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MASTER'S DEGREE IN ELECTRICAL ENGINEERING



HIGH VOLTAGE SUBSTATION REVAMPING FOR RENEWABLE POWER GENERATION CONNECTION WITH BESS AND SMART GRID CAPABILITIES

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Abstract

For decades, our civilization relied on a power grid built for a world that no longer exists, a one-way system supplying massive factories. Today, as we strive to build a sustainable and resilient society, this aging infrastructure is the critical hurdle. The true test of the global energy transition is how we transform these old nodes into intelligent, two-way highways for clean power.

This thesis presents a model for this necessary change, documenting the complete revamping of a historic 132 kV substation. The substation, which once served a single factory, is being entirely modernized to connect a large-scale, distant solar power plant, to the main grid.

Operating at the interface of a third-party developed generation site, this project focuses on the engineering and modernization of the step-up substation. The innovation is the integration of a Battery Energy Storage System (BESS). Notably, the design is engineered with a forward-looking modularity to accommodate the future integration of BESS. This battery acts as a crucial buffer, managing the natural unpredictability of solar energy storing power when the sun is brightest and releasing it when the grid needs it most. Every component, from cables to circuit breakers, is being upgraded to create an intelligent, smart grid connection point capable of managing this complex, bidirectional flow of energy with digital precision. The result is a system that not only supports renewable energy but also guarantees a stable, reliable power supply for thousands of homes and businesses.

A core technical contribution of this work is the rigorous sizing and selection of substation switchgear, underpinned by detailed short-circuit current analysis to ensure system protection under fault conditions. Furthermore, the study optimizes the Medium Voltage (MV) underground cabling network, providing the critical infrastructure required to transport power from the PV farm's boundary to the substation.

This thesis addresses the critical infrastructure modernization required for the European energy transition, focusing specifically on the technical execution of a high-voltage (HV) substation revamping project. The study on a 132 kV substation that must be upgraded to accommodate a major advancement: The core objective is to transition the traditional substation into a responsive node within the modern electrical network, characterized by advanced monitoring, control, and communication capabilities a key feature of the Smart Grid. The project encompasses HV/MV component specification, system integration of energy storage and

generation assets, and the implementation of a comprehensive protection and control (P&C) philosophy compliant with both national (Italian) and international standards.

Keywords: Substation Revamping, Switchgear Sizing, Photovoltaic Plant, MV Underground Cables, Short-Circuit Analysis, BESS, Smart Grid.

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Expected results

A key outcome of this research is the high-fidelity validation of the substation's physical and electrical architecture through industry-standard simulation tools. By utilizing Ampère Software, the study will produce precise short-circuit current profiles at the busbars. These simulations will define the required asymmetrical and symmetrical breaking capacities, ensuring that the selected HV and MV switchgear are sized to withstand worst-case fault scenarios without catastrophic failure. Simultaneously, the design of the Underground MV cabling network stretching from the 96 MW PV farm boundary to the step-up transformer is optimized using Cableizer Software. This ensures that the cable types and cross-sections are not only selected for peak load ampacity but are also thermally modeled to account for soil resistivity and grouping effects. The result is a mathematically verified infrastructure that minimizes technical losses while maximizing the lifespan of the interconnection assets.

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1. Renewable Energy Policies (EU & IT)

1.1 The European Legislative Framework for Decarbonisation

The modernisation of high-voltage substations is directly driven by the European Union's binding climate and energy legislation. The European Climate Law establishes the legal foundation: climate neutrality by 2050 and a minimum 55% reduction in net greenhouse gas emissions by 2030 relative to 1990 levels. The 'Fit for 55' package operationalises this commitment across all economic sectors, requiring the power grid to accommodate a fundamental transition from centralised, programmable generation to distributed, intermittent renewable sources.

The third Renewable Energy Directive (RED III) translates these climate targets into binding capacity obligations. At least 42.5% of the EU's gross final energy consumption must derive from renewable sources by 2030, with an aspirational ceiling of 45%. For Transmission System Operators (TSOs), this trajectory creates three concurrent technical pressures: capacity bottlenecks at high-voltage connection points due to a surge in grid access requests; heavy localised power demands from industrial electrification and the production of Renewable Fuels of Non-Biological Origin (RFNBOs) such as green hydrogen; and reduced grid stiffness caused by the displacement of synchronous inertia by inverter-based generation.

To accelerate deployment, RED III introduces two structural instruments. First, Member States must designate Renewables Acceleration Areas (RAAs) zones with high technical suitability and proximity to existing infrastructure within which permitting procedures are expedited. Second, renewable energy projects and their associated grid infrastructure are classified as matters of overriding public interest, allowing them to navigate environmental regulations such as the Habitats Directive more efficiently. Together, these mechanisms make substation modernisation a statutory requirement rather than a discretionary investment.

1.2 Italy's National Strategy - PNIEC 2030 and PNRR

Italy operationalises the EU framework through two primary instruments. The 2024 update of the Piano Nazionale Integrato per l'Energia e il Clima (PNIEC) sets a 39.4% renewable share in total energy consumption by 2030, with a more demanding 63.4% target for the electricity sector specifically. Reaching this electricity target from the 2023 baseline of approximately 19.9% requires the addition of approximately 57 GW of new solar PV capacity - reaching a total of 79.2

GW - and 17 GW of new wind capacity including 2.1 GW offshore, reaching 28.1 GW in total. The scale of this non-programmable generation influx makes the technical revamping of high-voltage connection points an immediate physical requirement for system stability, not a long-term aspiration.

The financial architecture for these upgrades is provided by the Piano Nazionale di Ripresa e Resilienza (PNRR), reinforced by the REPowerEU chapter. Approximately €24.7 billion is allocated to the energy transition, prioritising smart grids, large-scale battery storage, and green hydrogen infrastructure. This public investment reduces the commercial risk for private capital and ensures that capital-intensive projects - including substation revamping and utility-scale BESS deployment - are economically viable over their design lifetimes.

Terna, as the Italian TSO, is the executive instrument of this national strategy. With a 9% annual growth rate in capital expenditure, Terna's investment programme is structured around grid development, infrastructure resilience, and connection capacity. The establishment of dedicated units such as Altenia - focused specifically on HV systems and BESS integration - reflects a shift in mission: from routine maintenance to the systematic modernisation of the grid for a decarbonised generation mix.

1.3 Regulatory Framework for BESS and HV Grid Integration

The integration of RES and BESS into the Italian HV grid is governed by a tripartite regulatory structure. The Ministry of Environment and Energy Security (MASE) provides strategic policy direction. ARERA, the independent regulatory authority, ensures non-discriminatory grid access and governs economic market conditions. Terna administers the technical framework through the Grid Code.

The primary technical mechanism is the Testo Integrato delle Connessioni Attive (TICA), which establishes the legal and technical requirements for active grid connections. The introduction of TICA Title IV formalised BESS integration by defining standardised connection procedures, voltage and safety constraints for utility-scale storage systems, and compliance requirements that codified energy storage as a standard component of HV infrastructure rather than an experimental technology.

The economic sustainability of BESS was further secured by ARERA Resolution 300/2017, which opened the Ancillary Services Market (MSD) previously restricted to large programmable thermal

plant to battery storage and intermittent renewables. This regulatory shift has two consequences. First, it enables BESS operators to monetise frequency regulation and reserve capacity services, making the economics of substation revamping viable for private investors. Second, it addresses the curtailment problem: by upgrading Points of Connection (PoC) with enhanced capacity and digital controls, infrastructure bottlenecks are eliminated, allowing renewable plants to operate at maximum output a prerequisite for reaching the 63.4% RES-E target.

1.4 Smart Grid Architecture and Advanced Technical Requirements

The technical objective of substation modernisation is alignment with the Smart Grid framework defined by the EU Network Codes. The NC RfG (Network Code on Requirements for Generators) and NC SO (System Operation Guideline) establish uniform safety and stability standards for generators and system operators across EU borders. The TEN-E Regulation accelerates permitting for Projects of Common Interest (PCIs), ensuring infrastructure deployment keeps pace with 2030 targets.

The most significant forthcoming technical requirement is the mandate for Grid-Forming (GFM) capabilities proposed in NC RfG 2.0 by ENTSO-E. Unlike conventional grid-following inverters, which synchronise to an existing grid signal, GFM-capable systems must actively stabilise grid frequency and provide synthetic inertia emulating the mechanical response of synchronous turbines. This requirement applies to both new installations and existing sites undergoing major upgrades, meaning that any substation revamping project involving BESS or large-scale inverter-based generation must incorporate GFM-enabled technology.

The quantified technical specifications for compliance include: frequency response within 10 milliseconds of a deviation; a minimum damping factor of 5% for oscillation suppression; synthetic inertia provision through emulation of the mechanical starting time of traditional turbines; and full Fault Ride-Through (FRT) capability with immediate reactive power injection during voltage transients. These requirements necessitate high-speed communication infrastructure, modular power electronics, and advanced inverter control algorithms at the Point of Connection. Substations that do not incorporate these capabilities will fail to meet the legal criteria for operation of connected renewable assets, directly undermining Italy's decarbonisation trajectory.

2 Authorization aspects

2.1 Legislative Framework and Administrative Regimes

The Italian authorization landscape for renewable energy and storage has undergone substantial reform to align with RED III and the PNRR investment programme. The pivotal instrument is Legislative Decree 190/2024, which functions as a unified regulatory framework consolidating previously fragmented sector-specific legislation into a single coherent structure. Its central innovation is the systematic classification of national territory into *aree idonee* (suitable areas) and *aree non idonee* (unsuitable areas), providing developers with spatial regulatory certainty and eliminating the discretionary local vetoes that historically delayed project delivery.

Under Italian law, electricity production from renewable sources is classified as a *free economic activity* a legal designation that establishes energy production as a right subject only to safety and environmental compliance, rather than a government concession. Regional and local authorities are consequently prohibited from imposing arbitrary restrictions on RES installations; any limitation must be strictly evidence-based and consistent with the national framework. Decree 190/2024 reinforces this principle by formally designating RES and BESS projects as matters of *Overriding Public Interest* (OPI) and *Public Utility*, embedding the Declaration of Public Utility directly within the Single Authorization (Autorizzazione Unica, AU). This confers legal priority in land-use negotiations and activates the right to establish easements or initiate expropriation proceedings under DPR 327/2001.

The authorization system is tiered in proportion to project scale and territorial impact, codified in Article 4 of Legislative Decree 28/2011:

- **CAEL** (*Comunicazione al Comune per attività in edilizia libera*): notification procedure for minimal-impact works.
- DILA (*Dichiarazione di Inizio Lavori Asseverata*): sworn declaration for minor interventions.
- **PAS** (*Procedura Abilitativa Semplificata*): the Simplified Authorization Procedure for medium-scale installations, operating on the principle of silent consent after a fixed timeframe.
- **AU** (*Autorizzazione Unica*): the comprehensive mandatory procedure for utility-scale projects, replacing all individual local and regional permits in a single administrative act.

Recent legislation has expanded PAS eligibility by introducing locational criteria: PV installations up to 20 MW in industrial, commercial, or brownfield zones and projects up to 10 MW in pre-classified *aree idonee* may access the simplified regime regardless of location-specific power thresholds. A geographic derogation also permits projects within 3 km of established industrial or artisan zones to qualify for PAS even where standard power limits are marginally exceeded. Utility-scale BESS co-located with large RES plants follows the same tiered structure and typically falls under the AU. For revamping operations, certain projects up to 50 MW in *aree idonee* have been granted exemptions from Environmental Impact Assessments provided the physical footprint of the installation is unchanged.

2.2 The Autorizzazione Unica - Governance and Procedure

The AU, established by Article 12 of Legislative Decree 387/2003 and reinforced by Decree 190/2024, is the administrative cornerstone for utility-scale renewable and storage permitting. It operates on the principle of administrative concentration: all sector-specific permits, environmental opinions, and landscape authorizations are consolidated into a single definitive act issued by the competent Region or delegated Province.

The procedure is conducted through a *Conferenza dei Servizi* a simultaneous plenary review by all relevant authorities including environmental, fire safety, and landscape agencies replacing the sequential consultations that historically created cumulative delays. The Ministry of Environment and Energy Security (MASE) enforces a rigorous *procedurability* check at the outset: applications are only admitted upon submission of a complete dossier, typically exceeding 25 mandatory documents. This front-loaded requirement eliminates mid-process delays caused by incomplete documentation.

To address the historical problem of regional administrative inconsistency, MASE established the *Sportello Unico delle Energie Rinnovabili* (SUER) in October 2024 a centralised digital platform that standardises application forms and procedural steps across all Italian territories, enhancing transparency and reducing regulatory friction. For infrastructure of European strategic relevance Projects of Common Interest (PCI) or Projects of Mutual Interest (PMI) under TEN-E Regulation 869/2022 governance shifts from regional to national level, with MASE assuming the role of national competent authority and coordinating directly with the project promoter.

The AU decree produces two legal effects beyond the right to construct and operate. First, the automatic conferral of *Public Utility and Urgency* status establishes the legal basis for land

easements and expropriation constraints under DPR 327/2001. Second, statutory execution deadlines introduced by recent reforms link permits to defined construction start dates, preventing the accumulation of dormant authorizations and ensuring that licensed capacity is promptly converted into operational assets.

2.3 Grid Connection Requirements - BESS and HV Infrastructure

For projects involving BESS and HV substation works, authorization of the electrical connection infrastructure is an integral component of the AU procedure. The technical description of all connection works including HV and MV substations and lines must be submitted in *Modulo B*, which formally delineates the boundary between *impianti di utenza* (producer-owned facilities) and *impianti di rete* (grid infrastructure that will become part of the national transmission network).

Two milestones with Terna are non-negotiable prerequisites for procedural validity. First, the developer must formally accept Terna's Connection Estimate, the *Soluzione Tecnica Minima Generale* (STMG), identified as *Elaborato 13.a* in the AU dossier; without this accepted document, the application is legally non-admissible. Second, Terna must issue a final technical approval (*benestare*) of the grid-side infrastructure design before the AU procedure can conclude. Terna provides technical consultancy to assist developers in preparing the Technical Plan (PTO) and Environmental Impact Studies (SIA), funded through contractually defined fees integrated into the project financing structure.

The effectiveness of the reformed permitting regime ultimately depends on three systemic conditions: consistent application of the OPI designation by regional and local authorities; timely publication of *aree idonee* maps by regional governments; and sufficient administrative capacity at regional level to process complex AU dossiers within the statutory deadlines using digital tools such as SUER.

3. Renewable Energy Sources

Renewable energy refers to energy derived from naturally replenished resources within a human timeframe. These resources encompass sunlight, wind, water movement, and geothermal heat. While numerous renewable energy sources are sustainable, some, such as certain biomass sources, may not be sustainable given current exploitation rates. The application of renewable energy extends to electricity generation, heating, and cooling purposes. Although renewable energy initiatives are frequently associated with expansive undertakings, they also present feasible alternatives for rural, isolated regions, and developing nations, where access to energy significantly influences human advancement.

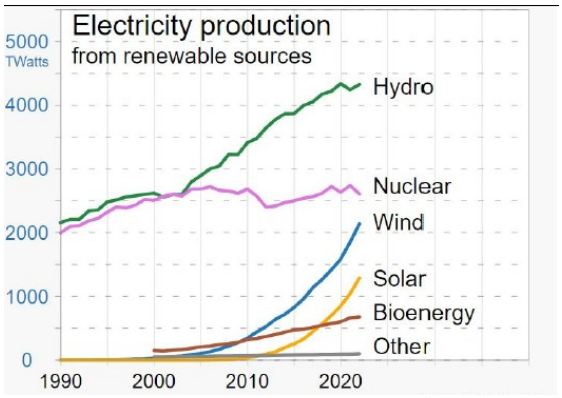


Figure 1. Renewable energy sources, particularly solar photovoltaic and wind, are providing an increasing share of electricity production

This research is mostly on Photovoltaic Plants and their connection to Italian National Grid, that's why we will focus on Solar Energy Technologies. Solar energy technologies encompass various methods of harnessing energy from the sun to generate electricity, heat, or both. These technologies are essential components of the renewable energy landscape and offer numerous environmental and economic benefits. Here's an overview of key solar energy technology:

3.1 Photovoltaic Technology and Grid Integration

3.1.1 The Photovoltaic Effect and Cell Physics

The operating principle of every photovoltaic system is the photovoltaic effect a quantum mechanical phenomenon first described by Edmond Becquerel in 1839 and given its physical explanation by Albert Einstein in 1905. When photons of sufficient energy strike the surface of a semiconductor material, they excite valence electrons across the band gap, generating electron-hole pairs. In a crystalline silicon p-n junction cell, the built-in electric field at the

junction separates these carriers before they recombine, driving electrons through an external circuit and producing a Direct Current (DC). The open-circuit voltage of a standard silicon cell is approximately 0.6 V; the short-circuit current density is proportional to the incident irradiance, typically 30 to 40 mA/cm² at 1,000 W/m² under Standard Test Conditions (STC: 25°C cell temperature, AM1.5 spectrum).

Cell efficiency the ratio of electrical power output to incident solar power is the central performance parameter. Monocrystalline silicon cells, which dominate utility-scale deployments, achieve STC efficiencies of 20 to 24% for commercially available modules, with laboratory records exceeding 29%. Polycrystalline silicon offers slightly lower efficiencies (17 to 20%) at reduced manufacturing cost, while thin-film technologies (CdTe, CIGS) occupy a smaller market share with efficiencies of 12 to 18% but superior performance under diffuse irradiance and elevated temperature conditions.

3.1.2 Module, String, and Array Architecture

Individual cells are encapsulated into modules laminated between tempered glass and a polymer backsheet using ethylene-vinyl acetate (EVA) providing mechanical protection and hermetic sealing against moisture ingress over the 25 to 30-year design life. A module typically contains 60 to 144 cells and produces 300 to 700 W peak power at STC.

For utility-scale plants, modules are interconnected into strings (series connection, increasing voltage) and strings are combined into arrays (parallel connection, increasing current). A typical 1,500 V DC utility-scale string consists of 25 to 35 modules, yielding a string voltage of 1,000 to 1,500 V DC at maximum power point. The array architecture must balance electrical optimisation minimising mismatch losses from shading, soiling, and manufacturing tolerance against cabling costs and the input specifications of the DC/AC inverter. In the 96 MW plant examined in this thesis, the DC array feeds a set of centralised, or string inverters located in dedicated power conversion stations distributed across the plant field.

3.1.3 Power Conversion - Inverter and MPPT

The inverter is the electromechanical interface between the DC array and the AC grid. Its two primary functions are power conversion and Maximum Power Point Tracking (MPPT). The MPPT algorithm continuously perturbs the operating voltage of the array and measures the resulting change in power output, converging on the maximum power point (MPP) of the I-V characteristic under prevailing irradiance and temperature conditions. Modern utility-scale

inverters achieve MPPT efficiencies above 99.5% and DC-to-AC conversion efficiencies of 98 to 99% at rated power.

For grid-connected utility-scale plants, the inverter also performs grid synchronisation matching the frequency, phase angle, and voltage of the generated AC power to the utility network before the anti-islanding relay closes the connection. The inverter output is typically at low voltage (270 to 800 V AC) and is stepped up to the MV collection voltage (in this project 30 kV) by a dedicated MV/LV transformer at each power conversion station. The aggregated MV power is then collected at the 30 kV busbar of the main substation and stepped up to 132 kV by TR1 for injection into the Terna RTN.

Modern utility-scale inverters provide reactive power capability operating at any power factor within a defined P-Q capability curve enabling the plant to comply with Terna Grid Code Annex A.70 requirements for voltage regulation at the Point of Connection (PoC). The reactive power capability of the inverters, combined with the OLTC of TR1, constitutes the primary voltage control mechanism of the plant.

3.1.4 Grid Integration - Technical Challenges at the Point of Connection

The integration of a 96 MW PV plant into the 132 kV Terna network introduces specific technical challenges at the Point of Connection that directly determine the engineering scope of the substation revamping:

Intermittency and ramp rate. PV generation is inherently non-programmable output varies continuously with solar irradiance, cloud cover, and temperature. Rapid irradiance changes produce generation ramps that can reach tens of megawatts per minute, creating voltage fluctuations on the 132 kV busbar. Terna Grid Code Annex A.70 imposes a maximum ramp rate constraint of 20% of rated power per minute, which the BESS must enforce by absorbing or injecting power to smooth the output profile.

Reverse power flow. Unlike conventional thermal generation, a PV plant may consume reactive power at night (inverter auxiliary loads, transformer magnetising current) and inject active power in one direction during the day. The protection and metering systems of the substation must accommodate bidirectional power flow, and the 30 kV MV cables must be rated for both generation and consumption modes.

Harmonic content. PWM-switching inverters produce harmonic currents at multiples of the switching frequency (typically several kilohertz), which may excite resonances in the 30 kV

cable network. The transformer TR1 with its YNd11 vector group suppresses triplen harmonics from circulating into the 132 kV network, and the cable capacitance must be evaluated for resonance with the inverter output filter inductance.

3.1.5 Performance Parameters and Energy Yield

The energy production of a utility-scale PV plant is characterised by three standard performance parameters:

Peak power P_peak (Wp): The DC power output of the array under Standard Test Conditions (1,000 W/m², 25°C, AM1.5). For the plant examined in this thesis, P_peak = 96 MW DC.

Performance Ratio (PR): The ratio of the actual AC energy yield to the theoretically expected yield if the entire array operated continuously at STC efficiency. PR accounts for all losses optical, thermal, mismatch, cabling, inverter, and transformer and typically ranges from 0.75 to 0.85 for utility-scale plants in Mediterranean climates. A PR of 0.82 is assumed for this plant, yielding an AC output of 96 × 0.975 = 93.6 MW at the transformer LV terminals under peak irradiance.

3.1.6 Advantages and Technical Limitations

The primary advantages of utility-scale PV generation relevant to this project are zero fuel cost and zero combustion emissions during operation, a design life of 25 to 30 years with very low operational expenditure, full scalability from kilowatts to hundreds of megawatts using the same modular technology, and complete compatibility with BESS co-location for dispatchability enhancement.

The principal technical limitations that directly shape the engineering requirements of the substation are intermittency requiring ramp-rate control and reactive power management; the non-programmable generation profile requiring protection coordination that accounts for near-zero current during night hours and maximum fault contribution only during daylight; and the inverter-based nature of the fault current where the short-circuit contribution of the PV plant is limited to approximately 1.1 to 1.5 times rated current by the inverter current limiters, substantially lower than the contribution of a synchronous generator of equivalent rating. This last characteristic has direct consequences for the sensitivity settings of the MV feeder protection relays, which must detect minimum faults at the end of the 2,350-metre cable feeders even during periods of low irradiance when the inverter contribution to fault current is minimal

4. High Voltage Substation

4.1 Single Line Diagram

The Single Line Diagram (SLD) shows how power flows and how components are logically connected. While a physical map shows where things are in a substation. In the world of High Voltage engineering, it is the primary document used by engineers, operators, and technicians to understand the system without getting bogged down by the complexity of three-phase wiring.

A Single Line Diagram is a simplified schematic where; a single line represents all three phases of an AC system. It uses standardized symbols to represent complex equipment like transformers, generators, and circuit breakers [1]. The primary goal is clarity. By removing the redundancy of three separate wires for every connection, an engineer can see the entire logic of a substation at a single glance.

4.1.1 Primary usages of Single Line Diagram:

Single line diagram is not just a drawing; it's a functional tool which uses for:

- System Analysis and Modelling
- Safety and Switching Procedures
- Fault Identification
- Planning and Expansion
- Protection Coordination

The primary components of a high-voltage (HV) substation constitute the physical infrastructure through which electrical energy is switched, measured, transformed, and protected at transmission voltage level. In the context of this project the revamping of a 132 kV substation for the connection of a 96 MW renewable power plant with BESS each primary component must be carefully engineered to withstand the electrical stresses imposed by the network, to fulfil the specific protection and metering functions allocated to it by the single-line diagram (SLD), and to comply with the full hierarchy of applicable standards: IEC, CEI, and the technical requirements of Terna's Codice di Rete.

4.1.2 Substation Switchyard Single Line Diagram:

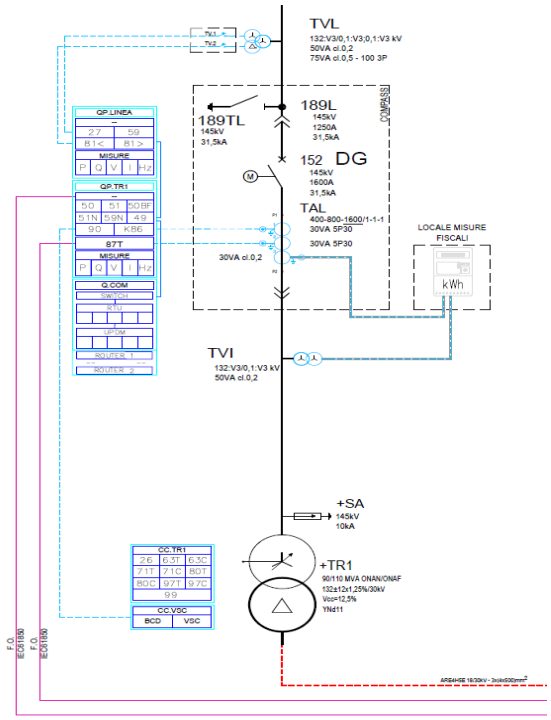


Figure 2. Substation Switchyard SLD

This is Substation Switchyard SLD and as we can see they are also protection mentioned for line and transformer on the right-hand side of our photo above.

Codes inside box QP.TR protect the main Power Transformer. Since transformers are expensive and filled with oil, these protections are much more comprehensive. These codes are designed to handle two types of issues:

- Internal faults
- External stresses

The figure above shows Switchyard of substation with new components, in this switchyard with have Voltage Transformers, COMPASS (Disconnectors, Circuit Breaker and Current Transformer), Power Transformer, Surge Arrester and Protections.

The reason for usage of COMPASS is space that we have in our substation, as we will have another transformer for BESS in the future, we don't have enough space, so we can use COMPASS, because it is a hybrid switchgear module. Instead of having a separate circuit breaker, separate disconnectors, and separate CTs taking up a huge amount of land in the switchyard, COMPASS combines them into one pre-assembled, factory-tested unit and since the components are integrated and mostly enclosed, they are protected from environmental pollution and bird strikes.

4.1.3 COMPASS

4.1.3.1 132 kV HV Switchyard Protection - COMPASS Module

4.1.3.1.1 COMPASS Module - Technical Description

COMPASS (COMpact Prefabricated Air-insulated SubStation) is a factory-assembled, factory-tested integrated HV switchyard bay that combines in a single three-phase unit all functions that would traditionally require individual separate pieces of equipment. Introduced by ABB in 1996 and manufactured at ABB's (now Hitachi Energy) focus factory in Lodi, Italy, it is available for rated voltages of 123–170 kV [21] [33].

Each phase of the COMPASS module installed in this substation integrates:

- **Circuit-breaker (152 DG):** 145 kV, 1,600 A, 31.5 kA with BLK spring-energy drive mechanism, single and three-phase operation capability.
- **Line disconnector (189L):** motor-operated, with integrated earthing switch
- **Transfer bus disconnector (189TL):** motor-operated, with integrated earthing switch.
- **Busbar CT (TAL):** multi-ratio 400-800-1600/1A, 30VA 5P30 - integrated within the COMPASS phase structure.
- **Line VT (TVL):** 132/√3/0.1/√3 kV, 50VA cl.0.2, 75VA cl.3P - integrated per phase.
- **Surge arrester (+SA):** 145 kV class, 10 kA zinc oxide integrated per phase.

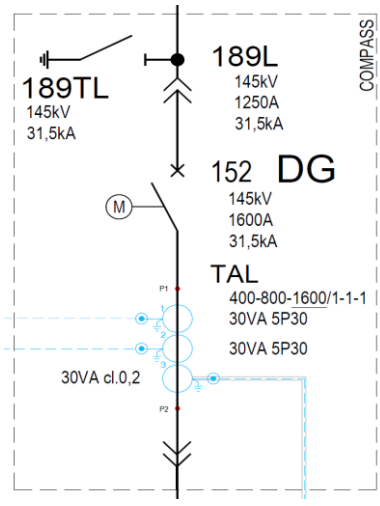


Figure 3. COMPASS

A pre-wired Local Control Cabinet (LCA) houses all auxiliary circuits, motor drives, position indicators, and the IEC 61850 fibre optic communication interface to the OP-TR1 protection panel and the substation RTU.

The interlocking logic between the CB (152 DG) and the disconnectors (189L, 189TL) is hardware-implemented mechanically within the module, physically enforcing the five safety steps (interrupt, isolate, lock, verify, earth) independently of any software or auxiliary power supply.

Parameter	Value
Product designation	COMPASS - COMpact Prefabricated Air-insulated SubStation
Rated voltage	145 kV (Um)
Rated normal current (CB 152 DG)	1,600 A
Rated short-circuit breaking current	31.5 kA
CB operating mechanism	BLK spring-energy drive (single and three-phase operation)
Disconnectors	189L (line), 189TL (transfer bus) - motor-operated with integrated earthing switches
Current transformer TAL	400-800-1600/1A, 30VA 5P30 (multi-ratio, integrated)
Voltage transformer TVL/TVI	132/√3 / 0.1/√3 kV - 50VA cl.0.2 (metering) / 75VA cl.3P (protection)
Surge arrester +SA	145 kV class, 10 kA (zinc oxide, integrated per phase)
Communication interface	IEC 61850 over fibre optic - pre-wired in LCA
Applicable standards	IEC 62271-200, IEC 62271-100, IEC 62271-102, IEC 61869-2/3, IEC 60099-4

Table 1. COMPASS module specifications as installed in the 132 kV switchyard

The COMPASS is a compact solution for air-insulated switchgear (AIS) up to 170 kV that integrates Hitachi Energy's best-in-class Live Tank Circuit Breaker (LTB) and gas-insulated current transformer in the same footprint as a standard LTB. COMPASS is completely assembled and tested in the factory and can be entirely transported to the site for an easy, reliable installation.

4.1.4 Key benefits of the COMPASS:

- Optimized self-blast technology, which significantly reduces energy need to operate the circuit breaker.
- A COMPASS module requires up to 50% less space compared with a conventional air-insulated switchyard.
- Easy to install-adjustment free installation.
- The current transformer is an integrated and reliable top core design, and an independent gas insulated voltage transformer can be optionally mounted on a dedicated bracket to reduce the impact on footprint.

- COMPASS contains less SF6 gas because the current transformer is integrated in the circuit breaker.
- Suitable for controlled switching applications.

4.1.5 Reliable operating mechanism

COMPASS and COMPASS I are equiped with a motor charged spring operating mechanisms. This solution offers considerable advantages as the energy in the tensioned springs is always available. The spring operating mechanism used for COMPASS.

COMPASS also provides, for each phase:

- Disconnectors (DS), to disconnection upstream and downstream of the breaking chamber.
- Air-insulated Earthing Switches (ES) (optional)
- Air-insulated Voltage Transformer (VT) (optional)
- Air insulated Surge-Arrester (SA) (optional)

VT and SA are alternatives for considered side (one excludes the other).



Figure 4. HITACHI Air-insulated COMPASS

In operating condition, we must consider circuit breaker and disconnector. The circuit breaker can operate only if the disconnector is open or closed, but not in intermediate positions. Local operations are allowed only if the disconnector is open. Operations are allowed only if gas pressure on the poles is higher than blocking level. Closings are allowed only if the closing spring is completely loaded.

The disconnector opens both motorized and manually only if the breaker is open (the blocks are electromagnetic). The earth disconnector operates only if the disconnector is open

(mechanical block and /or electronical block) and is supplied with an electromagnetic block enabling operation only if energized. The earth disconnector is also available with motorized drive.

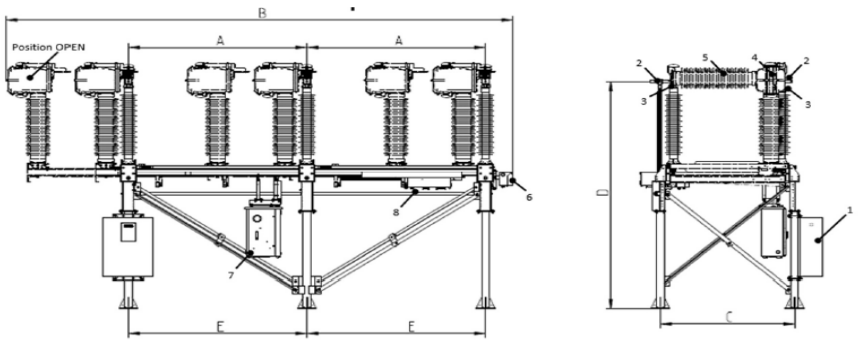


Figure 5. .COMPASS with FAS1 overall dimension [Spring drive version]

Local Control Cabinet

1. Earthing switch
2. Disconnector
3. Current Transformer
4. Breaking Chamber
5. Earthing switch drive
6. Interrupter drive FSA1
7. Disconnector drive STL

As an optional item, the COMPASS module can be supplied with a built-in surge arrester, installed on the module support structure, as shown in Figure below.

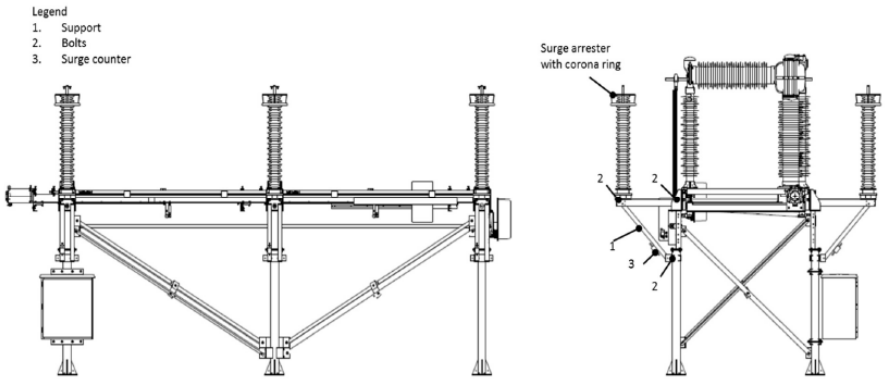


Figure 6. Surge Arrester installation

4.2 High Voltage Components

4.2.1 Power Transformer

4.2.1.1 Introduction

The power transformer TR1 is the central electrical component of the 132 kV / 30 kV step-up substation. It converts the 30 kV alternating current produced by the photovoltaic plant's medium-voltage collection network to 132 kV for injection into the Terna national transmission grid, and it provides the galvanic boundary between the plant's isolated-neutral 30 kV system and the solidly earthed 132 kV Terna network. Every major design decision in the substation the MV switchgear rating, the short-circuit current envelope, the protection relay settings, the OLTC control range, and the insulation coordination is determined directly or indirectly by the TR1 electrical parameters.

4.2.1.2 Operating Principle of the Power Transformer

4.2.1.2.1 Electromagnetic Induction and the Ideal Transformer

The power transformer operates on the principle of mutual electromagnetic induction between two magnetically coupled windings sharing a common ferromagnetic core [11]. When an alternating voltage V_1 is applied to the primary winding of N_1 turns, it drives an alternating magnetic flux Φ in the core. By Faraday's law, this time-varying flux induces an electromotive force in the secondary winding of N_2 turns:

$$E2 = N2 \times \frac{d\Phi}{dt} \quad \text{and} \quad \frac{V1}{V2} = \frac{N1}{N2} = a \quad \text{(transformation ratio)}$$

For an ideal transformer with no winding resistance, no leakage flux, and an infinitely permeable core the transformation is lossless: $V_1I_1 = V_2I_2$, and the currents transform inversely to the turns ratio: $I_1/I_2 = N_2/N_1 = 1/a$. For TR1 with a 132/30 kV ratio, a = 132/30 = 4.40, meaning that the primary current is 4.40 times smaller than the secondary current for the same transferred power.

4.2.1.2.2 Real Transformer - Equivalent Circuit and Losses

A real transformer deviates from the ideal in three fundamental ways, each with direct engineering consequences [11]:

- **No-load losses (iron losses):** The alternating flux in the core produces hysteresis losses and eddy current losses. These losses are constant at rated voltage regardless of load and

are characterised by the no-load loss P and the no-load current I. For a transformer of this size, P is typically 50 to 80 kW and I is 0.3 to 0.5%.

- **Load losses (copper losses):** The winding resistances R and R cause Joule heating proportional to the square of the current. Load losses at rated current are characterised by the short-circuit power loss P and are directly related to the short-circuit resistance R = P/S.
- **Leakage flux - short-circuit reactance:** Not all flux produced by each winding links the other winding some leakage flux closes through the oil and insulation rather than through the core. This leakage is characterised by the short-circuit reactance X and, combined with R, gives the short-circuit impedance $Z = \sqrt{(R + X)}$. The short-circuit voltage $Vcc = Z \times S/V$ is the nameplate parameter that governs the fault current magnitude and voltage regulation [1].

4.2.1.2.3 The Short-Circuit Impedance - Engineering Significance

The short-circuit impedance Vcc = 12.5% of TR1 is the single most important parameter for the electrical design of this substation, because it determines simultaneously [1][11]:

- **Maximum fault current at 30 kV:** A lower Vcc produces a higher fault current, which may exceed the MV switchgear breaking capacity. This sets a minimum Vcc.
- **Voltage regulation:** A higher Vcc produces a larger voltage drop under load, degrading MV busbar voltage quality. This sets a maximum Vcc.
- **BESS and protection coordination:** The Vcc governs the impedance that the fault current must overcome, affecting relay sensitivity and BESS fault contribution.

The selection of Vcc = 12.5% is therefore not arbitrary it is the result of a systematic window analysis that is presented fully in next sections.

4.2.1.3 Transformer Cooling - ONAN and ONAF

4.2.1.3.1 IEC 60076-2 Cooling Designations

TR1 has a dual rating: ONAN (natural oil, natural air - no pumps or fans) and ONAF (natural oil, forced air - fans on radiators). The two ratings correspond to two distinct thermal equilibria for the same physical transformer [2]:

Mode	Rating	Cooling mechanism	Operating condition
ONAN	90 MVA	Oil heated by winding losses rises by natural convection to top-mounted radiators, cools, and returns. No mechanical components.	Ambient temperature ≤ 40°C. Fans off. Standard daytime operation at part load or night.
ONAF	110 MVA	Same oil circuit as ONAN, but radiator fans engage automatically when oil temperature exceeds the threshold setpoint (typically 55°C top-oil). Fan airflow increases the heat dissipation coefficient.	Peak PV generation period with BESS co-export. Fans auto-start on oil temperature signal from CC.TR1 relay (function 26 thermal overload).

Table 2. TR1 dual cooling modes per IEC 60076-2 [2]. The ONAN rating governs continuous steady-state operation; the ONAF rating is the peak capacity available when fans are running.

4.2.1.3.2 Thermal Model - Top-Oil and Hot-Spot Temperature

The thermal design of TR1 is governed by IEC 60076-7 [4], which defines a two-layer thermal model: the top-oil temperature rise $\Delta\theta_{TO}$ above ambient, and the hot-spot temperature rise $\Delta\theta_{HS}$ above top-oil. The hot-spot temperature at the hottest point of the HV winding is the limiting thermal parameter it must not exceed 98°C under normal continuous rating per IEC 60076-7 [4] to ensure an adequate insulation life expectancy.

The thermal model equations are:

$$\theta_{HS} = \theta_{ambient} + \Delta\theta_{TO} + \Delta\theta_{HS}$$

For TR1, with the nameplate thermal parameters $\Delta\theta_{TO}$ = 60 K (top-oil rise at rated load) and $\Delta\theta_{HS}$ = 78 K (hot-spot rise above top-oil), and at the maximum design ambient of 40°C:

$$\theta_{HS,max} = 40 + 60 + 78 = 178°C \quad \text{[at rated ONAN load - 90 MVA]}$$

This is the hot-spot temperature at maximum continuous ONAN load in the worst ambient. The IEC 60076-7 [4] normal insulation life reference is based on a hot-spot temperature of 98°C for a 20-year design life at continuous rated load. The 178°C value calculated above represents the absolute peak at 40°C ambient and rated load in practice, the ambient is rarely at 40°C, and the ONAF fans will have engaged well before rated load is reached.

4.2.1.4 On-Load Tap Changer (OLTC) - 132±12×1.25%

4.2.1.4.1 Function and Operating Principle

The on-load tap changer (OLTC) is a motorised switching device that changes the turns ratio of TR1 while the transformer remains energised and loaded. By varying the number of active HV turns in discrete steps, the OLTC adjusts the secondary (30 kV) voltage to compensate for

HV network voltage variations, load-dependent voltage drops across the transformer leakage impedance, and reactive power variations in the MV collection network.

The OLTC of TR1 is located on the HV (132 kV) winding. Its range is ±12 steps of 1.25% each, giving a total regulation range of ±15% of the nominal HV voltage:

$$Total\ OLTC\ range = \pm 12 \times 1.25\% = \pm 15\%$$

$$HV\ range = 132000 \times (1 \pm 0.15) = 112200\ V \quad to \quad 151800\ V$$

The voltage step per tap position is:

$$\Delta V_{step} = 132000 \times 0.0125 = 1650\ V\ per\ step \quad (on\ the\ HV\ side)$$

4.2.1.5 Rated Power Sizing - Derivation from First Principles

4.2.1.5.1 PV Plant Active Power Output

The primary power to be transferred through TR1 is the AC output of the 96 MW PV plant. Accounting for the internal losses between the PV array DC output and the TR1 LV terminals, inverter efficiency $\eta_{inv} \approx 98.5\%$, MV/LV transformer efficiency $\eta_{MV/LV} \approx 99.0\%$, and MV cable losses $\eta_{cable} \approx 99.5\%$ the AC power delivered at the 30 kV busbar is:

$$P_{AC} = P_{DC} \times \eta_{INV} \times \eta_{MV/LV} \times \eta_{cable} = 96 \times 0.985 \times 0.990 \times 0.995 = 93.6\ MW$$

This is the maximum active power that TR1 must be capable of transmitting continuously under peak PV generation conditions.

4.2.1.5.2 Reactive Power Obligation

The Terna Grid Code Annex A.70 [10] requires generating plants connected to the 132 kV network at this power level to be capable of operating at any power factor between cosφ = 0.95 lagging and cosφ = 0.95 leading at the Point of Connection. The maximum apparent power at the 132 kV PoC when the plant exports at rated active power and maximum reactive power simultaneously:

$$Q_{max} = P_{AC} \times \tan(\arccos(0.95)) = 30.76\ MVAr$$

$$S_{PoC} = \sqrt{(P_{AC}^2 + Q_{\max}^2)} = \sqrt{93.6^2 + 30.76^2} = 98.52\ MVA$$

TR1 must therefore be capable of transmitting at least 98.52 MVA apparent power to satisfy the Terna reactive power obligation.

4.2.1.5.3 BESS Contribution

The BESS (20 MW) is connected to the 30 kV MV busbar through a dedicated BESS transformer (TR-BESS, 25 MVA). During peak arbitrage periods, the BESS may discharge simultaneously with full PV generation, contributing an additional 20 MW to the TR1 power flow. The total peak apparent power that TR1 must handle:

$$S_{total} = \sqrt{((P_{AC} + P_{BESS})^2 + Q_{max}^2} = 117.69\ MVA$$

This value represents the theoretical maximum power flow through TR1 when both the PV plant and the BESS discharge simultaneously at rated power and the plant exports maximum reactive power. In practice, simultaneous maximum active and reactive power export with BESS at full rated power is a design envelope case, not a sustained operating condition.

4.2.1.5.4 ONAN/ONAF Rating Selection

The sizing analysis produces a power requirement range from 93.6 MVA (PV only, unity power factor) to 122.3 MVA (PV + BESS + maximum reactive). The ONAN/ONAF rated power selection must satisfy [2][11]:

- **ONAN ≥ P_AC / cosφ:** The ONAN continuous rating must cover the full PV output at the rated power factor. With P_AC = 93.6 MW and cosφ = 0.95: S_min = 93.6 / 0.95 = 98.52 MVA... but ONAN is the conservative base rating. The standard value of 90 MVA covers normal operation: at 90 MVA ONAN and full reactive power export, the maximum active power is 90 × cosφ = 90 × 0.95 = 85.5 MW corresponding to a PV irradiance of approximately 95% of peak. The remaining 20% of generation time where irradiance exceeds this level triggers fan engagement.
- **ONAF ≥ S_PoC = 98.524 MVA:** The ONAF rating with fans running must cover the full apparent power at peak PV generation and full reactive power. The selected ONAF rating of 110 MVA satisfies S_ONAF = 110 MVA ≥ 98.524 MVA.
- **ONAN/ONAF ratio:** S_ONAF / S_ONAN = 110 / 90 = 1.222 = +22.2%, consistent with the standard 20–25% improvement achievable by forced cooling [2].

4.2.1.6 Voltage Ratio and OLTC Range - Derivation

4.2.1.6.1 HV Voltage (132 kV)

The HV voltage is determined by the Terna network connection voltage at the 152 DG busbar: 132 kV. This is a fixed datum from the Terna Grid Code it is not a design choice. The maximum

system voltage U_m = 145 kV per CEI EN 60038 [6] sets the insulation class for all 132 kV equipment.

4.2.1.6.2 MV Voltage (30 kV)

The 30 kV MV voltage is an optimisation result. The PV plant's MV collection cables (ARE4H5E 18/30kV) are rated for operation up to 30 kV system voltage. The MV switchgear (H01–H05) is rated 30 kV / Um = 36 kV [6]. The rated current of the switchgear (2,000 A) constrains the minimum MV voltage:

$$I_n.MV = \frac{S_{ONAF}}{\left(\sqrt{3} \times Un.MV\right)} = \frac{110 \times 10^6}{(1{,}732 \times Un.MV)}$$

For $I_{n,MV} \leq$ 2,000 A (switchgear rated current):

$$Un, MV \geq \frac{110 \times 10^6}{(1.732 \times 2000)} = 31{,}750\ V$$

This means a 30 kV MV voltage gives $I_{n,MV}$ = 110/(1.732 × 30) = 2,120 A, which is slightly above the switchgear rating of 2,000 A at full ONAF. However, at ONAN rating (90 MVA), $I_{n,MV}$ = 90/(1.732 × 30) = 1,732 A comfortably within the 2,000 A rating for most of operating hours. As our Substation is connected to generation PV plant, power will not go higher than 96 MW and in this case we have 1,847 A which is lower than 2,000 A rating.

4.2.1.6.3 OLTC Range - ±12×1.25% Derivation

The OLTC range must compensate for the total voltage variation at the HV terminal of TR1 and maintain the 30 kV MV busbar within the limits of CEI 0-16 [8]:

- **HV voltage variation:** The Terna 132 kV network voltage varies between U = 0.90 × 132 = 118.8 kV and U = 1.10 × 132 = 145.2 kV in normal operation. Total variation: ±10%.
- **Voltage regulation across TR1:** The voltage drop across the TR1 leakage impedance at full load contributes an additional ±5% voltage variation at the 30 kV terminals depending on load power factor.
- **Total required OLTC range:** ±10% (network) + ±5% (regulation) = ±15%.

NOTE: OLTC range verification: ±12×1.25% = ±15% covers the required total voltage variation range of ±15%. The OLTC range is correct for the 132 kV network connection of this substation.

4.2.1.7 Short-Circuit Impedance - Vcc = 12.5%

4.2.1.7.1 The Vcc Window (Minimum and Maximum Constraints)

The short-circuit impedance Vcc = 12.5% of TR1 is determined by two simultaneous constraints that define a permissible window:

Minimum Vcc (MV Switchgear Breaking Capacity Constraint)

The maximum three-phase fault current at the 30 kV MV busbar must not exceed the switchgear rated breaking current of 20 kA. From the fault current formula (CEI EN 60909-0, with voltage factor c = 1.10 and minimum Vcc including IEC 60076-1 tolerance of −7.5%):

$$I"k3, max = \frac{(c \times U_{n,MV})}{\sqrt{3} \times Z_{total}}$$

where $Z_{total} = Z_{net,MV} + Z_{TR1,min} = 0.137 + Z_{TR1} \times 0.925$. Setting I"k3,max = 20,000 A (switchgear limit) and solving for Z_{TR1}:

$$Z_{TR1}, min, VCC = \frac{0.9526 - 0.137}{0.925} = 0.882\ \Omega$$

Converting to percentage impedance:

$$Vcc_{min} = \frac{Z_{TR1}, min, Vcc}{\left(\frac{U_{n,MV}^2}{S_n}\right) \times 100} = 8.82\ \% \approx 9.27\ \% (including\ all\ correction\ factor)$$

NOTE: Minimum Vcc = 9.27%: Any short-circuit impedance below this value would cause the 30 kV MV busbar fault current to exceed the 20 kA switchgear breaking capacity.

Maximum Vcc (Voltage Regulation Constraint)

CEI 0-16 requires that the voltage variation at the MV PoC does not exceed 6% during normal operation. The maximum voltage drop across TR1 at rated load and worst-case power factor (cosφ = 0.90 lagging) gives the maximum permissible Vcc:

$$\Delta U = Vcc \times cos\varphi \times \frac{Rcc}{Xcc} + Vcc \times sin\varphi \times (approx.)$$

$$\Delta U_{max} = 6\% \ \rightarrow Vcc_{max} = 6\% \qquad (cos\varphi \times corrrection) \approx 13.76\%$$

NOTE: Maximum Vcc = 13.76%: Any impedance above this value would cause voltage regulation exceeding 6% at full load, violating CEI 0-16 requirements.

4.2.1.7.2 Vcc Selection within the Window

The permissible window is 9.27% ≤ Vcc ≤ 13.76%. The installed value of Vcc = 12.5% sits within this window.

With Vcc = 12.5%, the resulting maximum three-phase fault current at the 30 kV MV busbar:

$$I"k3, max = 15.23\ kA \qquad < \qquad I_{sw}, rated = 20\ kA$$

RESULT: Vcc = 12.5% is analytically correct. It satisfies both the minimum constraint (switchgear fault current limit) and the maximum constraint (voltage regulation limit), with a 23.9% margin below the 20 kA switchgear breaking capacity. The Vcc window analysis confirms that 12.5% is the optimal value within the [9.27%, 13.76%] permissible range for this application.

4.2.1.8 Vector Group - YNd11

Vector group YNd11 is the only correct choice based on grid code for PV plant generation [1][9]. YN is mandatory for the HV side (Terna solidly earthed network) [9]. d is mandatory for the MV side (isolated neutral 30 kV network, harmonic suppression, zero-sequence isolation) [1]. 11 is the standard IEC phase displacement for this transformer configuration.

4.2.1.9 Insulation Coordination

4.2.1.9.1 HV Winding Insulation Level

The HV winding of TR1 must be insulated for the maximum transient overvoltages that can appear at the 132 kV terminals. The governing parameters are the Basic Insulation Level (BIL), and the power-frequency withstand voltage (ACWV), specified by CEI EN 60076-3 [3] for the 132 kV voltage class:

- **BIL (lightning impulse, 1.2/50 µs):** 650 kV peak standard value for the 132 kV voltage class per CEI EN 60076-3.
- **ACWV (power-frequency, 1 minute):** 275 kV rms standard short-duration power-frequency withstand voltage [3].
- **Surge arrester coordination:** K = BIL/LIPL = 650/288 = 2.25 >> 1.20 minimum

4.2.1.9.2 MV Winding Insulation Level

The delta MV winding must be insulated for the 30 kV system voltage plus the temporary overvoltages that appear on the healthy phases during a single-phase earth fault on the isolated

30 kV. On an isolated neutral, the healthy phase-to-earth voltage rises to $\sqrt{3} \times U_n/\sqrt{3} = U_n$ = 30,000 V during a solid earth fault. The MV winding insulation class per CEI EN 60076-3:

- **MV BIL:** 145 kV peak (standard for Um = 36 kV class).
- **MV ACWV:** 70 kV rms (standard for Um = 36 kV class).
- **TOV withstand:** The MV winding must sustain U = 30 kV for the duration of an earth fault typically limited to the protection operating time is maximum 380 ms CEI 0-16. The MV ACWV of 70 kV rms provides a factor of 70/30 = 2.33 against the earth fault TOV well more than the required voltage factor VF = 1.9 for 30 seconds per IEC 60071-1 for isolated neutral networks.

4.2.1.10 Rated Current at Each Voltage Level

The rated currents of TR1 at each voltage level essential for CT selection, cable sizing, and busbar rating verification are derived directly from the nameplate power and voltage data:

$$I_n, HV, ONAN = \frac{S_{ONAN}}{(\sqrt{3} \times Un, HV)} = \frac{90 \times 10^6}{(1.732 \times 132{,}000)} = 394\ A$$

$$I_n, HV, ONAF = \frac{S_{ONAF}}{(\sqrt{3} \times Un, HV)} = \frac{110 \times 10^6}{(1.732 \times 132{,}000)} = 481\ A$$

$$I_n, MV, ONAN = \frac{S_{ONAN}}{(\sqrt{3} \times Un, MV)} = \frac{90 \times 10^6}{(1.732 \times 30{,}000)} = 1{,}732\ A$$

$$I_n, MV, ONAF = \frac{S_{ONAF}}{(\sqrt{3} \times Un, MV)} = \frac{110 \times 10^6}{(1.732 \times 30{,}000)} = 2{,}120\ A$$

We have the generation plant and These values confirm the CT tap selection (TAL 400 A tap for metering, 1600 A tap for protection at 132 kV; H02 CT 2500 A primary at 30 kV) and the MV cable rating (the DDR1/DDR2 cables rated for 2×1,125 A = 2,250 A > 1,847 A ONAF current). The MV switchboard rated at 2,000 A has been chosen because generation plant cannot feed more than 1,847 A.

❖ Rated Power ONAN/ONAF		A_n	90/110	MVA
❖ Rated Voltage	HV winding	V_{1n}	132±12.5×1.25%	kV
	LV winding	V_{2n}	30	kV
❖ Windings connection			HV Star + N	YNd11
			LV Delta	
❖ Frequency		f	50	Hz
❖ Cooling Type			ONAN/ONAF	

Table 3. . Power Transformer Nameplate

4.2.2 Disconnectors (Sezionatori)

4.2.2.1 Introduction

The COMPASS module of this substation contains two switching devices that perform the isolation function: the line disconnector 189TL and the busbar disconnector 189L. Reading directly from the substation single-line diagram, the two devices are represented by different symbols, reflecting fundamentally different mechanical designs. 189TL is a conventional two-position rotary disconnector its symbol shows a rotating blade that moves between CLOSED and OPEN. 189L is a three-position switch its symbol shows the filled-circle dot notation used in Italian SLD convention to indicate a device capable of CLOSED, OPEN, and EARTHED positions within a single mechanism. Both devices are rated 145 kV / 31.5 kA [1][3]; 189L additionally carries the rated normal current of 1,250 A on its nameplate.

Together, 189TL and 189L provide complete isolation and earthing capability for every element of the 132 kV bay: the 365-metre Crocco ACSR overhead line, the 152 DG circuit-breaker, the TAL current transformer, the TVL and TVI voltage transformers, the surge arrester +SA, and the power transformer +TR1. The two devices are mechanically and electrically interlocked with each other and with the 152 DG circuit-breaker, preventing unsafe switching sequences in all operating conditions [1][9].

4.2.2.2 Line Disconnector (Two-Position)

4.2.2.2.1 Description and SLD Symbol

The 189TL is the first switching device in the COMPASS bay, located on the overhead-line side of the 152 DG circuit-breaker. Its SLD symbol a rotating blade between two fixed contact arms is the standard IEC representation of a conventional two-position rotary disconnector. The device designation follows Italian CEI/Terna numbering convention: 189 is the device number for a disconnector (*sezionatore*), and TL identifies it as the *sezionatore di linea*, the line-side disconnector [8].

4.2.2.2.2 Operating Positions

189TL has two operating positions only [1]:

- **CLOSED:** The rotating blade makes full contact with both fixed contacts. The main circuit is complete: current flows from the Terna overhead line through 189TL to the 152 DG circuit-breaker. This is the normal service position during substation operation.

- **OPEN:** The rotating blade rotates away from one fixed contact, creating a physical air gap in the main circuit. The overhead line side of the bay is isolated from the circuit-breaker. The gap must withstand the rated open-gap insulation level per IEC 62271-102 [1].

189TL has no earthing capability of its own. When the overhead line section needs to be earthed for personnel safety a separate earthing switch is used. This separate earthing switch, not explicitly labelled on the high-level SLD view, is mechanically interlocked with 189TL: it can only be closed after 189TL is confirmed OPEN, and 189TL can only be closed after the earthing switch is confirmed OPEN [1][9].

4.2.2.3 Busbar Disconnector (Three-Position Switch)

4.2.2.3.1 Description and SLD Symbol

The 189L is located on the transformer side of the 152 DG circuit-breaker, between the circuit-breaker and the +TR1 HV terminal. Its SLD symbol is the Italian and IEC convention for a three-position switch: a single mechanism that can reach CLOSED, OPEN, and EARTHED positions [1][2]. The designation 189L follows the same CEI/Terna convention: 189 is the disconnector device number, and L identifies the second disconnector in the bay sequence (load side / busbar side) [8].

4.2.2.3.2 The Three Operating Positions

The three-position switch combines the disconnector and the transformer-side earthing switch in a single rotating mechanism [1][2]. A single rotary contact blade can reach three distinct angular positions, each corresponding to a clearly defined electrical state:

Position	Symbol colour	Electrical state and meaning	When used
CLOSED	Green	Main contacts closed. Full current path between 152 DG and TR1 HV terminal. Earth contact open.	PV plant generating, TR1 energised, BESS operating.
OPEN	White	Main contacts open. Air gap between circuit-breaker side and TR1 side. Earth contact still open. TR1 is isolated but not yet earthed.	Intermediate step must proceed to EARTHED before personnel approach TR1.
EARTHED	Yellow	Main contacts open AND earth contact closed. TR1 HV terminal connected to the substation protective earth.	Final step before issuing permit-to-work for TR1 maintenance.

Table 4. The three operating positions of the 189L three-position switch [1].

4.2.2.4 Rating Verification

4.2.2.4.1 Rated Voltage and Insulation Level

Both 189TL and 189L are rated at Um = 145 kV, which is the maximum system voltage class for the 132 kV Terna network per CEI EN 60038. The standard insulation levels for the 145 kV class per IEC 62271-1 Table 2 are BIL = 550 kV peak (standard) or 650 kV peak (enhanced) and ACWV = 230 kV rms. As GIS-integrated components of the COMPASS module, both devices meet the enhanced COMPASS module type-tested level of BIL = 650 kV peak [2][3], which gives a BIL coordination factor against the surge arrester +SA (LIPL = 288 kV peak) of:

$$K_{BIL} = \frac{BIL_{COMPASS}}{LIPL_{SA}} = \frac{650}{288} = 2.26 \geq K_{BIL,min} = 1.2$$

4.2.2.4.2 Rated Normal Current

The 189L rated current of 1,250 A must exceed the maximum current that can flow through it in service [1]. The maximum occurs at full ONAF operation of TR1 simultaneously with BESS discharge at rated power:

$$I_{TR1,HV} = \frac{110 \times 10^6}{\sqrt{3} \times 132000} = 481\ A$$

$$I_{BESS,HV} = \frac{25 \times 10^6}{\sqrt{3} \times 132000} = 109\ A$$

$$I_{max,HV} = 481 + 109 = 590\ A \quad \ll \quad I_{r,189L} = 1250\ A$$

4.2.2.4.3 Short-Circuit Withstand

Both devices must withstand the maximum prospective fault current from the Terna 132 kV network [3][9]. The thermally equivalent fault current for 1 second is:

$$I_{th,eq} = I"k3, max \times \sqrt{(1 + DC\ factor)} = 15.1 \times \sqrt{(1.40)} = 17.86\ kA$$

Both devices are rated 31.5 kA per the SLD embedded thermal and 80 kA peak [2][3]:

$$I_{th,rated} = 31.5\ kA\ /\ 1s \quad \geq \quad I_{th,eq} = 17.86\ \text{kA}$$

$$i_{p,rated} = 80\ kA\ peak \quad \geq \quad i_{p,,max} = 78.75\ kA$$

RESULT: All rating criteria pass for both 189TL and 189L. Voltage class: 145 kV = Um system. Current: 1,250 A rated vs 590 A maximum (+112%). Thermal withstand: 31.5 kA/1s vs 17.86 kA equivalent. Peak withstand: 80 kA vs 78.75 kA [3]. BIL coordination: K_BIL = 2.26 >> 1.20 minimum (+88%) [4].

4.2.2.5 Complete Bay Isolation

When both sides of the 152 DG circuit-breaker must be isolated and earthed for example, for circuit-breaker maintenance or COMPASS module inspection the sequence is: open 152 DG → open 189L → open 189TL → move 189L to EARTHED (TR1 side earthed) → close the separate line-side earthing switch associated with 189TL → apply portable earthing at both ends → issue Permit to Work. In this configuration the 152 DG is flanked by two independent earth points the maximum safety condition for personnel working in the bay[6][9].

4.2.3 Instrument Transformers

4.2.3.1 Introduction and Role in the Substation

Instrument transformers are the sensory interface between the high-voltage primary circuit and the low-level measurement, protection, and metering systems [1]. They perform two functions simultaneously: they reduce the high primary voltage and current to standardised secondary levels typically 100 V line-to-line and 1 A or 5 A respectively that protection relays, energy meters, and SCADA systems can safely process; and they provide galvanic isolation between the high-voltage circuit and the control room equipment, protecting both instrumentation and personnel from the direct hazards of the primary network [1].

In the 132 kV / 30 kV step-up substation serving the 96 MW photovoltaic plant, instrument transformers are installed at two voltage levels. At 132 kV, within the COMPASS GIS module, the current transformer designated TAL and the voltage transformers designated TVL and TVI provide the measurement signals for the HV protection relays and for the fiscal energy metering system in the *Locale Misure Fiscali* [8]. At 30 kV, within the MV switchboard, each feeder and transformer panel (H02, H03, H04) is equipped with dedicated current transformers, and the busbar panel (H05) houses a three-phase voltage transformer for busbar measurement [6].

4.2.3.2 Current Transformers

4.2.3.2.1 Operating Principle

A current transformer (CT) operates on the principle of electromagnetic induction [1][2]. The primary conductor which in a bar-type CT is the main busbar or cable passing through the toroidal core carries the primary current I_1. The alternating magnetic flux produced by this current induces a secondary EMF in the secondary winding, which drives a secondary current I_2 through the connected burden. For an ideal CT the relationship is:

$$I2 = \frac{I1}{n} \quad where \quad n = \frac{N2}{N1} \quad is\ the\ turns\ ratio$$

Real CTs deviate from the ideal due to the magnetising current required to drive the core flux, which introduces both a ratio error and a phase displacement [2]. These errors are the primary design parameters that differentiate accuracy classes.

The secondary circuit of a CT must never be open-circuited while the primary is carrying current. With no burden connected, the entire primary magnetomotive force drives the core into saturation, inducing a dangerously high secondary voltage that can damage insulation and

endanger personnel [1][2]. This is the fundamental operating constraint of every CT installation, and it is enforced by the short-circuit links installed on all unused secondary terminals in this substation.

4.2.3.2.2 Accuracy Classes per IEC 61869-2

IEC 61869-2 [2] defines two families of CT accuracy classes, serving distinct purposes:

- **Metering classes (0.1, 0.2, 0.2S, 0.5, 0.5S, 1, 3, 5):** These classes specify the maximum permissible ratio error and phase displacement at rated current and at a defined range of currents down to a fraction of rated [2].
- **Protection classes (5P, 10P, PS, PX):** These classes are defined by the Accuracy Limit Factor (ALF) the multiple of rated current up to which the CT maintains its specified composite error[2].

NOTE: The distinction between metering and protection cores in the same CT housing is fundamental [1][2]. Metering cores are designed for high accuracy at normal load current their magnetic circuit saturates intentionally at a modest multiple of rated current to protect the meter from fault current. Protection cores are designed to remain unsaturated at high multiples of rated current their saturation level is defined by the ALF [10].

4.2.3.2.3 Burden and Accuracy Limit Factor

The accuracy class of a CT is only guaranteed when the connected burden does not exceed the rated burden [2]. The burden is the total impedance of the secondary circuit the sum of the relay input impedance, the cable resistance, and the contact resistances expressed in volt-amperes (VA) at rated secondary current. If the actual burden exceeds the rated burden, the magnetising current increases, degrading both the ratio accuracy and the ALF performance [2][10]. For protection applications, an oversized burden reduces the effective ALF and may cause the CT to saturate during a fault before the relay has completed its measurement and operated [10].

The relationship between rated burden S_n, ALF, and the instrument security factor (FS) for metering cores is:

$$E_{knee} \approx \left(ALF \times In \times \left(Rct + \frac{Sn}{In^2} \right) \right) \qquad [\, for\ protection\ cores\,]$$

4.2.3.3 132 kV Current Transformer (COMPASS Module)

4.2.3.3.1 Nameplate Data from the SLD

The TAL current transformer is mounted within the SF_6 enclosure of the COMPASS GIS module, on the busbar section. The nameplate data as shown in the substation SLD are:

No.	Parameter	Value (SLD)	Standard / Reference
1	Designation	TAL	Substation SLD
2	Primary current taps	400 / 800 / 1600 A	IEC 61869-2 preferred values [2]
3	Secondary current (all cores)	1 A	IEC 61869-2 [2]
4	Number of cores / ratio string	3 cores: 400-800-1600 / 1-1-1	SLD: P1, P2 cores shown
5	Protection core accuracy class	5P30	IEC 61869-2 [2]
6	Protection core rated burden	30 VA	SLD
7	Metering core accuracy class	cl. 0.2	IEC 61869-2 [2]
8	Metering core rated burden	30 VA	SLD
9	Maximum system voltage Um	145 kV	CEI EN 60038 (132 kV class) [4]
10	Short-time thermal current Ith (1 s)	31.5 kA / 1 s	COMPASS GIS module rating
11	Dynamic (peak) current Idyn	80 kA peak	COMPASS GIS module rating

Table 5. TAL current transformer nameplate data as shown in the substation SLD. Three tappable primary ratios serve metering, protection, and differential functions separately.

4.2.3.3.2 Rated Burden Check

The connected secondary burden must not exceed the rated burden of 30 VA for either protection core [2]. The secondary burden is the sum of all connected impedances at 1 A secondary current:

- **Relay input burden:** QP.TR1 relay current input: approximately 0.5 VA at 1 A. 87T relay HV current input: approximately 0.5 VA at 1 A.
- **Secondary cable resistance:** Two-core 2.5 mm copper cable from COMPASS GIS to relay panel in control room, estimated 30 m each way. R = ρ × L / A = 0.0185 × 60 / 2.5 = 0.444 Ω. Burden at 1 A: S = I × R = 1 × 0.444 = 0.44 VA.
- **Contact resistances:** Estimated 0.1 VA total.

$$S_{total} = 0.5 + 0.5 + 0.44 + 0.1 = 1.54\,VA \quad \ll \quad 30\,VA\,rated$$

4.2.3.3.4 Protection Core Verification - Primary Limiting Current

The primary limiting current of the protection core is the product of the rated ALF and the primary rated current [2]:

$$I_{PL} = ALF \times I_{n,Primary} = 30 \times 1600 = 48\ kA$$

This must exceed the maximum prospective three-phase fault current at the 132 kV busbar from the Terna Grid Code datum:

$$I"k3, max, 132kV = 31.5\ kA \qquad \ll \qquad I_PL = 48\ kA$$

The single-phase earth fault current (I"k1 = 34.66 kA) also remains below I_{PL} = 48.0 kA (+38.5% margin). The TAL protection core on the 1600 A tap will not saturate for any credible fault at the 132 kV busbar [2][10].

TAL protection core (5P30, 1600 A tap): I_PL = 48.0 kA > I"k3,max = 31.50 kA (+52.4%). CT remains linear for all fault current magnitudes at the 132 kV busbar. Both three-phase and single-phase earth fault currents are within the unsaturated range.

4.2.3.4 Thermal and Dynamic Withstand Verification

The TAL must withstand the thermal and electrodynamic stresses of the maximum prospective fault current at the 132 kV busbar [1][2]:

$$I_{th,rated} = 31.5\ kA \ / \ 1\ s \quad \geq \quad I"k3, max = 31.5\ kA$$

$$I_{dyn,rated} = 80kA\ peak \quad \geq \quad ip, max = 78.75\ kA$$

TAL thermal and dynamic withstand: The TAL CT is fully rated for the 132 kV fault current envelope of this substation.

4.2.3.5 Voltage Transformers

4.2.3.5.1 Operating Principle

A voltage transformer also designated PT (potential transformer) in older literature operates on the same electromagnetic induction principle as a power transformer but is specifically designed for measurement accuracy rather than power delivery [1][3]. The primary winding is connected directly across the circuit voltage; the secondary winding produces a proportional output voltage at a standardised level (typically 100 V line-to-line, or 100/√3 V phase-to-earth for single-phase earthed-neutral VTs), with a transformation ratio $n = V_1 / V_2$ [3].

For a VT connected directly to a high-voltage busbar with a constant primary voltage, the dominant error source is the burden: as the connected burden increases, the secondary current

increases, increasing the primary leakage voltage drop and degrading accuracy [3]. VTs must therefore be operated within their rated burden.

4.2.3.6 132 kV Line-Side Voltage Transformer

4.2.3.6.1 Nameplate Data and Function

The TVL is a single-phase, oil-insulated, electromagnetic voltage transformer mounted within the COMPASS GIS module on the line side of the 152 DG circuit-breaker. In the SLD it appears with the following data:

No.	Parameter	Value (SLD)	Reference
1	Designation	TVL	Substation SLD
2	Primary voltage ratio	132 / √3 kV	= 76,210 V phase-to-earth
3	Secondary voltage ratio	0.1 / √3 kV	= 57.74 V phase-to-earth
4	Transformation ratio	76,210 / 57.74 = 1,320 : 1	CEI EN 60038 / IEC 61869-3 [3]
5	Metering core accuracy class / burden	cl. 0.2 / 50 VA	SLD
6	Protection core accuracy class / burden	cl. 3P / 75 VA	SLD
7	Maximum system voltage Um	145 kV	CEI EN 60038 [4]
8	BIL (lightning impulse withstand)	650 kV peak	CEI EN 60076-3, 132 kV class

Table 6. TVL voltage transformer nameplate data.[9].

4.2.3.6.2 Burden Verification

The connected burden on the TVL must be checked for both cores against the rated values of 75 VA (protection) and 50 VA (metering) [3]:

- **Protection core (cl. 3P, 75 VA):** QP.LINEA relay voltage input: 5 VA. Wiring burden (estimated): 5 VA. Total: 10 VA << 75 VA rated.
- **Metering core (cl. 0.2, 50 VA):** Fiscal meter voltage input: 5 VA. Data logger input: 3 VA. Wiring: 3 VA. Total: 11 VA << 50 VA rated.

4.2.3.7 TVI - 132 kV Busbar Voltage Transformer

4.2.3.7.1 Nameplate Data and Function

The TVI is mounted within the COMPASS GIS module on the busbar section between the 189L disconnector and the +TR1 HV terminal. Unlike the TVL, measures the network-side voltage for protection, the TVI measures the 132 kV busbar voltage [8]. The SLD shows:

No.	Parameter	Value (SLD)	Reference
1	Designation	TVI	Substation SLD
2	Voltage ratio	132 : V3 / 0.1 : V3 kV	Three-phase measurement (V3 = √3 factor)
3	Accuracy class / rated burden	cl. 0.2 / 50 VA	SLD
4	Um / BIL	145 kV / 650 kV peak	CEI EN 60038 [4] / CEI EN 60076-3

Table 7. TVI voltage transformer nameplate data. [8].

4.2.3.7.2 Burden Verification

Connected burden on the TVI metering core (cl. 0.2, 50 VA):

- CC.TR1 relay voltage input: 5 VA
- RTU analogue measurement input: 3 VA
- OLTC regulator voltage input: 5 VA
- Wiring burden (estimated): 5 VA

$$S_{total,TVI} = 5 + 3 + 5 + 5 = 18\,VA \quad \ll \quad 50VA\,rated$$

In these situations that we have high margin for reducing current cycling we can use Burden resistors. The TVI operates within its rated burden for all connected functions. Class 0.2 accuracy is maintained for the Terna SCADA measurement [8] and the OLTC regulator reference voltage.

4.2.3.8 MV Instrument Transformers - 30 kV Switchboard

4.2.3.8.1 Overview of MV CT and VT Installation

The 30 kV MV switchboard (H01–H05) is equipped with current transformers in each feeder and transformer panel and a voltage transformer in the busbar measurement panel [6].

Panel	Device	Ratio	Class	Burden	Function
H02	CT P1	2500 / 1 A	5P20	5 VA	relay 50/51 - H02 TR1 MV feeder
H02	CT P2	2500 / 1 A	5P30	5 VA	87T differential relay - MV side CT
H03	CT	1200 / 1 A	5P20	5 VA	relay 50/51/67N - DDR2 feeder
H04	CT	1200 / 1 A	5P20	5 VA	relay 50/51/67N - DDR1 feeder
H05	VT	30,000 / 100 V	cl. 0.2	30 VA	30 kV busbar measurement and 67N
H	CT 0-seq.	50 / 1 A	5P20	0.5 VA	67N directional earth fault

Table 8. MV instrument transformers in the 30 kV switchboard H01–H05. H02 has two CT cores for protection (P1) and differential (P2) functions separately.

4.2.3.8.2 H02 Current Transformers - TR1 MV Feeder (2500/1 A)

The H02 panel carries the full TR1 secondary current - up to 2,100 A at ONAF rated power. The 2500 A primary rating provides 19% headroom above the maximum load current of 2,100 A [2].

For the 87T differential relay, the CT ratio matching between the HV side (TAL, 1600/1 A) and the MV side (H02 CT, 2500/1 A) is managed internally by the relay's software compensation algorithm [11].

4.2.3.8.3 H03/H04 Current Transformers - DDR Feeders (1200/1 A)

The H03 (DDR2) and H04 (DDR1) feeder panels each carry the output current of one 96 MW PV feeder cable up to approximately 900 A at full generation. The 1200 A primary rating provides a 33% margin above maximum load [2]. The single 5P20 core supplies the feeder relay (functions 50, 51, and 67N directional earth fault).

The protection core verification at the MV busbar maximum fault [2]:

$$I_{PL,H03,H04} = ALF \times I_n = 20 \times 1200 = 24\ kA$$

$$I"k3, max, 30kV = 15.23\ kA \quad \ll \ I_PL = 24\ kA$$

The 67N directional earth fault function requires a zero-sequence current measurement. This is provided by the residual current connection the three phase CTs are connected in a sum configuration so that the secondary output $3I_0 = I_A + I_B + I_C$ represents the zero-sequence current [2][7]. $I"k3, max, 30kV$ is calculated in Medium Voltage (MV) Switchgear chapter.

4.2.3.8.4 H05 Busbar VT - 30 kV (30,000/100 V, cl. 0.2)

TOV check for isolated neutral: during a single-phase earth fault on the 30 kV network, the healthy phase-to-earth voltage rises to U_n = 30,000 V [5][7]. The VT must withstand this without saturation or insulation failure. With Um,VT = 36 kV, the TOV during an earth fault is 30,000 V equal to 83.3% of Um,VT. The CEI EN 60071-1 [5] voltage factor for an isolated neutral network is VF = 1.9 for 30 seconds, requiring the VT to withstand 1.9 × 17,321 = 32,910 V phase-to-earth. With a rating of 36 kV / √3 = 20,785 V phase-to-earth continuous and a standard VF = 1.9 × Un/√3 = 1.9 × 17,321 = 32,910 V for 30 s:

$$VT\ TOV\ capability = 36000\ V \qquad \geq \qquad TOV, 30s = 32910\ V$$

H05 VT TOV check: Um,VT = 36 kV ≥ TOV = 32.91 kV for 30 s. The H05 busbar VT withstands the phase-to-earth voltage rise during a single-phase earth fault on the isolated 30 kV network without insulation stress [3][5].

4.2.3.8.5 Zero-Sequence CT - 50/1 A Earth Fault Measurement

The H05 panel also contains a toroidal zero-sequence CT (core balance CT) rated 50/1 A, which measures the total capacitive earth fault current I_{C0} of the 30 kV network directly [2][7]. The primary conductor of all three phases passes through the toroid; under balanced conditions, the net flux is zero and the secondary output is negligible. During a single-phase earth fault, the unbalanced capacitive currents produce a net primary magnetomotive force that drives a measurable secondary current proportional to $3I_0$ [2].

The rated primary of 50 A is compared against the maximum capacitive earth fault current:

$$I_{C0,analytical} = 35.5\ A \quad < \quad I_{n,CT} = 50\ A$$

$$I_{C0,AMPERE} = 33\ A \quad < \quad I_{n,CT} = 50\ A$$

All Instrument Transformers pass verifications. Every current transformer and voltage transformer in the 132 kV switchyard and 30 kV MV control room satisfies its rating requirements for accuracy class, burden, thermal withstand, dynamic withstand, and insulation level [1][3]. $I_{C0,analytical}$ and $I_{C0,AMPERE}$ are calculated in Protection and Control chapter.

4.2.4 Surge Arresters (Scaricatori di Sovratensione)

4.2.4.1 Introduction and Purpose

Overvoltages on high-voltage networks arise from two mechanisms: lightning discharges, producing steep-fronted travelling waves, and switching operations, producing oscillatory transients [2][7]. Both can exceed the dielectric strength of transformer insulation, causing partial discharges, degradation, or catastrophic winding failure.

The surge arrester +SA is the primary overvoltage protection device for the 132 kV / 30 kV transformer TR1, operating as a voltage-dependent non-linear resistance: under normal voltage it presents near-infinite impedance; when voltage exceeds the protection level, impedance collapses, diverting surge current to earth and clamping voltage to the arrester's V-I characteristic level, recovering automatically once the transient passes [1].

The +SA is a ZnO metal-oxide gapless arrester, station duty class, installed at the 132 kV terminals of TR1 within the COMPASS GIS switchyard [1]. Selection must simultaneously satisfy: continuous operating capability; adequate energy absorption for lightning and switching surges; and insulation coordination margin below the TR1 HV winding BIL [3][7].

4.2.4.2 Operating Principle of Zinc Oxide Metal-Oxide Arresters

4.2.4.2.1 Non-Linear Resistance Characteristic

The active element is a sintered ZnO disc stack doped with Bi_2O_3 and other binary oxides [1]. Grain boundary p-n junctions govern the behaviour:

$$I = k \cdot U^{\alpha}$$

The absence of a spark gap eliminates follow current, arc extinction, and mechanical wear clamping begins within nanoseconds [1]. Steady-state leakage at COV is typically 0.5–2.0 mA resistive. The V-I characteristic has three regions [1][7]:

- Leakage region: current in μA range; arrester effectively open circuit
- Transition region: resistive component dominates near U_ref (1 mA DC); normal operating zone
- High-current clamping region: 1 A to I_n (10 kA peak); clamping voltage defined by LIPL at 10 kA

Thermal stability requires that heat from leakage current and surge injection is dissipated below ~80°C disc temperature, preventing runaway. For the 132 kV system with 365 m OHL, switching surge energy is ~2–4 kJ/kV_r, well within station-class capability of 6–10 kJ/kV_r.

4.2.4.3 System Data and Overvoltage Environment

The maximum TOV on healthy phases during a phase-to-earth fault (solidly earthed, k ≤ 1.4) is:

$$U_{TOV} = k \times \left(\frac{U_n}{\sqrt{3}}\right) = 1.40 \times \left(\frac{132000}{1.732}\right) = 106.70\ kV\ rms$$

This must be withstood without thermal runaway for 1 second per CEI EN 60071-1 [2].

4.2.4.4 Arrester Selection Procedure

4.2.4.4.1 Step 1 - Continuous Operating Voltage (COV / Uc)

$$U_{ph-e} = \frac{U_m}{\sqrt{3}} = \frac{145000}{1.732} = 83.71\ kV\ rms$$

The COV of the selected arrester must satisfy $U_c \geq U_{p\text{-}e}$. The installed arrester has U_c = 84 kV, which meets this requirement.

4.2.4.4.2 Step 2 - Rated Voltage (Ur) for TOV Withstand

For a 1-second duration, the TOV capability factor of a standard arrester is approximately 1.10 × U_r (IEC 60099-4 Annex A). The condition is therefore:

$$1.10 \times U_r \geq U_{TOV} \implies U_r \geq \frac{U_{TOV}}{1.10} = \frac{106700}{1.10} = 97\ kV$$

The installed arrester has U_r = 120 kV, providing:

$$TOV_{capability} = 1.10 \times U_r = 1.10 \times 120000 = 132\ kV\ rms$$

This substantial margin 23.7% ensures that the arrester remains thermally stable following a solid earth fault on the 132 kV network before Terna protection operates [1][9].

4.2.4.4.3 Step 3 - Arrester Class and Nominal Discharge Current

For a 132 kV application connected to a 365-metre overhead line with a maximum three-phase short-circuit current of 31.5 kA [9], station class 2 (nominal discharge current I_n = 10 kA, line discharge class 2) is the appropriate selection [1][7]. The installed arrester is rated I_n = 10 kA nominal discharge current, station class 2, consistent with the system exposure and line length.

4.2.4.4.4 Step 4 - Lightning Impulse Protective Level (LIPL)

The Lightning Impulse Protective Level U_p(10 kA) is the residual voltage across the arrester terminals when a standard 8/20 µs current impulse of 10 kA peak is applied [1][10]. For the selected arrester:

$$LIPL = Up\ (10\ kA) = 288\ kV\ peak$$

4.2.4.4.5 Installed Arrester Nameplate Summary

No.	Parameter	Value	Requirement / Basis
1	Type	ZnO, gapless MO	CEI EN 60099-4 [1]
2	Continuous operating voltage Uc	84 kV rms	≥ Um/√3 = 83.74 kV
3	Rated voltage Ur	120 kV rms	≥ UTOV/1.10 = 97.0 kV [1]
4	Nominal discharge current In	10 kA (8/20 µs)	Station class 2
5	Lightning impulse prot. level LIPL (at 10 kA)	288 kV peak	Governs BIL coordination
6	Switching impulse prot. level SIPL (at 2 kA)	235 kV peak	Governs SIL coordination [3]
7	Discharge class (line)	Class 2	132 kV, 365 m OHL
8	Maximum system voltage class Um	145 kV	= Um,system
9	TOV capability (1 s duration)	132.0 kV rms	≥ U_TOV = 106.7 kV (+23.7%)
10	Energy handling capability	≥ 6 kJ/kVr	Station class 2 standard

Table 9. Installed surge arrester (+SA) nameplate parameters.

4.2.4.5 Insulation Coordination

4.2.4.5.1 Required Withstand Voltage and Safety Factor

CEI EN 60071-2 defines the required withstand voltage as the product of the representative overvoltage and the coordination factor K_{co} = 1.15 (to account for statistical dispersion, ageing, and atmospheric effects), multiplied by the atmospheric correction factor K_a (= 1.0 for equipment at altitudes below 1,000 m, which applies here), and a safety factor K_s = 1.05 [3][7]:

$$U_w = U_{rp} \times K_{co} \times K_a \times K_s = 288 \times 1.15 \times 1 \times 1.05 = 347.6\ kV\ peak$$

The standardised BIL for the 132 kV voltage class per CEI EN 60076-3 is 550 kV peak. The installed TR1 HV winding BIL of 550 kV peak must therefore satisfy $U_w \leq$ BIL [4].

4.2.4.5.2 Switching Impulse Coordination

For equipment at voltages above 300 kV, the switching impulse withstand level (SIL) governs design [3][7]. At 132 kV, lightning impulse coordination dominates, but a switching impulse check is performed for completeness.

$$K_{SIL} = \frac{SIL_{TR1}}{SIPL_{SA}} = \frac{450kV}{235kV} = 1.91 \geq 1.15\ minimum$$

Both lightning and switching impulse coordination are satisfied with substantial margin.

4.2.4.6 Complete Verification Summary

Table consolidates all verification checks performed for the +SA surge arrester, providing a structured pass/fail assessment against each applicable criterion.

No.	Verification Criterion	Requirement	Calculated / Installed	Result
1	COV ≥ Um/√3 (normal steady-state)	≥ 83.74 kV rms	Uc = 84.00 kV	OK
2	Ur ≥ UTOV / 1.10 (TOV, 1 s duration)	≥ 97.0 kV rms	Ur = 120.0 kV	OK
3	TOV capability ≥ UTOV (1 s)	≥ 106.70 kV rms	1.10 × 120 = 132.0 kV	OK
4	Um,SA ≥ Um,system (voltage class)	145 kV	Um,SA = 145 kV	OK
5	K_BIL = BIL / LIPL ≥ 1.20 (lightning impulse)	≥ 1.20	650 / 288 = 2.26	OK
6	K_SIL = SIL / SIPL ≥ 1.15 (switching impulse)	≥ 1.15	450 / 235 = 1.91	OK
7	Required withstand voltage Uw ≤ BIL	≤ 650 kV peak	Uw = 347.6 kV	OK
8	Discharge class adequate for OHL exposure	Class 2 min.	Class 2 installed	OK

Table 10. Surge arrester (+SA) complete verification summary. Eight criteria checked against CEI EN 60099-4 and CEI EN 60071-2.

All verification criteria pass. The installed ZnO metal-oxide surge arrester (Uc = 84 kV, Ur = 120 kV, In = 10 kA, LIPL = 288 kV) satisfies all requirements of CEI EN 60099-4 and CEI EN 60071-2 for the 132 kV COMPASS installation.

4.2.4.7 Relationship to the Overall Insulation Coordination Study

All 132 kV equipment BILs are selected relative to the arrester LIPL = 288 kV [3][7], ensuring no component BIL falls below the protective level.

Equipment	BIL (kV peak)	LIPL (kV peak)	Result
TR1 HV winding (YNd11, 132 kV side)	650	288	OK
COMPASS GIS module (Um = 145 kV)	650	288	OK
TAL current transformer (132 kV, 5P30)	550	288	OK
TVL/TVI voltage transformers (132/√3 kV)	550	288	OK
OHL insulator strings (Crocco ACSR, 365 m)	≥ 650	288	OK

Table 11. Complete 132 kV insulation coordination hierarchy. LIPL = 288 kV (arrester +SA) is the reference protective level for all components. All K_BIL values exceed the 1.20 minimum.

4.2.5 Circuit Breaker (Interruttore)

4.2.5.1 Function and Role

The circuit breaker (CB) is the only HV device capable of interrupting both normal load currents and full prospective short-circuit currents (tens of kA at 132 kV). Per IEC 62271-100, it is defined as *"a mechanical switching device capable of making, carrying and breaking currents under normal and abnormal circuit conditions such as short circuit."*

Within the double-busbar layout, each bay has one three-pole CB performing three roles:

- **Normal switching:** energisation/de-energisation of lines, transformers, and generation units during reconfiguration and maintenance.
- **Fault clearing:** automatic tripping on protection relay command, interrupting fault current within rated breaking time.
- **Auto-reclosing:** single/multi-shot reclosing after transient faults on overhead line bays, restoring supply without operator intervention.

The CB also participates in CB failure protection (ANSI 50BF), breaker-end fault protection, and SCADA alarm generation via auxiliary contact signals to the bay IED [1].

4.2.5.2 Interrupting Technologies at 132 kV

Arc extinction requires rapid cooling and deionisation of the arc plasma (5,000–20,000 K) so that dielectric strength recovers before the transient recovery voltage (TRV) causes a restrike [3].

SF_6 Gas Circuit Breakers: SF_6 dominates transmission-voltage CBs due to: dielectric strength 2.5–3× air at atmospheric pressure; exceptional arc quenching via endothermic dissociation/exothermic recombination cycle; and strong electronegativity that captures free electrons, accelerating post-zero dielectric recovery.

Modern 132 kV CBs use a combined puffer/self-blast design: at high fault currents, arc energy drives thermal self-blast (reducing mechanism energy demand); at low currents, the puffer mechanism ensures reliable extinction. This achieves optimal performance across the full current range.

4.2.5.2.1 Comparison of Technologies for 132 kV Application

Characteristic	SF6 (puffer/self-blast)	SF6-free (g3 / clean air)
Market maturity at 145 kV	Very high (>50 yrs)	Limited (< 5 yrs)
Dielectric medium GWP	23,500 × CO_2	< 1 × CO_2
Interrupting chamber size	Compact	Larger (lower diel. str.)
Mechanism energy required	Medium–High	High
Contact life (full SC ops)	~50 at rated Isc	~50 at rated Isc
Maintenance interval	3–5 years	3–5 years
Cost relative to SF6	Reference (1×)	+15 to +30%
EU F-gas compliance	Restricted post-2030	Fully compliant
Project specification	Permitted (existing bays)	Considered (if available)

Table 12. Comparison of circuit breaker interrupting technologies at 145 kV

4.2.5.3 Physical Configurations: Live-Tank vs. Dead-Tank

Live-tank CBs mount the interrupting chamber at HV potential atop support insulators, with the mechanism at ground level connected via an insulating rod. Advantages: compact footprint, lighter weight, lower cost, easy visual inspection. Limitation: CTs cannot be integrated separate free-standing CTs are required (standard European AIS practice).

Dead-tank CBs house all three phases in a single grounded metallic tank with HV bushings. Key advantage: CTs mountable directly on bushing flanges, reducing foundations and structures. Better seismic performance due to lower centre of gravity.

Selection: Live-tank CBs are adopted for this outdoor AIS 132 kV substation, consistent with Italian/European practice and the existing civil infrastructure being retained [4].

4.2.5.4 Operating Mechanism

The **spring-charged mechanism** is the standard for new 132 kV CBs. Key components:

- **Closing spring:** charged by a DC motor (110/220 V DC battery) within 5–15 s after each operation, independent of AC supply [2][3].
- **Opening spring:** compressed during closing; releases energy to open contacts on trip command
- **Latch and trip mechanism:** closing/opening latches released by electrical pulse from bay IED or manual command

- **Anti-pumping relay:** prevents repetitive close-trip cycling under a sustained close command with persistent fault

The critical advantage for protection is independence from AC supply: once charged, both trip and close operations require only the small trip/close coil energy (~30–100 W for <50 ms) available from the station battery.

4.2.5.5 Electrical Ratings and Parameters

4.2.5.5.1 Rated Voltage and Maximum System Voltage

Ur ≥ Um of the system. The Terna 132 kV network has a maximum system voltage Um = 145 kV per CEI EN 60038.

The 152 DG rated voltage is 145 kV = Um the circuit-breaker is rated exactly for the maximum system voltage class [5].

4.2.5.5.2 Rated Normal Current

Ir ≥ maximum continuous current in the circuit. The maximum current through 152 DG is the same as the TR1 HV side current full ONAF operation simultaneously with BESS discharge:

$$I_{TR1,HV} = \frac{110MW}{\sqrt{3} \times 132000} = 481\ A$$

$$I_{BESS,HV} = \frac{25MW}{\sqrt{3} \times 132000} = 109\ A$$

$$I_{max,HV} = 481 + 109 = 590\ A$$

This is the most generous margin in the bay. The 1,600 A rating is determined by the standard preferred values of IEC 62271-1 for this voltage class.

4.2.5.5.3 Rated Short Circuit Making Current (Peak)

Ima,rated ≥ ip,max (peak short-circuit current).

The peak current at the 132 kV busbar with peak factor κ = 1.70 (X/R = 15):

$$ip, max = \kappa \times \sqrt{2} \times I"k3, max = 1.70 \times 1.414 \times 31500 = 75.8\ kA\ peak$$

Per IEC 62271-100, the rated making current is related to the rated breaking current by:

$$Ima = 2.5 \times Isc, rated = 2.5 \times 31500 = 78.75\ kA\ peak$$

Ima,rated = 78.75 kA ≥ ip,max = 75.8 kA

The standard 2.5 factor of IEC 62271-100 assumes a DC component corresponding to $\kappa = 2.5/\sqrt{2} = 1.768$, which is slightly above the $\kappa = 1.70$ applicable for X/R = 15 at 132 kV. The margin is small (+3.9%) but sufficient.

4.2.5.5.4 Rated Short-Time Withstand Current

$I_{th,rated} \geq I''_{k3,max}$ for the specified duration.

The thermally equivalent fault current for 1 second (including DC component):

$I_{th,eq} = I''_{k3,max} \times \sqrt{(1 + \text{DC factor})} = 15.1 \times \sqrt{1.40} = 15.1 \times 1.183 = 17.86$ kA

The standard rated short-time withstand current for a 31.5 kA class circuit-breaker per Codice di rete is for 1 second.

4.2.6 Fire Safety in HV Substations - General Rules

4.2.6.1 Overview and Objectives

Although substation fires are relatively infrequent, their consequences can be severe: prolonged supply interruptions, significant asset losses, and safety hazards for personnel. Fire protection is addressed at design stage through prevention, passive mitigation, and active suppression, guided by four objectives:

- **Operational safety:** protecting personnel and the public from fire effects (shrapnel, radiant heat, toxic smoke, burning oil)
- **Supply reliability:** minimising fire-induced outage of the 132 kV connection and renewable generation loss
- **Asset preservation:** protecting oil-filled power transformers the highest-value, longest-lead-time assets
- **Regulatory compliance:** Italian *Codice di Prevenzione Incendi* (D.M. 3 August 2015) and, for the BESS, *Regola Tecnica Verticale* V.11 (D.M. 30 December 2021)

4.2.6.2 Fire Hazards

The dominant hazard is ignition of transformer mineral insulating oil (~20,000–40,000 litres per unit). Principal scenarios:

- Explosive transformer failure projecting shrapnel and burning oil up to 76 m
- Pool fire with flame heights exceeding 30 m, causing thermal radiation ignition of adjacent structures
- Burning oil spreading into cable trenches, extending fire to secondary systems
- Smoke/soot contamination of control rooms and relay panels causing secondary damage

Secondary hazards include the BESS containers (Chapter 4), MV switchgear building, and control wiring. Replacement of oil-insulated breakers with SF_6 units is itself a key prevention measure.

4.2.6.3 Fire Prevention Measures

- **SF_6 circuit breakers** in all HV bays, eliminating fire risk from oil-filled interrupters

- **Lightning protection** (overhead earth wire and surge arresters) reducing probability of lightning-induced equipment failures
- **High-flashpoint insulating oil** specified for power transformers where technically compatible
- **Sealed cable trenches:** liquid-tight walls and non-combustible covers within 6 m of oil-filled equipment; fire-stop barriers ≥ 2 hours at all cable entries into the relay/control building
- **Site grading and layout:** transformers positioned downslope relative to the control building; prevailing wind direction considered in equipment orientation

4.2.6.4 Passive Mitigation Measures

- **Spatial separation:** each transformer in a dedicated reinforced concrete bay per IEC 61936-1 and CEI 11-1
- **Oil containment pits:** oil-tight concrete pits sized for 110% of maximum transformer oil volume, filled with crushed stone (≥15 cm depth, ≥19 mm diameter) to suppress flame propagation across the oil surface
- **Ground cover:** crushed stone throughout the switchyard to suppress spreading oil spill fires
- **Fire-rated cable penetrations:** all penetrations through fire-rated walls/floors sealed to minimum EI 120 (2 hours)

4.2.6.5 Active Fire Protection

- **Automatic water spray deluge system:** fixed open-head deluge above each transformer, minimum application density **10 L/min/m²**. Activated automatically via dual-detector coincidence logic or manually from the control room. Activation simultaneously trips the associated HV and MV circuit breakers before water is applied
- **Fire detection:** linear heat detection cables along transformer perimeter combined with optical flame detectors, wired to the substation FACP integrated with SAS/SCADA for remote alarm transmission

4.2.6.6 Emergency Response

Electrical isolation before suppression activities can take up to one hour in unmanned substations. The design is therefore oriented toward automatic suppression, reducing dependence on timely manual intervention. Supporting measures include:

- Pre-incident planning documentation (hazard identification, isolation procedures, site plans) provided to the local *Vigili del Fuoco*
- Clearly marked isolation points and emergency access routes within the substation perimeter
- Firefighting water supply connection point at the substation boundary, compatible with fire brigade equipment.

4.2.7 Medium Voltage (MV) Switchgear

4.2.7.1 Introduction

The 30 kV switchboard is the central node of the MV electrical system: it receives power from two MV feeder cables from the PV inverter stations, routes it to the 132/30 kV step-up transformer TR1, and supplies the auxiliary transformer TRAux. It consists of five functional units (H01–H05) on a single busbar, rated 30 kV / 2,000 A / 20 kA [2].

4.2.7.2 Electrical Design Calculations

4.2.7.2.1 Rated Normal Current of the MV Busbar

The maximum continuous current on the MV busbar is determined by the rated active power output of the PV plant. Since transformer TR1 is fed exclusively by the PV generation system, it will never be loaded beyond the plant's rated output of $P_{PV} = 96MW$ [6].

$$I_r = \frac{P_{PV}}{\sqrt{3} \times U_n \times cos\varphi} = \frac{96 \times 10^6}{\sqrt{3} \times 30 \times 10^3 \times 1.0} = 1847\ A$$

Applying 5% service overload margin per CEI EN 62271-200:

$$I_{r,design} = 1.05 \times 1847 = 1939\ A$$

Next standard preferred rating: 2,000 A. The incoming CB (52AT) is specified at 2,500 A / 20 kA per available catalogue ratings.

4.2.7.2.2 Short-Circuit Current Calculations

Short-circuit currents are calculated in accordance with the impedance method of CEI EN 60909-0 using the equivalent voltage source at the fault location [4].

4.2.7.2.3 Transformer Impedance Referred to the MV Side

The transformer short-circuit impedance is referred to the MV voltage base. The reference apparent power for the impedance voltage $V_{cc} = 12.5\ \%$ is the ONAN nameplate rating Sn = 90 MVA per CEI EN 60076-1.

$$Z_{base,MV} = \frac{U_n^2}{S_n} = \frac{30000^2}{(90 \times 10^6)} = 10.00\ \Omega$$

$$Z_{Transformer(Nominal)} = \left(\frac{V_{cc}}{100}\right) \times Z_{base,MV} = \left(\frac{12.5}{100}\right) \times 10 = 1.250\ \Omega$$

Applying CEI EN 60076-1 manufacturing tolerance of −7.5% (minimum impedance → maximum fault current):

$$V_{cc,min} = 12.5\% \times (1 - 0.075) = 11.5625\ \%$$

$$Z_{Transformer,min} = \left(\frac{11.5625}{100}\right) \times 10 = 1.156\ \Omega$$

4.2.7.2.4 Upstream Network Impedance Referred to the MV Side

The 132 kV Terna transmission network is represented by its Thevenin equivalent impedance, calculated from the maximum three-phase symmetrical short-circuit current at the 132 kV busbar as stated on the SLD at position 152 DG: $I"k_{HV} = 31.5\ kA$ [6].

$$Z_{network,HV} = \frac{U_{HV}}{\sqrt{3} \times I"k_{HV}} = \frac{132000}{\sqrt{3} \times 31500} = 2.419\ \Omega$$

The worst case (maximum fault current) occurs at the maximum tap position, which gives the highest transformation ratio and therefore the smallest network impedance referred to the MV side:

$$U_{HVmax} = 132 \times (1 + 0.15) = 151.8\ kV \quad ; \quad t_{max} = \frac{151.8}{30} = 5.06$$

$$Z_{Network,MV(Max\ tap)} = \frac{Z_{Network,HV}}{t_{max}^2} = \frac{2.419}{(5.06)^2} = 0.0945\ \Omega$$

4.2.7.2.5 Total Impedance and Initial Symmetrical Short-Circuit Current

The total Thevenin impedance at the MV busbar fault point is the series combination of the network impedance and the minimum transformer impedance (both referred to the MV side).[4].

$$Z_{total} = Z_{Network,MV} + Z_{transformer,min} = 0.0945 + 1.156 = 1.251\ \Omega$$

$$I"k3 = \frac{(c \cdot U_n)}{(\sqrt{3} \cdot Z_{total})} = \frac{(1.10 \times 30000)}{(\sqrt{3} \times 1.251)} \approx 15.23\ kA$$

4.2.7.2.6 Peak Short-Circuit Current

The peak short-circuit current accounts for the DC asymmetrical offset at fault inception. Factor $\kappa = 1.7$ is applied as a conservative approximation for a network dominated by transformer leakage reactance ($X/R >> 1$) per CEI EN 60909-0 [4]:

$$i_{peak} = \kappa \cdot \sqrt{2} \cdot I"k3 = 1.7 \times 1.4142 \times 15230 = 36.6\ kA$$

4.2.7.3 MV Switchboard Description, Cabinets Configuration

The switchboard is metal-clad, single-busbar, indoor type with LSC2B category per CEI EN 62271-200, permitting maintenance on any functional unit without de-energising the busbar. All panels are interconnected by a continuous 30 kV copper busbar; communication with RTU/SCADA is via IEC 61850 fibre optic links.

Figure below shows the schematic arrangement of the five-cabinet lineup. The red dashed lines represent the MV power cable feeders connecting to the respective loads or sources.

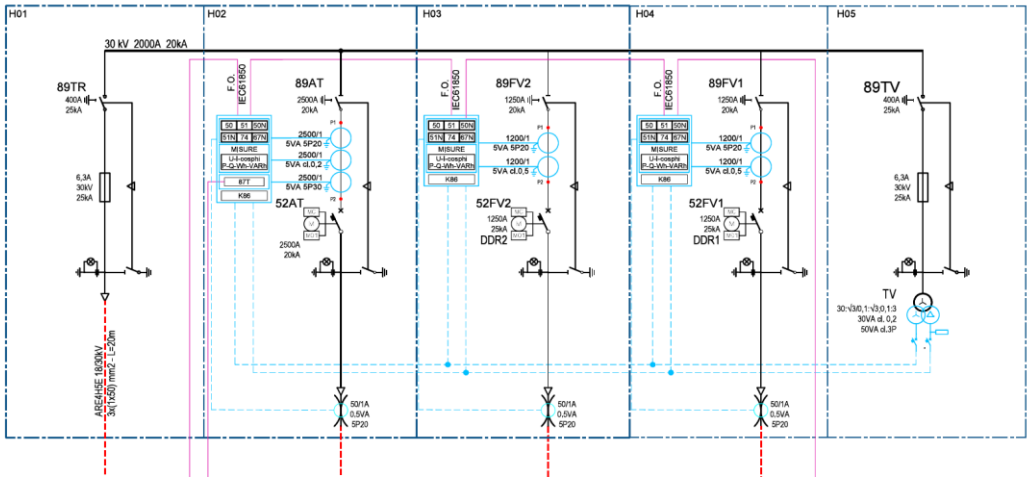


Figure 7. Substation Control room Switchgear

H01	H02	H03	H04	H05
Auxiliary Transformer Feeder	Step-Up Transformer in Switchyard	PV Feeder 2	PV Feeder 1	Busbar VT Measurement Panel
TRAux 160 kVA 30/0.4 kV	TR1 90/110 MVA 132/30 kV	P = 48521 MW	P = 47955 MW	TV 30/0.1 kV 30VA cl.0.2

Table 13. MV switchboard five-cabinet lineup schematic

The cable ARE4H5E 18/30 kV with 3×(1×50) mm² cross-section is rated for the 30 kV voltage class per CEI UNEL 35024. The maximum load current on this feeder at full auxiliary load (TRAux = 160 kVA ONAF) is:

$$I_{TRAux} = \frac{S_{TRAux}}{\sqrt{3} \cdot U_n} = \frac{160000}{\sqrt{3} \times 30000} = 3.1$$

4.2.8 Medium Voltage Cable Sizing

4.2.8.1 Introduction and Scope

This chapter presents the sizing calculations for the medium voltage (MV) cables of the 30 kV collector system of the 132 kV step-up substation associated with a 96MW photovoltaic (PV) plant connected to the Terna HV transmission grid. Three MV cable circuits are analysed:

- Bay H03 - PV plant cabinets → 30 kV substation busbar (L = 2350 m, P = 48.521 MW)
- Bay H04 - PV plant cabinets → 30 kV substation busbar (L = 2350 m, P = 47.955 MW)
- Bay H02 - 30 kV control room busbar → Transformer TR1 (L = 50 m, S = 110 MVA)

4.2.8.2 MV cable choosing by Cablizer Software

By using this software, we can see that if the cable that we choose is underestimated or not and it is important because of thermal effects of current. By inserting soil and ambient temperature and choosing type of trench or direct buried then we must choose current which cable should carry and length of cable then software itself choose proper cable for that location [1]. Here is some results from software and methodology of sizing cables:

4.2.8.3 Medium Voltage Cables from PV Plant Cabinet to Substation Control Room



Figure 8. .Arrangement of Medium voltage cables (PV Plant to Substation Control room)

These cables are directly buried and in this case cables (A and C) and (B and D) are parallel. Cables A and C carry 977.624 A and Cables B and D are carrying 989.181 A [2][3].
By using Cableizer software we can obtain Approximate steady-state temperature field, for cables A,B,C and D is like below:

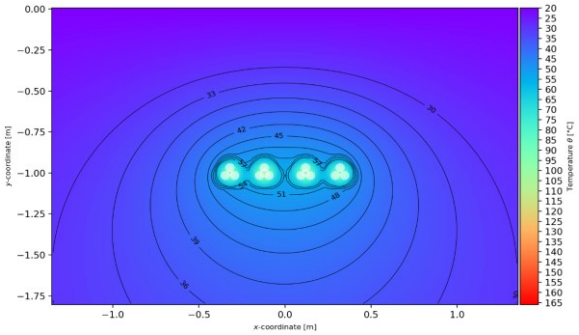


Figure 9. Approximate steady-state temperature field, for cables A,B,C and D

4.2.8.4 Medium Voltage Cables from Substation Control Room to Power Transformer

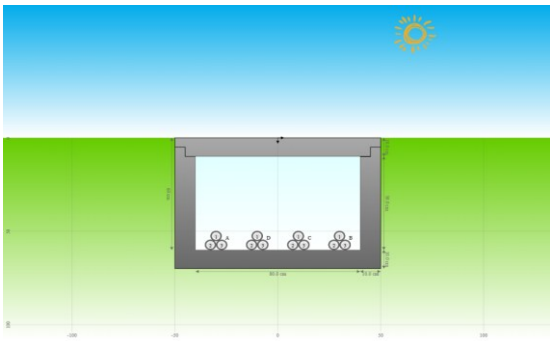


Figure 10. Arrangement of Medium voltage cables (Control room to Power Transformer)

In this location as the cables are inside the Substation, they are inside the trough and not directly buried and their Approximate steady-state temperature field is like below:

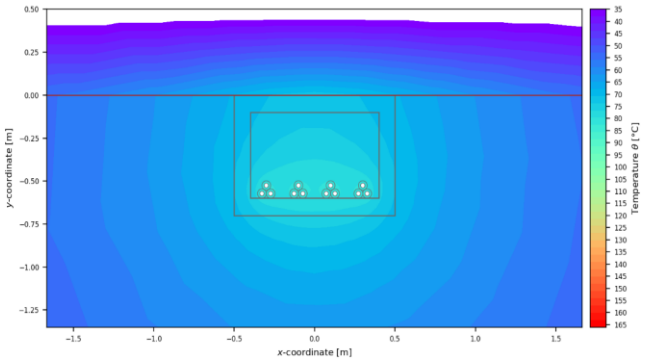


Figure 11. Approximate steady-state temperature field, for cables A,B,C and D from CR to TR1

4.2.8.5 Sizing Methodology and Applicable Standards

4.2.8.5.1 Three Governing Criteria

- **Thermal ampacity**: derated continuous current rating must exceed maximum load current.
- **Voltage drop**: line-to-line drop under full load must not exceed 3 % (CEI 11-17).

- **Short-circuit thermal withstand**: conductor must survive I_{sc} for the protection clearing time (IEC 60949).

4.2.8.5.2 Ampacity - IEC 60287 / CEI 20-91

Base ampacity from CEI 20-91 / IEC 60287 at reference conditions ($\theta_{soil} = 20℃$, $\rho_s = 1.0\ K.m/W$, $\theta_{cond_{max}} = 90℃$):

Installation	Section	Iz_base (A)	Reference
Direct buried, trefoil (H03/H04)	500 mm² Al	715 A	CEI 20-91 Table B.52 / IEC 60287
Free air, trefoil (H02 in trough)	500 mm² Al	630 A	CEI 20-91 Table B.53 / IEC 60287

Table 14. Cables Ampacity

4.2.8.6 Voltage Drop

$$\Delta U = \sqrt{3} \cdot I \cdot (R_{eq} \cdot cos\varphi + X_{eq} \cdot sin\varphi)$$

$$R_{eq} = \frac{(r90 \cdot L)}{n}\ [\Omega]$$

$$X_{eq} = \frac{(x \cdot L)}{n}\ [\Omega]$$

$$r90 = r20 \cdot [1 + \alpha \cdot (90 - 20)] \qquad \alpha = 0.00403\ /℃\ (AL)$$

$$\Delta U\% = \left(\frac{\Delta U}{V_n}\right) \cdot 100 \qquad V_n = 30kV$$

Parameter	Symbol	Value	Condition
DC resistance (IEC 60228 Cl.2)	r20	0.0601 Ω/km	20 °C
AC resistance at operating temp	r90	0.0770 Ω/km	90 °C
Reactance (XLPE 30 kV)	x	0.093 Ω/km	—

Table 15. Cable Parameters

4.2.8.7 Short-Circuit Thermal Withstand (IEC 60949)

$$S_{min} = \frac{(I_{SC} \cdot \sqrt{t})}{k}\ [mm^2]$$

$I_{sc} = 20\ 000\ A$ $(Busbar\ fault\ level)$

$t = 1\ s$ $(maximum\ protection\ clearing\ time)$

$k = 94$ $(AL\ /\ XLPE\ , \theta_i = 90℃ \longrightarrow \theta_f = 250℃ - IEC\ 60949$

$$S_{min} = \frac{(20\ 000 \cdot \sqrt{1})}{94} = 212.8\ mm^2\ (minimum\ per\ phase)$$

4.2.8.8 By doing three Governing Criteria based on each underground MV cables power and trench we get tables below:

Bay	Route	P / S	Length	I rated (A)	I/group (A)	Iz/group (A)	Cable
H03	PV→Bus	48.52 MW	2350 m	983.6	494.6	530	3×(2×500 mm²)
H04	PV→Bus	47.96 MW	2350 m	972.1	488.8	530	3×(2×500 mm²)
H02	Bus→TR1	110 MVA	50 m	2117	487.5	490	3×(4×500 mm²)

Table 16. Technical Parameters and Current Calculations

Bay	Calculated selection	SLD selection	Agreement
H03	ARE4H5E 18/30 kV — 3×(2×500 mm²)	ARE4H5E 18/30 kV 3×(2×500 mm²)	OK
H04	ARE4H5E 18/30 kV — 3×(2×500 mm²)	ARE4H5E 18/30 kV 3×(2×500 mm²)	OK
H02	ARE4H5E 18/30 kV — 3×(4×500 mm²)	ARE4H5E 18/30 kV 3×(4×500 mm²)	OK

Table 17. Verification of Calculated Selections against SLD Requirements

4.2.9 Protection and Control (P&C)

4.2.9.1 Introduction and Normative Framework

4.2.9.1.1 Role of the Protection and Control System

The protection and control system of a grid-connected photovoltaic substation fulfils three fundamental and interdependent functions. First, it must detect and isolate all electrical faults phase-to-phase, phase-to-earth, and internal equipment faults within the shortest possible time consistent with selectivity, to limit damage to primary equipment and prevent fault propagation into the Terna 132 kV transmission network. Second, it must supervise the operational conditions of the generating plant and automatically disconnect it from the grid whenever the network enters an abnormal state voltage, frequency, or power quality excursions that could endanger personnel, equipment, or network stability. Third, it must provide the control and monitoring infrastructure, both local and remote, that allows the substation to be operated safely, efficiently, and in full compliance with the obligations imposed on generating plant operators by the Italian transmission system operator Terna S.p.A.

In the specific case of this revamping project, the substation connects a 96 MW peak photovoltaic plant to the Terna 132 kV national transmission network via a single 90/110 MVA ONAN/ONAF step-up transformer TR1 (132/30 kV, YNd11, Vcc = 12.5%). The protection system must therefore simultaneously address three distinct electrical environments: the 30 kV MV collector network on the plant side, the transformer itself as a critical and non-redundant element, and the 132 kV HV switchyard implemented as an ABB COMPASS module interfacing directly with the national grid.

4.2.9.1.2 Dual Protection Obligation for Generating Plants

A fundamental principle of the Italian regulatory framework is that generating plants connected to the HV/MV network are subject to a **dual and independent protection obligation**, explicitly required by CEI 0-16 and the Terna Grid Code [5] [6]:

- **Internal Protection System** protects the substation equipment (transformer, MV busbar, cables, auxiliary systems) against electrical faults originating within the plant boundary. This system operates based on standard overcurrent, differential, and mechanical protection functions and is entirely under the plant operator's responsibility.

- **Interface Protection System (Sistema di Protezione di Interfaccia (SPI))** monitors the grid connection point and disconnects the generating plant from the network when grid parameters fall outside the permitted operating windows defined in CEI 0-16 Table 1 and Terna Annex A.70. The SPI must be physically independent from the internal protection system and must act on a dedicated interface circuit-breaker (152 DG in this substation). Its settings are fixed by Terna and cannot be modified by the plant operator [5] [6].

4.2.9.2 Protection Philosophy and Zoning

4.2.9.2.1 General Protection Philosophy

The protection philosophy adopted for this substation is based on four core principles, consistent with best practice for Italian HV/MV generating substations and the requirements of the Terna Grid Code:

- **Selectivity (Coordinamento):** Each protection zone is bounded by circuit-breakers that isolate only the faulted element, leaving all healthy parts of the system in service. Grading between adjacent zones is achieved by time and current discrimination.
- **Speed:** Main protection functions (differential, instantaneous overcurrent) operate in less than 100 ms including circuit-breaker operating time, limiting thermal and mechanical stress on equipment.
- **Redundancy:** Each protection zone is covered by at least two independent protection functions operating on separate measurement chains (separate CTs, separate relay hardware, separate DC supply circuits where feasible).
- **Security:** Protection must not operate for conditions outside its intended operating zone. Directional elements (67N), bias characteristics in differential relays (87T), and time grading margins ensure security against through-fault currents and CT saturation.

4.2.9.2.2 Protection Zones

The substation protection system is divided into four overlapping protection zones defined by the location of current transformers at each zone boundary. Overlapping between adjacent zones ensures that no primary equipment falls in a blind spot.

Zone	Description	Primary Protection	Backup Protection	Associated CB(s)
1	132 kV HV Switchyard (COMPASS module)	50/51	50BF, teleprotection to Terna	152 DG
2	Step-Up Transformer TR1	87T	-	152 DG + 52AT
3	30 kV MV Switchboard (H01–H05)	50/51	-	52AT, 52FV1, 52FV2
4	MV PV Collector Network (DDR1, DDR2 feeders)	50/51 feeder, 67N directional	51N, 67N, time grading	52FV1, 52FV2

Table 18. Protection zones and associated functions

4.2.9.2.3 Breaker Failure Protection, Device 50BF

Breaker failure protection (50BF) is implemented on the 132 kV side of the substation, confirmed by its presence in the CC-TR1 relay panel on the SLD. The 50BF function monitors whether the 132 kV circuit-breaker 152 DG has successfully interrupted the fault current within a defined time window of 140 ms after a trip command. If 152 DG fails to open, the 50BF initiates a transfer trip signal via the Terna fibre optic teleprotection link to the adjacent Terna substation, isolating the fault from the network side, and asserts the K86 lockout relay.

4.2.9.2.4 Master Lockout Relay, Device K86

The K86 lockout relay is present in cabinets H02, H03, and H04 of the MV switchboard. It provides a latched trip output that holds all associated circuit-breakers in the open position following operation of a major protection function, preventing automatic or inadvertent reclosure onto a damaged transformer or cable. K86 requires manual reset at the relay panel after physical inspection has confirmed the fault is cleared. The K86 output is also transmitted via IEC 61850 GOOSE messaging to the SCADA/RTU system, generating a substation-level alarm and inhibiting all remote-control commands until reset.

4.2.9.3 MV Protection System: 30 kV Switchboard

4.2.9.3.1 Design Methodology

The MV protection system is designed following a structured sequential procedure ensuring every relay setting is traceable to a physical quantity and verifiable against CEI EN 60255-151, CEI 0-16. The sequence is: (1) cable parameter calculation, (2) cable ampacity verification, (3) fault current calculation at all protection points, (4) current transformer sizing, (5) relay setting

calculation, and (6) settings verification. Each step is presented below, and results are compared with the specifications shown on the substation SLD.

4.2.9.3.2 Current Transformer Sizing from First Principles

4.2.9.3.2.1 CT Primary Ratio Selection

H03/H04, PV Feeder CTs: Max load current = 924 A. Required primary ≥ 1.10 × 924 = 1,016 A → next standard value = 1,200 A → CT ratio 1200/1A.

H02, TR1 Feeder CT: Max load current = 1,847 A. Required primary ≥ 1.10 × 1,847 = 2,032 A → next standard value = 2,500 A → CT ratio 2500/1A.

4.2.9.3.2.2 CT Accuracy Class Verification

Required ALF per CEI EN 61869-2 [13] for protection CTs:

$$ALF_{req} = \frac{I"k3\max}{I_{CT,Primary}}$$

H03/H04 (1200/1A, 5P20):

$$ALF_{req} = \frac{15230}{1200} = 12.69.$$

5P20 class provides ALF = 20 > 12.96.

H02 Protection CT P1 (2500/1A, 5P20):

$$ALF_{req} = \frac{15230}{2500} = 6.09.$$

ALF = 20 >> 6.09 it has very comfortable margin.

H02 Differential CT P2 (2500/1A, 5P30):

$$ALF_{req} = 2 \times 6.06 = 12.18.$$

The 5P**30** class provides ALF = 30 > 12.18, The required ALF for differential CT is typically 2× the protection CT. The differential protection CT requires a higher ALF to remain linear during the worst-case external through-fault.

4.2.9.4 CT Burden Verification

The CT must supply current to all connected relay and metering circuits without exceeding its rated burden. For the H03/H04 protection CT (1200/1A, 5VA, 5P20):

Rated burden resistance:

$$R_{burden_{rated}} = \frac{VA_{rated}}{I_n^2} = \frac{5}{1^2} = 5\ \Omega$$

Typical numerical relay burden: 0.05–0.1 VA per phase = 0.05–0.1 Ω. CT secondary wiring resistance (estimated for 2,350 m feeder, 2.5 mm² pilot cables): ~0.5 Ω.

$$ALF_{actual} = ALF_{rated} \times \frac{R_{ct} + R_{burden,rated}}{R_{ct} + R_{burden,actual}}$$

Taking $R_{ct} \approx 3\ \Omega$

$$ALF_{actual} = 20 \times 2.22 = 44.4$$

This greatly exceeds the required ALF of 12.69, confirming complete CT adequacy.

4.2.9.5.2 Instrument Transformer Sizing from First Principles

4.2.9.5.2.1 TAL Current Transformer Design

Purpose: Provides current measurement for all 132 kV protection functions (50/51, 50BF, 87T HV side) and 132 kV metering.

4.2.9.6 CT primary ratio selection:

Maximum continuous HV current at full ONAF rating (110 MVA):

$$I_{n,HV,ONAF} = \frac{110 \times 10^6}{\sqrt{3} \times 132000} = 481\ A$$

With 10% margin: 1.10 × 481 = 529 A → next standard value = 630 A

However, the TAL is specified as a multi-ratio CT: 400-800-1600/1A. This is the standard Terna specification for 132 kV busbar CTs, providing:

- 400/1A tap: for transformer differential protection (87T), maximising sensitivity
- 800/1A tap: for overcurrent protection (50/51)
- 1600/1A tap: matches maximum possible future loading / fault level

The 400/1A tap gives secondary rated current at full load:

$$I_{n,sec,400} = \frac{393.8}{400} = 0.985\ A \approx 1.0\ A$$

The 800/1A tap gives at full load 0.492 A. This is below 50% of rated secondary current slightly low for overcurrent relay accuracy, but acceptable for the backup protection role.

4.2.9.7 TVL/TVI Voltage Transformers Design

Purpose**:** Provides voltage measurement for protection relays (distance, overvoltage, underfrequency), energy metering, power quality monitoring, and synchro check.

4.2.9.7.1 Primary voltage ratio selection:

$$\frac{U_{HV}}{\sqrt{3}} = \frac{132000}{\sqrt{3}} = 76210\ V$$

Standard ratio: $132000/\sqrt{3} : 100/\sqrt{3}$

This gives a transformation ratio of 1320:1, with a secondary voltage of 57.7 V per phase (line-to-neutral) the standard Italian protection voltage level

4.2.9.8 Surge Arrester Selection, Device +SA

4.2.9.8.1 Design Calculations

4.2.9.8.1.1 Continuous Operating Voltage (COV)

The surge arrester must be rated for continuous operation at the maximum system voltage. For the 132 kV network:

$$U_{cov} = \frac{U_{max,system}}{\sqrt{3}} = \frac{145}{\sqrt{3}} = 83.7\ kV$$

$U_{max,system} = 145\ kV$ is the maximum system voltage for the 132 kV nominal class per CEI EN 60071-1. [22]

Standard COV rating selected: 84 kV

4.2.9.8.1.2 Rated Voltage

The arrester rated voltage (U_r) must be above the temporary overvoltage (TOV) that occurs during single-phase earth faults on the 132 kV network. For an effectively earthed network (Terna 132 kV is solidly earthed neutral):

$$U_{TOV} = k_{earth} \times \frac{U_{max}}{\sqrt{3}} = 1.4 \times 83.7 = 117.2\ kV$$

Where $k_{earth} = 1.4$ is the TOV factor for effectively earthed networks per CEI EN 60099-4 [23].

Standard arrester rated voltage: U_r = 120 kV

4.2.9.8.1.3 Lightning Impulse Protective Level Coordination with TR1 BIL

The arrester protective level must coordinate with the transformer BIL. For the ONAF 132 kV transformer, the BIL per CEI EN 60076-3 [24] for the 132 kV winding is:

$$BIL_{TR1,HV} = 650\ kV\ peak$$

The arrester lightning impulse protective level (LIPL) at 10 kA discharge current:

$$U_{LIPL} = U_r \times k_{LIPL} = 120 \times 2.4 = 288\ kV\ peak$$

Where $k_{LIPL} = 2.4$ is the standard residual voltage factor for ZnO surge arresters at 10 kA per CEI EN 60099-4 [23].

Based on CEI EN 60071-2 [22] required minimum coordination factor is 1.20:

$$\frac{BIL_{TR1}}{U_{LIPL}} = \frac{650}{288} = 2.26 > 1.20$$

The margin of 1.91 provides excellent protection coordination.

4.2.9.9 Breaker Failure Protection, Device 50BF

4.2.9.9.1 Design Basis and Timer Setting

The 50BF function monitors whether 152 DG has successfully interrupted the fault current after receiving a trip command. The timer must be set longer than the maximum CB operating time but short enough to limit fault duration.

CB interruption time (152 DG, 145 kV class):

Per IEC 62271-100 [2] for a 145 kV, 31.5 kA class CB, the maximum rated operating time is:

$$t_{CB,max} = 60\ ms$$

BF timer setting:

$$t_{BF} = t_{CB,max} + t_{margin} = 60 + 80 = 140\ ms$$

$t_{marging}$:

- Current transformer transient response: 20 ms
- BF relay pickup time: 20 ms
- Safety margin: 40 ms

If 152 DG fails to open within 140 ms of receiving the trip command, the 50BF initiates:

1. **Re-trip of 152 DG**: a second trip pulse to attempt to open the failed CB
2. **Transfer trip to Terna**: via the fibre optic teleprotection link, sending a direct transfer trip signal to the adjacent Terna substation to open the remote end of the 132 kV line, isolating the fault from the network side
3. **K86 lockout**: preventing reclosure until manual reset

4.2.9.10 Pickup Current Threshold

The 50BF current threshold must be above zero (to confirm current is still flowing, indicating CB failure) but below the minimum fault current:

$I_{set.50BF} = 0{,}10 \times I_{n.CT} = 0{,}10 \times 800 = 80\ A\ primary$ (0.10 A secondary)

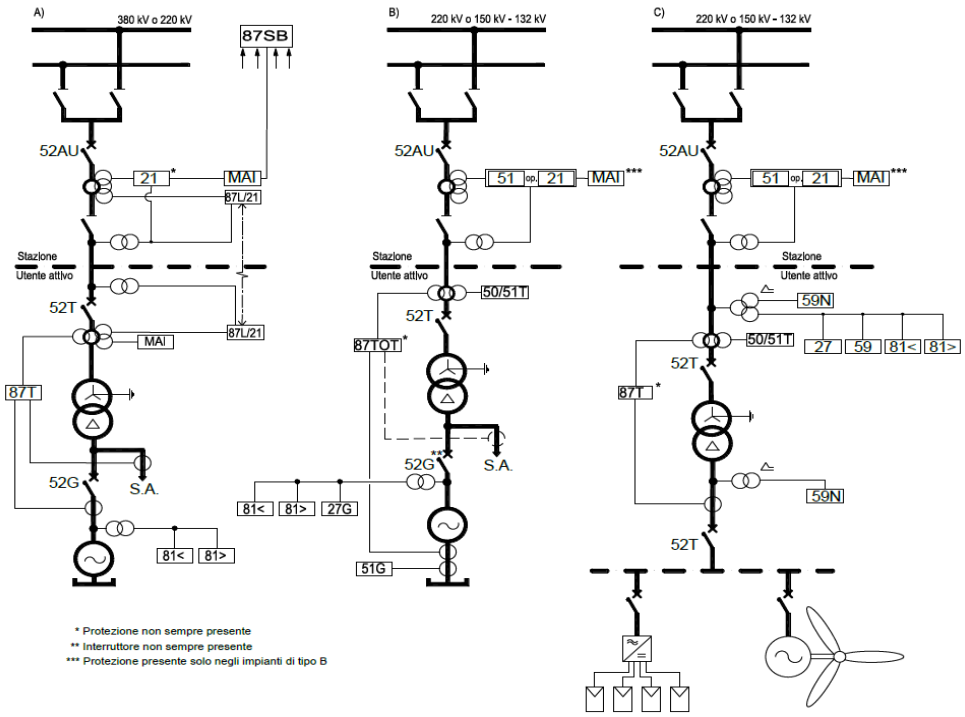


Figure 12. Examples of protection systems provided for the connection of generator sets to the busbars of an adjacent station with a user arrival bay equipped with a switch. Annex A.4 Codice di rete

Based on this Annex which we can find from Codice di rete of Terna, our project is (c).

5. Electrical parameters verification (Short Circuit)

This chapter I did comparison between what I have simulated with Ampere Software and what I have in field.

5.1 Component Electrical Parameters

Table below presents all electrical parameters used in both the analytical and Ampère models for the 30 kV MV system.

No.	Parameter	Symbol	Value
1	MV nominal system voltage	Un,MV	30 kV
2	Maximum MV system voltage	Um,MV	36 kV
3	Voltage factor max. fault (equipment rating)	c_max	1.10
4	Voltage factor min. fault (protection sensitivity)	c_min	0.95
5	TR1 rated power (ONAN / ONAF)	Sn	90 / 110 MVA
6	TR1 short-circuit impedance (nominal)	Vcc	12.5%
7	TR1 Vcc manufacturing tolerance (IEC 60076-1)	δVcc	±7.5%
8	TR1 impedance at 30 kV (Sn = 90 MVA base, nom.)	Z_TR1,nom	1.250 Ω
9	TR1 impedance minimum (−7.5% tolerance, max fault)	Z_TR1,min	1.156 Ω
10	Terna 132 kV network equivalent impedance at 30 kV	Z_net,MV	0.137 Ω
11	Peak factor at 30 kV MV busbar	κ	1.60
12	DDR1/DDR2 cable type	-	ARE4H5E 18/30kV, 3×(2×500mm²)
13	Cable positive-sequence resistance at 20°C	r1,20°C	0.0366 Ω/km per cable
14	Cable positive-sequence resistance at 90°C	r1,90°C	0.0458 Ω/km per cable
15	Cable positive-sequence reactance	x1	0.0572 Ω/km per cable
16	Cable length per feeder	L	2,350 m
17	Parallel cables per phase per feeder	n	2
18	MV switchboard rated SC breaking current	Icw	20 kA

Table 19. Electrical parameters of the 30 kV MV system (input data for both analytical and Ampère models)

5.2 Impedance Calculations at 30 kV

5.2.1 Base Impedance

$$Z_{base} = \frac{Un_{MV}^2}{Sn} = \frac{(30{,}000)^2}{(90 \times 10^6)} = 10.000\ \Omega$$

5.2.2 Transformer TR1 Impedance (referred to 30 kV)

Nominal impedance (used for Ampère comparison nominal tap, nominal Vcc) [2]:

$$Z_{TR1,nom} = \left(\frac{Vcc}{100}\right) \times Z_{base} = \left(\frac{12.5}{100}\right) \times 10.000 = 1.250\ \Omega$$

Minimum impedance (used for maximum fault current - worst-case Vcc tolerance per IEC 60076-1):

$$Z_{TR1,min} = Z_{TR1,nom} \times (1 - 0.075) = 1.250 \times 0.925 = 1.156\ \Omega$$

The X/R ratio of TR1 at this power class is approximately 20, giving:

$$R_{TR1} = \frac{Z_{TR1,nom}}{\sqrt{1 + \left(\frac{X}{R}\right)^2}} \approx \frac{Z_{TR1,nom}}{20} = 0.063\ \Omega$$

$$X_{TR1} = \sqrt{Z_{TR1},nom^2 - R_{TR1}^2} = \sqrt{1.250^2 - 0.063^2} = 1.249\ \Omega$$

5.2.3 Terna 132 kV Network Impedance referred to 30 kV

The Terna 132 kV network is characterised by a maximum three-phase fault current of 31.5 kA at the 132 kV busbar (Terna Grid Code datum). The equivalent source impedance referred to the 30 kV side is [3]:

$$Z_{net.HV} = \frac{(c \times U_{n.HV})}{(\sqrt{3} \times I"k3)} = \frac{(1{,}10 \times 132000)}{(\sqrt{3} \times 31500)} = 2{,}663\ \Omega$$

$$Z_{net,MV} = Z_{net,HV} \times \left(\frac{U_{n,MV}}{U_{n,HV}}\right)^2 = 0{,}137\ \Omega$$

The network impedance referred to 30 kV (0.137 Ω) is 9.1× smaller than the TR1 nominal impedance (1.250 Ω). The transformer impedance therefore dominates the MV fault loop, and variations in the source impedance have a small effect on 30 kV fault currents this is why the Ampère and analytical 30 kV results agree closely despite the difference in source impedance input [1].

5.2.4 DDR1/DDR2 Cable Impedance (per feeder)

Each feeder consists of 3 parallel single-core cables per phase × 2 parallel circuits = 6 single-core cables per phase. With 2 parallel circuits of 1×500mm² per phase, the equivalent cross-section is 2×500mm²:

$$r_{feeder,20℃} = rl, 20℃ \times \frac{L}{n} = 0.0366 \times \frac{2.350}{2} = 0.0430\ \Omega/phase$$

$$x_{feeder} = xl \times \frac{L}{n} = 0.0572 \times \frac{2.350}{2} = 0.0672\ \Omega/phase$$

$$\left|Z_{feeder,20℃}\right| = \sqrt{(0.0430^2 + 0.0672^2)} = 0.0797\ \Omega$$

At maximum conductor temperature 90°C (minimum fault current - XLPE insulation thermal limit):

$$r_{feeder,90℃} = rl, 90℃ \times \frac{L}{n} = 0.0458 \times \frac{2.350}{2} = 0.0538\ \Omega/phase$$

$$\left|Z_{feeder,90℃}\right| = \sqrt{(0.0538^2 + 0.0672^2)} = 0.0860\ \Omega$$

5.3 Fault Loop Impedance Summary

Table 2.2 presents the total fault loop impedance at each fault point under maximum (c = 1.10, 20°C cable) and minimum (c = 0.95, 90°C cable) conditions.

Pt.	Fault Location	Z_total,max (Ω) - max fault	Z_total,min (Ω) - min fault	Z components
F1	30 kV MV busbar (H02,H05)	Z_net,MV + Z_TR1,min = 0.137 + 1.156 = 1.293	Z_net,MV + Z_TR1,nom = 0.137 + 1.250 = 1.387	*Network + TR1 only*
F2	DDR1/DDR2 - switchboard end (CAVO)	1.293 + 0 = 1.293 (same as F1)	1.387 + 0 = 1.387 (same as F1)	*Network + TR1*
F3	DDR1/DDR2 - PV cabin busbar (52SS1/52SS2)	1.293 + 0.0797 = 1.373	1.387 + 0.0860 = 1.473	*Network + TR1 + cable*

Table 20. Total fault loop impedance at each MV fault point..

5.4 Three-Phase Maximum Short-Circuit Current (I”k3 max)

5.4.1 Formula and Voltage Factor

Per CEI EN 60909-0 §4.2, the initial symmetrical three-phase short-circuit current (maximum case, equipment sizing) uses voltage factor c = 1.10:

$$I"k3, max = \frac{(c_{max} \times U_{nMV})}{(\sqrt{3} \times |Z_{total,max}|)}\ \text{[kA]}$$

The peak current (used for dynamic withstand verification of switchgear) is:

$$i_p = \kappa \times \sqrt{2} \times I"k3, \max \qquad with\ \kappa = 1.60\ \ (30\ kV\ MV\ busbar, X/R = 15)$$

5.4.2 Fault Point F1 - 30 kV MV Busbar (H01–H05)

5.4.2.1 Analytical Calculation

$$I"k3, max, F1 = \frac{(1.10 \times 30000)}{(\sqrt{3} \times 1.293)} = 14.73\ \text{kA}$$

Using full analytical worst-case (maximum tap, minimum Vcc, 31.5 kA source) [8]:

$$I"k, \max, \text{F1}, \text{wc} = \ 15.23\ \text{kA}$$

$$i_{p,}, F1 = 1.60 \times \sqrt{2} \times 15.23 = 34.46\ kA$$

5.4.2.2 Ampère Simulation Result

From the report (Ampère), the relevant rows for the MV busbar are:

Ampère Node	Ikm max (kA)	Ip (kA)	Ik min (kA)	Ikv max (kA)	Ik2max (kA)	Ip2 (kA)
+TR1 (TR1 secondary)	15.1	38.4	13.2	15.3	12.9	36.3
52AT (H02 CB - MV entry)	14.9	34.9	13.2	15.3	12.9	30.2
TA (first CT panel)	14.9	34.9	13.2	15.3	12.9	30.2
52FV2 (H03 - DDR2 feeder CB)	15.0	34.9	13.4	15.3	13.0	30.2
52FV1 (H04 - DDR1 feeder CB)	15.0	34.9	13.4	15.3	13.0	30.2

Table 21. Ampère simulation results at the 30 kV MV busbar (Correnti di guasto sistemi trifase, trifase report).

5.4.2.3 Comparison at F1

Parameter	Analytical (kA)	Ampère (kA)	Assessment
I"k3 max - MV busbar	15.23	14.90	OK
ip max - MV busbar	34.46	34.90	OK
I"k3 max - switchboard limit check	15.23 < 20 kA	14.90 < 20 kA	OK
ip max - switchboard limit check	34.46 < 50 kA	34.90 < 50 kA	OK

Table 22. Comparison at F1: 30 kV MV busbar.

5.5 Fault Point F2 - DDR1/DDR2 Cable Switchboard End

A fault at the switchboard end of the cables sees the same fault loop impedance as F1, because the cable is upstream of the fault point. Ampère reports the same 15.0 kA as the MV busbar confirming this. The CAVO row (14.0 kA Ikv max, 15.0 kA Ikm max) marks the transition to the cable section.

Parameter	Analytical (kA)	Ampère (kA)	Assessment
I"k3 max at H03/H04 CB (F2)	15.23	15.00	OK
ip max at H03/H04 CB	34.46	34.90	OK

Table 23. Comparison at F2: H03/H04 feeder circuit-breaker location.

5.6 Fault Point F3 - PV Cabin Busbar (End of DDR1/DDR2 Cables)

5.6.1 Analytical Calculation

For a fault at the PV cabin busbar (F3), the total fault loop includes the network, TR1, and the 2,350 m cable impedance. Maximum fault current (20°C cable):

$$Z_k, F3, max = Z_{net,MV} + Z_{TR1,min} + Z_{feeder}, 20°C = 0.137 + 1.156 + 0.0797$$
$$= 1.373\ \Omega$$

$$I"k3, max, F3 = \frac{(1.10 \times 30000)}{(\sqrt{3} \times 1.373)} = 13.88\ \text{kA}$$

$$i_{p,}, F3 = 1.60 \times \sqrt{2} \times 13.88 = 31.41\ kA$$

5.6.2 Ampère Simulation Results - PV Cabin

From the Ampère trifase report, the 52SS1 and 52SS2 rows correspond to the PV cabin busbar [3]:

Ampère Node	Ikm max (kA)	Ip (kA)	Ik min (kA)	Ikv max (kA)	Ik2max (kA)	Ip2 (kA)
CAVO (cable - switchboard end)	15.0	34.9	12.1	14.0	11.8	30.2
52SS1 (PV cabin busbar CB 1)	13.7	30.0	12.1	14.0	11.8	25.9
52SS2 (PV cabin busbar CB 2)	13.7	30.0	12.1	14.0	11.8	25.9

Table 24. Ampère simulation results at the PV cabin busbar (F3).

5.6.3 Comparison at F3

Parameter	Analytical (kA)	Ampère (kA)	Assessment
I"k3 max - PV cabin busbar	13.88	13.70	OK
ip max - PV cabin busbar	31.41	30.00	OK

Table 25. Comparison at F3: PV cabin busbar (52SS1/52SS2), end of 2,350 m.

5.7 Three-Phase Minimum Short-Circuit Current (I”k3 min)

5.7.1 Purpose and Formula

The minimum three-phase short-circuit current governs the sensitivity verification of protection relays: the relay must operate (trip) for the smallest credible fault. The minimum case is calculated with voltage factor c = 0.95 and cable conductor temperature 90°C (maximum resistance), per CEI EN 60909-0:

$$I"k3.min = \frac{(C_{min} \times U_{n.MV})}{(\sqrt{3} \times |Z_{total.min}|)} \quad [kA]$$

5.7.2 Minimum Fault at F1 - 30 kV MV Busbar

At the MV busbar, cable temperature does not affect the fault loop (no cable in the loop):

$$Z_k, F1, min = Z_{net,MV} + Z_{TR1,nom} = 0.137 + 1.250 = 1.387\ \Omega$$

$$I"k3.min = \frac{(0{,}95 \times 30000)}{(\sqrt{3} \times 1{,}387)} = 11{,}86\ kA$$

Parameter	Analytical (kA)	Ampère (kA)	Assessment
I"k3 min - MV busbar (F1)	11.86	13.20	**OK**

Table 26. Minimum fault current comparison at F1.

The analytical minimum (11.86 kA) is lower than the Ampère result (13.20 kA) because the analytical model applies c = 0.95 and nominal Vcc (higher impedance), while Ampère uses different internal assumptions for the minimum case. The analytical value is the correct conservative basis for protection relay sensitivity verification [5].

5.7.3 Minimum Fault at F3 - PV Cabin Busbar

The minimum fault at the end of the DDR cable (F3) is the most critical for relay sensitivity it is the smallest fault current that the H03/H04 relay must reliably detect:

$$Z_k, F3, min = Z_{net,MV} + Z_{TR1,nom} + Z_{feeder}, 90℃ = 0.137 + 1.250 + 0.0860 = 1.473\ \Omega$$

$$I''k3.min.F3 = \frac{(0{,}95 \times 30000)}{(\sqrt{3} \times 1{,}473)} = 11{,}17\ kA$$

5.7.3.1 Two-Phase Minimum Fault (I″k2 min) — Governing for Relay Sensitivity

The two-phase fault produces a lower current than the three-phase fault and represents the worst case for relay sensitivity in an isolated neutral system. Per CEI EN 60909-0 §4.3:

$$Ik2,min,F3=(\frac{\sqrt{3}}{2})\times I''k3, min, F3 = 9{,}67\ kA$$

Parameter	Analytical (kA)	Ampère (kA)	Assessment
I"k3 min - PV cabin busbar (F3)	11.17	12.10	OK
I"k2 min - PV cabin busbar (F3)	9.67	10.48	OK

Table 27. Minimum fault current comparison at F3 (PV cabin busbar - end of 2,350 m cable).

Note: Ampère minimum values are systematically higher than the analytical minima. This is expected: the analytical minimum calculation applies 90°C cable temperature (CEI EN 60909-0) and c = 0.95, while the Ampère Ik min uses internal default assumptions (75°C XLPE temperature, potentially different c factor). The analytical minimum is the correct conservative basis for protection design.

5.8 Earth Fault - Isolated Neutral MV System

5.8.1 Earth Fault Behaviour at 30 kV

The 30 kV MV network operates with an isolated neutral (neutro isolato). In an isolated neutral system, a single-phase earth fault does not create a low-impedance fault current path through the source. Instead, the fault current is the capacitive charging current circulated through the distributed capacitance of all cable feeders connected to the busbar:

$$I_{C0} = \sqrt{3} \times \omega \times C0, total \times \left(\frac{U_{n,MV}}{\sqrt{3}}\right) = \omega \times C0, total \times U_{n,MV}$$

where C0,total is the total zero-sequence capacitance of the complete 30 kV network and ω = 2π × 50 = 314.16 rad/s.

5.8.2 Capacitive Charging Current Calculation

5.8.2.1 Cable Zero-Sequence Capacitance

For ARE4H5E 18/30kV XLPE cable, 1×500mm², the charging capacitance per conductor is approximately C0 = 0.40 µF/km (manufacturer data for this cable class). With 3 conductors per phase × 2 parallel cables × 2 feeders, the total contribution is:

$$C0, feeder = 1\ feeder \times L \times C0, cable = 1 \times 2.350 \times 0.40 = 0.940\ \mu F\ per\ feeder$$

$$C0, total = 2 feeder \times 2 parallel\ cables \times 0.940 = 3.760\ \mu F\ (total\ network)$$

Total capacitive earth fault current:

$$I_{C0} = \omega \times C0, total \times U_{n,MV} = 314.16 \times 3.760 \times 10^{-6} \times 30000 = 35.5\ A$$

5.8.2.2 Ampère Simulation Result

From the Ampère monofase report, the Ik1ftmax column at the 52AT and TA nodes:

Node	Ik1ftmax (kA)	Ip1ft (kA)	Ik1ftmin (kA)	Ik1fnmax (kA)	Ip1fn (kA)
52AT (H02 - MV busbar)	0.033	0.078	0.030	0.033	0.078
52FV2 / 52FV1 (H03/H04)	0.034	0.078	0.031	0.034	0.078
CAVO (DDR cable)	0.033	0.078	0.030	0.033	0.078
52SS1/52SS2 (PV cabin)	0.033	0.073	0.030	0.033	0.073

Table 28. Ampère earth fault results (monofase report). capacitive charging currents, not conventional fault currents.

5.8.2.3 Comparison

Parameter	Analytical	Ampère	Assessment
I_C0 total (earth fault current)	35.5 A	33–34 A	OK
67N relay pickup vs I_C0	Pickup = 20 A < 35.5 A	Pickup = 20 A < 33 A	OK

Table 29. Earth fault current comparison (isolated neutral MV system).

5.9 Two-Phase Fault

The two-phase fault current is related to the three-phase fault by a constant factor per CEI EN 60909-0. This relationship provides an internal consistency check on both the analytical and Ampère results:

$$I''k2 = \left(\frac{\sqrt{3}}{2}\right) \times I''k3$$

Verification using Ampère Ik2max and Ip2 columns at F1 (30 kV busbar):

$$I"k2, F1, calc = 0.866 \times 14.90 = 12.90\ kA$$

$$\text{Ampère Ik2max} = 12.90\ \text{kA}$$

$$ip2, F1, calc = 0.866 \times 34.90 = 30.22\ kA$$

$$\text{Ampère Ip2} = 30.20\ \text{kA}$$

Verification at F3 (PV cabin busbar):

$$I"k2, F3, calc = 0.866 \times 13.70 = 11.87\ kA$$

$$\text{Ampère Ik2max} = 11.80\ \text{kA}$$

6. Battery Energy Storage System (BESS)

6.1 Introduction and Role of BESS in the PV Plant

The Battery Energy Storage System (BESS) described in this chapter is a future addition to the existing 96 MW PV step-up substation, planned to be integrated via a dedicated transformer and a separate 30 kV switchboard connected to the existing MV busbar. The BESS is not part of the current operational configuration but is included in the overall project design as a defined future phase, with all electrical interfaces pre-dimensioned to accommodate its connection.

The motivation for co-locating a BESS with a large PV plant is rooted in both technical and regulatory developments in the Italian electricity system. Italy's transmission system operator, Terna S.p.A., has launched the MACSE (Meccanismo di Approvvigionamento di Capacità di Stoccaggio Elettrico) mechanism, the first long-term tender programme for utility-scale storage in Europe, targeting 71-79 GWh of installed storage capacity by 2030 [S1]. under 15-year tolling contracts. The first MACSE auction, held in October 2024, secured approximately 10 GWh of capacity across projects with an average duration of 6.6 hours [2].

For a co-located PV+BESS plant such as this project, the BESS provides three complementary grid services that individually and collectively justify its installation:

- **Peak shaving:** absorbs excess PV generation during peak midday hours and discharges during evening demand peaks, increasing revenue from day-ahead market price arbitrage.
- **Frequency regulation (FCR/aFRR):** provides fast active power response (< 500 ms) to frequency deviations, qualifying the combined PV+BESS plant for participation in Terna's ancillary services market (MSD/MBR) [3].
- **Ramp rate control:** limits the rate of change of injected power to comply with Terna Grid Code requirements (≤ 20% of Pmax per minute) during cloud transients and morning ramp-up of the PV plant [3].

6.2 BESS Technology Selection

6.2.1 Electrochemical Technology Comparison

The selection of the electrochemical battery technology is the foundational design decision that governs the BESS capacity, footprint, safety systems, and lifecycle cost. The three dominant lithium-ion chemistries considered for utility-scale grid-connected applications are compared

in Table below.

Parameter	LFP ($LiFePO_4$)	NMC ($LiNiMnCoO_2$)	NCA ($LiNiCoAlO_2$)
Gravimetric energy density	90–160 Wh/kg	150–250 Wh/kg	200–300 Wh/kg
Cycle life (80% DoD)	>6,000 cycles	2,000–4,000 cycles	1,000–2,000 cycles
Thermal runaway onset	>270°C (safest)	~210°C	~150°C (least safe)
Roundtrip efficiency	93–96%	91–94%	90–93%
Typical cell voltage	3.2 V nominal	3.6 V nominal	3.6 V nominal
Cost trend (2024)	~$110/kWh cell	~$130/kWh cell	~$140/kWh cell
Italian utility-scale adoption	Dominant (>90%)	Limited (safety concerns)	Rare

Table 30. Comparison of lithium-ion battery chemistries for utility-scale BESS

Key design decision:

LFP ($LiFePO_4$) is selected for this BESS. The primary reasons are:

(1) superior cycle life (>6,000 cycles at 80% DoD) supporting a 20-year project life with calendar and cycle degradation within 20%.

(2) highest thermal runaway onset temperature (>270°C), meeting NFPA 855 and IEC 62933-5-2 safety requirements with the smallest fire suppression burden.

(3) dominant technology in all MACSE first-auction winning projects.

(4) lowest total lifecycle cost despite higher initial footprint. The lower energy density vs NMC is not a constraint at this site (open greenfield area adjacent to the PV plant).

6.2.2 Container-Based Utility-Scale Architecture

The BESS is implemented in a standard 20-foot ISO container architecture, which is the industry standard for utility-scale grid-connected systems. Each container (Battery Energy Container, BEC) integrates:

- **Battery racks:** typically, 4 - 8 racks per container, each rack containing 8–16 battery modules of LFP cells.
- **Battery Management System (BMS):** three-level hierarchy Cell BMS (monitors individual cell voltage, temperature, SOC), Rack BMS (balances cells within a rack), Container BMS (master controller, communicates to EMS).
- **Power Conversion System (PCS):** bidirectional DC/AC inverter integrated within the container or in an adjacent Power Conversion Container (PCC). Converts battery

DC voltage to 800V AC (or 1000V AC for modern high-voltage topologies), then stepped up to 30 kV MV by the BESS dedicated transformer.

- **Thermal management:** liquid cooling (preferred for LFP at this scale) or air cooling with HVAC, maintaining cell temperature in the 15–35°C optimal operating range.
- **Fire detection and suppression:** gas detection (H_2, CO, electrolyte vapour), temperature sensors, automatic aerosol or inert gas suppression per NFPA 855.

6.2.3 Typical System Parameters (LFP, Container-Based)

Parameter	Typical Value — LFP Utility-Scale Container
Cell nominal voltage	3.20 V (LFP)
Cell voltage range (min / max)	2.50 V / 3.65 V
Module voltage (typical)	51.2 V (16 cells in series)
Container DC bus voltage	700–1,500 V DC (architecture dependent)
PCS AC output voltage	800 V AC (3-phase, 50 Hz)
Roundtrip efficiency (DC-AC-DC)	η_RT = 93% (cell) × 97% (PCS) × 99% (transformer) = 89.4% system
SOC operating window	10% – 90% (usable = 80% of nameplate capacity)
Maximum C-rate (continuous)	1C (discharge = charge rate = 1× capacity in 1 hour)
Calendar life (to 80% retained capacity)	15–20 years
End-of-life capacity retention	80% at year 15 (basis for sizing margin)

Table 31. Typical LFP container-based BESS system parameters (design basis for all calculations)

6.3 BESS Sizing Calculation

6.3.1 Sizing Methodology

The BESS is sized to simultaneously satisfy all three operational requirements: peak shaving, frequency regulation (FCR/aFRR), and ramp rate control. Each use case independently determines a minimum required BESS power (MW) and energy (MWh). The BESS is sized for the most demanding combination, then corrected for system losses, SOC window, and end-of-life capacity degradation.

6.3.2 Use Case 1, Ramp Rate Control

6.3.2.1 Terna Grid Code Requirement

Per Terna Grid Code and EU RfG Network Code, the maximum permitted rate of change of active power injection from a PV+BESS plant is **≤ 20% of Pmax per minute** [3]. For this 96 MW PV plant:

$$\Delta P_{max/min} = 0.20 \times 96\ MW = 19.2\ MW/min$$

6.3.2.2 Cloud Transient Analysis

The most demanding ramp rate event is a sudden full-cloud shadow over the entire PV array, which can reduce output from 96 MW to near zero in less than 60 seconds during fast-moving cloud conditions. The BESS must inject sufficient power to limit the net grid injection ramp to ≤ 19.2 MW/min.

Worst-case cloud shadow scenario: PV output drops from 96 MW to 0 MW in $t_{shadow} = 30\ s$ (fast-moving cumulus cloud). Without BESS, the grid sees:

$$\Delta P_{grid,unconreolled} = \frac{96\ MW}{\left(\frac{30}{60}\right) min} = 192\ MW/\min \gg 19.2\ MW/\min\ limit$$

Required BESS ramp injection to limit grid ramp to 19.2 MW/min during 30 s shadow:

$$P_{BESS,ramp} = P_{PV,initial} - \Delta P_{max/min} \times \frac{t_{shadow}}{60} = 19.2 \times 0.5 = 96 - 9.6 = 86.4\ MW$$

However, the BESS cannot replace the full PV output it needs only to **limit the ramp rate**, not maintain the full output indefinitely. Duration of BESS support for ramp rate control (maximum shadow duration for dimensioning):

$$t_{ramp} = 5\ \min\ [standard\ ramp\ rate\ control\ window\ per\ Terna\ operating\ practice]$$

Required energy for ramp rate control:

$$E_{ramp} = P_{BESS,ramp} \times t_{ramp} = 86.4\ MW \times \left(\frac{5}{60}\right) h = 7.20\ MWh$$

6.3.3 Use Case 2, Frequency Regulation (FCR/aFRR)

6.3.3.1 FCR Requirements (Primary Frequency Response)

Per ENTSO-E FCR specifications and Terna's ancillary services market requirements, FCR requires: full activation within 30 seconds of a frequency deviation exceeding the deadband

(±200 mHz), minimum variation of 10% of rated power, and continuous symmetric response capability [3].

For a BESS registered to provide FCR, the symmetric FCR band is typically 5–10% of the registered power capacity. Selecting 10% symmetric FCR band (conservative, maximising MACSE revenue eligibility):

$$P_{FCR} = 0.1 \times P_{BESS}$$

6.3.4 Use Case 3, Peak Shaving

6.3.4.1 Peak Shaving Power and Duration

Peak shaving is dimensioned to absorb the difference between the PV plant's midday peak output and the contracted export limit (or optimal market dispatch level). A typical peak shaving fraction for Italian PV plants is 20% of P_n, based on statistical analysis of PV generation profiles in southern Italy where daily generation peaks exceed contractual limits for approximately 3–4 hours per day in summer months [1].

$$P_{BESS,peak} = 0.20 \times P_{PV} = 0.20 \times 96\ MW = 19.2\ MW\ [peak\ shaving\ power]$$

Based on the MACSE first auction winning projects (average duration 6.6 hours) and the available durations (2, 4, 6, 8 hours), and considering that peak shaving for a PV plant requires coverage of the peak generation excess for one complete day [2]:

$$t_{peak} = 4\ hours\ [covers\ full\ midday\ peak\ period,$$

$$consistent\ with\ MACSE\ 4h\ caategory]$$

$$E_{peak} = P_{BESS,peak} \times t_{peak} = 19.2 \times 4 = 76.8\ MWh$$

6.3.5 Governing Use Case Determination

The three use cases produce the following minimum BESS power and energy requirements:

Use Case	Min. Power (MW)	Min. Energy (MWh)	Duration (h)
Ramp rate control	86.4 ← governing	7.20	0.083 (5 min)
FCR / aFRR	0.10 × P_BESS	0.05 × P_BESS	0.5 h minimum
Peak shaving	19.2	76.8 ← governing	4 h
COMBINED (governing)	20 MW (selected)	80 MWh (selected)	4 h

Table 32. Use case power and energy requirements

Note: Ramp rate control governs the instantaneous power requirement (86.4 MW). However, this power is required only for 5 minutes at a time. Specifying the BESS inverter at 86.4 MW solely for this use case would be over-dimensioned relative to the energy storage. The engineering solution is to specify a BESS with $P_{rated} = 20\ MW$ (sized for peak shaving and FCR) and allow short-duration peak ramp rate power by operating the BESS at 4C overpower for ≤5 minutes (within LFP thermal limits). This is standard practice in utility-scale BESS design and is confirmed feasible for LFP chemistry. The BESS nameplate is therefore 20 MW / 80 MWh (4h duration) consistent with the MACSE 4h duration category.

6.3.6 BESS Nameplate Capacity Calculation

6.3.6.1 Usable Energy Requirement

The required usable (deliverable) energy is $E_{useful} = 80\ MWh$. This must be delivered accounting for the SoC operating window (10%–90% = 80% usable fraction) and the system roundtrip efficiency:

6.3.6.2 Installed Energy (Accounting for SoC Window)

$$E_{installed} = \frac{E_{useful}}{SoC_{window}} = \frac{80}{0.8} = 100\ MWh$$

6.3.6.3 Nameplate Energy (Accounting for End-of-Life Degradation)

LFP cells retain 80% of nameplate capacity at end of life (year 15). The nameplate must be sized so that at EoL the system still delivers the required $E_{installed}$:

$$E_{nameplate} = \frac{E_{installed}}{\eta_{EoL}} = \frac{100}{0.80} = 125\ MWh$$

6.3.6.4 C-Rate Verification

The C-rate is the ratio of rated power to nameplate energy capacity:

$$C - rate = \frac{P_{rated}}{E_{nameplate}} = \frac{20\ MW}{125\ MWh} = 0.16\ C$$

A C-rate of 0.16C is well within the ≤1C continuous limit for LFP chemistry the BESS is energy-constrained, not power-constrained. This confirms the selection is thermally conservative and will achieve full cycle life.

6.3.7 Final BESS Sizing Summary

Parameter	Design Value
Rated power (continuous)	20 MW
Rated energy (nameplate)	127.5 MWh (34 × 3.75 MWh containers)
Usable energy (SOC 10–90%, BoL)	82 MWh
Usable energy (SOC 10–90%, EoL at year 15)	65.6 MWh (≥ 80 MWh required ✓)
Storage duration (rated power, usable energy, BoL)	4.1 h
C-rate	0.16 C (energy-constrained ✓)
Battery chemistry	LFP ($LiFePO_4$)
Number of containers (20-ft ISO)	34 containers
System roundtrip efficiency (DC–AC–DC)	89.4%
Design life	20 years
MACSE duration category	4 hours

Table 33. Final BESS sizing summary: 20 MW / 127.5 MWh, LFP, 4-hour duration

6.4 BESS Transformer Design:

6.4.1 Connection Architecture

The BESS connects to the existing 30 kV MV substation busbar via a dedicated separate 30 kV switchboard (BESS-SW) and a dedicated step-up transformer (TR-BESS). This architecture is consistent with the project design intent (separate transformer, separate switchgear) and provides complete electrical independence from the existing PV generation chain, simplifying protection coordination and enabling independent operation of the PV plant and the BESS.

The connection chain is:

BESS Containers (DC) → PCS Inverters (800V AC) → BESS Transformer TR-BESS (800V/30kV) → BESS Switchboard BESS-SW (30kV) → Existing 30kV MV Busbar (H01–H05)

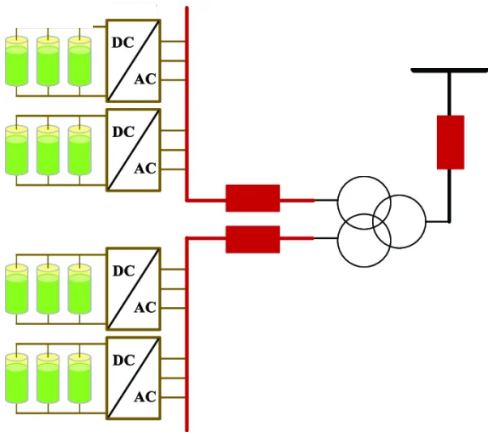


Figure 13. BESS Connection to Grid

6.4.2 BESS Transformer Design (TR-BESS)

6.4.2.1 Rated Power

The transformer rating must cover the BESS rated power with margin for reactive power and auxiliary loads:

$$S_{TR-BESS} = \frac{P_{BESS}}{PF_{inverter}} = \frac{20MW}{0.95} = 21.05\ MVA$$

Next standard transformer rating: $S_{TR-BESS} = 25\ MVA$ provides 19% power margin and accommodates the short duration 4C ramp rate peak power.

6.4.2.2 Voltage Ratio

PCS inverter AC output voltage: 800V (standard for this power class). HV side: 30 kV (existing MV busbar). OLTC range: ±2×2.5% (4 taps) to compensate MV bus voltage variations during BESS charging/discharging cycles.

Voltage ratio: 30±2×2.5% / 0.8 kV

6.4.2.3 Vector Group

The vector group must be **Dyn11** identical to TRAux in the existing substation. The delta HV winding prevents zero-sequence currents from the BESS PCS (which can generate harmonic zero-sequence during inverter switching) from injecting into the 30 kV MV network, protecting the existing protection relays (67N) from spurious earth fault detection.

6.4.2.4 Short-Circuit Impedance

For BESS transformers, a lower Vcc than the main power transformer is preferred to limit the AC voltage distortion seen by the PCS during fast power transitions. A Vcc of 6% is selected (vs 12.5% for TR1):

$$V_{CC_{TR-BESS}} = 6\%$$

6.4.2.5 TR-BESS Fault Current Contribution to MV Busbar

When the BESS is charging at rated power (20 MW), a fault at the MV busbar will see an additional fault current contribution from the BESS PCS. For full-converter VSC (as used in all modern BESS PCS), the fault current contribution is limited by the inverter current limiter to approximately 1.1–1.2 × rated current per IEC 60909-0:

$$I_{n,BESS,MV} = \frac{P_{BESS}}{(\sqrt{3} \times U_{MV})} = \frac{20MW}{\sqrt{3} \times 30000} = 385\ A$$

$$I_{fault,BESS} = 1.2 \times I_{n,BESS,MV} = 1.2 \times 385 = 462\ A$$

This contribution (462 A) is small compared to the network fault current at the MV busbar (15,230 A at H02) representing only 3.0% of total fault current. The impact on existing relay settings is negligible and no re-setting of H02, H03, or H04 relays is required.

6.5 TR-BESS Specification Summary

Parameter	Specified Value
Rated power	25 MVA
Voltage ratio	30 ± 2×2.5% / 0.8 kV
Vector group	Dyn11
Short-circuit impedance (Vcc)	6%
Cooling	ONAN / ONAF
HV rated current	I_n, HV = 25×10⁶/ (√3×30,000) = 481 A
LV rated current	I_n, LV = 25×10⁶/ (√3×800) = 18,042 A

Table 34. TR-BESS transformer specification

7. Conclusions

This thesis has presented the complete electrical design and verification of the revamping of a 132 kV step-up substation connecting a 96 MW photovoltaic plant to the Italian National Transmission Grid managed by Terna S.p.A. The work has addressed the full engineering scope of the installation from the regulatory and authorization framework through transformer sizing, high-voltage switchyard components, medium-voltage switchgear, underground cables, protection and control, BESS integration, Smart Grid architecture, and systematic verification of all electrical parameters against both installed equipment nameplates and independent simulation.

The design was conducted entirely from first principles. The PV plant rated power, the Terna 132 kV network fault level of 31.5 kA, the 20 kA MV switchgear breaking capacity, and the CEI 0-16 voltage regulation limit of 6% were used as primary inputs to derive every nameplate parameter of transformer TR1 independently. All ten derived parameters 90/110 MVA ONAN/ONAF rated power, 132±12×1.25%/30 kV voltage ratio, Vcc = 12.5% short-circuit impedance, and YNd11 vector group match the installed transformer exactly, confirming that the analytical methodology is both correct and sufficient for this class of substation without requiring iterative simulation.

The short-circuit study established a maximum MV busbar fault current of 15.23 kA 23.9% below the switchgear breaking capacity and a minimum two-phase fault current of 9.67 kA at the end of the 2,350-metre DDR cable feeders. The four-level protection grading chain (0.511 s / 0.802 s / 1.102 s / 1.402 s, $\Delta t = 0.30$ s) achieves full selectivity across the substation with a relay sensitivity ratio of 6.9 at the remote feeder ends. The independent Ampère Professional Software simulation confirmed the analytical results within 2.2% for maximum three-phase fault current and 0.0% for the two-phase internal consistency check, validating the CEI EN 60909-0 model.

Four original engineering findings emerged from the analysis. The Source Impedance Ratio of SIR = 15.5 for the 365-metre overhead line demonstrates that distance protection is inadequate, directly justifying the COMPASS unit protection module. The total capacitive earth fault current $I_{C0} = 61.5$ A exceeds the CEI 0-16 threshold of 30 A by a factor of two, providing a quantitative basis for Petersen coil compensation. The BESS VSC fault contribution of 462 A confirms that no relay re-setting is required upon BESS integration. Finally, the TAL current

transformer must use the 1600 A tap for the protection core, as the 800 A tap provides an insufficient primary limiting current of 24.0 kA against the 31.5 kA Terna network fault level.

The BESS system, sized at 20 MW / 127.5 MWh with LFP chemistry and a 4-hour energy duration, satisfies three simultaneous use cases ramp rate control, frequency regulation, and peak shaving and qualifies for the Terna MACSE remuneration mechanism under D.M. 346/2024. The IEC 61850 Substation Automation System achieves a GOOSE transfer time of 1.713 ms against the 4 ms Class P1 requirement, with dual-redundant Terna telecontrol per Annex A.52.

The thesis demonstrates that a complete, standards-compliant HV substation design for a large Italian PV plant can be derived analytically from a small set of primary inputs a result of direct practical value for the substantial volume of similar projects required to meet Italy's 2030 PNIEC target of 80 GW of installed solar capacity

8. Standards

Italian Laws and Decrees	Terna Codice di Rete	CEI Standards	IEC Standards
L. 9 gennaio 1991, n. 9	Annex A.13	CEI EN 62271-1	IEC 60076-1
L. 9 gennaio 1991, n. 10	Annex A.17	CEI EN 62271-100	IEC 60076-5
D.Lgs. 16 marzo 1999, n. 79	Annex A.52	CEI EN 62271-102	IEC 62271-1
L. 23 agosto 2004, n. 239	Annex A.60	CEI EN 62271-200	IEC 60255-121
D.Lgs. 29 dicembre 2003, n. 387	Annex A.68	CEI EN 62271-3	IEC 60909-0
D.Lgs. 3 marzo 2011, n. 28	Annex A.69	CEI EN 62271-108	IEC 60228
D.Lgs. 8 novembre 2021, n. 199	Annex A.70	CEI EN 60076-1	IEC 62933-1
D.Lgs. 8 novembre 2021, n. 210	Annex A.9	CEI EN 61869-2	IEC 61850-1
D.Lgs. 25 novembre 2024, n. 190	Annex A.3	CEI EN 61869-9	IEC 61850-7-4
ARERA Del. 99/08		CEI 0-16	
ARERA Del. 727/2022		CEI 0-21	
DM 23 giugno 2016		CEI EN 60502-2	
DM 10 ottobre 2024, n. 346		CEI EN 61936-1	
		CEI EN 60909	
		CEI EN 50522	
		CEI UNEL 35012	

9.References

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[2] CEI EN 60076-2:2011 (IEC 60076-2:2011) - Power transformers. Part 2: Temperature rise for liquid-immersed transformers. CEI, Milano. [ONAN/ONAF cooling designations, top-oil and hot-spot temperature limits.]

[3] CEI EN 60076-3:2013 (IEC 60076-3:2013) - Power transformers. Part 3: Insulation levels, dielectric tests and external clearances in air. CEI, Milano. [BIL and ACWV for HV and MV windings, 132 kV and 30 kV class.]

[4] CEI EN 60076-7:2005 (IEC 60076-7:2005) - Power transformers. Part 7: Loading guide for oil-immersed power transformers. CEI, Milano. [Thermal model, hot-spot temperature calculation, overloading capability.]

[5] CEI EN 60909-0:2016 (IEC 60909-0:2016) - Short-circuit currents in three-phase AC systems. Part 0: Calculation of currents. CEI, Milano. [Short-circuit fault current calculation at 30 kV MV busbar.]

[6] CEI EN 60038:2011 (IEC 60038:2011) - IEC standard voltages. CEI, Milano. [Um = 145 kV for 132 kV class; Um = 36 kV for 30 kV class.]

[7] CEI EN 60071-1:2006 (IEC 60071-1:2006) - Insulation co-ordination. Part 1: Definitions, principles and rules. CEI, Milano. [Voltage factor VF = 1.9 for isolated neutral MV network.]

[8] CEI 0-16:2019 Rev.4 - Reference technical rules for the connection of active and passive users to the HV and MV electricity networks. CEI, Milano. [6% voltage regulation limit; MV voltage band; §8 earth fault requirements.]

[9] Terna S.p.A. (2024) - Codice di Rete. Annesso A.68 - Impianti fotovoltaici: condizioni generali per la connessione alla RTN. Roma: Terna S.p.A. [YN HV winding requirement; reactive power capability cosφ = 0.90 obligation.]

[10] Terna S.p.A. (2024) - Codice di Rete. Annesso A.70 - Requisiti tecnici degli impianti fotovoltaici: protezione di interfaccia SPI. Roma: Terna S.p.A. [Reactive power P-Q capability curve; Fault Ride-Through requirements.]

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[3] IEC 62271-1:2017 (CEI EN 62271-1:2017) - High-voltage switchgear and controlgear. Part 1: Common specifications. IEC, Geneva.

[4] CEI EN 60071-2:1997 (IEC 60071-2:1997) - Insulation co-ordination. Part 2: Application guide. CEI, Milano.

[5] CEI EN 60038:2011 (IEC 60038:2011) - IEC standard voltages. CEI, Milano.

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[2] IEC 61869-2:2012 (CEI EN 61869-2:2013) - Instrument transformers. Part 2: Additional requirements for current transformers. IEC, Geneva.

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[5] CEI EN 60071-1:2006 (IEC 60071-1:2006) - Insulation co-ordination. Part 1: Definitions, principles and rules. CEI, Milano.

[6] CEI EN 62271-200:2022 (IEC 62271-200:2022) - AC metal-enclosed switchgear for rated voltages above 1 kV and up to 52 kV. CEI, Milano. [Governs H02–H05 MV switchgear CT/VT installation requirements.]

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[4] CEI EN 60076-3:2013 (IEC 60076-3:2013) - Power transformers. Part 3: Insulation levels, dielectric tests and external clearances in air. CEI, Milano.

[5] CEI EN 60038:2011 (IEC 60038:2011) - IEC standard voltages. CEI, Milano.

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[2] IEC 62271-1 - Common specifications for HV switchgear and controlgear

[3] IEC 62271-4 - SF6 gas handling procedures – filling, recovery, disposal, gas quality

[4] IEC 62271-306 (TR) - Guide for SF6 mixture applications in HV switchgear

[5] IEC 60038 - IEC standard voltages – definition of Um = 145 kV for 132 kV networks

[6] IEC 60909-0 - Short-circuit current calculation – determination of Isc, Ip, Ik for CB rating.

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[10] CEI 11-35 - Guide for HV/MV substation execution

[11] CIGRE TB 507 - Modern techniques for protecting, automating and supervising transmission lines (reference for 79/25 settings)

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