ADVANCED OPTIMISATION TRANSIENT VOLTAGE STABILITY IN PHOTOVOLTAIC INVERTERS

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Abstract: - Changes in the way the power grid is run are being brought about by the addition of more megawatt-scale photovoltaic (PV) power plants and other sizable inverter-based power stations to the power grid. In response to these modifications, new grid code requirements mandate that inverter-based power plants not only maintain grid connectivity in the event of failure but also offer dynamic assistance. The term "momentary cessation operation" is used in the literature to describe this phenomenon. The few published research on PV power plants' capacity to operate with a brief interruption have not provided any insight into how these systems could affect the larger issue of power system stability. This work suggests a control strategy for PV inverters that enhances the transient stability of a synchronous generator linked to the grid in an effort to address this problem. The research demonstrates how the suggested control method causes the dc link capacitors of the PV inverter to absorb part of the kinetic energy stored in the synchronous machine during temporary halt. Along with that, the suggested approach can raise voltage stability by injecting reactive power. Results from simulations and experiments are provided to show how well the suggested control method works.

Index Terms: - Photovoltaic generation, synchronous machine, transient stability, voltage stability

1. INTRODUCTION

The penetration of RE sources, which are often linked to the electricity grid via power converters (such as inverters), has significantly increased in recent years. The functioning of power networks under intense disturbances is a crucial topic since the growth in PV production entails certain new technological hurdles, such as transient stability [1]. This new system arrangement has less overall system inertia and governor reaction, which could have an adverse effect on how quickly SMs' rotor angles change. However, new possibilities like supplementary services to SMs are made possible by the inverters used in PV production. For instance, PV inverters may assist in preserving stability after a system disruption, such as a short circuit brought on by a lightning strike on a transmission line, which may result in the FD signal triggering the circuit breakers on the faulty line [2]. The considerable changes in the power system design involving the functioning of power inverters were not anticipated by the GCs of the previous two decades. Even now, future scenarios of RE generation are challenging to fathom and estimate. Due to this, GCs have demanded that the RE sources be turned off as soon as a disruption is found over the last ten years [3]. As long as the amount of RE penetration is not large, which is done to avoid the loss of synchronism, this criterion is acceptable. However, in order to preserve synchronism and voltage stability, the generating unit must not only stay connected to the power system but also provide assistance. This is because the GCs have evolved to need FRT capacity from RE units during disturbances [4]. The PV inverters used in distributed generating units and by PV plants linked to the medium voltage transmission grid must meet extra requirements set out by certain nations. Some of these standards permit MC operation or momentarily halt active power transmission to the grid while prioritising reactive power assistance to improve voltage stability. [5]–[7]. As may be observed in [5], [6], and [8], several GCs construct APRRR for postfault operation. The FRT capacity of PV systems that are compliant with the GCs has been extensively researched in the literature. For instance, [9] provides a FRT approach that allows the power quality to alter depending on a tradeoff between power ripple and current harmonics, as needed in the German GC [6], to assist the grid by injecting reactive power. [10] examines the effects of the following PV system operating modes on short-term voltage stability, post-fault recovery, and ultimately transient stability: grid disconnection, FRT in blocking mode, and FRT with dynamic voltage support. Another pertinent study is reported in [11], which develops a model of the LVRT capacity in PV facilities using findings from manufacturer-conducted field tests that adhered to the Chinese GC [7]. Finally, [12] adapts a PV plant's control system to incorporate current limiters and dc link voltage management, enabling the FRT capacity to handle any malfunction. A more extensive investigation of the effects that the GC's operating modes have on the system transient stability is still required, despite the fact that the application of FRT on PV systems and its advantages for dynamic voltage support have been explored in the literature. To comprehend how MC and post-fault APRRR affect stability, the NERC/WECC joint task group [13], [14] suggests running dynamic simulations. These investigations are required to ascertain the circumstances in which the MC should be utilised, whether it should supply active or reactive power, and the direction—positive, negative, or zero—in which the injected current should flow, if at all. The effect of the MC mode on transient stability has recently been the subject of considerable study [15], [16]. In order to guarantee transient stability, this work offers a FRT control scheme based on the absorption of the kinetic energy stored in the rotating mass of the SM. This is because it is crucial to make the PV plant have a beneficial influence on the system stability when operating in the MC mode. By supplying reactive power to the grid, the suggested control strategy also enhances voltage stability and its post-fault recovery. Using the suggested method, the SM active power output is raised to a level that is nearly equal to its pre-fault value. This restores the balance between the SM electrical power and mechanical power, which slows the rotor's rotational speed, which in turn lessens rotor angle excursions and ensures transient stability during the disturbance's initial cycles. The suggested control strategy does not call for any extra hardware in the inverters' dc link (as in [17]) or on the power system (as in [18]). The control technique given in this study performs better than the solutions suggested in [18] and [19], guaranteeing transient stability in the initial cycles after the FD. No new hardware has to be added to a PV plant's current gear in order to implement the proposed control approach, hence no extra expenditures are anticipated. But it depends on a PMU and a PDC, which may need to be set up. Despite the size of the expenditure, there is a growing trend towards employing smart grid technology to manage electricity networks in a cost-effective and coordinated manner. As they provide additional features for metering, monitoring, and control in this setting, PMUs and PDCs can therefore become into commodities.

2. SYSTEM MODELING

2.1 PROPOSED CONTROL SCHEME OF THE PV INVERTER

The transient stability study that is described below makes use of the power system configuration that is seen in Fig. 2.1.

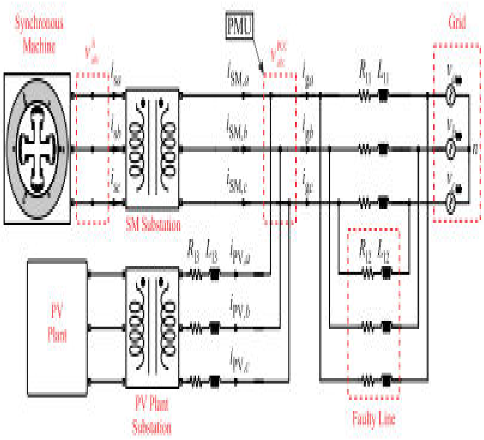

FIGURE 2.1. Three-phase diagram of a utility-scale hybrid power system.

This hybrid power system comprises of an SM running concurrently with a PV system, and two transmission lines link both power plants to the grid. The PV system is made up of n PV units, as illustrated in Fig. 2. During normal operation, these units are managed using an MPPT method. However, the PV inverters may activate FRT in MC mode and carry out the suggested control action to reduce the SM load angle (r) in the event of a malfunction in one of the transmission lines. It is well knowledge that an APF may indirectly affect grid currents by injecting the harmonic and reactive load current components. Similar to this, the currents that the PV inverters pump into the grid in order to manage the torque (or active power) and magnetic flux (or reactive power) may be enforced. This is possible because the SM governor typically responds after the fault has finished, while these inverters may intervene within the fault time period. By keeping the SM's active power output as near to its pre-fault state as feasible, the disequilibrium brought on by a disturbance may be reduced. This implies that during a failure, any excess active power that the defective grid is unable to handle must be sent to the PV units' dc link capacitors. It should be emphasised that this technique is dependent on the inverter's operating constraints, which must be taken into account. The goal of the suggested control strategy is to maintain the SM active power P f SM at its pre-fault value P pre-f SM during the fault. The PV plant reference active power should be in order to

$$P^{*}_{\mathrm{PV}} = \bar{P}^{\mathrm{f}}_{\mathrm{g}} - P^{\mathrm{pre\text{-}f}}_{\mathrm{SM}},$$

Pfg is the average active power added to the grid while the fault was present. The PV plant will need real-time monitoring of the SM and the grid, as shown by (1). A PMU is placed in the SM substation to monitor the voltage phasor at the PCC and the current phasors of the transmission lines for this purpose, as illustrated in Fig. 2.1. The PDC at the PV plant substation will receive synchro phasor data at a rate of up to 120 samples per second using current PMU technology [20], [21]. A PDC is used to combine and time-synchronize the phasor data obtained from one or more PMUs, from other PDCs, and from other sources. For control decision action, the PDC is a crucial connection between PMUs and the synchro phasor software programme, which receives the time-synchronized data [21]. The communication latency caused by sampling, data filtering and processing, communication system I/O, and communication distance is a crucial component in data transfer. The PV inverters won't be able to function effectively during the delay since no fluctuation in the SM active power output measurement reaches the PDC. As a result, the suggested control scheme must be successful in providing transient stability, therefore the communication system must be built to prevent delays that are greater than a certain threshold. This threshold is established as the greatest delay that does not do so.

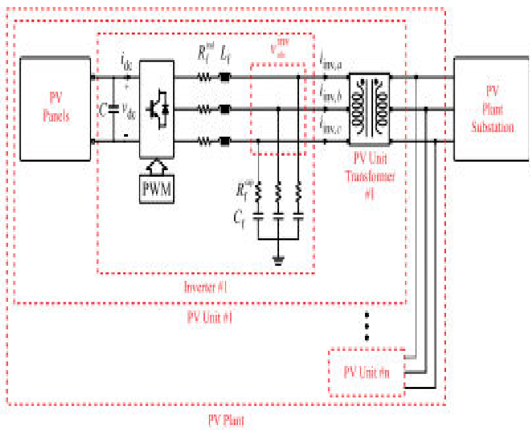

FIGURE 2.2. Three-phase diagram of each PV unit.

The PMU delay shouldn't be more than 20% of the entire fault time, according to this study's findings. The simulation in Section IV has a maximum delay of 28 ms, which is well within the 20–50 ms range that [20] describes as being common for a system. Fig. 2.2 depicts the suggested FRT system that will be used with the PV inverters. Once the PMU data are sent to the PV plant substation's PDC, it is possible to calculate the power references for each PV unit (Fig. 2) in the PV plant. Based on (1), it is necessary to calculate the pre-fault SM active power during the disturbance. This may be accomplished by using an extremely slow LPF with a time constant that is significantly longer than the normal fault duration, of the order of seconds. On the other hand, the control must take into account the decrease in the active power used by the grid. The harmonic and negative-sequence components of the voltages and currents produced by the fault are attenuated using a MAF. The PV reactive power reference calculation follows the same rules. No oscillatory power should be used in the computation of the reference power for PV plants, according to (1). MAFs and LPFs are used in order for this to occur during significant grid disruptions. The suggested control strategy can follow the changes in the average power being delivered via the grid in real time since the MAFs' cutoff frequency is greater. On the other hand, the SM pre-fault active power output, which serves as a reference signal in the suggested control scheme, is maintained by using the LPFs with lower cutoff frequencies. The power references of each PV unit are obtained by dividing the reference values through (1) by the quantity of PV units (n), as the reference values derived through (1) are for the PV plant. For safety reasons, the reference P * inv value must be restricted to the maximum active power P inv max that may be absorbed during the disturbance, which can be calculated using

$$P_{\max}^{\mathrm{inv}} = \frac{C}{2\Delta t}\left(v_{\mathrm{dc}}^{\max^2} - v_{\mathrm{dc}}^2\right),$$

where C is the dc link capacitance, 1t is the longest possible fault length, vdc is the dc link voltage in steady condition, and v max dc i is the highest dc voltage experienced during an interruption. This enforced restriction on the controller prevents the dc link voltage from going over the maximum inverter dc input voltage, which is a more stringent restriction than the capacitor's surge voltage of two times its nominal voltage, as in [23]. Additionally, the reference Q * inv must be constrained by the maximum reactive power Q inv max, which is determined as follows:

$$Q_{\max}^{\mathrm{inv}} = \sqrt{\left(S_{\max}^{\mathrm{inv}}\right)^2 - \left(P_{\mathrm{inv}}^{*}\right)^2}.$$

It should be noted that the calculation of the active power reference required to be absorbed by the PV units is given priority by the proposed control strategy. To increase voltage stability, as needed by certain GCs [5]–[7], the restriction set by (2) offers a power margin that may be used as reactive power support. In order to achieve constant power injection, which necessitates synthesising all odd harmonic current components, or oscillatory power injection of frequency 2, which necessitates only synthesising fundamental-frequency positive sequence (FFPS) currents, the FRT scheme computes the inverter current references, as shown in [9]. The oscillatory power injection, when used with the suggested control system, has no effect on the average SM active power output since its mean value is zero; hence, it has no bearing on the fluctuation of r. Also to be highlighted is the possibility of exceeding the inverter's maximum short circuit withstand capability when all odd harmonic currents are injected as opposed to only FFPS currents. For these reasons, the inverter current references used in this study only include the FFPS component. The "power to current" block establishes the current references based on the instantaneous power theory.

$$\begin{bmatrix} i_{+1,\alpha}^{\mathrm{inv}^*} \\ i_{+1,\beta}^{\mathrm{inv}^*} \end{bmatrix} = M_{\alpha\beta}^{+1} \begin{bmatrix} P_{\mathrm{inv}}^{*} \\ Q_{\mathrm{inv}}^{*} \end{bmatrix},$$

where M +1 αβ is given b

$$M_{\alpha\beta}^{+1} = \frac{1}{\left|\vec{v}_{+1,\alpha\beta}^{\mathrm{inv}}\right|^2} \begin{bmatrix} v_{+1,\alpha}^{\mathrm{inv}} & v_{+1,\beta}^{\mathrm{inv}} \\ v_{+1,\beta}^{\mathrm{inv}} & -v_{+1,\alpha}^{\mathrm{inv}} \end{bmatrix}.$$

Due to its superior performance features [25], a GDSC-PLL was employed to get the findings given in this study. In equation (5), the FFPS component of the voltage at the terminals Ev inv +1, of the PV unit, is obtained using a PLL. The short-circuit withstand capacity listed in the datasheet of the inverter unit should not be exceeded by the generated three-phase current, i abc inv.

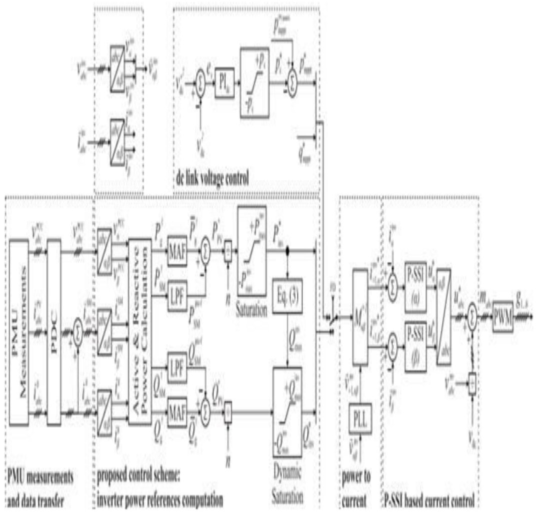

FIGURE 2.3. Proposed FRT method features calculation of FRT inverter power references, PMU measurements and data transmission, dc link voltage control, and P-SSI based current control.

3. SIMULINK MODELS AND RESULTS

This part simulates a utility-scale PV facility using Simulink/Matlab in order to test the suggested control method. The simulation results of the suggested control strategy are contrasted with those that were achieved after taking into account (i) the FRT specifications imposed by the German GC [6]; and (ii) the insertion of a VR-FCL, in which the effective resistance is established by the operation of an FLC [17]. Fig. 2.1 depicts the design of the simulated power system. An SM of 120 MVA and a PV plant of 100 MVA that produces 100 MW and 0 Mvar (operating at the maximum power point) were taken into account in the architecture in order to get the simulation results. The n = 50 PV units, each with a nominal apparent power of 2 MVA, make up the PV plant that is being studied in this section. The PDC receives data from the PMU unit at a rate of 60 samples per second with a 28 ms connection delay. The efficacy of the suggested control in minimising the r fluctuations might be jeopardised by a longer wait. The power plants are linked to the grid by two parallel transmission lines. Tables 3 to 6 provide the settings utilised for each system component. For the control and PWM of the converter, the sampling and switching frequencies (fs and fsw) are both

17.28 kHz. Based on the values reported in [29]-[31], the nominal voltage and dc link capacitance indicated in Table 2 were selected. The output LC filters are represented by the other Table 2 parameters. The gains used are Kp = 4.05 10-5 & Ki(1) = 0.0085 and Kpv = 7.788 & Kiv = 55.3 for the current and voltage controllers of each PV unit, respectively. With the aid of the existing controller gains, a GM of 12.6 dB, PM of 38.5, and ZF of 0.74 kHz were determined. The voltage controller gains were also computed to provide GM, PM, and ZF values of 63 dB, 51.2, and 7 Hz, respectively. In all of the study situations, the identical two-phase (phases b and c) to ground fault was simulated, but with a fault duration of TFD = 150 ms and a reclose time of Trcls = 600 ms. Both parameters are modified in accordance with international GCs using settings characteristic of protective systems.

TABLE 1. Synchronous machine parameters

v_{LL} (kV)	Poles	Velocity (rpm)	H (s)	r_s [a] (p.u.)	X_{ls} [a] (p.u.)	X_d [a] (p.u.)
13.8	4	1800	3.2	0.0029	0.18	1.305
X'_d [a] (p.u.)	X''_d [a] (p.u.)	X_q [a] (p.u.)	X''_q [a] (p.u.)	T'_d (s)	T''_d (s)	T''_{qo} (s)
0.296	0.252	0.474	0.243	1.01	0.053	0.1

TABLE 2. Inverter parameters of each PV unit.

C (mF)	v_{dc} (V)	v_{dc}^{max} (V)	S_{rated} (MVA)	R_f^{ind} ($\mu\Omega$)	L_f (μH)	R_f^{cap} (mΩ)	C_f (mF)
90	1100	1500	2	89.27	11.84	8.8	6

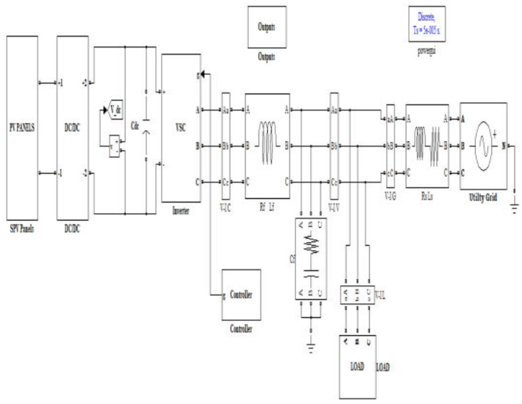

Fig 6.1 Grid connected pv system

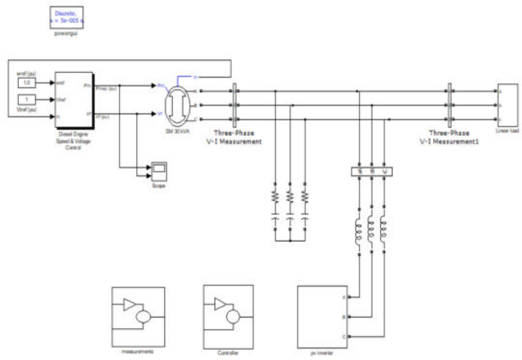

Fig6.1 pv dg-based grid connected system

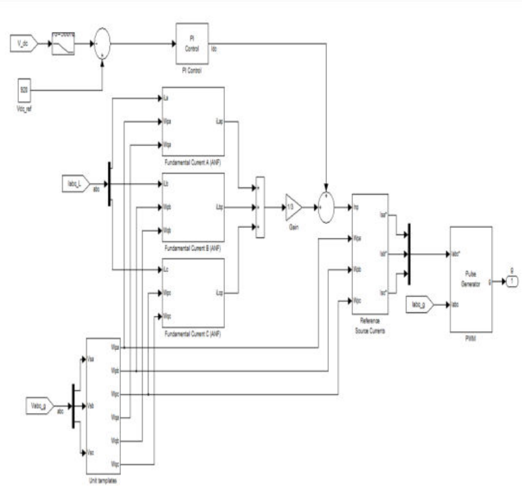

Fig 6.3 control circuit

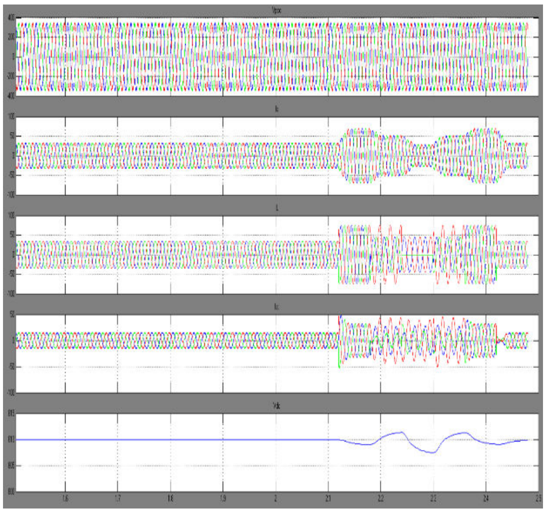

Fig 6.4 Grid voltage, grid current, load current , pv inverter current and dc voltage

4. CONCLUSIONS

In this work, a control scheme for PV inverters is proposed to act during faults that could compromise the transient and voltage stability of a hybrid power system. The analysis demonstrated that the proposed control scheme can act while the PV system is in MC operation, supporting the grid to recover stability during and after a disturbance on the transmission grid. The proposed control scheme makes the SM kinetic energy to be absorbed into the dc link capacitors to ensure transient stability. Besides that, it also enables the injection of reactive power into the grid to support voltage stability. simulation results have shown that the proposed control scheme can reduce the rotor angle oscillations within the first few cycles of the fault, effectively ensuring the SM's transient stability. It has also shown improvements in the grid voltages during the fault period and a very fast post-fault voltage recovery in comparison with other FRT control schemes.

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