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A Techno-Economic Assessment to Define Inertia Needs of the Italian Transmission Network in the 2030 Energy Scenario

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***Abstract*—Italian generation scenario, as many others, is foreseeing the replacement of conventional Synchronous Generators (SGs) in favour of Renewable Energy Sources (RES), thus leading to a reduction of the overall system inertia. This paper provides a techno-economic methodology for the estimation of the amount of additional inertia that will be needed in the Italian Transmission Network in the 2030 scenario, in order to limit the Rate of Change of Frequency (RoCoF) within sustainable limits. Moreover, the algorithm optimally distributes Synthetic Inertia (SI) contributions from RES and Battery Energy Storage Systems (BESSs) and the installation of new Synchronous Compensators (SCs) among the Italian market areas. The method is designed to be sufficiently simple to process a significant number of working scenarios and the relevant quantity of information owned by the TSO. Nevertheless, the results have shown to be highly accurate as demonstrated by comparison with detailed time domain simulations.**

***Index Terms*—Transmission System, System Inertia, Grid Flexibilization.**

I. INTRODUCTION

ELECTRIC networks are evolving towards more and more complex and heterogeneous systems. The integration of a rapidly increasing share of Renewable Energy Sources (RES), as Wind Turbines (WTs) and Photovoltaic (PV) units, in the traditional electric system, replacing or in addition to conventional Synchronous Generators (SGs) (e.g. thermoelectric and hydroelectric ones), poses a challenge for the system in terms of safety and adequacy, considering also the increasing share of inverter-based loads and of High Voltage Direct Current (HVDC) links. One of the main consequences of the increasing penetration of RES, besides the decrease of the system short-circuit power, is the reduction of the electric system inertia; this could lead to frequency instability problems in case of severe perturbations, especially for what concerns the Rate of Change of Frequency (RoCoF) and the frequency nadir [1], [2].

In order to face this problem, Transmission System Operators (TSOs) started putting in place several Frequency Support (FS) actions such as the installation of Synchronous Compensators (SCs) and the introduction of advanced control functionalities for inverter-based generation, to provide the FS services required by the network [2], [3].

SCs (with or without flywheel) have been widely exploited in the past for this purpose. They can both help in increasing the short-circuit power of the system [4], [5] and contributing to FS, limiting the RoCoF [6].

In order to enhance the frequency stability, TSOs are also updating grid code requirements to allow renewable power plants to participate in FS. Among the various FS services, Synthetic Inertia (SI) is a promising and fast developing technology to cope with the problem of the deterioration of the RoCoF [7-10]. SI will allow RES and Battery Energy Storage Systems (BESSs) to strongly impact the grid resiliency in terms of inertial frequency response due to their flexibility and capability to provide novel ancillary services [11, 12].

WTs, depending on the type of generator, are not able to "naturally" release the rotational energy stored in the movement of their blades: this is the case for WTs equipped with Permanent Magnet Synchronous Generator (PMSG) or Doubly Fed Induction Generator (DFIG), due to the fact that they are connected to the grid by means of a power electronic converter, that prevents them from the provision of FS service after a disturbance [7].

In order to provide an inertial response, WT generators need to be equipped with a dedicated control system. Control schemes for provision of SI appear in [8, 9, 13, 14] (and references therein); they consist of a signal within the active power channel proportional to the frequency derivative to keep the frequency within the desired interval. It should be noted that such technology has been widely employed at least at prototype stage, as witnessed by the European Projects, like Osmose and Migrate [15], [16] that proved the applicability of this type of service. The provision of SI by WT generators is beneficial not only from a technical point of view but also from an economic one, as highlighted in [17].

Considering PV power plants, an overview of the capability of the technology to participate in FS services is delivered by [18], that focuses on the role of grid-scale PV plants. Control schemes for the provision of SI are proposed in [19, 20].

BESSs can provide SI either in stand-alone configuration or coupled to other RES, like WTs or PV systems. The first configuration represents a promising solution, thanks to the characteristics and flexibility of BESSs: an application is represented by Hornsdale Power Reserve, in Australia, that is able to provide up to 3000 MWs of SI [21] and innovative configuration are also studied to mitigate the impact of RES into the power system [22]. The second configuration is applied e.g. in the Grand Ridge Energy Storage plant, in Illinois (USA), where a 31.5 MW battery system is coupled to PV and Wind power plants [23]. Beneficial effects of BESSs in stand-alone

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configuration during under-frequency transients are presented in [24], considering the Irish power system. A control scheme for the provision of SI is provided in [25].

However, if from one side there are many possible applications for SI technologies, few are the studies that aim at answering the question of how much SI is necessary in a given network to perform an effective FS action. Moreover, other key points are relevant to *i*) the choice of the best technical and economic mix among the different devices that are committed for the SI service and *ii*) the best placement of such devices in a national transmission grid. These aspects are becoming crucial for TSOs while designing the future of the networks they manage.

A methodology for the evaluation of the amount of inertia necessary at national and zonal level in order to limit RoCoF, even in case of network separation, is presented in [26], applied to the Southern Australian network. However, the possibility of requiring a provision of SI from RES generators is not taken into account, considering only the inertia provided by SGs and SCs, which is quite a limitation in light of the current energy transition.

A methodology for the estimation of the minimum synchronous inertia requirements of power systems characterised by large RES penetration is proposed in [27]. The methodology is applied to a future scenario of the Australian National Electricity Market. Again, only SGs and SCs are accounted for the provision of inertia. WT power plants are considered only for power reserve services and not for SI provision, whilst PV systems are considered neither for power reserve nor for SI provision, limiting the range of action of RES in FS services. Besides, no methodology for the subdivision of the necessary synchronous inertia among the Australian market zones is proposed.

In [28] a study of the impact of RES on the Croatian national grid is provided, focusing on RoCoF-related issues; the study shows how the provision of SI by PV and WTs contributes to the reduction of the RoCoF, by means of a simulation performed in DIgSILENT PowerFactory [29]. Nevertheless, a detailed focus on the quantification of the share of RES that should contribute to SI and on how that share should be distributed among the zones in which the Croatian grid is divided is still missing.

Starting from this state of art, the focus and novelty of the present paper is to define a tool to help the Italian TSO, Terna S.p.A. (from now on Terna), to estimate the best amount of inertia from a techno-economic point of view to guarantee an effective FS in the Italian transmission network 2030 scenario, characterised by a large penetration of RES generators. In details, it allows to determine the best *i*) amount of SI provision in the Italian transmission network, *ii*) mix among the sources contributing to inertial FS minimizing the system costs and *iii*) placement in the market zones of the Italian national grid.

In literature, no examples have been found proposing this complete methodology: previously-proposed approaches only quantified the need of additional inertia, without providing a methodology to allocate the resources within the network; other approaches did not consider the SI contribution of inverter-based sources, limiting their application in future power systems with large share of renewable generation.

In fact, the novelty of work presented in this paper is the development of a tool that, by setting up an optimisation problem, is able to evaluate the right amount of additional inertia needed to keep the RoCoF of the Italian network's Centre of Inertia (COI) within the range prescribed by the Italian grid code at $t=0^+$ (i.e., immediately after the contingency, which is the most critical instant as the controls have not started their action yet). The considered inertia-providing sources are new SCs to be installed, providing traditional inertia, and PV units, WT plants and BESSs, providing SI. The tool is able also to allocate the needed inertia-providing resources in the proper market zones.

It is worth pointing out that the methodology relies on a simplified model that allows a good balance between accuracy and computational effort (the data set used for the analysis is quite large). However, the reliability of the method is provided by means of comparison with the result provided by complete simulations in DIgSILENT PowerFactory for a reduced set of critical hours. Moreover, the proposed methodology has been applied to the Italian grid but it can be easily generalized for application in any other transmission grid divided in internal market areas.

The paper is structured as follows: Section II. presents the methodology of the study, gives an overview on the available dataset and comments on the main assumptions. Section III. fully details the proposed algorithm to estimate the overall inertia need at national level, Section IV. describes how it can be divided in the market zones, whilst Section V. and VI. show the numerical results of the two procedures. Finally, some conclusive remarks and possible future developments are discussed in Section VII. .

II. METHODOLOGY OVERVIEW

A. *Workflow of the method*

The aim of the study is to provide the TSO with an estimation of the additional inertia that will be necessary in each Italian market zone in the 2030 year to limit the RoCoF of the Italian network COI within a suitable interval.

To do this the following steps were identified:

a) definition of the reference contingency that originates the frequency transient;
b) estimation of the Italian inertia need to cope with such contingency and definition of the energy sources that should provide it;
c) optimal placement of such inertia in the market zones;
d) validation of the proposed approach by comparison with the results of a complete RMS time domain simulation for some sample hours of the 2030 scenario;
e) execution of the proposed algorithm for all the hours of the 2030 scenario and statistical analysis of the results.

As regards point a), the loss of the links between Italy and the rest of the EU grid is assumed as reference perturbation.

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This has been identified by Terna as the most critical contingency that the Italian transmission system could undergo. It is worth noticing that, according to its peculiar geography, the split of the Italian grid is a rare but not impossible scenario. In fact, it has been verified that the entity of the perturbation triggered by the loss of all the links with the EU grid is larger than the entity of the perturbation triggered by the loss of any Generation Unit (GU), where a GU is the “minimal part of generation plant able to inject power into the network” [30]. Besides, since the present study focuses on RoCoF containment, the loss of all the links with the EU grid implies that the Italian network cannot receive inertial support from the rest of the European network, constituting the worst possible scenario. Anyway, the method can be used for any other contingency without any loss of generality.

Regarding point b), for each hour of the considered year, the proposed algorithm firstly estimates the available inertia within the Italian network, associated to SGs and already-installed SCs and then defines the best technical and economic mix of technologies to provide the needed additional inertia. Such mix accounts for the possibility of upgrading the controllers of the inverter-based generators (PV, WTs and BESSs) to make them able to deliver SI, and the option of installing new SCs. From now on, this stage of the procedure will be labelled as National Algorithm (NA). The NA estimates the need of inertia of the Italian network by applying the swing equation to a Single Bus Bar (SBB) model of the Italian network and by considering the initial value of RoCoF after the contingency. The reason for such assumptions will be detailed in Section II-B.

As concerns point c), the results of the NA are processed by the second optimisation algorithm, called the Zonal Algorithm (ZA) where the amount of additional inertia needed to limit RoCoF at national level is divided among the Italian market zones, finding the share of new SCs to be installed and of the inverter-based generators to be updated in each market zone. Only at this level a multi busbar model of the Italian network is considered, where nodes are aggregated in correspondence of each market zone.

Regarding point d), in order to test the algorithms, some meaningful hours of the 2030 year are selected and the related results are implemented on DIgSILENT PowerFactory: for each selected hour, a detailed dynamic simulation is set up to verify that the RoCoF of the COI of Italy lays within the desired interval and to check the overall frequency transient during primary frequency regulation.

As to point e), once the validation process has given positive feedback, a statistical analysis of the zonal results is performed, to provide the TSO with an estimation of the share of inverter-based generators to be upgraded and of the SCs to be installed in each Italian market zone over the whole 2030 year.

A flowchart is proposed in Fig. 1, to give an overview of the developed procedure for a generic case of a transmission system composed of N market areas. The NA provides as output the contribution associated to the installation of new SCs and the SI contributions from WT power plants, BESSs and PV plants. The ZA acquires the output of the NA and provides the repartition of each technology among the considered N market areas. This procedure is iterated for the whole hours of the year and the resulting dataset is analysed from a statistic point of view to identify inertia need previsions per market area per technology.

The optimisation problem is divided in two parts because the NA deals with the national problem that is of extreme relevance for Terna, whose aim is to ensure the compliancy of the whole national network’s operating conditions with the grid codes. For this reason, the amount of additional inertia needed in order to limit the RoCoF of the COI of the Italian network at t=0^+ is of primary interest for Terna and is evaluated at the NA stage.

Then, in order to help Terna allocating the inertia sources among the Italian market zones, the ZA is developed.

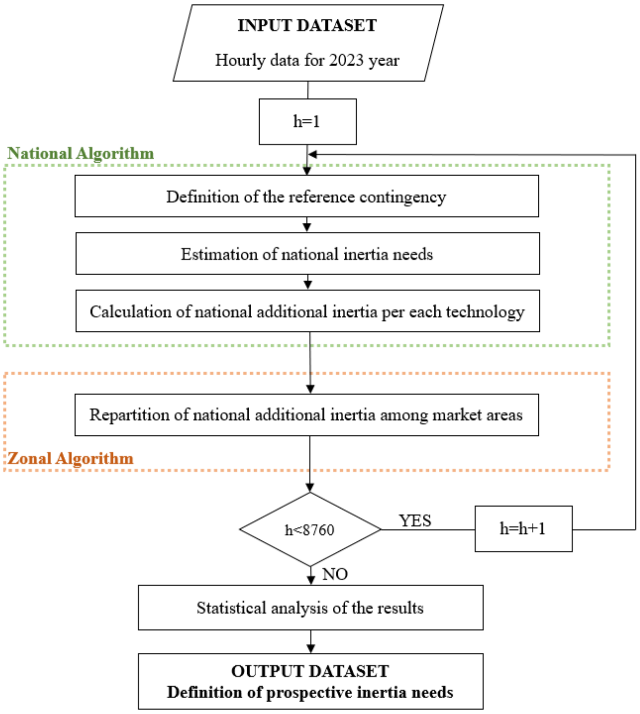

Fig. 1. Flowchart of the procedure.

B. Data set

Input data have been obtained by Terna following a forecasting approach, described in [31].

The Italian transmission network is modelled in the simplified configuration depicted in Fig. 2; as one can see, the network consists of N busses, each corresponding to a market zone (it is worth noticing that Sardinia market zone is connected to the peninsula only by HVDC links).

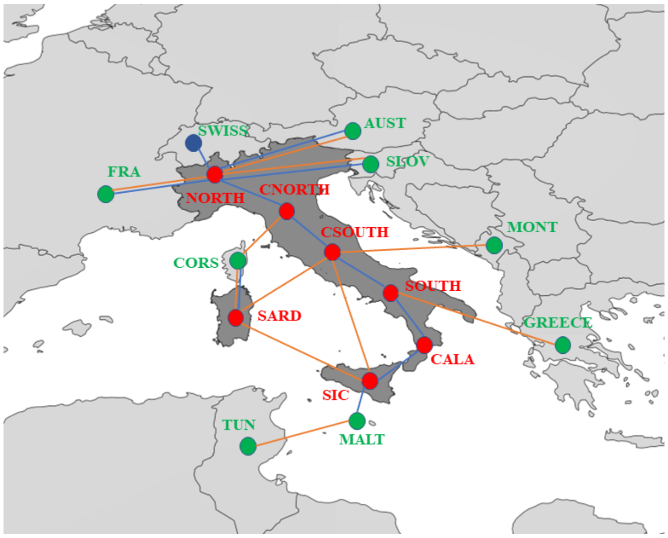

Fig. 2. Market zones in the Italian transmission network. Blue lines are AC transmission lines. Orange lines are HVDC transmission lines.

Starting from historical load profiles and from the expected diffusion of new electricity-consuming technologies (e.g., electric vehicles, heat pumps, etc.), an hourly demand profile is created for each market zone and for each of the 8760 hours of 2030 year. These profiles are the input of a market analysis algorithm that defines the hourly generation dispatch able to satisfy the demand according to market criteria, while granting the delivery of dispatching services (satisfaction of power reserve constraints, guarantee of the security of the system and resolution of possible congestions between market zones). The algorithm runs a simulation of the Day Ahead Market all over Europe, to foresee the power exchanges between Italy and its neighbouring countries too. So, the 2030 scenario data provided by Terna represents, for each bus of the network of Fig. 2 and for each hour of the year, an evaluation of the load active power request, the overall inertia constant H_i, i=1…N_{gen} of the rotating machines (SGs and SCs) foreseen in the 2030 network scenario and the amount of power generation connected to the grid in the specific hour and its active power generation (for all generating sources).

For confidentiality reason, the hourly generation and the hourly amount of power generation connected to the grid for each technology cannot be disclosed. Anyway, in order to give an overview of the Italian generation scenario and to enhance the reader's comprehension of the results that will be presented in Section VI the installed capacity for each technology is provided in TABLE I, for each market zone. Data related to traditional power plants equipped with SGs are provided separately for Thermoelectric power plants (TPPs) and for Hydroelectric power plants (HPPs).

TABLE I

INSTALLED CAPACITY BY TECHNOLOGY AND MARKET ZONE

	TPP [GW]	HPP [GW]	BESS [GW]	PV [GW]	WT [GW]
North	28.657	14.838	1.1671	22.870	0.1841
CNorth	4.5754	0.6738	0.2473	5.2943	0.2582
CSouth	6.1534	2.2330	1.1819	9.1419	3.7018
South	6.2568	0.2010	1.3861	7.7989	8.3002
Cala	2.0413	0.9425	0.4182	2.5672	2.5666
Sic	2.3158	0.1115	1.0992	4.3275	3.9891

Besides, according to the provided scenario, the 56.5% of the electric demand is satisfied by RES generation, at national level [32].

C. *Main assumptions*

The power system model used for the *NA* is the swing equation applied to a Single Bus Bar (*SBB*) model of the national grid at the time of the contingency (that is the most critical one as, afterwards, machines controllers start their action limiting the frequency variations). Such equation accepts in input the perturbation entity and, constraining the *RoCoF* at its limit, allows to estimate the necessary amount of inertia to guarantee that the frequency time derivative does not exceed the prescribed thresholds. Given that, a linear optimization algorithm is set up that provides in output the optimal technological mix to cover the inertia gap. Then, for the *ZA,* a SBB model will be applied to suitable portions of the Italian Transmission Network as will be detailed in Section 4.

One could argue that this model is too simplified and that a canonical Optimal Power Flow (OPF) should be run to obtain reliable results. Indeed, the choice of this simple model is justified by the following facts:

1) it is consistent with the topology of the input network and the typology of input data (see section II.B). Indeed, Terna's 2030 Development Plan only provides data for each market zone, which makes it impossible consider a more detailed network topology and consequently to set up a more sophisticated OPF;

2) it is consistent with the uncertainty of the input data that, being a projection of a future scenario, would not be coherent with a very detailed analysis whose result would be in any case affected by the imperfect knowledge of the input data;

3) it is consistent with Terna's objective to determine the amount of inertia to be installed in each market zone by each technology. A more detailed allocation would be useless for the TSO because sometimes there are other kinds of constraints (as an example, installing a new synchronous compensator would not be possible in any physical node of the Italian Transmission Network; for this reason Terna needs to have an indication of the market zone and then it will decide its optimal allocation within it considering other physical constraints);

4) it is consistent with Terna's objective to have a statistical indication of the inertia needs and on how to cover this gap. This claims for a huge number of simulations that would be computationally unbearable if a much more detailed network model were considered implying a much more complicated OPF problem.

III. ADDITIONAL INERTIA ESTIMATION ALGORITHM

This section presents the details of the developed NA to determine the amount of additional inertia needed at national level to limit RoCoF in the Italian Transmission Network in the 2030 Scenario.

A. Governing equation

For a given hour, starting from the initial working point defined by the input data, the loss of the connections with the countries bordering Italy on the Northern border is assumed as the contingency that gives origin to a frequency transient.

Modelling the overall Italian Network as a SBB system, the initial value of the frequency derivative can be calculated solving the swing equation [33] calculated at the initial instant t_0 of the transient:

$$\Delta P\left(t_0^+\right) = 2\left(H + H_{add}\right)\frac{df}{dt}\left(t_0^+\right) \tag{1}$$

where ΔP is the variation of the active power (i.e. the opposite of the active power that was injected by all the North bordering countries in the predefined working point) in per unit on a common base S_b, while f is the frequency in per unit referred to the nominal frequency of the system f_n.

Note that, even if all those data are hour dependent, in the present mathematical derivation this aspect is not accounted from a notational point of view for the sake of readability.

The system inertia, expressed on the common power base, is divided in two contributions: H is the inertia present in the considered power system (i.e. $H = \sum_{i=1}^{N_{gen}} H_i$) while H_{add} denotes the amount of additional inertia eventually necessary to limit the RoCoF.

The aim of the problem is keeping the frequency time-derivative within suitable ranges:

$$-RoCoF_{\text{lim}} \le \frac{df}{dt}\left(t_0^+\right) f_n \le RoCoF_{\text{lim}} \tag{2}$$

where $RoCoF_{lim}$ represents the maximum allowable value of the RoCoF expressed in Hz/s.

To meet the above requirement, some additional inertia H_{add} has to be provided, given by:

$$H_{add} = H_{add,c} + H_{add,w} + H_{add,st} + H_{add,PV}\,. \tag{3}$$

It is worth recalling that among all the contribution to the additional inertia, the only device that can provide physical inertia is the synchronous compensator; other contribution shall be provided by SI controllers. The standard control scheme for a SI controller is characterised as follows:

$$\Delta P_{synt} = 2H_{synt}\frac{df}{dt} \tag{4}$$

As one can see, the SI control provides an extra power contribution ΔP_{synt} proportional to the derivative of the system frequency $\frac{df}{dt}$ (here both ΔP_{syn} and $\frac{df}{dt}$ are in p.u. on the plant rating and on f_n respectively). The control parameter H_{synt}, is the SI coefficient and is expressed in *s* on the rating of the considered production plant. In view of defining an optimization problem, upper boundaries on the additional SI contributions from all the sources must be defined.

The SI provided by the different sources can vary according to the amount of generation in operation in the considered hour. It is worth noting that H_{synt} is a control parameter that can be chosen in principle ad libitum; in this analysis, its upper limit will be set according to the following guidelines: *i*) for each source and for each hour the maximum active power available for the SI service is estimated both for under-frequency ($\Delta P < 0$) and over-frequency ($\Delta P > 0$) transients; *ii*) the SI upper limit is calculated assuming the value of $RoCoF_{lim}$ in the expression relating the additional power to the SI coefficient.

B. SI coefficients upper limits estimation

1) Photovoltaic power plants

For PV systems, in under-frequency conditions inertial FS is provided only in presence of power curtailment, since PV plants extra power only if they are not working at their maximum power. For each node *i* of the network, with *i*=1...*N*, the curtailment power $P_{curt,i}$ can be expressed as the difference between the Maximum Power Point Tracking (MPPT) power $P_{PV,i,MPPT}$ of the PV source and the actually injected active power $P_{PV,i}$, i.e.:

$$P_{curt,i} = P_{PV,i,MPPT} - P_{PV,i}\,. \tag{5}$$

In over-frequency transient the power available to limit RoCoF is $P_{PV,i}$. So, inserting in (4) the per unit value of the available power for the FS and imposing the limit value of the frequency derivative $RoCoF_{lim}/f_n$, the SI coefficient $H_{PV,max}$ (referred to the rating of the sum of the PV plants apparent powers connected to the whole Italian network in the considered hour $A_{PV,on}$) can be calculated as follows:

$$H_{PV,max} = \begin{cases} \dfrac{\dfrac{\sum_{i=1}^{N} P_{curt,i}}{A_{PV,on}} f_n}{2RoCoF_{lim}} & \Delta P < 0 \\[2ex] \dfrac{\dfrac{\sum_{i=1}^{N} P_{PV,i}}{A_{PV,on}} f_n}{2RoCoF_{lim}} & \Delta P > 0 \end{cases} \tag{6}$$

2) Wind power plants

Concerning WT power plants, in case of under-frequency transients the evaluation of the maximum inertia constant can be done as follows. Assuming to know the active power production $P_{w,i}$ of all the WTs connected to the *i*-th node of the network, the corresponding apparent power $A_{w,on,i}$, it is possible to calculate the residual power available for the inertial support.

From a practical point of view, power electronic devices may endure a certain amount of overloading for a limited set of time such as the one necessary for inertial frequency support. This is considered by introducing a converter overloading coefficient, namely α, that enlarges the inverter capability to $\alpha A_{w,on,i}$. This parameter is a converter parameter and thus it may change according to the converter that is modelled. For the sake of completeness, this is treated as an independent parameter that can be set to one is if no overloading capability is possible. Reasonable values for this overloading coefficient range from 110% to 120%.

With this aspect in mind, to calculate the power available for inertial frequency support, it is necessary to estimate the reactive power production of the inverter in a conservative way and this is done by considering the minimum power factor $\cos\varphi_{min}$ that has to be granted according to the specific grid code requirement. In formulas:

$$Q_{w,i} = P_{w,i}\frac{\sqrt{1-\cos^2\varphi_{min}}}{\cos\varphi_{min}} \tag{7}$$

Therefore, the active power $\Delta P_{w,i}$ available for the SI provision can be calculated as:

$$\Delta P_{w,i} = \sqrt{\alpha^2 A^2_{w,on,i} - P^2_{w,i}\frac{1-\cos^2\varphi_{min}}{\cos^2\varphi_{min}}} - P_{w,i} \tag{8}$$

In case of over-frequency conditions, the approach is the same as for PV systems: the available active power for inertial support is the whole production of WTs at net of the minimum production to avoid cut off. Therefore, the SI coefficient $H_{w,max}$ (referred to the rating of the sum of the WT plants apparent powers connected to the whole Italian network in the considered hour $A_{w,on}$) can be calculated as:

$$H_{w,\max} = \begin{cases} \sum_{i=1}^{N} \dfrac{\dfrac{\Delta P_{w,i}}{A_{w,on}} f_n}{2RoCoF_{lim}} & \Delta P < 0 \\ \sum_{i=1}^{N} \dfrac{\dfrac{P_{w,i}}{A_{w,on}} f_n}{2RoCoF_{lim}} & \Delta P > 0 \end{cases} \tag{9}$$

3) Battery Energy Storage Systems

A similar approach is proposed for BESSs, for which:

$$H_{st,max} = \sum_{i=1}^{N} \frac{\dfrac{\Delta P_{st,i}}{A_{st,on}} f_n}{2RoCoF_{lim}} \tag{10}$$

where the main difference lays in the calculation of $\Delta P_{st,i}$ that needs to consider the bidirectional power flow of the storage unit, that is to say:

$$\Delta P_{st,i} = \begin{cases} \sqrt{\alpha^2 A^2_{st,on,i} - P^2_{st,i}\dfrac{1-\cos^2\varphi_{\min}}{\cos^2\varphi_{\min}}} - P_{st,i} & \Delta P < 0 \\ \left| -\sqrt{\alpha^2 A^2_{st,on,i} - P^2_{st,i}\dfrac{1-\cos^2\varphi_{\min}}{\cos^2\varphi_{\min}}} - P_{st,i} \right| & \Delta P > 0 \end{cases} \tag{11}$$

where all the symbols are in analogy with the ones defined for WT power plants.

C. Optimization problem structure

To set up the optimization problem, the relevant objective function is designed estimating the economic impact connected to the provision of inertia by each technology:

$$\begin{cases} C_w = k_w \dfrac{A_w}{A_{w,tower}} = k_w \dfrac{H_{add,w}}{A_{w,tower}} \dfrac{S_b}{H_{w,max}} \\ C_{st} = k_{st} A_{st} = k_{st} H_{add,st} \dfrac{S_b}{H_{st,max}} \\ C_{PV} = k_{PV} \dfrac{A_{PV}}{A_{PV,av}} = k_{PV} \dfrac{H_{add,PV}}{A_{PV,av}} \dfrac{S_b}{H_{PV,max}} \\ C_c = k_c A_c = k_c H_{add,c} \dfrac{S_b}{H_c} \end{cases} \tag{12}$$

where k_w, k_{st} and k_{PV} are respectively the cost of implementation of a SI controller in the control scheme of a WT, BESS or PV inverter, expressed in Euro per WT, Euro per MVA and Euro per inverter, and k_c is the cost in Euro per MVA of a SC. Moreover, $A_{w,tower}$ and $A_{PV,av}$ represent respectively the typical size of an inverter connected to a WT generator and to a PV unit. Finally, H_c is the inertia constant of one SC. The optimisation problem can be finally formalised as:

$$\begin{aligned} &\min\left[C_{st} + C_w + C_{PV} + C_c\right] \\ &s.t. \\ &-\frac{RoCoF_{\text{lim}}}{f_n} \le \frac{df}{dt} \le \frac{RoCoF_{\text{lim}}}{f_n} \\ &\Delta P = 2\left(H + H_{add,c} + H_{add,w} + H_{add,st} + H_{add,PV}\right)\frac{df}{dt} \\ &0 \le H_{add,w} \le H_{w,max}\frac{A_{w,on}}{S_b} \\ &0 \le H_{add,\text{st}} \le H_{st,max}\frac{A_{st,on}}{S_b} \\ &0 \le H_{add,PV} \le H_{PV,max}\frac{A_{PV,on}}{S_b} \end{aligned} \tag{13}$$

Examining (13), it is apparent that the optimal solution is the one in which the frequency derivative is equal to either its lower limit (under-frequency case) or its upper one (over-frequency case). This consideration leads to simplify the mathematical structure of the problem that can be reformulated as the union of two linear problems, one for the under-frequency and one for the over-frequency case. By way of example, the under-frequency case is here reported.

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$$
\begin{aligned}
&if \quad \Delta P < 0 \\
&\min\left[C_{st} + C_w + C_{PV} + C_c\right] \\
&s.t. \\
&\Delta P = -2\left(H + H_{add,c} + H_{add,w} + H_{add,st} + H_{add,PV}\right)\frac{RoCoF_{\lim}}{f_n} \\
&0 \le H_{add,w} \le H_{w,max}\frac{A_{w,on}}{S_b} \\
&0 \le H_{add,\mathrm{st}} \le H_{st,max}\frac{A_{st,on}}{S_b} \\
&0 \le H_{add,PV} \le H_{PV,max}\frac{A_{PV,on}}{S_b}
\end{aligned} \tag{14}
$$

The over-frequency case is obtained substituting $-RoCoF_{\lim}$ with $RoCoF_{\lim}$ in (14) and considering the relevant upper limits for the SI coefficients.

It is worth recalling that, the proposed formulation is independent from the transmission network topology.

IV. ZONAL ALGORITHM TO SHARE THE INERTIA AMONG THE MARKET ZONES

Once the overall additional inertia is defined at national level, it is necessary to define a way to share the inertia among the market zones. Considering the peculiar structure of the Italian peninsula, the ZA is implemented as follows: consider the southernmost market zone (i.e. Sicily) and assume a split from the remaining part of Italy (this latter scenario is not meaningless since some time Sicily is islanded from the main grid); then consider the split between the two southernmost zones (i.e. Sicily and Calabria) with the rest of Italy and repeat the procedure for all the country. This procedure origins N-1 possible split scenarios (and N-1 electric islands).

Without loss of generality, this procedure can be used also in transmission systems with a different geographical extension or topology, just by defining a rule for the definition of progressive islands that include an increasing number of market zones.

The sharing of the inertia is done to minimize the RoCoF of each island originated by the above defined splits. In formulas, one has:

$$
\min\left\{\sum_{i=1}^{N-1}\left|\frac{df_i}{dt}\right|\right\} \tag{15}
$$

s.t.:

$$
\begin{aligned}
&\Delta P_{i+1,i} = \\
&= 2\sum_{j=1}^{i}\left(H_j + H_{add,c,j} + H_{add,w,j} + H_{add,st,j} + H_{add,PV,j}\right)\frac{df_i}{dt}
\end{aligned} \tag{16}
$$

where H_j, $H_{add,c,j}$, $H_{add,w,j}$, $H_{add,st,j}$ e $H_{add,PV,j}$ are respectively the available inertia (related to already-installed SCs and to SGs), the additional inertia by newly-installed SCs, the additional inertia by WT power plants, the additional inertia by BESSs and the additional inertia by PV power plants, in the j-th market zone. $\Delta P_{i+1,i}$ is the opposite of the power flowing from zone i+1 to i before the contingency.

Equation (15) represents the objective function, aiming at minimizing, in absolute terms, the RoCoF of each island. Only the first N-1 islands are considered because the N-th island would be the whole Italian network, whose RoCoF is imposed within the constraints of the NA. The RoCoF of the N-1 islands are included here in the objective function and not in the constraints of the ZA because the aim of the ZA is not to limit the RoCoF of each island, but its aim is to share and locate the inertia sources among the market zones, keeping the RoCoF of the Italian COI within the desired range, while minimising the islands' RoCoF (in absolute value) as much as possible.

Equation (16) represents the swing equation applied to the i-th island: the sum on the right term of the equation, going from j=1 to j=i, means that the inertia contributions that have to be considered to support the RoCoF in the i-th island derive from the inertia sources allocated in the market zones going from the first one, Sicily, to the i-th one.

A second set of constraints imposes that, for each technology, the sum of the inertias that are installed in each market zone must be equal to the national inertia, output of the NA:

$$
\begin{aligned}
&\sum_{i=1}^{N} H_{add,c,i} = H_{add,c} \\
&\sum_{i=1}^{N} H_{add,w,i} = H_{add,w} \\
&\sum_{i=1}^{N} H_{add,st,i} = H_{add,st} \\
&\sum_{i=1}^{N} H_{add,PV,i} = H_{add,PV}
\end{aligned} \tag{17}
$$

A third set of constraints is given by (18): the inertia provided should not overcome a technological maximum limit, given for each market zone and for each technology (except for SCs).

$$
\begin{aligned}
&0 \le H_{add,w,i} \le H_{w,max,i} \\
&0 \le H_{add,PV,i} \le H_{PV,max,i} \\
&0 \le H_{add,st,i} \le H_{st,max,i} \\
&i = 1..N
\end{aligned} \tag{19}
$$

where the maximum limits, for the three sources, for the i-th market zone, can be estimated with an approach that is similar to the one applied to the NA, with a symbology that has been already defined in Section A. By way of example, the underfrequency case is here reported, whilst the over frequency one is omitted for the sake of brevity:

$$H_{PV,max,i}=\frac{\frac{P_{curt,i}}{S_b}f_n}{2RoCoF_{lim}}$$
$$H_{w,max,i}=\frac{\frac{\Delta P_{w,i}}{S_b}f_n}{2RoCoF_{lim}} \qquad (20)$$
$$H_{st,max,i}=\frac{\frac{\Delta P_{st,i}}{S_b}f_n}{2RoCoF_{lim}}$$

In order to apply the proposed methodology to transmission networks different from the Italian one, the choice of the first island has to be taken into account carefully. Due to the peculiar structure of the Italian transmission network, Sicily has been chosen as first market zone and therefore first island, being a weak portion of the grid that is easily forced to work in islanded mode. For other transmission networks, the choice has to be done in a similar way, selecting as starting island a market zone that is weakly connected to the national transmission network. The subsequent islands have to be defined starting from the previous ones adding one neighbouring market area each time.

V. VALIDATION OF THE DEVELOPED METHOD

Before applying the proposed procedure for all the dataset of hours of the 2030, a validation is mandatory to assess the reliability of the results achieved. This is performed via dynamic simulation in DIgSILENT PowerFactory to simulate the frequency transient in a limited number of hours in which, following the loss of all the links at the Italian northern border, the RoCoF of the Italian network COI is particularly critical. First, a simulation is carried out to define the "as-is" hourly scenario, in which no inertial support is provided by inverter-based generation and in which no additional SCs are installed. A second simulation is then performed by implementing in DIgSILENT PowerFactory the results of the proposed algorithm, in order to verify that, with the introduction of the inertial support by WTs, PV and BESSs and with the installation of new SCs, the RoCoF of COI can be limited within the desired interval [-0.5 Hz/s; 0.5 Hz/s].

In DIgSILENT PowerFactory, the electromechanical model of the Italian network depicted in Fig. 2 is implemented. This model reflects the subdivision in market zones that is presented in [20] with a high level of detail.

Starting from the data provided by Terna, it is supposed that six equivalent SGs are connected to the network at each node, one for each of the following technologies: steam power plants, gas power plants, combined cycle power plants, conventional hydro power plants, pumped-storage power plants and run-of-river power plants. Each type of generator is equipped with a governor and with an Automatic Voltage Regulator (AVR), whose models are taken from the Library of DIgSILENT PowerFactory [29]. Governor models are specific for each type of generation, whilst a common AVR model [29] has been chosen. They are reported in TABLE II:

TABLE II
GOVERNOR AND AVR MODELS [29]

		GOV	AVR
TPP	Combined Cycle	Gov_GENERAL	exc_SIMPLE
	Steam Turbine	Gov_STEAM	exc_SIMPLE
	Gas Turbine	Gov_GAS	exc_SIMPLE
HPP	Reservoir	Gov_HYDRO	exc_SIMPLE
	Run of River	Gov_HYDRO	exc_SIMPLE
	Reservoir with pumping	Gov_HYDRO	exc_SIMPLE

Inverter-based generation is considered as a static generation, so it is modelled as a current-controlled voltage source [35]. These generators are RMS-modelled, similarly to what has been done for SGs. Three equivalent generators are connected to each node of the network, representing PV, WT and BESS power plants. In order to validate the results of the optimisation algorithms, a detailed inertial controller has been developed for these technologies, so that they are able to provide SI [36], [37]. The controller implements the control equation reported in (4). The additional power term ΔP_{synt} is added within the active power channel of the inverter's control to the active power reference signal.

Finally, at each node of the network, two equivalent SCs are connected, representing the already-installed and the newly-installed ones.

As said before, the validation test is performed over a limited set of sample hours, distributed along the 2030 year. For the sake of brevity, the results for the most relevant hour are reported. The hour that has been selected is 09:00 AM, 13/08/2030, for which the RoCoF of the COI, following the considered contingency, is equal to -1.7 Hz/s.

The Input data of the scenario are sensitive data for the TSO; for this reason, grid parameters and load flow assignments cannot be disclosed.

The NA requires, as input data, the cost coefficients $k_{PV,}$ k_w, k_{st} and k_c: these coefficients have been provided by manufacturers and so, for confidentiality reasons, their value cannot be disclosed. Anyway, in order to better explain the results in the following section, the proportionality among those coefficients is the following: k_w=1.5* k_{PV}, k_{st}=6.5* k_{PV}, k_c=10* k_{PV}. Costs associated to PV systems, WT systems and SCs are coherent with the ones proposed in [38-40].

The values of additional inertia each technology has to provide, according to the developed method, are shown in TABLE III (in terms of energy).

TABLE III
RESULTS OF THE NA

SC [MWs]	BESS [MWs]	PV [MWs]	Wind [MWs]
315’746.02	60’010.81	0	30’200.12

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The ZA provides the repartition of the above quantities among the six market zones in which Italy is subdivided as detailed in TABLE IV (Sardinia is not considered since its connection to the peninsula is provided only by HVDC link, thus Sardinian frequency transient is decoupled).

TABLE IV
RESULTS OF THE ZA

	SC [MWs]	BESS [MWs]	PV [MWs]	Wind [MWs]
NORTH	57’020.75	10’885.94	0	65.35
CNORTH	57’449.50	2’307.21	0	234.03
CSOUTH	56’952.90	14’157.09	0	7’700.62
SOUTH	53’448.80	16’602.82	0	15’164.78
CALA	47’484.04	5’009.65	0	4’699.97
SIC	43’390.03	11’048.10	0	2’335.37

The trends of RoCoF are shown in Fig. 3, where the upper panel reports the base reference scenario while the lower panel the one with additional inertia. The split contingency is triggered after 20 s of system steady-state. The RoCoF profile of the base case scenario is characterized by a minimum RoCoF equal to -1.7 Hz/s. The second panel points out that the outcome of the proposed algorithm provides an effective limitation of the RoCoF of the COI that is taken to -0.45 Hz/s. This value is very close to the limitation imposed by the procedure confirming the soundness of the output provided by the proposed methodology.

In the light of the positive validation of the proposed procedure, the analysis is extended to the set of the yearly data of the Italian grid and results appear in the following section.

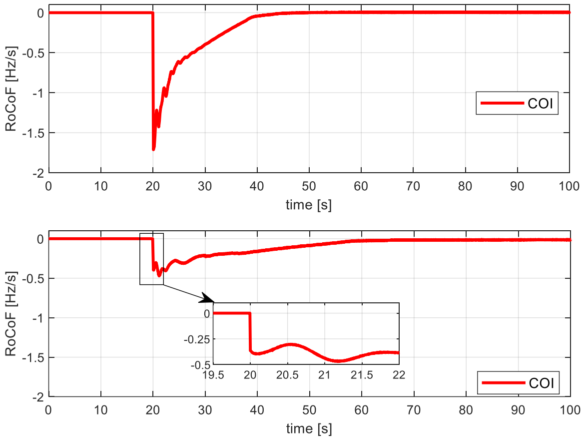

Fig. 3. RoCoF trends without and with frequency support.

VI. RESULTS

This section shows the results of the optimisation algorithm over the whole 2030 year. For the statistical analysis, 50 classes of equal amplitude have been considered.

A. Results of the National Algorithm for the 2030 test-case scenario

For the NA, histograms showing the statistical distribution of the energy provided by the four technologies are presented. Besides, the average value and the Standard Deviation (SD) value of these distributions are provided too. As shown in Fig. 4, PV systems do not provide inertial support for the majority of the hours, due to the fact that, according to the data Terna provided, rarely curtailment is applied to this technology.

The energy profile associated to WTs is reported in Fig. 5. The most frequent statistical class is the one that ranges from 0 to 2 GWs, with an occurrence probability equal to 20.5%. The rest of the distribution is quite smooth with a local maximum in correspondence of the fourth class, followed by a decreasing trend. The energy profile associated to BESSs (Fig. 6) shows two peaks, in correspondence of the first class and of the last class. This trend depends on the magnitude of the perturbation and on the ability of PV and WT to provide the necessary inertia to limit RoCoF.

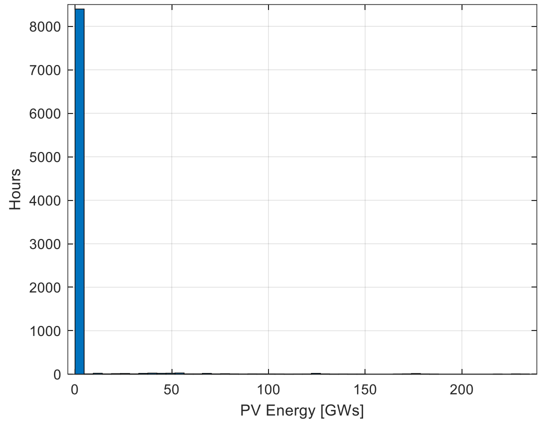

Fig. 4. Energy distribution for PV systems.

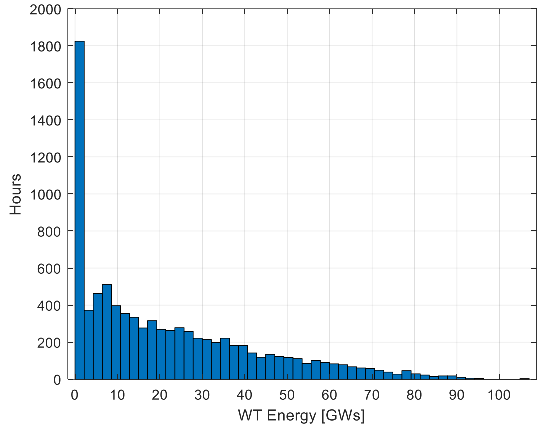

Fig. 5. Energy distribution for WTs.

The first peak, located close to 0, is either associated to those hours in which globally there is no need of additional inertia (i.e., the inertia contribution of synchronous generators and of already installed synchronous compensators is enough to limit RoCoF) or to the condition in which the need of inertia is satisfied totally by PV and WT power plants. The second peak, located in correspondence of the last statistical class, is associated to saturation conditions for BESSs (i.e., to the maximum provision of SI by BESSs). For all the hours in which BESSs provide the maximum possible SI, the installation of SCs is still required, due to the magnitude of the perturbation. It can be highlighted that the SI contribution provided by BESSs lays in the first statistical class, that ranges between 0 and 1.48 GWs, for the 22.8 % of the hours of the year.

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Finally, SCs energy distribution (Fig. 7) follows a variable profile, since no technological limit is imposed: in fact, SCs are the most expensive source and they act as a sort of “slack” source, meaning that if the SI providable by PV, WT plants and BESSs is not enough in order to limit RoCoF within suitable range, additional SCs have to be installed in order to limit it. The first statistical class, close to 0, is associated to the hours in which no inertia provision is needed at national level (i.e., the inertia contribution of synchronous generators and of already installed synchronous compensators is enough to limit RoCoF) or when PV, WT plants and BESSs are able to limit RoCoF with their SI contributions. The profile of the remaining part of the distribution depends on the need of inertia at national level and on the availability of the three inverter-based sources for the SI support. SCs are not required to provide additional inertia for the 30.8 % of the hours of the year.

TABLE V reports the average and SD values of additional inertia provided by each source. These values are calculated excluding the hours for which the considered source doesn’t provide inertial support. If one evaluates the coefficient of variation, defined as the ratio between the SD and the average, it becomes evident that the energy distribution characterised by the lowest dispersion is the one of BESSs; on the other hand, the distribution with the highest dispersion is the one associated to PV systems.

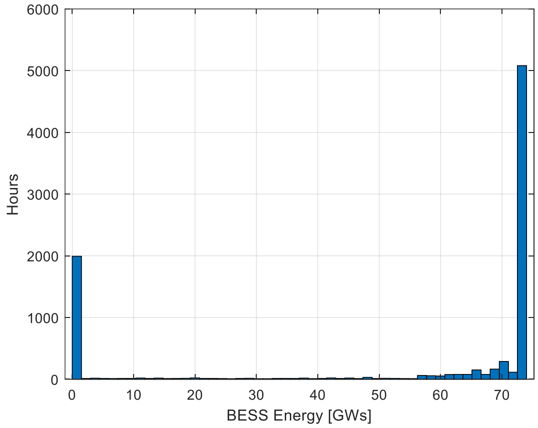

Fig. 6. Energy distribution for BESSs.

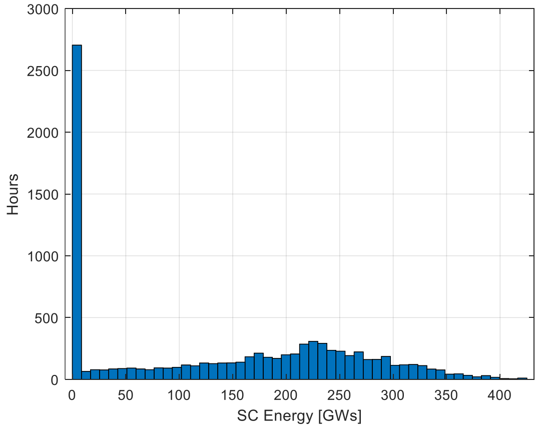

Fig. 7. Energy distribution for SCs.

TABLE V
NATIONAL RESULTS: AVERAGE AND SD VALUES

	SC [GWs]	BESS [GWs]	PV [GWs]	WT [GWs]
Average	235.361	62.4364	81.4163	24.7814
SD	103.749	10.2162	64.7549	19.0249

B. Zonal Algorithm results for the 2030 test-case scenario

The results of the ZA can be graphically resumed in the histogram shown in Fig. 8, that represents the repartition of the additional energy among the six considered market zones, without distinction of source.

For the sake of readability, the results of the ZA are reported only in TABLE VI, containing the average and SD values of the energy provided by each technology within each market zone. The same considerations made for the profiles of the distributions of the national results can be applied to the zonal ones, since the shapes of the zonal profiles – not reported here – reflect the shapes of the national ones.

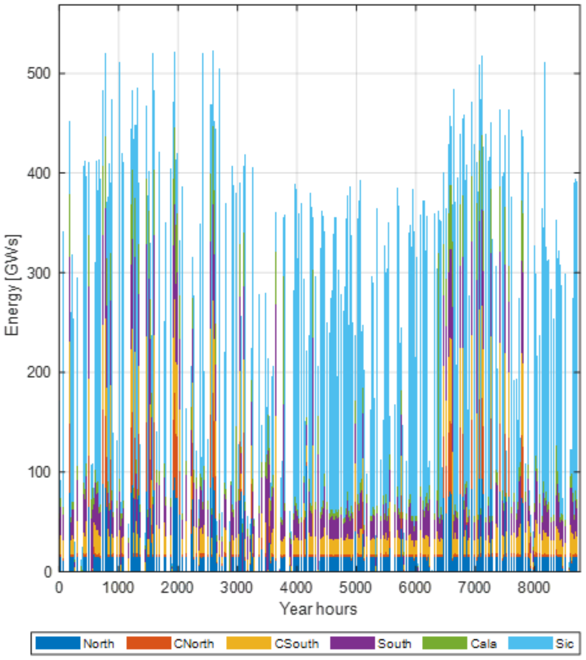

Fig. 8. Additional energy repartition among market zones.

TABLE VI
ZONAL RESULTS: AVERAGE AND SD VALUES

		SC [GWs]	BESS [GWs]	PV [GWs]	WT [GWs]
NORTH	Av	10.3177	12.9414	12.4399	0.250484
	SD	22.4438	2.99470	24.5617	0.211281
CNORTH	Av	10.6377	2.76789	5.37211	0.349099
	SD	22.5174	0.56919	12.9849	0.348709
CSOUTH	Av	12.5748	13.4370	3.37013	4.84181
	SD	25.6821	2.52228	10.4842	4.85879
SOUTH	Av	12.8429	15.7956	33.0852	10.8765
	SD	26.7514	2.94345	40.6575	8.69534
CALA	Av	11.7616	4.79355	11.7697	3.37672
	SD	25.8771	0.79634	11.9724	2.69252

SIC	Av	177.2262	12.7010	15.3793	5.08680
	SD	115.4873	1.39843	19.9227	4.87444

From Fig. 8 and TABLE VI it seems evident that, for the majority of the hours, the largest amount of additional energy is installed in Sicily and by SCs. The reason is double: first, SCs are the only technology whose installation is not limited from a physical point of view; secondly, according to the formulation of the ZA, in particular according to the criterion defined for the split of the network into islands, Sicily market zone is a part of all the *N*-1 electric islands that are considered within the optimisation procedure and consequently the solver opts to install the largest portion of SCs in Sicily, since SCs and all the other inertia sources there installed can deliver their inertial support within all the islands. Besides, Sicily is the weakest portion of the Italian network, that frequently is forced to work in islanded mode. As it is evident from Fig. 8, some market zones, like North and CSouth, present an energy contribution deriving from new inertia sources that is significant and almost constant during the year. On the other hand, it can be highlighted from the same figure that CNorth is a market zone characterised by a low energy contribution along the year.

As a general conclusive comment, the results obtained highlighted the capability of the proposed method to give a techno-economic guidance to TSO to foresee the upcoming needs of the transmission system inertia improvements to guarantee a sustainable transition of the energy system. This approach allows the possibility of repeating the evaluation year by year, when the system configuration and dataset shall become more reliable.

VII. CONCLUSIONS

This paper dealt with the critical frequency transients that future power systems will have to face due to the increasing share of RES, with particular attention to the problem of the limitation of RoCoF. The Italian test-case is considered, thanks to the 2030 dataset scenario provided by Terna S.p.A., Italian TSO, providing a prediction of the Italian transmission system configuration. Two optimisation algorithms were proposed in order to face the problem of inertia reduction in a techno-economic way: the first one defines the amount of additional inertia that PV, WT, BESSs and SCs will have to provide in order to limit the RoCoF of the Italian COI within the desired interval minimizing the cost of the updates necessary to integrate the system inertia, whilst the second one divides the inertia among the Italian market zones. The validation of the method results was performed implementing the Italian network in the DIgSILENT PowerFactory environment and simulating the frequency transient originated by the split between Italy and the rest of the EU network. The evaluation of the Italian COI frequency both with the PowerFactory simulation and with the proposed approach showed an excellent agreement in a number of selected hours of the 2030 scenario. Then the developed algorithms were used to estimate the additional inertia distribution for each source and for each market zone. Possible future developments may involve *i*) the generalisation of the ZA, so that it can be applied also to different network topologies (the Italian grid is peculiar due to Italy geography), *ii*) the study of the possible inertial contribution deriving from HVDC-converters and *iii*) the definition of an analogous method to estimate the need of short circuit power and/or reactive power to account voltage support issues too.

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