Accelerated Lifetime Testing of Photovoltaic Modules

Prepared by

(Mani) GovindaSamy TamizhMani
Joseph Kuitche
Photovoltaic Reliability Laboratory
Arizona State University

July 2013

Solar America Board for Codes and Standards
www.solarabcs.org

DISCLAIMER

Download a copy of the report:
www.solarabcs.org/acceleratedtesting

EXECUTIVE SUMMARY

Technology risk—the concern that a technology will underperform (durability) or become obsolete prematurely (reliability)—is one of the major barriers to photovoltaic (PV) diffusion and project financing. Climate-specific and technology-dependent durability and reliability are the primary determinants of PV module lifetimes.

Maximizing energy production and minimizing downtime results in the highest return on investment for PV systems and makes the technology attractive to investors and consumers. Improving durability (minimizing soft or degradative losses) maximizes energy production and improving reliability (minimizing hard or catastrophic failures) minimizes downtime.

The primary metric for PV module durability is the annual degradation rate (% degradation per year) and the primary metric for reliability is failure rates (number and duration as well as the effective influence on energy production). The purpose of accelerated testing (AT) is to assess the reliability and durability of products by inducing failures and degradation in a short period of time using accelerated test conditions much more severe than actual field operating conditions while replicating the actual field failure mechanisms.

This report does not attempt to develop a new AT methodology or to select an existing AT methodology, but rather provides a literature review and analysis of field failures, degradation, and available AT methodologies. Based on this review report and the other published literature, research teams can develop AT protocols that could be converted into an accelerated comparative testing and/or lifetime testing protocol/standard by one or more standards developing organizations or international/national industry organizations.

To generate this report, the authors collected and systematically analyzed a large number of published papers on PV module reliability and durability. This review report covers the following major topics:

- the difference between reliability and durability;
- failure and degradation modes and mechanisms of PV modules;
- accelerated stress types (including potential induced degradation), levels, and prioritization;
- pitfalls in preparing representative sample designs for accelerated stress testing;
- existing and future (potential) accelerated comparative and lifetime testing programs;
- key attributes of accelerated comparative and lifetime testing programs;
- considerations for designing and developing new accelerated comparative and lifetime testing programs;
- a possible approach for a PV rating system; and
- physical and statistical models for lifetime prediction using black-box and white-box approaches based on field degradation data and accelerated test data.

AUTHOR BIOGRAPHIES

Dr. (Mani) Govindasamy TamizhMani
Photovoltaic Reliability Laboratory
Arizona State University

Dr. (Mani) Govindasamy TamizhMani is the president of TÜV Rheinland Photovoltaic Testing Laboratory (TÜV-PTL) and a research professor in the Department of Engineering at Arizona State University. Dr. Mani has been involved in research and development activities related to photovoltaics (PV), fuel cells, and batteries for more than 29 years, and PV module testing and certification activities for more than 13 years. He has been involved in the development of PV standards since 1996 and served/is serving as a member of various standards committees, including the Canadian Standards Council, the Institute of Electrical and Electronics Engineers (IEEE), the International Electrotechnical Commission (IEC), and the American Society for Testing and Materials (ASTM). He has taught graduate level courses related to PV, fuel cells, electrolysis, and batteries; published more than 60 journal and conference papers; and made more than 80 resentations at various conferences, seminars, and workshops. He has also served as a reviewer of numerous federal grant applications and conference and journal publications, including IEEE *Journal of Photovoltaics, IEEE Photovoltaic Specialists Conference, Progress in Photovoltaics,* and *Journal of the Electrochemical Society.* Dr. Mani's email address is *manit@asu.edu*.

Joseph Kuitche
Photovoltaic Reliability Laboratory
Arizona State University

Mr. Joseph Kuitche is a Ph.D. student at Arizona State University and was the former operations manager of ASU/TÜV Rheinland PTL. He currently is the laboratory manager of the Arizona State University Photovoltaic Reliability Laboratory. Mr. Kuitche's email address is *kuitche@asu.edu.*

Acknowledgments

The authors gratefully acknowledge the constructive and critical comments of Dr. Bill Marion (National Renewable Energy Laboratory [NREL]), Dr. John Wohlgemuth (NREL), Dr. Sarah Kurtz (NREL), Dr. Jennifer Granata (Sandia National Laboratories), and Mr. George Kelly (BP Solar). This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. It consists of a collaboration of experts who formally gather and prioritize input from groups such as policy makers, manufacturers, installers, and large and small-scale consumers. Together, these entities make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

Solar America Board for Codes and Standards website:

www.solarabcs.org

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 4

SOLAR ABCS 4

ACKNOWLEDGMENTS 4

INTRODUCTION 6
- Need for Accelerated Lifetime Testing Program for Photovoltaic Modules 6
- Challenges in Developing Accelerated Lifetime Testing Program for Photovoltaic Modules 7
- Scope and Limitation of the Report 9

DIFFERENCE BETWEEN RELIABILITY AND DURABILITY 11
- Reliability (Failure) vs. Durability (Degradation): A Hypothetical Representation 11
- Reliability (Failure) vs. Durability (Degradation): An Actual Field Representation 12
- Plots for Failure Rate and Degradation Rate Analysis: A Hypothetical Representation 12
- Prediction of Energy Production Based on Failure Rate and Degradation Rate Data 14

PV FIELD FAILURES AND DEGRADATIONS 15
- Field Failure and Degradation Rates 15
- Field Failure and Degradation Modes 17
- Field Failure and Degradation Modes, Mechanisms, Causes, and Effects 19

PV ACCELERATED TESTING: STRESS TYPES, LEVELS, AND PRIORITIZATION 27
- Concept of Accelerated Testing for Photovoltaic Modules 27
- Types and Selection of Accelerated Tests for Photovoltaic Modules 29
  - Stress Level and Duration Limits of Accelerated Tests for Photovoltaic Modules 32
  - Stress Level and Duration Limits: Temperature 33
  - Stress Level and Duration Limits: Humidity 36
  - Stress Level and Duration Limits: UV 41
  - Stress Level and Duration Limits: Humidity-Freeze 44
  - Stress Level and Duration Limits: Voltage 44
- Prioritization of Lifetime Accelerated Tests for Photovoltaics 51
  - Prioritization From Reliability (Failure) Perspective 51
  - Prioritization From Durability (Degradation) Perspective 54
- Pre- and Post-Characterization of Materials and Modules 55

PV ACCELERATED TESTING: PRESENT AND FUTURE PROGRAMS 57
- Types of Accelerated Testing Programs 57
  - Accelerated Qualification Testing (AQT) 58
  - Accelerated Comparative Testing (ACT) 59
  - Accelerated Lifetime Testing (ALT) 60
- Key Attributes and Considerations for Designing Future ACT and ALT Programs 62

PV RATING SYSTEM: A POSSIBLE APPROACH 66

PV RELIABILITY PREDICTION: PHYSICAL AND STATISTICAL MODELS 68
- Black-Box Modeling 70
  - Field Degradation Modeling 70
  - Accelerated Degradation Modeling 81
- White-Box Modeling 85

CONCLUSIONS 88

ACRONYMS 89

REFERENCES 90

APPENDIX A: PV POWER PLANT VISUAL INSPECTION CHECKLIST 95

APPENDIX B: EVOLUTION OF MODULE DESIGN QUALITY BETWEEN 1997 AND 2011 101

APPENDIX C: SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS 103

APPENDIX D: EQUIPMENT AND EXPERTISE NEEDED FOR PV MODULE RELIABILITY RESEARCH PROGRAM—AN EXAMPLE 105

Introduction

Need for Accelerated Lifetime Testing Program for PV Modules

The levelized cost of energy (LCOE, $/kWh) of photovoltaic (PV) modules is dictated not only by the initial price of the modules (dollars per watt), but also by the reliability (distribution of surviving units over time) and durability (distribution of degradation rates over time) of the modules. Just a few failed modules (reliability) or underperforming modules (durability) can have a serious negative impact on both string level and system level performance.

Standards & Poor's is a global authority in credit quality and it identifies eight finance criteria for utility-scale PV projects (Standard & Poor's, 2009). Two of the criteria are technical criteria and the others are non-technical criteria. The technical criteria are based on technology reliability and resource availability. The Standards & Poor's report indicates that all of the PV technologies rely on accelerated testing (AT) for measuring and claiming useful lives of approximately 25 years.

Similarly, in February 2012, a Credit Suisse Equity Research Report indicates that (Credit Suisse, 2012): "Product quality in our view is THE MOST SIGNIFICANT metric for a solar companies' long-term survivability." A Web page article published by Burgess in the April 2012 issue of *Renewable Energy World* also notes the following on the importance of reducing the degradation rate over the lifetime of PV systems (Burgess, 2012):

> In a world where large solar assets are built with 80 percent debt leverage or more, a one percent change in output can equate to a 10 percent change in the ROI [return on investment] for the investors. The impact of an unanticipated drop in the performance ratio from 0.80 to 0.66 would probably wipe out any anticipated return from the project. This potential future variability has a major impact on site financial viability, but more importantly on the attractiveness of solar as an investable asset class. A key objective of the industry should be to increase the entitlement level for Performance Ratio beyond the 0.80 level and reduce the long-term risk of assets drifting off that entitlement level. This would: reduce the overbuild and hence initial capital outlay; reduce the levelized cost of electricity for the site; increase the ROI for the investors; and reduce the long-term financial risk, thus attracting financial backing and possibly reducing insurance premiums.

In addition, Solarex published a paper entitled "Testing Modules for Warranties" in 1993 (Wohlgemuth, 1993) that states: "The longer a module continues to produce electricity the greater will be its value to the customer. Failure of a large number of modules while still under warranty would impose a large financial burden on the manufacturer."

By reviewing and analyzing the results of these and other sources, this Solar America Board for Codes and Standards (Solar ABCs) report communicates and emphasizes the importance of AT for predictably assessing the reliability (failures) and durability (degradation) issues related to the lifetime of PV modules in the field. The LCOE of PV systems shown in Figure 1 is primarily dictated by site solar resource, the annual degradation rate of PV modules, and the inverter replacement price (U.S. Department of Energy, 2012). It is well known that failure rates are much higher for inverters than for PV modules. Surprisingly, however, the energy production (and hence LCOE) of the overall system during its lifetime is not strongly sensitive to variations in inverter failure rate or inverter disturbances compared to the degradation rates of PV modules because of the quick replacement or repair of failed inverters (Collins et al., 2009).

The manufacturer warranty period typically exceeds 20 years for crystalline silicon modules and 15 years for thin-film modules. Unfortunately, there is little or no systematically field monitored data or independent accelerated test data available to support most of these warranty claims. Investors, financiers, power purchasing agreement companies, and consumers are now expecting objective substantiations for these warranty claims. The PV module components, including cells and polymeric materials, must be protected from degradative losses (soft/durability losses) and catastrophic failures (hard/reliability failures) caused by stresses including temperature, humidity, ultraviolet (UV) radiation, wind, hail, and high system voltages, as well as effects including corrosion, broken interconnects, hotspots, delamination, and encapsulant discoloration.

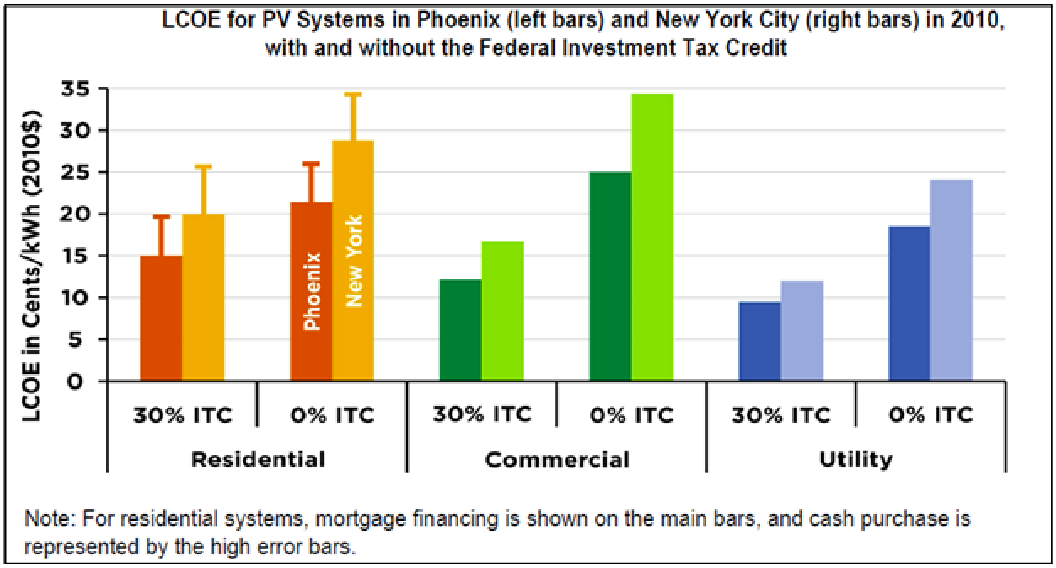
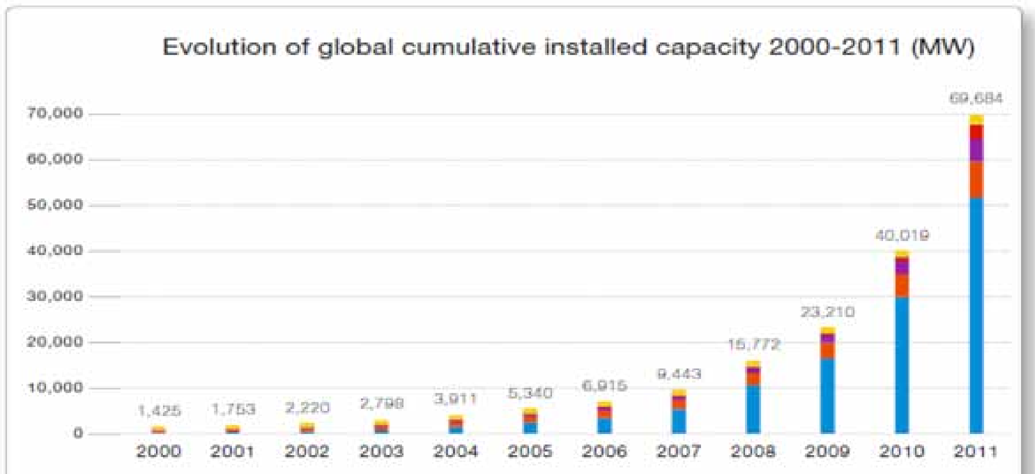


Figure 1: LCOE of PV systems in Phoenix and New York (U.S. Department of Energy, 2012).

Challenges in Developing an Accelerated Lifetime Testing Program for PV Modules

The anticipated lifetime of PV modules spans several decades. The construction materials and design are constantly changing to reduce LCOE, and the stakeholders cannot wait for decades to identify the failure modes and mechanisms of these new modules. The purpose of accelerated lifetime testing (ALT) for PV modules is to shorten the test time by using specified test conditions, which are more severe than the actual field operating conditions, to simulate actual field failure modes and mechanisms. As shown in Figure 2, only 4% (7 gigawatts [GW]) of the modules were installed before 2007, 38% (62 GW) were installed between 2007 and 2011), and 58% (95 GW) are expected to be installed between 2012 and 2015 (EPIA, 2012). Therefore, the required actual failure data and degradation data to develop an appropriate ALT program has to come from the field data of the 4% modules that were installed before 2007. Only a tiny fraction of the module data from the 4% modules (installed before 2007) is available for the degradation data analysis (due to availability of metered kWh data), however. In addition, little or no data from that 4% of modules is available for the failure analysis because there are only a few sustained event logs available for failures and replacements.

If the construction materials and design of the 4 % of modules produced before 2007 are the same as those produced between 2007 and 2011 and those that will be produced between 2012 and 2015, then developing AT programs for the newer modules based on the old modules' field failure and degradation data becomes reasonably simple. However, this is based on the assumption that statistically significant field failure data and field degradation data are available from a large number of PV systems installed in varied (hot-dry, hot-humid, and hot-cold [temperate]) climatic conditions. The development of a lifetime AT program for newer modules becomes very challenging if the construction materials and design are not the same (as is often the case now) and if the changes are projected to significantly influence (positively or negatively) the field failure and degradation rates based on some preliminary AT such as accelerated qualification testing. Various AT programs developed by the industry are extensively discussed in the later sections of this report.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
ROW	751	807	887	964	993	1,003	1,108	1,150	1,226	1,306	1,209	1,717
MEA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	21	205	336
China	19	30	45	55	64	68	80	100	145	373	893	3,093
America	146	177	222	287	379	496	645	856	1,205	1,744	2,820	5,053
APAC	355	491	677	902	1,178	1,475	1,797	2,080	2,643	3,409	5,116	7,769
Europe	154	248	389	590	1,297	2,299	3,285	5,257	10,554	16,357	29,777	51,716
Total	**1,425**	**1,753**	**2,220**	**2,798**	**3,911**	**5,340**	**6,915**	**9,443**	**15,772**	**23,210**	**40,019**	**69,684**

Figure 2: Only 4 % (7 GW) of the modules had been installed before 2007, leading to only very minimal long-term field data availability for the reliability evaluations (EPIA, 2012).

To reduce the cost and keep up with the product development pace of ever-evolving new materials and designs, accelerated tests need to be carried out with minimum sample size and at the shortest testing time. The reliability and durability data obtained from accelerated tests should allow PV module manufacturers to predict product lifetimes and build confidence in their warranty periods. Unfortunately, as experimentally determined (Wohlgemuth, Cunningham, Amin, Shaner, Xia, & Miller, 2008), a large number of modules (eight out of ten models from various manufacturers studied in this work) appear to be currently designed and manufactured just to meet the pass requirements of qualification standards of International Electrotechnical Commission (IEC) 61215 and IEC 61646 (IEC 61215, 2005; IEC 61646, 2008).

The qualification tests are not meant to test PV modules for the end-of-life (wear-out) failure mechanisms, but they do an excellent job of identifying design, materials, and process flaws that are likely to lead to premature failure (infant mortality)

(Wohlgemuth, 2012a). The qualification testing involves a set of well-defined accelerated stress tests (irradiation, environmental, mechanical, and electrical) with strict pass/fail criteria based on extended functionality/performance, minimum safety/insulation, and detailed visual requirements. The qualification testing does not, as anticipated, identify all the possible actual lifetime/reliability field failures, but it does identify the major/catastrophic design quality issues that would initially occur in the field. The type, extent, limits, and sequence of the accelerated stress tests of qualification standards have been stipulated with two goals in mind—accelerate the same failure mechanisms observed in the field without introducing other unknown failures that do not occur in the field and induce/accelerate these failure mechanisms in a reasonably short period of time, say 60-90 days, to reduce testing time and cost.

A background literature review of the history of qualification testing and on the failure rates in the qualification testing programs is available elsewhere (Osterwald & McMahon, 2009; TamizhMani et al., 2012). Therefore, it may be concluded that the qualification tests are the minimum requirements to initiate comparative or lifetime/reliability testing, but they cannot be considered as lifetime or reliability tests because they do not cover the failures related to wear-out mechanisms. In other words, the modules that do not meet the qualification testing requirements may not be considered for comparative or reliability testing. Various challenges in developing ALT are presented in later parts of this report.

Scope and Limitation of the Report

A history of the development of PV AT programs by various organizations has been reviewed and reported in an earlier publication (Osterwald & McMahon, 2009). This Solar ABCs report is the result of an extensive background literature review on the following major topics for PV modules:

- difference between reliability and durability;
- field reliability/hard failures;
- field durability/soft losses;
- general AT programs for PV modules including
  - o types/limits of accelerated tests,
  - o failure modes/mechanisms, and
  - o pre- and post-characterization of materials and modules;
- specific AT programs for PV modules including
  - o qualification testing,
  - o comparative testing,
  - o lifetime testing, and
  - o potential reliability testing protocols); and
- physical and statistical models for lifetime prediction of PV modules.

Because most of the long-term field and accelerated test data are available only for crystalline silicon modules, the technology specific reliability issues related to thin-film modules are not discussed in this report. Neither does this report attempt to provide any standardized accelerated comparative or lifetime testing protocol for PV modules. Rather, this report reviews and analyzes hundreds of publications and presentations, the major sources of which include:

- *Progress in Photovoltaics* (http://onlinelibrary.wiley.com/journal/10.1002/(ISSN)1099-159X),
- IEEE Photovoltaic Specialists Conference (www.ieee-pvsc.org),
- European Photovoltaic Solar Energy Conference (www.photovoltaic-conference.com),
- International Quality Assurance Forums (www.nrel.gov/ce/ipvmqa_forum),
- Photovoltaic Reliability Workshops (www.nrel.gov/pv/pvmrw.html),
- Jet Propulsion Laboratory (JPL) Reports (http://www2.jpl.nasa.gov/adv_tech/photovol/summary.htm), and
- Arizona State University Course Material (titled "Reliability and Standards of Photovoltaics").

Based on the review in this report, standardized accelerated comparative and/or lifetime testing protocols may be developed that in turn may potentially be considered for and converted into a test standard by national and/or international standards development organizations.

DIFFERENCE BETWEEN RELIABILITY AND DURABILITY

Reliability (Failure) vs. Durability (Degradation): A Hypothetical Representation

The term "reliability" for PV modules may be defined multiple ways. The ultimate definition of PV system reliability with storage may be described as "the lights go on when the switch is flipped" (Kurtz & Granata, 2009). A reliable PV module may also be defined as a PV module that has a high probability of performing its intended function adequately for 30 years under the operating conditions encountered (McMahon, Jorgensen, Hulstrom, King, & Quintana, 2000). For simplicity, it may be said that a PV module fails to provide service if its power output decreases by more than 30% after 30 years in its use environment. Also, "a high probability" means that 95% of the modules in the field will achieve this success. By "use environment" it is meant any and all use environments that the PV module will experience during service. Site meteorology, handling, and installation are included in use-environment considerations.

If the PV modules are removed (or replaced) from the field before the warranty period expires due to any type of failure, including power drop beyond warranty limit, then those failures may be classified as hard failures. In other words, all failures that qualify for warranty returns may be called a reliability failure. If the performance of PV modules degrades but still meets the warranty requirements, then those losses may be classified as soft losses or degradative losses. Toward the end of the module's life, multiple degradative mechanisms may develop and lead to wear-out failures due to accelerated degradative losses. The durability losses (and wear-out failures) and reliability failures can be hypothetically represented as shown in Figure 3. Overall, durability losses may be defined as degradative losses that meet the warranty requirements and the reliability failures may be defined as catastrophic and wear-out failures that do not meet the warranty requirements.

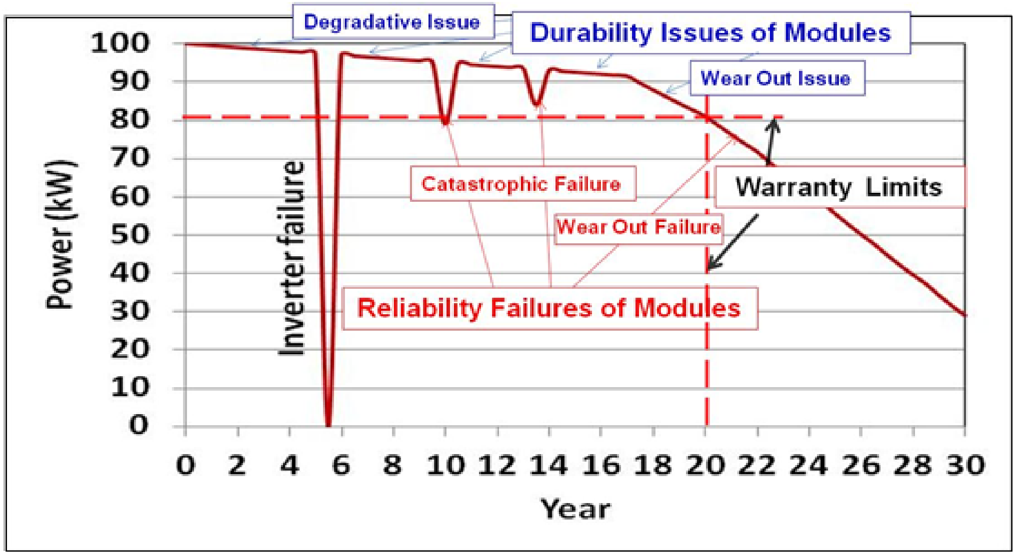


Figure 3: Reliability (failures) and durability (degradative) issues of PV modules—hypothetical plot.

Reliability (Failure) vs. Durability (Degradation): An Actual Field Representation

The hypothetical plot in Figure 3 shows durability losses and reliability failures of PV modules that can graphically be explained using actual field data shown in Figure 4. Figure 4 presents results obtained from 204 modules (composed of 53 different designs) field stressed over 18-22 years (Sample, 2011). Assuming all these modules are given a warranty of 20% maximum degradation over 20 years, about 34 modules have experienced reliability failures and the rest have experienced durability losses. Out of 34 reliability failed modules, four modules have experienced catastrophic delamination failures, six modules have experienced catastrophic diode (shorting) failures, and the other 24 modules have experienced cell and/or circuit wear-out failures.

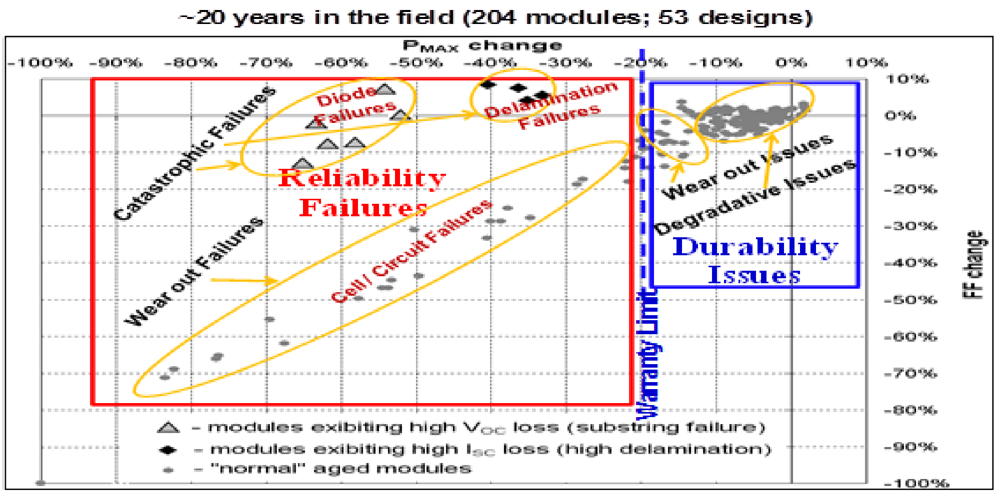


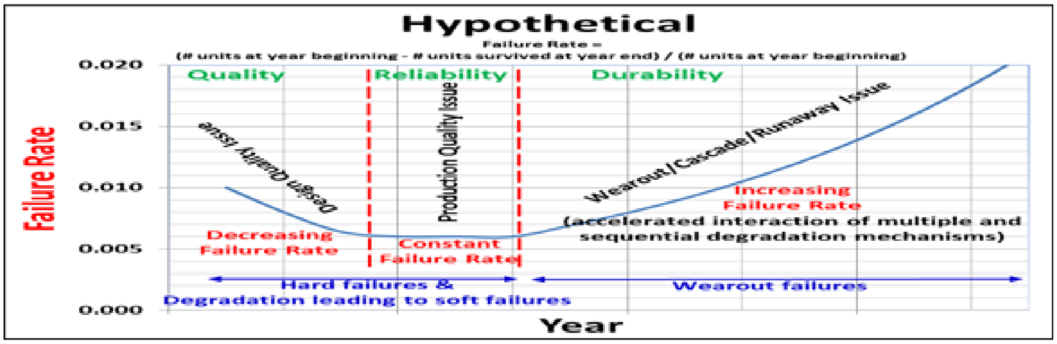
Figure 4: Reliability (failures) and durability (degradative) issues of PV modules—actual field data (figure based on data from Sample, 2011).

Plots for Failure Rate and Degradation Rate Analysis: A Hypothetical Representation

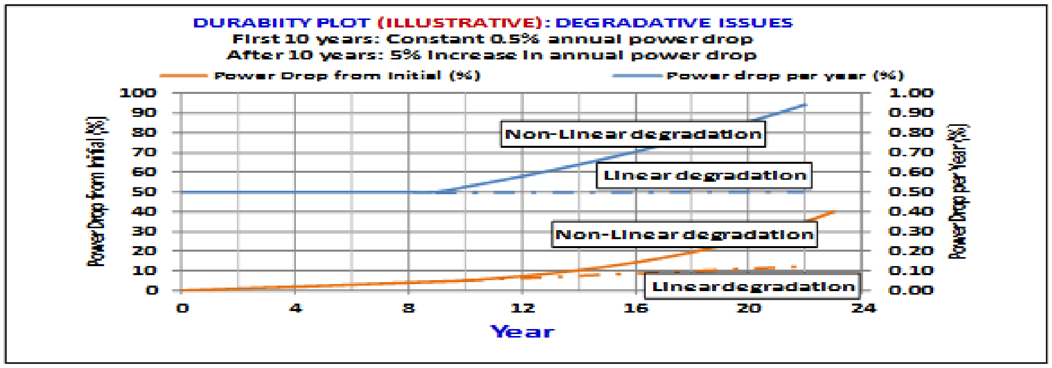
The reliability (catastrophic and wear-out) failures and durability (degradative and wear-out) losses of PV modules may be segregated and generalized using the hypothetical/illustrative plots shown in Figure 5A and Figure 5B. Failure rate is defined as the percentage of units failing per unit of time. In Figure 5A, the cause for the catastrophic failures could be attributed to the design quality (infant failures; decreasing failure rate) and production quality (useful life failures due to compounded design and production quality issues; constant failure rate) whereas the cause for the wear-out failures (end of life failures due to compounded design and production quality issues along with wear-out issues; increasing failure rate) could be attributed to the interaction of multiple degradative mechanisms accelerated by the catastrophic failures. For example, the corrosion degradative mechanism may be accelerated by the catastrophic delamination failure. The onset and slope of wear-out failures are dictated by the robustness of design quality and tolerance tightness of production quality. If there are workmanship issues, then there may be a few occasional spikes in the constant failure rate regime of the plot shown in Figure 5A. The data corresponding to these occasional spikes should not be considered in the statistical lifetime prediction, as the failure mechanisms corresponding to these spikes do not represent the normal degradation mechanisms of the product before the onset of the wear-out mechanisms, which are caused by the combination of multiple normal degradation mechanisms.

The lifetime energy production is heavily dictated by the degradation rate and this rate could be linear or non-linear depending on the failure mechanism. The Jet Propulsion Laboratory assigned a constant degradation rate for certain mechanisms and a linearly increasing degradation rate for the other mechanisms (Ross, 1984). In Figure 5B, the cause for the linear degradative failures in the first few years of operation in hot and humid climatic conditions could be attributed, for example, to fewer solder bond thermal fatigue failures and the non-linear degradative failures in the last few years of operation could be attributed to failures of additional solder bonds as failure of one bond puts more stress on others.

This hypothetical plot basically indicates that the non-linear degradation mechanism may happen right from the beginning of module installation but at a lower rank order as compared to the higher order linear degradation mechanism. However, the non-linear mechanism becomes dominant after several years of operation—10 years, for example—in the field. A recent literature review on the degradation rate of PV modules (Jordan & Kurtz, 2011) finds that "The median rate for exposure length up to 10 years is significantly higher than for studies of 10 years and longer." This investigation may seem to indicate that there could be a non-linear degradation of PV modules during 20+ years of field operation. However—as cautiously noted by the authors—this non-linearity might be due to the fact that modules with high degradation rates are unlikely to be left in the field and reported on as many times as modules with low degradation rates. Simple assumptions of a uniform and linear 0.8% degradation rate per year may or may not be valid and will need to be investigated carefully, especially when a significant number of higher degradation modules are removed in the early years, leaving the lower degradation modules.



(A)



(B)

Figure 5: Hypothetical representation of failure rate (A) and degradation (B) loss of PV modules.

Prediction of Energy Production Based on Failure Rate and Degradation Rate Data

The energy production in a specific year is basically dictated by the number of modules that survived in that year (reliability) and the performance level of the survived modules in that year (durability). The reliability and durability factors can be determined using the above plots and they can be used to calculate the annual or lifetime energy production by these modules using the following equations:

$$\text{Daily energy} = E_d = \sum_{h=1}^{h=24} E_h$$

$$\text{Annual energy} = E_a = \sum_{d=1}^{d=365} E_d$$

$$\text{Lifetime energy (for 20 years)} = E_L = \sum_{y=1}^{y=20} Ea$$

Hourly energy = E_h = Hourly Power x Hourly Durability Factor x Hourly Reliability Factor

For example:

Hourly Power = If hourly irradiance and module temperature are known or calculated (from ambient temperature, irradiance, and wind speed), then pick peak power (P_{max}) data for that irradiance and temperature from P_{max} matrix from IEC 61853-1 testing (IEC61853-1, 2011).

Hourly Durability Factor = 1 for y-1 hours; 0.995 for y-2 hours; 0.990 for y-3 hours; and so on for y-20 hours

Hourly Reliability Factor = number of samples survived (n for y-1 hrs, n-4 for y-2 hrs, n-? for y-20 hrs)

Summary—Reliability vs. Durability: If the PV modules are removed (or replaced) from the field before the warranty period expires for any types of failures, then those failures may be classified as reliability issues. If the performance of PV modules degrades but still meets the warranty requirements, then those losses may be classified as durability issues. Both reliability and durability issues are illustratively explained for both hypothetical and actual field scenarios.

PV FIELD FAILURES AND DEGRADATIONS

Field Failure and Degradation Rates

Table 1 is generated primarily from information in a paper published by Sandia (King, Boyson, & Kratochvil, 2002). As shown in Table 1, the performance loss of a grid-tied PV system could be caused by various non-failure factors and non-module degradation factors. In order to accurately determine and report the annual degradation rates and mismatch of PV modules, it is extremely important to isolate and remove the influence of all other factors. Another recent study carried out by Sandia serves as a good example of how to isolate and remove the influence of all the factors (which are not related to module durability issues) that determine module degradation rates (Granata, Boyson, Kratochvil, & Quintana, 2009). As shown in Figure 6, the module degradation rate can be as high as 4%/year, but the median and average degradation rates are only 0.5%/year and 0.8%/year, respectively (Jordan & Kurtz, 2011).

Table 1

De-Rating Factors Involved in the Energy Production of Grid-Tied PV Systems (based on data from King, Boyson, & Kratochvil, 2002)

Influence of Module and System Level Factors on AC-Energy Production		
Factor	**Range (%)**	**Issue**
Module orientation	-25 to +30	Installation issue
Array utilization losses (MPPT)	-30 to -5	Inverter issue
Module power specification	-15 to 0	Performance overrating issue
Module temperature coefficients	-10 to -2	Performance issue
Module (array) degradation (%/yr)	**-7 to -0.5**	**Durability issue**
Module Vmp vs. Irradiance	-5 to +5	Performance issue
Module soiling (annual average)	-10 to 0	Site and tilt angle issue
Angle-of-incidence optical losses	-5 to 0	Performance issue
Module mismatch in array	**-5 to 0**	**Durability variation issue**
Solar spectral variation	-3 to +1	Performance issue

Note: MPPT is maximum power point tracking; Vmp is voltage at maximum power point.

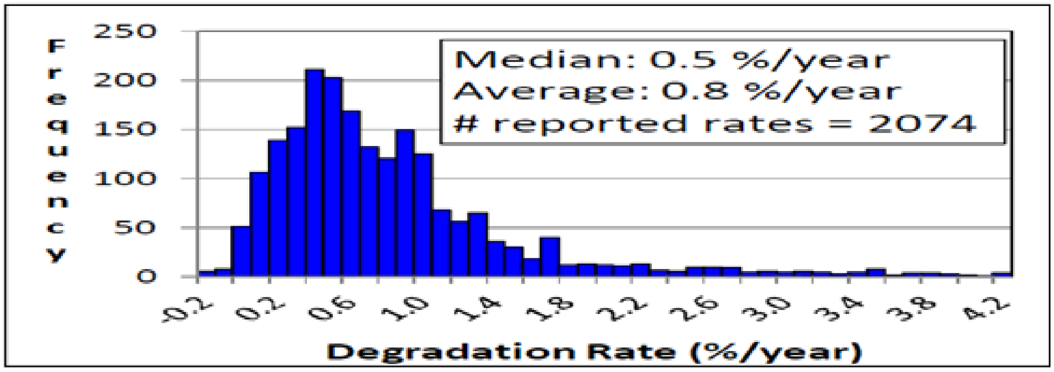


Figure 6: Annual degradation of PV modules based on 2074 reported data (Jordan & Kurtz, 2011).

The list of the module failures presented in Table 2 may seem to be very long, but in reality the crystalline silicon modules have a very impressive track record with only negligibly small field failure issues and warranty returns. As shown in Figure 7, most of the PV systems fail not due to modules but due to inverters (IEA-PVPS-TASK2, 2007).

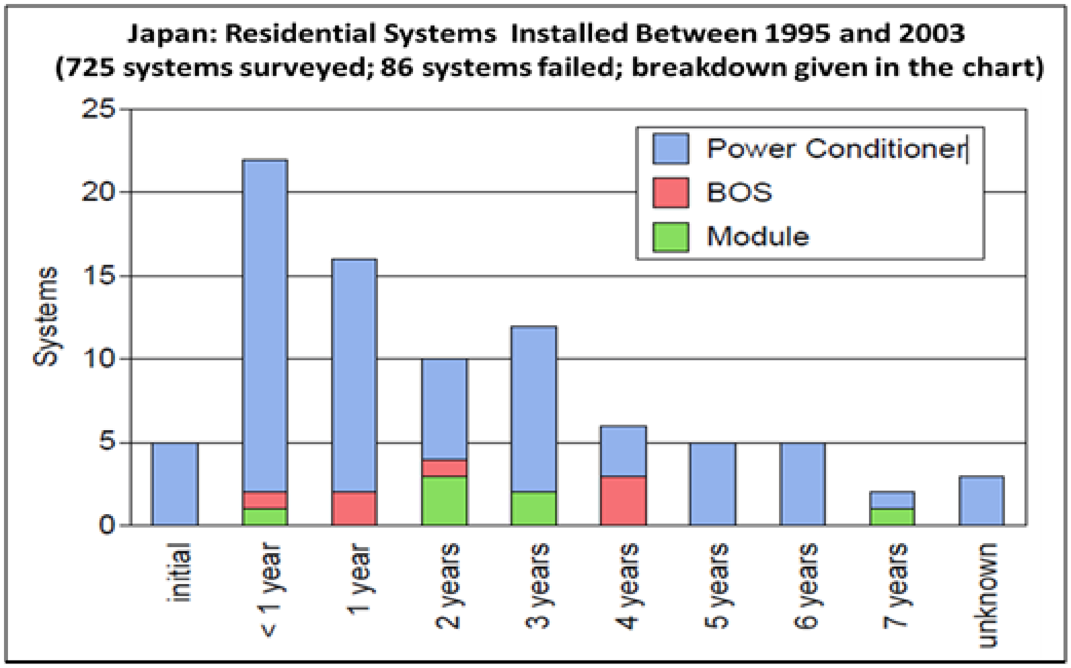


Figure 7: Failure rates of inverters, modules, and balance of system (BOS) in residential PV systems (IEA-PVPS-TASK2, 2007).

As noted earlier in this report, the inverters are replaced or repaired in a short period of time with less impact on lifetime energy production of the PV systems. The temporary energy production loss due to inverter failures during the lifetime of PV systems would be much less than the permanent energy production loss due to higher degradation rates of PV modules. The impact of higher degradation rate on the lifetime (and energy production) of PV modules would be dramatic, as shown in Figure 8 (Osterwald & McMahon, 2009).

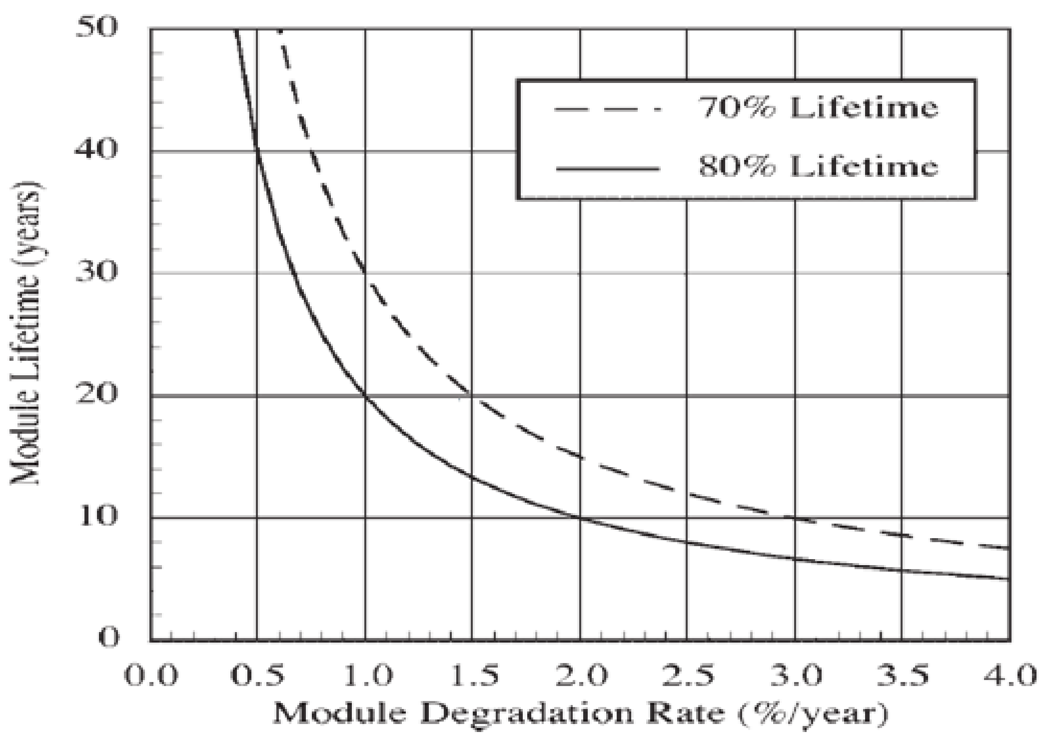


Figure 8: Serious impact of higher degradation rate on the lifetime of PV modules (Osterwald & McMahon, 2009).

Based on various publications, Wohlgemuth summarized recently reported field failure and warranty return rates for crystalline silicon modules (Wohlgemuth, 2012) as follows:

- less than 0.1 % of annual field failure rate on 10-year-old qualified (per qualification standards) modules,
- 0.005 % of annual field failure rate on up to 5-year-old modules (only six module failures out of 125,000 modules from 11 different manufacturers),
- 0.13 % warranty return rate on 1994-2005 modules (one failure every 4200 module-years of operation), and
- 0.01 % annual return rate on 2005-2008 modules.

Therefore, it may be concluded that the lifetime of PV modules is typically dictated by the degradation rates rather than failure rates. However, it is to be noted that the multiple failure modes over time could have cumulative influence on the degradation rates of the PV modules. For example, cracked cells and failed bypass diodes can electro-thermally accelerate degradation rates.

Summary—Field Failure and Degradation Rates: The degradation rate can be as high as 4 %/year but the median and average degradation rates are only 0.5 %/year and 0.8 %/year, respectively. Reports in the literature suggest that failure rates typically range between 0.005 % and 0.1 % per year depending on the duration of the modules in the field. The temporary energy production loss due to inverter failures during the lifetime of PV systems would be much less than the permanent energy production loss due to higher degradation rates of PV modules.

Field Failure and Degradation Modes

Failure and degradation modes and mechanisms of PV modules are dictated by their design/packaging/construction and the field environment in which they operate. As shown in Figure 9, the design/construction of PV modules has gone through a dramatic change since 1975 (Ross, 2012). The design and component changes include cell type (from monocrystalline silicon [mono-Si] to polycrystalline silicon [poly-Si] and mono-Si along with various thin-film technologies), superstrate (from silicone to glass), encapsulant (from silicone to ethylene vinyl acetate [EVA]), substrate (from fiberglass board to polymeric backsheet), cell string (from one to multiple), interconnect between cells (from one to multiple), and bypass diode (from none to multiple). An excellent representation of design evolution between 1975 and 1984 is shown in Figure 10 (Ross, 2012).

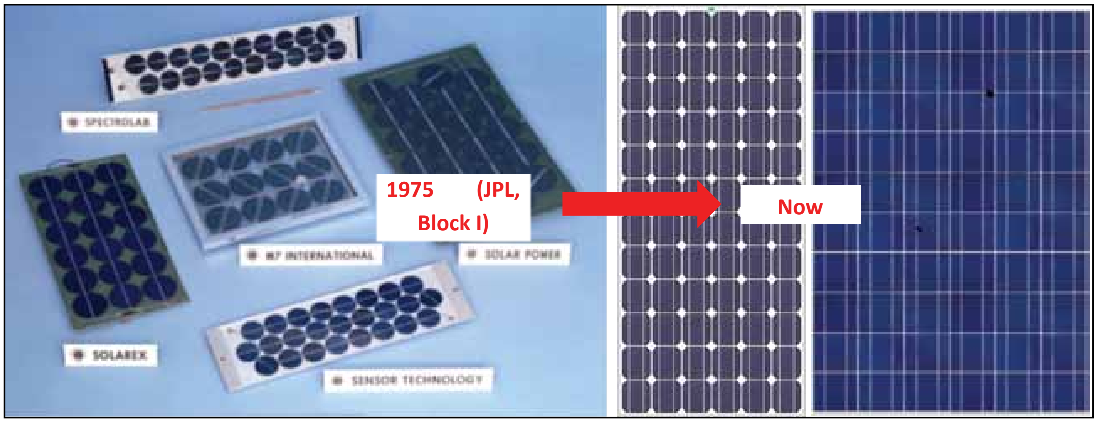


Figure 9: Evolution of PV module design since mid-1970s (Ross, 2012).

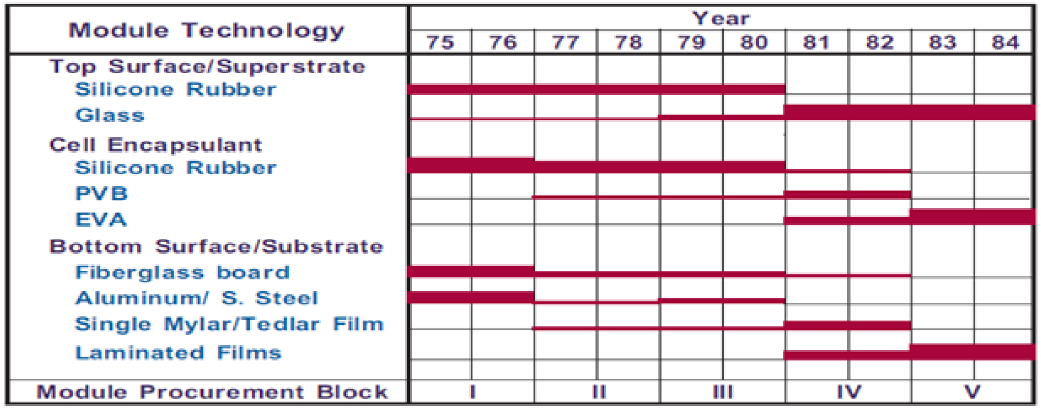


Figure 10: Evolution of PV module construction since 1975 (Ross, 2012).

The failure or degradation modes in PV modules indicate symptoms, whereas failure or degradation mechanisms represent the course for arriving at these symptoms. The field failures and degradation losses may be classified as reliability failures and durability losses, respectively. An extensive list of graphic and photographic representations and examples of field failure and degradation modes are not provided in this report, but can be obtained from the tutorials of various IEEE Photovoltaic Specialists Conferences. The typical field failure and degradation modes of crystalline-silicon PV modules in the field are shown in Table 2. The authors generated this classification table primarily based on information from tutorial material presented at the 2011 IEEE Photovoltaic Specialists Conference (Wohlgemuth, 2011). As stated earlier, the lifetime of PV modules is typically dictated by the degradation rates rather than failure rates, although the failure modes and rates could significantly influence the degradation rates of the PV modules.

Table 2

Failures and Degradation Modes of PV Modules

Failure Modes (Leading to immediate warranty returns)	**Degradation Modes** (Leading to power degradation warranty limit)
	
• Broken interconnects (leading to arcing, backskin burns, or glass shattering or power loss higher than warranty limit) • Solder bond failure (leading to backskin burns or glass shattering) • Severe corrosion (leading to backskin burns or power loss higher than warranty limit) • Chipped cells (leading to hotspots or power loss higher than warranty level) • Encapsulant delamination (leading to power loss higher than warranty level) • Broken glass (leading to safety issue) • Hotspots (leading to backskin burning and safety issue or power loss higher than warranty limit) • Ground faults (leading to safety issue or power loss higher than warranty limit) • Junction box failures (arcing or ground faults) • Connector failures (leading to safety issue) • Structural failures (leading to safety issue) • Bypass diode failures (leading to safety issue due to hot spot or power loss higher than warranty limit due to string loss)	• Gradual cracking of interconnects (leading to power degradation) • Gradual solder bond failure (leading to power degradation) • Slow corrosion (leading to metallization discoloration and power degradation) • Gradual cracking of cells (leading to power degradation) • Gradual encapsulant discoloration (leading to power degradation) • Gradual (photo)electrochemical degradation of semiconducting and/or metallic materials (potential induced degradation leading to power degradation) • Gradual backsheet warping (leading to power degradation) • Gradual increase of module mismatch (leading to power degradation) • Strongly adhering and gradual hardening of soil layer on superstrate (leading to slow cumulative/permanent increase in annual power degradation) or weakly adhering and rain/wind cleaning of soil layer (leading to fixed/temporary annual degradation due to non-cumulative reversible annual rain effect)

Summary—Field Failure and Degradation Modes: Based on the review of an extensive list of field failure and degradation modes, design/packaging/construction and the field environment in which they operate dictate the failure and degradation modes and mechanisms of PV modules.

Field Failure and Degradation Modes, Mechanisms, Causes, and Effects

A failure mechanism is responsible for one or more failure modes. A failure mechanism could be triggered by one or more failure causes and a failure mode could trigger one or more failure effects. The field failure analysis approach for PV modules may be represented as shown in the following sequence:

Failure Mechanism (Cause) ⟶ Failure Mode (Effect)

Example:

Thermo-mechanical fatigue (Expansions-Contractions) ⟶ Broken interconnects (Arcing)

As shown in Table 3, a single failure mechanism may be triggered by one or more failure causes leading to one or more failure modes with each failure mode leading to one or more failure effects. Some failure modes are caused by compound mechanisms instead of just a single mechanism. In the fault tree analysis, all the causes for every failure mode are systematically identified. This table can be used as a tool for troubleshooting through fault tree analysis.

For details on the failure and degradation modes and mechanisms, see Wohlgemuth's tutorial materials from the 2011 IEEE Photovoltaic Specialists Conference (Wohlgemuth, 2011).

Table 3

Field Failure and Degradation Modes and Mechanisms Along With Cause and Effect on PV Modules

Cautionary Note: To differentiate the reliability issues from the durability issues, this table is broken up into two sections—Failure Modes (reliability issues) and Degradation Modes (durability issues). Most of the degradation modes (presented in the second part of the table) can lead to failure modes (presented in the first part of the table) if they go far enough. In other words, most of the failure modes are also caused by the slow degradation modes, which could later become severe, leading to failure modes. For example, one broken interconnect on a cell that has two interconnects in a three-string module will reduce power due to degradation mode but not result in a failure mode as it is still within the warranty limit. However, when both the interconnect ribbons on a cell are broken, the diode will turn on and the module will lose ~ 1/3 of its power, leading to failure as the power drop in the module exceeds the warranty limit. Therefore, the difference between failure mode and degradation mode should be fully understood before assigning a specific field issue under failure mode or degradation mode category.

Field Failure Modes and Mechanisms			
Failure Mode	**Failure Cause**	**Failure Effect**	**Failure Mechanism**
Broken interconnects	• Thermal expansion and contraction of interconnects* • Flexing due to wind load or snow load* • Difference in thermal expansion coefficient as compared to substrate/superstrate** • Larger cells** • Thicker ribbon** • Kinks in ribbon** • No stress relief in ribbon**	• Arcing (due to short distance between the broken ribbons) • Backskin burns (due to joule heated hotspots) • Ground fault due to backskin burns (due to water access) • Power drop beyond warranty limit due to severe series resistance or diode activation	• Thermo-mechanical fatigue
Solder bond failure	• Thermal expansion and contraction* • Metal segregation* • Flexing due to wind load* • Vibration during shipment (poor packaging)* • Electrical cycle (day/night or sunny/cloudy)* • Fewer solder bonds per cell (per tabbing ribbon)** • Absence of redundancy for non-cell solder bonds** • No stress relief for interconnects** • Use of non-softer ribbon** • Poor quality of solder bonds (alloy/process)**	• Backskin burns (due to joule heated hotspots) • Ground fault due to backskin burns (due to water access) • Shattered glass (due to hotspots) • Power drop beyond warranty limit due to severe series resistance	• Thermo-mechanical fatigue

Corrosion	• Moisture ingress through backsheet or laminate edges* • Presence of higher ambient temperature along with humidity* • High system voltage due to sunlight presence* • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy)** sensitivity to moisture	• Hotspot induced backskin burns • Hotspot induced broken glass • Power drop beyond warranty limit due to severe series resistance	• Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime), or photoelctrochemical corrosion (semiconducting components during daytime) between cells or between cell and frame
Broken cells	• Difference in thermal expansion and contraction of cell components* • Vibration during shipment (poor packaging)* • Wind/snow load* • Larger cells** • Thinner cells** • Larger modules** • Cell chipping**	• Drop in power beyond acceptable/warranty limits (due to increase in crack length and chipping away active cell area; it is to be noted that broken cells often only result in a small power loss not a module failure) • Hotspots (due to reverse bias heating)	• Thermo-mechanical fatigue
Encapsulant delamination	• Sensitivity of adhesive bonds to ultraviolet (UV) light at higher temperatures or to humidity in the field* • Poor adhesive bonds at the interfaces during processing (glass/encapsulant; cell/encapsulant; backsheet/encapsulant)** • Contamination from the material (Excess Na in glass or acetic acid from encapsulant)**	• Moisture ingress • Enhanced encapsulant conductivity and interface conductivity (enhanced chemical/ electrochemical/ photoelectrochemical corrosion) • Major transmission loss • Power drop beyond warranty limit due to optical decoupling and moisture ingress induced corrosion	• Photothermal reaction (interface bonds breakage due to UV and temperature) • Chemical reaction (interface bond breakage because of humidity or contaminants)

Broken glass	• Primary cause may probably be attributed to flying pebbles from cutting the grass • Hotspots or arcs due to broken interconnects or solder bonds because of thermal expansion / contraction* • Thermal gradient within glass (for annealed glass)* • Vandalism (rock throwing)** • Failure of support structure** • Misuse of support structure** • Not following manufacturer's mounting instruction** • Process induced stress (only annealed glass)** • Defective supply chain **	• Ground fault • Enhanced corrosion due to moisture access during rainy and humid days • Dramatic drop in power during rainy days (short circuiting)	• Thermo-mechanical fatigue
Hotspots	• Thermal expansion/contraction of interconnects or solder bonds* • Shadowing** • Faulty cell or cells in a string** • Low shunt resistance cells** • Failure of bypass diode**	• Backskin burns • Decrease in power • Shattered glass • Encapsulant bubbling (localized) • Encapsulant discoloration (localized) • Power drop beyond warranty limit	• Thermo-mechanical fatigue or purely electrical
Junction box failures	• Thermal expansion/contraction of junction box circuit* • Thermal expansion/contraction of junction box attachment/adhesive* • Water access to the junction box circuit beneath the junction box due to poor attachment with backskin (workmanship issue)** • Junction box without proper pottant or drainage** • Water access to the junction box circuit through breathable hole**	• Arcing (inside junction box) • Ground fault • Corrosion • Power drop beyond warranty limit due to severe increase in series resistance	• Thermo-mechanical fatigue

Ground fault	• Installation error (sharp metallic penetration from mounting structure to active cell circuit)**	• Arcing with potential fire	• Not applicable
Backsheet warping/detaching/ cracking/crumbling	• Poor adhesion between encapsulant and backsheet • Moisture ingress through backsheet and/or laminate edges • Polymer disintegration over time	• Ground fault under wet conditions (due to water access to active circuit and frame; however, note that the backsheet issues do not usually result in module failure)	• Chemical reaction weakening interface bonds (due to higher ambient temperature and/or humidity)
Connector failures	• Thermal expansion and contraction* • UV/heat/humidity* • Installation error** • Incompatible male/female parts**	• Arcing • High voltage exposure risk (worse in flat roof puddles!) • Contact resistance energy loss • Connector lifetime reduction (due to higher operating temperature; worse in hot-sunny location rooftops)	• Thermo-mechanical fatigue • Chemical corrosion
Structural failures	• Wind load* • Snow load* • Not following manufacturer's mounting instruction** • Inappropriate frame adhesive** • Inappropriate frame profile** • Inappropriate mounting locations on the frame** • Inadequate installer training** • Insufficient glass thickness**	• Module breakage • Frame deformation	• Mechanical fatigue

Bypass diode failures	• Thermal expansion and contraction* • Insufficient diode rating** • Insufficient heat dissipation inside junction box**	• Open circuit failure of the bypass diode may not result in any noticeable change in module output • Without a functional bypass diode the module will be susceptible to hot spot problems and arcing if an open circuit occurs within the circuit protected by that bypass diode • Short circuit failure of the bypass diode will lead to a loss of the power (beyond warranty limit) produced by the cells being protected by the failed diode.	• Thermal fatigue

Degradation Modes and Mechanisms

Degradation Mode	**Degradation Cause**	**Degradation Effect**	**Degradation Mechanism**
Gradual cracking of interconnects	• Thermal expansion and contraction of interconnects* • Flexing due to wind load or snow load* • Difference in thermal expansion coefficient as compared to substrate** • Larger cells** • Thicker ribbon** • Kinks in ribbon** • No stress relief in ribbon**	• Slow decrease in power (due to increase in series resistance) but within warranty limit	• Thermo-mechanical fatigue
Slow corrosion	• Moisture ingress through backsheet or laminate edges* • Presence of higher ambient temperature along with humidity* • High system voltage due to sunlight presence* • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy)** sensitivity to moisture	• Increase in series resistance and decrease in power but within warranty limit	• Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime), or photoelctrochemical corrosion (semiconducting components during daytime) between cells or between cell and frame

Gradual cell breaking	• Difference in thermal expansion and contraction of cell components as compared to superstrate/substrate* • Vibration during shipment (poor packaging)* • Wind/snow load* • Larger cells** • Thinner cells** • Larger modules** • Cell chipping**	• Slow decrease in power (due to decrease in shunt resistance) but within warranty limit	• Thermo-mechanical fatigue
Gradual encapsulant discoloration	• UV exposure at higher operating temperatures* • Reduced breathability** • Higher UV concentration* • Inappropriate additives in EVA**	• Transmission loss • Reduced current/power but may not be affecting fill factor or warranty limit • Cosmetic/visual change	• Photothermal reaction (in the presence of UV and higher module temperature)
Gradual electrochemical corrosion or cation migration to the semiconductor surface/junction	• Moisture ingress through backsheet or laminate edges** • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy) sensitivity to moisture**	• Series resistance increase and/or shunt resistance decrease depending on bias polarity and climatic conditions • Potential induced degradation leading to power loss but within warranty limit	• Electrochemical corrosion (metallic components during daytime) or photoelctrochemical corrosion (semiconducting components during daytime are more sensitive to electrochemical reactions under light) between cells or between cell and frame
Gradual solder bond failures	• Thermal expansion and contraction* • Flexing due to wind load** • Vibration during shipment (poor packaging)** • Electrical cycle (day/night or sunny/cloudy)* • Small number of solder bonds per cell (per tabbing ribbon)** • Absence of redundancy for non-cell solder bonds** • No stress relief for interconnects** • Use of non-softer ribbon** • Poor quality of solder bonds (alloy/process)**	• Bussbar discoloration • Power decrease within warranty limit due to series resistance increase	• Thermo-mechanical fatigue

Gradual backsheet warping/detaching/ cracking/crumbling	• Poor adhesion between encapsulant and backsheet** • Moisture ingress through backsheet and/or laminate edges** • Polymer disintegration over time**	• Slow power degradation (due to corrosion of cell and circuit components) but within warranty limit	• Chemical reaction weakening interface bonds (due to higher ambient temperature and/or humidity)
Gradual module mismatch	• Difference in degradation rate between field-aged modules in a string caused by poor production quality control**	• Slow power loss at the string/array level (due to operation away from each module's maximum power point) but within warranty limit	• Not applicable
Gradual soiling	• Low tilt angle of modules in soiling-prone locations with infrequent rainfall*	• Slow transmission loss • Reduced current/power but may not be affecting fill factor or warranty limit • Cosmetic/visual change	• Strongly adhering and gradual hardening of soil layer on superstrate or weakly adhering and rain/wind cleaning of soil layer (leading to fixed/temporary annual degradation due to non-cumulative reversible annual rain effect)

Notes: * Environmental Cause ** Material/Design/Process/Construction Cause

A detailed visual inspection checklist, developed by the National Renewable Energy Laboratory (NREL) for recording field failures is presented in Appendix A. For the purposes of statistical and physical modeling of the power plants, these field issues may be segregated into two categories—Module Failures and Module Degradation—as indicated in Table 3.

Summary—Field Failure and Degradation Modes, Mechanisms, Causes, and Effects: Based on an extensive analysis of the individual failure and degradation modes, mechanisms, causes, and effects, failure mechanism could be triggered by one or more failure causes and a failure mode could trigger one or more failure effects.

PV ACCELERATED TESTING: STRESS TYPES, LEVELS, AND PRIORITIZATION

Concept of Accelerated Testing for Photovoltaic Modules

The life characteristics of a product including time-to-failure (TTF) are traditionally obtained using actual degradation field data. In the case of PV modules, the end of life (for example, time-to-degrade 20% from rated power) may be estimated using a simple linear extrapolation based on the annual field degradation rate (say, 0.8% P_{max} drop per year). However, the manufacturers and the other stakeholders will have difficulty waiting long enough to obtain the degradation data in the field. The reasons for this difficulty include the very small annual degradation rate and the small time period between design and release. In AT, the product is forced to fail more quickly than it would under use conditions. The sole purpose of an AT program is to obtain life characteristics of the product being tested. In any AT, the general approach is to apply higher stress levels than actual use conditions over a short period of time to induce failures that would normally occur in the field. The AT can be used to induce both hard failures (reliability) and soft losses (durability or degradation).

Highly accelerated life testing (HALT) is a destructive test typically performed in the reliability/design laboratories of manufacturers during product development cycle. The purpose of this test is to find ultimate design weaknesses of the product. Highly accelerated stress screening (HASS) is a non-destructive stress test performed in the manufacturing screens/processes. The purpose of this test is to fail bad products that most likely will fail early in the field and pass good products. Failing units in both tests are subjected to root-cause analysis and corrective action. Both tests are done well beyond use/field levels and the failures are detected in a few months instead of after years/decades in the field. HALT and HASS tests may be performed under step testing mode with one environmental variable at a time (for example, temperature or UV light) or combined testing mode with multiple environmental variables at a time (for example, temperature and humidity). There is no single "standard or universal" procedure for the HALT or HASS test for PV modules, but multiple procedures may potentially be developed for various location/climate specific conditions.

The lifetime of PV modules is a function of a few key major field stresses such as temperature, humidity, UV light, and system voltage. As shown in Figure 11, the acceleration factor is the ratio between time in the field (or use) test and time in the accelerated test. The purpose of accelerated tests for PV modules is to shorten the test time using simulated test conditions much more severe than the actual field operating conditions but without altering actual field failure mechanisms. A conceptual representation of AT of PV modules is shown in Figure 12. The concept basically involves several accelerated stress tests with pre- and post- characterizations. In the AT programs, the stress tests of PV modules are performed at higher levels than the field/use stress levels along with pre- and post-characterization of materials and modules from reliability, durability, and safety perspectives.

Summary—Concept of Accelerated Testing: The concept of and need for AT along with acceleration factor for PV modules are briefly discussed.

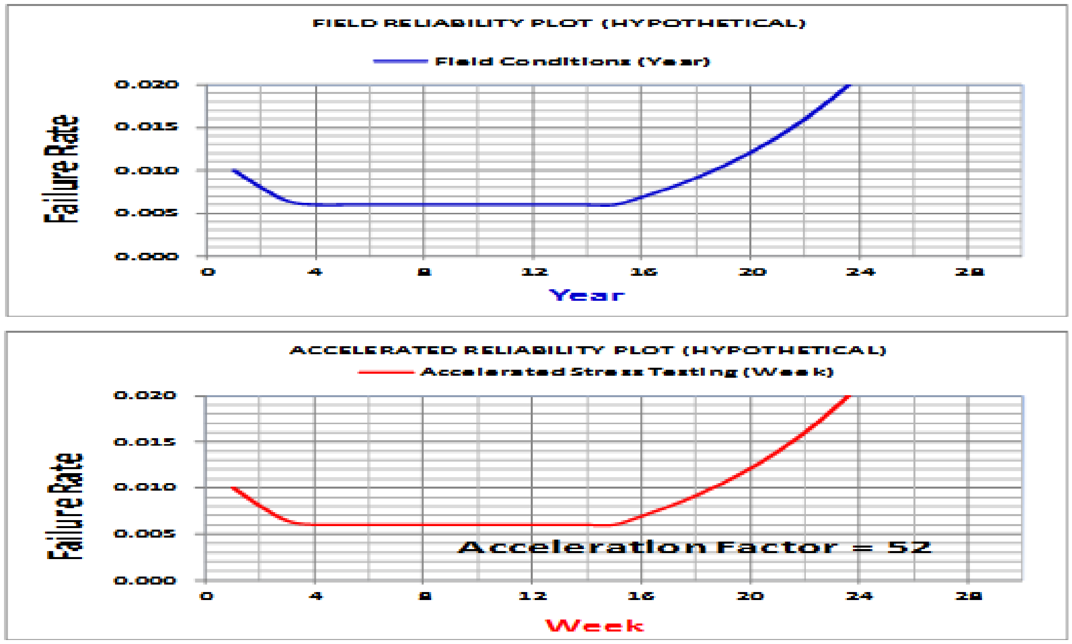


Figure 11: A rudimentary representation of acceleration factor from accelerated testing.

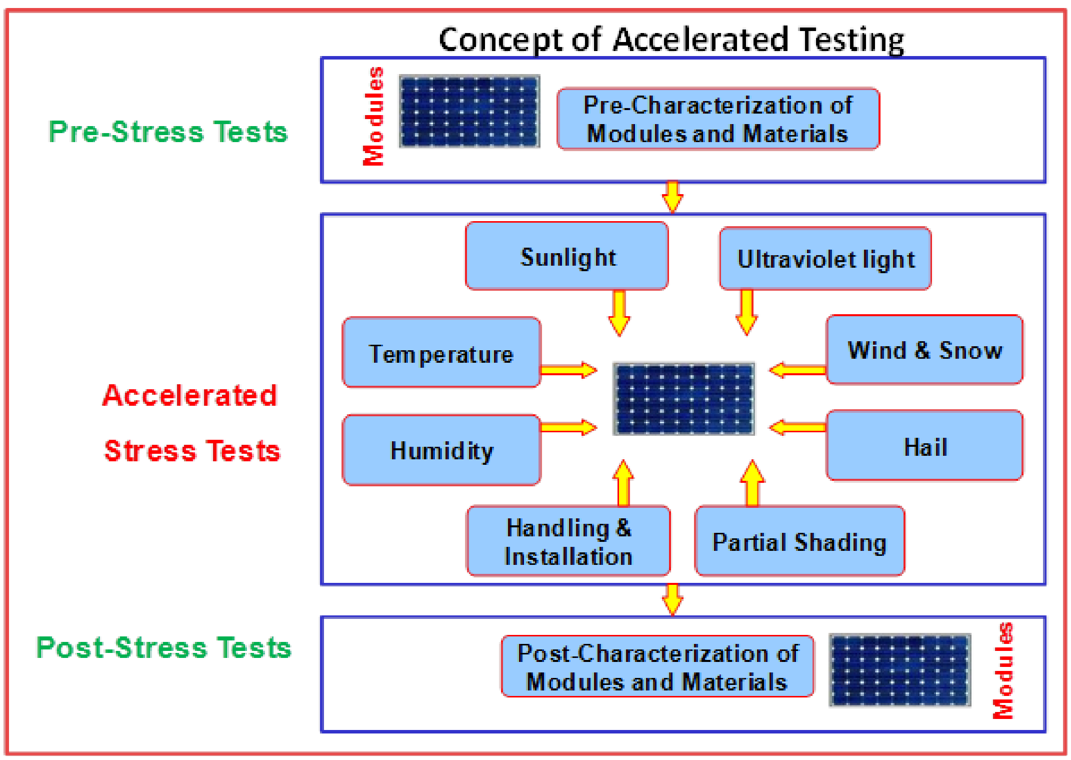


Figure 12: A conceptual representation of accelerated testing of PV modules.

Types and Selection of Accelerated Tests for Photovoltaic Modules

A reliability test can be accelerated in multiple ways. Increasing the level of experimental variables like UV light, temperature, humidity, or voltage can accelerate the chemical processes of certain failure mechanisms such as chemical degradation of adhesive chemical bonds (resulting in eventual weakening and failure) or of additives in the polymeric matrix (leading to discoloration). Variables like voltage and temperature cycling can both increase the rate of an electrochemical reaction (thus accelerating the aging rate). In such situations, when the effect of an accelerating variable is complicated, there may not be enough physical knowledge to provide an adequate physical model for acceleration (and extrapolation). Empirical models may or may not be useful for extrapolation to use conditions. The selected accelerated test programs must use one or more stresses simultaneously and/or sequentially to accelerate failure modes that actually occur in the real world. Module failure modes and lifetime in Miami, Florida, may be very different than in Phoenix, Arizona. One must decide which parameter(s) should be measured to best monitor the failure mode being evaluated and then define what constitutes a failure for that parameter (McMahon, 2004). The typical accelerated tests used to induce various failure modes of PV modules are listed in Table 4 (Wohlgemuth & Kurtz, 2011).

A study performed by BP Solar (Wohlgemuth, 2003) provides a good model for selecting appropriate accelerated tests and their limits specific to PV modules. In this study, BP Solar analyzed all the modules that were returned from the field from 1994-2002. During this time, nearly two million modules were in the field under warranty. The total number of returns during this nine-year period was 0.13%. About 45% of the modules were returned because of corrosion and about 41% were returned because of cell or interconnect breakage. BP Solar determined that the causes for failures were moisture ingress and thermal expansion/contraction, respectively.

Based on these field failure modes, BP Solar designed its AT program to perform thermal cycling in excess of the standard 200 cycles (IEC 61215) and the damp heat (DH) exposure in excess of the standard 1,000 hours (IEC 61215). There should be a standardized or defined approach to select appropriate accelerated tests. For example, the selection of appropriate accelerated tests may be obtained using a 11-step reliability testing program shown in Table 5.

Table 4

Selection of Appropriate Accelerated Tests to Induce Specific Field Failure Modes (Wohlgemuth & Kurtz, 2011)

Accelerated Stress	Failure Mode
Thermal Cycle	Broken interconnect
	Broken cell
	Solder bond failures
	Junction box adhesion
	Module connection open circuits
	Open circuits leading to arcing
Damp Heat Exposure	Corrosion
	Delamination of encapsulant
	Encapsulant loss of adhesion & elasticity
	Junction box adhesion
	Electrochemical corrosion of TCO
	Inadequate edge deletion
Humidity Freeze	Delamination of encapsulant
	Junction box adhesion
	Inadequate edge deletion
UV Test	Delamination of encapsulant
	Encapsulant loss of adhesion & elasticity
	Encapsulant discoloration
	Ground fault due to backsheet degradation
Mechanical Load	Broken interconnect
	Broken cell
	Solder bond failures
	Broken glass
	Structural failures
Dry and Wet Insulation Resistance	Delamination of encapsulant
	Ground faults
	Electrochemical corrosion of TCO
	Inadequate edge deletion
Hot Spot Test	Hot spots
	Shunts at the scribe lines
Hail Test	Broken cells
	Broken glass
Bypass Diode Thermal Test	Bypass diode failures

Note: TCO is transparent conductive oxides

Table 5:

Appropriate Selection of a PV Module Reliability Test Program—An Example With an 11-Step Approach

Task #	Task Type	Element	Example
1	Identify	Field/climate specific failure/degradation mode	Interconnect crack and backskin burning
2	Evaluate	Field failure/degradation effect(s)	Power drop by >20%
3	Identify	Field failure/degradation type	Hard failure
4	Identify	Field failure/degradation cause(s)	Thicker ribbon
5	Understand	Field/climate specific failure/degradation mechanism(s)	Thermo-mechanical fatigue
6	Identify	Appropriate lab accelerated stress test	Thermal cycling
7	Determine	Appropriate lab stress test upper and lower limits	Identification of correct temperature range would be very challenging. As an example, 85°C/-40°C range is used in IEC 61215 qualification standard but it may not be a correct range for the accelerated replication of a specific climatic condition.

8	Determine	Lab stress duration or cycles with ramp rate and dwell time	Identification of right cycle number is also challenging. As an example, 200 thermal cycles are used in IEC 61215 qualification standard but it is certainly not enough for almost all the sites if one is looking at a 25 year lifetime.
9	Identify	Lab failure mode	Power drop by <20%
10	Understand	Lab failure mechanism	Thermo-mechanical fatigue
11	Repeat tasks 6 through 10	Match the field failure mode and mechanism	Power drop exceeded 20%; stop the test

Summary—List and Selection of Accelerated Tests: An extensive list of accelerated tests corresponding to each failure module of PV modules is presented. For the selection of an appropriate accelerated test to quickly induce the required failure mode without compromising the failure mechanism, a 10-step reliability testing program is presented as an example.

Stress Level and Duration Limits of Accelerated Tests for Photovoltaic Modules

The maximum stress levels or duration used during the accelerated tests should not introduce failure modes that do not occur in the field (commonly called foolish failure modes). In order to determine the maximum stress level and duration during AT, it is necessary to identify the use stress level and failure mechanism in the field. The limits for testing time, cycle, and stress level need to be determined for various stresses including temperature, humidity, UV, and voltage. Because the qualification tests defined in the IEC 61215 and IEC 61646 standards were developed based on failure modes identified in the field, the limits identified in these standards may be used as starting points (Wohlgemuth & Kurtz, 2011). Again, the accelerated test levels should not alter the actual field failure mechanisms. For example, the limits identified in the standard thermal cycling test (85°C/-40°C; 200 cycles) and DH test (85°C/85% relative humidity [RH]; 1,000 hours) may be increased provided the failure modes and failure mechanisms of both field failures and accelerated test failure are identical. A few examples for the appropriate and inappropriate stress and duration limits of the primary accelerated tests (for temperature, humidity, UV, and voltage) are presented below.

Stress Level and Duration Limits: Temperature

The temperature cycling is a major stress test done on PV modules to determine the ability of the module to withstand thermal mismatch, fatigue, and other stresses caused by repeated changes of temperature.

Due to substantial difference in the thermal coefficients of expansion between the silicon wafer and the tinned-copper ribbon, bowing and breaking of the thinner wafers could occur if the ribbons are soldered continuously along the screen-printed bus lines on the silicon wafer or just soldered too close to the edge of the cell on front and back (Dhere, 2005). A joint paper published by Sandia and NREL indicates that the changes in solder-joint geometry caused by thermomechanical fatigue reduce the number of redundant solder-joints leading to increased series resistance and decreased performance (Quintana, King, McMahon, & Osterwald, 2002). The stress level and duration limit related to the temperature stress can be increased three ways: the duration of the thermal cycling test can be increased just by increasing the number of cycles at the standard cycle rate of less than 100°C per hour; the stress frequency during the thermal cycle test can be increased by increasing the cycle rate; the stress limit can be increased by increasing the temperature range.

<u>Low cycle rate:</u> Based on the outdoor exposure via comparison to field data and via modeling of weather data, the two hundred normal/standard thermal cycles (between 85°C and -40°C) that are used in the qualification testing have been equated to 10 to 11 years (Wohlgemuth & Kurtz, 2011). For a lifetime of 20 years, additional thermal cycling is required. If the normal 200 cycles equals 10 years of field exposure, then 500 cycles would represent 25 years, assuming linear dependence of power drop on the number of cycles (Wohlgemuth & Kurtz, 2011). The results obtained in another study, presented in Figure 13 (Herrmann et al., 2010), appear to indicate a linear dependence of power drop with the number of cycles during normal thermal cycling (NTC). If one assumes 20% power drop from the original is the durability/warranty requirement for thermal cycling, all seven but one (Figure 13) have met the warranty requirement up to 800 cycles at a temperature difference of 125°C (from -40°C to 85°C). Therefore, the required number of NTC for the lifetime determination may be calculated assuming linear degradation (for example, 0.5%-2.4% power drop per year) in the field and the linear degradation in the accelerated thermal cycling test and/or using the Coffin-Manson model.

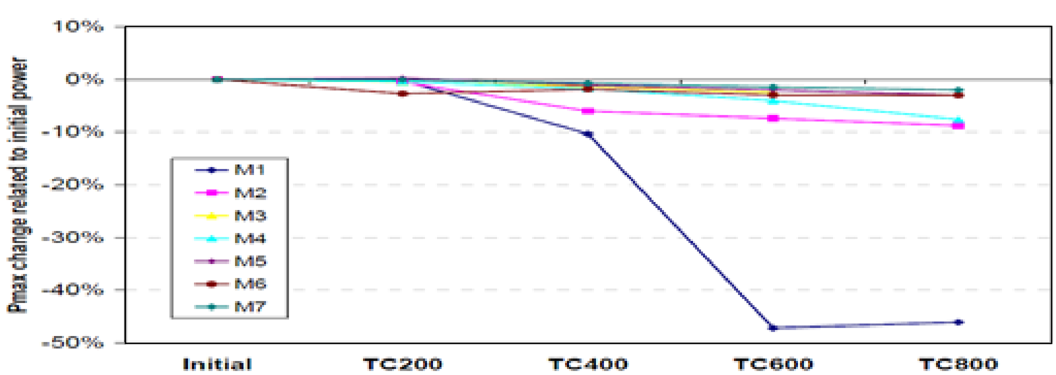


Figure 13: Cycle limit for thermal cycling stress of PV modules (Herrmann et al., 2010).

High cycle rate: A rate of 60°C/hour is commonly used in military specifications and 180°C/hour in space component specification (Hoffman & Ross, 1978). In order to reduce the cycling duration, another research group has attempted to use a rapid thermal cycling (RTC) method with a cycling rate of 400°C/hour (Aoki, Okamoto, Masuda, & Doi, 2010). This study has indicated a power loss of 37% and the failure of solder bonds within 500 cycles as indicated in the impedance study shown in Figure 14. During this 500 cycling period, the testing was paused three times (see Figure 14) and the module was maintained at room temperature, apparently, for the stress relaxation/annealing. Unfortunately, this rapid thermal cycling method has apparently been applied on only one sample with no comparison to the standard/normal cycling method on an identical sample. An extensive NTC study carried out by BP Solar on a specific crystalline silicon module type indicated that the interconnect and solder bond failure from thermal cycling is not likely to be the lifetime limiting failure mechanism for this specific module type (Wohlgemuth, 2008). If the solder bond failure from thermal cycling was not likely to be the lifetime limiting failure mechanism in the field, the failure observed in the RTC method within 500 cycles may be attributed to the thermal shock imposed on the solder bonds (Wohlgemuth & Kurtz, 2011). It may be possible to conclude that RTC at 400°C/hour rate may be a good screening test but it may not be an appropriate lifetime test; however, it may be worth exploring the RTC method with a large number of identical samples comparing NTC (perhaps at various cycling rates of 180, 300, and 400°C per hour cycle rates) and RTC failure modes and mechanisms. This comparative study might determine the upper limit for the cycling rate so the testing time can be significantly reduced.

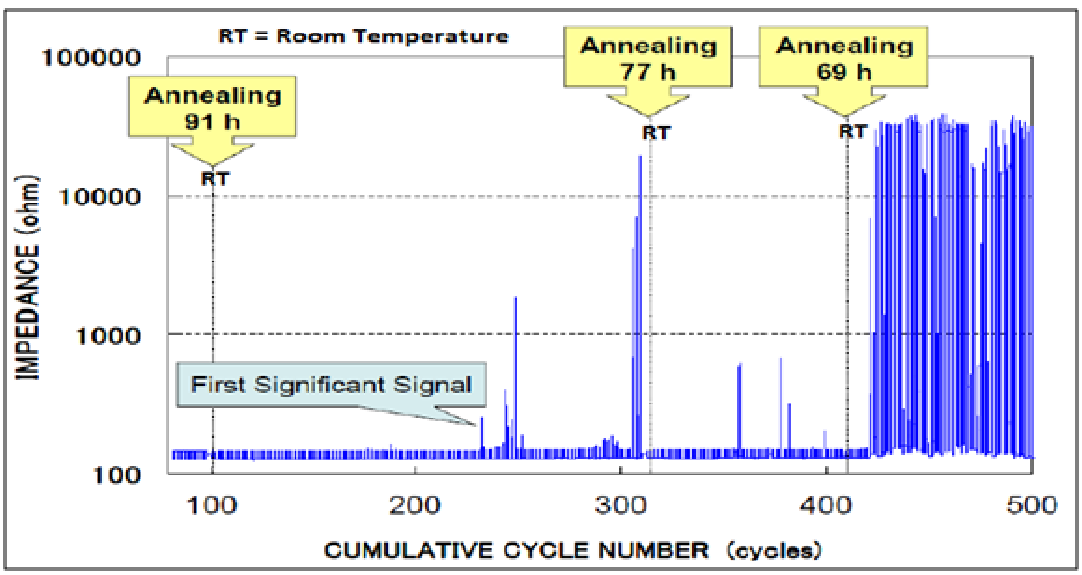


Figure 14: Variation of impedance of during rapid thermal cycling at 400°C/hour rate (Aoki, Okamoto, Masuda, & Doi, 2010).

High temperature range: As shown in Figure 15A, a study performed by SunPower indicates that the solder bond degradation cannot be differentiated between tin/lead (SnPb) and tin/silver (SnAg) if the number of thermal cycles is less than about 500 cycles at standard temperature range of -40°C and 90°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008). This plot also indicates that the SnPb solder bonds experience non-linear degradation with a dramatic increase after about 500 cycles whereas SnAg solder bonds experience linear degradation even up to 2000 cycles. In order to reduce the testing time (or number of cycles), SunPower performed testing on the solder bonds of these alloys at an increased upper temperature limit of 125°C (high temperature) instead of 90°C and the results are presented in Figure 15B. The required number of cycles for the lifetime determination can be calculated based on the linear and non-linear degradation behaviors of these soldering alloys. However, it is to be noted that, at this upper temperature limit of 125°C, the module encapsulant will be affected leading to other failures that are not seen in the field.

Summary—Temperature Stress Limits: Based on this literature review, the lifetime testing of PV modules for cyclic thermal stress can appropriately be performed just by increasing the number of standard/normal cycles at, perhaps, a higher cycling rate (for example, 200 cycles per hour) and temperature range (for example, -40°C to +90°C) without altering the failure mode and mechanism observed in the standard/normal thermal cycling test (200 cycles from -40°C to +85°C). This literature review indicates that the extended thermal cycling test between 500 and 800 thermal cycles at -40°C to +85°C with less than 100°C/hour ramp rate would be sufficient for the 20-year lifetime prediction of PV modules.

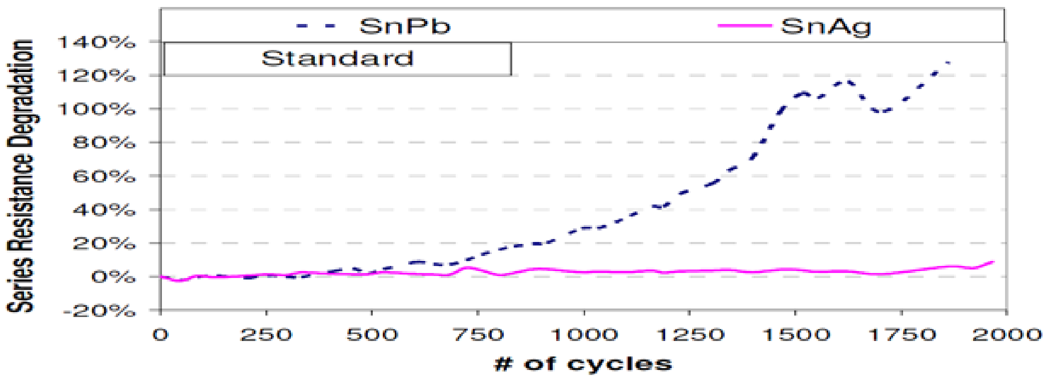


Figure 15A: Performance degradation of PV modules at the cycle temperature of -40°C and 90°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008).

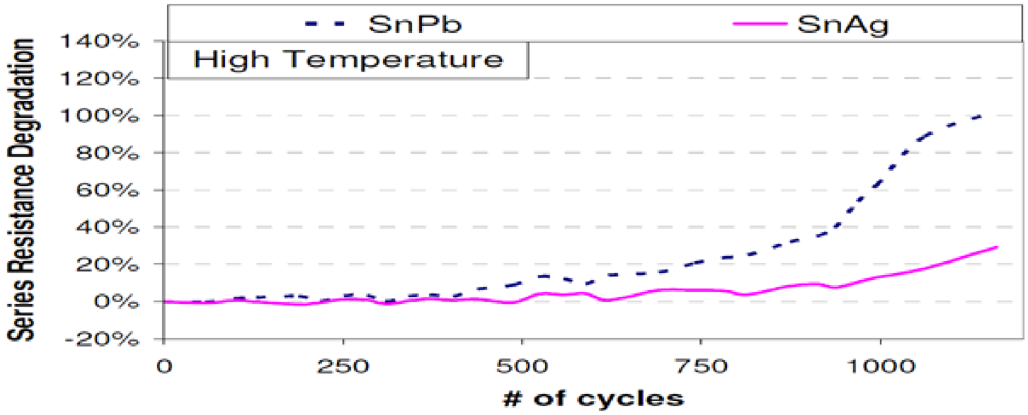


Figure 15B: Performance degradation of PV modules at the cycle temperature of -40°C and 125°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008).

Stress Level and Duration Limits: Humidity

The DH test is another major stress test done on PV modules to determine the ability of the module to withstand the effects of long-term penetration of humidity.

The encapsulant that has been laminated and cured on a flat glass will have reasonable bond strength in a dry environment, but may delaminate when exposed to a humid environment. As shown in Figure 16, the delamination will lead to moisture ingress and subsequent corrosion of cell components. As shown in Figure 21, the same Arco Solar M55 module in a hot-dry climatic condition undergoes encapsulant browning only instead of encapsulant browning and delamination.

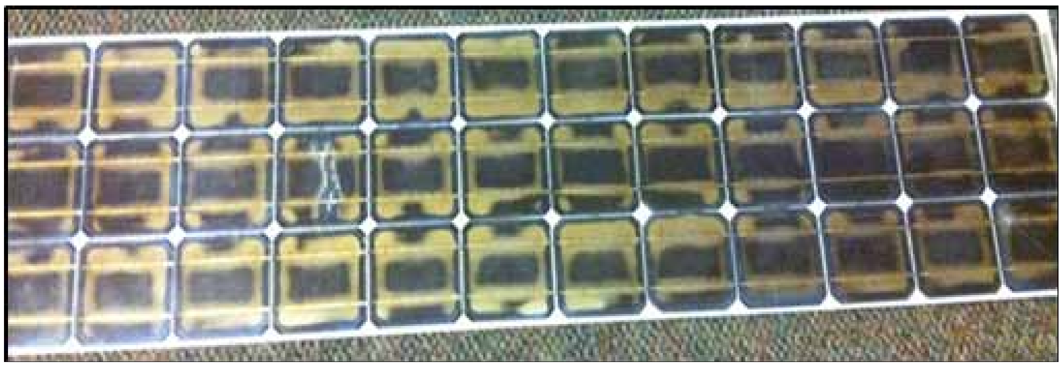


Figure 16: Encapsulant browning, delamination, and moisture ingress induced corrosion of cell components in a hot-humid condition (Site: Austin, Texas; Arco Solar M55 modules installed in approximately 1986 and apparently removed after about 10 years of operation. Photo courtesy: Bill Kaszeta, PVRI).

Currently, the DH testing condition of 85°C/85%RH is extensively used in the qualification standards and by the industry. The hot-humid environment used in this test for 1,000 hours could weaken the interfaces including backsheet/junction box and glass/encapsulant. A recent study indicated that 5.5% (10 out of 183) of the modules that were subjected to this test failed in the post-wet resistance test (TamizhMani et al., 2012). As shown in Figure 17, a detailed diagnostic test revealed that these post-wet resistance failures were due to the weakened interfaces of junction box attachment and laminate edge sealant failure.

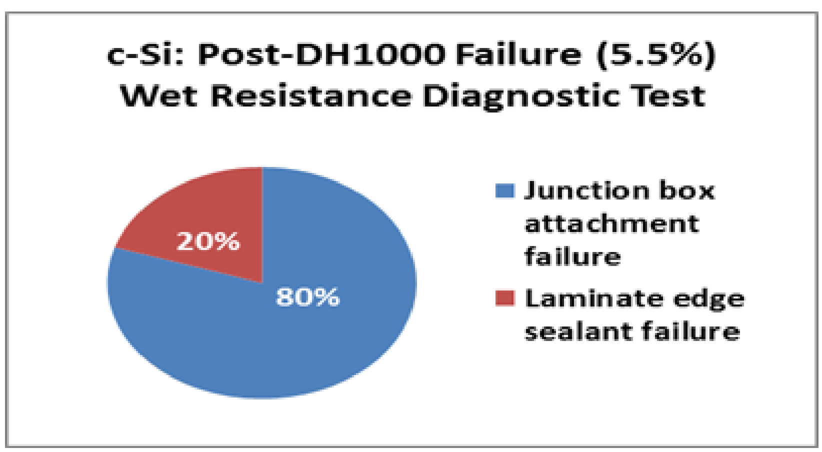


Figure 17: Post-DH diagnostic wet resistance test revealing weak interfaces (TamizhMani et al., 2012).

The stress limit and duration for this test was chosen by JPL in the early 1980s based on a review of nominal module operating conditions in the field and the limitation of the encapsulant material to operate at elevated temperatures. Therefore, a temperature value of 85°C was selected by JPL as a first choice because it was comfortably below the 100°C limit for most encapulant materials but high enough to provide rational test durations of less than six months. The combined 85°C/85% RH test condition was selected for the module testing because it was commonly used by the semiconductor industry and the cell level reliability research groups.

Module: The effects of high RH on the low temperature (early morning) glass surface of the PV modules could lead to potential induced degradation (discussed in the next section). However, the RH value inside the laminate and at the interfaces within the package is not necessarily the ambient RH and it is expected to be extremely limited inside the package during daytime due to high operating temperatures of the modules and to very limited moisture ingress from the laminate edges or transport through the typical backsheets. In the current accelerated DH testing of IEC 61215, a relative humidity on the glass surface is maintained at 85% when the cell temperature is at 85°C. This condition never happens in the field and it is difficult to judge what outdoor exposure the 1,000-hour exposure at 85°C/85% RH represents (Wohlgemuth & Kurtz, 2011).

In order to determine acceleration factors between actual field data and the accelerated test data (for example, 85°C/85% RH for 1,000 hours), an extensive experimental work based on the recent/current PV module designs and a detailed modeling study needs to be carried out similar to the study published by JPL in 1984 (Otth & Ross, 1983).

The typical meteorological year (TMY) database of United States and other countries provides weather data including hourly RH, irradiance, ambient temperature, and wind speed. Based on the hourly irradiance, ambient temperature, and wind speed, the hourly module temperature can be calculated using JPL, Sandia, or IEC models (Otth & Ross, 1983; IEC68153-2, Draft; King, Boyson, & Kratochvill, 2004). The JPL model (Otth & Ross, 1983) is reproduced below:

$$T_M = T_a + (0.325 - 0.01\ V)\ S \qquad (1)$$

$$RH = (P_d / P_M) \times 100 \qquad (2)$$

Where

T_M = module operating temperature °C

T_a = ambient dry-bulb air temperature °C

T_d = ambient dewpoint temperature °C

V = wind velocity m/s

S = irradiance level mW/cm^2

RH = module relative humidity, %

$P_M = P(T_M)$ = water saturation pressure at temperature T_M

$P_d = P(T_d)$ water saturation pressure at temperature T_d

and where $P(T_d)$ and $P(T_M)$ are evaluated from:

$$\log_{10} [P(T)/218.17] = [B (3.2438 + 0.005868\ B + (0.00227\ B)^3)] / [(T + 273.15)(1 + 0.002188\ B)]$$

Where $B = 374.12 - T$

If the reaction rate with respect to temperature and/or humidity doubles for every 10-unit (10°C or 10 % RH) following a conventional Arrhenius model, then one can calculate the acceleration factor for EVERY hour using JPL models shown below (Otth & Ross, 1983). In these models, 1 % RH is considered to be equivalent to 1 °C as was determined based on an experimental study of one degradation mechanism performed by another research group and referenced by JPL (Desombre, 1980). Based on these models, it is now possible to calculate the equivalent accelerated time required for each TMY/field-hour. Because the equivalent accelerated time for each field-hour is known, one can integrate the equivalent accelerated time for one year or twenty years.

$t_i = \Delta_i \times 2^{(T_i - 60)/10}$

and

$t_i = \Delta_i \times 2^{(T_i + RH_i - 100)/10}$

Where

Δ_i = duration of field – exposure interval i (1 Hr)

t_i = duration at 60°C , 40 % RH to yield same aging as i

T_i = module temperature during interval i °C.

RH_i = module relative humidity during interval i %

Based on the above models, JPL constructed the plots, shown in Figure 18A and Figure 18B, for Phoenix (hot-dry), Miami (hot-humid), and Boston (cold-dry or temperate) climatic conditions. If temperature is the only aging factor for the PV modules, then the AT at 85°C for 4,000, 8,000, and 10,000 hours is calculated to be equivalent to 20 years of lifetime in Boston, Miami, and Phoenix, respectively (Figure 18A). If combined temperature and humidity are the only aging factors for the PV modules, then the AT at 85°C and 85 % RH for 100, 350, and 700 hours should be equivalent to 20 years of lifetime in Phoenix, Boston, and Miami, respectively (Figure 18B).

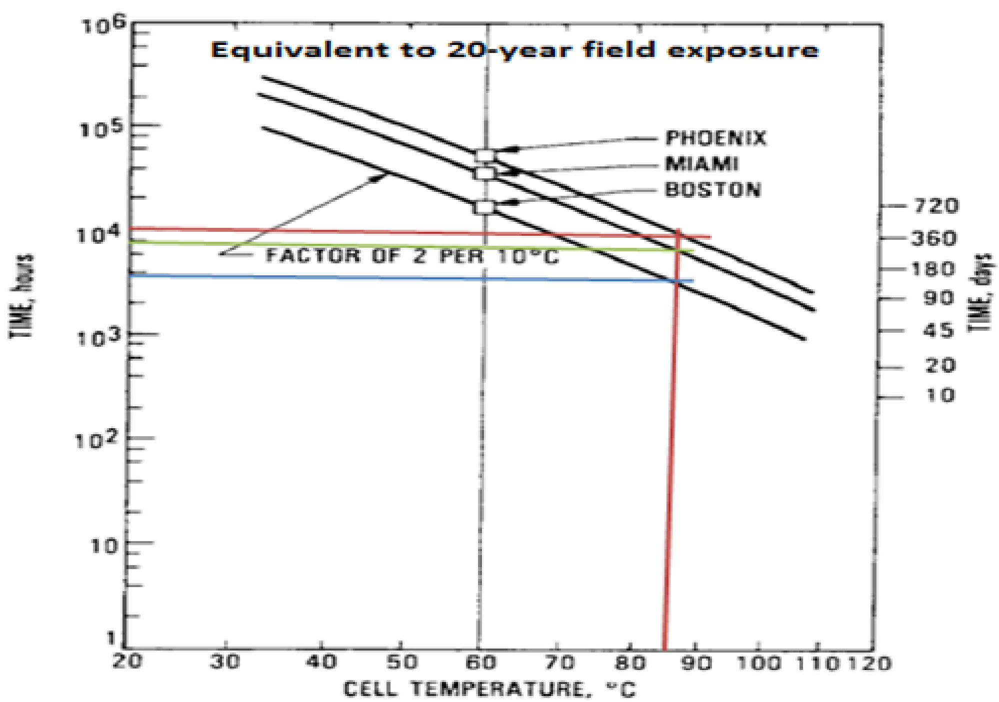


Figure 18A: Accelerated testing at 85°C for 4,000, 8,000, and 10,000 hours is calculated to be equivalent to 20 years of lifetime in Boston, Miami, and Phoenix, respectively.

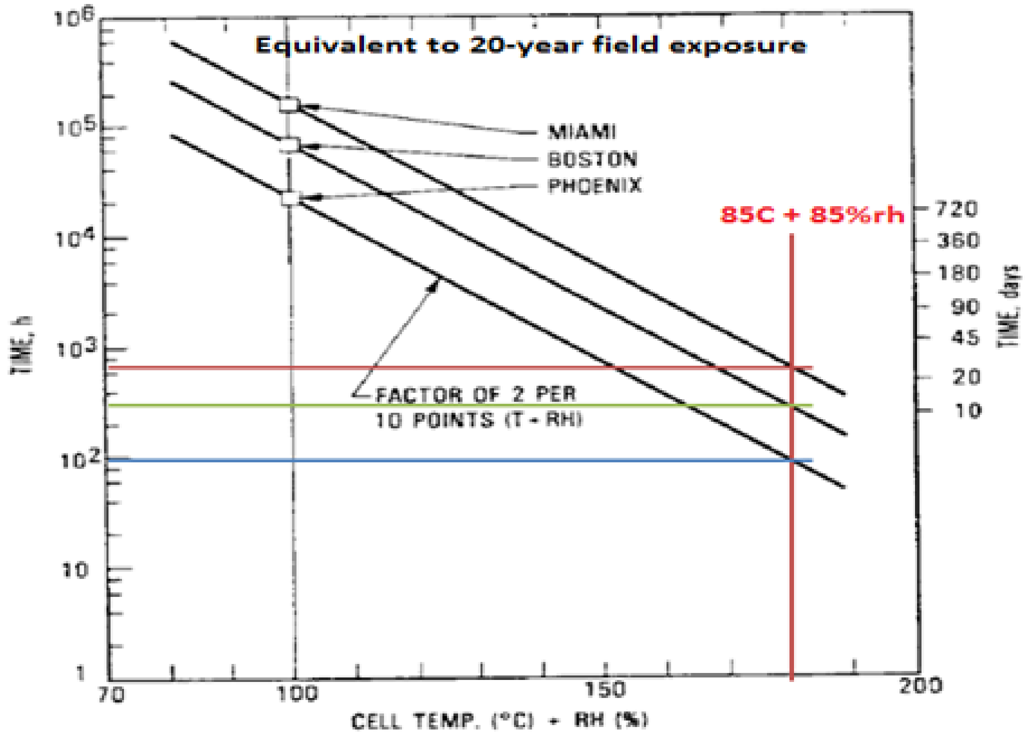


Figure 18B: Accelerated testing at 85°C and 85% RH for 100, 350, and 700 hours should be equivalent to 20 years of lifetime in Phoenix, Boston, and Miami, respectively.

Similar to the thermal cycling test, an approach may be taken to determine the required number of hours for the DH testing. As shown in Figure 19, for conventional screen-printed polycrystalline silicon technologies, it takes about 3,000 hours of DH testing (at 85°C/85%RH) to reach a 20% power loss, the level of degradation typically specified in the 25-year warranty (Wohlgemuth, 2008). However, it is again cautioned that the failure mode seen after 3,000 hours at 85°C/85%RH is not something that is commonly seen in field exposed modules because the modules tend to dry out (both at the surface and in the bulk) in the real world at this high temperature of 85°C. It appears that the 85°C/85%RH test condition uses unrealistic conditions—the 85°C/85%RH test condition appears to be a good screening test (for qualification or comparative testing) but not a good (too severe!) weathering test condition (for lifetime testing). Therefore, there is a need to match the field failure mechanisms and modes in the lifetime accelerated DH testing using a range of temperature and humidity levels. Also, it is yet to be objectively demonstrated that the modules that have experienced less than 20% degradation over 3,000 hours at 85°C/85%RH would have lasted 25 years in the field even if the difference in the failure modes/mechanisms between AT and field testing is ignored.

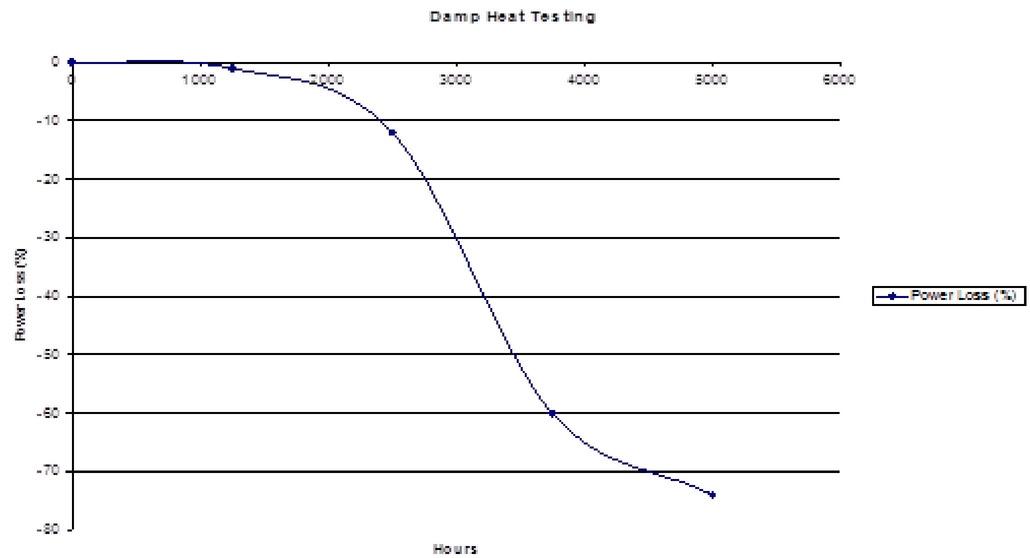


Figure 19: Maximum duration limit for damp heat stress of PV modules.

Backsheets and Encapsulants: The water vapor permeation (moisture ingress) rate through backsheets leads to many failure modes in PV modules and it is related to the change in the molecular weight of the backsheet polymer. For example, the molecular weight of a polyethylene terepthalate (PET) backsheet decreases during hot-humid field exposure through hydrolysis. As shown in Figure 20, a comparison of molecular weight decrease between field aged PET for 15 years at Rokko (Japan) and DH tested PET samples seems to indicate that the standard DH testing at 85°C/85%RH for 1,000 hours is equivalent to 45 years in the field (Eguchi, 2011). It is important to note that the phase change temperature of polymeric materials should not be exceeded when determining the upper and lower temperature limits for the accelerated tests. Because the 85°C limit used in the DH test is higher than the phase change temperature for PET, the above mentioned linear correlation should be used with caution.

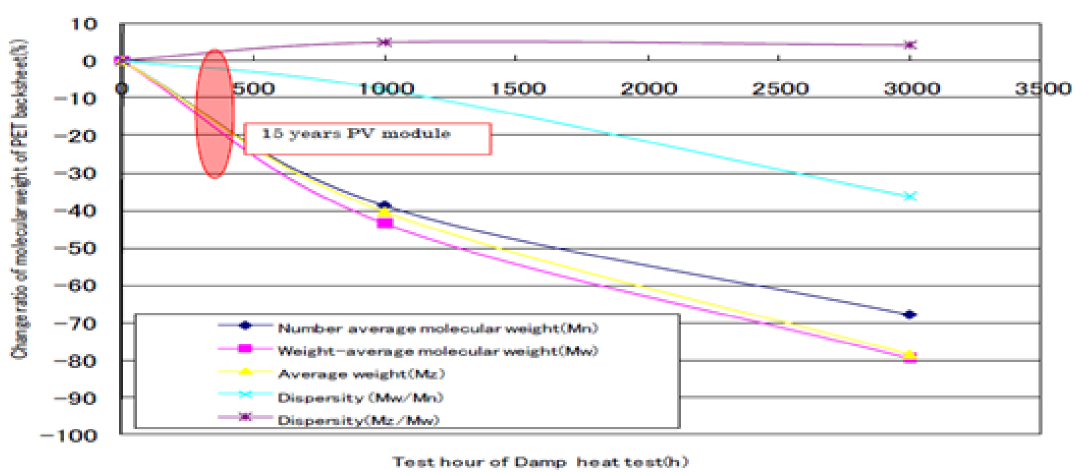


Figure 20: Loss of molecular weight of PET backsheet during extended damp heat test (Eguchi, 2011).

Based on the module operating temperatures at various climatic conditions and the indoor accelerated tests, Fraunhofer Institute ISE research group has calculated the required DH stress time limit for encapsulant and backsheet materials (Kohl, 2009). Depending on the reaction mechanism, the activation energy from one polymer to the other may differ. For example, the activation energies calculated for tedlar-polyester-tedlar (TPT) backsheet and EVA, thermoplastic polyurethane, and polyvinyl butyral encapsulants are 42, 34, 31, and 56 kJ/mole, respectively. This paper indicates that the DH test at the stress limit of 85°C/85%RH may need to be performed on EVA (activation energy of 34 kJ/mole) for a calculated time of about 1.5 years (13,000 hours) and about 0.5 year (4,000 hours) for a service lifetime of 25 years in tropic and desert climatic conditions, respectively. Similarly, for TPT, the calculated stress time at 85°C/85%RH stress limit for 25 years' service life in a desert condition is about 1,100 hours. If the activation energy is higher than the ones reported above, then the equivalent testing time at 85°C/85%RH would be dramatically lower as shown in this plot. It is to be noted that the calculated AT time presented in this work is based on the activation energy only without clearly identifying the corresponding actual field failure modes and mechanisms that are accelerated in the AT. An ongoing study at NREL seems to indicate that the PET layers undergo hydrolysis failure mechanism in the field (Kempe, 2012). Based on the chemical kinetics involved in the hydrolysis process, this work calculates that the 1,000 hours of DH testing at 85°C/85%RH is equivalent to about 300 years in Bangkok, one of the highest hot-humid climatic condition sites in the world.

Stress Level and Duration Limits: UV

The UV test is another important stress test done on PV modules to identify those materials and adhesive bonds that are susceptible to UV degradation. Typically, the UV absorbers are added in the encapsulant to keep UV from reaching the cell/encapsulant interfaces and the adhesives. Almost all modules contain EVA encapsulant and it does not discolor in UV. There are UV tolerant EVA formulae being sold today without UV absorbers (at least for front EVA). It is to be noted that the encapsulant discoloration occurs not due to the discoloration of EVA or UV absorbing additives but due to the other additives in EVA (anti-oxidants, curing systems, etc. that degrade in UV and cause discoloration) (Holley, Agro, Galica, & Yorgensen, 1996; Shigekuni & Kumano, 1997).

As shown in Figure 21, the discoloration of encapsulant is a common degradation mode due to UV exposure in the field, especially in hot-dry desert climatic conditions. As shown in Figure 16, the same Arco Solar M55 module in a hot-humid climatic condition undergoes encapsulant browning and delamination instead of just encapsulant browning.

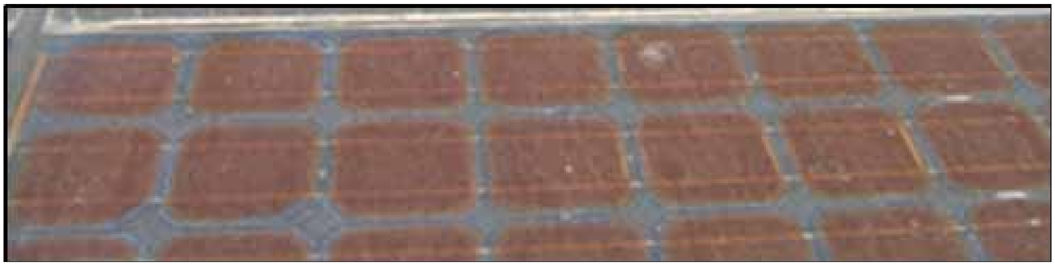


Figure 21: Encapsulant browning due to UV in a hot-dry condition (Site: Phoenix, Arizona; Arco Solar M55 modules installed in 1985 and still operating after 26+ years).

Based on the UV content of about 5.5% of the global irradiance in desert climatic conditions, the total UV-dose in desert conditions is calculated to be about 120 kWh/m^2/year (or about 3,000 kWh/m^2 over 25 years (Kohl, 2011). The UV absorbing additives used in EVA may chemically differ from one EVA manufacturer to the other and hence all EVAs cannot be considered the same. Before initiating the accelerated UV lifetime testing, two important things should be taken into account—selection of the UV source and selection of test sample construction.

The spectra of artificial UV sources strongly differ from the solar UV spectrum. Therefore, different aging behaviors of samples with different UV sources/lamps have to be expected and appropriately accounted for by using appropriate light sources (for example, xenon arc lamps) and correct optical filters. The extent of discoloration of encapsulant is dictated by two competing reactions: discoloration by UV light; bleaching by diffused oxygen through substrate or superstrate (Gonzalez, Liang, & Ross, 1985; Holley, Agro, Galica, & Yorgensen, 1996). Figure 22 clearly differentiates how the UV discoloration reaction dominates at the center of the cells and how the oxygen bleaching reaction (using diffused oxygen through the backsheet) dominates at the cell edges and cell cracks. Because the crystalline silicon (c-Si) wafers/cells do not allow oxygen to diffuse through and the inter-cell area is very limited in the current commercial modules (due to high packing density of square or scrounded cells as compared to round cells), the oxygen bleaching counter reaction of the encapuslant on the cell surfaces (which primarily dictate the power output) is very limited in current commercial modules.

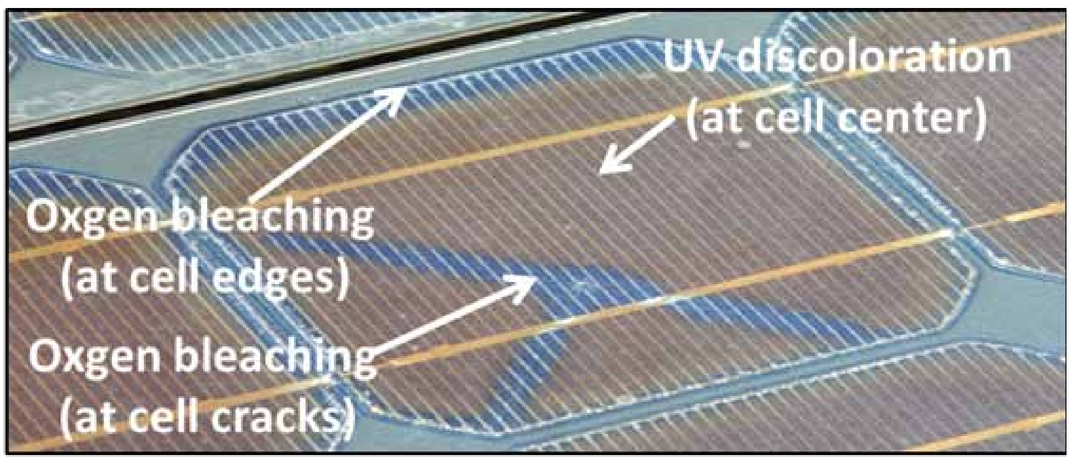


Figure 22: Encapsulant browning due to UV and bleaching around the cells and cell-cracks due to oxygen diffusion through backsheet and cell-cracks in a hot-dry condition (Site: Phoenix, Arizona; Arco Solar M55 modules installed in 1985 and still operating after 26+ years).

Figure 23 provides results of a specific EVA, called EVA-1 (Shioda, 2011). The modules based on EVA-1 were exposed in the field over 20 years and showed little (at the center and cell-gaps) or no (at the edges) activity loss of additives. The construction of these modules appears to be: glass/EVA/Cell/EVA/polymer backsheet with aluminum foil. Freshly constructed samples of the same EVA-1 were tested in the lab at 110°C and 60 W/m^2 UV irradiance (equivalent to UV dosage in natural sunlight) using a construction of glass/EVA/glass. When EVA-1 was tested in the lab at a UV irradiance tripled in intensity compared with that of natural sunlight (180 W/m^2) but at the same temperature of 110°C, the additives appear to have lost part of their activity without simulating the actual field failure mechanism. The temperature dependent EVA discoloration reaction rate without including oxygen bleaching counter reaction rate and the corresponding acceleration factor may be modeled using the Arrhenius equation (Gonzalez, Liang, & Ross, 1985). In order to evaluate the adhesion strength of EVA due to UV exposure over 20 years, it is necessary to continuously expose the test samples, with high UV transmittance glass in a typical weatherometer (2.5 UV suns at 60°C and 60%RH) for 6 to 7 months (Kempe, 2008). BP Solar reported the use of a UV-exposure at 90°C for 26 weeks (6.5 months) to verify a 25-year lifetime (Wohlgemuth, Cunningham, Monus, Miller, & Nguyen, 2006). The temperature limit (60-90°C) and the relevance of humidity presence (0-60%RH) with respect to encapsulant browning and delamination still need to be investigated.

Summary—UV Stress Limits: For the lifetime accelerated UV testing (for 20-25 years), the UV testing should be extended much beyond the qualification testing program. The literature indicates that the testing duration may have to be extended for 6 to 7 months with 2.5 times the UV dosage of natural sunlight. For the lifetime UV test, the temperature limit (60-90°C) and the relevance of humidity presence (0-60%RH) with respect to encapsulant browning and/or delamination still need to be investigated.

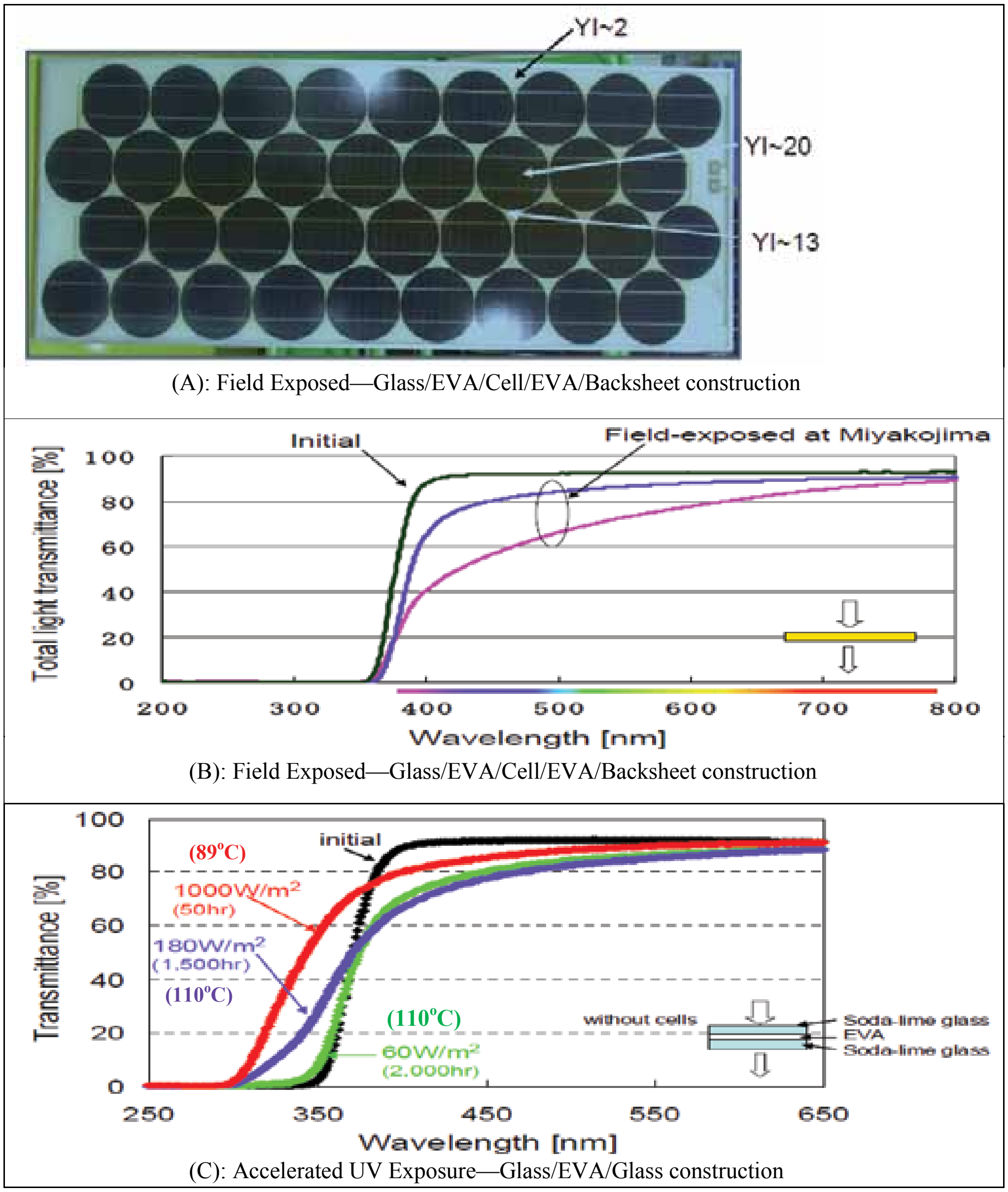


Figure 23: Acceleration limit for UV stress on glass/EVA/glass sample (Shioda, 2011).

Stress Level and Duration Limits: Humidity-Freeze

The purpose of this test is to determine the ability of the module to withstand the effects of high temperature and humidity followed by sub-zero temperatures. In the humidity-freeze test, the modules are cycled once a day for 10 days between -40°C and 85°C/85% RH. The hot-humid environment (causing absorption of moisture) followed by sub-zero temperature (causing expansion of the absorbed water as it freezes) used in this test detects weakness of the interfaces including backsheet/junction box and glass/encapsulant. A recent study indicated that 8.8% (11 out of 125) of the modules that were subjected to this test failed in the post-wet resistance test (TamizhMani et al., 2012). Similar to the DH test, the post-wet resistance failures were attributed to the weakened interfaces of junction box attachment and laminate edge sealant failure.

The humidity-freeze test was initially developed by JPL and the object of this test was to force moisture into the module and observe mechanical and moisture-induced corrosion via visual inspection. This stress test is usually done for 10 cycles between -40°C and +85°C in a sequence after short UV (15 kWh) and thermal cycling (50 cycles) pre-conditioning stresses. If there is an insufficient cross-linking or adhesion between interfaces (glass/encapsulant, encapsulant/cell, backsheet/encapsulant and junction box/backsheet in c-Si modules, and glass/edge sealant/glass in thin-film modules), this screening test can quickly identify these issues. This test is not considered to be a lifetime test and it does not necessarily need to be extended beyond 10 cycles. This test sequence has proven to be extremely sensitive and important in the qualification testing programs to pre-screen the adhesion strength of junction boxes to the backsheet of c-Si modules and the edge sealants of thin-film modules (the qualification test results of several thousands of modules are discussed in the next section).

Summary—Humidity-Freeze Stress Limits: Based on this literature review, the humidity-freeze test identified in the existing qualification testing would be sufficient to pre-screen the modules for the weak interfaces. Because it is not considered as a lifetime test, this test does not need to be extended beyond the 10 cycles identified in the current qualification standards.

Stress Level and Duration Limits: Voltage

Potential induced degradation (PID) due to high system voltages in hot-humid climates can be a major degradation mechanism in PV modules, and it adversely affects the performance of PV modules due to combined effects of two or more of the following factors: system voltage, superstrate/glass surface conductivity, encapsulant conductivity, and silicon nitride anti-reflection coating property. As shown in Figures 24A and 24B, a module can experience different types and extent of degradation depending on the grounding configuration, polarity, and module position in the string (Pingel et al., 2010).

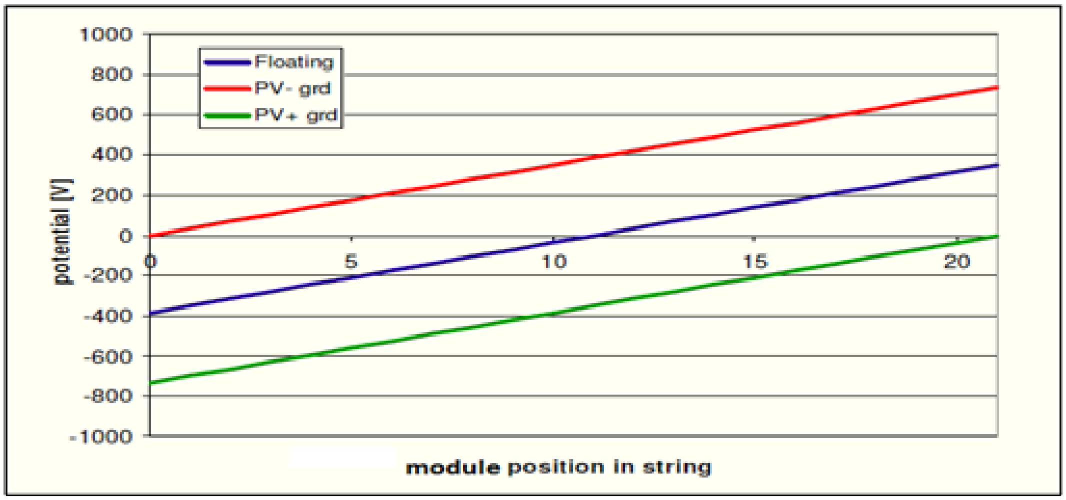


Figure 24A: Floating arrays with both positive and negative polarities and grounded arrays with either negative or positive polarity (Pingel et al., 2010).

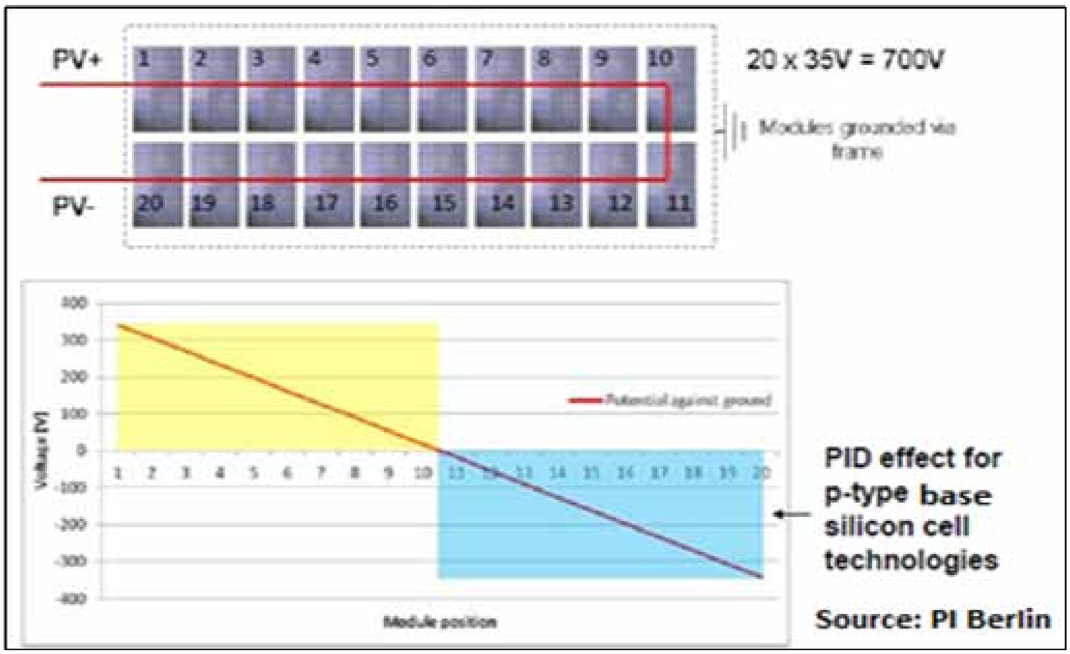


Figure 24B: An example of a floating array with both bias polarities (Pingel et al., 2010).

As shown in the simplified diagram of Figure 25, the high system voltages (600-1500 V) in the PV systems could lead to leakage current between the cell/active circuit and the ground and hence could cause gradual performance degradation depending on the cell bias type and magnitude of leakage current. PID can be increased by increasing applied/system voltage, operating temperature, or electrical conductivity between cell/active circuit and module frame through surface conductivity (for example, condensed water layer on the glass surface), interfacial conductivity (for example, between cell and encapsulant), and/or bulk conductivity (for example, through encapsulant).

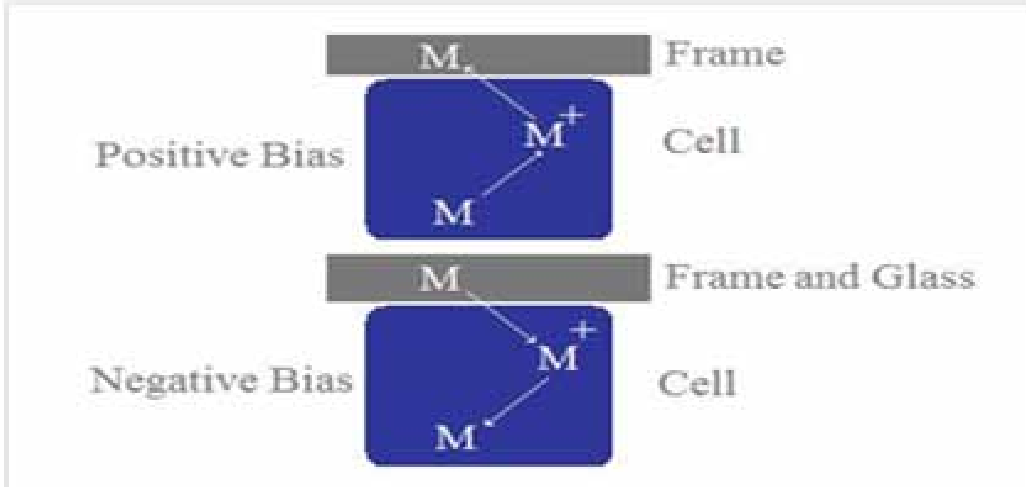


Figure 25: A representation of electrochemical activity between the frame/ glass and cell.

The original research on the electrochemical degradation of c-Si and thin-film modules was initiated by JPL in the 1980s (JPL, 1986). A renewed interest in this research, now named PID, was motivated by a few recent field issues related to electrochemical degradation of thin-film and crystalline silicon modules (Dhere, Pethe, & Kaul, 2010; Hacke et al., 2011). Figure 26 indicates that an accelerated factor of 427 for PID can be obtained for the hot-humid use condition in Florida at -600 V by stressing the modules at 60°C and 85% RH for 96 hours (Hacke, 2012). This stress condition is estimated to be equivalent to about 4.7 years of the field use condition of Florida. For a 20-year lifetime, this linearly translates to 400 hours of PID stress testing at 60°C and 85% RH. The higher stress levels at or above 70°C and 70% RH lead to high chemical activity of water that leads to degradation modes such as silicon nitride degradation and series resistance increases that are not seen in the field (Hacke et al., IEEE PVSC 2012). Therefore, it is important to eliminate PID stress conditions of the AT that induce electrochemical activities not seen in the field.

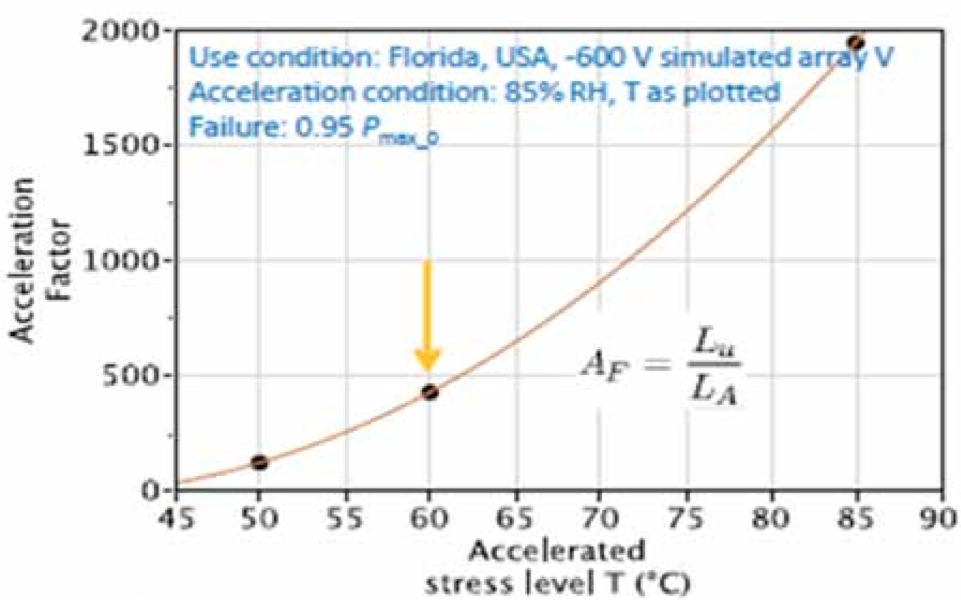


Figure 26: PID acceleration factor dependence on stress temperature level (Hacke, 2012).

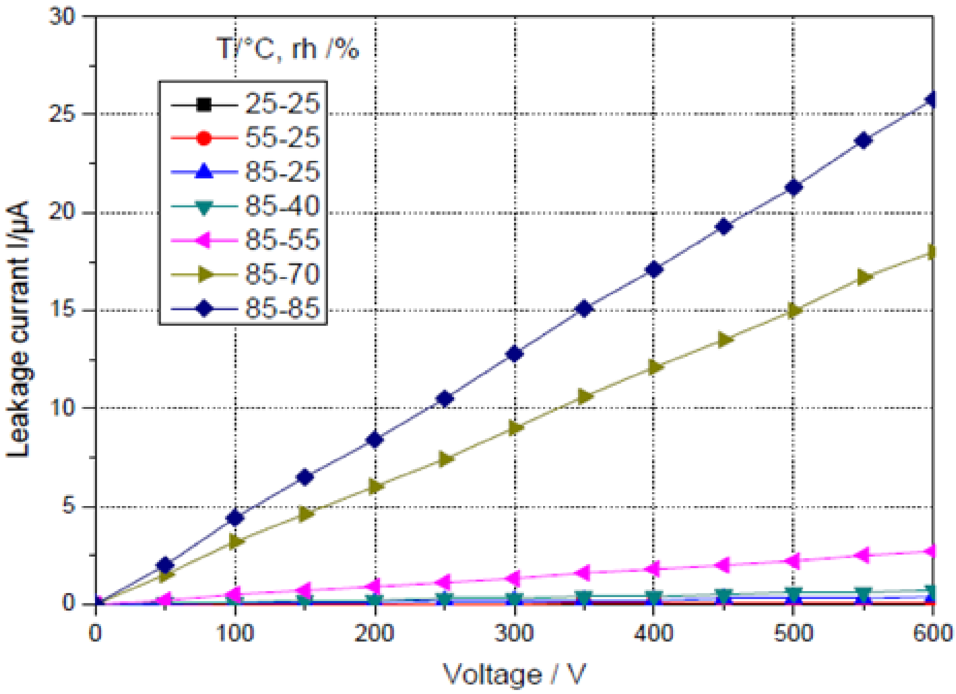
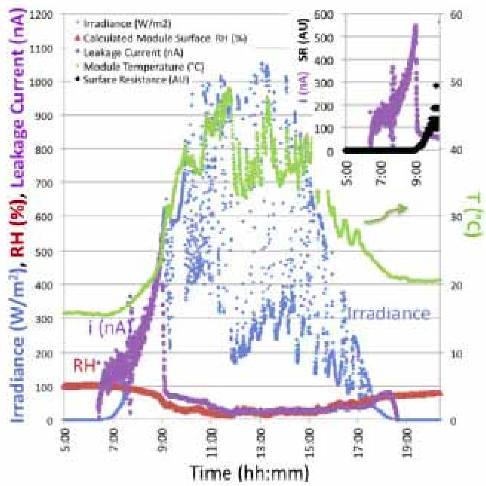


Figure 27: Linear dependence of current on stress voltage, and the combined voltage, temperature, and humidity effects on the leakage current of a module (Hoffmann & Koehl, 2012).

In chemical kinetics, the activation energy (in joules per mole) influences the chemical reaction rate (in moles per second) whereas in electrochemical kinetics the overpotential (in volts) influences the electrochemical reaction rate (in amps). Depending on the overpotential magnitude, either the Butler-Volmer (zero overpotential), Stern-Geary (low overpotential), or Tafel (high overpotential) equation may be applied (Revie, 2000; Greene, 1986). The low overpotential (called polarization overpotential due to polarization resistance, R_{pol}) is composed of activation overpotential (or electrochemical activation energy) and ohmic overpotential. The ohmic overpotential (due to ohmic resistance, R_{ohmic}) in a PV module is caused by the bulk resistance of encapsulant, bulk resistance of glass, surface resistance of glass (primary ohmic drop), and the interface between glass and encapsulant. The activation overpotential (due to activation resistance, Ract) in a PV module is caused by the interface between the electrode (active cell circuit) and electrolyte (encapsulant). The linear plot shown in Figure 27 above appears to be caused by both ohmic overpotential and activation overpotential. Because the ohmic overpotential in a PV module is extremely high as compared to the activation overpotential, the effect of activation overpotential is completely masked. In order to determine the activation overpotential and isolate it from the ohmic overpotential, it may be necessary to use the electrochemical impedance technique.

Figure 28 indicates that the module surface relative humidity is close to zero when the sun is shining in a hot-humid climatic condition (Hacke et al., 2011). During the sunny hot part of the day, the entire voltage is expected to drop on the glass surface with negligibly small voltage drop in the bulk and cell/encapsulant interface, leading to an absence of any PID during the sunny hot part of the day. The field data shown in this figure imply that the degradation may mostly occur first thing in the morning or after a rainstorm when there is high humidity and before the module has time to dry out in the sun. This situation may be simulated in the AT using a conductive carbon layer on the glass surface.



Leakage current to ground, irradiance, calculated module surface relative humidity (RH), and module temperature over a one-day period in Florida. The module is horizontally mounted, the active layer is biased to scale logarithmically with irradiance to a maximum voltage of -600 V with module leads connected to a load resistor to maintain approximately P_{max}. The leakage current is highest when morning dew is on the module face and the surface resistance (SR) is low (inset). When the module is dry, the current most closely follows the calculated module surface RH.

Figure 28: When sun is shining, the module surface relative humidity is close to zero even in a hot-humid climatic condition (Hacke et al., 2011).

Figure 29 shows the results of a simulated experiment with the interruption of surface conductivity using a carbon layer (Tatapudi, 2012). These PID experiments were performed on the thermal cycling (TC) (thermal cycling 200) and DH (DH 85°C/85 % RH) pre-stressed modules rather than fresh modules to simulate the field aged modules going through PID stress. As shown in Figure 29, the ohmic resistance could be increased (or PID eliminated) to a very high level by interrupting the surface conductivity of the glass near the frame edges using either hydrophobic coating, glass surface modification with water repellent properties, or thick edge sealants for the frame attachment. In the high surface conductivity PID test (surface fully carbon coated), the primary ohmic drop occurs in the bulk and interfaces similar to first thing in the morning or after a rainstorm in the field. In the disrupted surface conductivity PID test (surface partially carbon coated), the primary ohmic drop occurs on the glass surface similar to the sunny hot part of the day. This plot also indicates that the pre-DH-stressed modules degrade at much higher level than the pre-TC stressed modules possibly due to increase in the bulk conductivity of the encapsulant because of moisture ingress during the 1,000 hour DH test. It is important to note that no PID effect has been reported on the fresh modules if the cells do not have the silicon nitride antireflection coating. Recent studies on the fresh modules indicate that the PID effect is mostly, if not entirely, reversible if reverse voltage (positive voltage) is applied on c-Si with p-base (Hacke et al., 2011). This probably implies that the irreversible electrochemical reaction involving cell metallization may not occur on the fresh modules during PID stress testing. However, the irreversible electrochemical reaction involving cell metallization may occur if the module had been pre-stressed at 85°C/85 % RH for 1,000 hours (TamizhMani, 2012). This study seems to indicate that both reversible and irreversible degradation mechanisms may be operating on the DH pre-stressed modules. It is not yet clear whether PID involves only the silicon nitride (SiN) layer or both the SiN layer and the cell metallization in the actual field aged modules. This requires further investigations and characterizations of the field aged modules in hot-humid climatic conditions.

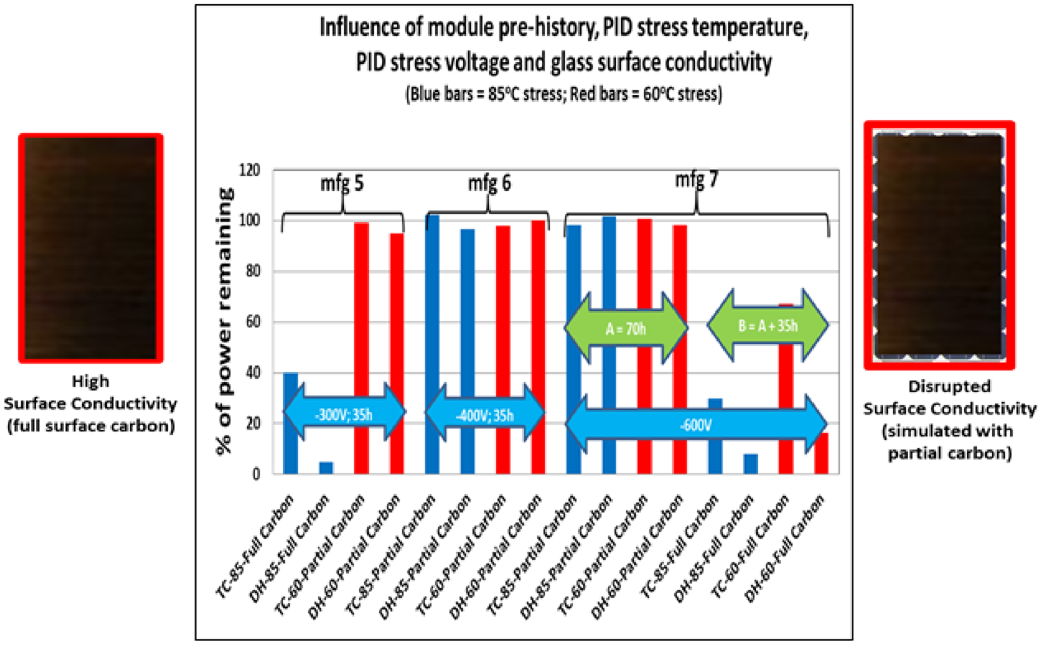


Figure 29: Avoiding PID by disrupting the glass surface conductivity near frame edges (Tatapudi, 2012).

A general model for the leakage current of PID test as a function of temperature, humidity, and voltage is given in the following equation (Hoffmann & Koehl, 2012).

$$I = I_{\max}/(1 + (I_{\max}/c - 1)/\exp(I_{\max} \times (rf - a) \times b))$$

with

$$I_{\max} = U/R_a(358\ \mathrm{K})\ A \cdot \exp[-(E_a/\ R) \cdot (1/T_{\mathrm{test}} - 1/358\ \mathrm{K})]$$

The remaining parameters a = 0.3, b = 1.5/mA, and c = 0.3 mA describe the slope of the current increase and the offset of the sigmoidal curve shown in Figure 30.

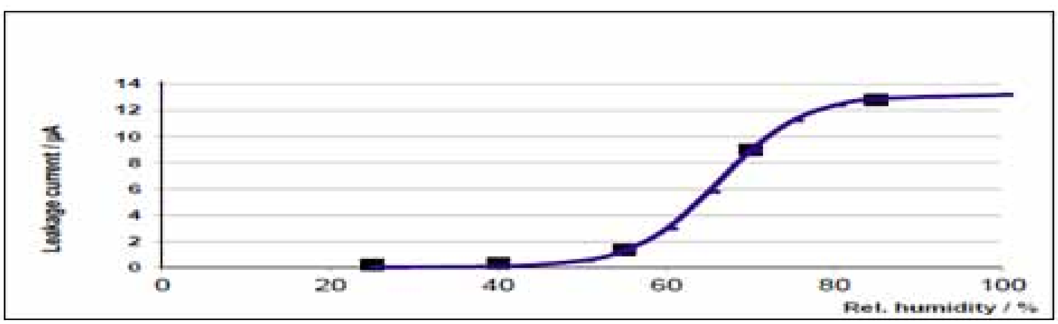


Figure 30: Sigmoidal leakage current dependence on relative humidity.

It is possible that the primary voltage drop location is shifted from the glass surface to the bulk and cell/encapsulant interface when the RH increases to higher than 60 %. The humidity on the glass surface probably forms a continuous water layer and efficiently conducts electricity when the RH exceeds 60 %. Therefore, at higher humidity and lower temperature levels (for example, 60°C/85 % RH), the primary voltage drop occurs in the bulk and cell/encapsulant interface due to low ohmic resistance on the glass surface. At lower humidity and higher temperature levels as in the field (85°C/60 % RH), the primary voltage drop occurs on the glass surface and in the glass and encapulant materials due to high ohmic resistance.

As shown in the voltage drop distribution schematic in Figure 31, the cell/interface reaction in the early morning is accelerated due to high surface humidity level (surface with dew) as compared to the daytime low/zero glass surface humidity. It may be envisioned that the shift in the location of voltage drop from surface (ohmic location) to interface (activation location) under high humidity condition may be identified by using the combination of both Arrhenius and electrochemical impedance plots obtained at different temperature and humidity levels. Because the semiconductor materials behave very differently in the presence of light and humidity in the interface, the PID tests may need to be performed in the presence of light to investigate the presence or absence of photoelectrochemical reaction at the cell/encapsulant interface (Noufi, Frank, & Nozik, 1981; Gerischer, 1977; Wrighton, 1977).

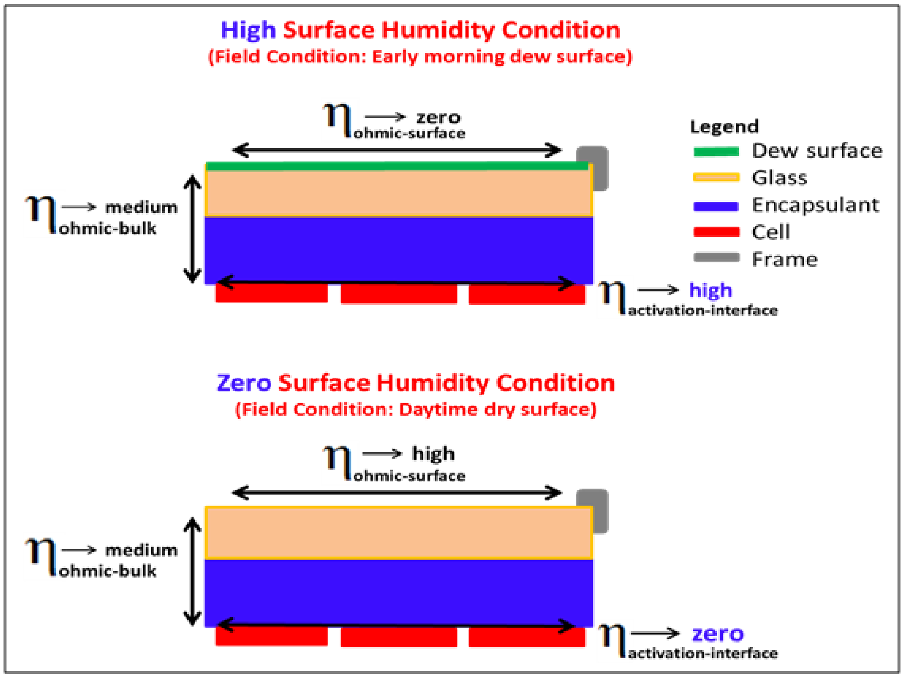


Figure 31: Voltage drop distribution under high and zero/low glass surface humidity levels

Summary—Voltage Stress Limits: Based on this literature review, the leakage current has a linear dependence on the applied voltage and it sharply increases when the RH increases above 60 %. Because the high humidity level on the glass surface is expected in early mornings and after rainstorms on the field operating modules, it may be important to perform the lifetime accelerated PID tests at higher humidity levels (> 60 % RH) for the proportional acceleration of voltage distribution across surface, bulk, and interface. In order to reduce the testing time, it may be necessary to increase the test temperature as high as possible but without compromising the replication of the field failure mechanisms. It has been shown that the PID testing at 85°C/85 % RH is too severe, not replicating the real field issue.

Recent studies appear to indicate that the use of 60°C/85 % RH test condition may be appropriate to replicate the real field issue. It may be possible to further reduce the testing time by increasing the temperature from 60°C to a higher temperature but less than 85°C. It is also recommended that the PID test be done on the post-DH stressed modules rather than on the fresh modules to correlate the results with the actual long-term (15 to 25 years) field data. It is recommended that the future PID investigations (with and without light) include both Arrhenius and electro-chemical impedance studies at different temperature and humidity levels, especially high humidity levels. Aluminum foil or carbon coated test method may be considered as a good screening technique for the PID susceptibility investigations of the cells but may not be a good durability test technique for the packaged modules as it does not simulate the field reality. The humidity in the field may be present on the glass surface and inside the bulk and interfaces of the encapsulant due to moisture penetration through backsheet and laminate edges whereas the metallic layer on the glass surface does not penetrate to the bulk of encapsulant. Also, there are a few unique module/laminate mounting solutions/ means adopted by the industry to avoid or reduce the PID effect, and those modules with unique mounting solutions may not be appropriately tested if the conductive metallic layer (aluminum or carbon) method is used, because it short circuits the mounting means with the glass surface.

Prioritization of Lifetime Accelerated Tests for Photovoltaics

In the previous sub-sections, the selection and level/duration of accelerated tests applicable to PV modules have been identified. In this sub-section, a prioritization of these accelerated tests is discussed. The accelerated tests need to be prioritized from both reliability (failure) and durability (degradation) perspectives. It is to be noted that the lifetime of PV modules may be limited either due to hard failure issues or to degradation issues (degradation beyond warranty limits).

Prioritization From Reliability (Failure) Perspective

The prioritization of accelerated tests may be based on the initial failures in the field or the wear-out failures in the field. The qualification testing deals with the initial failures in the field and the lifetime testing deals with wear-out failures in the field.

The prioritization of lifetime accelerated stress tests needs to be done based on the failure and degradation sensitivity of the technology to a specific set of environmental conditions. The specific set of environmental conditions could be hot-dry, hot-humid, and cold-dry (temperate). There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10 to 30 years) power plants that have similar or identical construction characteristics as that of the current generation modules. Because no such database currently exists based on the wear-out field failures, it is not possible to identify and prioritize the accelerated stress tests relevant to field-specific wear-out failures at this stage of research.

As indicated later in this report, the objective of qualification testing is to identify major failure modes during the initial stage in the field without attempting to make any predictions about the product's life under normal use condition. Because the current qualification testing programs (IEC 61215 and IEC 61646) have been developed based on the recorded initial field failures, the qualification failure databases from different test laboratories could help prioritize the accelerated stress tests, which would allow the manufacturers to successfully pass the qualification testing and to introduce the product in the marketplace. Note that the prioritization of the accelerated tests for the lifetime testing should be based on the field-specific wear-out failures, whereas the prioritization of the accelerated tests for meeting the qualification testing requirements may be based on the qualification testing failure databases of various test laboratories (TamizhMani et al., 2012). As shown in Figure 32A, crystalline silicon technology is sensitive to the following top three accelerated tests to meet the pass criteria of the IEC 61215 qualification testing standard (based on the testing of 1,111 modules of the most recent 2009-2011 designs): humidity freeze, thermal cycling, and DH. As shown in Figure 32B, these post-stress failures were identified using visual inspection, insulation test, and wet resistance failure criteria at the completion of each accelerated test of the qualification testing programs. (Note that the failure rate in Figure 32A may be lower than the sum of failure rates shown in Figure 32B due to the application of up to three pass criteria for each stress test).

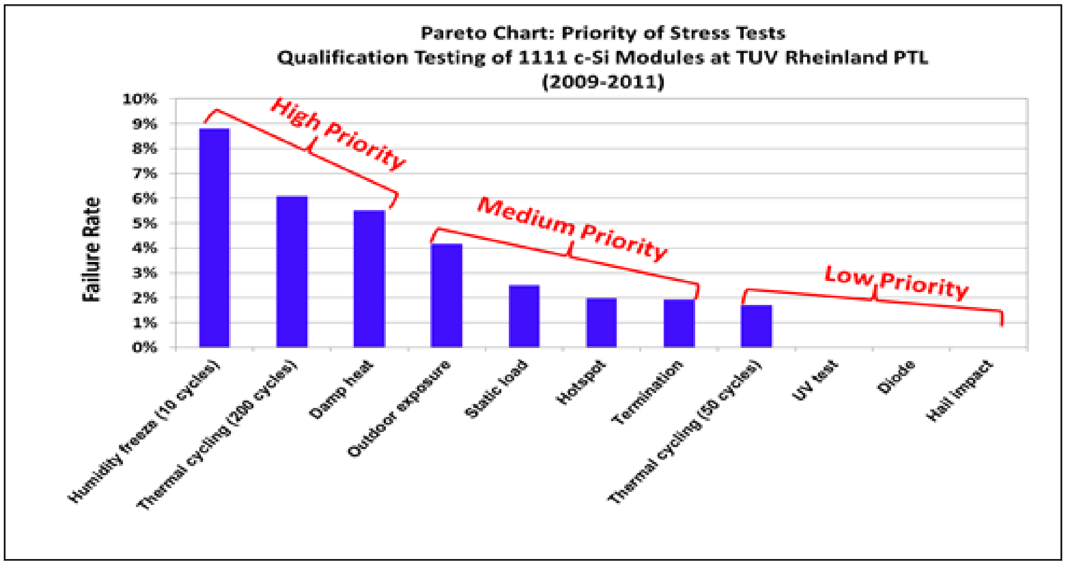


Figure 32A: Prioritization of accelerated stress tests for c-Si modules to meet the qualification testing standard of IEC 61215 (TamizhMani et al., 2012).

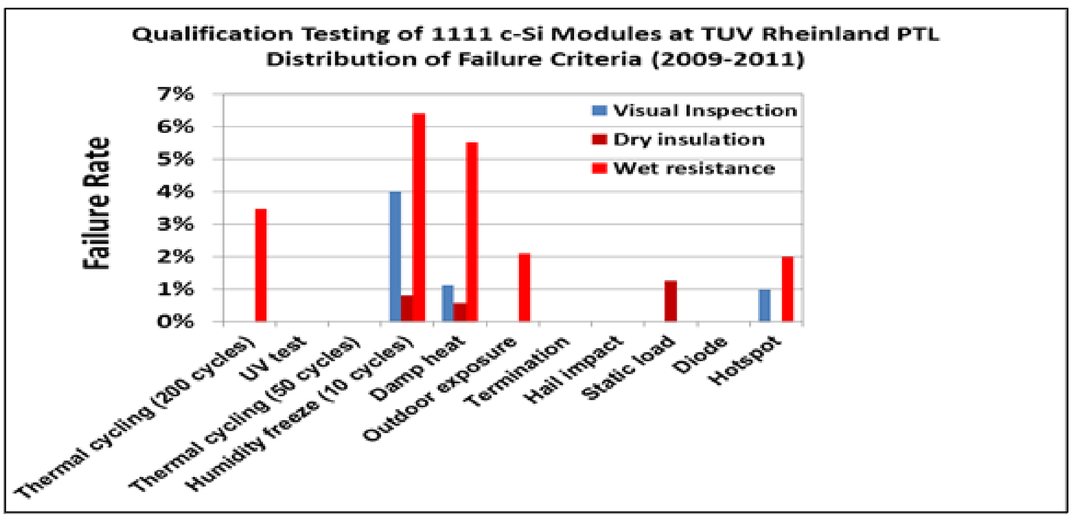


Figure 32B: Failure criteria (visual, dry, or wet) dictating the qualification failure rate for c-Si shown in Figure 32A (TamizhMani et al., 2012).

As shown in Figure 33A, the thin-film technologies are sensitive to the following top three accelerated tests to meet the pass criteria of the IEC 61646 qualification testing standard (based on the testing of 272 modules of the most recent 2009-2011 designs): humidity freeze, DH, and light soaking. As shown in Figure 33B, these post-stress failures were identified using visual inspection test, insulation test, and wet resistance failure criteria at the completion of each accelerated test of the qualification testing programs. All the other discussions presented above for the c-Si technology apply to the thin-film technologies as well.

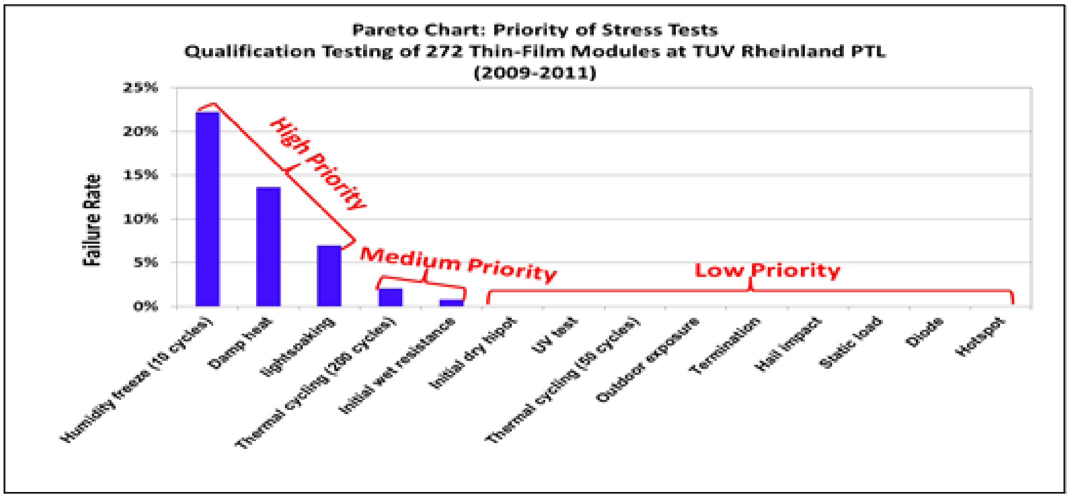


Figure 33A: Prioritization of accelerated stress tests for thin-film modules to meet the qualification testing standard of IEC 61646 (TamizhMani et al., 2012).

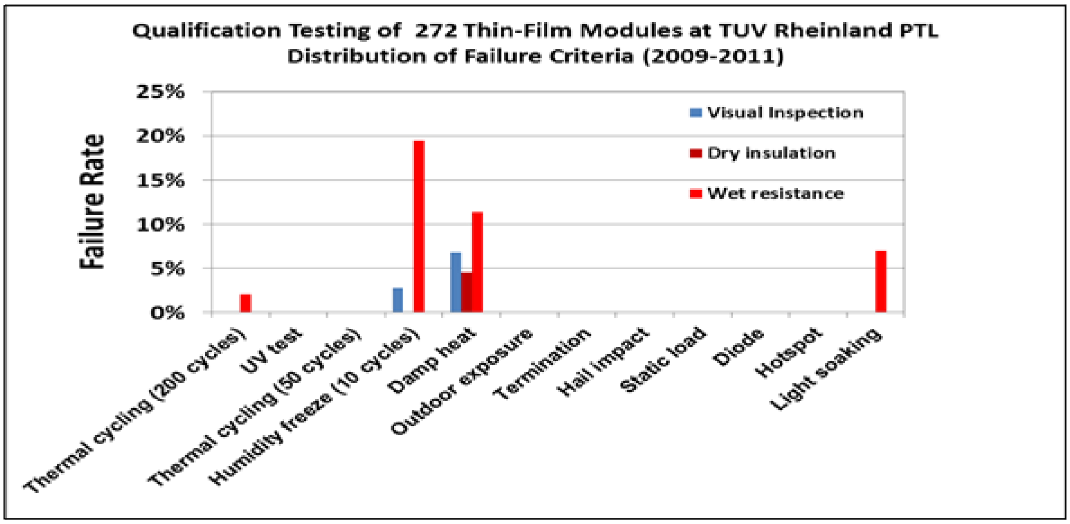


Figure 33B: Failure criteria (visual, dry, or wet) dictating the qualification failure rate for thin-film shown in Figure 33A (TamizhMani et al., 2012).

Prioritization From Durability (Degradation) Perspective

As shown in Figure 34, the post-stress qualification failures rates (identified in Figure 32A above for c-Si) are dictated not only by visual inspection observations, insulation test, and wet resistance test failure criteria but also by the power degradation criteria at the completion of each accelerated test. In the qualification testing of c-Si modules, a power degradation limit of 5% from the initial measured power is used whereas in the lifetime testing, a power degradation limit of 20% may be used assuming 20%/20-year warranty limit. In the qualification testing of thin-film modules, a power degradation limit of 10% from the rated power is used, whereas in the lifetime testing, a power degradation limit may be determined based on the warranty limit. Because—at the completion of the qualification testing programs—none of the 272 thin-film modules showed less than 90% of its rated power, no plot corresponding to the qualification failure rate due to degradation limit is presented here.

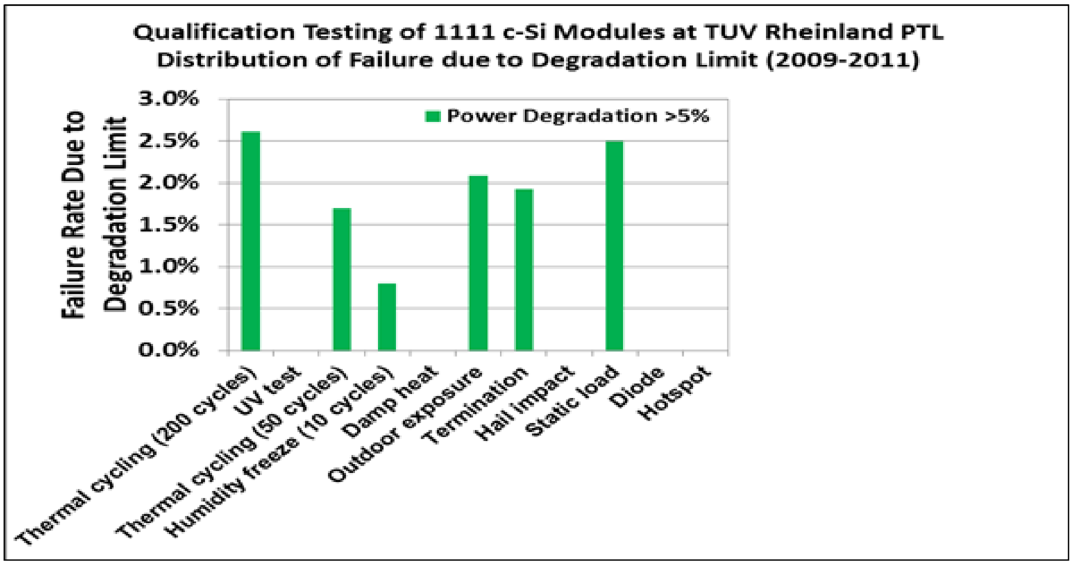


Figure 34: Degradation limit criterion dictating the qualification failure rate for c-Si shown in Figure 32A (TamizhMani et al., 2012).

Summary—Prioritization of Lifetime Accelerated Testing: There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10-30 years) power plants that have similar or identical construction characteristics to those of the current generation modules. Based on this wear-out failure database, a set of accelerated tests needs to be identified for each of climate-specific conditions. As done in the qualification testing by independent test labs, the identified accelerated tests (which are based on the wear-out field failures) need to be carried out on a large number of commercially available PV modules to identify the statistically relevant failure rates for each climate-specific condition. Based on the statistically relevant climate-specific failure rate database, it is possible to prioritize the accelerated stress tests unique to a specific climatic condition. It is important to note that the prioritization of the accelerated tests for the lifetime testing should be based on the field-specific wear-out failures, whereas the prioritization of the accelerated tests for meeting the qualification testing requirements may be based on the qualification testing failure databases of various test laboratories.

Pre-and Post-Characterization of Materials and Modules

The chemical, physical, thermal, and electrical properties of PV materials and devices used in a PV module dictate the overall quality, durability, and reliability, which in turn dictate LCOE. Understanding these properties before and after field installations and accelerated stress tests is very important to develop less expensive but more effective materials and devices. The materials will need to be characterized before and after HALT in environmental chambers and weathering (UV-temperature-humidity) chambers. Also, the old and existing materials will need to be evaluated before and after field installations.

As a minimum, the PV cell/module characterizations should include:

- visual inspection (see the visual inspection checklist provided in the Appendix A of this report),
- current-voltage measurements under various light conditions (it is the most important characterization for the failure and degradation evaluation and it is briefly discussed below),
- spectral response/quantum efficiency,
- electroluminescence, and
- infrared scanning.

The materials and package characterizations of PV modules may include:

- water vapor transmittance of backsheets;
- optical transmission for encapsulants and superstrates;
- bulk resistivity and dielectric withstand voltage for encapsulants and backsheets;
- compositions of polymeric and cell materials;
- phase change of polymeric materials;
- contaminations inside the materials and devices;
- UV-Vis spectrophotometric analysis of materials;
- Fourier transform infrared (FTIR) of materials;
- differential scanning calorimetry (DSC) of polymeric materials;
- thermogravimetric analysis of polymeric materials;
- chromatography of polymeric materials;
- dry and wet dielectric properties of packages;
- mechanical properties of materials using universal materials testers;
- scanning electron microscopy of materials and devices;
- optical microscopy of components and devices;
- Arrhenius analysis for activation energy determination;
- impedance analysis for activation overpotential determination;
- surface and bulk resistance testing of glass, encapsulant, and backsheet; and
- moisture ingress testing.

The current-voltage measurement is the most important characterization technique for the failure and degradation evaluation of PV modules and it is briefly discussed below. To detect various failure and degradation modes due to changes in the materials and/or cells in a PV module after the accelerated tests and field exposure, the current-voltage (I-V) curves can be analyzed in several different ways including (Wohlgemuth, 2011; TamizhMani, 2012):

- multiple shoulders in an I-V curve is an indication of cell mismatch;
- increase in slope of the horizontal part of I-V curve is an indication of decrease in shunt resistance;
- decrease in slope of the falling part of I-V curve is an indication of increase of series resistance;
- a drastic decrease in open-circuit voltage may be an indicator of activation of one or more bypass diodes in the module;
- a sharp break in the I-V curve is an indication of bypass diode activation;
- a decrease in short-circuit current may be an indicator of discoloration of encapsulant, anti-reflective coating, soiling, loss of surface passivation, loss of cell area via cracking and chipping;
- a decrease in open-circuit voltage may be an indicator of loss of cells from circuit, bypass diode shorting, cell junctions shunting, and loss of surface passivation;
- a decrease in fill factor may be an indicator of solder bond thermo-mechanical fatigue, metallization corrosion, solder bonds corrosion, interconnects corrosion, interconnect ribbons broken or partially broken, and cell junctions partially shunted; and
- a decrease in module efficiency and fill factor at low irradiance levels compared to high irradiance levels is a potential indicator of cell shunting issues, so characterizing the module at different irradiance and temperature levels as per IEC 61853-1 standard would be of great interest to identify the cell shunting issues.

The use of I-V characterization for the quality, durability, and reliability evaluation of an old array (26+ years in Phoenix, Arizona; hot-dry location) is illustratively explained in the plot shown in Figure 35 (Belmont & Olakonu, to be published). Note that the short circuit current (I_{sc}) loss of about 30% in this figure is primarily attributed to encapsulant browning, but this loss may also be due to a combination of other issues identified above. The I_{sc} loss due only to encapsulant discoloration or soiling can be identified and isolated by performing complementary quantum efficiency measurements.

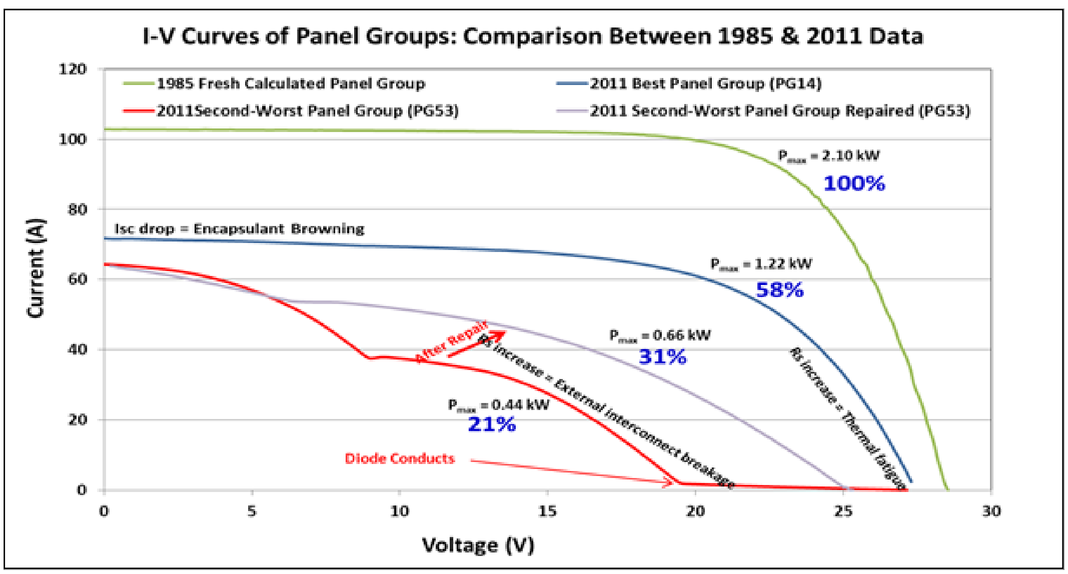


Figure 35: Use of I-V characterization in old PV power plants (panel group = 40 modules of ~55 W each) (Belmont & Olakonu, to be published).

PV ACCELERATED TESTING: PRESENT AND FUTURE PROGRAMS

Types of Accelerated Testing Programs

The purpose of AT is to shorten the test time using simulated test conditions much more severe and/or faster than the actual field operating conditions while replicating actual field failure and degradation modes and mechanisms. As shown in Figure 36, the accelerated test programs for PV modules may be classified as:

- accelerated qualification testing (minimum confidence in quality),
- accelerated comparative testing (medium confidence in quality), and
- accelerated lifetime testing (maximum confidence in quality).

The first two testing programs are qualitative AT programs and the last testing program is a quantitative AT program. In qualitative AT, the manufacturer is mostly interested in identifying failures and failure modes without attempting to make any predictions as to the product's life under normal use conditions. In quantitative AT, the manufacturer is interested in predicting the life of the product (or more specifically, life characteristics such as mean-time-to-failure, failure rate over time) at the desired use conditions, from data obtained in an accelerated lifetime testing program.

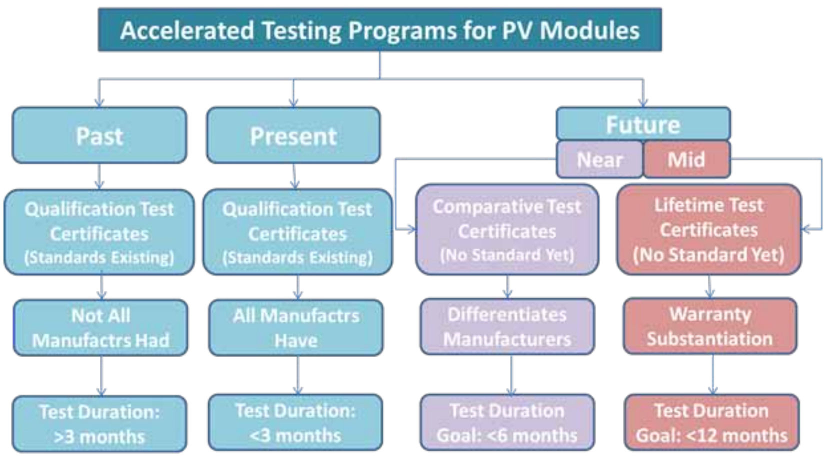


Figure 36: Past, present, and future accelerated testing programs of PV modules.

As indicated in the figure above, the standards for the qualification testing programs (IEC 61215 for c-Si, IEC 61646 for thin-film, and IEC 62108 for concentrated photovoltaics [CPV]) of PV modules have already been established and the standards for the comparative and lifetime test programs are yet to be developed. As an example, for ease of reading, the test sequence of IEC 61215 qualification standard is reproduced in Figure 37 (Wohlgemuth, 2011). Due to the high diffusion level of PV technology in the recent past (modules installed in the last 7 years account for 96% of all the modules cumulatively installed around the world), comparative and lifetime testing programs are expected, and even demanded, by consumers and investors so the products can be differentiated. Almost all PV products now have qualification certificates. A summary of all the three programs is provided in the text and in Table 6. The influence of these accelerated test programs on the reliability of PV modules are hypothetically explained in Figure 38. The test programs shown in this figure should be considered a hypothetical evolution of the test programs with due consideration to the eventual cost of the product and to statistically acceptable warranty returns.

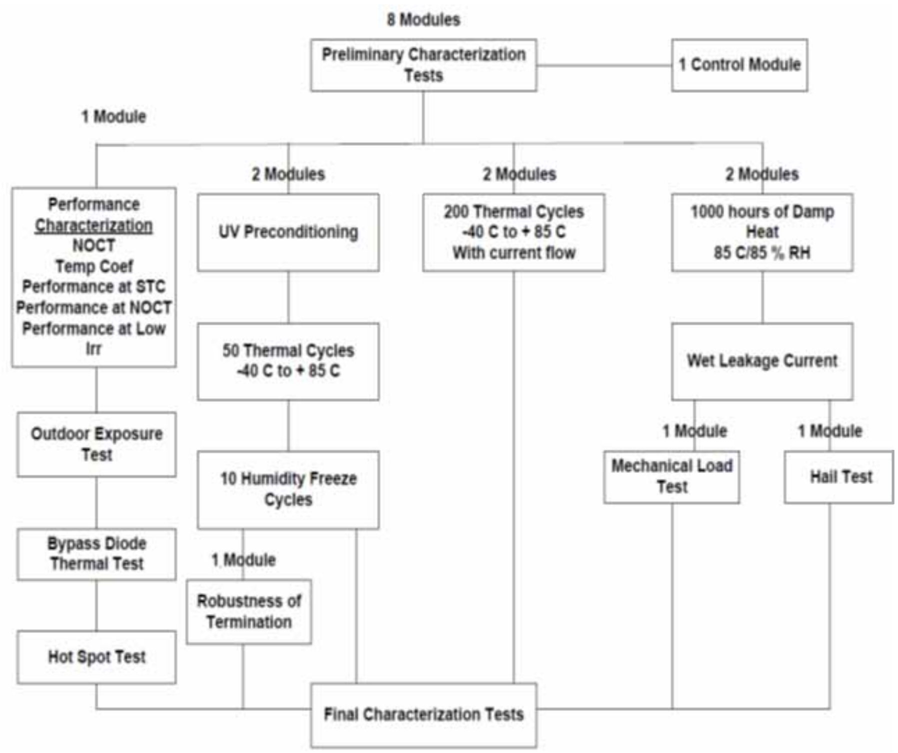


Figure 37: Test sequences of IEC 61215 qualification testing program (Wohlgemuth, 2011).

Accelerated Qualification Testing (AQT)

- Objective: The objective of qualification testing is to identify major failure modes during the initial stage in the field without attempting to make any predictions about the product's life under normal use conditions. The qualification testing defines minimum testing requirements to substantiate minimum durability (degradation) and reliability (failure) of a specific module design. This program DOES NOT attempt to account for the energy penalty over a lifetime of 20 or 25 years.
- Goal: The goal from a manufacturer perspective is to introduce the product into the marketplace with minimal required quality tests. This is a test-to-pass testing program; the testing is repeated with improved design until the modules pass this test.
- Cost and time: Minimum
- Testing protocol: Standardized protocols defined by the test standards (Examples: IEC 61215 for c-Si, IEC 61646 for thin-film, or IEC 62108 for CPV).
- Test requirement: It is a pass/fail test with a maximum allowed limit of 5% power drop per test (and 8% per test sequence) after accelerated stresses. Appendix B explains how module designs have struggled, evolved, and improved between 1997 and 2011 to meet the pass requirements of the qualification standards.

- User: Used by all manufacturers and it is a market/consumer/incentive driven requirement in Europe and around the world. The qualification standards (IEC 61215 for c-Si, IEC 61646 for thin film, and IEC 62108 for CPV) are the most extensively used PV standards in the industry. A recent publication from Wohlgemuth (Wohlgemuth, 2012b) indicated the following *"Whipple reported on 10 years of field results (using data from Rosenthal, Thomas, and Durand) that unqualified modules suffered from 45% field failure rate while qualified modules suffered from less than 0.1% field failure rate."* Unfortunately, even this minimum qualification testing is not required in the United States, except in Florida. Solar ABCs has recently released a policy statement recommending the adoption of the qualification testing requirement in the United States.

Accelerated Comparative Testing (ACT)

- Objective: The objective of comparative testing is to identify relative failures and performance losses between different designs without attempting to make any predictions as to the product's life under normal use condition. The comparative testing protocol should define extended, combined, or sequential AT requirements to compare the durability and reliability of different module designs. This program SHOULD attempt to account for the energy penalty (figure of merit) over lifetime of 20 or 25 years. For example, in the 1980s, JPL used a 10% energy/cost penalty as the figure of merit.

- Goal: The primary goal from a buyer or investor perspective is to differentiate the product designs from one manufacturer to the other in terms of their ability to survive in the field and to continue to produce power with minimal annual power loss.

- Cost and time: Medium—falls between qualification testing and lifetime testing.

- Testing protocol: Currently, several manufacturer or test laboratory defined comparative testing protocols are being used by the industry. A consensus-based uniform but climatic-specific and technology-sensitive protocol needs to be developed by a standards developing organization. Various testing laboratories, national laboratories, and manufacturers have developed several comparative testing protocols. An extended table presented in Appendix C compares these test programs. This table could serve as the basis for the development of a comparative testing standard by standards developing organization(s). The International Quality Assurance Forum (IQAF), a joint international effort from Europe, North America, and Asia, aims to develop such a high-demand protocol for the industry (see www.nrel.gov/ce/ipvmqa_task_force/ for additional details).

- Test requirement: It is a relative testing with periodic/intermittent monitoring (for failures and degradation) for a maximum allowed limit (limit the time and identify relative power loss or limit the power loss and identify relative time) defined by a standards developing organization or the consumer/investor.

- User: It could be used by the consumers or investors to compare and select appropriate climate-specific module design among various designs.

Accelerated Lifetime Testing (ALT)

- Objective: The objective of lifetime testing is to identify most, if not all, failure modes and mechanisms of the module during its entire lifetime in the field (initial, useful, and wear-out stages) with product's lifetime prediction (using statistical and physical models) under the desired field conditions. The lifetime testing protocol could define the testing requirements to predict the lifetime for any site-specific condition (and configuration). Or, the lifetime testing protocol could define the testing requirements to predict the lifetimes for the worst-case sites/climates (and configurations). This program may account for the energy penalty (figure of merit) over a lifetime of 25 years or may account for the remaining power (efficiency) through a rating system approach after 25 years of lifetime tests. For example, in the 1980s JPL used a 10% energy/cost penalty approach as the figure of merit whereas the quality assurance (QA) Task Force of IQAF appears to lean toward the rating system approach.

- Goal: It is the ultimate failure and degradation testing to predict lifetime and/or to substantiate the warranty.

- Cost and time: Maximum

- Testing protocol: Currently, none is publicly available. A unique consensus testing protocol needs to be developed based on field failure mechanisms, failure modes, and physical/statistical models. Appropriate physical and statistical distribution models will need to be developed as well. As shown in Appendix D, this testing program requires an extensive list of equipment for various standard and non-standard accelerated stress tests and pre- and post-stress/field characterizations along with physical and statistical modeling expertise. These test protocols may be developed by standards developing organization(s). As a first step, a comprehensive literature search and review needs to be conducted on the field failure and degradation modes and mechanisms, life-limiting failure modes, potential AT methods with stress/duration limits, and mathematical models. This report serves as a first step, providing a detailed literature search and review on the accelerated lifetime testing and the mathematical reliability models of PV modules. Again, the IQAF has recently instituted an all-encompassing task force to develop life testing protocols (see the website www.nrel.gov/ce/ipvmqa_task_force/ for additional details).

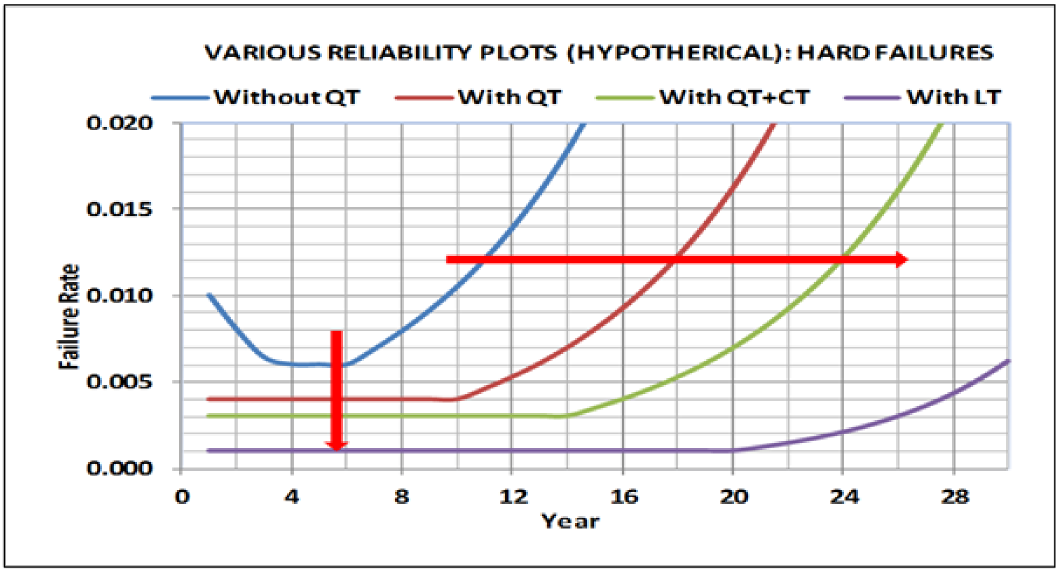
- Test requirement: It is a testing to determine the lifetime of the PV module design. A consensus definition for the term "lifetime" along with allowed energy penalty over lifetime will need to be developed by the standards developing organization or to be identified in the consumer-manufacturer agreement.

- User: It could be used by the individual manufacturers to determine liability for warranty returns or by consumers/investors as evidence of warranty substantiation.

Table 6

A Quick Summary Comparing Three Accelerated Testing Programs of PV Modules

	Accelerated Qualification Testing (AQT)	Accelerated Comparative Testing (ACT)	Accelerated Lifetime Testing (ALT)
Confidence level in quality	Minimum	Medium	High
Objective	Minimum testing for reliability and durability of a specific module design without attempting to make any predictions about the product's life under normal use conditions; energy penalty is not considered	Extended, combined, or sequential accelerated testing to compare relative reliability and durability of multiple designs or manufacturers without attempting to make any predictions about the product's life under normal use conditions; energy penalty should be considered	Climate-specific and technology-sensitive testing of any specific module design with product's lifetime prediction (using statistical and physical models) under normal field conditions; energy penalty should be considered
Cost and time	Low	Medium	High
Goal	Introduce the specific design into the market in a short period of time	Compare (to improve/purchase/invest in) multiple designs	Predict lifetime and/or substantiate warranty
Testing protocol	Test standards exist (IEC 61215, IEC 61646, IEC 62108)	Test laboratories or investor-defined protocols exist but a uniform/standardized protocol is needed; task group in the International PV Quality Assurance Forum has recently been created for the development of this protocol	None publicly exists; need a comprehensive understanding of failure/degradation modes/mechanisms and mathematical models to develop an appropriate testing protocol
Test requirement	Pass/Fail (>5% P_{max} drop = Fail)	Relative power loss for a specific stress time/cycles or relative stress time/cycles for a specific power loss	Identify ultimate failure mode and determine/substantiate warranty period
User	Manufacturers/Consumers/Investors	Manufacturers/Consumers/Investors	Manufacturers/Consumers/Investors



QT = Qualification Testing; CT = Comparative Testing; LT = Lifetime Testing

Figure 38: Influence various accelerated testing programs on reliability.

Key Attributes and Considerations for Designing Future ACT and ALT Programs

As indicated earlier, the purpose of AT is to shorten the testing turnaround time using simulated test conditions much more severe than the actual field operating conditions while replicating actual field failure and degradation modes and mechanisms. The qualification testing program takes two to three months to complete. Manufacturers cannot delay the release of products too long for financial reasons and the power plant investors cannot wait too long to make investment decisions. For these reasons, it is necessary to shorten the testing time to, for example, less than six months for comparative testing and less than 12 months for lifetime testing.

Based on the discussion presented in *PV Accelerated Testing: Stress Types, Levels, and Prioritization,* key attributes and considerations for developing future short turnaround but credible comparative and lifetime testing programs are summarized here. These attributes and considerations include stress level/cycle/ duration limits, sample preparation requirements, prioritization/extension/ combination/sequencing of stress tests, and a need for new climate-specific but technology-sensitive reliability test programs.

- Temperature
  - Temperature limit (hot end) is 90°C to avoid encapsulant related failures not seen in the field. This temperature limit may have to be increased to as high as 100°C for building integrated systems.
  - Temperature limit (cold end) is -40°C to avoid encapsulant related failures not seen in the field. This low temperature limit is already used in today's test programs.
  - Temperature dwell time (hot end): There is very limited research. Current minimum dwell time of 10 minutes per cycle at the hot end may be increased to investigate if the solder bonds fail at a higher rate and increase the series resistance without changing the failure mechanism. Recent simulation and analysis indicates that the increase of dwell time may not be helpful in shortening the time of the test (Silverman et al., 2012). However, this limited study may need to be extended and experimentally demonstrated with a large number of current commercial modules.
  - Temperature cycling rate: 100°C/h is too low for reducing test duration of comparative or lifetime testing but 400°C/h seems to be too high due to solder bond and interconnect related failures not seen in the field. The space industry has used a cycling rate up to 180°C/h and this moderate-thermal cycling rate may prove to be helpful to reduce the thermal cycling test duration (Hoffman & Ross, 1978).
  - Temperature cycle limit: It appears that 400 cycles are sufficient for a 20-year warranty, but up to 800 may be used for an extended lifetime prediction (Wohlgemuth & Kurtz, 2011; Herrmann et al., 2010).

- Humidity
    - DH limit: Current 85°C/85%RH DH test is reported to be unrealistically severe and this limit may not be exceeded due to encapsulant related failures not seen in the field. Simultaneous stressing with <85°C/85%RH, UV, mechanical load, etc., may also be explored to gauge consistency with realistic field conditions.
    - DH duration: Based on the findings reported in the literature, more than 3,000 hours of DH testing may not needed or recommended due to encapsulant and backsheet related failures not seen in the field.
- UV
    - UV intensity limit: Up to 5 times the UV intensity of natural sunlight seems to be optimal. High UV transmitting glass superstrate at higher temperature with high oxygen barrier substrate such as glass would be a very good screening test to identify the browning issue of an encapsulant in a short period of time.
    - UV duration: Six to seven months with about three times the natural sunlight UV dose seems to be sufficient for a 20-year lifetime prediction.
- PID
    - PID—Voltage limit: Currently, all the researchers are using the system voltage as the stress voltage. However, this system voltage is calculated based on the open-circuit voltage value at -40°C voltage. In reality, the system voltage based on the temperature at dew point temperature (or even higher for tropical locations) may be appropriate along with the stress at high temperature (between 60°C and 85°C) and high humidity on the glass surface (>60%RH) as presented below.
    - PID—Temperature limit: Between 60°C and 85°C.
    - PID—Humidity limit: More than 60%RH to shift high voltage drop from the glass surface to the cell/encapsulant interface to have same voltage distribution between glass surface and cell/encapsulant interface as seen in the field with rain in the daytime or dew on the glass surface during early morning hours.
    - PID—Sample preparation: Aluminum foil or carbon coated test method may be considered a good screening technique for the PID susceptibility investigations of the cells but it may not be a good durability test technique for the packaged modules, because it does not simulate field reality. The humidity in the field may be present on the glass surface and can also penetrate to the bulk of the encapsulant through backsheet and laminate edges, whereas the metallic layer on the glass surface does not penetrate to the bulk of encapsulant. Also, there are a few unique module/laminate mounting solutions/means adopted by the industry to avoid or reduce the PID effect, and those modules with unique mounting solutions may not be appropriately tested if the conductive metallic layer (aluminum or carbon) method is used, because it short circuits the mounting means with the glass surface.
    - PID—Sample preconditioning: The 1,000-hour DH pre-stressed modules are recommended as test samples for the PID test, because the PID issue in the field is expected be severe on aged modules compared with fresh modules.

- Prioritization of stress tests: There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10-30 years) power plants that have passed the qualification tests and have similar or identical construction characteristics to those of the current generation modules.

- Identification of right approach for comparative testing: Various approaches for comparative testing have been developed by the industry (see Appendix C). There is a need to determine if the extended test approach, combined test approach (mechanical load during thermal cycling or light soaking during DH test, for example), or sequential test approach is appropriate to develop a new comparative test program. In the new to-be-developed comparative test program, it is important to obtain the post-stress characterization data more frequently so the failure and degradation trends can be used to develop appropriate physical and statistical models. It is important to identify those field failures that occur for modules that pass the qualification tests and to determine what set of comparative accelerated tests will cause the same or similar failures as those seen in the field.

- Climate-specific technology-sensitive lifetime testing program: Figure 39 shows the photographs of identical modules (M55; Arco Solar) installed in 1985 in Austin, Texas, and Phoenix, Arizona (twin-systems). As shown in Figure 39, identical but field-aged modules close to the end of life can have completely different wear-out failure modes and degradation modes depending on the field condition (Belmont & Olakonu, to be published). This figure clearly shows that identical modules can have encapsulant delamination (and consequent cell corrosion) failure mode in the hot-humid climatic condition, and non-cell interconnect break failure mode (and consequent bypass triggering with no arcing or bypass diode opening with arcing), encapsulant browning (I_{sc} loss with no loss in fill factor) degradation mode, and solder bond fatigue (series resistance increase with fill factor loss) degradation modes in the hot-dry climatic condition. Therefore, it is imperative to develop a climate-specific but technology-sensitive accelerated lifetime test program for the warranty substantiation and lifetime prediction of PV modules. A similar argument can be applied to the comparative testing program. This study clearly indicates that a universal comparative or lifetime testing (and corresponding rating system) may not be appropriate and may prove to be expensive as the same, for example, encapsulant needs to be tailored to tolerate both UV-related issues in the hot-dry climatic condition and humidity-related issues in hot-humid climatic condition. As shown in Figure 40, the specific climates may potentially include hot-dry, hot-humid, and hot-cold (temperate).

- Technology-blinded standard vs. technology-specific protocol: Less than 4% of installed modules are more than seven years old and the share of the thin-film technology in this 4% is still small. The comparative and lifetime test programs or protocols can realistically be developed only based on the field data obtained from 10 or more year-old PV modules. Therefore, from the learning-curve point of view, the comparative and lifetime testing protocols (not the standards) may first need to be developed, probably by a non-standard body such as the IQAF, for the c-Si technologies while gathering field reliability data for the thin-film technologies. It is understandable, from the marketing and level playing field points of views, to develop a technology-blinded standard and to delay the release of such a standard.

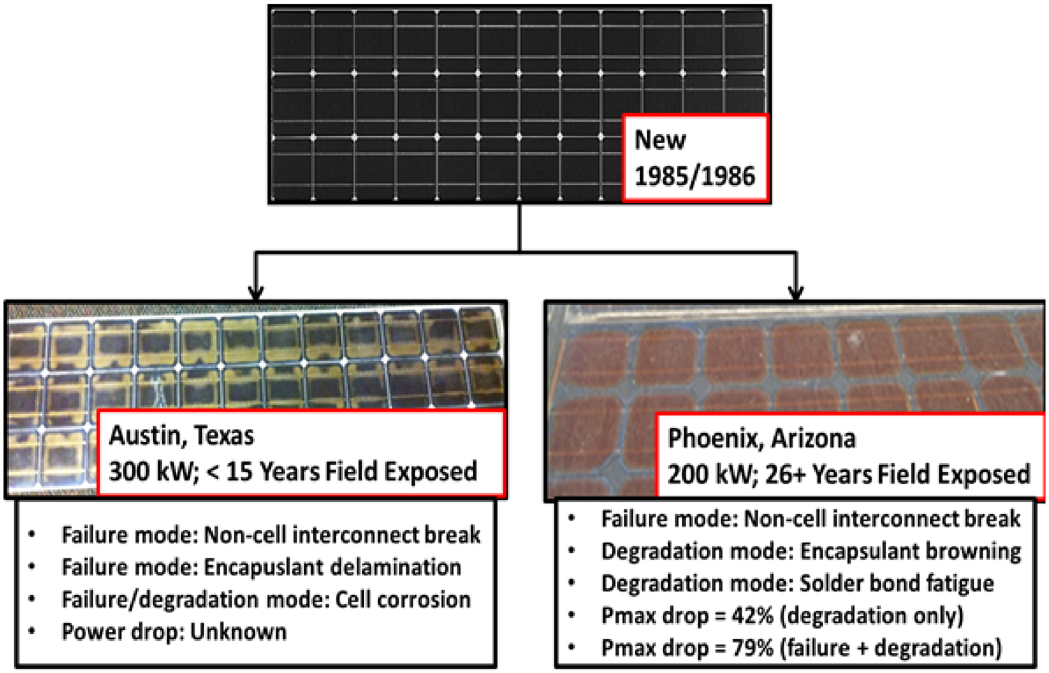


Figure 39: : Identical modules with different failure and degradation modes depending on the climatic condition (Belmont & Olakonu, to be published).

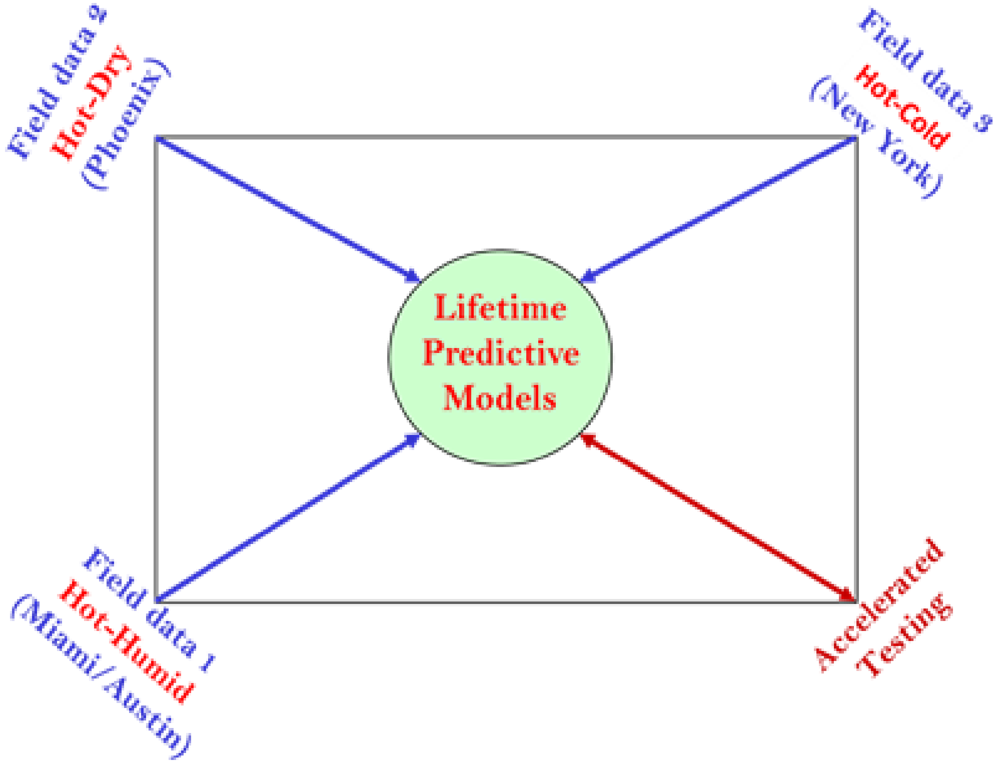


Figure 40: Potential climatic conditions to develop climate-specific lifetime testing program.

PV RATING SYSTEM: A POSSIBLE APPROACH

Based on the review, analysis, and discussion presented in this report, it becomes necessary to eventually develop a climatic-specific, technology-agnostic comparative rating system and lifetime rating system. Realistically, due to minimal availability of long-term reliability and durability data for thin-film technologies, it is challenging to develop technology-agnostic rating systems at this early stage of thin-film technology penetration and market share, and it will likely take several years to develop such a system. Consumers and investors are anxious to have a usable rating system right now, so it is important to start working—from a learning-curve perspective—on a rating system for the c-Si technology while gathering statistically significant reliability and durability data from the field for thin-film technologies. Because bankability depends on quality, reliability, and durability (Figure 41), the highest ROI for PV systems can be realized by maximizing energy production and minimizing downtime. The energy production can be maximized by producing high quality PV modules (performance/efficiency at various temperatures and irradiance levels), improving the durability (reducing degradation rate), and decreasing the downtime (reducing failure rate). Therefore, the rating system should be designed to account for the quality/performance, reliability, and durability.

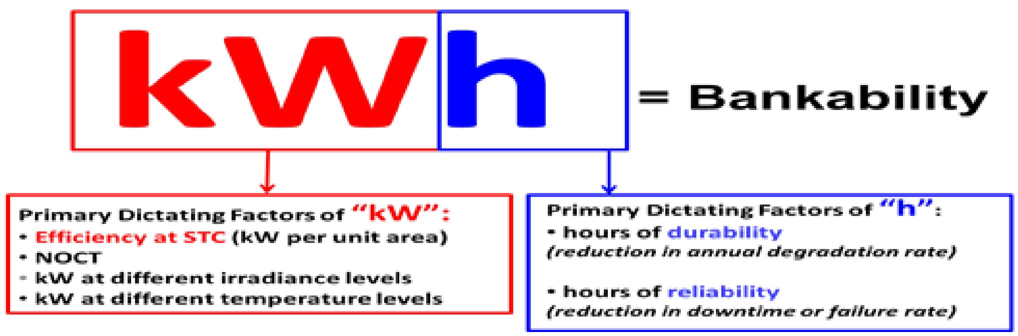


Figure 41: Bankability dictated by performance/quality, durability, and reliability.

The lifetime quality/performance, reliability, and durability characteristics can be accounted for in the rating system by assigning appropriate allocation or weighting factor for the quality of each performance parameter, degradation rate of each degradation mechanism, and failure rate of each failure mechanism. Such an approach is explained in a JPL paper published in 1982 (Ross, 1982). As shown in Figure 42, the life-cycle economic performance in 25 years should be equivalent to no degradation for 20 years (that is: to make up for the energy loss associated with failures and degradation, the product life needs to be extended for another 5 years). This equivalency allows for some gradual degradation over time but also provides for extended operation beyond 20 years, to yield a total integrated performance that is equivalent to 20 years with no degradation.

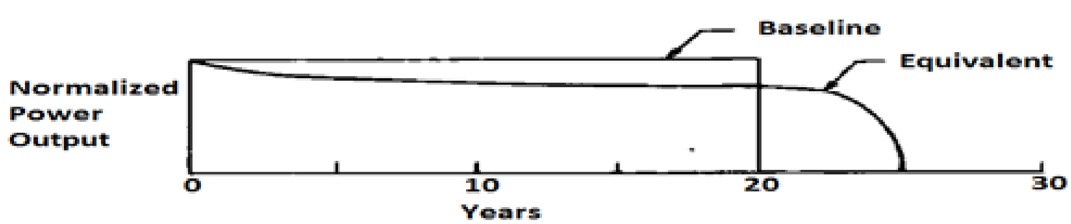


Figure 42: Life-cycle performance in 25 years should be equivalent to no degradation for 20 years.

The figure of merit for the significance of each mechanism is the level that will lead to a 10 % cost increase in the total energy from the plant (energy and economic penalty). Based on the technology maturity at that time (early 1980s) and the 10 % figure of merit, JPL developed the strawman degradation allocation shown in Table 7. A slightly modified approach may be used to develop rating systems for both comparative test and lifetime test programs, but the allocations need to be changed based on the current maturity of the technology and the expectations of the investors. Because this allocation will need to be changed for each of the major climatic conditions, a single module design is expected to receive multiple climate-specific ratings.

The rating system may be based on the reliability ratio (RR). As shown in Figure 43, the RR may be defined as the ratio between the area under predicted reliability curve and the area under the rectangular baseline curve. The area under the predicted reliability curve based on the accelerated test data may be determined using the approach used by JPL. If RR is equal to 1, the module gets the highest rating, and if it is 0.1 then it gets lowest rating. Like JPL did, the RR rating may be based on a projected quantitative energy penalty due to failures and degradation. Again, the RR rating value may not be based on a universal climatic condition but it may be based on a climatic-specific (and technology-sensitive) condition. Note that the QA Task Force of IQAF is exploring a rating system approach based on the remaining power (efficiency) after 25 years of lifetime tests.

Table 7:

Strawman Degradation Allocations for Degradations Over 25 years (equivalent to 20-year life) (Ross, 1982).

Strawman Degradation Allocations
Equivalent to 20-Year Life

Type of Degradation	Included Mechanisms	Units	Degradation Allocation
Fixed cell failure rate	Cell cracking, interconnect fatigue	Fraction per year	0.0001
Fixed module failure rate	Structural failure, insulation breakdown	Fraction per year	0.005
Linear drop in power	Yellowing, AR coating, cell degradation	Fraction per year	0.01
Fixed drop in power	Soiling	Fraction	0.05
Module wearout life	Obsolescence, corrosion	Years	25

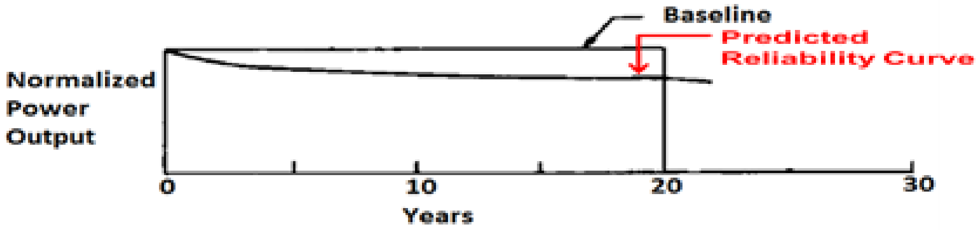


Figure 43: Reliability ratio is the area ratio between predicted reliability curve and baseline curve.

PV RELIABILITY PREDICTION: PHYSICAL AND STATISTICAL MODELS

Because only very few peer reviewed publications related to physical/empirical and statistical models of PV modules have been published in the literature, the primary focus of this section is to explain the approaches for developing appropriate statistical and physical/empirical models to predict the lifetime of PV modules. An overview on the published papers related to PV modules is also presented at the end of this section.

As shown in Figure 44, the reliability of a product is defined as the ability/probability of operating or performing under certain conditions for a certain period of time. Because the degradation losses leading to failure occur in an uncertain manner during the prolonged life of PV modules, the reliability of PV modules should be framed in a dynamic and probabilistic context. Hence, the reliability of a PV module or system may be defined as the probability that the product will perform its specified function under specified (environmental) conditions throughout its specified life expectancy.

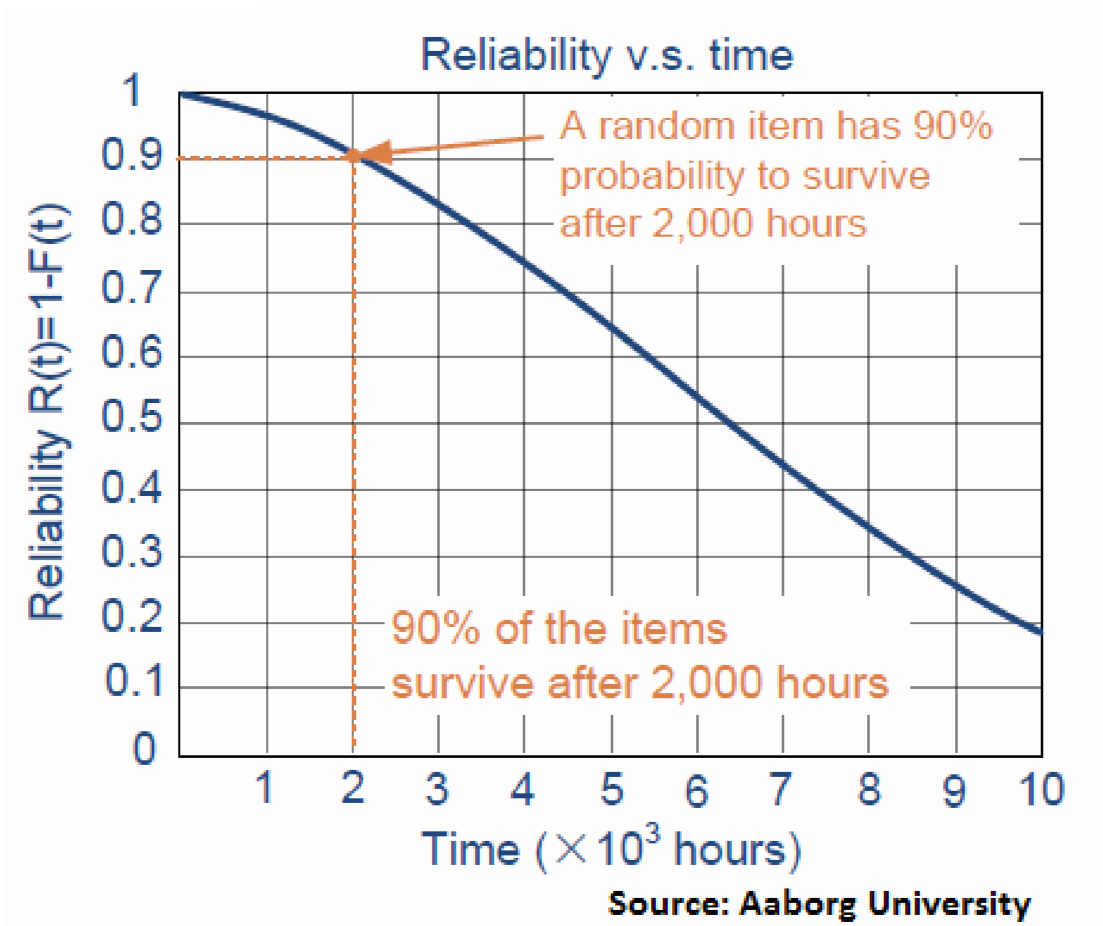


Figure 44: A hypothetical plot of reliability versus time.

AT requires extrapolation in the accelerating variable(s) and time. This implies critical importance of model choice. This section focuses on reliability modeling of PV modules. Modeling generally consists of analyzing the data to characterize the system or product, and then linking such characterization to a suitable mathematical formulation. Longrigg (Longrigg, 1989) provides a three-step summary of PV reliability modeling, methodology, and data analysis: (1) break-down the product or system into its components and analyze the criticality of individual parts; (2) for each system/product, subsystem, or component, collect and analyze either life test data or historical data on the failure rates; and (3) combine the results from (1) and (2) to obtain the reliability measure such as mean time between failure. Longrigg classifies the analysis as either statistical (operational reliability assessment from actual empirical data) or predictive (reliability estimation in the development stage from historical data).

Statistical analysis of PV module reliability data involves fitting the data to an empirical probability distribution, and then estimating the parameters of the distribution to derive the reliability characteristics such as failure rate, mean time to failure (MTTF), reliability function, etc. Murthy and Blishchke (Murthy & Blishchke, 2000) identify two approaches to modeling:

- In the "black-box" approach, the failure is modeled without consideration of the underlying mechanism. A product or component is either in a working or failed state. Typically, a component starts in its working state, and changes to a failed state after some time. Because the time to failure is uncertain, the appropriate mathematical formulation for modeling failure is a distribution function, such as exponential distribution, Weibull distribution, or lognormal distribution. This approach involves the empirical models (failure mechanism is unknown) to mathematically extrapolate the reliability characteristics from the accelerated condition to the actual use condition and the distribution models.

- In the "white-box" approach, the failure is characterized in terms of the underlying failure mechanism. Dasgupta and Pecht (Dasgupta & Pecht, 1991) categorize failure mechanisms into (1) overstress failures (interfacial deadhesion, brittle fracture, elastic deformation, etc.) and (2) wear-out failures (corrosion, diffusion, creep, fatigue crack, etc.). They also provide an alternate categorization based on the nature of the stresses that trigger the mechanism: mechanical failure, thermal failures, electrical failures, radiation failures, and chemical failures. Modeling of failure mechanisms involves the use of stochastic process formulations. This approach involves physical models (failure mechanism is known) to confidently extrapolate the reliability characteristics from accelerated condition to the actual use condition using physics/chemistry principles and the failure mechanism models.The types of reliability/durability data typically recorded for PV modules by the industry are degradation data; so understanding the degradation mechanisms is critical to the analysis.

  The "white-box" approach would be more appropriate, though difficult, for PV modules. Throughout this section, the focus is on aggregating laboratory test (AT) data and field (actual use) data in the context of reliability assessment. AT requires extrapolation in the accelerating variable(s) and time. This implies critical importance of model choice.

Black-Box Modeling

If we define an “acceptable” level of degradation, degradation points can be extrapolated to obtain failure times. A 20 % drop in the maximum power output is generally considered in the PV industry as an acceptable threshold. The degradation data could come either from the field or the AT. A large number of publications provide data related to field degradation of PV modules as compiled by Jordan et al. (Jordan & Kurtz, 2011). However, there are only very few or no publications related to the accelerated degradation data of PV modules available for the statistical lifetime prediction of PV modules. In this sub-section, we assume a product is either working/degrading or has failed, and the failure time of each test sample has been recorded. The modeling of failure times involves:

(1) providing a graphical representation of the failure time data (There are many charts available for that purpose, including frequency distribution charts or histograms, boxplots, pie charts, and time series charts. Histograms are widely used to provide a descriptive characterization of a product.),

(2) linking the descriptive representation above to a suitable probability distribution function and verifying your hypothesis (chosen distribution in step 1 above) using statistical tests such as chi-square goodness of fit test, and

(3) deriving the reliability characteristics from the assumed distribution.

Two black-box (underlying mechanism unknown) models can be applied for PV modules. The first is based on actual field degradation data and it is presented in Field Degradation Modeling below. The second is based on the accelerated degradation data (if assumed available) and it is presented in Accelerated Degradation Modeling .

Field Degradation Modeling

The overall approach for the first black-box modeling scenario is presented in the flow diagram in Figure 45. The eventual goal of this approach is to obtain the distribution characteristics such as MTTF based on field degradation data.

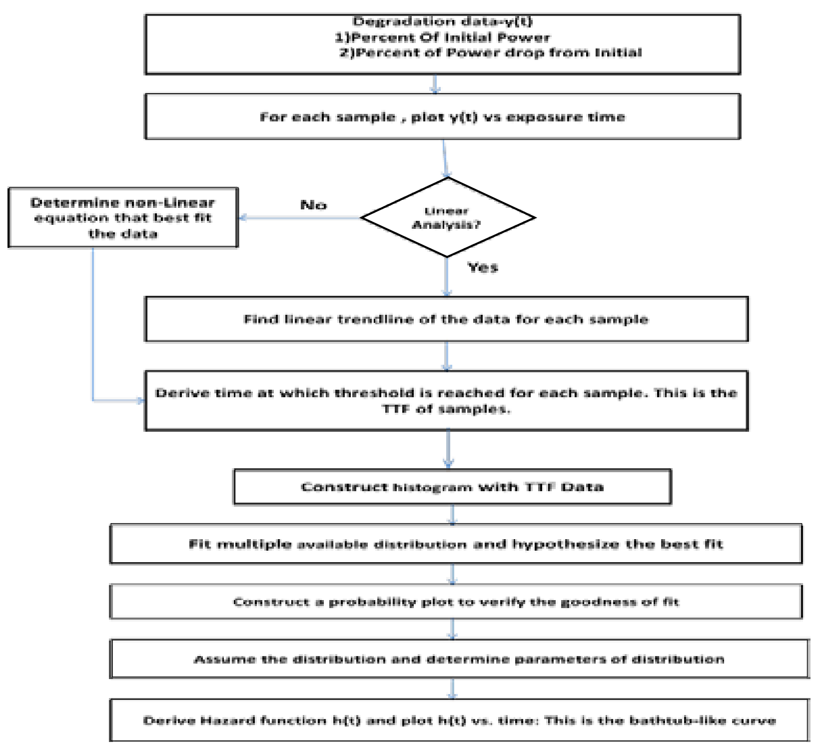


Figure 45: Flow diagram for black-box modeling using field monitored data.

The terms needed to describe and evaluate the reliability of a product are listed and briefly defined in Table 8. Note that the statistical analysis to generate these reliability characteristics should identify and appropriately account for premature failures related to workmanship issues and are not related to wear-out mechanisms that are dictating the lifetime of PV modules. This would warrant monitoring of old power plants (> 15 years) and recording failures that were caused by wear-out mechanisms. If there are workmanship issues, then there may be a few occasional spikes in the constant failure rate regime of the bathtub reliability curve. The data corresponding to these occasional spikes should not be considered in the statistical lifetime prediction, because the failure mechanisms corresponding to these spikes do not represent the normal degradation mechanisms of the product before the onset of the wear-out mechanisms (which are caused by the combination of multiple normal degradation mechanisms).

Table 8

Reliability Characteristics

Terms	Definitions
Distribution function, f(t)	probability of failure per unit of time
Reliability function R(t)	The likelihood that a product would still be operating after some time t, or R(t) = Pr (T>t)
Unreliability function	Likelihood that a product would fail by time t, or F(t) = Pr(T ≤ t) = 1 – R(t)
Failure rate, λ	Measure of failures per unit time.
Hazard rate, h(t)	Instantaneous failure rate $h(t) = \frac{f(t)}{R(t)}$ Constant hazard rate = failure rate
Mean time to failure (MTTF)	Expected lifetime of a brand new product until it fails $MTTF \int_0^\infty t\, f(t)\, dt$

The mathematical formulation appropriate for modeling TTFs is a distribution function. There are a variety of distributions available. We will focus on the ones frequently applied to PV products (Laronde, Charki, & Bigaud, 2010; Longrigg, 1989). The terms defined above are used to evaluate product reliability and are evaluated from the parameters of the assumed distribution. Table 9 provides the expressions of those terms for each distribution.

Table 9

Expressions of Reliability

Terms	Exponential distribution	Weibull distribution	Normal (lognormal) distribution
Application	Appropriate whenever failures occur randomly and are not age dependent	Popular for analyzing life data	Lognormal distribution, derived from normal distribution, is used extensively in modeling failure times, and seems very suitable for modeling semi-conductor degradation failure mechanisms
Distribution function, f(t)	$f(t) = \lambda e^{-\lambda t}$	$f\ t\ = \frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1} e^{-(t/\eta)^{\beta}}$	$f(t) = \frac{1}{\sigma\sqrt{2\pi}} e^{-(t-\mu)^2/2\sigma^2}$
Parameters of the distribution	λ: constant	β: *shape* η: *scale or characteristic li*	μ: *mean* (normal) T_{50}: *median lifetime* (lognormal) σ: *shape* (normal & lognormal)
Reliability function R(t)	$e^{-\lambda t}$	$e^{-(t/\eta)^{\beta}}$	$R(t) = 1 - \Phi\left(\frac{t-\mu}{\sigma}\right)$
Unreliability function	$1 - e^{\ \lambda t}$	$1 - e^{-(t/\eta)^{\beta}}$	1 – R(t)
Failure rate, λ	$\lambda = \frac{r}{\sum_{i=1}^{r} t_i + (n-r)T}$ r failures out of n on test T = test time ti = failure time of unit i	-	-
Hazard rate, h(t)	λ	$\frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1}$	$h(t) = \frac{f(t)}{R(t)}$
Mean time to failure (MTTF)	$1/\lambda$	$\eta\ \Gamma(\frac{1}{\beta}+1)$	$MTTF = \mu : normal$ $MTTF = T_{50} e^{\sigma^2/2} : Lognorm$

Example 1-1:

The data in Table 10 represent the PV module failure log dates for a PV system installed in Arizona (hot-dry climate) from October 2003 to December 2008. Figures 46A and 46B show the histograms assuming exponential and Weibull distributions, respectively. Taking 10/8/03 as starting point, the failure times in days were derived.

Table 10

Module Failure Log (only log dates are presented in this table; the histograms are presented in Figures 46A and 46B)

10/8/03	5/4/04	12/2/04	4/30/05	8/25/05	3/1/06	8/7/06	1/11/07	7/23/07	4/15/08
10/14/03	5/7/04	12/9/04	5/2/05	8/31/05	3/2/06	8/14/06	1/19/07	8/16/07	4/16/08
10/15/03	5/11/04	12/13/04	5/4/05	9/6/05	3/7/06	8/15/06	2/2/07	8/21/07	4/17/08
10/20/03	5/17/04	12/14/04	5/5/05	9/12/05	3/13/06	8/16/06	2/6/07	8/22/07	4/22/08
10/24/03	5/18/04	12/15/04	5/10/05	9/14/05	3/14/06	8/17/06	2/16/07	8/23/07	4/23/08
10/27/03	5/24/04	1/5/05	5/11/05	9/19/05	3/15/06	8/21/06	2/20/07	9/4/07	4/28/08
11/19/03	5/25/04	1/12/05	5/12/05	9/28/05	3/21/06	8/22/06	2/21/07	9/13/07	4/30/08
11/20/03	5/26/04	1/15/05	5/13/05	10/3/05	3/22/06	8/23/06	2/22/07	9/14/07	5/19/08
11/21/03	5/27/04	1/18/05	5/16/05	10/5/05	3/23/06	8/30/06	2/26/07	9/18/07	5/20/08
11/25/03	6/14/04	1/22/05	5/20/05	10/6/05	3/24/06	9/8/06	2/27/07	9/19/07	5/22/08
11/26/03	6/20/04	2/2/05	5/24/05	10/7/05	3/27/06	9/11/06	3/1/07	9/20/07	5/27/08
12/3/03	6/23/04	2/3/05	5/26/05	10/10/05	3/28/06	9/13/06	3/2/07	9/24/07	5/30/08
12/16/03	6/25/04	2/6/05	5/27/05	10/11/05	3/29/06	9/14/06	3/5/07	9/27/07	6/4/08
12/17/03	6/27/04	2/7/05	5/31/05	10/18/05	3/30/06	9/18/06	3/6/07	9/28/07	6/5/08
12/18/03	6/28/04	2/8/05	6/7/05	10/20/05	4/7/06	9/19/06	3/7/07	10/2/07	6/9/08
12/23/03	7/2/04	2/14/05	6/8/05	10/24/05	4/10/06	9/20/06	3/8/07	10/5/07	6/12/08
12/26/03	7/7/04	2/21/05	6/9/05	10/25/05	4/11/06	9/26/06	3/9/07	10/9/07	6/19/08
12/29/03	7/8/04	2/22/05	6/10/05	10/26/05	4/12/06	9/28/06	3/12/07	10/12/07	6/23/08
1/6/04	7/9/04	2/23/05	6/13/05	10/27/05	4/13/06	10/9/06	3/13/07	10/16/07	7/1/08
1/13/04	7/16/04	2/25/05	6/14/05	10/28/05	4/24/06	10/10/06	3/14/07	10/18/07	7/2/08
1/16/04	7/19/04	3/1/05	6/16/05	10/31/05	4/25/06	10/11/06	3/16/07	10/19/07	7/8/08
1/18/04	7/22/04	3/2/05	6/17/05	11/1/05	4/26/06	10/12/06	3/19/07	10/22/07	7/29/08
1/26/04	7/23/04	3/7/05	6/20/05	11/2/05	4/28/06	10/13/06	3/26/07	10/23/07	8/11/08
1/29/04	8/2/04	3/8/05	6/21/05	11/3/05	5/4/06	10/18/06	3/27/07	10/25/07	8/22/08
1/30/04	8/18/04	3/9/05	6/23/05	11/8/05	5/5/06	10/19/06	3/28/07	10/30/07	8/25/08
2/3/04	8/23/04	3/11/05	6/24/05	11/9/05	5/10/06	10/31/06	3/29/07	10/31/07	9/4/08
2/5/04	8/27/04	3/14/05	6/28/05	11/24/05	5/11/06	11/1/06	3/30/07	11/6/07	9/5/08
2/6/04	9/14/04	3/16/05	6/29/05	12/1/05	5/12/06	11/3/06	4/4/07	11/7/07	9/11/08
2/10/04	9/16/04	3/17/05	6/30/05	12/2/05	5/22/06	11/6/06	4/5/07	12/2/07	9/16/08
2/18/04	9/17/04	3/18/05	7/1/05	12/16/05	5/31/06	11/7/06	4/6/07	12/7/07	9/17/08
2/25/04	9/21/04	3/21/05	7/7/05	12/19/05	6/1/06	11/8/06	4/9/07	12/17/07	9/24/08
2/26/04	9/29/04	3/22/05	7/12/05	12/20/05	6/2/06	11/14/06	4/11/07	1/15/08	9/25/08
3/6/04	9/30/04	3/25/05	7/13/05	1/5/06	6/3/06	11/15/06	4/16/07	1/23/08	9/26/08
3/8/04	10/1/04	3/29/05	7/15/05	1/9/06	6/5/06	11/16/06	4/17/07	1/31/08	10/9/08
3/9/04	10/3/04	3/31/05	7/19/05	1/11/06	6/6/06	11/21/06	4/18/07	2/5/08	10/10/08
3/11/04	10/8/04	4/1/05	7/25/05	1/12/06	6/7/06	11/22/06	4/23/07	2/12/08	10/15/08
3/22/04	10/11/04	4/4/05	7/26/05	1/26/06	6/9/06	11/27/06	4/25/07	2/13/08	10/21/08
3/25/04	10/12/04	4/5/05	7/28/05	2/1/06	6/12/06	11/28/06	5/3/07	2/19/08	10/22/08
4/7/04	10/14/04	4/6/05	7/29/05	2/4/06	6/15/06	11/29/06	5/7/07	2/26/08	10/23/08
4/9/04	10/22/04	4/11/05	8/2/05	2/8/06	6/16/06	12/1/06	5/8/07	2/29/08	10/24/08
4/12/04	11/1/04	4/12/05	8/5/05	2/10/06	6/19/06	12/6/06	5/23/07	3/4/08	11/4/08
4/13/04	11/2/04	4/13/05	8/8/05	2/12/06	7/7/06	12/7/06	6/14/07	3/5/08	11/10/08
4/14/04	11/4/04	4/17/05	8/9/05	2/13/06	7/10/06	12/8/06	6/20/07	3/7/08	11/14/08
4/15/04	11/10/04	4/18/05	8/10/05	2/14/06	7/11/06	12/11/06	6/21/07	3/17/08	11/19/08
4/16/04	11/13/04	4/19/05	8/12/05	2/16/06	7/18/06	12/21/06	6/25/07	3/18/08	
4/20/04	11/16/04	4/20/05	8/15/05	2/21/06	7/19/06	12/26/06	6/28/07	3/31/08	
4/27/04	11/17/04	4/21/05	8/16/05	2/22/06	7/20/06	12/27/06	6/29/07	4/1/08	
4/28/04	11/18/04	4/24/05	8/19/05	2/23/06	7/28/06	1/2/07	7/11/07	4/2/08	
4/30/04	11/20/04	4/25/05	8/22/05	2/24/06	7/31/06	1/3/07	7/16/07	4/10/08	
5/1/04	11/24/04	4/26/05	8/23/05	2/25/06	8/2/06	1/4/07	7/18/07	4/11/08	
5/3/04	11/29/04	4/28/05	8/24/05	2/27/06	8/3/06	1/9/07	7/20/07	4/14/08	

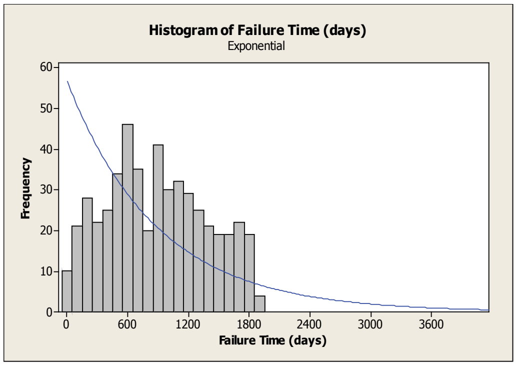


Figure 46A: Histogram of failure times (Expo)

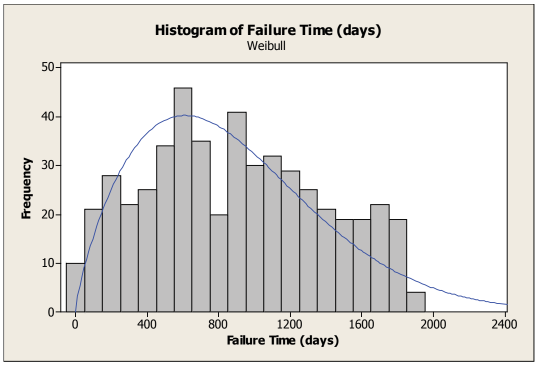


Figure 46B: Histogram of failure times (Weibull)

The Weibull distribution appears to provide a better fit than the exponential distribution. This implies that the characterization parameters obtained using the Weibull distribution are more appropriate than the ones obtained using exponential distribution.

To verify that hypothesis, the "linear rectification" procedure is used. It consists of putting the Weibull cumulative distribution function (CDF) equation into a linear form.

$$F(t)=1-e^{-(t/\eta)^{\beta}} \rightarrow \ln\{-ln[1-F(t)]\}=\beta lnt-\beta ln\eta$$

$$Y=\beta X-b, \text{ where } Y=\ln\{-ln[1-F(t)]\} \text{ and } X=lnt$$

If the assumption is correct, the plot Y = f(X) should follow a fairly straight line. Because Y depends on the CDF F(t), it is necessary to estimate F(t). There are several approaches to estimate F(t). Tobias and Trindade (1995) recommended using the "median ranks" method, where the CDF estimate can be approximated to:

$$\widehat{F(t_i)}=\frac{i-0.3}{n+0.4}$$

The plot of Y = f(X) of Figure 47A appears to follow a straight line. Figure 47B also shows the "empirical CDF" plot from Minitab. These graphical observations confirm that the assumed Weibull distribution can be used to analyze the data. As noted earlier, this analysis (based on short-term monitored data) may account only for the design and workmanship related failures rather than wear-out failures.

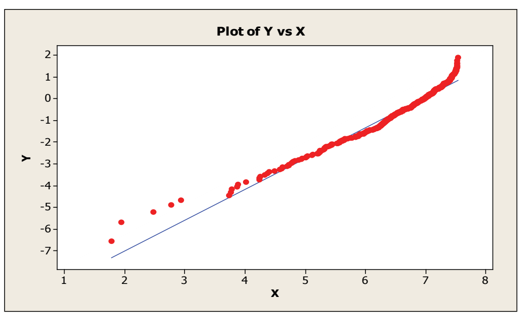


Figure 47A: Weibull probability plot.

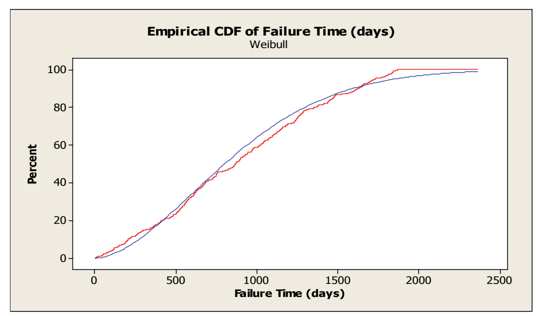


Figure 47B: Empirical CDF plot.

Example 1-2: Analysis of long-term outdoor exposure test data

Five PV modules were installed at latitude tilt in a hot desert climatic condition. After eight years of operation, the power output data were linearly extrapolated to estimate the failure time of each unit, assuming a unit would fail when its power drops by 20% or more (infant, random, and wear-out failure mechanisms are assumed to be the same but, in reality, they may or may not be the same). The failure times in years are presented in Table 11.

Table 11

Time to Failure (TTF) for the Test Samples

Unit	TTF (years)
3801	33.41386
4821	26.93645
DG22	25.60665
DG822	20.84669
RA240	32.01457

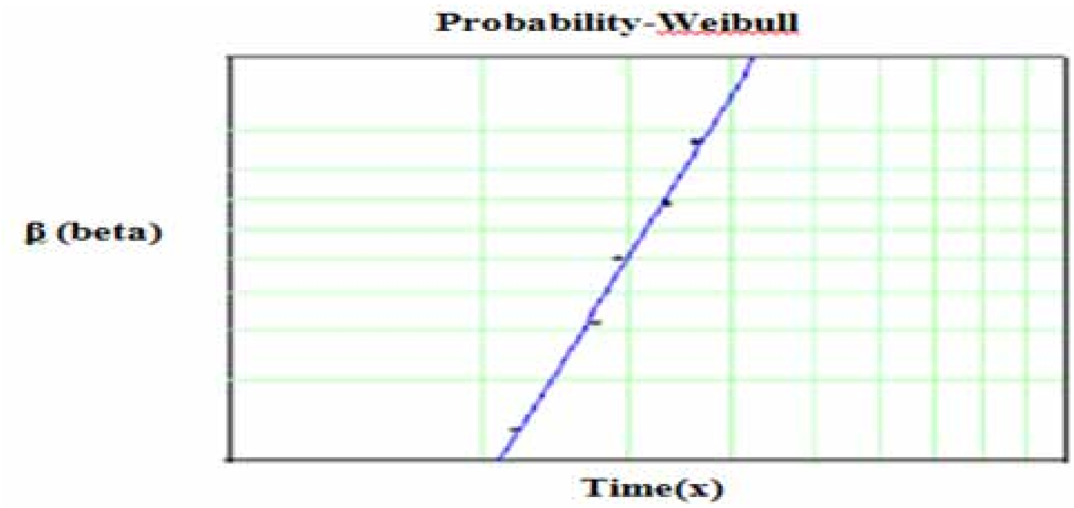


Figure 48: Weibull fit.

Those data were fitted to a Weibull distribution. As shown in Figure 48 above, all the data points are aligned along the straight line, indicating that this distribution is appropriate for analyzing the data.

Using Weibull + + 7 software, the parameters of the distribution shown in Table 12 were estimated.

Table 12

Characteristic Distribution Parameters

	Value	Lower Bound	Upper Bound
Beta (β)	5.3759	3.3	8.7484
Eta (η)	32.0597	28.5706	35.975
Mean Life (MTTF)	29.6	25.3	34.6
Failure Rate (λ)	24.3	0.2683	2208.7

The following observations can be drawn:

(1) A module from that batch would need an **average** of 29 years before seeing its power output drop below 80 %.

(2) An **average** of 24 of those samples are expected to fail per year.

This observation is made for a specific set of modules in Arizona (hot-dry climate) and this observation may or may not hold for all the existing/future modules and all the climatic conditions.

Statistical degradation data analysis

PV module degradation data are usually obtained by measuring power output of n test samples each at time ti, i = 1, 2, … and presented as shown in Table 13.

Table 13

Degradation Data Recording Format

		Time tj				
		t1	t2	…	…	tm
Sample i	1	y1,1	y1,2	…	…	y1,m
	2	y2,1	y2,2	…	…	y2,m
	…	…	…	…	…	…
	…	…	…	…	…	…
	n	yn,1	yn,2	…	…	yn,m

yi,j represents the degradation measured on sample i at time tj. Data can be collected at any time on any sample, meaning the measurement times for samples u and v need not be equal and can be denoted as tuj and tvk.

Vazquez and Rey-Stolle proposed a reliability-based model assuming normal distribution of module power output with the distribution parameters (mean and standard deviation) having a linear relationship with the time (Vazquez & Rey-Stolle, 2008). It is important to study the behavior of the power drop, rather than just the measured power.

Example 1-3:

In Figure 49, the horizontal line (10% drop) represents the "defined" level at which failure is assumed (Twenty percent is usually considered. Ten percent is used here for illustration purposes.).

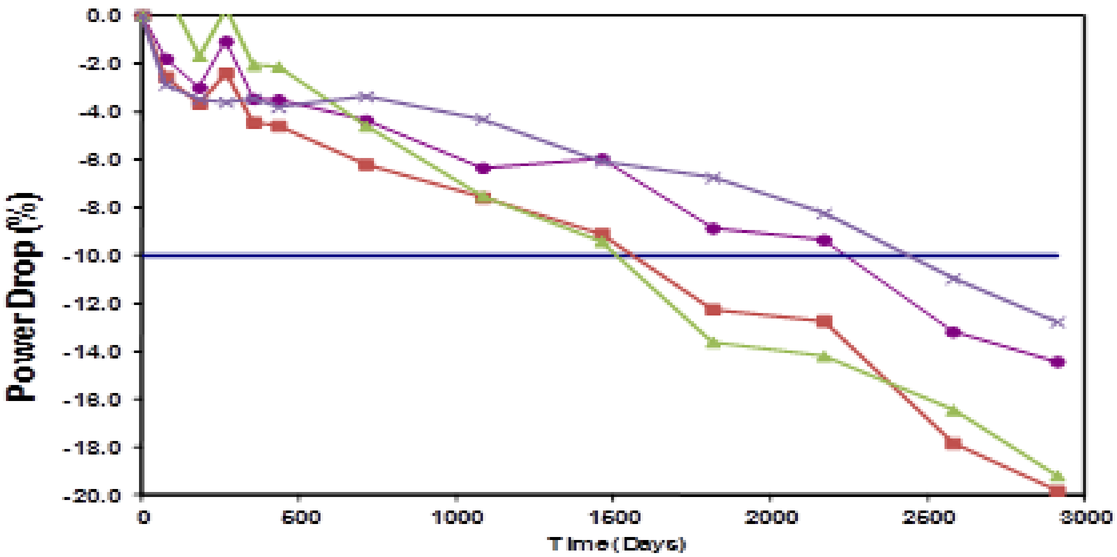


Figure 49: Power output degradation vs. time.

The following procedure is used to analyze the data:

- For each test sample, fit a mathematical model (for example, linear, exponential, power, logarithmic, ...) to the performance degradation data (path curve).
- Draw a vertical line to intercept all of the sample path curves at a fixed time t = tj. Rank the intercepting power drop values yij in ascending order. The number of test samples should be large enough for statistical purposes.
- Fit yij above to an appropriate probability distribution function f(y0̱, 0̱), where 0̱ is the time-dependent distribution parameter vector.
- Estimate the parameters of the distribution.
- Evaluate the reliability of the product based on the specified level of degradation.

The Reliasoft Weibull++7 software was used to analyze the data. It provides six mathematical models to choose from—linear, exponential, logarithmic, power, Gompertz, and Lloyd-Lipow. The degradation data were fit to each of them and the exponential and linear models provided the better fits. Figure 50 shows a side-by-side comparison of the two fits. The linear model seems to best fit the data.

Table 14

Mathematical Model Coefficients and Power Drop Estimates

Model Coefficients				
Sample ID	Parameter a	Parameter b		
s15	0.00316	2.11534		
s23	0.00662	0.01582		
s90	0.00425	1.30672		
s91	0.00582	1.78719		
Estimated power drop at observation times				
Tj	s15	s23	s90	s91
75	2.352637	0.031389	1.306853	1.794787
181	2.688019	0.033608	1.306862	1.794787
266	2.956957	0.035388	1.306870	1.794787
354	3.235387	0.037230	1.306878	1.794787
433	3.485341	0.038884	1.306885	1.794787
711	4.364928	0.044705	1.306910	1.794787
1083	5.541928	0.052494	1.306943	1.794788
1462	6.741076	0.060430	1.306976	1.794788
1815	7.857960	0.067821	1.307008	1.794788
2168	8.974845	0.075212	1.307039	1.794788
2579	10.275240	0.083818	1.307076	1.794788
2911	11.325681	0.090769	1.307106	1.794789

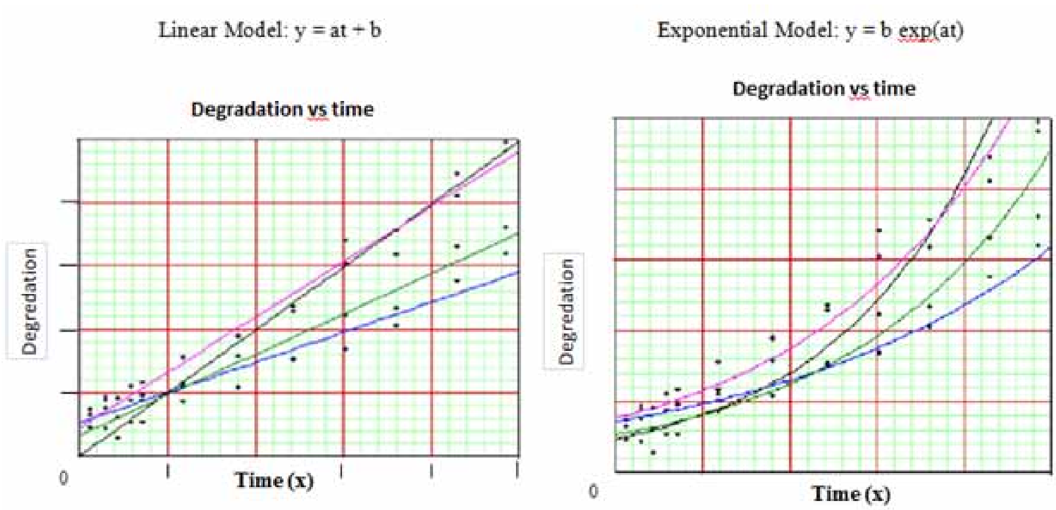


Figure 50: Mathematical model fit to the degradation data.

The model coefficients output from the software for each sample is shown at the top of Table 14. The lower half of the table shows the estimated power drop, yij, for each unit i at each measurement time tj. Note that negative drops were removed.

For each measurement time tj, the yijs are fit to an appropriate probability distribution. For degradation data analysis, the Weibull or lognormal distributions are often used.

Figure 51 shows the Weibull probability plots for six selected observation times: 1083, 1462, 1815, 2168, 2579, and 2911 days. Although the data points are not as close to the plot lines as we would wish, we will assume that these data follow a Weibull distribution for the purpose of this example. The shape (Beta) and the scale (Eta) parameters of the distribution estimated by the software are shown in Table 15.

The next step is to plot the distribution parameters vs. time. This plot is shown in Figure 52. It can be assumed from the plot that the parameter Beta is nearly constant. In fact, this observation makes sense as the shape parameter of the Weibull distribution is expected to be constant under the same environmental conditions. The scale parameter, Eta, appears to be a linear function of the time. Thus:

Beta = bo

Eta = at + b

The coefficients a, b, and bo were determined by the software to be:

bo = 0.876226

a = 4.74E-04

b = 1.481018

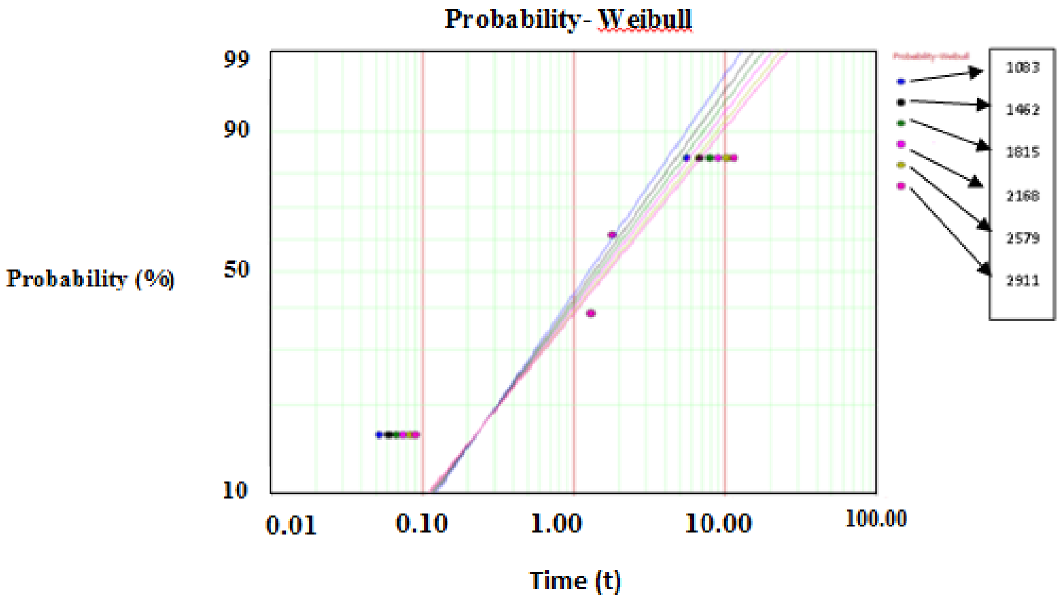


Figure 51: Weibull probability plot for the data shown in Table 14 above.

Table 15

Estimated Distribution Parameters

	1083	1462	1815	2168	2579	2911
Beta	0.81358	0.777149	0.750256	0.72794	0.706387	0.691509
Eta	1.979318	2.178436	2.353393	2.519707	2.704706	2.848166

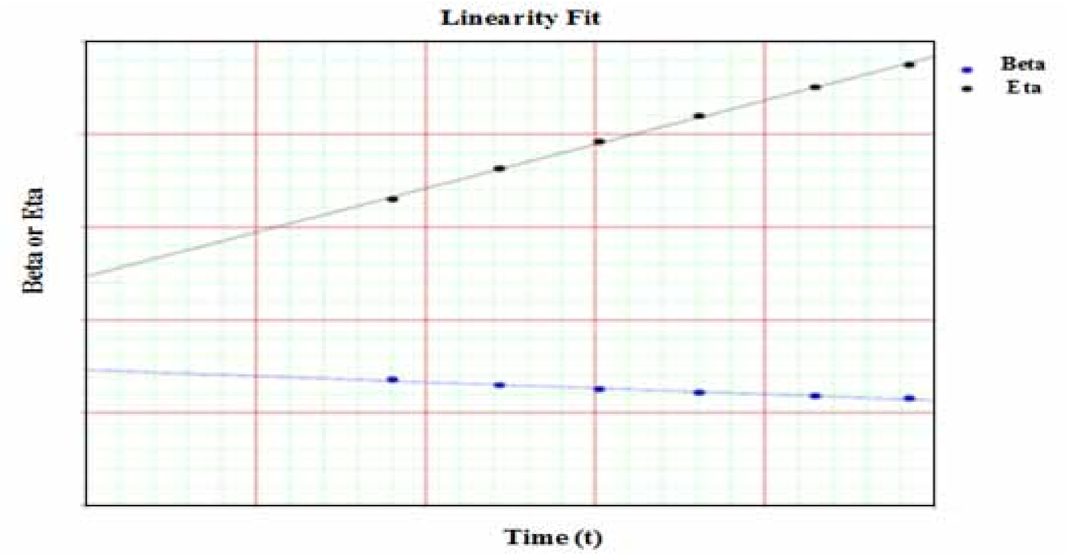


Figure 52: Plots of Weibull parameters vs. time.

To predict the reliability of these modules, recall that for a Weibull distribution, the reliability function R(t) is given by R(t) = exp(-t/Eta)^Beta.

Thus, $R(y,t) = e^{-(\frac{y}{Eta(t)})^{Beta}}$, y being the power degradation output.

<u>Question 1</u>: Assuming a module fails when its power output drops by more than 20%, what would be the reliability of these modules after 25 years?

The probability that the degradation y(t) is less than 20% can be expressed as F(y, t) = Pr(Y(t) < 20; because F(y, t) = 1 – R(y, t), we can substitute R(y, t).

$F(20,25) = 1 - e^{-(\frac{20}{0.000474*25*365+1.481018})^{0.876226}} = 0.948$

Thus, there is 94.8% chance that a random module of these types would not lose more than 20% of its power output after 25 years of operation.

<u>Question 2</u>: Assuming a module has degraded by 5% after eight years of operation, what would be its reliability at 25 years? We still assume 20% threshold.

This is determined using the conditional reliability concept.

Let D = 20% threshold

$$F(t = 25\text{years} \mid y1 = 5\%, t1 = 8\text{years}) = 1 - \frac{e^{-(\frac{D}{Etat(t_2)})^{Beta}}}{e^{-(\frac{y}{Etat(t_1)})^{Beta}}}$$

Accelerated Degradation Modeling

For a particular module, degradation measurements can be made over time. However, PV modules are designed to operate without significant failure or degradation for many years (20-30 years). For example, warranties of crystalline silicon modules allow for about 20 % deterioration in 20-30 years, meaning very few units would degrade significantly in a field test of, say, six months to one year. King et al. report a power drop of approximately 0.4 % per year after eight years of monitoring silicon modules (King, Quintana, Kratochvil, Ellibee, & Hansen, 2000). Ishii et al. evaluate the performance degradation of different PV technologies from 2005 to 2008 (Ishii, Takashima, & Otani, 2011). They found that the module power output was dropping at a rate of 1.3 % for amorphous silicon (a-Si) modules, 0.7 % for single-crystalline silicon modules, and 0.3 % for poly-crystalline silicon. Many studies of field installed PV modules have reportedly observed similar low degradation rates (Jordan & Kurtz, 2011).

AT is used to obtain information in a short period of time. The main goal of AT is to obtain and analyze reliability data under controlled conditions and then estimate the characteristics of interest under actual use conditions by applying an acceleration factor.

The acceleration factor (AF) relating the mean or characteristic lifetimes, say μ_1 and μ_2 at two different conditions (say controlled and used) is given by:

$$AF = \frac{\mu_1}{\mu_2}$$

If the lifetime prediction is to be done using AT, then the stress tests should be done at multiple stress levels (for example, different temperatures much higher than the use stress temperature). One TTF histogram needs to be generated for each stress level. For each histogram (that is, for each stress level), an appropriate lifetime distribution curve needs to be generated for each stress level using one of the best fit distribution models. If there are three stress levels, then there will be three lifetime distribution curves. Based on these three grouped curves, the lifetime distribution at use stress can be generated in conjunction with one of the seven life-stress models.

Five of the seven common life-stress models are used in the black-box approach. The five life-stress models used in the black-box approach are called empirical models and the other two used in the white-box approach are called physical models. The physical models are physics or chemistry based models, and empirical models are simple empirical models with no demonstrated physics or chemistry basis. A systematic approach for the black-box model based on the AT data is presented in the five steps below.

<u>Step 1</u>: Determine TTF for each module at each accelerated stress level.

In this step, a statistically significant number of modules is stressed at each stress level, designated here as accelerated stress 1 (AS1), AS2, and AS3. As shown in Figure 53, the time taken to reach the 20 % degradation limit is determined for each module at each stress level. Because the AS3 stress is more severe than the other two stress levels, the time taken to reach the 20 % degradation limit is much shorter than for the other two stresses.

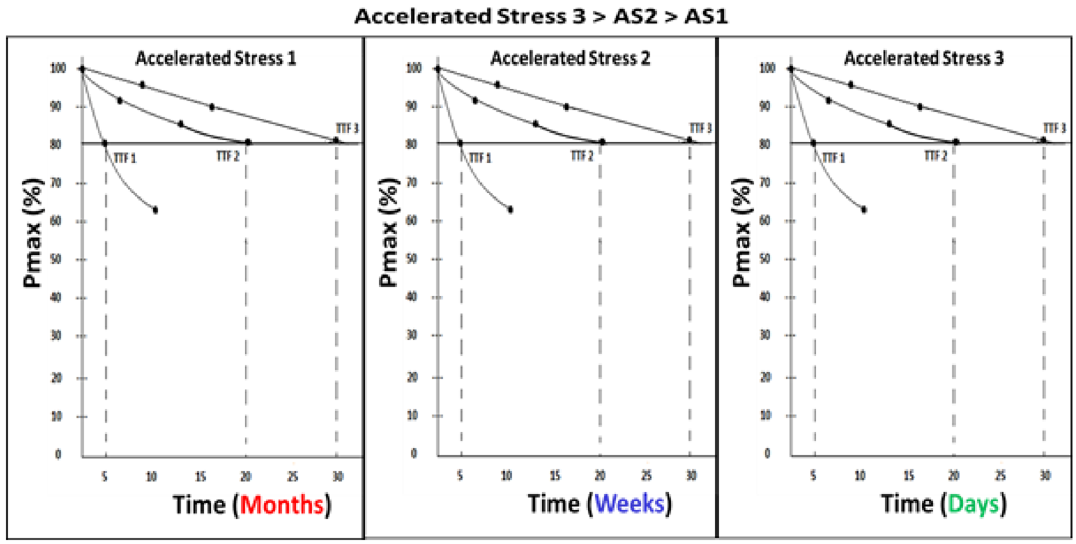


Figure 53: Determination of time to failure for each module at each accelerated stress level.

Step 2: Obtain histogram for each accelerated test level and identify the best fit failure distribution curve.

In this step, an individual histogram is obtained for each of the accelerated stress levels identified in step 1. The individual histograms are shown in Figure 54. For each histogram, the best fit distribution curve is obtained and shown as the "blue" curve in Figure 54. The goodness of the fit is verified using the procedure explained in the Field Degradation Modeling sub-section of this report.

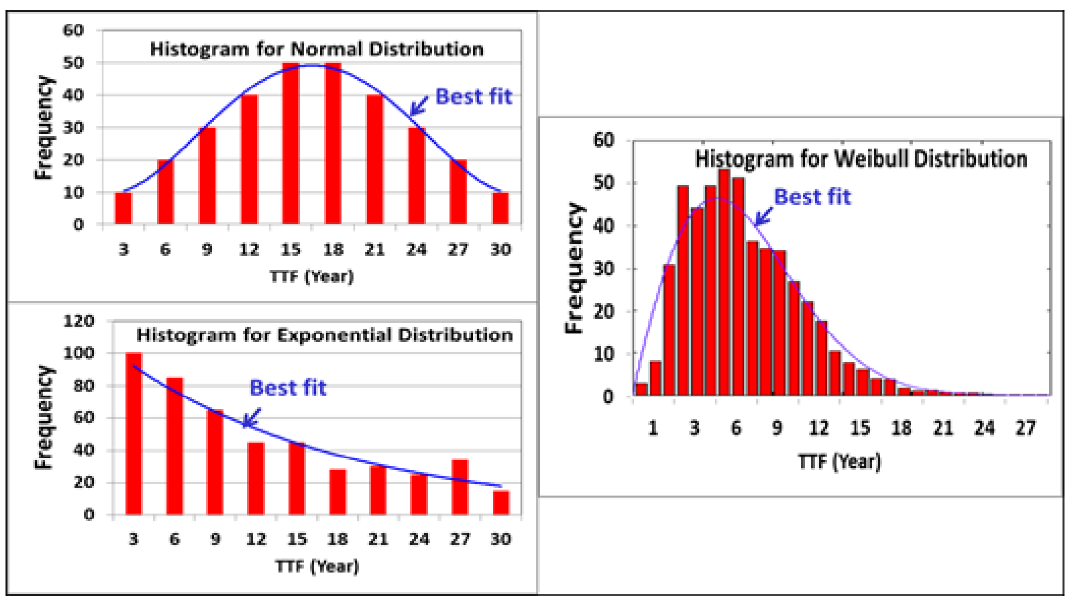


Figure 54: Determination of the best fit distribution for each histogram of all the modules at each accelerated stress level.

Step 3: Group the best-fit distribution curves of all accelerated test levels.

In step 3, the best fit distribution curves obtained in step 2 are grouped as shown in Figure 55.

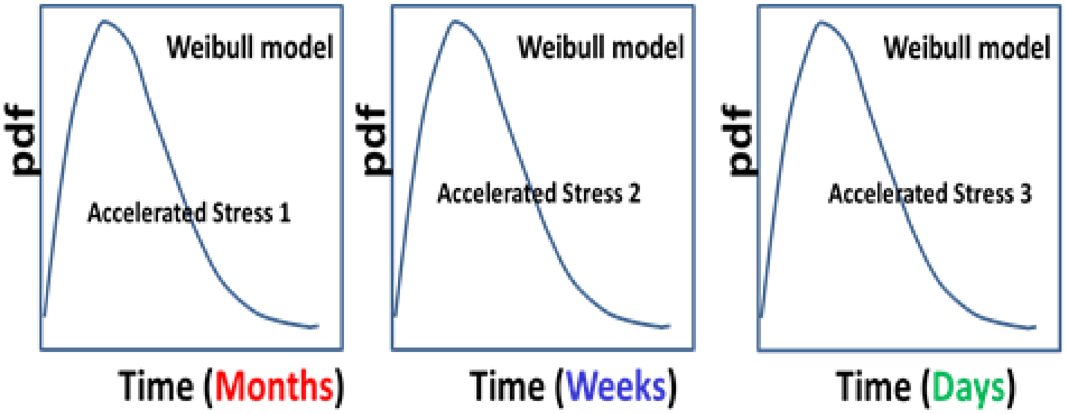


Figure 55: Grouping of the best fit distribution curves of all the modules at each accelerated stress level.

Step 4A: Obtain life-stress plot using the distribution curves of all three stress levels and an appropriate empirical model.

In step 4A, a life-stress plot shown in Figure 56 is obtained using the grouped distribution curves and an appropriate empirical model. The five "empirical" life-stress models typically used by various industries are:

1. inverse power law relationship,
2. temperature-humidity relationship,
3. temperature non-thermal relationship,
4. multivariable relationships—general log-linear and proportional hazards, and
5. time-varying stress models.

Details about these empirical models are available elsewhere (Reliawiki.Com).

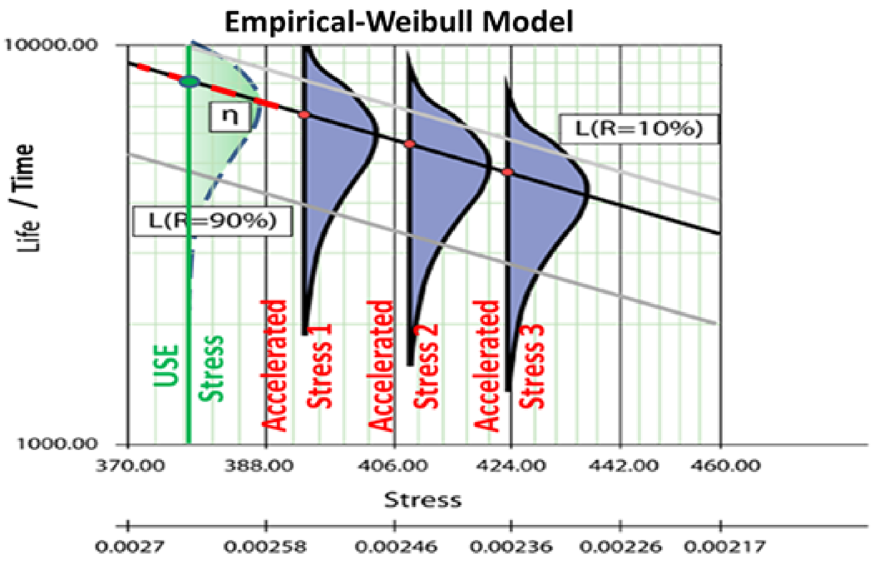


Figure 56: Life-stress plot based on the grouped distribution curves and an empirical model.

Step 4B: Determine if linear or non-linear extrapolation is to be used from accelerated stress lifetime data to use stress lifetime data.

As shown in Figure 57, it is important to select an appropriate empirical model to predict the lifetime of the product at use stress level. If not, the model may predict a wrong lifetime and this is the primary pitfall of the empirical model based extrapolation where the underlying degradation or failure mechanism is not understood.

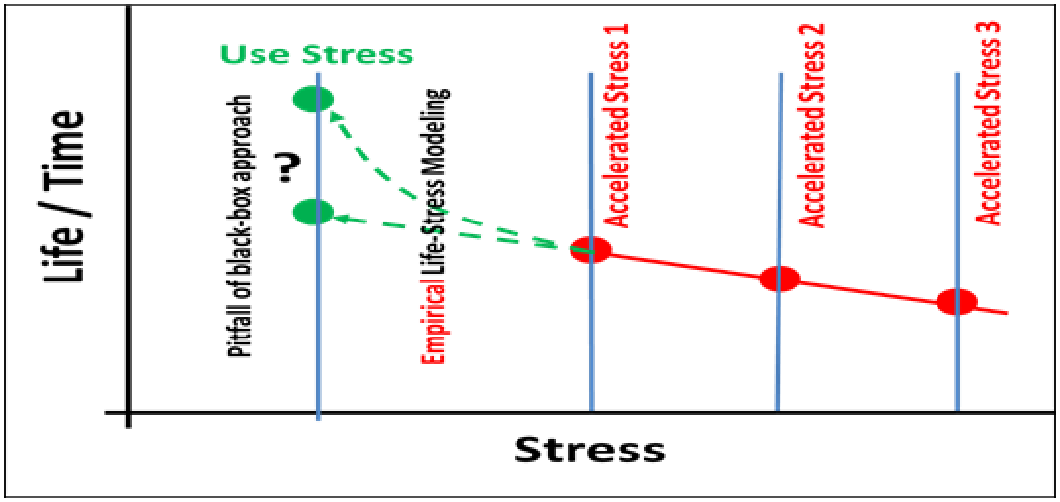
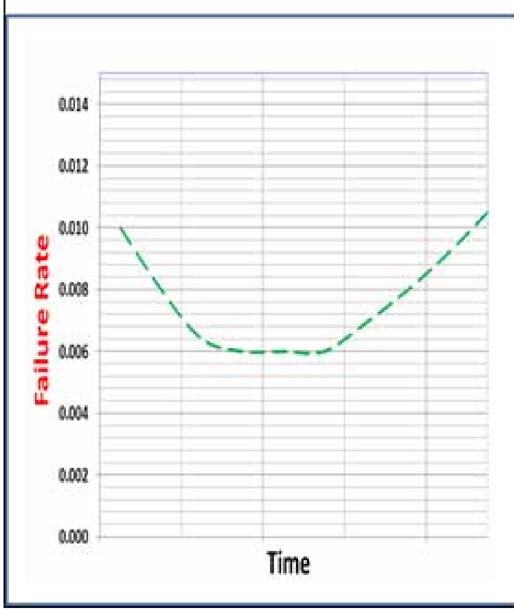


Figure 57: Life-stress plot based on the black-box approach (this life-stress plot is based on the grouped distribution curves and two different empirical models).

Step 5: Obtain the failure rate plot for use stress level and calculate all the other best fit parameters.

Based on the accelerated data, the best fit parameters for the use condition including failure rate vs. time (bathtub curve) and lifetime (MTTF) shown in Figure-Table 58 can be obtained.

Failure rate distribution



Best fit parameters including mean life

Parameter	Definitions
Distribution function, f(t)	probability of failure per unit of time
Reliability Function R(t)	The likelihood that a product would still be operating after some time t, or R(t) = Pr (T>t)
Unreliability Function	Likelihood that a product would fail by time t, or F(t) = Pr(T ≤ t) = 1 – R(t)
Failure Rate, λ	Measure of failures per unit time.
Hazard Rate, h(t)	Instantaneous failure rate Constant hazard rate = failure rate
Mean Time to Failure (MTTF)	Expected lifetime of a brand new product until it fails

Figure 58: Failure rate plot for use stress and calculated reliability characteristics data including lifetime (MTTF).

White-Box Modeling

As stated earlier, the black-box approach is based on the empirical life-stress models (failure mechanism unknown) whereas the white-box approach is based on the physical life-stress models (failure mechanism known). The white box approach uses the same five steps as the black-box approach, except in Step 4B, where the "physical" life-stress models (instead of empirical life-stress models) are used to extrapolate the data from accelerated conditions to the use condition. The physical life-stress models are based on the known failure mechanisms and hence they are expected to predict the lifetime of PV modules more accurately than the black-box models as shown in Figure 59. The most frequently used physical models are Arrhenius and Eyring models. They are briefly explained below and detailed explanations are available elsewhere (Reliawiki.Com).

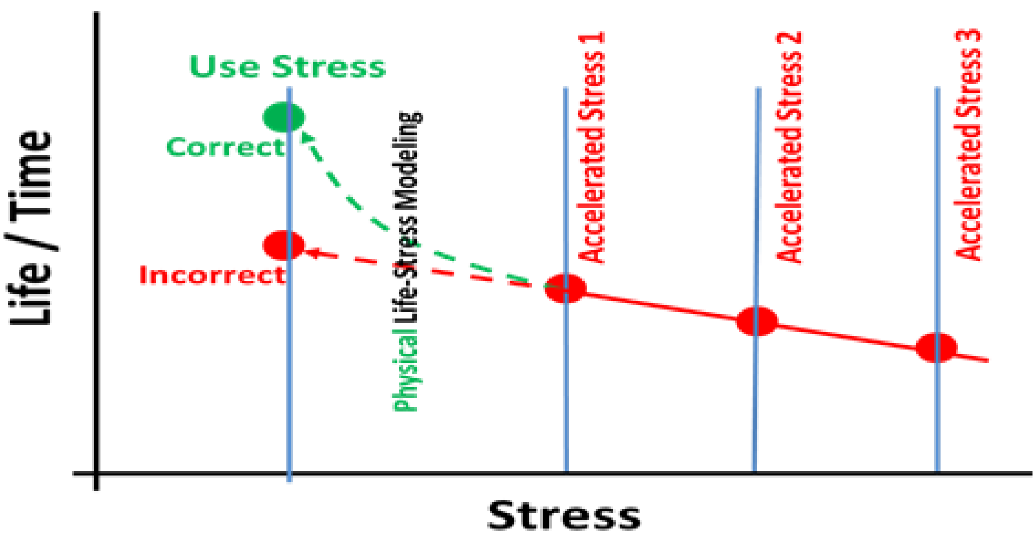


Figure 59: Life-stress plot based on the white-box approach. (This life-stress plot is based on the grouped distribution curves and two extrapolated curves. The correct extrapolated curve is based on the physical model with green dashed line and the incorrect extrapolated curve is based on the empirical model with red dashed line).

Products are subjected to higher stresses, such as temperature, voltage, humidity, etc., and the analysis requires the use of appropriate physical models that relate those stresses to normal field conditions.

For thermal stresses, the Arrhenius model is usually used. For example, Xia et al. (Xia, Wohlgemuth, & Cunningham, 2009) studied the longevity of polymer-based encapsulants and backsheets of PV modules using the Arrhenius theory to model the diffusion of moisture into a PV module. Kuznetsova et al. estimate the diffusivity at various temperatures using the Arrhenius model (Kuznetsova, Gaston, Bury, & Strand, 2009). Jorgensen et al. used the Arrhenius model to describe the permeability of PV packaging material (Jorgensen et al., 2006).

It is important to note that the Arrhenius relationship may not hold in all circumstances in which temperature is acting as the stress factor. For example, if there is more than one competing chemical reaction and those chemical reactions have different activation energies, the Arrhenius model will not describe the rate of the overall chemical reaction. A good example for two competing reactions in PV modules is the discoloration of encapsulant. The rate of discoloration of the encapsulants is dictated by two counter reactions—discoloration reaction by UV and bleaching reaction by oxygen. Because the temperature affects the two reaction processes differently, a nonlinearity will be introduced into the acceleration function relating times at two different temperatures. To obtain useful extrapolation models for degradation processes having more than one step, each with its own rate constant, it is, in general, necessary to have adequate models for the important individual steps. For example, when the individual processes can be observed, it may be possible to estimate the effect that temperature has on each of the rate constants.

When more than one stress is involved—temperature and voltage or temperature and humidity, for example—the Eyring model can be used, but it has not been applied much in the PV industry. There are many variants of these two models in the literature, such as the inverse power model, the Coffin-Manson model, etc. Table 16 provides the Arrhenius and Eyring expressions describing the effect of related stress(es) on the MTTF or other characteristics of failure for the exponential and Weibull distributions.

Table 16

Expression of the Effect of Stresses on the MTTF or Other Characteristics of Failure

Physical Models	Significant Stresses	Exponential Distribution	Weibull Distribution
Arrhenius model	Thermal (T)	$MTTF(T) = Ae^{\frac{\Delta H}{kT}}$	$\eta(T) = Ae^{\frac{\Delta H}{kT}}$
Eyring model	Thermal (T) and a second stress S, such as voltage or humidity	$MTTF(T,S) == [AT^{\alpha}e^{\frac{\Delta H}{kT}}][e^{(B+\frac{C}{T})S}]$	$\eta(T,S) == [AT^{\alpha}e^{\frac{\Delta H}{kT}}][e^{(B+\frac{C}{T})S}]$
$T = temperature\ in\ K$ $\Delta H = Activation\ energy$ k = Boltzmann's constant (8.617 x 10^{-5} in ev/K)			

At two different temperatures T_1 and T_2 ($T_2 > T_1$), the AF for the Arrhenius model and exponential failure time distribution is given by:

$$A\,F \quad \frac{MTTF_1}{MTTF_2}$$

$$AF = e^{\frac{\Delta H}{k}(\frac{1}{T_1}-\frac{1}{T_2})} = e^{11605\Delta H(\frac{1}{(T_1+273.16)}-\frac{1}{(T_2+273.16)})}$$

AF depends on T_1, T_2, and the activation energy ΔH

For modeling degradation data, the vector $\beta_i = (\beta_{1i}, \beta_{2i}, \ldots, \beta_{ki})$ of the degradation path expression is expressed as a function of stress(es). The examples below are from McMahon for the linear relationship (McMahon, 2004), and Meeker, Escobar, and Lu for the exponential relationship (Meeker, Escobar, & Lu, 1998):

$D(t) = k_S t$; where k_S is a function of the applicable stress. For thermal stress,

$k_S = Ae^{-\Delta H/T_S}$, T_S being the stressed or elevated temperature

$D(t) = A(1 - e^{-k_S t})$, where k_S can be defined as above.

The white-box approach consists of characterizing the failures in terms of the underlying failure mechanisms. There are many mechanisms that can lead to the failure or degradation of a PV module. McMahon et al. propose a five-step protocol for modeling PV modules lifetime (McMahon, Jorgensen, Hulstrom, King, & Quintana, 2000):

1. Identify and isolate failure mechanisms and modes.
2. Design and perform accelerated environmental testing.
3. Use appropriate statistical distribution to model specific failure rate.
4. Choose and apply relevant acceleration models to transform failure rates.
5. Develop total module failure rate as a composite of individual failure rates.

For steps 1 and 2, a good summary of the common failure modes, along with the accelerated tests that are used to analyze those known failures can be found elsewhere (Wohlgemuth & Kurtz, 2011). Steps 3 and 4 are covered in the previous sections. For step 5, the authors propose summing up individual failure rates. That is:

Let $h_k(t)$ denote the failure rate or hazard function for the kth failure mode. The total failure rate $h(t)$ for the M failure modes is given by:

$h(t) = \sum_{k}^{M} = 1\ h_k(t)$.

One key assumption, however, is that the failure modes be independent. Kuitche et al. analyzed module inspection data of 46 arrays from systems installed in Phoenix/Tempe, Arizona, and found strong correlations among many failure modes (Kuitche, TamizhMani, & Pan, 2011). This is an indication that failure times are not statistically independent for PV modules, meaning one should consider their interrelationships in assessing the module reliability.

CONCLUSIONS

Concerns about PV modules underperforming (durability) or becoming obsolete prematurely (reliability) are major barriers to PV diffusion and project financing. Accelerated testing is a way to assess the reliability and durability of PV products by inducing failures and degradation in a short period of time. It accomplishes this by using accelerated test conditions much more severe than actual field operating conditions while replicating the actual field failure mechanisms.

The detailed literature review and analysis in this report resulted in a number of observations about the current and future state of accelerated testing for PV modules. A few of these observations include:

- Based on the detailed literature review and analysis in this report, much of the information needed to develop accelerated testing protocols for comparative and lifetime testing of PV modules is available from a number of sources. These protocols can be developed through a concerted international effort along with statistically significant data sharing support from the industry. These protocols could then be converted into test standards by one or more standards developing organizations.

- The review of an extensive list of field failure and degradation modes indicates that the design, packaging, and construction of PV modules as well as the field environment in which they operate dictate their failure and degradation modes and mechanisms.

- There is a great need to develop a database of climate-specific technology-sensitive wear-out failures in old (10-30 years) PV power plants that have similar or identical construction characteristics as those of the current generation modules. Based on this wear-out failure database, a set of accelerated tests could be identified and prioritized for each climate-specific condition.

- There is little or no detailed physical and statistical modeling effort reported in the public literature, so this report attempts to present a background and detailed analysis on the physical and statistical models relevant to PV modules.

- This literature review and analysis suggests a need for the development of a climatic-specific, technology-agnostic comparative rating system and lifetime rating system. Due to the lack of long-term reliability and durability data for thin-film technologies, it is challenging to develop technology-agnostic rating systems at this early stage of thin-film technology penetration and market share. Consumers and investors are anxious to have a usable rating system right now, however, so it is important to begin work on a rating system for the c-Si technology while gathering statistically significant reliability and durability data from the field for thin-film technologies.

ACRONYMS

ACT	Accelerated Comparative Testing
AF	acceleration factor
ALT	accelerated lifetime testing
AQT	accelerated Qualification testing
AS	accelerated stress
a-Si	amorphous silicon
AT	accelerated testing
CDF	cumulative distribution function
CPV	concentrated photovoltaics
c-Si	crystalline silicon
DH	damp heat
DSC	differential scanning calorimetry
EPIA	European Photovoltaic Industry Association
EVA	ethylene vinyl acetate
FTIR	Fourier transform infrared
IEC	International Electrotechnical Commission
I_{sc}	short circuit current
I-V	current-voltage
GW	gigawatt
HALT	highly accelerated life testing
HASS	highly accelerated stress screening
IQAF	International Quality Assurance Forum
JPL	Jet Propulsion Laboratory
LCOE	levelized cost of energy
mono-Si	monocrystalline silicon
MTTF	mean time to failure
NREL	National Renewable Energy Laboratory
NTC	normal thermal cycling
PET	polyethylene terepthalate
PID	potential induced degradation
Pmax	peak power
poly-Si	polycrystalline silicon
PV	photovoltaic
QA	quality assurance
ROI	return on investment
RH	relative humidity
RR	reliability ratio
RTC	rapid thermal cycling
SiN	silicon nitride
SnPb	tin/lead
SnAg	tin/silver
Solar ABCs	Solar America Board for Codes and Standards
TC	thermal cycling
TMY	typical meteorological year
TPT	tedlar-polyester-tedlar
UV	ultraviolet

REFERENCES

Aoki, Y., Okamoto, M., Masuda, A., & Doi, T. (2010). Module performance degradation with rapid thermal-cycling. *Proceedings of Renewable Energy*.

Belmont, J. & Olakonu, K. (to be published). 26+-year-old photovoltaic power plant: Degradation and reliability.

Burgess, R. (2012, April 27). *Sophisticated monitoring can increase value and extend the life of an array*. Retrieved May 27, 2012, from http://www.renewableenergyworld.com/rea/news/article/2012/04/your-new-solar-array-actual-performance-may-vary

Collins, E., Miller, S., Mundt, M., Stein, J., Sorensen, R., Granata, J., et al. (2009). A reliability and availability sensitivity study of a large photovoltaic system. *IEEE Photovoltaic Specialists Conference (PVSC).*

Credit Suisse. (February 2012). *Equity Research—Solar Energy.*

Dasgupta, A. & Pecht, M. (1991). Material failure mechanisms and damage models. *IEEE Transactions on Reliability, Vol. 40. No. 5.*

Desombre, A. (1980). Methodology for a reliability study on photovoltaic modules. *Proceedings of the 3rd European Commission PV Solar Energy Conference.* Cannes, France. 741–745.

Dhere, N. (2005). Reliability of PV modules and balance-of-system components. *IEEE Photovoltaic Specialists Conference (PVSC).*

Dhere, N., Pethe, S., & Kaul, A. (2010). Photovoltaic module reliability studies at the Florida Solar Energy Center. *IEEE International Reliability Physics Symposium.*

Eguchi, Y. (2011). Evaluation and analysis of 15 years exposure PV module. *Photovoltaic Module Reliability Workshop.*

European Photovoltaic Industry Association (EPIA). (May 2012). *Global market outlook for photovoltaics until 2016.*

Gerischer, H. (1977). On the stability of semiconductor electrodes against photodecomposition. *Journal of Electroanalytical Chemistry,* 82:133.

Gonzalez, C., Liang, R., & Ross, R. (1985). Predicting field performance of photovoltaic modules from accelerated thermal and ultraviolet aging data. *Proceedings of the International Solar Energy Society Meeting*. Montreal, Canada.

Granata, J., Boyson, W., Kratochvil, J., & Quintana, M. (2009). Long-term performance and reliability assessment of 8 PV arrays. *IEEE Photovoltaic Specialists Conference.*

Greene, M. G. (1986). *Corrosion Engineering*. New York: McGraw Hill.

Hacke, P. (2012). PID—Considerations for a standardized test for potential induced degradation of crystalline silicon PV modules. *Photovoltaic Module Reliability Workshop*. Golden, CO. Presentation available at www.nrel.gov/docs/fy12osti/54581.pdf

Hacke, P., Terwilliger, K., Smith, R., Glick, S., Pankow, J., Kempe, M., et al. (2011). System voltage potential-induced degradation mechanisms in PV modules and methods for test. *IEEE Photovoltaic Specialists Conference.*

Herrmann, W., Bogdanski, N., Reil, F., Köhl, M., Weiss, K., Assmus, M., et al. (2010). PV module degradation caused by thermo-mechanical stress: Real impacts of outdoor weathering versus accelerated testing in the laboratory. *SPIE.*

Hoffman, A. & Ross, R. (June 1978). Environmental qualification testing of terrestrial solar cell modules. *IEEE Photovoltaic Specialists Conference.*

Hoffmann, S. & Koehl, M. (2012). Effect of humidity and temperature on the potential-induced degradation. *Progress in Photovoltaics: Research and Applications.*

Holley, W., Agro, S. Galica, J., & Yorgensen, R. (1996). UV stability and module testing of non-browning experimental PV encapsulant. *IEEE Photovoltaic Specialists Conference.*

IEA-PVPS-TASK2. (December 2007). *Cost and performance trends in grid-connected PV systems.* International Energy Agency Photovoltaic Power Systems Programme.

IEC 61215. (2005). Crystalline silicon terrestrial photovoltaic (PV) modules—Design qualification and type approval.

IEC 61646. (2008). Thin-film terrestrial photovoltaic (PV) modules—Design qualification and type approval.

IEC 61853-1. (2011). Photovoltaic (PV) module performance testing and energy rating—Part 1: irradiance and temperature performance measurements and power rating.

IEC 68153-2. (Draft). Photovoltaic (PV) module performance testing and energy rating—Part 2: Spectral response, incidence angle and module operating temperature measurements.

Ishii, T., Takashima, T., & Otani, K. (2011). Long-term performance degradation of various kinds of photovoltaic modules under moderate climatic conditions. *Progress in Photovoltaics: Research and Applications,* 19:170.

Jet Propulsion Laboratory (JPL). (1986). *Flat-Plate Solar Array Project, Volume VI, Final Report*.

Jordan, D. & Kurtz, S. (October 2011). Photovoltaic degradation rates—An analytical review. *Progress in Photovoltaics: Research and Applications.*

Jorgensen, G., Terwilliger, K., DelCueto, J., Glick, S., Kempe, M., Pankow, J., et al. (2006). Moisture transport, adhesion, and corrosion protection of PV module packaging materials. *Solar Energy Material & Solar Cells*, 90:2739.

Kempe, M. (2008). Accelerated UV test methods and selection criteria for encapsulants of photovoltaic modules. *IEEE Photovoltaic Specialists Conference.*

Kempe, M. (2012). Personal communication.

King, D., Boyson, W., & Kratochvil, J. (2002). Analysis of factors influencing the annual energy production of photovoltaic systems. *IEEE Photovoltaic Specialists Conference.*

King, D., Quintana, M., Kratochvil, J., Ellibee, D., & Hansen, B. (2000). Photovoltaic module performance and durability following long-term field exposure. *Progress in Photovoltaics*, 8: 241.

King, D., Boyson, W., & Kratochvill, J. (2004). *Photovoltaic array performance model.* SANDIA REPORT (SAND2004-3535).

Kohl, M. (2011). From climate data to accelerated test conditions. *Photovoltaic Module Reliability Workshop*.

Kohl, M. (2009). Progress towards service life assessment of PV modules. *ATCAE*.

Kuitche, J., TamizhMani, G., & Pan, R. (2011). Failure modes effects and criticality analysis (FMECA) approach to the crystalline silicon photovoltaic module reliability assessment. *SPIE.*

Kurtz, S. & Granata, J. (2009). Photovoltaic reliability R&D toward a solar-powered world. *SPIE*.

Kuznetsova, V., Gaston, R., Bury, S., & Strand, S. (2009). Photovoltaic reliability model development and validation. *IEEE Photovoltaic Specialists Conference.*

Laronde, R., Charki, A., & Bigaud, D. (April 2010). Reliability of photovoltaic modules based on climatic measurement data. *International Journal of Metrology and Quality Engineering*.

Longrigg, P. (1989). Reliability analysis of photovoltaic modules. *Solar Cells*, 26:241.

McMahon, T. (2004). Accelerated testing and failure of thin-film PV modules. *Progress in Photovoltaics: Research and Applications,* 12:235–248.

McMahon, T., Jorgensen, G., Hulstrom, a. R., King, D., & Quintana, M. (April 2000). Module 30 year life: What does it mean and is it predictable/achievable? *National Center for Photovoltaics Program Review Meeting*. Denver, CO.

Meeker, W., Escobar, L., & Lu, C. (May 1998). Accelerated degradation tests: Modeling and analysis. *Technometrics*.

Meydbray, Y., Wilson, K., Brambila, E., Terao, A., & Daroczi, S. (2008). Solder joint degradation in high efficiency all back contact solar cells. *IEEE Photovoltaic Specialists Conference.*

Murthy, D., & Blishchke, W. (2000). *Reliability modeling, prediction, and optimization*. John Wiley & Sons.

Noufi, R., Frank, A., & Nozik, A. (1981). Stabilization of n-type silicon photoelectrodes to surface oxidation in aqueous electrolyte solution and mediation of oxidation reaction by surface-attached organic conducting polymer. *Journal of the American Chemical Society,* 103:1849.

NREL. (2012). Proposed test protocols—IEC 61215 on steroids. *Photovoltaic Module Reliability Workshop*.

Osterwald, C. & McMahon, T. (2009). History of accelerated and qualification testing of terrestrial photovoltaic modules: A literature review. *Progress in Photovoltaics: Research and Applications,* 17:11-33.

Otth, D. & Ross, R. (April 1983). Assessing photovoltaic module degradation and lifetime from long-term environmental tests. *Proceedings of the Institute of Environmental Sciences 29th Annual Meeting*. Los Angeles, CA.

Packard, C., Wohlgemuth, J., & Kurtz, S. (August 2012). *Development of a visual inspection data collection tool for evaluation of fielded PV module condition*. National Renewable Energy Laboratory (Technical Report: NREL/TP-5200-56154).

Pingel, S., Frank, O., Winkler, M., Daryan, S., Geipel, T., Hoehne, H., et al. (2010). Potential induced degradation of solar cells and panels. *IEEE Photovoltaic Specialists Conference.*

Quintana, M., King, D., McMahon, T., & Osterwald, C. (2002). Commonly observed degradation in field-aged photovoltaic modules. *IEEE Photovoltaic Specialists Conference.*

Reliawiki.Com. (n.d.). *Introduction to accelerated life testing.* Retrieved from http://reliawiki.com/index.php/Introduction_to_Accelerated_Life_Testing

Revie, R. W. (2000). *Uhlig's corrosion handbook.* New York: John Wiley & Sons.

Ross, R. (July 2012). FSA engineering & reliability development methods—Can they be applied today? *InterSolar.* San Francisco, CA.

Ross, R. (1984). Reliability research toward 30-year-life photovoltaic modules. *Proceedings of the 1st International Photovoltaic Science and Engineering Conference.* Kobe, Japan.

Ross, R. (December, 1982). *Proceedings of the Flat-Plate Solar Array Project Research Forum on Quantifying Degradation.* Jet Propulsion Laboratory (Document 5101-231; DOE/JPL-1012-89).

Sample, T. (2011). Failure modes and degradation rates from field-aged crystalline silicon modules. *Photovoltaic Module Reliability Workshop.*

Shigekuni, T., & Kumano, M. (1997). Yellowing reaction in encapsulant of photovoltaic modules. *IEEE Photovoltaic Specialists Conference.*

Shioda, T. (2011). UV-accelerated test based on analysis of field-exposed PV modules. *Proceedings of the SPIE.*

Silverman, T., Bosco, N., & Kurtz, S. (2012). Relative lifetime prediction for CPV die-attach layers. *IEEE Photovoltaic Specialists Conference.*

Standard & Poor's. (November 2009). *Methodology and assumptions on risks for utility-scale solar photovoltaic projects.*

TamizhMani, G. (2012). A course titled *Reliability and Standards of Photovoltaics.* Arizona State University.

TamizhMani, G. (February 2012). 12-18-year-old PV power plants in Arizona: Potential induced degradation analysis of 1900 individual modules. *Photovoltaic Module Reliability Workshop.*

TamizhMani, G., Li, B., Arends, T., Shisler, W., Voropayev, A., Parker, D., et al. (2012). Failure rate analysis of module design qualification testing - IV: 1997-2005 vs. 2005-2007 vs. 2007-2009 vs. 2009-2011. *IEEE Photovoltaic Specialists Conference.*

Tatapudi, S. (December 2012). *Potential induced degradation (PID) of pre-stressed photovoltaic modules: Effect of glass surface conductivity disruption.* MS Thesis, Arizona State University.

U.S. Department of Energy. (February 2012). Chapter 4: Photovoltaics: Technologies, Cost and Performance. *SunShot Vision Study,* pp. 68-96. Retrieved from www1.eere.energy.gov/solar/pdfs/47927_chapter4.pdf Degradation Studies. *Progress in Photovoltaics,* 16:419

Vazquez, M. & Rey-Stolle, I. (2008). Photovoltaic module reliability model based on field degradation studies. *Progress in Photovoltaics,* 16:419.

Wohlgemuth, J. (2003). Long-term photovoltaic module reliability. *NCPV and Solar Program Review Meeting 2003*. NREL/CD-520-33586. 179-183.[9]. *(NREL/CD-520-33586).*

Wohlgemuth, J. (2008). Reliability of PV systems. *SPIE*. San Diego, CA.

Wohlgemuth, J. (1993). Testing for module warranties. *Photovoltaic Performance and Reliability Workshop*. Golden, CO.

Wohlgemuth, J. (2011). Tutorial/short course on reliability: PV cells, modules, and systems. *IEEE Photovoltaic Specialists Conference.* Seattle, WA.

Wohlgemuth, J. (2012a). IEC 61215: What it is and isn't. P*hotovoltaic Module Reliability Workshop (PVMRW).*

Wohlgemuth, J. (September 2012b). Standards for PV modules and components—Recent developments and challenges. *27th European Photovoltaic Solar Energy Conference and Exhibition (EU PVSEC).* (2012). Frankfurt, Germany: September 24-28, 2012. NREL Report number: NREL/CP-5200-56531.

Wohlgemuth, J., Cunningham, D., Amin, D., Shaner, J., Xia, Z., & Miller, J. (2008). Using accelerated tests and field data to predict module reliability and lifetime. *Proceedings of EUPVSEC.*

Wohlgemuth, J., Cunningham, D., Monus, P., Miller, J., & Nguyen, A. (2006). Long term reliability of photovoltaic modules. *Proceedings of the 4th World Conference on Photovoltaics.*

Wohlgemuth, J. & Kurtz, S. (April 2011). Reliability testing beyond qualification as a key component in photovoltaic's progress toward grid parity. *IEEE International Reliability Physics Symposium*. Monterey, CA.

Wrighton, A. J. (1977). Thermodynamic potential for the anodic dissolution of n-type semiconductors. *Journal of the Electrochemical Society,* 124:1706.

Xia, Z., Wohlgemuth, J., & Cunningham, D. (2009). A lifetime prediction of PV encapsulant and backsheet via time temperature superposition principle. *IEEE Photovoltaic Specialists Conference.*

APPENDIX A: PV POWER PLANT VISUAL INSPECTION CHECKLIST

[A detailed report titled *"Development of a Visual Inspection Data Collection Tool for Evaluation of Fielded PV Module Condition"* on the checklist has been developed in 2012 by NREL (Packard, Wohlgemuth, & Kurtz, 2012) and it can be downloaded from the following website by using the form with the report title shown above: http://nrelpubs.nrel.gov/Webtop/ws/nich/www/public/SearchForm]

<u>Documentation of module condition</u>
Date ______________________ Name of data recorder_____________________________
Location ____
Latitude__________________ Longitude ________________ Altitude __________________

<u>1. System Data</u>

System design: ☐ single module ☐ multiple modules (a.) ☐ unknown
(a.) Multiple module system:
Module location/number in a series string (from negative) _____________
\# of modules in series (string) _______ # of strings in parallel (array) _________
\# of bypass diodes___________ # of modules per bypass diode ___________
System Bias: ☐ open circuit ☐ resistive load ☐ max. power tracked ☐ short circuit ☐ unknown
System Grounding: ☐ grounded (a.) ☐ not grounded ☐ unknown
(a.) ☐ negative ☐ positive ☐ center of string ☐ unknown

BEGIN INSPECTION AT BACK SIDE OF MODULE

<u>2. Module Data</u>

Technology: ☐ mono Si ☐ multi Si ☐ a--Si ☐ CdTe ☐ CIGS/CIS ☐ other: ____________
Certification: ☐ unknown ☐ UL 1703 ☐ IEC 61215 ☐ IEC 61646 ☐ IEC 61730 ☐ other: ____________
Estimated deployment date ______________________

Photo taken of nameplate: ☐ **yes** ☐ **no**
Manufacturer ____________________________________
Model # ____
Serial # ____
Installation Site/Facility Serial # __________________________________
Width _____________cm Length _____________cm

Nameplate: ☐ nameplate missing
P_{max} _____________ V_{oc} ____________ I_{sc} ___________
Sys Volt_________ V_{max} __________ I_{max} _________
Bypass diode, I_r ___________________________________
Series fuse ____

<u>3. Rear-side Glass</u>: ☐ **not applicable** ☐ **applicable**

Damage: ☐ no damage ☐ small, localized ☐ extensive

Damage Type (mark all that apply):
☐ crazing or other non--crack damage
☐ shattered (tempered) ☐ shattered (non-tempered) ☐ cracked (a.) ☐ chipped (b.)
(a.) Cracks (#):☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Crack(s) start from: ☐ module corner ☐ module edge ☐ cell ☐ junction box
☐ foreign body impact location
(b.) Chips (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Chipping location: ☐ module corner ☐ module edge

4. Backsheet: ☐ **not applicable** ☐ **applicable**

Appearance: ☐ like new ☐ minor discoloration ☐ major discoloration
Texture: ☐ like new ☐ wavy (not delaminated) ☐ wavy (delaminated) ☐ dented
Material quality --chalking: ☐ none ☐ slight ☐ substantial
Damage: ☐ no damage ☐ small, localized ☐ extensive
Damage Type (mark all that apply):
☐ burn marks (a.) ☐ bubbles (b.) ☐ delamination (c.) ☐ cracks/scratches (d.)

(a.)Burn marks (#):☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Fraction of area burned:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(b.) Bubbles(#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Average bubble dimension: ☐ <5mm ☐ 5--30mm ☐ >30mm
Fraction of area with bubbles > 5 mm:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(c.) Fraction of area delaminated:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Fraction of delamination that exposes circuit or cell(s)
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(d.) Cracks/scratches (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Cracks/scratches location: ☐ random/no pattern ☐ over cells ☐ between cells
Fraction of area affected by cracks/scratches (approx.):
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Fraction of cracks/scratches that expose circuit (approx.):
☐ 0% ☐ 25% ☐ 50% ☐ 75% ☐ 100%

5. Wires/Connectors:

Wires: ☐ not applicable ☐ like new ☐ pliable, but degraded ☐ embrittled
(mark all that apply): ☐ cracked/disintegrated insulation ☐ burnt
☐ corroded ☐ animal bites/marks
Connectors: ☐ not applicable ☐ like new ☐ pliable, but degraded ☐ embrittled
Type: ☐ unsure ☐ MC3 or MC4 ☐ Tyco Solarlok ☐ other ________

(mark all that apply): ☐ cracked/disintegrated insulation ☐ burnt ☐ corroded

6. Junction Box:

Junction box itself: ☐ **not applicable/observable** ☐ **applicable**
Physical state: ☐ intact ☐ unsound structure
(mark all that apply): ☐ weathered ☐ cracked ☐ burnt ☐ warped
Lid: ☐ intact/potted ☐ loose ☐ fell off ☐ cracked
Junction box adhesive: ☐ **not applicable/observable** ☐ **applicable**
Attachment: ☐ well attached ☐ loose/brittle ☐ fell off
Pliability: ☐ like new ☐ pliable, but degraded ☐ embrittled
Junction box wire attachments: ☐ **not applicable/observable** ☐ **applicable**
Attachment: ☐ well attached ☐ loose ☐ fell off
Seal: ☐ good seal ☐ seal will leak
other: ☐ arced/started a fire

7. Frame Grounding:

Original state: ☐ Wired ground ☐ Resistive ground ☐ No ground ☐ unknown
Appearance: ☐ Not applicable ☐ Like new ☐ Some corrosion ☐ Major corrosion
Function: ☐ Well grounded ☐ No connection

Photos taken of ☐ **back, label, and junction box**

CONTINUE INSPECTION ON FRONT SIDE OF MODULE

8. Frame: ☐ **not applicable** ☐ **applicable**

Appearance: ☐ like new ☐ damaged (a.) ☐ missing
(a.) (mark all that apply): ☐ minor corrosion ☐ major corrosion ☐ frame joint separation
☐ frame cracking ☐ bent frame ☐ discoloration
Frame Adhesive: ☐ like new/not visible ☐ degraded (a.)
(a.) (mark all that apply): ☐ adhesive oozed out ☐ adhesive missing in areas

9. Frameless Edge Seal: ☐ **not applicable** ☐ **applicable**

Appearance: ☐ like new ☐ discoloration (a.) ☐ visibly degraded
(a.) Fraction affected by discoloration:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Material problems:
☐ squeezed/pinched out ☐ shows signs of moisture penetration
Delamination: ☐ none ☐ area(s) delaminated (a.)
(a.) Fraction Delaminated:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)

<u>10. Glass/Polymer (front):</u>

Material: ☐ glass ☐ polymer ☐ glass/polymer composite ☐ unknown
Features: ☐ smooth ☐ slightly textured ☐ pyramid/wave texture
☐ antireflection coating
Appearance: ☐ clean ☐ lightly soiled ☐ heavily soiled
<u>Location of soiling:</u>
☐ locally soiled near frame:
☐ left ☐ right ☐ top ☐ bottom ☐ all sides
☐ locally soiled on glass /bird droppings
Damage: ☐ no damage ☐ small, localized ☐ extensive
<u>Damage Type (mark all that apply):</u>
☐ crazing or other non--crack damage
☐ shattered (tempered) ☐ shattered (non--tempered) ☐ Cracked (a.)
☐ Chipped (b.) ☐ milky discoloration (c.)
(a.) Cracks (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Crack(s) start from: ☐ module corner ☐ module edge ☐ cell ☐ junction box
☐ foreign body impact location
(b.) Chips (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Chipping location: ☐ module corner ☐ module edge
(c.) Fraction of area:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% -- 100% (consistent overall)

<u>11. Metallization:</u>

Gridlines/Fingers: ☐ not applicable/barely observable ☐ applicable
<u>Appearance:</u> ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
Busbars: ☐ not applicable/not observable ☐ applicable
<u>Appearance:</u> ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
<u>(mark all that apply):</u> ☐ obvious corrosion ☐ diffuse burn mark(s) ☐ misaligned
Cell Interconnect Ribbon: ☐ not applicable/not observable ☐ applicable
<u>Appearance:</u> ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
<u>(mark all that apply):</u> ☐ obvious corrosion ☐burn marks ☐ breaks
String Interconnect: ☐ not applicable/not observable ☐ applicable
<u>Appearance:</u> ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
<u>(mark all that apply):</u> ☐ obvious corrosion ☐ burn marks ☐ breaks
☐ arc tracks (thin, small burns)

12. Silicon (mono or multi) module: ☐ not applicable ☐ applicable

Number of:

Cells in module ___________

Cells in series/string _______

Strings in parallel __________

Cell size: Width ____________ cm Length ____________ cm

Distance between frame and cell: ☐ >10 mm ☐ <10 mm

Distance between cells in a string: ☐ >1 mm ☐ <1 mm

Discoloration: ☐ none/like new ☐ light discoloration ☐ dark discoloration

Number of cells with any discoloration:_________________

of those, average % discolored area:

☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)

Discoloration location(s) (mark all that apply):

☐ module center ☐ module edges ☐ cell centers ☐ cell edges

☐ over gridlines ☐ over busbars ☐ over tabbing ☐ between cells

☐ individual cell(s)darker than others ☐ partial cell discoloration

Junction box area: ☐ same as elsewhere ☐ more affected ☐ less affected

Damage: ☐ none

(mark all that apply): ☐ burn mark (a.) ☐ cracking (b.) ☐ moisture

☐ worm marks/snail tracks (c.) ☐ foreign particle embedded

(a.) Burns (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4-10 ☐ >10

(b.) Number of cells cracked: ________________

(c.) Number of cells with worm marks/snail tracks:_____________

Delamination: ☐ none ☐ from edges ☐ uniform ☐ corner(s) ☐ near junction box

☐ between cells (a.) ☐ over cells (b.) ☐ near cell or string interconnect

(a.) Fraction delaminated between cells:

☐ <5% ☐ 5-25% ☐ 50% ☐ 75-100% (consistent overall)

(b.) Fraction delaminated over cells:

☐ <5% ☐ 5-25% ☐ 50% ☐ 75-100% (consistent overall)

Likely interface (choose 2):

☐ glass ☐ semiconductor ☐ encapsulant ☐ back sheet ☐ busbar

13. Thin film module: ☐ not applicable ☐ applicable

Number of cells:

Number of cells in module ___________

Number of cells in series/string _______

Number of strings in parallel ___________

Cell size: Width ____________ cm Length ____________ cm

Distance between frame and cell: ☐ >10 mm ☐ <10 mm

Appearance: ☐ like new ☐ minor/light discoloration ☐ major/dark discoloration

Discoloration type (mark all that apply):

☐ spotted degradation ☐ haze (encapsulant browning) ☐ other

Discoloration location (mark all that apply):
☐ overall/no location pattern ☐ module center ☐ module edge(s)
☐ cell center ☐ cell edges ☐ near crack(s)

Damage: ☐ no damage ☐ small, localized ☐ extensive
Damage Type (mark all that apply): ☐ burn mark(s) ☐ cracking
☐ possible moisture ☐ foreign particle embedded

Delamination: ☐ no delamination ☐ small, localized ☐ extensive
Location: ☐ from edges ☐ uniform ☐ corner(s) ☐ near junction box ☐ near busbar
☐ along scribe lines
Delamination Type: ☐ absorber delamination ☐ AR coating delamination ☐ other

Photos taken of ☐ front and defects

14. Electronic Records ☐ not applicable ☐ applicable
Photographs and I--V curves recorded electronically--list file names in blanks
Photo files ____
I--V curve ____
Connector function: ☐ functions ☐ no longer mates ☐ exposed
Irradiance ________________________Sensor _________________
Temperature ______________________Sensor _________________
EL picture _________________________
IR picture_________________________
Bypass Diode Test: ☐ not applicable ☐ applicable
Number of diodes:
In total____________, shorted_______________, open______________

OTHER

APPENDIX B:
EVOLUTION OF MODULE DESIGN QUALITY BETWEEN 1997 AND 2011

Figures B-1 and B-2 present the accelerated qualification test failure data of more than five thousand modules between 1997 and 2011 (TamizhMani et al., 2012). Figure B-1, corresponding to c-Si modules, indicates that the failure rate was low before 2005, became high in 2005-2007, and became low again after 2007 with lowest being between 2009 and 2011. Because the number of new manufacturers with limited module design and manufacturing experience became very high (from less than 50 old manufacturers to more than 200 new manufacturers) during 2005-2007 time period, the failure rate in the accelerated qualification testing dramatically increased. Ignoring the 2005-2007 data, the failure rates of various accelerated tests of the old modules (before 2005) and recent modules are nearly the same for the 2007-2009 period or even lower for the 2009-2011 period. If one assumes and proves that the accelerated qualification failure data for the periods after 2007 represent the infant/early field failure data (if made available) of the recent field installed modules (more than 80% of the cumulative installed modules have come from the modules produced after 2007), then one may tend to use the future qualification failure data (generated by independent test labs) to predict the infant failure rates of future field installed modules. In all these historical failure reporting years (1997-2011). The failure rates in the qualification testing of crystalline silicon modules were primarily influenced by the change in the number of manufacturers with varied manufacturing experience. However, in future, the trend of failure rates in the qualification testing of crystalline silicon modules may strongly be influenced by the change in the module construction materials and radically different designs and manufacturing processes. As shown in Figure B-3, the SunShot program aims to reduce the price of the module from about \$2/W to about \$0.5/W by primarily reducing the costs of module construction materials and manufacturing processes (U.S. Department of Energy, 2012). The change in construction materials includes the wafer (thickness), encapsulant, backsheet, edge seals, mounting hardware, cable connectors, cell interconnections, bus bars, and junction boxes. All these material level changes are expected to have significant influence in the failure rates of future qualification testing programs.

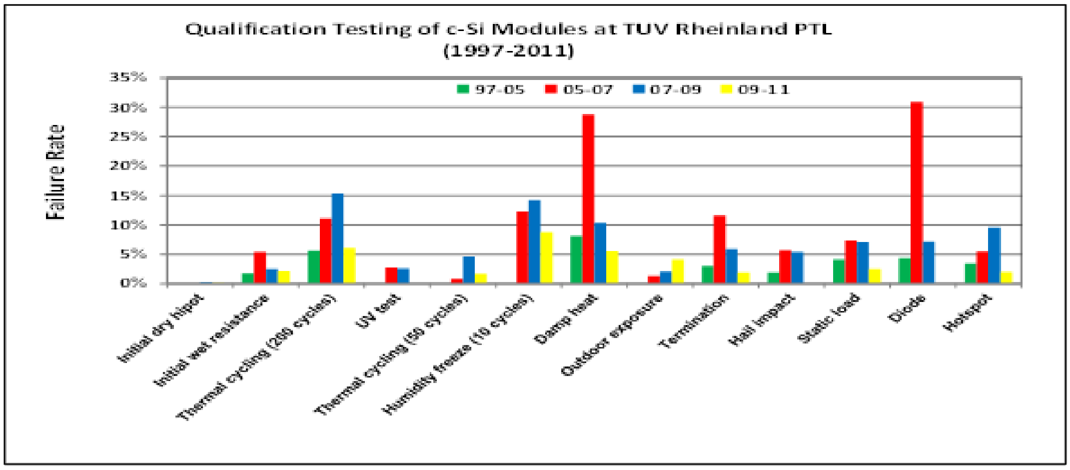


Figure B-1: Failure rates of crystalline silicon PV modules in qualification testing (TamizhMani et al., 2012).

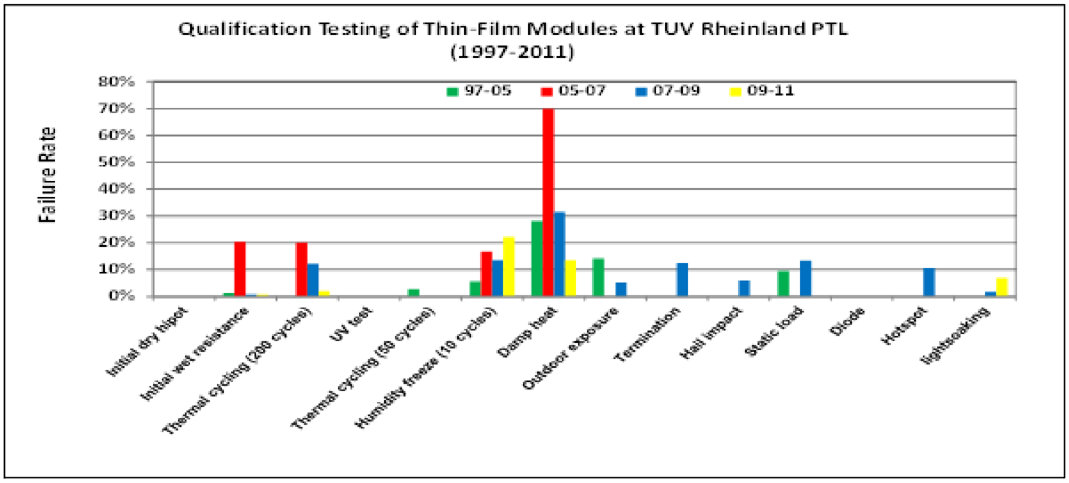


Figure B-2: Failure rates of thin film PV modules in qualification testing (TamizhMani et al., 2012).

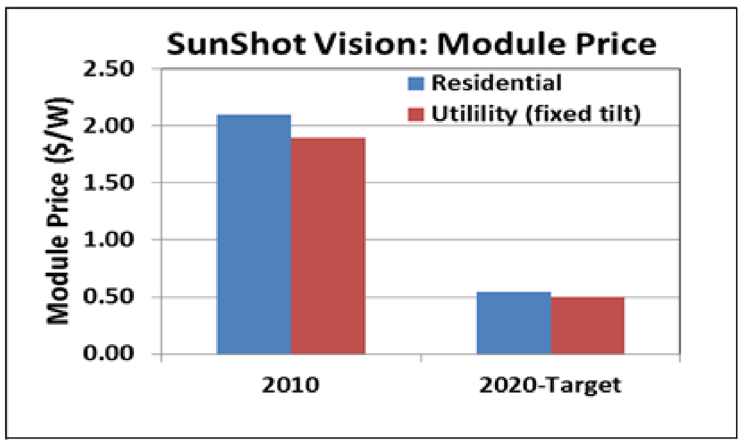


Figure B-3: Target reduction of module price by reducing cost of materials, manufacturing processes, and shipping (U.S. Department of Energy, 2012).

APPENDIX C:

SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS

(NREL, 2012)

Summary of Test Methods

			IEC 61215 on Steroids						Weather	New Tests				
	Protocol Name	IEC 61215	Holistic QA	Thresher Test	Reliability Demo Test	Durability initiative	Test to Failure	Long-term Sequential Testing	Atlas 25	Irradiation/ Thermal	Accelerated TC test	Vibration	ISAAC for Mounting	HV Bias Testing
	Contact person		Cunningham	Funcell	Meydbray	Meakin	Hacke	Mani	Scott	Hirota	Tanahashi	Schueneman	Friesen	Dhere
Combined Effects	High Voltage Bias Testing													A1
	Irradiation/Thermal Cycling								C4*	A1				
	Irradiation/HT Soak									B1				
	Damp Heat + System Bias	proposed		D1, D2, D3, D4, D5	F2, G2	A1, A2, A3, A4, A5	A1,C1							
Exposure	Outdoor Exposure	A1	A1			G1			A1, B1, C5					
	UV Exposure	B1	B1	B1	D1	B2		1000 h as option	C1					
	Hot Spot Test	A3	A3		F1, F3, G1, G3	H1								
	Salt								C2					
Mechanical	Mounting system load testing												A1*	
	Hail Impact Test	E2	E3										B1**	
	Static Mechanical Load	D2	D3		E5	D1, D2								
	Cyclic Mechanical Load		B2		E1	C1, C2						A1*		

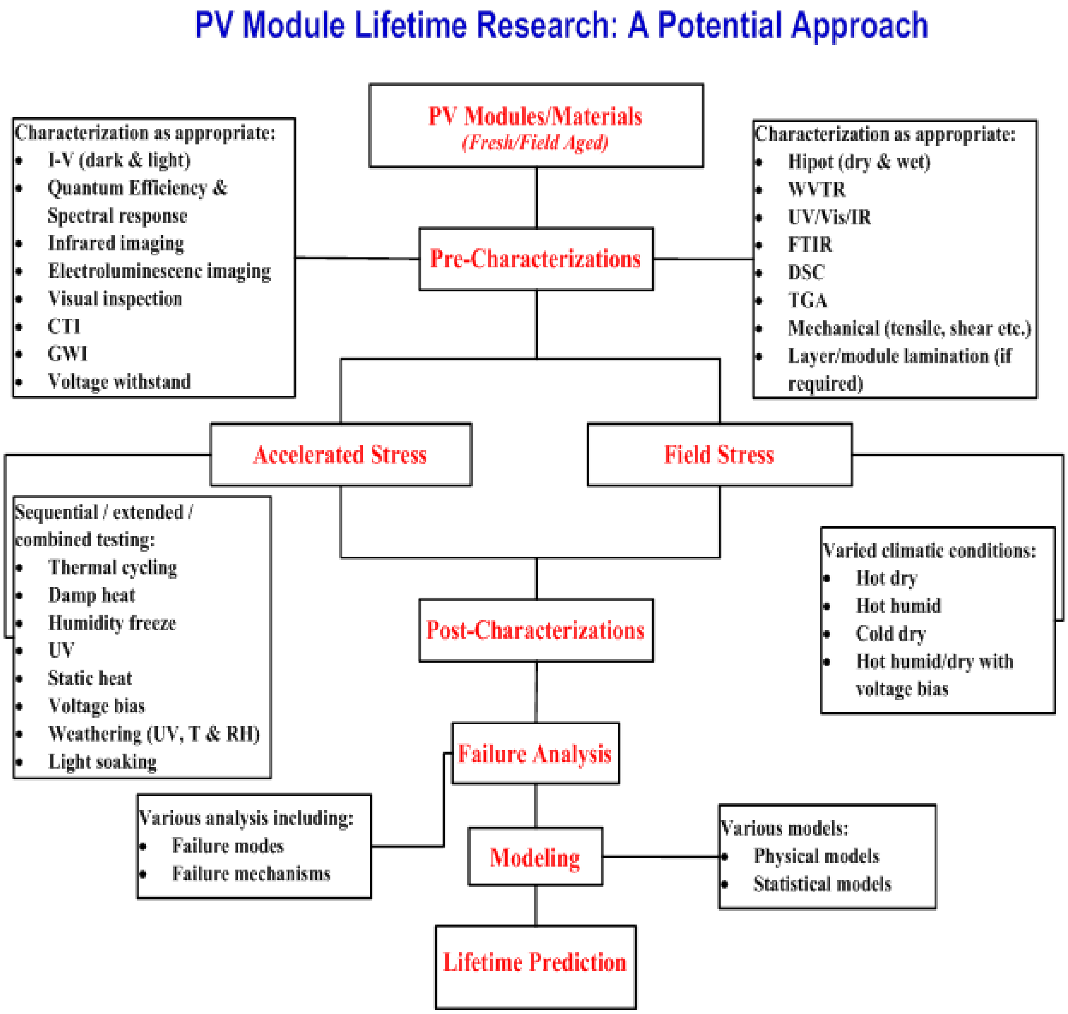
SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS (NREL, 2012)

			IEC 61215 on Steroids						Weather	New Tests				
	Protocol Name	IEC 61215	Holistic QA	Thresher Test	Reliability Demo Test	Durability initiative	Test to Failure	Long-term Sequential Testing	Atlas 25	Irradiation/ Thermal	Accelerated TC test	Vibration	ISAAC for Mounting	HV Bias Testing
	Contact person		Cunningham	Funcell	Meydbray	Meakin	Hacke	Mani	Scott	Hirota	Tanahashi	Schueneman	Friesen	Dhere
Thermal	Thermal Cycle	B2, C1	B3, C1	A1*	A1, E2	C3, D3, F1	B1	A6, B6			A2*, B2*			
	Humidity Freeze	B3	B4	B2	C1, E3	C4, D4		A9, B9			A1**			
	Damp Heat	D1, E1	D1, E1	C1*	B1	B1		A1, B1			B1**			
	Extended Damp Heat		D2, E2	C2, C3, C4, C5	B2, B3	B3	A2, A3, A4...A15, C3, C5...C15*	A2, A3, A4, A5	C3 condensing					
	Extended TC		C2	A2, A3, A4, A5, A6	A2, A3	F2, F3	B2, B3, B4...B15, C2, C4...C14	A7, A8, B7, B8	C4*					
	Extended Humidity Freeze			B3, B4, B5	C2, C3			A10, A11, A12, B10, B11, B12	C4*					
	Bybass Diode Test	A2	2A		F4, G4			A13, B13						
Summary	Expected duration	2 months	4 months	6 months	6 months	6 months	> 1 yr	1 yr	1 year		max: 3 month			
	Goal	Qualify design	Extended 61215	Compare by tracking changes	Comprehensive	Durability assessment	Comparative test to failure	Sequential	Simulate weather stress	Add light to uncover failures	Extend the limits of the TC	Vibration	Snow and wind on mounted module	
	General philosophy*	Baseline	1	1	1	1	1, 4, 6	1	2	4	1, 2	5	5	4, 5
	Change stress duration or level?	N/A	Duration	Duration	Duration	Duration	Duration	Duration	N/A	Combine	Level	New test	New test	New test
	Field test data ?		Yes			1 yr +		3 yr+ (optional)	Yes					
	Allow for different climate zones?							Optional field test in different climate zones	Yes					
	Measurements other than 61215?	N/A	EL	EL	IR, EL, diode	EL, IR, DIV		IR, EL (optional)	?	?	EI***, IR, Impedance	?	EL	?
	Number of measurements			up to 6		up to 6	up to 15	3-5 each						
	*Philosophy: 1. Comparative, Rank ordering 2. Simulation of stressful weather 3. Service life prediction 4. Identify failure modes (HAST) 5. Looks at specific failure modes 6. Test to failure?			*Test frequently			*DH includes system V		*Exposure conditions vary		*Raise Upper T level or Ramp rate **A1, B1 optional ***Quantify cell cracks	*Vibrational test	* 9000 Pascal **35 mm	

Definition of Terms used in the Previous Table (Summary of Comparative of Testing Programs)

- Each leg of the test is given a letter
- The steps in each leg are numbers, so look for A1, A2, etc. for the first leg and B1, B2 for the second leg
- This summary is simplified and doesn't describe the number of modules in each leg, the length of each step, nor the characterization that is done between each step
- Blue shading indicates that the step is fairly similar to IEC 61215; Yellow indicates that the test goes beyond IEC 61215 or differs in some other way
- The test methods are separted into 3 classes:
  1. IEC 61215 on steroids: Like IEC 61215, but with extended time or somehow slightly more severe
  2. One of the tests is very different from IEC 61215, but attempts to mimic the weather in order to identify all weathering issues
  3. Individual tests are proposed as add ons or modification to a more comprehensive test procedure
- Across the bottom, some higher level attributes are described briefly.

APPENDIX D: EQUIPMENT AND EXPERTISE NEEDED FOR PV MODULE RELIABILITY RESEARCH PROGRAM—AN EXAMPLE



Solar America Board for Codes and Standards

www.solarabcs.org