Sensor Cables  | 990      | 2,700 | 3,690   | 2,475    | 6,750 | 9,225   |
| Connections    | 486      | 2,835 | 3,321   | 1,215    | 7,088 | 8,303   |
| Ground Resistor| 6,563    | 832   | 7,395   | 13,761   | 2,925 | 16,686  |
| Signal Processor| 5,110    | 895   | 6,005   | 12,200   | 2,218 | 14,418  |
|                | 26,327   | 11,371| 37,704  | 62,591   | 29,238| 91,829  |
| Direct Cost    |          |       |         | 37,698   |       | 91,829  |
| Indirect Cost  |          | 5,686 |         |          |       | 14,619  |
| Total Field Cost|         |       |         | 43,384   |       | 106,448 |
| Engineering & Contingency |          |       |         | 12,147   |       | 29,805  |
| AFDC & Owner's Costs |          |       |         | 9,440    |       | 23,163  |
| Total Installed Cost |         |       |         | $54,471  |       | $159,416|
| Normalized Cost ($/m²) | 1.96    |       |         |          |       | 4.81    |
**G.2 FAULTED MODULE REPAIR COSTS**

The tables in this section present the details of the economic analyses of costs to repair faulted modules under several scenarios.

Input data includes the fault detection equipment costs and labor hours listed in Table 5-8. Other input data are listed on each of the tables.

As discussed in Section 5.7, the repair interval for the periodic replacement scenarios is the time taken to accumulate 8 hours of repair work. The limits with the failure rates are a full time repair crew at 1 percent per year and a minimum of one repair per day per year at 0.001 percent per year. Under the immediate replacement scenarios, a repair crew is called out each time the equipment detects a fault. An exception is the 1 percent per year failure rate where a full time repair crew is needed. The immediate replacement scenario accounts for response time by assuming the power loss due to a fault persists for a half a day and by including one hour (total) travel time per repair event.

The annual repair costs include the cost of the replacement modules at the prices listed. No additional allowances are made for possible costs associated with low-volume purchases, shipping or warehousing of the replacement modules. The cost of locating faulted modules is derived from the manhours as discussed in Section 5.7 and a burdened labor cost of $27 per hour. This labor rate is also used with the estimated times to replace failed modules. The detection equipment annual costs are derived from the costs in Table G-2 through G-11 multiplied by 20 (subfields per plant) and an annual charge rate of 18 percent which is taken as representative for a utility-owned plant. In addition to the subtotal comprised of the above items, the total cost includes an estimate of the value of energy lost between the times of module failure and repair. The energy is plant ac output for the module and balance of plant efficiencies, and insolations listed in Table 5-7.
A comparison is also made between the annual revenue of plants with repair of failures and an ideal plant which is totally free of failures. This comparison is also made for a scenario where there is no replacement of failed modules or fault detection equipment. It should be noted that this latter number is for the first year of operation. The results presented in Section 5.7 account for the effect of this rate of power decrease continuing over a 30-year plant life.

Tables G-12 through G-16 are for flat plate arrays and fault detection methods 1, 3, 9, 10 and 10a. Case 10a is the same as Case 10 (1000 ohm ground resistor) with the value of the resistor adjusted to limit single fault power losses to 2 percent of the source circuit power (approximately 40 k ohms). Tables G-17 through G-21 are the corresponding set of cases for the concentrator array. These first ten tables are for a $0.10/kWh value of energy. Tables G-22 through G-31 repeat the analyses for a $0.05/kWh value of energy.
Table G-12

MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE
MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS
CASE 1 - SOLID GROUND

FLAT PLATE ARRAY

821947 m² Aperture Area (nominal 100MW plant)

$100/m² Module Cost

0.30 mh to Replace Failed Modules

$27.00/mh Cost of Labor

$0.10/kWh Value of Energy

$21.80 million Annual Revenue of Fault-Free Plant

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<th>0.01</th>
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<td>Periodic</td>
<td>Immediate</td>
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<td>% of Fault-Free Plant Revenue</td>
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<td>With Replacement</td>
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<td>94.60</td>
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400 VOLT CASE

1.30 mh to Locate Failed Modules

| Replacement Scenario | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate |
| Replacement Period (days) | 0.66 | 0.07 | 6.60 | 0.66 | 66.01 | 6.60 | 365.00 | 66.01 |
| ANNUAL COSTS | | | | |
| Replacement Modules | 821947 | 821947 | 82195 | 82195 | 8219 | 8219 | 822 | 822 |
| Locating Failed Modules | 194089 | 194089 | 19409 | 53748 | 1941 | 5375 | 351 | 537 |
| Replacing Failed Modules | 44790 | 44790 | 4479 | 23888 | 448 | 2389 | 81 | 239 |
| Detection Equipment | 27842 | 27842 | 27842 | 27842 | 27842 | 27842 | 27842 | 27842 |
| Subtotal | 1088668 | 1088668 | 133525 | 187673 | 38451 | 43825 | 29096 | 29441 |
| Value of Lost Energy | 264444 | 264444 | 26444 | 26444 | 26444 | 26444 | 26444 | 26444 |
| Total Costs | 1115113 | 1115113 | 151380 | 190317 | 55906 | 44090 | 38749 | 29467 |
| % of Fault-Free Plant Revenue | | | | |
| With Replacement | 94.88 | 94.88 | 99.31 | 99.74 | 99.80 | 99.82 | 99.86 |
| Without Replacement or Equipment | 55.72 | 95.57 | 99.56 | | | | |

G-16
### Table G-13

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT CURRENTS AT PCS**  
**CASE 3 - SOLID GROUND**

#### FLAT PLATE ARRAY

- **821947 m² Aperture Area (nominal 1000MW plant)**
- **$100/m² Module Cost**
- **0.30 mn to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.10/kWh Value of Energy**
- **$21.80 million Annual Revenue of Fault-Free Plant**

#### MODULE FAILURES (%/year)

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#### 1.03 mn to Locate Failed Modules

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#### ANNUAL COSTS

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#### 400 VOLT CASE

| 0.83 mn to Locate Failed Modules
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<td>Periodic</td>
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</table>

#### ANNUAL COSTS

<table>
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<th>Replacing Failed Modules</th>
<th>Detection Equipment</th>
<th>Value of Lost Energy</th>
<th>Total Costs</th>
<th>% of Fault-Free Plant Revenue</th>
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<td>94.74</td>
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<td>4479</td>
<td>11470</td>
<td>56005</td>
<td>11470</td>
<td>94.74</td>
</tr>
</tbody>
</table>

#### % of Fault-Free Plant Revenue

| With Replacement | 94.74 | 94.74 | 99.02 | 99.01 | 99.62 | 99.74 |
| Without Replacement or Equipment | -0.00 | 88.19 | 98.82 | 99.88 |
### Table G-14

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS**  
**CASE 9 - RESISTANCE GROUND**

#### FLAT PLATE ARRAY

- **821947 m² Aperture Area (nominal 100MW plant)**
- **$100/m² Module Cost**
- **0.30 mh to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.10/kWh Value of Energy**
- **$21.80 million Annual Revenue of Fault-Free Plant**

#### MODULE FAILURES (%/year)

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<th>0.01</th>
<th>0.001</th>
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<td>Periodic</td>
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<td>Replacement Period (days)</td>
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<td>0.07</td>
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#### ANNUAL COSTS

- **Replacement Modules**
- **Locating Failed Modules**
- **Replacing Failed Modules**
- **Detection Equipment**
- **Value of Lost Energy**
- **Total Costs**

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<td>Periodic</td>
<td>Immediate</td>
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<td>Immediate</td>
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<tr>
<td>Replacement Period (days)</td>
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<td>0.07</td>
<td>9.35</td>
<td>0.66</td>
<td>93.46</td>
<td>6.60</td>
<td>365.00</td>
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</table>

#### % of Fault-Free Plant Revenue

- **With Replacement**
- **Without Replacement or Equipment**

#### FLAT PLATE ARRAY

- **821947 m² Aperture Area**
- **$100/m² Module Cost**
- **0.30 mh to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.10/kWh Value of Energy**
- **$21.80 million Annual Revenue of Fault-Free Plant**

#### MODULE FAILURES (%/year)

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<th>0.1</th>
<th>0.01</th>
<th>0.001</th>
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<td>0.07</td>
<td>9.03</td>
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<tr>
<td>Replacement Period (days)</td>
<td>0.93</td>
<td>0.07</td>
<td>9.35</td>
</tr>
</tbody>
</table>

#### ANNUAL COSTS

- **Replacement Modules**
- **Locating Failed Modules**
- **Replacing Failed Modules**
- **Detection Equipment**
- **Value of Lost Energy**
- **Total Costs**

<table>
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<td>0.66</td>
<td>93.46</td>
<td>6.60</td>
<td>365.00</td>
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</table>

#### % of Fault-Free Plant Revenue

- **With Replacement**
- **Without Replacement or Equipment**

---

G-18
Table G-15

MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE
MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS
CASE 10 - RESISTANCE GROUND

FLAT PLATE ARRAY

821947 m² Aperture Area (nominal 100MW plant)
$100/m² Module Cost
0.30 mh to Replace Failed Modules
$27.00/mh Cost of Labor
$0.10/kWh Value of Energy
$21.80 million Annual Revenue of Fault-Free Plant

<table>
<thead>
<tr>
<th>MODULE FAILURES (%/year)</th>
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<th>0.01</th>
<th>0.001</th>
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<td></td>
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<tr>
<td>0.40 mh to Locate Failed Modules</td>
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<td></td>
</tr>
<tr>
<td>Replacement Scenario</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Replacement Period (days)</td>
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<td>15.09</td>
<td>0.66</td>
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<td>200921</td>
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<tr>
<td>With Replacement</td>
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<td>93.46</td>
<td>99.07</td>
<td>99.07</td>
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<tr>
<td>Without Replacement or Equipment</td>
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<td>95.39</td>
<td>99.54</td>
<td>99.95</td>
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| 400 VOLT CASE         |      |      |      |       |
| 0.37 mh to Locate Failed Modules |      |      |      |       |
| Replacement Scenario   |      |      |      |       |
| Replacement Period (days) | 1.50 | 0.07 | 15.76| 0.66  |
| ANNUAL COSTS           |      |      |      |       |
| Replacement Modules    | 821947| 821947| 82195 | 82195 |
| Locating Failed Modules| 55241 | 259781| 5524  | 25978 |
| Replacing Failed Modules| 44790 | 238879| 4479  | 23888 |
| Detection Equipment    | 149857| 149857| 149857| 149857|
| Subtotal               | 1071835| 1470464| 281918| 159077 |
| Value of Lost Energy   | 16267 | 10320 | 10320 | 10320 |
| Total Costs            | 1088102| 1480784| 282950| 175344 |
| % of Fault-Free Plant Revenue |      |      |      |       |
| With Replacement       | 95.01 | 93.21 | 98.81 | 98.70 |
| Without Replacement or Equipment | 82.72 | 98.27 | 99.83 | 99.98 |
### Table G-16

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS**  
**CASE 10A - HIGH RESISTANCE GROUND**

#### FLAT PLATE ARRAY

- 821947 m² Aperture Area (nominal 100MW plant)
- $100/m² Module Cost
- 0.30 mh to Replace Failed Modules
- $27.00/mh Cost of Labor
- $0.10/kWh Value of Energy
- $21.80 million Annual Revenue of Fault-Free Plant

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<td>Subtotal</td>
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<tr>
<td>With Replacement</td>
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<tr>
<td>Without Replacement or Equipment</td>
</tr>
</tbody>
</table>

#### 400 VOLT CASE

| Replacement Scenario     |     |     |      |       |
| Replacement Period (days) | 1.58| 0.07| 15.76| 0.66  |
| Replacement Modules      | 821947 | 821947 | 82195 | 82195 |
| Locating Failed Modules  | 55241 | 259781 | 5524 | 25978 |
| Replacing Failed Modules | 44790 | 238079 | 4479 | 23888 |
| Detection Equipment      | 149857 | 149857 | 149857 | 149857 |
| Subtotal                 | 1071835 | 1470464 | 242055 | 281918 |
| Value of Lost Energy     | 2033  | 1290  | 2033  | 1290  |
| Total Costs              | 1073868 | 1471754 | 244088 | 282047 |

<table>
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<th>% of Fault-Free Plant Revenue</th>
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<tbody>
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<td>With Replacement</td>
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<td>Without Replacement or Equipment</td>
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## Table G-17

### MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE

**MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS**

### CASE 1 - SOLID GROUND

### CONCENTRATOR ARRAY

- **662256 m² Aperture Area** (nominal 100MW plant)
- **$115/m² Module Cost**
- **0.37 mh to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.10/kWh Value of Energy**
- **$23.11 million Annual Revenue of Fault-Free Plant**

### MODULE FAILURES (%/year)  1.0  0.1  0.01  0.001

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<td>With Replacement</td>
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#### 400 VOLT CASE

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Table G-18

MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE
MONITOR SOURCE CIRCUIT CURRENTS AT PCS
CASE 3 - SOLID GROUND

CONCENTRATOR ARRAY

662256 m² Aperture Area (nominal 100MW plant)
$113/m² Module Cost
0.37 mh to Replace Failed Modules
$27.00/mh Cost of Labor
$0.10/kWh Value of Energy
$23.11 million Annual Revenue of Fault-Free Plant

<table>
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<tr>
<th>MODULE FAILURES (%/year)</th>
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<th>0.001</th>
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<td></td>
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<td>0.73 mh to Locate Failed Modules</td>
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| 400 VOLT CASE            |     |     |      |      |
| 0.63 mh to Locate Failed Modules |     |     |      |      |
| Replacement Scenario     |     |     |      |      |
| Replacement Period (days) | 0.54| 0.03| 5.41 | 0.34 |
| ANNUAL COSTS             |     |     |      |      |
| Replacement Modules      | 745038| 745038| 74504 | 74504 |
| Locating Failed Modules  | 183708| 183708| 18371 | 65902 |
| Replacing Failed Modules | 107892| 107892| 10789 | 50738 |
| Detection Equipment      | 476057| 476057| 476057| 476057 |
| Subtotal                 | 1512695| 1512695| 579721| 667201 |
| Value of Lost Energy     | 15576| 15576| 8423 | 1558 |
| Total Costs              | 1528271| 1528271| 588143| 668758 |
| % of Fault-Free Plant Revenue |     |     |      |      |
| With Replacement         | 93.39| 93.39| 97.46 | 97.11 |
| Without Replacement or Equipment | 75.40| 97.54| 97.75 | 97.98 |
### Table G-19

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS**  
**CASE 9 - RESISTANCE GROUND**

**CONCENTRATOR ARRAY**

- 662256 m² Aperture Area (nominal 100MW plant)
- $113/m² Module Cost
- 0.37 mh to Replace Failed Modules
- $27.00/mh Cost of Labor
- $0.10/kWh Value of Energy
- $23.11 million Annual Revenue of Fault-Free Plant

<table>
<thead>
<tr>
<th>MODULE FAILURES (%/year)</th>
<th>1.0</th>
<th>0.1</th>
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<tr>
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% of Fault-Free Plant Revenue
- With Replacement: 94.79, 94.79, 99.18, 99.61, 99.60, 99.66, 99.68
- Without Replacement or Equipment: 76.00, 97.60, 99.76, 99.98

| **400 VOLT CASE**     |     |     |      |       |
| 0.87 mh to Locate Failed Modules |     |     |      |       |
| Replacement Scenario |     |     |      |       |
| Periodic | Immediate | Periodic | Immediate | Periodic | Immediate |
| Replacement Period (days) | 0.44 | 0.03 | 4.36 | 0.34 | 43.61 | 3.38 | 365.00 | 33.80 |
| **ANNUAL COSTS**        |     |     |      |       |
| Replacement Modules    | 745038 | 745038 | 74504 | 74504 | 7450 | 7450 | 745 | 745 |
| Locating Failed Modules | 253692 | 253692 | 25369 | 79898 | 2537 | 7990 | 303 | 799 |
| Replacing Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 129 | 507 |
| Detection Equipment    | .163757 | .163757 | .163757 | .163757 | .163757 | .163757 | .163757 | .163757 |
| Subtotal               | 1270379 | 1270379 | 274419 | 368897 | 174823 | 184271 | 164934 | 165808 |
| Value of Lost Energy   | .26079 | .26079 | .2651 | .608 | .2651 | .608 | .2219 | .6 |
| **Total Costs**         | 1276457 | 1276457 | 277070 | 369505 | 177474 | 184332 | 167153 | 165814 |

% of Fault-Free Plant Revenue
- With Replacement: 94.48, 94.48, 98.00, 98.40, 99.23, 99.20, 99.28, 99.28
## Table G-20

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS**  
**CASE 10 - RESISTANCE GROUND**

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<td>662256 m² Aperture Area (nominal 100MW plant)</td>
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<td>$113/m² Module Cost</td>
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<td>0.37 mh to Replace Failed Modules</td>
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<tr>
<td>$0.10/kWh Value of Energy</td>
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<tr>
<td>$23.11 million Annual Revenue of Fault-Free Plant</td>
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<th>0.01</th>
<th>0.001</th>
</tr>
</thead>
</table>
| **1000 VOLT CASE**  
0.37 mh to Locate Failed Modules |
| Replacement Scenario | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate |
| Replacement Period (days) | 0.73 | 0.03 | 7.31 | 0.34 | 73.07 | 3.38 | 365.00 | 33.80 |
| ANNUAL COSTS |
| Replacement Modules | 745038 | 745038 | 74504 | 74504 | 7450 | 7450 | 745 | 745 |
| Locating Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 216 | 507 |
| Replacing Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 216 | 507 |
| Detection Equipment | 233896 | 233896 | 233896 | 233896 | 233896 | 233896 | 233896 | 233896 |
| Subtotal | 1194718 | 1194718 | 329978 | 747876 | 243504 | 251494 | 235073 | 235655 |
| Value of Lost Energy | 151406 | 151406 | 11104 | 1520 | 11104 | 152 | 5547 | 15 |
| Total Costs | 1209914 | 1209914 | 341082 | 409876 | 254608 | 251646 | 240649 | 235671 |

<table>
<thead>
<tr>
<th>% of Fault-Free Plant Revenue</th>
<th>With Replacement</th>
<th>Without Replacement or Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>94.76</td>
<td>94.76</td>
<td>98.52</td>
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</table>

| **400 VOLT CASE**  
0.33 mh to Locate Failed Modules |
| Replacement Scenario | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate |
| Replacement Period (days) | 0.77 | 0.03 | 7.72 | 0.34 | 77.25 | 3.38 | 365.00 | 33.80 |
| ANNUAL COSTS |
| Replacement Modules | 745038 | 745038 | 74504 | 74504 | 7450 | 7450 | 745 | 745 |
| Locating Failed Modules | 96228 | 96228 | 9623 | 48406 | 962 | 4841 | 204 | 484 |
| Replacing Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 216 | 507 |
| Detection Equipment | 573899 | 573899 | 573899 | 573899 | 573899 | 573899 | 573899 | 573899 |
| Subtotal | 1523056 | 1523056 | 66813 | 747545 | 583389 | 591262 | 575075 | 575634 |
| Value of Lost Energy | 6027 | 6027 | 466 | 608 | 466 | 61 | 221 | 6 |
| Total Costs | 1529134 | 1529134 | 673509 | 748153 | 588085 | 591323 | 577293 | 575640 |

<table>
<thead>
<tr>
<th>% of Fault-Free Plant Revenue</th>
<th>With Replacement</th>
<th>Without Replacement or Equipment</th>
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</thead>
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<td>93.38</td>
<td>93.38</td>
<td>97.09</td>
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G-24
### Table G-21

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS**  
**CASE 10A - HIGH RESISTANCE GROUND**

**CONCENTRATOR ARRAY**

- 662,256 m² Aperture Area (nominal 100MW plant)
- $113/m² Module Cost
- 0.37 m² to Replace Failed Modules
- $27.00/m² Cost of Labor
- $0.10/kWh Value of Energy
- $23.11 million Annual Revenue of Fault-Free Plant

#### MODULE FAILURES (%/year)

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<td>Replacement Period (days)</td>
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<td>% of Fault-Free Plant Revenue</td>
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#### 400 VOLT CASE

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<td>93.41</td>
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**G-25**
## Table G-22

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**

**MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS**

**CASE 1 - SOLID GROUND**

### FLAT PLATE ARRAY

821947 m² Aperture Area (nominal 100MW plant)

- $100/m² Module Cost
- 0.30 mh to Replace Failed Modules
- $27.00/mh Cost of Labor
- $0.05/kWh Value of Energy
- $10.90 million Annual Revenue of Fault-Free Plant

### MODULE FAILURES (%/year)

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### 1000 VOLT CASE

#### 1.50 mh to Locate Failed Modules

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#### % of Fault-Free Plant Revenue

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### 400 VOLT CASE

#### 1.30 mh to Locate Failed Modules

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#### % of Fault-Free Plant Revenue

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<th>99.60</th>
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<td>Without Replacement or Equipment</td>
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<td>99.56</td>
<td>99.96</td>
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G-26
## Table G-23

### MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE

**MONITOR SOURCE CIRCUIT CURRENTS AT PCS**

**CASE 3 - SOLID GROUND**

### FLAT PLATE ARRAY

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<th>821947 m² Aperture Area (nominal 100MW plant)</th>
<th>$100/m² Module Cost</th>
<th>0.30 mh to Replace Failed Modules</th>
<th>$27.00/mh Cost of Labor</th>
<th>$0.05/kWh Value of Energy</th>
<th>$10.90 million Annual Revenue of Fault-Free Plant</th>
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### MODULE FAILURES (%/year)

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### 1000 VOLT CASE

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### Table G-24

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**
**MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS**
**CASE 9 - RESISTANCE GROUND**

#### FLAT PLATE ARRAY

- **821947 m² Aperture Area (nominal 100MW plant)**
- **$100/m² Module Cost**
- **0.30 mh to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.05/kWh Value of Energy**
- **$10.90 million Annual Revenue of Fault-Free Plant**

#### MODULE FAILURES (%/year)

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**ANNUAL COSTS**

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**% of Fault-Free Plant Revenue**

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#### 400 VOLT CASE

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**ANNUAL COSTS**

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**% of Fault-Free Plant Revenue**

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Table G-25

MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE
MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS
CASE 10 - RESISTANCE GROUND

FLAT PLATE ARRAY

821947 m² Aperture Area (nominal 100MW plant)
$100/m² Module Cost
0.30 mh to Replace Failed Modules
$27.00/mh Cost of Labor
$0.05/kWh Value of Energy
$10.90 million Annual Revenue of Fault-Free Plant

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400 VOLTS CASE

0.37 mh to Locate Failed Modules

| Replacement Scenario    |     |     |      |       |
| Replacement Period (days)| 1.58| 0.07| 15.76| 0.66  |
| ANNUAL COSTS            |     |     |      |       |
| Replacement Modules     | 821947 | 821947 | 82195 | 82195 |
| Locating Failed Modules | 55241 | 259781 | 5524 | 25978 |
| Replacing Failed Modules| 44790 | 23888 | 448 | 2389 |
| Detection Equipment     | 149857 | 149857 | 149857 | 149857 |
| Subtotal                | 1071835 | 1470464 | 159077 | 163063 |
| Value of Lost Energy    | 8134 | 5160 | 8134 | 516 |
| Total Costs             | 1079969 | 1475624 | 167211 | 163115 |
| % of Fault-Free Plant Revenue |     |     |      |       |
| With Replacement        | 90.09 | 86.46 | 98.70 | 97.41 |
| Without Replacement or Equipment | 82.72 | 98.27 | 99.83 | 99.98 |
Table G-26  

MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE  
MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS  
CASE 10A - HIGH RESISTANCE GROUND  

FLAT PLATE ARRAY  

| 321947 m² Aperture Area (nominal 100MW plant) |
|---|---|
| $100/m² Module Cost |
| 0.30 m² to Replace Failed Modules |
| $27.00/mh Cost of Labor |
| $0.05/kWh Value of Energy |
| $10.90 million Annual Revenue of Fault-Free Plant |

### MODULE FAILURES (%/year)  
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0.01  
0.001  

#### 1000 VOLT CASE  
0.40 m² to Locate Failed Modules  

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% of Fault-Free Plant Revenue  
With Replacement | 90.85 | 87.16 | 98.50 | 98.15 | 99.27 | 99.25 | 99.16 | 99.36 | 
Without Replacement or Equipment | 94.24 | 99.42 | 99.94 | 99.99 |

#### 400 VOLT CASE  
0.37 m² to Locate Failed Modules  

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% of Fault-Free Plant Revenue  
With Replacement | 90.16 | 86.50 | 97.77 | 97.41 | 98.53 | 98.50 | 98.61 | 98.61 | 
Without Replacement or Equipment | 97.84 | 99.78 | 99.98 | 100.00 |
Table G-27
MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE
MONITOR GROUP BUS DIFFERENTIAL CURRENT AT PCS
CASE 1 - SOLID GROUND

CONCENTRATOR ARRAY

662256 m² Aperture Area (nominal 100MW plant)
$113/m² Module Cost
0.37 mh to Replace Failed Modules
$27.00/mh Cost of Labor
$0.05/kWh Value of Energy
$11.56 million Annual Revenue of Fault-Free Plant

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<th>0.001</th>
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<tr>
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<td>88.98</td>
<td>98.62</td>
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<td>99.39</td>
<td>99.94</td>
</tr>
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| 400 VOLT CASE            |     |     |      |       |
| 1.17 mh to Locate Failed Modules |     |     |      |       |
| Replacement Scenario     | Periodic Immediate | Periodic Immediate | Periodic Immediate | Periodic Immediate |
| Replacement Period (days) | 0.35 | 0.03 | 3.51 | 0.34    | 35.11 | 3.38 | 351.13 | 33.80 |
| ANNUAL COSTS             |     |     |      |       |
| Replacement Modules      | 745038 | 745038 | 74504 | 74504 | 7450 | 7450 | 745 | 745 |
| Locating Failed Modules  | 341172 | 341172 | 34117 | 97394 | 3412 | 9739 | 341 | 974 |
| Replacing Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 1078 | 507 |
| Detection Equipment      | 65912 | 65912 | 65912 | 65912 | 65912 | 65912 | 65912 | 65912 |
| Value of Lost Energy     | 1260014 | 1260014 | 185323 | 268549 | 77853 | 88176 | 67107 | 68139 |
| Total Costs              | 1267803 | 1267803 | 188057 | 289328 | 80588 | 88254 | 69841 | 68147 |
| % of Fault-Free Plant Revenue |     |     |      |       |
| With Replacement         | 89.03 | 89.03 | 98.37 | 97.50 | 99.30 | 99.24 | 99.40 | 99.41 |
| Without Replacement or Equipment | 75.40 | 97.54 | 99.75 | 99.98 |
### Table G-28

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT CURRENTS AT PCS**  
**CASE 3 - SOLID GROUND**

**CONCENTRATOR ARRAY**

- 662256 m² Aperture Area (nominal 100MW plant)  
- $1.13/m² Module Cost  
- 0.37 mh to Replace Failed Modules  
- $27.00/mh Cost of Labor  
- $0.05/kWh Value of Energy  
- $11.56 million Annual Revenue of Fault-Free Plant

### MODULE FAILURES (%/year)

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#### 1000 VOLT CASE

**0.73 mh to Locate Failed Modules**

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#### ANNUAL COSTS

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<th>Replacing Failed Modules</th>
<th>Detection Equipment</th>
<th>Value of Lost Energy</th>
<th>Total Costs</th>
</tr>
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<td>1257584</td>
<td>1277055</td>
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<td>191786</td>
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<td>191786</td>
<td>1257584</td>
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<td>191786</td>
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#### Value of Lost Energy

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#### 400 VOLT CASE

**0.63 mh to Locate Failed Modules**

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#### ANNUAL COSTS

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<th>Detection Equipment</th>
<th>Value of Lost Energy</th>
<th>Total Costs</th>
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#### Value of Lost Energy

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<td>99.75</td>
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# Table G-29

## Module Fault Annual Repair Costs and Plant Revenue

**Monitor Group Bus Differential Current At PCS**  
**Case 9 - Resistance Ground**

### Concentrator Array

- **662256 m² Aperture Area (nominal 100MW plant)**
- **$113/m² Module Cost**
- **$0.37/mh to Replace Failed Modules**
- **$27.00/mh Cost of Labor**
- **$0.05/kWh Value of Energy**
- **$11.56 million Annual Revenue of Fault-Free Plant**

### Module Failures (%/year)

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<th>Periodic Immediate</th>
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### 400 Volt Case

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### Table G-30

**MODULE FAULT ANNUAL REPAIR COSTS AND PLANT REVENUE**  
**MONITOR SOURCE CIRCUIT DIFFERENTIAL CURRENT AT PCS**  
**CASE 10 - RESISTANCE GROUND**

**CONCENTRATOR ARRAY**

- 662256 m² Aperture Area (nominal 100MW plant)  
- $113/m² Module Cost  
- 0.37 mh to Replace Failed Modules  
- $27.00/mh Cost of Labor  
- $0.05/kWh Value of Energy  
- $11.56 million Annual Revenue of Fault-Free Plant

#### MODULE FAILURES (%/year)

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#### 1000 VOLT CASE

- 0.37 mh to Locate Failed Modules

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#### 400 VOLT CASE

- 0.33 mh to Locate Failed Modules

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# Table G-31

## Module Fault Annual Repair Costs and Plant Revenue

**Monitor Source Circuit Differential Current at PCS**

**Case 10A - High Resistance Ground**

### Concentrator Array

- 662,256 m² Aperture Area (nominal 100MW plant)
- $113/m² Module Cost
- 0.37 mh to Replace Failed Modules
- $27.00/mh Cost of Labor
- $0.05/kWh Value of Energy
- $11.56 million Annual Revenue of Fault-Free Plant

### Module Failures (%/year)

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<td>Immediate</td>
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<td>74504</td>
<td>74504</td>
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<td>% of Fault-Free Plant Revenue</td>
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<td>89.65</td>
<td>97.14</td>
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</table>

| Without Replacement or Equipment | 97.00 | 97.00 | 99.70 | 99.70 | 99.97 | 99.97 | 100.00 | 100.00 |

| 400 VOLT    |          |          |           |           |
| 0.33 mh to Locate Failed Modules |          |          |           |           |
| Replacement Scenario | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate | Periodic | Immediate |
| Replacement Period (days) | 0.77 | 0.03 | 7.32 | 0.34 | 77.25 | 3.38 | 365.00 | 33.80 |
| **ANNUAL COSTS** |          |          |           |           |
| Replacement Modules | 745038 | 745038 | 74504 | 74504 | 7450 | 7450 | 745 | 745 |
| Locating Failed Modules | 96228 | 96228 | 9623 | 48406 | 962 | 4841 | 204 | 404 |
| Replacing Failed Modules | 107892 | 107892 | 10789 | 50738 | 1079 | 5074 | 216 | 507 |
| Detection Equipment | 233899 | 233899 | 233899 | 233899 | 233899 | 233899 | 233899 | 233899 |
| Subtotal | 1523056 | 1523056 | 668813 | 747545 | 583389 | 591262 | 575075 | 575634 |
| Total Costs | 1523436 | 1523436 | 669107 | 747583 | 583683 | 591266 | 575213 | 575635 |
| % of Fault-Free Plant Revenue | 86.82 | 86.82 | 94.21 | 93.53 | 94.95 | 94.88 | 95.02 | 95.02 |

| Without Replacement or Equipment | 98.80 | 98.80 | 99.88 | 99.88 | 99.99 | 99.99 | 100.00 | 100.00 |
G.3 OPEN MODULE REPAIR ECONOMICS

Tables G-32 through G-35 present the computer outputs for the economic analysis of the repair of modules failed to an open circuit. Details of the table entries are discussed in Section 5.7.2.
### ANNUAL MAINTENANCE COST AND NET PRESENT VALUE OF PLANT ENERGY

#### FLAT PLATE ARRAY

$0.10/kWh Value of Energy

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<th>0.01</th>
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<tr>
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</table>
### Table G-33

**ANNUAL MAINTENANCE COST AND NET PRESENT VALUE OF PLANT ENERGY**

**CONCENTRATOR ARRAY**

**$0.10/kWh Value of Energy**

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<td>Subtotal</td>
<td>861939</td>
<td>94302</td>
<td>17539</td>
<td>9862</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>129422</td>
<td>129422</td>
<td>12942</td>
<td>12942</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>991361</td>
<td>107244</td>
<td>18833</td>
<td>9991</td>
</tr>
<tr>
<td><strong>30 Year Net Present Value (% of fault-free plant revenue)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With Replacement</td>
<td>95.71</td>
<td>99.54</td>
<td>99.92</td>
<td>99.96</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>99.54</td>
<td>99.95</td>
<td>100.00</td>
</tr>
</tbody>
</table>
### Table G-34

ANNUAL MAINTENANCE COST AND NET PRESENT VALUE OF PLANT ENERGY

#### FLAT PLATE ARRAY

**$0.05/kWh Value of Energy**

<table>
<thead>
<tr>
<th>Module Failure Rate (%/year)</th>
<th>1.0</th>
<th>0.1</th>
<th>0.01</th>
<th>0.001</th>
</tr>
</thead>
</table>

#### 7 Day Repair Interval

<table>
<thead>
<tr>
<th>Activity</th>
<th>Value of Lost Energy</th>
<th>Total Annual Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>8219</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>60538</td>
<td>60538</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>935015</strong></td>
<td><strong>76945</strong></td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>1171</td>
<td>117</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td><strong>956185</strong></td>
<td><strong>76957</strong></td>
</tr>
</tbody>
</table>

#### 30 Year Net Present Value (% of fault-free plant revenue)

- **With Replacement**: 91.41, 98.58, 99.29, 99.37
- **Without Replacement**: 95.35, 99.54, 99.95, 100.00

#### 30 Day Repair Interval

<table>
<thead>
<tr>
<th>Activity</th>
<th>Value of Lost Energy</th>
<th>Total Annual Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>8219</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>14126</td>
<td>14126</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>888603</strong></td>
<td><strong>30533</strong></td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>5012</td>
<td>502</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td><strong>936185</strong></td>
<td><strong>30583</strong></td>
</tr>
</tbody>
</table>

#### 30 Year Net Present Value (% of fault-free plant revenue)

- **With Replacement**: 91.80, 99.00, 99.72, 99.79
- **Without Replacement**: 95.35, 99.54, 99.95, 100.00

#### 180 Day Repair Interval

<table>
<thead>
<tr>
<th>Activity</th>
<th>Value of Lost Energy</th>
<th>Total Annual Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>8219</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>2354</td>
<td>2354</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>876831</strong></td>
<td><strong>18762</strong></td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>3010</td>
<td>301</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td><strong>906930</strong></td>
<td><strong>19063</strong></td>
</tr>
</tbody>
</table>

#### 30 Year Net Present Value (% of fault-free plant revenue)

- **With Replacement**: 91.68, 99.08, 99.83, 99.90
- **Without Replacement**: 95.35, 99.54, 99.95, 100.00

#### 365 Day Repair Interval

<table>
<thead>
<tr>
<th>Activity</th>
<th>Value of Lost Energy</th>
<th>Total Annual Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Modules</td>
<td>821947</td>
<td>8219</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>1161</td>
<td>1161</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>44790</td>
<td>4479</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>875638</strong></td>
<td><strong>17568</strong></td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>61035</td>
<td>610</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td><strong>936673</strong></td>
<td><strong>18179</strong></td>
</tr>
</tbody>
</table>

#### 30 Year Net Present Value (% of fault-free plant revenue)

- **With Replacement**: 91.41, 99.07, 99.83, 99.91
- **Without Replacement**: 95.35, 99.54, 99.95, 100.00

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# Table G-35

## ANNUAL MAINTENANCE COST AND NET PRESENT VALUE OF PLANT ENERGY

### CONCENTRATOR ARRAY

<table>
<thead>
<tr>
<th>$0.05/kWh Value of Energy</th>
<th>1.0</th>
<th>0.1</th>
<th>0.01</th>
<th>0.001</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MODULE FAILURE RATE (%/year)</strong></td>
<td>7 Day Repair Interval</td>
<td>30 Day Repair Interval</td>
<td>180 Day Repair Interval</td>
<td>365 Day Repair Interval</td>
</tr>
<tr>
<td>Replacement Modules</td>
<td>745038</td>
<td>745038</td>
<td>745038</td>
<td>745038</td>
</tr>
<tr>
<td>Locating Failed Modules</td>
<td>66169</td>
<td>66169</td>
<td>66169</td>
<td>66169</td>
</tr>
<tr>
<td>Replacing Failed Modules</td>
<td>107892</td>
<td>107892</td>
<td>107892</td>
<td>107892</td>
</tr>
<tr>
<td>Detection Equipment</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
<td>7740</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>926839</td>
<td>159202</td>
<td>82467</td>
<td>928080</td>
</tr>
<tr>
<td>Value of Lost Energy</td>
<td>1241</td>
<td>1241</td>
<td>1241</td>
<td>1241</td>
</tr>
<tr>
<td><strong>Total Annual Cost</strong></td>
<td>926839</td>
<td>159202</td>
<td>82467</td>
<td>928080</td>
</tr>
</tbody>
</table>

### 30 Year Net Present Value (% of fault-free plant revenue)

<table>
<thead>
<tr>
<th></th>
<th>7 Day Repair Interval</th>
<th>30 Day Repair Interval</th>
<th>180 Day Repair Interval</th>
<th>365 Day Repair Interval</th>
</tr>
</thead>
<tbody>
<tr>
<td>With Replacement</td>
<td>91.97</td>
<td>92.37</td>
<td>92.25</td>
<td>91.98</td>
</tr>
<tr>
<td>Without Replacement</td>
<td>95.35</td>
<td>95.35</td>
<td>95.35</td>
<td>95.35</td>
</tr>
</tbody>
</table>

---

**Note:** The table details the annual maintenance cost and net present value of plant energy concentrator array, with values calculated for different energy module failure rates and repair intervals. The calculations include the value of energy, locating and replacing failed modules, detection equipment, and the total annual cost, followed by the 30-year net present value as a percentage of the fault-free plant revenue, with or without replacement options.
Appendix H

LIGHTNING-INDUCED TRANSIENT MODELING

This appendix presents descriptions of the methods and computer programs used to model the effects of nearby lightning strikes on arrays and derive the results presented in Section 5.8. The appendix includes discussions of the:

- Methodology
- Flat Plate Array Model
- Concentrator Array Model
- Driving Voltages
- Terminal Protection Device Models

H.1 METHODOLOGY

Overall, the methodology consists of using a computer program to solve the equations for transient voltages and currents on an array which result from the electromagnetic fields and ground currents of a nearby lightning strike.

Equivalent electrical circuits were used to model the array. Circuit elements were used to represent the foundation resistance to ground, inductance of the structure and similar physical parameters that affect the electrical response of the arrays to nearby lightning strikes. The individual circuits analyzed are discussed in detail in Sections H.2 and H.3. These sections also include the equations used to calculate numerical values for the circuit elements from array dimensions, configurations, and other physical properties.

Several methods can be used to solve for the transient response of an electrical circuit to a driving force (e.g., lightning strike electromagnetic fields and ground currents). The method used is the
transition matrix. With this method, the variables are selected to correspond to energy in the circuit elements. That is, the circuit equations are written in terms of currents through inductances and voltages across capacitances. Driving voltages are also included in the set of variables. These driving voltages are discussed in Section H.4.

The loop and node equations for the circuit are then expressed in terms of the variables \( x \) and their first derivatives \( x' \). The equations are rewritten so that each first derivative is expressed as the sum of terms relating it to the variables. This relationship gives the system matrix, \( S \), such that:

\[
X'(t) = S \, X(t)
\]

where \( S \) is the system matrix, \( X \) is the variable vector, and \( X' \) is its derivative.

To solve these equations by computer, an appropriate time interval, \( T \), is selected. \( T \) must be small compared to the natural periods of the circuit and driving functions in order for the computer calculations to be stable. The solution for successive time intervals is given by:

\[
X[(k + 1)T] = M(T) \, X(kT)
\]

where \( k = 0, 1, 2, 3 \ldots \)

and \( M \) is the transition matrix as given by:

\[
M(T) = e^{ST} = I + ST = \frac{(ST)^2}{2!} + \frac{(ST)^3}{3!} + \frac{(ST)^4}{4!} + \frac{(ST)^5}{5!} + \ldots 
\]

The expansion for the transition matrix in the present computer solution is truncated when the percentage increase in the norm of the transition matrix is less than \( 10^{-6} \).

One potential difficulty with the above method is rewriting the circuit equations to obtain expressions for the individual derivatives. This process becomes very difficult as the number of circuit elements.
increases. To avoid this, the computer program is also used to obtain the system matrix. The loop and node equations can easily be written in matrix form with the variables and their derivatives separated so that:

\[ AX' + BX = 0 \]

This expression is solved for the system matrix:

\[ S = A^{-1}B \]

For cases which include nonlinear circuit elements such as metal oxide varistors and diode terminal protection devices, the resistance of these elements changes with applied (i.e., computed) voltage across the device. Thus, the system and transition matrices change. Recalculating the system matrix, A, for each time increment by inverting the first derivative coefficient matrix would lead to very long computer run times. Fortunately the affected terms in the system matrix are identifiable. These terms are changed and only the transition matrix is recalculated. To further decrease the computer run times, the transition matrix is only recalculated when the magnitude of the voltage across the nonlinear element is sufficient to cause significant current flow (about 10 milliamps for the present program).

Further details and listings of the computer programs used are included with the discussions of the flat plate and concentrator arrays in Sections H.2 and H.3.

H.2 - FLAT PLATE ARRAY MODEL

The flat plate array modeled is shown by Figure 2-1, which is reproduced here as Figure H-1 for convenient reference. The equivalent circuit model of this array is shown by Figure H-2. Each of the N sections of the equivalent circuit represents a 36-foot section of the array between foundations. The equations used to calculate the values for the equivalent circuit elements from array physical parameters are discussed in the following paragraphs.
This section presents the equations used in the computer program to calculate values for the elements in the flat plate array equivalent circuit shown in Figure H-2. For the numerical values shown in the equations, all dimensions must be in meters.

Module Inductance: The inductance of the module and other inductances were determined by considering the flux linkages due to flowing currents and by using the geometric mean distance (GMD) concept common to transmission line calculations. For the present calculations, the flat plate modules were considered to be a thin conducting sheet and the effective ground plane was simplified to be a single conductor equivalent to a transmission line neutral. The module inductance \( L_1 \) in Figure H-2 is then given by:

\[
L_1 = 10^{-7} S \left[1/2 + \ln(D_1/D_2)\right]
\]

where

- \( S \) is the length of all modules in the array
- \( D_1 \) is the effective distance (GMD) between the modules and ground plane
- \( D_2 \) is the self GMD of the modules

**Figure H-1. Flat Plate Array**
Figure H-2 Flat Plate Array Equivalent Circuit Model

- L1: Module/DC Wiring Inductance
- L2: Structure Inductance
- L3: Support/Foundation Inductance
- Lm: Module/Structure Mutual Inductance
- C: Module Capacitance to Structure
- R1: Module/DC Wiring Resistance
- R2: Module Leakage Resistance
- R3: Resistance Between Foundations
- V: Combined Magnetic and Ground Current Effects
For a rectangular cross section conductor (e.g., the modules), the self GMD, D2, is given by:

\[ D2 = 0.2235 \ (a + b) \]

In the above equation, \( a \) is the conductor width and \( b \) is the thickness. For the present configuration, \( D2 \) is essentially 0.2235 times the array slant height.

**Torque Tube Inductance**: The inductance of the torque tube portion of the array structure (L2 in Figure H-2) is determined by the equation given for the module inductance. In this case, \( a \) and \( b \) in the equation for the self GMD are both 6 inches, the cross-sectional dimensions of the torque tube.

**Module/Torque Tube Mutual Inductance**: Since the modules and torque tube are in close proximity, their mutual inductance was included. Following the previous transmission line equation, this mutual inductance (Lm in Figure H-2) is given by:

\[ Lm = 2 \ 10^{-7} \ S \ Ln(D1/D3) \]

where

- \( S \) is the length of the torque tube/module string
- \( D1 \) is the mean distance to the ground plane
- \( D3 \) is the distance between the modules and torque tube (taken as the effective torque tube diameter herein).

**Support and Foundation Inductance**: For purposes of the calculations, it was assumed that the foundations are incorporated into the system ground. That is, the rebar is suitably interconnected and is in turn connected to the torque tube portion of the array structure. It was further assumed that the rebar cage could be treated as an equivalent
conducting cylinder. With these assumption, the inductance of the foundation (L3 in Figure H-2) is given by:

\[ L_3 = 4 \times 10^{-7} D \ln(S/R) \]

where
- \( D \) is the distance between the torque tube and effective ground plane
- \( S \) is the spacing between foundations
- \( R \) is the radius of the rebar cage.

Module/Structure Capacitance: The capacitance between the cells and module frame/array structure (C in Figure H-2) was determined by considering the cells as a semi-infinite plane adjacent to a perpendicular conducting strip (i.e., module frame). The capacitance for this configuration is given by:

\[ C = 2 \varepsilon \left( \sqrt{\frac{W}{G}} + \frac{2}{W} \right) L \]

where
- \( \varepsilon \) is the permittivity of free space \((10^{-9}/36\ \pi \text{ farads / meter})\)
- \( W \) is the effective width of the frame
- \( G \) is the gap between the cells and frame
- \( L \) is the perimeter of all modules in a section of array

A 3/4-inch module frame and 1/4-inch gap were used for the numerical calculations.

The capacitances for the two end sections both represent half of a section of array. Thus, their values are half those of the interior sections.

The capacitance between the cells and the effective ground plane is about four orders of magnitude smaller and was not included.
Module Resistance: For purposes of the calculations, it was assumed that the module resistance (R1 in Figure H-2) can be represented by an equivalent .01-inch thick silicon sheet with a resistivity of 1.5 ohm-cm.

Module Leakage Resistance: For purposes of the numerical calculations, it was assumed that the modules just meet the JPL test specification of a 50 microampere leakage current at 3,000 volts (i.e., R = 60 megohms per 4' x 4' module in this case. This value may be considered low in that many commercially available modules exceed this resistance. At the same time, this value can also be high in that the modules may be wetted by rain accompanying the lightning events and thereby lose the surface resistance component of the leakage resistance.

As with the module capacitance, the leakage resistances at the two end sections represent half of a section of array. Thus, these two resistances are twice the value of the leakage resistances in the interior sections.

For midpoint grounded arrays, one of the end leakage resistors is replaced by a ground resistor. Two midpoint grounded cases were evaluated, high resistance and direct grounding. A 40,000 ohm resistor was used for the high resistance ground. This configuration showed essentially the same behavior as the ungrounded case (i.e., R\text{end} = 6.7 megohms). Solving the equations for the transient voltages and currents include dividing by R2. Thus, the direct ground case cannot use a zero resistance. Further, very low values for this resistance increase the computer program run time. A 0.1 ohm limit was used for the direct ground case.

In cases evaluating terminal protection devices, the devices are placed in parallel with the module leakage resistors. These terminal protection devices are discussed in Section H.5.
Foundation Resistances: As mentioned, it was assumed that the foundations are incorporated into the grounding system. The resistance between adjacent foundations (R3 in Figure H2) was determined by considering the foundation rebar cage as a conducting cylinder connected to the array structure. The resistance is then given by

\[ R_3 = \frac{R_e H}{2 \pi} \ln \left( \frac{4S}{D} \right) \]

where
- \( R_e \) is the soil resistivity in ohm meters
- \( H \) is the depth of the foundation
- \( S \) is the distance between foundations
- \( D \) is the effective diameter of the rebar cage.

Two means of coupling the lighting energy into the arrays were included, magnetic and ground currents. Initial calculations of electric field showed negligibly small contributions. The magnetic fields of the lightning strike are coupled into the loop formed by the modules and ground plane, and the loop formed by the array structure and ground plane. The ground currents result in a voltage being set up between adjacent foundation. Thus, these effects are combined into a single driving voltage (V in Figure H-2). The equations for this voltage are discussed in detail in Section H.4.

H.2.2 Computer Program

The computer program used for analyzing the flat plate array model is listed of the following pages. It is written in Fortran and was run on an IBM PC XT. With minor modifications, it could be run on a mainframe computer.

Several versions of the program were used. The version listed includes the equations for a metal oxide varistor terminal protection device.
PROGRAM LS
MODEL EFFECTS OF LIGHTNING-INDUCED SURGES USING TRANSITION MATRIX

DOUBLE PRECISION A(65,65),B(65,65),C(65,65),D(65,65),EA(65,65)
DOUBLE PRECISION U(65),V(65),T,T1,T2,TC,TINC,PI,VOLTSG,VOLTSM
DOUBLE PRECISION CM,R2,RV,RE,RG,ENERGY,CAL,VC
REAL TUS,UM(65)
INTEGER CLAMP,W,INVM,A1
CHARACTER P1,P2
COMMON MSIZE,N,LATCH,T1,TINC,VOLTSG,VOLTSM,CM,R2,RE
OPEN(6,FILE='PRN',STATUS='NEW')
WRITE(*,*),113
113 FORMAT(X,'NUMBER OF ARRAY SEGMENTS ? ',/)
READ(*,114)N
114 FORMAT(1X,'LATCH= ',I1)
KOUNT=0
KPRINT=50
ENERGY=0
T=0
T1=Time to stroke crest
T1=1.5D-6
T2=Time for stroke decay
T2=50.0D-6*2.00
TC=Time period over which calculations are made
TC=140.0D-6
TINC=Time increments
TINC=.002D-6
TUS=Time in microseconds
PI=3.14159265
P1=15
P2=18
BB FORMAT(1X,A1)
WRITE(6,88)P1
88 FORMAT(1X,A1)
DO 5 I=1,65
5 CONTINUE
U(I)=0
V(I)=0
UP(I)=0
UM(I)=0
DO 5 J=1,65
5 CONTINUE
A(I,J)=0
B(I,J)=0
C(I,J)=0
D(I,J)=0
EA(I,J)=0
CONTINUE
WRITE(*,11)
11 FORMAT(1X,'INCLUDE VOLTAGE CLAMP (1=YES 2=NO) ',/)
READ(*,21)CLAMP
21 FORMAT(I1)
IF(CLAMP.EQ.2) GOTO 24
WRITE(*,12)
12 FORMAT(1X,'EXIT ',A1)
D Line# 1

7

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60   12 FORMAT(1X,'CLAMP VOLTAGE = ',A1)
61    READ(*,23)VC
62    A1='30
63    23 FORMAT(F10.0)
64    CAL=1.D-3/VC**A1
65    24 CONTINUE
66    C
67    C Read, calculate and print input parameters
68    10 CONTINUE
69    WRITE(*,'(11H CALL INPAD)')
70    CALL INPAD
71    CONTINUE
72    C
73    GOTO(6,7)CLAMP
74    6 WRITE(6,8)VC,A1
75    8 FORMAT(1X,'clamp = ',F5.0,' Volts a=',I3)
76    RO=1./((1.D-3/VC+.5/R2)
77    GOTO 9
78    7 WRITE(6,'(17H NO VOLTAGE CLAMP)')
79    RO=R2
80    9 CONTINUE
81    WRITE(6,666)TINC*1.D6
82    666 FORMAT(1X,'Tinc=',F5.3,' microseconds')
83    WRITE(6,88)Pl
84    INVERT loop/node matrix
85    WRITE(*,13)
86    13 FORMAT(1X,'INVERT MATRIX =1. INVERT & WRITE TO FILE =2, READ =3 ') A',"
87    READ(*,14)INVM
88    14 FORMAT(I1)
89    GOTO(17,17,15)INVM
90    17 OPEN(8,FILE='MAT6.BIN',FORM='BINARY')
91    15 DO 16 I=1,MSIZE
92    16 READ(8) (EA(I,J),J=1,MSIZE)
93    CLOSE(8)
94    18 CONTINUE
95    17 WRITE(*,'(9H CALL INV)')
96    CALL INV
97    CONTINUE
98    C Calculate system matrix
99    DO 20 I=1,MSIZE
100    20 J=1,MSIZE
101    EA(I,J)=0
102    1 DO 20 L=1,MSIZE
103    2 EA(I,J)=EA(I,J)-C(I,L)*D(L,J)
104    3 20 CONTINUE
105    IF(INVM.EQ.1)GOTO 18
106    OPEN(8,FILE='MAT6.BIN',FORM='BINARY')
107    18 DO 19 I=1,MSIZE
108    19 WRITE(8) (EA(I,J),J=1,MSIZE)
109    CLOSE(8)
110    18 CONTINUE
111    18 CONTINUE
112    18 CONTINUE
113    18 CONTINUE
114    18 CONTINUE
115    18 CONTINUE
116    18 CONTINUE
117    18 CONTINUE
118    18 CONTINUE

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D Line# 1 7 Microsoft FORTRAN77 V3.13 8/05/85

119 WRITE(*,1)
120 1 FORMAT(1X,'OUTPUT TO DISK =1, TO PRINTER =2, BOTH =3, NEITHER =4
121  A ? ',")
122 READ(*,2)W
123 GOTO(111,112,111,112)W
124 111 PAUSE 'INSERT BLANK.,FORMATTED DISK FOR DATA OUTPUT IN DRIVE A'
125 112 CONTINUE
126 GOTO(22,25,22,25)W
127 22 OPEN(7,FILE='A:OUT1.PRN',STATUS='NEW',FORM='FORMATTED')
128 25 CONTINUE
129 C Calculate transition matrix
130 WRITE(*, (23H CALL TRANSITION MATRIX'))
131 CALL TM(K9)
132 CONTINUE
133 WRITE(*,26)K9
134 26 FORMAT(1X,I3,' EXPANSION TERMS')
135 WRITE(*,27)K9
136 WRITE(*, (12H CALCULATING')
137 30 CONTINUE
138 IF (T.GT.TC) GOTO 100
139 GOTO (40,50,60)K9
140 40 IF (T.EQ.T1) GOTO 60
141 LATCH=2
142 EA(4*N+4,4*N+3) = -(PI/T2)**2
143 EA(4*N+4,4*N+5) = VOLTS*(PI/T2)**2
144 V(4*N+3) = VOLTS+2.0DO
145 V(4*N+4) = VOLTS*(PI/T2)**2
146 V(4*N+5) = 1.0DO
147 GOTO 25
148 50 IF (T.LT.T1+T2) GOTO 60
149 LATCH=3
150 KPRINT=5*KPRINT
151 MSIZE=4*N+2
152 DO 55 I=4*N+3,4*N+5
153 55 CONTINUE
154 U(I)=0
155 55 CONTINUE
156 60 CONTINUE
157 IF (CLAMP.ED.2) GOTO 65
158 IF (DABS(V(3*N+2)).LT.VC .AND. RE.GT.RO/5.) GOTO 65
159 IF (DABS(V(3*N+2)).LT.1.6*VC .AND. RE.LT.1.01) GOTO 65
160 RV=1.0DO/CAL/DABS(V(3*N+2))**(A1-1)
161 RE=1.0DO/(1.0DO/RV+.5DO/R2)
162 IF (RE.LT.1.0DO)RE=1.0DO
163 EA(3*N+2,3*N+2) = -1.0DO/CM/RE
164 CALL TM(K9)
165 65 CONTINUE
166 DO 70 I=1,MSIZE
167 U(I)=0
168 DO 70 J=1,MSIZE
169 U(I)+=U(J)*C(I,J)*V(J)
170 70 CONTINUE
171 CLAMP=U(3*N+2)/RE
172 ENERGY=ENERGY+U(3*N+2)**2/RE*TINC
173 T=T*TINC
174 IF (W.EQ.1) GOTO 85
175 TUS=T*1.06
176 DO 71 I=1,4*N+3
177 71 UU(I)=U(I)

H-12
D Line# 1  7
178 72 GOTO((72,73,72,85))W
179 72 KCOUNT=KCOUNT+1
180 74 IF(KCOUNT.NE.50) GOTO 73
181 74 KCOUNT=0
182 74 WRITE(7.74)US
183 74 FORMAT(1X,F5.1,\)
184 79 DO 79 I=20,27
185 79 WRITE(7,B0)UP(I)
186 80 FORMAT(F7.0,\)
187 82 FORMAT(1X)
188 81 FORMAT(1X)
189 81 IF(W.EQ.1)GOTO 85
190 73 CONTINUE
191 73 KOUNT=KOUNT+1
192 76 WRITE(7,77)UP(I)
193 77 FORMAT(F8.0,\)
194 78 FORMAT(1X)
195 78 FORMA(T(D10.2)
196 79 KOUNT=0
197 85 CONTINUE
198 85 DO 95 I=1,MSIZE
199 85 IF(DABS(U(I)).GT.ABS(U(M)))UM(I)=U(I)
200 95 V(I)=U(I)
201 95 WRITE(*,91)T*1.06,UP(N+1)
202 91 FORMAT(1X,F7.3,F9.0)
203 91 GOTO 30
204 100 WRITE(6.8)P2
205 100 IF(W.EQ.1.OR. W.EQ.3)CLOSE(7)
206 100 WRITE(6.98)ENERGY
207 98 FORMAT(1X,'ENERGY IN CLAMP = ',F10.4, ' Joules')
208 98 WRITE(6,'(15H MAXIMUM VALUES)')
209 98 DO 94 I=1,4*N+3
210 94 I=1,4*N+3
211 94 CLAMPI=UP(I)
212 94 WRITE(6,99)I,UM(I)
213 99 FORMAT(1X.I3,F10.0)
214 99 STOP
215 99 END

Name  Type  Offset  P  Class
A REAL*8  0  /AR1  /
A1 INTEGER*4  736
ABS INTEGER*4  INTRINSIC
B REAL*8  0  /AR2  /
C REAL*8  0  /AR3  /
CAL REAL*8  748
CLAMP INTEGER*4  694
CLAMP REAL  1060
CM REAL*8  44  /COMM00/  
D REAL*8  0  /AR4  /
DAABS INTRINSIC

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223 C SUBROUTINE INPAD
224 C Read, calculate, and print input parameters
226 C
227 C DOUBLE PRECISION A(65,65), D(65,65), U(65), V(65)
228 C DOUBLE PRECISION SD, AS, TD, ASH, TM, FD, FDIAM, ATA, AMP, L1, L2, L3, LM
229 C DOUBLE PRECISION T1, TINC, VOLTSM, VOLTSG
231 C COMMON MSIZE, N, LATCH, T1, TINC, VOLTSG, VOLTSM, CM, R2, R6, RE
232 C
233 C READ, SET & WRITE INPUT PARAMETERS
234 CONTINUE
235 WRITE(6,1)
236 1 FORMAT('1', 'LIGHTNING-INDUCED SURGES')
237 WRITE(6,2)
238 2 FORMAT(1X, 'FIXED TILT FLAT PLATE ARRAYS')
239 WRITE(6,3) N
240 3 FORMAT(1X, 12, ' ARRAY SECTIONS')
241 WRITE(*, 10)
242 10 FORMAT(1X, 'STRIKE DISTANCE (IN FEET) =', \)
243 READ(*, 11) SD
244 11 FORMAT(F6.0)
D Line# 1

WRITE(6,13)SD
245 13 FORMAT('0', 'STRIKE DISTANCE =', F6.0, ' FEET')
246 AS=36.7
247 WRITE(6,14)AS
248 14 FORMAT(1X, 'ARRAY SPAN =', F4.0, ' FEET')
249 TTD=6.5
250 WRITE(6,15)TTD
251 15 FORMAT(1X, 'TORQUE TUBE DIAMETER =', F6.2, ' INCHES')
252 ASH=8.
253 WRITE(6,16)ASH
254 16 FORMAT(1X, 'ARRAY SLANT HEIGHT =', F3.0, ' FEET')
255 FD=5.
256 WRITE(6,17)FD
257 17 FORMAT(1X, 'FOUNDATION DEPTH =', F5.1, ' FEET')
258 FDIA=10.
259 WRITE(6,18)FDIA
260 18 FORMAT(1X, 'FOUNDATION DIAMETER =', F5.1, ' INCHES')
261 ATA=35.
262 WRITE(6,20)ATA
263 20 FORMAT(1X, 'ARRAY TILT ANGLE =', F4.0, ' DEGREES')
264 AMP=1.4D5
265 WRITE(6,21)AMP
266 21 FORMAT(1X, 'AMPS PEAK IN LIGHTNING STROKE')
267 WRITE(*,23)
268 23 FORMAT(1X, 'SOIL RESISTIVITY (in ohm-meters) = ? ', ")
269 READ(*,11)SR
270 WRITE(6,24)SR
271 27 FORMAT(1X, 'Ohm-Meter SOIL RESISTIVITY')
272 C CONVERG PARAMETERS TO METRIC
273 SD=SD*.3048
274 AS=AS*.3048
275 TTD=TTD/12.*.3048
276 ASH=ASH*.3048
277 FD=FD*.3048
278 FDIA=FDIA/12.*.3048
279 TGE=TGE/12.*.3048
280 PI=3.141592D0
281 ATA=ATA/180.*P1
282 TM=0.01*2.54/100
283 W=.75*2.54/100.
284 G=.25*2.54/100.
285 RA=(.6+.6)*.32225D0/12.*.3048
286 C EFFECTIVE GROUND PLANE DEPTH
287 GPD=ASH/2.*DSIN(ATA)+.6096+FD*.625
288 C MODULE INDUCTANCE
289 L1=1.D-7*AS*(.5D0+2.*DLOG(GPD/ASH/.2235D0))
290 C TORQUE TUBE INDUCTANCE
291 L2=1.D-7*AS*(.5D0+2.*DLOG((GPD+TTD)/RA))
292 C MODULE/TORQUE TUBE MUTUAL INDUCTANCE
293 LM=2.D-7*AS*DLOG(GPD/TTD)
294 C VERTICAL SUPPORT INDUCTANCE
295 L3=4.D-7*GPD*DLOG(AS/FDIA*.2)
296 C RESISTANCE BETWEEN GROUND RODS
297 R3=SR/2.0/FD*DLOG(4.*AS/FDIA)
298 C MODULE LEAKAGE RESISTANCE 50 UA.3000V FOR 4X4
299 R2=6.D7*(4.*.3048)**2/ASH*AS
300 C MODULE SERIES RESISTANCE
D Line# 1

304 R1=1.5D-2*TM/AS/ASH
305 CM=2.D-9/36/PI*(DSQRT(W/G)+2./W)*16
306
307 WRITE (6,305)L1
308 305 FORMAT('O','MODULE INDUCTANCE = ',D9.4)
309 WRITE (6,300)L2
310 300 FORMAT(1X,'TORQUE TUBE INDUCTANCE = ',D9.4)
311 WRITE (6,307)L3
312 307 FORMAT(1X,'MODULE / TORQUE TUBE MUTUAL INDUCTANCE = ',D9.4)
313 WRITE (6,301)L4
314 301 FORMAT(1X,'VERTICAL SUPPORT INDUCTANCE = ',D9.4)
315 WRITE (6,302)L5
316 302 FORMAT(1X,'MODULE CAPACITANCE = ',D9.4)
317 WRITE (6,303)L6
318 303 FORMAT(1X,'MODULE SERIES RESISTANCE = ',D9.4)
319 WRITE (6,306)R2
320 306 FORMAT(D12.4)
321 WRITE(6,300)RG
322 320 FORMAT('GROUND RESISTOR = ',D8.3)
323 READ(*,320)RG
324 321 FORMAT(I5,
325 WRITE(6,306)R2
326 306 FORMAT(1X,'MODULE LEAKAGE RESISTANCE = ',D9.4)
327 WRITE(6,304)R3
328 304 FORMAT(1X,'RESISTANCE BETWEEN FOUNDATIONS = ',D9.4)
329 WRITE(6,308)RG
330 308 FORMAT(1X,'GROUND RESISTOR = ',F8.0)
331 RE=2.DO*R2
332 C
333 C COMBINED MAGNETIC & GROUND CURRENT EFFECTS
334 C MAGNETIC EFFECT
335 VOLTSM=1.D-7*GPD*DLOG(1.+AS/SD)*AMP
336 C GROUND EFFECT
337 VOLTSG=SR/4./PI*(1./SD-1./(SD+AS))*AMP
338 C
339 C DEFINE SYSTEM MATRIX
340 200 CONTINUE
341 DD 30 I=1,65
1 342 DD 30 J=1,65
2 343 A(I,J)=0
2 344 D(I,J)=0
2 345 30 CONTINUE
346 DD 31 I=1,N
1 347 A(I,I)=L1
1 348 A(I,I+N)=L2+LM
1 349 D(I,I)=R1
1 350 D(I,3*N+1)=1.D0
1 351 D(I,3*N+2)=1.D0
1 352 A(I+N,1)=LM
1 353 A(I+N,N+N)=L2
1 354 A(I+N,2*N+1)=L3
1 355 A(I+N,2*N+I)=L3
1 356 D(N+1,4*N+5)=-1.D0
1 357 DD 32 J=2*N+1,2*N+1
2 358 32 D(N+1,1)=R3
2 359 A(I*2*N+1.2*N+1)=1.D0
1 360 A(I*2*N+1.1,1)=1.D0
1 361 IF (I.EQ.N) GOTO 33
1 362 A(I*2*N+1.1,1)=-1.D0

H-16
D Line# 1  7
1 363  33 A(2*N+1+1,N+1+I)=1.DO
1 364    IF (I.EQ.N) GOTO 34
1 365    A(2*N+1+1,N+1+I)=-1.DO
1 366    A(3*N+1+1,N+1+I)=-CM
1 368    D(3*N+1+1,N+1+I)=-1./R2
1 369    D(3*N+1+1,N+1+I)=-1.DO
1 370    D(3*N+2+1,N+1+I)=-1.DO
1 371 31 CONTINUE
1 372    A(2*N+1,2*N+1)=1.DO
1 373    A(4*N+2,4*N+2)=-CM/2.DO
1 374    A(3*N+2,3*N+2)=-CM/2.DO
1 375    D(3*N+2,3*N+2)=-1.DO/RE
1 376    D(4*N+2,4*N+2)=-1.DO/RE
1 377 40 A(4*N+3,4*N+3)=1.DO
1 378    D(4*N+3,4*N+3)=-1.DO
1 379    A(4*N+4,4*N+4)=1.DO
1 380    D(4*N+4,4*N+5)=(PI/T1)**2
1 381    D(4*N+4,4*N+5)=VOLTS*(PI/T1)**2
1 382    A(4*N+5,4*N+5)=1.DO
1 383    V(4*N+5)=1.DO
1 384    V(4*N+4)=VOLTS*(PI/T1)**2
1 385 60 CONTINUE
1 386    RETURN
1 387    END

Name  Type Offset  P  Class
A    REAL*8    0    /AR1    /
AMP   REAL*8  1696
A5    REAL*8   1406
ASH   REAL*8   1498
ATA   REAL*8  1648
CM    REAL*8   44    /COMM00/   
D    REAL*8    0    /AR4    /
DLOG  INTRINSIC
DSIN  INTRINSIC
DSORT INTRINSIC
FD    REAL*8  1548
FDIA  REAL*8  1596
G     REAL*8  1892
GPD   REAL*8  1908
I    INTEGER*4  2350
J    INTEGER*4  2354
L1    REAL*8   1916
L2    REAL*8   1924
L3    REAL*8   1940
LATCH INTEGER*4  8    /COMM00/   
LM    REAL*8  1932
MSIZE INTEGER*4  0    /COMM00/   
N    INTEGER*4   4    /COMM00/   
PI    REAL*8  1868
R1    REAL*8  1956
R2    REAL*8   52    /COMM00/   
R3    REAL*8  1948
RA    REAL*8  1900
RE    REAL*8   68    /COMM00/   
RG    REAL*8  60    /COMM00/   
SD    REAL*8  1350
D Line# 1

SR REAL*8 1796
TI REAL*8 12 /COMMCO/
TINC REAL*8 20 /COMMCO/
TM REAL*8 1876
TOE REAL 1864
TDD REAL*8 1446
U REAL*8 0 /AR6 /
V REAL*8 520 /AR6 /
VOLTS REAL*8 28 /COMMCO/
VOLTSM REAL*8 36 /COMMCO/
W REAL*8 1884

388 C
389 C
390 SUBROUTINE INV
391 C MATRIX INVERSION SUBROUTINE
392 DOUBLE PRECISION Z1,Z2,A(65,65),B(65,65),C(65,65)
393 COMMON /AR1/A,/AR2/B,/AR3/C
394 COMMON MSIZE
395 C
396 DD 105 I=1,MSIZE
397 DD 105 J=1,MSIZE
398 105 B(I,J)=A(I,J)
399 CALL DET(MSIZE,Z2)
400 IF (Z2.EQ.0) GOTO 100
401 DD 120 K=1,MSIZE
402 DD 120 L=1,MSIZE
403 DD 110 J=1,MSIZE-1
404 DD 110 I=1,MSIZE-1
405 IF (I.GE.J) I1=I+1
406 IF (J.GE.L) J1=J+1
407 B(I,J)=B(I,J)+Z1/Z2*(-1)**(K+L)
408 CONTINUE
409 CONTINUE
410 CALL DET(MSIZE-1,Z2)
411 C(L,K)=C(L,K)+Z1/Z2*(-1)**(K+L)
412 CONTINUE
413 GO TO 130
414 WRITE (*,140)
415 140 FORMAT (1X,'SINGULAR MATRIX')
416 STOP
417 RETURN
418 END

Name Type Offset F Class
A REAL*8 0 /AR1 /
B REAL*8 0 /AR2 /
C REAL*8 0 /AR3 /
I INTEGER*4 2366
J INTEGER*4 2414
J INTEGER*4 2374
J INTEGER*4 2418
K INTEGER*4 2390
L INTEGER*4 2398
MSIZE INTEGER*4 0 /COMMCO/
SUBROUTINE DET(MS,Z)

SUBROUTINE TO CALCULATE THE DETERMINANT.Z. OF A MxM MATRIX.B

DOUBLE PRECISION B(65,65),E(65),Z,X

COMMON /AR2/B

Z=1

DO 110 N1=MS.2.-1

N2=1

DO 120 N3=1.N1

IF(N2.EQ.N3)GOTO 115

IF(DABS(B(N2,1)).GT.DABS(B(N3,1))) THEN

N2=N2

ELSE

N3=N2

ENDIF

115 CONTINUE

DO 130 J=1.N1

X=B(N2,J)

IF(DABS(X).LT.1.D-290)X=DSIGN(1.D-290,X)

B(N2,J)=B(I,J)

E(J)=X

IF (N2.EQ.1) THEN

X=1.

ELSE

X=-1.

ENDIF

Z=Z*X*B(I,1)

DO 160 I=2,N1

B(I-1,J-1)=B(I,J)-B(I,1)*E(J)/E(1)

160 CONTINUE

110 CONTINUE

Z=Z*B(1,1)

130 CONTINUE

140 END
SUBROUTINE TM(K9)
CALCULATE TRANSITION MATRIX INPUT EA, OUTPUT C

DOUBLE PRECISION A(65,65), B(65,65), C(65,65), D(65,65), EA(65,65)
DOUBLE PRECISION AL, T1, TINC, X, Y
COMMON MSIZE, N, LATCH, T1, TINC

C
LEXP=EXPANSION TERM LIMIT
LEXP=100
AL=EXPANSION TERM ACCURACY LIMIT
AL=1.D-6
C
CALCULATE A->AT
DO 100 I=1, MSIZE
DO 100 J=1, MSIZE
AC(I,J)=EA(I,J)*TINC
B(I,J)=A(I,J)
C(I,J)=A(I,J)
100 CONTINUE
C
CALCULATE EXPANSION TERMS
DO 110 K=2, LEXP
DO 120 I=1, MSIZE
DO 120 J=I, MSIZE
D(I,J)=D(I,J)+B(I,L)*A(L,J)
120 CONTINUE
X=0
Y=0
DO 125 I=1, MSIZE
DO 125 J=1, MSIZE
X=X+DABS(C(I,J))
Y=Y+DABS(D(I,J))
125 CONTINUE
IF (Y/X .LT. AL) GOTO 150
DO 140 I=1, MSIZE
DO 140 J=1, MSIZE
B(I,J)=D(I,J)
140 CONTINUE
RETURN
END

Name  Type  Offset  P Class
A     REAL*B  0    /AR1/
B     REAL*B  3022 /AR2/
C     REAL*B  0    /AR3/
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Name        Type   Size  Class
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AR2         REAL*8  33800 COMMON
AR3         REAL*8  33800 COMMON
AR4         REAL*8  33800 COMMON
AR5         REAL*8  33800 COMMON
AR6         REAL*8  1040  COMMON
COMMQQ       INTEGER*4 | 76  | COMMON |
DET          REAL*8  0     | COMMON |
INPAD        REAL*8  0     | COMMON |
INV          REAL*8  0     | COMMON |
LS           REAL*8  0     | COMMON |
TM           REAL*8  0     | COMMON |

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The concentrator array modeled is shown in Figure 2-5, which is reproduced in this appendix as Figure H-3 for convenient reference. The equivalent circuit model developed for this array is shown in Figure H-4. The two halves of the circuit each represent one of two adjacent arrays connected to form a source circuit (+400 volt case). Equations used to calculate equivalent circuit parameters are presented in the following section.

H.3.1 Concentrator Array Equivalent Circuit Elements

This section presents the equations used in the computer program to calculate values for the elements in the concentrator array equivalent circuit shown in Figure H-4.

For the numerical values shown in the equations, all dimensions must be in meters.
Figure H-4 Concentrator Array Equivalent Circuit Model

- L1: Module Dc Wiring Inductance
- L2: Structure Inductance
- L3: Support & Foundation Inductance
- L4: Interarray Dc Cable Inductance
- Lm: Ground Wire/Dc Cable Mutual Inductance
- R1: Module & Wiring Resistance
- R2: Module Leakage Resistance
- R3: Resistance of Ground Wire to Earth
- R4: Resistance Between Foundations
- Vn: Magnetically Induced Voltages
- Vg: Voltage Due to Ground Currents
- C1: Cell & Wiring Capacitance To Structure
- C2: Interarray Capacitance
Module Inductance: The inductance calculations for the concentrator array follow those for the flat plates. The concentrator cells and dc wiring were considered to be a single conductor with a length equal to the physical length of the dc wiring on the array. The total module inductance per section of array (L1 in Figure H-4) is given by:

\[ L_1 = 10^{-7} \times (30L + S) \times \left[ \frac{1}{2} + \ln \left( \frac{D_1}{D_2} \right) \right] \]

where

(30L + S) is the length of the conductor path in meters (L was taken as 1.46 m and S was taken as 14.3 m herein)

D1 is the effective distance (GMD) between the modules and ground plane

D2 is the self GMD of the conductor (as for the flat plates, 0.2235 (a + b), where a and b are the cross sectional dimensions of the cells and conductor)

Structure Inductance: For purposes of calculating inductance, the concentrator structure was assumed to consist of a major horizontal conductor and 30 cross member conductors (per half array section in Figure H-4). The structure inductance is then given by:

\[ L_2 = 10^{-7} \times (30L + S/2) \times \left[ \frac{1}{2} + \ln \left( \frac{D_1}{D_2} \right) \right] \]

where

L is the length of the cross members
S is the array span

D1 is the effective distance between the conductors and ground plane
D2 is the self GMD of the conductors. (To simplify calculations, the structure was considered to be a conducting cylinder with a diameter equal to the "torque tube" diameter so that the self GMD is given by 0.3894 x dia.)

Foundation Inductance: The concentrator foundation inductance (L3 in Figure H-4) is calculated by the equation previously given for the flat plate foundation.
Dc Cable Inductance: The inductance of the dc power wiring between adjacent arrays (L4 in Figure H-4) is given by:

\[ L_4 = 2 \times 10^{-7} L \ln(D1/D2) \]

where

- \( L \) is the length of the cable in meters (taken as the interarray spacing plus stubups)
- \( D1 \) is the effective distance between the wiring and ground plane.
- \( D2 \) is the self GMD of the wire (\( 0.3894 \times \text{dia.} \))

Ground Wire Inductance: For purposes of the portion of the study, it was assumed that adjacent arrays are connected by a buried, bare ground wire. The path of the wire follows that of the interarray dc cable (except buried nominally one foot above). Its inductance (L5 in Figure H-4) is calculated by the equation previously given for the dc cable.

Ground Wire/Dc Cable Mutual Inductance: The mutual inductance between the ground wire and interarray dc cable was included. This inductance (Lm in Figure H-4) is given by:

\[ L_m = 2 \times 10^{-7} L[\ln(2L/d2)-1] \]

where

- \( L \) is the length of the conductors
- \( d2 \) is distance between the conductors

Module/Structure Mutual Inductance: The mutual inductance between the modules and array structure cross members was not included because the circuit configuration tends to produce cancelling flux linkages.

Module/Structure Capacitance: The capacitances between the cells and wiring and the array structure were estimated separately and then combined as a single element.
In estimating cell capacitance, it was assumed that 1.05 inch rectangular cells were mounted on a 1/16-inch thick alumina wafer. The capacitance for one cell is then given by:

\[
C_c = e e' \frac{A}{T}
\]

where

- \(e\) is the permittivity of free space
- \(e'\) is the relative dielectric constant (9 for alumina)
- \(A\) is the cell area
- \(T\) is the thickness of the insulating wafer

The wiring was assumed to continue to the next cell with a one-inch-wide strip with air insulation. Applying the foregoing equation for capacitance indicated the wiring only adds about 5% to the total capacitance and could be ignored within the accuracy of the assumptions for the effort. (However, this factor was left in place in the computer program.)

Figure H-4 shows two types of capacitances, \(C_1\) and \(C_2\). As with the flat plate arrays, the end capacitance, \(C_1\), represent half the capacitance of each section of the array apportioned to each end. The center sections have two such capacitance, \(C_2\), from adjacent sections. Thus \(C_2 = 2 \times C_1\).

Module Resistance: As for the flat plates, the module resistance (\(R_1\) in Figure H-4), was estimated by assuming 0.01 inch thick, 1.5 ohm-cm cells.

Module Leakage Resistance: The estimate of concentrator of module leakage resistances is based on the same cell/alumina wafer assumption used to estimate module capacitance. Both surface and volume resistance were calculated. These calculations showed the surface resistance to be about three orders of magnitude lower than the volume resistance for the assumptions made.
To calculate the surface resistance, it was assumed that the alumina wafer extended 1/4-inch past the cell and had a surface resistivity of $10^9$ ohms per square. This typical resistivity for alumina is for 90% relative humidity and a clean, dry surface. The calculated surface resistance for 14 cells and 30 modules is approximately $10^5$ ohms. The calculated volume resistance approximately $5 \times 10^8$ ohms. Thus, the parallel combination (R2 in Future H-4) is equal to the surface resistance, $1.2 \times 10^5$ ohms.

As with the flat plate, end resistors were shunted by terminal protection devices and midpoint resistances were shunted in computer runs evaluating midpoint grounded cases.

**Ground Wire Resistances:** As mentioned, it was assumed that adjacent arrays are connected by a bare ground wire. This wire has a resistance to earth given by:

$$ R = \frac{R_s}{\pi S} \left[ \ln \left( \frac{2S}{D} \right) - 1 \right] $$

where

- $R_s$ is the soil resistivity in ohm-meters
- $S$ is the spacing between arrays
- $D$ is the diameter of the wire (4/0 wire assumed)
- $H$ is the depth of burial (3 feet assumed)

This resistance was assumed to be apportioned between the two resistors shown in the equivalent circuit so that $R_3 = 2R$.

**Foundation Resistances:** The resistance between concentrator foundations is estimated by the equation given for the flat plate arrays.

**H.3.2 Computer Program**

The computer program used for analyzing the concentrator array equivalent circuit model is listed on the following pages. The subroutines for calculating the transition matrix, determinant, and inverse are identical to those in the flat plate array program and are not repeated with the concentrator program listing.

H-27
Model effects of lightning-induced surges using transition matrix

CONCENTRATOR VERSION

DOUBLE PRECISION A(65,65),B(65,65),C(65,65),D(65,65),EA(65,65)
DOUBLE PRECISION U(65),V(65),T1,T2,TC,TINC,P1,VOLTSG,VOLTSM
DOUBLE PRECISION CM,RO,R2,RV,RE,RE1,RE2,RG,ENERGY,CL,VC
DOUBLE PRECISION CL,CLM,VX1,VX2
REAL TUS,UP(65),UM(65)

INTEGER CLAMP,W,Al
CHARACTER P1,P2

COMMON MSIZE,TINC,T1,VOLTSG,VOLTSM,CM,R2,RG,RE,RE1,RE2,SR
OPEN(6,FILE='PRN',STATUS='NEW')

WRITE(*,1)
FORMAT(1X,'OUTPUT TO DISK =1, TO PRINTER =2, BOTH =3, NEITHER =4
A ? ',\)
READ(*,21)W
GOTO(111.112,111,112)W

PAUSE 'INSERT BLANK,FORMATTED DISK FOR DATA OUTPUT IN DRIVE A'
CONTINUE
WRITE(*,11)
FORMAT(1X,'INCLUDE VOLTAGE CLAMP (1=YES 2=NO )',\)
READ(*,21)CLAMP

MSIZE=24
LATCH=1
2 FORMAT(1X,'LATCH=',11)
KOUNTE=0
KCOUNT=0
KPRINT=5
ENERGY=0
T=0
35 C T1=Time to stroke crest
36 T1=1.5D-6
37 C T2=Time for stroke decay to half magnitude X 2
38 T2=50.D-6*2.0D
39 C TC=Time period over which calculations are made
40 TC=200.D-6
41 C TINC=Time increments
42 TINC=0.02D-6
43 C TUS=Time in microseconds
44 PI=3.14159265400
45 PI=15
P2=18
88 FORMAT(1X,A1)
WRITE(6,88)P2

DO 5 I=1,65
1 U(I)=0
1 V(I)=0
1 UP(I)=0
1 UM(I)=0
1 DD 5 J=1,65
2 A(I,J)=0
2 B(I,J)=0
2 C(I,J)=0
2 D(I,J)=0
EA(I,J) = 0
CONTINUE

IF(CLAMP.EQ.2) GOTO 24
WRITE(*,12)
FORMAT(1X,'CLAMP VOLTAGE = \13)
READ(*,23)VC

23 FORMAT(F10.0)

A1 = 30
CAL = 1.D-3/VC**A1
CONTINUE

WRITE(6,'(6.8)VC, A1')
FORMAT(2X,'VC = ',F6.0,' Volts, a = ',13)
RO = I./(I.0-3/VC+1./R2)
GOTO 9

7 WRITE(6,'(17H NO VOLTAGE CLAMP)')
CONTINUE

WRITE(6,88)
WRITE(6,89)
WRITE(6,87)

89 FORMAT('0', ' Time -- Module Currents -- Str.Curs. Gwire
AFound.Curs. -- Insulation Voltages -- Vg Vm
B Energy'遭到)
87 FORMAT(' usec. 1 2 3 4 5 6 7 8 9 10
A 17 18 11 12 13 14 15 16 17 20
B joules')

94 INVERT MATRIX = 1, INVERT TO FILE = 2, READ = 3
99 READ(*,14)INVM
14 FORMAT(1I)
17 WRITE(*,9H CALL INV)
D Line# 1

1

119 IF(INVM.EQ.1)GOTO 18
120 OPEN(8,FILE='MATC.BIN',FORM='BINARY')
121 DO 19 I=1,MSIZE
122 19 WRITE(8),(EA(I,J),J=1,MSIZE)
123 CLOSE(8)
124 18 CONTINUE
125 OPEN(22,25,25,25)W
126 DO 25 I=1,MSIZE
127 25 CONTINUE
128 C Calculate transition matrix
129 WRITE(*,'(23H CALL TRANSITION MATRIX)')
130 CONTINUE
131 WRITE(*,'(26H EXPANSION TERMS)')
132 WRITE(*,'(26H LATCH')
133 WRITE(*,'(26H CALLING)')
134 CONTINUE
135 IF(T.LT.T1+T2)GOTO 60
136 LATCH=2
137 IF(T.LT.T1)GOTO 60
138 EA(21,20)=-(PI/T2)**2
139 EA(24,23)=-(PI/T2)**2
140 V(21)=0
141 V(22)=VOLTS*2.DO
142 V(23)=0
143 V(24)=-VOLTS*(PI/T2)**2
144 GOTO 25
145 WRITE(*,'(26H CAL/CM/RE1')
146 K=2
147 EA(11,11)=-1.DO/CM/RE1
148 IF(VXI*V(11))=1.DO/CM/RE1
149 K=2
150 IF(DABS(V(11)).LT.VC).AND. RE1.GT.R0/2.)GOTO 62
151 IF(DABS(V(11)).GT.1.5*VC).AND. RE1.LT.1.1)GOTO 62
152 IF(DABS(VX1-V(11)).LT.1.)GOTO 62
153 RV=1.DO/CM/DABS(V(11))**2(A1-1)
154 RE1=1.DO/(1.DO/RV+.5DO/R2)
155 IF(RE1.LT.1.DO)RE1=1.DO
156 EA(11,11)=-1.DO/CM/RE1
157 K=2
158 IF(VXI*V(11))=1.DO/CM/RE1
159 K=2
160 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
161 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
162 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
163 RV=1.DO/CM/DABS(V(16))**2(A1-1)
164 RE2=1.DO/(1.DO/RV+.5DO/R2)
165 IF(RE2.LT.1.DO)RE2=1.DO
166 EA(16,16)=-1.DO/CM/RE2
167 K=2
168 VX2=V(16)
169 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
170 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
171 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
172 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
173 RV=1.DO/CM/DABS(V(16))**2(A1-1)
174 RE2=1.DO/(1.DO/RV+.5DO/R2)
175 IF(RE2.LT.1.DO)RE2=1.DO
176 EA(16,16)=-1.DO/CM/RE2
177 K=2
178 VX2=V(16)
179 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
180 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
181 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
182 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
183 RV=1.DO/CM/DABS(V(16))**2(A1-1)
184 RE2=1.DO/(1.DO/RV+.5DO/R2)
185 IF(RE2.LT.1.DO)RE2=1.DO
186 EA(16,16)=-1.DO/CM/RE2
187 K=2
188 VX2=V(16)
189 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
190 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
191 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
192 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
193 RV=1.DO/CM/DABS(V(16))**2(A1-1)
194 RE2=1.DO/(1.DO/RV+.5DO/R2)
195 IF(RE2.LT.1.DO)RE2=1.DO
196 EA(16,16)=-1.DO/CM/RE2
197 K=2
198 VX2=V(16)
199 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
200 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
201 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
202 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
203 RV=1.DO/CM/DABS(V(16))**2(A1-1)
204 RE2=1.DO/(1.DO/RV+.5DO/R2)
205 IF(RE2.LT.1.DO)RE2=1.DO
206 EA(16,16)=-1.DO/CM/RE2
207 K=2
208 VX2=V(16)
209 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
210 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
211 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
212 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
213 RV=1.DO/CM/DABS(V(16))**2(A1-1)
214 RE2=1.DO/(1.DO/RV+.5DO/R2)
215 IF(RE2.LT.1.DO)RE2=1.DO
216 EA(16,16)=-1.DO/CM/RE2
217 K=2
218 VX2=V(16)
219 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
220 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
221 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
222 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
223 RV=1.DO/CM/DABS(V(16))**2(A1-1)
224 RE2=1.DO/(1.DO/RV+.5DO/R2)
225 IF(RE2.LT.1.DO)RE2=1.DO
226 EA(16,16)=-1.DO/CM/RE2
227 K=2
228 VX2=V(16)
229 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
230 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
231 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
232 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
233 RV=1.DO/CM/DABS(V(16))**2(A1-1)
234 RE2=1.DO/(1.DO/RV+.5DO/R2)
235 IF(RE2.LT.1.DO)RE2=1.DO
236 EA(16,16)=-1.DO/CM/RE2
237 K=2
238 VX2=V(16)
239 IF(DABS(V(16)).LT.VC).AND. RE2.GT.R0/2.)GOTO 63
240 IF(DABS(V(16)).GT.1.5*VC).AND. RE2.LT.1.1)GOTO 63
241 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
242 IF(DABS(VX2-V(16)).LT.1.)GOTO 63
243 RV=1.DO/CM/DABS(V(16))**2(A1-1)
244 RE2=1.DO/(1.DO/RV+.5DO/R2)
245 IF(RE2.LT.1.DO)RE2=1.DO
246 EA(16,16)=-1.DO/CM/RE2
247 K=2
248 VX2=V(16)
DO 70 I=1,MSIZE
1 183 U(I)=0
1 184 DO 70 J=1,MSIZE
2 185 U(I)=U(I)+C(I,J)*V(J)
2 186 CONTINUE
1 187 CL=U(11)/REl
1 188 IF(DABS(CL).GT.DABS(CLM)) CLM=CL
1 189 ENERGY=ENERGY+U(11)**2/REl*TINC
1 190 T=T+TINC
1 191 IF(W.EQ.4)GOTO 85
1 192 TUS=T*1.D6
1 193 DO 71 I=1,MSIZE
1 194 UP C(I) =U(I)
1 195 GOTO(72,73,72,65)W
1 196 KCOUNT=KCOUNT+1
1 197 IF(KCOUNT.NE.5) GOTO 73
1 198 KCOUNT=0
1 199 WRITE(7,74) TUS
2 200 CONTINUE
2 201 DO 74 N=1,16
2 202 WRITE(7,80)U(I)
2 203 CONTINUE
2 204 WRITE(7,81) CL
2 205 IF(KCOUNT.NE.KPRINT) GOTO 85
2 206 CONTINUE
2 207 KOUNT=KCOUNT+1
2 208 IF(T.GE.4*T1) KPRINT=50
2 209 IF(KCOUNT.NE.KPRINT) GOTO 85
2 210 WRITE(6,75)TUS, (UP(I), I=1,5), UP(7), UP(8), UP(10), UP(17), UP(18),
2 211 UP(I), J=1,16), UP(20), UP(23)
2 212 WRITE(6,76)ENERGY, CL
2 213 WRITE(6,77)ENERGY, CL
2 214 WRITE(6,78)ENERGY, CL
2 215 KOUNT=0
2 216 B5 CONTINUE
2 217 DO 95 I=1,MSIZE
2 218 IF(DABS(U(I)).GT.DABS(UM(I))) UM(I)=U(I)
2 219 V(I)=U(I)
2 220 WRITE(*,91) T*1.D6, U(11)
2 221 IF(W.EQ.4) GOTO 30
2 222 WRITE(6,92)P2
2 223 WRITE(6,93)ENERGY
2 224 IF(W.EQ.4) GOTO 100
2 225 WRITE(6,94)ENERGY
2 226 WRITE(6,95)ENERGY IN CLAMP = .D10.4. Joules'
2 227 WRITE(6,96) (ISH MAXIMUM VALUES)' )
2 228 DO 94 I=1,24
2 229 WRITE(6,97)I, UM(I)
2 230 CONTINUE
2 231 FORMAT(1X,F7.0,F3.0)
2 232 WRITE(6,98) CLM
2 233 330 FORMAT(1X, 'CLAMP CURRENT ', F7.1)
2 234 STOP
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237 C
SUBROUTINE INPAD

Read, calculate, and print input parameters

DOUBLE PRECISION A(65,65), D(65,65), U(65), V(65)

DOUBLE PRECISION SD, AS, TTD, ASH, TM, FD, FDA, ATA, AMP, L1, L2, L3, L4, LG

DOUBLE PRECISION ASP, SR, GPD, F1, R1, R2, RA, RG, RE, RE1, RE2, CM, CS, LM

DOUBLE PRECISION T1, TINC, VOLTSM, VOLTSF, F1, F2, F3, F4

DOUBLE PRECISION RS, RSURFACE, RVOLUME, CELLS, CWIRE


COMMON MSIZE, TINC, T1, VOLTSG, VOLTSM, CM, R2, RG, RE, RE1, RE2, SR

READ, SET & WRITE INPUT PARAMETERS

100 CONTINUE

WRITE(6,1)

1 FORMAT('1', 'LIGHTNING-INDUCED SURGES')

WRITE(6,2)

2 FORMAT(1X, 'CONCENTRATOR ARRAYS')

WRITE(*,10)

10 FORMAT(1X, 'STRIKE DISTANCE (IN FEET) = ', F7.0, ' FEET')

READ(*,11) SD

11 FORMAT(F6.0)

WRITE(6,13) SD

13 FORMAT('0', 'STRIKE DISTANCE = ', F7.0, ' FEET')

ATA=35.

WRITE(6,114) ATA

114 FORMAT(1X,'ARRAY TILT ANGLE = ', F4.0)

AS=44.2

WRITE(6,14) AS

14 FORMAT(1X, 'ARRAY WIDTH = ', F5.1, ' FEET')

ASP=47.

WRITE(6,115) ASP

115 FORMAT(1X,'ARRAY SPACING = ', F5.0)

TTD=12.

WRITE(6,15) TTD

15 FORMAT(1X, 'TORQUE TUBE DIAMETER = ', F6.2, ' INCHES')

ASH=10.

WRITE(6,16) ASH

16 FORMAT(1X, 'ARRAY SLANT HEIGHT = ', F3.0, ' FEET')

FD=11.5

WRITE(6,17) FD

17 FORMAT(1X, 'FOUNDATION DEPTH = ', F5.1, ' FEET')

FDIA=10.

WRITE(6,18) FDIA

18 FORMAT(1X, 'FOUNDATION DIAMETER = ', F5.1, ' INCHES')

AMP=1.405

WRITE(6,21) AMP

21 FORMAT(1X, F7.0, ' AMPS PEAK IN LIGHTNING STROKE')
WRITE(*,23)
23 FORMAT(1X,'SOIL RESISTIVITY ( in ohm-meters ) = ',A)
READ(*,11)SR
WRITE(*,6.27)SR
27 FORMAT(1X,F6.1,' OHM-METER SOIL RESISTIVITY')
CONVERT PARAMETERS TO METRIC
SD=SD*.3048
AS=AS*.3048
TD=TD/.3048
ASH=ASH*.3048
ASP=ASP*.3048
FD=FD*.3048
FDIA=FDIA/.3048
PI=3.141592654D0
RA=(1.05+.01)*.2235D0/12.*.3048
ATA=ATA/PI/180.

EFFECTIVE GROUND PLANE DEPTH ( SPACING )
GPD=12.18*.3048+F/2.

MODULE INDUCTANCE
L1=1.D-7*(30.*1.46+AS/2.)*(.5D0+2.D0*DLOG(GPD/RA))
TORQUE TUBE INDUCTANCE
L2=1.D-7*(30.*1.46+AS/2.)*(.5D0+2.D0*DLOG(GPD/TTD/.3894D0))

VERTICAL SUPPORT INDUCTANCE
L3=4.D-7*GPD*DLOG(AS/FDIA*2.)

POWER WIRE INDUCTANCE
L4=2.D-7*(ASP+ASH)*DLOG((11.5D0/2.-2.)/(1.05/12.*.3894))
GROUND WIRE INDUCTANCE
LG=2.D-7*(ASP+3.*.3048)*DLOG((11.5D0/2.-3.)/(1.05/12.*.3894))

GROUND/POWER WIRE MUTUAL INDUCTANCE
LM=2.D0*(ASP+ASH)*(DLOG(2.D0*(ASP+ASH)/.3048)-1.D0)

RESISTANCE BETWEEN FOUNDATIONS
R=SR/PI/F*DLOG((4.4ASP-FDIA)/FDIA)

GROUND WIRE RESISTANCE
RS=2.*SR/F/ASP*(DLOG(2.*ASP/DSORT(.46D0/12.*.3.3048)-1.)

MODULE LEAKAGE RESISTANCE
RSURFACE=1.D9*.25/(.4*(1.05+.25))/14/30
R=VOLUME/.1D1*.062/(1.05**2*12.*.3048)/14/.30.
R2=1./(1./RSURFACE+1./RVOLUME)

MODULE SERIES RESISTANCE
R1=(1.5D-2*TH/(1.05/12.*.3048)**2+1.D-6*1.05/12.*.3048*.42)*14.*30

MODULE CAPACITANCE
CCELL8=1.D-9/36./PI*9.*1.05**2*.062/12.*.3048*14.*15.
D Line# 1

356 CWIRE=1.D-9/36./PI*(1.05+.42)**2*14.*15.
357 CM=CELLS+CWIRE
358 C ARRAY CAPACITANCE
359 C CS=2.D-9/36./PI*DSORT(ASH/(ASF-AS))
360 C
361 C WRITE(6,305)L1
362 305 FORMAT('O', 'MODULE INDUCTANCE = ',E12.4)
363 WRITE(6,300)L2
364 300 FORMAT(1X,'TORQUE TUBE INDUCTANCE = ',E12.4)
365 WRITE(6,301)L3
366 301 FORMAT(1X,'VERTICAL SUPPORT INDUCTANCE = ',E12.4)
367 WRITE(6,307)L4
368 307 FORMAT(1X,'POWER WIRE INDUCTANCE = ',E12.4)
369 WRITE(6,302)CM
370 302 FORMAT(1X,'MODULE CAPACITANCE = ',E12.4)
371 WRITE(6,303)L1
372 303 FORMAT(1X,'MODULE SERIES RESISTANCE = ',E12.4)
373 WRITE(6,306)R1
374 306 FORMAT(1X,'MODULE LEAKAGE RESISTANCE = ',E12.4)
375 WRITE(6,308)RG
376 308 FORMAT(1X,'GROUND RESISTOR = ',E12.4)
377 RE=2.DO*R2
378 RE1=RE
379 RE2=RE
380 C MAGNETIC EFFECT
381 F=DLOG(1.+21/SD)
382 F1=DLOG(1.+21/(SD-ASF/2.-AS/2.))/F
383 F2=DLOG(1.+21/(SD-ASF/2.))/F
384 F3=DLOG(1.+21/(SD+ASF/2.))/F
385 F4=DLOG(1.+21/(SD+ASF/2.+AS/2.))/F
386 VOLTSM=1.D-7*1.46*DSIN(ATA)*AMP*F*30
387 C GROUND EFFECT
388 VOLTSG=SR/4./PI*(1./SD-1./(SD+ASF))*AMP
389 C
390 C DEFINE SYSTEM MATRIX
391 A(1,1)=L1
392 A(1,6)=L2
393 A(2,2)=L1
394 A(2,7)=L2
395 A(3,3)=L4
396 A(3,10)=LM
397 A(4,4)=L1
398 A(4,9)=L2
399 A(5,5)=L1
400 A(5,9)=L2
401 A(6,1)=1.
402 A(6,6)=1.
\begin{verbatim}
D Line# 1
415  A(7.2)=1.
416  A(7.4)=-1.
417  A(7.7)=1.
418  A(7.8)=-1.
419  A(8.3)=-LM
420  A(8.7)=L2
421  A(8.8)=L2
422  A(8.10)=-LG
423  A(9.5)=1.
424  A(9.9)=1.
425  A(10.3)=LM
426  A(10.10)=LG
427  A(10.17)=-L3
428  A(10.18)=L3
429  A(11.11)=CM
430  A(12.12)=CM#2.
431  A(13.13)=CM
432  A(14.14)=CM
433  A(15.15)=CM#2.
434  A(16.16)=CM
435  A(17.17)=L3/RS
436  A(18.18)=L3/RS
437  A(19.19)=CS
438  A(20.20)=1.
439  A(21.21)=1.
440  A(22.22)=1.
441  A(23.23)=1.
442  A(24.24)=1.
443  D(1.1)=R1
444  D(1.11)=-1.
445  D(1.12)=1.
446  D(1.22)=F1
447  D(2.2)=R1
448  D(2.12)=-1.
449  D(2.13)=1.
450  D(2.23)=F2
451  D(3.13)=-1.
452  D(3.14)=1.
453  D(3.19)=-1.
454  D(4.4)=R1
455  D(4.14)=-1.
456  D(4.15)=1.
457  D(4.23)=F3
458  D(5.5)=R1
459  D(5.15)=-1.
460  D(5.16)=1.
461  D(5.23)=F4
462  D(8.19)=1.
463  D(10.2)=R
464  D(10.7)=R
465  D(10.10)=R
466  D(10.20)=-1.
467  D(11.1)=1.
468  D(11.11)=1./RE1
469  D(12.1)=-1.
470  D(12.2)=-1.
471  D(12.12)=1./R2
472  D(13.2)=1.
473  D(13.3)=1.
\end{verbatim}
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H.4 EQUIVALENT CIRCUIT DRIVING VOLTAGES

As previously mentioned, ground current and magnetic coupling effects are incorporated into the computer model. The equations used to represent these effects are discussed in this section.

The ground currents flowing through the soil set up a potential gradient (i.e., voltage) along the arrays as shown in Figure H-5. The voltage is given by:

\[ V_g(t) = \frac{R_s}{2\pi} \left( \frac{1}{D} + \frac{1}{S+D} \right) I(t) \]

where
- \( R_s \) is the resistivity of the soil (in ohm-meters)
- \( D \) is the distance to the lightning strike (in meters)
- \( S \) is the distance between adjacent foundations (in meters)
- \( I(t) \) is the lightning strike current

The equation assumes a uniform soil and a distance to the strike large enough to make any soil ionization effects negligible.

The magnetic fields setup by the lightning current couple to conducting loops in the arrays. This effect is illustrated in Figure H-2 for the flat plate array and in Figure H-2 for the concentrator. The induced voltage is given by:

\[ V_m(t) = \mu \frac{H}{2\pi} \ln \left( 1 + \frac{S}{D} \right) \frac{dI(t)}{dt} \]

where
- \( \mu \) is the permeability of free space (4\( \pi \times 10^{-7} \) henry/meter)
- \( M \) is the height of the loop (in meters)
- \( S \) is the width of the loop (in meters)
- \( D \) is the distance to the strike
- \( I(t) \) is the lightning current
HEMISPHERICAL EQUIPOTENTIALS IN SOIL

Figure H-5. Ground Current Effects

MAGNETIC FIELD LINES

Figure H-6. Magnetic Effects - Flat Plate

MAGNETIC FIELD LINES

Figure H-7. Magnetic Effects - Concentrator
For purposes of calculating magnetic coupling effects on the flat plate array it was assumed that the modules and dc circuit could be represented by an equivalent single conductor with an average height above grade equal to the height of the torque tube. It was further assumed that the effective ground plane is below grade slightly more than half way down the embedded length of the foundation (to account for end effects). This assumption allows combining the magnetic and ground current effects into a single source for the flat plate array.

For the concentrator array, it was assumed that "the" loop for magnetic coupling is made up of the loops formed by the dc wiring pattern shown in Figure H-7. These loops are not necessarily perpendicular to the magnet fields. Therefore the equation for the magnetically induced voltage must be multiplied by the sine of the array tilt angle. Stowing the array in a horizontal position would virtually eliminate magnetic coupling. Stowing the array vertically will, of course, maximize the detrimental effects of a ground strike.

Both the ground current and magnetically induced voltages are related to the lightning strike current, $I(t)$, as indicated by the foregoing equations. Ranges of parameters used to characterize lightning are shown in Table H-1. The general approach used in selecting parameters to use for the present study was to conservatively use a worst case parameter combination, but not quite the maximum values recorded. The peak current used for calculations was 140 kiloamps. This value is approximately ten times the typical value and about half the maximum. Approximately one percent of the lightning strikes will exceed the 140 kiloamps. A time to peak current of 1.5 microseconds and time to decay to half value of 50 microseconds were used to correspond to typical test parameters.
Table H-1

LIGHTNING PARAMETERS

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<td>Time to Peak Current (microseconds)</td>
<td>.5</td>
<td>1.5-2</td>
<td>30</td>
</tr>
<tr>
<td>Rate of Rise (kiloamps/microsecond)</td>
<td>1</td>
<td>20</td>
<td>210</td>
</tr>
<tr>
<td>Time to Decay to Half of Peak Current</td>
<td>10</td>
<td>40-50</td>
<td>250</td>
</tr>
<tr>
<td>(microseconds)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strokes per Flash</td>
<td>1</td>
<td>2-4</td>
<td>26</td>
</tr>
<tr>
<td>Time Between Strokes (milliseconds)</td>
<td>3</td>
<td>40-60</td>
<td>100</td>
</tr>
</tbody>
</table>

The time between strikes did not directly impact the calculations since the array circuit is essentially returned to its initial state before the next strike. The rate of rise is discussed below.

There are several generally similar waveshapes commonly used to approximate lightning strike currents. Two waveshapes, the double exponential and sinusoidal, were evaluated. These are shown in Figures H-8 and H-9. The expanded time scale in Figure H-9 shows the initial portion of the double exponential waveshape to have a very steep initial rate of rise. The leads to very high magnetic fields and could be expected to produce higher array voltages than the sinusoidal waveshape which as a lower rate of rise by about a factor of four. However, this was found not to be the case. Using the exponential lightning waveshape in the computer solution lead to lower peak array voltages. It is believed that this is due to the frequency components of the sinusoidal waveshape being closer to the resonant frequencies of the arrays (both concentrator and flat plate). Also the sinusoidal initial portion of the waveshape corresponds more closely to test waveshape illustrated in ANSI and IEEE standards. Thus, it was decided to use the sinusoidal waveshape in the rising portion of the lightning current waveshape.
Figure H-8. Lighting Stroke Current Waveshapes

Figure H-9. Lighting Stroke Current Waveshapes -- Expanded Scale
The two waveshapes could have been combined with an initial sinusoidal rise and exponential decay. However, the two waveshapes are relatively similar in the region of interest (20 to 30 microseconds past the peak current) where peak array voltages and maximum terminal protection device currents were found to occur. Thus, the sinusoidal waveshape was carried into the region past the peak current.

H.5 TERMINAL PROTECTION DEVICES

As discussed in Section 5.8, two types of terminal protection devices (TPDs) were evaluated in detail. These were metal oxide varistors and silicon avalanche diodes. Details on the modeling of these TPD are presented in this section.

H.5.1 Metal Oxide Varistors

Metal oxide varistors are nonlinear devices whose resistance decreases with applied voltage. Over its operating range the current through such TPDs is generally expressed as:

\[ I = kV^a \]

The exponent, \( a \), determines the sharpness of the voltage clamping effect and is often used a figure of merit in comparing such devices. This exponent generally ranges from 15 to 30 for commercially available devices. The proportionality constant, \( k \), can be determined from the "varistor voltage" given in vendor literature. Usually this is the voltage which causes a current of 1 milliamp to flow.

The characteristics of a commercially available device were modeled for the present study. The device selected was the General Electric V420LA20A (Ref. 5-7). Selection was based on considerations discussed in Section 5.8. Similar devices are available from several other manufacturers. The varistor voltage of the V420LA20A is given as 680 volts, with a range of 610 to 748 volts. The maximum continuous dc voltage is specified to be 560 volts, a factor which governed selection of this model in the series.
The voltage-current characteristics of the selected device are shown in Figure H-10. As near as could be determined from curves in the manufacturer's literature (Ref. 5-7), the exponent of this particular device is 30. This value is the upper end of the range for MOVs in this series and most other similar MOVs. The figure also shows the current given by the equation used in the computer program. As can be seen, there is a disagreement between the two curves in the high current region. The manufacturer's literature states that "The curve departs from the nonlinear relation and approaches the value of the material bulk resistance, about 1 to 10 ohms." The more optimistic 1 ohm limit was used in the computer program. At low currents, (e.g., below, .05 amps) the resistance of the MOV becomes negligible because it is paralleled by the leakage resistance of the module. The manufacturer's suggested model of the MOV also includes a shunt capacitance and series inductance. These were not included in the computer model because initial calculations showed their values to be negligibly small compared to module capacitances and inductances.
The curve given by the manufacturer's literature is for the upper end of the tolerance range. The equation used was adjusted to the midrange value. Thus again it is pointed out that manufacturing tolerances can result in performance better or worse than calculated herein. Because of this inherent uncertainty, temperature corrections where not applied to the MOV characteristics.

H.5.2 Silicon Avalanche Diodes

Silicon avalanche diodes have characteristics similar to metal oxide varistors. However, they generally have a higher voltage exponent and thus a sharper clamping voltage effect, particularly at low currents.

Since diodes are unidirectional, two diodes must be used to clamp the oscillatory voltages in this application. The commercially available device selected for the computer modeling incorporates two diodes onto a single die. The device selected is the DSAS 07-2 from Brown Bovari Corp. Although the search was not exhaustive, no similar device at the requisite voltage level was found to be available from other manufacturers.

The voltage-current characteristics of this device (Ref. 5-8) are shown in Figure H-11. The curve in the manufacturer's literature was extrapolated as indicated by the dashed line. The curve used in the computer program matches that of the manufacturer within the accuracy of the drawing. This was done by breaking the curve into four regions with $a = \infty$, 78, 34 and 14.

As can be seen by comparing Figures H-10 and H-11, the diode more closely approximates an ideal voltage clamp. (Note also the expanded vertical scale in Figure H-11.) The curve shown is for the lower end of the manufacturing tolerance range. As with the MOV, the curve used was adjusted to the middle of the manufacturing tolerance range and temperature corrections were not applied.
Figure H-11. Diode Characteristics