

BEST-PRACTICES GUIDELINES AND LESSONS LEARNT FOR ON-GRID AND PV-DIESEL HYBRID SYSTEMS



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SMALL DECENTRALIZED
RENEWABLE ENERGY
POWER GENERATION



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Note: The information contained within this document has been developed within a specific scope, and might be updated in the future.

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BACKGROUND

The Small Decentralized Renewable Energy Power Generation Project, also known as DREG, is funded by the Global Environment Facility (GEF) and implemented through the United Nations Development Programme (UNDP). DREG is executed nationally by the Ministry of Energy and Water (MoEW) in coordination with the Lebanese Center for Energy Conservation (LCEC). The project's objective is to reduce greenhouse gas emissions by the removal of barriers to assist in the distribution and application of decentralized renewable energy power generation.

Part of the project's activities includes focusing on local capacity building. In this regard, DREG organized a workshop in Beirut on *Best-practices guidelines and lessons learnt for on-grid and PV-diesel hybrid systems* that was attended by 60 professionals. As a result of the workshop, this guideline was drafted; it is a working document that principally focuses on the design and installation of photovoltaic (PV) plants that are embedded in electrical installations.

This guideline is based on best-practices that were implemented in DREG's PV demonstration projects based on international standards and renowned guides while also tackling some lessons that were learnt during implementation.

This guideline is complementary to required technical and financial assessments such as energy performance or space availability, interconnection, etc., which are also carried out as part of a feasibility study.

1. INTRODUCTION

This guideline aims at establishing a common and general procedure to ensure safe and technically-sound implementation of PV plants and it is mainly directed at engineers and individuals knowledgeable in the field of photovoltaics. Due to Lebanon's PV market's foreseen development characteristics, the guideline focuses on PV plants that are interconnected to a client's electrical distribution grid. In most cases, these will be rooftop PV plants, but most of the procedures and protection measures suggested also apply to ground-mounted PV plants.

The topics covered in this guideline are mainly related to safety, protection, technical optimization, and design compliance to international standards and best-practices.

The issues discussed in this document are commonly encountered during the design and installation phases of a PV system, and so the purpose of this guideline is to dissect these issues and showcase all the technical details behind them for a better understanding of the best-practices and the dangers and drawbacks of not abiding by them.

2. OPTIMIZATION OF THE PV ARRAY

PV design and simulation software are useful tools that system integrators could rely on in the planning, feasibility, and design phases of any project, but special attention should be given to constantly keep the virtual reproduction of the PV system in line with the actual conditions in the field. This includes shading sources, physical obstructions, skylights, and any other elements that could impact the PV system's performance. Taking into account all the potential obstacles at the early stages of the project will allow for a smoother execution and little to no variations. In case of any modifications or adjustments during the implementation on site, these should be reflected in updated drawings and simulations for the sake of accuracy and transparency vis-à-vis the client.

In addition to obstacles and shading elements, a correct understanding of the facility's load profile, operation hours, generation sources, and other critical aspects is key to a sound and feasible PV project.

The design of PV strings is a critical and important milestone in the implementation of a PV project that should be given due consideration since it has a considerable impact on both the technical and economic aspects of the project. Minimum and maximum temperatures, the number and location of combiner boxes (if any), surge protection devices, and inverter specifications and quantity are all factors that should be accounted for when designing PV strings such that the equilibrium between the technical soundness and the economic feasibility of the project is preserved.

Regarding the wiring of strings in DREG's projects, it was highly recommended to system integrators that they use the skip-wiring method (also known as leap-frog) instead of the conventional daisy-chain method. Skip-wiring was proven to have a positive impact both on the technical end, mainly in terms of electromagnetic loop reduction, and on the economic end as in most cases the lengths of the DC cables are reduced by more than 90% compared to the daisy-chain method. It is worth noting that in the cases where the panels' cables are not sufficiently long, skip-wiring is not feasible.

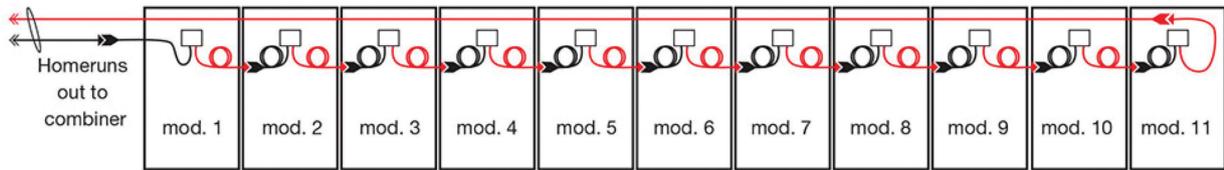


Figure 1a – Conventional daisy-chain wiring (Source: solarprofessional.com)

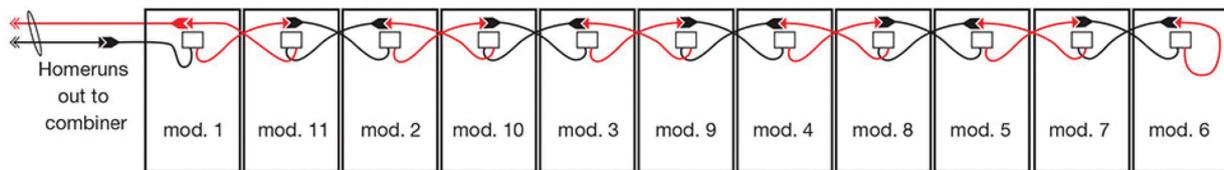


Figure 1b – Proposed skip-wiring method (Source: solarprofessional.com)

Skip-wiring can also be applied to strings that span over more than one row in what is called the X-wiring method.

In order to validate a PV array's installation, open-circuit voltage (V_{oc}) and short-circuit current (I_{sc}) tests should be done on site for each string; the insulation resistance (Riso) test is also an important test that verifies the soundness of the installation before the commissioning, even though one should know that any insulation fault will instantly be flagged after the PV system is operational. The V_{oc} test is a very good indicator of a string's length (i.e. number of panels per string) and its condition when comparing theoretical V_{oc} values to the actual measured values. Regarding the short-circuit test, its importance lies in measuring a string's output I_{sc} and comparing it to the theoretical I_{sc} , which is directly related to the irradiance at that instant. This test is mostly done to validate the string's condition and the wiring, knowing that the whole string's output current can be drastically reduced even if only one of the panels in series has a lower I_{sc} than the others of the same string. That panel could be defective, shaded, dirty, or it could be a wiring-related issue. In order to perform these tests, it is crucial to have the adequate equipment with ratings suitable to handle the voltage and current of the measured strings. The testing equipment could be a purchased kit or it can be assembled in-house.

3. OVERCURRENT & REVERSE CURRENT PROTECTION

Photovoltaic systems generate a limited amount of power directly related to the irradiance and temperature at a specific moment; however, this does not exclude their need for protection. On the DC side, a potential danger stems from the fact that one faulty string could be seen as a load by the remaining parallel “healthy” strings, which will inject their combined current in the defective string instead of the inverter.

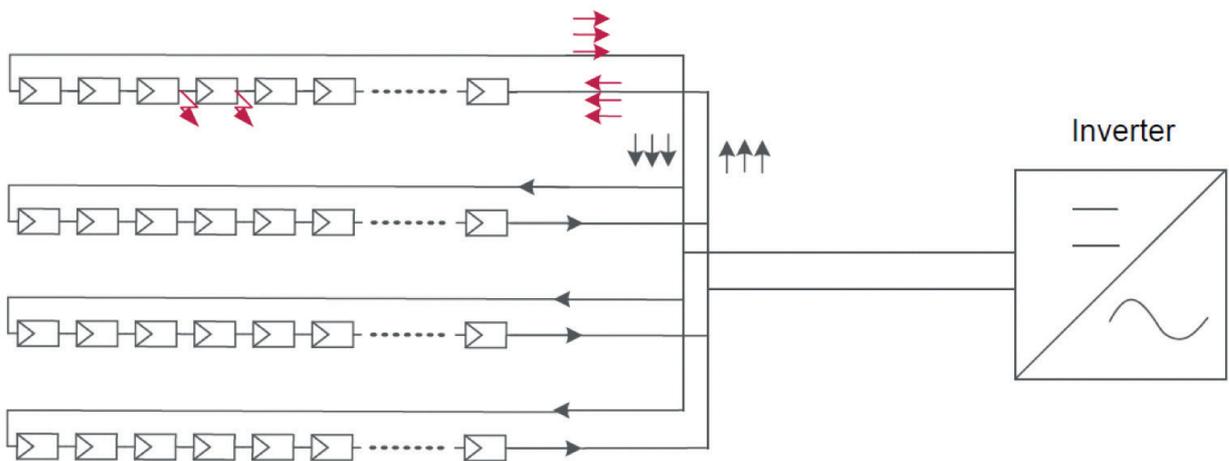


Figure 2 – The reverse current phenomenon (Source: Safe and reliable photovoltaic energy generation)

If the PV modules' withstanding capability is exceeded, this reverse current could lead to dangerous temperature rises and fire hazards in the faulty string. Accordingly, reverse current protection should be added where strings are paralleled (i.e. combiner boxes or inverters) if $(N-1) \cdot I_{sc,STC} \cdot 1.25 > \text{maximum series fuse rating of the PV module}$ where N is the number of strings in parallel and $I_{sc,STC}$ is the short-circuit current at Standard Test Conditions (STC); the maximum series fuse rating can be found in the module's datasheet (commonly 15 A or 20 A). In the case of one or two strings (and sometimes even three strings) in parallel, reverse current protection is not needed.

Reverse current protection is most commonly implemented using gPV fuses **on both the positive and negative cables; a common mistake is to only fuse the positive cables because this will not guarantee total reverse current protection** (see Figure 3).

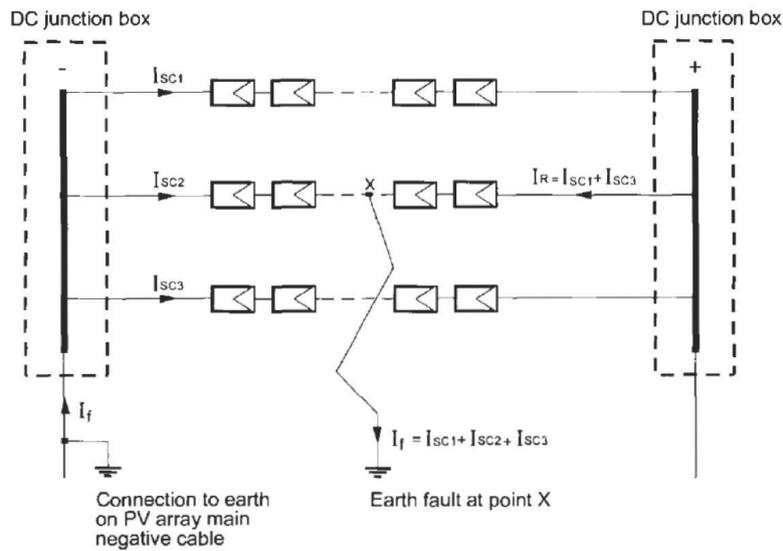


Figure 3 – Double earth-fault scenario on the DC side (Source: Practical handbook of photovoltaics: fundamentals and applications)

Figure 3 shows a double earth-fault scenario whereby it is assumed that there is a long-standing fault at the PV array's main negative cable, and another fault appears at point X shown in the figure. In this scenario, fuses on the positive cables are required to clear the fault. In case the long-standing fault is at the PV array's main positive cable instead of the negative cable, only fuses on the negative cables could clear the fault, hence the requirement to fuse both poles.

These fuses should have adequate voltage rating (e.g. 1000 V DC) and a current rating such that $I_{sc,STC} * 1.25 \leq \text{fuse rating} \leq \text{maximum series fuse rating mentioned in the module's datasheet}$. DC circuit breakers can also be used for reverse current protection instead of fuses.

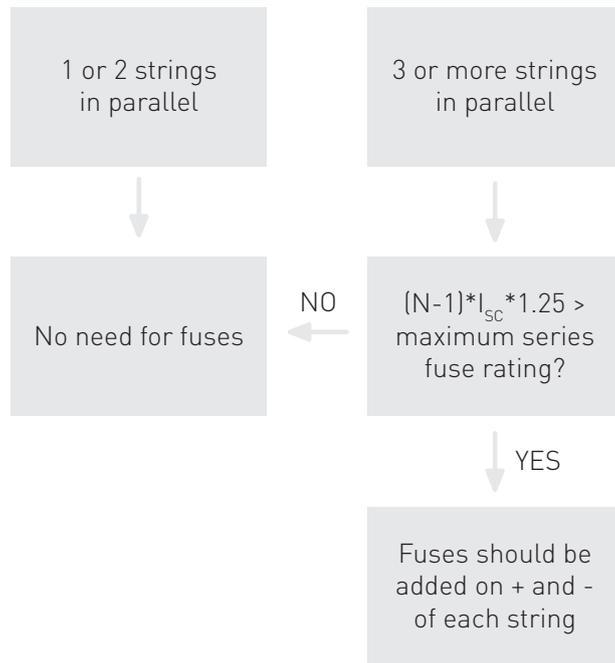


Figure 4 – DC protection flowchart

On the AC side, protection is required for fault currents that originate from the mains (origin) end. **Installing the circuit breakers close to the inverters instead of the interconnection point does not provide the required protection since the current output of the inverters is limited**, and in this case, the circuit breakers will only have a disconnection function and they cannot protect the AC cables. **Effective protection requires that circuit breakers be located in the AC combiner boxes and at the interconnection point with the existing network so that, in the event of a fault on the AC side of the PV system, the circuit breakers will be well-positioned to intercept fault currents originating from the client’s network end.** Circuit breakers ratings should take into account the maximum output current of the inverters, a derating factor for grouped circuit breakers (usually 0.8 for multiple circuit breakers mounted in one enclosure), and the prospective short-circuit current.

4. SHORT-CIRCUIT CALCULATIONS

An often overlooked rating when selecting circuit breakers for a PV project is the short-circuit withstanding capacity. As discussed in the previous section, in the event of a fault in the PV system, high fault currents originate from the existing network, more specifically coming from the grid (when the mains is available) and from auxiliary generation sources such as diesel generators that will be operating during blackouts. Power simulation software, tables, and formulae are available to calculate the prospective short-circuit current (I_{sc}) at any point in a network. **This value will have to be taken into account when selecting the circuit breakers since the withstanding capacity will have to be greater than the prospective short-circuit value.** Therefore, it is important to note that a circuit breaker's datasheet usually lists two short-circuit withstanding capacities, which can sometimes be equal in value: the ultimate short-circuit breaking capacity (I_{cu}) and the service short-circuit breaking capacity (I_{cs}); I_{cu} refers to the maximum short-circuit current that the circuit breaker can clear without sustaining any physical damage, but with no guarantee that it will properly operate in the future. I_{cs} refers to the maximum short-circuit current that the circuit breaker can clear without physical damage and still remain operational. Accordingly, it is recommended to select the circuit breaker's I_{cs} to be greater than the prospective short circuit current it is expected to withstand in order to maximize safety and autonomy of the system. If, for economic reasons, the circuit breaker selected is such that $I_{cs} < I_{sc} < I_{cu}$, the client or the system operator should be made aware that the circuit breaker should always be tested after it clears a fault. In all cases, it is considered good practice to always test a circuit breaker after it has tripped, even if $I_{cs} > I_{sc}$.

5. VOLTAGE DROP CALCULATIONS & CABLE SELECTION

When selecting cables for an electrical installation, the most important criteria that should be examined are the protective equipment's rating, the currents that the conductors should be able to carry, the maximum acceptable voltage drop, the method of installation, and the number of cables and the clearances between them. Cable selection for PV systems is no different, but some specifics should be kept in mind.

On the DC side of PV systems, only "solar cables" should be used, i.e. double-insulated and UV-resistant. The system voltage (e.g. 600 V DC, 1000 V DC, 1500 V DC) should be taken into consideration when selecting DC cables. Even though the current on the DC side of a PV system is relatively small, voltage drop calculations should be done to ensure that ohmic losses are kept at a minimum and that the inverter's input voltage is kept within the specified maximum power point (MPP) range to maximize efficiency. International guidelines propose a total permissible voltage drop value of 3% for the DC and AC sides combined; for DREG's projects, the maximum permissible voltage drop

was required to be 1.5% on the DC side + 1.5% on the AC side. Some integrators might find it more feasible for other projects to increase the permissible drop on one side at the expense of the other, which is acceptable provided that the technical constraints (e.g. MPP input voltage, inverter's maximum output voltage, etc.) are respected.

The cables on the AC side are usually selected to have PVC or XLPE insulation with copper or aluminum conductors. On the AC side of a PV system, we can speak of voltage rise instead of voltage drop because the output voltage of the inverter is equal to the voltage at the interconnection point plus the voltage that results from the inverter output current passing through the resistance of the conductors (i.e. the voltage rise); or if looked at the other way around, the voltage at the interconnection point is equal to the inverter output voltage minus the voltage that results from the inverter output current passing through the resistance of the conductors, which is from this perspective called voltage drop. Aside from the ohmic losses which reduce the overall efficiency of the PV system, if the voltage rise is high enough, it could also lead to serious irreversible damage to the inverter in case the output voltage of the latter exceeds the rated value. Note that inverter manufacturers will usually require installers to abide by a certain maximum conductor size at the input and output of their inverters; therefore, even if the selected cable conductor's cross-section is greater than the maximum allowed by the manufacturer to minimize the voltage drop, the installer will have to reduce the conductor's cross-section at the input or output of the inverter through splicing, terminal blocks, etc.

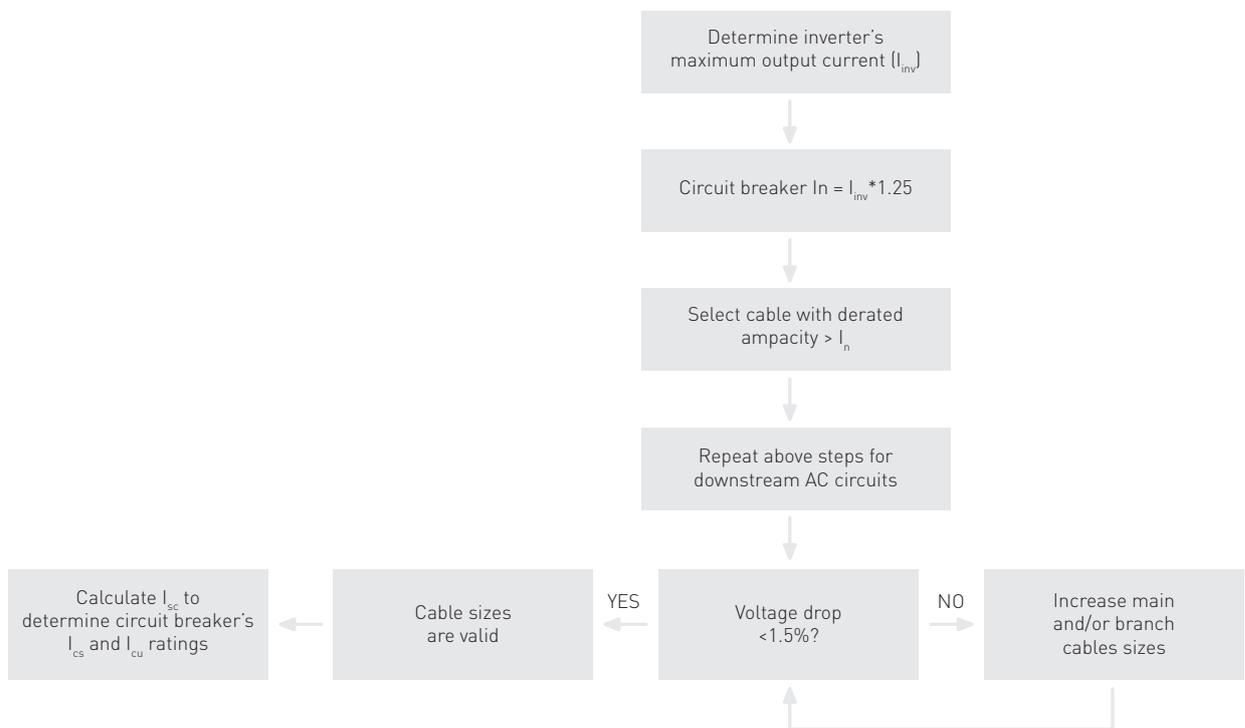


Figure 5 – AC protection and cable sizing flowchart

6. LEAKAGE CURRENT PROTECTION

Leakage current is an electrical issue that is quite often overlooked, especially in photovoltaic systems. This is mainly due to the fact that codes are sometimes ambiguous about this issue and many manufacturers claim that their (transformer-less) inverters can detect leakage current both on the DC and AC sides, which this section will show is not totally accurate. Earth leakage current is a high-occurrence risk in PV systems due to the nature of the installations, which are exposed to rodent attacks and other external elements that could primarily damage cables' insulations. This damage could result in fires if adequate protection is not provided.

In conventional electrical networks, residual current devices are mainly added to protect from electrical shocks and fires; for PV systems, we are mainly interested in the latter, since protection from electrical shocks (i.e. 30mA leakage current) is not feasible in PV systems and will entail nuisance tripping. Most transformer-less PV inverters are designed such that they can detect leakage current on the DC side. Prior to connecting the inverter to the grid (e.g. every morning), a Riso test is carried out on the DC side by a special circuit integrated in the inverter; if the Riso value is below a certain preset value, the inverter will flag a Riso issue and it will not connect to the grid. During operation, a residual current monitoring unit integrated in the inverter actively looks for any leakage current. The Residual Current Monitoring Unit (RCMU) generally detects and only emits a signal if any leakage current is detected, unless the inverter manufacturer specifically states that the inverter will also shut down. The inverter can only detect leakage currents on the DC side (i.e. anywhere from the array to the inverter), and on the AC side but only inside the inverter itself **(the circuit between the inverter and the AC main combiner box or interconnection point is not protected by the inverter's RCD or RCMU)**. That is why a residual current device (RCD) should be installed on the AC side at the mains/source end (directly downstream from the circuit breaker protecting the inverter if an RCCB is used). This RCD, be it a residual current circuit breaker (RCCB; only leakage current protection) or a residual current circuit breaker with overcurrent protection (RCBO), will provide protection to both the DC and AC sides (up to the RCD). It is important to note that there are three types of residual current devices: AC, A, and B. The AC type only provides protection against AC leakage currents, while type A provides protection against AC leakage currents and DC pulse currents. Type B RCDs are classified as universal current sensitive, meaning they protect against both AC and DC leakage currents. The IEC 60364-7-712 and VDE-100-0712 state the following:

“Where an electrical installation includes a PV power supply system without at least simple separation between the AC side and the DC side, an RCD installed to provide fault protection by automatic disconnection of supply shall be type B according to IEC 60755, amendment 2. Where the PV inverter by construction is not able to feed DC fault currents into the electrical installation, an RCD of type B according to IEC 60755 amendment 2 is not required.”

The above statement is based on the fact that in PV systems where transformer-less inverters are used, DC leakage currents would flow from the ground into the AC mains circuit through the neutral-to-earth connection at the source and back to the DC circuit through the transformer-less inverter. In this case, using type AC or type A RCDs could lead to the DC leakage current saturating the RCD's coil, and hence, in the best case, a less-than-optimal operation of the RCD, and in the worst case, a totally impaired operation.

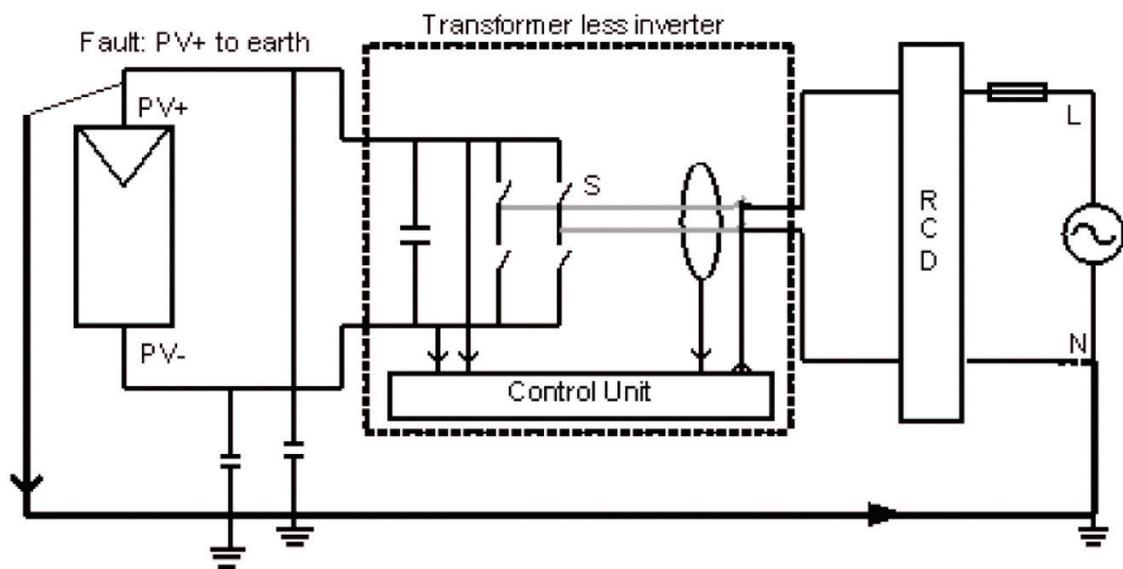


Figure 6 – Flow of leakage current in event of PV+ to earth fault
(Source: Guidance on proper residual current device selection for solar inverters)

Nevertheless, in order to conserve the feasibility of a project and knowing the considerable price difference between type A and type B RCDs (i.e. type B costs 10 times more than type A), **it is acceptable to opt for type A RCDs in PV systems using transformer-less inverters but only if the manufacturer is willing to guarantee, through an official statement, that a type A RCD can be used with their inverters.** Some manufacturers will also acknowledge that a type A RCD's operation will be degraded to some extent, but that it will nonetheless fulfill its function in case of any current leakage.

The RCD should be rated to withstand a steady-state and a short-circuit current at least equal to the rated values of the circuit breaker upstream of it. In terms of sensitivity, the inverter's manual should be consulted for the minimum acceptable mA rating so that nuisance tripping is avoided. **A sensitivity of 300 mA (fire protection) for an RCD protecting up to three inverters in parallel is usually considered adequate.**

7. OVERVOLTAGE PROTECTION

Overvoltage protection is thoroughly explained in a dedicated guide that was released by UNDP DREG in November 2016 and during a workshop that preceded it. The Earthing and Lightning Overvoltage Protection for PV Plants Guideline Report can be downloaded from DREG's webpage at www.lb.undp.org/DREG.

It has been noticed that surge protection devices are incorrectly considered optional and unnecessary devices that incur additional costs without any tangible use. Engineering best-practice and international codes clearly require the installation of overvoltage protection in any electrical system, even more in PV systems that are particularly vulnerable to the direct and indirect effects of lightning strikes.

To recap, selecting surge protection devices for roof-mounted PV systems is based on the following three scenarios:

- Building without external lightning protection system
- Building with external lightning protection system and sufficient separation distance
- Building with external lightning protection system and insufficient separation distance

The third scenario includes metallic roofs whereby the roof itself is considered as the lightning protection system and the PV system is mounted and physically linked to that roof. This scenario is considered the "worst-case" and thus type 1+2 SPDs are required in order to mitigate overvoltage risks caused by both direct lightning strikes and inductive coupling. Protecting a PV installation with SPDs also means that the existing network is shielded from any overvoltage that could appear in the PV system.

It should always be kept in mind that a PV system is meant to last at least 25 years with maximum autonomy and minimum risk and thus if a proper lightning risk assessment of the facility's location shows the need for overvoltage protection, then the system integrator would be wise to install SPDs as required.

Many facilities in Lebanon have no earthing system or a non-functional/flawed one at best. That is why system integrators should always examine and test existing earth networks and decide accordingly whether they are adequate or not, and if a new earth network should be put in place dedicated to the PV system or if the latter can be connected to the facility's existing earth network.

8. REACTIVE POWER COMPENSATION

Reactive power has never been the concern of low-voltage subscribers, at least not in Lebanon. EDL and its concessions only include kVARh in the tariffs of medium-voltage subscribers. During the course of any billing period, if the kVARh consumption is greater than 75% of the kWh consumption, the subscriber is penalized 50 LBP for every excess kVARh.

To illustrate this equation, suppose a medium-voltage facility has, over a billing period of say one month, a metered EDL consumption of 40,000 kWh and 35,000 kVARh. The facility's excess kVARh consumption is $35,000 - 40,000 \cdot 0.75 = 5,000$ kVARh, which translates into $5,000 \cdot 50 = 250,000$ LBP in reactive power penalties. It is more than 5% of the amount paid for kWh consumption.

Suppose the above-mentioned facility is interested in installing a PV system to offset its consumption, but the system integrator did not implement any reactive power compensation. The kWh metered by EDL will be reduced, but the kVARh consumption will remain the same. This will lead to even higher reactive power penalties because the excess kVARh increases. Using the previous example, suppose the PV system has offset the metered kWh consumption by 8,000 kWh over one month. The excess kVARh consumption is then calculated as $35,000 - (40,000 - 8,000) \cdot 0.75 = 11,000$ kVARh or 550,000 LBP (versus 250,000 LBP before adding the PV system). This is because, from a metering point of view, the power factor after adding the PV system appears to be even lower; the meter will register a 32,000 kWh consumption with an unchanged reactive power consumption of 35,000 kVARh.

The solution to this issue lies in programming the inverters to act as reactive power compensators in addition to the injection of active power. Using the unexploited capacity of the inverters to compensate kVARs does it. For example, if an inverter rated 25 kVA is outputting 20 kW at one time, it can exploit the inverter's remaining capacity to compensate up to $\sqrt{25^2 - 20^2} = 15$ kVAR.



Figure 7 – Apparent, real, and reactive power analogy (Source: e2e.ti.com)

Reflecting on the aforementioned discussion on the analogy in Figure 7, the inverter's rated kVA capacity is the glass and the outputted active power is the soda noted "real power". Any remaining "empty" part of the glass can be filled with foam, which represents reactive power.

It is always recommended that the PV system's power factor is programmed to follow that of the facility's load. This will prevent any degradation of the power factor seen at the meter, but it will not improve it as well. System integrators can always do a case-by-case study to find the optimal reactive power compensation scenario for a project, but some factors should be taken into consideration, mainly the danger lying in diesel generators operating at a leading power factor.

If not properly sized relative to the PV installation, inverters may "sacrifice" some active power in order to compensate reactive power up to a certain limit that can be parameterized by the programmer. Back to Figure 7, if the glass is completely filled with soda, a certain volume of the latter will have to be emptied in order to have room for foam. Accordingly, it would seem wise, specifically for projects in Lebanon, to select the inverter's kVA rating such that the ratio of PV peak capacity to inverter capacity is between 1:1 and 1:1.2, taking into account the facility's power factor.

It is important to note that reactive power compensation also has benefits when diesel generators are running because the lower the power factor, the lower the generator efficiency.

9. INTERCONNECTION OF THE PV SYSTEM WITH THE EXISTING NETWORK

Connection of the PV system to the load side of an existing network through a circuit breaker in the distribution panel is quite common, but some precautions should be taken into consideration primarily to prevent “back-dooring” from happening. Consider the following example:

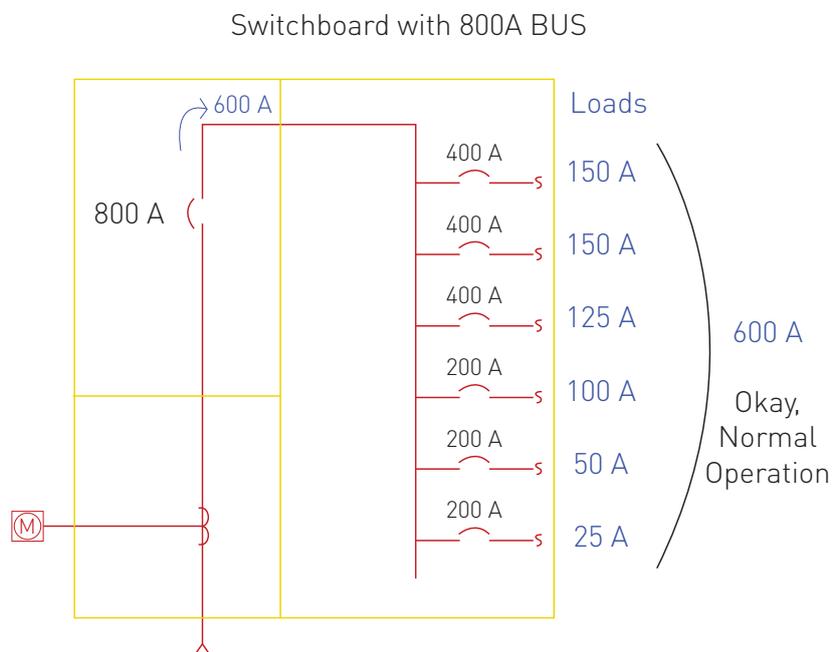


Figure 8a – Normal operation without PV (Source: purepower.com)

Figure 8a shows a switchboard or panel rated 800A and protected by an 800A main circuit breaker. The total load in the figure is 600A and it is considered to be operating normally.

Switchboard with 800A BUS

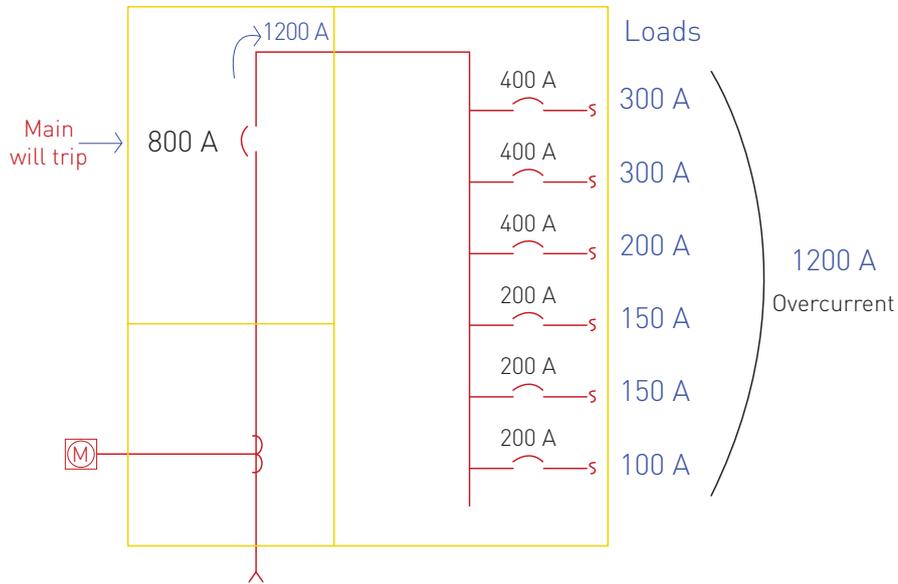


Figure 8b – Overload scenario without PV (Source: purepower.com)

Figure 8b illustrates an overload scenario whereby the total load reaches 1200A but the tripping of the 800A main circuit breaker prevents overcurrent and the panel is protected.

Assuming a PV system is installed for this facility, and the interconnection is done through a 600A circuit breaker at the load side similar to what is shown in Figure 8c, the scenario below is bound to happen.

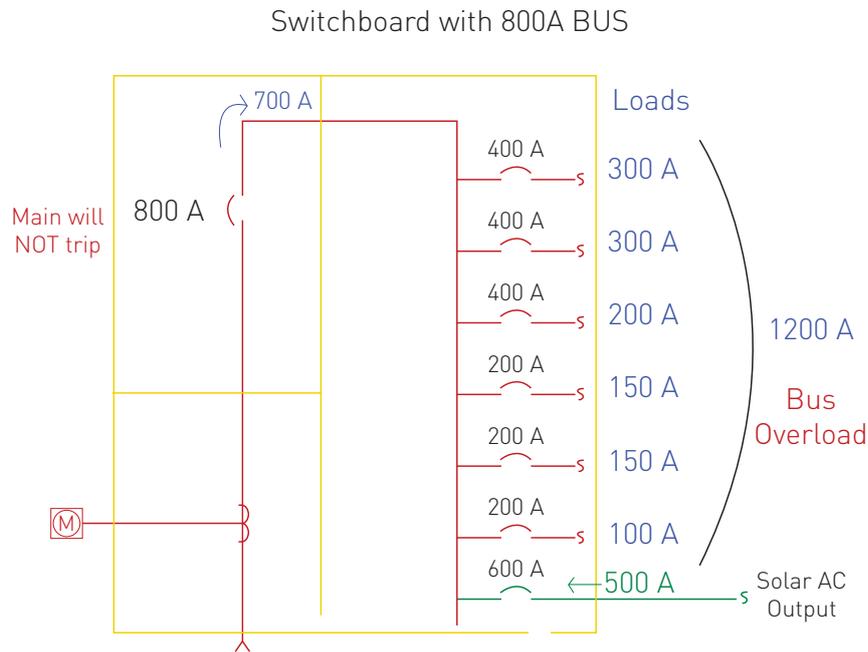


Figure 8c – Overload scenario with load-side PV interconnection [Source: purepower.com]

In Figure 8c, the total load reached 1200A and the 800A main circuit breaker did not trip. This occurs because a current equivalent to the total load (1200A) minus the solar output (500A) equal to 700A is being fed from the mains. According to the main circuit breaker, there is no overcurrent whatsoever, even though the panel's bus is overloaded in what is referred to as back-dooring. This could lead to serious physical damage to the bus and presents a high fire hazard risk.

In Figure 8d below, a supply-side connection is made upstream of the main circuit breaker.

Switchboard with 800A BUS

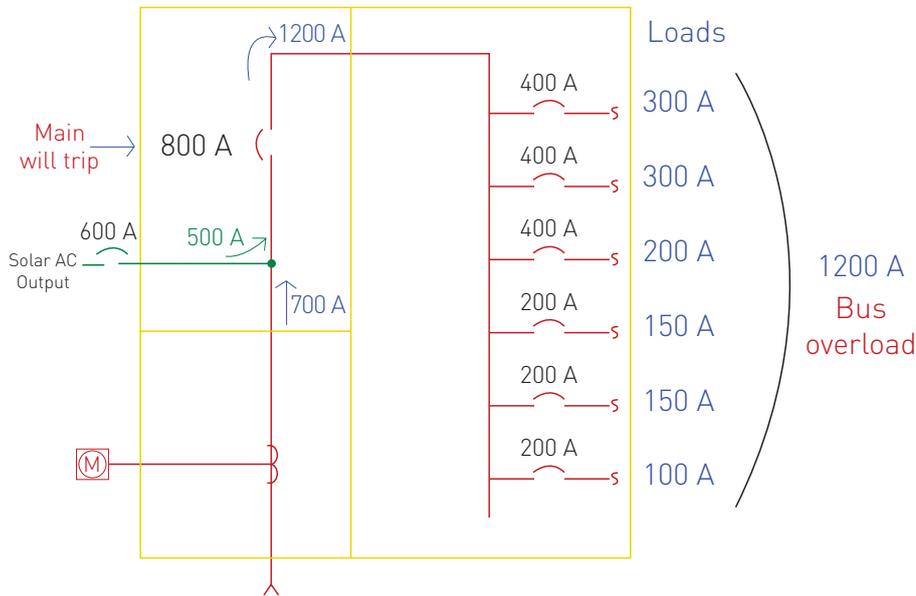


Figure 8d – Overload scenario with supply-side PV interconnection (Source: purepower.com)

In the case of supply-side interconnection, any overload is always detected by the main circuit breaker, which makes it a safer option than load-side interconnection.

This does not mean that load-side interconnection is never safe or technically inadequate, but some factors should be taken into consideration. The first condition, which is common to both load-side and supply-side scenarios, is that the PV main circuit breaker's rating should be no greater than the rating of the circuit breaker protecting the panel's upstream feeder:

Condition 1: PV main circuit breaker ≤ Upstream feeder circuit breaker

The second condition states that the PV main circuit breaker's rating should be no greater than the bus-bar's rating (to which it will be connected) minus the upstream feeder circuit breaker's rating. The NEC provides details related to this issue in what is called the "120% rule". It states that if the PV's circuit breaker can be mounted in the panel at the opposite end of the panel's main circuit breaker, the second condition can be allowed to be:

$$\text{PV circuit breaker} + \text{Upstream feeder circuit breaker} \leq 120\% \text{ of bus-bar rating}$$

However, if the PV's circuit breaker cannot be mounted in that location, the allowance drops from 120% to 100% of the bus-bar's rating. It is always recommended to opt for the worst-case scenario (i.e. 100% of bus-bar rating) for the sake of safety and best-practice, especially since many facilities that are installing PV systems are considered relatively old and quite often their switch-boards are not properly maintained.

Condition 2:

PV circuit breaker + Upstream feeder circuit breaker \leq 100% of bus-bars rating

Proceeding with the above-mentioned condition and in the event that it cannot be respected, the system integrators are faced with the following three options, all of which are impractical and/or not feasible:

- Decrease the rating of the PV's main circuit breaker: this would lead to constrained PV production, nuisance tripping, and/or limitation of any future expansion of the PV system.
- Decrease the rating of the panel's main circuit breaker: this option requires a careful study of the loads at hand and the client's approval. There is a risk of nuisance tripping and constrained load expansion.
- Increase the rating of the panel's bus-bar: this option presents economic and practical constraints and will most probably be rejected by the client.

Based on the above, load-side interconnection clearly presents many obstacles that could lead one to consider supply-side interconnection instead. The PV's circuit breaker could then be connected directly upstream of the panel's main circuit breaker if Panel's bus-bars rating \geq Panel's main circuit breaker, which is not always the case since the panel's main circuit breaker can be oversized and is only used for disconnection purposes, while actual overcurrent protection is provided by the upstream feeder's circuit breaker to which, in most cases, the panel's bus-bars rating is matched. In that case, the PV circuit breaker should instead be connected directly upstream of the facility's main circuit breaker (optimal solution) or upstream of the panel's feeder circuit breaker (keeping in mind that condition 2 has to be satisfied for the upstream feeder's board). This also applies to the case where a main disconnect switch is installed in the panel instead of a main circuit breaker.

The flow-chart in Figure 9 illustrates all the conditions pertaining to supply-side (dark blue) and load-side (light blue) interconnection. For the sake of simplicity, it is assumed that condition 2 is met for the upstream feeder's board.

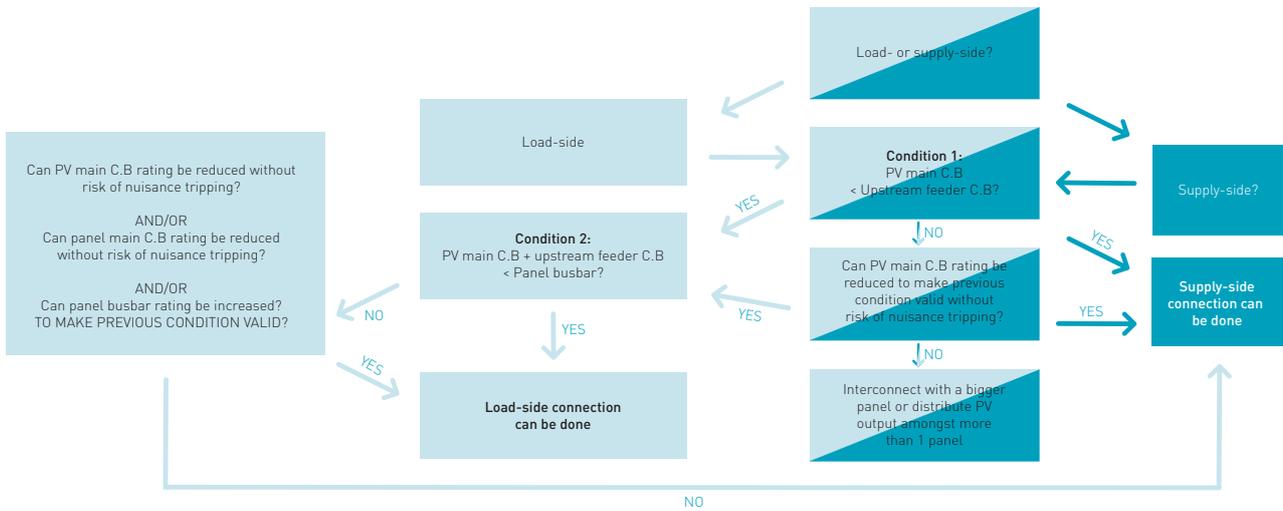


Figure 9 – Supply-side and load-side interconnection conditions flowchart

Figures 10a, 10b, 10c, and 10d illustrate some interconnection scenarios that could be commonly encountered.

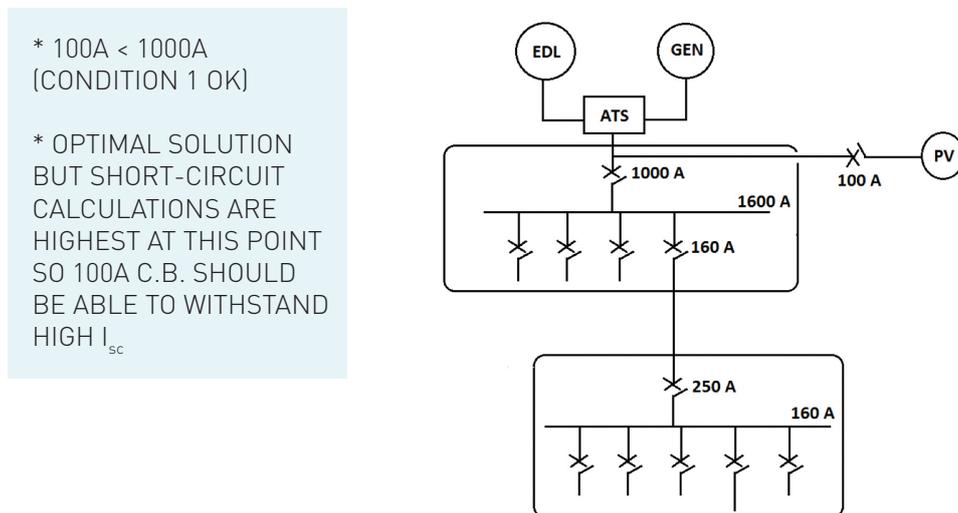


Figure 10a – Interconnection of PV upstream of the facility's main circuit breaker

* $100A < 160A$
(CONDITION 1 OK)

* 160 A BUS PROTECTED BY 160A C.B.

* $100A + 1000A < 1600 A$
(CONDITION 2 OK FOR 1600A BUS)
=> INTERCONNECTION AT THIS POINT IS VALID

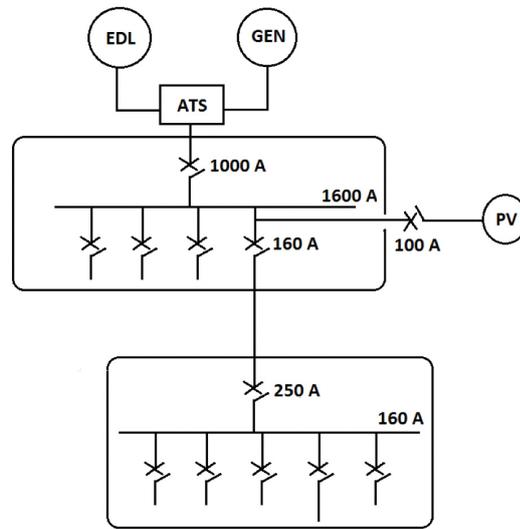


Figure 10b – Interconnection of PV upstream of 160 A feeder circuit breaker

* $100A < 160A$
(CONDITION 1 OK)

* RISK OF 160A BUS OVERLOAD
=> INTERCONNECTION AT THIS POINT NOT PERMISSIBLE

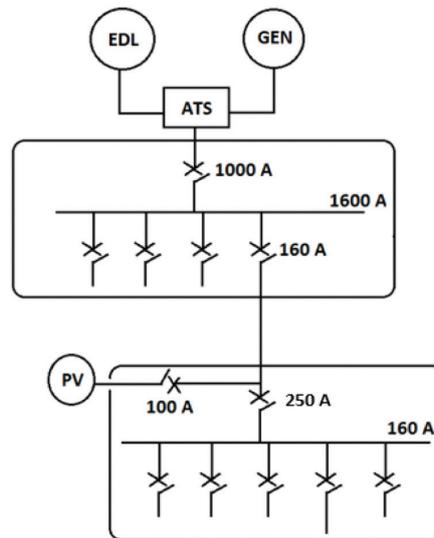


Figure 10c – Interconnection of PV upstream of 250 A panel circuit breaker

* $100A < 160A$
(CONDITION 1 OK)

* PANEL'S 160A MAIN
CIRCUIT BREAKER
PROTECTS
DOWNSTREAM 160A BUS
FROM ANY OVERLOAD

* $100A + 1000A < 1600A$
(CONDITION 2 OK)
=> INTERCONNECTION
VALID

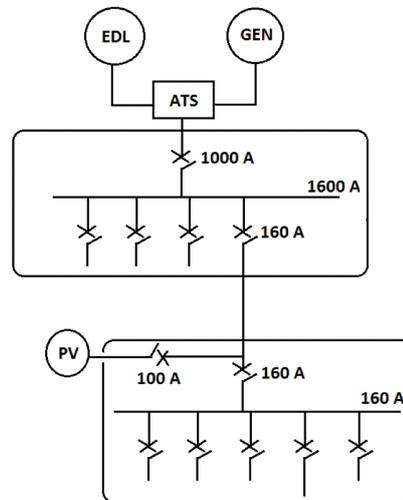


Figure 10d – Interconnection of PV upstream of 160 A panel circuit breaker

It is important to note that, as a general electrical rule also applicable to PV, the PV main circuit breaker should not be farther than three meters from the point of interconnection.

An important reminder is that whenever there is a disconnect switch instead of a circuit breaker, an interconnection directly upstream of that disconnect is not permissible since it does not provide any overload protection.

10. SAFETY AND QUALITY OF SITE WORKS

Abiding by safety standards is the first and foremost rule to follow before and during works on site. The necessary gear and equipment should be provided to workers, including safety ropes (for roof works), vests, shoes, helmets, protective eye-ware, etc. A system integrator should always adopt a safety culture and aim for an accident-free project, regardless of the extra costs.

It is highly recommended to have skilled workers on site with previous experience in PV installations. They should always be properly briefed before a project starts and constantly reminded of the potential hazards of working with PV systems.

Any changes imposed by constraints on site, no matter how minor they are, should be reviewed and evaluated to determine their impact on the technical and economic feasibility of the project.

It should always be kept in mind that a PV project's estimated lifetime is no less than 25 years and so the necessary measures should be taken to guarantee a safe and autonomous operation of the system with as minimum intervention and disruption as possible.

11. CONCLUSION

The topics mentioned in this guide are encountered in virtually all PV projects and so this document attempts to set a common engineering process and provides optimal solutions to resort to when faced with these issues during the design, installation, and commissioning of PV systems. Nevertheless, it is highly recommended to revisit and adapt the subjects in this document on a case-by-case basis, keeping in mind the importance of the balance between the technical and economic aspects of the project.

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