

2025

Target Capacity Assessment Report

2025 Edition

Final Document

March 2025



“ Terna is investing in Italy's development

We guarantee energy security and balance electricity supply and demand 24 hours a day, ensuring that the system is reliable, efficient and accessible to all.

We invest and innovate every day in the development of an electricity grid capable of integrating the energy produced from renewable sources, improving links between the different areas of the country and strengthening cross-border interconnections, applying a sustainable approach that takes into account the needs of the communities and people we work with. ”

MISSION

“ We are behind the energy you use every day

We are responsible for guaranteeing the continuity of power supply, essential in making sure that electricity reaches Italian homes and businesses at all times.

We provide everyone with equal access to electricity and are working to provide clean energy for future generations. ”

PURPOSE

“ We care about the future of energy

We are committed to building a future powered by clean energy, enabling new forms of consumption and production increasingly based on renewable sources. This will allow us to achieve the goal of delivering an energy transition that is fair and inclusive, whilst also lowering costs.

Thanks to our overall vision of the electricity system and new digital technologies, we are leading the country's drive to get to net zero by 2050, in line with European climate goals. ”

VISION

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Introduction

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1.1 Regulatory framework

The first edition of the **Target Capacity Identification Report** was published in 2018 at the request of the Italian Regulatory Authority for Energy, Networks and Environment (hereinafter, the Authority or ARERA) with Resolution 884/2017/R/EEL “*First implementation provisions on incentive mechanisms for transmission service outputs*”¹, in preparation for the mechanism governed by Resolution 129/2018/R/EEL “*Urgent provisions on incentive mechanisms for transmission service outputs. Adjustment of the provisions on the recognition of incentives for projects with high risks*”², aimed at providing the Transmission Grid Operator with incentives to build additional transmission capacity useful for the system up to the target capacity values in the 2019-2023 regulatory period.

In this respect, the **Target Capacity** is defined as “*the transmission capacity that is economically efficient to achieve, since the marginal benefits are greater than the marginal costs*”. Therefore, the final target capacity between two market zones and between borders is identified as the existing capacity plus the additional target transmission capacity.

Following publication of the “**Target Capacity Identification Report, 2018 Edition**”³, with Resolution 698/2018/R/EEL “*Determination of parameters and targets for the incentive mechanism of the transmission service output related to the realisation of interzonal transmission capacities*”⁴, the Authority:

- has identified the relevant borders and sections for the incentive mechanism for realisation of the additional transmission capacity and determined the corresponding values of starting and target transmission capacity with reference to the *winter peak* scenario:
 - Italy - Northern nations (aggregation of France, Switzerland and Austria);
 - Italy - Eastern nations (aggregation from Slovenia to Greece);
 - North zone - Centre North zone;
 - Centre North zone - Centre South zone;
 - Centre South zone - South zone;
 - Centre North zone - Sardinia zone;
 - Sardinia zone - Centre South zone;
- has envisaged that Terna:
 - prepare the second edition of the target capacity identification report by 30 September 2020;
 - review the methodology for identifying the target capacities and carry out stakeholder consultations on both the methodology for identifying the target transport capacities and the reporting scheme and, after each consultation, send the Authority its assessments and observations on the comments received during the consultation.

¹ <https://www.arera.it/fileadmin/allegati/docs/17/884-17.pdf>

² <https://www.arera.it/fileadmin/allegati/docs/18/129-18.pdf>

³ <https://download.terna.it/terna/0000/1149/78.PDF>

⁴ <https://www.arera.it/fileadmin/allegati/docs/18/698-18.pdf>

The broadest output-based *regulation* of the electricity transmission service for the 2020-2023 regulation semi-period was established with Resolution 567/2019/R/EEL⁵, introducing with Article 46, Annex A of the same resolution, the possibility for Terna to earn an additional premium in the case of achievement of transmission capacity at investment costs below the reference costs defined therein.

Subsequently, the second edition of the report was drafted by Terna with reference to the updated zonal configuration⁶, effective from January 1, 2021, according to Resolution 103/2019/R/EEL *“Further provisions regarding zoning of the relevant grid, as a result of the review process carried out pursuant to Regulation (EU) 2015/1222 (CACM)”*⁷, in light of which the Authority, with Resolution 436/2020/R/EEL, containing provisions on the subject of *“Extraordinary measures on infrastructural regulation of the electricity transmission service in relation to the Covid-19 epidemiological emergency and ancillary provisions on output-based regulation of the transmission service”*⁸, updated the deadline by which it was required to be prepared, i.e. to January 31, 2021.

In view of the above, in December 2020, Terna published the final version of the **“Target Capacity Identification Report, 2020 Edition”**⁹, following two public consultations with stakeholders, respectively regarding:

- the “Methodology for the identification of target transport capacities”¹⁰, finalised on September 4, 2020, in the update of which the observations of the two independent external assessment reports on the 2018 Target Transport Capacity Identification Report were also taken into account;
- the “Target Capacity Identification Report”¹¹, concluded on November 24, 2020, on the outline of the report;

during which comments emerged that contributed to the final version of the second edition of the report, containing improvements to the methodology and new target transmission capacity values.

Following the second edition, with Resolution 446/2021/R/EEL *“Determination of parameters and targets for the incentive mechanism of the transmission service output related to the realisation of interzonal transmission capacities”*¹², ARERA expressed its opinion on the parameters and capacity targets for the incentive mechanism relating to the realisation of transmission capacity. Compared to the previous Resolution 698/2018/R/EEL, ARERA:

- aligned the definition of the internal sections with the zonal configuration in effect as of January 1, 2021 by updating the “Centre South zone - Centre North zone” section and introducing the new “South zone - Calabria zone”, “Sicily zone - Calabria zone”, “Sicily zone - Centre South zone” and “Sicily zone - Sardinia zone” sections;
- determined the starting and target transmission capacity values with reference to the *winter peak* scenario, valued the congestion rents of the years 2016 and 2017 and the coefficient of the expected annual benefit B1 functional to the valuation of the reward for the 2020-2023 semi-period.

⁵ <https://www.arera.it/en/atti-e-provvedimenti/dettaglio/19/567-19>

⁶ Changes to the zonal configuration in force as of January 1, 2021: moving Umbria from the Centre North zone to the Centre South zone and the introduction of the Calabria zone, with deletion of the Rossano limited production hub

⁷ <https://www.arera.it/fileadmin/allegati/docs/19/103-19.pdf>

⁸ <https://www.arera.it/fileadmin/allegati/docs/20/436-20.pdf>

⁹ <https://www.terna.it/DesktopModules/AdactioBackend/API/download/get?guid=49cf8f88-cc3e-eb11-9104-00155d8bf435>

¹⁰ https://download.terna.it/terna/Metodologia%20Identificazione%20Capacit%C3%A0%20Obiettivo%202020%20_8d83ac38b2c5d8d.pdf

¹¹ <https://www.terna.it/DesktopModules/AdactioBackend/API/download/get?guid=b87be2e5-d51d-eb11-9110-00155d8bf41f>

¹² <https://www.arera.it/fileadmin/allegati/docs/21/446-21.pdf>

In the year 2022, with Resolution 23/2022/R/EEL “*Determination of the premium for the implementation of interzonal transmission capacity in the year 2020*”¹³, the Authority recognised a premium for Terna of €103.6 million in relation to the transmission output-based incentive mechanism for the year 2020, attributable to the increase in transit capacity on the following sections, made available from January 2021 during the *winter peak* scenario:

- North ↔ Centre North for 400 MW;
- Centre North ↔ Centre South for 400 MW;
- South → Centre South for 250 MW;
- Calabria → Sicily for 400 MW.

In addition, an efficiency bonus in the amount of €40 million was recognised for the increase in transmission capacity on the four sections mentioned above, as the associated investment costs were lower than both the reference costs defined for each section and the limit of €10 million as defined in the *output-based* Regulation.

Subsequently, Terna prepared and published, first for consultation in January 2023 and then in its final version in June 2023, the “**Target Capacity Identification Report, 2023 Edition**”¹⁴, in response to the position expressed by the Authority in Consultation Document 422/2022/R/EEL “*Development of the electricity transmission grid*”¹⁵ concerning the preparation of the third edition of the report for identification of the target transmission capacity necessary for extension/modification of the incentive mechanism starting from the year 2024.

A second bonus was recognised to Terna by the Authority with Resolution 473/2023/R/EEL “*Determination of bonuses for the creation of interzonal transmission capacity and for the efficiency of investments related to the electricity transmission service*”¹⁶ for a value of €23.7 million and €12.8 million attributable, respectively, to the increase in transit capacity on the following borders/sections available during 2022 in the *winter peak* scenario and to the efficiency of the related investment costs:

- Northern border (France, Switzerland, Austria) → North for 277 MW;
- South → Centre South for 250 MW.

The framework of bonuses recognised to Terna was further updated with Resolution 445/2024/R/EEL “*Determination of bonuses for the creation of interzonal transmission capacity and for the efficiency of investments, in 2023, related to the electricity transmission service*”¹⁷, which recognised a bonus of €14.4 million for the realisation of additional transmission capacity of 300 MW on the Northern Border with Austria and a bonus of €7.2 million for investment cost efficiency.

In light of the efficient results achieved in the development of the transmission grid, especially with capital light solutions, and the significant need for new transmission capacity in the context of the energy transition, with Resolution 55/2024/R/EEL “*Approval of output-based regulation of the electricity transmission service, for the period 2024-2027*”¹⁸, the Authority confirmed, for the regulatory period 2024-2027, the incentive mechanism for the realisation of transmission capacity between zones, requiring drafting of the new edition of the report identifying the target capacities.

¹³ <https://www.arera.it/fileadmin/allegati/docs/22/023-22.pdf>

¹⁴ https://download.terna.it/terna/Terna_Rapporto_Capacita%CC%80_Obiettivo_2023_8db6776a1f286f1.pdf

¹⁵ <https://www.arera.it/fileadmin/allegati/docs/22/422-22.pdf>

¹⁶ <https://www.arera.it/fileadmin/allegati/docs/23/473-23.pdf>

¹⁷ <https://www.arera.it/fileadmin/allegati/docs/24/445-2024-R-eel.pdf>

¹⁸ <https://www.arera.it/fileadmin/allegati/docs/24/055-2024-R-eel.pdf>

1.2 Expert-based verifications carried out on previous editions of the Report

The 2018 and 2020 editions of the Target Capacity Identification Report underwent two independent external expert-based verification processes in 2020, 2022, and 2023, respectively, pursuant to Article 40 of the *output-based* transmission regulation, from which several useful insights emerged for its improvement.

In this regard, the main improvement points that emerged, in addition to editorial and structural aspects recommended by the reviewers, were elaborated and incorporated in past editions. Terna is currently studying the possibility of an evolution of the heuristic iterative method implemented to date towards an alternative constrained optimisation model that would allow market and grid simulations to be conducted in an integrated manner and identify a global optimum for the system.

1.3 Document structure

This document is structured as follows:

- **Chapter 2** contains the main **bibliographical references**, both national and non-national, and a concise glossary to support reading of the text;
- **Chapter 3** presents a brief discussion of the **“Identification of System Needs” analysis** conducted by ENTSO-E (a comprehensive discussion is provided in Annex 1);
- **Chapter 4** analyses the **assumptions and reference hypotheses** for target capacity assessment;
- **Chapter 5** presents the **development strategies** derived from simulations conducted for the **2030 and 2040 reference scenarios**. Additionally, it provides insights into the target capacity values achievable by 2030 in the event of changes to the input assumptions related to cross-border capacity and storage scenarios, as well as the expected hydrogen capacity by 2040;
- **Chapter 6** discusses the **final results** based on the development strategies identified, the sensitivity analyses and application of the *“advanced least regret”* within the contrasting 2040 scenarios.

The **annexes** respectively provide:

1. a complete discussion of practices at the European level;
2. a description of the simulation tools used;
3. the methodology developed and adopted in the exercise with:
 - assessment of the marginal cost data;
 - the criteria for the definition of development strategies for each section/border and the subsequent execution of iterations for identification of the target capacities;
 - the criteria and evaluation of marginal benefit data, including data on Grid Constraints.
4. marginal cost information for each section/border;
5. information on the marginal benefit for each section/border and information on the average simulation time for each section/border at each iteration;
6. the benefit/cost curves for each section/border;
7. details of the expected flows in the Policy 2030 and 2040 and Inertial 2040 scenarios.

1.4 Executive Summary

The paper presents the results of the target capacity identification analyses, conducted at horizon year 2030 (only NECP Policy 2030 scenario) and horizon year 2040 (in the two contrasting scenarios of policy DE 2040 and inertial NECP slow 2040). The scenarios used are consistent with the 2024 Scenarios Description Document¹⁹.

In continuity with previous editions of the Report, the *least regret* technique has been adopted to select the single set of additional target capacity values for each section/border when using several study scenarios at the same horizon year, with the aim of identifying the target capacity set that exposes the system to the least regret. Therefore, at the 2030 horizon year, there is no need to apply the *least regret* and the target capacity values are defined on the basis of evidence of the analyses conducted in the Policy 2030 scenario (NECP Policy 2030), while at 2040, through application of the advanced *least regret*, it emerges that the additional target capacity values coincide with the set of values defined in the inertial scenario 2040 (NECP slow 2040).

Starting with the previous edition of the Target Capacity Identification Report (2023 edition), for the sake of completeness of the study, sensitivity analyses were carried out to capture the impact of changes in certain input variables on the target capacity. For the present edition, in addition to what was done in the previous report, two additional sensitivities were included to assess the impact of the change in energy storage capacity by 2030 (*storage sensitivity*) and electrolyser consumption by 2040 (*hydrogen sensitivity*).

At 2030 horizon year, constraints were also set on the maximum target capacity on the borders, in line with the planned capacity at the same horizon year in the Development Plan, taking into account existing agreements with foreign TSOs and, therefore, a realistic forecast of border development by prioritising the development of target capacity on the internal sections.

At 2040 horizon year, the border constraints were eased to a value representative of the sum of: i) planned capacity at the same horizon year in the Development Plan; ii) capacity associated with the *merchant line projects* authorised in Italy; iii) projects under study in the Development Plans; iv) an additional 500 MW on each border.

The border constraints as reported in the previous point were used to perform a sensitivity analysis for 2030 (*Borders sensitivity*) functional to the definition of the final target capacity strategy in the 2030 Policy scenario, allowing the identification of the border development profitability and the cross-border target capacity to aim for as a reference point, following the identification of the efficient strategy on the internal sections.

An additional sensitivity analysis was conducted at the 2030 horizon year (*Montenegro sensitivity*), further limiting the development of the border with Montenegro in view of the “under evaluation” status of the MONITA 2 project, in consideration of the opinions on the Development Plans prior to the 2023 edition.

The process workflow adopted is briefly illustrated in [Figure 1](#), while [Table 1](#) and [Table 2](#) show the target capacity values in the analysed scenarios for 2030 and 2040, respectively.

¹⁹ https://download.terna.it/terna/Documento_Descrizione_Scenari_2024_8dce2430d44d101.pdf

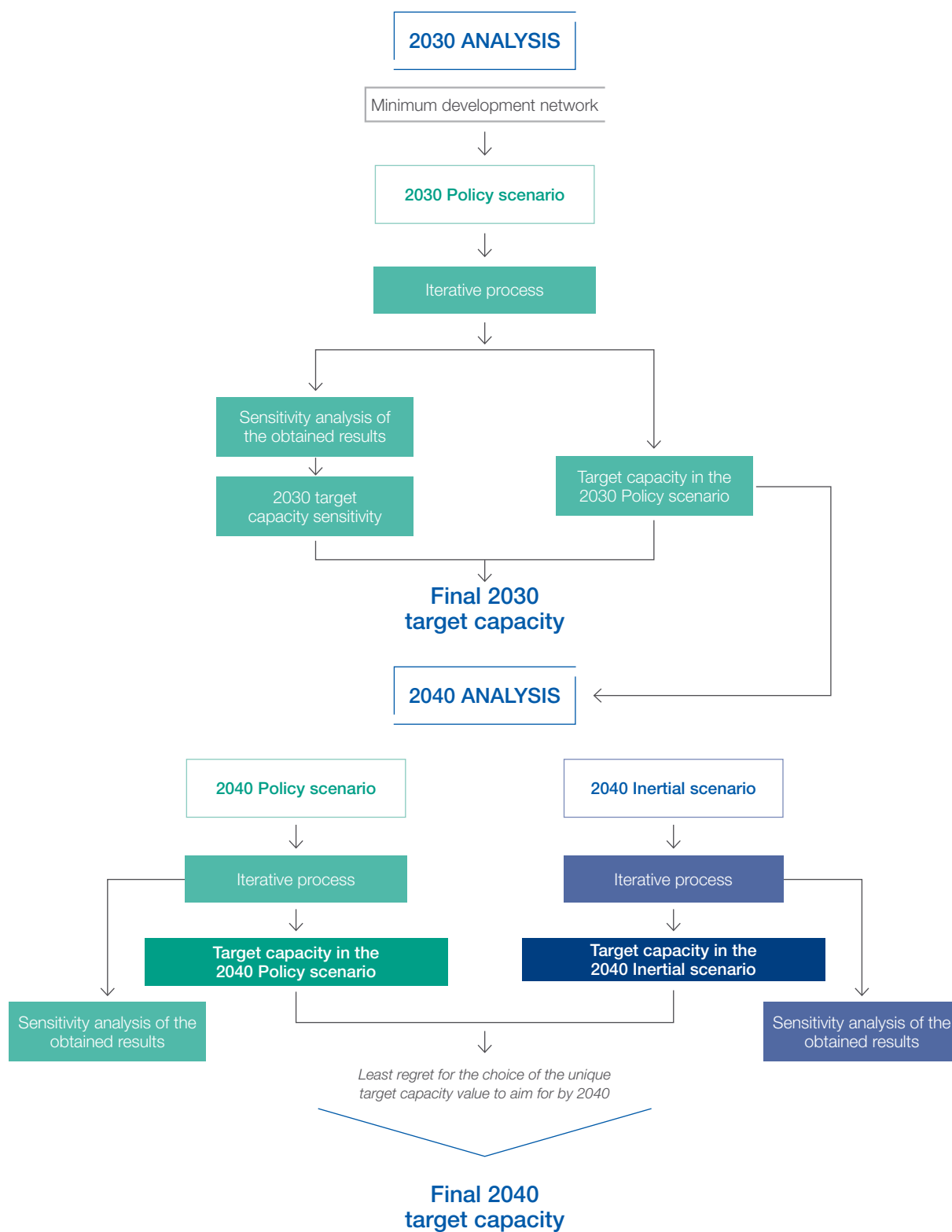
Figure 1 *Workflow of the adopted process*


Table 1 Additional target transmission capacity values at the 2030 horizon year

	ADDITIONAL TARGET CAPACITY (MW) NECP 2030	
	←	→
North-IT border	2,650	
East-IT border	950	
North Africa-IT border	500-600	
ITcn-ITn section	3,100	3,500
ITcs-ITcn section	2,600	
ITs-ITcs section	2,050	
ITn-ITcs section	1,050	
ITn-ITs section	2,100	
ITsar-ITcn section	250	
ITsar-ITcs section	150	
ITsar-ITsic section	1,000	
ITsic-ITcs section	1,100	
ITsic-ITcal section	1,450	
ITcal-ITs section	1,050	

Table 2 Additional target transmission capacity values in the two reference scenarios at the 2040 horizon year

	ADDITIONAL TARGET CAPACITY (MW)					
	DE 2040		NECP SLOW 2040		UNIQUE VALUE	
	←	→	←	→	←	→
North-IT border	4,380		4,830		4,830	
East-IT border	1,850		1,900		1,900	
North Africa-IT border	1,100		1,100		1,100	
ITcn-ITn section	5,850	6,250	4,750	5,150	4,750	5,150
ITcs-ITcn section	5,450		3,600		3,600	
ITs-ITcs section	3,550		3,550		3,550	
ITn-ITcs section	2,100		2,100		2,100	
ITn-ITs section	2,100		2,100		2,100	
ITsar-ITcn section	1,550		1,450		1,450	
ITsar-ITcs section	1,850		1,350		1,350	
ITsar-ITsic section	1,000		1,000		1,000	
ITsic-ITcs section	1,850		1,500		1,500	
ITsic-ITcal section	2,550		2,950		2,950	
ITcal-ITs section	2,150		2,150		2,150	

Bibliography and glossary



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²⁰ <https://www.arera.it/operatori/trasmissione.htm>
https://www.arera.it/allegati/operatori/pds/Rapporto_verifica_Pilo.pdf
https://www.arera.it/allegati/operatori/pds/MA_TROVATO_Relazione_Finale_Target_Capacity_2018.pdf

2.2 Glossary

Cost Benefit Analysis (CBA): a method based on the comparison of the costs and benefits of major development initiatives for the purpose of calculating the SUI (system utility index).

Bottom up, Top down: information processing and knowledge management strategies.

Transmission capacity: active power flow that can be transported between two grid portions compatibly with the operational safety of the electrical system.

Starting transmission capacity: the existing transmission capacity net of any planned decommissioning referring to the so-called “winter peak”, i.e. the maximum winter exchange limit value on each section/border.

Additional target transmission capacity: the additional transmission capacity that is economically efficient to realise, as the marginal benefits are greater than the marginal costs referring to the so-called “winter peak” scenario.

Target transmission capacity (or Target Capacity): final transmission capacity (combination of the initial transmission capacity and the additional target capacity) that is economically efficient to realise, as the marginal benefits are greater than the marginal costs referring to the so-called “winter peak” scenario.

Connecting Europe Facility (CEF): a key financial instrument to promote growth, employment and competitiveness through targeted infrastructure investments at the European level (*Connecting Europe Facility Regulation* no. 1316/2013).

Border: reference section between the Italian electricity system and neighbouring electricity systems for the purpose of target and additional transmission capacity assessments.

Criterion N: an electrical system is in this safe state when all its N components are functioning properly, but this is generally no longer true in the case of a failure.

Criterion N-1: safety assessed on the assumption that the accidental and sudden failure of any component of the electrical system (e.g. line, transformer, generator set) does not lead to exceeding of the operating limits of the other components remaining in service.

Demand response (demand participation): change in electricity consumption by the end user in response to changes in price over time or through incentives.

Electricity demand (needs): electricity demand to be met by the national electricity system. It is variable over time, over the course of the day, month and year.

ENTSO-E (European Network of Transmission System Operators for Electricity): an association formed by 43 European Network Operators from 36 countries with the main purpose of promoting the reliable operation, optimal management and development of the European electricity transmission network.

Grid operator: entity holding the concession for electricity transmission service.

Indicator I21: increase in interconnection or transmission capacity between grid sections, in terms of MW.

SUI (System Utility Index): ratio of discounted benefits to discounted costs of the investment.

Least regret: method to identify the set of target capacity values of each scenario that, in a set of possible strategies, has the so-called “least regret”.

Advanced least regret: method that by successive approximations allows identification of the set of intermediate target capacity values that, in a set of possible strategies, has the so-called “least regret”.

Day-Ahead Market (MGP): trading venue for the purchase and sale bids of electricity for each relevant period of the day following the day of trading.

Market for Dispatching Service (MSD): trading venue for dispatching service resources.

Balancing Market (MB): set of activities carried out by the Operator for the selection of bids submitted on the Market for dispatching service for congestion resolution and the establishment of secondary and tertiary power reserve margins, conducted on the same day as the day to which the bids refer.

Development Plan (DP): an instrument for planning the development of the national electricity transmission grid, prepared annually by the Operator based on:

- the energy demand trend and the forecast of electricity demand to be met;
- the need for expansion of the grid;
- requests to connect new generation plants to the grid.

PINT (Put IN one at a Time): evaluation method for the benefits described in the ENTSO-E Cost Benefit Analysis, which involves including a single intervention at a time in the network and market reference models under study (which normally do not include future development interventions), and then calculates the benefits differentially between results with the intervention (“WITH”) and results without the intervention (“WITHOUT”).

Projects of Common Interest (PCI): pursuant to Art. 4 of Regulation (EU) no. 347/2013, projects with significant positive effects on at least two Member States, contributing to the integration of electricity markets and increased competition within the EU, improving the security of the energy supply and contributing to the increase in electricity production from renewable energy sources (RES) and to the reduction of CO₂ emissions.

CACM (Capacity Allocation and Congestion Management) Regulation: EU Regulation 2015/1222 CACM (Capacity Allocation and Congestion Management) which came into force on August 14, 2015 and establishes guidelines on capacity allocation and congestion management.

Energy transmission service: the activities that concern the planning, development and maintenance of the National Transmission Grid (NTG).

Section: reference section between zones of the relevant grid referred to in Article 15 of Annex A to Resolution 111/06.

SEW (Social Economic Welfare): indicator related to the functioning of the energy market and the increase in transit limits between relevant grid zones or at borders. Social welfare is assessed through the Total Surplus (TS) approach in which the objective function is to maximise system welfare in marginal price system-based markets. In such systems, if congestion is present, this is equivalent to maximising the sum of consumer surplus, producer surplus and congestion rents.

National Electricity System (NES): the set of generation plants, transmission and distribution networks, as well as ancillary services and interconnection devices located on the national territory.

Storage (Storage system): set of devices, equipment and management and control procedures, functional for absorbing and releasing electricity capable of altering the exchange profiles with the electricity grid (input and/or withdrawal).

Consumer Surplus: positive difference between the price an individual is willing to pay to receive a particular good or service and the market price (marginal price) of the same good.

Producer Surplus: positive difference between the price of a given good paid to the producer and the price the producer would have been willing to accept for smaller quantities of that good.

Grid development: Interventions on the electricity grid that involve an adjustment or enhancement of transmission, transformation, connection and interconnection capacity, or an increase in the operational flexibility of the grid, or a decommissioning of grid elements.

TOPSIS (Technique for Order of Preference by Similarity to Ideal Solution): method for multi-criteria decision analysis aimed at selecting the sections/borders with the most favourable conditions for implementing additional transmission capacity.

TOOT (Take Out One at a Time): evaluation method for the benefits described in the ENTSO-E Cost Benefit Analysis, which involves removing a single development intervention at a time in the network and market reference models under study (which normally includes all future development interventions), and then calculates the benefits differentially between results with the intervention ("WITH") and results without the intervention ("WITHOUT").

TYNDP (Ten-Year Network Development Plan): Ten-year European Grid Development Plan drawn up every two years.

Overview at European level

3

3.1 Identification of System Needs 2024

Starting in 2012, in its Opinion 06/2012 on the draft TYNDP 2012, the Agency for the Cooperation of Energy Regulators (ACER) proposed the introduction of the concept of target capacities; subsequently, in Opinion 01/2017, ACER made a number of recommendations on System Needs identification activities.

To this end, as part of the drafting of the Ten-Year Development Plan (TYNDP) 2024 and in continuity with previous editions of the TYNDP, in January 2025, ENTSO-E published for consultation the report **“Opportunities for a more efficient European power system by 2050 - Infrastructure Gaps Report 2024”**²¹, containing the results of analyses and needs of the European power system over a medium (2030), long (2040) and very long (2050) term.

The reference network used (2030 horizon) for the analyses was chosen to include all candidate projects in the TYNDP that are currently under construction and/or at an advanced stage and are expected to be completed by 2030, in addition to the existing 2025 network.

The studies are developed on the basis of **zonal analyses**: this represents a necessary compromise due to the extension of the scope of analysis and simplifies the more complex network simulations that consider flows on each power line, but require significantly greater computational complexity.

The current methodology for identifying system needs focuses on benefits in terms of SEW (*socio-economic welfare*) and integration of renewable energy sources. Therefore, the reduction in CO₂ emissions is partially accounted for in the SEW through the ETS CO₂ price, the *extra-bid price* included in the generation cost.

The results of these analyses show that at least 88 GW are needed by 2030 compared to the pan-European reference grid as at 2030, while looking at the 2040 time horizon, infrastructure development needs at the pan-European level increase to 108 GW and then to 224 GW by 2050.

This increase in transmission capacity will lead to an increase in cross-border exchanges with possible impacts on national grids and consequent need for internal reinforcements.

Furthermore, as far as storage systems are concerned, analyses have highlighted the need to develop an additional 56 GW of battery storage systems by 2030, looking at a target of more than 500 GW in 2050.

²¹ https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/forconsultation/Infrastructure_Gaps_Report.pdf

Key assumptions and hypotheses

4

The overall framework of the assumptions and reference hypotheses, detailed in the following paragraphs, is shown in *Figure 2*.

Figure 2 *Key assumptions and hypotheses: overall picture*

HORIZON YEARS	Analyses were performed on two time horizons: 2030 and 2040 .
REFERENCE SCENARIOS	The scenarios used for the analyses are consistent with those presented in the 2024 Scenarios Description Document and adopted for the 2025 National Development Plan (NCEP Policy 2030, NCEP Slow 2040 and DE 2040).
ZONAL STRUCTURE	The analyses are based on the current zonal configuration , consistent with the 2025 National Development Plan.
MINIMUM DEVELOPMENT NETWORK	The minimum development network consists of the existing exchange capacity as of 01.01.2024 , along with authorised projects for which supply contracts have been signed , construction tenders awarded, or under construction.

4.1 Horizon years

In this Target Capacity Assessment Report, consistent with 2023 edition, analyses were conducted over two time horizons, a medium-term horizon to 2030 and a long-term horizon to 2040. This dual-year approach aims to assess output variability under contrasting development scenarios across different timeframes.

The selection of the study years reflects insights gained from expert-based verification processes conducted for 2018 and 2020 editions, experience gathered from European TYNDP and IoSN analyses, and the twenty-year time horizon of the planning studies.

4.2 Reference scenarios

The analyses for identifying target capacities were carried out in the scenarios elaborated and described in the [2024 Scenarios Description Document \(SDD\)](#)²². In detail, the contrasting reference scenarios used for the analyses are:

- the **“NECP Policy” scenario** at 2030;
- the **“Distributed Energy” (DE) policy scenario** at 2040;
- the **representative scenario of a slower energy transition “NECP Slow”** at 2040.

The **NECP Policy 2030 scenario** is based on the latest government indications from the National Energy and Climate Plan (NECP), published in June 2024. This scenario outlines the objectives of the European “Fit-for-55” and “RepowerEU” legislative packages at the national level. For the 2040 time horizon, two contrasting scenarios are considered: the **DE policy scenario**, which builds upon the NECP Policy 2030 and aligns with ENTSO-e’s European framework, reflecting the intermediate, non-binding objectives toward achieving the Net Zero Emissions target by 2050, considering strong penetration of the electric carrier; and the **NECP Slow**, scenario, which instead represents a slower transition towards the decarbonisation targets.

In detail:

- the **NECP Policy 2030** is the policy scenario at 2030, it assumes an efficient combination of investments in gas and electricity grid infrastructures, electric and molecular renewables, energy storage and new digital technologies that are compatible with the main technical, economic and administrative constraints that might otherwise prevent their realisation within in such a tight timeframe. By 2030, coal-fired thermal power plants are expected to be completely decommissioned, leading to a significant expansion of non-programmable renewables, particularly photovoltaics and wind power. Ambitious targets to reduce greenhouse gas (GHG) emissions by at least 55% by 2030, compared to 1990 levels, are driving the electrification of energy consumption, a substantial increase in renewable generation and the adoption of carbon capture and storage (CCS) technology;
- the **Distributed Energy 2040** is the policy scenario at 2040, aligned with the ENTSO-E Distributed Energy storyline of TYNDP 2024²³ and derived from the NECP Policy 2030 scenario. It represents a possible pathway for achieving Carbon Neutrality in 2050, through strong penetration of the electric carrier in all sectors (civil, transport and industry) by maximising the use of renewable generation coupled with a strong development of storage capacity and overgeneration recovery solutions. The use of green gases is marginal and limited to the hard-to-abate and heavy transport sectors. CCS/CCU (Carbon Capture & Storage/Utilisation) technologies are mainly envisaged in the industrial sector for the capture of combustion and process emissions;
- the **NECP Slow 2040** is the inertial scenario at 2040, constructed with reference to the objectives of the DE 2040 scenario, but assuming a slower trajectory in reaching the decarbonisation targets. In particular, a slower electrification of consumption is expected, with a consequent reduction in electricity demand, a delay in the development of RES, more limited development of electrolyzers and CCS technology, non-maximised development of biomethane and reduced penetration of green hydrogen.

Electricity demand

Electricity demand is not only influenced by macroeconomic conditions and demographic change but also heavily depends on the development of technologies, such as electric vehicles and heat pumps, as well as planned energy efficiency measures. In all scenarios, an increase in total electricity demand is expected, as shown in [Figure 3](#).

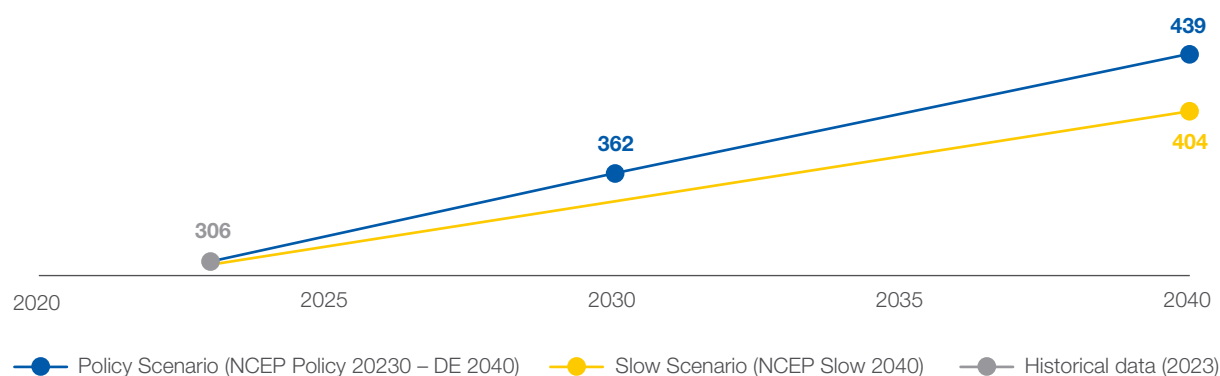
The **NECP Policy 2030** scenario, consistent with the June ‘24 NECP, envisages an acceleration of the electrification process in the transport and civil sectors, and thus an increased penetration of the electric carrier and an increase in electricity demand, net of energy efficiency, attributable to electrification in the transport sector itself (including an

²² https://download.terna.it/terna/Documento_Descrizione_Scenari_2024_8dce2430d44d101.pdf

²³ The 2024 SDD contains two development scenarios to 2040: Distributed Energy Italy (DE-IT) and Global Ambition Italy (GA-IT). These scenarios contrast with each other and are aligned with the similar ENTSOs scenarios and differ with respect to the path outlined for achieving Carbon Neutrality by 2050, in terms of greater or lesser development and penetration of individual technologies and, in particular, of the electricity carrier.

increase in electricity consumption in the shipping sector due to so-called “Cold Ironing”), the use of electric heat pumps, GDP growth and the production of hydrogen from electrolysis. These assumptions lead to an increase in demand of up to 362 TWh, about +56 TWh compared to 306 TWh in 2023. In continuity with the development of the factors already in play in the NECP Policy 2030, the **Distributed Energy 2040** scenario entails further growth in electricity demand of +133 TWh compared to consumption in 2023, for a total of 439 TWh in 2040. Instead, in the **NECP Slow 2040 scenario**, the increase in electricity demand is lower than the policy ones, reaching a value of 404 TWh, due to reduced energy requirements for hydrogen production and a lower penetration of fully electric vehicles and heat pumps.

Figure 3 Demand Growth (TWh) in the reference scenarios



Installed Capacity

In all reference scenarios, the evolution of the expected generation capacity in the coming years is significantly influenced by the *phase-out* of coal from the Italian thermoelectric park and by the increase in renewable generation capacity, particularly from solar and wind power, in synergy with the increase in storage capacity through the construction of hydroelectric pumping and electrochemical storage. In all scenarios, the outcomes of Capacity Market auctions are considered in terms of both conversion of existing plants and the development of new ones; however, no assumptions are made regarding the potential decommissioning of part of the gas-fired generation capacity. Hydroelectric capacity remains unchanged compared to the current levels, while the overall renewable capacity from other sources (e.g. biomass, geothermal, etc.) is slightly reduced.

The scenario **NCEP Policy 2030** is characterised by the complete *phase-out* of coal-powered capacity and the need for almost 107 GW of installed solar and wind power capacity by 2030 in order to meet policy targets. This translates into an increase in installed RES of +65 GW by 2023, enabling renewable sources to cover approximately 63% of total electricity demand. The zonal distribution of RES drawn up for the 2024 SDD is consistent with the “Suitable Areas Ministerial Decree”, which sets out the criteria for the regions to identify areas suitable for renewable plants installations. The increase in RES is accompanied and supported by an increase in “utility scale” and “small scale” storage capacity, reaching up to +65 GWh compared to existing levels.

RES growth reaches its peak in the **Distributed Energy 2040** scenario up to +127 GW total, supported by a corresponding total storage capacity of 167 GWh compared to 6.6 GWh in 2023. In contrast the **NCEP Slow 2040** scenario considers a more moderate growth of installed solar and wind power by +102 GW by 2040 and 117 GWh of total storage capacity.

The elements described above are depicted in [Figure 4](#), illustrating the installed wind and solar generation capacity (GW), [Figure 5](#), which shows the evolution of the total energy storage capacity (GWh), and [Figure 6](#), with regard to evolution of the installed capacity of new electrolysisers.

Figure 4 *Wind and solar installed generation capacity (GW) in the reference scenarios to 2030 and 2040*

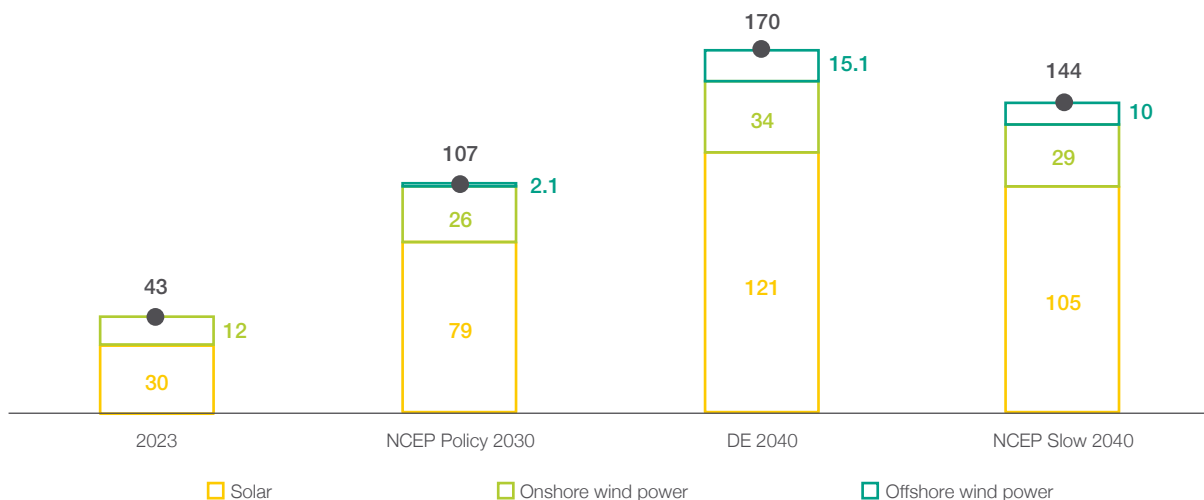


Figure 5 *Energy storage capacity (GWh) in the reference scenarios to 2030 and 2040 (net of existing pumping)*

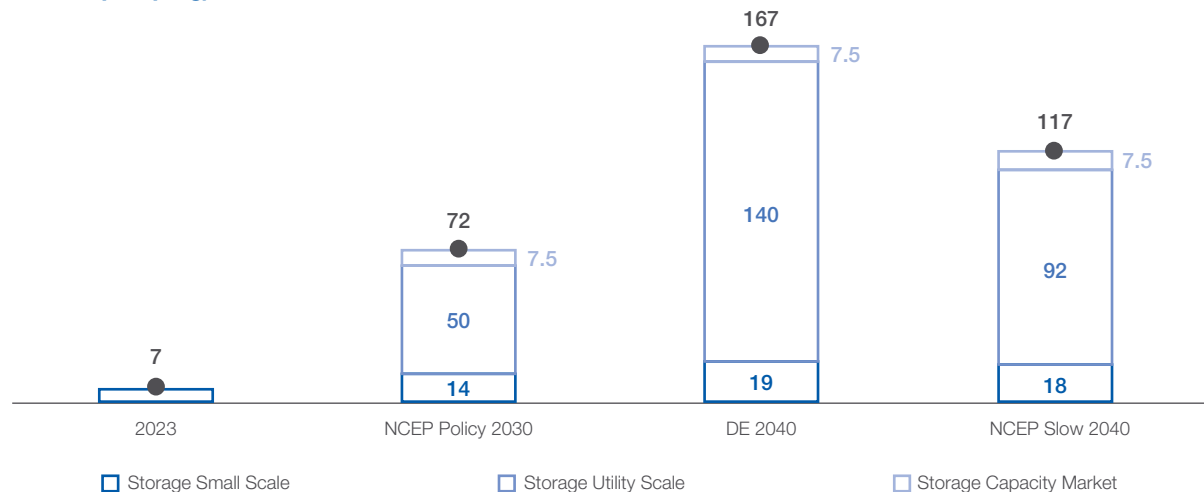
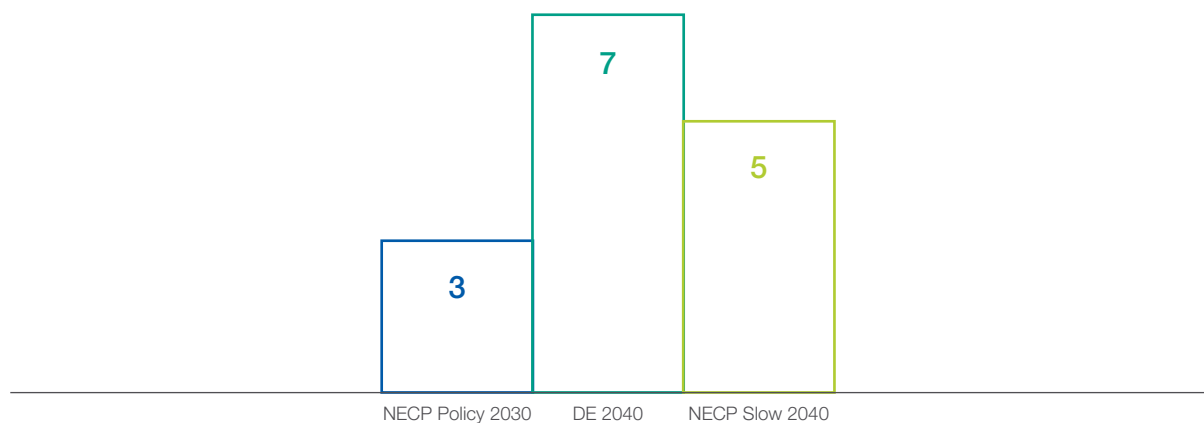


Figure 6 *Electrolyser capacity (GW) in the reference scenarios to 2030 and 2040*



4.3 Zonal structure

The zonal configuration taken as reference for the target capacity identification is the one that came into effect from January 1, 2021 with ARERA Resolution 103/2019/R/EEL.

As depicted in *Figure 7*, the zonal structure divides the National Transmission Grid into 7 geographical zones (North, Centre North, Centre South, South, Calabria, Sicily and Sardinia).

Considering the current zonal structure and the borders or sections impacted by interzonal projects planned by the TSO, the borders and sections under analysis for the 2030 and 2040 horizon years are illustrated in *Figure 8* and are listed as follows²⁴:

- North (France, Switzerland, Austria and Slovenia) - Italy border;
- East (Montenegro and Greece) - Italy border;
- North Africa (Tunisia) - Italy border;
- North - Centre North section;
- Centre North - Centre South section;
- Centre South - South section;
- North - Centre South section;
- North - South section;
- South - Calabria section;
- Calabria - Sicily section;
- Sicily - Sardinia section;
- Sicily - Centre South section;
- Centre North - Sardinia section;
- Sardinia - Centre South section.

4.4 Market and grid models

In market studies, the same model used in the 2024 TYNDP is applied to the foreign network and depicted in *Figure 9*²⁵, along with the more detailed national model used in the Development Plan analyses. In addition, the countries included in the North Africa electricity market (Morocco, Tunisia, Algeria, Egypt and Libya) and the Middle East (Israel and Palestine) which are part of the *Mediterranean Transmission System Operators* (MedTSO)²⁶ are also modelled.

The electricity system is modelled using a nodal topology, where market zones are modelled as nodes interconnected through a single branch with a capacity

Figure 7 Zonal structure



Figure 8 Sections/Borders investigated at 2030 and 2040 time horizons



²⁴ Italy-Malta border is not included in the set of sections/borders under analysis; being a minor unmeshed island, the radial connection (antenna or double antenna) to Sicily does not significantly affect Sicily's load profile and Sicily's equivalent demand.

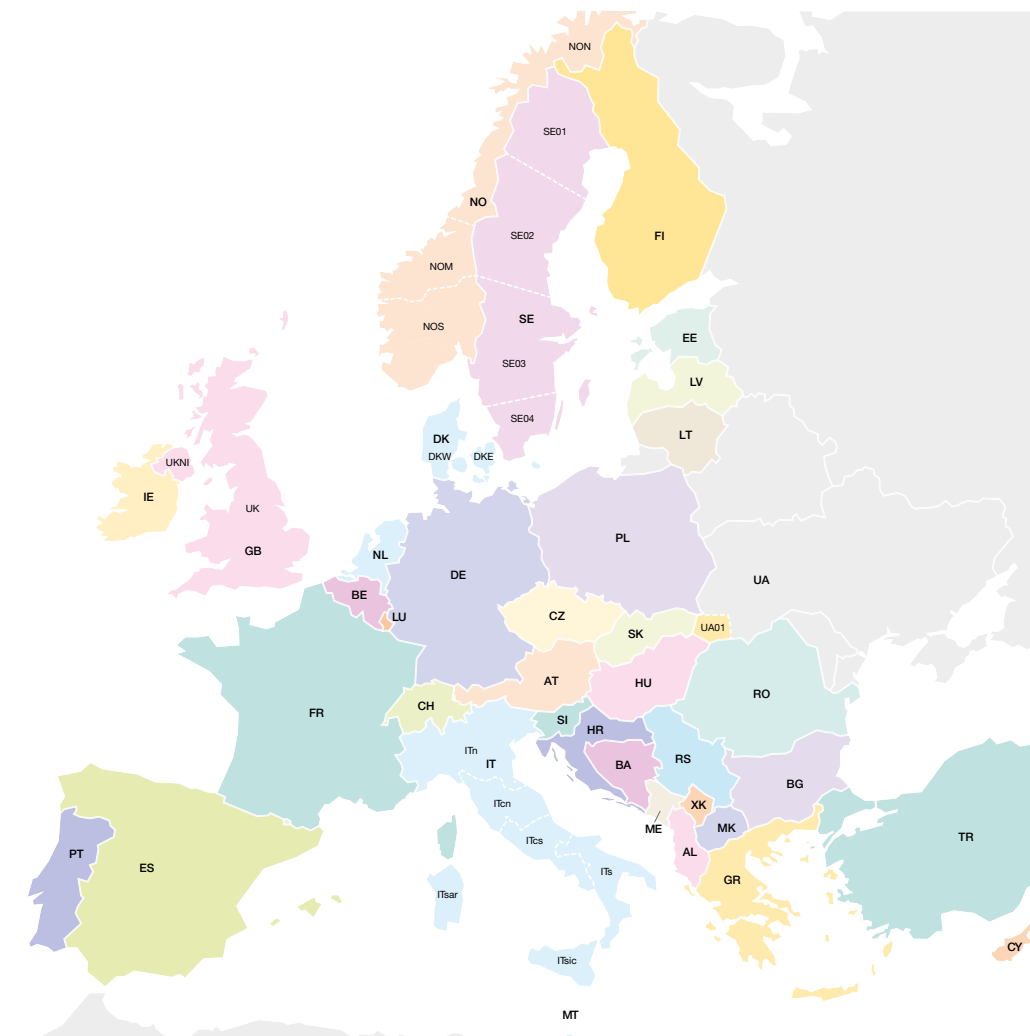
²⁵ *Figure 9* explains the foreign model used in the zonal market simulations. With regard to the internal zonal structure adopted, please refer to paragraph 4.3.

²⁶ <https://med-tso.org/en/home/>

equivalent to the *net transfer capacity* (NTC) between each market zone. Each country is modelled as a single node with the exception of Denmark, Italy, Luxembourg, Norway, France (Corsica), Great Britain (Northern Ireland), Greece (Crete) and Sweden. Each node is characterised by a mix of generation, demand and interconnection capacity.

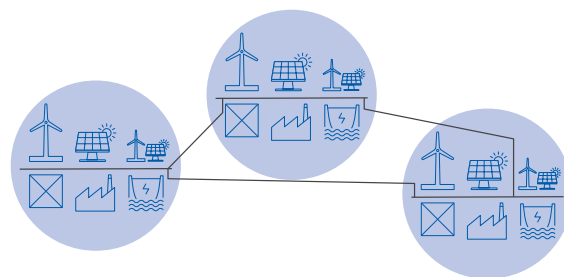
The reference data used to define the scenario assumptions for the entire ENTSO-E scope of countries is the TYNDP 2024 Scenario Report²⁷.

Figure 9 *Market model used (source: 2024 TYNDP)*



For network studies, the model of the complete National Transmission Grid with voltage levels of 380, 220, 150 and 132 kV is used. The model also includes an equivalent of the European network, modelled through a bus-bar network (*Figure 10*) without the detail of the internal transmission grid. For each of these countries, load and generation is mapped in line with the TYNDP scenarios.

Figure 10 *Example of a bus-bar network model*



²⁷ <https://2024.entsos-tyndp-scenarios.eu/>

4.5 Reference grid

For the analyses conducted in this report, a single reference network was evaluated—referred to as the **base case** or “**minimum development**” scenario. Compared to the current network configuration, this scenario includes the implementation of **projects** from the 2023 Development Plan that have already been **authorised**, for which supply contracts have been signed and/or tenders awarded for construction, or that are currently under construction, based on the most up-to-date information available.

Figure 11 Projects included in the Minimum Development Network



Project	MW	Section/ Border
1 132 kV Prati di Vizzè Steinach	100 MW	ITn – AT
2 Colunga-Calenzano	400 MW	ITcn – ITn
3 HVDC Adriatic Link	1,000/600 MW 1,000 MW	ITcn > ITn/ ITn > ITcn ITcs – ITcn
4 Removal of Limitations	400 MW	ITcs – ITcn
5 HVDC SACOI3	400 MW*	ITsar – ITcn
6 HVDC West Tyrrhenian link	1,000 MW	ITsar – ITsic
7 HVDC East Tyrrhenian link	1,000 MW	ITsic – ITcs

* The increase on the ITsar-ITcn section is +100MW compared to the current exchange limits taking into account the end of life of the existing SACOI2 with which an exchange capacity of 300MW is associated

For the **base case** and the individual interventions, analyses were carried out in the NCEP Policy 2030 scenario with a TOOT approach to assess the benefits of the interventions included in the minimum development. For the assessment of additional transmission capacity, a PINT (Put IN one at a Time) approach was used in the NCEP Policy 2030, NCEP Slow 2040 and DE 2040 scenarios, as outlined below:

- **TOOT (Take Out One at a Time) approach:** Starting from the minimum development case, interventions on a given section or border are individually removed to evaluate their specific impact²⁹;
- **PINT approach (Put IN one at a Time):** Benefits related to increased transmission capacity are assessed by adding only the capacity increases on specific sections or borders under consideration, if the conditions described in Annex 3 are met.

The PINT simulations aim to analyse “development strategies” – namely, progressive capacity increases on one or more network sections or borders (see Annex 3 for details) – and to define alternative development strategies for each of these sections/borders.

The analyses conducted using the PINT approach in the NCEP Slow 2040 and DE 2040 scenarios, aimed at defining target capacities in a very long-term scenario, were carried out from a reference network characterised by the development strategy resulting from the analyses at the 2030 horizon year.

²⁸ <https://www.terna.it/it/sistema-elettrico/programmazione-territoriale-efficiente/piano-sviluppo-rete>

²⁹ Resolution 129/2018/R/EEL refers to the additional transmission capacity at the “border” between the Italian electricity system and neighbouring electricity systems. For the purposes of the target capacity, the border was defined as an aggregate of borders where they are territorially contiguous and/or do not show a significant mismatch in the estimated price differentials.

For the sake of clarity, [Table 3](#) presents the exchange capacity values between internal sections and across borders for the current network (1 January 2024) and the minimum development network. The transmission limits of the existing network take into account capacity increases achieved between 2020 and 2023 through *capital light* measures, both on the Northern Border³⁰ and on the internal market sections of the Italian electricity system³¹.

Table 3 *Capacity values between internal sections and on foreign borders for the existing network and the minimum development network*

	EXISTING NETWORK CAPACITY (MW)		MINIMUM DEVELOPMENT NETWORK CAPACITY (MW)	
	←	→	←	→
North-IT border	4,995	10,435	5,095	10,535
East-IT border	1,100	1,100	1,100	1,100
North Africa-IT border	0	0	0	0
ITcn-ITn section	4,300	3,100	5,300	4,500
ITcs-ITcn section	2,900	2,800	4,300	4,200
ITs-ITcs section	2400	5,200	2,400	5,200
ITn-ITcs section	0	0	0	0
ITn-ITs section	0	0	0	0
ITsar-ITcn section	325	425	425	525
ITsar-ITcs section	720	900	720	900
ITsar-ITsic section	0	0	1,000	1,000
ITsic-ITcs section	0	0	1,000	1,000
ITsic-ITcal section	1,550	1,300	1,550	1,300
ITcal-ITs section	1,100	2,350	1,100	2,350

4.6 Constraints on the target development capacity of the grid

4.6.1 Definition of additional capacity achievable on borders

Given the ambitious national renewable penetration targets and considering the timeframes and complexities involved in coordinating with foreign European and non-European TSOs for the development of cross-border projects, in continuity with the 2023 edition, it was deemed appropriate to impose a **constraint on the additional capacity that can be targeted on foreign borders** in development strategies **to horizon years 2030 and 2040** (new in this edition), **based on the following criteria**:

- For the 2030 horizon, the constraint on additional target capacity was set according to the values already planned in the Development Plan for that year.
- For the 2040 horizon, the constraint was determined considering: i) the values already planned at that horizon in the Development Plan, ii) the merchant lines projects authorised in Italy, iii) the projects under examination, and iv) an additional 500 MW of additional capacity at each border.

This methodological approach enables a more realistic assessment of project feasibility and their impact on internal section capacity requirements in target capacity analyses. In fact, defining a grid development strategy that assumes significant increases in cross-border transmission capacity—beyond what is realistically achievable by 2030 or even 2040—would underestimate the target capacities required on internal sections. This could lead to a distortion of the overall development strategy, ultimately hindering effective planning of the national electricity grid.

³⁰ "NTC values in import direction on the Italian borders - YEAR 2024" <https://www.terna.it/it/sistema-elettrico/mercato-elettrico/capacita-interconnessione-estero>

³¹ "Values of transit limits between market zones", rev 30 <https://dati.terna.it/mercato-adequatezza/limiti-di-transito-tra-zone-di-mercato>

The capacity increases (PINT) on the borders were therefore confirmed within the constrained values defined for 2030 and 2040 horizon years, as illustrated, respectively, in [Figure 12](#) and [Figure 13](#). In addition, the profitability of the cross-border development beyond the constraint is assessed by measuring the benefits associated with an additional PINT both in the iteration in which the constraint itself is activated and in all subsequent iterations, up to the identification of the optimal development strategy across all borders and sections.

Figure 12 Constraints on additional capacity attainable on foreign borders in the 2030 analysis



BORDER	INTERVENTION	INTERVENTION CODE	NTC INCREASE [MW]
IT-SI	Increased interconnection capacity with Slovenia	200-I	400
IT-MNE	HVDC MONITA 2	401-P	600
IT-TN	HVDC TUNITA	601-I	600

Figure 13 Constraints on additional capacity attainable on foreign borders in the 2040 analysis



BORDER	INTERVENTION	INTERVENTION CODE	NTC INCREASE [MW]
IT-AT	Auronzo-Lienz	204-P	500
	Dobbiaco-Sillian	252-P	160
	Somplago-Wurmlach	ML	-
IT-CH	Valtellina-Valchiavenna	167-P	1,000
	Greenconnector	ML	-
IT-SI	Increased interconnection capacity with Slovenia	200-I	1,000
	Dekani-Zaule	ML	-
	Vrtojba-Redipuglia	ML	-
IT-MNE	HVDC MONITA 2	401-P	600
IT-GR	HVDC GRITA 2	554-P	1,000
IT-TN	HVDC TUNITA	601-I	600

4.6.2 Definition of additional capacity achievable on competing internal sections

Similarly to the exercise carried out for the definition of border constraints, it was considered appropriate to also impose a constraint on the incremental capacity that can be achieved on two novel internal sections introduced in addition to those examined in the 2023 edition, the North - South section and the North - Centre South section, taking into account the currently planned projects, as shown in [Table 4](#).

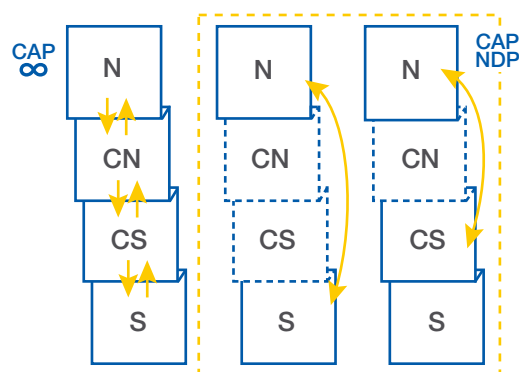
Since the new sections enable a direct connection between two non-contiguous market areas—bypassing the intermediate ones—network development along these sections appears to be competitive with and/or an alternative to the development of infrastructure corridors between adjacent areas. Given the possibility of both indirect and direct connections between the above sections, see [Figure 14](#), PINT simulations were conducted in parallel on the ITn-ITcn, ITcn-ITcs and ITcs-ITs sections and on the ITn-ITcs and ITn-ITs sections so that the benefits associated with alternative development strategies could be investigated simultaneously and the optimal grid development strategy identified.

In any case, the incremental capacity achievable on the new ITn-ITcs and ITn-ITs sections is constrained to the maximum exchange capacity currently planned in the Development Plan, as these represent potential new expansion routes that are still under assessment and subject to further consolidation.

Table 4 Constraints on incremental capacity achievable on new internal sections

SECTION	INTERVENTION	INTERVENTION CODE	NTC INCREASE [MW]
ITn-ITcs	HG Tyrrhenian North Backbone	355-N	2,100
ITn-ITs	HG Adriatic Backbone	447-N	2,100

Figure 14 Competing internal sections based on projects in NDP 25



4.7 Sensitivity analysis

In this edition of the Target Capacity Assessment Report, in accordance with the previous version, a number of developments have been implemented to take into account expert-based audits conducted on the previous editions of the report and the new forecasted energy scenarios.

In particular, in this edition, the **sensitivity analyses conducted at year 2030** consist of:

- a sensitivity **analysis** by relaxing the **CAP constraint** previously **imposed** on the maximum incremental capacity achievable at the borders, based on the interconnection projects planned for the 2030 horizon. This analysis assesses the profitability of increasing target capacity at the borders under a revised border limit, taking into account the following factors projected to the 2040 horizon: interconnection projects already planned, authorised merchant line projects in Italy, projects currently under study, and an additional 500 MW of capacity at each border.

As a result, the constraint is raised in alignment with the CAP values applied for the 2040 horizon;

- a **sensitivity analysis** by imposing on the border with **Montenegro** a zero additional capacity compared to the minimum development network, taking into account the current status of “*under evaluation*” of the IT-ME interconnection project (401-S) formulated in the opinions to the Development Plans prior to the 2023 edition and evaluating the increased target capacity on the internal sections necessary to develop further benefits for the system;
- a **sensitivity analysis on the installed storage capacity to 2030**, in which only the share of additional Utility Scale storage systems was reduced—bringing the target for this technology back to current levels. The objective of this analysis is to assess the need for increased transmission capacity resulting from the absence of significant additional storage capacity.

At 2040 time horizon, the analyses were completed with an additional **sensitivity analysis on electrolyser consumption**, aimed at defining the additional target capacity to be developed in the event of no initiatives for new electrolyzers to reduce the *overgeneration* and produce hydrogen.

Application of the methodology

5

This paragraph presents the **development strategies resulting from the application of the methodology** described in Annex 3 **respectively in the Policy and Inertial scenarios, for the 2030 and 2040 time horizons**. For completeness, the development strategies obtained as an output of the sensitivity analyses on the final target capacity values for 2030 and 2040 are also included.

In general, the following **three conditions** may occur in iterative simulations:

1. when simulating an increase in transmission capacity (discrete “step”) on a generic section/border, the resulting benefits are greater than the related investment costs (**B/C ratio > 1**), a point on the marginal benefit curve is described and **the capacity increase is confirmed** in the next iteration;
2. when simulating an increase in transmission capacity (discrete “step”) on a generic section/border, the resulting benefits are lower than the related investment costs (**B/C ratio < 1**), no point on the marginal benefits curve is described and **the capacity increase is not confirmed** in the next iteration;
3. when simulating an increase in capacity (discrete “step”) on a generic section/border, the resulting benefits are greater than the related investment costs (**B/C ratio > 1**), but no point on the benefits curve is described and **the capacity increase is not confirmed** in the next iteration, **because** the simulated additional capacity **exceeds the constraint** imposed on the additional capacity achievable on the competing borders and/or sections.

Although the methodology for identifying target capacities involves the application of the multi-criteria TOPSIS (Technique for Order Performance by Similarity to Ideal Solution) method to select a subset of the sections/borders on which to simulate the capacity increase (PINT) in a generic iteration, reducing the computational burden, pending the finalisation of the methodological *upgrades* in the definition of the judgement criteria underlying the calculation of the performance indices, the capacity increments have been extensively tested on all sections/borders.

In addition, in the first of the three above-mentioned conditions, with the aim of pursuing the criterion of selectivity in the development strategies for each analysis scenario to the benefit of overall system efficiency, if several competing sections/borders present B/C values of greater than one in an iteration, the capacity increases are only **confirmed on those sections/borders for which B/C values are greater than an empirically defined threshold value** for each iteration at horizon years 2030 and 2040³². Thus, the first of the three conditions described above can be broken down into two additional cases:

1. if the benefits associated with the increase in transmission capacity on a generic section/border are greater than the related investment costs (B/C ratio > 1), as well as for competing sections, and the B/C ratio of the section/border under consideration is greater than and/or equal to the defined threshold value, a point on the marginal benefit curve is described and the increase is confirmed in the next iteration;
2. if the benefits associated with the increase in transmission capacity on a generic section/border are greater than the related investment costs (B/C ratio > 1), as well as for competing sections, and the **B/C ratio** of the section/border under consideration is **lower than the defined threshold value**, no point on the marginal benefit curve is described and **the increase is not confirmed** in the next iteration.

³² This threshold value was empirically defined iteration by iteration as a function of the resulting B/C values.

Lastly, regarding the third condition previously described, having considered it appropriate to limit the additional transmission capacity that can be realised at the borders and on the new direct internal sections as described in paragraph 4.6, the development strategies for these sections/borders are defined by testing sequential PINTs of incremental capacity until the CAP values are reached. If a generic iteration results in a B/C ratio > 1 at a tested incremental capacity greater than and/or equal to the capacity limit, a point in the marginal benefit curve is described, a capacity increment is confirmed in the next iteration up to the incremental capacity limit defined with the CAP, and from subsequent iterations, no further capacity increment is confirmed, despite the occurrence of a profitable B/C condition.

Figure 15 shows in legend form a summary of all possible conditions that may occur during a generic iteration.

Figure 15 Legend of possible cases in a generic iteration of the methodology for identifying target capacities

KEY			
PINT=YES	+step B/C>1	PINT CONFIRMED	1) The PINT benefits check is POSITIVE B/C>1 2) The B/C ratio is greater than the threshold value 3) A point in the benefit curve is described 4) PINT is confirmed in the next iteration
PINT=YES	+step B/C>1	PINT NOT CONFIRMED	1) The PINT benefits check is POSITIVE B/C>1 2) The B/C ratio is less than the threshold value 3) A point in the benefit curve is NOT described 4) PINT is NOT confirmed in the next iteration
PINT=YES	+step B/C<1	PINT NOT CONFIRMED	1) The PINT benefits check is NEGATIVE with B/C<1 2) A point in the benefit curve is NOT described 3) PINT is NOT confirmed in the next iteration
PINT=YES	+step B/C>1	PINT NOT CONFIRMED	1) The PINT benefits check is POSITIVE B/C>1 2) The simulated additional capacity exceeds the constraint imposed on the additional capacity on the borders or competing sections 3) A point in the benefit curve is NOT described 4) PINT is NOT confirmed in the next iteration

The following paragraphs illustrate the development strategies as a result of the simulations carried out for the 2030 and 2040 horizon years.

5.1 Results of Policy 2030 scenario

5.1.1 Results of methodology application

The development strategy resulting from the target capacity identification analyses conducted on the NCEP Policy 2030 scenario are illustrated in *Figure 16* and *Figure 17*. **The iterative process ends at the 8th iteration and capacity increments of halved size are tested starting from the 7th iteration.**

In *Figure 18*, the target capacity values identified for the 2030 horizon through the application of the methodology are illustrated.

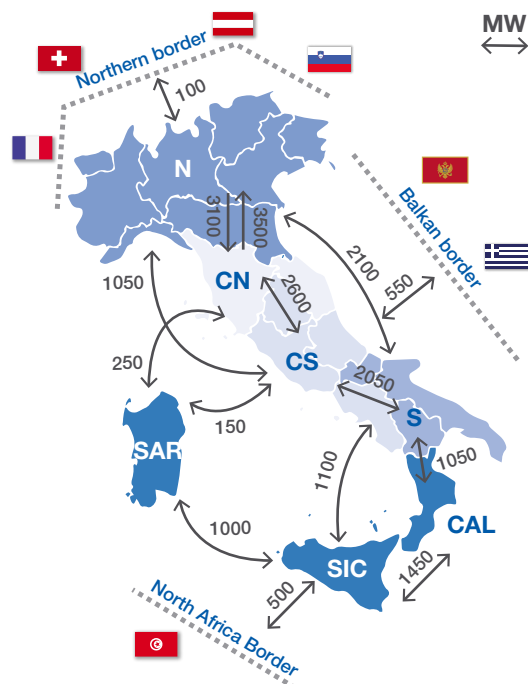
Figure 16 Development strategy resulting from the application of the methodology in the Policy 2030 scenario (Iteration 1-4)

NECP 2030		ITERATION 1 - PINT		ITERATION 2 - PINT		ITERATION 3 - PINT		ITERATION 4 - PINT	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

Figure 17 *Development strategy resulting from the application of the methodology in the Policy 2030 scenario (Iteration 5-8)*

NECP 2030		ITERATION 5 - PINT		ITERATION 6 - PINT		ITERATION 7 - HALVED PINT		ITERATION 8 - HALVED PINT	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Internal sections	ITcn - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

Figure 18 *Target Capacity Values (NECP Policy 2030)*



5.1.2 Border sensitivity

Starting from the target capacity values identified in the NECP Policy 2030 scenario through the development strategy described in paragraph 5.1.1, a sensitivity analysis was conducted to **asses the impact of imposing relaxed constraints on the maximum additional capacity target at the borders by the 2030 horizon year**. The previously imposed CAP constraint, defined on the basis of planned projects with entry into operation by the year 2030, is eased by imposing the same CAP limits used to the year 2040, **taking into account the planned cross-border transmission capacity up to 2040 horizon year, of merchant line projects authorised in Italy, projects under study and an additional margin of 500 MW that can be realised on each border**.

From the 8th iteration onwards, the iterative process extends for **further six iterations** concluding at the 14th iteration, as depicted in *Figure 19* and *Figure 20*.

Figure 19 *Development strategy resulting from the border sensitivity in the 2030 Policy scenario (Iteration 8-11)*

NECP 2030		ITERATION 8 - HALVED PINT BORDERS SENSITIVITY		ITERATION 9 - HALVED PINT BORDERS SENSITIVITY		ITERATION 10 - HALVED PINT BORDERS SENSITIVITY		ITERATION 11 - HALVED PINT BORDERS SENSITIVITY	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

Figure 20 *Development strategy resulting from the border sensitivity in the 2030 Policy scenario (Iteration 12-14)*

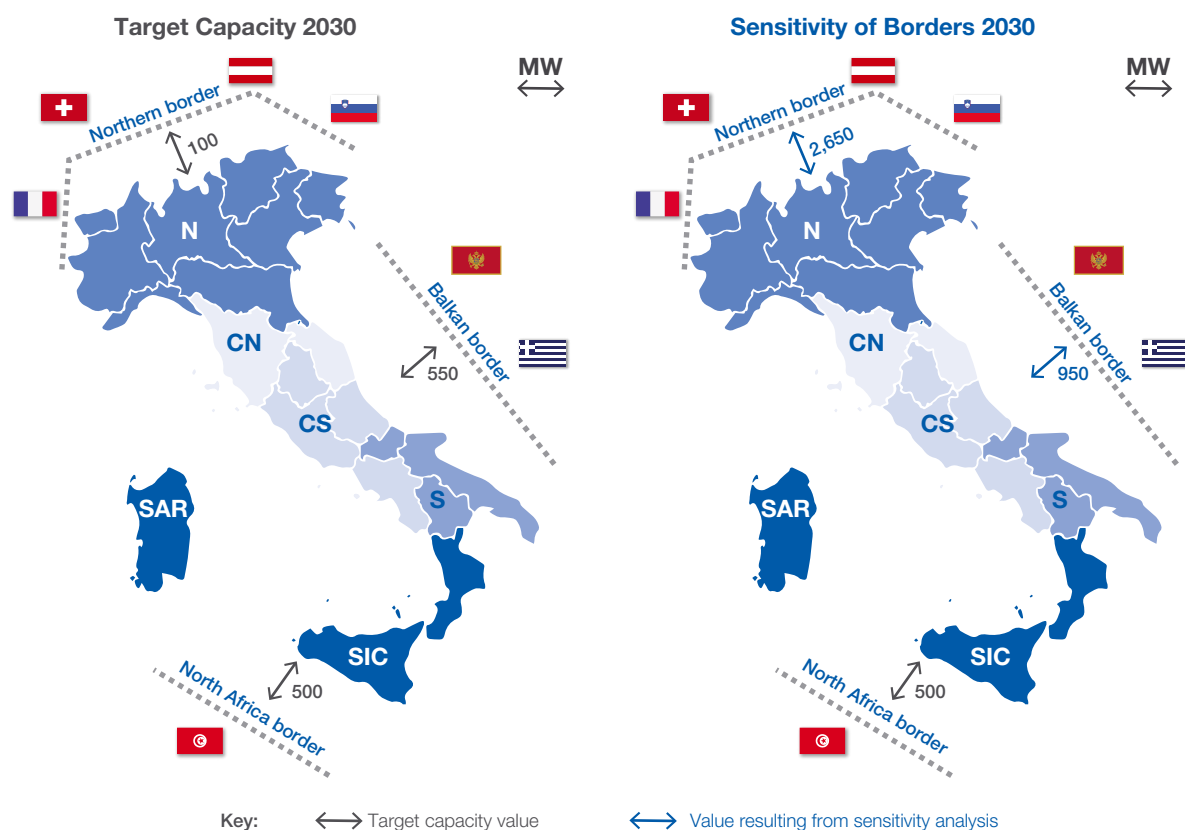
NECP 2030		ITERATION 12 - HALVED PINT BORDERS SENSITIVITY		ITERATION 13 - HALVED PINT BORDERS SENSITIVITY		ITERATION 14 - HALVED PINT BORDERS SENSITIVITY	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

The results of the sensitivity analysis carried out by relaxing the CAP constraints at the borders are shown in *Figure 21*. Overall, the NECP Policy 2030 scenario shows an **increase in the previously identified target capacity on the borders of about +3 GW**, of which 86% at the Northern Border and 14% at the Balkan Border.

From the analysis of the B/C ratios associated with each simulated PINT in the sensitivity of borders (see *Table 13* and *Table 14* in Annex 5), a marked profitability of the Northern Border is observed, in particular towards France and Austria, as already shown in the exercise with reduced CAPs to the planned 2030, pursuant to paragraph 5.1.1 (see *Table 9* to *Table 11* in Annex 5).

For the Italy-France border, despite benefits significantly exceeding costs in most iterations, due to the absence of planned and shared projects with the foreign TSO, a low target capacity value equal to the imposed CAP is identified, already achieved from the second iteration.

Figure 21 Comparison of target capacity values and sensitivity of borders (Policy 2030)



5.1.3 Montenegro sensitivity

Starting from the target capacity values identified in the NECP Policy 2030 scenario through the development strategy described in paragraph 5.1.1, a sensitivity analysis was conducted to determine the impact of imposing more stringent constraints on the achievable transit capacity at the eastern border. In particular, a **capacity constraint equal to the minimum development value was imposed at the 2030 horizon on the ME-ITCs border**, considering the current positioning in the assessment of the 600 MW Italy-Montenegro MONITA2 interconnection project, following the Authority's opinions prior to the NDP 2023, **determining** through further iterations **the impact on the additional capacity of the internal sections**.

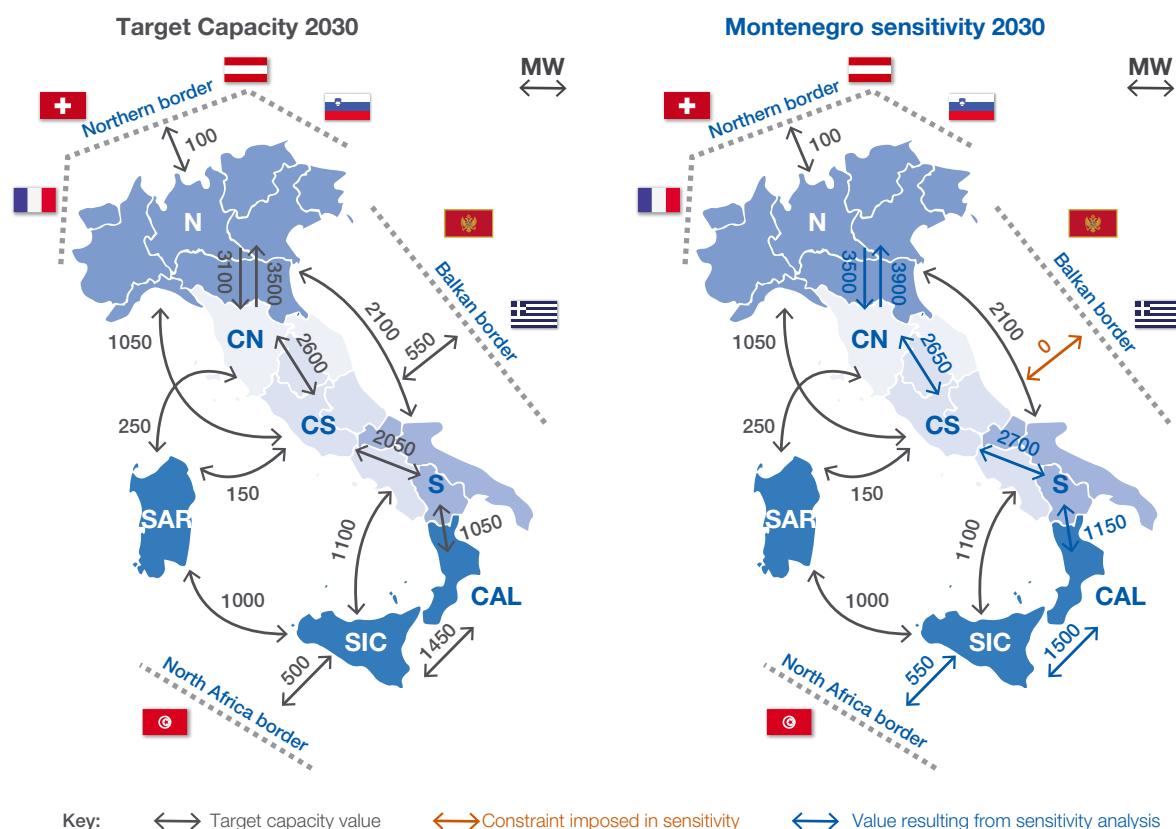
From the 9th iteration onwards, the iterative process extends for **further three iterations** concluding at the 11th iteration, as shown in *Figure 22*.

Figure 22 Development strategy resulting from the Montenegro sensitivity in the 2030 Policy scenario

NECP 2030		ITERATION 9 - HALVED PINT ME SENSITIVITY		ITERATION 10 - HALVED PINT ME SENSITIVITY		ITERATION 11 - HALVED PINT ME SENSITIVITY	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

The results of the sensitivity analysis conducted by reducing the capacity towards Montenegro are shown in [Figure 23](#). The reduction of the cross-border target capacity with Montenegro has the effect of **increasing the efficient capacity on the internal sections, especially on the North - Centre North and South - Centre South**. **Overall**, the NECP Policy 2030 scenario shows an increase in the previously identified target capacity on internal sections of **+1.25 GW**.

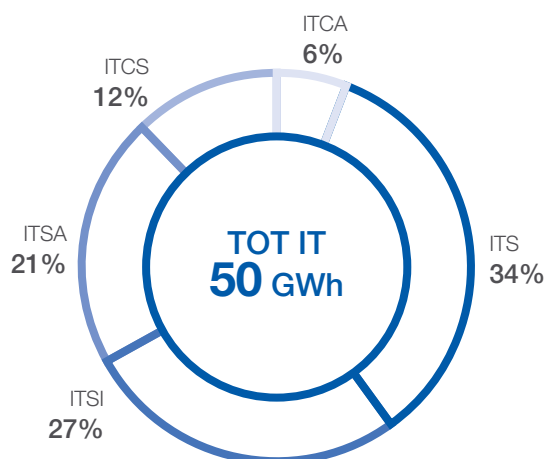
Figure 23 Comparison of target capacity values and Montenegro sensitivity (Policy 2030)



5.1.4 Storage sensitivity

Starting from the target capacity values identified in the NECP Policy 2030 scenario through the development strategy described in paragraph 5.1.1, a sensitivity analysis was carried out to determine the impact of a **constraint on the development of forecasted Utility Scale storage capacity** installed in the Italian Market Zones³³. This was done by imposing a scenario value equal to the current installed capacity, with the aim of **assessing the implications on the additional target capacity in the event that a significant share of the forecasted storage capacity** shown in *Figure 24* is not achieved.

Figure 24 Energy Capacity of Utility Scale Storage (NECP Policy 2030)



³³ Except for situations where the complete elimination of installed utility scale storage would have significantly impacted the adequacy of the electricity system.

From the 9th iteration onwards, the iterative process extends for further **six iterations** concluding at the 14th iteration, as depicted in *Figure 25* and *Figure 26*.

Figure 25 Development strategy resulting from the storage sensitivity in the 2030 Policy scenario (Iteration 9-11)

NECP 2030		ITERATION 9 - PINT STORAGE SENSITIVITY		ITERATION 10 - PINT STORAGE SENSITIVITY		ITERATION 11 - HALVED PINT STORAGE SENSITIVITY	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Internal sections	ITcn - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

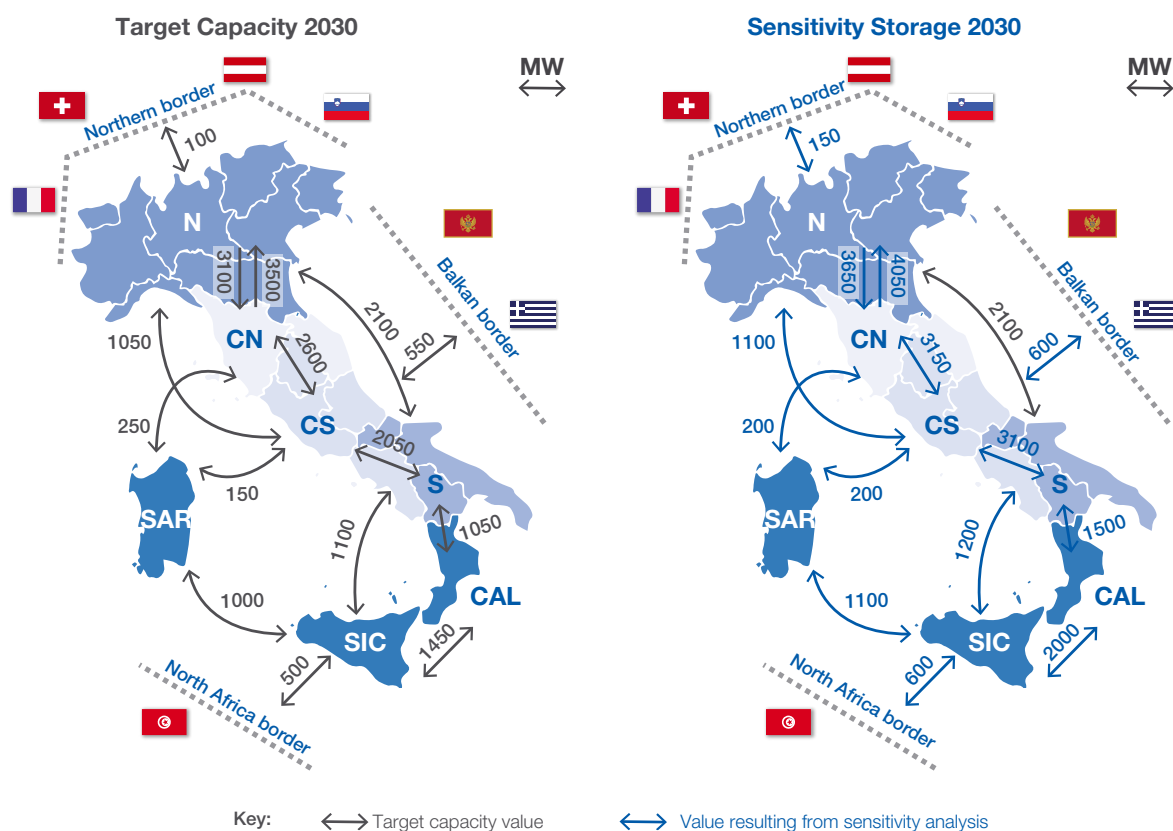


Figure 26 *Development strategy resulting from the storage sensitivity in the 2030 Policy scenario (Iteration 12-14)*

NECP 2030		ITERATION 12 - HALVED PINT STORAGE SENSITIVITY		ITERATION 13 - HALVED PINT STORAGE SENSITIVITY		ITERATION 14 - HALVED PINT STORAGE SENSITIVITY	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
North Africa border	ITsic - TUN	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1

The results of the sensitivity analysis performed by reducing the installed capacity of additional Utility Scale storage compared to the current one are shown in [Figure 27](#). Overall, the NECP Policy 2030 scenario shows a **significant increase in the previously identified target capacity on the internal sections of +3.4 GW**, especially on North-Centre North, South-Centre North, South-Centre South, Calabria-South and Sicily-Calabria.

Figure 27 Comparison of target capacity values and storage sensitivity (Policy 2030)



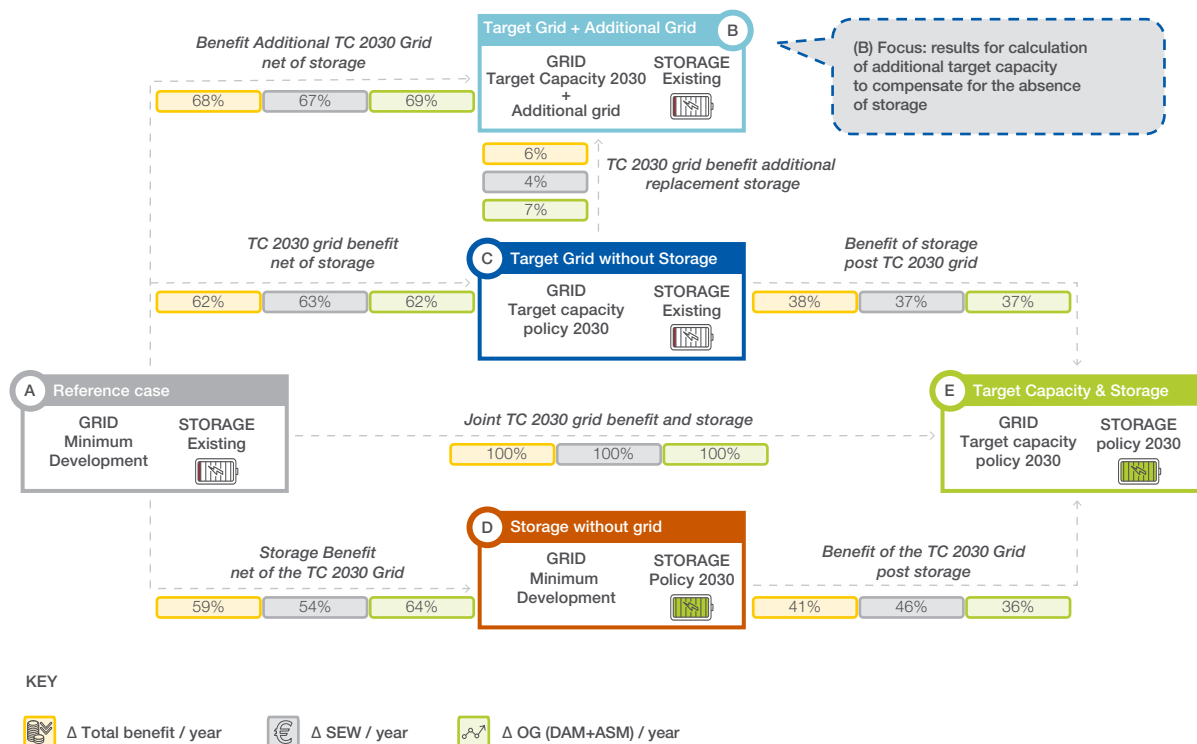
Analysing the benefits (total, in terms of SEW and integrated renewable generation) associated with the following five case studies (Figure 28):

- *Case A*: reference case characterised by minimum network development and an installed utility scale storage equal to the current installed value;
- *Case B*: characterised by transit capacity values equal to the target capacity values as a result of the storage sensitivity (TC 2030 Grid + additional capacity to compensate for the absence of storage) and an installed utility scale storage equal to the current installed value;
- *Case C*: characterised by transit capacity values equal to the target capacity values as a result of the storage sensitivity (TC 2030 Grid) and an installed utility scale storage equal to the current installed value;
- *Case D*: characterised by the minimum development network and an installed storage equal to the value envisaged in the policy 2030 scenario;
- *Case E*: characterised by transit capacity values equal to the target capacity values (TC 2030 Grid) and by an installed storage equal to the value envisaged in the policy 2030 scenario.

In this regard, taking the joint benefit of *Case E*, incremental with respect to *Case A*, as a reference value (set at +100%), the individual incremental benefits of the TC 2030 Grid and the installed incremental storage, recorded respectively in *Case C* and *Case D*, stand at significantly lower values. This result highlights a positive synergy of the combination TC Grid and installed incremental storage, since the benefit is due to a transfer of energy not only in space but also in time.

Even if additional transfer capacity were to be realised to compensate for the absence of storage (Case B), there are considerably fewer incremental benefits than in Case E.

Figure 28 Details of storage sensitivity benefits



The percentage values take as a reference the 3 benefit categories equal to 100% of Case E.

5.2 Results of Policy and Inertial 2040 scenarios

5.2.1 Results of methodology application

Starting from the target capacity values identified in the NECP Policy scenario for 2030 in paragraph 5.1.1, the iterative methodology has been applied to the scenarios adopted for the very long term year 2040, inertial “NECP Slow” and “DE” policy.

In the first analysis the development strategies achieved in the NECP slow 2040 and DE 2040 scenarios lead to significantly higher target capacity values than in 2030 on both internal sections and external borders.

The iterative process ends at the 9th iteration in the inertial scenario and the 9th iteration in the policy scenario, as shown in Figures 29 and 32.

Figure 33 illustrates the target capacity values identified at the 2040 horizon year through application of the methodology.

Figure 29 Development strategy resulting from the application of the methodology in the Inertial 2040 scenario (iteration 1-5)

NECP SLOW 2040		ITERATION 1 - PINT		ITERATION 2 - PINT		ITERATION 3 - PINT		ITERATION 4 - PINT		ITERATION 5 - PINT	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1



Figure 30 *Development strategy resulting from the application of the methodology in the Inertial 2040 scenario (iteration 6-9)*

NECP SLOW 2040		ITERATION 6 - PINT		ITERATION 7 - PINT		ITERATION 8 - PINT		ITERATION 9 - PINT	
Northern border	AT - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<2
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

Figure 31 *Development strategy resulting from the application of the methodology in the Policy 2040 scenario (Iteration 1-5)*

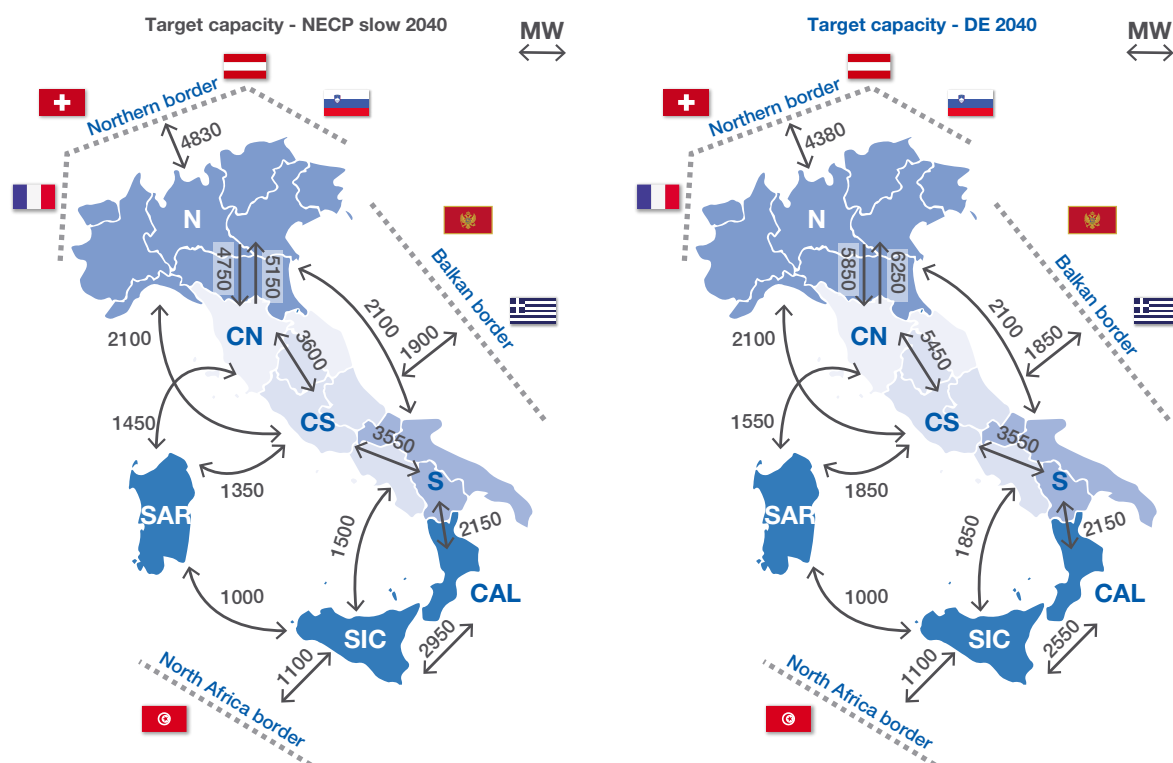
DE 2040		ITERATION 1 - PINT		ITERATION 2 - PINT		ITERATION 3 - PINT		ITERATION 4 - PINT		ITERATION 5 - PINT	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1



Figure 32 *Development strategy resulting from the application of the methodology in the Policy 2040 scenario (Iteration 6-9)*

DE 2040		ITERATION 6 - PINT		ITERATION 7 - PINT		ITERATION 8 - PINT		ITERATION 9 - PINT	
Northern border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

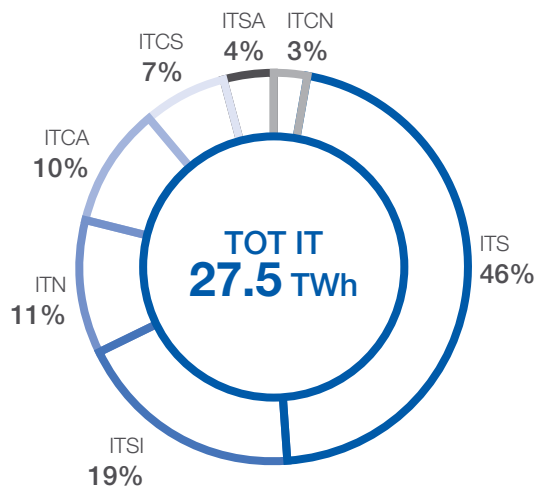
Figure 33 **Target Capacity Values (NECP slow and DE 2040)**



5.2.2 Electrolyser sensitivity

Starting from the target capacity values identified in the DE 2040 scenario through the development strategy described in paragraph 5.2.1, a sensitivity analysis was carried out to determine the impact of a **constraint on the development of the forecasted capacity of electrolyser consumption** in the Italian Market Zones. This analysis imposed a scenario value equal to the current installed capacity, with the aim of assessing the implications for the **additional target capacity** in the event in which the initiatives for new electrolyzers modelled to reduce *overgeneration* and produce hydrogen in *Figure 34* do not materialise.

Figure 34 **Annual electrolyser consumption (DE 2040)**





From the 9th iteration onwards, the iterative process extends for further **nine iterations** concluding at the 17th iteration, as shown in [Figure 35](#) and [Figure 36](#).

Figure 35 *Development strategy resulting from the electrolyser sensitivity in the Policy 2040 scenario (Iteration 9-13)*

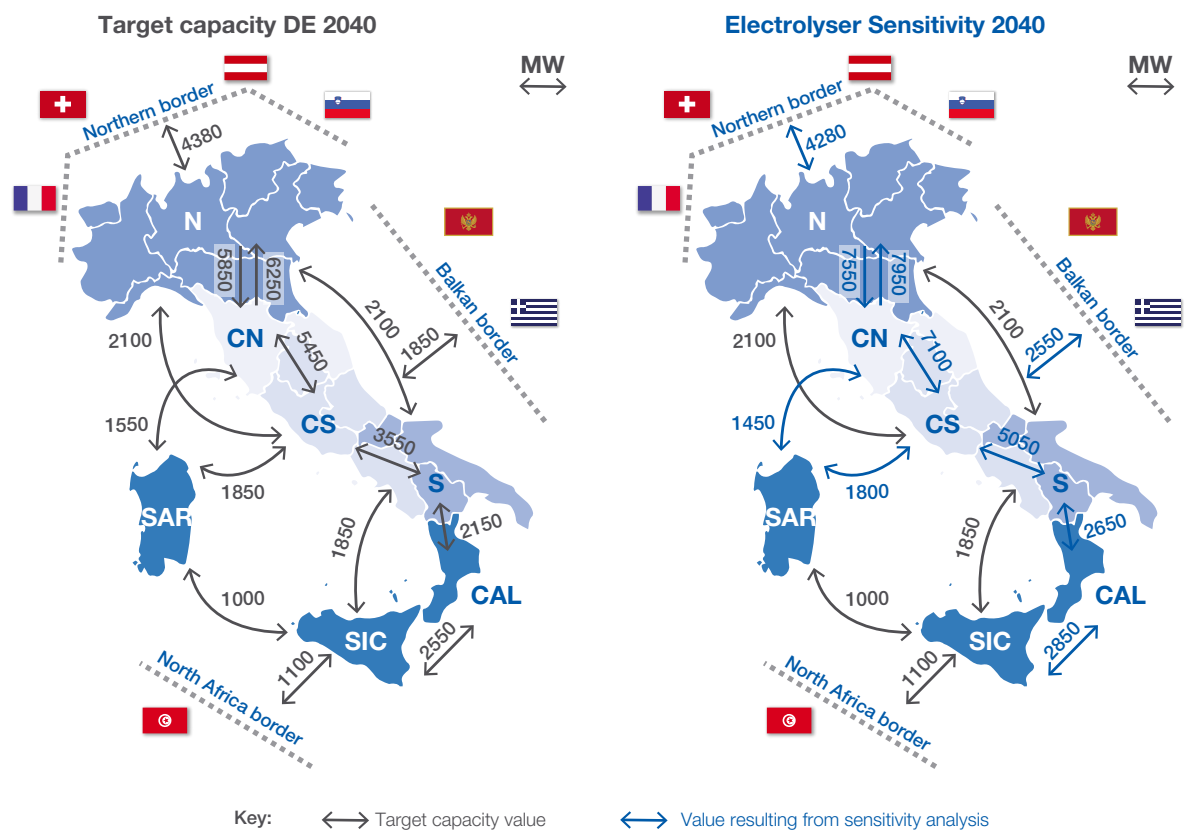
DE 2040		ITERATION 9 - PINT ELECTROLYSER SENSITIVITY		ITERATION 10 - PINT ELECTROLYSER SENSITIVITY		ITERATION 11 - PINT ELECTROLYSER SENSITIVITY		ITERATION 12 - PINT ELECTROLYSER SENSITIVITY		ITERATION 13 - PINT ELECTROLYSER SENSITIVITY	
North border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - GR	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1

Figure 36 Development strategy resulting from the electrolyser sensitivity in the Policy 2040 scenario (Iteration 14-17)

DE 2040		ITERATION 14 - PINT ELECTROLYSER SENSITIVITY		ITERATION 15 - PINT ELECTROLYSER SENSITIVITY		ITERATION 16 - PINT ELECTROLYSER SENSITIVITY		ITERATION 17 - PINT ELECTROLYSER SENSITIVITY	
North border	AT - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	CH - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	FR - ITn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	SI - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
Balkan border	ME - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<2
	ITs - GR	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
North Africa border	ITsic - TUN	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
Internal sections	ITcn - ITn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcs - ITcn	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITs - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1
	ITn - ITcs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITn - ITs	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1	PINT=YES	+step B/C>1
	ITsar - ITcn	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsar - ITsic	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITsic - ITcal	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1
	ITcal - ITs	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1	PINT=YES	+step B/C<1

The results of the sensitivity analysis performed by reducing the electrolyser capacity are shown in [Figure 37](#). Overall, the DE 2040 scenario shows **a significant increase in the target capacity previously identified on the internal sections of +5.5 GW**, especially on the North-Centre North, South-Centre North and South-Centre South.

Figure 37 *Comparison of target capacity values and electrolyser sensitivity (Policy 2040)*



Identification of Target Capacity

6

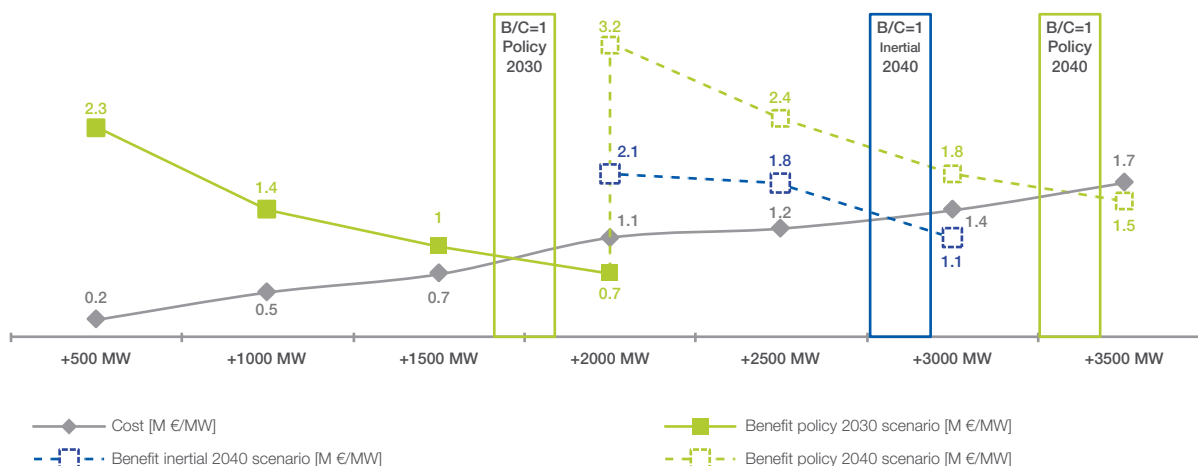
6.1 Results of the Target Capacity identification analysis

Following the determination of the marginal cost and benefit, for each section/border in the 2030 (NECP Policy) and 2040 (NECP Slow and DE) scenarios, the **intersection between each respective total marginal benefit and marginal cost curve is identified**.

The intersection point between the curves represents the area where the target capacity for that section/border is identified based on the sequence of capacity increments (development strategy). The additional target capacity value $C_{i,z}$ (where i indicates the generic section/border and z the scenario considered) is the sum of all simulated discrete capacity increments that produced $B/C > 1$, plus a capacity value dependent on the size of the PINT simulated in the last iteration multiplied by the relevant B/C ratio.

For each section/border, the proposed methodology determines a single target capacity value at the 2030 horizon year and two target capacity values at the 2040 horizon year, one for each of the considered scenario, as depicted in Figure 38.

Figure 38 Example of marginal cost vs. total marginal benefit comparison for a generic section/border in the considered scenarios in both 2030 and 2040 horizon years



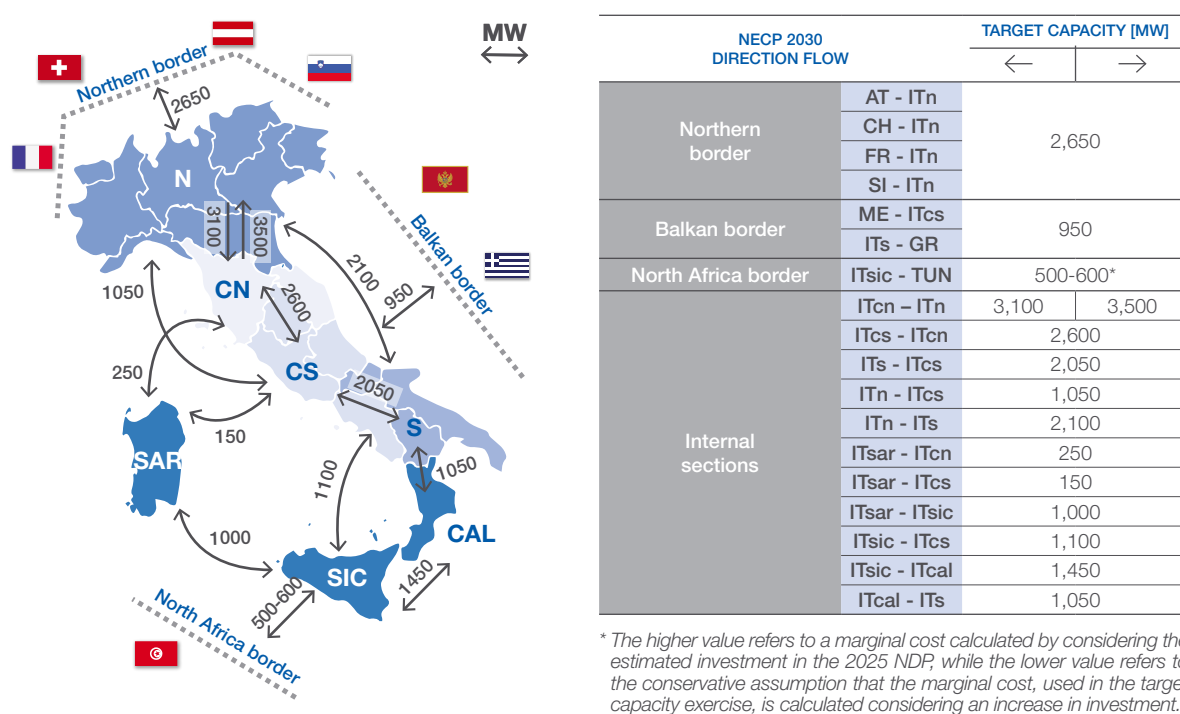
Lastly, given that:

- the target capacity $C_{i,z}$ represents the point at which $B/C = 1$, i.e. an “arithmetic” number with decimals;
- the target capacity represents the economically efficient level of additional transmission capacity to be realized, i.e. when the marginal benefits are greater than the marginal costs, thus excluding the point $B/C = 1$;
- the estimated transmission capacity values in the National Development Plan are rounded to the nearest hundreds of MW in accordance with technical reality;
- the target capacity value $C_{i,z}$ is rounded to the nearest fiftieth.

Figure 39 shows the final set of values of additional target capacities to 2030 defined as a result of the simulations, taking into account the sensitivities carried out in the NECP Policy 2030 scenario. It is deemed appropriate **to take into account, for the internal sections, the results achieved with the more stringent border CAP (paragraph 5.1.1) and to integrate, for the Northern Border and Balkan Border, the results achieved with the Borders sensitivity (paragraph 5.1.2).**

Compared to storage and Montenegro sensitivities, the application of a more or less stringent constraint on borders in line with the planned interconnection capacity (*Border sensitivity*) is the only input for which the TSO has a high level of accountability. Therefore, it is coherent to calculate the set of target capacity values for 2030 on internal sections with more stringent constraints, by applying a true feasibility criterion of the projects thus avoiding the erosion of capacity on internal sections with development strategies on foreign borders that are difficult to achieve by the 2030 horizon, and additionally to highlighting the profitability and development strategy on the borders by easing the constraints only after defining an efficient strategy for the internal sections.

Figure 39 Additional target capacity values in the NECP Policy 2030 scenario



To support the resulting target capacity values, Figure 40 depicts the net benefits, defined as total benefits net of the total realization costs, associated with each development strategy identified in paragraph 5.1. The set of target capacity values that takes into account the values resulting from the sensitivity on borders is the strategy that maximises the net benefits for the electricity system.

Figure 40 Net benefit of development strategies defined at the 2030 horizon year

NET BENEFIT [M€/YEAR]	TARGET CAPACITY BORDER CONSTRAINT	TARGET CAPACITY BORDER SENSITIVITY	TARGET CAPACITY MONTENEGRO SENSITIVITY	TARGET CAPACITY STORAGE SENSITIVITY
	443	539	430	357

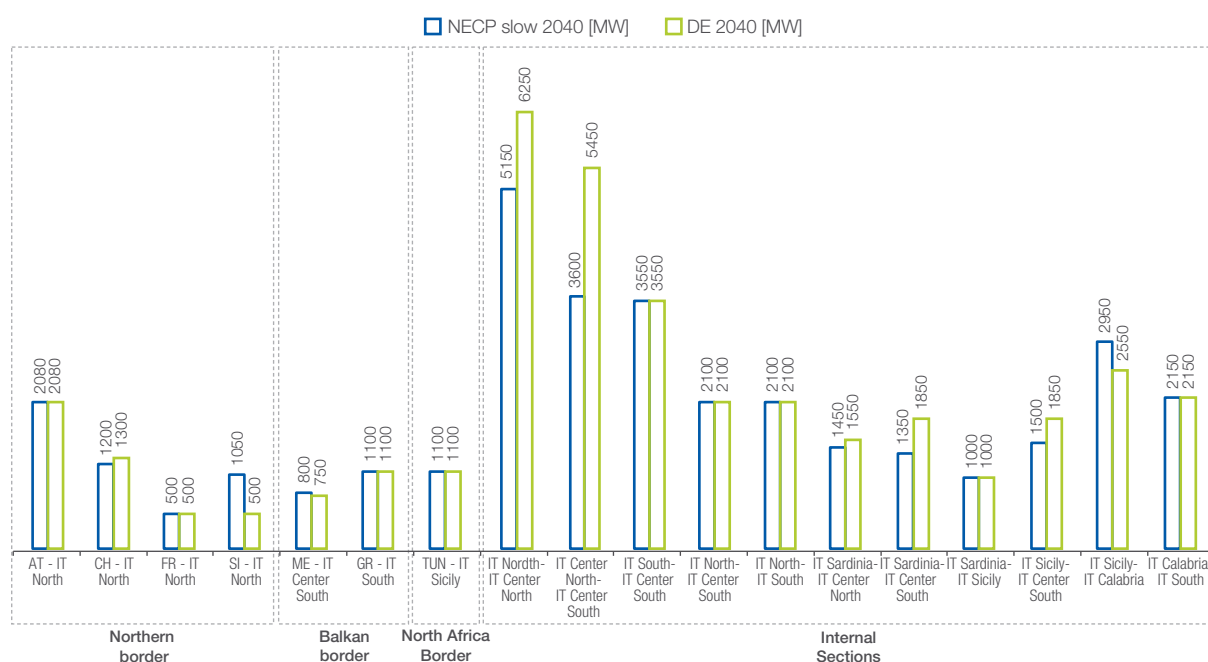
In conclusion, the following considerations emerge from the results of the analyses identifying the target capacities in the NECP Policy 2030 scenario:

- the 2030 additional target capacity on internal sections is between +15.9 GW and +16.3 GW, taking into account flow directions;
- the additional 2030 target capacity on the borders is +100 MW on the Northern Border, +550 MW on the Balkan Border and +500 MW on the North Africa Border when constraining the cross-border target capacity to be equal to the planned capacity for the year 2030, and increasing to +2.65 GW on the Northern Border and +950 MW on the Balkan Border in the event of less stringent constraints considered in the Borders sensitivity.

- the imposition of a zero CAP on the border with Montenegro highlights an additional capacity development need on the continental internal sections for an additional +1.25 GW;
- the lack of realization of new utility scale storage systems would call for an additional +3.4 GW of reinforcements on internal sections, underlining the synergy and benefit for the Italian electricity system of joint development of the transmission grid and storage systems.

Looking at horizon year 2040, [Figure 41](#) shows the values of the additional target capacities as a result of the simulations carried out in the NECP Slow 2040 and DE 2040 scenarios.

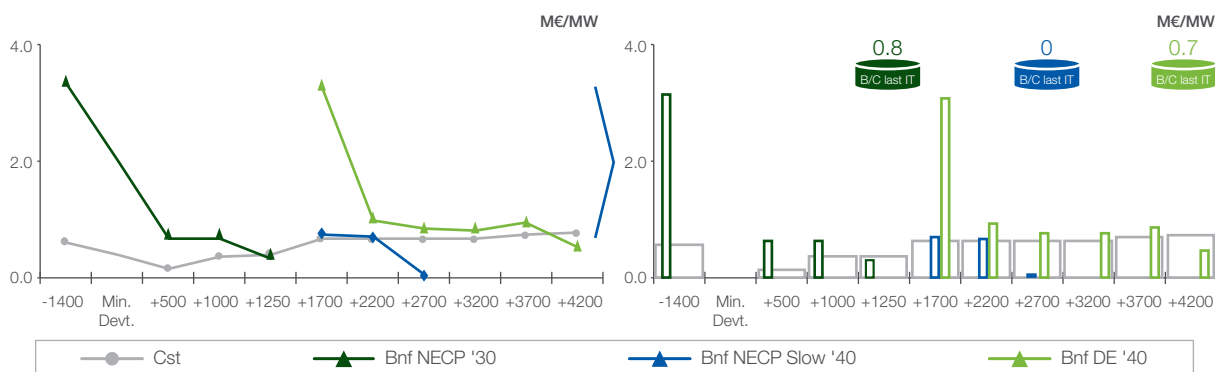
Figure 41 Additional target capacity values in the 2040 NECP Slow and DE scenarios



The additional 2040 target capacity over the existing transit capacity in the DE policy scenario stands at +30.4 GW on internal sections and +7.3 GW on borders, while in the NECP Slow inertial scenario it stands at 26.9 GW on internal sections and +7.8 GW on borders.

Annex 6 shows the marginal benefit/cost curves for each section/border and [Figure 42](#) provides an illustrative example of the marginal benefit/cost curve for the Centre North (ITcn)-Centre South (ITcs) section: the marginal cost curve (grey), the marginal benefit curve in the NECP Policy 2030 scenario (dark green), the NECP slow 2040 scenario (blue) and the DE 2040 scenario (light green) are represented, identifying step B/C = 1 where the curves cross in each reference scenario.

Figure 42 Example marginal benefit/cost curves for the ITcn-ITcs section



6.2 Overview on the single Target Capacity value

Since the first edition of the report, the need to achieve a single target capacity value for each section/border has been shared among all stakeholders.

After evaluating the various proposals received and the experience gained internationally, the *least regret* approach, illustrated in Annex 3, was adopted to identify a unique capacity value that would minimise the risk for the consumer.

The net benefit associated with each of the two options analysed in the different scenarios was evaluated; for each option, the associated net benefit is defined as the difference between the total benefits and the total costs to be incurred to achieve the additional capacity itself, i.e. for strategy i:

$$B_{net,i} = B_{total,i} - C_{realization,i}$$

At this point, we proceed to calculate the *regret* for each of the options in the different scenarios, calculated as the difference between the net benefit associated with the best option and the net benefit of each option. For each of the assessed options, we define the “*worst regret*”, i.e. the highest risk faced by implementing each strategy in the scenarios under study. The development strategy, namely the set of additional target capacity values with “*least regret*”, represents the final set of target capacity values.

In the 2020 edition, it was already proposed that the search for the single set of additional target capacity values to aim for in order to minimise regret in the scenarios under study could be improved by analysing sets of intermediate values among the options (with discrete values) with the aim to identify a **development strategy with the least regret of all those analysed**. The method, detailed in Annex 3, has been named *Advanced Least Regret*.

As only one energy policy scenario was analysed for the 2030 horizon year, the *advanced least regret* method in this edition has been applied to the 2040 horizon only and, the following paragraphs report the options examined in the exercise to define the single target capacity value at 2040.

6.3 Advanced Least regret on Policy and Inertial 2040 scenarios

Implementation of the Advanced Least Regret on the sets of target capacity values derived from the Policy Slow 2040 and DE 2040 simulations requires the definition of the following examined options:

- **Option 1 (NECP Slow):** the set of target capacity values (final for each section/border) resulting from simulations in the **NECP Slow 2040 scenario**;
- **Option 2 (DE):** the set of target capacity values (final for each section/border) resulting from simulations in the **DE 2040 scenario**;
- **Option 3 (average):** the set of target capacity values (final for each section/border) calculated as **average of the values** resulting from simulations in the **NECP Slow 2040** and **DE 2040** scenarios for each section/border.

All identified development options were simulated in each of the two scenarios, so as to estimate the net benefit derived and the “*worst regret*”, i.e. the greater risk involved in realising it in the scenarios under study. [Table 5](#) shows the results of the *Advanced Least Regret*:

- *Option 1* is the strategy with the highest net benefit in the NECP Slow 2040 scenario;
- *Option 2* is the strategy with the highest net benefit in the DE 2040 scenario.

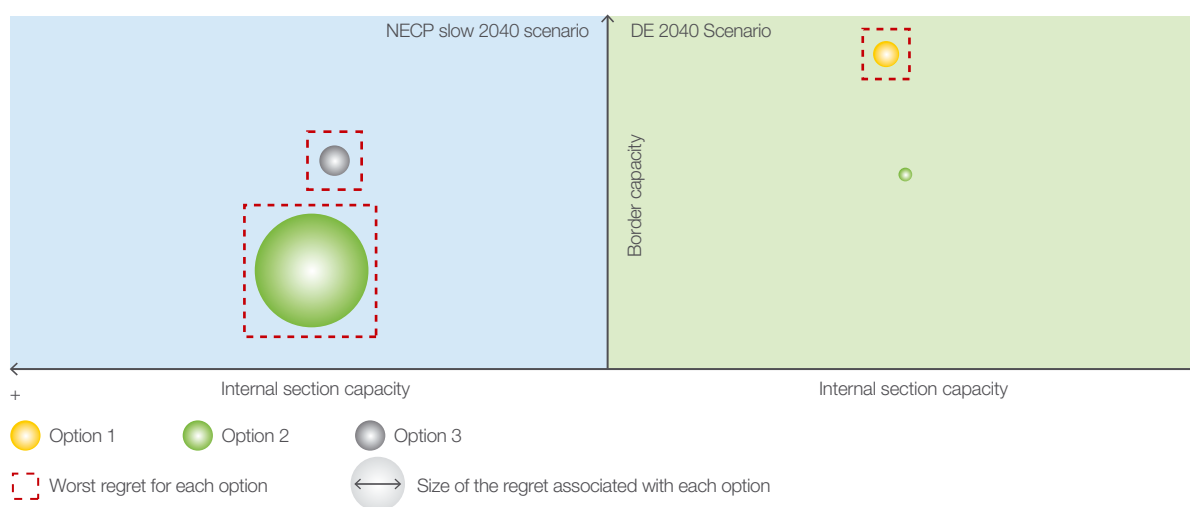
Option 1 (NECP Slow) minimises regret in the scenarios analysed.

Table 5 *Application of Advanced Least Regret in the NECP Slow 2040 and DE 2040 scenarios*

NET BENEFIT [M€/YEAR]	SCENARIO	OPTION 1 (NECP SLOW)	OPTION 2 (DE)	OPTION 3 (AVERAGE)
	NECP Slow 2040	815	620	748
	DE 2040	1,497	1,524	1,526
REGRET [M€/YEAR]	SCENARIO	OPTION 1 (NECP SLOW)	OPTION 2 (DE)	OPTION 3 (AVERAGE)
	NECP Slow 2040	0	195	67
	DE 2040	29	3	0
	<i>Worst Regret</i>	29	195	67
	<i>Least Regret</i>		29	

Figure 43 graphically represents the application of the *Advanced Least Regret* in the NECP Slow and DE scenarios and the regret associated with the implementation of each development strategy (option) in each of the two scenarios.

Figure 43 *Graphical representation of the Advanced Least Regret method applied in the NECP Slow and DE 2040 scenarios*



6.4 Final considerations

6.4.1 Considerations for 2030 horizon year

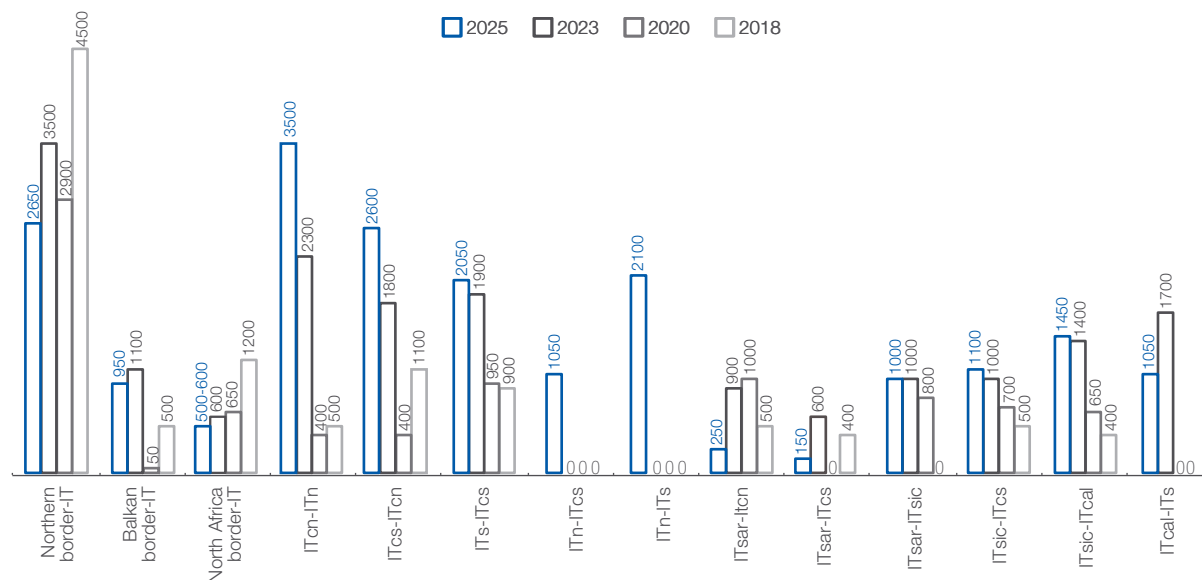
Figure 44 shows the 2030 additional target capacity values obtained by applying the methodology, taking into account the results of the Border sensitivity, compared to the values reported in previous editions, from 2018 to 2023, for the same horizon year.

The differences between the values determined in the four editions of the Target Capacity Identification Report can be attributed to the following aspects:

- the editions have been drawn up approximately every two years (2018, 2020, 2023 and 2025), ensuring that the assumptions of the progressively updated reference Energy Scenarios are aligned and taken into account in the analyses. Thus, target capacity values are closely dependent on the input assumptions of the analyses, and in particular on variations in the share of installed renewable capacity, storage capacity and energy demand. Furthermore, in editions where two separate energy scenarios at 2030 were considered, the final development strategy was identified through application of the *least regret* methodology, whose output leaned towards an intermediate set of target capacity values compared to the more extreme ones obtained in the respective reference scenarios. Conversely, in this edition of the report, the 2030 analyses were conducted in the policy 2030 scenario alone in which higher values tend to be identified;
- with regard to the reference zonal structure, starting from the 2020 edition, the updated zonal structure in force as of 2021 has been taken into account, with the main change being the introduction of the new market zone of Calabria, and the market sections under analysis have consequently been updated. Furthermore, the set of market sections under study has been progressively extended to the new sections introduced in the National Development Plans: first with the Sicily-Centre South and Sardinia-Sicily sections and in this report with the North-Centre South and North-South sections;
- the editions also differ in the minimum development network: the completion of projects such as the 1,200 MW Italy-France Interconnection and the 300 MW Nauders-Glorenza Interconnection at the Northern border was done in 2023, and the 400 MW Deliceto-Bisaccia Interconnection on the South-Centre South section in 2022, leading to a reduction in the target capacity values defined in the following editions. In particular, the 1,500 MW realized at the Northern border through the above-mentioned projects are included in the exchange limits of the existing grid in this analysis and therefore do not contribute to the definition of target capacity values;
- starting from 2023, in the iterative process underlying the definition of the target capacities at 2030 horizon, a constraint was placed on the additional target capacity on foreign borders equal to the transmission capacity associated with the planned projects, thus determining a realistic border development without underestimating the *need* for development on internal sections;
- lastly, the analyses to identify target capacities have been progressively enhanced and refined, by including *sensitivities* that allowed the values obtained to be consolidated against a change in inputs relating to storage capacity or forecasted electrolyzers or by modifying the constraints on target capacity at the borders.

Looking at the various editions, there is a tendency for target capacity values to increase for internal sections and to be more contained for the borders, as justified by the considerations outlined above, but there is a significant consistency between the results obtained in the last two editions of the Report.

Figure 44 Comparison of final sets of additional target capacity values at 2030 horizon resulting from the analyses conducted in the 2018 to 2025 editions of the Report



For the purposes of presenting the results, the following aggregation criteria were taken into account, merging the territorial and electrical boundaries as per the 2023 edition:

- The North border includes the France, Switzerland, Austria, and Slovenia borders;
- The East border includes the borders of Montenegro and Greece;
- The North Africa border includes Tunisia.

It is also necessary to bear in mind that calculation of the border exchange capacity schedule is now defined on a security basis and the schedules are determined jointly with neighbouring network TSOs through a coordinated calculation process. This aspect tends to confirm the assumption made on the Northern border in particular, as it is known that a project implemented on a single border cannot disregard the effects on the entire Northern border electricity system. Moreover, aggregation of the borders gives Terna the opportunity to make a choice about the projects to be implemented in a later stage after further studies/considerations, and avoids that the target capacity value identified is a function of this methodology rather than of detailed and cost-benefit analysis as arranged in the minimum requirements for drawing up the National Development Plans. This does not exclude the possibility of considering refinements to these aggregation criteria or further proposals that might emerge during the consultation.

Figure 45 shows the target capacity values referring to the winter peak scenario, divided into:

1. the starting capacity values (existing network capacity);
2. the additional target capacity values;
3. the final target capacity values.

As far as the final target capacity is concerned, for those sections/borders where the simulations showed a clear prevalence of the benefits referable to one direction of the energy flows (prevalence represented by the % in the "Direction" column), the final capacity was represented only with reference to that direction, consistent with the commitment that the Grid Operator will have to implement in order to guarantee use of the capacity in the direction most useful to the system. Where there is no clear predominance, the final target capacity was represented for both sides.



In summary, [Figure 46](#) shows the energy flows expected from the implementation in the reference network of minimum development, of the target capacities in the NECP Policy 2030 scenario.

Figure 45 Target capacity values for 2030 horizon year³⁴

BORDER/SECTION	DIRECTION	START	WINTER PEAK CAPACITY (MW)			
			ADDITIONAL	OBJECTIVE		FINAL
				DIRECTION NECP '30	DIRECTION	
North-IT border	→	10,435	2,650	88%	→	13,085
	←	4,995		12%		
East-IT border	→	1,100	950	56%	→	2,050
	←	1,100		68%		
N. Africa-IT border	→	0	500-600	23%	→	500-600
	←	0		77%		
ITcn - ITn section	→	3,100	3,500	63%	→	6,600
	←	4,300	3,100	37%		
ITcs - ITcn section	→	2,800	2,600	71%	→	5,400
	←	2,900		29%		
ITs - ITcs section	→	5,200	2,050	98%	→	7,250
	←	2,400		2%		
ITn - ITcs section	→	0	1,050	25%	→	1,050
	←	0		75%		
ITn - ITs section	→	0	2,100	26%	→	2,100
	←	0		74%		
ITsar - ITcn* section	→**	425	250	93%	→	675
	←	320		7%		
ITsar - ITcs section	→	900	150	85%	→	1,050
	←	720		15%		
ITsar - ITsic section	→	0	1,000	77%	→	1,000
	←	0		23%		
ITsic - ITcs section	→	0	1,100	72%	→	1,100
	←	0		28%		
ITsic - ITcal section	→	1,300	1,450	55%	→	2,750
	←	1,550		45%		
ITcal - ITs section	→	2,350	1,050	79%	→	3,400
	←	1,100		21%		

* The additional target capacity takes into account the contribution from the decommissioning of SACOI2 for end of life (-300 MW) and the new SACOI3 link (+400 MW).

** The starting capacity ITsar → ITcn takes into account the contribution of the two links SACOI2 (+300 MW) and SARCO (+125 MW) respectively.

³⁴ The starting capacities in the direction from the North border to IT are 4485, 4572, 625, and 753 MW for the FR, CH, AT and SI borders, respectively.

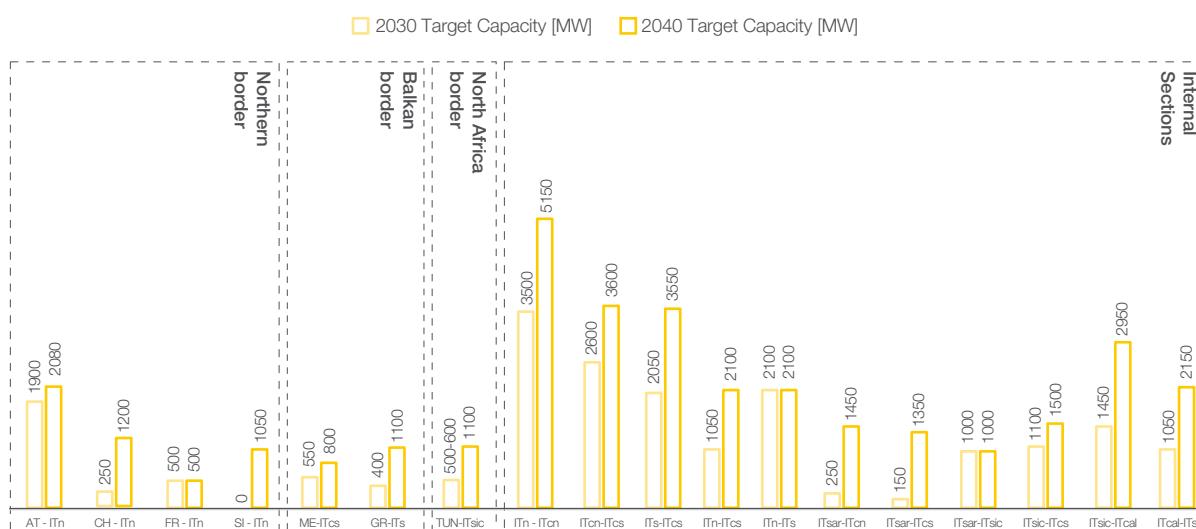
Figure 46 *Energy flows expected from implementation in the reference network of minimum development, of target capacities in the NECP Policy 2030 scenario*



6.4.2 Considerations for 2040 horizon year

As a result of the application of *Advanced Least Regret* for the 2040 horizon year, the final set of additional target capacity values was identified in Option 1, which is the set of target capacity values calculated in the NECP slow 2040 inertial scenario. *Figure 47* shows a comparison of the target capacity values achieved in this report for 2030³⁵ and 2040 horizon years.

Figure 47 *Comparison of final sets of additional target capacity values for 2030 and 2040 horizon years*



The differences highlighted between the two horizon years can be attributed to the fact that the 2040 very long-term scenarios, in which target capacity values are significantly higher than those at 2030, are more ambitious in terms of incremental renewable installation.

³⁵ Taking into account the results achieved in the 2030 Borders sensitivity.



Especially for borders, given the application of the same constraints on the maximum achievable capacity in the 2040 and 2030 Border sensitivity analysis, there are less marked differences if the CAP was to be reached already at 2030, despite the fact that the profitability of all three borders shows a sharply growing trend.

Figure 48 shows the target capacity values, following the same aggregation rules for the borders and representations used in Figure 45 at 2030 horizon year.

Lastly, Figure 49 shows the energy flows expected from the implementation in the reference network of minimum development, of the target capacities respectively in the NECP slow 2040 and DE 2040 scenarios.

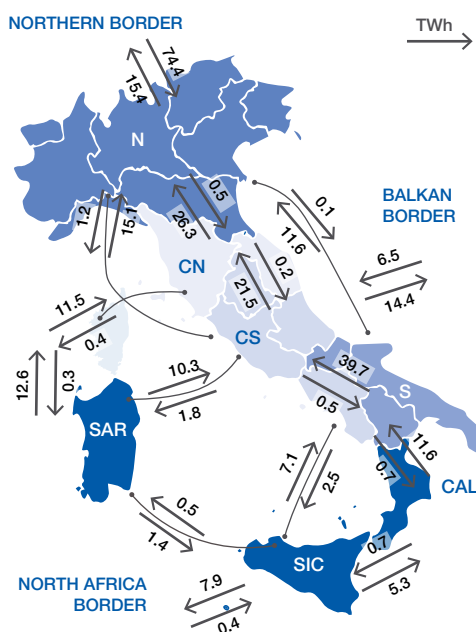
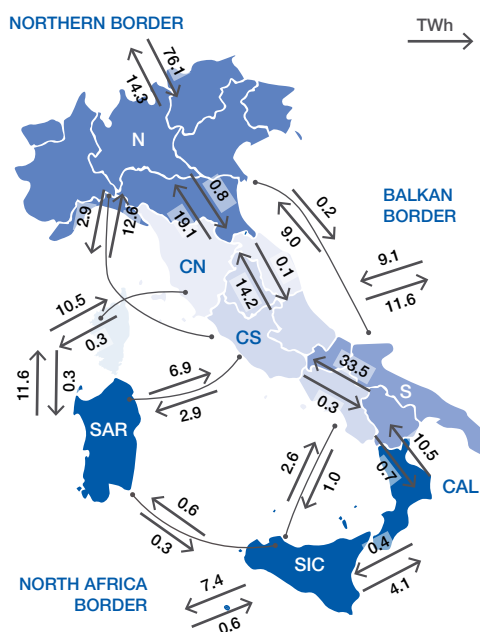
Figure 48 Target capacity values for 2040 horizon year

BORDER/SECTION	DIRECTION	WINTER PEAK CAPACITY (MW)					
		START	ADDITIONAL	OBJECTIVE			FINAL
				DIRECTION NECP SLOW '40	DIRECTION DE '40	DIRECTION	
North-IT border	→	10,435	4,830	84%	83%	→	15,265
	←	4,995		16%	17%	←	9,825
East-IT border	→	1,100	1,900	44%	31%	→	3,000
	←	1,100		56%	69%	←	3,000
N. Africa-IT border	→	0	1,100	8%	5%	←	1,100
	←	0		93%	95%		
ITcn - ITn section	→	3,100	5,150	96%	98%	→	8,250
	←	4,300	4,750	4%	2%		
ITcs - ITcn section	→	2,800	3,600	99%	99%	→	6,400
	←	2,900		1%	1%		
ITs - ITcs section	→	5,200	3,550	99%	99%	→	8,750
	←	2,400		1%	1%		
ITn - ITcs section	→	0	2,100	19%	7%	→	2,100
	←	0		81%	93%	←	2,100
ITn - ITs section	→	0	2,100	2%	1%	←	2,100
	←	0		98%	99%		
ITsar - ITcn* section	→**	425	1,450	97%	97%	→	1,875
	←	320		3%	3%		
ITsar - ITcs section	→	900	1,350	70%	85%	→	2,250
	←	720		30%	15%	←	2,070
ITsar - ITsic section	→	0	1,000	33%	74%	→	1,000
	←	0		67%	26%	←	1,000
ITsic - ITcs section	→	0	1,500	65%	74%	→	1,500
	←	0		35%	26%	←	1,500
ITsic - ITcal section	→	1,300	2,950	91%	88%	→	4,250
	←	1,550		9%	12%		
ITcal - ITs section	→	2,350	2,150	94%	94%	→	4,500
	←	1,100		6%	6%		3,250

* The additional target capacity takes into account the contribution from the decommissioning of SACOI2 for end of life (-300 MW) and the new SACOI3 link (+400 MW).

** The starting capacity ITsar → ITcn takes into account the contribution of the two links SACOI2 (+300 MW) and SARCO (+125 MW).

Expected energy flows: NECP slow 2040 scenario



Annexes

7

Annex 1

European Practices

Criteria and Recommendations of the Commission Expert Group (CEG) on Electricity Interconnection Targets

The European Commission has identified the enhancement of cross-border electricity interconnections as a tool for achieving climate and energy goals: the connections of European electricity systems allow for increased security of the electricity supply and integration of more renewable sources into the energy markets. Reliable interconnections between European countries reduce the risk of electricity blackouts and facilitate the management of intermittent renewable energy sources, such as solar and wind power; for example, surplus renewable energy produced in one country could be used by another where electricity demand is high, precisely through new interconnections.

In October 2014, the European Council called on all EU countries to increase interconnection capacity to at least 10% of installed generation capacity by 2020. This interconnection target was subsequently increased to 15% by 2030.

In this regard, the Expert Group on Interconnections (CEG), consisting of 15 experts from European industry organisations, universities, research institutions and non-governmental organisations, was established in 2016 with the aim of providing the European Commission with technical guidance on how to achieve these targets.

The Expert Group presented a report in November 2017, making a proposal to set an interconnection target of 15% by 2030, and suggesting ways to make interconnection projects easier to implement, particularly in the financing stage. The report recommends evaluating the development of new interconnection capacity on the basis of specific indices reflecting the guarantee of security of supply, integration of renewables and efficiency of the internal energy market. In the light of this report, in its communication on strengthening European energy networks published in November 2017, the Commission proposed refining the 15% target through a number of additional and more specific thresholds. The use of these thresholds will serve as an indicator to define an action plan to achieve the European energy and environment targets.

The *Report of the Commission Expert Group on electricity interconnection targets "Toward a sustainable and integrated Europe"*³⁶, published in November 2017, recognises interconnection as a driver to achieve a single European market and proposes a new methodology to assess the need to develop new interconnection capacity.

The two key objectives are:

- maximising the social welfare of the new electricity interconnections;
- prioritising the electricity interconnections necessary to ensure market integration, national demand coverage and access to renewable energy sources by neighbouring countries.

³⁶ https://ec.europa.eu/energy/sites/ener/files/documents/report_of_the_commission_expert_group_on_electricity_interconnection_targets.pdf

To this end, three indicators are defined to assess the need for new trading capacity for a specific market area:

- *Indicator A*: coverage of electricity demand;
- *Indicator B*: need for integration of renewable production from one country to another;
- *Indicator C*: minimisation of the price differential and thus better integration of electricity markets.

Indicator A

Coverage of electricity demand is considered to be guaranteed if:

$$A = \frac{\text{Nom. Trasm. Capacity}}{\text{Peak load}} > 30\%$$

Where:

Nom. Trasm. Capacity (Nominal Transmission Capacity) = represents the physical capacity with which the interconnection link is designed and corresponds to the maximum power flow that can be transmitted under security conditions. The nominal transmission capacity is not affected by market mechanisms and rules.

Peak load = represents the maximum or peak demand.

If value A is **less than 30%**, an increase in capacity **must be** urgently considered.

If value A is **between 30% and 60%**, continuous assessments must be conducted to **monitor** the need for new projects. Since the annual peak demand varies significantly depending on weather conditions, the Expert Group suggests considering the 99th percentile of the annual demand distribution.

Indicator B

The export of potential excess renewable production is considered guaranteed if:

$$B = \frac{\text{Nom. Trasm. Capacity}}{\text{Renew. Gen. Capacity}} > 30\%$$

where:

Nom. Trasm. Capacity (Nominal Transmission Capacity) = represents the physical capacity with which the interconnection link is designed and corresponds to the maximum power flow that can be transmitted under security conditions. The nominal transmission capacity is not affected by market mechanisms and rules.

Renew. Gen. Capacity (Renewable Generation Capacity) = represents the expected renewable generation capacity.

This parameter reflects the expected development of production from renewable sources compared to the exchange capacity with other countries.

If value B is below 30%, an increase in capacity must be urgently considered.

If value B is between 30% and 60%, continuous assessments must be conducted to monitor the need for new projects.

Indicator C

Relevant threshold for price differential between market zones 2€/MWh:

$$C = \text{Yearly average of price differential} < 2 \text{ €/MWh}$$

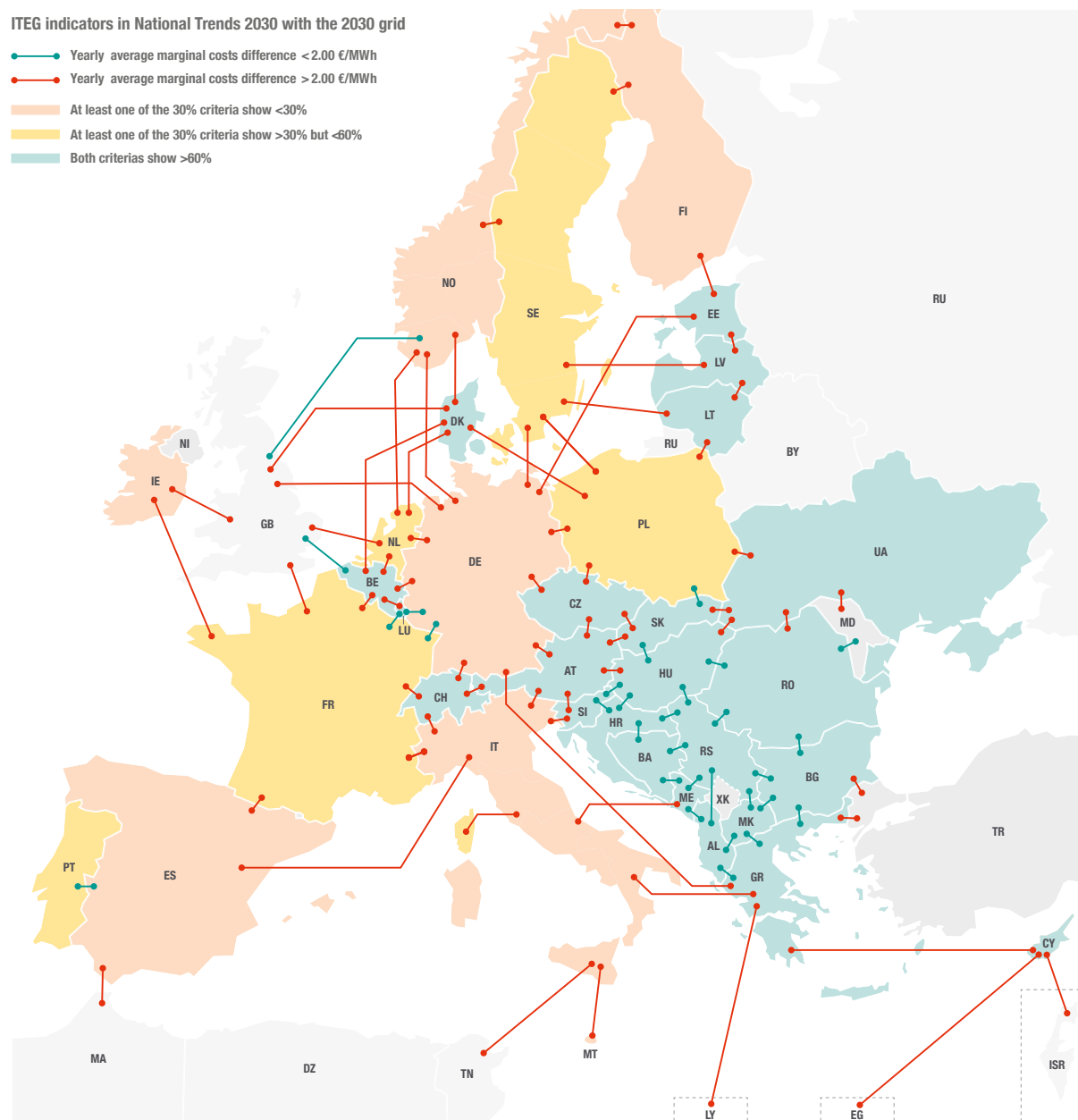
If value C is **greater than 2 €/MWh**, an increase in capacity **must be** urgently considered.

When even just one of the three criteria is critical, it will be useful to evaluate a new interconnection project for the market area under study by carrying out a **cost-benefit analysis** (conditio sine qua non). The project will only be developed if the CBA is positive ($SUI > 1$).

The Expert Group suggests that the proposed methodology be reviewed regularly (no longer than 5 years), taking into account the evolution of the electricity system, in particular with regard to the dissemination of storage, digitisation and Demand Side Response and their effects on the system.

The Expert Group applied this methodology to the 2016 TYNDP scenarios for the first time. As part of the 2024 TYNDP, ENTSO-E updated these indicators in the light of the NT 2030 scenario, taking the network to 2030 as a reference, obtaining the results shown in [Figure 50](#).

Figure 50 Summary Indicators applied to the NT 2030 scenario of the 2024 TYNDP



As seen from the figures above, Italy has critical issues in terms of price differentials greater than 2 €/MWh on all borders and the need to strengthen cross-border transmission capacity.

Identification of System Needs 2024

Starting from 2012, in its Opinion 06/2012 on the draft TYNDP 2012, the Agency for the Cooperation of Energy Regulators (ACER) proposed the introduction of the concept of target capacities; subsequently, in Opinion 01/2017, ACER made a number of recommendations on system needs identification activities, including:

- a) identifying the infrastructure investment needs for all three criteria adopted at the European level, i.e. market integration, security of procurement and next-generation connection;
- b) analysing all relevant sections between the zones represented in ENTSO-E's pan-European market model;
- c) analysing the system needs for each study year and for each scenario considered;
- d) ensuring the quantification (and, when possible, monetisation according to specific parameters) of system needs;
- e) using simple indicators, such as:
 - market integration: increase in Social Economic Welfare (SEW) per capacity increase (Euro /MW);
 - generation connection: reduction of generation disconnections (GWh);
 - security of supply: reduction in expected non-supplied energy (GWh);
- f) supplementing the SEW analysis by presenting the expected marginal cost difference (€/MWh), taking into account the marginal cost spreads in both flow directions.

To this end, as part of preparation of the Ten-Year Development Plan (TYNDP) 2024, in an update to previous plans, in January 2025, ENTSO-E published for consultation the report **“Opportunities for a more efficient European power system by 2050”**³⁷, containing the results of the Identification of System Needs (IoSN) analyses over a medium (2030), long (2040) and very long (2050) term horizon of the needs of the European power system.

Reference scenario for Identification of System Needs 2024 analysis

The central scenario for the TYNDP 2024 used for the Identification of System Needs 2024 analysis is the National Trend (NT) 2030 and the National Trend 2040, and to the Distributed Energy for 2050.

The NT scenario takes into account the National Energy and Climate Plans (NECPs) of the EU Member States, thus enabling the assessment of infrastructure needs with respect to the climate targets set by the EU.

Reference grid

The reference grid used for these analyses is the TYNDP 2030 network for Identification of System Needs analyses in the 2030, 2040 and 2050 scenarios.

Specifically, the TYNDP 2030 grid presents the following internal and interconnection projects for Italy (developed by Terna)³⁸ at 2030, in addition to the lines already in operation as of 2023:

1. Italy-Tunisia (ELMED project)
2. Tyrrhenian Link
3. Adriatic Link
4. HG North Tyrrhenian Corridor
5. Central Link
6. Sicily-Calabria
7. Southern Italy
8. Removal of 380 kV and 220 kV grid restrictions interconnected to Slovenia
9. Central Northern Italy
10. Central Southern Italy
11. SACOI 3

³⁷ For further details, please refer to the document: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/forconsultation/Infrastructure_Gaps_Report.pdf

³⁸ For further details, please refer to the document: <https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/forconsultation/SystemNeedsMethodology.pdf>

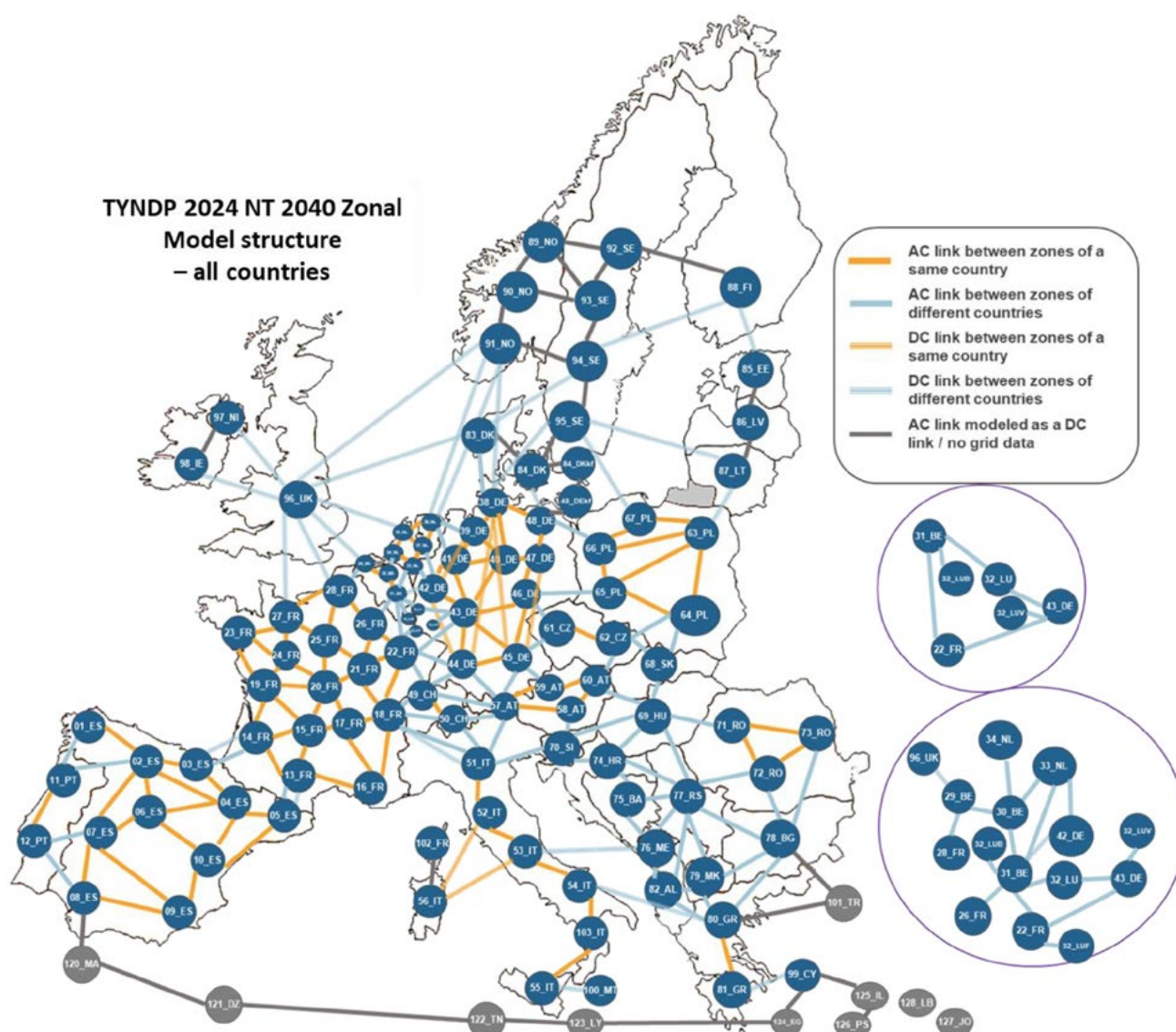
In summary, starting from a reference network that includes all interventions already planned for the 2030 horizon year, the analyses are developed on the basis of a model in which market data are considered (the network is equivalent).

Methodology

The modelling improvements achieved in the IoSN 2024 analysis, building on what was already done in the previous IoSN 2022, aim to achieve greater granularity of data than in the previous Identification of System Needs and allow physical flows to be taken into account while simultaneously making calculation times reasonable.

The pan-European model includes over 100 nodes connected by equivalent links, constituting a reduced network model. Specific constraints are applied to the links between nodes in order to simulate Kirchhoff's laws.

Figure 51 Zonal model developed for IoSN 2040 analyses obtained within the framework of the 2024 TYNDP



Consequently, optimal dispatching can be simulated at a European level, taking into account the physical limits of the network. The advantage of this methodology, therefore, is having concentrated the market and network simulations in a single analysis, avoiding cyclic transitions between the two different models and simplifying the entire process.

The system needs study assesses the optimum potential for interconnection capacity between countries for 2030, 2040 and 2050, with flexibility needs identified for each horizon year. Starting with the reference network, an expansion model developed in the Antares and Plexos tool optimises total system costs based on increases in optimal interconnection

capacity. From a set of possible network increments, the model chooses the best combination that minimises the total system costs, consisting of network investments and generation costs. The interconnection cost assumptions considered for the capacity increases are derived from the cost assumptions of the TYNDP 2024 projects, and for the further increases the TSOs provided the best estimate.

Below some methodological details on the simulations carried out with the Antares tool are reported. The simulations were carried out in the following order:

- **STEP 1 of the IoSN using the TYNDP 2024 projects**

The objective of this step is to show which projects of the TYNDP 2024 have been identified as needs for 2030 (2040 and 2050) and to see how much dumped energy, CO₂ and SEW can be captured with these projects. At this stage, standard costs for each border provided by third-party TSOs and project promoters on the basis of existing projects are considered.

- **STEP 2 of the IoSN using the TYNDP 2024 projects discarded in step 1 and additional projects**

Some projects, not selected by the optimisation process during the first STEP, will be evaluated in the next STEP and also analysed with additional projects in order to capture all needs for 2030 (2040 and 2050). At this stage, further needs on borders that do not have projects in the TYNDP 2024 are evaluated. Therefore, TSOs were required to provide standard costs on borders so that they could be investigated.

Capacity increases per horizon year 2030, 2040 and 2050

Provided below are the increases in transmission capacity on European borders revealed by the pan-European analyses. In horizon year 2030, there are high capacity increases between the borders of France and Great Britain, Norway, Germany, and Finland. There is also a need to increase capacity between the Italian border and the Northern border (over 4000 MW), with the eastern border (over 1500 MW) and with Tunisia (600 MW).

Figure 52 Capacity increases related to projects under construction or in the authorisation phase planned to be in operation in 2030, in addition to existing capacity already in operation - Reference Grid 2030

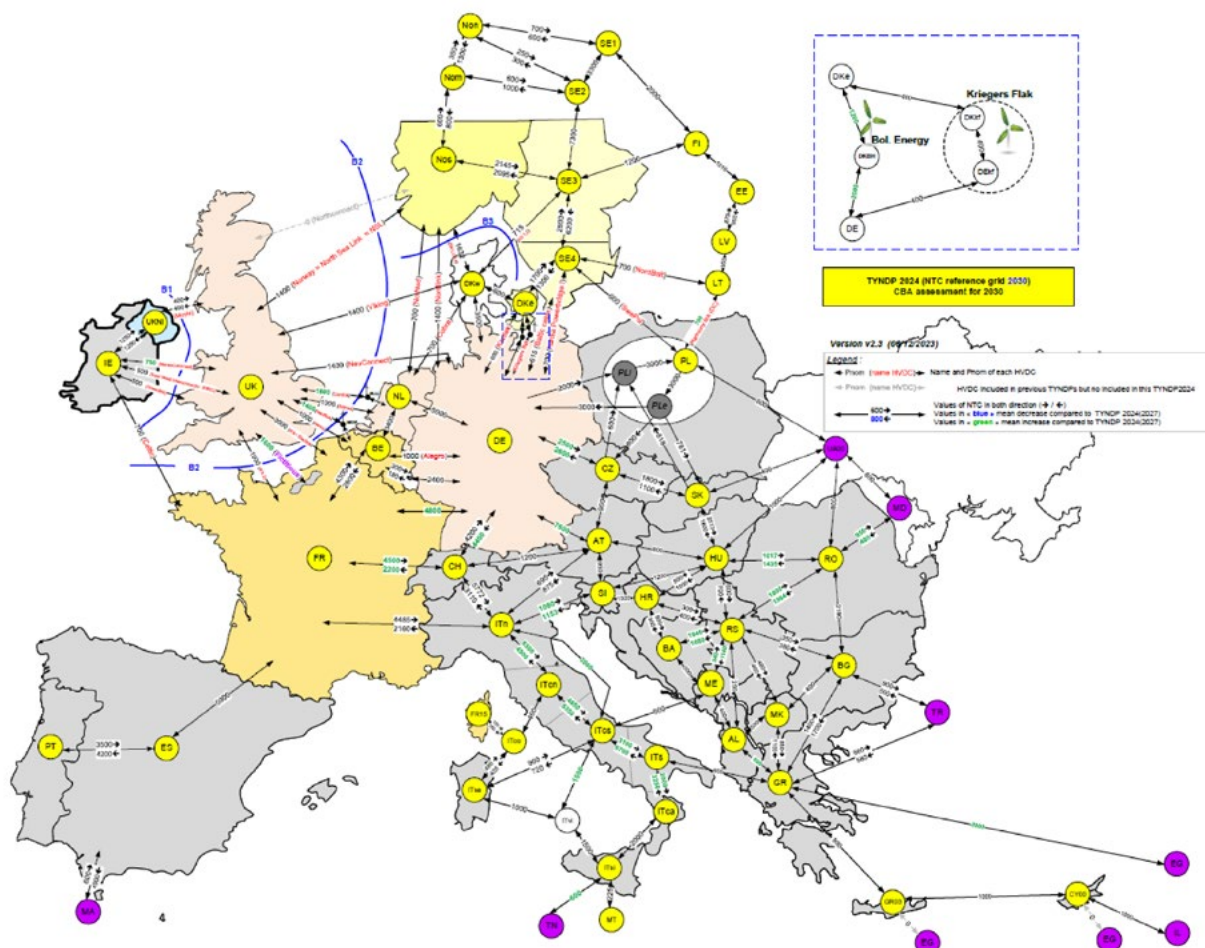
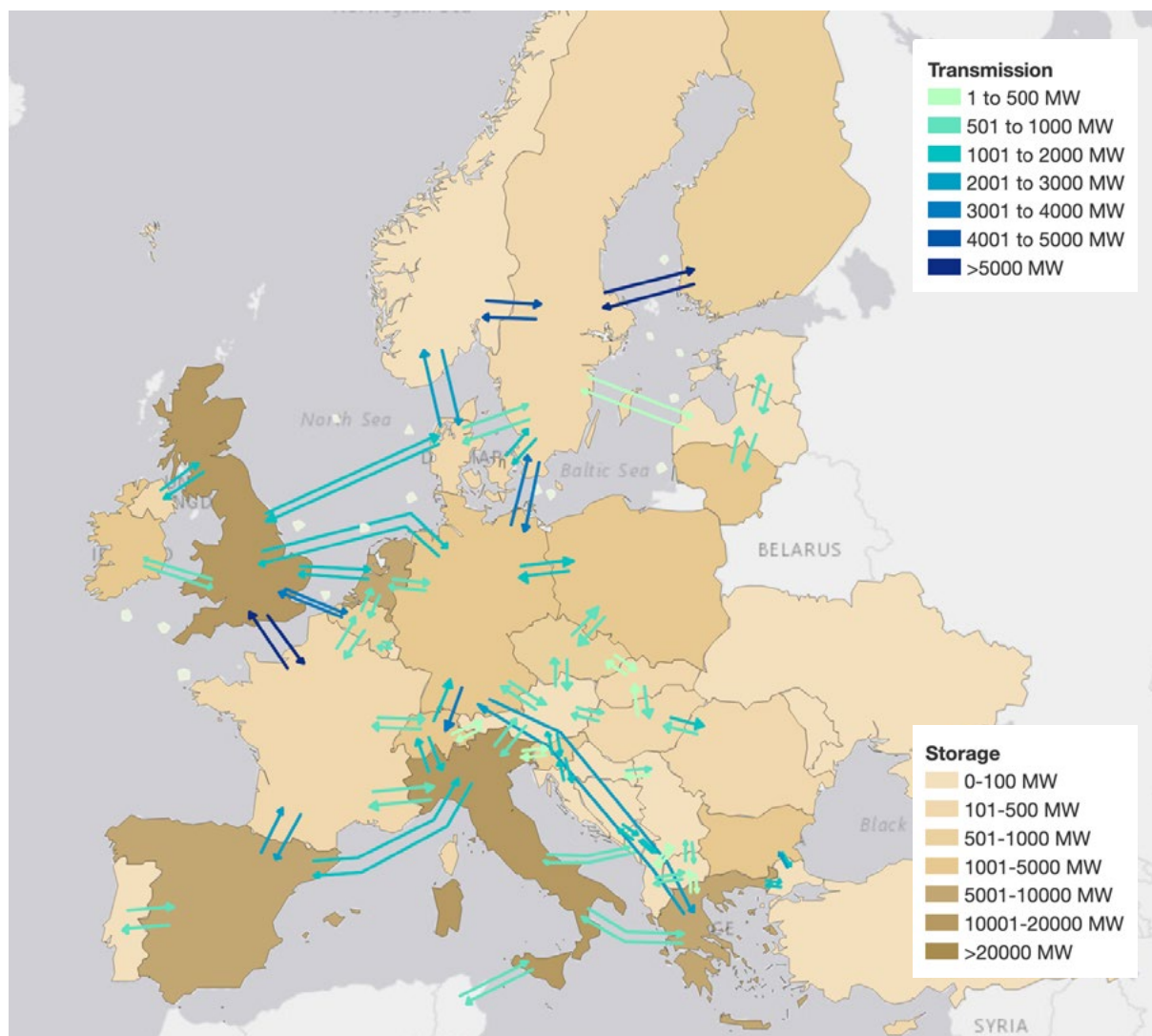


Figure 53 Capacity increases for the 2030 horizon year, in addition to the 2030 reference network

In horizon years 2040 and 2050, the highest increase in capacity is expected in the northern seas, due to the high concentrations of offshore capacity expected in these time horizons.

As partly already emerged in the 2030 horizon year, on a very long term horizon, significant capacity increases are needed for the Italian border to the North (over 6000 MW), with the Balkans (over 3000) and, lastly, 1000 MW with Tunisia and 2000 MW with Spain.

Moreover, in addition to the above-mentioned results, the analyses conducted reveal storage integration needs in parts of Europe in all of the horizon years analysed.

Please refer to the official document⁴⁰ published on the ENTSO-E website for further details.

⁴⁰ <https://www.entsoe.eu/outlooks/tyndp/2024/#>

Figure 54 *Capacity increases for the 2040 horizon year, in addition to the 2030 reference network*

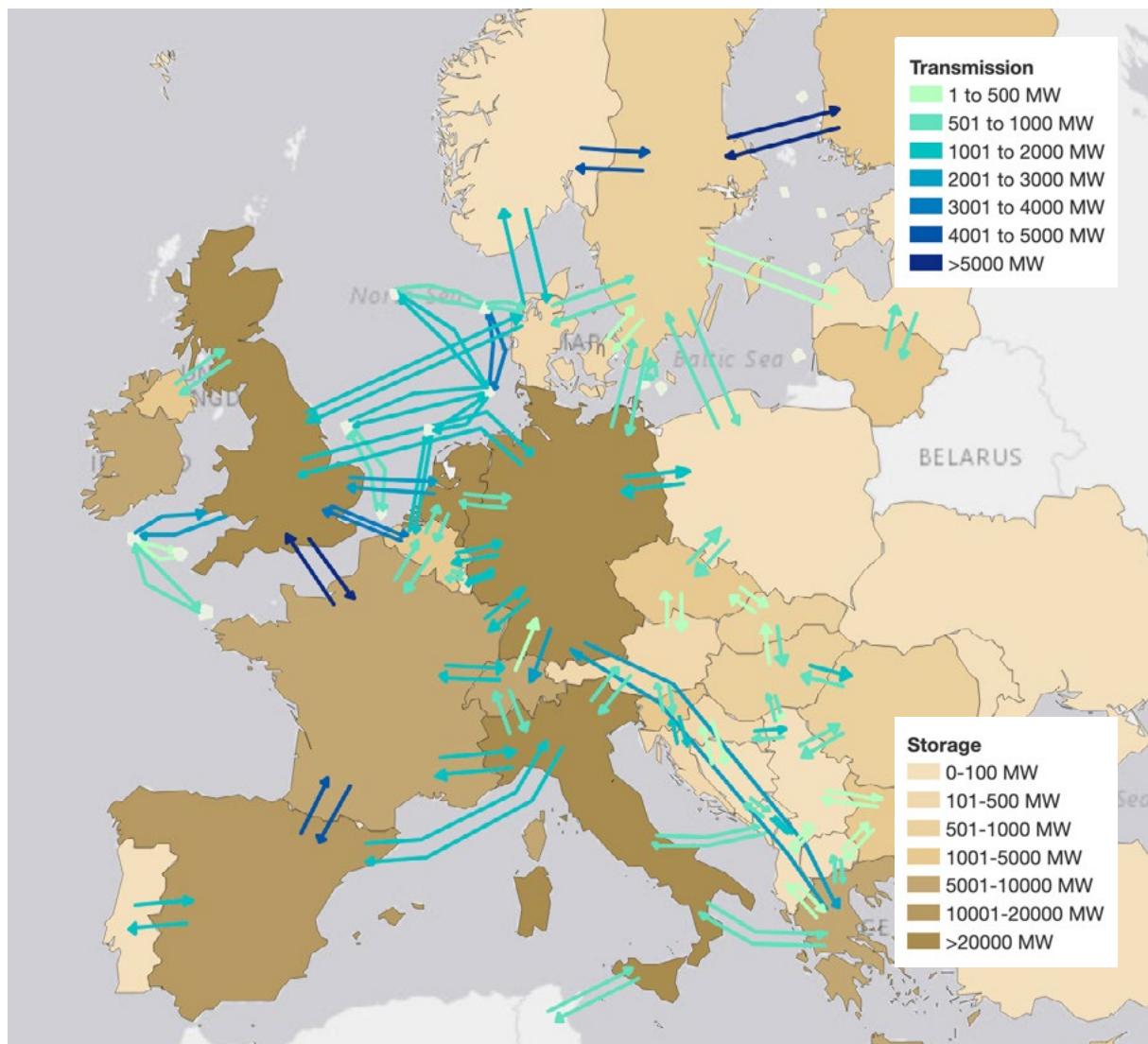
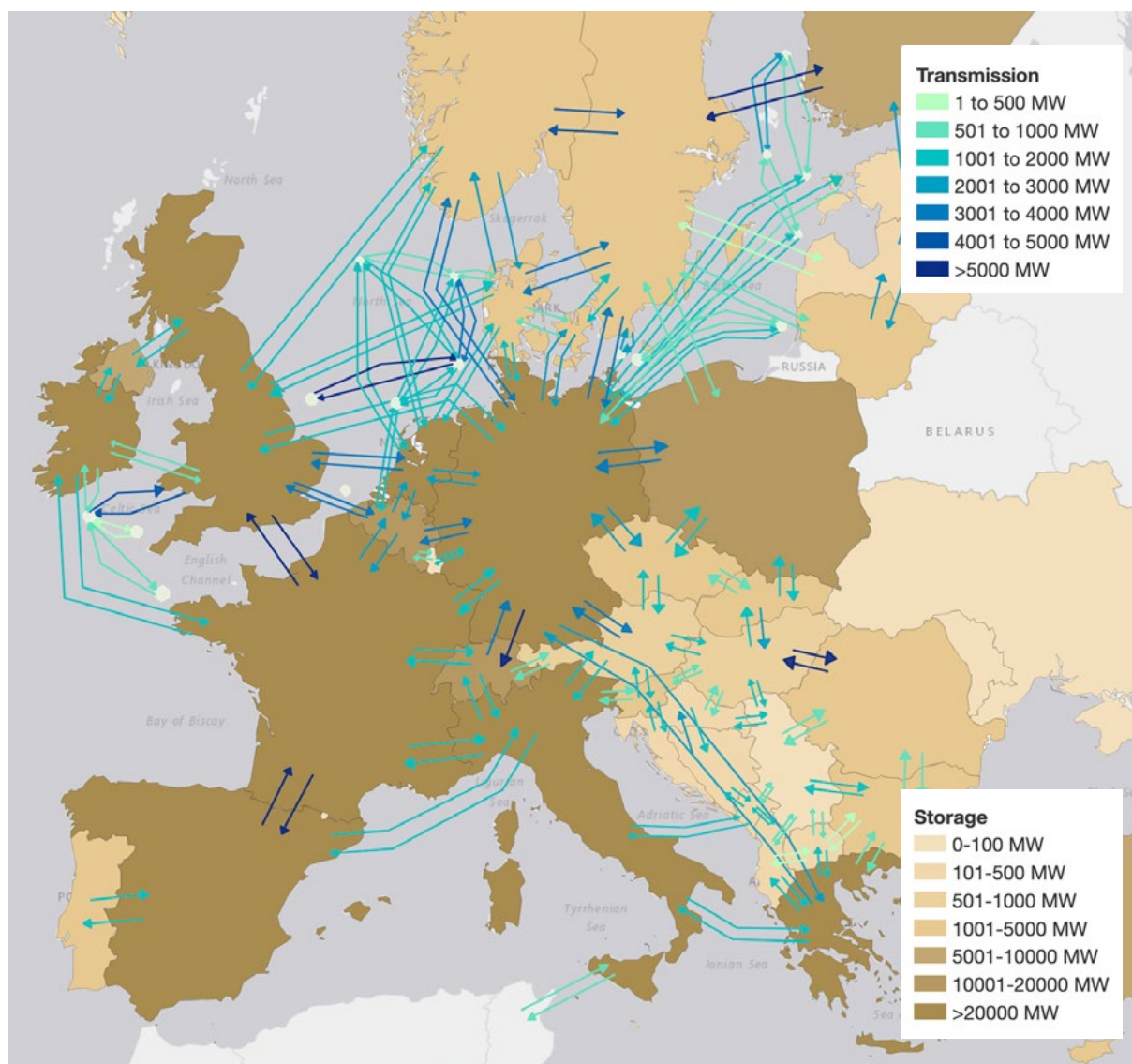


Figure 55 Capacity increases for the 2050 horizon year, in addition to the 2030 reference network

Annex 2

Simulation tools

The need to carry out simulations at the system level led to the choice of market and network simulators based on methodologies already established and used in both European (TYNDP) and national (National Development Plan) contexts.

During the iterative process, zonal market simulations (both DAM and ASM) and nodal network simulations are carried out. With regard to the latter, the network analyses already carried out for the 2023 NDP will be reused wherever possible, ensuring that new ones are carried out if they are not compatible with the assumptions set out in this document.

The simulation tools adopted by Terna for target capacity identification analyses are illustrated below. For further details and references, refer to the 2023 Development Plan and, in particular, to the *“Methodological document for the application of cost-benefit analyses applied to the 2023 Development Plan”*⁴⁰.

⁴⁰ https://download.terna.it/terna/Terna_Piano_Sviluppo_2023_Documento_Metodologico_applicazione_analisi_costi_benefici_8db254c3b3edff1.pdf

1. Zonal market simulations

The zonal market simulator “Promed”⁴¹ is used to perform optimal economic calculations on a model that simulates the operation of electrical energy markets.

Analyses are developed by simulating the optimal scheduling of hourly dispatching of the hydro-thermoelectric generation park on yearly forecast scenarios, while for non-programmable resources, generation profiles by zone and technology are used. This simulation makes it possible to estimate the operating costs of generation units and the hourly energy price in the different market zones and, consequently, producer surplus, consumer surplus as well as congestion rents between market zones (*Social Economic Welfare*).

2. Simulations of the Dispatching and Balancing Services Market

The tool used for simulations of the dispatching (ASM) and balancing (MB) services market “Modis”⁴² is able to perform analyses on an annual horizon and with hourly detail, evaluating, with cost-effectiveness criteria and in compliance with the technical constraints⁴³ of the authorised generating units, the measures required to meet the balancing and safe operation constraints of the electricity system.

3. Probabilistic network simulations

The network simulations used for the calculation of the target capacities refer mainly to probabilistic analyses, using the “Grare” simulator⁴⁴.

The probabilistic analysis, starting from a planning network model in the year under study, allows all relevant configurations of the electricity system to be simulated in the forecast scenarios in a standard, predominantly island grid set-up. The probabilistic method, with reference to an entire year of operation, randomly selects a state of operation of the electricity system based on the unavailability rates of each network/plant element and planned generation group, the level of non-programmable generation, the availability of capacity at the border and the energy demand, ensuring load coverage according to the economic merit order of the generating units. In this type of analysis, a large number of simulations are considered (typically without varying the operating set-up), allowing an equally large number of possible operating situations to be analysed, including N-k events, which are then appropriately weighted for their probability of occurrence. By means of probabilistic simulations, it is possible to assess the change in the risk of energy not being supplied (ENS), the lesser reduction in production from renewable sources (RES) in the presence of the development intervention (overgeneration - OG), and the lesser movements on the ASM necessary to eliminate congestion in the specific market area on which it is located.

⁴¹ B. Cova, P. Capurso, E. Elia, et al., “Market integration in Europe: a market simulator taking into account different market zones and the increasing penetration of RES generation,” CIGRE General Session 2012, Paris, August 2012, paper C5-101.

⁴² B. Cova, S. Osti, M. Stabile, A. Venturini, E.M. Carlini, P. Capurso, C. Gadaleta. “Assessing the impact of transmission investments on the Italian Ancillary Services Market using MODIS simulator”, CIGRE General Session 2018, Paris, August 2012, paper C1-103.

⁴³ Minimum and maximum power, reserve bands that can be dispensed, permanence constraints, start-up costs, reservoir volumes of hydropower units, etc.

⁴⁴ Terna. Grid reliability and adequacy risk evaluator. 2017. Available online: <https://www.cesi.it/grare>.

Annex 3

Methodology for the Target Capacities Assessment

General Criteria

The target capacity on a section/border is *“the transmission capacity that is economically efficient to realize, as the marginal benefits are greater than the marginal costs”*, and the methodology for identifying target capacities consists of an iterative, heuristic and multi-scenario analysis in which all relevant internal market sections and external borders of the Italian electricity system are analysed in an integrated approach through subsequent iterations considering discrete transmission capacity increases starting from a reference grid and their profitability assessed. Therefore, it is clear that the methodology set forth in this document neither replaces nor supersedes the Cost-Benefit Analysis (CBA), which, through the valuation of two indicators, the System Utility Index (SUI) and the Net Present Value (NPV), defines the positive contribution to the Italian electricity system of the interventions in the Development Plan under contrasting scenarios. In fact, these are different methods intended for distinct applications: the target capacity is able to identify efficient power system expansion directions in contrasting scenarios, leaving the Development Plan the task of carrying out detailed studies to define the projects characteristics and the related capacity increases achievable, considering the specific features of the Italian electricity system.

Marginal cost assessment

An important element underpinning the target capacities assessment is the definition of the reference marginal cost [M€/MW] for the investment related to the additional transmission capacity.

The cost of building new transmission capacity varies significantly between projects: the key drivers are the technology, length, voltage level and capacity of the link. In fact, it is reasonable to consider cost estimates for projects increasing transmission capacity between internal bidding zones or across external borders currently not included in a Network Development Plan, subject to significant uncertainty, in the absence of specific technical details.

At European level, first in 2015⁴⁵ and then in 2023⁴⁶, the *Agency for the Coordination of Electricity Regulators (ACER)* defined "standard costs" following specific surveys among different TSOs. However, the standard costs reported in the UIC 2023 document are not categorised by type of use (technology, voltage level, transfer capacity) and are not updated following the costs increase registered in recent years, as they are defined based on a small number of samples and relate to projects already completed between 2012-2020. Consequently, they were not taken into account for the purpose of the target capacity assessment.

For the purposes of this document and in relation to the reference sections and borders under analysis, it is deemed necessary to state the following:

- to estimate the costs in M€/MW associated with predefined capacity increases (steps), the best cost estimates available or prepared by the TSO starting from public information included in the NDP and TYNDP are used for each border/section;
- for projects already envisaged in the NDP and up to the capacity values already planned, the cost estimate referring to the 2023 Development Plan and, when available, to the most recent investment estimates referring to the 2025 Development Plan⁴⁷ are used. In the event in which an intervention has already been partially realised and we have released an increase in capacity to the market, the part of the cost relating to works already completed will be deducted appropriately from the total cost of the intervention (CAPEX and OPEX);
- cost information of the Merchant Lines is considered as possible projects that can be implemented at the borders and contribute to the achievement of the targets⁴⁸;

⁴⁵ http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/UIC%20Report%20-%20-%20Electricity%20infrastructure.pdf.

⁴⁶ https://www.acer.europa.eu/sites/default/files/documents/Reports/UIC_report_2023.pdf

⁴⁷ When available, the costs of standard projects relating to the most recent investment estimates that will be presented starting from the next 2025 Development Plan have already been considered; the implementation cost includes any network rearrangements, rationalisations, and interference works that normally enabling the sustainability of the project on the territory, in the absence of which the project would not be authorised and/or would not be approved by the Local Authorities; the choice maintains consistency by also considering the VRE benefits deriving from any network rearrangements included in the intervention, net of the works already in operation that have therefore accrued benefits;

⁴⁸ for the Merchant Lines, cost estimates were formulated by the TSO on the basis of publicly and privately available information, which was also forwarded during the NDP consultation, although not shown in this report;

- the allocation of the marginal cost curves to the borders, in the absence of other information, considers a cost of 50%, recalling the typically adopted practice of cost sharing among TSOs involved in the project on a territorial basis⁴⁹;
- the marginal cost curve typically assumes an upward trend in order to align with the methodology that, through structured capacity increases, identifies the point at which marginal costs equal marginal benefits⁵⁰;
- for exchange increment values beyond those already foreseen/predictable on a section/border, the need to still identify the steps necessary for construction of the marginal cost curve entails the use of internal cost estimates made by taking into account planned projects investment costs increment factors and the definition of standard projects in order to “close” iterations by always identifying the point at which marginal costs equal marginal benefits;
- for each section/border, priority is given to projects in the Development Plan, subject to the principle of a typically increasing marginal cost curve;
- in the event in which, through network studies conducted as part of the Development Plan, “*capital light*” interventions capable of achieving capacity increases between market areas with low capital investment have been identified, the cost and capacity information relating to the latter was included in the process of constructing marginal cost curves for the identification of target capacities;
- the OPEX are included based on official data from the Cost Benefit Analyses of projects in Development Plans. It should be noted that since these costs are annual for the entire useful life of the asset, equal to 25 years, in order to obtain a single value to be added to the marginal construction costs and determine the total estimated investment for each project, these costs must be discounted. Similarly, therefore, to what is assumed for benefits, the procedure involves multiplying the annual OPEX by 15.6. The value of 15.6 represents the 4% discounting of 1 p.u. of constant cash flow over a useful life of 25 years.

By way of example, Table 6 shows the approach adopted to calculate the marginal cost for the Centre South - Centre North section.

The “INPUT” cost data to define the marginal cost up to an incremental capacity of +3,000 MW for the Centre South-Centre North section are the following:

- estimated cost of the actions indicated in the Development Plans compared to the increase in transmission capacity (I21) that these actions are estimated to guarantee (e.g., Removal of Limitations Centre South-Centre North section, Removal of Limitations Calenzano-Suvereto, HG - Central link, HG - Adriatic Backbone (Forlì-Foggia), HG - North Tyrrhenian Backbone (Milan-Montalto).
- In addition, cost and transfer capacity increase estimates are considered for interzonal actions that will be realised through “*capital light*” or “*non-capital intensive*” solutions, which are grouped in terms of cost (M€) and capacity (MW) with the other planned infrastructure actions mentioned above.

For projects simulated as TOOT with respect to the minimum development network, the marginal cost associated with a decrease in capacity of 1400 MW compared to the base case was calculated as the sum of the contributions of the authorised or being authorised interventions involving the same market section:

- 28% (=400/1400) of the marginal cost of Removing Limitations in the Centre South-Centre North section (I21: +400 MW);
- 72% (=1000/1400) of the marginal cost of the HVDC Adriatic Link (I21: +1000 MW).

On the other hand, to define the marginal cost of the section under consideration at an increment of 1000 MW compared to the minimum development case, the input data and marginal costs of the projects already set out in the Development Plan in the 500-1000 MW increment range are considered.

⁴⁹ stable logic over time, as it is independent from ownership of the initiative (interconnector, ML, L.99/09), avoiding the excessive randomness of inputs that are more defined only in the presence of established agreements and usually in the start-up phase of implementation;

⁵⁰ in the presence of a non-increasing cost curve, there is a risk of early identification of point B/C=1 in contradiction to the principle of efficiency, on which the process is based; according to the same principle, mature projects whose analyses have indicated a TTC value < nominal capacity may be less competitive than less mature projects with TTC=nominal capacity; therefore, in the presence of a mature project, the marginal cost is calculated as the ratio of cost (M€) to the arithmetic mean of TTC and nominal capacity.

Specifically, the marginal cost for a capacity increase of +500 MW (from 500 MW to 1000 MW) was calculated as the sum of the contributions of a number of interventions falling within the same section:

- 10% ($=50/500$) of the marginal cost of the Centre South - Centre North Cluster;
- 90% ($=450/500$) of the marginal cost of the HG - Central Link;

Capacity increases steps at each iteration are conventionally set at 500 MW for borders and sections. Acknowledging the observation to reduce iteration steps, a mechanism to halve the size of capacity increases (250 MW steps for internal sections and borders) is envisaged during the iterative process if after the iterations following the first iteration benefit/cost values result around or below the unit value for almost all sections or borders. In fact, benefit/cost values of less than 1 would lead to the full capacity increase not being confirmed. The adoption of halved PINTs makes it possible to refine the evaluation of benefits (and related target capacity values) in the final iterations.

If capacity increments are halved in a given iteration for a specific scenario, subsequent iterations continue with halved PINTs.

The marginal cost values of the halved PINTs (in Table 6 for example at the +250 MW, +750 MW and 1250 MW step) are calculated using the same logic as for the full PINTs.

This has made it possible to define the OUTPUT data table with the marginal costs for each section/border, distinguishing main works and other works. Details of the INPUT information and OUTPUT marginal cost data are provided in Annex 4.

Table 6 *Determination of the marginal cost curve INPUT vs. OUTPUT: Example of application to the Centre South-Centre North section*

[illegible]

Marginal benefit assessment

• Marginal benefit assessment steps

The **marginal benefit assessment** consists of four steps.

Step 1: starting from the base case, the marginal benefit assessment is developed through zonal simulations of the energy market (SEW) and zonal simulations of the ancillary services market (ASM) using the following approach:

- TOOT simulations of the transmission capacity increase value for the projects included in the minimum development network on the only sections/borders subject to capacity change compared to current *winter peak* values;
- PINT simulations of simultaneous and/or consecutive capacity increases between one or more network sections/borders, verifying the comparison between marginal benefit and marginal cost, until the equilibrium point between the marginal benefit and marginal cost curves is reached, aimed at identifying “development strategies”.

For each TOOT simulation, the variation in exchange capacity is assumed to be equal to the value stated in the NDP (and indicated by code I21).

In order to construct the development strategy (strategies) and select the sections and borders on which capacity increases (PINT) are to be carried out, each section/border is analysed for its overall response (“performance” P_{1+}) to four criteria, through a multi-criteria decision method, detailed in Annex 3.

Note that the four inputs for the multi-criteria analysis, analysed for each specific iteration, are:

- C_1 : Hours of congestion as a result of energy market simulations [h];
- C_2 : Price spread of energy market simulations [€]
- C_3 : Investment cost related to the additional capacity realization [M€/MW];
- C_4 : Implementation cost status, defined according to the projects considered.

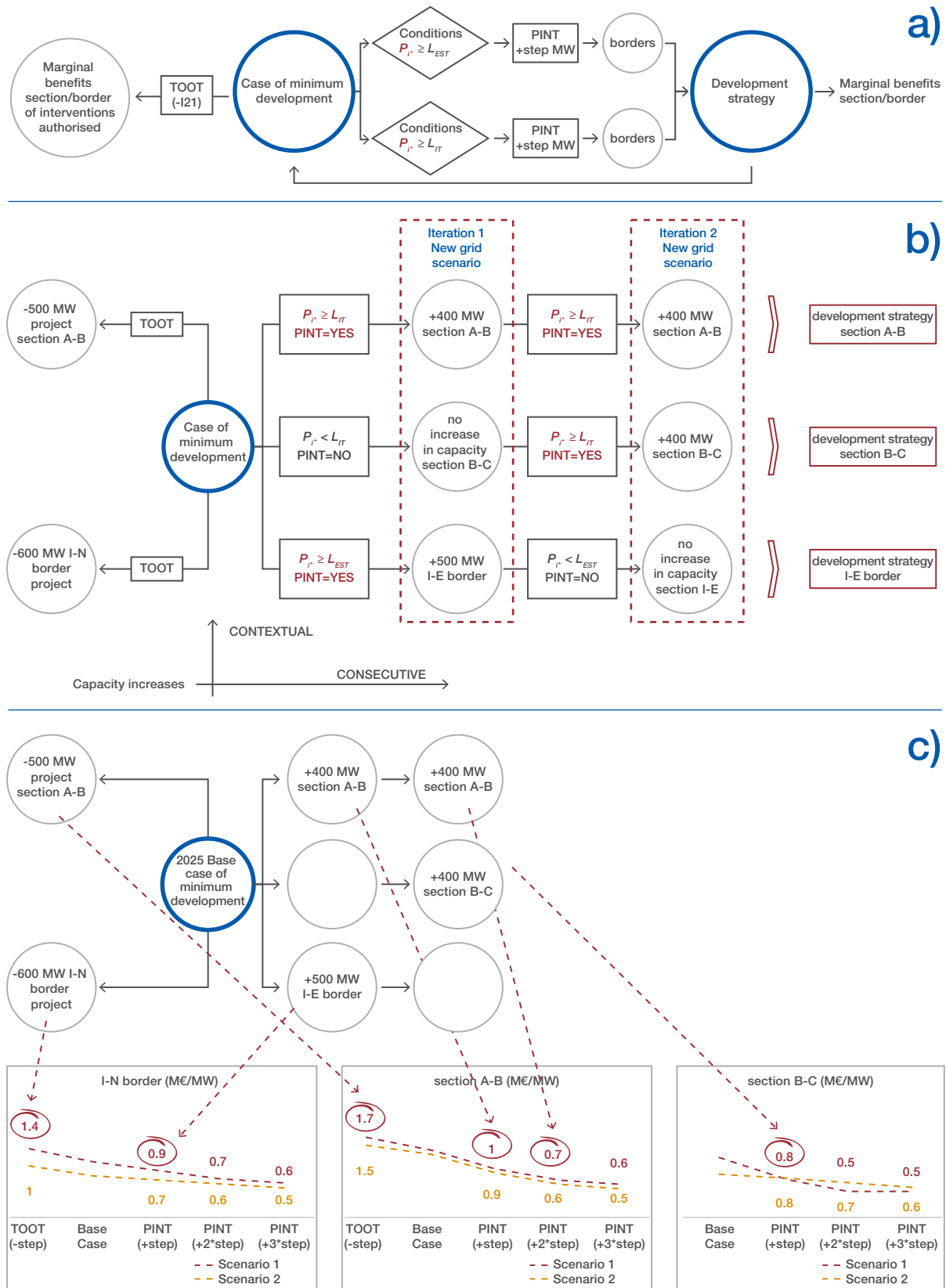
For sections or borders where the following condition is verified as a result of applying the multi-criteria analysis:

- P_{1+} is greater than or equal to a L_{EST} threshold value for borders;
- P_{1+} is greater than or equal to a L_{IT} threshold value for sections;

the need/opportunity to test additional capacity implementation is determined.

The evaluation on all sections/borders will lead to the definition of a new reference network from which the methodology can be reapplied, defining one or more development strategies that will make it possible to identify the marginal benefit ($Bi_{sec/bord}$) for each section/border expressed in M€/MW.

Figure 56 *Example of application of the methodological process: a) Process for defining the initial marginal benefit curve in a generic scenario, b) and c) Example of application of the conditions for defining development strategies*



Confirmation of the capacity increase only occurs if condition $B/C > 1$ (marginal benefits greater than marginal costs) is verified. This results in a new reference network including all confirmed capacity increases, and from which the multi-criteria analysis is again applied to select the sections/borders on which further capacity increases are to be tested.

Figure 56 illustrates examples of the definition of development strategies.

For simulations of development strategies through PINT, the increment value of the exchange capacity is assumed to be equal to a reference step generally as follows:

- $\text{border}_{\text{step}} = 500 \text{ MW}$ on external borders;
- $\text{section}_{\text{step}} = 500 \text{ MW}$ between internal zones.

This does not exclude the possibility of defining different and lower steps depending on the market areas concerned and/or more detailed information. The correlation between reduced steps and increased processing times make lower capacity steps difficult to use for the entire iterative process, as well as not very meaningful for the objective of the analysis. However, the definition of **lower steps** is useful in the later stages of the iterative process to allow a more **refined definition of target capacity** and define in greater detail the last points of the marginal benefit and marginal cost curves.

The need (or opportunity) to resort to **simultaneous and/or consecutive capacity increases** is mainly dictated by the need to take into account the possibility of translation of the congested section. Therefore if one or more sections/borders positively verify the condition $P_i + \geq L_{IT}/P_i + \geq L_{EST}$, they will be incremented by one step at the same time in the same iteration; contextuality guarantees a congruous number of successive iterations.

Lastly, consecutiveness ensures that, where capacity increases on a section/border lead to positive benefits only after other developments (capacity increases), the need accrues in subsequent iterations.

During the course of the simulations, the **competitive situation** occurred for some internal sections or, in the same iteration, the PINT benefits linked to additional capacity development are correlated and competitive with each other (**competitors**).

In the initial iterations/simulations, irrespective of the scenario being analysed, all competing sections were confirmed in the next iteration where, having verified the condition $P_i + \geq L_{IT}$ of the TOPSIS method, the benefit/cost ratio is clearly much greater than 1. This is based on the fact that for high B/C values, selectivity would simply increase the number of iterations.

Subsequent to the initial iterations, if developments in similar competing sections are confirmed, where the Benefit/Cost ratio is greater than 1 in these sections, a *merit order* mechanism is applied: in the next iteration, only the capacity increase with the highest B/C ratio compared to the competing sections is confirmed. This creates selectivity in increments and favours the most competitive sections.

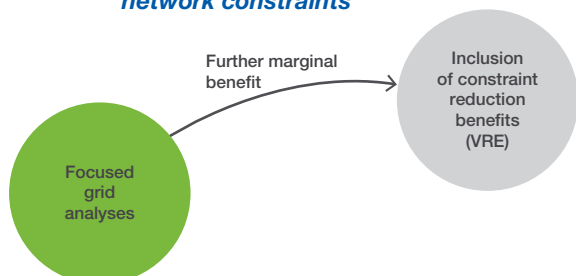
Step 2: in this phase, the initial benefit curve is constructed for each scenario and each section. In fact, each iteration resulting from the market simulations returns the annual benefit on the two contrasting scenarios (inertial and policy), which discounted (with a 4% rate for 25 years) and compared to the associated capacity increase, determines the initial marginal benefit underlying the capacity increase.

At the end of step 2, each section and each border will be characterised by its own initial benefit curves, one for each scenario under analysis.

Step 3: in this phase, network analyses are conducted, which are an important step in consolidating the benefit curves (Figure 57). In fact, the analyses carried out in steps 1 and 2 refer only to zonal market simulations; based on the results

of these simulations, network analyses in line with the European approach are also carried out in order to measure all other benefits necessary to avoid an underestimation of the magnitude of benefits.

Figure 57 Inclusion of benefits from reduction of network constraints



Therefore, other benefits have also been included in the benefit curves, referred to conventionally in this document as “Benefits of grid constraint reduction” (VRE).

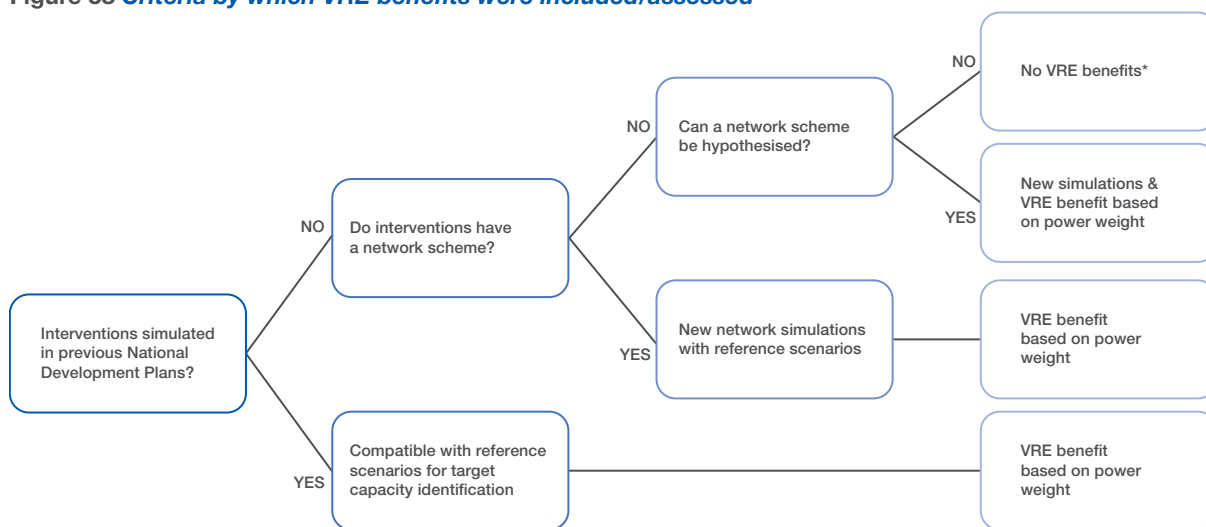
Grid analyses (including probabilistic ones) have already been conducted as part of the Development Plan and the results have been published at the intervention level. Therefore, where such data can be used with the hypothesised development scenarios and strategies, the benefits at the intervention level, already included in previous NDPs, will be used as power in the marginal

benefit curve; where such data cannot be used, targeted network simulations will be carried out (some).

Lastly, for capacity increases that cannot be associated to a project in the network model (e.g. interconnection nodes), as detailed studies are necessary to define a network scheme, the VRE benefit will not be evaluated.

Figure 58 shows the criteria for including/assessing VRE benefits.

Figure 58 Criteria by which VRE benefits were included/assessed



* Not including VRE benefits of the Interconnectors L. 99/09 and/or Merchant Line, unless calculated in previous NDPs.

Step 4: in this step, the benefit curve is consolidated from the initial one (inclusive of SEW and ASMz) to the final one (inclusive of the benefit reducing VRE Grid Constraints).

Network analyses allow a more detailed estimation of the benefits related to an increase in exchange capacity between sections/borders.

In this context, the VRE benefit (reduced grid constraints) is defined as the sum of the following benefit categories: Non-supplied Energy risk (B3), renewable integration (B5) and ASMn at the nodal level (B7n).

• Benefit Categories

In keeping with the previous editions of the report, [Table 7](#) provides a summary of the benefits that will be considered for the purposes of this target capacity assessment with respect to the total benefits used for CBA purposes in the 2023 NDP and provided for in Resolution 627/2016/R/eel as amended.

Table 7 Benefit categories of the 2023 NDP included in this methodology

	RESOLUTION 627/2016 AS AMENDED AND 2023 NDP	FOR TARGET CAPACITY ASSESSMENT METHODOLOGY
B1	Social Economic Welfare	YES
B2	Reduction of grid losses	NO
B3	Reduction of ENS risk	YES (VRE)
B4	Reduction of UESS costs	YES (VRE)
B5	RES integration	YES (VRE)
B6	NTG investments avoided	NO
B7	Reduction/increase in ASM costs	YES (DSMn in the VRE)
B13	Increased resilience	NO
B18	Reduction in CO₂ emissions	YES
B19	Reduction in other emissions	YES

• Criteria for selecting sections/borders on which to simulate capacity increases

Following the first editions and the comments received in the expert-based external audits, it was decided that a multi-criteria decision-making method (MCDM) would be used for the problem of choosing the sections/borders on which to simulate the additional capacity increases in subsequent iterations.

In fact, MCDM methods provide a valuable tool to support the Decision Maker in complex problems, characterised by many possible alternative solutions and numerous criteria against which they must be evaluated.

Of the numerous MCDM methods available, the choice was made to use the “**TOPSIS**” method (Technique for Order Preference by Similarity to Ideal Solution, Hwang and Yoon, 1981⁵¹) which, as explained below, is well suited to solving the particular decision-making problem in question.

Details of the TOPSIS method

The basis of multi-criteria analysis using the TOPSIS approach is the expression of the problem in matrix form: the decision matrix D of order $n \times m$ is created, with n representing the number of alternative solutions and m the number of judgement criteria taken into account. The generic element a_{ij} of the matrix expresses the performance of the generic alternative A_i ($i=1, 2, \dots, n$) with respect to the generic criterion C_j ($j=1, 2, \dots, m$). An example of a decision matrix is depicted in [Figure 59](#).

Figure 59 Decision matrix

ALTERNATIVES	SELECTION CRITERIA AND RELATIVE WEIGHTS				
		$C_1(W_1)$	$C_2(W_2)$	...	$C_m(w_m)$
	A_1	a_{12}	a_{12}	...	a_{1m}
	A_{21}	a_{21}	...	...	a_{2m}
	...	...	...	...	...
	...	...	...	...	...
	A_{n1}	a_{n1}	a_{n2}	...	a_{nm}

Once the decision maker has identified the criteria against which the performance of each alternative is to be evaluated and the value of the weights (i.e. relative importance) w_j associated with each of them ($j=1, 2, \dots, m$), the decision problem consists of determining the optimal solution A^* belonging to the set of possible alternatives A as the one characterised by the best overall compliance with the criteria C_j , based on the established weights.

⁵¹ C.L. Hwang and K. Yoon, Multiple attribute decision making. Methods and applications: a state-of-the-art survey. Berlin and New York: Springer-Verlag, 1981.

The main steps for applying the method are summarised below.

STEP 1: Construction of the normalised decision matrix.

In general, normalisation of the decision matrix D is necessary due to the presence of the different units involved. The normalised decision matrix X is obtained by determining each element x_{ij} as follows:

$$x_{ij} = \frac{a_{ij}}{\sqrt{\sum_{k=1}^n a_{kj}^2}}$$

$$X = \begin{bmatrix} x_{11} & \dots & x_{1m} \\ \dots & \dots & \dots \\ x_{n1} & \dots & x_{nm} \end{bmatrix}$$

STEP 2: Construction of the weighted normalised decision matrix

The weighted normalised decision matrix Y is obtained by multiplying each column of the normalised decision matrix X by the weight of the criterion corresponding to it:

$$Y = \begin{bmatrix} w_1 x_{11} & \dots & w_m x_{1m} \\ \dots & \dots & \dots \\ w_1 x_{n1} & \dots & w_m x_{nm} \end{bmatrix} = \begin{bmatrix} y_{11} & \dots & y_{1m} \\ \dots & \dots & \dots \\ y_{n1} & \dots & y_{nm} \end{bmatrix}$$

STEP 3: Determination of the ideal positive solution A^+ and ideal negative solution A^-

The ideal positive A^+ and negative A^- solutions are defined on the basis of the normalised and weighted evaluations contained in matrix Y.

The positive ideal solution A^+ is determined by considering, for each criterion, the best performance offered by the alternatives under consideration, i.e:

- the highest value offered by the alternatives, when referring to a benefit criterion;
- the lowest value offered by the alternatives, when referring to a cost criterion.

Conversely, the ideal negative solution A^- is obtained by considering, for each criterion, the worst performance offered by the alternatives in play, i.e:

- the lowest value offered by the alternatives, when referring to a benefit criterion;
- the highest value offered by the alternatives, when referring to a cost criterion.

Given J_b as the set of benefit criteria considered and J_c as the set of cost criteria, the definition of the two ideal solutions is expressed as:

$$A^+ = \left\{ \left(\max_i y_{ij} \mid j \in J_b \right), \left(\min_i y_{ij} \mid j \in J_c \right), i = 1, 2, \dots, n \right\} = \{y_{1+}, y_{2+}, \dots, y_{n+}\}$$

$$A^- = \left\{ \left(\min_i y_{ij} \mid j \in J_b \right), \left(\max_i y_{ij} \mid j \in J_c \right), i = 1, 2, \dots, n \right\} = \{y_{1-}, y_{2-}, \dots, y_{n-}\}$$

STEP 4: Calculation of the distance of each alternative from A^+ and A^-

At this point, for each alternative A_i , it is possible to calculate the Euclidean distance S_{i+} from the ideal positive alternative A^+ , and the Euclidean distance S_{i-} from the ideal negative alternative A^- , by means of the expressions:

$$S_{i+} = \sqrt{\sum_{j=1}^m (y_{ij} - y_{j+})^2} \text{ for } i = 1, 2, \dots, n$$

$$S_{i-} = \sqrt{\sum_{j=1}^m (y_{ij} - y_{j-})^2} \text{ for } i = 1, 2, \dots, n$$

STEP 5: Determining the relative distance of the alternatives from the ideal solution

Given the distances S_{i+} and S_{i-} for each alternative A_i , it is possible to determine the relative distance of that alternative from the ideal solution using the following expression:

$$P_{i+} = \frac{S_{i-}}{S_{i+} + S_{i-}}$$

Con $0 \leq P_{i+} \leq 1$.

STEP 6: Ranking of preference of the alternatives

Lastly, it is possible to define a preference ranking of alternatives with reference to the value of P_{i+} for each alternative. As can be inferred, solutions with the highest P_{i+} value will be preferred.

Application of the TOPSIS method to the selection of PINTs for the construction of development strategies

With regard to the process of identifying target capacities, the possible alternatives are identified in the sections/borders to be analysed at each iteration, while the criteria considered are listed in [Table 8](#).

Table 8 Criteria considered in the MCDM analysis for the selection of PINTs

CODE	DESCRIPTION	UNIT OF MEASURE
C ₁	Congestion Hours	h
C ₂	Price spread resulting from Day-Ahead Market simulations	€/MWh
C ₃	Investment cost for additional capacity realization in the specific iteration	M€/MW
C ₄	Implementation cost status in the specific iteration	-

While the quantification of criteria C₁, C₂ (obtained as a result of the DAM simulations at the start of each iteration) and C₃ (coinciding with the marginal cost of the capacity increase under consideration for the specific section/border) can be inferred, the valuation of criterion C₄ needs to be clarified.

In particular, a scale from 1 to 4 is defined, which identifies:

- 1: network development for capacity increase **at standard costs**⁵²;
- 2: network development for capacity increase **planned**;
- 3: network development for capacity increase **designed**;
- 4: network development for capacity increase **under authorisation**.

It is important to clarify that both the evaluation criterion based on the marginal cost of implementation and the evaluation criterion based on the project's progress considered in the specific iteration for a given section/border refer to actual data updated to the latest available information (Annex 4), adding to the analysis of the choice of PINTs to be simulated two further evaluation elements that reflect the efficiency and feasibility of the additional capacity to be tested.

The PINT activation thresholds are differentiated for foreign borders and domestic sections and the multi-criteria analysis is conducted separately due to the differences typically found in the values of price differentials and congestion hours.

The decision matrices for foreign borders and internal sections in a generic iteration are represented in [Figure 60](#) and [Figure 61](#).

⁵² Refers to capacity increases not included in the NDP.

Figure 60 Decision matrix for external borders

		$C_1(W_1)$	$C_2(W_2)$	$C_3(W_3)$	$C_4(W_4)$
1	AT - ITn	$a_{EST,11}$	$a_{EST,12}$	$a_{EST,13}$	$a_{EST,14}$
2	CH - ITn	$a_{EST,21}$	$a_{EST,22}$	$a_{EST,23}$	$a_{EST,24}$
3	FR - ITn	$a_{EST,31}$	$a_{EST,32}$	$a_{EST,33}$	$a_{EST,34}$
4	SI - ITn	$a_{EST,41}$	$a_{EST,42}$	$a_{EST,43}$	$a_{EST,44}$
5	ITcn - HR	$a_{EST,51}$	$a_{EST,52}$	$a_{EST,53}$	$a_{EST,54}$
6	MNE - ITcs	$a_{EST,61}$	$a_{EST,62}$	$a_{EST,63}$	$a_{EST,64}$
7	ITs - GR	$a_{EST,71}$	$a_{EST,72}$	$a_{EST,73}$	$a_{EST,74}$
8	ITsic - TUN	$a_{EST,81}$	$a_{EST,82}$	$a_{EST,83}$	$a_{EST,84}$

Figure 61 Decision matrix for internal market sections

		$C_1(W_1)$	$C_2(W_2)$	$C_3(W_3)$	$C_4(W_4)$
1	ITcn - ITn	$a_{IT,11}$	$a_{IT,12}$	$a_{IT,13}$	$a_{IT,14}$
2	ITcs - ITcn	$a_{IT,21}$	$a_{IT,22}$	$a_{IT,23}$	$a_{IT,24}$
3	ITs - ITcs	$a_{IT,31}$	$a_{IT,32}$	$a_{IT,33}$	$a_{IT,34}$
4	ITsar - ITcn	$a_{IT,41}$	$a_{IT,42}$	$a_{IT,43}$	$a_{IT,44}$
5	ITsar - ITcs	$a_{IT,51}$	$a_{IT,52}$	$a_{IT,53}$	$a_{IT,54}$
6	ITsar - ITsic	$a_{IT,61}$	$a_{IT,62}$	$a_{IT,63}$	$a_{IT,64}$
7	ITsic - ITcs	$a_{IT,71}$	$a_{IT,72}$	$a_{IT,73}$	$a_{IT,74}$
8	ITsic - ITcal	$a_{IT,81}$	$a_{IT,82}$	$a_{IT,83}$	$a_{IT,84}$
9	ITcal - ITs	$a_{IT,91}$	$a_{IT,92}$	$a_{IT,93}$	$a_{IT,94}$

As is known, the purpose of the target capacity assessment is to achieve efficient capacity by reducing congestion hours and price differentials. Therefore, with the exception of cost criterion C_3 for which the positive ideal solution A^+ is determined by considering the lowest value offered by the alternatives, for the other three criteria the A^+ solution coincides with the highest value offered by the alternatives, as the objective is to realise additional transmission capacity where the greatest number of hours of congestion, the greatest price differential and the most advanced projects are present. The reverse applies to the definition of A^- , as depicted in [Figure 62](#).

Figure 62 Positive and negative ideal solutions for the four criteria considered

		$C_1(W_1)$	$C_2(W_2)$	$C_3(W_3)$	$C_4(W_4)$
Positive ideal solution	A^+	$\max y_{ij}$	$\max y_{ij}$	$\max y_{ij}$	$\max y_{ij}$
Ideal negative solution	A^-	$\min y_{ij}$	$\min y_{ij}$	$\min y_{ij}$	$\min y_{ij}$

With regard to the relative importance of the considered criteria w_j , initially adopting equal weighting for each of them is deemed appropriate. Since, as iterations progress and capacity increases are implemented, the values of price differentials and congestion hours for internal sections and on foreign borders are expected to be aligned, the possibility of giving greater weight to criteria C_3 and C_4 cannot be ruled out, as they are more significant in the final iterations.

Defining the relative distance of the alternatives from the ideal P_{ij} solution allows assessment of the overall response or “performance” of a given section/border in a specific iteration with respect to the criteria considered. It is then possible, for each iteration, to rank the sections and borders with the most favourable conditions for the implementation of new transmission capacity. Once all P_{ij} values have been obtained, they are sorted in descending order and the median value, L_{IT} and L_{EST} are calculated for internal sections and foreign borders respectively:

- $P_{ij} \geq L_{IT}$ on internal sections;
- $P_{ij} \geq L_{EST}$ on external borders.

Finally, should conditions arise in which mutually competing sections (or borders) assume performance indices that are very close to each other even if slightly below the threshold value resulting from the median, it is in any case considered reasonable to test capacity increments in order to assess the resulting benefits, with the aim of confirming the most profitable capacity increments in a specific iteration without running the risk of affecting subsequent iterations.

Advanced Least Regret

The *Advanced Least Regret* allows one to identify, in addition to the two diverging development strategies, further strategies characterised by a set of intermediate capacity values, calculated as the average of the values identified in the analysed scenarios for each section/border. Each set of intermediate capacity values will be associated with cost values, calculated using the curves defined for each section/border. It should be noted that the cost curves are independent from the scenario being analysed, as they are only related to the overall capacity values being assessed for each section/border (and thus to the relevant projects).

At this point, the sets of intermediate capacity values in the two scenarios are simulated at the same time in order to assess the overall net benefit derived. This process continues by setting further intermediate (albeit discrete) options until **reaching a set of values that presents the lowest “regret” with respect to all strategies examined**.

Figure 63 shows an explanatory representation of the methodology identified. Having defined two scenarios, scenario A and scenario B, three development options are defined:

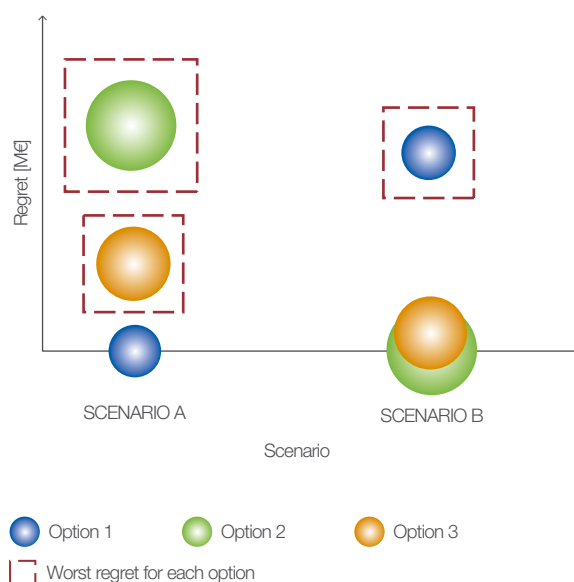
- **Option 1 (low capacity values):** set of capacity values identified as a result of the simulations in scenario A;
- **Option 2 (high capacity values):** set of capacity values identified as a result of the simulations in scenario B;
- **Option 3 (intermediate capacity values):** set of target capacity values calculated as the arithmetic mean of the capacity values associated with Options 1 and 2 in each section/border (intermediate capacities).

In this circumstance it is evident that:

- *Option 1* has zero regret in scenario A and maximum regret in scenario B;
- *Option 2* has zero regret in scenario B and maximum regret in scenario A;
- *Option 3* has intermediate regret in scenario A and is close to Option 2 in scenario B.

The highest regret is represented by Option 2 in Scenario A, while Option 3 is the “*least regret*”, namely the solution that minimises regret.

Figure 63 *Example of Advanced Least Regret representation*



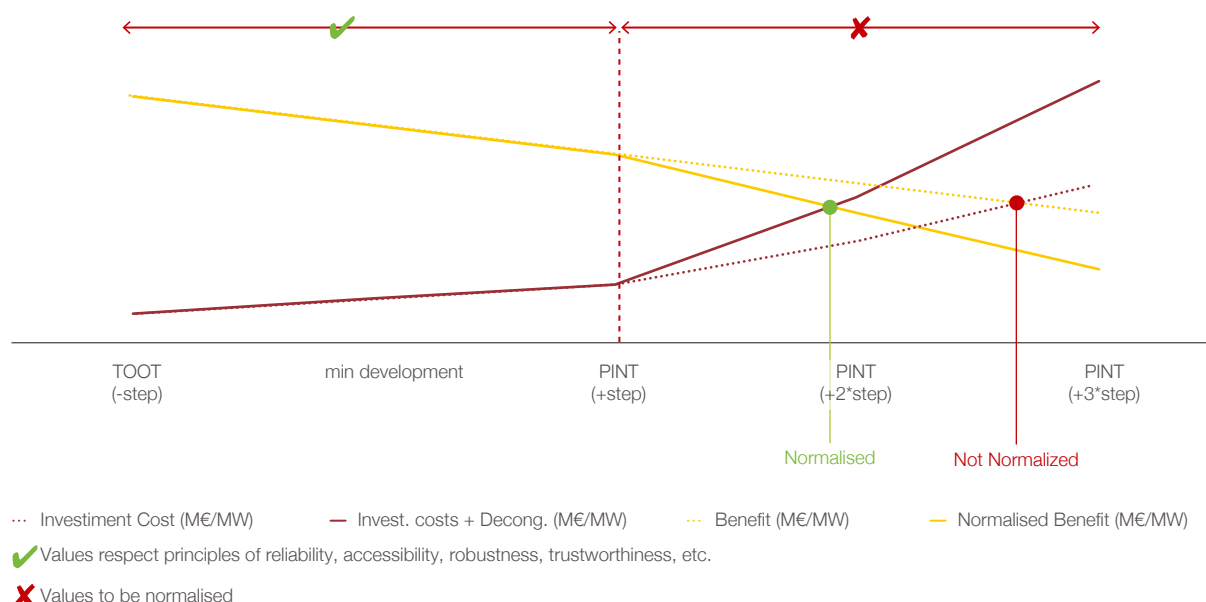
The process described, applied here on only three options, can be conducted by means of successive approximations by identifying from the sets of target capacity values, as a result of the simulation in the two scenarios, further refinements to identify the best option.

Methodology for normalising high Target Capacity values

With reference to the situation of high target capacity development values on a border, due to the need to have unbiased target capacity results, an approach to deal with “significantly high” values was introduced in previous editions of the report.

This approach required careful assessment of inputs and outputs: marginal costs and marginal benefits are the only levers to enable the “normalisation” of high target capacity values, allowing a congruent intersection point between the curves and thus providing final values that reflect the principles of reliability, achievability, robustness and reliability (Figure 64).

Figure 64 *Effect of the normalisation process*



Significantly high target capacity values can be normalised:

- on costs, introducing **decongestion costs** to represent the costs associated with any intrazonal decongestion infrastructure;
- and on benefits, introducing a **benefit normalisation coefficient** (<100%), defined as the ratio of normalised hourly energy flows to not-normalised hourly energy flows. The normalised hourly energy flows always have an hourly value of less than or equal to the residual demand in the North zone.

In this report, the process of normalising the target capacity values at the borders was not needed, as the application of constraints on the maximum target capacity is already an effective strategy for the definition of realistic and reliable development strategies.

INPUT information details for the Eastern and North Africa border

INPUT									
Intervention costs estimated dTTC(12)									
HYDCELANE (401-P) 620 = 1.1 600									
HYDCELTUN (601-L) 620 = 1.1 600									
SRIFA 2 (554-L) 1260 = 1.3 1000									
Marginal cost per capacity increase [M€/MW]									
dTTC - TOT									
ITC - WNE	1,400	1,350	1,400	1,450	1,500	1,550	1,600	1,650	1,700
ITC - GR						1.5	1.5		
ITSc - TUN									
dTTC - PNT									
ITC - WNE	1,300	1,350	1,400	1,450	1,500	1,550	1,600	1,650	1,700
ITC - GR						1.5	1.5		
ITSc - TUN									
Marginal cost per capacity increase [M€/MW]									
dTTC - TOT									
ITC - WNE	1,400	1,350	1,400	1,450	1,500	1,550	1,600	1,650	1,700
ITC - GR						1.5	1.5		
ITSc - TUN									
dTTC - PNT									
ITC - WNE	1,300	1,350	1,400	1,450	1,500	1,550	1,600	1,650	1,700
ITC - GR						1.5	1.5		
ITSc - TUN									

KEY	
Input from NDP 23/TYNDP 24/Preview NDP 25	
Input from Standard Projects	
output flows into the benefit curve (TOT)	
output flows into the benefit curve (whole PNT)	
output flows into the benefit curve (halved PNT)	

[illegible]

INPUT information details for internal sections (North-Centre South and North-South)

INPUT

Intervention costs

stimulo

dTC/dP (€)

4100 = 1.5

2700 = 1.5

NG Backbone North Tyrrhenian (Milano-Montalto) (355-M)

40.0 = 1.2

27.00 = 1.00

HG Adriatic Backbone (Porto-Foggia) (442-M)

40.0 = 1.2

27.00 = 1.00

Marginal cost per capacity increase (M€/MW)

dTC/dP (€)

100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200	1,250	1,300	1,350	1,400	1,450	1,500	1,550	1,600	
TC ₁ (P)								1.5										1.5					1.5								
TC ₂ (P)								1.2										1.2													

Marginal cost per capacity increase (M€/MW)

dTC/dP (€)

1,700	1,750	1,800	1,850	1,900	2,000	2,050	2,250	2,300	2,350	2,400	2,450	2,500	2,550	2,600	2,650	2,700	2,750	2,800	2,850	2,900	2,950	3,000	3,050	3,100	3,150	3,200	3,250	3,300	3,350	3,400	
TC ₁ (P)						1.5							1.5	1.5																	
TC ₂ (P)					1.2	1.2	1.2					1.2			1.2																

INPUT information details for internal sections (Sardinia-Centre North, Sardinia-Centre South and Sardinia-Sicily)

INPUT

Intervention costs

estimated

dTTC(2,1)

SACOB (301-P)

781 = 2.0

400

Tymbanian link - WEST (723-P)

1956 = 2.0

1000

SAPRI 2 (732-P)

2304 = 2.3

1000

dTTC - TOOT		Marginal cost per capacity increase [M€/MW]																dTTC - PNT									
		100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200	1,250		
ITsar-Itcn	2.0				2.5				2.5				2.5						2.5					2.8			
ITsar-Itcs					2.3				2.3				2.3						2.3					2.5			
ITsar-Itsc	2.0				2.5				2.5										2.5								

dTTC - PNT		Marginal cost per capacity increase [M€/MW]																													
		1,300	1,350	1,400	1,450	1,500	1,550	1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050	2,100	2,150	2,200	2,250	2,300	2,350	2,400	2,450	2,500	2,550	2,600	2,650	3,000	
ITsar-Itcn	3.3								3.3																						
ITsar-Itcs	3.0								3.0										3.3												
ITsar-Itsc									3.0																						3.9

KEY

Input from NDP 23/TNDP 24/Preview NDP 25

Input from Standard Projects

output flows into the benefit curve [TOOT]

output flows into the benefit curve (whole PNT)



INPUT information details for internal sections (Sicily-Centre South, Sicily-Calabria and Calabria-South)

INPUT

Intervention costs
estimated
dITTC(21)

1853
1000

Tyrrhenian link - EAST(723-P)

274
610

Bolano Amunizata (556-P) + Capital/light

456
900

Northern Calabria Grid Restructuring + 380 kV Montescovino - Avellino North - Benevento 380 kV line (591-P/506-P) + Capital/light

		Marginal cost per capacity increase (MW/MW)																dITTC - PNT																			
		dITTC - TCO2T																		dITTC - PNT																	
		1,400	1,000	400	100	minimum developm ent	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200	1,250							
ITsc-ITcs																2.4	2.4	2.4							2.4	2.4		2.6									
ITsc-ITcal										2.4					0.5	0.5								0.5		0.9		1.0		1.0							
ITcal-ITcs															0.5										0.6					1.0							

Intervention costs
estimated
dITTC(21)

2093
2100

HG - Ionica-Tirrenica Backbone (Rosarno-Montescovino) (563-N)

501
430

Removal of limitations Segrate-Riviconi (501-P)

210
2100

HG - Ionica-Tirrenica Backbone (Rido-Rosarno-Montescovino-Lathia) (563-N)

		Marginal cost per capacity increase (MW/MW)																dITTC - PNT																			
		dITTC - TCO2T																		dITTC - PNT																	
		2,750	2,800	2,850	2,900	2,950	3,000	3,050	3,100	3,150	3,200	3,250	3,300	3,350	3,400	3,450	3,500	3,550	3,600	3,650	3,700	3,750	3,800	3,850	3,900	3,950	4,000	4,050	4,100	4,150							
ITsc-ITcs																																					
ITsc-ITcal																															2.5						
ITcal-ITcs																															1.3						

INPUT

Intervention costs
estimated
dITTC(21)

2093
2100

HG - Ionica-Tirrenica Backbone (Rosarno-Montescovino) (563-N)

501
430

Removal of limitations Segrate-Riviconi (501-P)

210
2100

HG - Ionica-Tirrenica Backbone (Rido-Rosarno-Montescovino-Lathia) (563-N)

		Marginal cost per capacity increase (MW/MW)																dITTC - PNT																			
		dITTC - TCO2T																		dITTC - PNT																	
		2,750	2,800	2,850	2,900	2,950	3,000	3,050	3,100	3,150	3,200	3,250	3,300	3,350	3,400	3,450	3,500	3,550	3,600	3,650	3,700	3,750	3,800	3,850	3,900	3,950	4,000	4,050	4,100	4,150							
ITsc-ITcs																																					
ITsc-ITcal																															2.5						
ITcal-ITcs																															1.3						

KEY	
Input from NDP 25/TPNDP 26/Preview NDP 25	
Input from Standard Projects	
output flows into the benefit curve (TODT)	
output flows into the benefit curve (whole PNT)	
output flows into the benefit curve (halved PNT)	

OUTPUT marginal cost data for each border

	Marginal cost per capacity increase [M€/MW]													
	dTTC - TOOT					dTTC - PINT								
	1,400	1,000	400	100		100	160	200	250	300	350	380	450	500
AT - ITn				0.3	minimum develop ment		0.5		0.5			0.5		0.6
CH - ITn									0.8					0.8
FR - ITn									0.9					0.9
SI - ITn							0.5			0.5				0.5
ITcs - MNE									1.1					1.1
ITs - GR									1.3					1.3
ITsic - TUN														

	dTTC - PINT													
	550	600	650	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200
AT - ITn					0.7				0.7	0.7				
CH - ITn										0.8				
SI - ITn										0.5		0.5		0.7
ITcs - MNE		1.1			1.3					1.4	1.4			
ITs - GR										1.3				
ITsic - TUN														

	dTTC - PINT													
	1,250	1,300	1,350	1,400	1,480	1,500	1,550	1,600	1,650	1,700	1,750	1,800	1,850	1,900
AT - ITn	1.0				1.0	1.0					1.3			
CH - ITn						1.6								
FR - ITn								1.1						
SI - ITn						0.8								
ITcs - MNE							1.5	1.5						
ITs - GR						1.6								
ITsic - TUN														

$dTTC - PINT$												
	1,950	2,000	2,050	2,100	2,150	2,200	2,250	2,300	2,350	2,400	2,450	2,480
AT - ITn		1.3										1.3
CH - ITn		1.6										
FR - ITn												
SI - ITn						0.9						
ITcs - MNE												
ITs - GR		1.6										
ITsic - TUN												



OUTPUT marginal cost data for each section

Marginal cost per capacity increase (M€/MWh)																													
dTTC - T00T													dTTC - PINT																
1,400	1,250	1,000	400	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950	1,000	1,050	1,100	1,150	1,200	1,250	1,300	1,350
ITn-ITn	0.7											0.5										0.5							
ITn-ITcs	0.6							0.1				0.1	0.2									0.4					0.4	0.4	
ITcs-ITcs												0.5										0.5							
ITn-ITfs												1.5	1.2									1.5							
ITfsar-ITn							2.5					2.2	2.2									2.2			2.8				
ITfsar-ITcs				2.0			2.3	2.3				2.3	2.3		2.5							2.3			2.5				
ITfsic-ITcs			2.0				2.5					2.5	2.5		2.4							2.5							
ITfsic-ITcal			1.9				2.4					2.4	2.4									2.4			2.6				
ITcal-ITfs												0.5	0.5									0.9					1.0	1.0	
												0.5										0.6							

dTTC - PINT																														
1,400	1,450	1,500	1,550	1,600	1,650	1,700	1,750	1,800	1,850	1,900	1,950	2,000	2,050	2,100	2,150	2,200	2,250	2,300	2,350	2,400	2,450	2,500	2,550	2,600	2,650	2,700	2,750	2,800	2,850	2,900
ITn-ITn												0.5	0.5			0.6	0.5					0.5	0.5		0.5		0.6	0.5		0.6
ITn-ITcs							0.6	0.6				0.6	0.6			0.5	0.5					0.5	0.5		0.5		0.5	0.5		
ITcs-ITcs												1.5	1.5			1.5	1.5					1.5	1.5		1.5		1.5			
ITn-ITfs												1.2	1.2			1.2	1.2		1.2			1.2	1.2		1.2		1.5			
ITfsar-ITn						3.3						3.3	3.3																	
ITfsar-ITcs						3.0						3.0	3.0		3.3															
ITfsic-ITcs						3.0						3.1	3.1																	
ITfsic-ITcal							1.0					1.0	1.0																	
ITcal-ITfs				1.0	1.0									1.0								1.0	1.0				1.0			
dTTC - PINT																														
2,950	3,000	3,050	3,100	3,150	3,200	3,250	3,300	3,350	3,400	3,450	3,500	3,550	3,600	3,650	3,700	3,750	3,800	3,850	3,900	3,950	4,000	4,050	4,100	4,150	4,200	4,300	4,400	4,500	4,550	4,600
ITn-ITn																														
ITn-ITcs													1.0			0.7														
ITcs-ITcs																														
ITn-ITfs																														
ITfsar-ITn																														
ITfsar-ITcs																														
ITfsic-ITcs																														
ITfsic-ITcal																														
ITcal-ITfs																														
dTTC - PINT																														
4,700	4,800	4,900	5,000	5,050	5,100	5,200	5,300	5,400	5,500	5,550	5,600	5,700	5,800	5,900	6,000	6,050	6,100	6,200	6,600	7,000	7,100									
ITn-ITn																														
ITn-ITcs																														
ITcs-ITcs																														
ITn-ITfs																														
ITfsar-ITn																														
ITfsar-ITcs																														
ITfsic-ITcs																														
ITfsic-ITcal																														
ITcal-ITfs																														

Annex 5

Details of information to determine the marginal benefit for each section/border

Table 9 Marginal benefit data of the Policy 2030 scenario for each section/border as a function of the iterations (iterations 0-2)

NECP 2030		ITERATION 0 - TOOT			ITERATION 1 - PINT			ITERATION 2 - PINT		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.3	100	7.5	0.6	500	2.8	0.6	500	3.6
	CH - ITn				0.8	500	0.6	0.8	500	1.0
	FR - ITn				0.9	500	2.2	0.9	500	2.7
	SI - ITn				0.5	500	0.0	0.5	500	0.4
Balkan border	ME - ITcs				1.1	500	1.8	1.4	1000	1.0
	ITs - GR				1.3	500	1.8	1.3	500	1.7
North Africa border	ITsic - TUN				-	500	2.2	-	1000	0.8
Internal sections	ITcn - ITn	0.7	1400	5.0	0.5	500	3.4	0.5	1000	3.2
	ITcs - ITcn	0.6	1400	5.6	0.1	500	4.8	0.4	1000	1.8
	ITs - ITcs				0.5	500	2.5	0.5	1000	2.3
	ITn - ITcs				1.5	500	1.7	1.5	1000	1.6
	ITn - ITs				1.2	500	3.8	1.2	1000	3.0
	ITsar - ITcn	2.0	400	2.1	2.5	500	0.7	2.5	500	0.7
	ITsar - ITcs				2.3	500	0.8	2.3	500	0.8
	ITsar - ITsic	2.0	1000	1.3	2.5	500	0.1	2.5	500	0.2
	ITsic - ITcs	1.9	1000	1.7	2.4	500	0.9	2.4	500	0.8
	ITsic - ITcal				0.5	500	4.6	0.9	1000	1.0
	ITcal - ITs				0.5	500	0.4	0.5	500	1.5

Table 10 Marginal benefit data of the Policy 2030 scenario for each section/border as a function of the iterations (iterations 3-5)

NECP 2030		ITERATION 3 - PINT			ITERATION 4 - PINT			ITERATION 5 - PINT		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.6	500	3.3	0.6	500	3.2	0.6	500	3.0
	CH - ITn	0.8	500	0.8	0.8	500	0.8	0.8	500	0.7
	FR - ITn	0.9	500	2.5	0.9	500	2.4	0.9	500	2.4
	SI - ITn	0.5	500	0.1	0.5	500	0.0	0.5	500	0.0
Balkan border	ME - ITcs	1.4	1000	0.6	1.4	1000	0.5	1.4	1000	0.4
	ITs - GR	1.3	500	1.2	1.3	500	0.9	1.3	500	0.7
North Africa border	ITsic - TUN	-	1000	0.5	-	1000	0.1	-	1000	0.0
Internal sections	ITcn - ITn	0.5	1500	2.2	0.5	2000	1.4	0.5	2500	0.6
	ITcs - ITcn	0.5	1500	0.7	0.5	1500	1.0	0.5	1500	1.0
	ITs - ITcs	0.5	1500	1.7	0.5	2000	1.0	0.5	2500	0.5
	ITn - ITcs	1.5	1500	0.7	1.5	1500	0.7	1.5	1500	0.5
	ITn - ITs	1.2	1500	1.9	1.2	2000	1.3	1.2	2500	0.6
	ITsar - ITcn	2.5	500	0.5	2.5	500	0.5	2.5	500	0.5
	ITsar - ITcs	2.3	500	0.9	2.3	500	0.9	2.3	500	0.8
	ITsar - ITsic	2.5	500	0.1	2.5	500	0.0	2.5	500	0.0
	ITsic - ITcs	2.4	500	0.7	2.4	500	0.6	2.4	500	0.6
	ITsic - ITcal	0.9	1000	1.6	1.0	1500	0.7	1.0	1500	0.5
	ITcal - ITs	0.6	1000	0.7	0.6	1000	0.9	0.6	1000	1.3

Table 11 Marginal benefit data of the Policy 2030 scenario for each section/border as a function of the iterations (iterations 6-8)

NECP 2030		ITERATION 6 - PINT			ITERATION 7 - halved PINT			ITERATION 8 - halved PINT		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.6	500	3.1	0.5	250	3.7	0.5	250	3.3
	CH - ITn	0.8	500	0.8	0.8	250	1.1	0.8	250	1.0
	FR - ITn	0.9	500	2.4	0.9	250	2.2	0.9	250	2.1
	SI - ITn	0.5	500	0.0	0.5	250	0.0	0.5	250	0.0
Balkan border	ME - ITcs	1.4	1000	0.4	1.3	750	0.3	1.3	750	0.1
	ITs - GR	1.3	500	0.8	1.3	250	0.5	1.3	250	0.5
North Africa border	ITsic - TUN	-	1000	0.0	-	750	0.0	-	750	0.0
Internal sections	ITcn - ITn	0.5	2500	0.2	0.5	2250	0.5	0.5	2250	0.5
	ITcs - ITcn	0.5	1500	0.6	0.4	1250	0.4	0.4	1250	0.8
	ITs - ITcs	0.5	2500	0.4	0.5	2250	0.6	0.5	2250	0.3
	ITn - ITcs	1.5	1500	0.5	1.5	1250	0.4	1.5	1250	0.3
	ITn - ITs	1.2	2500	0.5	1.2	2250	0.5	1.2	2250	0.5
	ITsar - ITcn	2.5	500	0.5	2.5	250	0.4	2.5	250	0.5
	ITsar - ITcs	2.3	500	0.7	2.3	250	0.8	2.3	250	0.7
	ITsar - ITsic	2.5	500	0.0	2.5	250	0.0	2.5	250	0.0
	ITsic - ITcs	2.4	500	0.5	2.4	250	0.5	2.4	250	0.4
	ITsic - ITcal	1.0	1500	0.7	1.0	1250	1.0	1.0	1500	0.7
	ITcal - ITs	1.0	1500	0.3	1.0	1250	0.1	1.0	1250	0.1

Table 12 *Marginal benefit data of Montenegro sensitivity in the Policy 2030 scenario for each section/ border as a function of the iterations (iterations 9-11)*

NECP 2030		ITERATION 9 - halved PINT ME sensitivity			ITERATION 10 - halved PINT ME sensitivity			ITERATION 11 - halved PINT ME sensitivity		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.5	250	3.9	0.5	250	3.8	0.5	250	3.0
	CH - ITn	0.8	250	1.2	0.8	250	1.2	0.8	250	0.8
	FR - ITn	0.9	250	2.5	0.9	250	2.7	0.9	250	2.3
	SI - ITn	0.5	250	0.3	0.5	250	0.5	0.5	250	0.0
Balkan border	ME - ITcs	1.1	250	1.2	1.1	250	1.1	1.1	250	0.9
	ITs - GR	1.3	250	0.9	1.3	250	0.9	1.3	250	0.6
North Africa border	ITsic - TUN	-	750	0.3	-	750	0.4	-	750	0.3
Internal sections	ITcn - ITn	0.5	2250	1.3	0.5	2500	1.0	0.5	2750	0.0
	ITcs - ITcn	0.4	1250	1.8	0.5	1500	0.8	0.5	1500	0.0
	ITs - ITcs	0.5	2250	1.2	0.5	2500	1.1	0.5	2750	0.7
	ITn - ITcs	1.5	1250	0.7	1.5	1250	0.7	1.5	1250	0.1
	ITn - ITs	1.2	2250	0.9	1.2	2250	0.8	1.2	2250	0.4
	ITsar - ITcn	2.5	250	0.8	2.5	250	0.7	2.5	250	0.5
	ITsar - ITcs	2.3	250	0.9	2.3	250	1.0	2.3	250	0.5
	ITsar - ITsic	2.5	250	0.1	2.5	250	0.2	2.5	250	0.0
	ITsic - ITcs	2.4	250	0.5	2.4	250	0.5	2.4	250	0.5
	ITsic - ITcal	1.0	1500	1.1	1.0	1750	0.7	1.0	1750	0.0
	ITcal - ITs	1.0	1250	0.6	1.0	1250	0.9	1.0	1250	0.6

Table 13 *Marginal benefit data of Border sensitivity in the Policy 2030 scenario for each section/border as a function of the iterations (iterations 8-11)*

NECP 2030		ITERATION 8 - halved PINT Border sensitivity			ITERATION 9 - halved PINT Border sensitivity			ITERATION 10 - halved PINT Border sensitivity			ITERATION 11 - halved PINT Border sensitivity		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.6	500	3.4	0.7	750	2.4	0.7	1000	1.6	1.0	1250	1.3
	CH - ITn	0.8	250	0.9	0.8	250	0.9	0.8	250	0.7	0.8	250	1.0
	FR - ITn	0.9	500	2.6	1.0	750	1.6	1.0	750	1.3	1.0	750	1.8
	SI - ITn	0.5	250	0.3	0.5	250	0.7	0.5	250	0.1	0.5	250	0.3
Balkan border	ME - ITcs	1.3	750	0.5	1.3	750	0.6	1.3	750	0.4	1.3	750	0.4
	ITs - GR	1.3	250	1.0	1.3	250	1.0	1.3	500	0.9	1.3	500	0.7
North Africa border	ITsic - TUN	-	750	0.2	-	750	0.5	-	750	0.2	-	750	0.3

Table 14 *Marginal benefit data of Border sensitivity in the Policy 2030 scenario for each section/border as a function of the iterations (iterations 12-14)*

NECP 2030		ITERATION 12 - halved PINT Border sensitivity			ITERATION 13 - halved PINT Border sensitivity			ITERATION 14 - halved PINT Border sensitivity		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	1.0	1500	1.4	1.3	1750	1.0	1.3	2000	0.2
	CH - ITn	0.8	250	0.8	0.8	250	1.0	0.8	500	0.0
	FR - ITn	1.0	750	1.9	1.0	750	2.1	1.0	750	0.5
	SI - ITn	0.5	250	0.0	0.5	250	0.0	0.5	250	0.0
Balkan border	ME - ITcs	1.3	750	0.3	1.3	750	0.2	1.3	750	0.2
	ITs - GR	1.3	500	0.6	1.3	500	0.7	1.3	500	0.6
North Africa border	ITsic - TUN	-	750	0.2	-	750	0.3	-	750	0.0

Table 15 *Marginal benefit data of Storage sensitivity in the Policy 2030 scenario for each section/border as a function of the iterations (iterations 9-11)*

NECP 2030		ITERATION 9 - PINT Storage sensitivity			ITERATION 10 - PINT Storage sensitivity			ITERATION 11 - halved PINT Storage sensitivity		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.8	500	2.2	0.8	500	2.4	0.7	250	1.3
	CH - ITn	1.6	500	0.5	1.6	500	0.5	1.6	250	0.4
	FR - ITn	0.9	500	2.2	0.9	500	2.3	0.9	250	2.3
	SI - ITn	0.5	500	0.4	0.5	500	0.4	0.5	250	0.1
Balkan border	ME - ITcs	1.4	1000	0.6	1.4	1000	0.6	1.3	750	0.7
	ITs - GR	1.3	500	1.2	1.3	500	1.1	1.3	250	0.8
North Africa border	ITsic - TUN	-	1000	0.3	-	1000	0.3	1.3	750	0.5
Internal sections	ITcn - ITn	0.5	2500	0.9	0.5	2500	0.8	0.5	2250	0.9
	ITcs - ITcn	0.5	1500	1.2	0.6	2000	0.4	0.6	1750	0.2
	ITs - ITcs	0.5	2500	2.0	0.6	3000	0.9	0.5	2750	0.8
	ITn - ITcs	1.5	1500	0.6	1.5	1500	0.6	1.5	1250	0.6
	ITn - ITs	1.2	2500	1.3	1.2	2600	1.1	1.2	2350	1.1
	ITsar - ITcn	2.5	500	0.6	2.5	500	0.3	2.5	250	0.3
	ITsar - ITcs	2.3	500	0.9	2.3	500	0.8	2.3	250	0.8
	ITsar - ITsic	2.5	500	0.5	2.5	500	0.4	2.5	250	0.5
	ITsic - ITcs	2.4	500	1.0	2.4	500	0.9	2.4	250	1.0
	ITsic - ITcal	1.0	1750	1.0	1.0	1750	0.9	1.0	1500	1.1
	ITcal - ITs	1.0	1500	1.0	1.0	1500	0.7	1.0	1250	0.6

Table 16 *Marginal benefit data of Storage sensitivity in the Policy 2030 scenario for each section/border as a function of the iterations (iterations 12-14)*

NECP 2030		ITERATION 12 - halved PINT Storage sensitivity			ITERATION 13 - halved PINT Storage sensitivity			ITERATION 14 - halved PINT Storage sensitivity		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.7	250	2.5	0.7	250	2.6	0.7	250	2.2
	CH - ITn	1.6	250	0.4	1.6	250	0.4	1.6	250	0.2
	FR - ITn	0.9	250	2.4	0.9	250	2.4	0.9	250	2.2
	SI - ITn	0.5	250	0.4	0.5	250	0.4	0.5	250	0.1
Balkan border	ME - ITcs	1.3	750	0.8	1.3	750	0.8	1.3	750	0.8
	ITs - GR	1.3	250	0.9	1.3	250	1.0	1.3	250	1.1
North Africa border	ITsic - TUN	-	750	0.7	-	750	0.7	-	750	0.4
Internal sections	ITcn - ITn	0.5	2250	1.3	0.5	2500	1.4	0.5	2750	0.6
	ITcs - ITcn	0.6	1750	0.2	0.6	1750	1.5	0.6	2000	0.1
	ITs - ITcs	0.5	2750	1.2	0.6	3000	1.4	0.7	3250	0.4
	ITn - ITcs	1.5	1250	0.7	1.5	1250	0.9	1.5	1250	0.5
	ITn - ITs	1.2	2350	1.3	1.2	2350	1.6	1.2	2350	0.9
	ITsar - ITcn	2.5	250	0.5	2.5	250	0.6	2.5	250	0.4
	ITsar - ITcs	2.3	250	0.9	2.3	250	1.0	2.3	250	0.9
	ITsar - ITsic	2.5	250	0.4	2.5	250	0.6	2.5	250	0.4
	ITsic - ITn	2.4	250	0.6	2.4	250	1.2	2.4	250	0.8
	ITsic - ITcal	1.0	1750	0.7	1.0	1750	1.6	1.0	2000	0.9
	ITcal - ITs	1.0	1250	1.1	1.0	1500	1.2	1.0	1500	1.0

Table 17 *Marginal benefit data of the Inertial 2040 scenario for each section/border as a function of the iterations (iterations 1-5)*

NECP slow 2040		ITERATION 1 - PINT			ITERATION 2 - PINT			ITERATION 3 - PINT			ITERATION 4 - PINT			ITERATION 5 - PINT		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	0.6	500	5.5	0.7	1000	3.6	1.0	1500	2.5	1.3	2000	1.8	1.3	2480	1.0
	CH - ITn	0.8	500	3.8	0.8	1000	2.8	1.6	1500	0.2	1.6	1500	0.3	1.6	1500	0.2
	FR - ITn	0.9	500	2.5	1.1	1000	3.1	1.1	1000	3.0	1.1	1000	3.0	1.1	1000	3.5
	SI - ITn	0.5	500	0.8	0.5	500	0.9	0.5	500	1.8	0.5	1000	0.2	0.5	1000	1.8
Balkan border	ME - ITcs	1.4	1050	0.2	1.4	1050	0.6	1.4	1050	0.6	1.4	1050	0.6	1.4	1050	0.5
	ITs - GR	1.3	500	2.0	1.3	1000	1.3	1.6	1500	1.0	1.6	1500	0.6	1.6	1500	0.5
North Africa border	ITsic - TUN	-	1000	6.5	-	1500	2.8	-	1800	2.5	-	1800	2.6	-	1800	2.5
Internal sections	ITcn - ITn	0.5	2600	0.0	0.5	2600	1.1	0.5	2600	2.3	0.7	3100	0.6	0.7	3100	1.5
	ITcs - ITcn	0.6	1700	1.1	0.6	1700	1.0	0.6	1700	0.7	0.6	1700	0.7	0.6	1700	0.4
	ITs - ITcs	0.5	2550	0.8	0.5	2550	1.0	0.5	2550	1.7	0.7	3050	1.4	0.8	3550	0.7
	ITn - ITcs	1.5	1550	1.1	1.5	1550	1.3	1.5	2050	1.3	1.5	2550	0.8	1.5	2550	0.7
	ITn - ITs	1.2	2600	2.5	1.2	2600	2.2	1.2	2600	1.5	1.2	2600	1.9	1.2	2600	2.0
	ITsar - ITcn	2.5	650	2.6	2.8	1150	1.2	3.3	1650	0.7	3.3	1650	0.6	3.3	1650	0.6
	ITsar - ITcs	2.3	650	2.8	2.5	1150	1.3	3.0	1650	0.6	3.0	1650	0.6	3.0	1650	0.7
	ITsar - ITsic	2.5	500	0.0	2.5	500	0.0	2.5	500	0.3	2.5	500	0.1	2.5	500	0.1
	ITsic - ITcs	2.4	600	1.6	2.4	600	1.1	2.4	600	1.0	2.4	600	0.8	2.4	600	0.8
	ITsic - ITcal	1.0	1950	2.6	1.0	2450	0.8	1.0	2450	1.5	1.5	2950	0.5	1.5	2950	1.3
	ITcal - ITs	1.0	1550	0.8	1.0	1550	1.2	1.0	2050	1.1	1.0	2050	0.8	1.0	2050	0.7

Table 18 *Marginal benefit data of the Inertial 2040 scenario for each section/border as a function of the iterations (iterations 6-9)*

NECP slow 2040		ITERATION 6 - PINT			ITERATION 7 - PINT			ITERATION 8 - PINT			ITERATION 9 - PINT		
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	1.3	2480	0.8	1.3	2480	0.8	1.3	2480	0.8	1.3	2480	1.0
	CH - ITn	1.6	1500	0.5	1.6	1500	0.5	1.6	1500	0.6	1.6	1500	0.4
	FR - ITn	1.1	1000	3.0	1.1	1000	2.6	1.1	1000	2.8	1.1	1000	2.5
	SI - ITn	0.8	1500	0.5	0.8	1500	0.5	0.8	1500	0.6	0.8	1500	0.1
Balkan border	ME - ITcs	1.4	1050	0.7	1.4	1050	0.9	1.4	1050	0.7	1.4	1050	0.5
	ITs - GR	1.6	1500	0.7	1.6	1500	0.4	1.6	1500	0.3	1.6	1500	0.2
North Africa border	ITsic - TUN	-	1600	2.2	-	1600	1.8	-	1600	2.0	-	1600	1.6
Internal sections	ITcn - ITn	1.0	3600	0.7	1.0	3600	0.6	1.0	3600	1.2	1.0	4100	0.3
	ITcs - ITcn	0.6	1700	1.1	0.6	2200	1.1	0.6	2700	0.2	0.6	2700	0.0
	ITs - ITcs	0.8	3550	1.3	1.0	4050	0.3	1.0	4050	0.3	1.0	4050	0.0
	ITn - ITcs	1.5	2550	1.5	1.5	2600	0.7	1.5	2600	0.7	1.5	2600	0.3
	ITn - ITs	1.2	2600	1.3	1.2	2600	1.4	1.2	2600	1.0	1.2	2600	1.0
	ITsar - ITcn	3.3	1650	0.5	3.3	1650	0.7	3.3	1650	0.5	3.3	1650	0.4
	ITsar - ITcs	3.0	1650	0.5	3.0	1650	0.7	3.0	1650	0.7	3.0	1650	0.4
	ITsar - ITsic	2.5	500	0.3	2.5	500	0.1	2.5	500	0.3	2.5	500	0.0
	ITsic - ITcs	2.4	600	0.8	2.4	600	0.8	2.4	600	0.5	2.4	600	0.8
	ITsic - ITcal	2.8	3450	0.2	2.8	3450	0.2	2.8	3450	0.0	2.8	3450	0.0
	ITcal - ITs	1.0	2050	1.2	1.0	2550	0.8	1.0	2550	0.8	1.0	2550	0.2



Table 19 Marginal benefit data of the Policy 2040 scenario for each section/border as a function of the iterations (iterations 1-5)

DE2040				ITERATION 1 - PINT				ITERATION 2 - PINT				ITERATION 3 - PINT				ITERATION 4 - PINT				ITERATION 5 - PINT			
Sections/Borders				Cost	B/C	Capacity	B/C	Cost	B/C	Capacity	B/C	Cost	B/C	Capacity	B/C	Cost	B/C	Capacity	B/C	Cost	B/C	Capacity	B/C
				Marg [M€/MW]	[MW]		[MW]	Marg [M€/MW]		[MW]	Marg [M€/MW]		[MW]	Marg [M€/MW]		[MW]	Marg [M€/MW]		[MW]	Marg [M€/MW]		[MW]	Marg [M€/MW]
Northern border	AT - ITn		0.6	500	8.7	1000	3.5	0.7	1000	2.4	1.0	1500	2.4	1.3	2000	1.9	1.3	2480	1.3	2480	1.3	2480	1.5
	CH - ITn		0.8	500	2.7	1000		0.8	1000	0.6	1.6	1500	0.6	1.6	1500	0.6	1.6	1500	0.6	1500	0.7	1500	0.7
	FR - ITn		0.9	500	3.7	1000	3.2	1.1	1000	3.2	1.1	1000	3.2	1.1	1000	3.4	1.1	1000	1.1	1000	3.5	1000	3.5
	SI - ITn		0.5	500	2.2	1000	0.0	0.5	1000	0.0	0.5	1000	0.0	0.5	1000	0.0	0.5	1000	0.0	1000	0.0	1000	0.0
Balkan border	ME - ITcs		1.4	1050	1.8	1050	0.7	1.4	1050	0.3	1.4	1050	0.3	1.4	1050	0.4	1.4	1050	0.4	1050	1.4	1050	0.4
	ITs - GR		1.3	500	4.0	1000	1.7	1.3	1000		1.6	1500	0.3	1.6	1500	0.4	1.6	1500	0.4	1500	1.6	1500	0.2
North Africa border	ITsic - TUN		-	1000	5.8	1500	4.3	-	1500	2.9	-	1600	2.9	-	1600	2.6	-	1600	2.3	1600	-	1600	2.3
	ITn - ITn		0.5	2800	2.0	2800	2.9	0.7	2800	2.4	0.7	3100	2.4	1.0	3600	1.2	1.0	4100	0.7	4100	1.0	4100	0.7
Internal sections	ITcs - ITcn		0.6	1700	5.1	2200	1.7	0.6	2200	1.5	0.6	2200	1.5	0.6	2700	1.3	0.6	3200	1.3	3200	0.6	3200	1.3
	ITs - ITcs		0.5	2550	4.7	3050	2.7	0.7	3050	1.2	0.8	3550	1.2	1.0	4050	0.4	1.0	4050	0.4	4050	1.0	4050	0.0
	ITn - ITcs		1.5	1950	3.0	2050	2.3	1.5	2050	1.8	1.5	2550	1.8	1.5	2600	1.5	1.5	2600	1.2	2600	1.5	2600	1.2
	ITn - ITs		1.2	2800	6.0	2800	3.6	1.2	2800	3.1	1.2	2800	3.1	1.2	2800	2.2	1.2	2800	1.8	2800	1.2	2800	1.8
	ITsar - ITcn		2.5	650	3.9	2.8	1150	2.1	3.3	1650	1.0	3.3	1650	0.7	3.3	1650	0.6	3.3	1650	0.6	3.3	1650	0.6
	ITsar - ITcs		2.3	650	3.8	2.5	1150	1.8	3.0	1650	1.2	3.3	1650	0.5	3.3	1650	0.5	3.3	1650	0.5	3.3	1650	0.5
	ITsar - ITsic		2.5	500	0.0	500	0.0	2.5	500	0.0	2.5	500	0.0	2.5	500	0.0	2.5	500	0.0	500	2.5	500	0.0
	ITsic - ITcs		2.4	600	2.2	2.4	600	1.4	2.4	600	1.3	2.6	1000	0.6	2.6	1000	0.4	2.6	1000	0.4	2.6	1000	0.4
	ITsic - ITcal		1.0	1950	2.8	1.0	2450	1.3	1.0	2450	1.5	1.5	2950	0.6	1.5	2950	0.6	1.5	2950	0.6	1.5	2950	0.6
	ITcal - ITs		1.0	1550	1.4	1.0	1550	1.8	1.0	1550	0.9	1.0	2050	1.0	1.0	2050	1.0	1.0	2550	0.2	2550	1.0	2550

Table 20 Marginal benefit data of the Policy 2040 scenario for each section/border as a function of the iterations (iterations 6-9)

DE2040				ITERATION 6 - PINT			ITERATION 7 - PINT			ITERATION 8 - PINT			ITERATION 9 - PINT			
Sections/Borders		Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C	Cost Marg [M€/MW]	Capacity [MW]	B/C
Northern border	AT - ITn	1.3	2480	1.5	1.3	2480	1.9	1.3	2480	1.9	1.3	2480	1.9	1.3	2480	1.5
	CH - ITn	1.6	1500	0.6	1.6	1500	0.7	1.6	1500	0.8	1.6	1500	0.8	1.6	1500	0.6
	FR - ITn	1.1	1000	3.3	1.1	1000	3.8	1.1	1000	3.7	1.1	1000	3.7	1.1	1000	3.3
	SI - ITn	0.5	1000	0.0	0.5	1000	0.0	0.5	1000	0.0	0.5	1000	0.0	0.5	1000	0.0
Balkan border	ME - ITcs	1.4	1050	0.2	1.4	1050	0.3	1.4	1050	0.3	1.4	1050	0.1	1.4	1050	0.4
North Africa border	ITs - GR	1.6	1500	0.4	1.6	1500	0.4	1.6	1500	0.1	1.6	1500	0.1	1.6	1500	0.2
	ITsic - TUN	-	1600	2.4	-	1600	2.3	-	1600	2.3	-	1600	2.3	-	1600	2.4
Internal sections	ITcn - ITn	1.0	4100	1.2	1.0	4600	1.0	1.1	5100	1.0	1.1	5100	1.0	1.1	5100	0.5
	ITcs - ITcn	0.7	3700	0.9	0.7	3700	0.8	0.7	3700	1.3	0.8	4200	1.3	0.8	4200	0.7
	ITs - ITcs	1.0	4050	0.0	1.0	4050	0.5	1.0	4050	0.1	1.0	4050	0.1	1.0	4050	0.0
	ITn - ITcs	1.5	2600	1.3	1.5	2600	0.9	1.5	2600	0.7	1.5	2600	0.7	1.5	2600	0.8
	ITn - ITs	1.2	2600	2.0	1.2	2600	2.1	1.2	2600	1.7	1.2	2600	1.7	1.2	2600	1.2
	ITsar - ITcn	3.3	1650	0.5	3.3	1650	0.6	3.3	1650	0.7	3.3	1650	0.7	3.3	1650	0.6
	ITsar - ITcs	3.3	2150	0.5	3.3	2150	0.5	3.3	2150	0.5	3.3	2150	0.5	3.3	2150	0.4
	ITsar - ITsic	2.5	500	0.0	2.5	500	0.0	2.5	500	0.0	2.5	500	0.0	2.5	500	0.0
	ITsic - ITcs	2.6	1100	0.5	2.6	1100	0.5	2.6	1100	0.5	2.6	1100	0.5	2.6	1100	0.5
	ITsic - ITcal	1.5	2950	0.6	1.5	2950	0.7	1.5	2950	0.7	1.5	2950	0.7	1.5	2950	0.2
ITcal - ITs	1.0	2550	0.6	1.0	2550	0.7	1.0	2550	0.4	1.0	2550	0.4	1.0	2550	0.2	

Table 21 Marginal benefit data of Electrolyser sensitivity in the Policy 2040 scenario for each section/border as a function of the iterations
(iterations 9-13)

DE 2040	Sections/Borders	ITERATION 9 - PINT Electrolyser Sensitivity				ITERATION 10 - PINT Electrolyser Sensitivity				ITERATION 11 - PINT Electrolyser Sensitivity				ITERATION 12 - PINT Electrolyser Sensitivity				ITERATION 13 - PINT Electrolyser Sensitivity			
		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C	
Northern border	AT - ITn	1.3	2480	2.0		1.3	2480	1.8		1.3	2480	1.4		1.3	2480	1.7		1.3	2480	1.6	
	CH - ITn	1.6	1500	0.8		1.6	1500	0.5		1.6	1500	0.4		1.6	1500	0.3		1.6	1500	0.3	
	FR - ITn	1.1	1000	3.4		1.1	1000	2.8		1.1	1000	2.7		1.1	1000	2.3		1.1	1000	2.5	
	SI - ITn	0.5	1000	0.0		0.5	1000	0.0		0.5	1000	0.0		0.5	1000	0.0		0.5	1000	0.0	
Balkan border	ME - ITcs	1.4	1050	1.3		1.5	1550	0.0		1.5	1550	0.0		1.5	1550	0.0		1.5	1550	0.0	
	ITs - GR	1.6	1500	1.0		1.6	1500	1.0		1.6	2000	1.4		1.6	2000	1.2		1.6	2000	1.1	
North Africa border	ITsic - TUN	-	1600	4.1		-	1600	3.5		-	1600	3.8		-	1600	4.0		-	1600	3.6	
	ITcn - ITn	1.1	5100	1.6		1.3	5800	1.0		1.3	5800	1.4		1.4	6100	0.5		1.4	6100	1.1	
Internal sections	ITcs - ITcn	0.8	4200	1.6		0.8	4700	1.0		0.8	4700	0.9		0.8	4700	1.7		0.8	5200	0.7	
	ITs - ITcs	1.0	4050	1.5		1.0	4550	0.8		1.0	4550	1.2		1.0	5050	0.8		1.0	5050	0.5	
	ITn - ITcs	1.5	2600	2.1		1.5	2600	1.1		1.5	2600	1.3		1.5	2600	1.3		1.5	2600	1.2	
	ITn - ITs	1.2	2600	3.8		1.2	2600	2.4		1.2	2600	3.5		1.2	2600	2.6		1.2	2600	2.9	
	ITsar - ITcn	3.3	1650	0.6		3.3	1650	0.5		3.3	1650	0.6		3.3	1650	0.8		3.3	1650	0.7	
	ITsar - ITcs	3.3	2150	0.5		3.3	2150	0.2		3.3	2150	0.5		3.3	2150	0.6		3.3	2150	0.6	
	ITsar - ITsic	2.5	500	0.0		2.5	500	0.0		2.5	500	0.0		2.5	500	0.0		2.5	500	0.0	
	ITsic - ITcs	2.6	1100	0.9		2.6	1100	0.6		2.6	1100	0.8		2.6	1100	0.9		2.6	1100	0.9	
	ITsic - ITcat	1.5	2950	0.4		1.5	2950	0.6		1.5	2950	0.5		1.5	2950	0.6		1.5	2950	0.4	
	ITcat - ITs	1.0	2550	0.8		1.0	2550	0.2		1.0	2550	0.4		1.0	2550	0.4		1.0	2550	1.0	

Table 22 Marginal benefit data of Electrolyser sensitivity in the Policy 2040 scenario for each section/border as a function of the iterations
(iterations 14-17)

DE 2040	Sections/Borders	ITERATION 14 - PINT Electrolyser Sensitivity				ITERATION 15 - PINT Electrolyser Sensitivity				ITERATION 16 - PINT Electrolyser Sensitivity				ITERATION 17 - PINT Electrolyser Sensitivity			
		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C		Cost Marg [M€/MW]	Capacity [MW]	B/C	
Northern border	AT - ITn	1.3	2480	1.7		1.3	2480	1.9		1.3	2480	1.6		1.3	2480	1.4	
	CH - ITn	1.6	1500	0.6		1.6	1500	0.4		1.6	1500	0.3		1.6	1500	0.4	
	FR - ITn	1.1	1000	2.9		1.1	1000	2.7		1.1	1000	2.5		1.1	1000	2.2	
	SI - ITn	0.5	1000	0.0		0.5	1000	0.0		0.5	1000	0.0		0.5	1000	0.0	
Balkan border	ME - ITcs	1.5	1550	0.0		1.5	1550	0.0		1.5	1550	0.0		1.5	1550	0.0	
	ITs - GR	1.6	2000	1.4		1.6	2000	1.0		1.6	2000	1.0		1.6	2000	0.6	
North Africa border	ITsic - TUN	-	1600	3.7		-	1600	3.5		-	1600	3.2		-	1600	3.1	
	ITcn - ITn	1.7	6600	0.4		1.7	6600	0.5		1.7	6600	0.7		1.7	6600	0.9	
Internal sections	ITcs - ITcn	0.8	5200	1.3		0.8	5700	1.2		0.8	6200	0.0		0.8	6200	0.0	
	ITs - ITcs	1.0	5050	1.3		1.0	5550	0.3		1.0	5550	1.0		1.1	6050	0.0	
	ITn - ITcs	1.5	2600	1.5		1.5	2600	1.2		1.5	2600	0.9		1.5	2600	0.8	
	ITn - ITs	1.2	2600	2.5		1.2	2600	2.5		1.2	2600	2.5		1.2	2600	1.6	
	ITsar - ITcn	3.3	1650	0.7		3.3	1650	0.5		3.3	1650	0.3		3.3	1650	0.4	
	ITsar - ITcs	3.3	2150	0.6		3.3	2150	0.4		3.3	2150	0.5		3.3	2150	0.3	
	ITsar - ITsic	2.5	500	0.0		2.5	500	0.0		2.5	500	0.0		2.5	500	0.0	
	ITsic - ITcs	2.6	1100	0.8		2.6	1100	0.7		2.6	1100	0.7		2.6	1100	0.5	
	ITsic - ITcat	1.5	2950	0.5		1.5	2950	0.9		1.5	2950	0.5		1.5	2950	0.8	
	ITcat - ITs	1.0	3050	0.2		1.0	3050	0.5		1.0	3050	0.2		1.0	3050	0.2	

MRE marginal benefit data for each section/boundary - Policy 2030 and 2040

		GTC - FPA1																																
		160	250	500	600	650	1,000	1,250	1,500	1,550	1,700	1,750	1,850	2,000	2,050	2,200	2,250	2,400	2,500	2,600	2,700	2,750	2,800	3,000	3,050	3,100	3,200	3,250	3,500	3,600	3,800	4,000		
Sections/Roads	AT - trf	0.00					0.01																											
	CH - trf		0.01																															
	RR - trf																																	
	SI - trf			0.00																														
	HE - trfcs		0.02			0.02																												
Balkan border	frs - GR																																	
	frs - TUN			0.00	0.00																													
	frs - ITN			0.01			0.01							0.01																				
	frs - ITN			0.00	0.00		0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.01																				
North Africa border	frs - ITN			0.00			0.02	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.02			0.02	0.02						0.02																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00	0.00						0.00																				
Internal sections	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITN			0.00			0.00	0.00						0.00																				
	frs - ITCS			0.00			0.00																											

VRE marginal benefit data for each section/border - Inertial 2040

[illegible]

Key

PINT=YES	+step B/C>1	SIMULATION PERFORMED	ME: time in hours (h) spent on energy market simulations using the “Promed” zonal market simulator;
PINT=YES	+step B/C>1	SIMULATION PERFORMED	
PINT=YES	+step B/C<1	SIMULATION PERFORMED	MSD: time in hours (h) used for simulations on the dispatching and balancing services market via the “Modis” simulator.
PINT=YES	+step B/C>1	SIMULATION PERFORMED	

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Table 25 Average simulation times for each section/border at each iteration in the Policy 2030 scenario (Iteration 1-4)

NECP2030		ITERATION 1- PINT		ITERATION 2- PINT		ITERATION 3- PINT		ITERATION 4- PINT	
Northern border	AT - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00
	CH - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00
	FR - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00
	SI - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00
Balkan border	ME - ITcs	ME	07:00	ME	07:00	ME	07:00	ME	07:00
	ITs - GR	ME	07:00	ME	07:00	ME	07:00	ME	07:00
North Africa border	ITsic - TUN	ME	07:00	ME	07:00	ME	07:00	ME	07:00
Internal sections	ITcn - ITn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITcs - ITcn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITs - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITn - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITn - ITs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITsar - ITcn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITsar - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITsar - ITsic	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITsic - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITsic - ITcal	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
	ITcal - ITs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00
Total		148:00:00		148:00:00		148:00:00		148:00:00	



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Table 26 *Average simulation times for each section/border at each iteration in the Policy 2030 scenario (Iteration 5-8)*

NECP 2030		ITERATION 5 - PINT		ITERATION 6 - PINT		ITERATION 7 - halved PINT		ITERATION 8 - halved PINT		SIMULATION TIMES
Northern border	AT - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
	CH - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
	FR - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
	SI - ITn	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
Balkan border	ME - ITcs	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
	ITs - GR	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
North Africa border	ITsic - TUN	ME	07:00	ME	07:00	ME	07:00	ME	07:00	56:00:00
Internal sections	ITcn - ITn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITcs - ITcn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITs - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITn - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITn - ITs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITsar - ITcn	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITsar - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITsar - ITsic	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITsic - ITcs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITsic - ITcal	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
	ITcal - ITs	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	ME MSD	09:00	72:00:00
Total		148:00:00		148:00:00		148:00:00		148:00:00		1184:00:00

Table 27 *Average simulation times for each section/border at each iteration in the Inertial 2040 scenario (Iteration 1-5)*

NECPslow 2040		ITERATION 1 - PINT		ITERATION 2 - PINT		ITERATION 3 - PINT		ITERATION 4 - PINT		ITERATION 5 - PINT	
Northern border	AT - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	CH - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	FR - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	SI - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
Balkan border	ME - ITcs	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	ITs - GR	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
North Africa border	ITsic - TUN	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
Internal sections	ITcn - ITn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITcs - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITs - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITn - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITn - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITsic	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsic - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsic - ITcal	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITcal - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
Total		202:00:00		202:00:00		202:00:00		202:00:00		202:00:00	

Table 28 *Average simulation times for each section/border at each iteration in the Inertial 2040 scenario (Iteration 6-9)*

NECPslow 2040		ITERATION 6 - PINT		ITERATION 7 - PINT		ITERATION 8 - PINT		ITERATION 9 - PINT		SIMULATION TIMES
Northern border	AT - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	CH - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	FR - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	SI - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
Balkan border	ME - ITcs	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	ITs - GR	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
North Africa border	ITsic - TUN	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
Internal sections	ITcn - ITn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITcs - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITs - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITn - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITn - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITsic	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsic - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsic - ITcal	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITcal - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
Total		202:00:00		202:00:00		202:00:00		202:00:00		1818:00:00

Table 29 *Average simulation times for each section/border at each iteration in the Policy 2040 scenario (Iteration 1-5)*

DE 2040		ITERATION 1 - PINT		ITERATION 2 - PINT		ITERATION 3 - PINT		ITERATION 4 - PINT		ITERATION 5 - PINT	
Northern border	AT - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	CH - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	FR - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	SI - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
Balkan border	ME - ITcs	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
	ITs - GR	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
North Africa border	ITsic - TUN	ME	10:00	ME	10:00	ME	10:00	ME	10:00	ME	10:00
Internal sections	ITcn - ITn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITcs - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITs - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITn - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITn - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsar - ITsic	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsic - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITsic - ITcal	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
	ITcal - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00
Total		202:00:00		202:00:00		202:00:00		202:00:00		202:00:00	

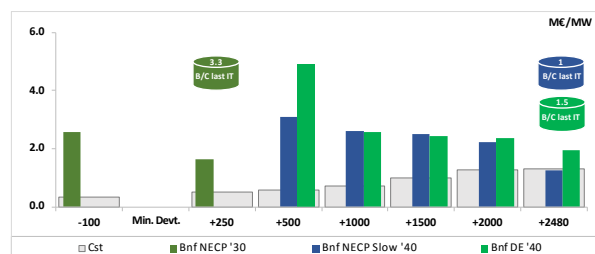
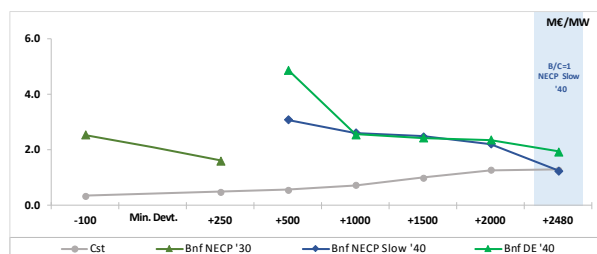


Table 30 *Average simulation times for each section/border at each iteration in the Policy 2040 scenario (Iteration 6-9)*

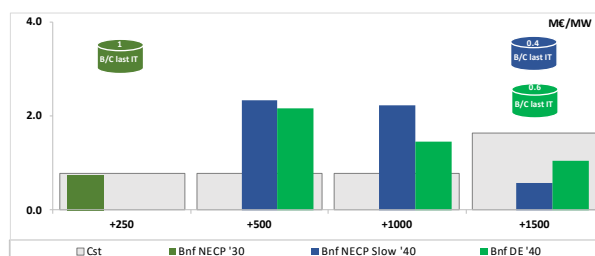
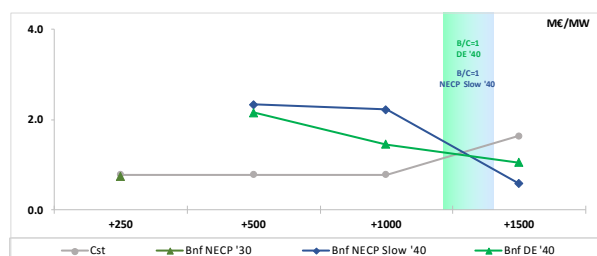
DE 2040		ITERATION 6 - PINT		ITERATION 7 - PINT		ITERATION 8 - PINT		ITERATION 9 - PINT		SIMULATION TIMES
Northern border	AT - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	CH - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	FR - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	SI - ITn	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
Balkan border	ME - ITcs	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
	ITs - GR	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
North Africa border	ITsic - TUN	ME	10:00	ME	10:00	ME	10:00	ME	10:00	90:00:00
Internal sections	ITcn - ITn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITcs - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITs - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITn - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITn - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITcn	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsar - ITsic	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsic - ITcs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITsic - ITcal	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
	ITcal - ITs	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	ME MSD	12:00	108:00:00
Total		202:00:00		202:00:00		202:00:00		202:00:00		1818:00:00

Benefit/cost curves for each section/border

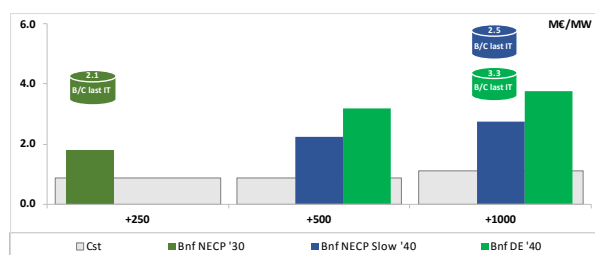
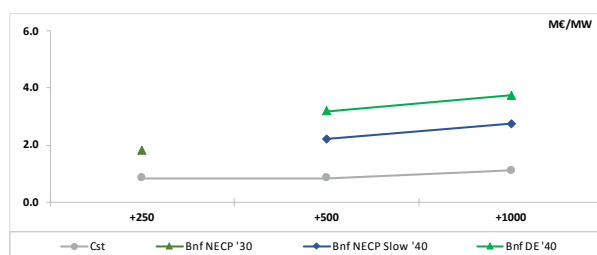
Italy - Austria border



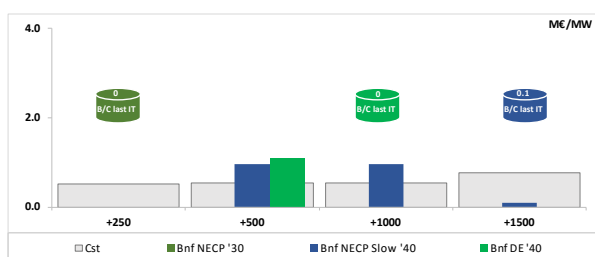
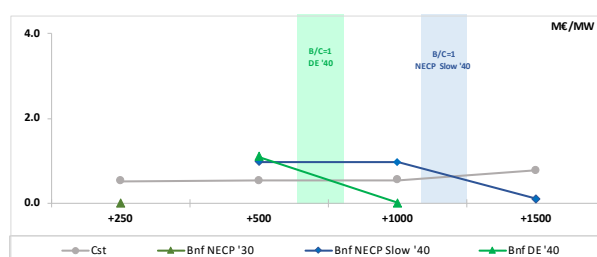
Italy - Switzerland border



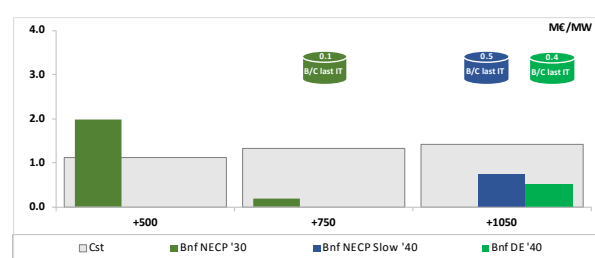
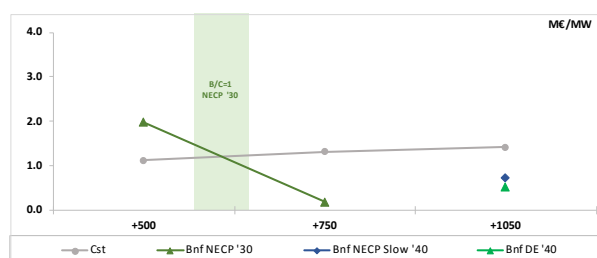
Italy - France border



Italy - Slovenia border

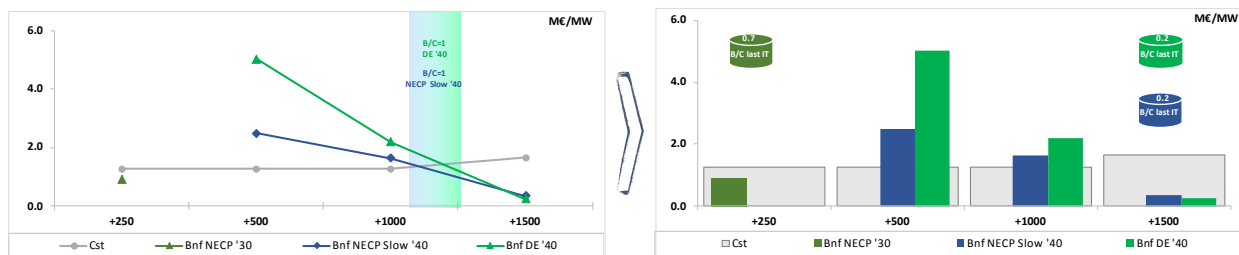


Italy - Montenegro border

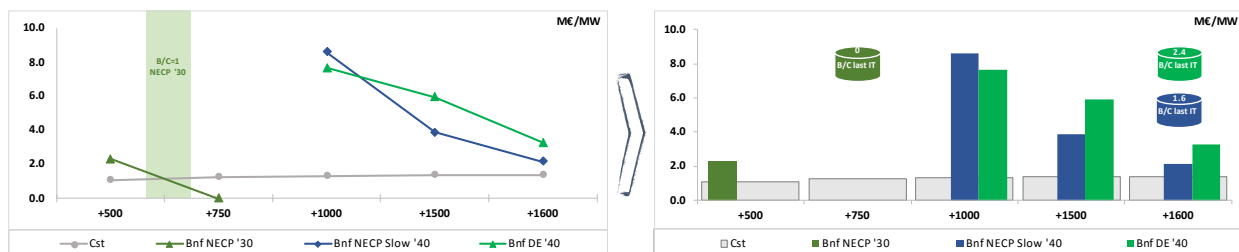




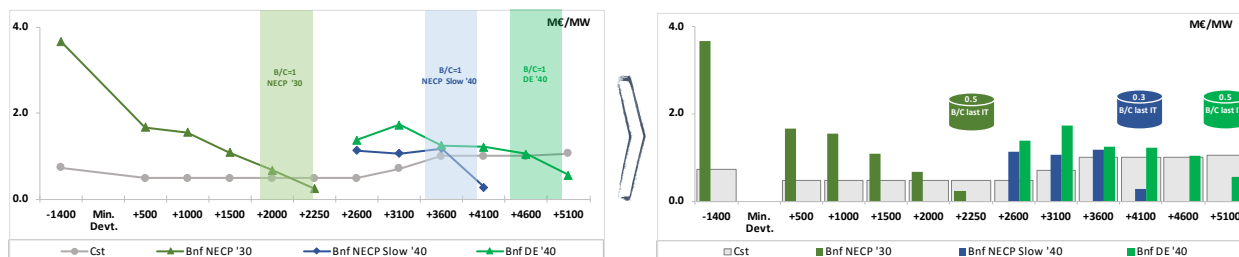
Italy - Greece border



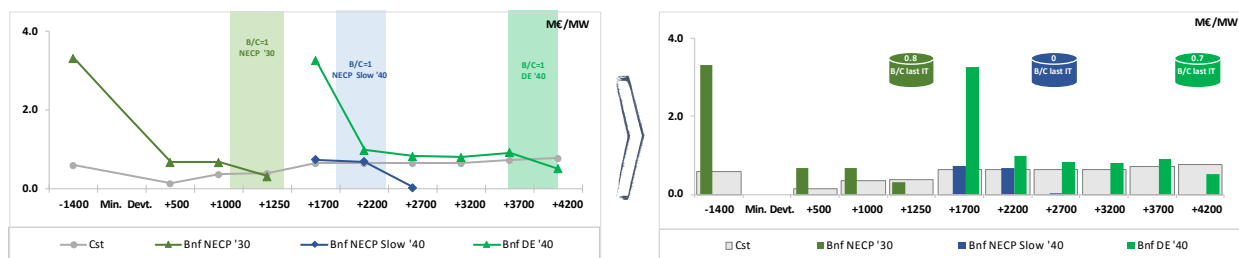
Italy - Tunisia border



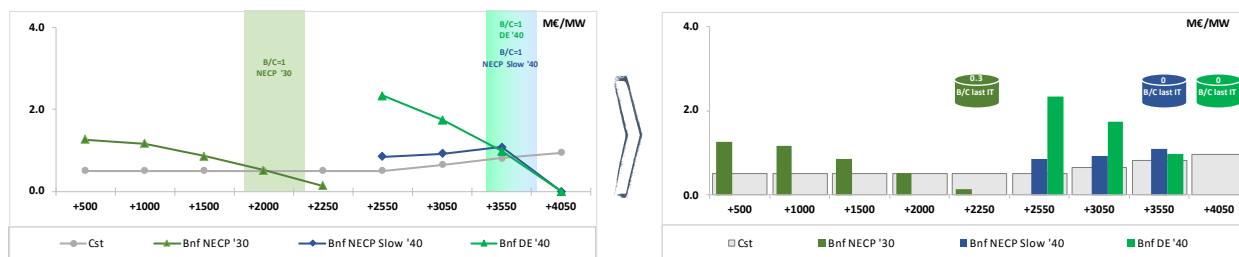
North - Centre North section



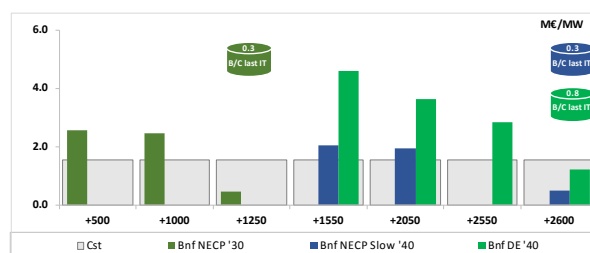
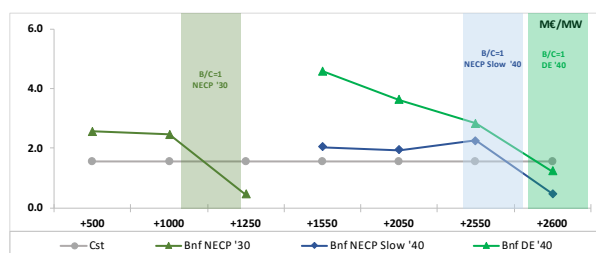
Centre North - Centre South section



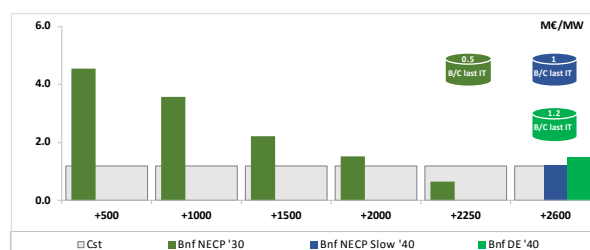
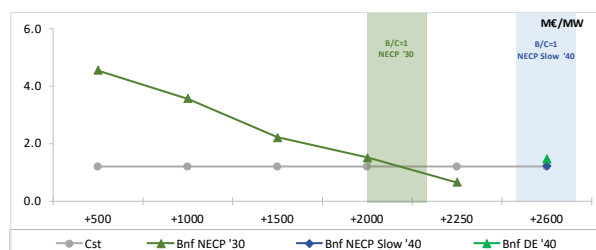
Centre South - South section



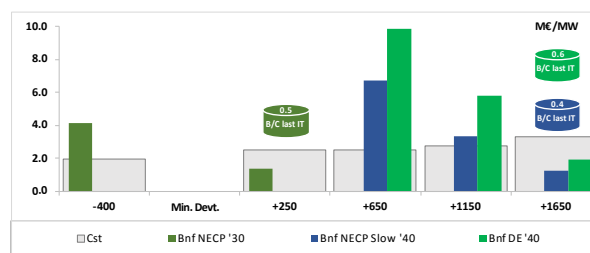
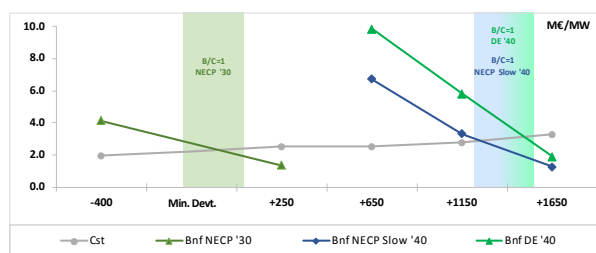
North - Centre South section



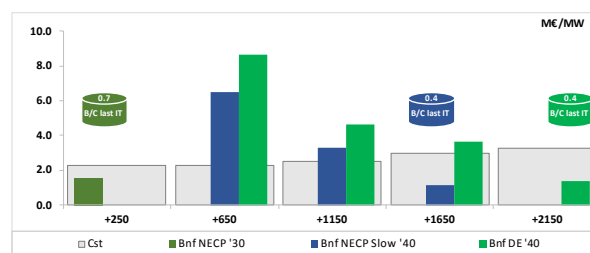
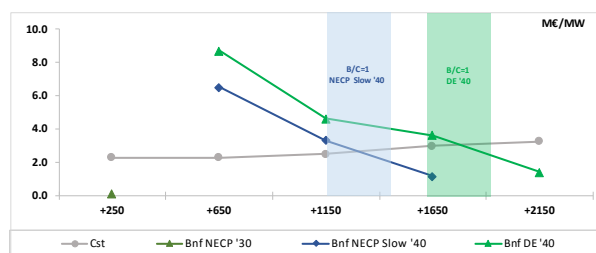
North - South section



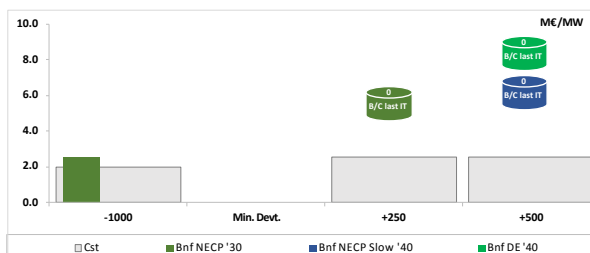
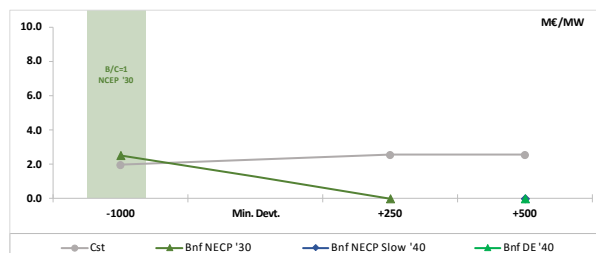
Sardinia - Centre North section



Sardinia - Centre South section

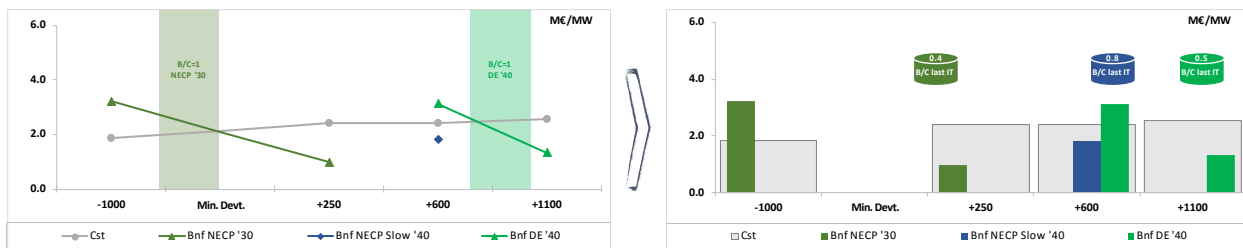


Sardinia - Sicily section

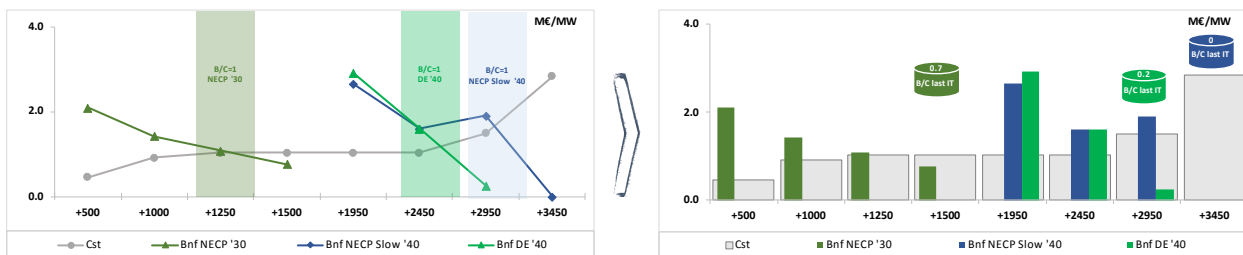




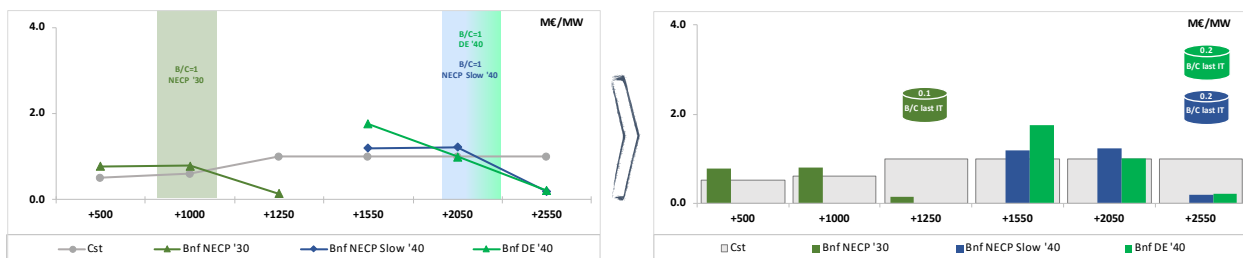
Sicily - Centre South section



Sicily - Calabria section

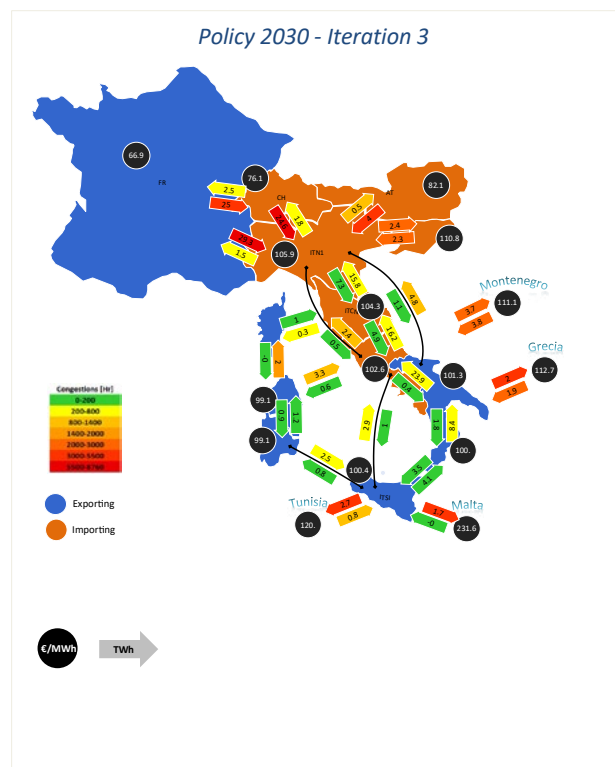
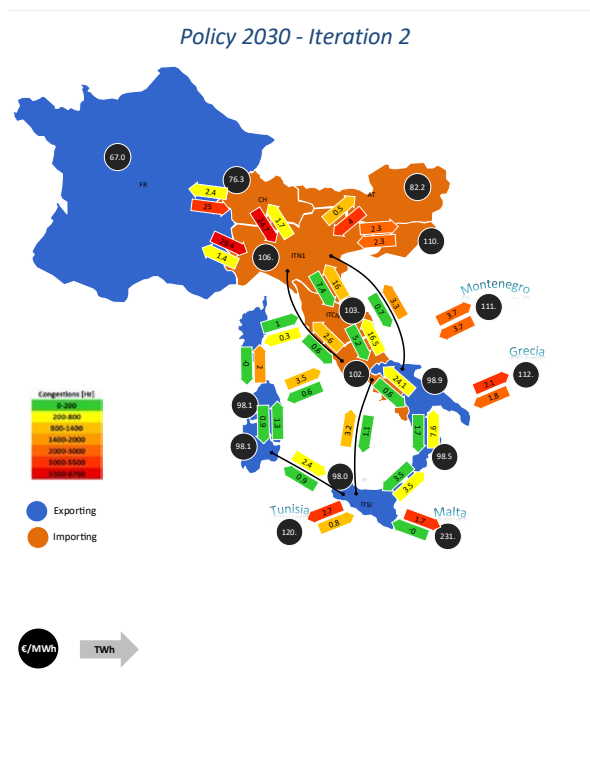
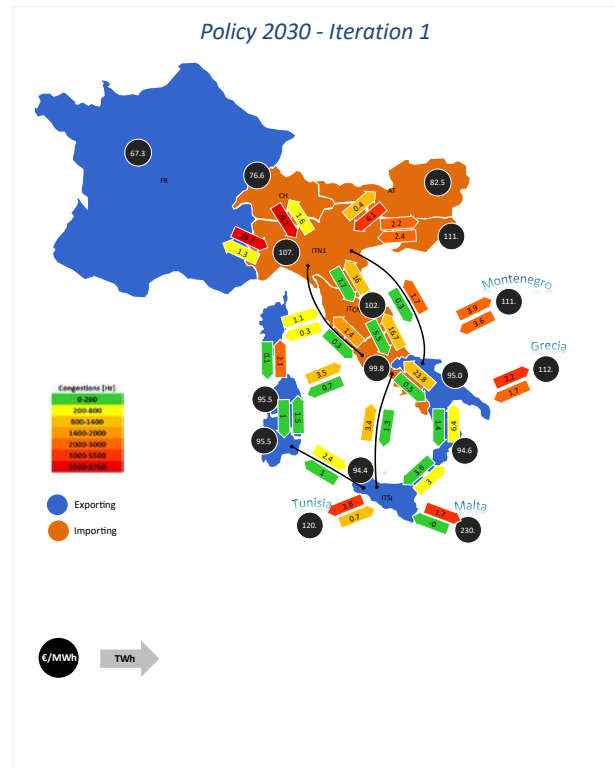
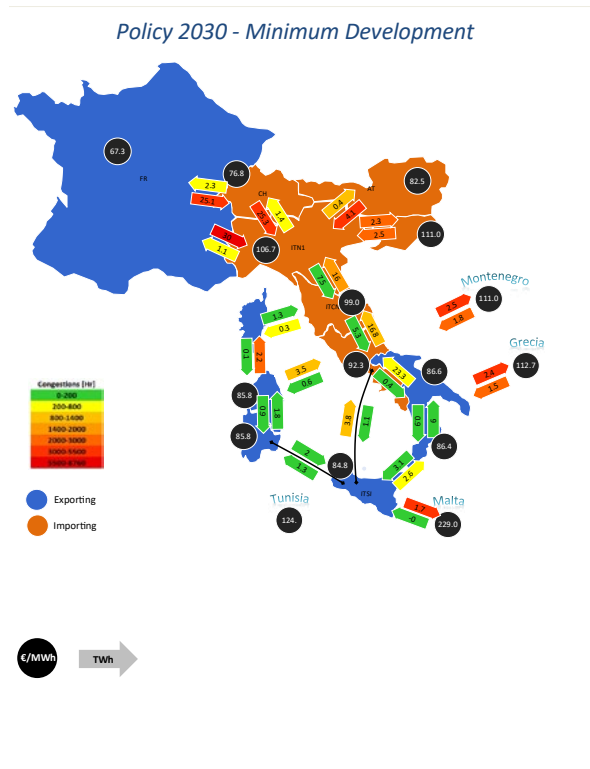


Calabria - South section



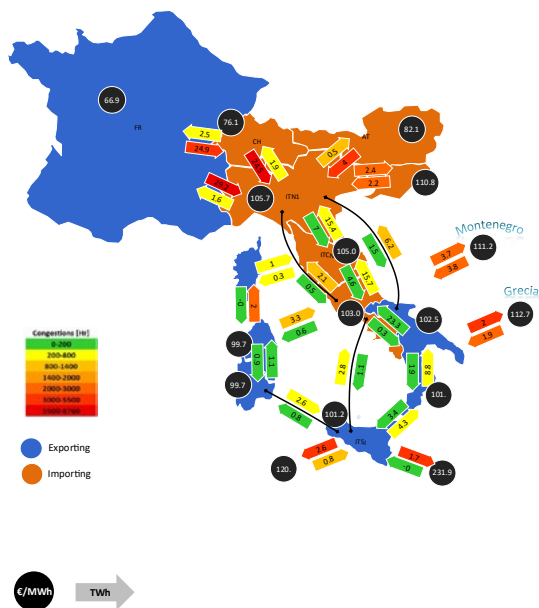
Annex 7

Expected flows: 2030 and 2040 scenarios

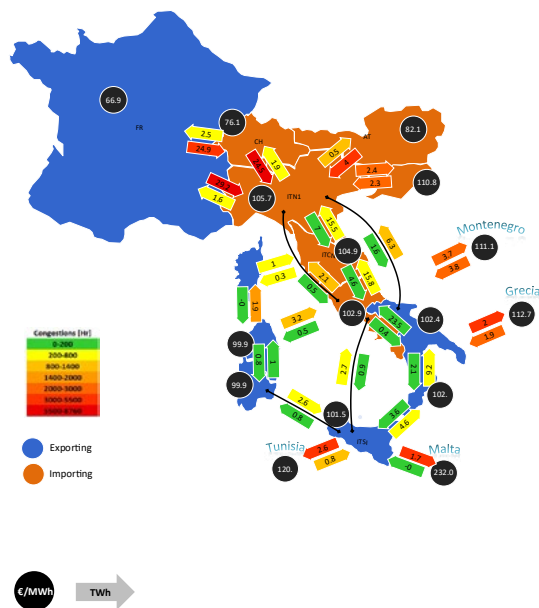




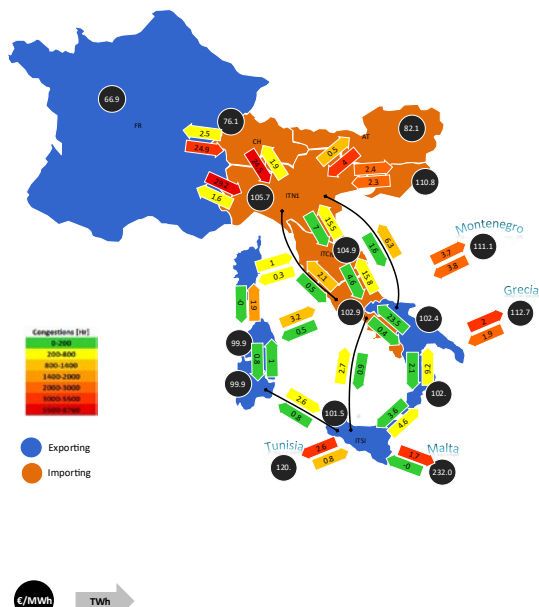
Policy 2030 - Iteration 4



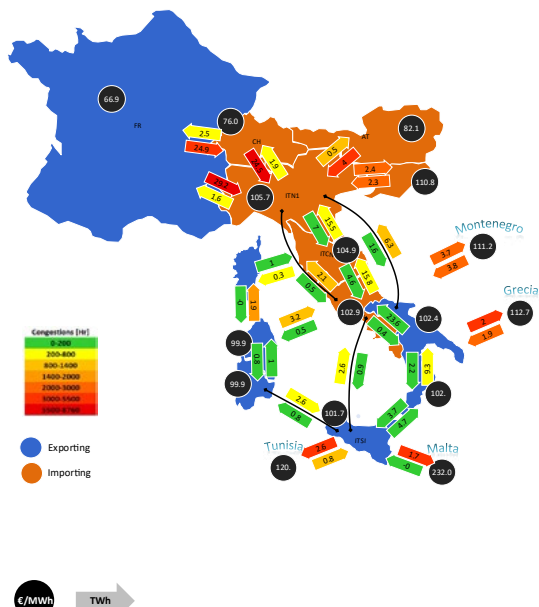
Policy 2030 - Iteration 5



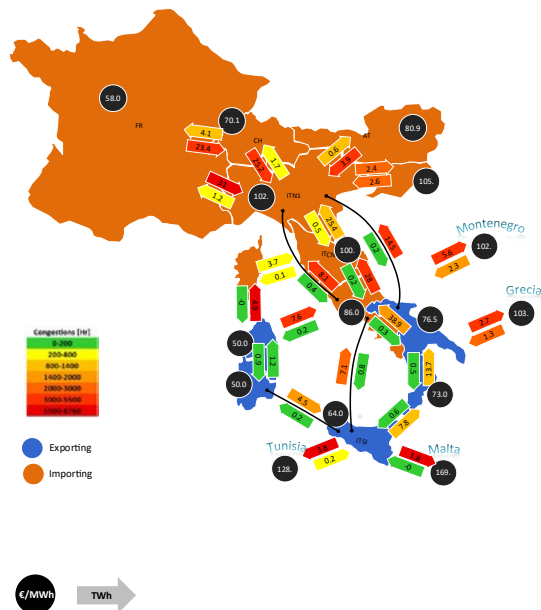
Policy 2030 - Iteration 6



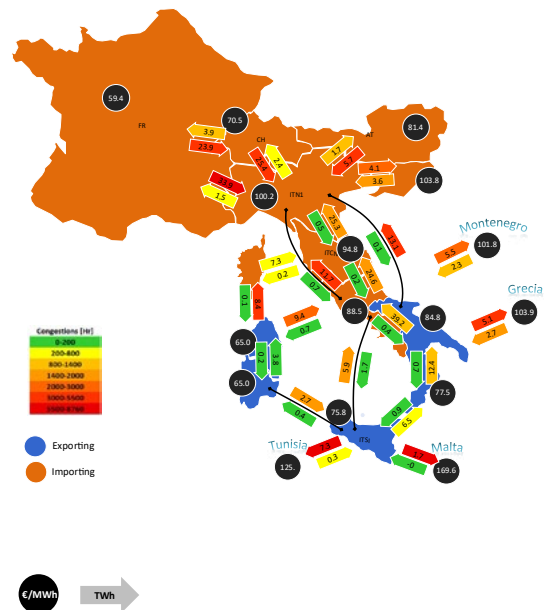
Policy 2030 - Iteration 7



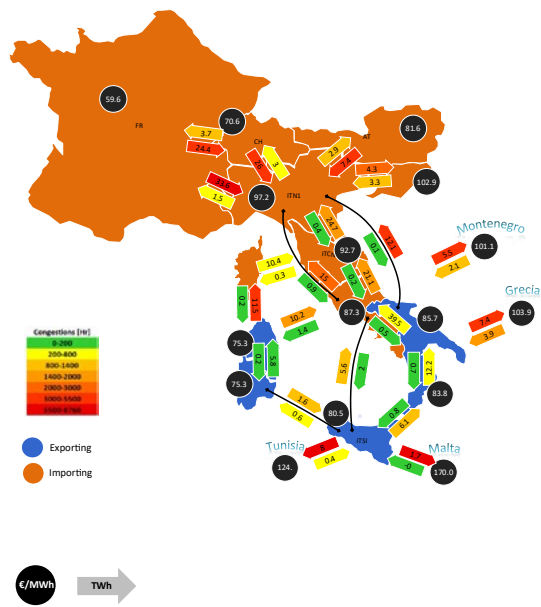
Policy 2040 - Base Case



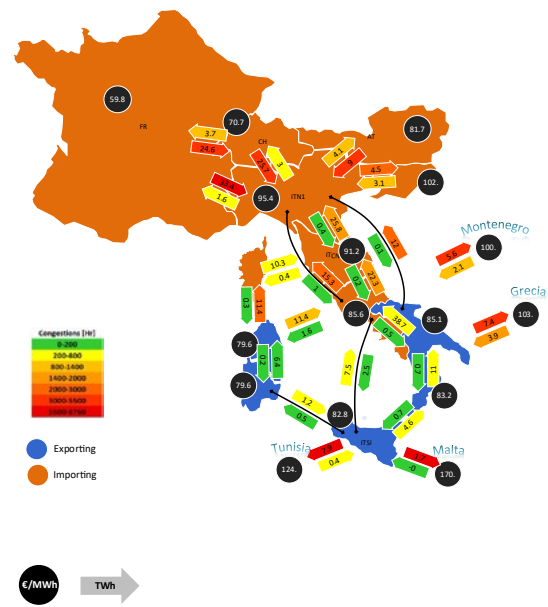
Policy 2040 - Iteration 1



Policy 2040 - Iteration 2

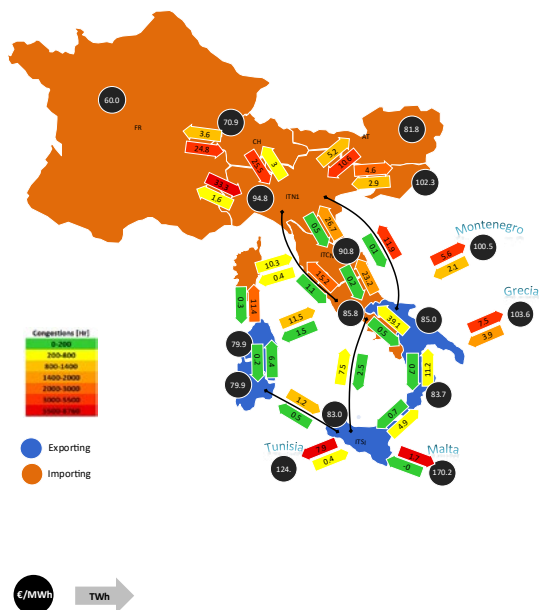


Policy 2040 - Iteration 3

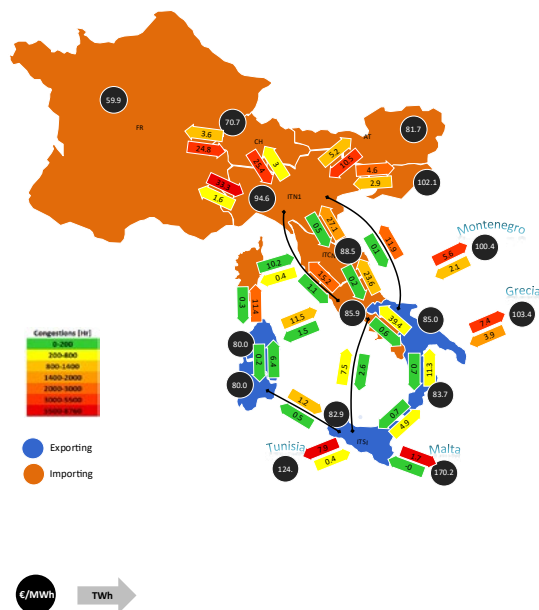




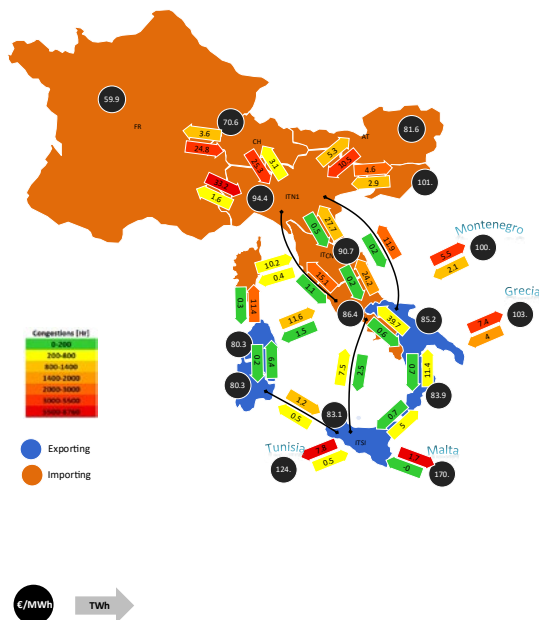
Policy 2040 - Iteration 4



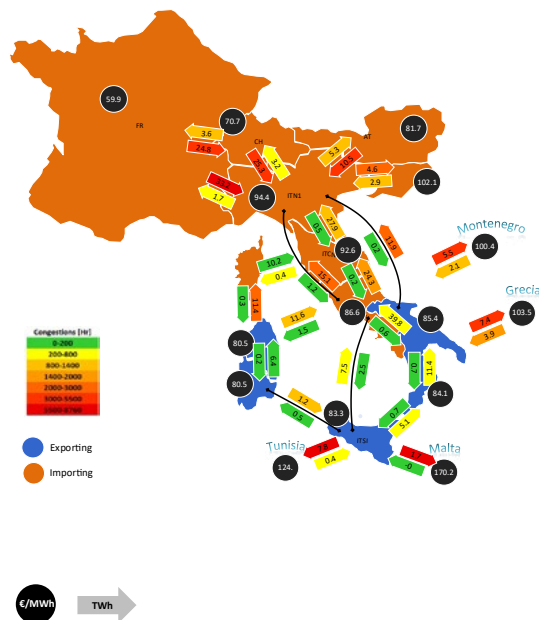
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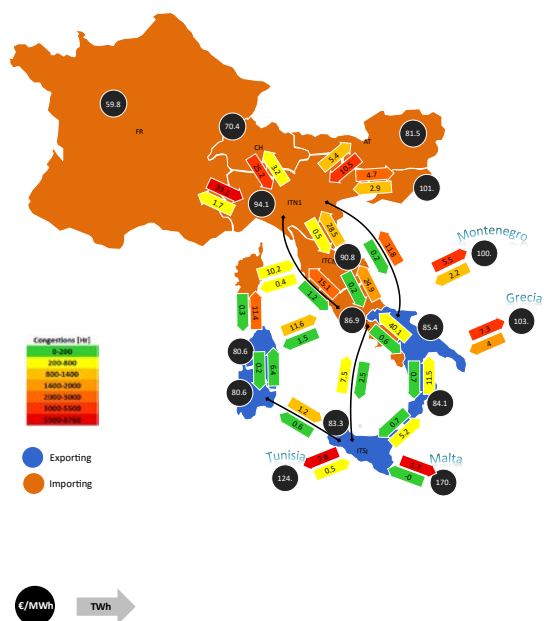
Policy 2040 - Iteration 6



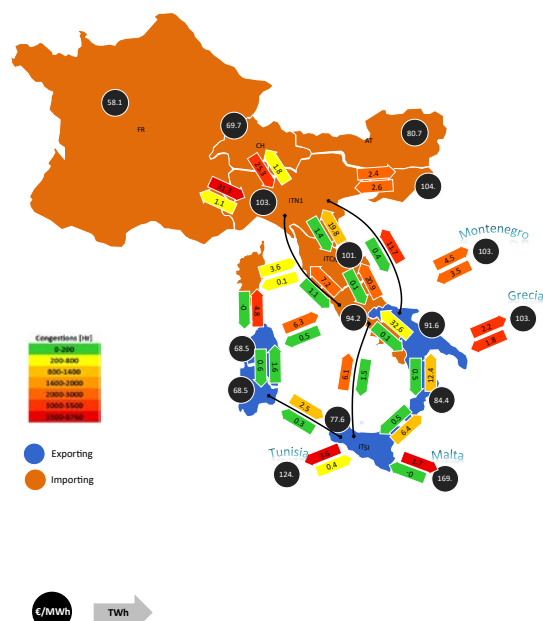
Policy 2040 - Iteration 7



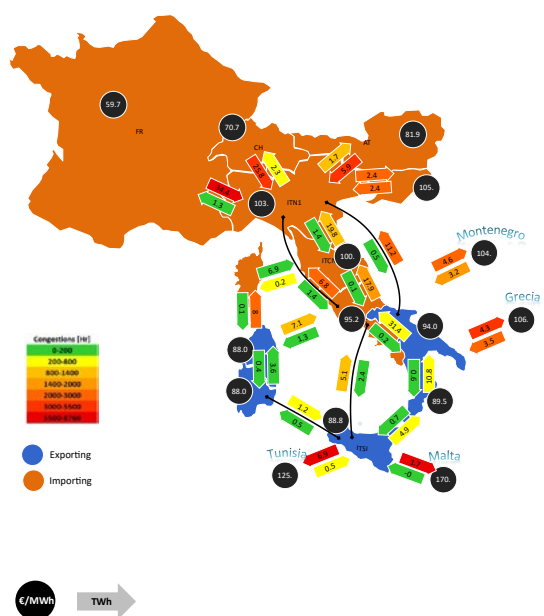
Policy 2040 - Iteration 8



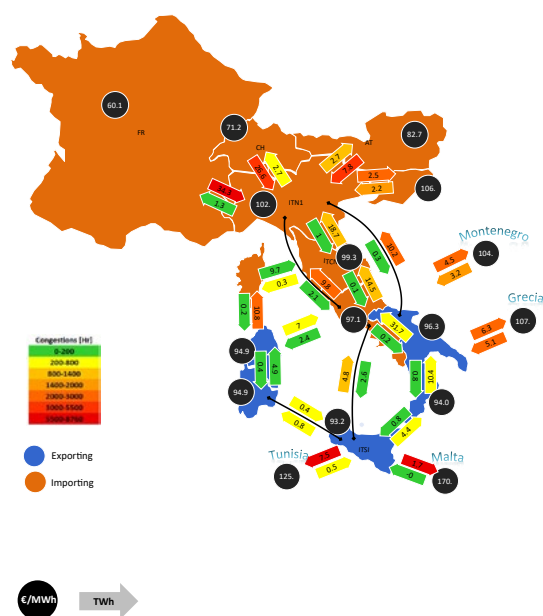
Inertial 2040 - Base Case



Inertial 2040 - Iteration 1

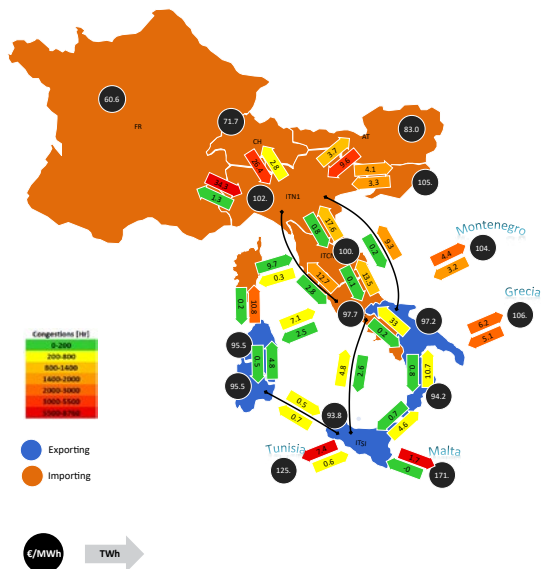


Inertial 2040 - Iteration 2

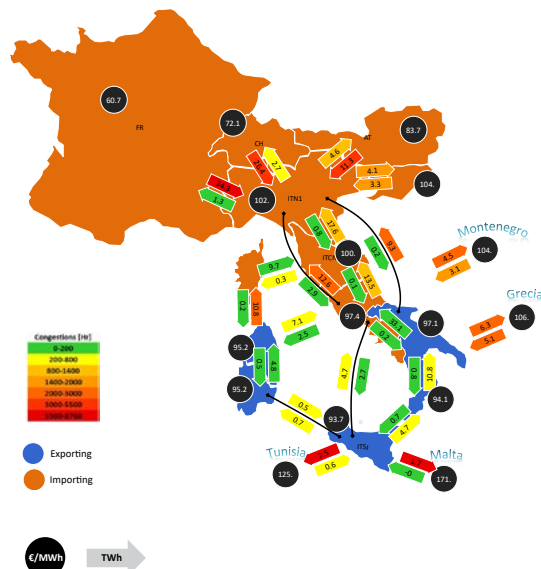




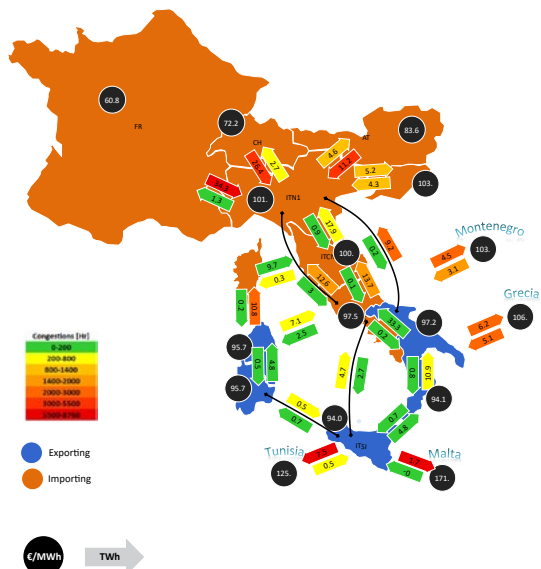
Inertial 2040 - Iteration 3



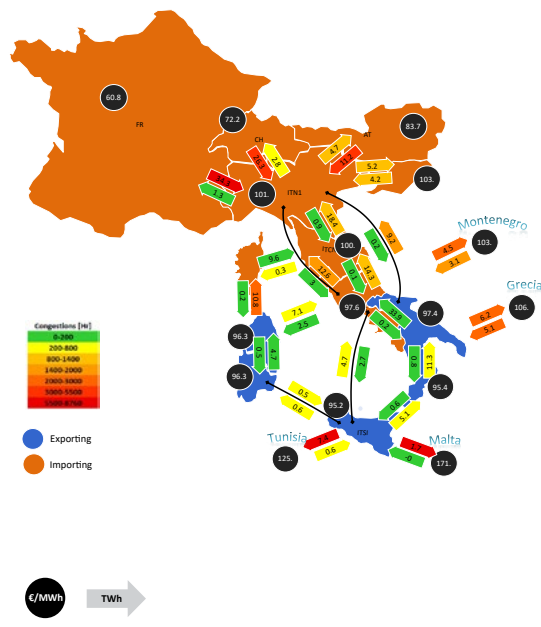
Inertial 2040 - Iteration 4



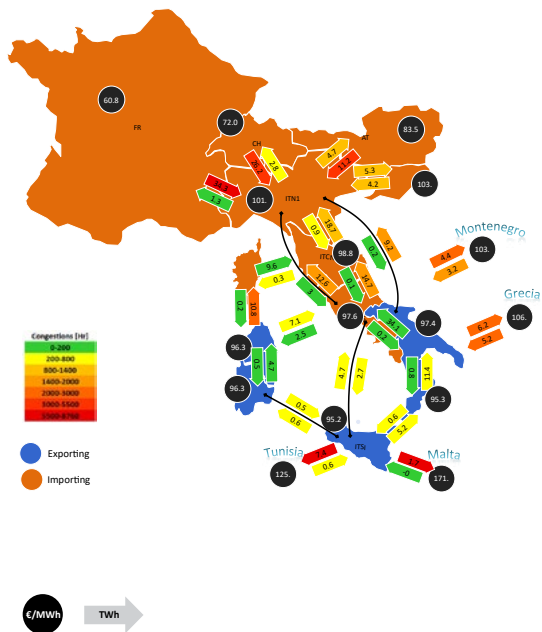
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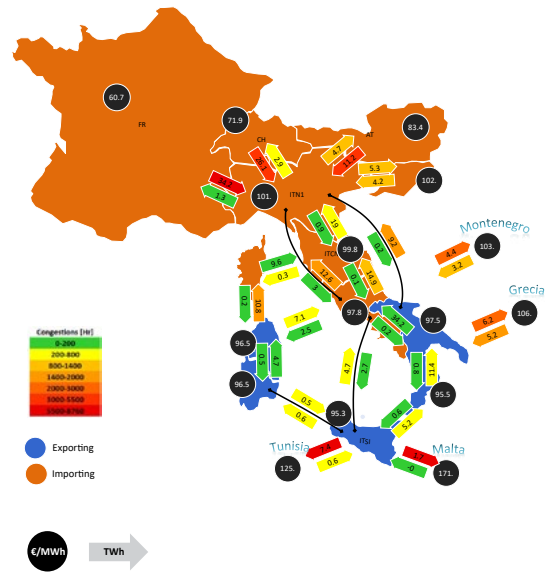
Inertial 2040 - Iteration 6



Inertial 2040 - Iteration 7



Inertial 2040 - Iteration 8



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