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Pacific Power Association, Suva, Fiji Islands. The PPA is an inter-governmental agency and member of the Council of Regional Organisations in the Pacific (CROP) established to promote the direct cooperation of the Pacific Island Power Utilities in technical training, exchange of information, sharing of senior managment and engineering expertise and other activities of benefit to the members.

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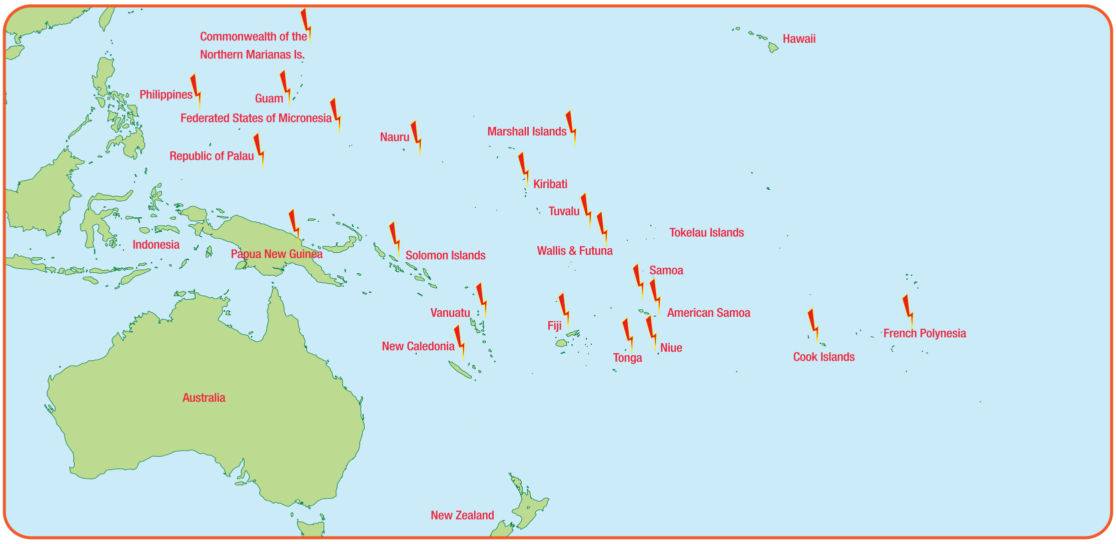

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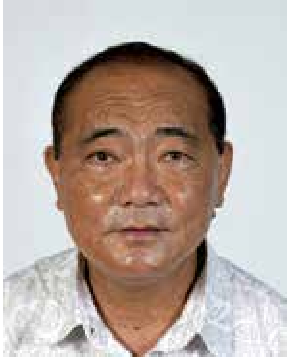


Editor’s Note

Gordon Chang
Acting Executive Director

Bula and Greetings from Suva.

The Pacific Power Association will be currently finalizing the logistics for the 29th Annual PPA Conference and Trade Exhibition in Brisbane, Australia from the 21-24 November 2022. It is going to be a well-attended event by the utility CEOs, one Utility Board member and one engineer as they will be funded by DFAT, Australia, World Bank and ADB. I hope that all the allied members will consider attending as all active members will be present in Brisbane, Australia. An interesting conference Programme has been organized for the week and I would encourage delegates to participate by presenting a paper that is in tuned with the conference theme.

The conference theme “Supporting Utilities towards Environmental Stewardship, Operational Performance and Financial Stability” PPA utilities are fortunate as donor partners will be in attendance and they are readily available to discuss funding options with them.

There has been much progress with the remaining activities with the World Bank funded “Sustainable Industry Development Project (SEIDP) to the Pacific Power Association as PPA is going full speed to complete the remaining activities as we approach the project end date in February 2023.

May I on behalf of the Association welcome the new Allied Member who has just recently joined the PPA, Longi Solar Technology Co, Ltd.

Lastly but not the least, my most sincere appreciation to the donor partners who assisted in funding the utilities attendance to this year’s conference.

Vinaka vakalevu.
Gordon Chang

Lateral Reclosers Transform Reliability for Island Nation

Jason Lander
Vice President, AP & EMEA, S&C Electric Company

Few places in the world match the remoteness of Pohnpei Island, a Pacific island that is part of the Federated States of Micronesia. The island and its 40,000 inhabitants are located approximately 1,000 miles from the closest land mass, Guam. Renowned for its beauty, Pohnpei's lush rainforest flourishes from more than 300 inches of rain per year, making it one of the wettest places on earth.

The TripSaver II recloser is helping PUC prevent nuisance outages caused by common problems, such as vegetation overgrowth

The scenery may be alluring to locals and visitors alike, but the island's remoteness and weather also present unique obstacles for essential service providers. For the state-owned utility, Pohnpei Utilities Corporation (PUC), the isolation makes providing reliable and resilient electrical power an ongoing challenge. PUC maintains an independent grid and is solely responsible for power generation and distribution.

PUC had relied exclusively on diesel oil for power generation but acquiring the fossil fuel was expensive because of the island's remoteness. The utility wanted to reduce its carbon emissions by curbing diesel oil consumption and using more renewable resources, such as solar and wind. It began that transition through a $15.5 million grant from the World Bank in partnership with the Asian Development Bank.

When PUC stabilized generation production by upgrading its diesel generators, the utility expected to see improved reliability. However, frequent temporary faults along its distribution system were causing lengthy power outages, negating the generation improvements and forcing PUC to reevaluate its strategy.

Securing the Backbone of the Grid

Crews were frequently traveling to fault locations to make repairs regardless of whether the underlying cause was permanent. The utility realized it needed to secure the backbone of its electrical grid and upgrade its aging distribution infrastructure, but environmental conditions also were making reliability and resilience improvements difficult.

PUC's distribution grid was designed and installed in the 1960s with limited segmentation, meaning a single fault would affect a large portion of each feeder. The independent grid uses three main feeders—West, East, and Kolonia 2—to distribute power to the entire island. As part of that system, long feeder and lateral lines weave over mountains, low coastal zones, and into a smaller adjacent island. The abundant annual rainfall was also causing a fast vegetation growth cycle that only exacerbated the number of temporary faults. Each required a truck to travel to the fault location to make repairs because fuses would blow every time a fault occurred.

The utility had a set amount in its budget to address its distribution system reliability problem, so it needed to make sure a solution would be economical and long-lasting. It determined it had two options: use available funding for extensive vegetation management, which would be a recurring expense, or explore smart devices that could provide a long-term reliability solution.

The solution had to be adaptable to the present grid and require minimal maintenance. PUC chose to explore lateral reclosers able to operate on 13.8-kV overhead three-phase feeders along with single-phase lateral lines.

Using Advanced Lateral Protection

PUC officials knew of S&C's TripSaver® II Cutout-Mounted Recloser, and they were impressed by the device's rating flexibility and ability to integrate into existing cutouts. With up to 80% of overhead distribution faults being temporary in nature and with the utility's grid primarily consisting of overhead lines, they believed the device could dramatically improve PUC's power reliability. The device accomplishes this by testing whether faults are temporary or permanent and closing back in if the temporary cause goes away. The TripSaver II recloser's proven success at preventing temporary faults from becoming permanent outages was a key selling point because fewer outages meant the utility could save money by reducing repair trips.

PUC believed the TripSaver II recloser was the superior choice over other options because the device required minimal maintenance, could be installed into existing fuse cutouts, and S&C would provide support. Local support was critical because hands-on training allowed the utility's crews to learn how to install and operate the new devices quickly.

The utility decided to pilot three TripSaver II reclosers, installing them on main feeders for a six-month period. It chose the locations because they experienced the highest rate of temporary faults. The feeders also faced the heaviest problems from overgrown vegetation, and the pilot's goal was to prevent temporary faults from becoming permanent outages. The TripSaver II reclosers also would provide sectionalizing points, so if a permanent outage were to occur, they would typically minimize the number of customers who would lose power.

Transformational Outcome

PUC was thrilled with the results of the pilot. Within one year, the three TripSaver II reclosers used in the pilot prevented 59 temporary outages from becoming permanent, translating into substantial O&M savings by avoiding 59 repair trips. Most importantly, it allowed the utility to transition from reactive to proactive management of its network. Because PUC was able to reduce costs by cutting back on the number of repair trips, it was able to reallocate resources to other key tasks, including replacing poles, repairing cutouts damaged from saltwater, and other essential maintenance activities.

PUC's chief executive officer, Nixon T. Anson, praised the TripSaver II recloser's performance. "As an island, our isolation presents unique reliability and resiliency challenges. Installing S&C's TripSaver II Cutout-Mounted Reclosers solved our issues with temporary faults, allowing us to keep the power on for our entire nation," Anson said.

The TripSaver II recloser was key to improving PUC's distribution system reliability for the entire island

The utility was so elated with the initial pilot's success, it decided to deploy nine more TripSaver II reclosers, with the goal to continue deploying more throughout its feeders to cover a systemwide deployment on the island. Afterward, PUC planned to use the TripSaver II reclosers' versatility by installing the advanced protective devices along laterals as well.

S&C's TripSaver II reclosers enhanced PUC's ability to improve its reliability and resilience, helping ensure the power stays on across the entire island. By bolstering its distribution system, the utility can now maximize the investment in both diesel and renewable power generation along with comprehensively modernizing the grid. Today, even in blue- or black-sky days, PUC can more routinely provide reliable and resilient energy to its island nation.

What Causes Solar Fires and How to Prevent Them

GSES Technical Team
Global Sustainable Energy Solutions

Figure 1 - Fire damaged array. Solar fires are headaches for the owner and the installer

PV system fires are rare but can cause a lot of damage to a building and its contents. While it is rare for panels to catch fire on their own, poor workmanship combined with negligence can cause issues that eventually lead to electrical fires on the roof or at the inverter.

In recent months, GSES has attended multiple sites to conduct investigative fire inspections on commercial solar systems. The findings from the visits concluded that the fire was likely caused by water ingress or loose connections at rooftop isolators. Fortunately, in all instances, major damage was averted due to favourable conditions and the quick responses of personnel onsite and emergency services

As solar fires are a major risk to the reputation of the Australian solar industry as well as an obvious risk to safety and property; it is important to understand the causes of PV system failures and how to prevent them.

Our engineers and inspectors have inspected over 10,000 grid-connected solar PV systems in the past ten years. During this time, we have concluded that there are three main causes of fires:

Cause 1 – Water ingress into DC isolators.

DC isolators, especially the DC isolators located at the roof (rooftop isolators), are a known common cause of fires in PV systems. Historically, rooftop isolators have been a requirement in Australia to allow fire safety services and other workers to disconnect the system at the array – i.e. while on the roof. However, with rooftop isolators being more exposed to the elements, they are more prone to damage and deterioration. They are also less visible, resulting in issues occurring at the rooftop isolator often being missed until it is too late. While recent regulatory changes now allow alternatives to rooftop isolators, there will still be millions of rooftop isolators already installed[1].

Without proper installation methods to maintain the ingress protection (IP) of the isolator enclosures, water can get in and accumulate inside the isolator enclosure, causing corrosion of the terminals and, in the case of inundated isolators, damage internal components of the isolator too. When the isolator carries current in this state, higher resistance at points where corrosions has occurred, causing a hot joint which can eventually lead to fire.

Figure 2 - evidence of corrosion at an isolator terminal

Figure 3 – partial immersion of the isolator and corrosion evident with watermark and presence of green - copper conductor corroded, and brown- iron screw corroded

Some common points of water entry at DC isolators:

a. Conduit not glued. This allows water to seep in slowly at the connection point, or allow movement which results in the conduit falling out creating a penetration point. Conduit entries, including caps for unused entries, should all be glued.

Figure 4 – Conduit not glued and falling out of the adaptor. Conduit must be glued to ensure watertightness and steadfastness at the connection.

[1] https://www.energy.gov.au/news-media/news/australia-achieves-3-million-rooftop-solar-pv-installations

b. Screws not sealed. This can allow water to slowly seep in from the other side of the screw.

Figure 5 - moisture build-up and corrosion evident at a screw that hasn't been sealed by cap or silicone

c. Improper cable glands used. Multi-hole cable glands, instead of single hole compression gland, must be used to accommodate the cables entering the conduits. Extra holes that are not used must be plugged up.

Figure 6 - single hole compression gland used for multiple cables entering the gland.

d. Improper penetration of enclosures. Drilling holes in an enclosure without sealing them with purpose made products can lead to water seeping in. Penetrations made anywhere other that the lower surface of the enclosure have an increased risk of allowing water to drip onto components or even accumulate in the enclosure.

Figure 7 - penetration of and enclosure without appropriate sealing and not utilising the lower surface.

e. Overtightened screws leading to cracked enclosure or loose screws leading to an inadequate seal. Both are cases where the manufacturer's torque settings have not been followed, allowing water to seep in.

Figure 8 - loose screws causing inadequate sealing of the lid.

Figure 9 - An overtightened screw causing damage to the enclosure.

Hopefully, there will be a reduction of instances of water ingress with AS/NZS 5003:2021 removing the requirement for rooftop isolators in specific scenarios. AS/NZS 5003:2021 Clause 4.4.7 outlines installation requirements to prevent water ingress, the above is a subset of the most common non-compliances seen in the field causing water ingress.

Cause 2 – Cable terminations

Terminals and other connections need to be properly tightened for the current to flow through properly. When the torque settings are not followed or connections are loose, hot joints can be created. The heat can melt the plastic around the cables and start a fire.

Figure 10 - Torque being checked at a terminal. Always make sure you have tightened all your connections to the manufacturer's specification.

Attention should also be paid to the length and location of the cables in the enclosure to avoid pinching and damaging the cables.

Figure 11 - DC cable pinched by enclosure lid.

Cause 3 – Damage to module

Solar modules are tested to withstand various conditions. However, damage to the module can cause internal cracks that are not easily visible. Microcracks can lead to hotspots in the cell, which then may lead to fires.

Cracks and microcracks in the cell can be caused by:

a. Smashed module (golf ball, cricket ball, hail)
b. Earthing lugs installed against backsheet causing abrasion

Figure 12 - earth lug installed hard against the underside of the module]

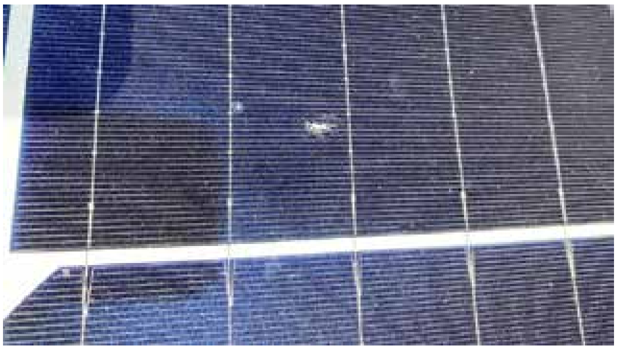


Figure 13 - evidence of damage on the front side of the module. The cracks are points of high ristance in the cell and can lead to hot spots.

c. People walking on modules/improper transport

Figure 14 - cell degradation and hot spot from crack in module

Another way damage can occur is via delamination of the module backsheet causing water ingress into the panel itself and short-circuit of the module current to earth. This usually does not cause fire; however, it does reduce system output and cause the roof to be hazardous.

Prevention

Solar fires are often the result of a number of mistakes and oversights. Most commonly, the risk exists because care has not been taken during installation to keep water out, and fire starts when the issue is not picked up early by the way of monitoring or regular inspections.

The severity of fires can be increased if leaf litter is allowed to build up, or common points of failure, e.g. the rooftop isolator, are installed in close proximity to flammable materials.

Figure 15 - Vegetation build-up under panels due to bird nesting. Gutter guards can be installed around the modules to prevent debris build-up and fauna access.

Whether by lack of knowledge or motivation, when the issue isn't addressed, dangerous situations can occur. But solar fires are avoidable. For big projects, 3rd party independent inspections at the point of handover can help pick up issues right at the start. There should be a plan in place to inspect the system at regular intervals to ensure connections are still tight, ingress protection is maintained and debris at the array is kept to a minimum. Also, make sure to occasionally check the performance of your solar system. This can, in some cases, identify issues before they escalate.

Here are a few things you can do to keep your rooftop PV system operational and safe.

- Use quality products that are less likely to fail and that have reliable warranties.
- Choose reliable installers that are less likely to make installation mistakes. Ensure they have a workmanship warranty.
- Regularly inspect the system. We recommend inspecting the system one year after installation and every 5 years after that. Follow-up inspections could be included in the system procurement contract
- Clean under and around the array. Fire can propagate faster if there are leaves and other debris under the modules.
- Don't install on combustible material.
- Use asset management tools such as GSES' 'Diagno' to investigate drops in production early. A hot joint or short circuit is likely to reduce the system's output. Asset management tools will identify if there is an issue with production and prompt the customer or asset manager to inspect the system for faults.

Contact GSES today for more information about how Diagno can help you keep your property safe from the risk of potentially devastating solar fires.

PV OVERCURRENT PROTECTION CHANGES FROM AS/NZS 5033:2014 TO AS/NZS 5033:2021

GSES Technical Team.
Global Sustainable Energy Solutions

AS/NZS 5033:2014 requirements

Overcurrent protection requirements were covered almost entirely within Clause 3.3 in AS/NZS 5033:2014.

Clause 3.3.4 explained when string overcurrent protection was required, while Clause 3.3.5.1 listed the sizing requirements for string overcurrent protection.

Clause 3.3.5.2.2 and Clause 3.3.5.2.3 explained when sub-array overcurrent protection was required, while Clause 3.3.5.2.3 listed the sizing requirements for sub-array overcurrent protection.

Clause 3.3.5.3 explained when array overcurrent protection was required, and the relevant sizing requirements.

The formulas were expressed as summarised below.

String overcurrent protection required if:
((SA – 1) × ISC MOD) > IMOD MAX OCPR

String overcurrent protection sizing In must comply with:
In > 1.5 × ISC MOD
In < 2.4 × ISC MOD
In ≤ IMOD MAX OCPR
There's also an alternative calculation where strings are grouped in parallel, but this was removed in the 2021 version.

Sub-array overcurrent protection required if:
More than two sub-arrays
ISC ARRAY × 1.25 is less than the CCC (current carrying capacity) of any sub-array cable, switching and connection device

Sub-array overcurrent protection sizing In must comply with:
In ≥ 1.25 × ISC S-ARRAY
In ≤ 2.4 × ISC S-ARRAY

Array overcurrent protection required if:
Systems connected to batteries or where other sources of current might feed into the PV array under fault conditions.

Array overcurrent protection sizing In must comply with:
In ≥ 1.25 × ISC ARRAY
In ≤ 2.4 × ISC ARRAY

AS/NZS 5033:2021 requirements

The requirements for overcurrent protection are still covered in Clause 3.3.3 in AS/NZS 5033:2021, but cross-referencing between different sub-clauses becomes important.

Clause 3.3.3.1 explains how to calculate the maximum expected string current, which is used in Clause 3.3.3.2 to calculate the potential string fault current, Clause 3.3.3.3 to calculate the potential sub-array fault current, and in Table 3.1 to calculate the various overcurrent protection ratings.

The calculation of potential string fault current in Clause 3.3.3.2 is then used in Clause 3.3.4.1 to determine if string overcurrent protection is required. There are no explicit requirements to test whether sub-array and array overcurrent protection is required.

Clause 3.3.5 and Table 3.1 gives the sizing requirements for string, sub-array and array overcurrent protection, using values calculated from the previous clauses.

One of the reasons for the rearrangement of clauses in AS/NZS 5033:2021 is accommodating the introduction of DCUs (DC conditioning units) into the calculations. Clause 3.3.3.1 offers three different methods for calculating the maximum string current ISTRING MAX, depending on the presence of DCUs within the string.

Maximum string current where there are no DCUs (3.3.3.1a):
ISTRING MAX = 1.25 × KI × ISC MOD
This is analogous to the AS/NZS 5033:2014 formulas.

Maximum string current where all PV modules have DCUs attached (3.3.3.1c):
ISTRING MAX = IDCU string max

Maximum string current where only some PV modules have DCUs attached (3.3.3.1b):
Whichever of the previous two formulas gives the larger result.

The sizing requirements in Table 3.1 for all three types of overcurrent protection are then based on the calculated I STRING MAX.

String overcurrent protection sizing In must comply with:
Where there are no DCUs:
1.2 × ISTRING MAX < In ≤ IMOD MAX OCPR

Where all PV modules have DCUs attached:
ISTRING MAX < In ≤ IDCU OCPR

Where only some PV modules have DCUs attached:
Comply with both of the previous two formulas.

Sub-array overcurrent protection sizing In must comply with:
In ≥ SSA × I STRING MAX

Array overcurrent protection sizing In must comply with:
In ≥ SA × I STRING MAX

To work out whether string overcurrent protection is required, an additional calculation of potential string fault current is required, as per Clause 3.3.3.2.

Potential string fault current:
IF STRING = (S¬A – 1) × ISTRING MAX
If there is only one string, IF STRING = ISTRING MAX.

Whether string overcurrent protection is required, as per Clause 3.3.4.1, is then based on IF STRING.

String overcurrent protection required if:
IF STRING + IBF TOTAL > IMOD MAX OCPR

Clauses 3.3.4.2 and 3.3.4.3 don't specify situations in which sub-array and array overcurrent protection would be required, just that if they are not used, the cable size will need to be larger as per Clause 4.4.2. Inclusion of sub-array and array overcurrent protection therefore becomes an economic decision, balancing the cost of protection against potentially larger cables.

Comparison of AS/NZS 5033:2014 and AS/NZS 5033:2021 requirements

There are clearly significant changes from the 2014 version to the 2021 version in terms of notation and formula arrangement. AS/NZS 5033:2014 formulas tend to be based around ISC MOD, while the 2021 equivalents tend to be based on ISTRING MAX. However, the numerical results are only slightly changed. There are obviously substantial changes if the system contains DCUs, however <u>if no DCUs are included</u>, the changes to the actual calculations are simply:

- Removal of the 2.4 upper factor for overcurrent ratings
- Inclusion of the KI factor to all formulas
- Inclusion of the 1.25 factor and backfeed current when determining if string overcurrent protection is required
- Removal of explicit requirements for sub-array and array overcurrent protection

Worked example of string overcurrent protection

A PV system has 3 strings of bifacial PV modules, and no DCUs. The modules have a ISC of 9.8 A and an IOCPR of 20 A. The KI factor has been determined to be 1.1, and the inverter has a potential backfeed current of 3 A.

According to AS/NZS 5033:2014, string overcurrent protection is required if:
(SA – 1) × ISC MOD > IMOD MAX OCPR
(3 – 1) × 9.8 A > 20 A
19.6 A > 20 A FALSE, so string overcurrent protection is not required.

According to AS/NZS 5033:2021, string overcurrent protection is required if:
IF STRING + IBF TOTAL > IMOD MAX OCPR
Which becomes: (S¬A – 1) × ISTRING MAX + IBF TOTAL > IMOD MAX OCPR
Which becomes: (S¬A – 1) × 1.25 × KI × ISC MOD + IBF TOTAL > IMOD MAX OCPR
(3 – 1) × 1.25 × 1.1 × 9.8 A + 3 A > 20 A
26.95 A + 3 A > 20 A TRUE, so string overcurrent protection is required.

The changes from AS/NZS 5033:2014 to AS/NZS 5033:2021 are inclusion of a 1.25 factor, inclusion of the KI factor, and inclusion of the backfeed current. In this example, the changes are significant enough to alter the result of the calculation.

String overcurrent protection sizing, assuming string overcurrent protection is installed:
According to AS/NZS 5033:2014, string overcurrent protection sizing In must comply with:
In > 1.5 × ISC MOD
In < 2.4 × ISC MOD
In ≤ IMOD MAX OCPR
Therefore In must be more than 14.7 A, less than 23.52 A, and less than or equal to 20 A. We would probably choose a 15 A or a 20 A fuse.

According to AS/NZS 5033:2021, string overcurrent protection sizing In must comply with:
1.2 × ISTRING MAX < In ≤ IMOD MAX OCPR
Which becomes: 1.2 × 1.25 × KI × ISC MOD < In ≤ IMOD MAX OCPR
Therefore In must be more than 16.17 A and less than or equal to 20 A. We would probably choose a 20 A fuse.
The only differences from the 2014 requirements are the removal of the 2.4 factor test in the maximum calculation and the inclusion of the 1.1 KI factor in the minimum calculation, because the 1.2 × 1.25 from AS/NZS 5033:2021 is numerically equivalent to 1.5 from AS/NZS 5033:2014. This may or may not affect our final fuse size selection.

Definitions of terms
ISC MOD = short circuit current of a PV module or PV string at STC, as specified by the manufacturer in the product specification plate.

IMOD MAX OCPR = PV module maximum overcurrent protection rating as determined by IEC 61730-2. Also referred to as maximum series fuse rating, or maximum reverse current rating, and can be found on the PV module datasheet.

ISC ARRAY = short circuit current of the array at STC. Equal to ISC MOD × SA.

ISC S-ARRAY = short circuit current of the sub-array at STC. Equal to ISC MOD × SSA.

ISTRING MAX = maximum current in a string, dependant on the PV system configuration. Calculated according to AS/NZS 5033:2021 Clause 3.3.3.1.

IDCU string max = DCU maximum overcurrent protection on the DCU string side.

IDCU OCPR = DCU maximum overcurrent protection rating as determined by the DCU manufacturer.

SSA = total number of parallel connected PV strings in the PV sub-array.

SA = total number of parallel connected PV strings in the PV array.

IF STRING = potential fault current in a string from other parallel strings. Calculated according to AS/NZS 5033:2021 Clause 3.3.3.2.

IBF TOTAL = the sum of all backfeed sources of current not originating at the PV modules, such as from PCE/s or other external sources that are directly connected to the array. The inverter backfeed short-circuit current, if present, can be obtained from the inverter manufacturer's installation manual.

More information

Want more information on the AS/NZS 5033:2021 updates? Check out our Deep Dive technical article here, or enrol in our AS/NZS 5033:2021 updates course below.

AS/NZS 5033: 2021 updates courses below
AS/NZS 5033: 2021 update - What you need to know

AS/NZS 5033:2021 UPDATE

GSES Technical Team
Global Sustainable Energy Solutions

AS/NZS 5033:2021 Update – What You Need to Know.

As part of the solar industry, you're probably accustomed to the 2014 version of the standard, which had two amendments published in 2018. In November 2021, this standard was updated to reflect the rapid growth of this industry and provide updated safety practices. Knowledge is power, and these changes could impact your business as you transition over to the new standard.

This standard is now the current version, but installers and designers will need to check with their state regulator to determine if they will be enacting a transition period of six months from the date of publishing as stated within the standard. During the transition period, installers and designers can opt to use AS/NZS 5033:2014 or AS/NZS 5033:2021, but not parts of each. The updated version of the standard can be purchased from Standards Australia, SAI Global or Techstreet.

What's new in the 2021 PV array installation and safety requirements standard?

To start, the 2021 version of this standard is slightly longer than the previous 2014 version at 142 pages compared to 125. Although that may seem tedious to read, the 2021 version has addressed this concern with a more reader friendly and simplified layout. Many of the extra pages come in the form of extended appendices which provide helpful examples and explanations useful for understanding the standard. In addition, several clauses have been removed, rewritten or restructured to reflect this new approach.

Why are these changes necessary? In short, the updated standard aims to tackle key issues which have arisen due to technology changes and shifting industry expectations since the previous version. The most important changes for designers and installers are:

1. Scope of the standard
2. Changes to the rooftop isolator requirements
3. Disconnection points
4. Maximum system voltage
5. PV circuit current calculation
6. Conductor sizing and selection
7. Installation of cables in the ceiling space
8. Other cable and DC isolator installation changes
9. Signage and documentation

These changes impact most PV designers and installers in commercial and residential spaces. Businesses working in the PV sector would also be affected by this standard.

1. Scope of the standard

The scope of the AS/NZS 5033:2021 has broadened. Previously, AS/NZS 5033:2014 did not cover arrays larger than 240 kW (although the general requirements were typically still applied to projects of this size), nor arrays less than 240 W and 50 V in portable equipment.

Clause 1.1 has removed the >240 kW exception and instead states that the standard does not apply to PV arrays on large-scale ground mounted PV power plants with restricted access to personnel and connected to dedicated high voltage systems. However, it is noted that the standard should still be used as guidance in the absence of other standards.

The lower extent of the scope has been reduced so that the standard does not apply to PV arrays less than 100 W and less than 35 V open circuit at STC, but this is no longer limited to portable devices. The standard also does not apply to PV arrays in transportable structures, vehicles and boats.

What this means for you

Designers and installers who work on PV systems larger than 240 kW that are not utility scale solar plants, are now required to comply with the full standard. Most companies in this space would have been already applying the requirements of AS/NZS 5033:2014 to their projects, but the ability to vary commercial- and industrial-scale PV designs based on engineering justification has been removed, except where explicitly permitted by AS/NZS 5033:2021.

Designers and installers involved with PV arrays on transportable structures and vehicles (e.g. campervans, food trucks, demountables, mobile road signs) are no longer required to abide by AS/NZS 5033:2021, but should refer to AS/NZS 3001 instead. Designers and installers involved with PV arrays on boats are no longer required to abide by AS/NZS 5033:2021, but should refer to AS/NZS 3004 instead.

2. Maximum system voltage

Domestic PV systems are growing in demand and size, and the recent update has reflected these changing conditions. Maximum allowable system voltage has persisted at 600 V for domestic dwelling systems since 2014, limiting design choices for designers. The revision of maximum system voltage has provided more design choices and ensured future proofing for the standard going forward. However, the ability to install domestic systems greater than 600 V is not yet able to be implemented due to a conflict with AS/NZS 4777.1:2016.

Updated Clauses:

- Maximum voltage limits (Clause 3.1)
- PV d.c. circuit maximum voltage calculation (Clause 4.2.1.3)

What has changed?

Clause 3.1 has increased the maximum PV array voltage from 600 V.d.c. to 1000 V.d.c. for domestic systems. It has also introduced a 1500 V.d.c. maximum PV array voltage limit for other installations; previously no limit applied. The term "domestic dwelling" has been dropped and replaced by "domestic electrical installation" broadening the application for this standard to a wider range of buildings. As discussed previously, this has provided much needed future proofing and aligned the standard with international standards. Unfortunately, electrical regulators have determined that this change does not override Clause 2.3 in AS/NZS 4777.1:2016, which also specifies a 600 V.d.c. limit for systems in domestic dwellings. Therefore, designers and installers are not able to install systems over 600 V.d.c. in houses, apartment blocks or hotels until AS/NZS 4777.1 is updated or amended.

It is important for designers and installers to note that the PV array maximum voltage (now called maximum voltage of PV d.c. circuits) is still a temperature adjusted voltage, meaning that it is calculated based on the lowest expected operating temperature at the installation site. This is not changed from AS/NZS 5033:2014, but it is a common oversight particularly when documented at the Fire Emergency Information sign.

Clause 4.2.1.3 also updated calculations for the PV array maximum voltage where the array is either partially or fully optimised. AS/NZS 5033:2021 refers to these configurations as "systems containing partial DCUs" and "systems containing DCUs on all modules" respectively, where "DCU" stands for d.c. Conditioning Unit, aka module level power electronics or d.c. optimisers. The PV array maximum voltage is now equal to the maximum DCU voltage output multiplied by the number of DCUs in series, plus the temperature-adjusted maximum voltage of any non-optimised PV modules in the same string. However, the clause also permits calculation of the PV array maximum voltage in accordance with IEC 62548 which may increase design flexibility for fully optimised systems such as SolarEdge. DCU manufacturers will be able to provide specific information on calculations for their products.

3. PV circuit current calculations

The calculation of maximum current in a circuit is critical to the correct sizing of the circuit conductors and any overcurrent protection. AS/NZS 5033:2021 has made major changes to the formulas used for current calculations, but this is primarily re-organisation and clarification rather than substantive alterations to component sizing.

Updated Clauses:

– Calculation of maximum string current (Clause 3.3.3.1)
– Calculation of potential string fault current (Clause 3.3.3.2)
– Calculation of potential sub-array fault current (Clause 3.3.3.3)
– Requirements for overcurrent protection (Clause 3.3.4)
– Nominal overcurrent protection rating calculations (Clause 3.3.5)
– PV d.c. circuit current calculations (Clause 4.4.2)

What has changed?

Rather than basing overcurrent device sizing and cable current carrying capacity directly on ISC_MOD (short circuit current of the PV module) with various other factors, AS/NZS 5033:2021 now defines maximum string current (Clause 3.3.3.1) and potential string/sub-array fault current (Clauses 3.3.3.2 and 3.3.3.3) in terms of ISTRING MAX and bases equipment sizing on these (Clauses 3.3.4, 3.3.5 and 4.4.2).

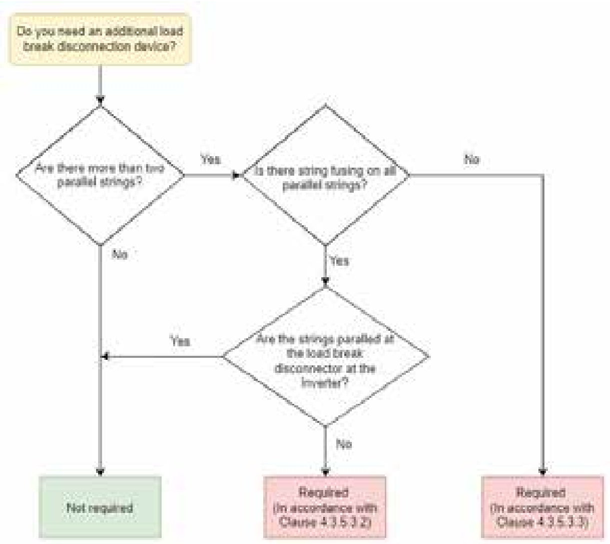
Therefore, although from a brief glance the clauses look different with adjusted notations, the calculated end result should only be different from AS/NZS 5033:2014 if bi-facial modules, DCUs, or inverters with backfeed potential are being used. The addition of a d.c. current rating adjustment factor for bi-facial modules (K_I), detailed in Appendix J, reflects the increased irradiation available to this type of module.

A new term IBF TOTAL has been defined, as the sum of all backfeed sources of current other than the PV modules. When determining whether string overcurrent protection is required, as per Clause 3.3.4.1, the total backfeed current must be added to the potential fault current from the PV strings, prior to checking whether the value is greater than the reverse current rating of the PV module. This change will only affect you if the PV inverter or solar controller you use has a backfeed current. Most grid-connect PV inverters do not have backfeed current, but you will find this in the inverter manual (not datasheet).

Further changes also occurred in Clause 3.3.5 with regards to the maximum current rating for overcurrent protection, with the removal of the redundant 2.4x upper limit. The nominal rating for the overcurrent protection must still be less than or equal to the current carrying capacity of the relevant cable, and if installed at the string level, less than or equal to the reverse current rating of the PV module or DCU.

Designers/installers should be aware that the notations of these formulas have been updated, but the changes will not affect calculations for most system designs.

4. Changes to rooftop D.C. isolator requirements



Rooftop isolators requirement decision flowchart: see Figure 4.2 in AS/NZS 5033:2021

In recent years, it has become apparent that D.C. isolators are a common point of failure in rooftop PV systems. To address this, the requirements for D.C. isolators have been altered to ensure a more appropriate use of isolators when necessary.
The change in D.C. isolator requirement provides more flexibility to designers and installers given appropriate safety measures are taken.

Updated Clauses:

– PV isolation methods (Clause 4.3.3)
– PV isolation methods for systems exceeding 120 V (Clause 4.3.3.1)
– PV Isolation methods for systems not exceeding 120 V (Clause 4.3.3.2)

What has changed?

Installers and designers need to be aware of the adjustments to the clauses to stay compliant and reduce the need for unnecessary components. According to Clause 4.3.3 of the standard, rooftop D.C. isolators are no longer required for all systems. However, installers and designers need to comply with the additional requirements around disconnection points, wiring locations and signage that have been introduced in place of the rooftop isolator requirements.

<u>For systems using microinverters</u>
There are no major changes to isolator requirements. A DC isolator is not required if the inverter and PV module are within 1.5 metres, and the input to the inverter doesn't exceed 120 V. Rooftop AC isolator requirements are specified in AS/NZS 4777.1.

<u>For systems with only 1 or 2 strings in parallel</u>
An isolator (load break disconnection device) is no longer required adjacent to the PV array. It has been replaced with a "disconnection point" (see point 5 below). An isolator is still required adjacent to or integrated with the inverter, with the same sizing requirements as Amendment 2 of AS/NZS 5033:2014.

<u>For systems with more than 2 strings in parallel that have string fusing on every string</u>
A DC isolator (load break disconnection device) is required at the point where the strings are paralleled together. A standard combiner box with integrated fusing and switch disconnector should meet this requirement, providing the devices are appropriately rated.

<u>For systems with more than 2 strings in parallel without string fusing</u>
In this case, a DC isolator is required at the point where the strings are paralleled together, such that when it is turned off, there are no more than 2 strings in parallel. It may be difficult to find an appropriately rated isolator for this situation. In this case an isolator at the inverter is required to be separate to the inverter.

5. Disconnection points

"Disconnection point" is a new term defined in AS/NZS 5033:2021, and is essentially the replacement for rooftop isolators in most situations. It's a form of non-load breaking disconnection and will commonly be implemented as the plug-and-socket connectors that come preinstalled on most PV modules. To comply as a disconnection point, there are a few additional requirements for these connectors (see Clause 4.3.5.2.1). The main changes that will require a change in installation practices are:

- The PV module or structure must be labelled with "WARNING: PV String Disconnection Point" within 300mm of the disconnection point to show the disconnection point's location. (see Figure A.4(d) in AS/NZS 5033:2021)
- The cables of the positive and negative connectors must both be labelled with a sign ""WARNING: LOADS MUST BE ISOLATED AND CIRCUIT MUST BE TESTED FOR ABSENCE OF CURRENT BEFORE UNPLUGGING" and the signs must be within 100 mm of the connectors.
- They must be documented on the PV (Solar) Site Information Sign (see section 9).
- The positive and negative connectors must be located together.
- The connectors must not be more than 150mm from the edge of the PV module that they are installed under.

- They must be readily available i.e. reachable for inspection, maintenance or repairs without needing to dismantle structural parts.
- New considerations for cable installation in the ceiling space (see section 7).

Clause 4.3.3.1 allows for a load break disconnection device to be installed adjacent to the PV modules, in lieu of a disconnection point – i.e. using a rooftop isolator instead of the new disconnection point rules.

Updated Clauses:

– Disconnection point (Clause 1.3.11)
– PV isolation methods (Clause 4.3.3)
– Disconnection point (Clause 4.3.5.2.1)

6. Conductor sizing and selection

Conductor sizing and selection can not only impact the performance and cost of a system but are critical to safe operation of the system. The new standard has amended the previous minimum conductor sizing due to changing industry requirements. Maximum allowable voltage drop has also been updated to allow more flexible system design and installations.

Updated Clauses:

– Selection of cables: General (Clause 4.4.2.1)
– Conductor size (Clause 4.4.2.3)
– Voltage drop (Clause 4.4.2.4)
– Underground cables (Clause 4.4.2.5)
– Earthing or bonding conductor size (4.6.5)

What has changed?

A minimum conductor cross-sectional area of 4 mm2 has been introduced for both PV d.c. cables (compulsory requirement as per Clause 4.4.2.3) and earth conductors (recommendation as per Clause 4.6.5).
Clause 4.6.5 also introduces additional earth conductor sizing considerations based on the type of inverter installed and the nature of the a.c. electrical installation. Designers working with commercial- and industrial-scale systems will need to familiarise themselves with Table 4.6, since it may require substantial upsizing of earth cables relative to the AS/NZS 5033:2014 requirements. For non-separated inverters with powered neutral (i.e. most transformerless inverters), the d.c. earth conductor must be at least as large as the d.c. active conductor, and as per Table 5.1 of AS/NZS 3000 with respect to the inverter a.c. active conductor.

Size of a.c. active conductor (mm2)	Minimum size of d.c. earth conductor (mm2)
Up to and including 10	4
16 and 25	6
35	10
50	16
75 and 95	25
120	35

Designers familiar with Table 4.2 from AS/NZS 5033:2014 will notice a change in notation in AS/NZS 5033:2021; however as mentioned in point 5 above, this will not affect the current carrying capacity calculations for most systems.

Clause 4.4.2.4 has introduced a maximum allowable d.c. voltage drop to a permissible value of 5% for systems greater than 120 V. This does not replace the familiar value of 3% from AS/NZS 5033:2014 – the recommendation of a 3% voltage drop limit has been shifted from Clause 2.1.10 in the 2014 version to Clause 2.2.3 in the 2021 version but retained in full. Designers need to be aware that the 5% limit in Clause 4.4.2.4 is a compulsory requirement (denoted by “shall”) while the 3% limit in Clause 2.2.3 is a recommendation.

In terms of cable specifications, PV d.c. cables must be double insulated where the PV d.c. circuit maximum voltage is above 35V instead of the previous LV requirement. Cables installed in a functionally earthed system or in a system with a non-separated inverter (i.e. most grid connected PV systems) are now explicitly required to have their conductor-to-earth d.c. voltage rating greater than or equal to the PV d.c. circuit maximum voltage. Furthermore, PV1-F compliance is no longer a requirement, instead PV d.c. cables must conform to IEC 62930 if installed above ground and a relevant standard for underground cables if not.

7.Installation of cables in the ceiling space

To accompany the removal of rooftop isolators, there are increased restrictions for where and how PV cables are installed in the ceiling space. These requirements are implemented to reduce the chances of cables collapsing below the ceiling in the event of a ceiling collapse.

Updated Clauses:

– Wiring enclosures for the wiring system (Clause 4.4.5.2)

What are the changes?

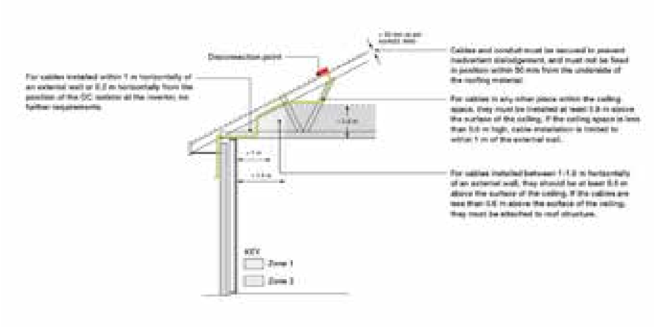
The PV cables are now classified into 4 sections:

- Between the PV modules and the disconnection point
- Between the disconnection point and the load break disconnection device
- Between the load break disconnection device and the inverter
- Between non-adjacent groups of PV modules

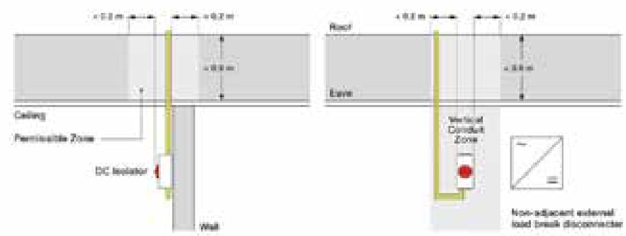
In general, the ceiling space installation requirements for cables between the isolator and inverter have not changed. This means that if a rooftop isolator is installed, installers should not need to make changes to their ceiling space installation practices.

If there is no rooftop isolator, there are increased restrictions on where cables can be installed in the ceiling space. These rules apply to the cable section between the disconnection point and the load break disconnection device (isolator) and between non-adjacent groups of PV modules.

- Cables and conduit must be secured to prevent inadvertent dislodgement, and must not be fixed in position within 50 mm from the underside of the roofing material.
- For cables installed within 1 m horizontally of an external wall or 0.2 m horizontally from the position of the DC isolator at the inverter, no further requirements.
- For cables installed between 1-1.5 m horizontally of an external wall, they should be at least 0.6 m above the surface of the ceiling. If the cables are less than 0.6 m above the surface of the ceiling, they must be attached to roof structure.
- For cables in any other place within the ceiling space, they must be installed at least 0.6 m above the surface of the ceiling. If the ceiling space is less than 0.6 m high, cable installation is limited to within 1 m of the external wall.
- If the roof space is accessible, or the cables are installed in an accessible floor space, signage is required as per point 9.



Example wiring system within 1m and 1.5m of an external wall: see Figure 4.6 in AS/NZS 5033:2021



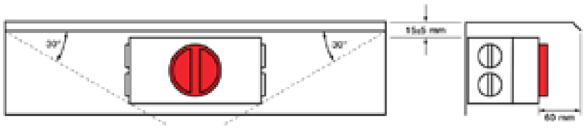
Example wiring system above the load break disconnection device: see Figure 4.5 in AS/NZS 5033:2021

8. Other cable and DC isolator installation changes

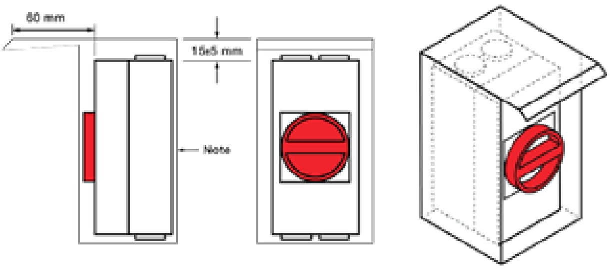
The AS/NZS 5033:2021 update includes a number of new or updated requirements with respect to installation of cables and DC isolators. Notable changes that installers should be aware of include:

– **DC isolator enclosure and mounting.** Clause 4.3.5.3.1 introduces new requirements for load break disconnection devices – these apply to the DC isolator at the inverter as well as the rooftop isolator if one is installed. The isolator must be either mounted on 0.2 mm or thicker metal shroud, inside a 0.2 mm or thicker metal enclosure, or mounted on a non-combustible surface or barrier material that extends at least 200 mm either side. If it has penetrations through a surface that protects against spread of fire, the hole must be sealed with fire retardant sealant. The isolator must also be installed external to the building (this does not include the isolator required at the inverter). See section 4.5.3 for requirements on the isolator at the inverter.

– **Weather protection of DC isolators.** The requirement for isolators to be protected from direct sunlight and weather has been quantified in Clause 4.4.7.3. An imaginary line is drawn at a 30 degree angle from the edge of the roof eaves, balcony edge or shroud, and the isolator must be installed fully within this zone. Appendix K demonstrates these protection requirements for the isolators, and examples of acceptable shrouding can be seen below.



Minimum clearance for a shroud for a horizontally mounted d.c. isolator: see Appendix K2 in AS/NZS 5033:2021



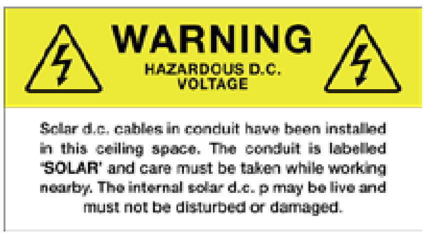
Minimum clearance for a shroud for a vertically mounted d.c. isolator: see Appendix K3 in AS/NZS 5033:2021

- **DC isolator enclosures.** Clause 4.4.6.2 now requires enclosures containing disconnection devices to have pressure equalisation valves fitted into the enclosure or integrated into other equipment within 300 mm. Dedicated individual enclosures must be rated to AS 60947.3, as was the case in Amendment 2 of AS/NZS 5033:2014, but enclosures for assemblies or circuit breakers must now conform to IEC 61439-1 and IEC 61439-2, and be rated to at least IP56 if installed outdoors.
- **Enclosures containing conductor terminations.** Clause 4.4.6 requires enclosures containing conductor terminations to be rated at a minimum of IPXXB and IP2X. If containing conductor terminations and exposed outdoors then the enclosure must be rated at IP55 minimum. Likewise, cable glands exposed to outdoor environments must be IP56 minimum. Note: 'enclosures containing conductor terminations' includes DC isolators but does not include inverters for the purposes of this clause.
- **Entries/exit of enclosures containing conductor terminations.** Clause 4.4.7.2.1 now allows top-entry for the cable between one indoor isolator and an adjacent indoor inverter or another adjacent indoor isolator. This change albeit small provides a bit more flexibility to installers. Clause 4.4.7.2.2 requires cable gland entries or exits in outdoor environments to include a drip loop, and if the entry or exit is from the side face of the enclosure, then the gland must be within a 30 degree area from the edge of the roof eaves, balcony edge or shroud. According to Clause 4.4.7.2.3, if an outdoor conduit section terminates into an enclosure containing conductor terminations, even if the enclosure is indoors, the open ends of the conduit must be sealed with a gland that complies with the outdoor environment requirements (Clause 4.4.7.2.2). If the conduit termination is into an enclosure containing a disconnection device, an IP56 drain device is required at the lowest point of the conduit system. The requirements in these clauses also apply to cable entries into inverters, if the inverter is exposed to weather as per Clause 4.4.7.2.1.
- **Restricted access to PV d.c. cables.** Where PV d.c. cables are installed external to the building, Clause 4.4.5.2.2 requires that they have restricted access, either by being in a restricted access location or by being installed in a wiring enclosure. However, 300 mm of unprotected cable is still permitted at the inverter or DC isolator, and the AS/NZS 5033:2014 limit of 600 V for this exception has now been removed. Installers are permitted to have a maximum of 300 mm of unprotected PV d.c. cable at the inverter or DC isolator as long as the location is not subject to mechanical damage.
- **Lightning protection system (LPS) and surge protection devices (SPDS).** There were also amendments to the lightning protection system. Appendix G3 requires bonding if the structure of the LPS provides protection for the PV array. Adjustments to surge protection minimum specifications are prevalent in Appendix G4, but largely not important for residential installations.

9. Signage and documentation

A variety of adjustments have been made to the signage and documentation section of AS/NZS 5033:2021. The main changes are as follows:

- A new warning sign for solar d.c. cable in accessible roof/floor space was added (Figure A.1).



Warning sign for solar d.c. cables in accessible roof/floor space: see Appendix A1 in AS/NZS 5033:2021

– Clause 5.4 contains new fire and emergency information sign. Previously just a green reflective circle with the letters "PV" sufficed. Now the standard requires additional letters to identify the type of isolation method (microinverters (AC), disconnection point (DP) or load-break disconnection device (SW)) (Figure A.3) and must be placed on or immediately adjacent to the main metering panel and main switchboard. The "AC" denoted sign is only applicable for inverters where the PV d.c. circuit maximum voltage is less than 120 V d.c. at the inverter PV input, and the PV modules are within 1.5m of the inverter.

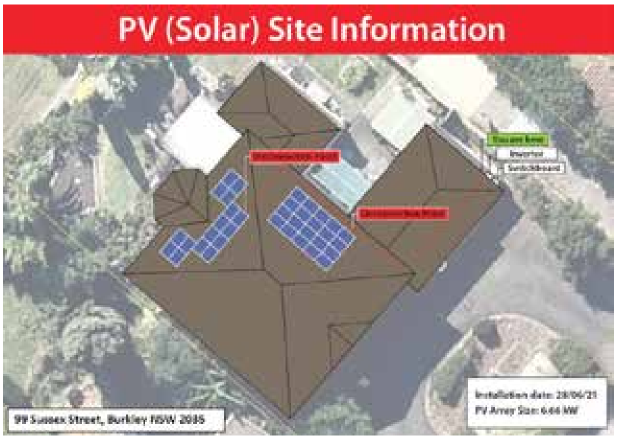
Example of fire and emergency information signs: see Appendix A3 in AS/NZS 5033:2021

– New labelling is required for disconnection points (Figure A.4(c) and A.4(d)). Figure A.4(c) must be placed within 100 mm of the disconnection point on both the positive and negative cable. Figure A.4(d) must be placed within 300mm of the disconnection point and be attached to the PV module or structure.

Disconnection point sign: see Appendix A4(c) in AS/NZS 5033:2021

PV string disconnection point sign: see Appendix A4(d) in AS/NZS 5033:2021

– A new sign at the main switchboard and/or meter box is required to show the solar system layout. This will be a major change for designers/installers, as the details required on the sign are highly site-specific and may thus require a change in workplace procedure in order to finalise the details on the sign prior to installation day (Figure A.5).



Typical solar system layout located at switchboard: see Appendix A5 in AS/NZS 5033:2021

– The system manual is now required to include the disconnection device location and cable routing. Installers will be able to meet this requirement by including a copy of the solar system layout sign in the system manual paperwork.

FAQ

Q: What are the fault loop requirements in AS/NZS 3000 to meet the new DC earth sizing requirements on large roofs?

A: There are a couple of different locations in AS/NZS 3000 and a few different clauses that will have to be abided. The first one is 0.5 Ohm maximum resistance from the earth bar to the furthest module so that was already applicable even under the old version of AS/NZS 5033. In the new version, they specifically called out compliance to AS/NZS 3000 in regards to earthing of the array. That will ensure from a practical perspective that the earth fault loop impedance is low enough that you can trigger your overcurrent protection. So, whether that's a string fuse, if you have string fusing on the DC side of the inverter or your overcurrent protective device on the AC side of the inverter. Requirements as per AS/NZS 5033:2021 are to refer to the inverters AC cable size, given you're using a non-separated inverter. It is only if you have an excessively long or very long distance between your modules to your earth bar that you're likely to have earth fault loop impedance issues, as long as you're following the other requirements as they're written in AS/NZS 5033:2021.

Q: How does the PV site information map layout correlate with multi-storey buildings? Or multiple NMI in the building? So not for a straightforward house?

A: This case really comes down to your best judgement in regards to the specific site. For multi-storey buildings, it can be a matter of having a floor plan that shows specific levels that equipment is installed on. Potentially for a simple site, you could have locations from a plan view and an annotation indicating what level or whether internally or externally the equipment is installed. Priority should be in terms of readability and making sure that anyone who needs that information is able to interpret that easily, accurately and quickly.

Q: Are rooftop AC isolators required for microinverter installations?

A: Microinverters are referred to as PCEs that are within 1.5 m of the module and not more than 120 V input. There are no major changes to AC isolators as they are covered by AS/NZS 4777.1, which has not been updated.

Q: With regards to rooftop isolators, is there a specific guideline for removing isolators from old existing systems that have been blown up or water logged?

A: Would really come under the category of like for like replacement, for dealing with repairs of the system. As long as you're not changing the rating of the system, then that would be falling under like for like replacement. It would definitely be recommended to improve the safety of the system. With modern products, as long as you're not changing the ratings of the system it won't be reclassified as an upgrade.

Q: Can we now remove the rooftop isolators from older systems and what other changes are needed to make the system compliant?

A: You can remove the rooftop isolators but you'll need to make the entire system up to AS/NZS 5033:2021 requirements. So that will include making sure that the cables in the ceiling space meet the 0.6 m and associated rules, making sure your load break isolator at the inverter is mounted on non-combustible material and those similar requirements. So yes, but you then have to upgrade the whole system to AS/NZS 5033:2021. You can't pick and choose parts of each standard to apply.

Q: For inverter integrated DC isolators is there any change to that?

A: So as long as you're familiar with those requirements there aren't any changes there. The utilisation categories requirements remain as DCPV-2, and the environmental conditions that the isolators have to be rated according to are also applicable. So, 40 degrees for internal and external shaded, and 60 degrees for external with temperature effects.

Q: If you're using rooftop isolator, and the restrictions don't apply for running the cables, are the roof access point labels still required?

A: The roof access point label is in clause 4.4.5.2.3, which doesn't apply to the cable between a load break isolator and the inverter, so it would not be required by AS/NZS 5033:2021 if you're using a rooftop isolator.

Q: Do DC isolators at the inverter need to be on a non-combustible material? Does that mean the inverter itself with inbuilt DC isolators need to be installed also in a non-combustible material?

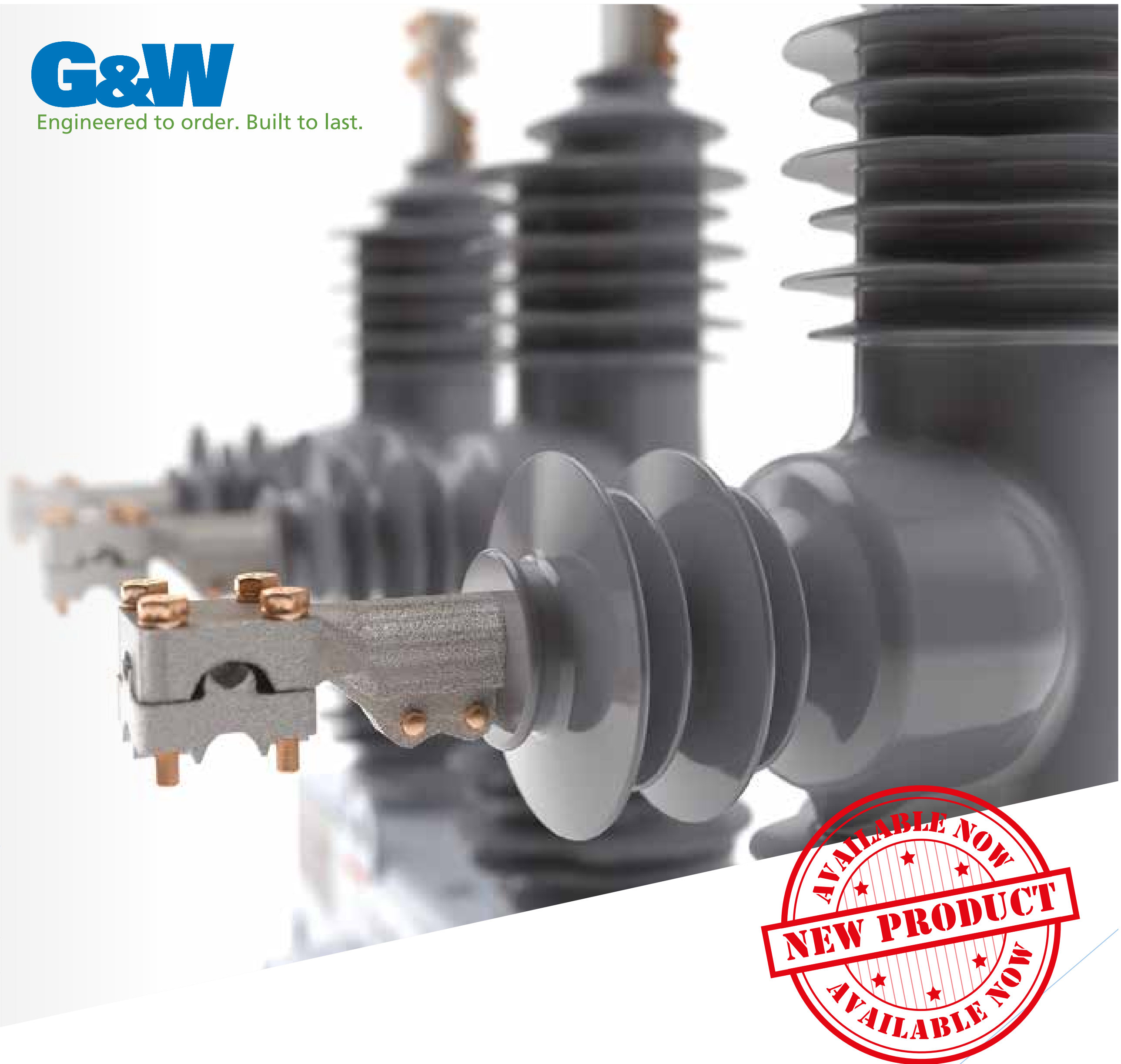
A: The list of materials that an inverter adjacent isolator can be installed upon that does specifically refer to physically separate and adjacent isolators. So Clause 4.5.4.1 would not apply to inverter-integrated isolators.

Q: Mounting isolator at a 30-degree angle can be an issue because some houses have very small soffits, which means the mounting isolators behind the wall. What are the shroud requirements for the isolator?

A: One thing to consider is that if you install the isolator against the side of a PV module, that is effectively shading that side of the isolator. The shroud would then extend to the side that the module is not on and doesn't need to extend as far on the module side. As far as the size of eaves, assuming that you could then actually install some sort of shroud in a situation where you don't want to be installing and high up under an eave. It guards 200 mm on either side. The other option is a shroud that actually has walls that encloses the isolator rather than just having that single plane across the top and there are some products that that will satisfy that requirement.

Q: Does each microinverter that is attached to a panel over a 350 watt require a separate disconnection point between the panel and the micro inverter?

A: The requirement is for microinverters that they have disconnection device, but not a disconnection point. There is no longer a 350 W limit for the microinverter input. The requirement for a disconnection point, including the positive and negative conductors together, not more than 150 mm, from the inverter, and so on. Those would not apply in that case. The disconnection device requirements for the microinverter would be covered entirely by your standard connector between your microinverter and your PV module.



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ELECTRATHERM HEAT TO POWER TECHNOLOGY – POWER MODULE PM75

David Knight,
Business Development Analyst, ElectraTherm Inc

ElectraTherm announce the release of their latest ORC (Organic Rankine Cycle) offering, the Power Module PM75.

The Power Module PM75 is a compact modular ORC incorporating the commercially proven BITZER semi-hermetic expander.

ElectraTherm's research and development program is focussed on the continued improvement of their ORC technology, to provide increased performance in a robust proven design. The Power Module PM75 is an advanced development of the previous Power+4400B ORC which has now been discontinued.

The improvements in the new design include a refined working fluid circuit, redesign of the electrical panels and an improved control system. These changes have resulted in a reduction in the overall dimensions and weight of the unit.

The generating capacity of the Power Module PM75 is 20–75 kWe with hot water heat input of 770C to 1320C. Overall dimensions are width 1829mm, length 2413mm and height 2159mm and the weighs 2591 kgs.

The supply of the Power Module PM75 can be as a stand-alone unit, supplied with an integrated cooling package or mounted on a robust skid.

The Power Module PM75 continues with the standard ElectraTherm features including;

- Ease of Installation
- Low Maintenance
- Semi-Hermetic Twin Screw Expander Power Module incorporating a 75kWe Induction Generator
- CE Certified
- Automated control system programmed to maximise outputs against heat input and condensing water temperatures.
- Modular and Scalable
- Base Load Renewable Power where heat input is waste heat or provided from a non-fossil fuel source.

The Pathway to Nett Zero 2050

The pathway to achieving nett zero by 2050 can only be achieved by utilizing all available technologies for the generation of renewable energy.

These technologies include;

- o Solar and Wind Power Generation
- o Battery storage systems
- o Energy Efficiency
- o Biomass and Biogas Systems
- o Waste Heat to Power Generation using ElectraTherm ORC Technologies
- o Geothermal resources
- o Next Generation Fuels such as hydrogen and ammonia fuels.

For the Pacific Island Nations, internal combustion engines, whilst supported by solar/wind and battery technologies, will remain an important component of base load power generation for a significant period in the future. This will be especially true as electricity usage in the islands continues to increase.

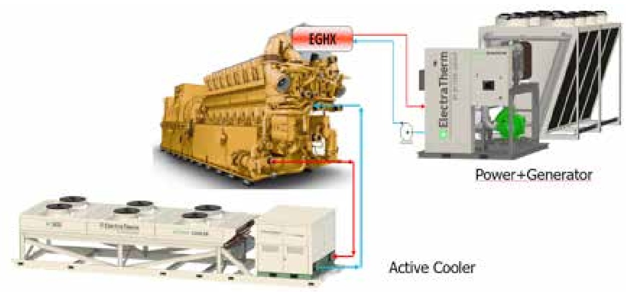
As diesel, and in some locations natural gas, remain the primary fuel source for these engines it is imperative for both economic and environmental reasons to incorporate technologies that improve the efficiency of power generation. Apart from the installation of newer and more efficient engines the recovery and use of waste heat remains the primary opportunity to achieve improvements in power generation.

When next generation fuels become available, power generation efficiency will remain an important economic consideration due to the expected increased cost of these fuels. As a result, ORC systems installed now will remain relevant with the new fuels, and therefore will not become a stranded asset.

ElectraTherm Energy Efficiency Solutions

ElectraTherm ORC Solutions have been specifically designed to utilise the waste heat from internal combustion engines to generate additional electricity from the same fuel input.

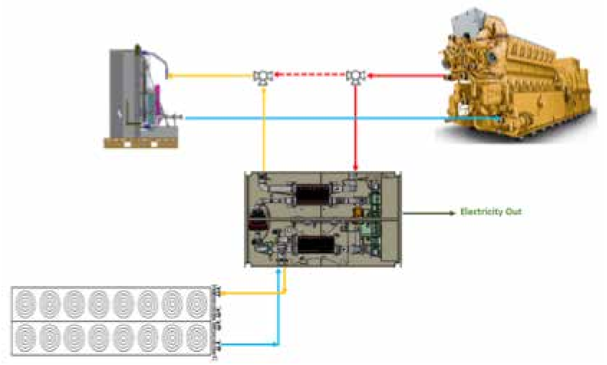
Examples of the use of waste heat from the engine include the Power+6500B+/Power Module PM75 to utilise the high temperature waste heat from the engine exhaust



and the next generation Active Cooler system using waste heat from the jacket water to provide electrical power for the operation of the engine cooling system.

For larger capacity engines the Power Module PM75 can also be installed as an additional cooling component on the jacket water cooling system using the heat contained within the engine jacket water to generate renewable electricity.

The incorporation of the Power Module PM75 will also alleviate part of the cooling load on the existing radiator system improving cooling efficiency and reducing the sacrificial power requirements of the existing radiator.



The ElectraTherm ORC solutions are also suitable for alternative power generation sources include both primary and waste heat from small to medium sized biomass, biogas, waste to energy and geothermal resources. Innovative solutions can also include combining the ElectraTherm ORC with a heat storage to provide power demand load shifting.

ElectraTherm Pacific Commitment

Despite the disruptions of the past couple of years, due to Covid 19, ElectraTherm's commitment to the Pacific has remained unchanged. Our commitment includes

- Continuing to work with the power authorities in the development of innovative heat to power generation solutions and the preparation of documentation to access project finance
- Providing training of local staff in the operation and maintenance of ORC technology,
- Providing continuing support through online assistance and technology upgrades, and
- An ongoing commitment to stay and support all PPA members for the future development of energy efficient systems.

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STORAGE
SOLUTIONS

PLUG & PLAY

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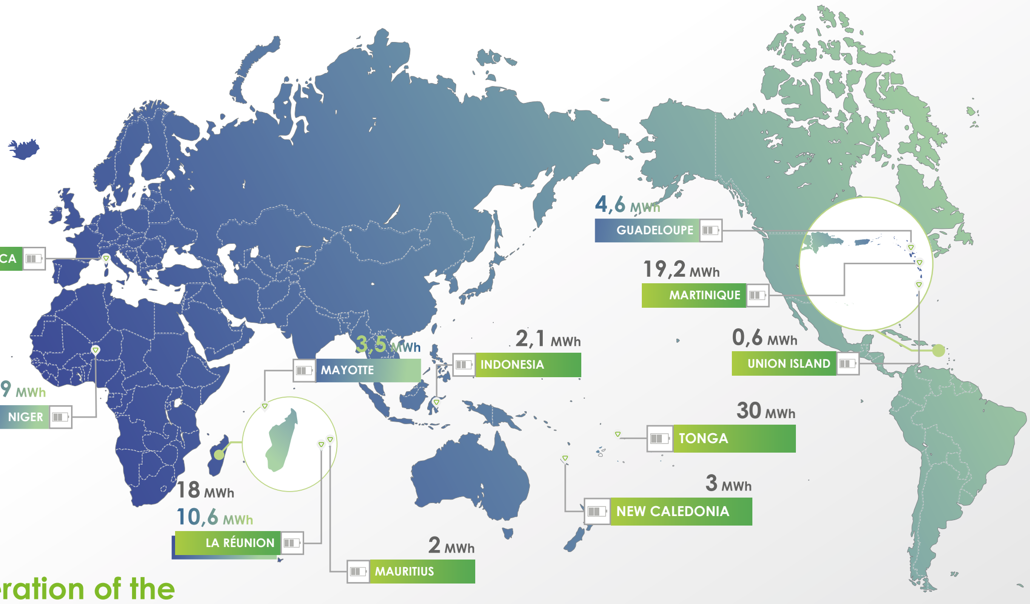
A strong track-record

80 MWh
In operation

22 MWh
Under construction



In operation   Under construction

Akuo successfully started operation of the largest battery storage projects in the South Pacific totaling 30 MWh in Tonga in the end of 2021!

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PROTECTING BLIND SPOTS ON DISTRIBUTION NETWORKS

Goran Stojadinovic, MCE, MEE
Product and Innovation Manager - Transnet NZ Limited

Background

- Historically, many Pacific nations have been almost entirely dependent on diesel generation
- Over the last decade, there was a steady uptake of solar energy and other renewable generation in the Pacific, bringing tangible benefits to the communities and distribution networks
- However, the high uptake and integration of Distributed Generation (DG) is starting to make notable impacts on the protection systems of distribution networks
- It significantly changes the electrical parameters of the distribution system and affects the protection, raising many challenges and questions on how a fault should be detected and isolated
- It creates serious problems like decreased fault level, blind spots, and false tripping
- In many cases, protection relays can not cope with these network changes, which can result in decreased reliability, increased SAIDI, and potential safety issues

Effects of DG on Protection Systems

High uptake of distributed generation can reduce the fault level.
Any changes in the fault current level at any point within a distribution feeder can affect its protection as follows [Ref.1]:

- Reverse power flow
- False tripping
- Blind areas e.g. spots on a feeder that protection can not 'see'
- Islanding
- Not synchronised reclosing
- Loss of main power

In addition, there could be some grounding problems due to more than one ground current path.

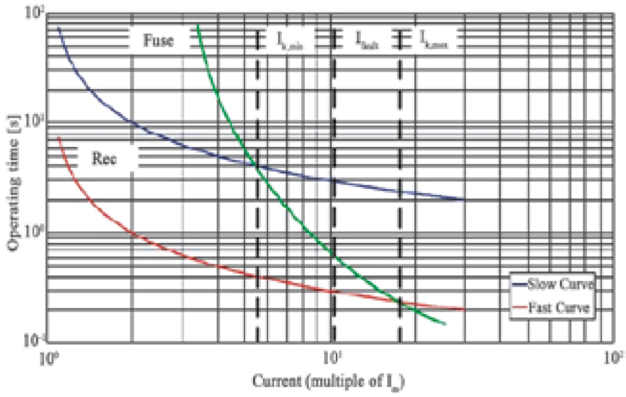
Effects of DG on Protection of Radial Networks

Integrated DG presents an even bigger challenge for radial networks.

In a Radial Network – it is critical that the Recloser-Fuse Coordination is accurate. [Ref. 2]

Fig. 1 Fuse-recloser coordination curves.

At the instant of fault current - the fuse should operate after the recloser's "fast curve" and before the recloser's "slow curve" [Ref. 2 – Fig.10]



However, when a DG is connected to a radial distribution feeder, the fuse-recloser coordination is lost:

- The fuse may "see" more fault current, as compared to recloser
- The fuse will then operate before the recloser operates
- It may result in false tripping i.e. tripping on a transient (temporary) fault, instead on a permanent fault only
- Recloser will have no chance to clear a transient fault
- This will in turn affect the overall reliability of the feeder

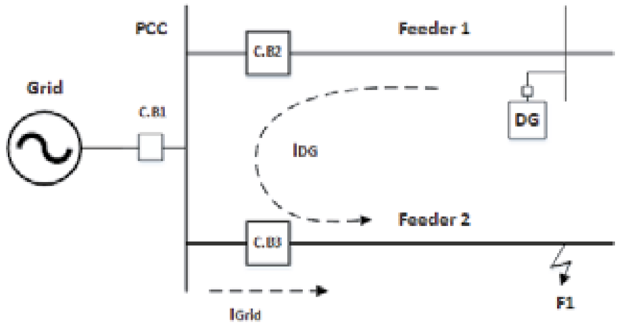
Root Cause of the Problem

The traditional protection coordination of a radial feeder is based on the premise that the network is passive e.g. it contains only loads.

However, the integration of DG in the distribution network introduces the Bi-directional power ow e.g. it is now an active network [Ref. 3].

- It directly affects the coordination of protection system e.g. between reclosers, protection OC relays (over- current relays), and fuses
- It creates blind spots for the protection, for example, if there is a fault on the feeder adjacent to the feeder with DG
- It decreases the stability and reliability of the network performance
- Therefore, it requires a change in the network topology and the protection system arrangements, which could be quite complex, tedious, and very expensive process.

Fig. 2
An example of possible false tripping due to a fault on another feeder [Ref. 3 – Fig.1]



Potential Solutions

- There are many potential solutions to this problem that are proposed in [Ref. 1–4] and other sources:
- Adaptive protection schemes
- Increasing sensitivity of over-current relays
- Improving coordination
- Protection of inverter-interfaced DG units
- Differential protection using communication
- A balanced combination of various types of DG sources
- Symmetrical and differential current components
- Fault Current Limiters
- Centralized protection
- Rate of voltage change
- Artificial Intelligence, etc...

However, most of the above solutions have one or more drawbacks, as follows:

- Can be very complex and/or complicated (e.g. difficult to implement)
- Require additional equipment and significant investment
- Require perfect coordination between protection relays and reclosers
- Require comprehensive study and analysis of network impedances and other parameters
- Too expensive
- In many cases, these techniques do not significantly improve the problem of blind spots, while they can compromise other critical parameters and make protection too sophisticated, very sensitive to further network changes and upgrades, and difficult to maintain

Recommended Solutions

The Pacific Island distribution networks are relatively small and less complex than in NZ or Australia. In many cases, the above solutions are too complex, complicated, and not very affordable.
Any solution to this problem with protection schemes in the Pacific Island networks should be:

- Affordable
- Relatively simply to implement
- Maintenance free or with reduced maintenance
- Should maximise the use of existing resources and equipment (if already there)
- Any additional investment should be minimal, however, it should be based on proven and reliable brands

Therefore, one of the best solutions for the Pacific distbution networks is potentially what is already there, or with minimal additional investment.

In fact:

- In most cases, the modern Reclosers can be successfully used to cover the blind spots and improve protection in distribution networks with DGs
- It could be one of the most effective and affordable solutions to the problem of blind spots, as demonstrated in the following study

Recommended Solution (cont.)

A comprehensive case study has been conducted based on a real power system and simulating real-case scenarios in DIGSILENT software [Ref. 5]. The research aimed to avoid blind areas and improve the reliability of the distribution network.
It has been demonstrated that a recloser with proper settings and if put in an optimal point along a feeder can cover the blind spots and improve protection.
This solution is based on the simple fact that a modern recloser is faster than over-current relays.

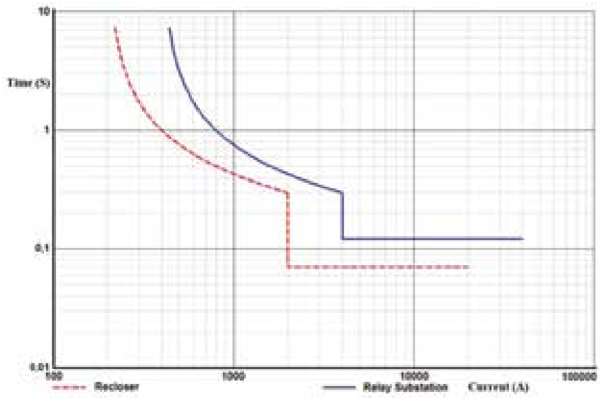


Fig. 3
Comparison of over-current relay characteristic curves of substation 20 kV feeder and recloser relays. [Ref. 5 – Fig. 3]

Recommended Solution – Technical Considerations

The key functions of any Recloser are to provide over-current protection and reliability. Reclosers detect over-current and break the fault current. They should eliminate temporary faults with their "trip & reclose" capability.
In a conventional radial feeder, reclosers are only expected to detect the unidirectional fow of current.

However, with the addition of DG in radial feeders, the fault point impedance changes and it is important to place a Recloser in an optimal location and adjust its settings.
The results of the study show that: [Ref. 5]

- The operating time of the protective relay increases with the fault point impedance, which forces the OC relay to go into a blind area
- On the other hand - the recloser curve setting closes faster than the feeder OC relay curve, so the recloser operates faster than the OC relay
- Therefore, the recloser protects the blind areas that OC relays can't see
- Moreover, the recloser improves the reliability of the feeder by reducing the total outage to approx. half

Further details can be found in the study [Ref. 5].

Selecting the Right Recloser

There are several types of reclosers from different manufacturers. Most of them are classical reclosers. Most of them are very good, but they are made for bigger and more complex distribution networks to be integrated with SCADA or some automation schemes that also include conventional sectionalisers.

Fig. 4 - Teros

However, they are probably a "technology overkill" for radial feeders in the Paci c distribution networks in terms of what is required and pricing.
After a careful investigation and comparison of various reclosers, it seems that one of them stands out. It fits both basic requirements for the Pacific distribution networks:

- Excellent technical characteristics and capabilities, and
- Economic value (e.g. best value for money)

The name of that recloser is: **Teros** (by G&W Electric)
It is a new recloser on the market from a reputable manufacturer and it could be a perfect solution for the Pacific distribution networks with DG (Distributed Generation like solar and wind), as follows.

Introducing Teros

Features and Benefits

- Durability and Maintenance free construction - The simple lightweight mechanism, highly reliable, and maintenance-free with a minimum of operating components and no operating electronics
- Smart Grid Automation ready - Can be site ready for distribution automation applications with the integration of 6 voltage sensors as a standard offering (e.g. ready for any future automation need)
- Protection from environmental damage - As a standard, it has higher creepage modules and a sealed mechanism that significantly reduces the potential of damage from the adverse environmental conditions throughout its service life
- Easy-access control system - It provides easy access to all the electronic components inside the control versus in the recloser mechanism
- Transparent cover for mechanism visibility - the viewing window on the mechanism cover allows for clear visibility of the position indicator from a safe distance at the bottom of the pole
- Modular controls - Simple, modular layout of control components allows for quick disconnecting and reconnecting of components without removal of other/unrelated devices
- Highest level of reliability at a minimum cost - developed and made by G&W Electric, the North American industry leader in reclosers

Teros Offers the Best Economic Value

A successful distribution company must balance its investment in the distribution network with system reliability and customer satisfaction. There is a sweet spot (i.e. optimal cost) in the "Cost vs System Reliability" graph of any distribution company. It is the point at which investment provides the optimal balance of costs and benefits.
For optimal investment in the protection of a radial feeder, and assuming a uniformly distributed load - it is recommended that a recloser is installed halfway of the feeder [Ref. 5]. This would result in approx. 50% reliability improvement to customers upstream from the recloser.
Similarly, if two reclosers are installed, they should be placed at 1/3 and 2/3 of the feeder length for the optimal investment.

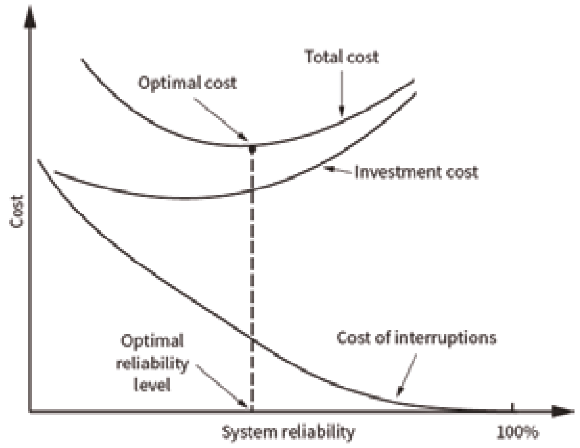


Fig. 5 Cost versus system reliability [Ref. 5 – Fig. 8]

This balance is not easy if not impossible to achieve with most reclosers on the market, especially with two reclosers. However, Teros can meet this economic factor. it is currently the most economical recloser on the market that offers equally good or even better performance than its bigger brothers at an affordable price. In other words – Teros can provide the highest level of reliability at a minimum cost.

Tonga Power – Case Study

Tonga Power Limited (TPL) has a generating capacity that consists of 13.8 MW of diesel, 6.3 MW of solar, and 1.375 MW of wind. In approx. 2 months' time solar would be 10.3 MW excluding the small distributed generation (rooftop solar). This presents a significant uptake of DG.
The TPL's OH distribution network has approx. 200 km of 11kV lines, 250 km of 6.6 kV, and 600 km of LV.
TPL is fully aware of potential issues with the high uptake of solar and wind in their distribution network, including blind spots for feeder protection. They also have challenges like adverse environments i.e. sea spray, vegetation, and seasonal storms that badly affect the reliability of the already stressed network.
TPL was looking for a cost-effective and reliable solution. After a careful investigation, they took a whole new approach to the protection of blind spots in their network.
TPL is now in the process of implementing a new protection scheme in parts of their distribution network that are interconnected with DG (solar and wind), as follows:

- A complete review, re-modeling, and update of the network topology and protection schemes in these areas
- Introduction of three (3) Teros reclosers
- Introduction of eighteen (18) sets of Smart FID (Smart Fault Isolation Device) to replace old EDOs

Why Teros (recloser) and FID (sectionaliser)?

As discussed, the key to any successful protection is the accurate coordination between reclosers and fuses.
Reclosers have evolved to very sophisticated modern switching devices and are becoming more affordable. However, there are still a lot of old-style fuses (EDOs, thermal devices) in distribution networks, and it is very dif cult to create good coordination between them, OC relays, and modern reclosers, especially in predominantly radial distribution networks with integrated DG.
To maximize the utilization of the new Recloser, it will need downstream some smart fuses or sectionalisers that can work in sync with the recloser, and also recognize and differentiate between permanent and transient faults.
For that reason, TPL has decided to complement their three (3) new Teros reclosers with eighteen (18) sets of FID devices. FIDs coordinate with upstream reclosers and have many other advanced features as follows:

- Can act as a sectionaliser or as a stand-alone device (fuse)
- Can be retro tted to existing EDO brackets
- All three phases will open simultaneously
- It is an electronic device, so there is no arcing, etc.

Teros' and SFIDs will be installed in strategic points on feeders with DG (solar and wind) to cover blind spots. FID smart fuses will act as sectionaliser to create an ef cient and affordable protection scheme.
Note: More details about Teros and FID can be found here https://tinyurl.com/25uupdut or from the Author of this article.

Conclusions

In this paper, a Recloser was proposed as the means to avoid blind spots for protection due to Distributed Generation connected to distribution networks with radial feeders.
In most cases, a modern Recloser can successfully solve this problem:

- It must be con gured appropriately
- It must be placed at the right location on the feeder
- To maximise the bene ts, it should be also supported by smart downstream fuses and/or sectionalisers
- It should also provide the highest level of reliability at a minimum cost

This approach is suitable for the Pacific distribution networks with radial feeders.
It is also highly relevant and can be adopted by New Zealand and Australian distribution companies. They are facing the same problem of blind spots for protection due to the high penetration of DG.

"What new technology does is create new opportunities to do a job that customers want done."

Tim O'Reilly (O'Reilly Media)

FUNAOTA STAND-ALONE SOLAR HOME (SASH) SYSTEMS TO SAVE 14KG OF CARBON DIOXIDE ANNUALLY.

Mafalu Lotolua
General Manager, Tuvalu Electricity Corporation

The Tuvalu Electricity Corporation (TEC) has been on a mission to show the world that although Tuvalu's emission is very negligible, while the rising tides situation is threatening to take our homes, TEC still hopes to lead by example and show the world that Tuvalu is doing its best to further reduce greenhouse (GHG) emissions by promoting renewable energy and energy efficiency (RE/EE) technology applications.

Solar PV System

Today, Tuvalu has commissioned its Stand-Alone Solar Home System (SASH) project, a project that aims to reduce the reliance on fossil fuel for electricity generation of Funaota islet, thus reducing greenhouse gases (GHG) emission. Funaota, an islet of Nukufetau was dedicated by the Nukufetau Falekaupule (Council) to help develop business ventures on the islet.

The project is providing 24/7 electricity using an enhanced storage battery system to three households which includes: (i) the dormitory to house the workers and also provide power supply to the Manager's residence; (ii) coconut oil processing plant that house processing machineries; and (iii) the piggery to provide electricity to operate electrical equipment for the piggery. The project also provides Very High Frequency (VHF) radio for a communication link between the islands of Savave and Funaota.

According to TEC calculation, the SASH project would save about 14 kilograms of carbon dioxide yearly from the 7kW systems installed at Funaota Islet.

At the commissioning of the project, TEC and the Nukufetau Kaupule signed a one-year Memorandum of Understanding (MoU) to ensure that both parties understand their roles in the safe keeping of the project. The MoU will expire on 18 July, 2022. After the expiration date, the project will be handed over to the Nukufetau Kaupule for operation and maintenance. TEC will continue to standby to offer their service when needed.

At the commissioning ceremony of the SASH project, the Pule Kaupule (Island Leader) emphasized the importance of Action. "Tuvalu is truly grateful to all the donors for the support to ensure Tuvalu achieves its RE and EE goal nationally and globally".

The project has been made possible through the India-UN Development Partnership Fund – Commonwealth Window, which has provided financial assistance of USD214K to the Government of Tuvalu. The UNDP/GEF-funded FASNETT Project as a village RE/EE demonstration technology also supported the project's energy storage and communication systems. The support from India-UN Development Fund and the partial support from GEF funded FASNETT Project was made possible by the excellent support provided by UNDP Pacific Office, Suva, Fiji.

Portable Generator – to charge the batteries

Generator

Protection Circuit

HF Radio System

Radio System

MoU Signed

For more information please contact:
Mafalu Lotolua, General Manager-TEC,
Tel: (688) 20352/20357; email: mafaluloto2@gmail.com

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THE FIVE MOST COMMON USES FOR A NOJA POWER OSM RECLOSER

Martin Van Der Linde
General Manager - Marketing, Noja Power

16 August 2022 –With over 85,000 installations in more than 104 countries worldwide, the OSM Recloser has been used as the key protection and control device for the medium voltage distribution network in many different applications.

The core benefit of this unit is it prevents 80% of overhead distribution outages.

The popularity of this primary plant is enabled by the long feature set of the standard product, enabled by the RC controller that is bundled with the switchgear. The NOJA Power RC10, RC15 or RC20 controllers have an extensive feature set, and this enables the equipment to be configured for many different applications.

Here we share some of the most common applications for the equipment in the electricity distribution network:

1. Overhead Lines Protection
2. Renewable Energy Connection
3. Sectionalising Applications
4. Protecting Underground Cables
5. Connecting Three Phase Mining Equipment

1 - Overhead Lines Protection

This is the core, original application of Reclosers, and it is the most common application for the equipment today. Power systems' research says 80% of overhead network faults are transient. This implies they only exist for a short period of time.

A NOJA Power OSM Recloser protecting Overhead Lines

Practically speaking, these sorts of faults include vegetation or wildlife coming into contact with overhead powerlines, causing a short circuit. 80% of these faults will "self-clear". That is, the branch or fauna will fall off the line after the first short circuit.

Without reclosers, the protection circuit breaker upstream would simply trip to open, protecting the network. However, then most faults then cause extended outages for customers, even though the fault is long gone. Reclosers detect the faults and reclose, to mitigate the 80% of momentary faults, and advanced ones like the OSM Recloser, can determine the fault type and respond in a safe way.

NOJA Power's OSM Recloser can detect most faults on the network and allow for configurable reclosing based on the kind of fault that is present on the network. That way, you get a balance of safety and reliability.

Installing a NOJA Power OSM Recloser allows you to remove 80% of faults leading to outages, saving you a fortune in lost revenue and reliability penalties.

"Installing reclosers on overhead medium voltage feeders eliminates 80% of the faults on those feeders," reports NOJA Power Group Managing Director Neil O'Sullivan, "and increases network reliability far more than any other smart grid solution will. Smart Grid Automation ready devices like our OSM reclosers can also help reduce that last 20% as well."

2 - Renewable Energy Connection

A NOJA Power OSM Recloser connecting Renewable Generation Energy to the Distribution Grid

Connecting renewable generation to the distribution grid has its own challenges. Most electricity distribution networks were originally designed to take electricity from generators via the transmission grid (the big towers), and distribute it to all the lower voltage customers, where it would be stepped down to residential and commercial voltages for consumption.

Today, the electricity industry is transitioning at a very high rate to using large volumes of renewable and distributed generation. In Queensland Australia, there is more than 2000 MW of Solar power generation on rooftops alone, where an average winter day the demand is around 7000 MW { https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/data-dashboard-nem }. Some nations are even running on 100% renewables today.

The challenge with renewables is they behave differently to centralized power plants, and the projects are commonly connected at the distribution network, instead of the transmission network. Accordingly, these connections need special protection, control and metering. NOJA Power OSM Reclosers are commonly used as the grid connection point for renewable energy such as solar and wind, as the product includes most of the technical control requirements for this distributed generation connection.

The reason NOJA Power OSM Reclosers are used for this application is that the standard product includes ROCOF and VVS protection. Therefore, most engineering businesses that are building these projects can be compliant with utility requirements to connect the renewable energy to the distribution grid. Also, with all connection requirements in a single switchgear device, this saves a fortune in site engineering works.

Some of these sites also call for revenue metering or additional protection. Typically, these applications then use a NOJA Power GMK which is an OSM. Recloser in a pad mounted kiosk. This kiosk allows engineers to custom add features such as revenue metering, advanced power quality metering or an earth switch, to meet the operational, grid connection or bespoke project requirements in a single integrated product.

3 - Sectionalising Applications

A sectionaliser is an automatic switch that opens when the power lines are not energized to isolate faulted sections.

Typically, they are used to break up distribution lines into sections (that is, feeder “sectionalization”, hence the name). When a fault occurs, the protection recloser or substation breaker opens, and all the devices along the line will see a loss of voltage.

Devices that saw high current followed by a loss of voltage are clearly “upstream” of the fault. They can then open while the upstream device is open, and when it recloses, the fault is then “isolated”. This gives major reliability benefits to utilities, as the outage area is minimized. Furthermore, there are almost zero constraints on how many sectionalisers you can install on a network – they act on loss of voltage and accordingly suffer much less grading issues.

Many years ago, there used to be a major price difference between a Pole Mounted Sectionalisers and Pole Mounted Reclosers. This is no longer true for modern devices of those classes. Likewise, since a sectionaliser is a Recloser that waits for the lines to be dead to operate, it is easy for NOJA Power OSM Reclosers to be configured to act this way.

There are two main reasons for this:

1. You can install more reclosers and sectionalisers on your lines, breaking up the network into smaller zones and providing better reliability in each of those zones. Outages affect smaller and smaller groups, the more reclosers and sectionalisers you have on your network

2. Standardization. If a recloser, such as the OSM Recloser, can fulfil both roles, utilities can standardize on installation, warehousing, parts, training, and a whole host of scale advantages. The upfront cost is offset by the extensive savings in operational expenses.

4 – Protecting Underground Cables

Whilst underground cables do not have the same momentary fault profile as overhead lines, they still need protection. Fundamentally, protection for underground cable still needs a circuit breaker, sensors to detect faults, and protection relays to take the signals and actuate the circuit breaker.

Accordingly, the NOJA Power GMK was invented to bring the overhead protection capabilities to the underground domain.

There are 2 main variants of this product, a simple compact version (the 1000 series) and a fully customizable system with type tested Internal Arc Classification.

Aside from renewable generation applications, these units have been used on mines, underground cable protection and railway power supply environments. They use the same standard equipment as the overhead unit. This gives the equipment economies of scale, providing a flexible off-the-shelf product that solves most of these applications.

5 - Connecting Three Phase Mining Equipment

A common application in the resources sector for electrical engineering, heavy mining machinery that connects at the medium voltage level also requires connection control and protection. Accordingly, there are many successful use cases of NOJA Power OSM Reclosers in Mining applications.

These units often require specialist Sensitive Earth Fault Protection at 500mA, a unique capability of NOJA Power's OSM Recloser with SEF option. Accordingly, electrical engineers in the mining sector can use the NOJA Power OSM Recloser as a system to protect their mining equipment.

Welcome!

New Allied Member

One new Company has joined PPA as an Allied Member since our last PPA Magazine. The new member is:

LONGI AUSTRALIA: LONGI Australia is based in Sydney, Australia. Their primary activity is wind renewable energy systems.


AvK