Is It Time to Rethink How We Model Long-Term Performance & Maintenance Costs in the Utility Solar Market?

By Daniel Tarico, M.S., MBA, Director, Renewables
Published July 2025, E3 Consulting Services, LLC

INTRODUCTION

It's a truth that many are hesitant to acknowledge: Long-term performance models and O&M costs for utility solar projects are difficult to develop and plagued by uncertainty, largely because the industry has evolved so rapidly over the past 15 years.

Utility solar power has only recently emerged on a global scale in the past 15 years. During this time, designs, technologies, project scale, operations, and major equipment have evolved rapidly. Early utility solar projects were typically 10-50 MWdc, used monofacial modules in the 270 W to 300 W range, fixed mounting systems, and central inverters rated between 500 kWac and 1 MWac size. Projects were designed and financed with 25-year operating life projections.

Performance degradation was assumed to be slow and steady, based on relatively short-term field and laboratory data. Inverters and other equipment were expected to be maintained for the project's operating life, and it was assumed that spare parts and support would be available over the whole lifecycle.

Fast forward to 2025: Today's projects typically range from 200 MWdc to as high as 1,000+ MWdc, utilize bifacial modules exceeding 500 W, are mounted on trackers, and employ central inverters of 2 to 5 MWac size. They are often financed based on projections of 30- to 40-year operating lives. Most performance and operating expense (OPEX) models still assume that modules will be reliable and will degrade slowly. Inverters are now typically budgeted for full replacement at 10- to 12-year intervals, whereas trackers are still assumed to be reliable and low-maintenance for the full operating life.

Rapid scaling and evolving equipment technology have made it difficult to find reliable long-term operating cost data. Even though there are tens of thousands of commercial-scale operating projects, there is not a central database that tracks the operating performance that could be used to project the behavior of projects now being or recently commissioned. Even if such data were available, the wide variation in size, location, technology, operating conditions, and maintenance history would make accurate projections difficult.

Despite the absence of comprehensive data, the industry is beginning to acknowledge that the relatively simple OPEX and performance models currently used are built on assumptions that do not align with near-or long-term operating experience. Published data now indicate that project underperformance is widespread within the PV industry. A 2025 report by kWh Analytics, a climate insurance and renewable energy risk management firm, shows that solar assets are broadly performing below expectations, by a ~8–9% deviation from P50 (kWh Analytics, June 10, 2025, 2025 Solar Risk Assessment: Top Risk Management Challenges for Renewable Energy and Battery Energy Storage Systems).

Many experts in the industry, including performance modeling specialists and independent engineers, are revising their narratives on both maintenance expenses and performance degradation to account for observed project performance. In addition to revising projections to better align with near-term data, the methodology is now trending to incorporate well-known reliability engineering principles, as well as more complex failure models and system degradation mechanisms to more accurately predict long-term operating costs and performance.

The Current Standard Assumptions

Currently, the majority of solar O&M cost projections are based on a similar and relatively simple set of assumptions:

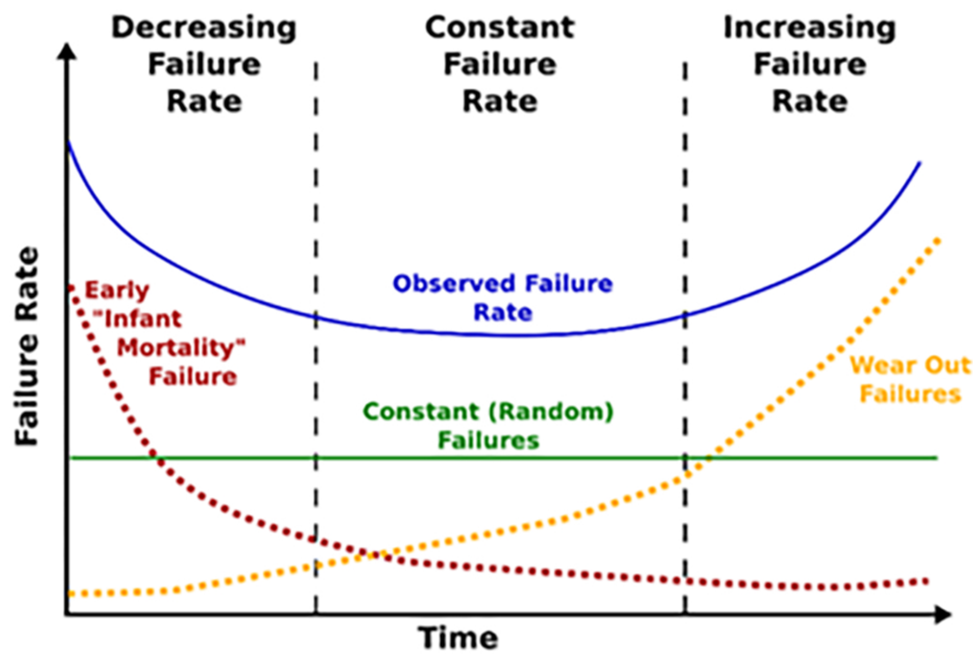
1. Contracted preventive maintenance is priced in the open market, the current price is correct, and the price will increase slowly with inflation (assumed 2-3% per annum)
2. Corrective maintenance costs less than scheduled preventive maintenance. During the first five years, while warranties are in force, material costs will be low. After those warranties expire, costs will step up to account for replacement components, and failure rates will remain constant. Costs will increase slowly with inflation.
3. All inverters will be replaced around year 12.
4. There will be ongoing maintenance of the AC systems at the facility, included in the PM and CM budgets.
5. This maintenance will be sufficient to maintain the solar facility in a high state of performance, with overall plant " functional availability" ranging from 95% to 99%.

However, these assumptions are not supported by actual industry experience. Across the industry, underperformance for large solar facilities is reported to average near six percent. Though few large, staffed facilities are more than 10 years old, there are many commercial scale (100's of kW) and distribution level plants (3 MW-10 MW), that have been operating for more than eight years, and most are underperforming, with some having been abandoned due to excessive maintenance cost. Thus, a modified approach to solar O&M cost projections is warranted.

Rethinking Standard Assumptions: A Modified Approach

Several concepts can be employed to modify current industry assumptions. The first of these is the widely understood "bathtub" curve of reliability that broadly applies to operating equipment, facilities, and systems. In the early stages, there may be a few significant defects that manifest quickly as failures, in some cases requiring the replacement or significant rework of equipment. These early failures decrease in frequency relatively quickly. In the case of a PV plant, many initial defects are detected and corrected under the EPC or manufacturer's warranties. This scenario is consistent with the assumed initial low-cost period of corrective maintenance. Early failures and their mechanisms do not significantly contribute to long-term maintenance costs.

Figure 1
The Bathtub Curve of Reliability



Khan, Aamir. Design Tools for Reliability Analysis

Throughout the lifecycle of a project, the reliability model assumes a relatively constant frequency of random equipment failures. These may be caused by latent defects and damage, operating stresses, or environmental factors. This is captured in the current O&M model as a steady-state failure rate that increases corrective maintenance costs solely due to inflation. Some of these failures will occur during the warranty period, while others will occur after.

Wear-out failures, aside from inverters, are not included in standard assumptions for PV maintenance. Inverters are typically warranted for only five years (with optional 10-year warranties being offered), after which replacement costs for failed components fall on the owner. Inverter electronics, control electronics, and power electronics are subjected to high electrical and thermal stresses. Though some inverters are currently advertised as maintainable for 25 years, the industry still assumes a 10-15-year replacement cycle is prudent budgeting.

Other components of the solar plant are typically excluded from wear-out modeling and budgeting for repairs. The implied assumption is that the components are engineered for life-of-plant durability; however, this is often not the case. For example, trackers are electro-mechanical systems that will wear over time, with expected increasing failure rates as the plant ages. Some of the components will require periodic upgrades or replacement. DC wire management and wiring connectors will also begin to experience increasing failures as the plant ages, and field experience indicates that the severity of these failures increases with frequency. For the sake of budgeting, this accumulated wear and aging means higher-costs and more frequent repairs.

Solar modules also suffer wear-out (aging) failures that increase in frequency as the project ages. Solar modules typically have 12-year defect and 25-30-year performance warranties. Enforcing these warranties can be costly and increasingly impossible under current contractual obligations. This is because module warranty is provided at Standard Test Conditions (1000 W/m², 25 deg C, and 1.5 Airmass index). The conditions in the field are entirely different, and the owner must send the suspect modules to a certified test laboratory. After receiving the test laboratory's results, the OEM can also justify uncertainty in measurements as a basis for not covering any warranty claims. Furthermore, the cost of detecting and replacing defective or underperforming modules will often exceed the economic value of additional generation from individual modules.

There are typically no specific clauses in the module supply agreements that address the sampling rate and frequency of module testing which define a serial defect, leading to an open-ended argument from the developer or owner. After a few years of operation, and before the end of the product warranty, direct replacement modules may not be available, making module replacement technically difficult or infeasible.

A second important concept in creating a modified O&M cost model is the risk of cascading failures within the PV field. This risk is often overlooked when maintenance is deferred, or defective modules are allowed to remain in service. Individual crystalline silicon modules are connected in strings of up to 30 modules. A single malfunctioning module will adversely impact an entire string's performance and will add electrical stress to the other modules in the string. Although it is possible to bypass a single module in a string, there are limits on the number of modules that can be bypassed before it impacts other strings in the array, which significantly reduces plant performance and results in lost production from the defective module.

To avoid the deleterious effects of individual defective modules distributed throughout the array, the modules must be removed from service in a timely manner and replaced with new or with salvaged serviceable modules from other parts of the plant. This maintenance approach has high labor costs and is typically not considered to be economically feasible; however, it may be necessary to maintain the plant in a high state of functional availability, which is consistent with modeled production.

A third conceptual approach helpful in understanding the escalation in maintenance costs and reduction in performance is to view them in terms of decreasing the mean time to failure (MTTF) for the individual components and an increasing the mean time to repair (MTTR) for the failed components or system as a whole. As the system ages, wear-out failures increase in frequency, reducing the MTTF for the individual components. This increases maintenance demand. In practice, replacement modules, inverter parts, and tracker parts become more difficult to source, and owners, facing unbudgeted operating expenses coupled with declining revenue, are slow to approve repairs. These have the combined effect of significantly extending the MTTR, reducing availability, production, and revenue. In some cases, this initiates a vicious downward cycle, where lost revenue reduces cash available for timely repairs, resulting in extended downtime, declining performance, and ever-greater lost revenue. In this case, system aging, as a form of wear-out, and technological advancements making repair components unavailable, contribute to accelerating O&M costs and reducing system performance.

Rethinking O&M Costing Assumptions: Modified O&M Costing Assumptions

Considering the preceding discussion, it appears prudent to modify the standard O&M cost and performance assumptions that are commonly incorporated into project financial proformas.

1. Contracted preventive maintenance: This scope of work is well defined, and the service providers appear to have sufficient experience to price it accurately. Since the contracts typically include a requirement

that the provider will monitor the system and respond to alarms, it is likely that the workload will increase slowly as the system ages. Some of this workload may be offset by the use of increased automation tools for performing inspections and analyzing performance data. Overall, it is reasonable to assume this cost will escalate with or only slightly above the inflation rate.

Recommendation: Contracted maintenance in line with current contracts is reasonable for long-term budgeting with escalators for inflation and increased maintenance frequency, partially or fully offset by improved monitoring, inspection, and dispatch automation.

2. Corrective maintenance initially is low cost as it benefits from warranty support for early failures and relatively new equipment that has few random failures and little wear-out. However, after the warranty period, there is a step-up in budget requirements to purchase replacement components. In light of generally accepted reliability engineering concepts and industry experience, it is reasonable to assume that corrective maintenance events will increase in frequency and the cost of the repairs will increase as they become more complex and challenging to resolve.

   Recommendation: Once a baseline level of expected corrective maintenance is established, it should be adjusted annually for inflation, for frequency as the project ages, and for repair complexity. The annual budget for replacement components (excluding modules) should be added as a separate line item after warranty expiration and increased annually based on inflation. (This model assumes that replacement components will remain in production and available for purchase.)

3. Inverter service and replacements appear to be adequately budgeted within the current standard assumptions. If inverters are fully operational at the end of the warranty period, it is reasonable to believe they will be economically maintainable for an additional two to five years. In this case, inverters should be budgeted for replacement around year 10, if accompanied by a five-year warranty, and around year 15 if accompanied by a 10-year warranty. For projects with a planned operating life of 30 years or more, it may be beneficial to purchase 10-year warranties to avoid an additional inverter replacement cycle. New inverters with a 20-year or longer engineered lifespan may prove to be durable and maintainable, but the industry lacks sufficient experience to validate these products.

   Recommendation: Budget for inverter replacement at five years after warranty expiration. Drop-in replacements are unlikely to be available, so the budget should include engineering studies, labor and material to reconfigure the system to integrated updated equipment. Solar inverters continue to decline in price and improve reliability, but inflation will drive up the cost of raw materials and labor required to exchange the inverters.

4. Tracker maintenance is often neglected as a specific line item in the maintenance budget; however, equipment failures will increase steadily over the project lifecycle. Batteries for self-powered trackers and dampers will need full replacement at least once during the project lifecycle. Motors, control electronics, and linear actuators (when used) will all experience some level of failures. Life-of-project slew drives for solar trackers are available, and the associated small DC motors are relatively reliable and simple to replace in the case of failure.

   Recommendation: Add a line item for tracker maintenance separate from the project corrective maintenance. Though labor cost may be wrapped into the overall PM and CM budgets, component budgets should be modeled to reflect the wear and tear on the system. Batteries should be budgeted for replacement every 10 years, and dampers will likely need replacement within 15 years.

5. Alternating current equipment is typically reliable and durable. Preventive maintenance is currently included in the site PM. There is some risk of medium voltage transformer failure, though these are infrequent. A modest reserve may be established specifically for AC system repair or to maintain a small stock of critical replacements.

   Recommendation: Current budgeting assumptions and PM contracts include service for the medium voltage collection system and substation, where applicable. It may be advisable to have a substation maintenance specialist review the spares list and repair reserve to ensure it is adequate.

6. To date, the industry has not developed a comprehensive strategy for addressing module defects and failures. Module inspections have been significantly improved with the use of aerial photographic and thermographic surveys. These are typically included in PM budgets and permit rapid, low-labor cost identification of many module-level defects and string malfunctions. But the timely correction of module failures may not be economic. Early in a project's lifecycle, spare modules are often stored on the site and are used to replace broken or otherwise failed modules. Once this supply is depleted, exact replacements are rarely available, and suitable substitutes may be difficult to identify and source. In the latter half the operating lifecycle, it may be impossible to locate suitable replacements, leaving as the only option the decommissioning of some array sections so modules may be salvaged and used as replacements. Neglecting the defects may amplify the failures in other components, accelerating performance degradation.

   Recommendation: There is not currently an industry standard for module replacement. It may be most economic to budget for repowering a portion of the project near year 12 when the modules are still covered by a workmanship warranty, allowing for the use of salvaged serviceable modules as spares to replace distributed failures throughout the other parts of the array. For projects that have not yet signed the module supply agreement, it may be prudent to add a clause regarding performance warranty and how it will be measured. The module supply agreement should specify the sampling rate, the number of samples, the tests that are going to be conducted, and the results, along with the uncertainty band. The agreement should define a mutually agreeable way of making warranty claims, and should have regular check-ups scheduled in the O&M to test any signs of additional degradation.

Availability and Energy Production

Availability is often discussed as fundamental to the performance of solar power projects, but this term is not well-defined and is used differently by developers, owners, and service providers. At times, the term is used to refer exclusively to the inverters. O&M contracts typically include a provision for "guaranteed availability" backed by liquidated damages, but there are enough exclusions that the guarantee has little effect on production. For example, a plant may record 98% or greater "contractual availability" while its actual production is below 75% of weather-adjusted projected production. Guarantees do incentivize timely fault diagnosis and reactive maintenance, however, the service provider is often not authorized or required to perform the repair and will open a service ticket with the inverter manufacturer or request authorization from the owner to procure parts and expend labor. Portions of the system will be left offline while repairs are pending.

A more intentional definition of "availability" would be a metric of the plant's physical ability to generate electricity at its modeled capacity, subject to weather conditions. In this case, the best method to measure the "functional availability" would be the actual generation versus weather-adjusted modeled production. If the developer validated plant capacity during commissioning, the actual performance should capture all the effects of accumulated module and wiring defects, non-operational or underperforming equipment, soiling, tracker misalignment, partial shading, and similar factors. This "functional availability" is relevant to the financial performance because it ultimately determines the maximum possible energy generation and revenue at any time.

Rethinking Availability Assumptions: A Modified Approach

Currently, plant availability assumptions are indirectly built into the project proformas in two areas. First, there is an option to reduce the PVSyst modeled generation by adding unavailability in the PVSyst model, which in turn reduces the P50 production accordingly. A second, implied availability adjustment, is often taken by financiers or project acquirers when they build revenue projections based on P90 or P99 modeled performance. Though in theory these adjustments are intended to account for weather uncertainty, they also have the effect of allowing for chronic underperformance that is often driven by plant unavailability.

Although availability is usually poorly defined and difficult to measure, building a more comprehensive understanding of functional availability will permit the development of a more accurate model of project performance. It is also worth noting that the prior discussion of OPEX costs was conducted to develop an operations budget that will yield superior project performance through thoughtful and timely investments in the physical asset and its availability.

With standard assumptions, availability is assumed to decline by a fixed percentage year over year. However, as we noted earlier, the plant's age will accelerate unavailability. Some approaches to modifying this may be:

1. A simple year-over-year module and other plant degradation are currently assumed to be module-warranted maximum degradation (0.3% to 0.4%) plus 0.2% to account for connectors, inverter degradation, and other slow component degradation. This assumption is consistent with current industry data.

   Recommendation: Retain this assumption until or unless further data emerges that warrants adjustment. We also recommend adding degradation uncertainty into the downside scenarios calculation, as not all modules will degrade at the same level.

2. Inverter availability is believed to be the primary cause of system unavailability. It is reasonable that highly reliable, well-maintained inverters can deliver greater than 98% uptime for many years, but this is infrequently observed, often due to high MTTR caused by a lack of OEM repair technicians and spare parts.

   Recommendation: Although it is simple to retain the current baseline assumption of 97% +/- availability, with the P90 or P99 generation in the proforma, a more comprehensive method would be beneficial. Remove unavailability from the PVSyst estimate and add an availability modifier to the proforma. This would permit the functional availability to be adjusted annually and can decrease faster in later years as performance and MTTF decrease.

3. Tracker availability is rarely modeled, but each 1% of tracker unavailability causes approximately 0.4% production loss. Unlike inverters, trackers are retained for the life of the project and will fail at higher rates as the plant ages. MTTF will decrease and MTTR will increase, particularly if replacement parts are

unavailable.

Recommendation: Add a tracker availability line to the project proforma and model accelerating unavailability after warranty ends, particularly late in plant operating life.

CONCLUSION

The current industry-accepted approach to modeling long-term maintenance and performance of PV generation facilities is not supported by operational results. Long-term owners whose investment returns depend on plant performance could benefit from revising the operating and maintenance narrative that currently forms the basis of most financial models, so that it more closely aligns with the observed behavior of equipment in service, as discussed above. Although this is expected to increase initial capital budgets and operational budgets that are built into the models, these investments will improve the likelihood that a project will meet both near-term and longer-term performance expectations.

Consistent with the recommendations above and the explanations provided, investing in better initial design, more durable equipment, and extended warranties during development and construction is expected to yield long-term dividends, including higher production and reduced unplanned expenses. Likewise, more detailed maintenance budgeting that takes account of the operating environment and system aging will align asset management expectations with the practical realities of the physical plant. By avoiding surprises, this has the added benefit of improving plant availability by reducing the decision delay for corrective maintenance, which often causes considerable production losses that can lead to project financial distress.

About the author: **Daniel Tarico** is Director of Renewables, supporting E3's solar and energy storage practices. He has more than 17 years of design, construction, and operations experience in Utility Solar power and the C&I solar market. His insights into renewable infrastructure projects are guided by his knowledge of Finance, Engineering, and Construction, his long tenure in the space, and the breadth of his experience and education. Before entering the solar industry, Mr. Tarico held varied roles in technology development/industrial R&D and has nearly 25 years of total experience managing, working in, and continually improving construction projects of many types. He holds an M.B.A., with an emphasis on Finance and International Management, a M.S. in Materials Science, and B.S. in Metallurgical Engineering from the University of Arizona.

For additional information about E3's solar practice and how we can support your project, please contact **daniel. tarico@e3co.com** or **602-510-3967.**