SOLAR PHOTOVOLTAIC DC SYSTEMS: BASICS AND SAFETY

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Peter McNutt, MSEE PE
Senior Member, IEEE
NREL
15013 Denver West Pkwy
Golden, CO 80401
USA
peter.mcnutt@nrel.gov

William R. Sekulic, BSEE PE
Member, IEEE
NREL
15013 Denver West Pkwy
Golden, CO 80401
USA
bill.sekulic@nrel.gov

Gary Dreifuerst, PhDEE
Life Member, IEEE
LLNL (retired)
1083 Eve Lane
Livermore, CA 94550
USA
gdreifuerst@gmail.com

Abstract – Solar photovoltaic (PV) systems are common and growing, with 42.4 GW of installed capacity currently in the United States and nearly 15 GW added in 2016. This paper will help electrical workers and firefighters understand some basic operating principles and hazards of PV DC arrays. We briefly discuss the effects of solar radiation and temperature on power output; PV module testing standards; methods for calculating the number of modules in a PV string; some National Electrical Code guidelines that are aimed toward improving array safety; DC array commissioning, periodic maintenance, and testing; arc flash hazard potential; ways firefighters can and do work safely around PV arrays; potential risk posed by moonlight and other light sources; and some unique DC-system hazards. We also present some statistics on PV DC array electrical incidents and injuries.

Index Terms — Photovoltaic DC System, Firefighters, PV Electrical Safety.

I. INTRODUCTION

During the 2017 IEEE ESW, a presentation was given on the "Hazards in the Installation and Maintenance of Solar Panels" [1]. The talk generated a lot of good and interesting questions about solar/photovoltaic (PV) systems, including:

- Do all PV strings have the same number of modules?
- Why would workers be exposed to hazardous DC voltages in a PV system?
- Can a moonlit PV array generate lethal voltages?

PV systems are common and growing, with 42.4 GW of installed capacity currently in the United States and nearly 15 GW added in 2016 [2]. This paper describes only the DC side of solar/PV systems. We touch briefly on electrical safety basics for PV DC systems. This paper summarizes and references other papers and studies, allowing readers—primarily firefighters—to consult reports that present data on how to best interact safely with PV arrays in emergency situations.

This paper is not highly technical; instead, this is a survey of reports that present technical data about which types of alternative light sources might produce hazardous voltages and currents from PV arrays. We also present data that might help firefighters minimize the risk of electric shock while fighting fires around PV arrays. The appendix includes references and training resources that will help firefighters understand and mitigate electrical hazards in PV arrays.

The paper also gives a brief overview of the rigorous PV module qualification tests that have been developed since the mid-1970s. These tests have led to reliable and safe modules with life expectancies exceeding 20 years.

II. PV ARRAY OPERATING CHARACTERISTICS

Fig. 1 shows a typical current-voltage (I-V) curve for an individual PV module. The maximum power point (Pmp) is on the I-V curve at the intersection of the maximum power current (Imp) and maximum power voltage (Vmp). The short-circuit current (Isc) is approximately 10% more than the operating or maximum power current (Imp). The significance of this is that Isc for a single string will not blow the fuse. String fuses are provided to protect the modules in the strings from being damaged by back-feeding faults from the system.

Most PV systems consist of multiple modules in strings and several strings connected in parallel. This generalized curve can be scaled up depending on the number of series and parallel modules in an array. An array's rated open-circuit voltage (Voc) is the number of modules in series multiplied by Voc for a single module. An array's Isc is the number of parallel strings multiplied by Isc for a single module. The array's nameplate power is the number of modules in the array multiplied by Pmp for a single module.

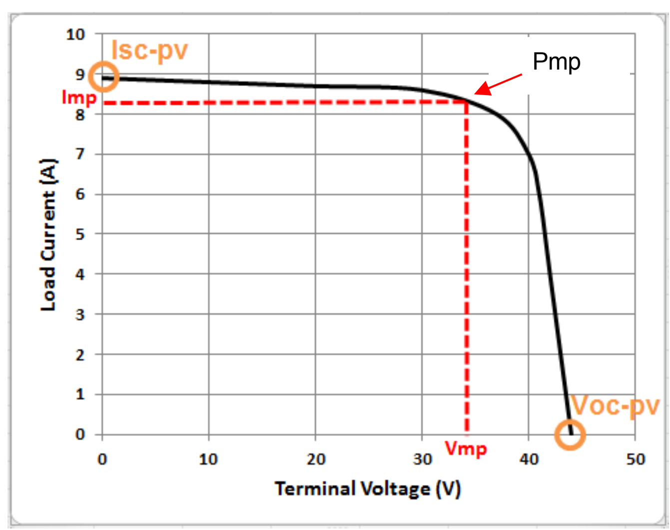

Fig. 1 Typical I-V curve for a PV module

The nameplate output of a module is specified at standard test conditions (STC) under controlled laboratory conditions: STC are 1,000 W/m^2 irradiance (solar intensity), 25°C cell temperature (temperature of the cell inside the module as distinguished from air temperature), and an air mass of 1.5 (the angle or thickness of the atmosphere through which the sunlight travels). During normal operation, cell temperature can be significantly warmer than the air temperature.

The output of the PV array is affected by the solar irradiance and array temperature. In Fig. 2, the current is directly affected by the irradiance. As an example in the Denver, Colorado, area, the solar irradiance might reach 1,100 W/m^2 at solar noon on a clear summer day. If the irradiance were reduced to 500 W/m^2 (one-half of STC), the output current for the module or array would also be reduced by one-half (a characteristic that can be used to actually determine solar irradiance).

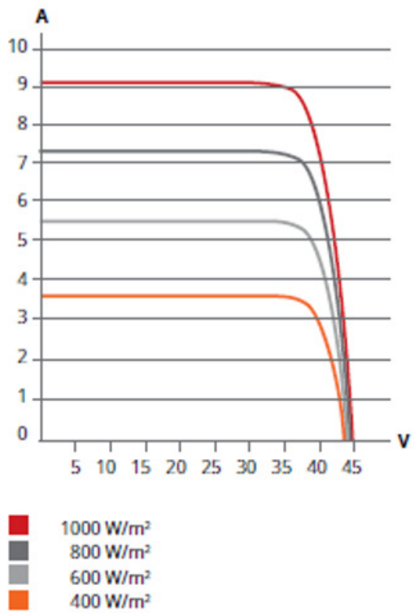

Fig. 2 Solar irradiance effect on module current

What surprises some people is that the output of a PV array is inversely affected by temperature: a lower temperature produces a higher voltage (Fig. 3) as well as more power output. Arrays produce more power in cooler locations. Also, arrays with better air/wind circulation produce more power.

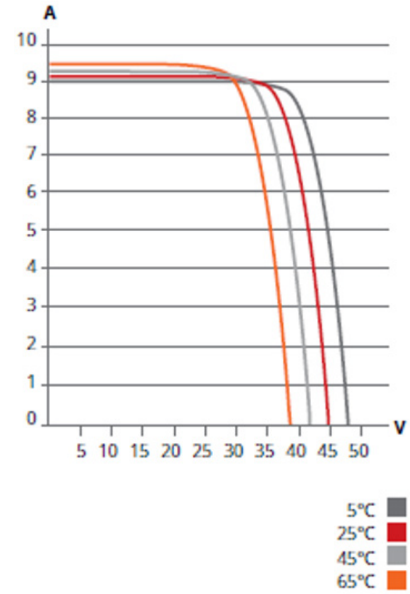

Fig. 3 Temperature effect on module voltage

Fig. 3 shows the dramatic effect temperature can have on voltage. Modules in the sun become very hot (think about picking up a metallic tool that has been lying in the sun). As shown, the voltage of a module operating at a cell temperature of 65°C (149°F) will experience an approximate 15% decrease from its nameplate voltage. Module temperatures even higher are not uncommon on hot summer days. Conversely, a module exposed to sunlight on a cold winter day might operate at a lower temperature, e.g., 5°C (41°F), as shown in the figure, and its voltage would be 7% more than the nameplate voltage corresponding to a power increase.

The operating voltage increase at colder temperatures might be significant. National Electrical Code (NEC) Table 690.7 [3] provides typical guidelines to allow array designers to account for this voltage increase. For example, for an extreme minimum ambient temperature of -25°C [4], Table 690.7 specifies a correction factor of 1.20 for Voc. In the Denver area, these very cold conditions tend to occur early on snowy mornings when the sun is rising. An array voltage that is too high might actually damage the electronics in the inverter. Most module manufacturers provide the temperature coefficients for power, voltage, and current. These coefficients will be more accurate than the values found in Table 690.7.

The temperature characteristics of the modules become important for sizing strings.

III. SIZING A PV STRING

At the 2017 ESW conference, several people asked how to compute the number of modules in a string. The number is dependent on several values, including the maximum input voltage of the inverter, Voc of the module, and record-low temperature of the array site. Some inverter manufacturers provide software sizing tools that allow input of the module parameters and ambient temperatures for a specific site. The tools basically determine the maximum module Voc at the expected minimum site temperature. The maximum inverter voltage is determined by the number of modules in series, multiplied by the module Voc, adjusted for the minimum site temperature (usually 600 Vdc for residential inverters, but it can be as high as 1,500 Vdc for utility-grade inverters). The maximum inverter voltage value cannot be exceeded without damaging the inverter. Depending on the inverter type, multiple strings of modules might be connected to it in parallel. It is not uncommon for an inverter to be fed from an array with a nameplate power output that is more than the input power rating of the inverter. Most inverters can self-protect against higher power levels by electronically limiting the incoming array current. The inverter sizing tools indicate the maximum number of series-connected modules and parallel-connected strings that can be safely connected to the inverter.

IV. SOLAR MODULE TESTING STANDARDS AND QUALIFICATIONS

The commercial success of PV is largely based on well-documented and rigorous qualification testing protocols of PV modules. Today's modules are typically qualified/certified to International Electrotechnical Commission (IEC) 61215 for Crystalline Silicon Modules [5] or IEC 61646 for Thin Film Modules [7]. These qualification tests identify weaknesses in designs, materials, and manufacturing flaws that could lead to premature field failures.

The testing matrix for crystalline silicon modules is found in IEC 61215. The 8 modules of a particular model are run through one of four paths that include the following tests: 1,000 hours of damp heat, ultraviolet exposure, hot spot, wet and dry high-potential testing, humidity/freeze cycling, outdoor exposure, mechanical loading, hail impact, and performance testing. Modules cannot present safety issues after any testing protocol. A module must not lose more than 8% of power during any testing path. All modules are tested for power output before and after each test path. If any module fails a testing protocol, the module family will not receive certification.

The IEC 61215 testing matrix is derived from a 1975 National Aeronautics and Space Administration (NASA) Jet Propulsion Laboratory (JPL) program that began investigating reliability in solar modules with a block buy contracting program. NASA was looking to vet or flush out early PV module reliability failures through an accelerated testing process. Damp heat, high-potential, and outdoor exposure stress tests were the initial tests used to stress materials and manufacturing processes. By 1986, JPL had performed five block buy sequences and finalized six accelerated tests. By the last sequence, significant changes to module design, materials, and fabrication allowed most modules to pass the gauntlet of tests. The qualification tests used by manufacturers today largely reflect enhanced versions of the JPL testing matrix. The final six JPL tests included thermal cycling, humidity freeze, hot spot, mechanical loading, hail impact, and high potential. All of these tests are still used in the UL and IEC qualification matrices.

UL 1703 Flat-Plate Photovoltaic Modules and Panels [6] is basically the U.S. version of Europe's IEC 61215. The IEC document was adopted from the UL version in an effort to establish a worldwide standard. As of 2016, there are few differences between the two.

The benefits to the rigorous qualification testing can be seen in module warranties and the overall safety of PV systems. Module warranty periods have steadily climbed, with some companies offering power guarantees for up to 30 years. Power warranties usually specify that the actual module power output will be no less than 80% of the labeled power at the end of the warranty period. Several solar power systems have been monitored and tested for well past the warranty period, and after 20 years in the field, these systems still operate at more than 80% of rated power. Current module safety and longevity success can be directly attributed to the initial JPL block qualification tests.

Consider an example of how well-engineered PV modules are: on May 8, 2017, the National Renewable Energy Laboratory (NREL) was struck by a hailstorm with golf-ball size hail. Of more than 3,500 modules on the NREL campus, only 6 modules sustained damage.

V. PV DC SYSTEM SAFETY AND THE NEC

The NEC safeguards persons and property from electrical hazards—shock and fire. Article 690 and Article 691 deal with PV systems, and Article 690 deals with systems smaller than 5,000 kW. In addition, all PV systems must adhere to the entire NEC. Article 690 (10 pages in the 2017 code) represents the knowledge of many years of experience from many PV experts. Arrays are expected to produce power for 20-plus years; the systems need to be professionally designed and installed. In this section, we briefly describe some aspects of system design that can reduce the shock hazard to people working around these systems.

A. Array Grounding Methods

Per NEC Article 690.41, PV arrays may be grounded or ungrounded. Grounded PV arrays—wherein one of the current-carrying conductors (either the positive or negative) is connected to the ground—can become a shock hazard if a person contacts a single ungrounded lead and earth ground. Until recently, grounded systems were the most common type of system in the United States. Sophisticated monitoring is required to detect and protect against ground faults and historically was not required under NEC code.

Ungrounded arrays are another option. In this case, a person can be shocked (or a fault created) only by contacting two ungrounded leads (Fig 4). The probability of a shock is reduced in a system that is undamaged and operating normally. Recently, the inverter test standard UL 1741 was updated to include requirements for ungrounded inverters. Because of this, equipment manufacturers and system installers are now more willing to consider installing ungrounded inverters in the United States [9].

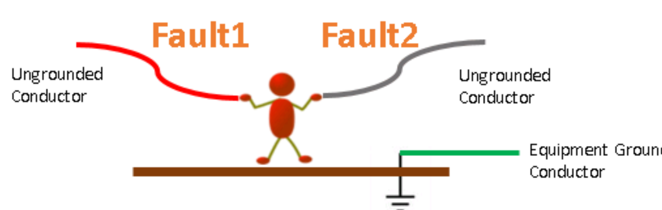

Fig. 4 Ungrounded system fault path

Another system configuration uses bipolar arrays with a functional ground reference (center tap). The maximum voltage is the sum of the absolute values of Voc of the two circuits [3]. When selecting personal protective equipment (PPE), workers must consider the maximum voltage to which they will be exposed.

B. Rapid Shutdown Systems

In 2014, NEC 690.12 on the Rapid Shutdown of PV Systems on Buildings was introduced. The goal of this change is to create a safer system (voltages less than 80 Vdc) with the operation of a readily accessible switch to firefighters that plainly indicates if the system is in the “off” or “on” position.

Fig. 5 shows an example of the label as specified by NEC 690.56 [10]. In this type of rapid shutdown, the array voltage and voltage within the array will be reduced to less than 80 Vdc. Systems might also shut down the voltage of only the main DC conductors, such that the array voltage is not reduced (Fig. 6). Rapid shutdown products are available from inverter manufacturers and are even offered as module-level electronic add-ons.

The intent of the 80-Vdc threshold is not to create a hazard-free environment but rather to lower the shock risk to workers and firefighters. It is not based on any specific safety threshold; instead, it is a compromise of the thresholds that were in effect at the time: IEC: 120 V; National Fire Protection Association (NFPA) 70E: 100 V [10]; Occupational Safety and Health Administration: 50 V; UL: 30 V in wet conditions [11].

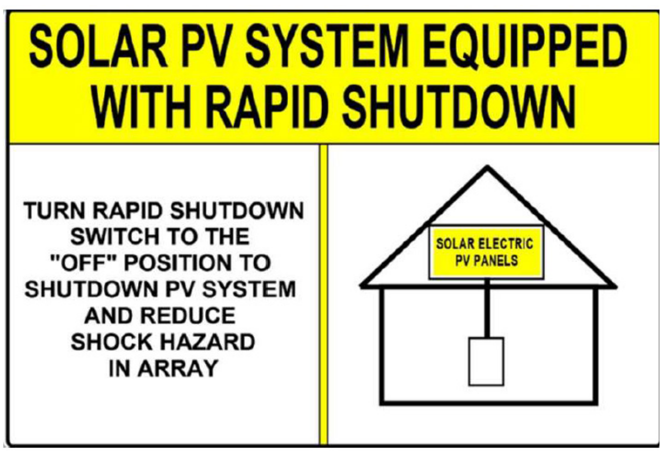

Fig. 5 Label for rapid shutdown of the array and conductors leaving the array.

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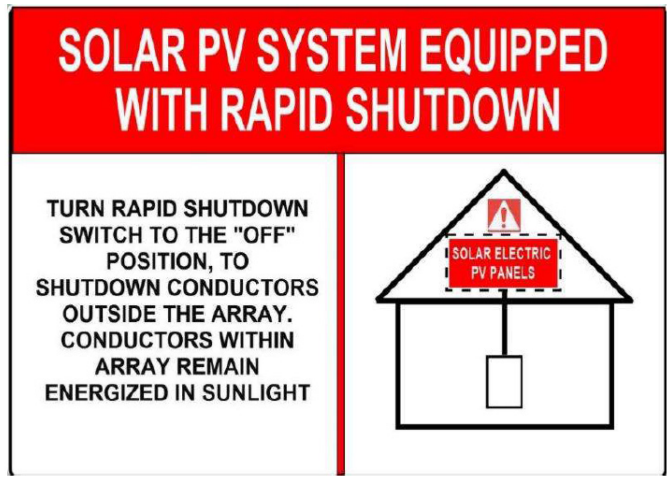

Fig. 6 Label for rapid shutdown of only the conductors leaving the array energized.

Used with permission from Bill Brooks

VI. COMMISSIONING, MAINTENANCE, AND PERIODIC TESTING

As an array is being installed and as part of the commissioning, workers will test the output of each string by measuring its Voc and Isc. Periodically, workers will also perform a visual inspection of the arrays and combiner boxes looking for any evidence of damage. They might use infrared thermography to look for evidence of hot spots. The infrared images can indicate loose connections or failing modules. Workers might also verify the torque of terminals and connectors. In addition, periodically workers will open combiner boxes to take I-V traces (Fig. 7). A set of I-V traces can quickly identify an underperforming string or module (Fig. 8). While taking I-V traces, workers will open the main DC conductors and string fuses. Workers wear at least safety glasses and voltage-rated gloves while connecting and disconnecting the I-V tracer connectors to each string. Workers then sweep the curve and collect the data. At NREL, the arrays operate at less than 1,500 Vdc (usually less than 600 Vdc). Class 0 gloves are rated for 1,000 Vac and 1,500 Vdc. We inspect our rubber insulating gloves visually and perform an inflation test daily before use. Insulated gloves must be tested every 6 months per NFPA 70E, 130.7(c) [12].

Fig. 7 Performing a periodic I-V trace test

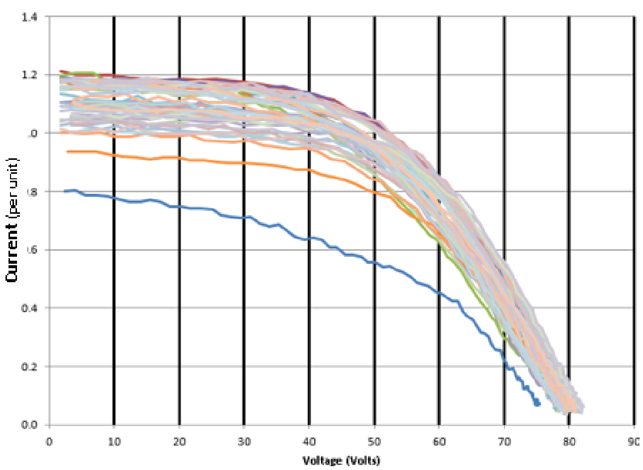

Fig. 8 Typical set of I-V traces

Personal protective equipment (PPE) for personnel working around solar arrays is selected based on voltage levels, mainly for shock and thermal burns. Arc flash hazard levels must be calculated. Arc flash PPE needs to follow the direction from NFPA 70E [10]. This typically consists of protection for the face and eyes as well as the upper and lower body that is of sufficient energy rating to protect the worker for the calculated incident energy levels. These hazards exist throughout the total operational lifetime of the PV array system. Workers should never work alone in array fields.

Annex D.5 of 70E "Direct-Current Incident Energy Calculations" describes the maximum power method, usually referred to as the Doan method. This is commonly used to calculate potential DC arc flash [12]. This method requires knowing the bolted fault current, the system voltage, and fault clearing time. This method is simple, assumes linear sources, and applies to systems rated up to 1,000 Vdc.

Other methods can be found and are described in NFPA 70E, Annex D.5.2 [12], or at the website for the U.S. Department of Energy, Energy Facilities Contractors Group (EFCOG), Electrical Safety Task Group DC Working Group (DC WG), Best Practice #194 [13]. This EFCOG tool incorporates the nonlinear source characteristics of PV arrays, first published by Enrique [14]. It shows that compared to the 70E (Doan method), including the temperature compensation factor (a rise in the PV output voltage for cold temperatures) results in a factor of almost four times the 70E (Doan method) for calculating arc flash PPE worker protection levels. The EFCOG DC WG is investigating the accuracy of each of these methods. Further publications from Doan [21] and Klement [22] present alternative arc flash calculation approaches that take the nonlinear nature of a PV system into consideration.

To reduce the DC arc flash potential during routine maintenance, PV systems should be shut down early in the morning or later in the evening. Solar irradiance largely determines how much power a PV panel will produce. For any fixed-tilt installation the PV panels will produce maximum power around solar noon. This equates to a high DC arc flash potential +/- 3 hours from solar noon. A tracking PV system will exhibit a high DC arc potential almost as soon as the sun illuminates the panels.

VII. SAFETY FOR EMERGENCY RESPONDERS

After the 2017 ESW, we began researching whether moonlight could cause potentially hazardous voltages and currents in a PV array. (We were dubious that moonlight could present a hazard.) In the process of researching this claim, we came across the Clean Energy States Alliance CESA "Fire Safety Training" presentation [15], which contains information on array hazards caused by light sources other than sunlight—i.e., moonlight, firelight, and artificial lights. It also contains information for how firefighters should best approach a fire on an array to minimize electric shock. Much of the data in the CESA report was gleaned from a 2011 UL report on "Firefighter Safety and PV Installations Research Project" [16]. We also found a recently published Sandia National Laboratories report on "Updated Evaluation of Shock Hazards to Firefighters Working in Proximity of PV Systems" [17]. This is basically an update and more thorough look at the results of the UL report.

In 2012, NREL engineers were invited by the National Park Service (NPS) to inspect and commission a 67-kW PV system at Mesa Verde National Park (Fig. 9). A fire safety expert present at the commissioning asked what firefighters should do in case an electrical fire broke out in or around the array. He asked if firefighters should jump up onto one subarray for a better vantage point to spray water on other subarrays. We recommended against this because of the electrical hazards of climbing onto a 482-Vdc array. We did not know what else to recommend. This was our first awareness of the problem of firefighters working around PV arrays, and it became another catalyst for writing this paper. At that time, our recommendations included:

- Open as many load-break rated disconnects (AC and DC) as can be done safely.
- Do not climb on or touch live arrays.
- Spray water around and underneath the arrays to prevent vegetation from catching fire.

- Have the NPS create a 30-foot defensible fire perimeter cleared of vegetation around the site.
- Ultimately, firefighters might need to wait for the electrical fire to burn itself out.

Fig. 9 PV array and inverter at Mesa Verde National Park

A. *Minimizing the Electrical Hazard*

The CESA and UL reports concluded that there is an electrical hazard to firefighters spraying water on PV arrays, but the reports included data showing that the following steps could be taken to minimize exposure to hazardous voltages (Fig. 10):

- Remain at least 20 feet away for a smooth bore.
- Use at least a 10-degree angle for an adjustable nozzle.
- Refer to UL 401 Standard, 30-degree minimum cone angle, "Portable Spray Hose Nozzles for Fire-Protection Service."

Fig. 10 UL firehose test setup – water sprayed at 1000-Vdc plate.
Used with permission from UL

Presently, the only way to control the shock risk is for firefighters to be aware that they are working around PV systems. With time, engineered solutions will become more widely available (such as rapid shutdown systems). Leakage current is associated with shock potential. If the leakage current can be minimized by standing far enough away and using a dispersive spray pattern, the shock potential can be minimized.

B. *Alternative Light Sources*

Data resulting from NREL testing indicates that the shock risk from moonlight on a PV array is nonexistent (Fig. 11) assuming there are no other light sources illuminating the array. The red plot represents the solar irradiance, which shows evidence of passing clouds in the morning and peaks at solar noon and then drops to zero after sunset. The blue plot is the voltage of the array during daylight hours, which dipped slightly midday because of elevated array temperatures. After sunset, the voltage dropped to less than 1 Vdc. UL produced similar data in their report [16].

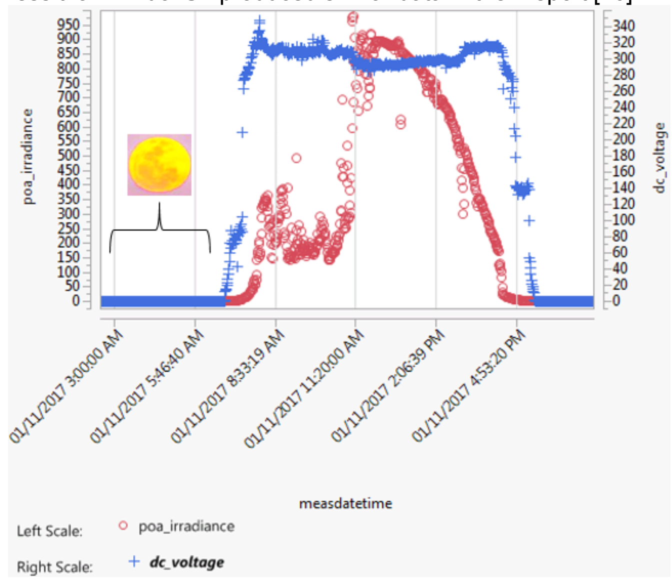

Fig. 11 Full moon hazard, January 11, 2017. Sunset occurred at 18:30.

The UL report included data showing that light from a fire on a PV array could produce hazardous voltages and currents (Fig. 12). In a darkened laboratory, a special test fixture was constructed using two PV modules (nominal 37-V open circuit, 7.5-A short circuit). The modules were mounted side by side on a mobile cart that could be moved various distances incident to the fire (from 15 to 75 feet). The fire was created by using 12 wood skids in two side-by-side rows of six. At various distances from the fire, open-circuit voltage was measured on one module and current on the other module. Voc ranged between 81% and 89% of full output. (The value of one module can be multiplied to represent any number of modules in a typical PV string.) Isc ranged between 52 mA and 62 mA. Tens of milliamps can kill a person. At the range shown above, a person could be electrocuted. Caution must be exercised by firefighters working in this situation [16].

Fig. 12 UL firelight test setup.
Used with permission from UL

UL also tested the output of a PV array (26-module test array Voc = 1,000 V) under artificial lights (Fig. 13). UL illuminated a

1,000-V array with common firefighting lights after dark. They used differing light sets ranging from 1.4 kW to 28.5 kW. The distance from the array varied from 25 to 75 feet. Depending on the test configuration, the results were:

- Voc ranged between 340 V and 836 V.
- Isc ranged between 1.5 mA and 212 mA.

Per the 2015 NFPA 70E, 100 Vdc is considered hazardous, and tens of milliamps can be fatal. Hazardous voltages and currents might exist in this situation.

Fig. 13 UL artificial light test setup.
Used with permission from UL

With hazardous voltages and currents being produced by PV arrays exposed to artificial lights and firelight, it is critical that firefighters have access to rapid shutdown systems or use the recommended techniques described above to eliminate the risk of electric shock.

Firefighter boots and gloves can provide some electrical insulation and might protect against electric shock, up to 1,000 Vdc; however, they must be dry and intact. Firefighter PPE must not be relied on to protect against electric shock [18].

Training resources for firefighter safety around PV systems are found in Appendix A.

VIII. PV DC SYSTEM ELECTRICAL ACCIDENTS

In 2016, there were more than 137,000 solar/PV installers in the United States [19]. We could not find data on how many PV array workers were injured from DC-only electrical incidents.

As of fall 2016, there have been no U.S. firefighter deaths from PV systems [15].

In Germany, to date no firefighter has been injured by PV power while putting out a fire. In Germany, one electrical death of a firefighter was reported as being caused by a PV system when in fact it was actually a solar hot water heating system [20].

Of more than 1.4 million PV power plants in Germany, during a 20-year period, 120 systems caught fire, resulting in severe damage in 75 cases, and in 10 cases entire buildings burned to the ground. Third-party PV system acceptance testing is recommended to prevent these types of incidents [20].

IX. HAZARDS UNIQUE TO PV DC SYSTEMS

This is a short list of some of the hazards and conditions unique to PV DC systems:

- Large DC systems generate arc flash hazards that persist throughout the lifetime of the system. Calculations need to be updated for any change in the configuration of array combiners and recombiner.
- Some digital multimeters may default to measure AC voltage when first powered on. In AC mode, they will indicate zero V when hazardous DC voltages are actually present.
- Voltage “sniffers” or proximity detectors detect only AC voltage.
- Do not walk on modules. Although they might seem sturdy, this might cause mechanical and electrical damage through excessive flexing.
- Cold water might cause thermal shock that can crack glass. Avoid spraying an array with water during sunny weather or when it is hot.
- Beware of tools and rocks on the front glass, weed whackers, and even a hard hat, etc., hitting the back of a module. These might crack the front glass or tear and damage the back sheet.
- Airborne objects can damage modules (e.g., thrown rocks). Periodic visual inspections of the array are critical.
- Check modules after wind or hailstorms—anytime damage is suspected.
- Broken glass or torn back sheets will compromise the voltage rating of modules.
- A PV professional should be consulted after any array damage is found.

X. CONCLUSIONS

PV systems are simple, reliable sources of power and are becoming more common as part of building systems. They must be engineered, installed, operated, and maintained properly for safe and reliable power. Modules and system designs are becoming better and safer as the technology matures. With system life expectancies in excess of 20 years, a mixture of old and new PV array technologies will exist for many years. Firefighters might not know which safety features, if any, are designed into the systems they encounter during emergencies. Therefore, it is critical that firefighters have the knowledge to understand the hazards and minimize the electrical risks. The best way to avoid electrical injury from a PV system is to avoid contact especially with those damaged by fire or water.

XI. ACKNOWLEDGMENTS

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XIII. VITA

Peter McNutt graduated from the University of Colorado at Denver in 1994 with an MSEE. He began working at NREL in 1997 in the areas of PV performance, deployment, and energy systems integration. At NREL, he serves as an electrical safety officer. He is a registered PE in the State of Colorado.

William Sekulic graduated from Colorado School of Mines in 2013 with a BSEE in electrical engineering. He has been a member of the NREL PV Reliability group since 2001. Along with his research duties, he is a member of the NREL Electrical Safety Committee and is a part-time Electrical Safety Officer responsible for verifying designs and inspecting custom-built electrical equipment. He is a registered professional engineer in electrical power in the State of Colorado.

Gary R. Dreifuerst (IEEE M'1970, LM'2015) is a retired electronics engineer from Lawrence Livermore National Laboratory (LLNL). He joined LLNL in June 1981 after receiving his electrical engineering Ph.D. degree from the University of Wisconsin at Madison. He specializes in power electronics, computer control, pulsed power systems, power systems analysis, and high-voltage DC systems analysis. He has been a member of the NFPA DC WG for the last two code cycles of 70E. He is a member of the IEEE 1584 Arc Flash Standard WG.

APPENDIX A

RESOURCES

Training

UL / DHS "PV and Firefighter Safety" on line training:

https://lms.ulknowledgeservices.com/catalog/display.resource.aspx?resourceid=352901.

IAFF Firefighters / IREC Solar PV Safety for Firefighters online training:

http://client.prod.iaff.org/#page=SolarPVHome.

Reports

M. Piantedosi, T Granato, Solar Photovoltaic (PV) Fire Safety Training, CESA, 2012.

R. Backstrom, D. Dini, Firefighter Safety and Photovoltaic Installations Research Project, UL, Nov 2011.

O. Lavrova, et al, Updated evaluation of shock hazards to firefighters working in Proximity of PV systems, Sandia, 2017.

R. Backstrom, Dennis Grubb, Firefighter Safety and Photovoltaic (PV) Systems, ICLEI, DOE SunShot.