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Optimisation of transmission infrastructure investments in the EU power sector

ERSE (ENEA Ricerca sul Sistema Elettrico) with contributions of ERIRAS and OME

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1 Introduction

This study is aimed to assess the impact of a non-optimal development of the European cross-border electricity transmission network.

The assessment has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by ERSE) and is focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO₂ emissions).

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.

The reference frameworks within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT)*, *Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT)*.

In the following, the results of the study will be reported according to the six-steps methodology defined within the SECURE project.

2 STEP 1: threat identification and assessment

The threat taken into account in this study is a non-optimal development of the European cross-border electricity transmission network.

Indeed, this is currently not a threat but a fact. Cross-border interconnection capacity was originally developed in Europe for security reasons and for mutual support between different power systems, but, especially after the coming into force of directive 96/92/EC that liberalized the electricity sector with the aim to create a single Internal Electricity Market, cross-border trading activities became more and more important, thus requiring an increase of transmission capacity.

Unfortunately, the development of cross-border transmission network did not keep the pace with the development of demand, of generation and of the related trading needs.

In fact, even today many EU countries do not reach the minimum interconnection level agreed in the EU Council held in Barcelona in March 2002, corresponding to a transmission capacity at least equal to 10% of the installed generation capacity. Such target should have been attained by 2005.

That's why the Council of European Energy Regulators (CEER) in its 2010 work programme (see [1]) plans to produce a "*Status Review on regional electricity interconnection management and use*", stating that regulators aim "*to create a reliable regulatory climate for new and massive investments in the cross-border capacity that the EU needs.*"

Similarly, the European Network of Transmission System Operators for Electricity (ENTSO-E), in its "*Ten year network development plan 2010-2020*" (see [2]) deals with the investment needs on the European power grid, highlighting the insufficiency of cross-border transmission capacity in several frontiers, both in the mid and in the long term.

So, provided that the current status of cross-border transmission infrastructures is definitely non-optimal in Europe, the probability of reaching an optimal status with future developments in the next 10÷20 years is quite low.

In fact, as ENTSO-E highlights in [2], the completion of network projects frequently requires more than 10, and sometimes up to 20 years, when major obstacles are encountered.

Within this context, the main cause of delay are the long permitting procedures involving a multitude of different authorities, typically strongly influenced by the lack of social acceptance that characterizes such kind of projects.

As ENTSO-E states in [2], "*cross-border lines are frequently perceived by the public as mere "transit lines" or "commercial lines" of limited or nil benefit for the local community and therefore, opposition against these lines is often stronger*".

Moreover, since such projects involve different countries, incongruous permitting procedures can cause additional problems and consequent delays.

Another cause hindering transmission development is related to market uncertainties and the related risks concerning the profitability of the investments, in particular in case of merchant lines.

3 STEP 2: impact assessment

The non-optimal development of the European cross-border electricity transmission network, as explained in chapter 2, is not a potential threat but a certainty, not only considering the current situation, but also for the next 10÷20 years.

As for the Step 2 of the SECURE methodology, the assessment of the impact of this “threat” would require to define an “optimal” level of network development, and then quantify a “sub-optimal” level to be analyzed in the further steps of the methodology.

In such a case, the definition of an “optimal” level can derive only from the cost assessment carried out in Step 4 of the methodology: please refer to chapter 5 for more details on this issue.

As for the assumptions concerning the “sub-optimal” level, the main references are the estimations made by ERSE within the context of the FP7 research project REALISEGRID (see [3]), together with the cross-border network investments foreseen by ENTSO-E in [2][4], focused on interconnections which are expected to be congested in the future, as well as the European Wind Energy Association’s report [5] and the network development plan of the Italian TSO TERNA [6].

In particular, the new interconnections taken into account till 2015 and from 2016 to 2030 are reported in the following Table 1 and Table 2. The abbreviations used in the tables are:

- AL: Albania
- AT: Austria
- BE: Belgium
- BG: Bulgaria
- BH: Bosnia and Herzegovina
- BY: Belarus
- CH: Switzerland
- CZ: Czech Republic
- DE: Germany
- DK_E: Denmark East
- DK_W: Denmark West
- DZ: Algeria
- EE: Estonia
- ES: Spain
- FI: Finland
- FR: France
- GB: Great Britain
- GR: Greece
- HR: Croatia
- HU: Hungary
- IE: Republic of Ireland
- IT: Italy
- KA: Kaliningrad region (Russia)
- LT: Lithuania
- LU: Luxembourg
- LV: Latvia

- MD: Moldova
- ME: Montenegro
- MT: Malta
- NI: Northern Ireland
- NL: The Netherlands
- NO: Norway
- PL: Poland
- PT: Portugal
- RO: Romania
- RS: Serbia
- RU: Russia
- SE: Sweden
- SI: Slovenia
- SK: Slovak Republic
- TR: Turkey
- TU: Tunisia
- UA: Rest of Ukraine
- UA_W: Ukraine West

Such investments have been assessed either by each TSO individually or through bilateral grid studies, on the basis of scenario hypotheses used in the Transmission Development Plan of each TSO. Therefore, they are not the result of a Europe-wide optimization process, like the one that will be carried out in the present study.

Moreover, some of the proposed projects are quite mature (already or nearly under construction), while others are only under study and their probability of realization depends also on the considered time horizon.

It must also be taken into account that the analysis carried out in the present study takes as a reference the main assumptions deriving from the different POLES scenarios, that, in particular in terms of generation / load development, might be different from the scenario hypotheses used by the TSOs that foresaw the aforementioned cross-border network expansions.

Interconnected countries	Type of investment	From - To
AT-HU	New 400 kV AC line	Wien - Győr/Szombathely
NO-DK_W	New HVDC cable (Skagerrak 4)	Kristiansand - Tjele
AT-IT	Upgrading of an existing 110/132 kV line and installation of 2 new PSTs	Steinach - Prati di Vizze
FR-BE	Doubling of an existing 220 kV line and replacement of conductors	Moulaine - Aubange
FR-LU	New 220 kV AC line	Moulaine - Belval
BG-GR	New 400 kV AC line	Maritsa - N. Santa
DE-NL	New double 400 kV AC line	Niederrhein - Doetinchem
DE-PL	Upgrading of an existing 220 kV line and installation of two new 400 kV PSTs	Vierraden - Krajnik
FI-EE	New HVDC cable (Estlink 2)	Anttila - Püssi
ES-FR	New HVDC cable	Santa Llogaia - Baixas
ES-PT	New double 400 kV AC line	Guillena - Tavira
ES-PT	New double 400 kV AC line	Cartelle/Pazos - Recarei
SE-FI	New HVDC cable (Fenno-Skan 2)	Finnböle - Rauma
FR-IT	A new PST and line upgrades with high temperature conductors	Cornier - Venaus
HU-HR	New double 400 kV AC line	Pécs - Ernestinovo
IE-GB	New HVDC cable	Woodland - Deeside
IT-MT	To be defined	To be defined
IT-SI	Installation of a new 400 kV PST	Slovenia
IT-AL	New HVDC cable	Brindisi – Babica
IT-ME	New HVDC cable	Villanova - Tivat
PL-LT	New HVAC line (LitPol) and installation of a back-to-back converter	Elk - Alytus
GB-NL	New HVDC cable (BritNed)	Isle of Grain - Maasvlakte
DK_E-DK_W	New HVDC line (Great Belt)	Herslev - Fraugde
NO-SE	New 420 kV AC line	Nea - Jarpstrommen

Table 1: New cross-border interconnection projects taken into account till 2015.

Interconnected countries	Type of investment	From - To
RO-RS	New 400 kV AC line	Săcălaz - Novi Sad
HU-SI	New 400 kV AC line	Pince - Cirkovce
PL-SK	New 400 kV AC line	Byczyna - Varin
SI-HR	New 400 kV AC line	Cirkovce - Žerjavinec
DE-PL	New 400 kV AC line	Eisenhüttenstadt - Baczyna/Plewiska
AT-SK	New double 400 kV AC line	Bisamberg/Wien - Stupava
CZ-DE	New double 400 kV AC line	Hradec - Mechlenreuth
HU-SK	New double 400 kV AC line	Győr - Gabčíkovo
IT-SI	New double 400 kV AC line	Udine ovest - Okroglo
FR-IT	New HVDC cable	Grande Ile - Piossasco
CH-IT	New HVDC cable	Sils - Verderio
CH-IT	New 400 kV AC line	Lavorgo - Morbegno
AT-IT	New 220 kV AC line	Passo Resia
AT-IT	New 400 kV AC line	Lienz - Cordignano
AT-IT	New cable	Innsbruck - Bressanone
AT-DE	New double 400 kV AC line	St. Peter – Isar/Pleinting
AT-DE	Upgrading of an existing 220 kV line	Westtirol - Memmingen
AT-DE	Upgrading of an existing 220 kV line	Silz - Oberbachern
IT-AL	New HVDC cable	Manfredonia-Kalmet
IT-AL	New HVDC cable	Casamassima-Porto Romano
IT-HR	New HVDC cable	Candia - Konjsko
IE-GB	New HVDC cable	To be defined
NL-NO	New HVDC cable	To be defined
NO-DE	New HVDC cable (Nordlink)	To be defined
NO-DE	New HVDC cable (NorGer)	To be defined
FR-IE	New HVDC cable	To be defined
UK-NO	New HVDC cable	To be defined
SE-LT	New HVDC cable	Nybro - Klaipeda
SE-LV	New HVDC cable	To be defined
IT-TU	New HVDC cable	Partanna - El Auaria
DZ-ES	New HVDC cable	To be defined
FI-RU	New HVDC line	To be defined
KA-PL	New HVAC line and installation of a back-to-back converter	To be defined
BY-PL	New HVAC line and installation of a back-to-back converter	To be defined
PL-UA	Modernization and re-commissioning of a 750 kV line and installation of a back-to-back converter	Rzeszów - Khmel'nitskaya
UA-UA_W	Installation of a back-to-back converter	Zakhidnoukrainska
RO-MD	New 400 kV AC line	Suceava - Bălți
TR-RO	New HVDC cable	Pasakoy - Constanta
HR-BH	New 400 kV AC line	To be defined
BE-DE	New AC or DC line	To be defined
ES-FR	To be defined	To be defined

DK_W-NL	New HVDC cable	Endrup - Eemshaven
IE-NI	New 400 kV AC line	Moyhill - Turleenan
UK-BE	New HVDC cable	Richborough - Zeebrugge
DE-DK_E	New HVDC cable (Kriegers Flak)	Bentwisch - Ishøj/Bjæverskov
NO-SE	New HVDC cable (South West link)	Tveiten - Hurva/Hallsberg
NO-SE	To be defined	To be defined
SE-FI	New 400 kV AC line	To be defined

Table 2: New cross-border interconnection projects taken into account from 2016 to 2030.

4 STEP 3: assessment of EU vulnerability to energy risks

In order to assess the EU vulnerability to non-optimal development of the cross-border electricity transmission network, we calculated how loaded were the different interconnections in July and in December 2008 (peak load periods), on a monthly average.

The calculations have been done by dividing the monthly energy flows by the maximum amount of energy that could have been transmitted, corresponding to the NTC (Net Transfer Capacity) of each interconnection times the 744 hours of each month (data source: ENTSO-E [7]).

The results are reported in Figure 1 and in Figure 2. The abbreviations used are the following:

- AT: Austria
- BG: Bulgaria
- BL: Belgium and Luxembourg
- BX: Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia)
- BT: Baltic countries (Estonia, Latvia and Lithuania)
- CH: Switzerland
- CZ: Czech Republic
- DE: Germany and Denmark West
- ES: Spain
- FI: Finland
- FR: France
- GR: Greece
- HR: Croatia
- HU: Hungary
- IE: Republic of Ireland
- IT: Italy
- NL: The Netherlands
- NO: Norway
- PL: Poland
- PT: Portugal
- RO: Romania
- SE: Sweden and Denmark East
- SI: Slovenia
- SK: Slovak Republic
- UA_W: Ukraine West
- UK: United Kingdom (Great Britain and Northern Ireland)

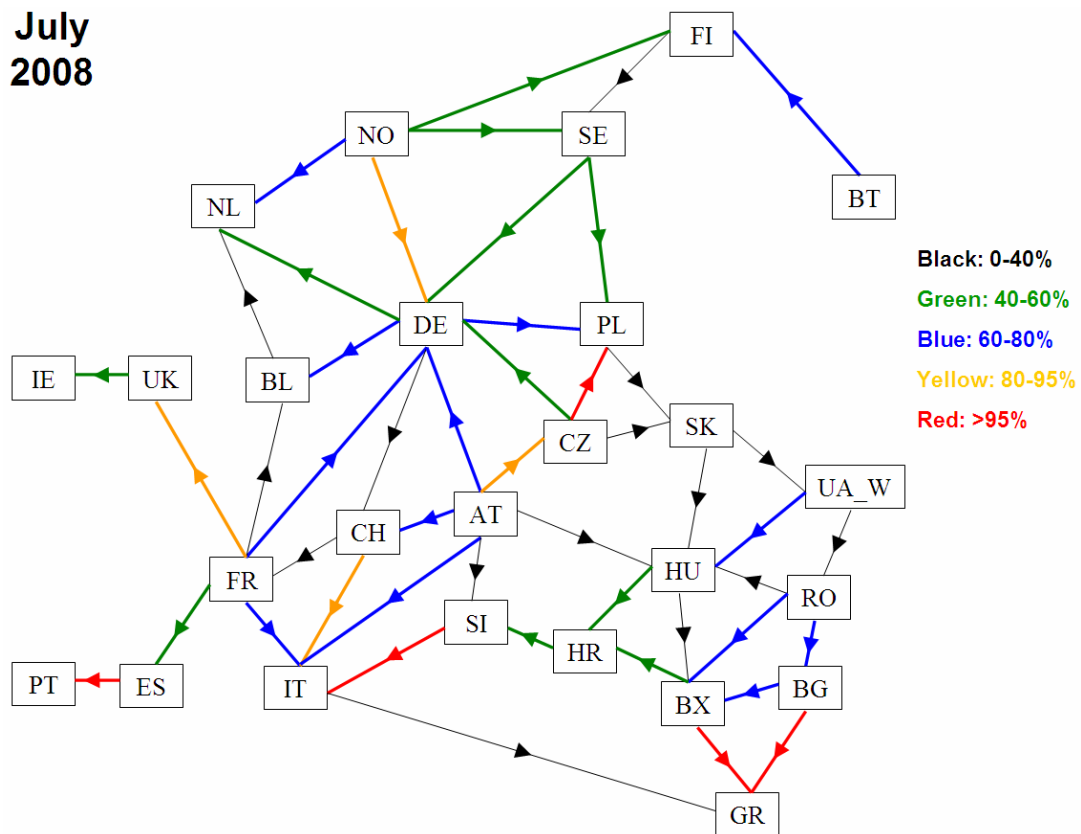


Figure 1: Average loading level of cross-border interconnections in July 2008.

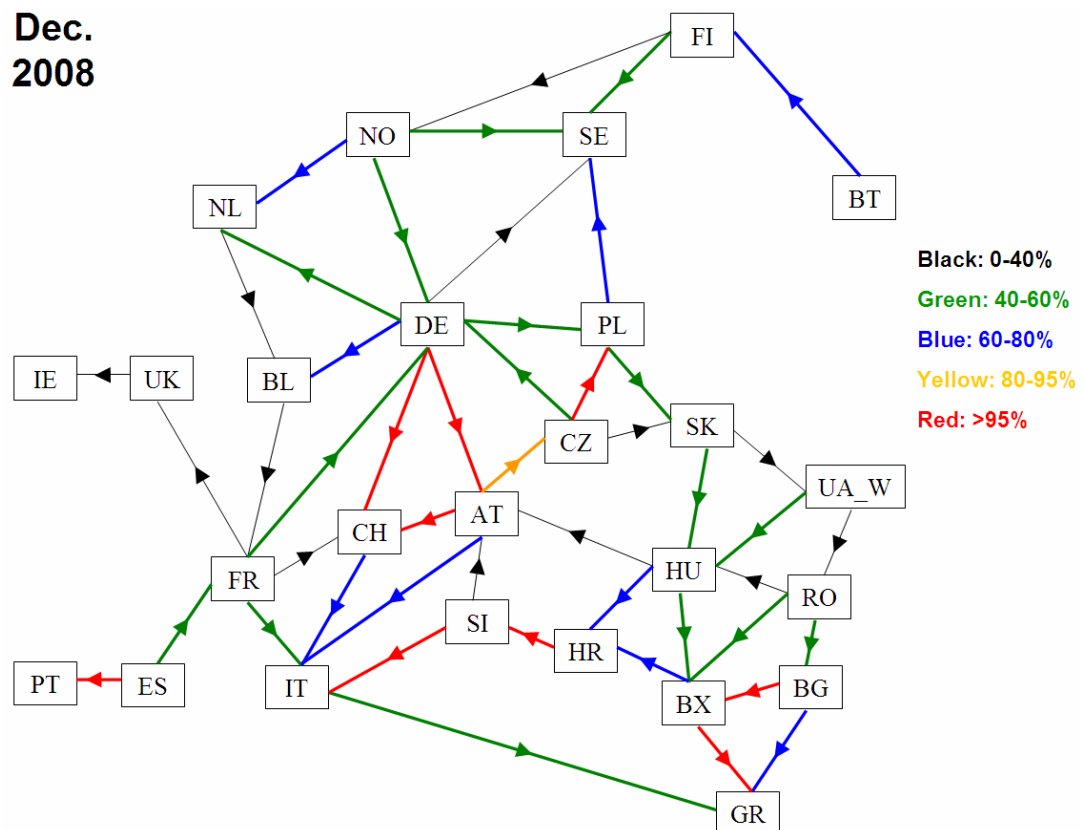


Figure 2: Average loading level of cross-border interconnections in December 2008.

It is evident that several interconnections are highly loaded even on a monthly average: this means that congestion is likely to occur in several hours.

The fact that cross-border congestion is a significant problem in the European power system is clearly shown in Figure 3, reporting the occurrence of congestion in the different frontiers in 2006.

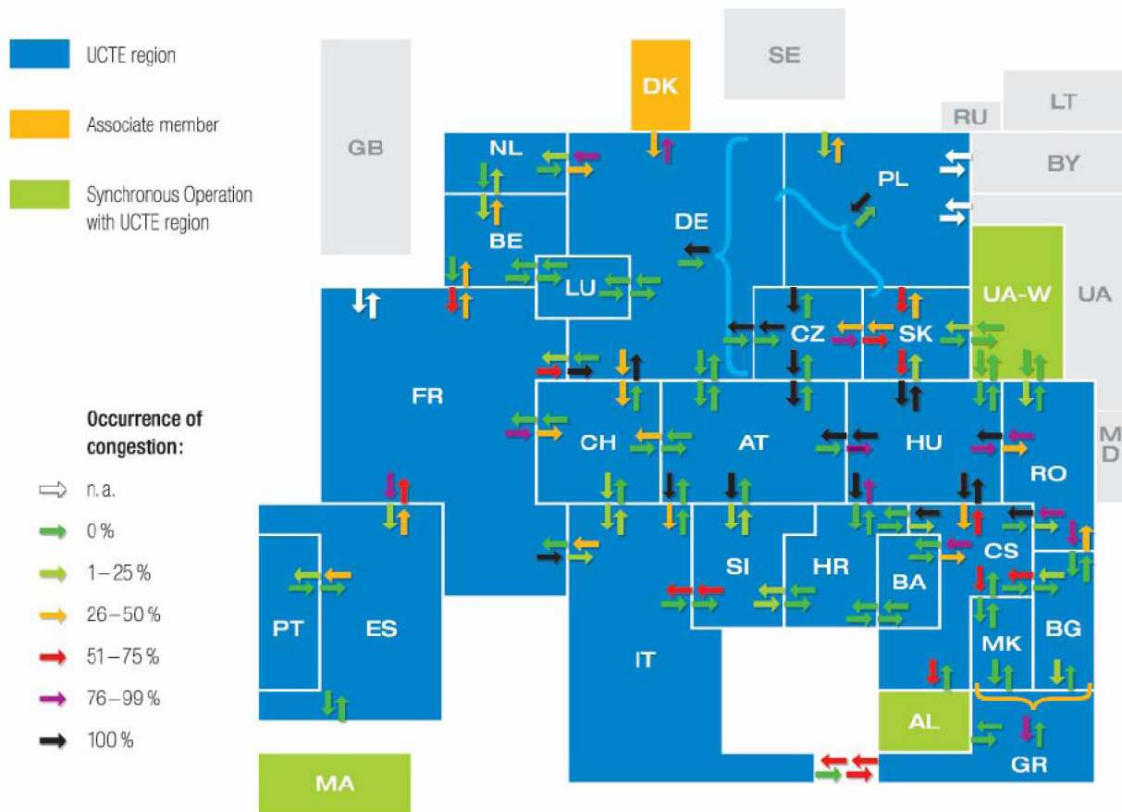


Figure 3: Occurrence of cross-border congestion in continental Europe in 2006 (source: UCTE).

5 STEP 4: cost assessment

The impact and cost quantitative assessment of a non-optimal development of cross-border electricity transmission network has been focused on the following main aspects:

- security of supply (i.e. possible electric energy not supplied);
- competitiveness (i.e. electricity production costs);
- sustainability (i.e. CO₂ emissions).

The assessment has been carried out by developing and running a model of the European power system, based on the MTSIM simulator, developed by ERSE.

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal developments determined by MTSIM.

The model and the results of its runs will be described in the following.

The reference frameworks within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security (see [9]):

- *Muddling Through (MT)*: this scenario supposes a failure in the efforts to develop a common framework of targets, rules and mechanisms for climate policies; in this case only weak domestic climate policies are implemented without any element of coordination of the different actions;
- *Europe Alone (EA)*: this scenario supposes that Europe goes along a stringent climate policy line, while the rest of the world continues on the same line as the *Muddling Through*;
- *Global Regime with Full Trade (GR-FT)*: this scenario assumes the introduction of a global cap on emissions, with abatement programs corresponding to a cost-effective program resulting from a unique carbon value, as introduced either by a global carbon market or by an international carbon tax.

The reference years considered in the study are 2015 and 2030. It must be noted that, as far as year 2015 is concerned, the various POLES scenarios are quite similar: in fact, their differences become evident mainly after 2020 till 2050, i.e. in the second part of the considered time horizon. Therefore, for the reference year 2015 we will consider only the GR-FT scenario, while for year 2030 all the three POLES scenarios will be taken into account.

5.1 The MTSIM power system simulator

MTSIM (*Medium Term SIMulator*), developed by ERSE, is a zonal electricity market simulator able to determine the hourly clearing of the market over an annual time horizon, calculating the zonal prices and taking primarily into account:

- variable fuel costs of thermal power plants;
- other variable costs that affect power plants (such as O&M, CO₂ emissions, etc.);
- bidding strategies put in practice by producers, in terms of mark-ups over production costs.

The main results provided by the simulator are:

- hourly marginal price for each market zone;
- hourly dispatching of all dispatchable power plants;
- fuel consumption and related cost for each thermal power plant;
- emissions of CO₂ (and of other pollutants) and related costs for emission allowances;
- power flows on the interconnections between market zones;
- revenues, variable profits and market shares of the modeled generation companies.

The model can handle several types of constraints, such as:

- power transfer capacity on the interconnections between market zones; the equivalent transmission network is modeled using the so-called *Power Transfer Distribution Factors* (PTDF¹) and MTSIM can model active power flows by calculating a DC Optimal Power Flow; in this way, transmission bottlenecks can be identified and the needs for network reinforcement can be quantified;
- power plants forced and scheduled unavailability, as well as start-up and shut-down flexibility;
- constraints on plant operation (e.g. “must-run”) and on fuel consumption over a certain time period (this feature has been used to model the gas shortages in [8]);
- emission constraints and related trading of emission allowances at an exogenous price set in the relevant international markets (e.g. ETS, CDM, JI).

Non-dispatchable power plants operation (typically renewable sources such as wind, photovoltaic, run-of-river hydro, etc.) is not modelled endogenously: hourly generation profiles have to be provided as input to the simulator.

An important new feature recently implemented in the simulator is the “network expansion” capability: it can increase inter-zonal transmission capacities in case the annualized costs of such expansions are lower than the consequent reduction of generation costs due to more efficient dispatching.

In the present study, this feature has been used to determine the optimal expansion of the European AC cross-border transmission network.

As for the expansion of DC interconnectors, it has been done “manually” by selecting the most congested ones, by expanding them by a typical size (e.g. 1000 MW), and by checking that the related extra-cost is lower than the reduction of the overall system costs due to the expansion.

¹ Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B.

5.2 The model of the European power system

As a general remark, the model of the European power system used in the present study has been developed starting from the model used in the study reported in [8], to which reference will often be made in the following.

5.2.1 Representation of the transmission network

Just like in [8], the European transmission network has been modeled with an equivalent representation where each country (or aggregate of countries, such as in the Balkans) is represented by a node (i.e. market zone), interconnected with the neighboring countries via equivalent lines characterized by a transmission capacity equal to the corresponding cross-border Net Transfer Capacity (NTC). The NTC values are based on the estimations made in [3].

Since the study will be focused on two reference years, namely 2015 and 2030, two different models of the network, characterized by different foreseen interconnections, have been set up: they are shown in Figure 4 and in Figure 5.

In the figures, cross-border AC interconnections (in black), DC interconnections (in red) and interconnections with other power systems (in blue) are shown.

For the sake of simplicity, in case two synchronous zones are connected by both AC and DC transmission lines (such as Sweden and Finland), a single AC interconnection has been modeled, characterized by the sum of the NTCs of the different lines.

Moreover, AC interconnections equipped with a back-to-back AC-DC-AC converter station (e.g. the new interconnection between Poland and Lithuania) have been modeled in the same way as DC interconnections.

In addition to the abbreviations reported in chapter 4, the following ones are used in the figures:

- BY: Belarus
- DZ: Algeria
- KA: Kaliningrad region (Russia)
- MA: Morocco
- MD: Moldova
- MT: Malta
- RU: Russia
- TR: Turkey
- TU: Tunisia
- UA: Rest of Ukraine

In particular, the model of the European power system developed for the study reported in [8] has been extended to include additional countries, i.e. the United Kingdom, Ireland, Norway, Sweden, Finland, Estonia, Latvia and Lithuania.

2015

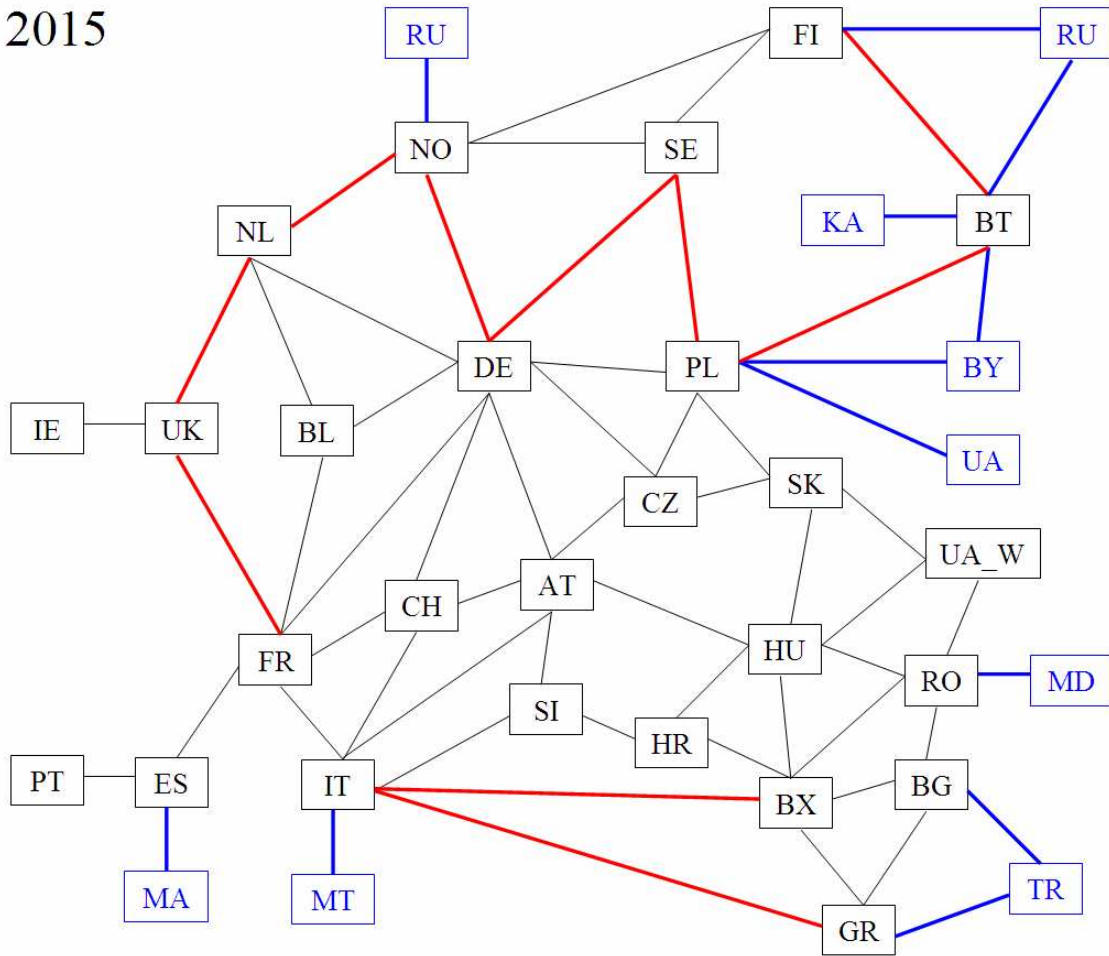


Figure 4: Equivalent representation of the European transmission network in 2015.

2030

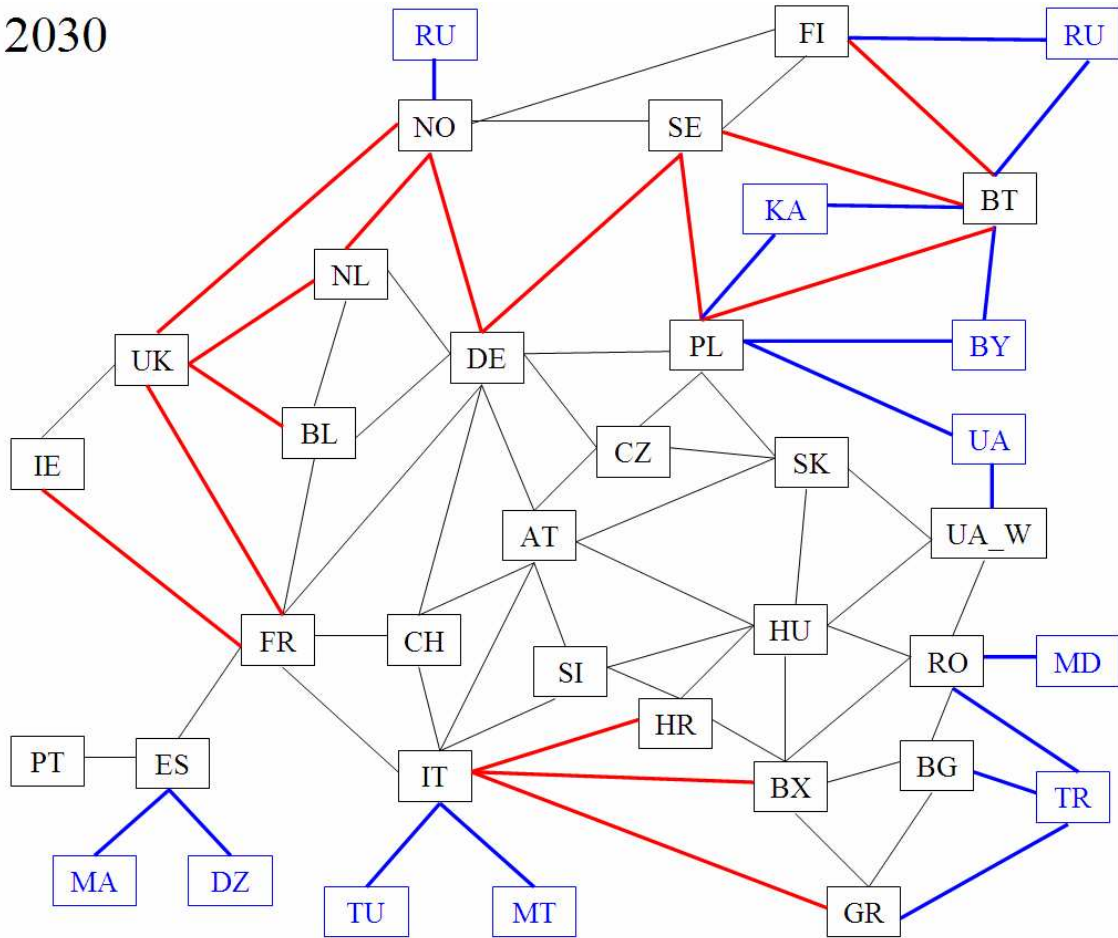


Figure 5: Equivalent representation of the European transmission network in 2030.

The PTDF² (*Power Transfer Distribution Factor*) matrix used in the MTSIM simulator has been calculated using an AC transmission grid model, that represents the former UCTE network, with two voltage levels (220 and 380 kV), composed of about 4000 nodes.

As for the 2015 network, PTDFs have been determined on the basis of the aforementioned UCTE system model, executing a series of load flows calculated with the slack node put in Germany.

As for the 2030 network, in order to account for the considered investments in new cross-border lines (see chapter 3) that increase NTC values of some interconnections, new equivalent reactance values have been considered to assess the impact on the corresponding different distribution of power flows.

As for the Nordic transmission grid (basically a triangle composed of Norway, Sweden and Finland: see Figure 4) that is not included in the aforementioned UCTE system model, PTDFs have been calculated on the basis of the NTC values adopted in the different scenarios (the error deriving from this simplification should be acceptable, considering in particular the weakness of the link between Norway and Finland).

As for the Ireland / Great Britain block, PTDFs are quite straightforward, since there is only a single equivalent AC interconnection between the two countries, that are linked to the rest of the European AC network only via DC cables.

As far as the NTC values³ (for both flow directions) are concerned, they have been determined in [3] starting from the latest ENTSO-E available data (Summer 2009 and Winter 2009-2010: see [7]) and taking into account the future development of each European cross-border interconnection up to either 2015 or 2030 (see chapter 3), the two reference years considered in the present study.

Given the difficulty of estimating, for each cross-border interconnection, both a summer and a winter NTC value, it has been decided to define only a single annual value corresponding to the maximum NTC estimated value (in the vast majority of cases, the winter one).

In the following Table 3, Table 4, Table 5 and Table 6, NTC values of the cross-border AC and DC interconnections considered for the 2015 and 2030 scenarios are reported.

² Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B.

³ What we call here “NTC values” for the sake of brevity should more precisely be intended as “maximum estimated cross-border transmission capacity”.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
PT→ES	3000	3000
ES→FR	2600	2600
FR→IT	3250	1595
IT→CH	1810	4640
FR→CH	3200	2300
FR→DE	2900	3050
FR→BL	4000	3100
CH→DE	3200	1500
DE→BL	980	0
BL→NL	2400	2400
NL→DE	4500	5350
DE→PL	1600	1500
DE→CZ	800	2300
DE→AT	2200	2000
CH→AT	1200	1200
IT→AT	285	300
IT→SI	650	650
PL→CZ	2000	800
PL→SK	600	500
CZ→SK	2000	1000
CZ→AT	2180	1200
SK→HU	1500	600
AT→HU	1500	1200
AT→SI	900	900
HU→BX	600	600
HU→RO	600	1400
BX→BG	750	1100
BX→RO	300	650
RO→BG	950	950
BG→GR	1500	1400
BX→GR	500	600
HR→BX	1060	1050
HR→SI	1000	1000
HR→HU	3000	2500
RO→UA_W	400	400
HU→UA_W	650	650
SK→UA_W	400	400
UK→IE	950	580
NO→SE	3550	3350
SE→FI	2550	2450
FI→NO	100	100

Table 3: NTC values (MW) of the considered AC cross-border interconnections in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
PT→ES	3000	3000
ES→FR	4000	4000
FR→IT	4200	2595
IT→CH	3710	6540
FR→CH	3200	2300
FR→DE	2900	3050
FR→BL	4000	3100
CH→DE	3200	1500
DE→BL	1980	1000
BL→NL	2400	2400
NL→DE	5100	5950
DE→PL	2500	2400
DE→CZ	2300	3800
DE→AT	6880	6880
CH→AT	1400	1400
IT→AT	2200	2200
IT→SI	2150	2150
PL→CZ	2000	800
PL→SK	1500	1400
CZ→SK	2000	1000
CZ→AT	2000	1100
SK→HU	3000	2100
AT→HU	1500	1200
AT→SI	1200	1200
SI→HU	900	900
SK→AT	1500	1500
AT→SI	1200	1200
HU→BX	600	600
HU→RO	600	1400
BX→BG	750	1100
BX→RO	500	850
RO→BG	950	950
BG→GR	1500	1400
BX→GR	500	600
HR→BX	2210	2200
HR→SI	1900	1900
HR→HU	3000	2500
RO→UA_W	400	400
HU→UA_W	650	1150
SK→UA_W	400	400
UK→IE	1300	930
NO→SE	5450	5250
SE→FI	2800	2700
FI→NO	100	100

Table 4: NTC values (MW) of the considered AC cross-border interconnections in the 2030 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
IT→GR	500	500
FR→UK	2000	2000
UK→NL	1320	1320
DE→NO	1600	1600
DE→SE	1890	1830
PL→BT	500	500
FI→BT	1000	1000
NO→NL	700	700
SE→PL	600	600
BX→IT	1500	1500

Table 5: NTC values (MW) of the considered DC cross-border interconnections in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
IT→GR	500	500
IT→BX	3000	3000
IT→HR	1000	1000
FR→IE	1000	1000
FR→UK	3000	3000
UK→BL	1000	1000
UK→NL	1320	1320
UK→NO	1400	1400
NL→NO	1400	1400
DE→NO	4000	4000
DE→SE	2490	2430
SE→PL	600	600
PL→BT	1000	1000
SE→BT	1700	1700
FI→BT	1000	1000

Table 6: NTC values (MW) of the considered DC cross-border interconnections in the 2030 scenarios.

As far as the electricity exchanges via DC interconnections are concerned, differently from the study reported in [8], their hourly profiles have not been exogenously imposed, but they have been determined by the MTSIM simulator, basically on the basis of the hourly electricity price differences between the zones they connect.

As for AC and DC interconnections with other power systems, hourly profiles have been imposed. In particular, for each interconnection, firstly the prevailing direction of annual net power exchanges has been envisaged. Then, the NTC value and the annual net electricity exchange have been hypothesized. Finally, this latter value has been profiled in accordance with the load profile of the importing country.

In the following Table 7 and Table 8, the NTC values and the annual net electricity exchanges imposed on the considered AC and DC interconnections with other power systems are reported [3].

Interconnection (A→B)	NTC values (A→B) [MW]	Net exchanges (A→B) [GWh]
KA→BT	680	1500
RU→BT	400	1300
BY→BT	1400	2453
RU→FI	1400	9600
RU→NO	50	220
BY→PL	120	521
UA→PL	248	760
MD→RO	600	2891
TR→BG	500	3066
TR→GR	500	3066
IT→MT	200	876
ES→MA	900	5519

Table 7: NTC values (MW) and annual net electricity exchanges (GWh) imposed on the considered AC and DC interconnections with other power systems in the 2015 scenario.

Interconnection (A→B)	NTC values (A→B) [MW]	Net exchanges (A→B) [GWh]
KA→BT	1000	3000
KA→PL	600	3000
RU→BT	400	2000
BY→BT	1400	0
RU→FI	1900	12600
RU→NO	50	220
BY→PL	1000	6000
UA→PL	1448	8118
UA→UA_W	500	3000
MD→RO	1500	7227
TR→RO	600	3679
TR→BG	500	3066
TR→GR	800	4906
IT→MT	200	1314
TU→IT	1000	6570
DZ→ES	1000	6570
ES→MA	1400	8585

Table 8: NTC values (MW) and annual net electricity exchanges (GWh) imposed on the considered AC and DC interconnections with other power systems in the 2030 scenarios.

5.2.2 Representation of the power generation system

As shown in Figure 4 and in Figure 5, in the model each country has been “collapsed” into a node of the equivalent AC European network, therefore, for each country, an “equivalent” power plant for each main generation technology has been defined, as detailed in the following.

In particular, for the reference year 2015 the same net generation capacity values (for each technology/fuel) defined for the study reported in [8] have been used, with some minor updates.

They have been taken from the “Conservative Scenario” (Scenario A) of the UCTE (now ENTSO-E) *System Adequacy Forecast (SAF) 2009-2020* (available from [5]). Such scenario takes into account the commissioning of new power plants considered as sure and the shutdown of power plants expected during the study period.

Additional information necessary for a more detailed subdivision of the UCTE data have been taken from the results of the FP6 project ENCOURAGED (see [10]) and of the FP7 project REALISEGRID (see [3]), as well as estimated by ERSE.

As for the countries that have been added to the model described in [8] (i.e. the United Kingdom, Ireland, Norway, Sweden, Finland, Estonia, Latvia and Lithuania), the net generation capacity data have been taken from the respective Transmission System Operators’ annual statistics (see [11]) and system adequacy reports (see [12], [13] and [14]), or from the electricity market operator’s website (see [15]) and from other sources (see [16]).

As for the reference year 2030, all generation capacity data have been derived from the results of the three POLES scenarios MT, EA and GR-FT. It must be taken into account that POLES does not model a minimum size for power plants of the different technologies, therefore in some cases generation capacity data well below a realistic plant size are reported: such data, that are basically negligible, have not been considered in the model implemented with MTSIM.

5.2.2.1 Fossil fuelled thermal power plants

In addition to conventional fossil fuelled generation technologies considered in the study reported in [8], hard coal-fired USC, CCGT and IGCC power plants equipped with Carbon Capture and Storage (CCS) technology have been added.

In the following, data already reported in a detailed manner in the tables contained in [8] are aggregated under the item “Rest of Europe”. Data concerning Germany + Denmark West (DE) for year 2015 have been slightly modified w.r.t. the data reported in [8], therefore, for the sake of clarity, they have not been aggregated under the item “Rest of Europe”.

5.2.2.1.1 Net generation capacity

- Total generation capacity

In the following Table 9 and Table 10, for each country, data concerning the total fossil fuelled generation capacity installed in the 2015 and in the 2030 scenarios are reported.

Country	Net generation capacity [MW]
BT	5696
DE	109515
FI	13810
IE	5679
NO	979
SE	19626
UK	89191
Rest of Europe	384102
Total	628598

Table 9: Total fossil fuelled generation capacity (MW) installed in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	6671	5249	5576
BG	7177	4139	4443
BL	18307	18617	18746
BT	5899	5146	5693
BX	11216	10319	9915
CH	4824	4215	4414
CZ	17189	14954	15127
DE	82527	61409	69345
ES	64744	57897	60395
FI	15143	10376	11166
FR	105405	103163	108884
GR	13443	11161	12071
HR	3087	2845	2769
HU	8477	7229	7598
IE	5642	3622	5224
IT	55650	52603	52937
NL	23485	14618	14774
NO	4838	4376	4122
PL	33607	31525	32512
PT	10923	8665	9584
RO	9555	7518	8151
SE	16911	11759	12785
SI	3254	3022	3197
SK	4949	4523	4759
UA_W	4078	4057	3991
UK	78372	82235	81951
Total	615373	545242	570129

Table 10: Total fossil fuelled generation capacity (MW) installed in the 2030 scenarios.

- CHP generation capacity

In the following Table 11, Table 12 and Table 13 the net generation capacity and the estimated electricity production of the fossil fuelled and RES CHP power plants for each country are reported.

Just like in [8], since no data are available about the split of CHP production into the different application sectors (industry, residential, tertiary, etc.), it has not been possible to differentiate it into different production profiles. Therefore, in the model a flat annual profile has been assumed.

Country	Net generation capacity [MW]	Electricity production [GWh]
BT	3230	1780
DE	24580	88020
FI	5820	27920
IE	270	1780
NO	191	150
SE	6070	18500
UK	5470	25340
Rest of Europe	68676	277259
Total	114307	440749

Table 11: Net generation capacity (MW) and estimated electricity production (GWh) of CHP power plants in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1925	1647	1752
BG	362	374	385
BL	698	636	666
BT	281	247	275
BX	130	130	123
CH	311	322	235
CZ	1219	1116	1159
DE	4526	4111	4245
ES	14726	13104	13692
FI	1716	1375	1574
FR	2207	1888	1999
GR	223	205	221
HR	20	20	19
HU	326	302	322
IE	466	439	465
IT	15110	14168	14525
NL	2084	1830	1929
NO	311	322	235
PL	1095	1167	1248
PT	870	773	826
RO	368	301	335
SE	563	491	537
SI	418	354	377
SK	76	69	77
UA_W	200	200	200
UK	12344	10999	11597
Total	62575	56590	59018

Table 12: Net generation capacity (MW) of fossil fuelled CHP power plants in the 2030 scenarios.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	5728	4884	5202
BG	1080	1116	1150
BL	2086	1898	1991
BT	843	740	824
BX	387	387	366
CH	933	966	703
CZ	3661	3349	3479
DE	13215	11960	12367
ES	43732	38824	40606
FI	5128	4092	4694
FR	6397	5433	5768
GR	671	615	666
HR	60	60	57
HU	978	906	967
IE	1395	1314	1393
IT	45143	42283	43366
NL	6041	5271	5568
NO	933	966	703
PL	3306	3522	3771
PT	2586	2292	2454
RO	1113	909	1012
SE	1685	1465	1607
SI	1260	1066	1136
SK	224	202	227
UA_W	572	572	569
UK	36684	32604	34416
Total	185841	167696	175062

Table 13: Estimated electricity production (GWh) of fossil fuelled CHP power plants in the 2030 scenarios.

- Steam turbine power plants

In the following tables, for each country, the net generation capacities of the different kinds of steam turbine power plants, both non-CHP and CHP, considered in the 2015 scenario are reported.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	793	2036	2829
DE	5264	236	5500
FI	220	175	395
SE	2791	0	2791
UK	3694	0	3694
Rest of Europe	16614	771	17385
Total	29376	3218	32594

Table 14: Net generation capacity (MW) of fuel oil-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	1787	104	1891
DE	3359	393	3752
FI	185	625	810
IE	258	0	258
SE	560	346	906
Rest of Europe	15178	1938	17116
Total	21327	3406	24733

Table 15: Net generation capacity (MW) of natural gas-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
DE	31970	10555	42525
FI	2159	1010	3169
IE	848	0	848
SE	753	1934	2687
UK	29510	0	29510
Rest of Europe	50009	11157	61166
Total	115249	24656	139905

Table 16: Net generation capacity (MW) of hard coal-fired steam turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
DE	16008	4592	20600
FI	170	513	683
IE	346	0	346
Rest of Europe	28251	15588	43839
Total	44775	20693	65468

Table 17: Net generation capacity (MW) of lignite/peat-fired steam turbine power plants (2015).

In the following tables, for each country, the net generation capacities of the different kinds of steam turbine power plants considered in the three different 2030 scenarios are reported.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	334	297	304
BG	162	152	154
BL	785	762	767
BT	1022	998	1003
BX	486	482	447
CZ	331	309	313
DE	1955	1650	1770
ES	3388	3315	3321
FI	301	277	280
FR	4582	4438	4459
GR	1326	1300	1306
HU	336	315	320
IE	133	127	129
IT	2904	2904	2904
NL	282	278	279
NO	409	403	390
PL	853	779	795
PT	1116	1110	1112
RO	1348	1321	1326
SE	1289	1282	1284
SK	331	320	324
UK	2017	2008	2011
Total	25690	24827	24998

Table 18: Net generation capacity (MW) of fuel oil-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	399	131	178
BL	2824	2670	2614
BT	679	613	604
BX	458	500	458
DE	3359	1847	2186
FI	185	185	185
HU	895	802	814
IT	6403	6403	6403
PT	959	782	747
SE	560	543	560
Total	16721	14476	14749

Table 19: Net generation capacity (MW) of natural gas-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1309	1067	1118
BG	1054	706	738
BL	2459	2407	2514
BT	1612	944	1237
CH	67	92	84
CZ	1076	841	883
DE	18536	17677	18384
ES	5775	4810	5197
FI	2290	2291	2291
FR	12078	9672	10858
GR	853	512	589
HR	587	543	490
HU	251	139	197
IE	850	613	703
IT	1892	1888	1893
NL	2262	2064	2071
NO	121	76	69
PL	9271	7428	7801
PT	1553	1097	1210
RO	1066	757	857
SE	1873	1313	1445
SI	229	196	207
SK	620	473	488
UA_W	2002	1990	1955
UK	6964	6963	7117
Total	76650	66559	70396

Table 20: Net generation capacity (MW) of hard coal-fired steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	440	49	131
BG	1224	61	171
BL	6300	2303	3777
BT	1023	237	479
BX	141	120	63
CH	263	359	204
CZ	3988	916	1517
DE	28178	5476	11039
ES	12923	2449	5497
FI	2400	54	179
FR	13689	2562	5282
GR	1429	473	798
HR	41	35	18
HU	1519	281	550
IE	2024	283	918
IT	5131	1246	2249
NL	6376	785	909
NO	480	297	170
PL	8814	1822	3571
PT	4064	982	1900
RO	1728	228	561
SE	3708	487	1081
SI	639	144	277
SK	795	132	294
UK	14051	3071	5958
Total	121368	24852	47593

Table 21: Net generation capacity (MW) of hard coal-fired USC steam turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	3	6	1
BG	30	51	91
BL	117	4257	3171
BT	9	404	381
BX	0	0	9
CH	0	0	42
CZ	93	1604	1436
DE	519	6676	7166
ES	249	5267	4843
FI	42	15	90
FR	254	4633	4319
GR	17	553	452
HR	0	0	3
HU	30	581	497
IE	37	406	883
IT	65	1913	1539
NL	120	464	432
NO	0	0	34
PL	200	4573	3974
PT	67	1455	1294
RO	38	584	535
SE	33	277	297
SI	13	240	229
SK	18	306	302
UK	243	6396	5282
Total	2197	40661	37302

Table 22: Net generation capacity (MW) of hard coal-fired USC steam turbine power plants with CCS (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
BG	1861	1247	1304
BX	4596	4235	3780
CZ	6038	4719	4958
DE	9068	8626	8989
ES	2590	2157	2331
FI	180	180	180
GR	5130	3075	3540
HU	1730	956	1177
IE	347	249	286
PL	5573	5573	5573
RO	2091	1484	1682
SI	840	719	757
SK	451	344	355
Total	40495	33564	34912

Table 23: Net generation capacity (MW) of lignite/peat-fired steam turbine power plants (2030).

- Gas turbine power plants

In the following tables, for each country, the net generation capacities of open cycle and combined cycle gas turbine power plants and of IGCC CCS power plants, both non-CHP and CHP, considered in the 2015 scenario are reported.

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
DE	7098	2462	9560
FI	840	0	840
IE	1072	127	1199
NO	249	0	249
SE	418	70	488
UK	589	158	747
Rest of Europe	9333	5860	15193
Total	19599	8677	28276

Table 24: Net generation capacity (MW) of open cycle gas turbine power plants (2015).

Country	Net generation capacity [MW]		
	non-CHP	CHP	Total
BT	11	698	709
DE	10735	5043	15778
FI	1875	1742	3617
IE	2885	143	3028
NO	730	0	730
SE	2214	512	2726
UK	38055	4416	42471
Rest of Europe	97957	32881	130838
Total	154462	45435	199897

Table 25: Net generation capacity (MW) of combined cycle gas turbine power plants (2015).

Country	Net generation capacity [MW]
UK	3325
Rest of Europe	0
Total	3325

Table 26: Net generation capacity (MW) of IGCC CCS power plants (2015).

In the following tables, for each country, the net generation capacities of open cycle and combined cycle gas turbine power plants (without and with CCS) considered in the three different 2030 scenarios are reported.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1468	1468	1468
BG	573	361	390
BL	246	177	177
BX	1788	1670	1670
CH	253	243	242
CZ	826	646	633
DE	7658	7542	7542
ES	7968	5962	5502
FI	2592	2455	2599
FR	9537	7631	9070
GR	1712	1338	1467
HR	1365	1301	1243
HU	584	584	584
IE	831	718	839
IT	4111	2904	2346
NL	5065	4711	4781
NO	2746	2607	2591
PL	2302	1675	1751
PT	532	532	532
RO	1845	1739	1741
SE	2867	2193	2289
SI	215	220	208
SK	770	732	744
UA_W	412	409	375
UK	6625	6273	6396
Total	64891	56091	57180

Table 27: Net generation capacity (MW) of open cycle gas turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	758	534	603
BG	322	112	141
BL	1649	1686	1619
BT	233	201	214
BX	1633	1475	1046
CH	106	92	54
CZ	552	300	351
DE	8466	6265	6880
ES	9522	8459	8534
FI	2494	974	1248
FR	4856	3425	3894
GR	877	834	834
HR	496	449	321
HU	624	515	542
IE	817	665	684
IT	19411	14498	16966
NL	3799	3443	3424
NO	771	671	606
PL	1433	573	976
PT	1227	963	1035
RO	227	106	154
SE	1517	642	816
SI	47	30	34
SK	437	317	358
UA_W	1019	1027	599
UK	19680	15757	16891
Total	82973	64013	68824

Table 28: Net generation capacity (MW) of combined cycle gas turbine power plants (2030).

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	1	49	19
BG	3	10	4
BL	10	422	215
BT	1	27	14
BX	0	1	217
CH	0	0	33
CZ	10	229	149
DE	104	1441	1070
ES	84	2151	1420
FI	16	78	48
FR	36	771	491
GR	1	167	118
HR	0	0	63
HU	5	96	63
IE	4	48	84
IT	211	5974	3455
NL	0	67	45
NO	0	0	27
PL	25	753	455
PT	4	225	148
RO	3	62	38
SE	4	70	30
SI	0	23	15
SK	4	72	53
UA_W	5	6	229
UK ⁴	3539	9445	7262
Total	4070	22187	15765

Table 29: Net generation capacity (MW) of combined cycle gas turbine power plants with CCS (2030).

- Nuclear power plants

In the following Table 30 and Table 31, for each country, the net generation capacities of nuclear power plants in the 2015 and in the 2030 scenarios are reported.

⁴ Including 3325 MW of IGCC CCS power plants.

Country	Net generation capacity [MW]
DE	11800
FI	4296
SE	10028
UK	9444
Rest of Europe	95002
Total	130570

Table 30: Net generation capacity (MW) of nuclear power plants in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	34	1	2
BG	1586	1065	1065
BL	3219	3297	3226
BT	1039	1475	1486
BX	1984	1706	2102
CH	3824	3107	3520
CZ	3056	4274	3728
DE	158	98	74
ES	7519	10223	10058
FI	2927	2492	2492
FR	58166	68143	68512
GR	1875	2704	2746
HR	578	497	612
HU	2177	2658	2532
IE	133	74	233
IT	412	705	657
NL	3497	976	904
NO	0	0	0
PL	4041	7182	6368
PT	531	746	780
RO	841	936	922
SE	4497	4461	4446
SI	853	1096	1093
SK	1447	1758	1764
UA_W	440	425	633
UK	12909	21323	19437
Total	117743	141422	139392

Table 31: Net generation capacity (MW) of nuclear power plants in the 2030 scenario.

5.2.2.1.2 Electrical efficiencies

The ranges of the average electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the different countries in the 2015 and 2030 scenarios are reported in the following Table 32.

Technology	Efficiency [%]
Oil fired steam turbine	34 ÷ 36
Natural gas fired steam turbine	32 ÷ 38.8
Repowering	39.7
Hard coal fired steam turbine	33 ÷ 45
Lignite fired steam turbine	32 ÷ 35
Open cycle gas turbine	28.1 ÷ 37
Combined Cycle Gas Turbine	50 ÷ 60
IGCC CCS	45
Nuclear	30 ÷ 36

Table 32: Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the 2015 scenario.

Technology	Efficiency [%]
Oil fired steam turbine	34 ÷ 36
Natural gas fired steam turbine	32 ÷ 38.8
Repowering	39.7
Hard coal fired steam turbine	33 ÷ 45
Hard coal fired USC steam turbine	48
Hard coal fired USC steam turbine with CCS	44
Lignite fired steam turbine	32 ÷ 35
Open Cycle Gas Turbine	28.1 ÷ 37
Combined Cycle Gas Turbine	55 ÷ 60
Combined Cycle Gas Turbine with CCS	55
IGCC with CCS	45
Nuclear	30 ÷ 36

Table 33: Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the 2030 scenarios.

5.2.2.1.3 Forced and scheduled unavailability

In the following Table 34, forced (in p.u.) and scheduled (in days per year) average unavailability rates adopted for the different fossil fuelled generation technologies are reported.

As for nuclear generation, for each country, the average unavailability data of the last three years of operation (2006-2008) taken from the IAEA PRIS website [18]) have been used.

Technology	Unavailability	
	Unforced [p.u.]	Scheduled [days]
Oil fired steam turbine	0.08	42
Natural gas fired steam turbine / Repowering	0.055	42
Old hard coal fired steam turbine	0.1	70
New hard coal fired steam turbine	0.055	35
Hard coal fired USC steam turbine	0.055	35
Hard coal fired USC steam turbine with CCS	0.055	35
Lignite fired steam turbine	0.113	70
Open Cycle and Combined Cycle Gas Turbine	0.05	35
Combined Cycle Gas Turbine with CCS	0.05	35
IGCC with CCS	0.05	35
Nuclear	0.001 ÷ 0.293	25

Table 34: Forced (p.u.) and scheduled (days) unavailability rates adopted for the different fossil fuelled generation technologies.

As for the scheduled unavailability, similarly to [8], a monthly distribution (shown in Table 35) of the planned outages as close as possible to reality has been adopted, by concentrating it in the months characterized by a lower load.

Month	Scheduled Unavailability Distribution [%]
January	8.41
February	8.80
March	9.98
April	9.04
May	8.85
June	6.60
July	5.13
August	8.99
September	9.07
October	9.79
November	8.15
December	7.19

Table 35: Distribution over the year of the scheduled unavailability adopted for the fossil fuelled generation technologies.

5.2.2.1.4 CO₂ emission rates of fossil fuels

In the following Table 36, CO₂ emission rates of the different fossil fuels adopted for the simulations are reported. Such data, together with plant efficiencies (see Table 32), allow to calculate CO₂ emission rates of the different generation technologies.

Fuel	Emission rate [tCO ₂ /GJ]
Fuel oil	0.077
Gas	0.056
Coal	0.094
Lignite	0.101
Coal with CCS	0.009
Gas with CCS	0.008

Table 36: CO₂ emission rates (tCO₂/GJ) of the different fossil fuels.

5.2.2.2 Hydro power plants

The MTSIM simulator can dispatch both reservoir and pumped storage hydro power plants, provided that, among others, data concerning the volumes of reservoirs / basins are defined. Since, for the different European countries, no information are available that allow to define the volumes of equivalent reservoirs / basins for their hydro power plants, it has been necessary to define and impose specific hourly production (as well as consumption, in case of pumped storage) profiles.

As for the monthly values of hydro energy production (or consumption) in each of the countries not considered in the study reported in [8], the average values of all the years available in the corresponding annual energy statistics (see [11], [19], [20] and [21]) have been taken into account for the 2015 scenario.

On the other hand, concerning the 2030 scenarios, the annual electricity hydro production data have been taken from the results of the three POLES scenarios (MT, EA and GR-FT). The subdivision of hydro production into the different plant typologies (not available from POLES, just like generation capacity) has been done proportionally to the 2015 subdivision.

As for the annual electricity consumption of pumped storage hydro power plants, since the weight of natural inflows on their production is not known, so that consumption cannot be calculated from production, it has been decided to use the same values of the 2015 scenario in all the three 2030 scenarios.

The following Table 37 reports the total net hydro generation capacity assumed for the simulations in the different countries in the 2030 scenarios.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	20619	20575	20549
BG	2703	2774	2742
BL	2690	2727	2718
BT	2688	2769	2768
BX	11192	11161	10789
CH	14270	14271	14272
CZ	3126	3202	3175
DE	12073	12359	12301
ES	23349	23809	23769
FI	4282	4229	4226
FR	33720	32996	32944
GR	3529	3648	3639
HR	3506	3496	3379
HU	75	77	77
IE	580	587	585
IT	26633	28386	28223
NL	50	50	49
NO	31556	31558	31560
PL	2881	2984	2975
PT	8403	8615	8571
RO	9888	9259	9241
SE	42223	42072	42137
SI	1609	1493	1486
SK	3556	3588	3587
UA_W	27	27	27
UK	5128	5220	5210
Total	270356	271932	270999

Table 37: Total net hydro generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

More details, according to the plant type, are provided in the following, where data already reported in a detailed manner in the tables contained in [8] are aggregated under the item “Rest of Europe”.

5.2.2.2.1 Run of river hydro power plants

The hourly generation profile of run of river hydro power plants has been assumed flat and its level has been differentiated among the four seasons.

The generation capacity and the seasonal production assumed for the simulations in the different countries in the 2015 scenario are reported in the following Table 38.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
BT	1572	1413	501	577	769	3260
FI	3147	3453	2982	2978	3526	12939
IE	238	84	51	100	132	367
UK	1127	683	317	817	1135	2952
Rest of Europe	39730	38872	37618	29947	31584	138021
Total	45814	44505	41469	34419	37146	157539

Table 38: Run of river hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries.

In the following tables, data concerning seasonal production of run of river hydro power plants in the 2030 scenarios are reported.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9734	11314	8220	6672	35940
BG	348	288	189	272	1097
BL	42	41	36	35	154
BT	1659	588	678	903	3828
BX	10288	6346	7168	9958	33760
CH	3948	5771	4109	3368	17196
CZ	108	69	68	87	332
DE	1932	1995	1640	1640	7207
ES	3271	2429	2004	2696	10400
FI	5026	4340	4335	5133	18834
FR	11798	9891	7792	9408	38889
GR	68	62	41	60	231
HR	1538	979	1005	1505	5027
HU	51	65	59	52	227
IE	121	74	145	191	531
IT	4975	6255	4621	4144	19995
NL	39	25	22	41	127
PL	747	529	547	650	2473
PT	1537	924	1054	1553	5068
RO	4413	4298	3419	3401	15531
SI	1396	1499	1235	904	5034
SK	1664	1299	940	1133	5036
UA_W	51	31	24	28	134
UK	1777	826	2125	2954	7682
Total	66531	59938	51476	56788	234733

Table 39: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9704	11279	8195	6652	35830
BG	357	295	193	279	1124
BL	41	37	36	43	157
BT	1708	606	698	930	3942
BX	10259	6328	7148	9931	33666
CH	3948	5771	4109	3368	17196
CZ	110	70	70	88	338
DE	1981	2047	1683	1682	7393
ES	3345	2483	2050	2757	10635
FI	4988	4307	4302	5094	18691
FR	11453	9602	7565	9133	37753
GR	71	65	42	63	241
HR	1534	977	1002	1500	5013
HU	52	66	60	53	231
IE	123	74	146	193	536
IT	5432	6829	5045	4524	21830
NL	39	25	22	41	127
PL	773	547	566	672	2558
PT	1567	942	1075	1583	5167
RO	4154	4046	3218	3201	14619
SI	1310	1406	1159	847	4722
SK	1665	1299	941	1134	5039
UA_W	51	31	24	28	134
UK	1830	850	2188	3040	7908
Total	66495	59982	51537	56836	234850

Table 40: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	9694	11267	8186	6645	35792
BG	352	291	191	275	1109
BL	41	36	36	43	156
BT	1708	605	698	929	3940
BX	9915	6116	6909	9597	32537
CH	3948	5771	4108	3368	17195
CZ	108	70	69	87	334
DE	1972	2037	1674	1674	7357
ES	3337	2477	2045	2750	10609
FI	4985	4305	4300	5092	18682
FR	11430	9582	7549	9115	37676
GR	71	64	43	63	241
HR	1483	944	968	1450	4845
HU	52	65	60	53	230
IE	123	74	146	192	535
IT	5398	6786	5013	4495	21692
NL	38	24	22	40	124
PL	770	546	564	670	2550
PT	1558	936	1069	1574	5137
RO	4146	4037	3212	3195	14590
SI	1305	1401	1154	844	4704
SK	1664	1299	941	1134	5038
UA_W	51	31	24	28	134
UK	1824	848	2181	3031	7884
Total	65973	59612	51162	56344	233091

Table 41: Run of river hydro seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

5.2.2.2.2 Reservoir and pumped storage hydro power plants

In order to define the hourly production (and consumption) profiles of reservoir and pumped storage hydro power plants, it has been assumed that they can generate at least between 6:00 and 23:00 and that they can pump only between 23:00 and 6:00.

As for the consumption of pumped storage plants, the hourly profile has been considered flat and its level has been differentiated among the four seasons.

The seasonal consumption of pumped storage hydro power plants assumed for the simulations in the different countries and in the different scenarios are reported in the following Table 42.

Country	Electricity consumption [GWh]				
	Spring	Summer	Autumn	Winter	Year
BT	168	135	158	214	675
IE	124	133	135	143	535
NO	283	247	292	351	1173
SE	10	8	9	11	38
UK	241	257	261	274	1033
Rest of Europe	10524	10533	11449	11531	44037
Total	11350	11313	12304	12524	47491

Table 42: Pumped storage hydro seasonal consumption (GWh) assumed for the simulations in the different countries and in the different scenarios.

As for the reservoir and pumped storage hydro power plants (that we will call “dispatchable hydro”), the criteria used to determine their imposed production profile are the same reported in [8].

The generation capacity and the seasonal production of dispatchable hydro power plants assumed for the simulations in the different countries in the 2015 scenario are reported in the following Table 43.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
BT	760	118	93	112	151	474
IE	292	81	86	87	92	346
NO	30074	30072	26199	31105	37385	124761
SE	16195	17092	13547	15634	19275	65548
UK	2744	168	180	183	192	723
Rest of Europe	106201	46412	44613	35709	39039	165773
Total	156266	93943	84718	82830	96134	357625

Table 43: Dispatchable hydro generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

As for the three 2030 scenarios, data concerning seasonal production are reported in the following tables.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5203	6049	4396	3565	19213
BG	1523	1256	814	1193	4786
BL	686	608	611	716	2621
BT	139	109	132	176	556
BX	8295	4148	5810	9152	27405
CH	4894	7160	5098	4174	21326
CZ	1030	669	651	811	3161
DE	5477	5651	4654	4647	20429
ES	6524	4837	3997	5369	20727
FR	11316	9484	7474	9020	37294
GR	1773	1590	1060	1594	6017
HR	3073	1957	1993	3003	10026
IE	116	125	127	133	501
IT	8456	10631	7855	7037	33979
NO	33326	29033	34469	41429	138257
PL	638	452	462	555	2107
PT	1220	734	834	1231	4019
RO	4565	4445	3533	3518	16061
SE	24027	19045	21977	27096	92145
SI	159	171	138	100	568
SK	563	442	318	384	1707
UK	438	469	475	500	1882
Total	123441	109065	106878	125403	464787

Table 44: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5187	6031	4382	3555	19155
BG	1560	1286	834	1223	4903
BL	698	619	622	728	2667
BT	143	112	136	182	573
BX	8272	4136	5794	9126	27328
CH	4894	7160	5098	4174	21326
CZ	1047	679	661	824	3211
DE	5617	5796	4774	4766	20953
ES	6671	4947	4087	5490	21195
FR	10985	9207	7255	8757	36204
GR	1851	1659	1107	1663	6280
HR	3065	1952	1987	2994	9998
IE	118	126	128	135	507
IT	9232	11607	8576	7684	37099
NO	33326	29033	34469	41429	138257
PL	660	467	478	574	2179
PT	1243	749	850	1255	4097
RO	4296	4184	3326	3311	15117
SE	23899	18943	21861	26952	91655
SI	149	160	130	94	533
SK	563	443	318	384	1708
UK	451	483	489	514	1937
Total	123927	109779	107362	125814	466882

Table 45: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Electricity production [GWh]				
	Spring	Summer	Autumn	Winter	Year
AT	5182	6024	4378	3551	19135
BG	1540	1270	823	1207	4840
BL	694	616	619	724	2653
BT	143	112	136	182	573
BX	7995	3998	5599	8820	26412
CH	4894	7160	5097	4174	21325
CZ	1034	671	653	814	3172
DE	5590	5768	4751	4743	20852
ES	6655	4935	4077	5477	21144
FR	10962	9188	7240	8739	36129
GR	1845	1654	1104	1659	6262
HR	2962	1886	1921	2894	9663
IE	117	126	128	134	505
IT	9174	11533	8521	7635	36863
NO	33324	29031	34468	41426	138249
PL	658	466	477	572	2173
PT	1236	745	845	1248	4074
RO	4288	4176	3319	3305	15088
SE	23937	18974	21896	26995	91802
SI	148	160	130	93	531
SK	563	442	318	384	1707
UK	449	481	488	513	1931
Total	123390	109416	106988	125289	465083

Table 46: Dispatchable hydro seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

5.2.2.3 Renewable energy power plants

Since renewable energy power plants are in most cases non dispatchable, specific hourly production profiles have been defined and imposed in the simulations, adopting different assumptions according to the operating characteristics of the generation technologies considered, as reported in the following paragraphs.

5.2.2.3.1 Wind power plants

As for wind power plants, for the countries not considered in [8] data have been collected concerning the equivalent full-load annual hours and the seasonal distribution of production (see [11]÷[14], [21], [22]). The 2015 annual electricity production has therefore been calculated as the product of the equivalent full-load annual hours times the installed capacity.

Moreover, a flat generation profile for each season has been defined.

As for year 2030, data concerning the annual electricity production have been taken from the results of the three POLES scenarios (MT, EA and GR-FT), while the seasonal distribution has been assumed equal to the 2015 one.

The generation capacity and the seasonal production of wind power plants assumed for the simulations in the different countries and in the different scenarios are reported in the following tables.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
BT	995	452	452	448	443	1795
DE ⁵	41032	16774	11010	16638	24164	68586
FI	183	67	58	101	111	337
IE	3282	1483	1185	1757	1949	6374
IT ⁵	7112	4487	2289	2832	3773	13381
NO	555	226	180	390	401	1197
SE	3822	1420	1484	2374	2612	7890
UK	14723	8901	7399	11518	12016	39834
Rest of Europe	55502	32526	30596	31655	33966	128743
Total	127206	66336	54653	67713	79435	268137

Table 47: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

⁵ Data modified w.r.t. what reported in [8], according to more updated information.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	4617	1849	1849	1828	1808	7334
BG	3460	2233	1674	2512	2512	8931
BL	6979	4174	4174	4129	4084	16561
BT	2907	1433	1433	1417	1401	5684
BX	58	36	36	35	35	142
CH	273	110	110	109	108	437
CZ	5031	1961	1961	1940	1918	7780
DE	45354	24521	16095	24322	35324	100262
ES	25675	14815	14815	14655	14493	58778
FI	7313	3108	2689	4721	5200	15718
FR	31518	17159	17159	16972	16785	68075
GR	5684	3520	3520	3482	3444	13966
HR	206	142	101	121	141	505
HU	2776	1121	1121	1108	1096	4446
IE	2869	1688	1349	1999	2218	7254
IT	25202	14590	7443	9210	12268	43511
NL	8389	4962	3383	4517	7484	20346
NO	1635	716	571	1237	1271	3795
PL	16005	9029	9029	8931	8832	35821
PT	4746	2405	1821	2173	2621	9020
RO	5377	3378	3118	3118	3378	12992
SE	11425	4547	4750	7600	8364	25261
SI	667	387	290	387	483	1547
SK	2090	839	839	831	821	3330
UK	32642	18020	14979	23319	24327	80645
Total	252898	136743	114309	140673	160416	552141

Table 48: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the MT 2030 scenario.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	3811	1487	1487	1470	1454	5898
BG	4126	2462	1846	2769	2769	9846
BL	6815	4103	4103	4059	4014	16279
BT	5188	2615	2615	2586	2557	10373
BX	53	33	33	33	32	131
CH	323	130	130	129	128	517
CZ	6714	2559	2559	2531	2504	10153
DE	62502	35647	23397	35358	51352	145754
ES	40391	23790	23790	23532	23273	94385
FI	9046	3773	3265	5731	6312	19081
FR	50342	26150	26150	25865	25581	103746
GR	9063	5451	5451	5392	5332	21626
HR	188	130	93	111	130	464
HU	4603	1831	1831	1810	1791	7263
IE	4154	2361	1887	2797	3103	10148
IT	30034	17686	9022	11164	14871	52743
NL	6919	4032	2749	3670	6081	16532
NO	1940	929	741	1606	1649	4925
PL	25406	13258	13258	13114	12970	52600
PT	8765	4601	3483	4155	5012	17251
RO	7458	4777	4410	4409	4777	18373
SE	12027	4362	4557	7292	8025	24236
SI	978	560	420	560	701	2241
SK	3426	1331	1331	1317	1302	5281
UK	42438	24491	20358	31694	33065	109608
Total	346710	188549	158966	193154	218785	759454

Table 49: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the EA 2030 scenario.

Country	Net generation capacity [MW]	Electricity production [GWh]				
		Spring	Summer	Autumn	Winter	Year
AT	3298	1302	1302	1289	1274	5167
BG	3270	2012	1509	2264	2263	8048
BL	5846	3315	3315	3280	3243	13153
BT	3135	1590	1590	1573	1556	6309
BX	67	41	41	41	41	164
CH	243	98	98	97	96	389
CZ	4753	1860	1860	1840	1820	7380
DE	44914	24123	15833	23927	34751	98634
ES	28292	16400	16400	16222	16044	65066
FI	6251	2652	2295	4029	4436	13412
FR	27888	14527	14527	14369	14212	57635
GR	5392	3216	3216	3181	3147	12760
HR	238	164	117	141	164	586
HU	2852	1151	1151	1139	1126	4567
IE	2748	1602	1280	1898	2105	6885
IT	24662	14225	7257	8979	11961	42422
NL	6474	3687	2514	3356	5561	15118
NO	1460	710	566	1226	1259	3761
PL	16643	9092	9092	8994	8895	36073
PT	5916	3107	2352	2806	3385	11650
RO	5562	3557	3284	3284	3557	13682
SE	12414	4671	4880	7809	8593	25953
SI	622	358	269	358	447	1432
SK	2294	915	915	904	895	3629
UK	30074	16251	13508	21029	21939	72727
Total	245308	113102	94479	111744	129489	448814

Table 50: Wind generation capacity (MW) and seasonal production (GWh) assumed for the simulations in the different countries in the GR-FT 2030 scenario.

5.2.2.3.2 Photovoltaic solar power plants

As for photovoltaic solar power plants, in the countries not considered in [8] the estimated installed generation capacity in 2015 can be considered basically negligible. As for year 2030, installed capacity data have been taken from the results of the three POLES scenarios (MT, EA and GR-FT).

Just like in [8], data concerning the annual / monthly production of each installed kW at optimal inclination have been taken from the *Photovoltaic Geographical Information System* (PVGIS) of the JRC - *Joint Research Centre* [23]), while the hourly generation profiles have been built on the basis of the average daily hours of light in each month taken from [24].

The generation capacity and the annual production of photovoltaic solar power plants assumed for the simulations in the different countries in the 2030 scenarios are reported in the following tables.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	969	968	966
BG	133	151	157
BL	623	560	571
BT	60	57	56
BX	48	38	39
CH	296	268	302
CZ	1443	1444	1444
DE	11217	11209	11213
ES	10973	9789	10012
FI	132	172	175
FR	16864	16864	16864
GR	3689	3683	3682
HR	14	11	12
HU	78	80	80
IE	67	63	64
IT	13875	13875	13875
NL	190	232	215
PL	30	31	31
PT	1578	1574	1574
RO	50	98	100
SE	1262	712	868
SI	802	808	818
SK	427	348	351
UK	107	119	116
Total	64927	63154	63585

Table 51: Photovoltaic solar generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	1151	1147	1143
BG	383	436	451
BL	581	523	532
BT	173	164	160
BX	137	109	111
CH	753	671	767
CZ	1709	1712	1712
DE	11209	11201	11205
ES	21884	18472	19114
FI	360	472	482
FR	22004	22005	22005
GR	5442	5425	5424
HR	40	32	34
HU	224	231	230
IE	193	182	183
IT	19325	19325	19325
NL	173	211	195
PL	86	87	87
PT	2333	2324	2323
RO	142	283	287
SE	3579	1993	2442
SI	1589	1609	1630
SK	594	502	506
UK	104	115	112
Total	94168	89231	90460

Table 52: Photovoltaic solar annual production (GWh) assumed for the simulations in the different countries in the 2030 scenarios.

5.2.2.3.3 Other RES + waste

To estimate the electricity production of other renewable energy sources (biomass, biogas, geothermal, etc.) and of waste non-CHP power plants, like in [8] a value of 4500 equivalent full-load annual hours has been taken into account⁶. Moreover, a flat generation profile has been assumed.

Concerning the countries not considered in [8], data for the 2015 scenario have been taken from [11], [12], [13] and [14] and are reported in the following Table 53.

As for year 2030, data concerning the annual electricity production have been taken from the results of the three POLES scenarios (MT, EA and GR-FT).

The generation capacity and the annual production of such power plants assumed for the simulations in the 2030 scenarios in the different countries are reported in the following Table 54 and Table 55.

⁶ A more detailed estimation for each source has been carried out for Italy.

Country	Net generation capacity [MW]	Electricity production [GWh]
DE ⁷	8400	37797
FI	201	904
IE	168	756
Rest of Europe	9568	46570
Total	18337	86027

Table 53: “Other RES + waste” non-CHP generation capacity (MW) and annual production (GWh) assumed for the simulations in the different countries in the 2015 scenario.

Country	Net generation capacity [MW]		
	MT	EA	GR-FT
AT	861	1256	1203
BG	250	3028	3239
BL	657	956	1392
BT	371	766	1237
CH	418	373	414
CZ	965	1971	2159
DE	5884	16302	17473
ES	526	3064	4825
FI	3482	4382	4471
FR	1933	3624	4084
GR	100	481	510
HR	71	62	72
HU	977	2128	2370
IE	542	1351	890
IT	2488	3328	3841
NL	4957	9544	9489
NO	199	178	198
PL	1726	6327	8380
PT	283	698	1137
RO	497	1251	1857
SE	4905	5756	6705
SI	47	44	83
SK	563	1554	1777
UA_W	29	26	39
UK	2389	3684	3471
Total	35120	72134	81316

Table 54: “Other RES + waste” generation capacity (MW) assumed for the simulations in the different countries in the 2030 scenarios.

⁷ Data modified w.r.t. what reported in [8], according to more updated information.

Country	Electricity production [GWh]		
	MT	EA	GR-FT
AT	1858	3083	3573
BG	1856	10262	11524
BL	3331	5333	7482
BT	2303	3474	4469
CH	1623	1488	1534
CZ	3827	12291	13403
DE	43146	118630	127180
ES	1315	8369	12342
FI	17556	21698	22189
FR	9385	9352	13678
GR	711	2879	3287
HR	402	338	403
HU	4011	6328	7536
IE	778	3955	2225
IT	15977	21820	27355
NL	12674	41442	44223
NO	773	710	734
PL	13441	37488	45112
PT	1862	3901	5814
RO	3217	8640	10894
SE	7809	11341	9608
SI	193	250	442
SK	3636	4096	3853
UA_W	229	205	307
UK	9621	13555	20408
Total	161534	350928	399575

Table 55: “Other RES + waste” annual production (GWh) assumed for the simulations in the different countries in the 2030 scenarios.

5.2.3 Other scenario assumptions

Just like in [8], concerning year 2015, in most cases the other main scenario assumptions have been derived from the POLES scenario “*GR-FT Global Regime with Full Trade*”, since in that year the various POLES scenarios are quite similar.

In fact, their differences become evident mainly after 2020 till 2050, i.e. in the second part of the considered time horizon: for this reason, for year 2030, data specific for each POLES scenario have been taken into account, as reported in the following.

5.2.3.1 Fuel prices

Like in [8], oil, coal and gas prices have been directly taken from the POLES scenarios, while lignite and fuel oil prices have been calculated as indexed to coal and oil prices, respectively.

The nuclear fuel price has been derived by the POLES scenario’s fuel costs of nuclear generation, assuming an average electrical efficiency of 34,2%.

Fuel	Price [€/GJ]
Coal	1.936
Lignite	0.871
Gas	5.076
Fuel Oil	8.358
Nuclear	0.428
Coal CCS ⁸	2.408

Table 56: Fuel prices assumed for year 2015 in the simulations.

Fuel	Price [€/GJ]		
	MT	EA	GR-FT
Coal	2.223	2.197	2.122
Lignite	1.001	0.989	0.955
Gas	6.340	6.248	5.655
Fuel Oil	11.800	11.303	10.398
Nuclear	0.485	0.485	0.508
Coal CCS ⁸	2.696	2.669	2.595
Gas CCS ⁹	6.812	6.721	6.127

Table 57: Fuel prices assumed for year 2030 in the simulations.

⁸ CO₂ transportation and storage costs, estimated equal to 5 €/tCO₂, are here included in the fuel price proportionally to its carbon content: for coal it corresponds to about 0.472 €/GJ.

⁹ CO₂ transportation and storage costs, estimated equal to 5 €/tCO₂, are here included in the fuel price proportionally to its carbon content: for natural gas it corresponds to about 0.279 €/GJ.

5.2.3.2 CO₂ emissions value

The CO₂ emissions value for year 2015 is 13.25 €/tCO₂, as in the GR-FT scenario. In the different 2030 scenarios CO₂ emissions values are the ones reported in Table 58.

	MT	EA	GR-FT
CO₂ emissions value [€/tCO₂]	24.26	90.28	63.26

Table 58: CO₂ emissions values in the different 2030 scenarios.

5.2.3.3 Electricity demand

Also for the countries not considered in [8], the annual values of the 2015 electrical load (final consumptions plus network losses; pumped storage consumption not included: see paragraph 5.2.2.2.2) have been taken from the GR-FT scenario, except for Norway, whose data are not detailed in POLES. Since the overall 2015 European load is quite similar to the 2008 one, Norway's 2015 load has been assumed equal to the 2008 one. The considered annual load values for the 2015 scenario are reported in the following Table 59.

Country	Final consumption + network losses [GWh]		
	2008	2015	Δ%
BT	25669	25226	-1.73
FI	85223	86121	1.05
IE	28903	27834	-3.70
NO	125879	125879	0.00
SE	156228	149294	-4.44
UK	340022	366114	7.67
Rest of Europe	2614046	2588412	-0.98
Total	3375970	3368880	-0.21

Table 59: 2008 and 2015 annual electrical load values for the considered countries.

As for year 2030, data have been taken from the three POLES scenarios or, in case of countries whose data are aggregated in POLES, data have been extrapolated on the basis of the share that each country had in 2008 in the aggregate of countries considered by POLES.

The considered annual load values for the 2030 scenarios are reported in the following Table 60.

Country	Final consumption + network losses [GWh]		
	MT	EA	GR-FT
AT	76764	72905	73371
BG	42760	38702	39876
BL	119525	109452	111057
BT	31730	29385	29323
BX	100443	96009	91548
CH	67341	65924	65761
CZ	87272	80683	81285
DE	721219	658956	668815
ES	391627	381346	375822
FI	105162	102066	102570
FR	629152	604302	602042
GR	85628	77650	77640
HR	25140	24031	22914
HU	51525	48376	48221
IE	36543	34924	35010
IT	366876	362064	362488
NL	158043	151753	151415
NO	134722	131887	131561
PL	188913	173414	173210
PT	72476	66778	67435
RO	65510	62999	63357
SE	171391	165121	164555
SI	18894	17972	17893
SK	31804	29570	29604
UA_W	6161	6148	5944
UK	483641	455429	457234
Total	4270262	4047846	4049951

Table 60: 2030 annual electrical load values for the considered countries.

As for the hourly profile, each country's 2008 profile has been taken from the ENTSO-E Statistical Database (see [2][7]), then it has been scaled according to the 2015 or 2030 / 2008 annual load ratio. The last step has been to align the working days and the holidays of 2015 or 2030 with those of 2008.

Concerning the countries not considered in [8], load profiles have been either taken or estimated using data from [25], [26], [27], [28], [29][30][31] and [32].

5.2.3.4 VOLL (Value Of Lost Load)

As reported in [33], VOLL estimation is a very difficult task and the results obtained are subject to several uncertainties. On the basis of the broad ranges and on the considerations reported in [34], we decided to subdivide the European countries taken into account into three groups:

- totally developed countries, characterized by a 20 €/kWh VOLL value;
- developed countries which still have growth margins higher than those included in the first group, characterized by a 10 €/kWh VOLL value;
- developing countries, characterized by a 3,5 €/kWh VOLL value.

Since the MTSIM simulator does not allow to specify VOLL values for each country, a single “European” VOLL value has been determined calculating the average of each country’s value, weighted on the corresponding 2015 electrical load.

With these assumptions, the resulting VOLL value is equal to 16.36 €/kWh.

In any case, it must be taken into account that the precision of the definition of such a value is definitely not critical for the results of the simulations: it is sufficient to get the right order of magnitude.

5.2.3.5 Costs of cross-border network expansion

As far as network expansion is concerned, we used the average cost data considered within the context of the FP7 REALISEGRID project (see [3]), based on publicly available sources and information from TSOs and from manufacturers. Of course, it must be taken into account that cost values may vary depending on different parameters, such as line characteristics (such as type, length, power rating, voltage level) as well as on several local factors, like manpower costs, environmental constraints, geographical conditions, etc.

In particular, the main assumptions are the following:

- ***HVAC overhead lines***

- average line length: 80 km
- average investment cost (CAPEX): 50 k€/MW
- average local compensation costs: 15% CAPEX una tantum
- average O&M costs: 5% CAPEX yearly
- interest rate: 8%
- operating life: 40 years
- ⇒ annualized cost: **7322 €/MW**

- ***HVDC cables***

- average line length: 130 km
- average investment cost – cable: 220 k€/MW
- average investment cost – converters: 140 k€/MW
- average local compensation costs: no costs

- | | |
|----------------------|-------------------|
| ○ average O&M costs: | 5% CAPEX yearly |
| ○ interest rate: | 8% |
| ○ operating life: | 40 years |
| ⇒ annualized cost: | 48190 €/MW |

5.3 Results of the simulations

As above mentioned, we compared scenarios characterized by the developments of cross-border interconnections specified in chapter 3, mainly proposed by the different European TSOs (that we will call “*proposed expansion*”) [2][3][4][5][6], with the optimal developments determined by MTSIM (that we will call “*optimal expansion*”) in the different 2015 and 2030 scenarios.

Of course, the decision to build a cross-border transmission line is based on a detailed analysis of several factors that are not taken into account in the simulations carried out in the present study, nevertheless, even if approximated, the results reported in the following can provide an interesting insight on the optimality (in terms of costs) level of the European cross-border transmission network.

In particular, in this study MTSIM has been used to simulate the optimal behavior of the modeled European power system, having as objective function the cost (fuel, CO₂ allowances and network expansion) minimization. No market power exercise has been simulated, in order to focus on the “natural” best response of the modeled power system.

As far as security of supply is concerned, the main general result of the simulations is that in no one of the considered scenarios there is Energy Not Supplied (ENS): this means that the modelled generation / transmission system is always able to supply the load.

In the following, for each considered scenario, we report the main results concerning:

- impact on congestion,
- impact on electricity prices,
- impact on fuel consumption,
- impact on CO₂ emissions,
- impact on costs.

5.3.1 2015 scenario

5.3.1.1 Impact on congestion

In the 2015 scenario, the simulation determined the optimal expansion (w.r.t. the “proposed expansion”) of cross-border transmission network reported in the following Table 61.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC values (B→A) [MW]
ES→FR	6351	8951	8951
FR→DE	4713	7613	7763
DE→NO	1000	2600	2600
DE→SE	1000	2890	2830
FR→UK	1000	3000	3000
CH→AT	744	1944	1944
BG→GR	689	2189	2089
BX→RO	621	921	1271
FI→NO	469	569	569
DE→PL	456	2056	1956
SK→UA_W	345	745	745
IT→SI	275	925	925
RO→UA_W	266	666	666
HU→UA_W	222	872	872
CH→DE	90	3290	1590
HU→BX	39	639	639

Table 61: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2015 scenario.

In Figure 6, Figure 7, Figure 8 and Figure 9 a comparison between the percentages of hours with congestion (i.e. when the power flow saturates the interconnection transmission capacity) in the different cross-border interconnections in July and in December 2015 with the “proposed expansion” and with the “optimal expansion” is reported.

In the July 2015 “optimal expansion” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

In the December 2015 “optimal expansion” scenario, congestion is still reduced, even if in a less significant way than in July 2015.

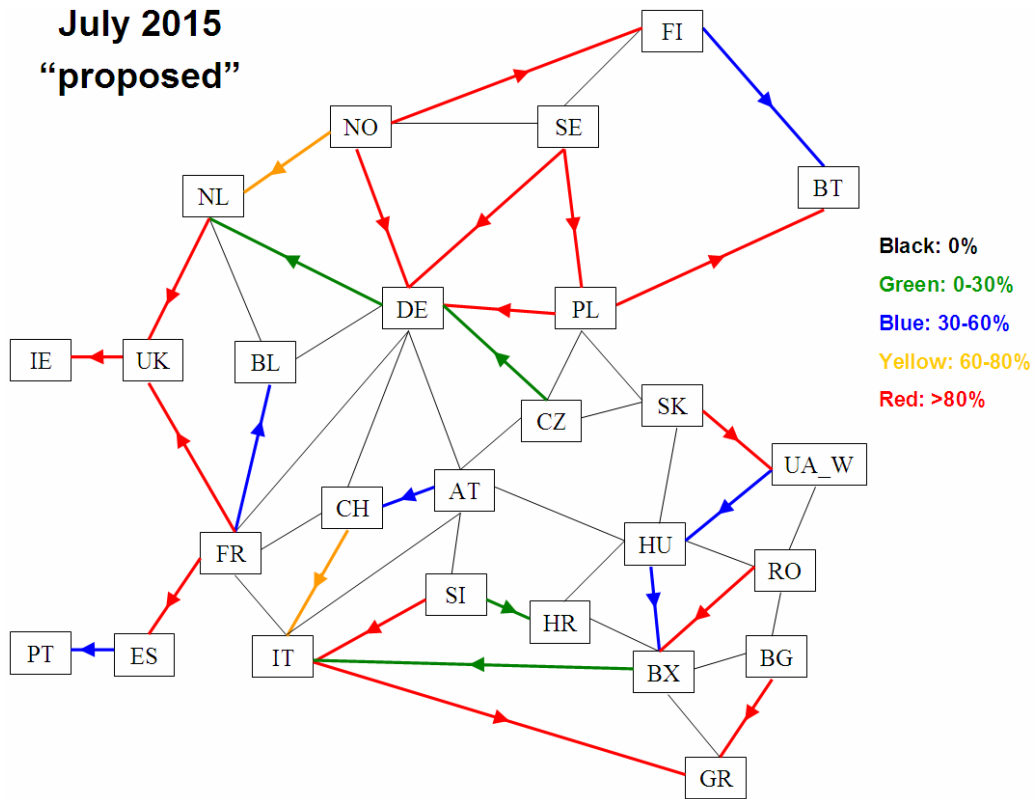


Figure 6: Percentages of hours with congestion in July 2015 with the “proposed expansion”.

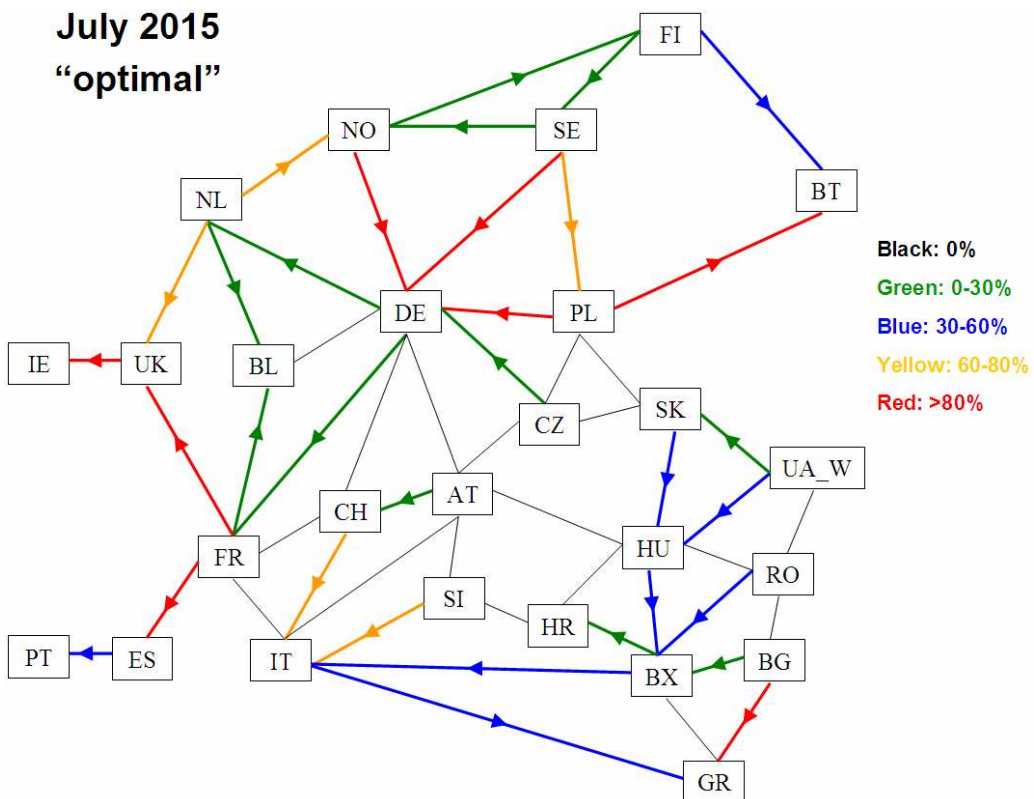


Figure 7: Percentages of hours with congestion in July 2015 with the “optimal expansion”.

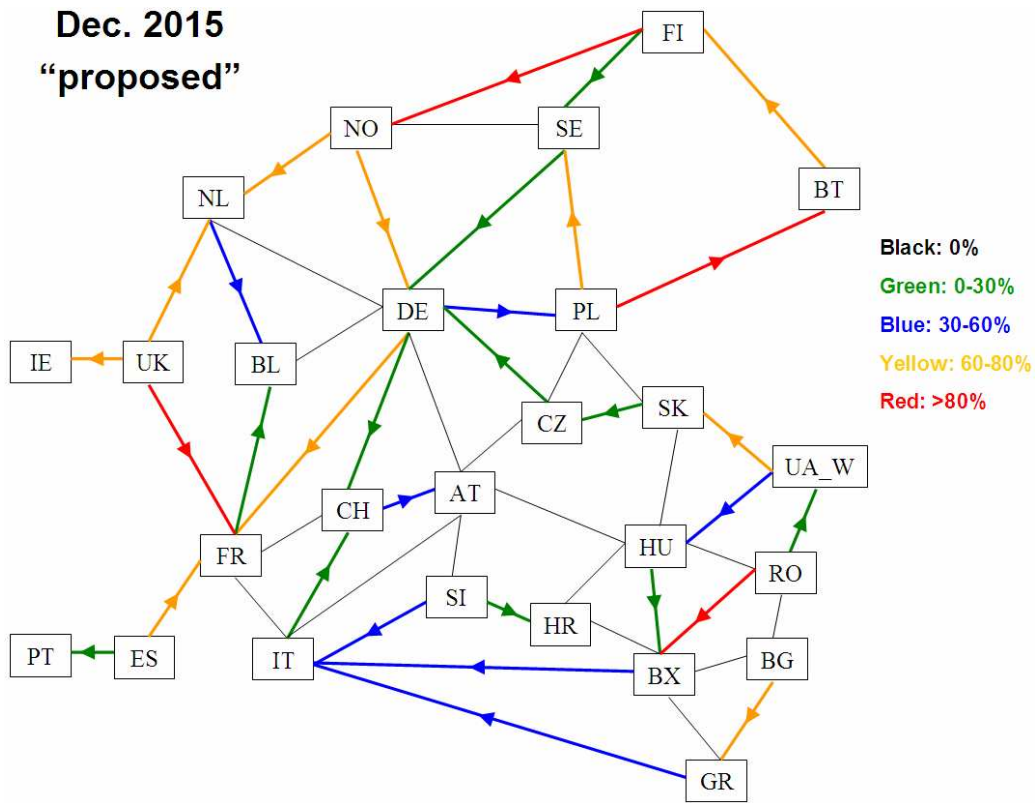


Figure 8: Percentages of hours with congestion in December 2015 with the “proposed expansion”.

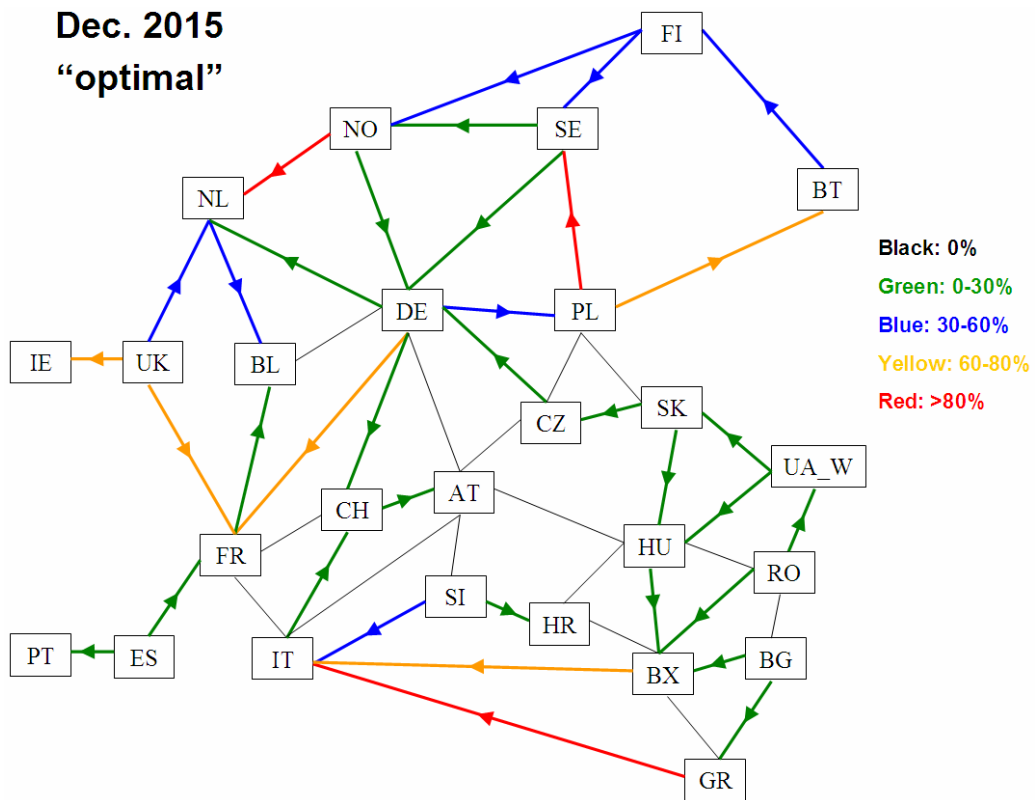


Figure 9: Percentages of hours with congestion in December 2015 with the “optimal expansion”.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- “*proposed expansion*”: throughout the year, the percentage of congested hours is almost always over 80% and from May to August the interconnection is completely saturated;
- “*optimal expansion*”: congestion significantly decreases and no month shows a complete saturation; July is the only month that remains still critical, with a percentage over 80%.

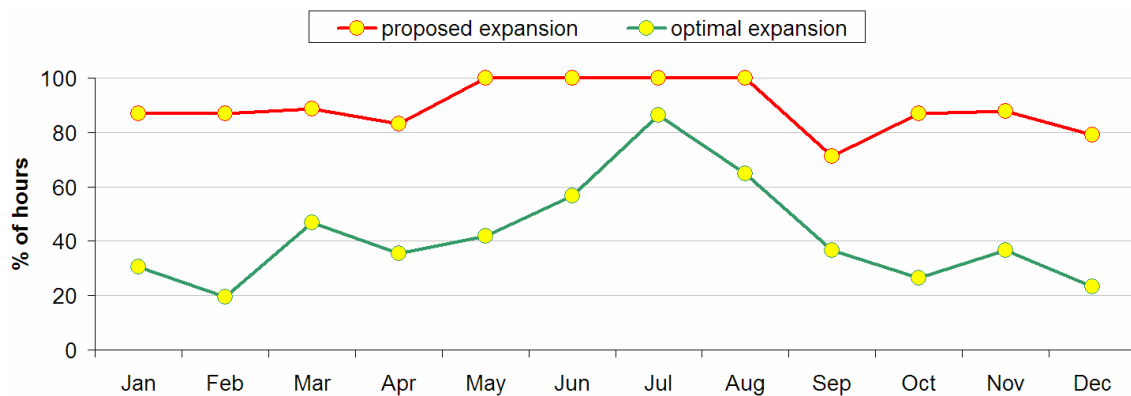


Figure 10: Percentages of congested hours in the France – Spain interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Poland (PL) – Germany and Denmark West (DE)

- “*proposed expansion*”: the most critical period is summer (from May to August), when the interconnection is almost completely saturated;
- “*optimal expansion*”: congestion decreases significantly in summer, except July, whereas in winter the situation is similar to the “proposed expansion”.

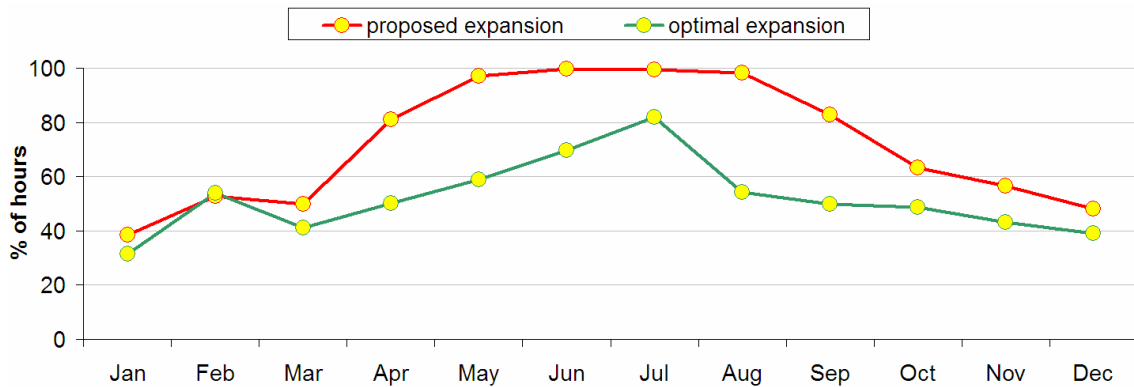


Figure 11: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Romania (RO) – Balkan countries (BX)

- “*proposed expansion*”: the percentage of congested hours is quite high, being near or over 80% from March to December;
- “*optimal expansion*”: congestion decreases dramatically, so that the highest values reach about 50% only in June and in July.

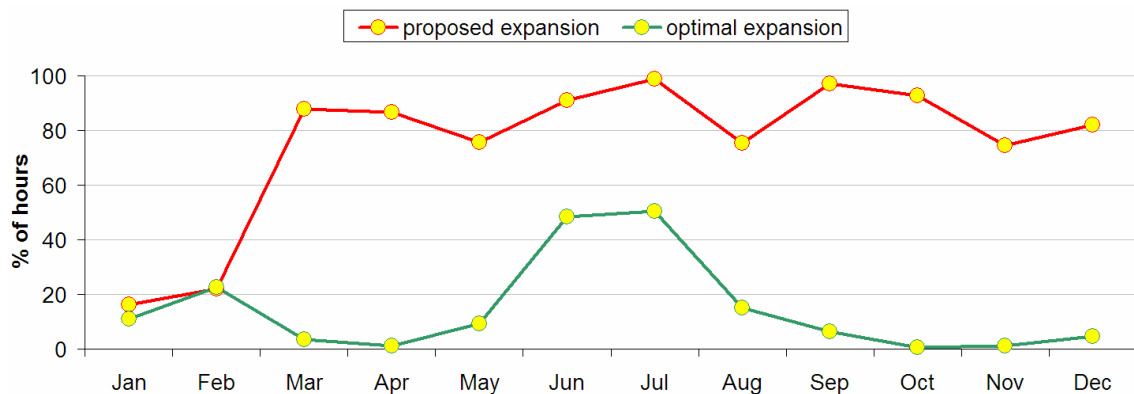


Figure 12: Percentages of congested hours in the Romania – Balkan countries interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Bulgaria (BG) – Greece (GR)

- “*proposed expansion*”: the interconnection is highly congested in summer, with a complete saturation in July;
- “*optimal expansion*”: congestion decreases, but less significantly during the summer months; in July the situation remains critical reaching a value close to 90%.

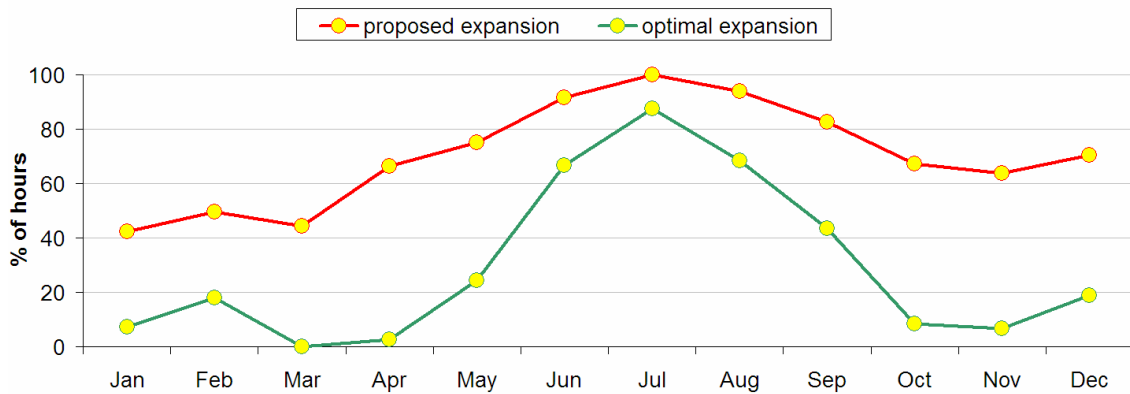


Figure 13: Percentages of congested hours in the Bulgaria – Greece interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Norway (NO) – Finland (FI)

- “*proposed expansion*”: congestion situation is very critical throughout the entire year, being almost always over 80%, with a complete saturation in July;
- “*optimal expansion*”: congestion situation improves significantly, especially during spring and summer.

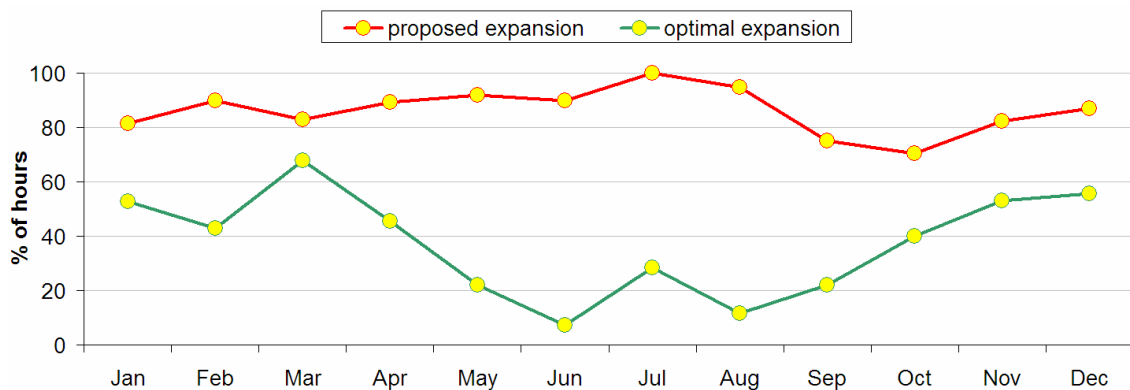


Figure 14: Percentages of congested hours in the Norway – Finland interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

France (FR) – United Kingdom (UK)

- “*proposed expansion*”: congestion situation remains critical throughout the entire year and, in particular, during the summer period, when a complete saturation occurs from May to August;
- “*optimal expansion*”: congestion situation improves slightly during the summer period, even though, throughout the year, the percentage remains always above 65%.

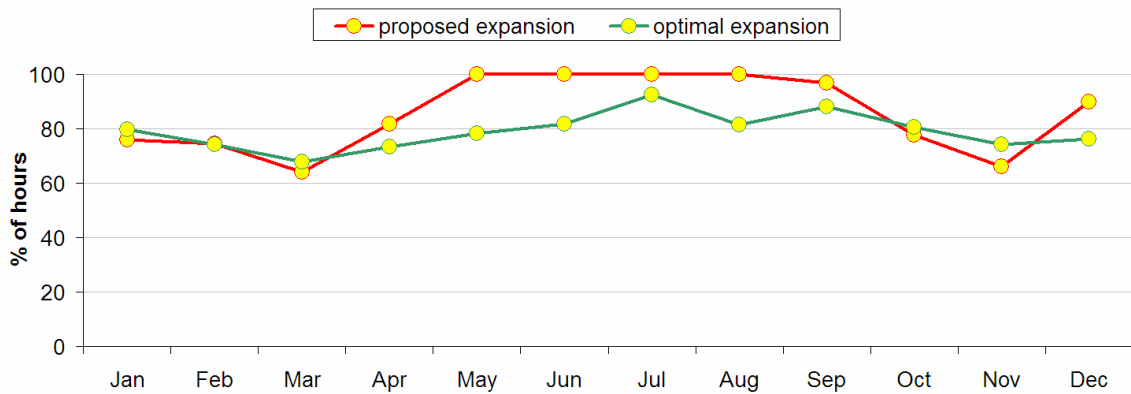


Figure 15: Percentages of congested hours in the France – United Kingdom interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Norway (NO) – Germany and Denmark West (DE)

- “*proposed expansion*”: congestion situation remains very critical throughout the summer period between June and September, with an almost complete saturation;
- “*optimal expansion*”: congestion situation improves throughout the year, but it remains relatively critical in June, July and August, when the percentage is always over 80%.

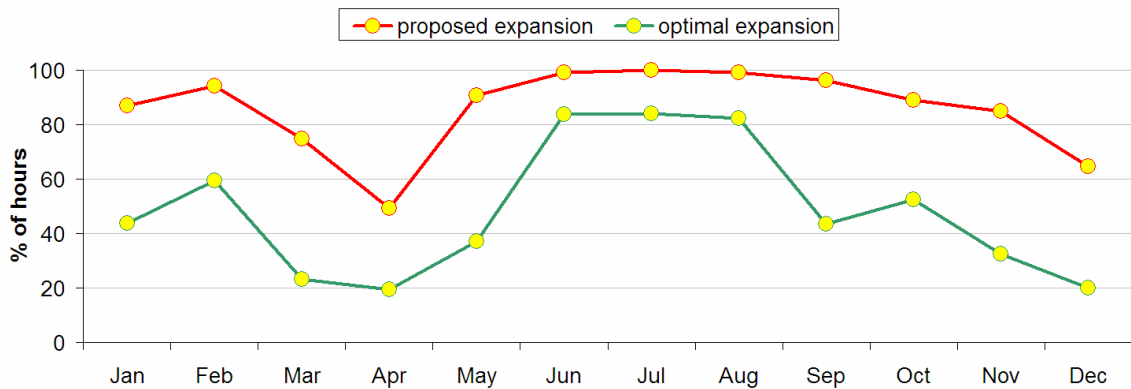


Figure 16: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- “*proposed expansion*”: congestion situation is very critical during the summer period between May and August, since the percentage remains above 95% and it reaches a full saturation in July;
- “*optimal expansion*”: congestion situation improves slightly, but it remains critical during the period between May and August, with values over 90%.

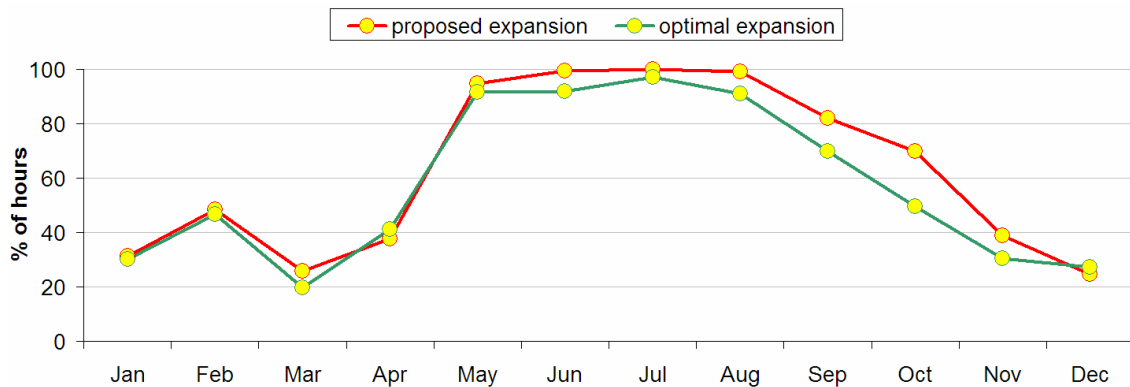


Figure 17: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

Sweden and Denmark East (SE) – Poland (PL)

- “*proposed expansion*”: congestions situation is relatively critical throughout the entire year and, in particular, in July when a complete saturation occurs;
- “*optimal expansion*”: the redistribution of power flows in the optimal expansion scenario improves congestion situation during the summer period between May and August, while it worsen during the rest of the year.

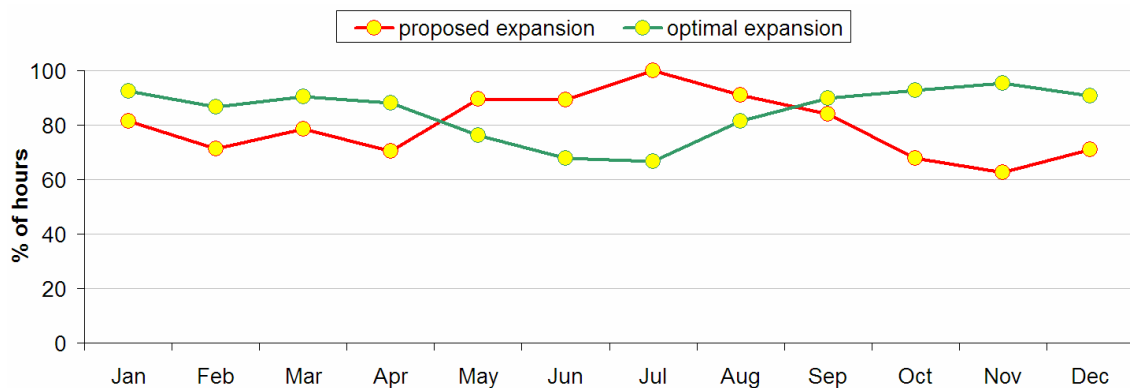


Figure 18: Percentages of congested hours in the Sweden and Denmark East – Poland interconnection in the “proposed expansion” and in the “optimal expansion” 2015 scenarios.

5.3.1.2 Impact on electricity prices

In a zonal electricity market, like the one modeled in the present study, congestion causes price differentiation between the zones. Therefore, it is interesting to see how electricity prices (or, better, marginal generation costs, in our case) vary when cross-border network is “optimally” expanded, w.r.t. the “proposed expansion” scenario.

In this way it is possible to determine “winners” and “losers”, i.e countries where the optimal expansion causes, respectively, a decrease or an increase of electricity prices.

In the following Figure 19 “winners” are shown in green, and “losers” are shown in red. The reported numerical values are the differences between the annual average zonal prices in the “optimal expansion” and in the “proposed expansion” scenarios. It can be noted that the main “winners” in this scenario are Poland, Portugal and Spain, while the main “losers” are Sweden and Denmark East, France, Austria, Romania, Bulgaria and Slovenia.

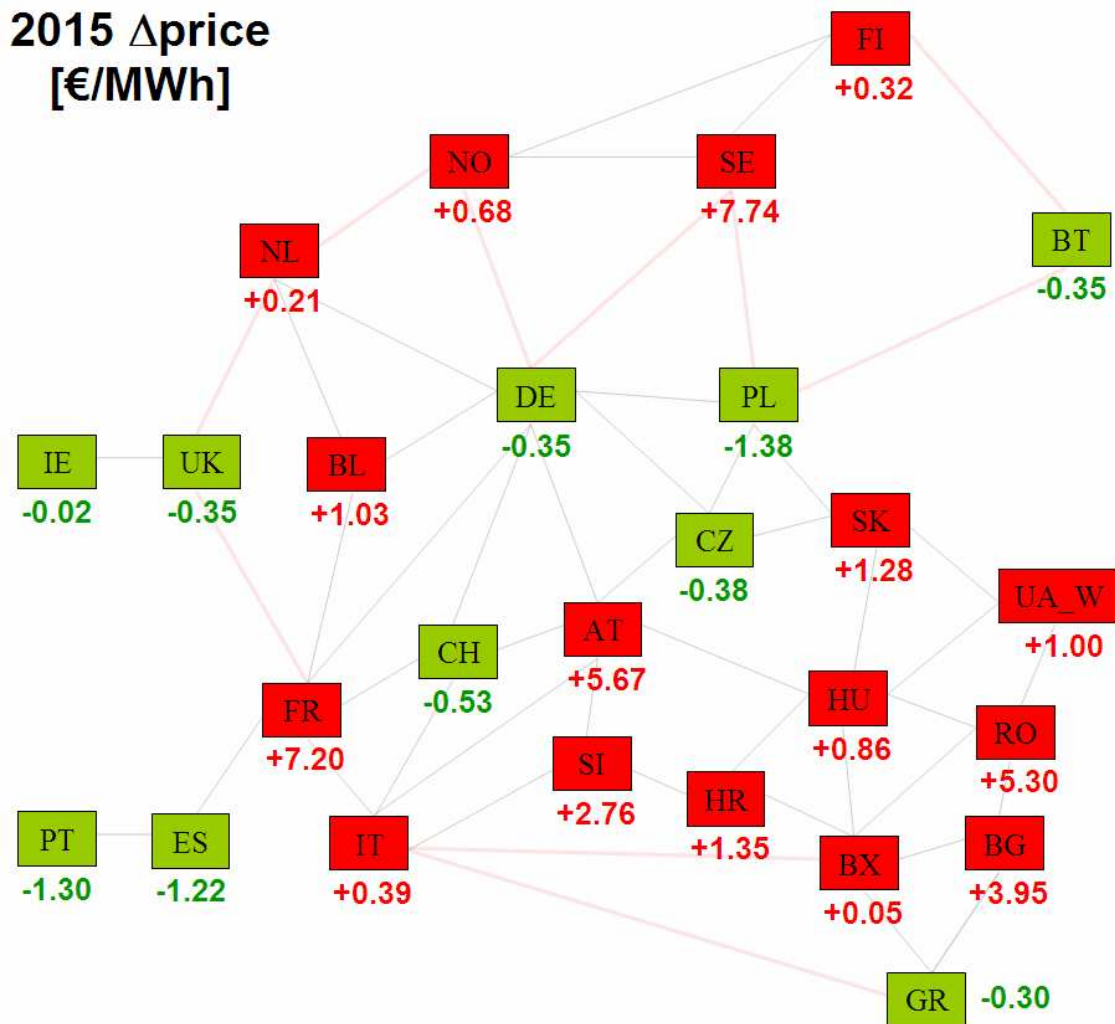


Figure 19: Zonal price differences between the “optimal expansion” and the “proposed expansion” 2015 scenarios.

5.3.1.3 Impact on fuel consumption

In the following Table 62, a comparison between electricity production by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

The consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal and lignite) at the expense of mid-merit / peak-load natural gas fired power plants.

In Table 63 the corresponding data in terms of fuel consumption are reported: the greater use of less efficient generation technologies slightly increases total fuel consumption.

Fuel	“proposed expansion” [GWh]	“optimal expansion” [GWh]	Δ [GWh]	Δ%
Nuclear	915363	929249	13886	1.5
Hard coal	609131	616591	7460	1.2
Lignite	277575	280048	2473	0.9
Natural gas	216890	193070	-23820	-11.0
Fuel oil	-	-	-	-
Coal CCS	25017	25017	-	-

Table 62: Comparison between electricity generation by different fuels of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2015 scenarios (GWh).

Fuel	“proposed expansion” [PJ]	“optimal expansion” [PJ]	Δ [PJ]	Δ%
Nuclear	9482.9	9625.7	142.8	1.5
Hard coal	6246.9	6323.9	77	1.2
Lignite	2865.9	2891.8	25.9	0.9
Natural gas	1553.4	1389.1	-164.3	-10.6
Fuel oil	-	-	-	-
Coal CCS	200.1	200.1	-	-
Total	20349.2	20430.6	81.4	0.4

Table 63: Comparison between fuel consumption of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2015 scenarios (PJ).

5.3.1.4 Impact on CO₂ emissions

In the following Table 64 a comparison between CO₂ emissions by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

Due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO₂ emissions slightly increase, by about **660 ktCO₂**.

Fuel	“proposed expansion” [MtCO ₂]	“optimal expansion” [MtCO ₂]	Δ [MtCO ₂]	Δ%
Hard coal	587.21	594.45	7.24	1.2
Lignite	289.68	292.30	2.62	0.9
Natural gas	86.99	77.79	-9.20	-10.6
Fuel oil	-	-	-	-
Coal CCS	1.88	1.88	-	-
Total	965.76	966.42	0.66	0.07

Table 64: Comparison between CO₂ emissions of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2015 scenarios (MtCO₂).

5.3.1.5 Impact on costs

In the following Table 65 a comparison between each cost item of the modelled power system in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

It can be noted that a significant reduction of fuel costs (about 600 M€) is partially compensated especially by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **335 millions of Euros**.

Cost item	“proposed expansion” [M€]	“optimal expansion” [M€]	Δ [M€]	Δ%
Fuel consumption	27017	26416	-601	-2.2
CO ₂ emissions allowances	12793	12802	9	0.1
Investments / O&M AC lines	-	112	112	-
Investments / O&M DC lines	-	145	145	-
TOTAL COSTS	39810	39475	-335	-0.8

Table 65: Comparison between costs of the modeled power system in the “proposed expansion” and in the “optimal expansion” 2015 scenarios (M€).

5.3.2 2030 “MT – Muddling Through” scenario

5.3.2.1 Impact on congestion

In the 2030 MT scenario, the simulation determined the optimal expansion (w.r.t. the “*proposed expansion*”) of cross-border transmission network reported in the following Table 66.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	5612	8512	8662
DE→PL	4501	7001	6901
SK→UA_W	3097	3497	3497
ES→FR	2835	6835	6835
BX→RO	2425	2925	3275
RO→UA_W	1759	2159	2159
IT→SI	1555	3705	3705
HR→BX	1424	3634	3624
UK→NO	1400	2800	2800
CZ→SK	1382	3382	2382
DE→SE	1000	3490	3430
FI→BT	1000	2000	2000
IT→GR	1000	1500	1500
PL→BT	1000	2000	2000
SE→PL	1000	1600	1600
BX→BG	784	1534	1884
HU→RO	530	1130	1930
HU→BX	410	1010	1010
DE→CZ	336	2636	4136
FR→BL	160	4160	3260
HR→SI	158	2058	2058
IT→AT	77	2277	2277
UK→IE	77	1377	1007
FI→NO	64	164	164
CZ→PL	9	809	2009

Table 66: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2030 MT scenario.

MT - July 2030
“proposed”

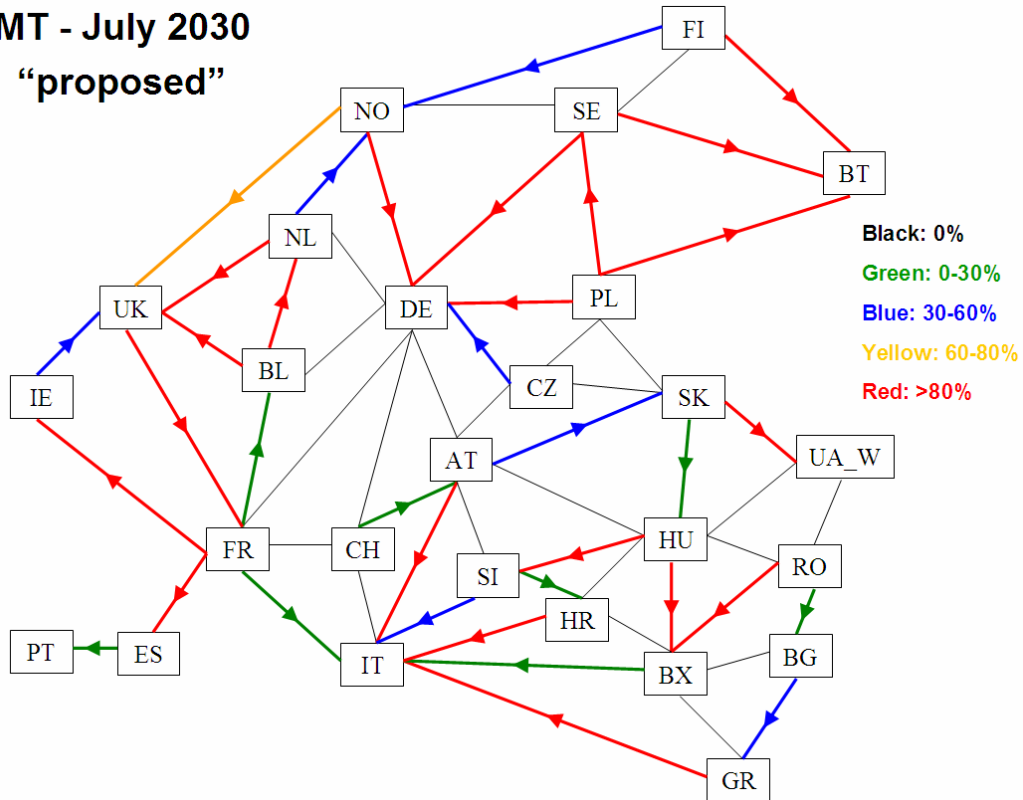


Figure 20: Percentages of hours with congestion in July 2030 with the “proposed expansion”.

MT - July 2030
“optimal”

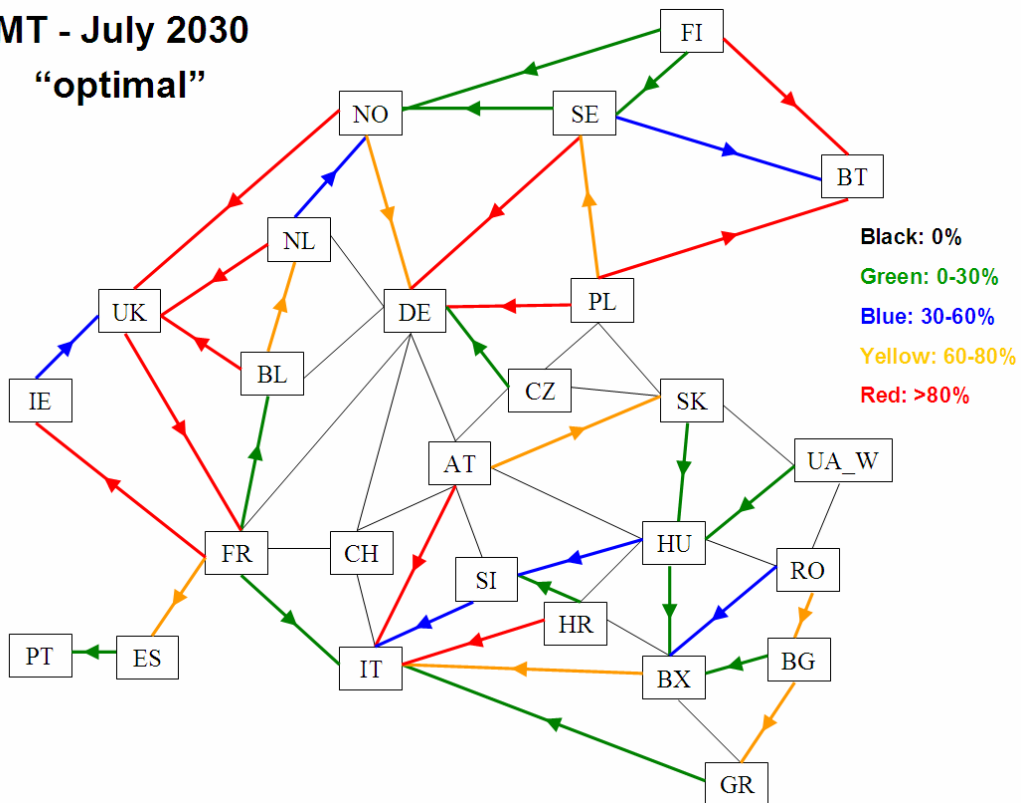


Figure 21: Percentages of hours with congestion in July 2030 with the “optimal expansion”.

MT - Jan. 2030
“proposed”

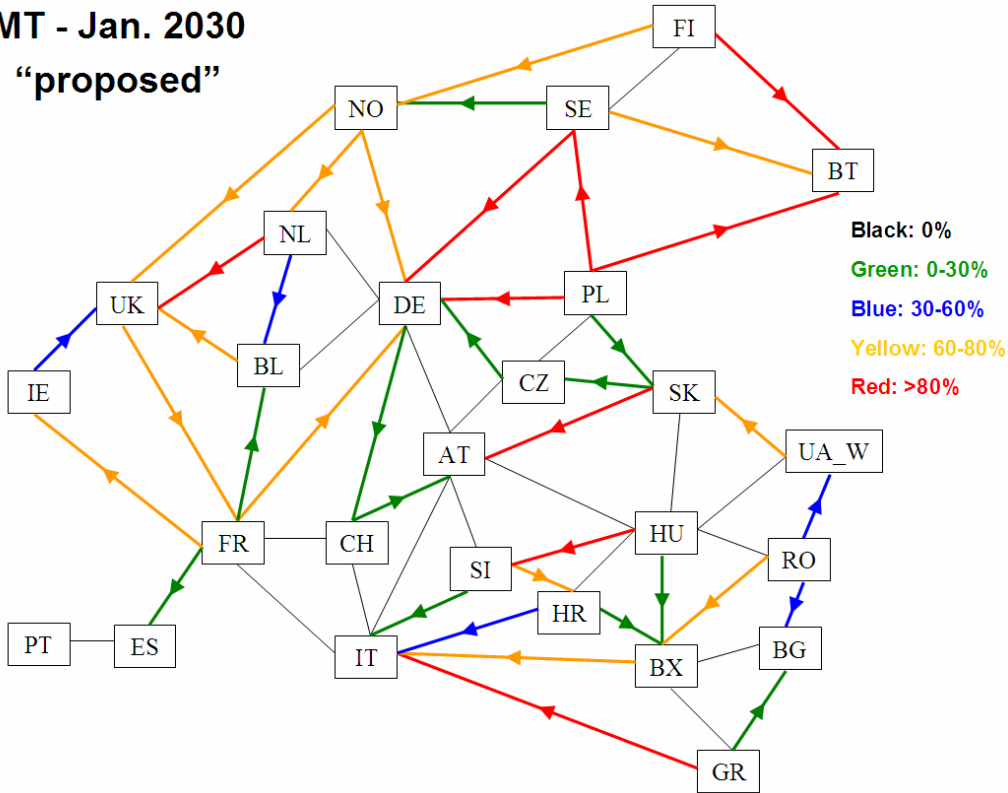


Figure 22: Percentages of hours with congestion in January 2030 with the “proposed expansion”.

MT - Jan. 2030
“optimal”

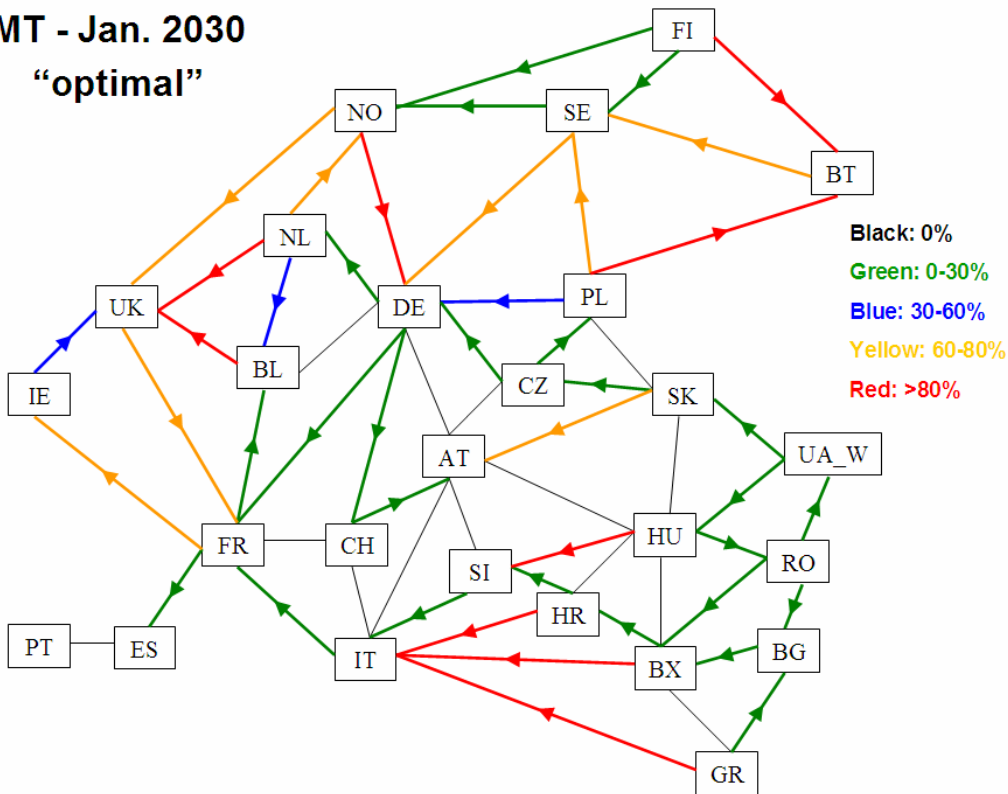


Figure 23: Percentages of hours with congestion in January 2030 with the “optimal expansion”.

In Figure 20, Figure 21, Figure 22 and Figure 23 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the “proposed expansion” and with the “optimal expansion” is reported.

In the July 2030 “optimal expansion” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

In the January 2030 “optimal expansion” scenario, congestion is still reduced, even if in a less significant way than in July 2030.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

Spain (ES) – France (FR)

- “*proposed expansion*”: congestion situation is critical from May to September, with an almost complete saturation in July and August; however, in the rest of the year, especially during winter months, congestion is not a problem;
- “*optimal expansion*”: congestions situation improves significantly throughout the year; only July remains critical, with a value around 80%.

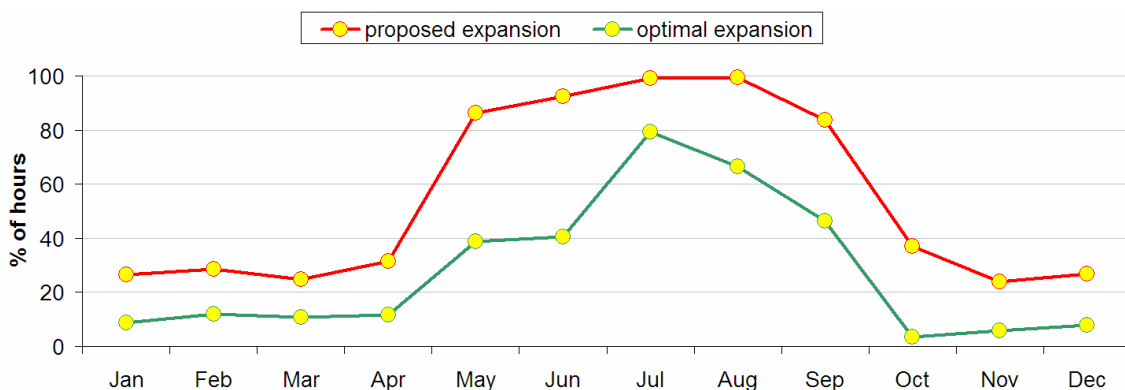


Figure 24: Percentages of congested hours in the Spain – France interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Poland (PL) – Germany and Denmark West (DE)

- “*proposed expansion*”: congestion situation is extremely critical throughout the whole year, with a complete saturation during nine months;
- “*optimal expansion*”: congestion situation improves especially in autumn and in winter; the percentage remains almost always in the range 60÷85%.

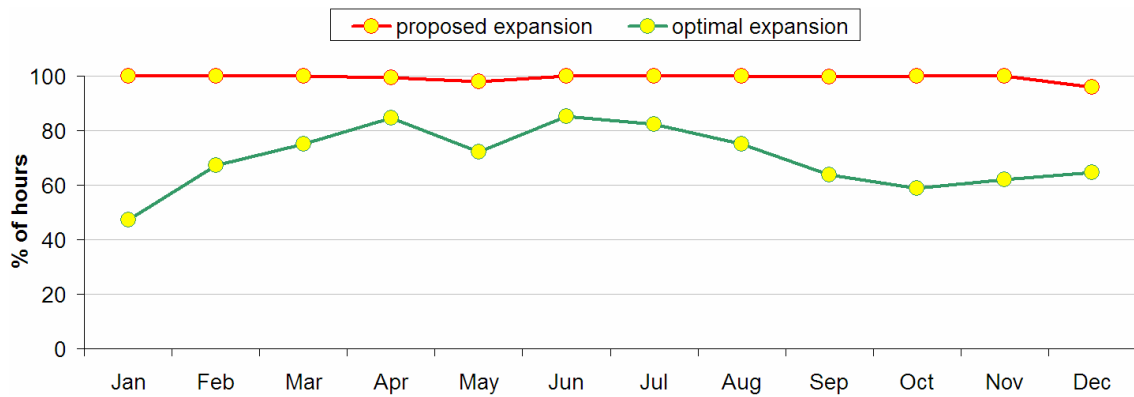


Figure 25: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Switzerland (CH) – Austria (AT)

- “*proposed expansion*”: the interconnection is completely saturated in April; congestion situation is relatively critical also in March, May, October and November;
- “*optimal expansion*”: congestion situation improves significantly in February, March and November, while in the remaining months there are no significant differences; the percentage in April is still high (93%).

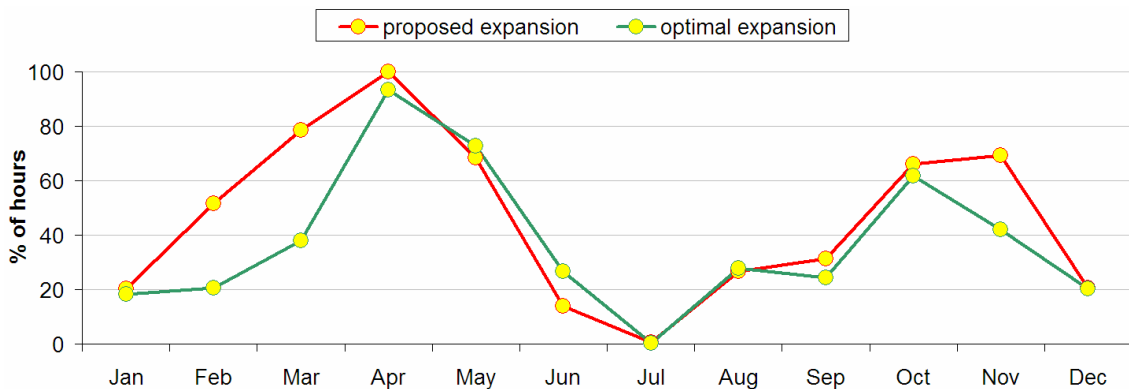


Figure 26: Percentages of congested hours in the Switzerland – Austria interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Austria (AT) – Italy (IT)

- “*proposed expansion*”: the interconnection is highly congested only during summer months, with a complete saturation in July; in winter there is no congestion;
- “*optimal expansion*”: congestion situation improves in a uniform manner, even though it remains quite critical in July (91%).

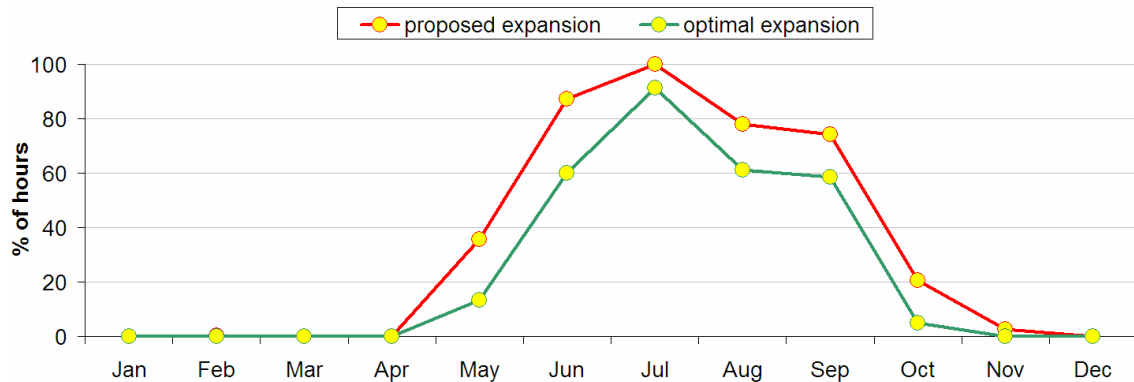


Figure 27: Percentages of congested hours in the Austria – Italy interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Romania (RO) – Balkan countries (BX)

- “proposed expansion”: congestion situation is quite critical between June and October, when the percentage is near full saturation;
- “optimal expansion”: congestions situation significantly improves throughout the year and in particular in autumn and winter, when congestion almost disappear.

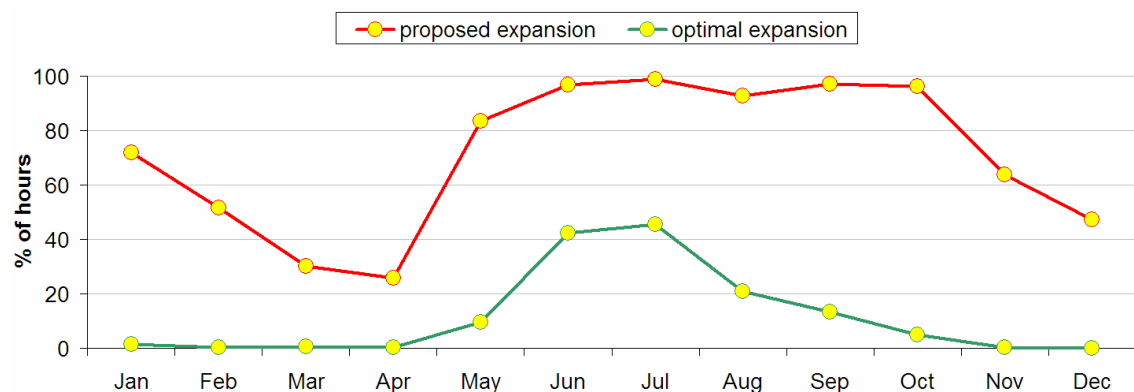


Figure 28: Percentages of congested hours in the Romania – Balkan countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Greece (GR) – Italy (IT)

- “proposed expansion”: the interconnection is completely saturated during autumn and winter; congestion situation is less critical in summer, even though the percentage is always greater than about 80%;
- “optimal expansion”: congestion situation improves significantly in summer, while in the rest of the year the situation remains critical.

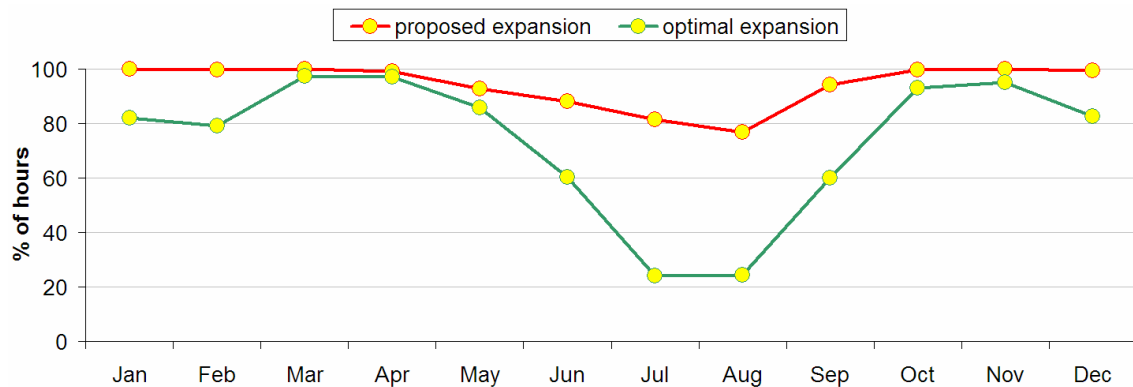


Figure 29: Percentages of congested hours in the Greece – Italy interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is fully saturated between June and October and in the other months congestion situation remains critical;
- “*optimal expansion*”: congestion situation improves significantly throughout the year, except in February and in July when it remains quite critical.

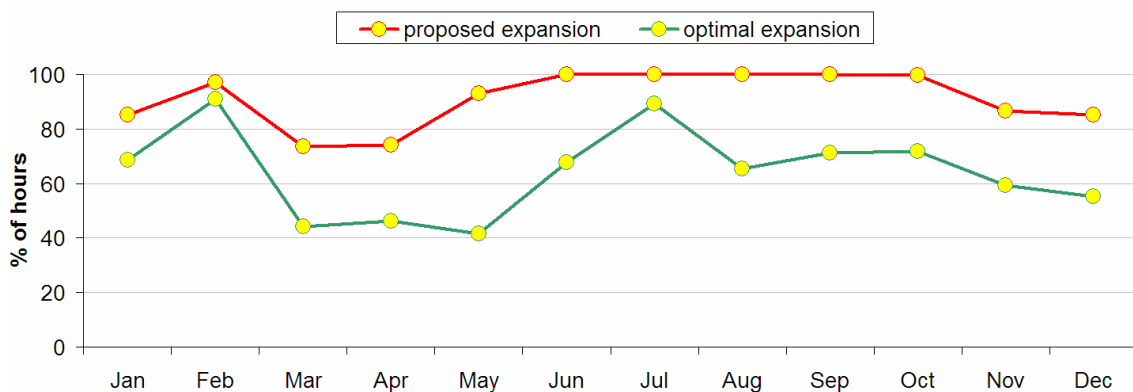


Figure 30: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Poland (PL) – Sweden and Denmark East (SE)

- “*proposed expansion*”: congestion situation is extremely critical throughout the whole year, with the interconnection almost completely saturated;
- “*optimal expansion*”: congestion situation improves in an almost uniform manner throughout the year.

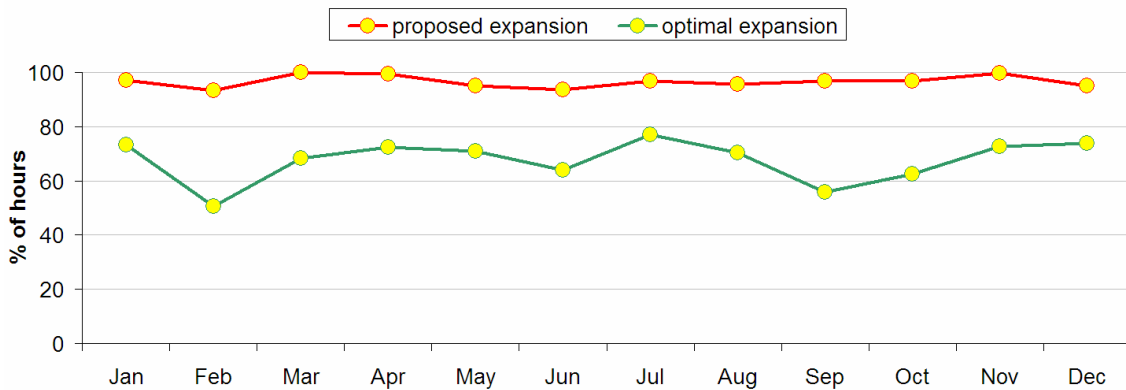


Figure 31: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Poland (PL) – Baltic countries (BT)

- “*proposed expansion*”: congestion situation is extremely critical throughout the whole year, with the interconnection almost always completely saturated;
- “*optimal expansion*”: congestion situation improves in an almost uniform manner throughout the year, even if it remains critical, with percentages around 80%.

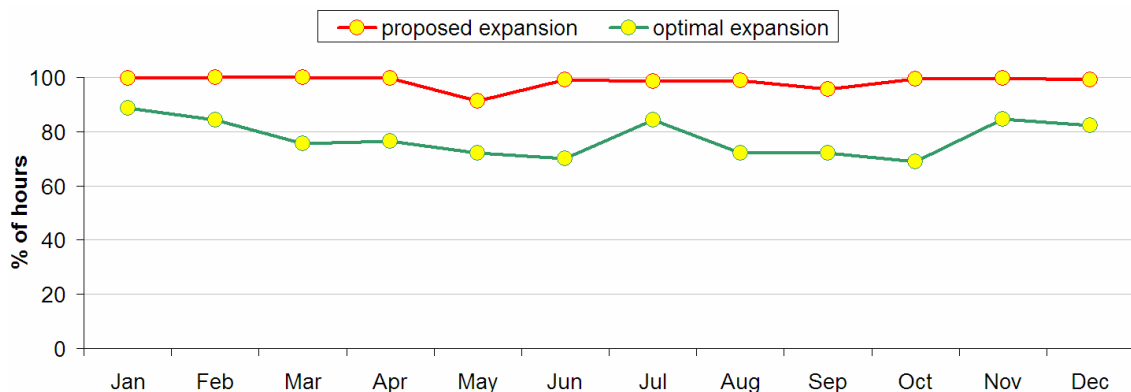


Figure 32: Percentages of congested hours in the Poland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

Finland (FI) – Baltic countries (BT)

- “*proposed expansion*”: congestion situation is extremely critical throughout the whole year, with the interconnection almost always completely saturated;
- “*optimal expansion*”: congestion situation improves slightly throughout the year, but it remains quite critical, since that the percentage remains around 90%.

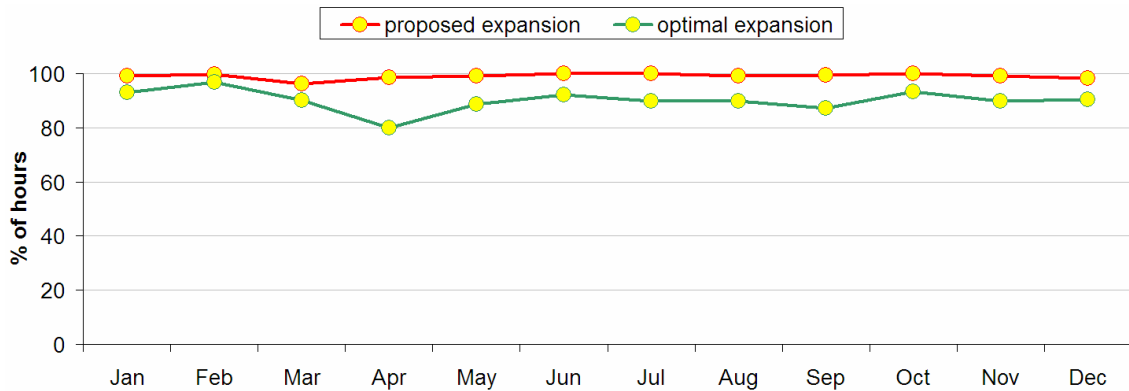


Figure 33: Percentages of congested hours in the Finland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios.

5.3.2.2 Impact on electricity prices

Similarly to paragraph 5.3.1.2, in Figure 34 we report the differences between the annual average zonal prices in the “optimal expansion” and in the “proposed expansion” scenarios.

It can be noted that the main “winners” in this scenario are United Kingdom, Germany, Baltic countries, Belgium, Ireland, The Netherlands and Switzerland while the main “losers” are Romania, Poland, Bulgaria, Ukraine West and Greece.

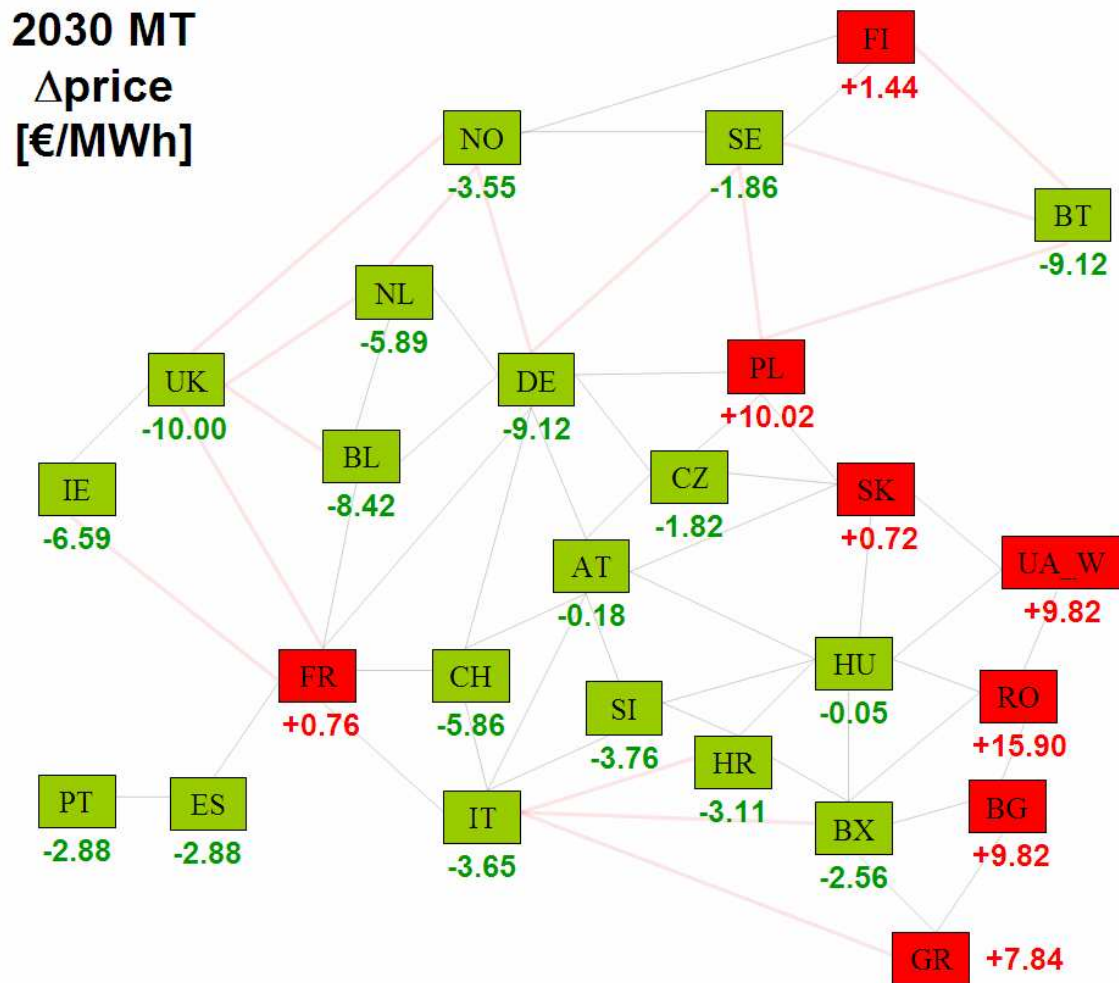


Figure 34: Zonal price differences between the “optimal expansion” and the “proposed expansion” 2030 MT scenarios.

5.3.2.3 Impact on fuel consumption

In the following Table 67, a comparison between electricity production by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

The consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by cheaper base-load power plants (nuclear, hard coal, lignite and power plants equipped with CCS technology) at the expense of mid-merit / peak-load natural gas and fuel oil fired power plants.

In Table 68 the corresponding data in terms of fuel consumption are reported: the greater use of less efficient generation technologies slightly increases total fuel consumption.

Fuel	“proposed expansion” [GWh]	“optimal expansion” [GWh]	Δ [GWh]	Δ%
Nuclear	842515	843056	541	0.1
Hard coal	1187927	1222786	34859	2.9
Lignite	219024	229668	10644	4.9
Natural gas	268503	223198	-45305	-16.9
Fuel oil	902	241	-661	-73.3
Coal CCS	41381	41460	79	0.2
Gas CCS	4307	4334	27	0.6

Table 67: Comparison between electricity generation by different fuels of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios (GWh).

Fuel	“proposed expansion” [PJ]	“optimal expansion” [PJ]	Δ [PJ]	Δ%
Nuclear	8673.3	8679.2	5.9	0.1
Hard coal	9777.6	10064.9	287.3	2.9
Lignite	2267.5	2376.1	108.6	4.8
Natural gas	1948.9	1579.9	-369	-18.9
Fuel oil	10.7	5.3	-5.4	-50.5
Coal CCS	334.0	334.7	0.7	0.2
Gas CCS	28.2	28.4	0.2	0.7
Total	23040.2	23068.5	28.3	0.1

Table 68: Comparison between fuel consumption of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios (PJ).

5.3.2.4 Impact on CO₂ emissions

In the following Table 69 a comparison between CO₂ emissions by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

Due to substitution of natural gas fired generation with less efficient and more emissive (apart from nuclear) power plants, overall CO₂ emissions increase, by about **16.9 MtCO₂**.

Fuel	“proposed expansion” [MtCO ₂]	“optimal expansion” [MtCO ₂]	Δ [MtCO ₂]	Δ%
Hard coal	919.10	946.10	27.00	2.9
Lignite	229.20	240.18	10.98	4.8
Natural gas	109.14	88.48	-20.66	-18.9
Fuel oil	0.82	0.41	-0.41	-50.0
Coal CCS	3.14	3.15	0.01	0.3
Gas CCS	0.24	0.24	-	-
Total	1261.64	1278.56	16.92	1.3

Table 69: Comparison between CO₂ emissions of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios (MtCO₂).

5.3.2.5 Impact on costs

In the following Table 70 a comparison between each cost item of the modelled power system in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

It can be noted that a significant reduction of fuel costs (about 1650 M€) is partially compensated by CO₂ emissions allowances and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **728 millions of Euros**.

Cost item	“proposed expansion” [M€]	“optimal expansion” [M€]	Δ [M€]	Δ%
Fuel consumption	41789	40139	-1650	-3.9
CO ₂ emissions allowances	30611	31022	411	1.3
Investments / O&M AC lines	-	199	199	-
Investments / O&M DC lines	-	312	312	-
TOTAL COSTS	72400	71672	-728	-1.0

Table 70: Comparison between costs of the modeled power system in the “proposed expansion” and in the “optimal expansion” 2030 MT scenarios (M€).

5.3.3 2030 “EA – Europe Alone” scenario

5.3.3.1 Impact on congestion

In the 2030 EA scenario, the simulation determined the optimal expansion (w.r.t. the “*proposed expansion*”) of cross-border transmission network reported in the following Table 71.

It can be noted that the expansion of the France – Germany and Denmark West interconnection is extremely high in this scenario, being around 17 GW, that could be unrealistic. In any case we remark that the objective of this study is not to determine the realistic cross-border network expansion potentials on each frontier (that would require an analysis site by site of a multitude of other factors outside the scope of this project), but the definition of “optimal” expansion levels to be considered as targets to which it would be convenient to go as near as possible.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	17019	19919	20069
DE→PL	6795	9295	9195
ES→FR	2178	6178	6178
SE→PL	2000	2600	2600
SK→UA_W	1949	2349	2349
BX→RO	1736	2236	2586
RO→UA_W	1415	1815	1815
DE→NO	1000	5000	5000
DE→SE	1000	3490	3430
FI→BT	1000	2000	2000
PL→BT	1000	2000	2000
FR→BL	804	4804	3904
CZ→SK	695	2695	2695
IT→AT	614	2814	2814
RO→BG	554	1504	1504
BX→BG	399	1149	1499
HU→RO	308	908	1708
HU→BX	261	861	861
FR→IT	211	4411	2806
CH→AT	71	1471	1471
BG→GR	40	1540	1440
UK→NO	3	1403	1403

Table 71: Optimal expansion values (additional capacity) and corresponding new NTC values (MW) in the 2030 EA scenario.

EA - July 2030

“proposed”

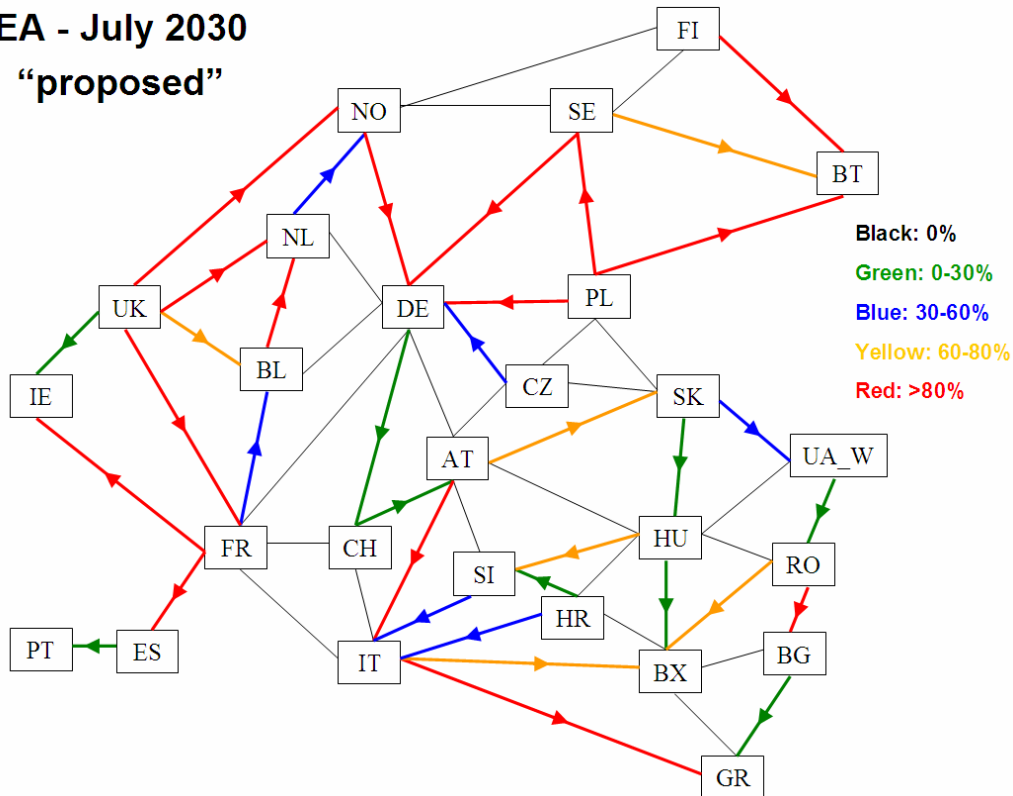


Figure 35: Percentages of hours with congestion in July 2030 with the “proposed expansion”.

EA - July 2030

“optimal”

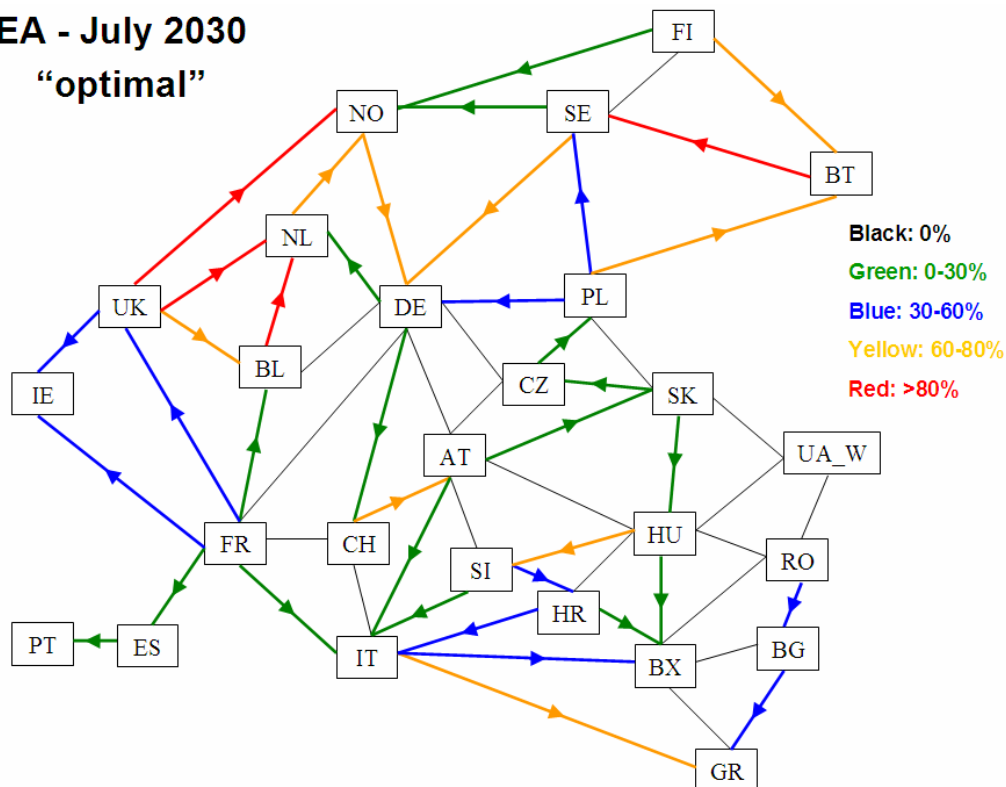


Figure 36: Percentages of hours with congestion in July 2030 with the “optimal expansion”.

EA - Jan. 2030

“proposed”

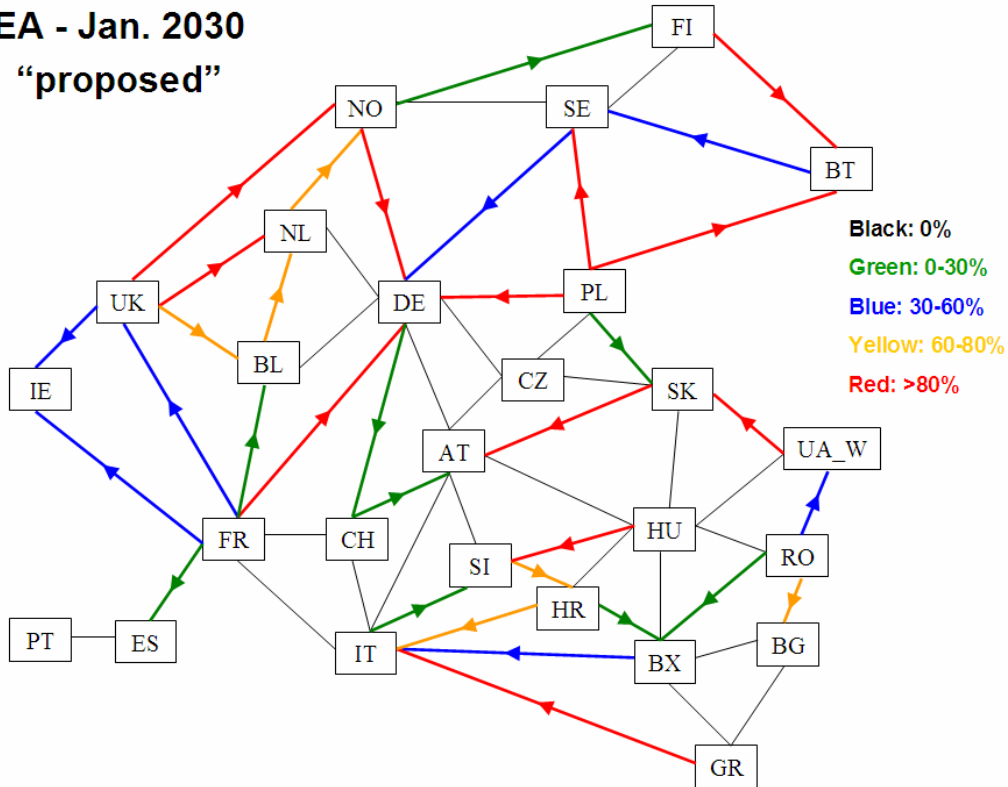


Figure 37: Percentages of hours with congestion in January 2030 with the “proposed expansion”.

EA - Jan. 2030

“optimal”

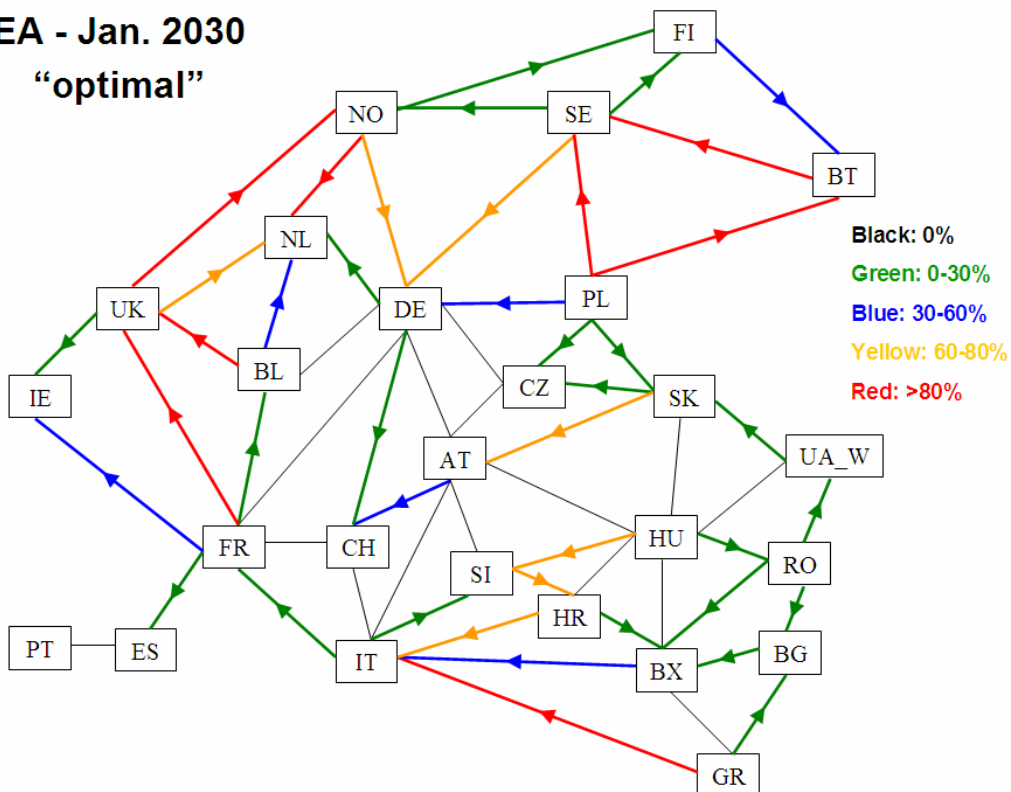


Figure 38: Percentages of hours with congestion in January 2030 with the “optimal expansion”.

In Figure 35, Figure 36, Figure 37 and Figure 38 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the “proposed expansion” and with the “optimal expansion” is reported.

In the July 2030 “optimal expansion” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is reduced to one third.

In the January 2030 “optimal expansion” scenario, congestion is still reduced, even if in a less significant way than in July 2030.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- “*proposed expansion*”: congestion situation is particularly critical between May and September, when the interconnection is almost completely saturated;
- “*optimal expansion*”: congestion dramatically decreases, with percentages below 20% throughout the year.

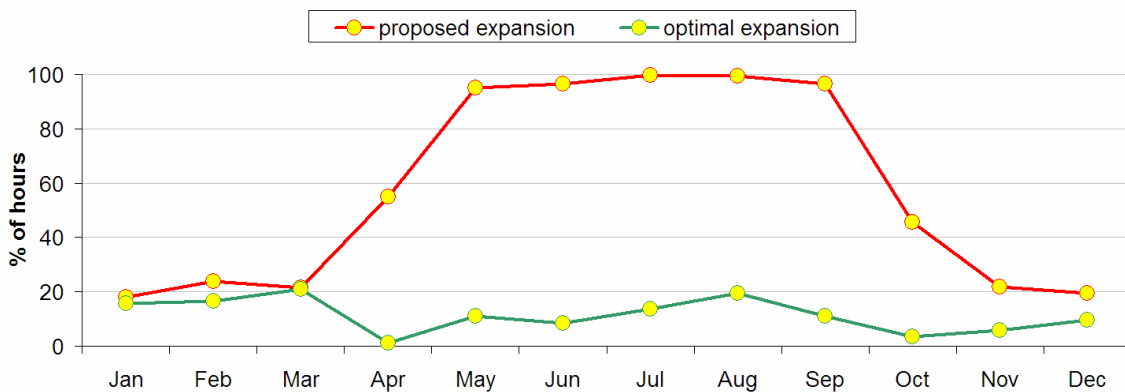


Figure 39: Percentages of congested hours in the France – Spain interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

France (FR) – Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is highly congested only between January and April and in October and November; from May to September there is no congestion at all;
- “*optimal expansion*”: in the previously congested months, congestion dramatically decreases, with percentages below 20%.

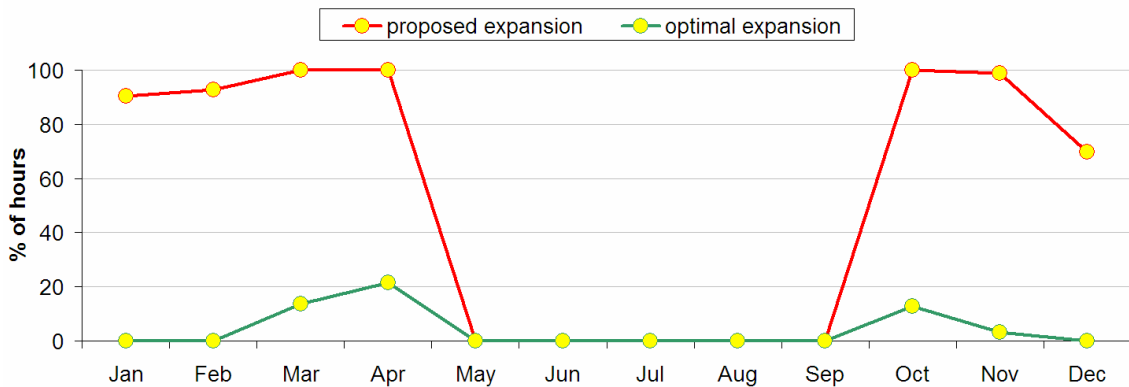


Figure 40: Percentages of congested hours in the France – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Belgium and Luxembourg (BL) – The Netherlands (NL)

- “*proposed expansion*”: congestion situation is quite critical throughout the year, with an almost complete saturation in several months, but with a slight improvement in winter;
- “*optimal expansion*”: congestion situation improves significantly; only in July and August percentages remain critical, around 80%.

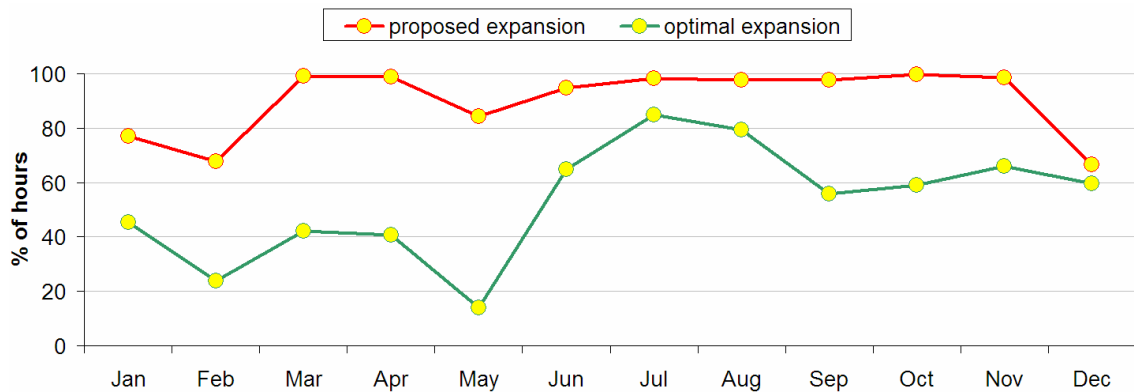


Figure 41: Percentages of congested hours in the Belgium and Luxembourg – The Netherlands interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Poland (PL) - Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is completely saturated throughout the entire year, except December;
- “*optimal expansion*”: congestion situation improves significantly, with percentages around 40% or below.

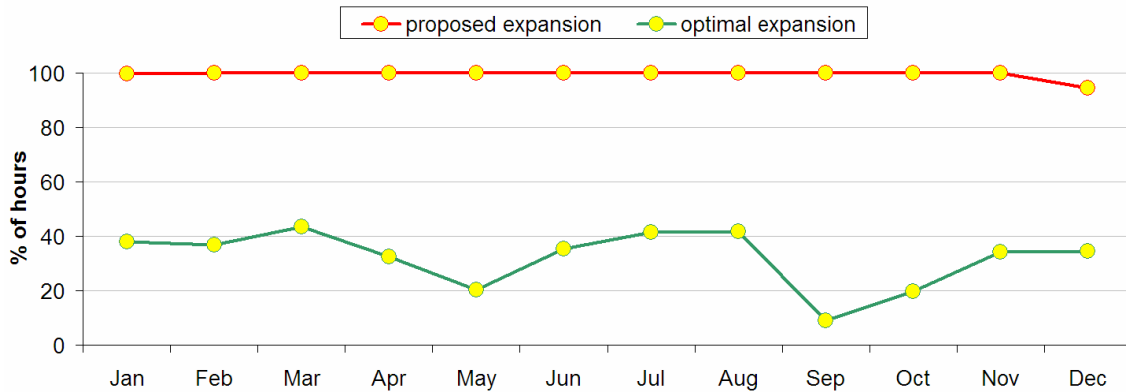


Figure 42: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Romania (RO) – Balkan countries (BX)

- “proposed expansion”: congestions situation is relatively critical from April to October, with a peak in May and in June, when the interconnection is almost completely saturated;
- “optimal expansion”: congestion dramatically decreases, with percentages below 20% throughout the year.

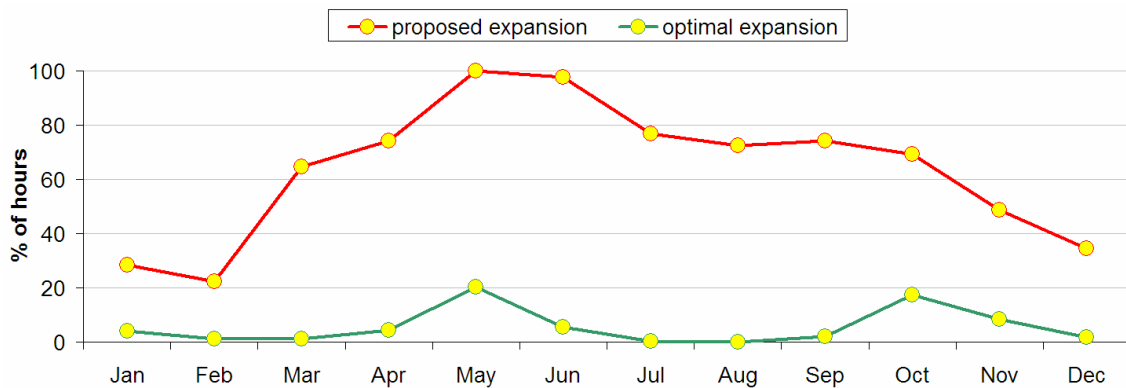


Figure 43: Percentages of congested hours in the Romania – Balkan countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

United Kingdom (UK) - Norway (NO)

- “proposed expansion”: congestion situation is quite critical throughout the year, with percentages almost always higher than 90%;
- “optimal expansion”: congestion situation improves a little, but it remains critical, with percentages higher than 80% throughout the year.

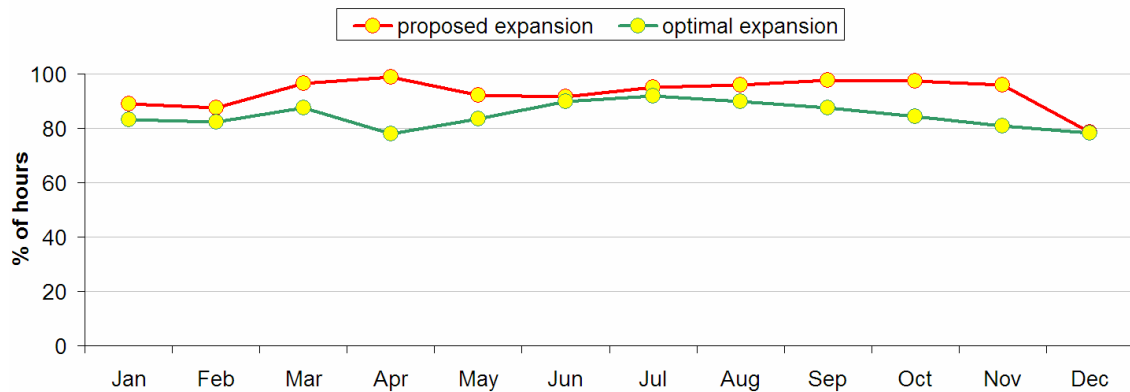


Figure 44: Percentages of congested hours in the United Kingdom – Norway interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

France (FR) - Republic of Ireland (IE)

- “proposed expansion”: congestion situation is highly critical in spring and in summer, with an almost complete saturation from May to August;
- “optimal expansion”: congestion situation improves in an almost uniform manner throughout the year, with percentages between 40% and 80%.

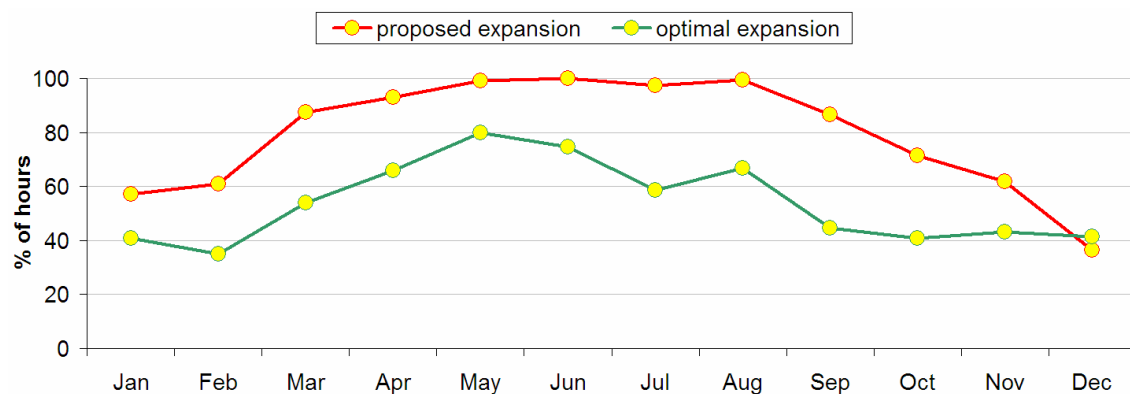


Figure 45: Percentages of congested hours in the France – Ireland interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

United Kingdom (UK) - France (FR)

- “proposed expansion”: congestion situation is very critical between May and August, when the interconnection is almost completely saturated;
- “optimal expansion”: congestion situation improves in spring and in summer, but worsen in autumn and in winter; percentages are almost always in the range 60% ÷ 85% throughout the year.

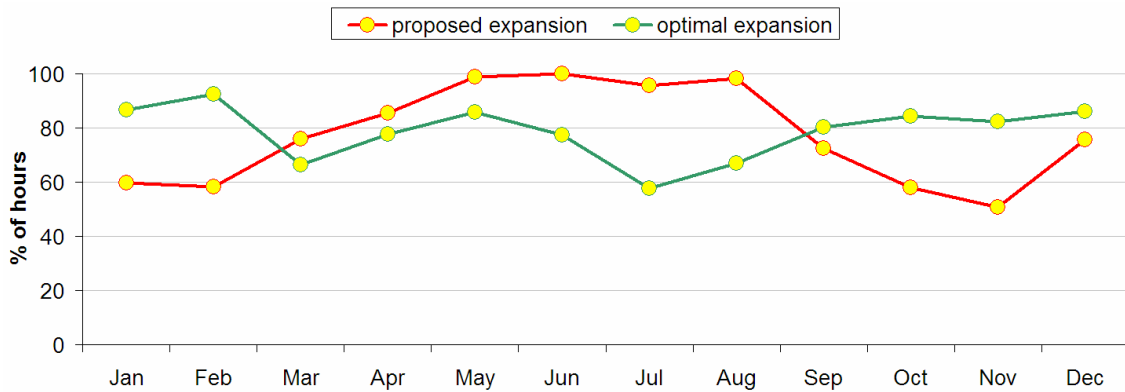


Figure 46: Percentages of congested hours in the United Kingdom – France interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Norway (NO) - Germany and Denmark West (DE)

- “*proposed expansion*”: congestion situation is extremely critical throughout the year, with the interconnection almost always saturated;
- “*optimal expansion*”: congestion situation improves significantly, with percentages always below 80%.

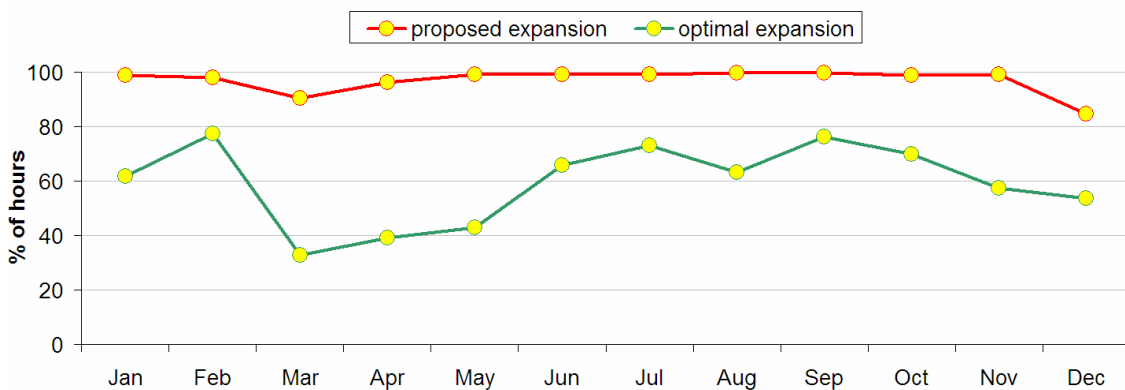


Figure 47: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Sweden and Denmark East (SE) - Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is completely saturated between June and September; in the remaining months, except February and October (90%), congestion situation is not critical;
- “*optimal expansion*”: congestion situation improves when it was more critical and worsen when it was less critical; percentages remain in the range 60% ÷ 80% throughout the year.

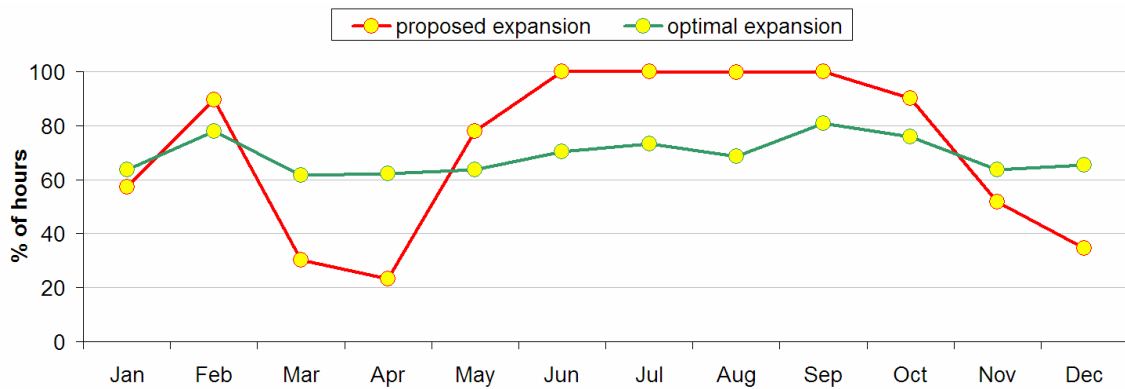


Figure 48: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Poland (PL) - Sweden and Denmark East (SE)

- “*proposed expansion*”: congestion situation is extremely critical, since the interconnection is completely saturated throughout the entire year;
- “*optimal expansion*”: congestion situation improves significantly, but only in spring and in summer.

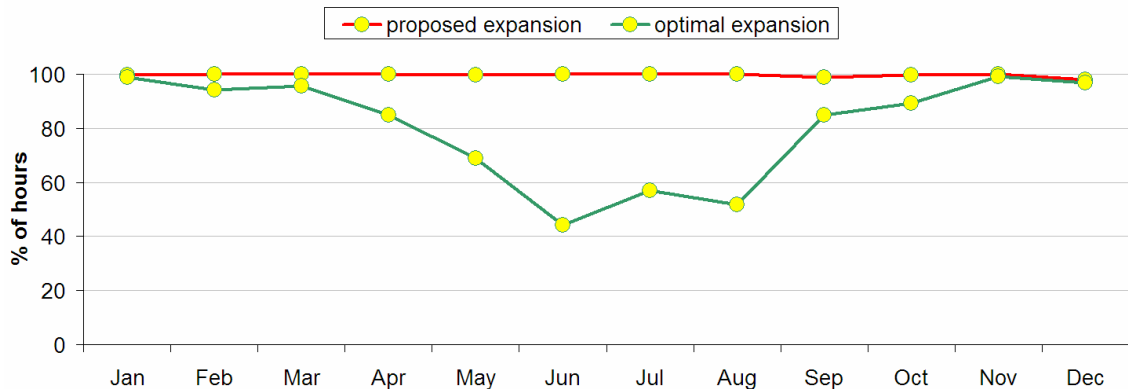


Figure 49: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Poland (PL) – Baltic countries (BT)

- “*proposed expansion*”: congestion situation is extremely critical, since the interconnection is almost completely saturated throughout the entire year;
- “*optimal expansion*”: congestion situation improves a little especially in summer, but percentages remain always over 80%.

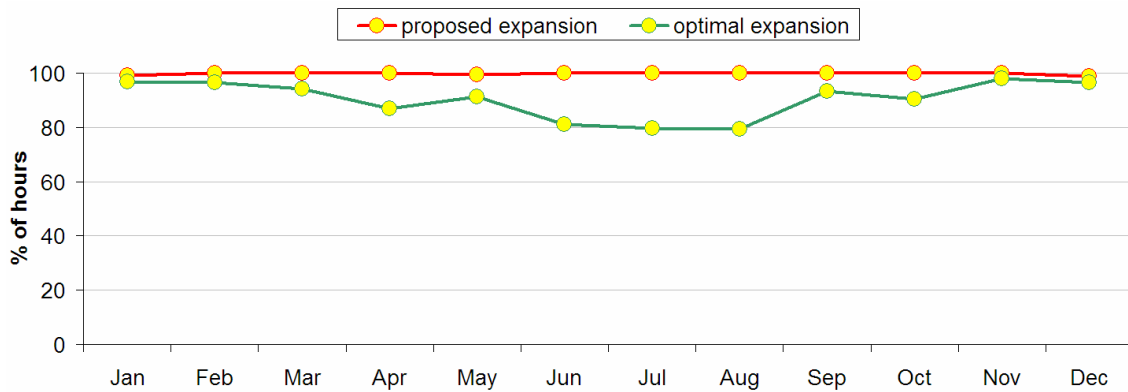


Figure 50: Percentages of congested hours in the Poland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

Finland (FI) – Baltic countries (BT)

- “proposed expansion”: congestion situation is highly critical throughout the year, since the interconnection is almost completely saturated;
- “optimal expansion”: congestion situation improves significantly with only a few months around 80%.

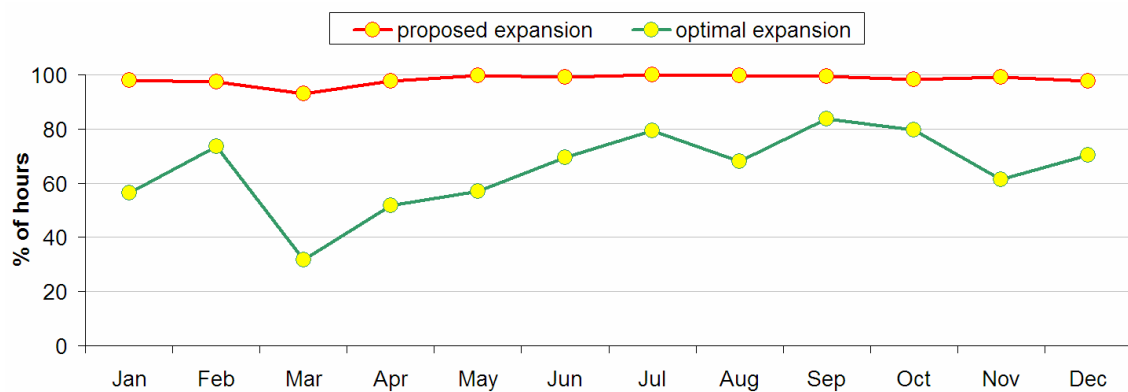


Figure 51: Percentages of congested hours in the Finland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios.

5.3.3.2 Impact on electricity prices

Similarly to paragraph 5.3.1.2, in Figure 34 we report the differences between the annual average zonal prices in the “optimal expansion” and in the “proposed expansion” scenarios.

It can be noted that the main “winners” in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main “losers” are Romania, France, Ukraine West, Poland, Bulgaria, and Greece.

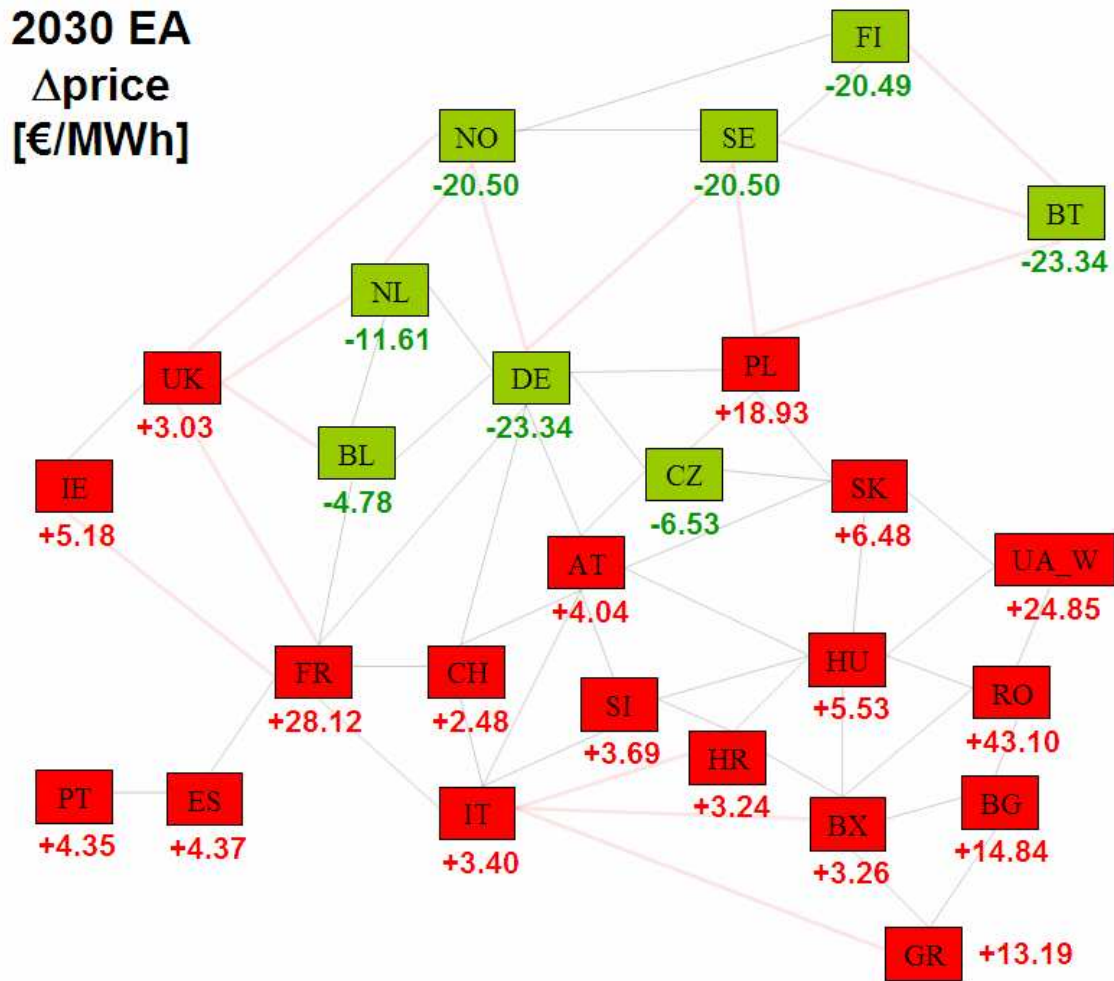


Figure 52: Zonal price differences between the “optimal expansion” and the “proposed expansion” 2030 EA scenarios.

5.3.3.3 Impact on fuel consumption

In the following Table 72, a comparison between electricity production by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

The consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO₂ emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the “Europe Alone” scenario is characterized by a very high CO₂ emissions value (about 90 €/tCO₂: see paragraph 5.2.3.2).

In Table 73 the corresponding data in terms of fuel consumption are reported: the greater use of less emissive generation technologies slightly decreases total fuel consumption.

Fuel	“proposed expansion” [GWh]	“optimal expansion” [GWh]	Δ [GWh]	Δ%
Nuclear	982103	1000961	18858	1.9
Hard coal	178057	133354	-44703	-25.1
Lignite	63056	43406	-19650	-31.2
Natural gas	317887	340532	22645	7.1
Fuel oil	11	0	-11	-100
Coal CCS	302703	319779	17076	5.6
Gas CCS	123269	128521	5252	4.3

Table 72: Comparison between electricity generation by different fuels of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (GWh).

Fuel	“proposed expansion” [PJ]	“optimal expansion” [PJ]	Δ [PJ]	Δ%
Nuclear	10064.1	10262.6	198.5	2.0
Hard coal	1581.5	1099.3	-482.2	-30.5
Lignite	649.3	448.0	-201.3	-31.0
Natural gas	2201.5	2329.0	127.5	5.8
Fuel oil	2.1	0	-2.1	-100
Coal CCS	2472.2	2611.8	139.6	5.6
Gas CCS	806.8	841.2	34.4	4.3
Total	17777.5	17591.9	-185.6	-1.0

Table 73: Comparison between fuel consumption of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (PJ).

5.3.3.4 Impact on CO₂ emissions

In the following Table 74 a comparison between CO₂ emissions by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

Due to substitution of more emissive generation with less emissive one, overall CO₂ emissions significantly decrease, by about **57 MtCO₂**.

Fuel	“proposed expansion” [MtCO ₂]	“optimal expansion” [MtCO ₂]	Δ [MtCO ₂]	Δ%
Hard coal	148.66	103.34	-45.32	-30.5
Lignite	65.63	45.29	-20.34	-31.0
Natural gas	123.28	130.52	7.24	5.9
Fuel oil	0.16	0	-0.16	-100
Coal CCS	23.24	24.55	1.31	5.6
Gas CCS	6.78	7.07	0.29	4.3
Total	367.75	310.77	-56.98	-15.5

Table 74: Comparison between CO₂ emissions of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (MtCO₂).

5.3.3.5 Impact on costs

In the following Table 75 a comparison between each cost item of the modelled power system in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

It can be noted that the very high reduction of CO₂ costs (5145 M€) is only partially compensated by the increase of fuel costs and by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **4362 millions of Euros**.

Cost item	“proposed expansion” [M€]	“optimal expansion” [M€]	Δ [M€]	Δ%
Fuel consumption	34802	35039	237	0.7
CO ₂ emissions allowances	33200	28055	-5145	-15.5
Investments / O&M AC lines	-	257	257	-
Investments / O&M DC lines	-	289	289	-
TOTAL COSTS	68002	63640	-4362	-6.4

Table 75: Comparison between costs of the modeled power system in the “proposed expansion” and in the “optimal expansion” 2030 EA scenarios (M€).

5.3.4 2030 “GR-FT – Global Regime with Full Trade” scenario

5.3.4.1 Impact on congestion

In the 2030 GR-FT scenario, the simulation determined the optimal expansion (w.r.t. the “*proposed expansion*”) of cross-border transmission network reported in the following Table 76.

Interconnection (A→B)	Expansion values [MW]	NTC values (A→B) [MW]	NTC Values (B→A) [MW]
FR→DE	13596	16496	16646
DE→PL	7464	9964	9864
SK→UA_W	1818	2218	2218
ES→FR	1639	5639	5639
BX→RO	1357	1857	2207
RO→UA_W	1216	1616	1616
DE→NO	1000	5000	5000
FI→BT	1000	2000	2000
FR→IE	1000	2000	2000
PL→BT	1000	2000	2000
SE→PL	1000	1600	1600
FR→BL	578	4578	3678
RO→BG	570	1520	1520
CZ→SK	461	2461	1461
HU→BX	237	837	837
HU→RO	215	815	1615
BG→GR	189	1689	1589
BX→BG	132	882	1232

Table 76: Optimal expansion (additional capacity) values and corresponding new NTC values (MW) in the 2030 GR-FT scenario.

In Figure 53, Figure 54, Figure 55 and Figure 56 a comparison between the percentages of hours with congestion in the different cross-border interconnections in July and in January 2030 with the “*proposed expansion*” and with the “*optimal expansion*” is reported.

In the July 2030 “*optimal expansion*” scenario, it may be noted that the number of interconnections characterized by a congestion percentage exceeding 80% (red lines) is basically halved.

More or less the same happens in the January 2030 “*optimal expansion*” scenario.

GR-FT - July 2030

“proposed”

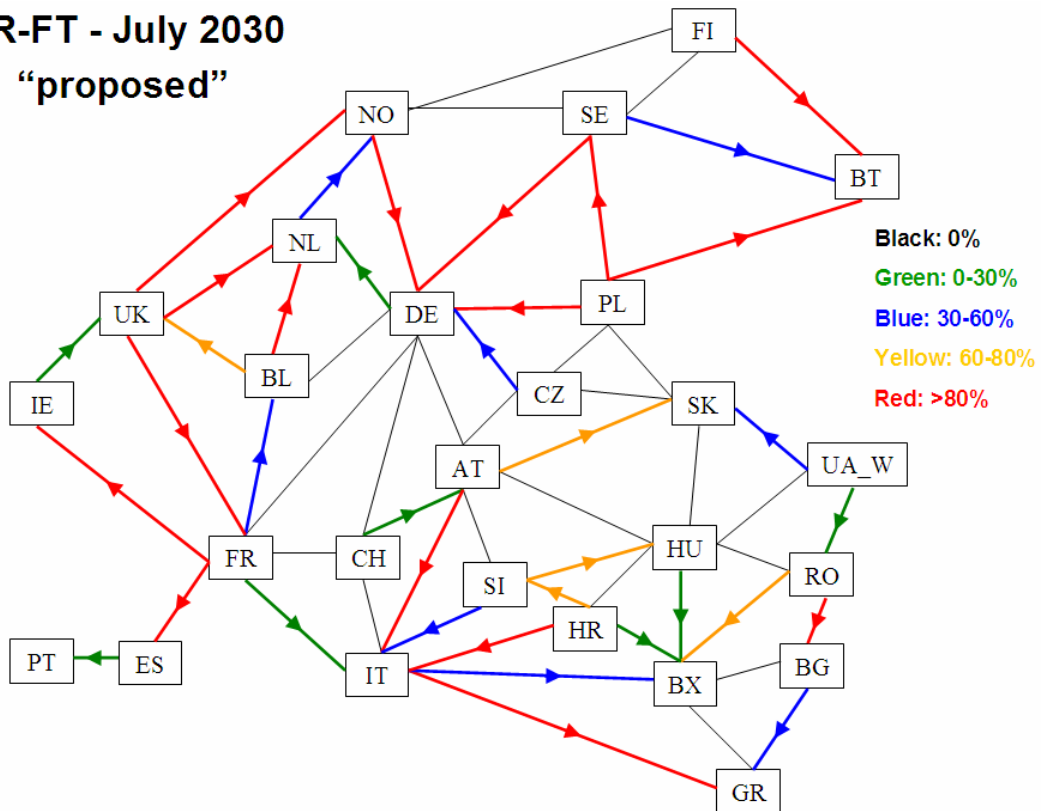


Figure 53: Percentages of hours with congestion in July 2030 with the “proposed expansion”.

GR-FT - July 2030

“optimal”

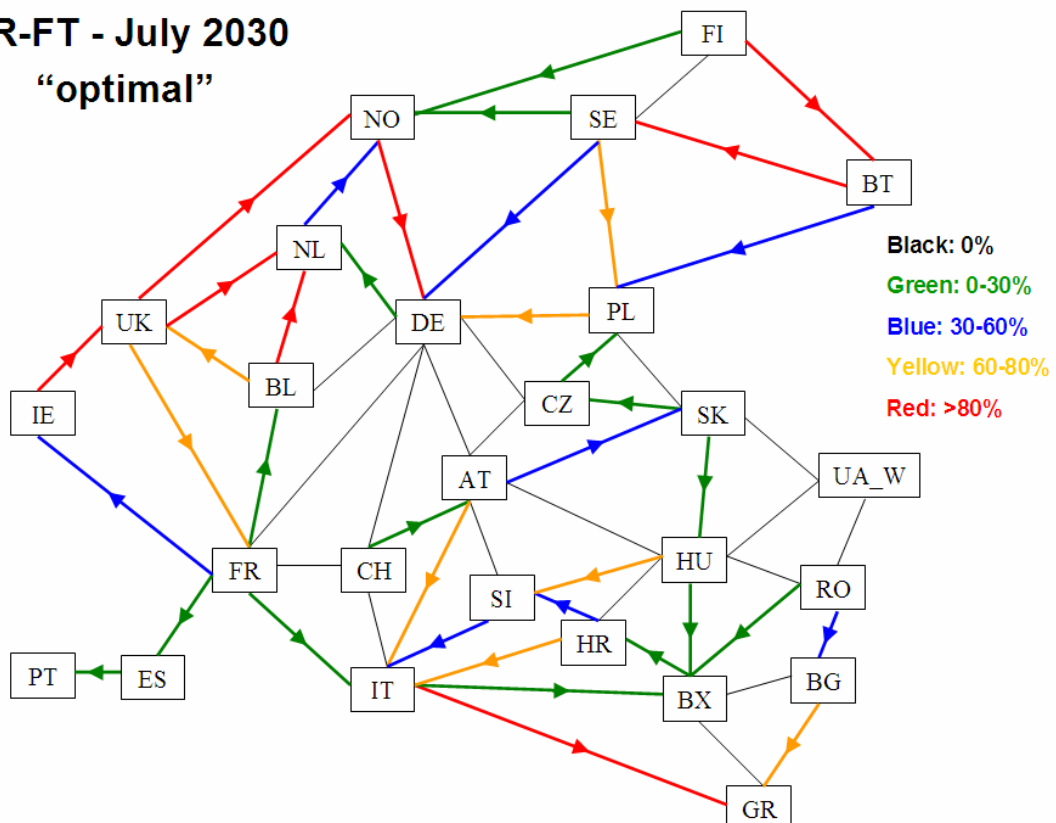


Figure 54: Percentages of hours with congestion in July 2030 with the “optimal expansion”.

GR-FT - Jan. 2030
“proposed”

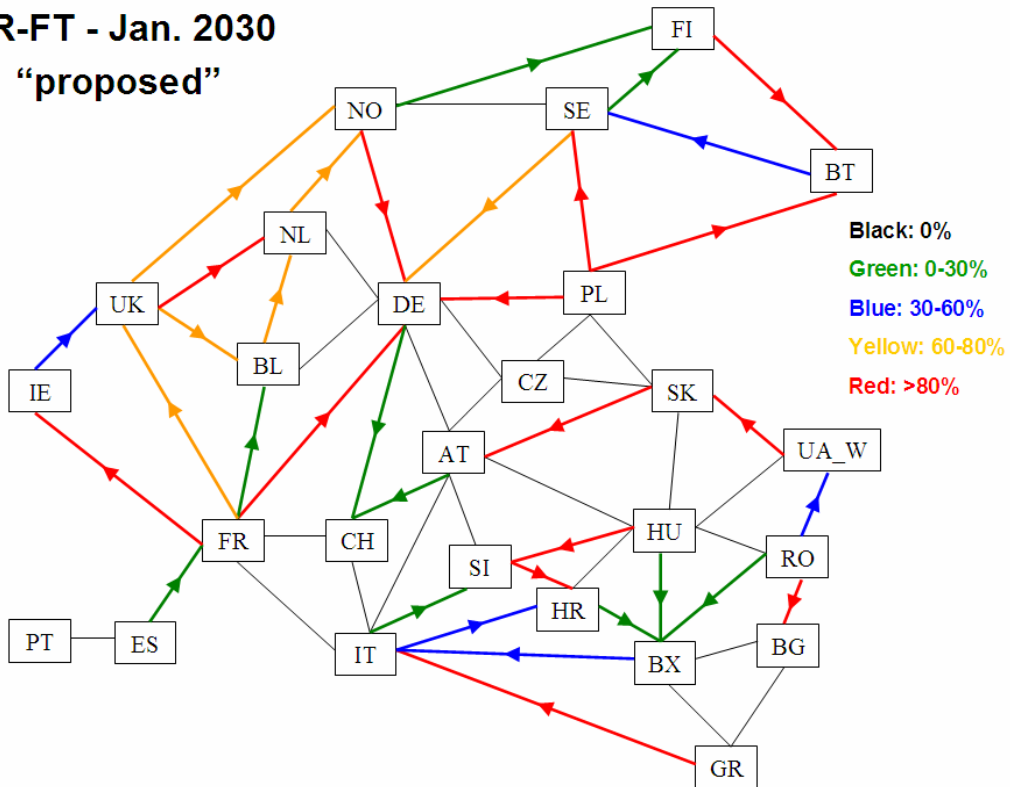


Figure 55: Percentages of hours with congestion in January 2030 with the “proposed expansion”.

GR-FT - Jan. 2030
“optimal”

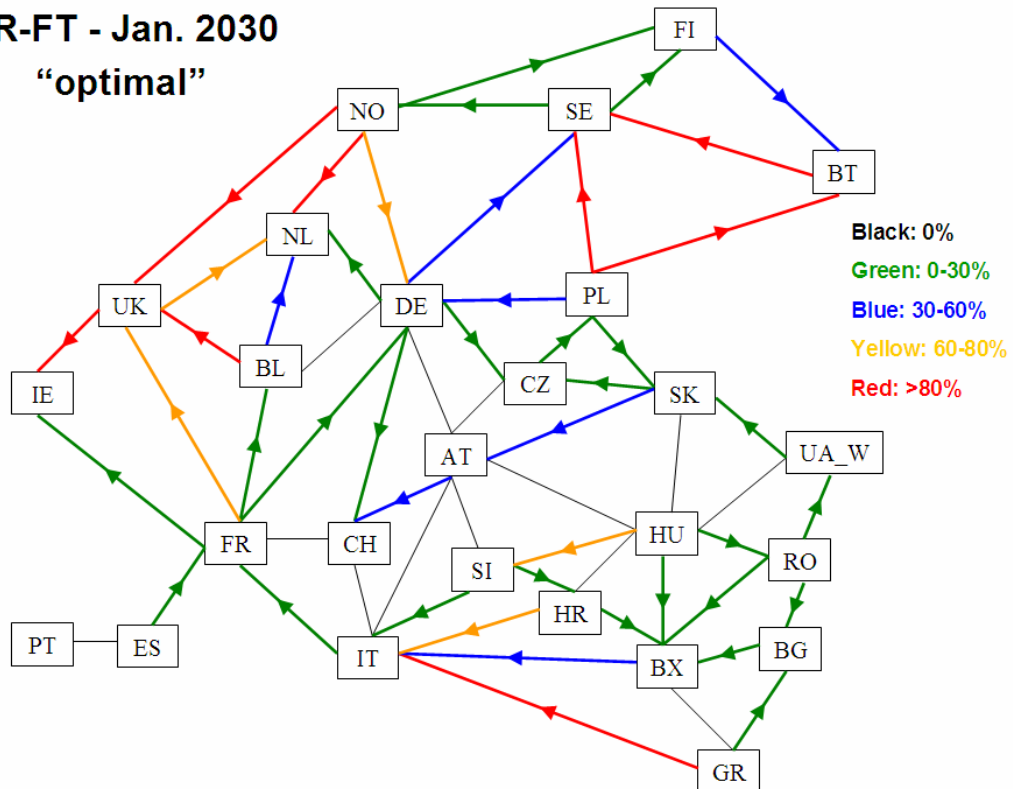


Figure 56: Percentages of hours with congestion in January 2030 with the “optimal expansion”.

In the following, the congestion situation of the most critical European cross-border AC and DC interconnections is briefly analyzed in detail.

France (FR) – Spain (ES)

- “*proposed expansion*”: congestion situation is particularly critical between May and September, when the interconnection is almost completely saturated;
- “*optimal expansion*”: congestion dramatically decreases, with percentages below 20% throughout the year (except March).

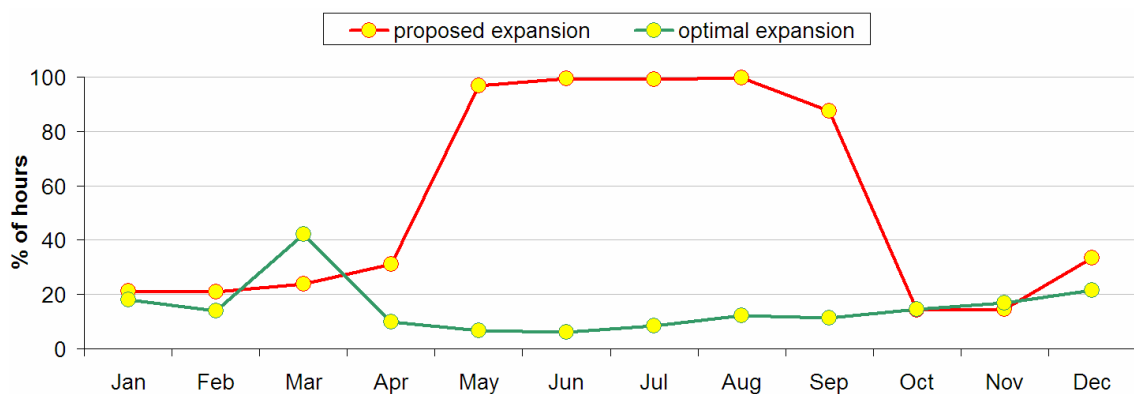


Figure 57: Percentages of congested hours in the France – Spain interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

France (FR) – Germany and Denmark West (DE)

- “*proposed expansion*”: congestion situation is particularly critical between October and April, while no congestion occurs between May and September;
- “*optimal expansion*”: congestion dramatically decreases in the critical period, with percentages almost always below 30%.

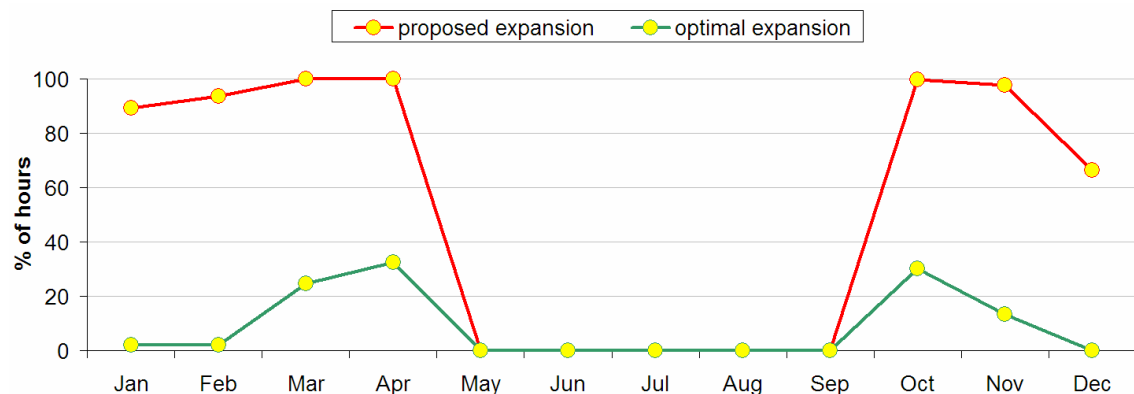


Figure 58: Percentages of congested hours in the France – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Poland (PL) – Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is almost always completely saturated throughout the entire year;
- “*optimal expansion*”: congestion significantly decreases, with percentages almost always below 60%.

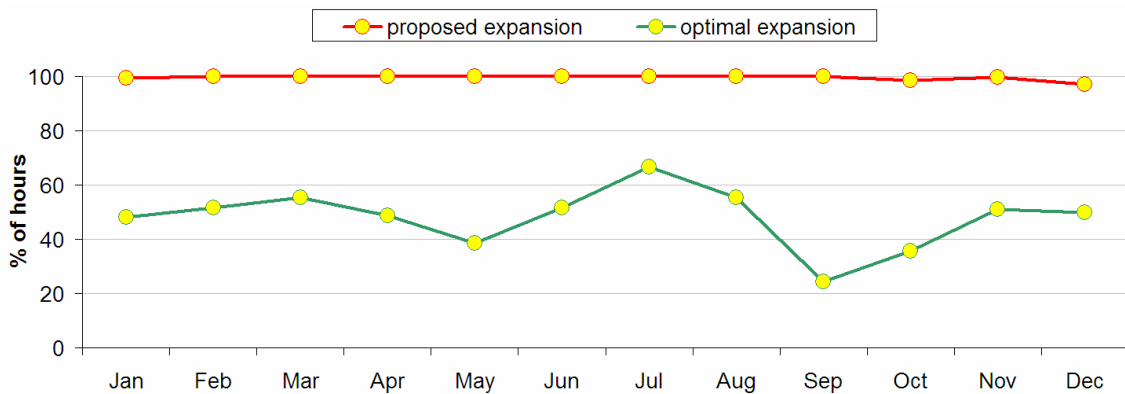


Figure 59: Percentages of congested hours in the Poland – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Romania (RO) – Bulgaria (BG)

- “*proposed expansion*”: the interconnection is almost completely saturated in summer and in the rest of the year percentages are almost always over 60%;
- “*optimal expansion*”: congestion dramatically decreases, with very low percentages except in July and in August (51% and 35%, respectively).

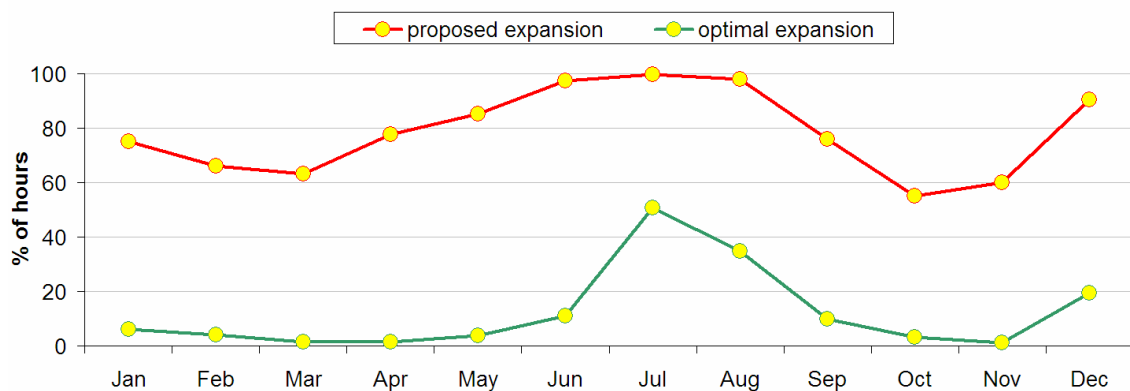


Figure 60: Percentages of congested hours in the Romania – Bulgaria interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

France (FR) – Republic of Ireland (IE)

- “*proposed expansion*”: the interconnection is highly congested throughout the year, and especially between April and August;
- “*optimal expansion*”: congestion dramatically decreases, with very low percentages between September and April, while between May and August they are in the range 40%÷60%.

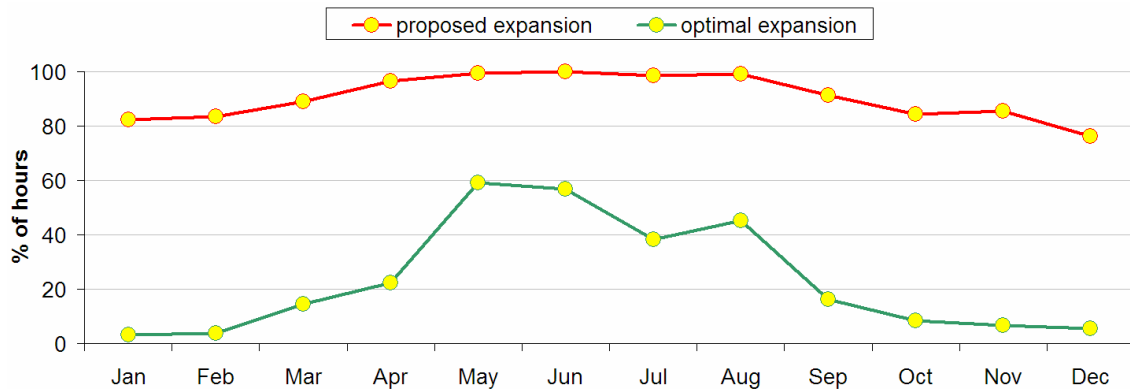


Figure 61: Percentages of congested hours in the France – Ireland interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

United Kingdom (UK) – France (FR)

- “*proposed expansion*”: the interconnection is highly congested especially in spring and in summer;
- “*optimal expansion*”: congestion decreases, but it remains in the range 60%÷80% throughout the year.

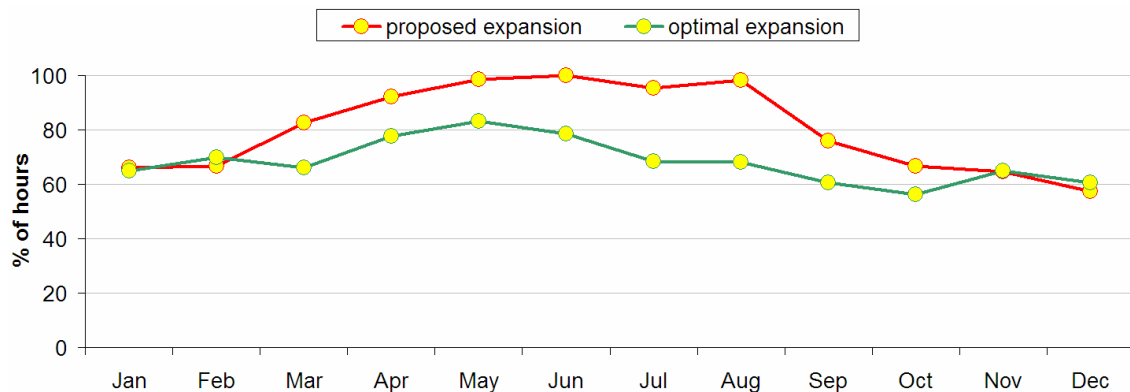


Figure 62: Percentages of congested hours in the United Kingdom – France interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Norway (NO) – Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is almost always completely saturated;
- “*optimal expansion*”: congestion significantly decreases between November and January and between March and May.

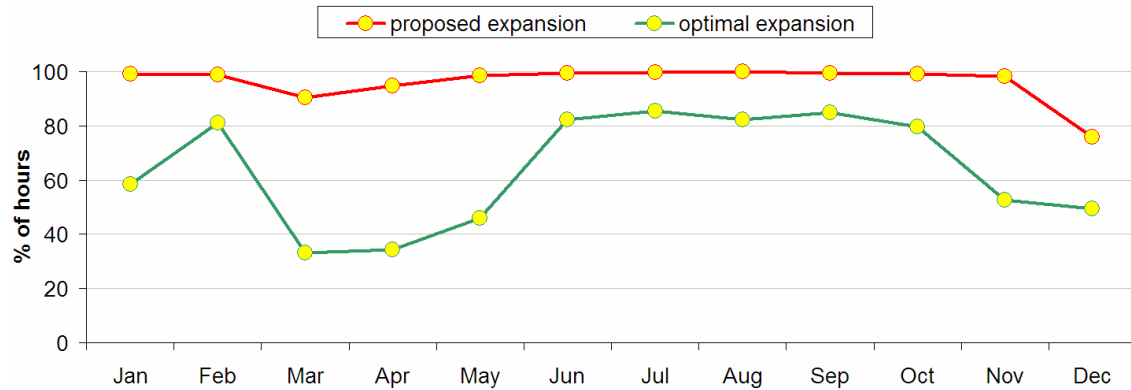


Figure 63: Percentages of congested hours in the Norway – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Sweden and Denmark East (SE) – Germany and Denmark West (DE)

- “*proposed expansion*”: the interconnection is highly congested between June and October and in February;
- “*optimal expansion*”: congestion significantly decreases in the most critical period, but increases in March and in April, that are not critical in the “proposed expansion” scenario.

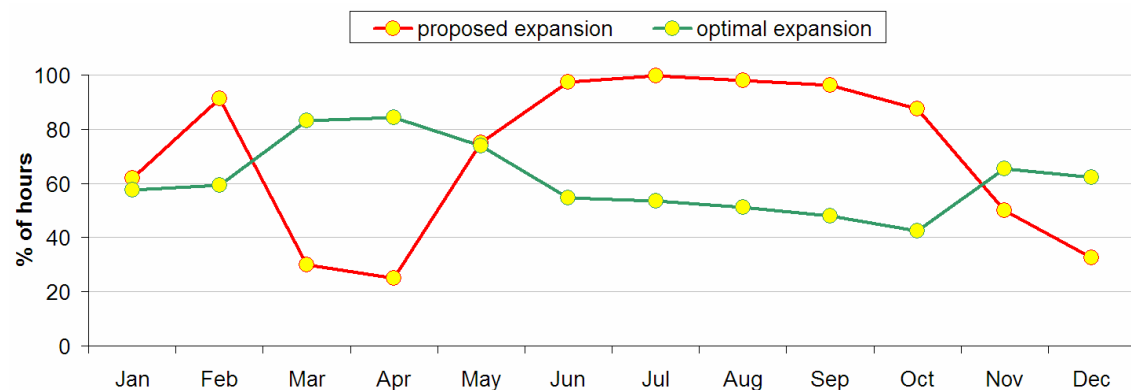


Figure 64: Percentages of congested hours in the Sweden and Denmark East – Germany and Denmark West interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Poland (PL) – Sweden and Denmark East (SE)

- “*proposed expansion*”: the interconnection is almost completely saturated throughout the entire year;
- “*optimal expansion*”: congestion decreases especially in summer, but it remains critical in the rest of the year.

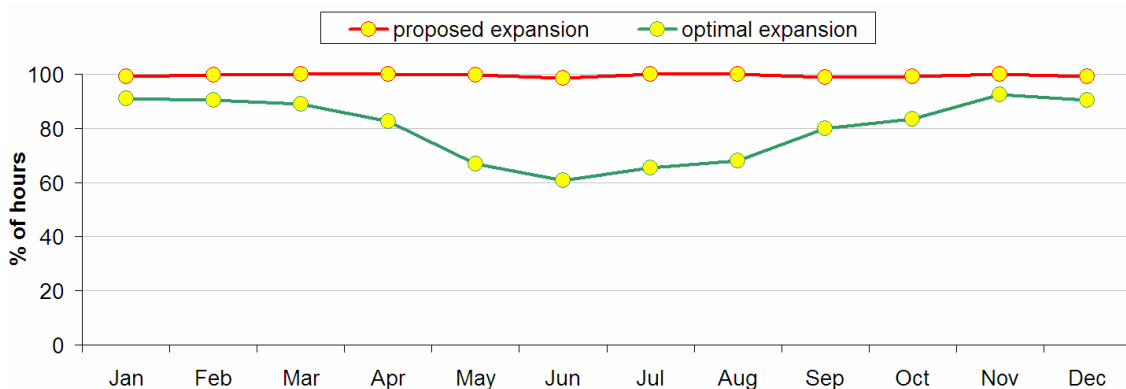


Figure 65: Percentages of congested hours in the Poland – Sweden and Denmark East interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Poland (PL) – Baltic countries (BT)

- “*proposed expansion*”: the interconnection is almost completely saturated throughout the entire year;
- “*optimal expansion*”: congestion decreases especially in summer, but it remains critical in the rest of the year.

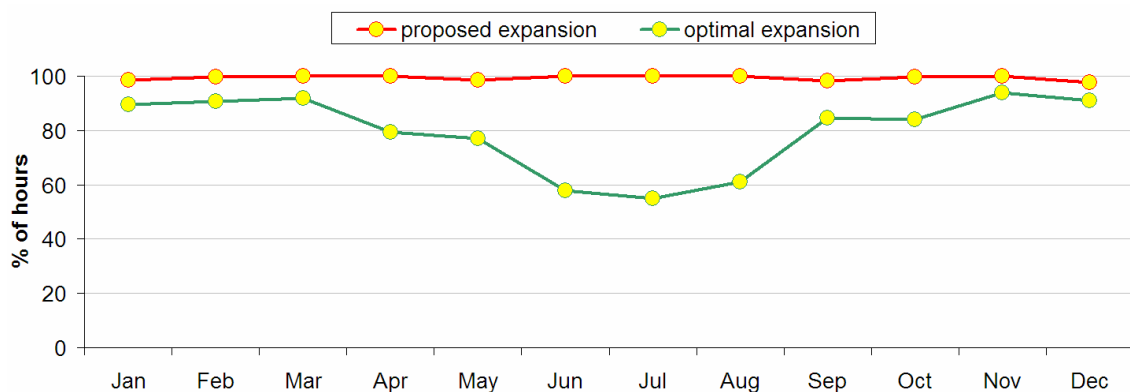


Figure 66: Percentages of congested hours in the Poland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

Finland (FI) – Baltic countries (BT)

- “*proposed expansion*”: the interconnection is almost completely saturated throughout the entire year;

- “*optimal expansion*”: congestion decreases especially in winter and in spring, but it remains critical in the rest of the year.

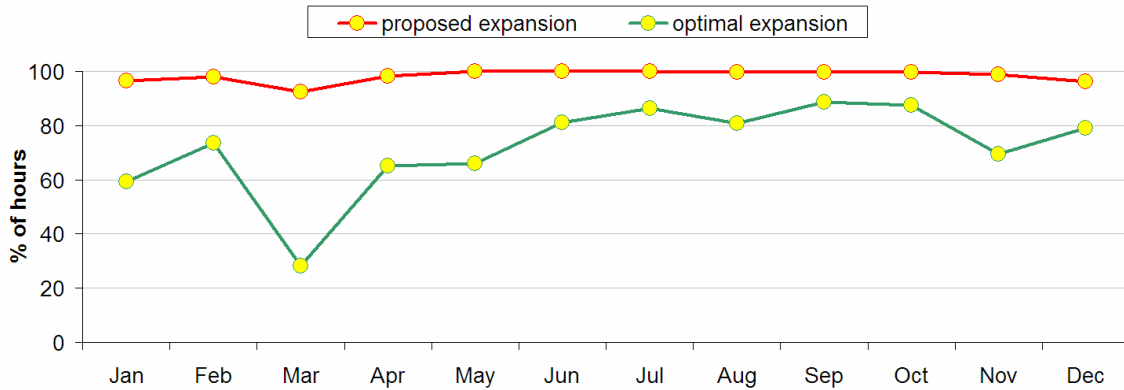


Figure 67: Percentages of congested hours in the Finland – Baltic countries interconnection in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios.

5.3.4.2 Impact on electricity prices

Similarly to paragraph 5.3.1.2, in Figure 34 we report the differences between the annual average zonal prices in the “optimal expansion” and in the “proposed expansion” scenarios.

It can be noted that the main “winners” in this scenario are Germany, Baltic countries, Norway, Sweden, Finland and The Netherlands while the main “losers” are Romania, Ukraine West, France, Poland, Bulgaria, and Greece.

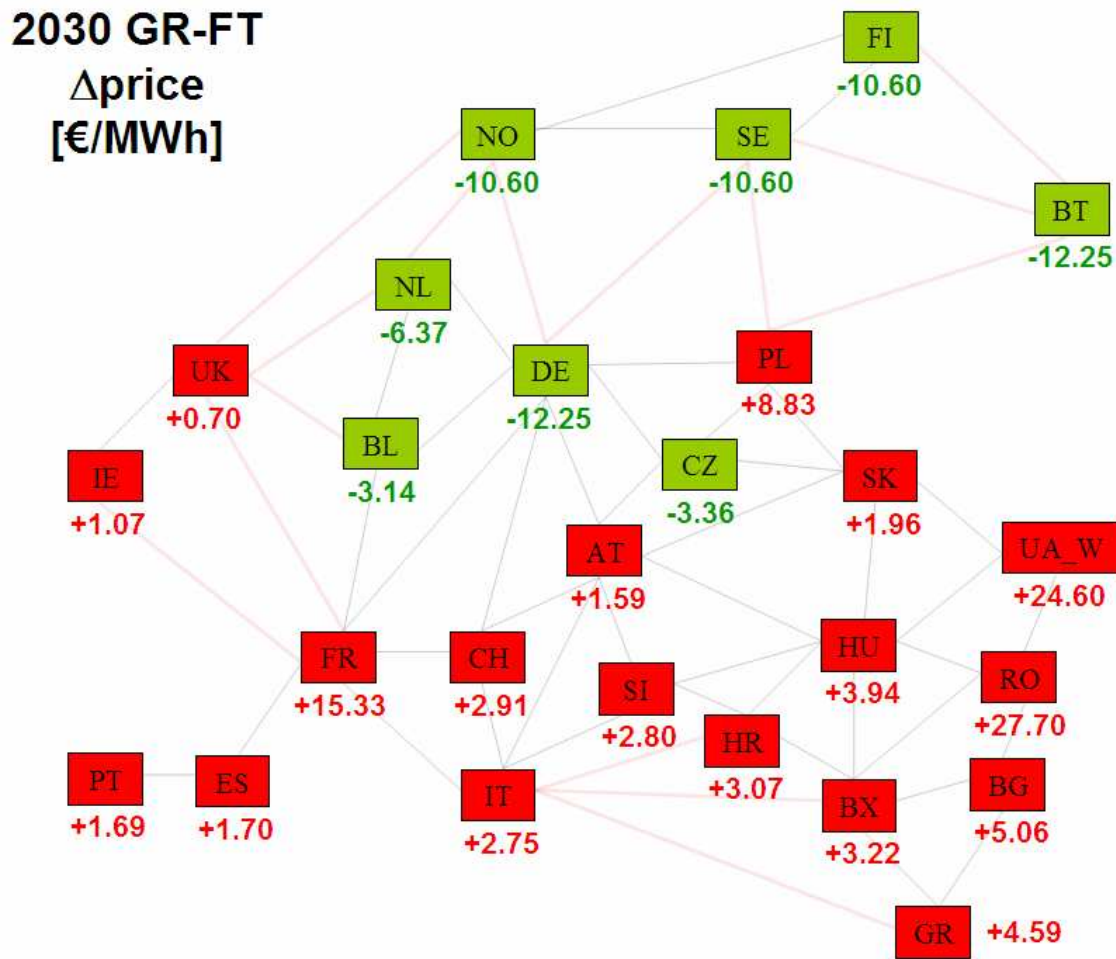


Figure 68: Zonal price differences between the “optimal expansion” and the “proposed expansion” 2030 GR-FT scenarios.

5.3.4.3 Impact on fuel consumption

In the following Table 77, a comparison between electricity production by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

The consequence of the “optimal expansion” (that reduces network constraints) is an increase of production by power plants characterized by the lowest CO₂ emission rates (nuclear, natural gas and plants equipped with CCS technology) at the expense of the more emissive ones (hard coal, lignite and fuel oil). In fact, the “Global Regime with Full Trade” scenario is characterized by a quite high CO₂ emissions value (about 63 €/tCO₂: see paragraph 5.2.3.2).

In Table 78 the corresponding data in terms of fuel consumption are reported: the greater use of less emissive generation technologies slightly decreases total fuel consumption.

Fuel	“proposed expansion” [GWh]	“optimal expansion” [GWh]	Δ [GWh]	Δ%
Nuclear	981360	989951	8591	0.9
Hard coal	371722	364287	-7435	-2.0
Lignite	70723	54427	-16296	-23.0
Natural gas	344337	345805	1468	0.4
Fuel oil	19	0	-19	-100
Coal CCS	293031	302181	9150	3.1
Gas CCS	86879	91175	4296	4.9

Table 77: Comparison between electricity generation by different fuels of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios (GWh).

Fuel	“proposed expansion” [PJ]	“optimal expansion” [PJ]	Δ [PJ]	Δ%
Nuclear	10060.6	10151.7	91.1	0.9
Hard coal	3059.8	2886.3	-173.5	-5.7
Lignite	729.3	562.3	-167	-22.9
Natural gas	2376.1	2353.8	-22.3	-0.9
Fuel oil	1.3	0	-1.3	-100
Coal CCS	2393.0	2467.8	74.8	3.1
Gas CCS	568.7	596.8	28.1	4.9
Total	19188.8	19018.7	-170.1	-0.9

Table 78: Comparison between fuel consumption of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios (PJ).

5.3.4.4 Impact on CO₂ emissions

In the following Table 79 a comparison between CO₂ emissions by different fuels of non-CHP power plants in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

Due to substitution of more emissive generation with less emissive one, overall CO₂ emissions significantly decrease, by about **33.6 MtCO₂**.

Fuel	“proposed expansion” [MtCO ₂]	“optimal expansion” [MtCO ₂]	Δ [MtCO ₂]	Δ%
Hard coal	287.62	271.31	-16.31	-5.7
Lignite	73.72	56.84	-16.88	-22.9
Natural gas	133.06	131.84	-1.22	-0.9
Fuel oil	0.10	0	-0.1	-100
Coal CCS	22.49	23.20	0.71	3.2
Gas CCS	4.78	5.01	0.23	4.8
Total	521.77	488.2	-33.57	-6.4

Table 79: Comparison between CO₂ emissions of non-CHP plants in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios (MtCO₂).

5.3.4.5 Impact on costs

In the following Table 80 a comparison between each cost item of the modelled power system in the “proposed expansion” and in the “optimal expansion” scenarios is reported.

It can be noted that the quite high reduction of CO₂ costs (2124 M€), as well as the reduction of fuel costs is only partially compensated by the annualized investment and O&M costs related to cross-border network expansions, so that the total saving is about **1916 millions of Euros**.

Cost item	“proposed expansion” [M€]	“optimal expansion” [M€]	Δ [M€]	Δ%
Fuel consumption	35445	35196	-249	-0.7
CO ₂ emissions allowances	33006	30882	-2124	-6.4
Investments / O&M AC lines	-	216	216	-
Investments / O&M DC lines	-	241	241	-
TOTAL COSTS	68451	66535	-1916	-2.8

Table 80: Comparison between costs of the modeled power system in the “proposed expansion” and in the “optimal expansion” 2030 GR-FT scenarios (M€).

5.3.5 Comparison among scenarios

First of all, as far as security of supply is concerned, it must be noted that in no one of the considered scenarios there is Energy Not Supplied (ENS): this means that the modelled generation / transmission system is always able to supply the load.

As for cross-border network expansions, in the following Table 81, the first five interconnections with the greatest increases of transmission capacity in the “optimal expansion” w.r.t. the “proposed expansion” scenarios are reported (see also Table 61, Table 66, Table 71 and Table 76).

2015	MT 2030	EA 2030	GR-FT 2030
ES→FR	FR→DE	FR→DE	FR→DE
FR→DE	DE→PL	DE→PL	DE→PL
DE→NO	SK→UA_W	ES→FR	SK→UA_W
DE→SE	ES→FR	SE→PL	ES→FR
FR→UK	BX→RO	SK→UA_W	BX→RO

Table 81: Interconnections with the greatest increases of transmission capacity in the “optimal expansion” w.r.t. the “proposed expansion” scenarios (interconnections that occur in different scenarios are highlighted with the same color).

It can be noted that the interconnections between **France and Spain** and between **France and Germany** are among the most expanded both in the 2015 and in the 2030 scenarios.

Moreover, as far as 2030 scenarios are concerned, the interconnections between **Slovak Republic and Ukraine West** and between **Balkan countries and Romania** are among the most expanded, too.

Other interconnections that are often significantly expanded in the optimal w.r.t. the proposed expansion scenarios are the ones between **Germany and Norway**, **Germany and Sweden**, **Sweden and Poland**, **Romania and Ukraine West**, **Finland and Baltic countries** and **Poland and Baltic countries**.

This means that, for the aforementioned interconnections, the proposed expansion levels seem to be far from the optimal ones under the assumptions of the considered scenarios.

Concerning the electricity price differences between the “optimal expansion” and the “proposed expansion” scenarios, the main 2015 “winner” (i.e. countries where the average price decreases) countries (i.e. **Poland**, **Portugal** and **Spain**) do not maintain their positions in the 2030 scenarios, where the main “winners” are **Germany**, **Baltic countries**, **The Netherlands** and **Belgium**, together with **Norway**, **Sweden** and **Finland** especially in the two most environmentally friendly scenarios (EA and GR-FT).

On the other hand, the main “losers” (i.e. countries where the average price increases) are most often **Romania**, **Poland**, **Bulgaria**, **Ukraine West**, **France** and **Greece**.

In the following Table 82, the variations of fuel consumption of non-CHP plants in the “optimal expansion” w.r.t. the “proposed expansion” in the different scenarios are reported.

It can be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO₂ emissions values (respectively, about 13 and 24 €/MtCO₂) the “optimal expansion” causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.

On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO₂ emissions values are quite high (respectively 90 and 63 €/MtCO₂), the “optimal expansion” causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO₂ emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).

In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.

Fuel	Δ 2015 [PJ]	Δ MT 2030 [PJ]	Δ EA 2030 [PJ]	Δ GR-FT 2030 [PJ]
Nuclear	142.8	5.9	198.5	91.1
Hard coal	77	287.3	-482.2	-173.5
Lignite	25.9	108.6	-201.3	-167
Natural gas	-164.3	-369	127.5	-22.3
Fuel oil	-	-5.4	-2.1	-1.3
Coal CCS	-	0.7	139.6	74.8
Gas CCS	-	0.2	34.4	28.1
Total [PJ]	81.4	28.3	-185.6	-170.1
Total [Mtoe]	1.9	0.7	-4.4	-4.1

Table 82: Variations of fuel consumption of non-CHP plants in the “optimal expansion” w.r.t. the “proposed expansion” in the different scenarios.

Fuel	Δ 2015 [MtCO ₂]	Δ MT 2030 [MtCO ₂]	Δ EA 2030 [MtCO ₂]	Δ GR-FT 2030 [MtCO ₂]
Hard coal	7.24	27.00	-45.32	-16.31
Lignite	2.62	10.98	-20.34	-16.88
Natural gas	-9.20	-20.66	7.24	-1.22
Fuel oil	-	-0.41	-0.16	-0.1
Coal CCS	-	0.01	1.31	0.71
Gas CCS	-	-	0.29	0.23
Total	0.66	16.92	-56.98	-33.57

Table 83: Variations of CO₂ emissions of non-CHP plants in the “optimal expansion” w.r.t. the “proposed expansion” in the different scenarios.

The aforementioned fuel consumption data have a direct consequence on the variations of CO₂ emissions, reported in Table 83. It can be noted that, while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO₂ emissions. On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO₂ emissions reductions.

As for the variations of the costs of the modeled power system, reported in Table 84, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO₂ emissions values the main component of cost reduction is fuel cost, while in the two more environmentally friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO₂ emissions allowances.

In this latter case, cost savings due to the “optimal expansion” w.r.t. the “proposed expansion” can be significant, ranging from 1.9 to 4.4 billions Euros.

Cost item	Δ 2015 [M€]	Δ MT 2030 [M€]	Δ EA 2030 [M€]	Δ GR-FT 2030 [M€]
Fuel consumption	-601	-1650	237	-249
CO ₂ emissions allowances	9	411	-5145	-2124
Investments / O&M AC lines	112	199	257	216
Investments / O&M DC lines	145	312	289	241
TOTAL COSTS	-335	-728	-4362	-1916

Table 84: Variations of the costs of the modeled power system in the “optimal expansion” w.r.t. the “proposed expansion” in the different scenarios.

6 Step 5: remedies assessment

Remedies to tackle with the impact of a non optimal development of the European cross-border electricity transmission network can be put in practice both in the short and in the long term.

6.1 Short-term remedies

- Dispatch more expensive generation in the importing countries

Actually, this is not exactly a remedy to the considered threat, but a natural consequence, since cross-border network constraints prevent cheaper energy from going where it is needed.

- Reduce demand

Instead of dispatching more expensive generation in order to tackle with the impossibility to import cheaper energy, another possibility is to reduce demand, especially at peak load time.

In case of necessity, contracts for interruptible loads can be activated to reduce electricity demand, but this typically happens for security reasons and not only for economic reasons.

Similarly, where implemented, *Demand Side Management* programs can help reducing peak loads (for example with *Critical Peak Pricing* schemes) and the related stress on the power generation system.

6.2 Long-term remedies

- Increase cross-border transmission capacity

Needless to say, the main remedy to a non optimal development of the European cross-border electricity transmission network is to invest in new interconnections, so that the reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a more optimized operation of the generation set and for an increase of competition in the market, with significant economic benefits.

This remedy is of course not so easy to implement, neither by TSOs, nor by private investors interested in merchant lines projects. In fact, such investments are typically affected by several uncertainties (see [2]), mainly due to:

- complex legal and regulatory contexts, especially for permitting procedures (see [34]), stemming from a multitude of different authorities, with different administrative levels (European, national, local) that may differ from one country to another and that may have different priorities;
- the lack of social acceptance that severely delays or jeopardizes the realisation of such projects;
- due to the long-term time horizon that characterizes network projects, the inherent uncertainty in predicting the future location and amount of generation and consumption,

as well as the changes over time in the way electricity is generated and consumed, also due to the impact of different policies (and of different policy implementation options) such as energy demand reduction and efficiency, renewable energy sources integration, CO₂ emissions reduction, decommissioning of polluting units, etc.

To reduce such uncertainties¹⁰:

- the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package (see [35]) should be a significant step towards a more harmonized regulatory framework at the European level;
- as for the several other authorities involved in the permitting procedures, ENTSO-E in [2] states that “*competing priorities are one of the major sources of slow development processes, requiring guidelines with a strong influence on national and also local governments in a way that all involved stakeholders are able to unambiguously prioritise projects*”;
- to speed-up permitting procedures, ENTSO-E in [34] provides the following recommendations:
 - ⇒ *The public interest of important electricity infrastructure projects shall be stated in law. The need for the development of these projects shall be stated “objectively” (e.g. in a list of high priority projects) and therefore the justification does not always need to be argued by TSOs during the proceedings.*
 - ⇒ *There should be clear and explicit linkage between TEN-E projects and national law (recognition of TEN-E projects in national law). The public interest of TEN-E projects should a priori be recognised by their definition.*
 - ⇒ *Authorisation procedures for strategic infrastructure projects should be centralised at one (national) level.*
 - ⇒ *The number of permits required should be reduced by creating an integrated procedure for infrastructure projects or for projects subject to an environmental impact assessment including the connection to substations with the same requirements in all regions of the country.*
 - ⇒ *The result of the procedure for transmission lines and for substations should be a building permit with the right of way that allows construction to start immediately.*
 - ⇒ *There should be simplified procedures with a shorter duration for the upgrading of existing lines (e.g. to a higher voltage).*
 - ⇒ *There should be effective and compulsory time limits to grant the TSOs legal certainty as regards the timely completion of permitting procedures (including the closing-off of submissions of allegedly new statements and evidence opposing the construction of an infrastructure project).*
 - ⇒ *There should be a clear definition of what documents are needed during the authorisation procedures (e.g. during EIA).*
 - ⇒ *Effective consultation mechanisms are vital especially at the very beginning of a project. Duplication of such time-consuming mechanisms shall be avoided if their purpose can be achieved through only one single consultation, otherwise there must be a coordination between different consultations (e.g. between the Environmental Evaluation for the whole Grid Plan and the Environmental Evaluation for the single project of the Grid Plan).*

¹⁰ The reported recommendations are to be further deepened within the EC REALISEGRID project [3].

- ⇒ *A Region should not have the right to stop strategic national and cross border infrastructure: it should be stated that the final permitting decision should remain with the National Authorities.*
 - ⇒ *It should still be possible to build necessary infrastructure projects in protected areas (e.g. Natura 2000) if the environmental effects of these projects can be mitigated and compensation measures are taken.*
 - ⇒ *There should be a simplified procedure for the assessment of the effects on the environment of certain Plans approved on annual basis (e.g. Grid Transmission Plans).*
 - ⇒ *It should be possible to reserve so-called “infrastructure corridors” for high priority infrastructure projects.*
 - ⇒ *Common agreement with involved parties concerning corridors and in particular common dedicated corridors for different types of infrastructure (pipelines, highways, railways, high voltage lines, etc.) would be desirable.*
 - ⇒ *The relevant authorities should define new infrastructure corridors for high priority infrastructure projects.*
 - ⇒ *For new infrastructure and/or upgrading of the existing infrastructure existing routes should preferably be used.*
 - ⇒ *Sufficient and specialized manpower is necessary to deal with infrastructure projects in an effective and timely manner in the TSOs as also in external resources (e.g. authorities).*
- as for the lack of social acceptance, a correct and complete information provided to the involved populations by all the concerned bodies is of paramount importance; in particular, concerns about the environmental impact of the projects (e.g. impact on natural areas, visual impact, alleged health effects of electromagnetic fields, etc.) must be discussed on a clear and sound scientific basis, in order to allow for an informed comparison between such “cons” and the “pros” of the projects;
 - as for the “pros”, the public benefits of the projects must be clearly stated and quantified, especially from the security of supply, from the sustainability (in particular when renewable energy flows are involved) and from the economic points of view; also, the strategic importance that characterizes cross-border transmission projects must be highlighted with the support of the highest political decision levels;
 - the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice;
 - as for the uncertainties concerning the future developments of generation and demand, they can be effectively tackled by carrying out adequate *scenario analyses*, just like it has been done in the present study on the basis of POLES scenarios; this approach is supported also by ENTSO-E that in [2] states that “*scenario analyses at national, regional and pan-European levels are key elements in order to decide on grid extensions and to adequately assist political reasoning*” taking into account “*fuel prices, economic and monetary conditions, geopolitical developments, meteorological conditions, technological breakthroughs, market mechanisms, regulatory and legal frameworks*”.

Up to this point we have discussed the problems related to *each generic* development of the European cross-border transmission network, but it is very important to end up with an *optimal set* of developments, according to the considered reference scenarios.

Again, this is exactly what has been done in the present study, following an approach supported also by ENTSO-E, that in its recent “*Research and Development Plan*” [36] foresees the development of “*Advanced tools for analyzing the pan-European network expansion options according to energy scenarios for Europe (i.e. expansion optima that must be searched to maximize European welfare)*”, specifying that optima are to be searched at EU level and no longer at national level.

- *Increase energy efficiency in electricity consumption*

A greater end use electric energy efficiency would entail a demand reduction that would decrease the criticalities related to the impossibility to import cheaper energy.

EU is supporting this process with some Directives (e.g. Directive 2005/32/EC of 6 July 2005 establishing a framework for the setting of ecodesign requirements for energy-using products and amending Council Directive 92/42/EEC and Directives 96/57/EC and 2000/55/EC, Directive 2006/32/EC of 5 April 2006 on energy end-use efficiency and energy services and repealing Council Directive 93/76/EEC, etc.) and EU countries are implementing them within the framework of their National Energy Efficiency Action Plans (see also [37]).

Another beneficial action would be the promotion of the above mentioned Demand Side Management programs to increase demand response in case of critical situations.

7 Step 6: how remedies should be financed / paid for

7.1 Short-term remedies

The economic consequences of dispatching more expensive generation are in the end borne by consumers, paying higher electricity prices.

As for demand reduction, costs related to interruptible contracts are socialized in the tariffs, since they benefit the whole system with a greater security of supply.

On the other hand, *Demand Side Management* programs can reduce costs both for the participating consumers and for the system as a whole.

7.2 Long-term remedies

Investments in new cross-border transmission capacity can be carried out either by TSOs or by private investors building the so-called “merchant lines”.

Investments by TSOs are remunerated with a fair return through transmission tariffs defined by regulators.

Due to the strategic importance of cross-border lines, regulators may acknowledge to such projects a rate of return higher than for normal transmission lines: for example, in Italy, investments that increase cross-border Net Transfer Capacity are acknowledged an increase of the rate of return of 3% for 12 years (see [38]).

As for investments in “merchant lines”, they are basically remunerated by electricity price differentials between the markets they interconnect.

In fact, due to Regulations no. 1228/2003 [39] and 714/2009 [40], such projects may be exempted for a limited period of time (by the regulatory authorities of the Member States concerned) from Third Party Access requirement, established by Directive 2003/54/EC [41] and confirmed by Directive 2009/72/EC [42]. Such exemption may cover all or part of the capacity of the new interconnector, or of the existing interconnector with significantly increased capacity.

As for financing issues, apart from banks, a key role is often played by the European Investment Bank (EIB), especially concerning the Trans-European Energy Networks (TENs) projects.

EIB’s contribution typically does not exceed 50% of the total investment cost, in order to capitalize on its first-rate lending terms to attract other sources of financing. This enables the borrowers to set up a diversified finance plan in partnership with other financial institutions and banks. As for the borrowers, they can be public authorities or private entities, including special purpose vehicles, as well as banks and financial institutions.

Examples of cross-border interconnectors financed by EIB are the following:

- *NorNed* project, a 580 km-long HVDC hybrid bipolar submarine power cable link across the North Sea between Eemshaven (in The Netherlands) and Fedaa (in Norway); the project is a joint venture between the Dutch (TenneT) and the Norwegian (Statnett) TSOs that have invested 600 M€ of which 280 M€ financed by the EIB;

- *BritNed* project, a 260 km-long HVDC submarine power cable link between the Isle of Grain in Kent (UK) and Maasvlakte near Rotterdam (The Netherlands); the project is a joint venture between the Dutch (TenneT) and the British (National Grid) TSOs that invest 600 M€, of which 300 M€ financed by the EIB;
- *EWIC (East-West InterConnector)* project, a 256 km-long HVDC submarine power cable link between Woodland (Ireland) and Deeside (Wales); the Irish TSO EirGrid invests about 600 M€, of which 300 M€ financed by the EIB.

As for increasing energy efficiency in electricity consumption, even if most of the actions in this field have a “negative” cost, some promotion is necessary, typically with fiscal incentives together with obligation schemes, such as White Certificates, whose costs are socialized.

8 Conclusions

This study assessed the impact of a non-optimal development of the European cross-border electricity transmission network.

Indeed, such non-optimality is currently not a “threat” but a fact, since the development of cross-border transmission network, originally mainly aimed at operational security and at mutual support between different power systems, did not keep the pace with the development of demand, of generation and of the related trading needs deriving from the electricity market liberalization. This is clearly shown by the level of congestion that affects several interconnections.

Moreover, the long delays that affect new transmission projects, mainly due to complex permitting procedures and to lack of social acceptance, entail that the probability of reaching an optimal status with future developments in the next 10÷20 years is quite low.

The impact assessment of the considered “threat” has been carried out by developing and running a model of the European power system (based on the MTSIM simulator, developed by ERSE) and has been focused on the security of electricity supply, as well as on the impact on electricity production costs and on the environmental impact (in terms of CO₂ emissions).

In particular, with the model, we compared scenarios characterized by the developments of cross-border interconnections proposed by the different European TSOs with the optimal (least cost) developments determined by MTSIM. The reference years considered in the study are 2015 and 2030.

The reference framework within which this modeling exercise has been carried out are the three POLES scenarios developed in the SECURE project to analyze climate policies and their consequences on energy security: *Muddling Through (MT)*, *Europe Alone (EA)* and *Global Regime with Full Trade (GR-FT)*.

The results of the simulations show that in no one of the considered scenarios there is Energy Not Supplied (ENS), therefore there are no problems in terms of security of supply due to insufficient cross-border transmission capacity or to available generation capacity.

Moreover, the proposed cross-border network expansions are clearly sub-optimal: in the considered scenarios, for example, the interconnections between France and Germany, France and Spain, Slovak Republic and Ukraine West, Balkan countries and Romania, as well as several others, in the “optimal expansion” case are expanded significantly more than in the “proposed expansion” case.

In the “optimal expansion”, the countries where the average electricity price decreases (w.r.t. the “proposed expansion” case) are Poland, Portugal and Spain in the 2015 scenario, while in the 2030 scenarios they are replaced by Germany, Baltic countries, The Netherlands and Belgium, together with Norway, Sweden and Finland especially in the two most environmentally friendly scenarios (EA and GR-FT).

On the other hand, the countries where the average price increases are most often Romania, Poland, Bulgaria, Ukraine West, France and Greece.

It can also be noted that in the 2015 and in the MT 2030 scenarios, characterized by relatively low CO₂ emissions values (respectively, about 13 and 24 €/MtCO₂) the “optimal expansion” causes an overall increase of fuel consumption, by reducing natural gas and increasing coal and lignite (as well as nuclear in 2015) consumptions.

On the other hand, in the two most environmentally friendly scenarios (EA 2030 and GR-FT 2030), where CO₂ emissions values are quite high (respectively 90 and 63

€/MtCO₂), the “optimal expansion” causes an overall decrease of fuel consumption, by increasing consumption of power plants characterized by the lowest CO₂ emission rates (nuclear, natural gas and plants equipped with CCS technology), but significantly reducing consumption of the more emissive ones (hard coal and lignite).

In any case, the variations of fuel consumption between the optimal and the proposed expansion scenarios are not very high, ranging from +1.9 to -4.4 Mtoe.

The aforementioned fuel consumption data have a direct consequence on the variations of CO₂ emissions: while variation of the 2015 scenario is almost negligible (due to the increase of nuclear production that compensates the greater hard coal and lignite productions), the MT 2030 scenario is characterized by a slight increase of CO₂ emissions (about 17 MtCO₂). On the contrary, the more environmentally friendly EA and GR-FT 2030 scenarios show more significant CO₂ emissions reductions (respectively, about 57 and 34 MtCO₂).

As for the variations of the costs of the modeled power system, it can be noted that in the two scenarios (2015 and MT 2030) characterized by low CO₂ emissions values the main component of cost reduction is fuel cost, while in the two more environmentally friendly scenarios (EA and GR-FT 2030) the main component is by far the reduction of costs related to CO₂ emissions allowances.

In this latter case, cost savings due to the “optimal expansion” w.r.t. the “proposed expansion” can be significant, ranging from 1.9 to 4.4 billions Euros.

The main remedy to a non optimal development of the European cross-border electricity transmission network is of course to invest in new interconnections, so that the reduction of bottlenecks makes easier to transport cheaper energy where it is needed, increasing security of supply, but also allowing for a more optimized operation of the generation set, with significant economic benefits.

This remedy is not so easy to implement due to the several uncertainties that affect such kind of investments, mostly related to complex legal and regulatory contexts, especially for permitting procedures, stemming from a multitude of different authorities, to the lack of social acceptance and to the inherent uncertainty in predicting the future location and amount of generation and consumption, as well as the changes over time in the way electricity is generated and consumed.

To reduce such uncertainty, the establishment of the *Agency for the Cooperation of Energy Regulators – ACER* foreseen by the 3rd Energy Package should be a significant step towards a more harmonized regulatory framework at the European level. As for permitting procedures, besides being more efficient and clear, they should also have a reasonable and mandatory time limit for their duration.

As far as the lack of social acceptance is concerned, the public benefits of the projects should be clearly stated and quantified, especially from the security of supply, from the sustainability (in particular when renewable energy flows are involved) and from the economic points of view. In particular, the economic side of the problem is very important to gain consensus among the involved populations: they must know that the realization of the projects will reduce their electricity bills (either by imports of cheaper energy or by direct compensations), otherwise the *nimby* attitude would be their first and easiest choice.

Moreover, the strategic importance that characterizes cross-border transmission projects must be highlighted with the support of the highest political decision levels: the proponents of the investments must not be left alone.

As for the uncertainties concerning the future developments of generation and demand, they can be effectively tackled by carrying out adequate scenario analyses, that should be used as a reference to determine a set of cross-border network expansions that is

optimal at the European level and no longer only at the national level, as done in the past: this implies the necessity of a higher level of coordination that can be effectively carried out by the European Network of Transmission System Operators for Electricity ENTSO-E.

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