Project Acronym/ Acronimo del progetto:

INTEGRIDS

Project title:

Electric and thermal grids integration with energy flexible building

Titolo del progetto:

Studio dell'integrazione di reti elettriche e termiche con la flessibilità energetica degli edifici

Deliverable name	Modellazione di transitori e fattibilità tecnica di sistemi energetici ad alta penetrazione di rinnovabili.
Deliverable N°.	D 4.2
Task	4.2
Author of the deliverable: Approved by:	Matteo Giacomo Prina, Marco Cozzini, Grazia Barchi David Moser
Due date	30-09-2018

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Executive summary

Il presente report intitolato “Modellazione di transitori e fattibilità tecnica di sistemi energetici ad alta penetrazione di rinnovabili” è diviso sostanzialmente in due parti descritte brevemente di seguito con i relativi risultati.

Nella prima parte viene presentata la metodologia per sviluppare il modello del sistema energetico basato su un approccio multi-nodo utilizzando il software open-source Oemof. Tale modello, applicato al sistema elettrico italiano utilizza profili annuali orari di generazione e consumo basati sui dati raccolti del 2014. Tale approccio è stato confrontato con il tradizionale modello a singolo nodo per studiare l’impatto delle fonti di energia rinnovabile nel sistema elettrico italiano. In particolare, l’Italia è stata divisa in 6 diversi nodi, corrispondenti alle regioni del mercato elettrico tenendo conto dei vincoli legati alla trasmissione tra una regione e l’altra.

I risultati ottenuti mostrano come il modello multi-nodo sia più accurato ed appropriato del modello a singolo nodo per una nazione come l’Italia che presenta la maggior penetrazione di rinnovabile al sud, mentre la maggior parte dell’energia stoccabile tramite idroelettrico a pompaggio si trova al nord. Le simulazioni mostrano come attualmente la rete di trasmissione, di fronte ad una significativa crescita delle fonti di energia rinnovabili variabili, non sia in grado di supportare la sovrapproduzione senza creare congestioni o portare al curtailments. Nello specifico caso dei due modelli utilizzati quello che si ha è che il modello a singolo nodo sottostima il curtailment di circa il 7% e questo provoca una sovrastima dell’integrazione di energia elettrica da fonti rinnovabili nel sistema di circa il 6.6%. Successivamente sono stati analizzati i benefici derivanti dallo stoccaggio di idroelettrico al fine di mitigare gli effetti dell’integrazione di rinnovabili. Partendo dall’attuale capacità installata di stoccaggio idroelettrico, sono stati simulati i due scenari con e senza stoccaggio all’aumentare di RES (renewable energy sources). I risultati dimostrano come il pompaggio idroelettrico sia necessario per poter integrare un numero crescente di rinnovabili nel sistema di trasmissione e come un futuro meccanismo di mercato elettrico dovrà privilegiare questo tipo di stoccaggio al fine di mitigare gli effetti di intermittenza causati da questo tipo di fonti.

Il modello sviluppato in Oemof, viene utilizzato anche per analizzare la flessibilità delle centrali a ciclo combinato a gas naturale (CCGT) includendone il costo. Vengono considerati i vincoli legati al tempo di avviamento, le rampe associate ed il decadimento di efficienza a carico parziale al fine di studiarne i transitori. Sono considerati tre tipi di avviamento: cold, warm e hot. È stato quindi sviluppato un nuovo modello chiamato Oemof_Transient ed applicato al caso Italiano considerando una crescente penetrazione di rinnovabili. I risultati mostrano che i vincoli legati alle variazioni transitorie dei CCGT ed i costi associati non possono essere trascurati. In particolare, viene mostrato come il dispacciamento orario sia affetto da questi vincoli e come all’aumentare delle rinnovabili installate aumenti il costo di cycling di questi impianti con valori limite pari a 10 € / MWh.

Successivamente viene presentata una sezione di collegamento dedicata alle differenze e/o similitudini tra le reti elettriche di trasmissione e di distribuzione. Ed inclusa una definizione di distretto energetico come un insieme di edifici appartenenti ad un’area urbana e contemperamene connessi alla stessa rete elettrica e termica di distribuzione. Questo fa sì che si possano sviluppare logiche di sinergie tra reti elettriche e termiche come quella presentata nella seconda parte dedicata all’accoppiamento di settore tramite pompe di calore.

Al fine di aumentare la flessibilità della rete, si presenta il concetto di interazione elettrico-termica basata su pompe di calore decentralizzate. In questo contesto, le pompe di calore sono il collegamento chiave che collega i due settori e possono essere sfruttate per le strategie DSM. A titolo di esempio pratico, nel report viene presentata una semplice logica di controllo per le pompe di calore in cui l’operatività delle stesse è influenzata dal prezzo dell'elettricità. Questa

logica è stata simulata in un modello completo di un singolo edificio collegato alla rete di teleriscaldamento e teleraffrescamento, mostrando la possibilità di trasferire dalle ore di punta alle ore non di punta fino al 20% dell'energia elettrica consumata per la produzione di acqua calda sanitaria. L'effetto ottenuto sarà scalato quando si considera l'intero insieme di pompe di calore presenti nella rete.

1 Introduction

This deliverable deals with the integration aspects of high share of variable renewable energy sources (VRES) into the electric grid. A model based on the Oemof python framework has been developed in order to perform a multi-nodes analysis on the Italian electricity sector [1, 2]. The model is characterized by hourly base dispatch optimization which means that the use of resources is optimized to satisfy the demand at least costs in terms of CO2 emissions.

With this model the final aim is to assess the current and potential renewable energy sources (RES) electricity generation, the congestion problems and the degree of integration of RES into the grid. The purpose is also to identify the role of the already installed pumped hydro storage capacity and to quantify the importance of a multi-nodes versus a single-node modelling approach.

The novelty of the present work is given by the multi-nodes modelling approach coupled to the hourly based dispatch optimization accounting for the national power system constraints: the variability of RES generation, the congestion problems between nodes and the role of storage.

This methodology is applied to the Italian case because of its morphological characteristics: there are significant differences in the variable generation by photovoltaic (PV) and wind power between areas, especially between north and south. The actual configuration of the Italian electric system consists in six main zones defined by the grid transmission capacity. The first critical obstacle concerns the geographical location of the different resources where the renewable energy generation and its potential is mainly placed in the south of Italy and the availability of pumped hydroelectric storage (PHS) is in the north.

The potential of PV and wind power has been estimated for the Italian territory. A multi-nodes model has been developed to assess eventual issues of the electric system configurations in the transition towards the installation of the whole variable renewable energy potential. Results show the importance of the multi-nodes approach compared to the single-node approach. The curtailments from renewables estimated through the single-node approach are largely under-estimated if compared to the values obtained through the multi-nodes approach. The results show also the fundamental role of the already installed pumped hydroelectric storage capacity to increase the renewables penetration in Italy. The possibility to install batteries or other types of electric storage is not considered in this work, but it will be considered for future development.

2 Methodology used in the case study: Oemof framework

High penetration of wind and solar sources is necessary to increase RES generation up to 100%, and, thus, issues related to the non-dispatchable power production must be faced. This work assesses the integration of RES from a technical and economic point of view to regional scale, applying the model to the Italian case. For several nations and regions single node models have been implemented showing its capabilities together with the needs of widely RES based scenarios. Examples are the model elaborated for Germany by H. M. Henning et al. [3, 4] or other models elaborated through the EnergyPLAN software [5-10]. From a European perspective Pleßmann et al. [11] have developed some decarbonization pathways for European electricity supply until 2050. In this work, a similar multi-nodes model is developed using the Open Energy System Modelling Framework (Oemof) which is a free, open source toolbox to assess energy supply systems. It is developed in Python and designed as a framework with a modular structure [1, 2]. Through this framework, for example, C. Möller et al. [12] have studied the technical potential of electrical storage technologies for a region in the northern part of Germany. In particular, the focus was the required storage capacity at different RES shares by using annual simulations in hourly time steps.

2.1 Oemof framework

Figure 1 shows the structure of the multi-nodes model created for the Italian electricity system. The model takes into consideration not programmable RES like PV and wind power, RES with a fixed constant production like geothermal and biomass power plants, programmable RES like hydro power, programmable conventional power plants and pumped hydro storage.

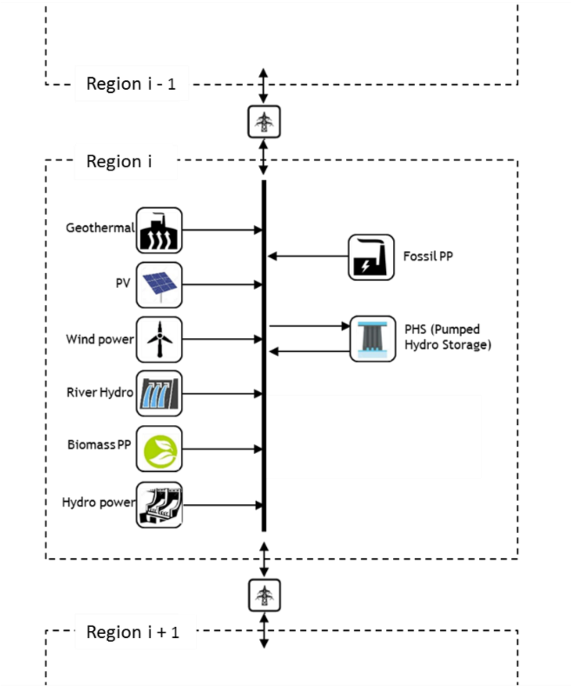


Figure 1: Structure of the multi-nodes model developed for the Italian electricity system.

The developed model is based on hourly base dispatch optimization which means that the use of the sources is optimized to supply the demand minimizing the CO_2 emissions. Therefore, the optimization starts to cover the demand for every hour in each node with the production from RES and then uses the power production from fossil fuel plants. If excess electricity production from RES occurs, the optimization evaluates the best option among the export of electricity to another node, storing electricity through pumped hydro storage if available or exporting to another node where there is availability of storage. The transmission losses that have been considered between two adjacent nodes are equal to 3% [1]. Figure 2 shows a diagram that summaries the main choices available within the dispatch optimization analysis.

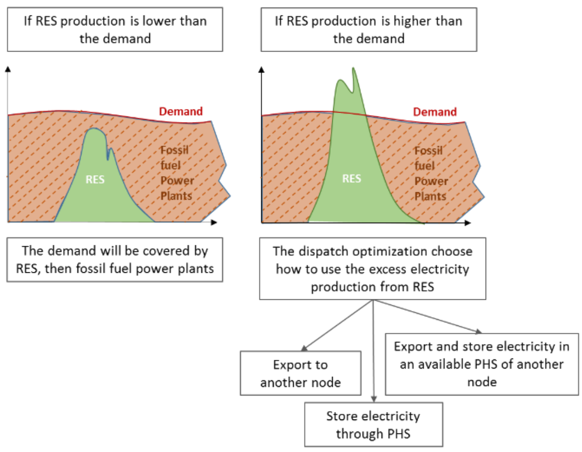


Figure 2: Diagram of the dispatch optimization operations.

The Oemof framework based on pyomo library [13-14] allows us to create and solve linear programming (LP) and mixed integer linear programming (MILP) optimization models specific to energy systems. It allows the flexible creation of the energy system model choosing between different components such as: source, sink, transformer and storage. Linear programming is used in this framework to produce a least-cost energy system where the costs can also be represented by the CO_2 emissions. Each component added to the energy system model brings a certain number of constraints to the model.

3 Results - application to the Italian electricity system

Firstly, the structure of the electric system with the corresponding transmission constraints has been analyzed [15, 16]. Figure 3 shows the six main areas in which the Italian electric system is divided and the grid connection capacities between them.

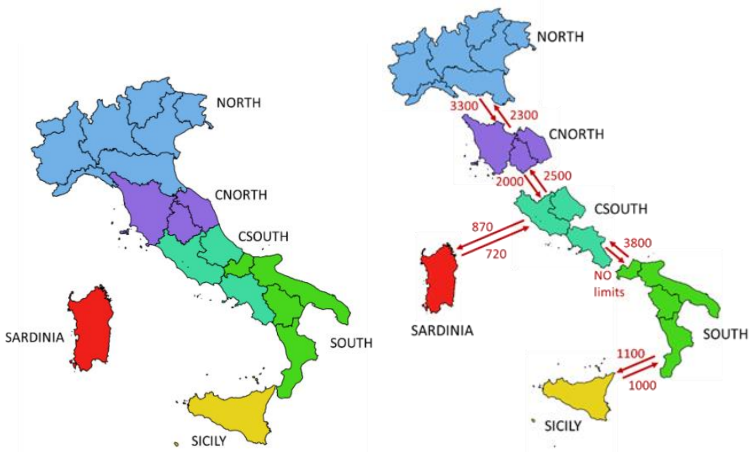


Figure 3: Division of the Italian territory into the different main areas of the electric system, identified by the transmission constraints of the grid [MW] [16].

The data set, on which this analysis is based, is made by data series with hourly resolution for the year 2014 [16]. The electricity production by hydro power has been normalized on the average equivalent hours of the previous five years. For each node, the baseline of the current electric system has been created.

3.1 The multi-node Italian energy system

The importance of a multi-nodes versus single-node approach can be easily identified by looking at the spatial characteristics of the Italian already installed renewable generation park. The distribution among the regions of the PV and wind installed power, and the capacity of pumped hydro storage is reported in Figure 4. This latter shows a fundamental and critical issue of the Italian electric system. While PV is homogeneously distributed, the majority of the wind installed power together with its potential is concentrated into the south of Italy in contrast to the available installed capacity of storage placed in the north.

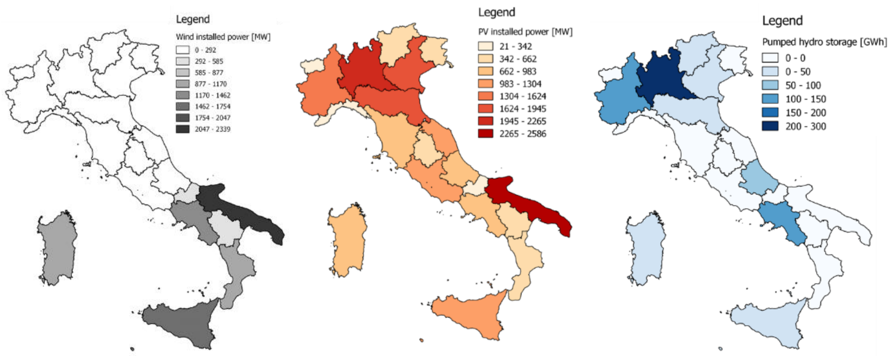
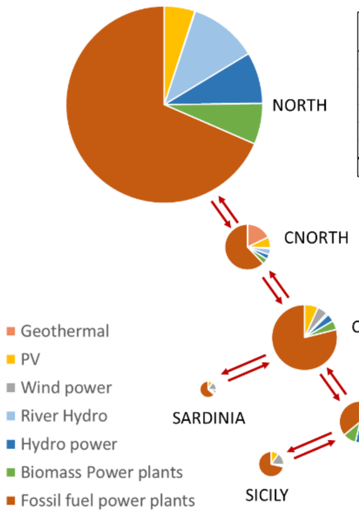


Figure 4: Distribution of the installed power of PV, wind and installed capacity of pumped hydro storage among the Italian regions [16, 17].

The developed baseline 2014 for Italy presents the following characteristics: an overall electricity consumption of 310.9 TWh and an average RES percentage of 33.4 %. Figure 5 shows the different RES production share on the overall electricity consumption of the zone. The highest value is in the South region characterized by large electricity production from PV and wind power. The overall minimum load of the whole Italy is about 19 GW with the maximum being 53 GW.



	Electricity demand [TWh]	RES percentage
North	173.2	31.5
CNorth	33.2	37.9
CSouth	49.3	20.9
South	26.2	66.1
Sardinia	9.5	36.5
Sicily	19.5	27.9
Total	310.9	33.4

Figure 5: Italian energy system baseline for the year 2014.

3.2 Renewable energy sources potentials

The maximum potential of rooftop PV and wind has been estimated for each region following the Re-shaping European project for wind [18] and some other studies for PVs [19, 20]. The overall potential is equal to about 120 GW and 49 GW for PV and wind power respectively, while the installed capacity in 2014 was 18.6 GW of PV and 8.7 GW of wind power. The distribution of these capacities in the Italian regions is based on different assumptions. For wind power, the assumption of the Re-shaping project is to replace existing turbines with larger ones, therefore the potential distribution reflects the current installed power distribution. A homogeneous distribution per dwelling is assumed for rooftop PV. Thus, the final distribution depends on the number of inhabitants per region and deviates from the current installed power distribution. Figure 6 summarizes the increase of installed PV and wind power for the six zones for the considered scenarios.

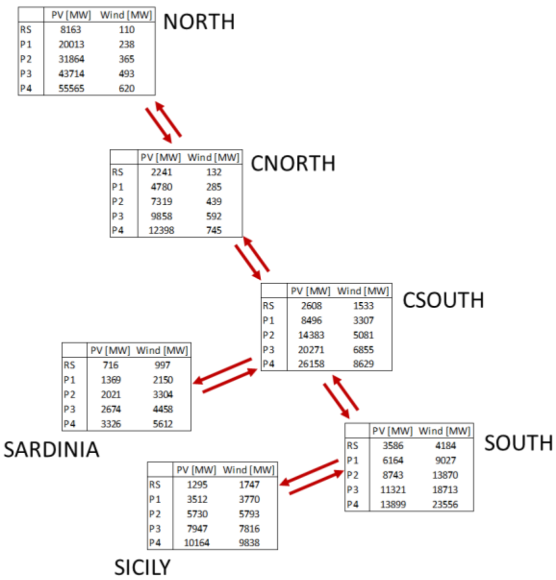


Figure 6: Installed power of PV and wind power divided per region for the reference scenario and four other scenarios with additional installed capacity.

4 Results - Single-node vs Multi-node

The multi-nodes approach has been inspected and compared to the single-node in order to quantify the differences linked to the single-node assumption. Figure 7 shows four different solutions with increasing capacity of PV and wind power starting from the reference scenario solution that refers to the Italian electricity system in 2014. The final solution P4 represents the configuration of the energy system where the maximum potential PV and wind power are exploited (i.e. 120 GW for PV and 49 GW for wind). The intermediate solutions, points P1, P2, P3 are characterized respectively by the 25%, 50% and 75% of the overall missed VRES potential (see figure 6). Figure 7 outlines the importance of the multi-node approach when large RES penetration is considered. While for modelling the reference scenario the use of single-node approach does not produce different results if compared to the multi-nodes, due to limited VRES installed power, it underestimates the curtailments for increasing RES capacities together with an over-estimation of the percentage of renewables in the system.

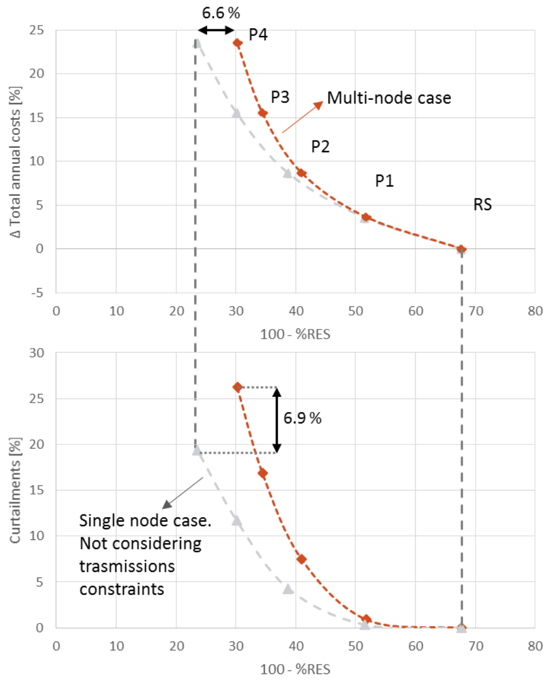
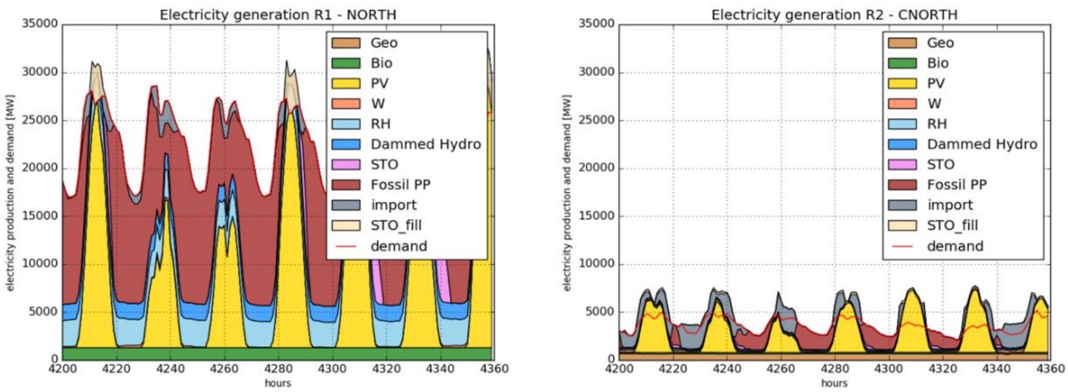


Figure 7: Mapping of the different configuration of the electric system increasing the capacity of PV and wind power. Comparison between the multi-nodes and single-node approach.

Figure 8 shows the hourly electricity production in the six main zones of Italy for scenario P3 in a summer week. Scenario P3 is characterized by PV and wind power equal to the 75% of their potential. This figure allows to highlight the over-generation problems, especially in south regions. The region R4 – SOUTH present peaks of over-generation higher than 10 GW while the transmission constraints of the grid from south to northern regions is in the order of 3-4 GW (see Figure 1).



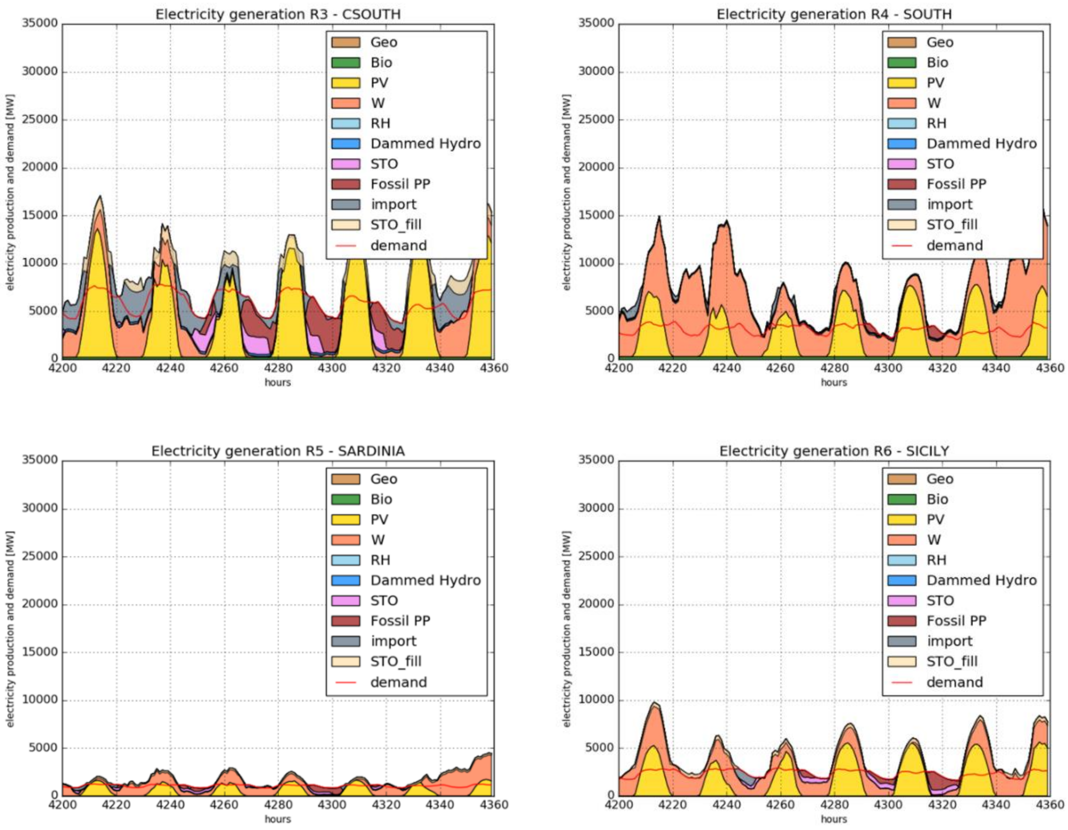


Figure 8: Hourly electricity production in the six main zones of Italy for scenario P3, where PV and wind power are increased to the 75% of their potential, in a week of summer.

5 Results – the role of storage

In order to identify the future potential role of pumped hydro storage systems already installed over the Italian territory, other simulations has been run neglecting the pumped hydro storage capacity. Figure 9 shows the comparison between the actual case considering pumped hydro storage and the one not considering it. In this way, it is possible to estimate the future potential contribution of PHS. In the P4 scenario, with all the potential PV and wind power installed, the already existing pumped hydro storage capacity leads to an electricity consumption increase from renewables by 3.6%. The actual installed capacity of PHS permits to save curtailments of the grid equal to 4.7% of the total production from RES.

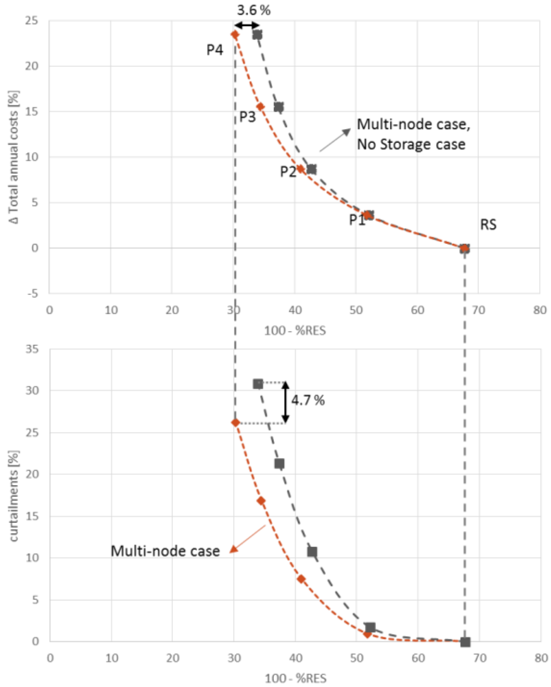


Figure 9: Mapping the different configuration of the electric system increasing the capacity of PV and wind power. Comparison with the case not considering pumped hydro storage.

6 Results – the role of CCGT flexibility constraints and additional costs

Fossil fuel power plants are modelled in Oemof as fully-flexible units (power output can vary from zero to the maximum in one time-step) and the decay of performances during partial operations is not implemented. In order to evaluate with higher technological detail the impact of fossil fuel power plants' transient operations on electricity dispatch, Oemof is enhanced. New constraints have been developed in this work and have led to the creation of Oemof _Transient model. The model created performs a time-dependent analysis of fossil fuel power plants' transient operations: this means that the constraints implemented introduce in the optimization additional costs, emissions and ramp rate of available power that, for each instant of time, are a function of the hours of stop and of the power output of the plant. In particular time-dependent start-up costs, time-dependent ramp constraints and decay of efficiency during partial load operations are introduced in the model. Start-up costs are set depending on the hours of stop of the plant (hot start, warm start and cold start are distinguished) and penalize the start-up of a unit; ramp constraints impose fixed amounts of available power at start-up based on the hours of stop of the plant, while the decay of efficiency at partial load penalizes the off-design working conditions by introducing in the optimization additional costs and emissions every time a power plant is not producing at full load (nominal power).

In Table 1 are reported the start-up costs introduced in the model: the optimistic scenario with low start-up costs [21] (named Best case), the medium case and the pessimistic scenario with high start-up costs [22] (named Worst case). Figure 10 shows the curve of the decay of efficiency at partial load and its linear interpolation used in the model. In table 2 all the constraints are presented.

Table 1 Start-up costs, Best, medium and worst case.

Best case	Hot start	*[€/MWh]*	32.4
	Warm start	*[€/MWh]*	51.0
	Cold start	*[€/MWh]*	73.2
Average case	Hot start	*[€/MWh]*	45
	Warm start	*[€/MWh]*	70
	Cold start	*[€/MWh]*	110
Worst case	Hot start	*[€/MWh]*	156
	Warm start	*[€/MWh]*	211
	Cold start	*[€/MWh]*	393

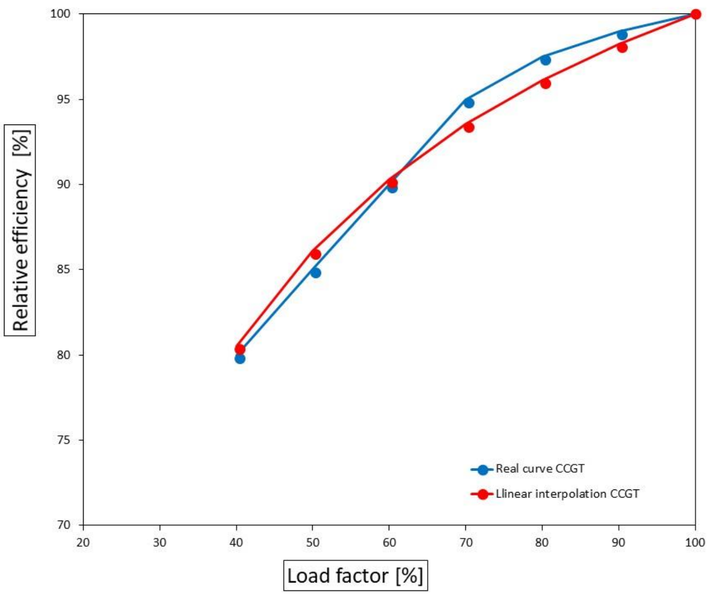


Figure 10: Curve of the decay of efficiency at partial load and its linear interpolation used in the model.

Table 2 Technical characteristics and constraints of CCGT.

Types of start	Hot start	*[h]*	<=8
	Warm start	*[h]*	>8 ∧ <24
	Cold start	*[h]*	>=24
Ramp rate	Hot start	*[MW/min]*	14
	Warm start	*[MW/min]*	7
	Cold start	*[MW/min]*	4
Nominal efficiency	*[%]*	55	
Decay of efficiency	Curve of the decay of efficiency at partial load		
Technical minimum	*[%]*	25	
Fuel	Natural gas		
Cost	*[€/MWh]*	24.9	
CO_2 emission factor	*[kg/MWh]*	204.8	

In Figure 11 and 12 (for a summer week in 2014) are reported the results of the optimizations for the different scenarios (Best and Worst case) considering the following constraints: three start-up costs (hot, warm and cold start), one ramp constraints and decay of efficiency at partial load. It is possible to notice from the graphs that changing the start-up costs, the constraints affect in different way the optimization dispatch problem: with low start-up costs (Best case) the constraint on the decay of efficiency at partial load is the most influent, thus CCGT are forced to work at higher loads and so higher efficiency. With high start-up costs (Worst case) the impact of the constraints on the optimization is different, in particular in this case the influence of start-up costs is higher respect to the decay of efficiency, thus the number of starts is reduced at minimum, CCGT are started-up less frequently and only if strictly necessary and they works longer at lower loads; with medium start-up costs (Average case) the optimization results are more similar to the case with low start-up costs (Best case).

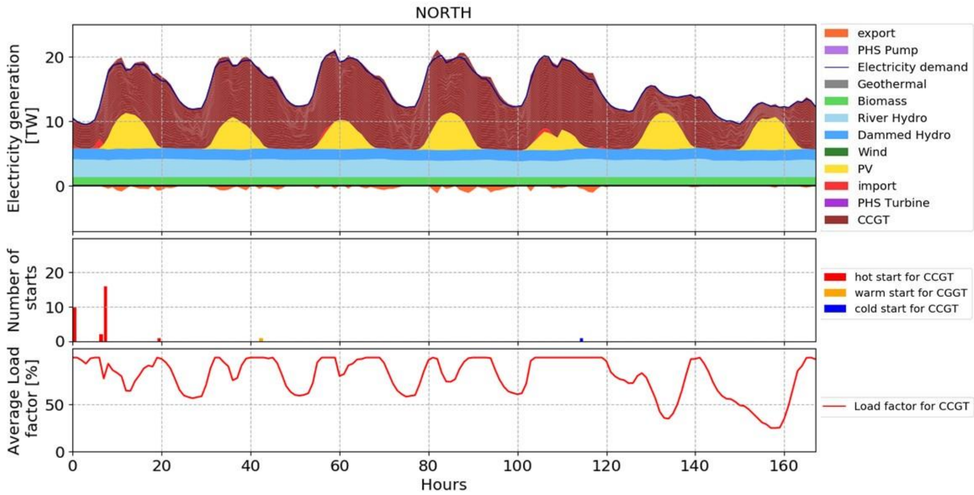


Figure 11: Results of the optimization with constraints on CCGT considering high start-up costs (Worst case) for the first week of July in 2014 in the macro-region North: on the top matching between electricity demand and generation, in the middle number of starts of CCGT differentiated by start-up modes, while on the bottom Average Load factor (electricity produced from CCGT at time t divided by the maximum amount of electricity that can be generated from the CCGT that are turned on) as function of time.

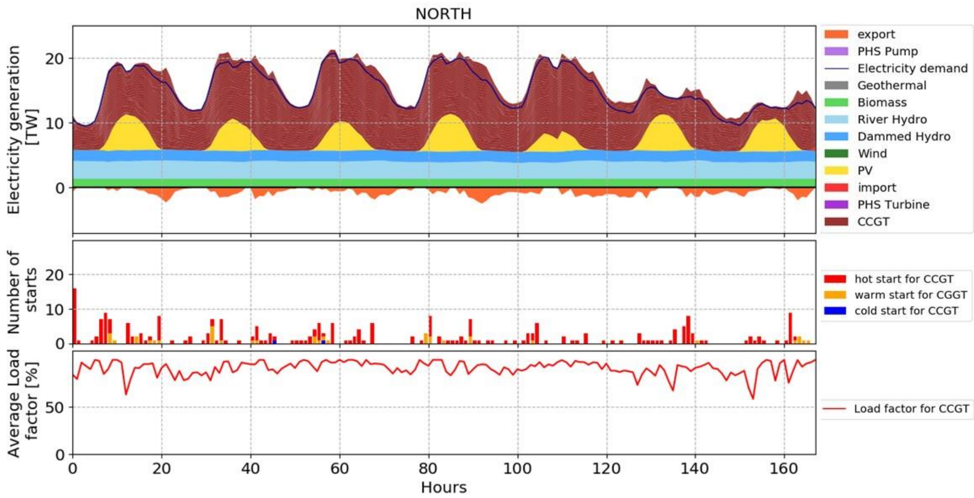


Figure 12: Results of the optimization with constraints on CCGT considering low start-up costs (Best case) for the first week of July in 2014 in the macro- region North: on the top matching between electricity demand and generation, in the middle number of starts of CCGT differentiated by start-up modes, while on the bottom Average Load factor (electricity produced

from CCGT at time t divided by the maximum amount of electricity that can be generated from the CCGT that are turned on) as function of time.

In Figure 13 the characteristics of the transient operations of CCGT are reported for the different configurations of the Italian energy system analyzed assuming medium start-up costs (Average case). In particular specific CO2 emissions and specific costs caused by the transient operations of CCGT are reported. Specific cycling costs are split into decay of efficiency costs and start-up costs. It is possible to notice that as the VRES installed capacity increases, the specific start-up costs are higher, thus CCGT are stared/stopped more frequently in order to follow the load and provide flexibility to the generation side. Specific decay of efficiency costs and specific CO2 emissions show the same behaviour, because CCGT work longer at lower loads (low efficiency) as VRES penetration increases. The scenarios VRES_25%, VRES_50%, VRES_75% are VRES_100% correspond to the already mentioned P1, P2, P3 and P4.

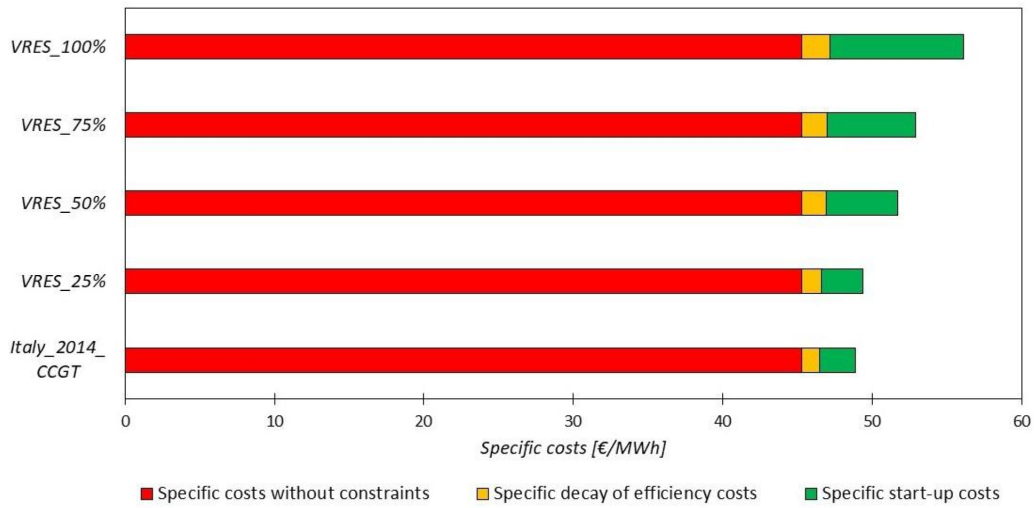


Figure 13: Oemof_Transient optimizations results considering multinode configurations with constraints on CCGT (Average case).

7 From transmission to distribution networks

Previous paragraphs have shown how it is possible to evaluate the high share of renewable energy in transmission grids using a multi-node approach. The procedure highlights that currently the transmission system needs reinforcement or energy storage applications in order to be able to integrate an high share of renewable. The best energy mix described in D4.1, the RES penetration in transmission system presented in the previous paragraph will be completed by the power flow analysis and methodology that will be presented in D4.3 completely focused on electricity distribution grid. The aim of this paragraph is to begin the conceptual transition from transmission analysis to distribution ones, presenting the differences and similarities between the transmission and distribution electricity grids from a physical and technical point of view moving the focus from transmission to distribution networks. Since the last part of this deliverable will present a case study on integration between electric and thermal grid at district level. The concept and definition of energy district will be also provided. After that an introduction of RES penetration at distribution level will be also given in order to introduce the concept of energy district which will be analysed for thermal part in the paragraph 8 about district heating and cooling.

7.1 Transmission and distribution system description

The electricity system is simplified in Figure 14.

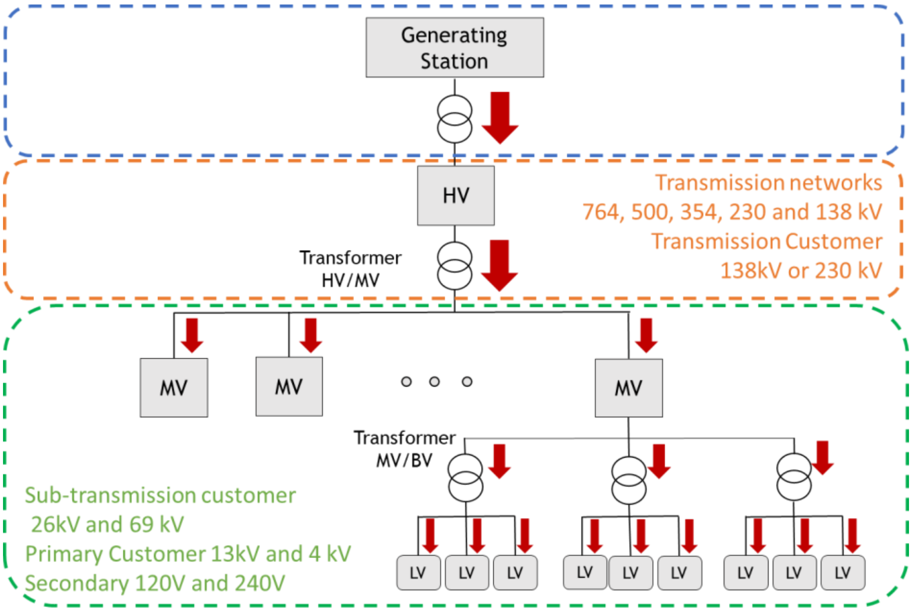


Figure 14: Simplified diagram of the traditional electric power system

The electricity produced by traditional generators in power plant is then transmitter at high voltage (HV) around 115kV or more to reduce the energy loss which are present to cross long distances. Transmission lines are usually overhead power lines because their cost is cheaper with respect to the underground cable, which are mainly used on urban area or to diminish the maintenance costs. The energy generated should be mostly the same the energy consumed this assure that the system is interconnected and working with the same frequency (i.e. 50Hz in Europe or 60Hz in USA). The consistence between demand and production is assured by the control system which through sophisticated techniques can forecast, plan and properly dispatch the energy within the entire power system. If the demand and the production do not match, there is an imbalance of the system that can cause generation or transmission automatic disconnection or shut down to prevent damages.

Power delivery is divided in two general tiers which are the already mentioned transmission system than spans long distance using HV on the order of hundreds of kV and a more local distribution system at intermediate voltage in the low tens of kV. Physically, the boundary between transmission and distribution systems is demarcated by transformers, grouped at distribution substations along with other equipment such as circuit breakers and monitoring instrumentations [23].

The Italian electricity network is simplified in Figure 15. The energy generated in different power plants are delivery through the HV electricity transmission (380 kV – 220 kV – 150kV) managed by the Transmission System Operator (TSO) which in Italy is the only responsible for the National Transmission Grid. In order to transmit the power produced in the plants to final consumer, several lines, powers and transformer plants are necessary that is the elements that form the Transmission Grid which cover 72000 km of lines in Italy.

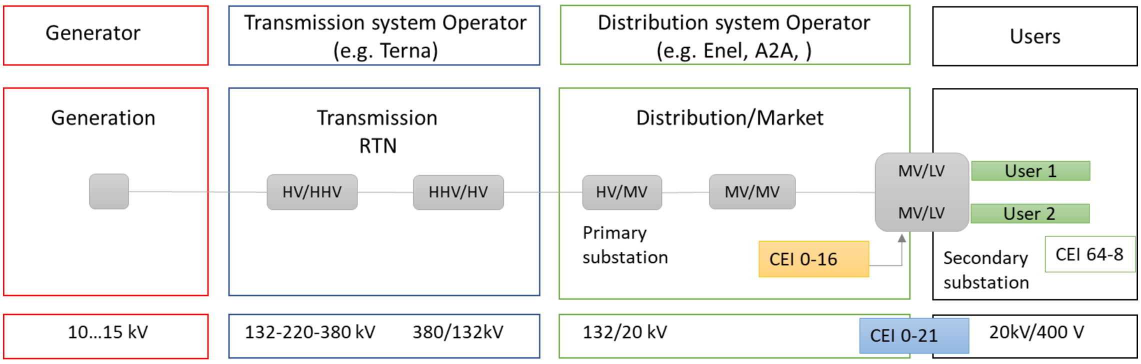


Figure 15: Italian electricity system example

The TSO operates the electricity flows for Italy under security conditions under dispatching keeping the electricity production and demand in balance during all the year. After the transmission and in order to achieve the final user the electricity is transformed to medium and lower voltage through the primary and secondary substation to be delivery through the distribution network.
Transmission circuits may be built either underground or overhead. Underground cables are used predominantly in urban areas where acquisition of overhead rights of way are costly or not possible; they are also used for transmission under rivers, lakes and bays. Overhead conductors are much less expensive than underground cables, thus they are used for a given voltage level.

The distribution system presents different characteristics with respect to the transmission one. Indeed, the transmission system is responsible to transfer large amounts of power and are characterized by mesh topology, high line reactance-resistance (X/R) ratios and a quite limited number of lines and buses. On the contrary, distribution systems typically transfer limited amounts of power, exhibit a radial topology consisting of many nodes with low X/R values and unbalanced loads.
The distribution system conveys the power from the transmission system/substation to the customer. The equipment associated with the distribution system starts downstream of the distribution feeder circuit breaker. Transformers and circuit breakers are under the supervision of a "substations department", while the distribution feeders consist of combinations of overhead and underground conductor, 3-phase and single-phase switches with load break and non-load break ability, relayed protective devices, fuses, transformers (to utilization voltage), surge arresters, voltage regulators and capacitors.

7.2 Energy district as a portion of the distribution grid

One of the core objectives of Integrids is the synergy between thermal and electrical grid and how their cooperation can improve the capacity to install more renewable. This analysis and potentialities are commonly applied to a limited portion of the distribution grid (both thermal or electrical) which we referee as “energy district”. There are more than a definition for an energy district, in some case it corresponds to a topological and geographical urban district, in some other it is only a portion of a city which has similar and peculiar characteristics.

From our point of view, and in INTEGRIDS, we will indicate with energy districts a multitude of buildings (mainly or only residential) located close to each other and interconnected with the same district heating and cooling (DHC) system and with the same distribution network. The district will share also the energy management control for both electric and thermal grid and allow to implement and re-think this portion of the network as a decentralized microgrid which can behave and optimize its flows autonomously.

While for DHC the association to district is within its own name, for electricity grid, as above mentioned, a hierarchical structure already exists. In particular the single residential buildings are connected to the secondary substation, which is a passive node, where the energy demands are aggregated and sent to the control center or primary substation.

In the low voltage side, there are several buildings connected to the same secondary substation. In order to define or identify which of these buildings are a district, we make the assumption that only the subset of customers which are interconnected both to DHC and a secondary substation are in the energy district.

In this case, they can participate actively, with production and consumption, to improve the energy management system in the district.

8 District heating and cooling system

The previous sections discussed some issues related to the integration of fluctuating RES into the electricity grid. The importance of adopting a multi-node approach was highlighted, as well as the role played by pumped hydro. The emerging picture shows that the current energy system cannot directly integrate all the needed RES. Possible solutions should involve the increase of the transmission capacity between different areas of the electricity system and could comprise the installation of additional electric energy storages like batteries. Currently available electric energy storages are however quite expensive. For this reason, it is important to analyse all the possibilities of coupling with the thermal sector, where energy storages are much cheaper, in line with the Integrids point of view.

This section indeed highlights how the coupling of the electric and thermal sectors can be beneficial for flexibility and hence to increase the penetration of RES. The example considered here focuses on district heating and cooling (DHC) in combination with heat pumps (HPs).

While traditional DHC can be linked to electricity through combined heat and power (CHP) or power to heat, without adding much to the discussion presented above (apart from the role of thermal storages in load levelling), a particular type of DHC can offer additional options. This is the case of neutral-temperature DHC based on decentralized heat pumps, like in geothermal applications.

8.1 DHC based on decentralized HPs

In neutral-temperature DHC based on decentralized heat pumps the temperature of the thermal network is kept very close to the surrounding temperature. This drastically reduces thermal losses (or it even converts them into gains), but on the other hand makes it impossible to use the network water for direct conditioning. Heating and cooling is hence achieved thanks to heat pumps, installed at customer substations. In practice, traditional district heating substations based on heat exchangers are enhanced with reversible HPs. This solution was named 5-th generation DHC at EURAC. It exploits technologies already used in geothermal systems and sometimes called “cold district heating”, but it extends the corresponding concept to the case of cooling and to more variable water temperatures. A key strength of this approach is the possibility to directly exploit low-temperature waste heat, something impossible for traditional networks (only indirect integration through high-temperature heat pumps can be considered in that case, typically with unfavourable economics).

Besides the mentioned benefits (network reversibility, lower thermal losses, low-temperature waste heat exploitation), this approach also involves some criticalities. The major ones are the significant costs of heat pumps and of electricity. However, considering the electrification trend of the energy system, the coupling with the electric sector might be more an opportunity than a barrier. In particular, it offers the possibility to exploit heat pumps for demand side management (DSM) strategies for the electric grid.

8.2 DSM

Demand side management (DSM) includes a series of strategies aiming at modifying the electricity demand, with benefit for electricity generation and distribution. More specifically, demand response (DR) introduces incentive-based or price-based programs to push customers to adapt their consumption patterns to the grid convenience.

Major examples are peak shaving and load shifting, where the objective is to reduce the load peaks in order to decrease the required installed power and to move consumptions to periods more convenient for energy production. This is especially relevant for non-programmable RES, which, in the case of excess production with respect to demand (or with respect to the grid transmission capacity) could be subject to curtailment, with environmental and economic disadvantages [24].

This work focuses on the case of price-based DR, assuming time-of-use (TOU) pricing (i.e., pricing based on a limited number of tariffs applied during different periods of the day, as opposed to real-time pricing where the electricity price can continuously change as in a stock exchange context).

8.3 Concept and involved equipment

The considered concept is as follows. The operation of heat pumps is shifted (anticipated or delayed in time) in order to exploit the most convenient electricity prices. Since prices can be seen as representative of the electricity production portfolio, one can expect lower prices when production from RES is higher. Moreover, the considered analysis could be applied to any type of “driving” signal (e.g., one could substitute the price value with the RES fraction value).

In order to perform this operation shift, the domestic hot water (DHW) tank connected to the HP is exploited. The crucial point is that a thermal energy storage (TES) is used to act as an electricity storage, thanks to the hybrid role of the heat pump. Of course, since the conversion of electricity into thermal energy is not reversible, this is a “one-way” approach. Anyway, thermal storages are much less expensive than batteries or other electric storage solutions. Moreover, in the case of HPs providing DHW, a TES is anyway needed by current plant solutions, so that no additional equipment costs are involved. It is also worth noticing that, in principle, the residential environment could offer other thermal storage possibilities (space heating or space cooling buffers or even the building thermal capacity itself). This analysis was however limited to the DHW tank due to its simplicity and its constant availability/use throughout the year, without significant seasonality effects.

While for a single heat pump the load shifting potential might be negligible and of low interest for an individual user, in the case of a 5-th generation DHC network, where large HP pools can be operated simultaneously, this can give rise to a sizable effect, both in terms of electric power and economic value. Moreover, the presence of a network manager, typically taking care of all substations together, could allow for simpler and more effective control solutions.

Before studying in detail this clustering effect, in a first research phase at EURAC the attention was focused on a single heat pump. Nevertheless, the actual connection to the network was included in the analysis both from the point of view of operating temperatures of the heat pump and from the point of view of thermal energy prices.

8.4 Simplified estimates

Before presenting the investigation carried out with detailed simulations, it is useful to briefly discuss some simple relations which highlight the different effects at play.

Operating the heat pump during off-peak hours, gives the obvious advantage of exploiting lower electricity prices. On the other hand, anticipating DHW production typically requires increasing the tank temperature, during the storage charge. One then has the drawback of operating the HP at higher temperatures at the condenser, reducing its coefficient of performance (COP). These two competing effects must both be taken into account when evaluating the overall balance: the final cost is indeed the electricity price times the amount of used electricity, and if the electricity amount increases more than the price decreases, then the convenience is lost.

Neglecting additional thermal losses and effects on the network side, the consumed electricity is $E_{el} = E_{th}/COP$, where E_{th} is the thermal energy needed for DHW. One can then write the following simple inequality

$$\frac{c_{el,off-peak}}{COP} < \frac{c_{el,peak}}{COP_{max}},$$

where c_{el} is the unit electricity price, the subscripts "peak" and "off-peak" have obvious meaning, and COP_{max} is the maximum COP (obtained when the storage temperature is lowest). The above inequality must be satisfied in order to make the system economically convenient.

Exploiting typical formulas for the COP dependence on temperatures, one can use this relationship to estimate how big could be the temperature increase in the tank set point before worsening the COP too much. Typical values for HPs and typical variations of electricity prices suggest a limited range of about 5 K. In the more detailed calculations presented below, a larger range was however used, as this simple estimate neglects effects related to network heat (both in terms of amount and prices) and it was considered interesting to extend this variation.

8.5 Simulations

Detailed simulations were carried out in TRNSYS. To this purpose, a complete building model was used. This work is also reported in the paper "Potential study on demand side management in district heating and cooling networks with decentralized heat pumps", by Simone Buffa et al. [25].

Building model. A multi-family house consisting of 10 apartments subdivided into 5 floors was considered. The single apartments have a floor area of 50 m^2. From the point of view of energy efficiency, performances typical of a recent or refurbished building were assumed, corresponding to consumptions of about 45 kWh/(m^2 y) for space heating (SH). The climate conditions of Rome (Italy) were applied, in view of a setup also interesting for cooling. For the domestic hot water (DHW) profiles, the DHWcalc software was used, with a time resolution of 1 min. The applied occupancy level is 2 people/apartment with a DHW demand of 40 l/(person day), finally yielding a specific DHW load of about 24 kWh/(m^2 y). The SH and space cooling (SC) demands of the building have been assessed by means of dynamic simulations using TRNSYS Type 56. The peak thermal power for SH results in 22.7 kW. Some space cooling (SC) was also considered, though its description is not relevant for this work. The thermal energy storage (TES) for DHW consists of a stratified water tank and it has been sized according to the Italian standard UNI 9182 (2010) resulting in a volume of 450 litres (centralized storage for the entire building). The water source heat pump used for the plant was slightly oversized, with a peak power of 25 kWt. Since DHW must be readily supplied to the single apartments, a continuous recirculation within the distribution plant is assumed. This gives rise to non-negligible losses. However, to decouple these losses from the DHW TES temperature (which can be set higher within DSM-related control strategies), a 3-way mixing valve was assumed at the TES outlet. In this way, the

DHW circulation temperature can be assumed equal to the minimum set point of 50 °C even for higher TES temperature. The plant scheme is reported in the figure below.

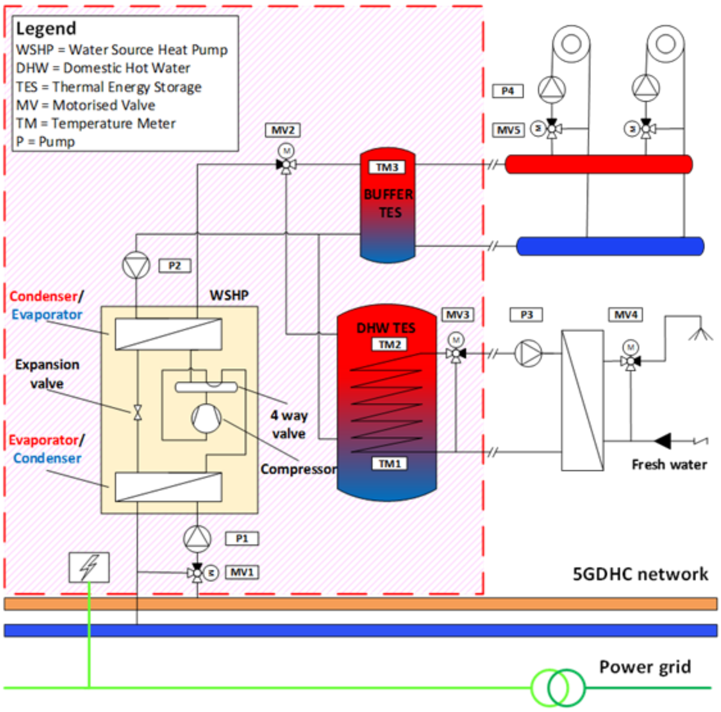


Figure 16. Plant scheme of the residential substation based on a reversible heat pump.

<u>Control logic</u>. The time-of-use case is considered here. The real-time pricing case will be considered in a future continuation of this study (one can expect it could give rise to a higher impact). The Italian tariff D1 is used, distinguishing peak hours (08:00-19:00, working days) from off-peak hours (remaining hours and weekends). The DR signal is hence activated during off-peak hours, in particular during the two hours preceding the starting of off-peak hours, to pre-charge the DHW tank.

- Tank set points without DR. The maximum tank temperature is set to 50 °C, with a bandwidth of 5 K for the tank hysteresis cycle.
- Tank set points with DR. The maximum tank temperature is set to 60 °C, with a bandwidth of 15 K for the tank hysteresis cycle.

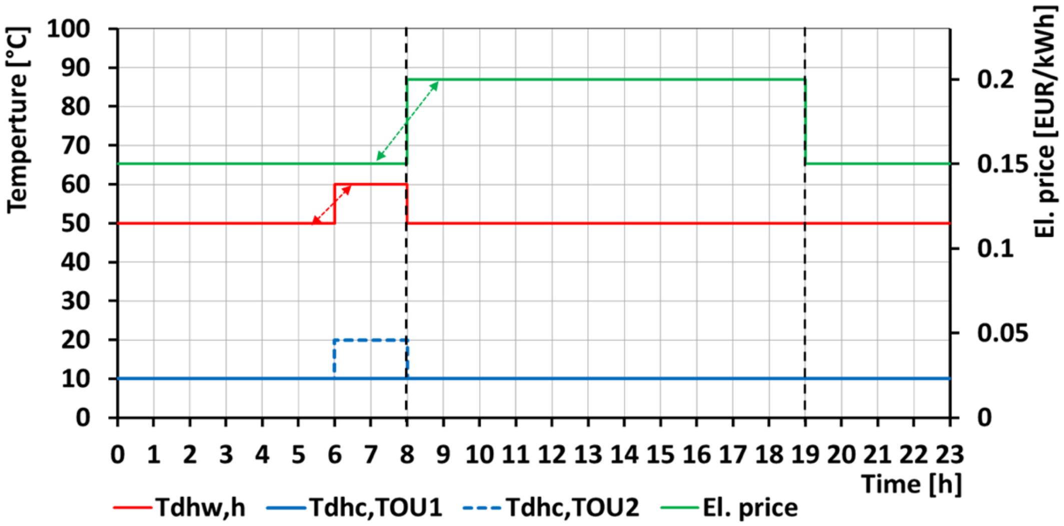


Figure 17. Temperature and price signal along a typical day.

Prices. For electricity prices, an off-peak electricity price of 0.15 EUR/kWh was assumed, while two cases were considered for the peak electricity price, namely 0.17 EUR/kWh and 0.20 EUR/kWh (exploited in different simulations). In this way, a minimal sensitivity analysis could be performed. Similarly, to cases for the network heat price were analysed: 0.05 EUR/kWh and 0.10 EUR/kWh.

DHC network temperature. Two cases for the network temperature were considered. In the first case the network is operated at a constant temperature of 10 °C. In the second case, an increase of the network temperature in correspondence with the DSM operation was allowed. This approach assumes an involvement of the network manager in the entire control. Without entering here in the details of how this temperature increase could be applied (one could for example imagine a higher temperature sources available only during part of the day, e.g., due to its low size with respect to the overall heat demand), this second case is relevant to understand the interplay between the network management and the substation operation. Synchronizing the network temperature increase with the tank temperature increase, the decay in the HP performance (i.e., the COP reduction) can be possibly avoided.

Results. The quantitative results obtained in simulations are summarized in the tables reported below, one for the energetic performances and the other for the economic performances. In general, it can be seen that the observed effects are small and that in some case the results are not favourable from the economic point of view. Moreover, the additional flexibility comes at a cost of a slight energy consumption increase. On the other hand, the energy shift from peak hours to off-peak hours can be of the order of 20 % (with respect to the reference peak hour consumption for DHW), already a sizable effect.

This work could be extended in several directions. First of all, the application of similar control strategies to the real-time pricing case could be considered. Additional points could involve parametric analyses of the tank temperature variation and of the tank size, possibly including space heating and space cooling buffers. Finally, a more detailed investigation of the coupling with the thermal network (both in terms of network temperature variations and in terms of combined effect of multiple substations) would be important.

It is also worth pointing out that the proper evaluation of these strategies would require to rank/score the value of electricity flexibility itself, possibly not only in terms of energy amounts and prices, but also in terms of power ramp smoothing. Similarly to the application of self-consumption maximization in the case of individual photovoltaics plants, a massive exploitation of these techniques could affect the shape of load curves in an important way.

Table 3. Energetic performances of the considered DSM strategies. The reference scenario refers to the case without DSM. The 2 TOU scenarios refer instead to the same DSM strategy, but applied with the two different network temperatures mentioned in the text.

		Unit	Ref. scenario	Scenario TOU1 Tdhc const. (10°C)	Scenario TOU2 Tdhc var. (10÷20°C)
DHW use	$SCOP_{DHW}$	-	2.36	2.32	2.42
	Qdhw,load	MWh	11.96	11.96	11.96
	Qdhw,in	MWh	16.20	16.21	16.21
	ΔQdhw,in	MWh		**0.01**	**0.01**
	Qloss	MWh	4.24	4.25	4.25
	ΔQloss	MWh		**0.01 (+0.24%)**	**0.01 (+0.24%)**
	Qstored,DR	MWh	0.38	1.36	1.27
	ΔQstored,DR	MWh		**0.98 (+258%)**	**0.89 (+234%)**
Electricity use	Eel,dhw peak hours	MWh	1.64	1.30	1.36
	ΔEel,dhw peak hours	MWh		**-0.33 (-20%)**	**-0.28 (-17%)**
	Eel,dhw off-peak hours	MWh	5.25	5.72	5.36
	ΔEel,dhw off-peak hours	MWh		**0.46 (+8.7%)**	**0.11 (+2.1%)**
	Tot Eel,dhw	MWh	6.89	7.02	6.72
	ΔEel,dhw	MWh		**0.13 (+1.8%)**	**-0.17 (-3.2%)**
DHC use	Qdhc TOU	MWh	9.53	9.41	9.70
	ΔQdhc	MWh		**-0.12 (-1.3%)**	**0.17 (+1.8%)**

Table 4. Economic performances of the considered DSM strategies. The reference scenario refers to the case without DSM. The 2 TOU scenarios refer instead to the same DSM strategy, but applied with the two different network temperatures mentioned in the text.

		Unit	Scenario TOU1A Tdhc const. (10°C)	Scenario TOU1B Tdhc const. (10°C)	Scenario TOU2A Tdhc var. (10÷20°C)	Scenario TOU2B Tdhc var. (10÷20°C)
	Peak hour Eel Price incr.	%	15%	30%	15%	30%
	Cel off-peak /Cel peak	-	0.87	0.77	0.87	0.77
	Eel prices off-peak hours	€/kWh	0.15	0.15	0.15	0.15
	Eel prices peak hours	€/kWh	0.17	0.20	0.17	0.20
	Tot Eel costs ref.	€	1070.5	1107.3	1070.5	1107.3
	Tot Eel costs TOU	€	1082.2	1111.5	1038.7	1069.3
	ΔTot Eel costs	€	**11.7(+1.1%)**	**4.2(+0.4%)**	**-31.8(-3%)**	**-38.0(-3.4%)**
C_{Qdhc}=0.05 €/kWh	Total costs Qdhc ref.	€	476.6	476.6	476.6	476.6
	Total costs Qdhc TOU	€	470.5	470.5	485.2	485.2
	ΔTot Qdhc costs	€	**-6.1(-1.3%)**	**-6.1(-1.3%)**	**8.6(+1.8%)**	**8.6(+1.8%)**
	Total costs ref.	€	1547.0	1583.9	1547.0	1583.9
	Total costs TOU	€	1552.7	1582.0	1523.8	1554.5
	ΔTot costs	€	**5.7(+0.4%)**	**-1.9(-0.1%)**	**-23.2(-1.5%)**	**-29.4(-1.9%)**
C_{Qdhc}=0.1	Total costs Qdhc	€	953.1	953.1	953.1	953.1
	Total costs Qdhc TOU	€	941.0	941.0	970.4	970.4
	ΔTot Qdhc costs	€	**-12.1(-1.3%)**	**-12.1(-1.3%)**	**17.2(+1.8%)**	**17.2(+1.8%)**

	Total costs ref.	€	2023.6	2060.4	2023.6	2060.4
	Total costs TOU	€	2023.2	2052.5	2009.0	2039.6
	ΔTot costs	€	**-0.4(-0.02%)**	**-7.9(-0.4%)**	**-14.6(-0.7%)**	**-20.8(-1%)**

9 Conclusions

In the initial chapters of this report, a multi-node energy system model has been created to simulate one year with hourly time-step. The model has been applied to the Italian electricity system. The baseline for the Italian electricity system has been created starting from real data for the year 2014.

The aim of the paper is to investigate and quantify the importance of multi-node versus single-node approach and the role of the already installed storage at the increasing of variable renewable energy sources installed power.

The results have shown the importance of the multi-node versus single-node approach in energy system modelling. The multi-node approach has resulted particularly important for a territory like Italy where the majority of the installed power and especially the potential of variable renewable energy sources is placed in the south of Italy while the installed capacity of pumped hydro storage is placed mainly in the North. The simulation highlighted how the current transmission grid with an increase of variable RES is not sufficient to absorb the over-generation from RES without congestion problems and curtailments. The single-node modelling approach has shown non-negligible differences with the multi-node approach. Indeed, the single-node model presents an under-estimation of the curtailments of about 7% and thus an over-estimation of the percentage of renewables in the system equal to 6.6%, considering the overall potential of VRES within the system.

Secondly, the potential benefits of pumped hydro storage in terms of integration of renewables have been inspected. The already installed capacity of pumped hydro storage has been considered and two different kinds of simulations have been run with the multi-node approach: with and without this storage in order to evaluate its contribution at the increasing of RES. PHS has resulted to have a central role in the future integration of RES. For this reason, at the increasing of variable renewable energy sources, in the electricity market a mechanism to privilege pumped hydro storage systems has to be created in order to exploit the renewables integration potential role of these plants.

The role of CCGT flexibility has been inspected integrating into the Oemof model constraints and additional costs of this type of plants. The considered constraints are time-dependent start-up, associated ramps and decay of efficiency at partial load. In particular, three type of start-ups are considered: cold, warm and hot start-ups. The Oemof _Transient model has been thus developed and applied to the Italian case studying scenarios with different level of penetration of intermittent renewable energy sources. The results showed the importance of considering this type of constraints and additional costs in the modelling. They depicted how the hourly dispatch is affected by these constraints and how at the increasing of intermittent renewable energy installed power the specific cost of cycling increase, reaching values in the order of 10 €/MWh.

A link section dedicated to the differences and similarities between transmission and distribution grids is also presented. A definition of energy district is also included to link the last part of the deliverable devoted to synergy between thermal and electric grids.

Finally, a chapter has been devoted to the topic of sector coupling – as an additional mean to enhance the grid flexibility – in particular considering the interaction of the electric grid (electric sector) with an innovative concept of district heating and cooling (thermal sector) based on decentralized heat pumps. In this context, heat pumps are the key link connecting the two sectors and can be exploited for DSM strategies. As a practical example, the report has presented a simple control logic for heat pumps where operation is influenced by the electricity price (in a time-of-use pricing scenario). This logic has been simulated in a full model of a single building connected to the district heating and cooling network, showing the possibility to shift from peak hours to off-peak hours up to 20 % of the electricity consumed for domestic hot water production. The obtained effect would then be scaled up when considering the entire heat pump pool of the network.

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