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Incorporating combined cycle gas turbine flexibility constraints and additional costs into the EPLANopt model: The Italian case study

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ABSTRACT

The planning of an energy system with high penetration of renewables is increasing in complexity as only an effective implementation can allow the tackling of environmental and energy security issues. The aim of this study is to present the integration of combined cycle gas turbine cycling costs in EPLANopt, a simulation software consisting of EnergyPLAN coupled to a Multi-Objective Evolutionary Algorithm. The model is then applied to the Italian energy system which is characterized by a very high capacity and electricity production from combined cycle gas turbine systems. The proposed approach established a first step in the direction of modelling their role for load modulation accounting for technical constraints and additional costs related to start-up and partial load condition. Results show the importance of considering cycling costs of combined cycle gas turbine system within energy system modelling as the nature of these costs at the increasing of intermittent renewable generation can reach peaks of 33.5 €/MWh. Additionally, the inclusion of CCGT cycling costs in high penetration non programmable renewable energy sources scenarios opens up favorable business models for other load modulation strategies (e.g. electric batteries).

1. Introduction

In recent years, the development of energy scenarios and the planning of energy systems has become a highly relevant topic, as consequence of the environmental and security issues of energy systems. Policy makers need tools capable of simulating energy systems over the years to develop effective energy policies. Researchers that study the impact of the energy production and consumption on climate change need tools able to account for those aspects. Finally, developing Countries facing problems of energy access and security require modelling tools to plan energy systems to overcome those problems and to evaluate their impact on the local economies.

Energy system models represent a simplified picture of the real energy system and its costs. In literature, it is possible to classify two main approaches: top-down models, with focus on the economic theory, and bottom-up models, with focus on the technology analysis. A. Herbst et al. [1] present a review of these two approaches to the problem of energy system modelling. Both approaches present different advantages and limitations and develop a more detailed analysis on different aspects of the energy system. Many existing models for simulating and analyzing the integration of renewable energy into the energy system have been analyzed in detail by Connolly et al. [2]. The EnergyPLAN software [3] developed by Aalborg University and based on the bottom-up approach has resulted in one of the most complete tools to describe future energy system in a very short computational time [4]. EnergyPLAN is a deterministic input/output model that integrates the three primary sectors of any national energy system, (electricity, heat and transport sectors) thanks to predefined priorities [5]. This characteristic allows for a complete simulation of the interactions between different energy system sectors. The program is a descriptive and analytically programmed computer model for hourly base simulation of a regional or national energy system. High time resolution allows the modeler to catch the variability of non-programmable renewable energy sources. The EnergyPLAN

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Acronyms

CCGT	Combined Cycle Gas Turbine
UC	Unit commitment
SO	Single-Objective
MO	Multi-Objective
VRES	Variable renewable energy sources
CHP	Combined Heat and Power
HP	Heat Pump
MOEA	Multi-Objective Evolutionary Algorithm
MOO	Multi-Objective Optimization
PV	Photovoltaic
TSO	Trasmission system operator

Nomenclature

x	Set of all decision variables
m	Objective function index
$\boldsymbol{f_m}$	$\boldsymbol{m}$-th objective function
i	Decision variable index
$\boldsymbol{x_i}$	$\boldsymbol{i}$-th decision variable
$\boldsymbol{x_i^{(L)}}$	Lower bound of $\boldsymbol{i}$-th decision variable
$\boldsymbol{x_i^{(U)}}$	Upper bound of $\boldsymbol{i}$-th decision variable
k	Scenario index
Δ***Total annual costs***	Variation of the costs for scenario k with respect to the reference scenario [%]
Δ***Emissions***	Variation of CO_2 emissions for scenario k with respect to the reference scenario [%]
$\boldsymbol{Total\ annual\ costs_k}$	Total annual costs of scenario k [M€]
$\boldsymbol{Total\ annual\ costs_{REF}}$	Total annual costs of reference scenario [M€]
$\boldsymbol{Emissions_k}$	Total annual CO_2 emissions of scenario k [Mt]
$\boldsymbol{Emissions_{REF}}$	Total annual CO_2 emissions of reference scenario [Mt]
$\boldsymbol{Total\ annual\ costs}_{\mathrm{CCGT\ cycling}}$	Total annual costs due to cycling of combined cycle gas turbine systems [€]
$\boldsymbol{StartUp_{costs}}$	Start-up costs [€]
$\boldsymbol{DecayOfEfficiency_{costs}}$	Costs derived from partial load operation due to the decay of efficiency. [€]
$\boldsymbol{Curtailments_{costs}}$	Costs due to the imperfect flexibility of the power system and the generated curtailments [€]
t	Time-step index
j	Type of start-up index
$\boldsymbol{N\_StartUp_{j,\,t}}$	Number of starts per each time-step t and each type of start j
$\boldsymbol{cost\_StartUp_j}$	Specific cost per each type of start j [€/MW]
Reference_plant	Size of the reference CCGT system [MW]
additional_fuel	Additional fuel due to partial load operation [MWh]
cost_NG	Cost of natural gas [€/MWh]
n	CCGT plant index
$\boldsymbol{eff\_rel_{t,\,n}}$	Relative efficiency of each plant n (given by the curve in Fig. 2) at time-step t
eff_nom	The nominal efficiency of the reference CCGT plant (assumed equal to 55%)
$\boldsymbol{Ongoing\_plants\_gen_t}$	The overall electricity generation from CCGT systems for each time-step t [MWh]
$\boldsymbol{d_t}$	the hourly distribution of CCGT electricity production from EnergyPLAN [MWh]
$\boldsymbol{costs_{CCGT\ cycling}}$	Specific costs for cycling of combined cycle gas turbine systems [€/MWh]
$\boldsymbol{El\_p_{CCGT}}$	Total annual electricity production from combined cycle gas turbine systems [MWh]
$\boldsymbol{costs_{CCGT}}$	Specific costs of combined cycle gas turbine systems [€/MWh]
$\boldsymbol{Total\ annual\ costs_{CCGT}}$	Total annual costs of combined cycle gas turbine systems [€]

software does not readily find the best mix of technologies through an optimization process. The optimization of different technologies and sources within the energy system is a multi-objective problem because it concerns economical, technical and environmental aspects. The optimization analysis on these competing objectives produces a Pareto front of best solutions or future configurations of the energy system.

Bjelic et al. [6] have realized a soft-linking of EnergyPLAN software with a generic optimization program (GenOpt). This approach opens up the possibility to perform single objective optimization analysis and has been used to define the minimal increase in the costs of the total national energy system for Serbia under the EU 2030 framework. Mahbub et al. [7] have coupled EnergyPLAN to a multi-objective evolutionary algorithm written in Java to evaluate the Pareto front of best configurations of the energy system. Using a similar approach, EURAC research has developed the python model EPLANopt characterized by an open source code and documentation [8]. The model has been already presented in another paper [9] and for this reason is not matter of this study. However it is important to mention that the EPLANopt model is based on the simulation deterministic model, EnergyPLAN, developed by Aalborg University, coupled to a Multi-Objective Evolutionary Algorithm based on DEAP python library [10].

The scope of this paper is to apply this model to the Italian energy system incorporating combined cycle gas turbine (CCGT) flexibility constraints and additional costs in order to evaluate their future impact. The Italian energy system was considered as case study of the developed models since it is characterized by a very high capacity and electricity production from CCGT systems. In the future, their role for modulating the load might increase as an option to guarantee the national grid stability as well as the spinning reserve. The EnergyPLAN model considers CCGT systems, like the other power plants, as fully flexible power plants that can increase their production from 0 to 100% in a single hour independently from how many hours of stop had previously undergone. This is based on the assumption that in the future the power plants will reach a very high level of flexibility.

As shown in Table 1, several studies have inspected the impact of operational flexibility in energy system modelling. They are mostly characterized by hourly resolution unit commitment (UC) models that integrates flexibility requirements like ramp constraints, start-up costs and partial load operation. They almost entirely focus only on the power sector. This for this is that unit commitment models based on mixed integer linear programming applied to energy planning problems are characterized by a heavy computational burden [19].

Table 1 shows various approaches that tried to reduce the computational time through different techniques like integer clustering applied at unit commitment models. Even using these approaches the planning problem remains concentrated on the

Table 1
Comparison of different approaches incorporating flexibility operations into energy system modelling.

Approaches	Type of model	Time resolution	Energy sectors considered	Optimization of generation expansion	Flexibility constraints and costs considered	Time-dependent start-up considered (hot, warm, cold start-up)	Applied to	Reference
A. Shortt et al.	Unit commitment (based on MILP)	Hour	Power sector	–	Ramp constraints, start up costs, partial load operation	no	Finland, Ireland, Texas	[11]
B. S. Palmintier et al.	Integer clustering technique applied to Unit commitment (based on MILP)	Hour	Power sector	SO (costs) with constraint on carbon emission	Ramp constraints, start up costs, partial load operation	no	ERCOT (which covers majority of Texas)	[12]
M. Welsch et al.	Solft-link of a long-term dispatch model (TIMES) with a unit commitment (PLEXOS)	12 time-slice (TIMES), Hour (PLEXOS)	Power, heat and transport sector (within TIMES)	SO (costs) with constraint on renewable share	Ramp constraints, start up costs	no	Ireland	[13]
D. S. Kirschen et al.	Unit commitment (based on MILP)	Hour (4 weeks compose the average year)	Power sector	SO (costs)	Ramp constraints, start up costs, partial load operation	no	IEEE-RTS	[14]
A. Belderbos et al.	Integration of a sceering curve model and a MILP model	Hour	Power sector	SO (costs)	Ramp constraints, start up costs	Cold start-up costs	Belgium	[15]
B. Palmintier	Clustered integer unit commitment (based on MILP)	Hour	Power sector	SO (costs) with constraint on carbon emission	Ramp constraints, start up costs, partial load operation	no	ERCOT (which covers majority of Texas)	[16]
l. Zhang et al.	Unit commitment algorithm based on LP	Half hour (horizon: week)	Power sector	–	Ramp constraints, start up costs	no	Reduced version of Great Britain	[17]
J.P. Deane at al.	Soft-linking of a long-term dispatch model (TIMES) with a unit commitment (PLEXOS)	12 time-slice (TIMES), Hour (PLEXOS)	Power, heat and transport sector (within TIMES)	SO (costs)	Ramp constraints, start up costs	no	Ireland	[18]
EPLANopt + CCGT model	EnergyPLAN (based on internal priorities)	Hour	Power, heat and transport sector	MO (costs and CO_2 emissions)	Ramp constraints, start up costs, partial load operation	Cold, warm, hot start-up costs	Italy	

power sector due to the computational effort, not inspecting the flexibility options provided by the integration of power with heat and transport sectors. M. Welsch et al. [13] and J.P. Deane at al [18]. presented soft-linking techniques of the UC PLEXOS model and the long-term dispatch model TIMES that allows to include heat and transport sectors. However this kind of model is used with a low temporal resolution characterized usually by 12 time-slice that difficultly catches the seasonal and intra-day variability introduced by intermittent renewable energy sources.

The aim of this paper is to propose a simplified and fast technique to include operational flexibility in energy planning models that consider hourly time-step on one year horizon and the integration of the three primary sectors of the energy system. Moreover, the different studies proposed in Table 1 present an optimization method for generation expansion that is based on single objective approach. This paper adopts the EPLANopt energy system model that, as mentioned before, is characterized by a multi-objective optimization approach. Table 2 shows a summary of the different approaches coupling EnergyPLAN software with an optimization algorithm.

The structure of the paper is the following: the methods section focuses on the explanation of the EPLANopt model, the assumptions used to build the baseline for the Italian energy system and the explanation of the external code developed for considering flexibility constraints and additional costs concerning the different types of start and partial load operation of CCGT systems. The result section presents the main results of the model and its application to the Italian energy system.

2. Methods

The energy system modelling techniques adopted in this paper belong to the bottom-up approach. An hourly time-step modelling of energy system with the presence of variable renewable energy sources (VRES) shows advantages over the approach in which the simulation of the year is created through characteristic days [20]. The energy system integrated modelling that considers the electricity, heat and transport sector shows advantages compared to the software characterized by sector modelling [21]. For example, Nastasi et al. highlighted the sector coupling benefits from hydrogen [22] and power-to-gas [23] techniques as means to link heat and electricity. G. Lo Basso et al. [24] showed the advantages of coupling Combined Heat and Power (CHP) and Heat Pump (HP) for thermal management. H. Lund et al. [25] conceptualized the smart energy system approach underling the importance of synergies between different sectors to maximise efficiency and reduce costs.

The EnergyPLAN software integrates annual simulation with hourly time-step modelling and integration of electricity, thermal and mobility sector. However, this model does not provide the best mix of technologies through an optimization process. Furthermore, EnergyPLAN includes internal priorities and simplifications based on how a power plant is supposed to work in a future energy systems: the positive aspect is that the model is very fast and robust, the drawback is a loss of flexibility if compared to other energy system models based on linear programming.

Table 2
Comparison of different tools linking EnergyPLAN to an optimization algorithm.

Tools	Integration of electric, thermal and transport	Simulation	Investment optimization	Possibility to integrate energy efficiency among decision variables	Flexibility constraints of CCGT considered	Reference
EnergyPLAN	✓	✓	–	–	–	[3–5]
Bjelic et al.	✓	✓	SO	✓	–	[6]
Mahbub et al.	✓	✓	MO	–	–	[7]
EPLANopt	✓	✓	MO	✓	–	[8,9]
EPLANopt + CCGT model	✓	✓	MO	✓	✓	

2.1. The EPLANopt model

The EPLANopt model [9] is based on the simulation deterministic model, EnergyPLAN, coupled to a Multi-Objective Evolutionary Algorithm based on DEAP python library [10]. EnergyPLAN [4] is a deterministic model because there is no effect of randomness or probability profile in the calculation of a given output. It is a simulation model that assesses the behavior of an energy system configuration, as opposed to an optimization model where the objective is to find the best technology mix for the configuration of the energy system. EnergyPLAN is analytically programmed because there is not a solver in the model that calculates the optimal hourly dispatch based on a set of constraints and an objective function. A set of priorities drives the energy balances resulting in a very short computational time. The main purpose of the model is to support the design of national energy planning strategies through the technical and economic analyses of different configurations of the energy system. The model has been applied at different scales: at European level [26], at national level (B. Ćosić et al. [27] applied it to Macedonia, D. Connolly et al. [28] to Ireland, L. Fernandes et al. [29] to Portugal and H. Lund et al. [30] to Denmark) as well as at local level for energy system planning of towns and municipalities [31].

In this paper, the EnergyPLAN model is applied to the Italian energy system with a single node approach. Thus, transmission constraints are not considered in the model. The Multi-Objective evolutionary algorithm in the EPLANopt model [9] is a meta-heuristic optimization algorithm that is inspired by the principle of natural selection [32]. A heuristic optimization algorithms is particularly suited for finding solutions in a fast and easy way [7]. Multi-objective evolutionary algorithms (MOEA) [33] are a version of EAs for multi-objective optimization (MOO) problems. J. L. Bernal-Agustín et al. [34] have used genetic algorithms for an efficient design of hybrid renewable energy systems.

The optimization starts with a population of solutions generated with random values of the decision variables from their respective range. Each solution is then evaluated by the simulation model, all required distributions and relevant cost are fixed inputs parameters of EnergyPLAN as they do not change during the algorithm evolution. In this model learning effects in terms of investment cost reduction are not endogenously modelled, the effects of this economic transition are accounted considering expected costs for the technology at the time of investment. Each individual is then ranked considering the multiple objectives of the optimization. If a stopping criteria is met the optimization is completed, otherwise the MOEA generates a new population of individuals applying the typical operators of genetic algorithms: parent selection, crossover and mutation. After completion of all the generations, a Pareto front is generated by the MOEA. Fig. 1 shows the scheme of the interaction of the algorithm and software that compose the EPLANopt model.

The structure of the multi-objective optimization problem in its more general form is characterized by the following structure:

$$\begin{array}{lll} \text{Optimization function} & \min\limits_{\boldsymbol{x}}[\boldsymbol{f}_{\boldsymbol{m}}(\boldsymbol{x})] & \boldsymbol{m} = 1, 2, \ldots, \boldsymbol{M} \\ \text{Subject to} & x_i^{(L)} \le x_i \le x_i^{(U)} & i = 1, 2, \ldots, N \end{array} \tag{1}$$

f_m denotes the m-th objective function to be minimized. $\boldsymbol{x}$ is the vector of the decision variables x_i within a lower $x_i^{(L)}$ and an upper bound $x_i^{(U)}$. The optimization function is subjected not only to the bounds constraints of the decision variables but also to equality and inequality constraints, i.e. the equality of generation and demand in each time-step, that are contained into the EnergyPLAN model (please refer to [3]).

The optimization problem applied to the Italian case study is characterized by the minimization of two objectives: total annual costs and CO_2 emissions. Hence, considering both economic and environmental goals. Its formulation can be represented as follow:

$$\begin{array}{lll} \text{Optimization function} & \min\limits_{\boldsymbol{x}}\begin{bmatrix} \Delta\boldsymbol{\mathit{Total\ annual}}\ \text{costs}\ [\%] \\ \Delta\text{Emissions}\ [\%] \end{bmatrix} & \\ \text{Subject to} & \mathit{CurrentValue} \le x_i \le \mathit{PotentialValue} & i = 1, 2, \ldots, N \end{array} \tag{2}$$

The two objectives are expressed as percentage of the reference scenario. In fact, Δ*Total annual costs* [%] represents the variation of the costs for scenario k with respect to the reference scenario or baseline 2014:

$$\Delta\boldsymbol{\mathit{Total\ annual\ costs}} = \boldsymbol{\mathit{Total\ annual\ costs}}_{\boldsymbol{k}}[\boldsymbol{M}€] / \boldsymbol{\mathit{Total\ annual\ costs}}_{\boldsymbol{REF}}[\boldsymbol{M}€] \tag{3}$$

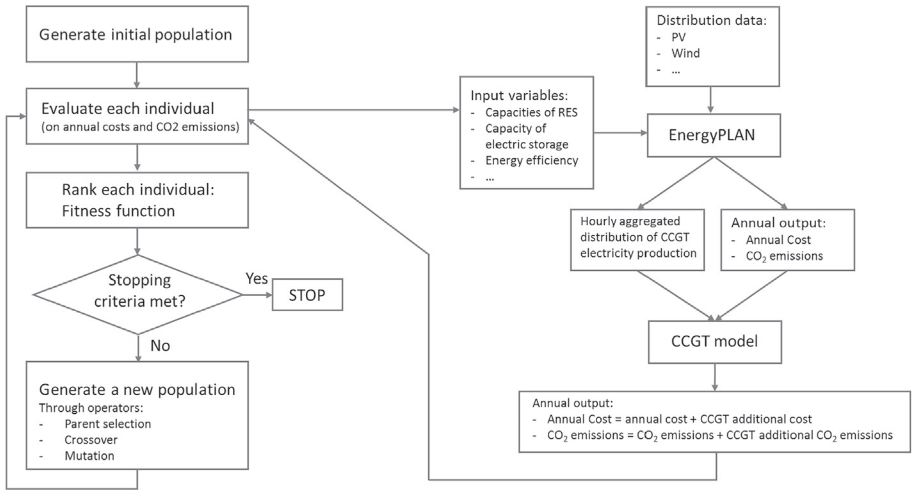

Fig. 1. Diagram of the overall model.

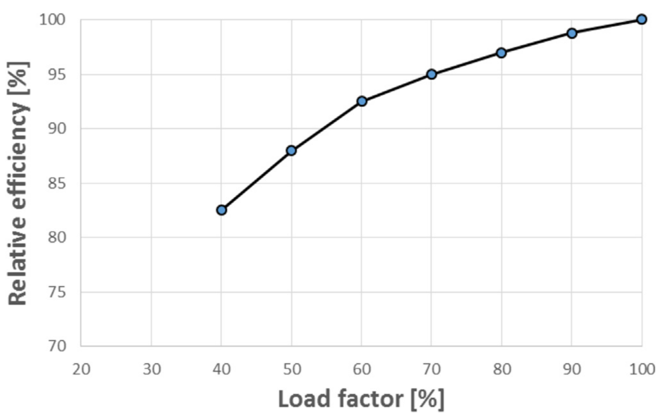

Fig. 2. Decay of performance as function of the load for CCGT systems [38].

$\Delta \boldsymbol{Emissions}[\%]$ represents the variation of CO_2 emissions for scenario k with respect to the reference scenario or baseline 2014:

$$\Delta \boldsymbol{emissions} = \boldsymbol{Emissions_k}[\boldsymbol{Mt}] / \boldsymbol{Emissions_{REF}}[\boldsymbol{Mt}] \tag{4}$$

The decision variables taken into consideration as input of the optimization analysis for the Italian application are the following: capacity of rooftop photovoltaic (PV), capacity of wind power, pumped hydro storage subdivided in capacity of the pump, capacity of the turbine and capacity of the storage, capacity of batteries, energy efficiency and heat pumps for the residential thermal sector. The maximum potential of rooftop photovoltaic for different European Countries has been estimated by Taylor et al. [35] as 2 kW of installed power per person. The result is a maximum potential of rooftop photovoltaic installed power of about 122 GW for Italy. The maximum potential for onshore wind power has been estimated considering the Italian wind atlas. It has been defined in the RE-SHAPING project of the European Union [36] and it is equal to 49 GW. The maximum potential for these sources has been evaluated and set as constraint into the optimization algorithm.

3. Combined cycle gas turbine constraints and additional cost model: the CCGT model

In EnergyPLAN and in general in bottom-up energy system models, conventional power plants are modelled as fully flexible power plants that can reduce or increase their production without limitations and ramp rates. Thus, the production can move from 0 to 100% in one single hour if needed. In this paper, a specific external code to model CCGT has been developed to account for current technological constraints and additional costs of CCGT flexible operation. This CCGT model has been applied through a post-processing approach to EnergyPLAN. Using the distribution of electricity production of CCGT system evaluated by EnergyPLAN and the annual output (total annual costs and CO_2 emissions of the system), the CCGT model calculates the additional annual costs and CO_2 emissions due to cycling and then returns the overall costs and emissions to the genetic algorithm for the evaluation and rank of the analyzed configuration of the energy system (as depicted in Fig. 1). Table 3 summaries the technical constraints and additional costs of CCGT systems considered in the model. The main technical constraints are: different types of start, the ramp-rates connected to the types of start and the technical minimum of CCGT system operation as explained by V. de B. Harry jaeger in Ref. [37] and by K. Van Den Bergh et al. in Ref. [38].

Three different types of start conditions are defined by the number of hours of plant stop: cold, warm and hot starts. The additional costs are due to start-up and the cost of a decrease in rated efficiency due to part load operation. The costs of start-up are connected to costs of auxiliary services, capital replacement costs due to shorter lifetime and maintenance costs related to load following, cost of forced outages due to cycling. In literature several works try to estimate the start-up costs. Two extreme scenarios are considered in the work: the optimistic with lowest costs [39], called best case assumption and the pessimistic with highest costs [41], called worst case assumption. The decrease in efficiency due to the operation of the plant at partial load produces an increase in the fuel demand and thus higher costs and CO_2 emissions. The curve that describes the decrease of relative efficiency of CCGT systems depending on the load factor is shown in Fig. 2 [38].

A simplified approach is considered to account for CCGT start-up and partial load operating conditions: a reference CCGT plant is defined, gas turbine of 270 MW and steam turbine of 130 MW, and it is assumed that the overall Italian CCGT capacity is distributed among N equal plants of the same size. (For assumptions and comparison to the real Italian CCGT capacity see appendix A).

Fig. 3 shows the diagram of the logical steps of the CCGT model. Given a distribution of production from CCGT systems calculated in EnergyPLAN, for each hour of the year the model calculates the

Table 3
Technical constraints and additional costs of CCGT systems considered in the CCGT model. The best case assumption [39], average values of the start-up costs [40] and worst case assumption [41].

Technical constraints				Additional Costs			
Types of start	Hot start	[h]	<8	Costs of start (Best case assumption)	Hot start	[€/MW]	32.4
	Warm start	[h]	8–24		Warm start	[€/MW]	51.0
	Cold start	[h]	>24		Cold start	[€/MW]	73.2
Ramp rate	Hot start	[MW/min]	14	Costs of start (Worst case assumption)	Hot start	[€/MW]	156
	Warm start	[MW/min]	7		Warm start	[€/MW]	211
	Cold start	[MW/min]	4		Cold start	[€/MW]	393
Technical minimum	Partial load	[%]	50	Costs due to partial load		Decay of performance curve	

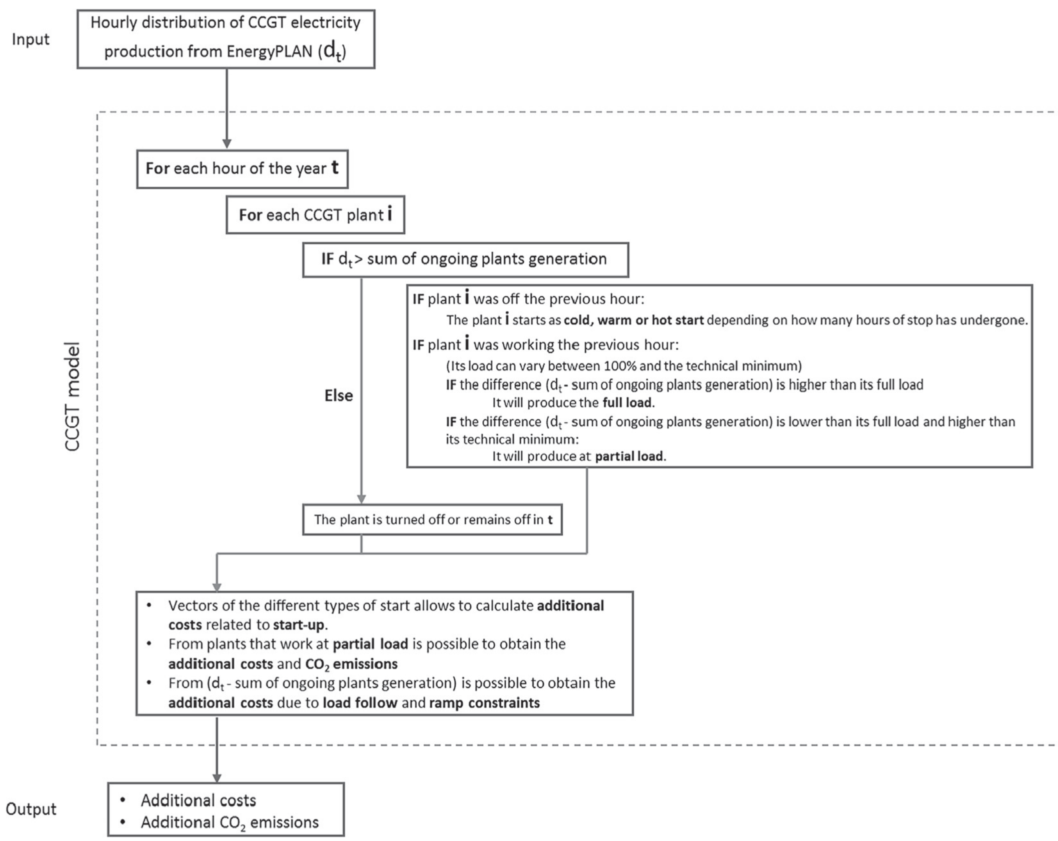

Fig. 3. Diagram of the CCGT model.

number of plants that produce electricity in order to cover the demand. A new curve representing the aggregated production of CCGT system is then created and used to evaluate the additional costs. The CCGT model follows the EnergyPLAN approach and tries to minimize the waste of resources. For this reason, if possible, the production from a CCGT plant is set at regime, optimal condition of 100% of load with no efficiency reduction. The partial load working condition of a plant is set only for those plants that has to cover the demand without the possibility of the regime operation. This approach can be adopted because the nation is modelled by a single node, without any transportation constraints.

A representation of the operation of the CCGT model is presented in Fig. 4. This figure represents a theoretical example of how the CCGT model deals with different start-up, ramps, partial loads and technical minimum constraints.

Given the constraints for the combined cycle plants in terms of ramp rate and technical minimum, the production can exceed the demand in certain moments because the plants are not ideally

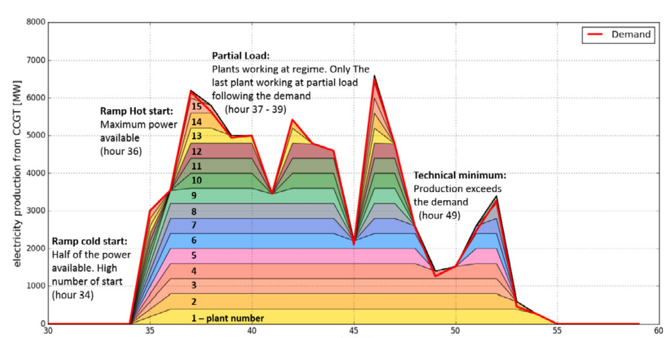

Fig. 4. Example of the result of the script for the evaluation of cycling cost.

flexible. This overproduction is a result of the imperfect flexibility of the power system and is considered as curtailments. It is also important to mention that reserve is not considered in this study due to the perfect forecast assumption on VRES and malfunction of generation units only considered in the operation and maintenance costs.

Fig. 4 shows that the first ramp is covered by plants which were stopped for more than 24 h. The result is a cold start for each plant. A high number of plants must be started in order to cover the demand. The second ramp is covered with plants in hot start conditions that for this reason can produce at nominal power. The optimal production from combined cycle plants results in a number of plants working at regime conditions, and only the last plant that covers the demand working at partial load (this can occur because a single node analysis is performed without transmission constraints). If the partial load required is lower than the technical minimum of the plant, an overproduction occurs. Fig. 4 shows that the difference between the CCGT production distribution, result of the EnergyPLAN simulation and represented in the picture as the demand to the CCGT systems, and the sum of the production of the single plants evaluated through the CCGT model is very limited. On annual average, the sum of the production of the single plants evaluated through the CCGT model is 0.5% higher than the CCGT production distribution evaluated in EnergyPLAN. This is a consequence of the typical CCGT size assumed: larger CCGT plant would lead to higher overproduction.

After running the optimization algorithm and finding the optimal configurations of the energy system under costs and CO_2 emissions minimization it is important to estimate the impact of the CCGT model. In order to do this, the specific costs for cycling have been chosen as indicator and compared to the overall specific costs of CCGT systems.

$$\begin{aligned}\boldsymbol{Total\ annual\ costs_{CCGT\ cycling}}[€] &= \boldsymbol{StartUp_{costs}}[€] + \boldsymbol{DecayOfEfficiency_{costs}}[€] \\ &+ \boldsymbol{Curtailments_{costs}}[€]\end{aligned} \tag{5}$$

In equation (5) are summarized all the contributions to the CCGT cycling total annual costs: i) Start-up costs divided into cold, warm and hot start-up, ii) the costs derived from partial load operation due to the decay of efficiency and iii) the costs due to the imperfect flexibility of the power system and the generated curtailments.

$$\boldsymbol{StartUp_{costs}}[€] = \sum_j \sum_t \Big(\boldsymbol{N\_StartUp_{j,\,t}} \cdot \boldsymbol{Reference\_plant}[\boldsymbol{MW}] \cdot \boldsymbol{cost\_StartUp_j}[€/\boldsymbol{MW}]\Big) \tag{6}$$

Equation (6) shows how the start-up costs are calculated. $N\_StartUp_{j,\,t}$ is a variable that gives the number of starts per each time-step t and each type of start j (hot, warm or cold start-up). The $cost\_StartUp_j$ is the specific cost per each type of start j (see Table 3). The $Reference\_plant$ is the size of the reference CCGT system, equal to 400 MW.

$$\boldsymbol{DecayOfEfficiency}_{\ \boldsymbol{costs}}[€] = \boldsymbol{additional\_fuel}[\boldsymbol{MWh}] \cdot \boldsymbol{cost\_NG}[€/\boldsymbol{MWh}] \tag{7}$$

$$\boldsymbol{additional\_fuel} = \sum_t \sum_n \frac{\boldsymbol{Reference\_plant}[\boldsymbol{MW}] \cdot 1[\boldsymbol{h}] \cdot (1 - \boldsymbol{eff\_rel_{t,\,n}})}{\boldsymbol{eff\_rel_{t,\,n}} \cdot \boldsymbol{eff\_nom}} \tag{8}$$

Equations (7) and (8) shows how the costs derived from partial load operation are calculated. The $cost\_NG$ is the fixed cost of natural gas (assumed equal to 25 €/MWh). $eff\_rel_{t,\,n}$ is the relative efficiency of each plant n (given by the curve in Fig. 2) at time-step t. eff_nom is the nominal efficiency of the reference CCGT plant (assumed equal to 55%).

$$\boldsymbol{Curtailments_{costs}}[€] = \boldsymbol{cost\_NG}[€/\boldsymbol{MWh}] \cdot \sum_t \frac{\boldsymbol{Ongoing\_plants\_gen_t}[\boldsymbol{MWh}] - \boldsymbol{d_t}[\boldsymbol{MWh}]}{\boldsymbol{eff_{nom}}} \tag{9}$$

Equation (9) shows how the costs due to the imperfect flexibility of the power system are obtained. The variable $Ongoing\_plants\_gen_t$ gives for each time-step t the overall electricity generation from CCGT systems (as explained in Fig. 3). d_t is the hourly distribution of CCGT electricity production from EnergyPLAN.

$$\boldsymbol{costs_{CCGT\,cycling}} = \boldsymbol{Totalannualcosts_{CCGT\,cycling}}[€] \Big/ \boldsymbol{El\,p_{CCGT}}[\boldsymbol{MWh}] \tag{10}$$

$$\boldsymbol{costs_{CCGT}} = \boldsymbol{Total\ annual\ costs_{CCGT}}[€] \big/ \boldsymbol{El\_p_{CCGT}}\ [\boldsymbol{MWh}] \tag{11}$$

In equation (10) specific costs for cycling are given by the overall annual costs due to cycling obtained by the CCGT model divided by the overall annual CCGT electricity production. This costs are compared to the specific costs of CCGT systems expressed by equation (11). Specific costs are given by the overall annual costs of CCGT systems, thus annualized investment costs, operation and maintenance costs, costs of the fuel and cycling costs divided by the overall annual CCGT electricity production.

4. Case study: Italian energy system

The creation of the Italian baseline in the simulation model EnergyPLAN is the first step of the analysis. In literature, an EnergyPLAN baseline for Italy within the STRATEGO project [42] has already been developed. However, this baseline regards the year 2010 and therefore it has to be updated due to the significant variations between 2010 and 2014 in the energy system and in particular in the electricity sector. The created energy system model is based on a single node approach. Thus, a perfect transmission grid without bottlenecks and transmission losses is assumed.

The electricity data about demand and production for every source are collected in the report of GSE [43], the managing authority of the energetic services, and Terna, the Italian transmission system operator (TSO), [44]. The distribution profile of electricity production from the different sources is obtained through hourly real data published on the Terna website [45]. Distributions are inputs of the simulation model EnergyPLAN and represent the availability of each renewable source. They are composed by 8784 values that represents the available production in each hour of the day. Combining the installed power of the source with its distribution profile, the production is calculated by the model. CCGT system covered 60% of the Italian conventional generation in 2014 [46]. The remaining part represented by coal and oil power plants is going to be decommissioned before 2030 [47]. The optimization analysis elaborated in this paper regards the future year 2050. For this reason, the capacity mix of dispatchable plants has been assumed to be constant and entirely composed by CCGT system burning natural gas.

The structure of the thermal sector has not changed comparing the situation of 2010 and 2014. It is divided in: individual heating and cooling, services heating and cooling and industrial heating. The individual heating relies on fossil fuels, mainly natural gas boilers, even if oil boilers are still used, and biomass boilers. In recent years, the adoption of heat pumps has increased [48]. The transport sector is mainly covered by petrol, with a small portion of natural gas, biofuels and electric vehicle [42]. This sector is considered in the analysis in the sense that the fuel consumption is considered by the model but is not included in the optimization analysis. Thus, the possibility of an increase of zero emission mobility is not part of this analysis, but is an important future development of this work.

The validation of the simulation of the Italian energy system is performed comparing the results of total CO_2 emissions with the results calculated from the different international agencies like IEA, international energy agency [49], and World Bank [50].

5. Results

The optimization analysis has been run and the result is a Pareto front of best configurations of the energy system for the year 2050. Fig. 5 shows the results for three cases: without implementing the CCGT model, the best-case and worst-case for CCGT system. Thus, in the first case there is no post-processing analysis after the calculation of each configuration in EnergyPLAN. This is taken as reference solution and is compared to the results obtained by the entire model presented, including also the CCGT model. To compare the three different Pareto fronts, four solutions have been chosen among the Pareto front set of each case.

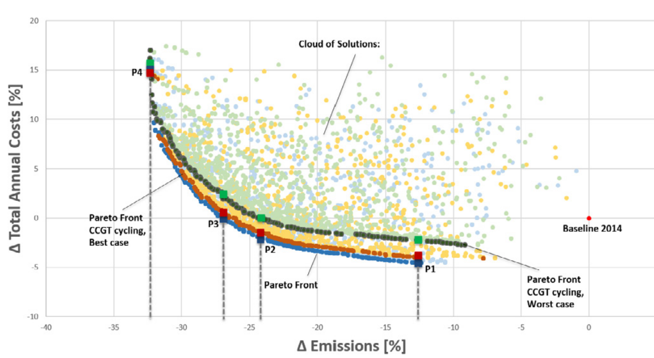

Fig. 5. Results of the optimization analysis: the Pareto front of best solutions for the Italian energy system, the Pareto front considering the CCGT constraints and costs of cycling, best case, and the Pareto front considering the CCGT constraints and costs of cycling, worst case.

For all the three Pareto fronts, the cost increase is limited from P1 to P2 as the cheapest technologies (i.e. photovoltaic, wind, storage from hydro pumped plants and heat pumps) can be installed. In these cases, the percentage of energy efficiency in the residential sector (heat demand) is limited. The energy efficiency costs associated to the heat demand reduction at this level of penetration are not very high. With higher energy efficiency penetration in the residential sector, costs increase more than linearly [9]. Solutions with high reduction of CO_2 emissions, P3 and P4, are characterized by the full exploitation of the possibility of the decision variables. To achieve high level of reduction of CO_2 emissions also decision variables with high cost related are exploited: storage from batteries and high level of energy efficiency in the residential sector.

In addition, it can be noted that the impact of CCGT cycling is relevant in P1 to P3, while in P4 the difference is less pronounced. This is because the CCGT electricity production, and consequent costs, is very limited in P4.

Details about the different solutions are reported in Table 4: when higher costs of CCGT cycling are considered the high cost electric storage through batteries becomes more competitive. As a result, the optimization will choose on the Pareto front solutions characterized by installed capacity of batteries at an earlier stage. An example is represented indeed by scenario P3 where the best solution for fully flexible CCGT is characterized by 5 GWh of batteries while considering the best case cost assumption produces a best solution with 15 GWh and worst case cost assumption 60 GWh.

The four solutions on the Pareto front for the best-case assumption for the cycling costs are analyzed in detail showing the hourly dispatch, the energy mix and the structure of the costs in Figs. 6 and 7. In Fig. 6, the matching between electricity demand and production is shown for a summer week. It can be highlighted the storage increases with the increase of variable renewable energy installed power. While for point P2, the only potential of power of pumped hydro storage is exploited, for point P3 and P4 the increase of VRES requires the installation of additional storage, batteries, even if the price of this type of storage is higher. In this way, in summer, for the extreme scenario P4 it is possible to cover the entire electricity demand without electricity production from

Table 4
Analysis of the single solutions from P1 to P4.

Scenarios	PV [GW]	Wind power [GW]	Storage Pump [GW]	Storage Turbine [GW]	Pumped Hydro Storage Capacity [GWh]	Batteries [GWh]	Heat pumps [%]	Energy Efficiency [%]	Total emissions [%]	Total Annual Costs [%]
Baseline 2014	18.6	8.7	6.1	7.8	701	0	0	0	0.0	0.0
P1	55.8	8.7	6.9	7.9	705	0	10	45	−12.7	−4.5
P1, Best-case	55.8	8.7	6.1	7.6	715	0	10	45	−12.6	−4.0
P1, Worst-case	43.4	11.6	6.4	7.6	701	0	10	45	−12.7	−2.3
P2	80.6	49.4	9.1	7.6	705	0	90	50	−24.2	−2.0
P2, Best-case	68.2	49.4	8.9	8.1	705	0	80	55	−24.2	−1.4
P2, Worst-case	80.6	49.4	9.1	7.6	705	0	100	50	−24.2	0
P3	93.0	49.4	9.1	7.9	725	5	100	60	−27.0	0.2
P3, Best-case	93.0	49.4	9.1	9.6	725	15	100	60	−27.0	0.7
P3, Worst-case	111.6	49.4	8.9	9.4	725	60	100	55	−27.0	2.6
P4	117.8	49.4	9.1	8.6	725	620	100	75	−32.3	15.3
P4, Best-case	117.8	49.4	9.1	10.1	725	560	100	75	−32.3	14.6
P4, Worst-case	117.8	49.4	9.1	10.1	725	655	100	75	−32.3	16

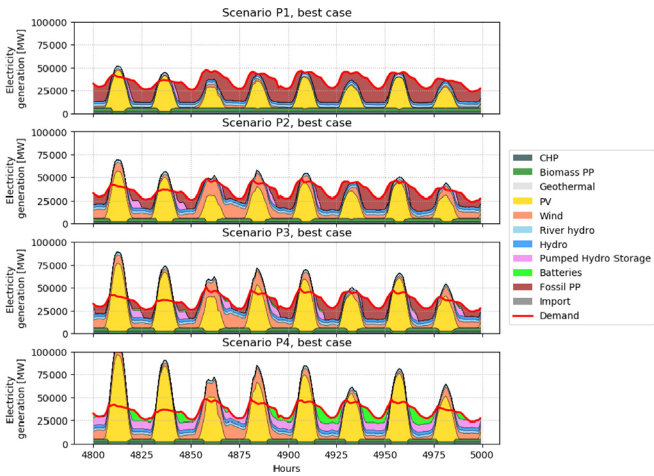

Fig. 6. Results of the three considered solutions P1, P2 and P3. The matching between electricity demand and production for a week of summer.

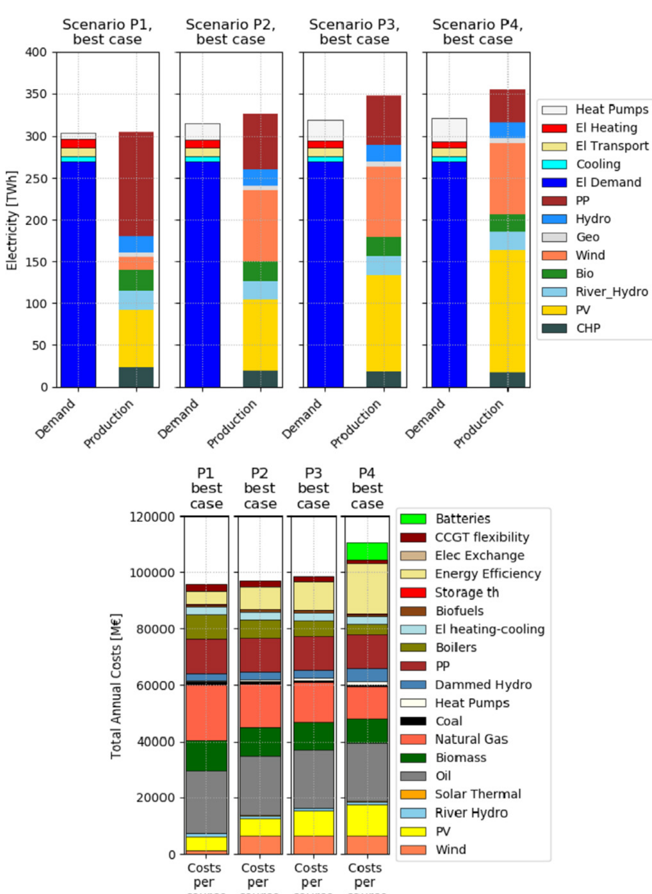

Fig. 7. Results of the three considered solutions P1, P2 and P3. On the top, the annual electricity balance for the three solutions. On the bottom, the annual costs for the three solutions.

fossil Power Plants.

Fig. 7 shows the annual electricity balance and the total annual cost balance of the system. The strong increase in PV and wind power production from Solution P1 to Solution P4 is evident. On the demand side, there is an increase of the electric demand from heat pumps connected to the individual heating. The increase of energy efficiency from solution P1 to solution P4 results in a decrease of electric heating demand. About the total annual cost balance, from P1 to P4, there is an increase of the costs for PV, wind power, energy efficiency and batteries and the decrease of the total costs for fuels like natural gas and oil.

The values of the electricity demand, electricity production, renewable electricity production and renewable share for scenarios from P1 to P4 in the best-case assumption for the CCGT cycling costs are shown in Table 5.

The higher the production from variable renewable energy sources the lower the electricity production from CCGT. This reduction in CCGT electricity generation together with a less constant hourly profile of production increase the specific costs for cycling. Table 6 highlights this reduction of CCGT production from solution P1 to solution P4 and the increase of the specific costs for cycling. However, the overall additional costs for cycling reduce from 484.5 M€ in P1 to 272.8 M€ in P4.

The difference on the same configurations of the energy system P1, P2, P3 and P4 when evaluated with the worst case costs for cycling is even more significant. Fig. 8 summarizes the relative annual cost and cycling cost variation along the Pareto front for the two cases. Moving from right to left, solutions are characterized by increasing specific costs for cycling produced by a more discontinuous production from CCGT. The sensitivity analysis between the best case and worst case assumption for CCGT cycling costs highlights the difference of the resulting specific costs for CCGT cycling in this two extreme cases found in literature.

The results obtained through the three cases, without implementing the CCGT model, the best-case and worst-case for CCGT systems, have been presented. The comparison between the three cases has been done comparing the energy mix of the solutions on the different Pareto fronts and using the indicator of the specific costs for cycling. Analyzing the energy mix obtained by the optimization, it has been possible to observe how the introduction of flexibility costs and constraints for CCGT systems produces the installation of electric storage at an earlier stage on the Pareto front. Calculating the specific costs for cycling of the different solution on the Pareto fronts allows to catch the correlation between intermittent renewable energy sources and the flexible operation of CCGT systems.

It is also important to underline that the CCGT model could overestimate the problem as consequence of the problem simplification. In reality, a large number of CCGT system would operate at partial load instead of minimizing the number of working CCGT system reducing the overall number of start-up costs.

6. Conclusions

This paper discussed the improvement of the EPLANopt model, a multi-objective evolutionary algorithm combined to the simulation

Table 5
Analysis of the percentage of renewables in the solutions from P1 to P4.

Scenarios	Electric Demand [TWh]	Electric production [TWh]	Renewable electricity production [TWh]	Renewable share [%]
P1	304.5	305.5	157.2	52
P2	315.5	326.4	240.7	76
P3	319.8	347.4	270.9	85
P4	322.0	355.1	299.7	93

Table 6
Analysis of the specific costs for cycling in the solutions from P1 to P4.

Scenarios	Specific cost for cycling [€/MWh]	Production by CCGT [TWh]	CCGT equivalent hours [h]
P1	3.87	125.2	2277
P2	6.44	66.0	1200
P3	7.29	58.2	1058
P4	7.16	38.1	693

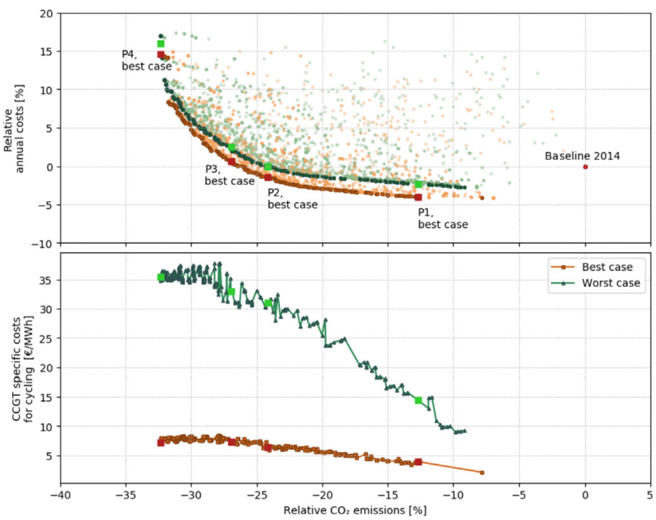

Fig. 8. On the top, the Pareto fronts obtained through the best case (red squares) and worst case assumption (green squares) for CCGT cycling costs. On the bottom the resulting CCGT specific costs for cycling of the corresponding Pareto front solutions.

software EnergyPLAN, by considering the additional costs and consumption of CCGT cycling. The model was applied to the Italian case as it is characterized by a very high capacity and electricity production from combined cycle gas turbine systems. In the future, their role for modulating the load will even increase considering the planned coal phase out planned in Italy by 2030. The set of input variables of the optimization analysis have been concentrated on the electricity and heat sectors. The transport sector was accounted in the model, but not included in the optimization analysis. However, the considered case is relevant to discuss the new approach and the CCGT cycling impact in the energy scenario definition. Results show that the evaluated final specific costs for cycling cannot be neglected even in the best scenario with the lowest costs assumed. The situation become even worse considering worst case scenario where the final specific costs for cycling can be as high as 33.5 €/MWh corresponding to an overall increase of energy costs of the energy system by 5%. It is important to underline that the calculated specific costs for cycling could be underestimated as the CCGT model maximizes the number of CCGT systems working at regime and the single-node approach. This method has established a first step in the direction of modelling CCGT role for modulating the load considering technical constraints and additional costs from start-up and working at partial load. It has been shown that considering costs of CCGT cycling at the increase of renewable energy sources makes the high cost electric storage through batteries more competitive. Thus it is important to consider these constraints and costs in the evaluation of the best future alternatives for the energy system.

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Appendix A

The choice of a reference CCGT system composed by a gas turbine of 270 MW and steam turbine of 130 MW is mainly driven by the available data about decay of efficiency and start-up costs that refer to this reference size. Figure A.9 shows the comparison between the size of the reference plant and the size of the Italian CCGT systems. The average size of Italian CCGT system is above the one of the reference plant. Hence, this assumption is conservative and can underestimate the final results since a larger number of smaller plants can provide higher flexibility to the system than a lower number of bigger plants.

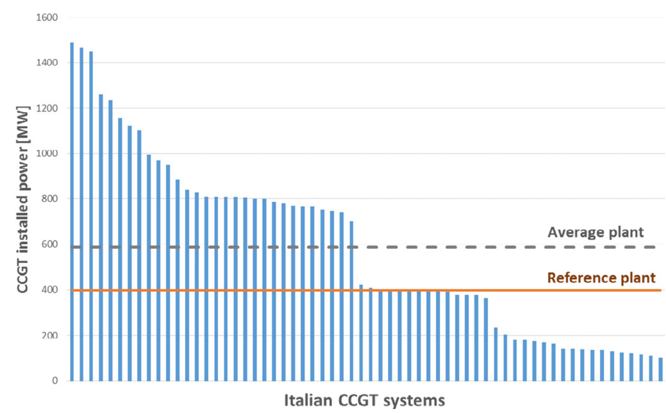

Fig. A.9. List of Italian CCGT systems ordered by installed power and compared to the reference plant.

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