Electric Power Systems Research 96 (2013) 119–132

Contents lists available at SciVerse ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Effects of North-African electricity import on the European and the Italian power systems: a techno-economic analysis

C. Brancucci Martínez-Anido[a,c], A. L'Abbate[b], G. Migliavacca[b,*], R. Calisti[b], M. Soranno[b], G. Fulli[a], C. Alecu[a], L.J. de Vries[c]

[a] European Commission, Joint Research Centre, Institute for Energy and Transport, Westerduinweg 3, Petten, 1755LE, The Netherlands
[b] RSE (Ricerca sul Sistema Energetico) SpA, Milan, Italy
[c] TU Delft, Infrastructure Systems and Services Department, Energy and Industry, Jaffalaan 5, 2628BX, Delft, The Netherlands

ARTICLE INFO

Article history:
Received 7 May 2012
Received in revised form
11 September 2012
Accepted 1 November 2012
Available online 8 December 2012

Keywords:
Transmission planning
RES integration
Mediterranean Solar Plan

ABSTRACT

Several European initiatives consider the electrical integration of the Euro-Mediterranean region a key priority for meeting future European Union (EU) energy policy goals. Ambitious plans include the development of Renewable Energy Sources (RES) in the region as well as transmission interconnectors between the two shores of the Mediterranean Sea. The success of such initiatives, in addition to several techno-economic, political, environmental, regulatory and financial obstacles, depends on the ability of the European electricity network to suitably accommodate large electricity imports from North Africa. In order to address the issue, this paper, based on the combination of two methodologies, presents a first techno-economic analysis of the effects of electricity imports from North Africa on the European and the Italian power systems in 2030. Within a common framework, the adopted approach has proved its feasibility with coherent results showing a decrease in electricity prices in Europe. The European study shows how net electricity exchanges tend to follow the direction from South to North. The impact of North-African electricity on the Italian system is relevant. Also, Italy's potential of becoming a Mediterranean electricity hub is emphasised. National internal grid congestion results to be a crucial issue for the Euro-Mediterranean electrical integration.

1. Introduction: overview of the Euro-Mediterranean framework

Towards the achievement of the three main targets (system competitiveness, environmental sustainability, security of energy supply) of the European Union (EU) energy policy, the electrical integration of the Euro-Mediterranean region represents a key priority [1]. In the context of the ambitious EU 2020 and 2050 sustainability targets [2], particular focus is on the countries of the so-called MENA (Middle East and North Africa) region, which are located around (or close to) the Mediterranean Basin and feature a sizable potential for RES (Renewable Energy Source) generation. This has been the main trigger of the launch of the MSP (Mediterranean Solar Plan) by the EU in 2008. Also other initiatives [3,4] aim at fostering the development of RES generation in the MENA region and the related transmission interconnection capacity between the two shores of the Mediterranean Sea. However, towards these goals there currently exist several techno-economic, socio-political, environmental, regulatory and financing issues [5]. Additional obstacles arise from transporting North-African energy to the large consumption centres located in Central Europe. The success of the various, ambitious initiatives [3–5] depends on the ability of the European transmission grid to accommodate massive (RES but also non-RES, mainly gas-based) power injections from Africa. These may add on other large RES-based flows from South Europe, mostly due to boosting solar penetration. Considering increasingly large flows from North and North-West Europe (mainly due to onshore and offshore wind generation), it has to be expected that in the future significant bottlenecks will arise in the European transmission system. For this reason, the European network will need to be reinforced considerably [6]. The need for a pan-European highway for integrating large volumes of RES has

Abbreviations: CSP, Concentrated Solar Power; EC, European Commission; EHV, Extra High Voltage; ENTSO-E, European Network of Transmission System Operators for Electricity; EU, European Union; GIL, Gas Insulated Line; HV, High Voltage; HVAC, High Voltage Alternating Current; HVDC, High Voltage Direct Current; LV, Low Voltage; MCFP, Minimum Cost Flow Problem; MENA, Middle East and North Africa; MSP, Mediterranean Solar Plan; MV, Medium Voltage; NTC, Net Transfer Capacity; OPF, Optimal Power Flow; PST, Phase Shifting Transformer; PV, Photovoltaic; RES, Renewable Energy Source.

* Corresponding author. Tel.: +39 02 39925489; fax: +39 02 39925557.
E-mail addresses: carlo.brancucci@ec.europa.eu (C. Brancucci Martínez-Anido), angelo.labbate@rse-web.it (A. L'Abbate), gianluigi.migliavacca@rse-web.it (G. Migliavacca), roberto.calisti@rse-web.it (R. Calisti), michela.soranno@rse-web.it (M. Soranno), gianluca.fulli@ec.europa.eu (G. Fulli), corina.alecu@ec.europa.eu (C. Alecu), l.j.devries@tudelft.nl (L.J. de Vries).

0378-7796/$ – see front matter © 2012 Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.epsr.2012.11.001

been highlighted by the European Commission (EC) in its recent energy infrastructure policy documents [1,7] as well as by ENTSO-E (European Network of Transmission System Operators for Electricity) [8].

In this situation, the key roles of Italy and Spain, the closest countries to Africa, clearly emerge. In Italy, some critical sections of the two north-south transmission backbones (along the Tyrrhenian and the Adriatic Seas) are nowadays regularly congested and they would be even more stressed by the foreseen large power flows from Africa. In addition, the geographically closest injection areas for energy import (Sicily and Sardinia) are both weakly connected to the mainland. Due to its peculiar geographical position, favourable for importing energy both from North Europe and from Africa, Italy may become an important Mediterranean electricity hub. Depending on the prevailing flow, the internal Italian network could be stressed in a completely different manner.

Against this background, the present paper describes two tightly interrelated studies, both within a 2030 time horizon for network layout, generation set and system demand evolutions: one from a European perspective and one from a national (Italian) perspective. The former study investigates the effect of North-African imports on the global European power system in terms of cross-border electricity flows and total marginal generation costs (corridor-based approach). The latter, taking account of border conditions from the former study, performs an in-depth analysis of the impact of North-African imports on the Italian grid, highlighting system criticalities and possible solutions on a national/regional scale in Italy (grid-based approach). The reference time horizon chosen for the present analysis is 2030 in accordance with TSOs' studies that most realistically consider bulk power transport between North Africa and South Europe as feasible not before 2030 [6,28]. In this paper, Section 2 describes the integrated approach in terms of methodology, scenarios and data inputs for both the European and the Italian studies. Section 3 introduces the scenarios for the Mediterranean interconnections. Section 4 illustrates the results of both performed analyses. Section 5 draws conclusions and provides an outlook for further work.

2. The adopted methodology for an integrated approach

2.1. The European model

The impacts of North-African energy imports on the European system in 2030 have been studied with the use of EUPowerDispatch, a minimum-cost dispatch model of the European electricity transmission network developed by the Smart Electricity Systems research group at the Institute for Energy and Transport of the European Commission's Joint Research Centre introduced in [9]. EUPowerDispatch is a mixed-integer linear program which solves a Minimum Cost Flow Problem (MCFP), taking into account generation and transmission corridor constraints. The model inputs and outputs are managed and edited within Matlab [10]. The optimisation, instead, is coded in the General Algebraic Modeling System (GAMS) [11] using CPLEX [12], a high-performance mathematical programming solver from IBM. Its objective function is the minimisation of the annual variable electricity production costs in the interconnected European power system. Variable electricity generation costs, different for each energy source, comprise variable maintenance and operational costs, fuel costs and CO_2 taxes.

The model examines the European electricity system in 2030 by taking into account the impact of imports from North Africa. The model includes 32 nodes, each representing a European country ("copper plate"), and 72 equivalent interconnections, each representing a European cross-border corridor. In addition, the interconnections between North Africa and Southern Europe (Spain and Italy) are included and studied for the selected scenarios.

EUPowerDispatch models one year with 52 weekly simulations with 1-h time-steps. A preliminary yearly run with weekly time-steps sets the hydro seasonal reservoir levels at the start and end of each week. Simulating a whole year with 1-h time-step is not possible given the large number of variables and the limited available computational capabilities. However, as hydro reservoirs are the only storage elements with an annual management in the model, it is assumed that the other variables, such as generation levels and cross-border electricity flows, can be computed by 52 different weekly simulations. The main model inputs are the installed net generation capacities, load time-series at each node, cross-border transmission capacity limits, weather data (including solar radiation, wind speed, run of river flows and hydro reservoir inflows) and variable electricity production costs for each energy source type. The main model outputs include generation levels, cross-border flows, marginal variable electricity production costs and CO_2 emissions.

The electricity load is modelled using 1-h time-series for each European country (starting from ENTSO-E data [13]). Installed net generation capacities at each node are represented for different energy sources including nuclear, fossil fuels, hydro and renewable energies. A virtual power plant for each energy source representing the total installed generation capacity is modelled at each node. The preliminary assumption is that generation technologies features are kept in consistency with the ones of currently available types. Different availability factors, accounting for planned and unplanned unavailability, are considered, such as e.g. 84.5% for nuclear [14] and 90% for fossil-fired power plants [15]. Reserves are not modelled separately, they are assumed to be included within the availability factors and partly considered when fixing the minimum operational power plant output levels; e.g. for nuclear energy sources, the virtual power plant in a country is assumed to be able to vary its power output between 70 and 100% of the available rated power. These constraints are also included to restrict ramping rates. In the case of gas, oil and mixed fuels (gas and oil) fired power plants, which are considered fast-reacting units, the power output is assumed to vary as necessary between shut-down and maximum available power.

Power plants based on lignite and hard coal are considered differently than the other fossil fuel-based generation plants due to their operational characteristics regarding start-up time, ramp-up rate and shut-down time. The same approach is used for both types of plants. The total installed generation capacity in a country is divided into single units with a rated available power around 750 MW and represented by a binary variable which describes their operation, in other words, if they are turned on or switched off. The binary values, which transform a linear program into a mixed integer linear program, are implemented in order to keep the time between shut-down and start-up and vice versa to a minimum of 4 h. This short time represents a hot start-up. However, a more realistic approach would include larger start-up and shut-down times, which cannot be implemented due to computational constraints, as the number of equations and hence the computation time increase as minimum start-up time increases. The power output of each unit is limited between 70 and 100% of their rated power.

Hydro power plants are classified in three categories: run of river plants with an uncontrollable generation which depends on natural inflows; seasonal storage plants with an upper reservoir which is fed by a natural inflow and which is managed with seasonal and daily strategies; pure pumping plants which have a daily dispatch strategy and where water is pumped from a lower reservoir into an upper one with no natural inflow. An ideal flexibility is assumed with negligible start-up, shut-down, ramp-up or ramp-down costs. Reservoir levels are optimised for overall variable electricity

Table 1
Electricity variable production cost per energy source (Euro/MWh).

Nuclear	Lignite	Hard coal	Gas	Oil
11.0	62.9	55.0	61.9	108.7
Mixed fuels	Hydro	Wind	Solar	Biomass
114.5	3	2	0	53.1

production costs only and the lower limits are set to 30% on seasonal reservoir levels in order to partially consider environmental and landscape constraints. Round trip pumping efficiency is assumed to be 75%.

Renewable Energy Sources including wind (both onshore and offshore), solar (photovoltaic, PV, and concentrated solar power, CSP) and biomass are modelled using the same approach of a virtual power plant per country/node. 6-h wind speed time-series [16], linearly interpolated in time, with 2.5° latitude–longitude spatial resolution, are used together with regional installed wind farm installed capacity data [17] in order to obtain average onshore and offshore wind power outputs for each hour of the year for each country. For solar energy, 1-h solar radiation time-series [18] have been used to represent the energy output delivered to the grid with 1.51° latitude–longitude spatial resolution. Due to data unavailability, PV installed capacity is assumed to be equally distributed across a single country. For biomass, the virtual power plant at each node is only constrained by the installed generation capacity. Its weekly availability is kept at 50% in order to take into account the fuel's accessibility. In addition, geothermal energy, modelled as a negative load, is only considered for Italy in order to keep a consistency with the detailed Italian model.

Electricity transfer between the 32 European nodes is represented by 72 equivalent corridor interconnections defined by their bi-directional maximum net transfer capacities. Network losses, comprising distribution and national transmission losses, are included in the load time-series. However, cross-border transmission is also subject to relatively small losses. These cross-border transmission losses are assumed to be proportional to the surface areas of the two bordering countries (consequently, transmission losses between two small countries are smaller than between two large countries). This assumption has been made in order to represent, in the model with one node per country, the fact that line losses increase with distance. Otherwise, cross-border flows through very long distances across Europe would appear unrealistically attractive. In addition, the electricity interconnectors from North Africa, included in the model, are assumed to be constantly available to carry their capacity. Also, the electricity flowing across them from Africa to Europe is assumed to have a constant variable cost.

Concerning the data inputs for building up the 2030 European study model, the installed generation capacities for each energy source in the analysed European countries are based on the 2025 Best Estimate Scenario of ENTSO-E's Scenario Outlook & Adequacy Forecasts (SO&AF) 2011–2025 [19]. The notable exceptions are represented by the systems of Italy and Germany for which the scenario dataset has been updated taking into due account the German nuclear phase-out plans, the Italian current situation related to the dismantling of the nuclear programme, and the Italian and German extremely large deployment of PV installations [31]. The same ENTSO-E scenario is used to calculate the expected electricity consumption increase in Europe between 2010 and 2030 [20].

Table 1 shows the variable electricity production costs that are assumed for 2030 in every European country. The values are based on the data used in TradeWind [21], assuming a CO_2 tax of 35 Euro/tonne. The variable production cost of electricity from North Africa is assumed to be 41.25 Euro/MWh, which is lower than European fossil-fired sources but higher than European nuclear sources. This value takes also into account the fact that the interconnections from North Africa, as originally planned, will also serve to dispatch thermal (mainly gas-based) generation. In a sensitivity analysis, this North-African generation cost is varied to a value of 10.52 Euro/MWh, taking into account a much higher solar contribution with respect to the thermal one.

To construct a scenario for the evolution of the cross-border transmission system in Europe from the current state (2010–2011) to 2030, an approach similar to the one developed and utilised within REALISEGRID [22] and SUSPLAN [23,24] has been followed. To perform a projection of the future development of European cross-border interconnections from 2010–2011 up to 2030, the information and the data contained in several public sources regarding existing interconnection projects (ongoing, planned, under study, potential) in Europe have been used [6]. The aim has been to determine the values of the future 'maximum cross-border transmission capacity'[1] (for both flow directions at each border) in the European system, starting from the reference year 2010[2] [8,22]. In absence of information about the expected net capacity increase provided by the single expansion project, opportune assumptions have been made, also based on the fact that, due to existing internal network constraints, only a quota of the theoretically available capacity increase can be effectively considered as net capacity increment[3] [24,31]. Fig. 1 shows the assumed level of net cross-border capacities in Europe at 2030.

EUPowerDispatch is a tool for analysing the impacts of electricity patterns on the European cross-border transmission system due to its high 1-h time resolution over a time span of one year, its high resolution wind speed and solar radiation data and its annual management of large scale hydropower storage resources. The model takes account of the aggregated generation representations at country level for each energy source and does not represent the internal transmission network for each national system (copperplate or corridor-based approach). These two features, due to data availability and computational capabilities, do not however limit the scope of the European analysis presented in this article, whose aim is to provide an overall picture of the pan-European system, before analysing grid level details.

2.2. The Italian model

The Italian study is tightly and consistently interrelated with the European approach. The method for evaluating the impact of the electricity imports from North Africa on the Italian system at 2030, differently from other studies (see for instance [32]), is based on a transmission planning oriented approach. This consists in the analysis of grid simulation results for the Italian system in which 2030 scenarios for generation, load demand, fuel costs, CO_2 penalty tax and cross-border interconnections have been considered while the internal transmission network (at 220 and 380 kV level, also including equivalent injections from 132/150 kV grid portions) has been taken into account as frozen in its 2020 shape. The purpose is then to investigate how congested the transmission network might be in 2030, given the different boundary conditions, including the new interconnections, also comprising the ones with North Africa, according to the different case studies. The Italian

[1] This definition has been meant to be more proper than the one of NTC (Net Transfer Capacity), because the (present and future) NTC estimation can be only carried out by TSOs (Transmission System Operators) and is officially published by ENTSO-E. However, the two concepts are similar.

[2] In case of discordant NTC values between TSOs at the same border and flow direction, the choice to consider the highest value of the two possible options has been made.

[3] This situation is assumed not to change by 2030.

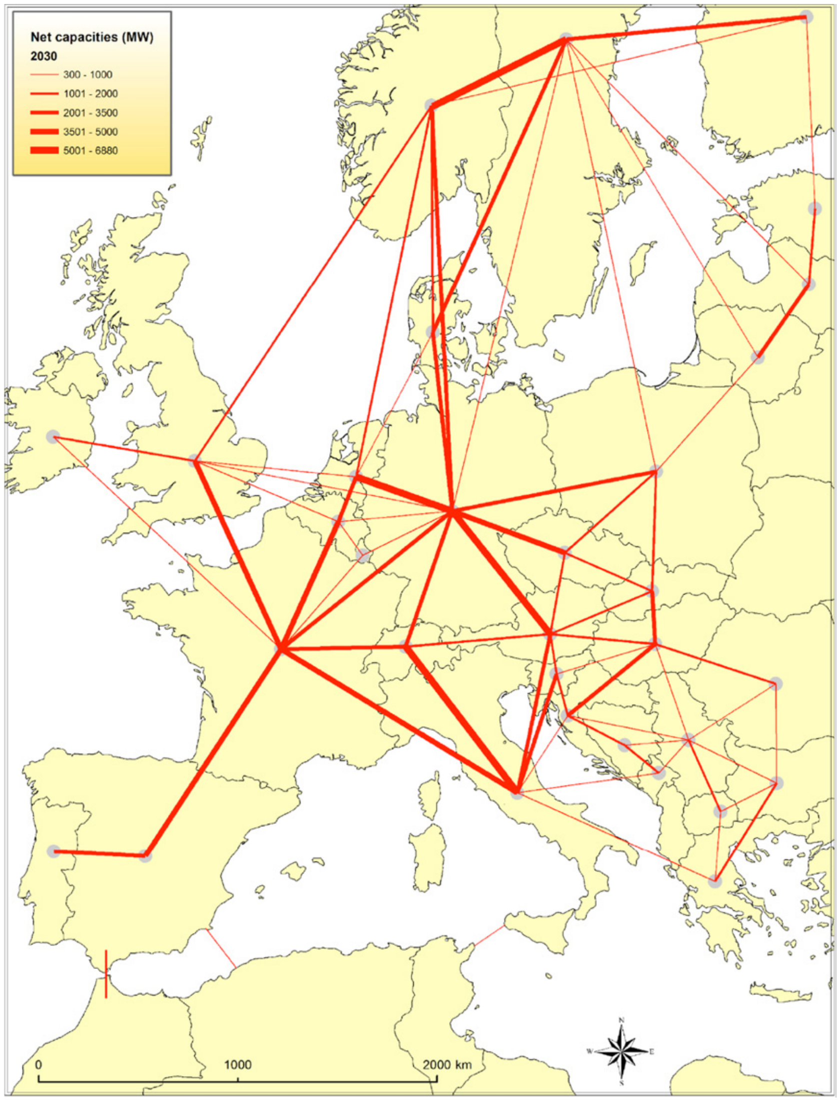

Fig. 1. The assumed net cross-border capacities in Europe at 2030.

study is carried out using the tool REMARK [25], able to conduct an OPF (Optimal Power Flow)-based analysis integrated by a non-sequential Montecarlo methodology for static reliability investigation of complex liberalised electric systems divided in areas. This tool features full network representation by the simplified direct current model; variable wind generation is treated by the Montecarlo methodology as well. REMARK is able to perform a quantitative assessment of the reliability and economic benefits, as well as other types of benefits, derived by transmission network expansion [26,31].

To model the inputs for the Italian study, the Italian power system situation at 2010 has been considered as starting point for building up the 2030 scenarios. Table 2 introduces the amounts of the installed net generating capacity for Italy used for both European and Italian studies. Several references have been duly taken into account as sources of the data for the present (2010–2011) situation as well as for the estimation of the future (2020 and 2030) evolution of the generation park in Italy [19,27,31]. In particular, the trends emerged during 2011 concerning the boosting penetration of PV (recorded by over 12,000 MW capacity level in 2011), the PV incentive target (23,000 MW capacity installed by 2016) and the interruption of the nuclear programme have been fully considered for this estimation [31].

In Italy, a continuously increasing generation quota, especially by RES (like PV and biomass in addition to hydroelectric and geothermal sources), is distributed over the downstream (LV–MV[4] distribution) grids. Since the focus of this study is on transmission and its grid-impacting generation, most downstream production units have been taken into account either directly or indirectly (via compensation balance of local loads). While wind capacity is fully taken into the picture [28], of the total RES biomass capacity, 4180 MW, assumed in Italy for 2030, 2228 MW represents the amount considered located on downstream (LV–MV) networks [31]. Concerning solar capacity, 5.4 GW (15% of the total) has been assumed to be connected to the HV/EHV level in Italy at 2030, directly impacting on the transmission system.

Further steps in the 2030 generation scenario build-up have consisted first in the regional breakdown and then in the repartition among the connection voltage levels of the different generation capacities, where relevant, based on [27,28] and on opportune assumptions [31]. This evaluation has led to the choice of location of nodal injections by the various generation sources in the

[4] LV: Low Voltage; MV: Medium Voltage; HV: High Voltage; EHV: Extra High Voltage.

Table 2
Total installed net generating capacity in Italy (in MW).

Source	2010	2020	2030	Source	2010	2020	2030
Hydroelectric	21,521	22,000	23,000	Biomass	4832	6340	6700
Geothermal	728	920	1086	Nuclear	0	0	0
Solar (PV)	3470	28,600	35,000	Thermal (coal)	6600	7000	7000
Solar (CSP)	0	600	1000	Thermal (gas)	50,979	60,089	64,000
Wind (onshore)	5794	12,000	20,000	Thermal (oil)	8179	4235	4000
Wind (offshore)	0	680	1000	Thermal (mixed)	6811	7113	7113

Table 3
Average yearly load growth rate in Italian areas.

Area	% 2010–2021	% 2021–2030	Area	% 2010–2021	% 2021–2030
North	1.6	1.0	South	2.3	1.0
Center	1.8	1.0	Islands	1.6	1.0

transmission grid. Concerning wind generation, it is modelled by REMARK according to specific hourly profiles (for both onshore and offshore installations) and is granted dispatch priority. The wind profiles used for the Italian areas are based on the ones used in [24]. Similarly, but with their own profiles, other RES (based on PV, RES biomass, hydroelectric and geothermal sources) are also taken into account by REMARK and dispatched with priority. To calculate the PV generation in Italy, the actual PV output has been taken into account by data available in [18]. On the other hand, the thermal (non-RES) generation is treated to simulate a merit order dispatch: it is then priced based on the variable generation costs adopted in the European study (see Table 1) and dispatched from the most convenient generation source up to the marginal one, given the system, zonal, interconnection and nodal constraints [25]. The estimation of the national hourly demand for 2030 has been based starting from the 2010 data for the total energy consumption and the hourly load profiles specified for each region. To represent the scenario up to 2030, an average yearly growth rate has been applied to these regional profiles over the years, keeping the area distinction, as shown in Table 3,[5] and taking into due account the available forecasts [19,29]. The total energy consumption in Italy at 2030 consistently corresponds to the total value assumed in the European analysis for Italy.

Upon building up the load profiles, reduced by the RES amounts injected in the downstream (MV–LV) distribution, a discretisation is needed to better allow REMARK to cope with a huge amount of data with a lower calculation time. Therefore, four time-slices have been set to draw the load over every day, distinguishing working and weekend day for each of the four seasons, resulting in 32 time-slices for a year. It has to be highlighted that the choice of hourly profiles subdivision has been also based on the impact of large PV penetration on peak load over the daily hours in the diverse seasons.

Concerning the transmission network evolution, the new interconnections foreseen and planned up to 2030 have been taken into account. These include the three submarine links of Italy with North Africa, namely with Algeria (via Sardinia) and with Tunisia and Libya (both via Sicily). The starting point of this analysis has been the opportune adaptation of the 2020 Italian grid model developed in [30] and updated with the most recent and relevant reinforcements contained in [28]. Table 4[6] displays the list of existing and future cross-border transmission interconnections around Italy taken into consideration in the 2030 study (in accordance with the set scenarios) [6,28]. The corresponding net capacity values between Italy and bordering countries have been calculated according to the approach described in [22,24] (recalled in Section 2.1) and have been used first in the European study and then in the Italian specific case.

In order to take into account the effect of cross-border flows (import and export) across Italian borders, a simplified, yet effective, modelling approach has been followed towards an extended merit order dispatch. Within REMARK the bordering foreign buses have been modelled as connection points of both equivalent generating units and loads: the generators are considered like thermal power plants participating in the merit order with the corresponding hourly marginal costs resulting from the European analysis. The exceptions to the approach of using equivalent generators concern the links with Malta and with Corsica (France), where only a load is seen on the foreign side. Finally, opportune assumptions, also based on current and future system evolutions in Albania, have been made to include the corresponding Albanian generation and load in the 2030 model by an equivalent bus representation.

The Italian system model used in the study consists of 1042 buses, 556 generating units, 856 lines, 479 transformers.

Finally, the approach followed for the Italian study, as here formulated and performed, much differs from the one used in other works, as for instance in [32]. In fact, the analysis in [32] aims at investigating the impact of large RES-generated electricity imports from North Africa on the Italian power market: this is merely based on a zonal approach, towards the investigation of the impact of North-African imports on Italian zonal market prices. On the other hand, the present analysis performs a grid-detailed study, too. Furthermore, the conditions of the Italian electricity market and power system, as well as the related scenarios, data and assumptions of the present study are very different from the ones used in [32]. Also the tools adopted for carrying out the two analyses on the Italian system present different features [25,32].

3. The Mediterranean interconnection scenarios

Four synchronous areas can be recognised around the Mediterranean basin: the European continental network, to which north western Maghreb countries (Morocco, Algeria and Tunisia) are

[5] The Italian areas are subdivided as in the following: North (Piedmont, Valle d'Aosta, Lombardy, Trentino Alto Adige, Friuli Venetia Giulia, Liguria, Emilia Romagna), Center (Tuscany, Umbria, Marche, Lazio), South (Abruzzo, Campania, Molise, Apulia, Basilicata, Calabria), Islands (Sicily, Sardinia).

[6] HVAC: High Voltage Alternating Current; HVDC: High Voltage Direct Current. It has to be remarked that some links in Table 4 refer to existing interconnections to be expanded, like the one between Italy and Greece (from 500 MW to 1000 MW) or to be repowered, like the one between Italy and France (Corsica) (from 300 MW to 600 MW). The Italy–Austria link to Thaur via Brennertunnel may be based on HVAC via GIL (Gas Insulated Line) technology or on HVDC. The Italy–Malta link is based on 220 kV HVAC submarine cable. It has to be also said that on many cross-border links with the Alpine region (France, Switzerland, Austria, Slovenia) power flow controlling devices like PST (Phase Shifting Transformers) exist or will be installed, to increase the cross-border capacity and overcome congestions.

Table 4
Interconnections at Italian borders considered in 2030 scenario.

Node	Country	Node	Country	Type
Tivat	Montenegro	Villanova	Italy	HVDC (future)
Zuwarah	Libya	Chiaramonte	Italy	HVDC (future)
El Haouaria	Tunisia	Partanna	Italy	HVDC (future)
El Hadjar	Algeria	Rumianca	Italy	HVDC (future)
Arachthos	Greece	Galatina	Italy	HVDC (existing)
Candia	Italy	Konjsko	Croatia	HVDC (future)
Divača	Slovenia	Redipuglia	Italy	HVAC (existing)
Okroglo	Slovenia	Udine ovest	Italy	HVAC (future)
Divača	Slovenia	Padriciano	Italy	HVAC (existing)
Volpago	Italy	Lienz	Austria	HVAC (future)
Cardano	Italy	Thaur	Austria	HVAC or HVDC (future)
Glorenza	Italy	Nauders/West Tirol	Austria	HVAC (future)
Babica	Albania	Brindisi Sud st.	Italy	HVDC (future)
Robbia	Switzerland	Tirano/S. Fiorano	Italy	HVAC (existing)
Cagno	Italy	Mendrisio	Switzerland	HVAC (existing)
Musignano	Italy	Lavorgo	Switzerland	HVAC (existing)
Morbegno	Italy	Lavorgo	Switzerland	HVAC (future)
Mese	Italy	Soazza	Switzerland	HVAC (existing)
Verderio	Italy	Sils	Switzerland	HVDC (future)
Mese	Italy	Gorduno	Switzerland	HVAC (existing)
Avise	Italy	Riddes	Switzerland	HVAC (existing)
Valpelline	Italy	Riddes	Switzerland	HVAC (existing)
Ponte	Italy	Airolo	Switzerland	HVAC (existing)
Pallanzeno	Italy	Serra	Switzerland	HVAC (existing)
Grand'ile	France	Piossasco	Italy	HVDC (future)
Rondissone	Italy	Albertville	France	HVAC (existing)
Venaus	Italy	Villarodin	France	HVAC (existing)
Broc carros	France	Camporosso	Italy	HVAC (existing)
Maghtab	Malta	Ragusa	Italy	HVAC (future)
Lucciana	France (Corsica)	Codrongianus	Italy	HVDC (existing)
Lucciana	France (Corsica)	Suvereto	Italy	HVDC (existing)

synchronously coupled; the system of the interconnected north eastern Maghreb (Libya, Egypt) and Mashreq countries (Jordan, Syria and Lebanon); the system of Israel and Palestinian Territories; the network of Turkey. Upon completion of ongoing developments, the Turkish system is expected to be fully synchronised with the European continental network by 2013 (a trial parallel operation of the two systems is currently in place) [5,8]. For the interconnection expansion between North-African and European systems, realistic estimations have been carried out, shifting the implementation of very ambitious plans (like the ones in [3,33]) to the post-2030 period. Thus, each corridor analysed at the cross-Mediterranean interface, namely at Spain–Morocco, Spain–Algeria as well as at Italy–Tunisia, Italy–Algeria, Italy–Libya borders, in the most optimistic scenario has been considered as carrying a maximum NTC equal to 2000 MW. In order to analyse the effects of power imports from Africa on the interconnected European electricity system and the Italian grid, three main scenarios, pessimistic ("A"), reference ("B") and optimistic ("C"), are assumed in terms of the interconnectors between North Africa and Europe and their maximum transfer capacity. Table 5 shows the maximum transfer capacities from Africa for the three scenarios (see also Fig. 2). In addition, in order to better understand the effects and the possible benefits of importing electricity from Africa, the model is run for a scenario with no power imports from Africa (scenario "D"). Finally, a sensitivity analysis based on the optimistic scenario with the African interconnectors is performed by lowering the African electricity variable production cost (from 41.25 to 10.52 Euro/MWh) below the European electricity variable production cost for nuclear sources, varying therefore the merit order (scenario "C1").

4. Test results

4.1. European study

EUPowerDispatch has been run for each of the previously defined 2030 scenarios. The European perspective on power imports from North Africa in 2030 is assessed in terms of three variables: the annual cross-border net exchanges, the hourly marginal energy source in each European country and the economic impacts of the power imports from Africa on the total annual variable electricity generation costs in Europe.

The main and most visible finding is that in each of the three scenarios, the interconnectors between North Africa and Italy are practically 100% loaded during every hour of the year. The interconnectors between North Africa and Spain are also fully loaded during 99.9% of the hours of the year. In the case of Spain, the results of scenario C show how there are very few hours of the year during which the cheaper local energy sources (including hydro, wind, solar, nuclear) and in some cases the imports (mainly from Portugal) are sufficient for meeting the local load and therefore the power imports from Africa are not needed. In other few hours of the year the African imports are the marginal energy source in Spain (and/or Portugal) and the interconnectors are not fully loaded. Fig. 3 shows the Spanish energy mix (for scenario C) for a 12-h period in

Table 5
Interconnection capacities between Africa and Europe for the three main scenarios.

Interconnector	Pessimistic scenario ("A")	Reference scenario ("B")	Optimistic scenario ("C")
Morocco–Spain	1400 MW	2000 MW	2000 MW
Tunisia–Italy	1000 MW	1000 MW	2000 MW
Algeria–Spain	1000 MW	1000 MW	2000 MW
Algeria–Italy	–	1000 MW	2000 MW
Libya–Italy	–	1000 MW	2000 MW

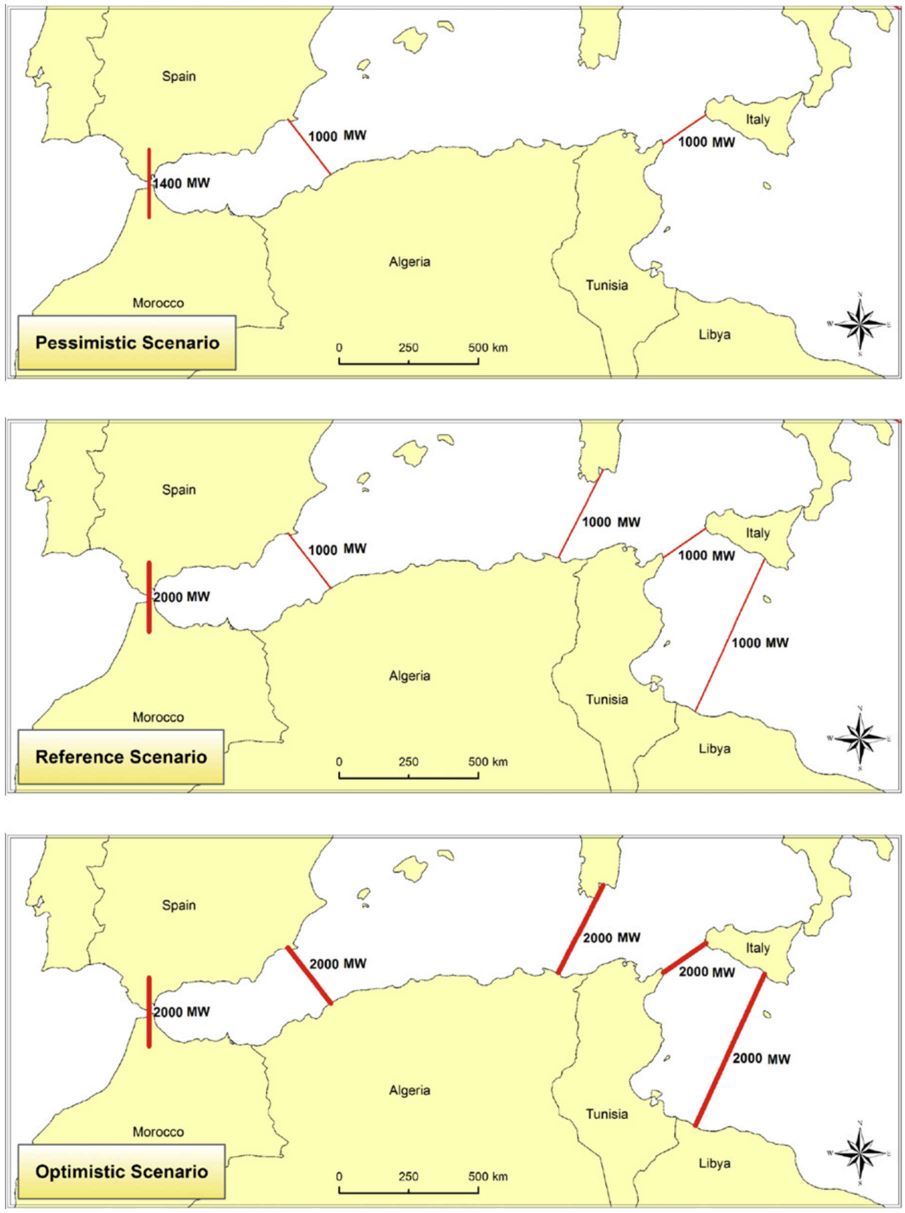

Fig. 2. The three main 2030 scenarios for the interconnection between North Africa and Europe.

February during which the electricity imports from North Africa are only partially needed or not needed at all due to the low electricity demand and the availability of cheaper energy sources (nuclear, hydro and wind) during few hours. In addition, it can be observed how the excess wind is exported (to both neighbouring systems of France and Portugal) and pumped into the hydro reservoirs.

Fig. 4 shows the annual cross-border net exchanges in Europe in each of the three main scenarios. A first observation is that the net power exchanges tend to follow the direction from South to North. In addition, in contrast with the present situation, Spain and Italy are net exporters of electricity. Together with the expected high installed generation capacities of wind and solar sources in Spain and Italy, the power imports from Africa contribute strongly to this behaviour. The optimistic scenario, which represents a larger import from Africa, shows higher Italian and Spanish power exports than the reference and pessimistic scenarios do. It is important to highlight the assumption behind the European analysis that the North-African power imports and/or the Spanish and Italian exports are not limited by internal transmission congestions or loop flows. The Italian study in the next section analyses this issue more in detail by focusing on the Italian grid in all its aspects.

An interesting result of the European study is the number of hours in a year during which each of the energy sources is the marginal generation technology in Italy, Spain and their neighbouring countries. As shown in Table 6, gas is the marginal energy source during the majority of the hours of the year. As interconnection capacities between North Africa and Europe increase, the number of hours during which African generation is marginal increase in Spain and Portugal. In addition, there are few hours during which hydro power is the marginal source. During these hours the interconnectors between Africa and Spain are not used as previously mentioned. For Italy, instead, the African imports, in this analysis, do not represent in any scenario the marginal source, which is consistent with the finding that the African interconnectors to the Italian grid are practically constantly 100% loaded (the situation will however look different in the Italian study considering the whole national system and the internal grid bottlenecks). Furthermore, the imports from Africa cause changes to marginal

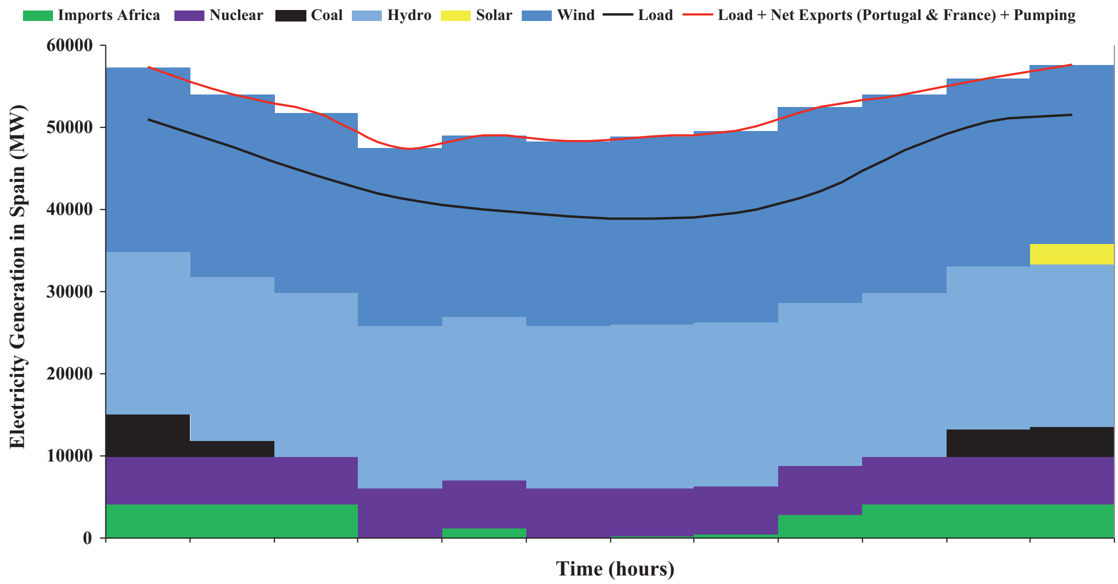

Fig. 3. Energy mix for Spain in period of none or marginal imports from North Africa.

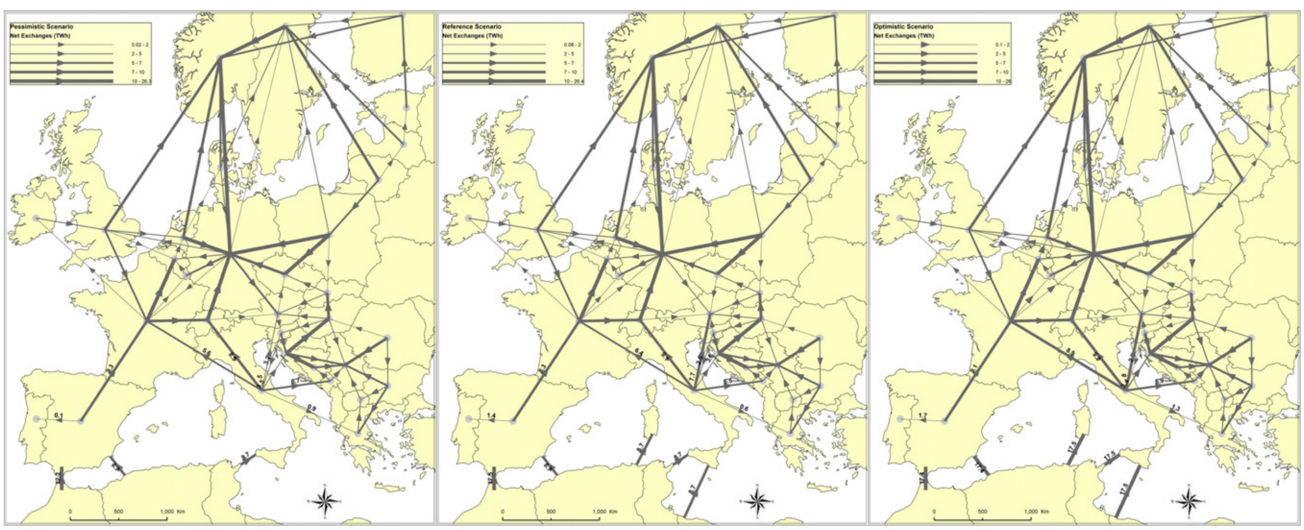

Fig. 4. Annual cross-border net exchanges for the pessimistic, reference and optimistic scenarios.

Table 6
Hours of marginal energy sources.[a] Number of hours in the year during which an energy source is the marginal generator in a country.

Energy source/country	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
Scenario without African power imports (“D”)											
Hydro	0	22	0	0	14	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	0	0	0	0	0	0	0	0	0	0	0
Biomass	58	30	31	0	8	0	0	0	0	0	0
Coal	139	281	45	3	40	2	3	3	3	3	9
Gas	8538	8402	8283	8733	8234	6802	8666	8666	8496	8434	8444
Lignite	1	1	370	0	440	1932	67	67	237	299	283
Oil	0	0	7	0	0	0	0	0	0	0	0
Optimistic scenario (“C”)											
Hydro	0	22	0	0	14	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	60	26	0	0	0	0	0	0	0	0	0
Biomass	138	84	33	1	6	0	0	0	0	1	0
Coal	262	339	65	21	46	4	15	15	15	20	21
Gas	8276	8265	8252	8714	8290	6779	8654	8654	8482	8408	8423
Lignite	0	0	379	0	380	1953	67	67	239	307	292
Oil	0	0	7	0	0	0	0	0	0	0	0

[a] AT: Austria; CH: Switzerland; DE: Germany; ES: Spain; FR: France; GR: Greece; HR: Croatia; IT: Italy; ME: Montenegro; PT: Portugal; SI: Slovenia.

Table 7
Economic evaluation.

Scenario	A	B	C	C1	D
Annual system variable generation cost (Billion €)	134.16	133.70	132.98	130.29	134.76
Annual savings compared to scenario D (Million €)	605	1071	1786	4469	N/A
Annual electricity generation in Africa (TWh)	29.69	52.39	87.29	87.35	N/A
Annual African variable generation costs (Billion €)	1.225	2.161	3.601	0.919	N/A
Annual threshold value for investment (Billion €)	1.830	3.232	5.387	5.388	N/A

generation sources throughout the year in the entire European power system causing lower electricity prices, although the effects decrease from South to North.

It is also important to mention that the electricity imports from North Africa replace gas (mainly) and coal (slightly) – fired power plants generation. The reduction of electricity generation from gas and coal increases as the electricity imports from North Africa increase. However, the maximum power output from gas power plants is not reduced during the year in any European country (apart from Spain) due to the electricity imports from North Africa. The only exception concerns Spain whose maximum gas power output is reduced by 536 MW in the optimistic scenario ("C"). These results show the key role of gas-fired power plants in electricity network with high penetration of variable Renewable Energy Sources. In addition, it is shown that as electricity imports from North Africa increase, the need for back-up gas-fired power plants decreases (as shown for Spain). However, if cross-border interconnection capacities would increase, gas-fired power plants could be needed and used more to export electricity to Northern Europe, especially in period of low wind.

A sensitivity analysis has been performed by using the optimistic scenario and assuming a lower variable generation cost for North-African imports. The results are very similar in terms of the overall behaviour of the European power system. A small change occurs in the loading of the interconnection between Africa and Spain. Due to the lower variable generation cost, more power is transported from Africa to Spain. However, this difference is almost insignificant due to the already extremely high average loading of such cross-Mediterranean interconnectors.

Finally, the three main scenarios ("A", "B", "C") and the one used for the sensitivity analysis ("C1") are compared to the scenario without North-African imports ("D") in terms of annual electricity variable generation costs for whole Europe. Table 7 shows the savings in terms of annual variable generation costs for each of the 4 scenarios compared to the one without interconnections between North Africa and Europe.

The fourth scenario ("C1") shows a much higher potential for savings due to the lower variable generation cost of the electricity produced in Africa. However, this difference (between scenarios "C" and "C1") does not affect the threshold value below which the investment would be profitable. The threshold value, which is also provided in Table 7, gives the value below which the investment annuity of importing power from North Africa to Europe can be profitable. The investment annuity should be calculated considering the overall project's lifetime, the "annual-correspondent" generation and transmission investments and the annual fixed and variable generation costs.

4.2. Italian study

The same boundary conditions seen in the European study have been applied to the Italian case at 2030, considering then the three main scenarios ("A", "B", "C") together with the sensitivity variant ("C1") and the base scenario ("D") with no link between Africa and Europe. The runs of REMARK have provided several results, which are summarised in terms of zonal balances and inter-zonal exchange flows (Fig. 5) and in terms of average marginal zonal prices (Table 8 and Fig. 6). The Italian system is considered to be split in the following market zones[7]: North, Center-North, Center-South, South, Sicily and Sardinia. In the run cases, a 2000 MW NTC has been considered on the South-Sicily interface; furthermore, between Sardinia and Center-North (through Corsica) the limit is given by the SA.CO.I. cable link capacity, namely 600 MW, while between Sardinia and Center-South the maximum capacity transfer amounts to 1000 MW (due to SA.PE.I. rating). Other inter-zonal limits in Italy in the 2030 scenarios have not been taken into account.

A first very important outcome of the analysis is that there is a clear, relevant flow of electricity from North Africa to Italy (Sicily and Sardinia). This import reaches its peak in scenario "C" (and similarly in case "C1") as expected, but in relative terms the case "B" sees the most favourable conditions. In the latter scenario, for most yearly hours the interconnectors are almost fully loaded; it can be however appreciated that for very few hours Sicily is also able to export electricity to Tunisia and Libya. This applies also in the other relevant cases. In scenario "C" (and similarly in case "C1") the maximum utilisation of each corridor's capacity amounts to ca. 80%, while in the case "B" this value can reach even 99% ca. This difference means that an increase of each interconnector's capacity (from 1000 to 2000 MW) does not necessarily lead to an increased import from North Africa to Italy because internal grid constraints limit this flow, and also due to local RES generation in Sardinia and Sicily that is dispatched prior to North-African electricity. In fact, this occurs in "C" (and similarly in "C1") in Sardinia and can be highlighted by the capacity limits of inter-zonal links with the Italian peninsula (due to SA.CO.I. and SA.PE.I.). In the case of Sicily, instead, the constraint of the link with South zone plays a major role in this not full exploitation of North-African import.

It has to be also highlighted that in the case "C" (and similarly in case "C1") the largest African exporter is represented by Tunisia: its electricity also serves to supply the fixed 250 MW load in Malta.

Another important outcome of the study is that in all cases, at the interfaces with the Alpine region, Italy is a net electricity exporter to the bordering countries of Switzerland, Austria, Slovenia, while a net import to Italy is recorded from France. This is partially in line with the trends emerged in the European study, and can be observed already in case "D": this also reveals the impact of the large capacities of wind and solar sources installed in Italy. The main differences with the European study partially depend on the internal grid bottlenecks and cross-border constraints that make the RES generation, mostly concentrated in the southern and insular parts of the Italian peninsula, reach the north-eastern borders to be exported to Slovenia, while the contrary occurs at north-western borders with France. The same applies to the African imports and their impact on northern borders.

Concerning the flows at its eastern borders with the Balkan region, here the situation is even clearer as Italy is heavily

[7] The difference between Italian zones and areas (see Section 2.2) is that while North is the same in both categories, Center-North zone includes the regions of Tuscany, Marche, Umbria, while Lazio, Campania, Abruzzo belong to Center-South zone; Sardinia and Sicily are individually considered as zones whereas the remaining regions are part of South zone.

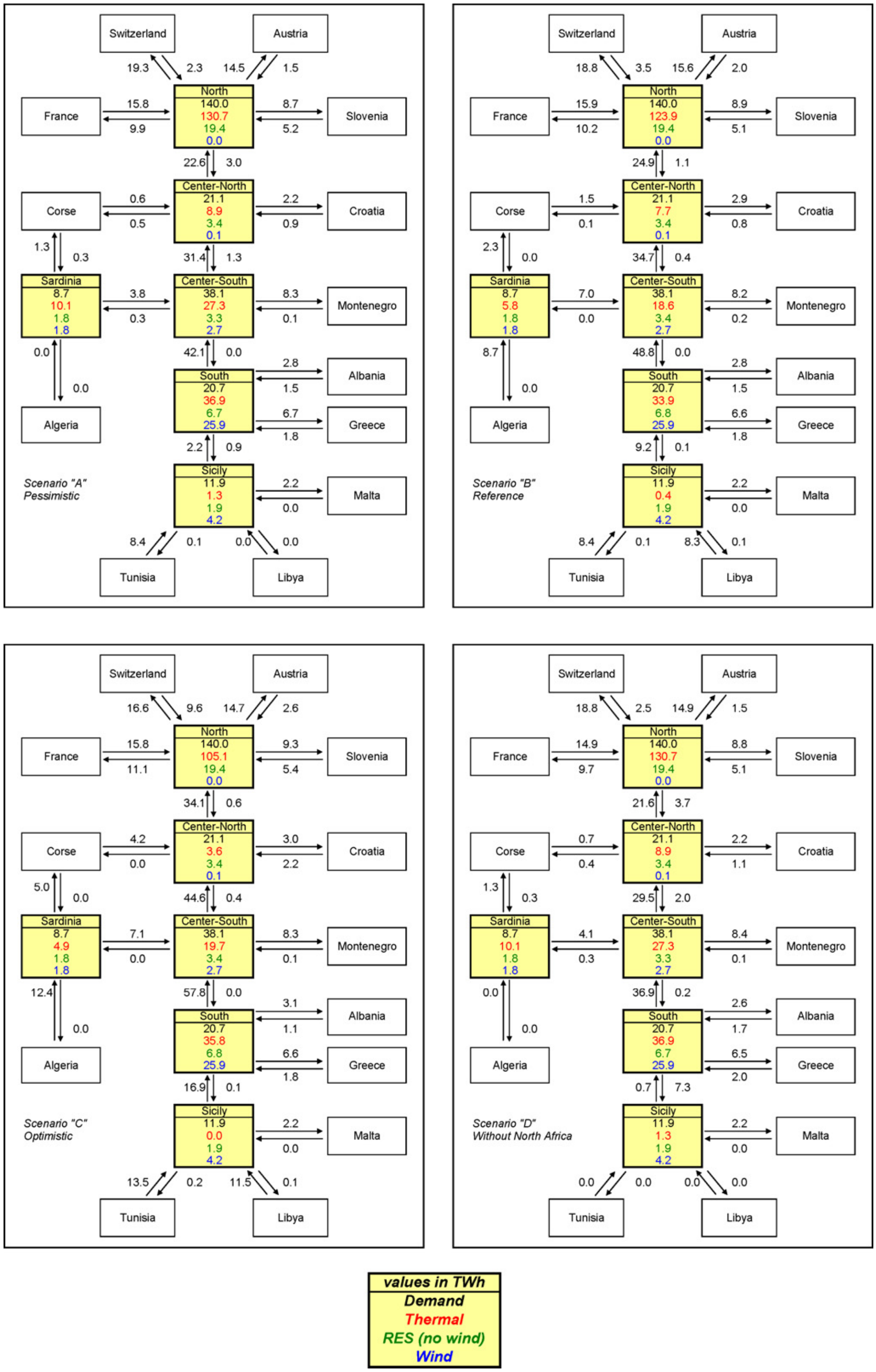

Fig. 5. Flows and electrical power balances.

exporting to Montenegro in all cases and this export does not notably change with the increase of import from North Africa. A similar situation occurs at the interface with Greece, although the amount of exported energy is less high with respect to the one with Montenegro. The net flow balance with Croatia and Albania sees also Italy exporting in all cases; the export trend recorded with Albania is impacted by the increase of import from North Africa.

Another important result is that, with the increased import from North Africa, the net flows of electricity are more and more directed from the islands and from the south of the country up to the north where large consumption is mainly concentrated. This can be seen from all cases, with an increase trend from scenario "D" up to scenario "C" (and similarly "C1") where the net power flow between the zones (from Sicily and South to North) reaches its limit. This

Table 8
Locational marginal prices.

Zones	Locational marginal costs (€/MWh)			
	Scenario "D"	Scenario "A"	Scenario "B"	Scenario "C"
North	61.90	61.90	61.90	61.89
Center-North	61.88	61.88	61.87	61.86
Center-South	61.32	61.50	61.48	61.45
South	60.07	60.54	60.36	60.28
Sicily	60.10	60.60	60.43	41.94
Sardinia	61.87	61.87	61.22	52.05
France	62.27	62.24	62.28	62.27
Corsica	61.87	61.87	61.81	61.79
Switzerland	62.19	62.16	62.20	62.20
Austria	61.97	61.96	61.97	61.97
Slovenia	61.91	61.91	61.91	61.89
Croatia	61.90	61.90	61.90	61.88
Montenegro	61.98	62.00	62.11	61.97
Albania	61.86	61.87	61.87	61.83
Greece	61.08	61.40	61.20	61.07
Libya			41.25	41.25
Tunisia		41.10	41.25	41.25
Algeria			41.25	41.25
Malta	60.09	60.60	60.43	41.75

confirms the African import influence as well as the impact of Italian RES generation location.

Further elements of analysis can be derived from the results in Table 8 (whose details are depicted in Fig. 6), in which the average yearly marginal prices are displayed for the different market zones as weighted with respect to loads, where present. From Fig. 6 the comparison among the scenarios "A", "B", "C" and "D" has been considered in detail for the Italian market zones.

It is evident that the averagely weighted locational marginal prices in Table 8 are strongly dependent on the marginal generation source, which in most zones in all scenarios is represented by thermal (gas) production. The notable exceptions to this outcome are given by the Italian market zones of Sicily and Sardinia in which, more evidently in case "C", the impact of import from North Africa is strong and makes the marginal costs quite lower than in the rest of Italian zones in the corresponding cases. In scenario "C1" this effect is, as expected, much more pronounced as the average yearly marginal prices in Sicily and in Sardinia result to be even much lower (ca. 12 €/MWh and 37 €/MWh, respectively) than in the rest of Italy. The same outcome of cases "C" and "C1" does not occur in the other Italian zones mainly due to internal grid bottlenecks, as said. This is surely an important result. Instead, scenario "A" has led to a reduction of the zonal prices differences with respect to the scenario "D": the price of Sardinia is unvaried whereas the zones of South, Sicily and Center-South show a slight increase.

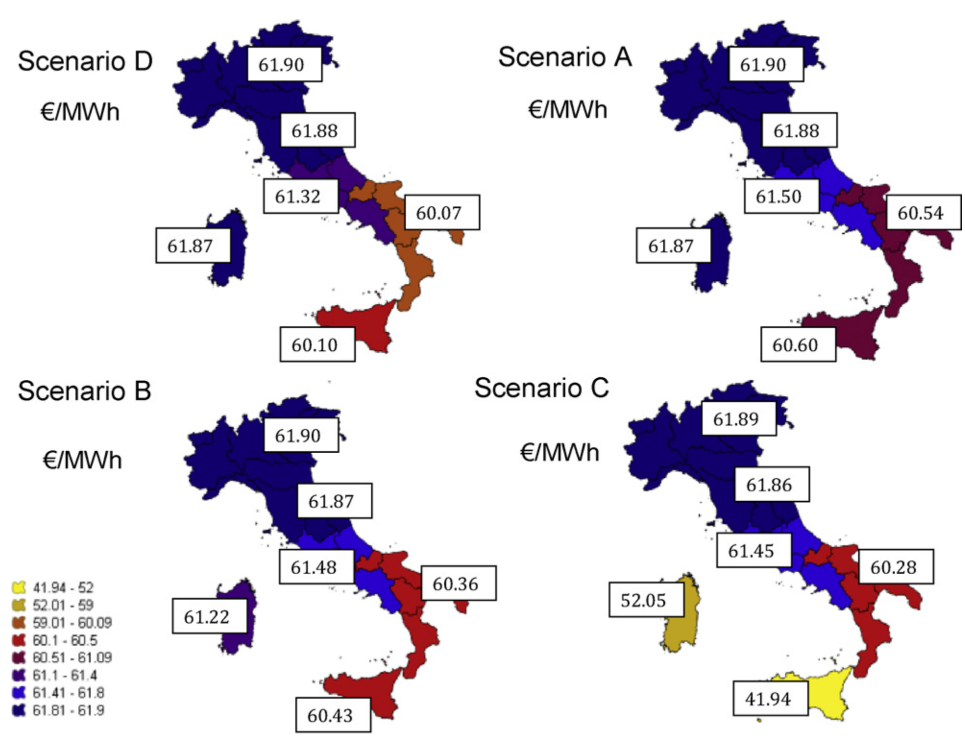

Fig. 6. Zonal prices in different scenarios.

Table 9
Flows in scenario "B" and variants.

Inter-zonal interfaces		Exchange flows in GWh					
		Scenario "B" without PST		Scenario "B"		Scenario "B" with reinforcement Latina-Garigliano	
From/To	From/To	→	←	→	←	→	←
North	France	9267	16,016	10,152	15,865	9787	15,543
North	Switzerland	22,443	2607	18,790	3484	23,309	2969
North	Austria	17,280	777	15,630	1961	15,227	1139
North	Slovenia	9643	3591	8920	5064	10,080	3396
Center-North	Croatia	2723	1103	2905	830	5484	403
Center-South	Montenegro	7716	251	8178	174	8388	55
South	Albania	3158	1087	2814	1460	3138	1172
South	Greece	6650	1804	6646	1809	6582	1897
Sardinia	Algeria	–	8667	–	8666	–	8666
Sicily	Tunisia	260	8294	53	8387	54	8436
Sicily	Libya	291	8251	103	8345	47	8408
Sicily	Malta	2186	–	2186	–	2186	–
North	Center-North	1003	26,860	1109	24,860	1763	21,873
Center-North	Corsica	136	1949	113	1505	104	1846
Sardinia	Corsica	2749	60	2311	43	2659	41
Center-North	Center-South	483	38,185	356	34,678	220	36,552
Center-South	Sardinia	–	6863	–	6983	–	6676
Center-South	South	6	53,099	2	48,808	1	52,495
South	Sicily	456	9225	82	9191	35	9420

It can be additionally highlighted that also Malta's marginal cost is strongly influenced by North-African import, being even slightly lower than the average one in Sicily in some cases.

Considering the results of the study in terms of transmission grid behaviour, it has been also essential to analyse the possible weaknesses of the internal Italian network and the potential reinforcement options to overcome them.

This analysis has led to the conclusions that several areas in the Italian system present a critical situation, especially in the scenarios "B", "C", "C1". These stressed portions of the grid are mainly located in Sardinia, around the metropolitan areas of Rome, Naples, Milan, in Tuscany, in Center-South along the Tyrrhenian and Adriatic axes and at the interfaces between South and Sicily as well as between Center-South and South. The critical situations between Center-South and South zones have been then specifically investigated with focus on the case "B". In particular, at this interface the effect of the utilisation of five inter-zonal PSTs (each rated 1800 MVA at 380 kV level), of which two located at Villanova substation in Center-South zone (to control the inter-zonal flows on both 380 kV Adriatic axis lines Villanova-Gissi-Foggia and Villanova-Larino-Foggia), one located at Foggia substation in South zone (to control the flow due to massive local RES generation along the 380 kV transversal line Foggia-Benevento) and two located at Bisaccia substation in Center-South zone (to control the flows at the crucial intersection between the two 380 kV lines Bisaccia-Deliceto-Foggia and S. Sofia-Bisaccia-Matera), can be

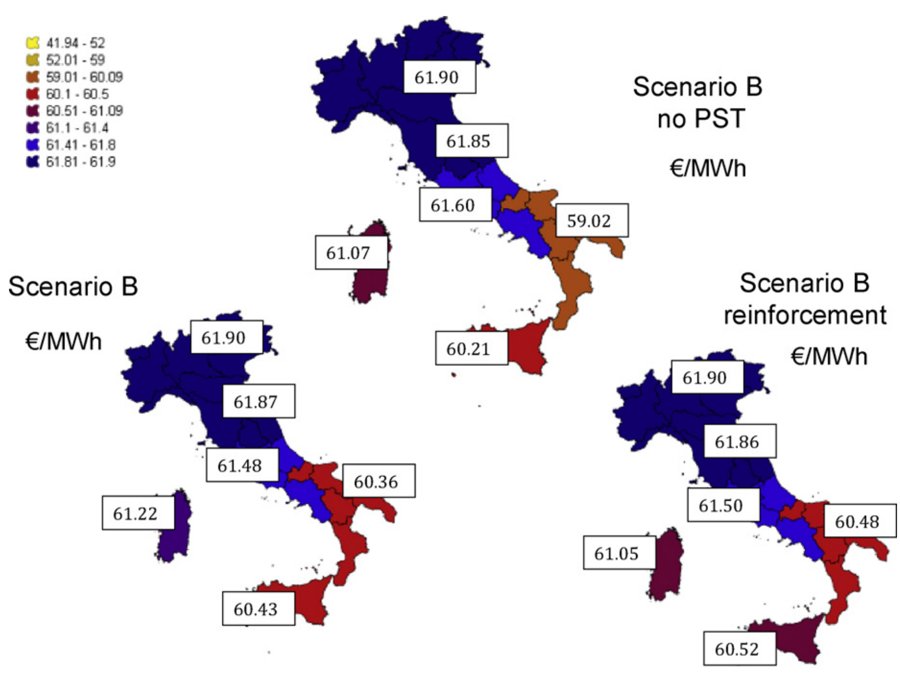

Fig. 7. Zonal prices (sensitivity scenario "B").

seen by comparing the case "B" without PSTs and the reference case "B". From Table 9 and Fig. 7 the impact of these devices on flow dispatch and on average marginal prices can be respectively highlighted. In particular, it can be noticed (see Table 9) that the installation of the internal PSTs allows a larger export from Italy to Montenegro (towards HVDC cable capacity saturation) and also to Croatia and France while a quite reduced export to Switzerland, Austria, Slovenia as well as to Albania is recorded. Moreover, the inter-zonal flows in Italy are also directly impacted with a general reduction of the total energy transfer from South towards North via Center-South and Center-North zones: the PSTs, while solving local congestions, shift the flows, in this case from the Adriatic towards the Tyrrhenian axis. In terms of economic benefits, the PSTs allow reducing the total dispatch costs of 21.7 M€ while exploiting RES generation monetised by 7 M€ (assuming 61 €/MWh as average compensation price for RES curtailment). The total economic benefit of 28.7 M€ at 2030 is to be compared with the total annuity, which is equal to 25.5 M€, by considering a cost of 50 M€[8] [34,35] for each PST (with a discount rate of 8% and an amortisation time of 20 years).

Another reinforcement option taken into account has been the doubling of the 380 kV line Latina-Garigliano located in Center-South zone between the areas of Rome and Naples: the aim is in fact to alleviate the congestions existing in this grid portion. Concerning economic benefits, the impact of this reinforcement option with respect to the "B" case can be seen only in terms of total dispatch cost reduction, amounting to 4 M€. The annuity of such expansion investment is equal to 6.2 M€ (by assuming a cost of 61 M€ for the 380 kV line doubling, with a discount rate of 8% and an amortisation time of 20 years).

Considering scenario "B" and its variants (without PSTs and with reinforcement Latina-Garigliano) in terms of marginal costs (see Fig. 7), it can be noticed how in the former variant a bottleneck between the South and the Center-South zones exists, determining a net price difference; on the other hand, the latter variant has a higher price homogeneity. In both cases the Sardinia situation improves with respect to the case "B".

5. Conclusions and future work

This paper, based on an integrated approach, investigates the effects of the North-African electricity imports on the European and Italian power systems in a 2030 perspective. It combines two methodologies, making use of models of the European system and of the Italian transmission grid. Within a common set of assumptions, the two interrelated studies analyse the North-African import impact in terms of marginal prices in the European countries and in the Italian market zones as well as inter-zonal flows for the different scenarios. The described approach proves its feasibility: the outcomes of the two studies are affected by the role played by grid constraints. The results show a general decrease of the electricity prices in Europe due to North-African electricity import. The European study highlights that net electricity exchanges tend to follow the direction from South to North. Also, Italy's potential of becoming a Mediterranean electricity hub is emphasised. The Italian study shows that the North-African import effects are relevant, leading to internal grid congestion and prices reduction in Sicily and Sardinia. The transmission limits between the two islands and the Italian peninsula as well as on the interfaces between South and Center-South zones play a major role.

The paper also shows the impact of the implementation of selected reinforcements on the Italian grid in a scenario. In particular, the expansion options of 5 PSTs in South and Center-South zones and the doubling of a 380 kV link in Center-South provide their benefits on the system dispatch.

Future work includes further investigations on the Italian grid and the application of a thorough cost-benefit analysis for comparing different reinforcement options mutually and with respect to the use of storage technologies for handling grid congestion and facilitate RES integration. A further future investigation will consist in a detailed evaluation of the investments on the African side (generation and grid) so as to allow to carry out a detailed profitability analysis of the different investment alternatives.

Disclaimer

The views expressed in this paper are the sole responsibility of the authors and do not necessarily reflect the views of the European Commission.

This work has been partially financed by the Research Fund for the Italian Electrical System under the Contract Agreement between ERSE (now RSE) and the Ministry of Economic Development – General Directorate for Energy and Mining Resources stipulated on July 29, 2009 in compliance with the Decree of March 19, 2009.

References

[1] European Commission, Energy infrastructure priorities for 2020 and beyond – A Blueprint for an integrated European energy network, COM(2010) 677 final, November 2010.
[2] European Commission, Energy Roadmap 2050, COM(2011) 885, December 2011.
[3] DESERTEC Industrial Initiative (DII). http://dii-eumena.com/
[4] Medgrid. http://www.medgrid-psm.com/
[5] MED-EMIP, MEDRING Update Study: Mediterranean electricity interconnections, April 2010. http://www.medemip.eu
[6] ENTSO-E, Ten-Year Network Development Plan (TYNDP) 2010–2020, June 2010. https://www.entsoe.eu/index.php?id=232
[7] European Commission, Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No. 1364/2006/EC, COM(2011) 658 final, October 2011.
[8] ENTSO-E. http://www.entsoe.eu
[9] European Commission, Joint Research Centre, Institute for Energy and Transport, Smart Electricity Systems, EUPowerDispatch. http://ses.jrc.ec.europa.eu/eupowerdispatch
[10] Matlab version 7.13.0, The Mathworks Inc., Natick, MA, 2011.
[11] GAMS version 23.6.5, GAMS Development Corp., Washington, DC, 2010.
[12] IBM ILOG CPLEX version 12, IBM Corp., Somers, NY, 2010.
[13] ENTSO-E, Consumption data. https://www.entsoe.eu/resources/data-portal/consumption/
[14] World Nuclear Association, Optimizes Capacity: Global Trends and Issues, 2010.
[15] VGB PowerTech e.V., Availability of Thermal Power Plants 2001–2010, VGB Technical-Scientific Reports "Thermal Power Plants", 2011.
[16] Kalnay, et al., The NCEP/NCAR 40-year reanalysis project, Bulletin of the American Meteorological Society 77 (1996) 437–470.
[17] G. van der Toorn, Wind Power Capacity Data Collection, Report D2.1 TradeWind project, April 2007. http://www.trade-wind.eu/
[18] M. Suri, T. Huld, E. Dunlop, H. Ossenbrink, Potential of Solar Electricity Generation in the European Union Member States and Candidate Countries, Solar Energy 81 (10) (2007) 1295–1305.
[19] ENTSO-E, Scenario Outlook & Adequacy Forecasts 2011–2025, 2011. http://www.entsoe.eu
[20] European Commission, DG Energy, EU Energy Trends to 2030 – update 2009, August 2010.
[21] M. Korpås, L. Warland, J.O.G. Tande, K. Uhlen, K. Purchala, S. Wagemans, Grid modelling and power system data, Report D3.2 TradeWind project, December 2007. http://www.trade-wind.eu/
[22] European FP7 project REALISEGRID. http://realisegrid.rse-web.it/
[23] European FP7 project SUSPLAN. http://www.susplan.eu/
[24] J. de Joode, O. Ozdemir, K. Veum, A. van der Welle, G. Migliavacca, A. Zani, A. L'Abbate, Trans-national infrastructure developments on the electricity and gas market, Report D3.1 SUSPLAN project, February 2011. http://www.susplan.eu/fileadmin/susplan/documents/downloads/WP_3/D3.1_main_report.pdf
[25] R. Calisti, M.V. Cazzol, Tool for the assessment of benefits given by the expansion of transmission infrastructures, Report D3.3.3 REALISEGRID project, June 2011. http://realisegrid.rse-web.it/content/files/File/Publications%20and%20results/Deliverable_REALISEGRID_3.3.3.pdf
[26] I. Losa, R. Calisti, A. L'Abbate, G. Migliavacca, C. Vergine, A. Sallati, Application of the REALISEGRID framework to assess technical-economic and strategic

[8] The unitary investment cost assumed in the study for each PST is 27.5 k€/MVA [34,35].

benefits of specific transmission projects, Report D3.5.1 REALISEGRID project, July 2011. http://realisegrid.rse-web.it/content/files/File/Publications%20and%20results/Deliverable_REALISEGRID_3.5.1.pdf

[27] Italian Government, NREAP 2020, 2010. http://ec.europa.eu/energy/renewables/transparency_platform/doc/national_renewable_energy_action_plan_italy_en.pdf

[28] TERNA, Network Development Plan 2011, 2011. http://www.terna.it/LinkClick.aspx?fileticket=dBsoVKFo2KM%3D&tabid=5069&mid=24684

[29] TERNA, load forecast 2021, 2011. http://www.terna.it/LinkClick.aspx?fileticket=%2BDWkoQzOqi8%3D&tabid=375&mid=434

[30] D. Cirio, A. Pitto, Studi sull'inserimento nella rete italiana di impianti nucleari, Report RSE no. 11001111, 2011 (in Italian).

[31] G. Migliavacca, A. L'Abbate, R. Calisti, M. Soranno, C. Brancucci, C. Alecu, M. Vandenbergh, G. Fulli, Solar import from Africa: the Italian and the European perspective, in: 13th RSCAS-EUI Mediterranean Research Meeting 2012, Montecatini T., Italy, 21–24 March, 2012.

[32] B. Pfluger, F. Sensfuss, M. Wietschel, Agent-based simulation of the effect of an import of electricity from renewable sources in Northern Africa into the Italian power market, in: IEWT 2009, Vienna, Austria, 11–13 February, 2009.

[33] F. Trieb, M. O'Sullivan, T. Pregger, C. Schillings, W. Krewit, Characterization of solar electricity import corridors from MENA to Europe – Potential, Infrastructure and Cost, DLR report for REACCESS project, July 2009. http://www.dlr.de/Portaldata/41/Resources/dokumente/institut/system/publications/Solar_import_DLR_2009_07.pdf

[34] A. Vaféas, S. Galant, T. Pagano, Final WP1 report on cost/benefit analysis of innovative technologies and grid technologies roadmap report validated by the external partners, Report D1.4.2 REALISEGRID project, May 2011. http://realisegrid.rse-web.it/content/files/File/Publications%20and%20results/Deliverable_REALISEGRID_1.4.2.pdf

[35] C. Schaffner, R. Mihalic, Economic evaluation of controllable devices in the Slovenian electric power system – a case study, in: PSCC2005 Conference, Liège, Belgium, 22–26 August, 2005.