ENTSO-E

Report on the Locational Marginal Pricing Study of the Bidding Zone Review Process

30 June 2022

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ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 39 member TSOs, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the interconnected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources.

ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with **climate objectives** and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility.**

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with **transparency** and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its **legally mandated tasks**, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

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Introduction

With the Clean Energy for all Europeans package published in June 2019, the European Commission (EC) continues its path to transform the energy system from one based on fossil fuel toward a renewable energy system. According to the EC's vision, the design of the future electricity market should be "more flexible, more market-based and better placed to integrate a greater share of renewables".[1]

A major element of the design of the European electricity market is the delineation of bidding zones, which are, as defined by Regulation 543/2013, the largest geographical area within which market participants can exchange energy without capacity allocation. As part of the Clean Energy for all Europeans package, the entry into force of Article 14(3) of Regulation (EU) 2019/943 of the European Parliament and the Council on the internal market for electricity, triggered a bidding zone review (BZR) process.

On behalf of transmission system operators (TSOs), ENTSO-E submitted a proposal concerning the methodology and assumptions to be applied in the BZR process and for alternative bidding zone configurations to be assessed by the relevant National Regulatory Authorities (NRAs) for approval, pursuant to Article 14(5) of Regulation (EU) 2019/943.Since the NRAs did not agree to approve the proposal, the decision on the methodology, assumptions, and alternative bidding zone configurations to be considered in the BZR process was transferred to the EU Agency for the Cooperation of Energy Regulators (ACER) on 13 July 2020.

On 24th November 2020, ACER issued its decision (Decision No 29/2020) on the methodology and assumptions that are to be used in the BZR process and the alternative bidding zone configurations to be considered (hereafter: ACER Decision on the BZR Methodology). Additionally, Annex 2 of the ACER Decision on the BZR Methodology includes a request for TSOs to deliver the results of a European Locational Marginal Pricing (LMP) simulation pursuant to Article 11 of the methodology. The results are intended as input for ACER to define the alternative bidding zone configurations for the BZR process.

Pursuant to Article 2, Annex II of the ACER Decision on the BZR Methodology, TSOs were tasked with providing data in three steps:

- by 28 February 2021, delivery of templates detailing the specific formats to be used by TSOs when delivering the data to ACER and at least one network model per synchronous area for use in the simulations;
- by 31 May 2021, delivery of the provisional results of the analysis; and
- by 31 October 2021, delivery of the final results of the analysis.

The first two steps were completed on time.

In the period prior to 31 October, due to the calculation complexity, methodological requirements and data formatting challenges, the TSOs informed ACER that additional time was needed to deliver the final LMP results (the third step above). It was decided, in close coordination with ACER, that the quality of results should be prioritised. The TSOs estimated the additional time and set a new delivery date of 28th February 2022, noting the remaining risks in this timeline related to unforeseen events; these risks mainly concerned the model's size and methodological requirements and could not be discarded. The first package of final results was delivered by TSOs on 4 March 2022, and the final package of LMP results was delivered on the 31 of March 2022.

With this report, TSOs are transparently and comprehensively reporting the assumptions, limitations, simplifications, and results of this European LMP simulation. The report covers projects in

- Continental Europe and Ireland, and
- the Nordic region.

1 https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en

Continental Europe and Ireland project

In addition to meeting the legal requirements specified in Annex 2 of the ACER Decision on the BZR Methodology, the TSOs delivered additional data items to ACER to ensure a comprehensive and high-quality approach to the LMP results and fulfil ACER's additional requirements related to data and formats beyond those specified in the methodology. Alongside these additional data items, the TSOs submitted:

- snapshots in PSSE format and an aligned PowerFactory grid topology model ensuring compatibility, as requested by ACER, with the simulation software PowerFactory 2019 (for PowerFactory format) and Transmission Network Analyser (for PSSE format);
- a mapping of node identifiers from the simulation-model-formats (Power System Simulator for Engineering [PSSE], PowerFactory and Common Grid Model Exchange Standard [CGMES]) requested by ACER and historical Union for the Co-ordination of Transmission of Electricity (UCTE) models, which were delivered by TSOs in 2020 in the context of a BZR data collection process; and
- additional information on modelling specifics applied by TSOs in line with the BZR Methodology, e.g., methodologies for nodal disaggregation of generation and demand, a list of grid elements considered and details of grid elements for which dynamic line rating was applied.

A nodal simulation study of this size and level of complexity has never before been performed for Continental Europe and Ireland. In total, the simulation model includes around 25,000 generators, 22,000 lines, 25,000 nodes and 25,000 critical network elements and contingencies.

Voltage Level kV	nr. Nodes
≥ 380	3,747
379–221	107
220–111	7,639
≤ 110	13,847

Table 1: Breakdown of nodes per voltage level

Section: Nordic Region introduction

Before the study began, none of the modelling tools available to Nordic TSOs enabled market modelling on a nodal model of this size. Significant development efforts were required to adapt our existing modelling tools to ACER methodological requirements, with many problems having emerged and been solved along the way. In the study, nodal prices were calculated for all nodes ≥ 200 kV in Norway, Sweden, Finland and Eastern Denmark; results are available for three different climate years.

In addition to the results from the nodal simulations, 24 snapshots in PSSE format were delivered to ACER on behalf of the Nordic TSOs.

Statement on the absence of the Baltic

The TSOs of the Baltic BZRR in agreement with ACER, postponed their study due to the upcoming synchronisation. As a result, there are no LMP calculations performed for this region.

Outline of the report

The outline of the report is as follows:

- **Section 1** sets out the assumptions applicable to all the BZRRs that performed LMP calculations.
- **Section 2** sets out the market and grid assumptions, the simulation chain and the results of the LMP calculations as performed for the following BZRRs: Continental Europe and Ireland.
- **Section 3** sets out the market and grid assumptions, the simulation chain and the results of the LMP calculations as performed for the BZRR Nordics.

The report includes three annexes:

- **Annex 1** comprises a detailed description and the mathematical formulation of the climate-year and week selection methodology.
- **Annex 2** sets out the network projects from the TYNDP 2025 dataset that were excluded from the LMP calculations.
- **Annex 3** sets out a more detailed description of the grid assumptions for the nodal allocation.
- **Annex 4** sets out a more detailed description of the contingency selection.
- **Annex 5** sets out the results from additional sensitivity analyses to assess the impact of certain modelling choices.

1. Assumptions Relevant to all BZRRs

1.1 Clarification of BZRRs that Performed LMP Calculations for the BZR

The following BZRRs performed LMP calculations for the BZR in the following cooperation arrangements:

LMP region	BZRRs
Continental Europe & Ireland	Central Europe
	Central Southern Italy
	Iberian Peninsula
	South-East Europe
	Ireland
Nordic	Nordic

Table 2: BZRRs that performed LMP calculations for the purpose of the current BZR

Two BZRRs have not performed LMP calculations for the purpose of the current BZR:

- **Baltic:** The TSOs of the Baltic BZRR postponed the study due to the upcoming synchronisation.
- **Great Britain:** Because of Brexit, the BZR no longer has to be conducted for Great Britain.

1.2 Methodology for Selecting Climate Years for Each BZRR

1.2.1 Scope of the methodology

Article 4.4 of Annex I of the BZR Methodology specifies the following with respect to the selection of climate years used in the BZR process: *"TSOs shall jointly select three reference climate years to assess BZ configurations. These three years shall be selected among the thirty most recent available climate years. The reference climate years shall be consistently used across all [BZRRs] and BZ configurations. A BZRR may select additional climate years, which shall be justified and published before the modelling chain starts […]. Unless stated otherwise and duly justified, all selected reference climate years shall have the same weight in the assessment and conclusions made for each criterion and configuration. Additional climate years may also be used as a sensitivity analysis as described in paragraph 10 of this article."*

A TSO methodology has to be developed to fulfil this requirement and must include all elements considered relevant in each BZRR climate year for both the LMP simulations and the second stage of the BZR.

According to Article 11.8 of the BZR Methodology, when computing LMPs, *"TSOs may limit the time horizon to a minimum of eight weeks, ensuring that this limited time horizon is representative of the entire target year"*. Given the complexity of these simulations, TSOs have decided to limit the computations to the 8-week minimum for each of the three reference climate years. A dedicated methodology was developed to select representative weeks to be used for the LMP simulations.

1.2.2 Climate-year-selection algorithm

The residual load is available for ex-ante simulation, and is the indicator that best captures the phenomena for which representativeness be achieved (market price formation). The subset selection algorithm selects the most representative combination of years in terms of the occurrence of residual loads.

In total, there are more than 4,000 different possible 3-year combinations out of 30 available years. The algorithm identifies the combination of years for which the aggregate dataset of hourly occurrences has the highest average mean and standard deviation relative to all other combinations while simultaneously indicating good performance as cluster centroids.

The residual load indicator is computed on a macro-region level. Each region is then included in the selection algorithm with a weighting factor corresponding to its share in the overall load. The full mathematical formulation defining the indicator, the selection algorithm and visualisations can be found in Annex 1.

1.2.3 Climate-week-selection algorithm

In order to identify 8 out of 52 representative weeks per year, the climate year selection algorithm has been adjusted with one additional constraint. Of the over 750 million possible combinations of 8 in 52, the algorithm selects the top candidate with at least one week per season. Annex 1 contains a detailed description of this selection.

1.2.4 Outcomes of year and week selection

The algorithm identified the combination of 1989, 1995, and 2009 as the most representative combination of climate years. Table 3 sets out the most representative combination of climate weeks per selected climate year:

1989	WK 04, 10, 11, 17, 20, 31, 40, 52
1995	WK 02, 12, 16, 21, 27, 36, 38, 49
2009	WK 04, 08, 11, 15, 16, 21, 31, 48

Table 3: Outcomes of climate year and week selection

1.3 Market assumptions

For both regions, data is taken from the Pan-European Market Modelling Database (PEMMDB) according to the scenarios used in the Mid-term Adequacy Forecast (MAF) 2020 – National Trends 2025. Further details are provided in Sections 2.1. and 3.1.

2. Explanation of assumptions, applied simulation chain and results of LMP calculations for Continental Europe and Ireland

2.1 Market Assumptions

2.1.1 Scenarios used for generation and demand

According to the ACER Decision on the BZR Methodology and assumptions that are to be taken into account by TSOs in the BZR process (including the LMP study), the target year must be three years later than the year in which the configurations for a given BZR Region are approved. Assuming that the alternative bidding zone configurations to be studied in the BZR process will be defined by ACER in the course of 2022, the generation and demand scenarios for the LMP study were created for the target year 2025. These scenarios originate from the data package released by ENTSO-E's Data & Models working group as input for the MAF in 2020. This data is employed as it is the most recently released (at the beginning of the LMP study in late 2020). The different datasets used as inputs for the LMP study are briefly described in the following sections.

Pan European market modelling database

ENTSO-E uses a single source for supply-side and market modelling data across all of its studies: the PEMMDB. This database contains data collected from TSOs on plants' net generation capacities, interconnection capacities, generation planned outages and a range of other characteristics. The database is aligned with national development plans and contains data about the power system according to the best knowledge of the TSOs at the time of data collection. The PEMMDB's resolution is highly granular; it contains unit-by-unit data of European power plants, their technical and economic parameters, their expected decommissioning dates as well as the forecasted development of renewable capacities. Moreover, it provides hourly time series of must-run obligations and derating ratios of thermal units. As part of the process of building a nodal model of the European power system, it was necessary to match the per unit generation data contained in PEMMDB with the corresponding per unit data in the CGM (cf Appendix 3)

Temperature Regression and loAd Projection with UNcerTainty Analysis

To create the forecasted hourly load profiles for each region, ENTSO-E uses a single tool, Temperature Regression and LoAd Projection with UNcertainty Analysis (TRAPUNTA). This tool builds hourly load profile forecasts for all regions (with some exceptions) by combining information from time series of historical load, temperature and other climate variables as well as additional historical data. Its methodology incorporates the decomposition of time series into basic functions using Singular Value Decomposition. In the second phase, the tool adjusts the forecasted load time series using bottom-up scenarios provided by the TSOs; these reflect the future evolution of technologies that influence load patterns (e.g., penetration of heat pumps, electric vehicles and batteries). The TSOs additionally had the option of providing their own demand time series. The regional load profiles obtained from TRAPUNTA or provided directly by the respective TSOs were then used as inputs for the nodal disaggregation procedure described in Section 2.2.3.

Pan European Climate Database

ENTSO-E developed the Pan European Climate Database (PECD), consisting of re-analysed hourly weather data and load factors for variable generation (i.e., wind and solar). The PECD datasets are prepared by external experts using industry best practices to ensure a representative estimation of demand (although here TRAPUNTA outputs, described above, are used instead), variable generation and other climate-related quantities. In 2019 the PECD was extended to include hydro-generation data. A standardised central methodology was designed based on re-analysed data concerning hydro inflows.

The historical inflows are mapped to generation data and support the building of a model to project hydro generation, including hydro run-of-river, hydro-reservoir and pump-storage generation. In 2020, the database was further improved by increasing the granularity of North Sea offshore zones and updating the zone configuration in Belgium.

2.1.2 RES modelling

For the scope of the LMP simulations, RES units are modelled as variable-generation units with available capacity according to hourly time series derived from PECD datasets for the selected climate weeks. In line with the BZR Methodology Article 7, the following assumptions apply to RES variable generation costs for wind and solar units:

1) Wind units bid at −1 €/MWh
2) Solar units bid at −20 €/MWh

These values are chosen to reflect the assumption that wind units will be more price sensitive than solar units in 2025 while keeping the absolute values low to narrow the default value of 0 €/MWh proposed by the BZR Methodology. Other RES units bid at 0 €/MWh.

2.1.3 Short Run Marginal Cost

For the purpose of simulation, LMP SRMCs are calculated using the following formula:

SRMC = Fuel Price × Marginal Heat Rate + VOM Charge + Emissions Incremental Cost

A summary of fuel prices taken from Scenario Building 2022 is set out in Table 4.

Zone	Fuel prices (€/GJ)	Zone	Fuel prices (€/GJ)
Closed loop pumping	0	Light oil	12.87
Open loop pumping	0	Lignite G1	1.4
Reservoir	0	Lignite G2	1.8
Run of river and pondage	0	Lignite G3	2.37
Gas	5.57	Lignite G4	3.1
Hard coal	2.30	Nuclear	0.47
Heavy oil	10.56	Oil shale	1.56

Table 4: Short run marginal costs

Biofuels are used as secondary fuels. Per-unit Biofuel prices are provided in the PEMMDB either according to customary units or, if the TSO did not provide a price, the primary fuel price was used.

The prices are then randomised, as requested by the methodology, in a range of ±1€/MWh hourly around the original value. Heat rates are defined per unit; therefore, units with the same fuel price can result in different SRMCs.

The CO_2 price of 40 €/t was taken from Scenario Building 2022 in order to update with the MAF 2020 value that appeared too low compared to current prices.

2.1.4 Demand-side response

According to the BZR Methodology (Article 4), resources for both explicit and implicit demand side responses (DSRs) are to be modelled. The main differences between explicit and implicit DSRs are summarised below.

Aspect	Explicit DSR	Implicit DSR
Definition	Explicit DSR is committed, dispatchable flexibility that can be traded on the different energy markets (wholesale, balancing, system support and reserves markets). This form of demand-side flexibility is often referred to as "incentive driven" demand-side flexibility.	Implicit DSR is the consumer's reaction to price signals. Where consumers have the possibility, they can adapt their behaviour (through automation or personal choices) to save on energy expenses. This type of demand-side flexibility is often referred to as "price-based" demand-side flexibility.
Participation in market segments	It can potentially participate in all market segments/ mechanisms (balancing, ancillary services, etc.).	A priori, it does not participate in other market segments or mechanisms (balancing, ancillary services, etc.).
Visibility/identification of offers	Individual offers can be often identified.	› May be 'visible' in the wholesale (day-ahead or intraday markets) or partly 'hidden', e. g. in the portfolio of vertically integrated companies. › Individual offers difficult to identify.
Activation prices	In theory, activation at any price. In practice, based on TSOs' information, only identifiable at 'relatively' high prices (e. g. 150 €/MWh or well above).	At any price.

Table 5. DSR Definition

Explicit DSR

Explicit DSR resources are represented in the model adopted for computing LMPs of equivalent generators. These are available to produce at the predefined price level (a generation increase is equivalent to a load decrease for the scope of the study).Table 6 reports the total explicit DSR capacity per (existing) bidding zone and price level.

Zone	Price (€/MWh)	Capacity* (MW)	Zone	Price (€/MWh)	Capacity* (MW)
AT00	500	200	ITCN	200	65.3
BE00	300	219		400	65.3
	500	438	ITCS	200	87.4
	1,000	146		400	87.4
	1,500	146	ITN1	200	549.2
	2,000	511		400	549.2
DE00	200	822	ITS1	200	64.6
	300	428		400	64.6
FR00	350	2900	ITSA	200	3.4
HR00	150	20		400	3.4
IE00	150	100	ITSI	200	25.7
	250	100		400	25.7
	350	300	NL00	500	700
ITCA	200	7.5	SI00	240	› 67
	400	7.5	UKNI	300	94

Table 6: Explicit DSR Capacity per Zone
(* Each price band shows an additional capacity that is activated if the market price reaches the offered price.)

Implicit DSR

Implicit DSR was simulated following a two-step approach:

1. In the first step, demand elasticity values were applied and a simplified zonal yearly simulation run (activating the Plexos Cournot competition model). This step is intended to derive the demand slope and intercept to be adopted in the final simulations.

2. In the second step, computed hourly demand and intercept parameters are assigned to each (existing) Bidding Zone and adopted in the final LMP simulations.

Demand elasticity values are the main input for assessing implicit DSR parameters. Following the relevant literature[2], a standard value of −0.08 was adopted for all countries except Germany, for which a different value (−0.05) was adopted following a specific assessment of demand elasticity conducted for Germany.[3]

2 Relevant papers: Csereklyei, Z. (2020). Price and income elasticities of residential and industrial electricity demand in the European Union. Energy Policy, 137, 111079; Knaut, A (2017). "When Are Consumers Responding to Electricity Prices? An Hourly Pattern of Demand Elasticity", Chapter 4 in Essays on the integration of renewables in electricity markets. PhD Thesis. University of Cologne.

3 Hirth, L., Khanna, T., Ruhnau, O. (2022). The (very) short-term price elasticity of German electricity demand. ZBW - Leibniz Information Centre for Economics, Kiel, Hamburg.

2.1.5 Reserve modelling

Article 11.5.d of the BZR Methodology prescribes that, among others contraints, *"reserves and balancing requirements, as described in Article 4.3"* shall be considered in LMP simulation, and *"shall be consistent with the ones adopted for the day-ahead market dispatch according to Article 7.4"*.

Article 4.3 states: *"Reserve requirements: Reserve requirements shall be set separately for Frequency Containment Reserve (FCR), Frequency Restoration Reserve (FRR) and Replacement Reserve (RR).*

- *For each target year, the dimensioning of FCR, FRR and RR, and the related contribution of each TSO, shall reflect reserve needs to cover imbalances in line with Articles 153, 157 and 160 of SO Regulation.*
- *The assignment of these balancing reserves to generation, demand and storage shall reflect expected operational practices for the target year."*

In order to fulfil these requirements:

- All the three main reserve products were modelled consistent with the PEMMDB data, considering their activation time and duration and qualified generation units.
- Hourly requirements for each (existing) bidding zone and reserve product were collected:
  - FCR and FRR requirements are modelled as mandatory;
  - RR is modelled as optional.

Please note that in performing nodal simulations, Plexos does not allow reserve sharing across bidding zones to be taken into account. Hence, each reserve requirement must be fulfilled with generation units located in the given bidding zone.

2.2 Grid Assumptions

2.2.1 Grid Model

According to Article 4.2 (e) of the BZR Methodology, TSOs have the opportunity to model new network elements based on either of the following options:

- define multiple network models appropriately reflecting the gradual commissioning of new network elements throughout the target year; or
- where the first option is not possible, include, in all network models, all new network elements expected to be commissioned by 30 June of the target year.

The grid model was created In line with Article 4.2 (e) of the BZR Methodology described above, as well as with the generation and demand scenarios. The grid model was based on the TYNDP 2020 national trends scenario reflecting all projects with an expected commissioning date before the end of June 2025. A list of network elements excluded from the TYNDP 2025 reference case can be found in Annex 2.

2.2.2 Dynamic Line Rating

The Dynamic Line Rating (DLR) of OverHead Lines (OHLs) relies on the ampacity of OHLs being dependent on ambient weather conditions. Commonly, OHLs are designed for peak summer conditions, where the ampacity is at its lowest due to the high temperatures. As weather conditions are less severe for most of the year, the ampacity of the existing lines can be significantly increased in these periods. The highest potential for DLR is observed in windy areas, as convective cooling and loading of OHLs are strongly coupled.

The major task for system operators in applying DLR is assessing the present and forecasting the future ambient conditions as well as the initial status of the line. The current carrying capacity is calculated based on these conditions, and the results are integrated into dispatch centre processes, considering adequate security margins. An increase in ampacity supports grid operators in making more efficient use of existing grid assets and avoiding congestion restrictions.

A decentralised approach was used to model the DLR. DLR values were collected from each TSO through dedicated data collection. For the selected climate years (1989, 1995, and 2009), TSOs reported maximum dynamic capacity (F_{max}) values. This represents the first time DLR collecting and modelling were undertaken for an ENTSO-E study. In general, the modelling approach adopted in this study reflects expected operational practices in 2025 as well as modelling approaches adopted by TSOs in other long terms studies (e.g. TYNDP, National Deveopment Plans [NDP]). Roughly 500 lines adopted DLR in the framework of this study.

2.2.3 Nodal allocation

The model developed for the LMP study is highly granular, as the network is modelled on a nodal level. Therefore, the information provided within the datasets or by forecasting tools for generation and demand had to be allocated to the nodes of the network. A high-level overview of these processes is provided below, and a more detailed description can be found in Annex 3.

The individual nodal load time series are derived from the hourly zonal load forecast used for the MAF 2020, produced by the tool TRAPUNTA. This disaggregation process uses a load snapshot from the TYNDP 2020, which allows nodal power consumption to be split between unscalable and scalable loads. The scalable load pattern is adjusted to the aforementioned MAF climate-dependent hourly forecast for each of the three selected climate years.

The highly granular generation information needed for the study comes from two different databases, the PEMMDB and the Common Grid Model (CGM); it is, therefore, necessary to match and align the generation data (capacities and technology types) of the databases. This matching is performed internally by ENTSO-E for every PEMMDB generation unit – using the common unit identifier when available or a unit-specific set of characteristics (such as generator name, location, capacity, or fuel category) otherwise – and then validated by TSOs. A second step is required to cope with PEMMDB aggregated capacity. The CGM's remaining unmatched capacity per production type must be aligned to the more recent PEMMDB data. TSOs are therefore given the option to either upscale/downscale CGM capacity or create/delete generating units to even the datasets. After this step, any significant gap remaining (>3 %) is dealt with by adjusting the loads, therefore distributing the misalignment on all nodes. Finally, the PEMMDB aggregated capacity is disaggregated to the generating unit level using the formerly unmatched CGM units.

Additional measures might be considered for specific technologies:

Although the TSOs eventually made the disaggregation of PEMMDB excessive renewable generation capacity (second step) entirely expert-based, in the case of wind and solar (farm and Rooftop undistinguished), the use of an algorithm was considered. Such an algorithm would assess the likelihood of each of the country's municipalities having wind or solar generation and the maximum potential amount of installed capacity based on meteorological and topographical features and information on existing constructions and facilities. This information can then be aggregated per substation (each municipality being allocated to the nearest substation) before the algorithm optimises the total potential electricity production (likelihood multiplied by capacity) to determine the generators to be created for each substation in the grid model.

For some types of hydro technology, generating units must be linked to a head reservoir or a tail reservoir – which could have been used to model cascading. However, this information on storage can only be found in the PEMMDB. Matching a CGM generation unit to a reservoir is quite straightforward when the corresponding unit can be found in the PEMMDB, but aggregated generation and storage capacities or units that do not have a reservoir attached in the PEMMDB require the cautious splitting of the aggregated zonal storage capacity to the nodal level proportionally to the capacity of the generating units without a storage reference. Furthermore, zonal hydro inflows and constraints for technologies are distributed among the nodal generating units and storage relative to their capacity.

The CGM's ´Other RES´ nomenclature is addressed by aggregating the PEMMDB's five corresponding production types before aligning the capacities. The corresponding hourly time series for available generating capacity are aggregated accordingly, proportional to the installed capacity for each production type.

The same procedure was applied to the various PEMMDB bands for the 'Other Non-RES' production type. Information contained in each band and the corresponding time series are weighted according to the capacity of the band and are then aggregated.

Although the PEMMDB contains information about DSR, TSOs were asked to provide details about explicit and implicit DSR at the zonal level. The TYNDP snapshot with nodal-level scalable and unscalable load categories was then used to distribute the two DSR categories at the nodal level. On the one hand, since explicit DSR is provided by industries, it was assumed it could be distributed among the nodes proportionally to each node's unscalable load; One the other hand implicit DSR corresponds to the price elasticity of the load and was distributed proportionally to the scalable load of each node.

2.3 Simulation Chain

2.3.1 Description for the different steps of the simulation

A proper simulation chain was set up to compute reliable LMPs for the Continental Europe and Irish power system. This chain comprises three main steps:

1. Planned outage scheduling step: in order to reflect the impact of planned maintenances of generation units on prices, a simulation step was introduced to define a suitable outage plan.
2. Critical network element with a contingency (CNEC) list definition: the list of critical network elements and contingencies to be considered when computing LMPs is defined according to a dedicated procedure.
3. N-1 final simulations: LMPs are computed by implementing the N-1 security criterion.

In addition, an ex-post workstream investigated the impact of topological remedial actions for highly congested weeks (identified according to the methodology described in Section 2.3.5). For this scope, two additional steps were carried out:

4. Identification of relevant topological remedial actions (TRAs).
5. TRA simulation.

A DC (optimal) power flow approach was applied in each relevant step of this study.

Planned Outage Scheduling	› Planned maintenance for thermal generation units are allocated in each climate year in order to minimise the impacts on reserve margins. The PASA model available in the Plexos software was adopted for this, while planned maintenance data are taken from the PEMMDB dataset.
CNEC selection	› Daily targets for storage are defined over the weekly time-horizon running a mid-term (MT) optimisation, considering weekly initial and end values fixed (according to PEMMDB data) › An n-0 nodal market simulation is performed to estimate the expected loading of each 380 kV grid element; 380 kV elements loaded more than 70 % (50 % in case of double circuit lines) are identified as CNE. › Relevant contingencies for each CNE are identified, obtaining the initial CNECs list. › The list is validated/integrated by TSOs.
Final N-1 simulation	› Weekly storage targets are derived running a yearly MT simulation. › A zonal simulation is run considering zonal elasticity values to derive demand curve parameters (slope and intercept) to be implemented in the successive steps. › Daily targets for storage are defined over the weekly time-horizon running MT optimisation, considering weekly initial and end values fixed (according to PEMMDB data) › The final n-1 nodal market simulation is performed, considering all the relevant features (e.g. DSR implicit and explicit, DLR, final CNEC list, storage targets). No topological remedial actions (TRAs) were applied.
Identification of relevant TRAs	› On a subset of (3) selected weeks, TSOs identified relevant TRAs to be applied in order to relieve detected congestions in the "Final N-1 simulations" › TRAs have been properly modelled.
TRAs simulation	› Daily targets for storages are defined over the weekly time-horizon running a mid-term (MT) optimisation, considering weekly initial and end values fixed (according to PEMMDB data) › The final n-1 nodal market simulation is performed, considering all the relevant features (e.g. DSR implicit and explicit, DLR, final CNEC list, storage targets) and also TRAs.

Figure 1: Simulation Chain

In the following sub-sections, a detailed description of each of these steps is provided.

2.3.2 Step 1: Planned outage scheduling

Electricity market prices, as well as flows on the transmission network, are affected by generation availability. This is even more true when looking at nodal markets/simulations, where the availability of single power plants can change flow patterns and, consequently, nodal prices.

For this reason, it is important to model planned maintenance of generation units (especially for the "baseload" big power plants) in the LMP simulation chain.

Key maintenance data (e. g. average frequency and duration in a year) are applied in this study, considering available data in the PEMMDB for each single power plant. Then, the Plexos PASA ("Projected Assessment of System Adequacy") model was run. The objective of the PASA optimisation is to equalise capacity reserves across all peak periods, i. e. daily, weekly or monthly peak intervals in the given climate year.

The output of the PASA model is the maintenance period for each of the thermal generation units (consistent with the number of maintenance actions and average duration provided as an input); these outages are then implemented in each of the successive simulation steps.

2.3.3 Step 2: Scope and description of CNEC selection procedure

Scope of the procedure

Power systems are managed according to the so-called "N-1 criterion" to ensure a proper level of reliability. This is reflected in the System Operation Guidelines (Commission Regulation (EU) 2017/1485, SOGL hereafter), where this criterion is defined as: "the rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits".

Article 11.5.c of the "Methodology and assumptions that are to be used in the BZR process" confirms that security constraints based on Operational Security Limits (OSLs) and contingencies shall be reflected in the LMP computation, in line with Article 4.2 of the same document. This clarifies that:

- Contingencies and OSLs related to network elements operating at a nominal voltage higher than or equal to 380 kV shall be included;
- Contingencies and OSLs related to network elements operating at nominal voltage levels below 380 kV shall be excluded unless TSOs are able to properly justify their inclusion (considering the potential reasons provided in the methodology).

In any event, considering the huge dimensions of the model adopted in this study (≈25,000 nodes, ≈22,000 lines, ≈12,000 trafos, ≈15,000 generation units), a full N-1 assessment would require overly long run times, even if limited to the 380 kV network. For this reason, a proper CNEC selection procedure was introduced: the scope of this is to identify relevant CNECs that could bind the nodal simulations, limiting the set of constraints to be included in the models (e.g. avoid including constraints that would never be binding).

Description of the procedure

The CNEC selection procedure adopted in this study is based on three main steps:

1. Identification of relevant (380 kV or above) CNEs, using N-0 simulations

2. For each CNE, identification of relevant (380 kV or above) Contingency

3. Validation of the resulting CNEC list

Note that trips of generation units have not been explicitly considered; they have been deemed less impactful. If they are radially connected, and the radial connection is identified as a relevant contingency for one or mode CNEs, they are implicitly simulated.

CNEs selection	› **A N-State premininary simulation has been run** › **Among all the 380 kV network elements, the most loaded ones are identified as CNEs** (Loaded more than 70 % (50 % if part of a double circuit line). Cross-border one are included by default.)
Contingency idetification	› **For each selected CNE most impacting contingencies are identified.** (A procedure in line with the "Methology for coordinating operational security analysis in accordance with Article 75 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation"
Validation	› **TSOs have been asked to check the results and integrate additional CNECs considered relevant** (including 220kV elements)

Figure 2: Visual representation of the CNEC selection process

In the first step, an n-0 nodal simulation was run. In this simulation, no implicit DSR was modelled, and a linear unit commitment optimality approach was applied. The outcomes of these runs were used to identify relevant CNEs (380 kV or above): all the elements loaded to more than a given threshold in at least one of the simulated hours (considering all climate years and weeks) are identified as a relevant CNE. For the purposes of this study, this threshold was fixed to 70 % (and 50 % for lines that are part of a double circuit connection). In addition, all the 380kV cross-border elements in the existing bidding zone configuration are identified as relevant CNEs.

In the second step, for each relevant CNE identified in the first step, the set of relevant contingencies is identified by applying a methodology in line with the influence computation method defined in the "Methodology for coordinating operational security analysis in accordance with Article 75 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation" (further details are provided in Annex 4).

After this step, a preliminary CNEC list is produced, including all the CNEs identified in the first step alone and in combination with each contingency identified in the second step.

In the last step, TSOs were asked to validate the list and/or to include additional CNECs in the list as follows:

1. CNECs that are included in the existing capacity calculation processes (for the existing bidding zone configuration);
2. CNECs that include elements (CNE and/or contingency) at a voltage level lower than 380 kV, with a justification provided for each;
3. CNECs that include exceptional contingencies relevant to the study.

Table 7 summarises the number of CNECs added per country and the reason for inclusion (specifying the type of justification for the second reason).

<table>
<tr><th>Country</th><th>Reason for Inclusion</th><th>Justification (for Reason 2)</th><th colspan="2">Number of CNECs</th></tr>
<tr><td>AT</td><td>1) Capacity calculation</td><td></td><td colspan="2">5</td></tr>
<tr><td></td><td>2) Lower voltage CNEC</td><td>Cross-zonal status</td><td colspan="2">92</td></tr>
<tr><td>BE</td><td>1) Capacity calculation</td><td></td><td colspan="2">47</td></tr>
<tr><td>CZ</td><td>1) Capacity calculation</td><td></td><td colspan="2">19</td></tr>
<tr><td></td><td>2) Lower voltage CNEC</td><td>Important in CC process</td><td colspan="2">16</td></tr>
<tr><td>DE</td><td>1) Capacity calculation</td><td></td><td colspan="2">432</td></tr>
<tr><td></td><td>2) Exceptional contingencies</td><td></td><td colspan="2">2</td></tr>
<tr><td>FR</td><td>1) Capacity calculation</td><td></td><td colspan="2">6</td></tr>
<tr><td>HU</td><td>1) Capacity calculation</td><td></td><td colspan="2">6</td></tr>
<tr><td></td><td>2) Lower voltage CNEC</td><td>Based on NDP model</td><td colspan="2">4</td></tr>
<tr><td>IT</td><td>1) Capacity calculation</td><td></td><td colspan="2">36</td></tr>
<tr><td></td><td>2) Lower voltage CNEC</td><td>Important in CC process</td><td colspan="2">51</td></tr>
<tr><td></td><td>3) Exceptional contingencies</td><td></td><td colspan="2">18</td></tr>
<tr><td>NL</td><td>1) Capacity calculation</td><td></td><td colspan="2">985</td></tr>
<tr><td rowspan="2">PL</td><td rowspan="2">2) Lower voltage CNEC</td><td>Cross-zonal status</td><td>2</td><td rowspan="2">5</td></tr>
<tr><td>Connected to cross-zonal element</td><td>3</td></tr>
<tr><td>PT</td><td>1) Capacity calculation</td><td></td><td colspan="2">3</td></tr>
</table>

Table 7: Additional CNECs per country (if relevant) (Due to a technical issue, around 50 additional CNECs provided for the Spanish Electrical System were not considered in the model for the final LMP simulations.)

The total number of CNECs included in the final model is around 25,000. Table 8 summarises the total N-1 CNECs and N-0 CNEs at <380 kV requested by TSOs (all elements at voltage level 380 kV and above are included by default in N-0 CNECs.).

Country	Nr. CNECs		Country	Nr. CNECs		Country	Nr. CNECs
AL	115		ES	882		PL	338
AT	327		FR	1,484		PT	221
BA	51		GR	175		RO	269
BE	631		HR	163		RS	529
BG	243		HU	484		SI	164
CH	533		IT	2,274		SK	369
CZ	304		ME	60		IE_UKNI	34
DE	4,887		MK	199			
DK	84		NL	3,766			

Table 8: Total number of N-1 CNECs and N-0 CNEs at <380kV requested by TSOs.
All elements at voltage level 380 kV and above are included by default in N-0 CNECs.

2.3.4 Step 3: Final N-1 simulation and main simplifications

Final LMP simulations were run with the following key features:

- 380/220 kV grid of the Continental Europe and Ireland power system is extensively modelled
- N-1 security criterion implemented
- Planned outages of generation units considered
- Explicit and implicit DSR modelled

The following main simplifications of the ACER methodology were applied to achieve reasonable runtimes (to meet the project deadline):

- **Linear unit commitment optimality approach, applying a must-run constraint for nuclear units:** this approach reduces the runtime of the model since it relaxes the mathematical formulation from a mixed-integer linear to a linear problem. In this regard, the significant positive effect on runtimes results from the large number of generators in the model for which integer constraints would have been considered otherwise. Considering that a significant share of the generation capacity in 2025 is contributed by small decentralised units and given the long-term horizon of this study, the impact of this simplification is deemed negligible (in relation to the scope of this study to identify the main geographical price patterns).
- **Two-hour granularity: each day is divided into 12 two-hour blocks, with input data (e. g., load and RES) averaged among them: c**onsidering the long-term planning horizon, the uncertainties in load and RES profiles, and that the 1-h MTU is, in any event, a simplification of a more complex reality (in 2025, a 15-min MTU will be applied in the EU and real-time operation is performed with an even higher degree of granularity), TSOs deemed the increase of the MTU size acceptable (considering the study's scope to identify main geographical price patterns).
- **Parallel daily simulations:** each day of the week is simulated independently, but a weekly storage optimisation is run on top to ensure the proper coordination of storage resources across the week (and across the year, since weekly targets are derived in advance with a dedicated mid-term yearly simulation). Sequential simulations (in which the d-th day in the week starts from the fixed results of day d-1) required an increased runtime due to overconstrained domains faced by the algorithm in the first hours of each day after the first. For this reason, each day was treated independently, but a coherency in the storage management was ensured across the week. Again, considering that the scope of the study is to detect main geographical price patterns and that we are simulating a long-term horizon, this assumption was deemed acceptable by TSOs.

For each of these assumptions (and for some others), a dedicated sensitivity analysis was carried out to prove their impact was negligible given the scope of this study (see Section 2.3.7).

2.3.5 Ex-post workstream – identification of topological remedial actions

According to the ACER Decision on the BZR Methodology, assumptions for the BZR process and the alternative bidding zone configurations to be considered (Annex I of the BZR Methodology, Article 9.6), the availability and activation of non-costly remedial actions shall reflect the expected operational practices of TSOs for the target year. These non-costly remedial actions are assumed to have no cost implications.

In the course of the project, some TSOs used the possibility of applying preventive TRAs on a set of relevant weeks that are relatively congested. The selection of weeks for TRAs is based on a ranking obtained by summing the shadow prices for the week, considering this quantity for the entire BZRR but also taking into account disparities between subsidiary regions.

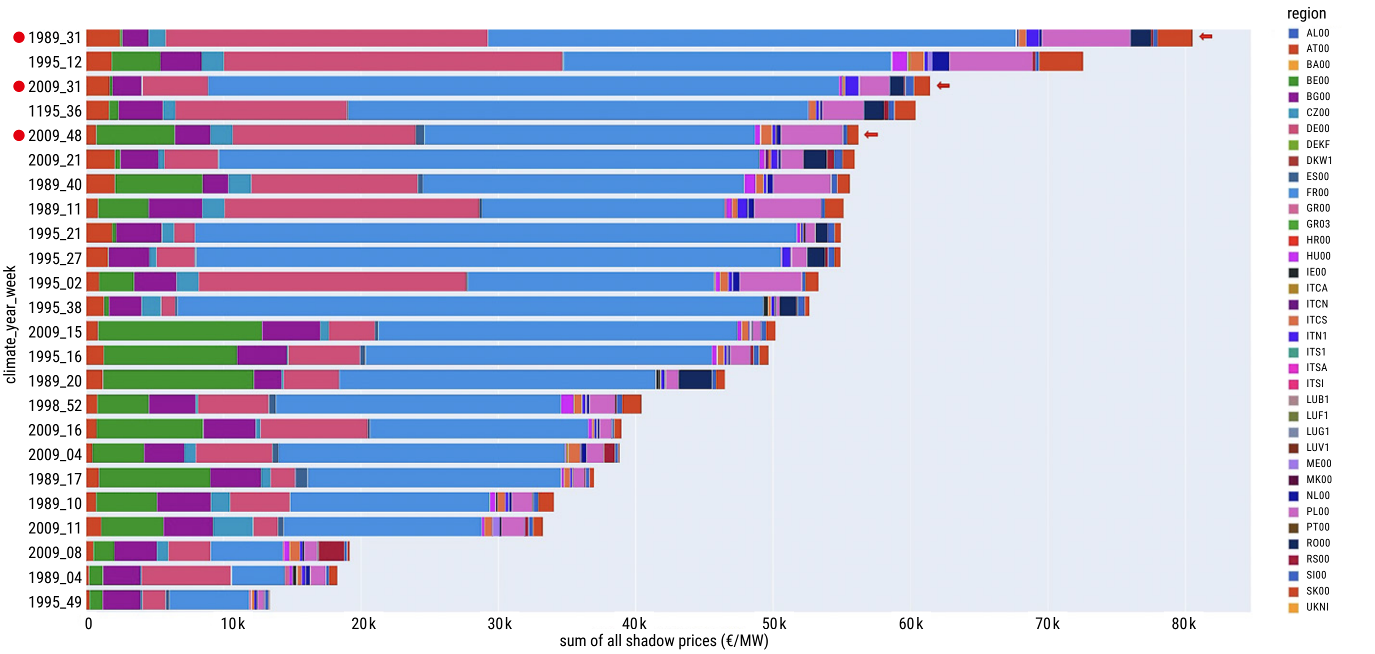

Figure 3: Topological remedial actions by week[4]

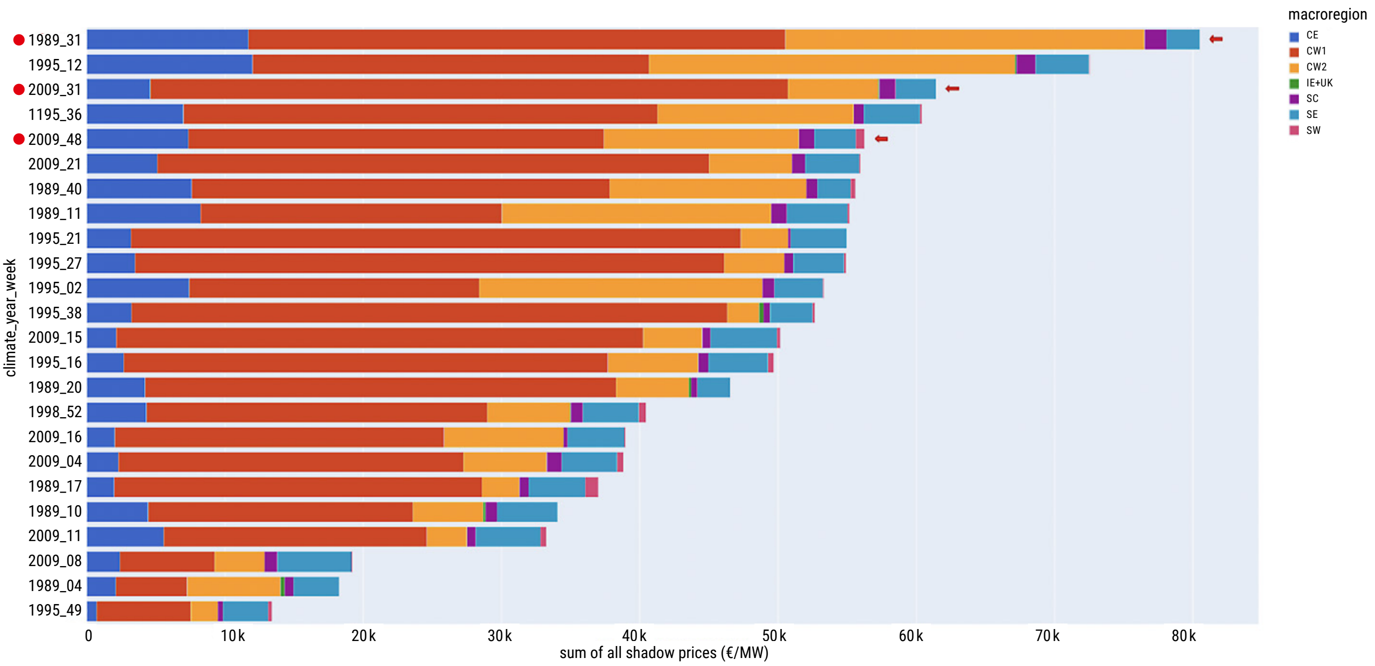

Figure 4: Topological remedial actions by week[5]

4 Selection based on the sum of the shadow prices per region for each week. The proposed selected weeks are identified by a red dot.
5 Selection based on the sum of the shadow prices per macroregion for each week. The proposed selected weeks are identified by a red dot.

The selected weeks considered for TRAs are:

- Climate week 1989_w31 – the most congested week for the entire synchronous area
- Climate week 2009_w31 – the most representative week for CW1 and IN, and the most congested week for FR00
- Climate week 2009_w48 – the most congested for SWE

Four TSOs delivered topological remedial actions as indicated in the list below:

- France for all three weeks
- The Czech Republic for the climate weeks 1989w31 and 2009w31
- Spain and Portugal for climate week 2009w48

TSOs applying TRAs for a given week had the opportunity to consider two types of actions:

- Weekly reconfiguration of given substations
- Hourly management of breakers open/close status. For a given element, the TSOs must specify time slots within which the status of the element is switched from its normal status to the other.

Reconfiguration of given substations

For every substation, TSOs could provide the lines connected to the considered busbars, allowing the substation to be reconfigured for the TRA. This offers new modelling possibilities of, for example, switching a line from one busbar to another. Note that when reconfiguring the substation in this way, the new configuration is then fixed for the entire week, and there is no longer a dynamic hourly configuration in the simulation. The last-mentioned action, the dynamic hourly configuration, was also possible and allowed TSOs to dynamically assign lines to different busbars.

Hourly management of breakers status

For every breaker/switch element within a substation, TSOs could provide an hourly schedule for the management of the element. The window during which the TRA is applied to the considered element is described with the given start and end hours between which the status of the element is switched from its normal status. Several such timeslots could be provided to allow for elements to be opened and closed multiple times within the week.

2.3.6 Ex-post Workstream – TRA simulation

LMP simulations were run to test the beneficial effect of modelled TRAs with the following main features:

- 380/220 kV grid model of the Continental Europe and Irish Power system extensively modelled
- N-1 security criterion implemented
- Planned outages of generation units considered
- Explicit and implicit DSR modelled
- Topological Remedial Actions modelled

In order to achieve reasonable runtimes (to meet the project deadline), the three main simplifications mentioned in paragraph 2.3.4 were applied.

2.3.7 Sensitivity analysis

In the course of the project, several sensitivity runs (without TRAs) were performed to provide further insights into the results of the LMP simulation. In particular, the aim of the sensitivity runs was to understand how the applied simplifications, described in Section 2.3.4., as well as different CO_2 and fuel-price assumptions, would have changed the results.

In total, the following six sensitivity runs were performed for a congested winter week (climate week 1995_w12):

- S1: Integer unit commitment (instead of the linear approach)
- S2: Sequential daily optimisation (instead of the parallel approach)
- S3: 1-h granularity (instead of the 2-h granularity)
- S4: CO_2 price (increased to 90 €/t)
- S5: New fuel prices (in addition to the increased CO_2 price of 90€/t)
- S6: Nuclear must-run deactivated.

Fuel	Prices used for Scenario Building 2022 (€/GJ)	New Fuels Prices for Sensitivity Runs (€/GJ)
Closed loop pumping	0	0
Open loop pumping	0	0
Reservoir	0	0
Run of river and pondage	0	0
Gas	5.569	26.3889
Hard coal	2.304	2.6751
Heavy oil	10.56	12.9285
Light oil	12.87	15.7567
Lignite G1	1.4	1.6255
Lignite G2	1.8	2.0899
Lignite G3	2.37	2.7517
Lignite G4	3.1	3.5993
Nuclear	0.47	0.47
Oil shale	1.56	1.9099

Table 9: New fuels prices for sensitivity runs

Overall, the results of the sensitivity analyses indicate that:

- The simplifications introduced in the main simulations (linear unit commitment with must-run constraints for nuclear, parallel daily optimisation, 2-h granularity) do not significantly affect the results; and
- Results are sensitive to CO_2 and fuel price assumptions

In Section 2.4.2, we focus on the results of the sensitivity runs S1 and S2 that were requested by ACER. The results of the further sensitivity runs can be found in Annex 5.

2.3.8 Additional steps: Snapshot selection

From all simulated timesteps, a subset of snapshots is identified for a full flow decomposition analysis to identify loop-flows and other components under different network conditions.

The LMP SG developed a methodology to identify the subset that is the most:

- representative in terms of different network conditions (e.g. large flows/high congestion vs few flows/low congestion); and
- representative in terms of capturing the respective variety of conditions across the entire synchronous area.

The methodology is based on a network flow indicator (MW × km) for which different percentiles across the distribution are selected.

1. Indicator
- **Sum of network flows multiplied with flow distance [MW km]**

2. Geographic aggregation / weighting
- **Macroregions w/ load based weighting**

3. Selection algorithm
- **24 percentiles across the space: [0.04, 0.08, 0.12, …, 0.92, 0.96]**

For each percentile, choose the snapshot that, across all 6 macroregions, best represents the respective percentile.

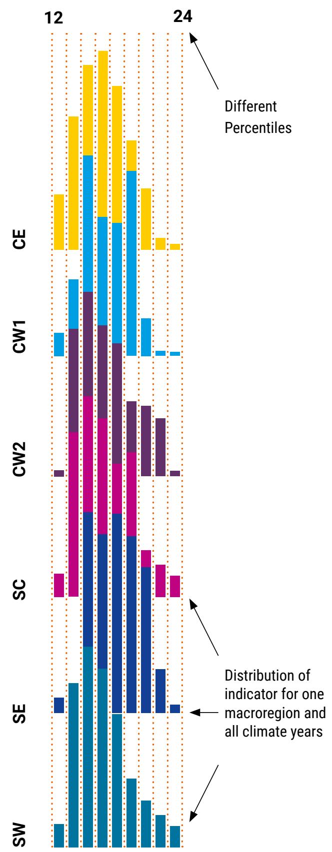

Figure 5: Snapshot selection

$$\lambda_r = \frac{\sum_{y\in Y} V_{y,r}^{load}}{\sum_{y\in Y}\sum_{r\in R} V_{y,r}^{load}} \qquad \forall\, r \in R$$

$$\Omega_{r,s} = \sum_{l\in L_r} |F_{l,s}| \cdot geographical\_length\,(l) \qquad \forall\, r \in R, \quad s \in S$$

$$\Omega_{r,s}^{stw.} = \lambda_r \cdot \frac{\Omega_{r,s} - mean(\boldsymbol{\Omega}_{r,s\in S})}{std(\boldsymbol{\Omega}_{r,s\in S})} \qquad \forall\, r \in R, \quad s \in S$$

$$E_{p,s} = \sqrt{\sum_{r\in R} \left[\Omega_{r,s}^{stw.} - percentile\left(\boldsymbol{\Omega}_{r,s\in S}^{stw.}, \quad p\right)\right]^2} \qquad \forall\, p \in P, \quad s \in S$$

→ For every $p \in P$, choose $s \in S$ with minimum $E_{p,s}$.

λ: weighting factor
R: set of regions (i.e. macroregions)
s: Snapshot (year_week_hour)
S: set of all snapshots / mtus
F: line flow [MW]
L: set of all lines inside synchronous area
L_r: subset of all lines in region r
Ω: Network Flow indicator
Y: set of all years (1987 - 2016)
P: set of percentiles p
stw.: standardised and weighted

Figure 6: Snapshot selection formulation

Percentile	Winning Snapshot	Climate Year & Week	Hour of Week	Duplicated Snapshot?
P_0.04	2009-08-04/00:00:00	2009_31	120	No
p_0.08	1989-08-03/08:00:00	1989_31	104	No
p_0.12	1995-07-07/00:00:00	1995_27	120	No
p_0.16	1989-08-03/06:00:00	1989_31	102	No
p_0.20	**1989-08-03/06:00:00**	**1989_31**	**102**	**Yes**
p_0.24	1995-07-03/22:00:00	1995_27	46	No
p_0.28	**1995-07-03/22:00:00**	**1995_27**	**46**	**Yes**
p_0.32	**1995-07-03/22:00:00**	**1995_27**	**46**	**Yes**
p_0.36	**1995-07-03/22:00:00**	**1995_27**	**46**	**Yes**
p_0.40	1995-09-17/18:00:00	1995_38	18	No
p_0.44	**1995-09-17/18:00:00**	**1995_38**	**18**	**Yes**
p_0.48	1989-03-08/22:00:00	1989_10	94	No
p_0.52	2009-03-15/10:00:00	2009_11	82	No
p_0.56	1995-09-20/14:00:00	1995_38	86	No
p_0.60	**1995-09-20/14:00:00**	**1995_38**	**86**	**Yes**
p_0.64	1995-12-03/14:00:00	1995_49	14	No
p_0.68	2009-01-24/06:00:00	2009_04	54	No
p_0.72	2009-01-24/14:00:00	2009_04	62	No
p_0.76	1995-01-08/08:00:00	1995_02	8	No
p_0.80	**1995-01-08/08:00:00**	**1995_02**	**8**	**Yes**
p_0.84	2009-02-23/10:00:00	2009_08	106	No
p_0.88	1995-01-09/22:00:00	1995_02	46	No
p_0.92	**1995-01-09/22:00:00**	**1995_02**	**46**	**Yes**
p_0.96	2009-01-23/10:00:00	2009_04	34	No

Table 10: Snapshot Selection Results. Snapshots highlighted in bold are duplicates.

2.3.9 Implementation of the selected snapshots in the PSSE model

Section 2.3.8 describes the selection of snapshots for a flow decomposition analysis of flow patterns, specifically loop and internal flows, under different network conditions. Since this assessment is carried out using the software PSSE, its model must be linked to the market outcomes from the Plexos model; a script was built to accomplish this.

The automated process takes various quantities from the Plexos results files as inputs. The script then uses these to produce commands for the PSSE API based on various mappings linking the representations of several classes of Plexos model elements to their representations in PSSE.

Specifically, the Plexos market-outcome quantities to which the corresponding model elements in PSSE were adjusted are:

- generator active power,
- active power of batteries and P2G units,
- load active power (whereas the amount of activated DSR was subtracted from the load),
- power flows through High Voltage Direct Current (HVDC) and High Voltage Alternating Current (HVAC) elements, and
- PST phase angles.

Disclaimer

The TSOs also delivered the requested snapshots for flow decomposition analysis/assessing loop flow and internal flow indicators in the first step of ACER's procedure for identifying alternative bidding zone configurations. The large geographical scope of the area under assessment prevents TSOs from identifying a subset of two or four snapshots that are representative of all regions and bidding zones, the 24 simulated weeks and their different power flow scenarios (high, average and low flow) in the power system). For this reason, TSOs could not decide on a relevant proposal to select a suitable subset as requested by ACER; ACER is strongly advised to use all snapshots provided in their assessment.

2.4 Results

2.4.1 Nodal prices

The central outcome of the LMP-simulations is the nodal prices, which reflect the marginal costs of an additional load at a specific node in the grid. A separate nodal price is calculated for each of the 2016 simulated timestamps[6] and every node included in the grid model.

First, the hourly nodal prices per country for all the nodes within the country are presented in Figure 7. This graph shows the observed volatility of the nodal prices in a country but does not necessarily show the within-country price spreads. For the latter, we have to look at the intraregional price spread, defined as the price for the 5th and 95th percentile of the hourly nodal prices in a country. This intraregional price spread is given in Figure 8.

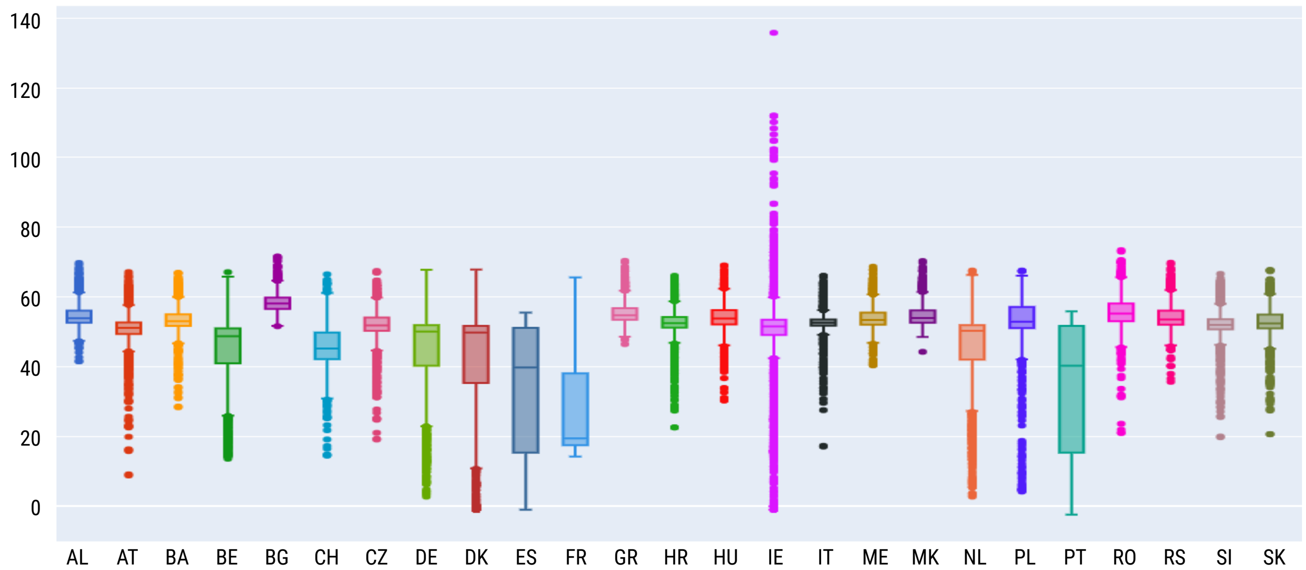

Figure 7: Boxplot: hourly nodal prices per country [€/MWh]

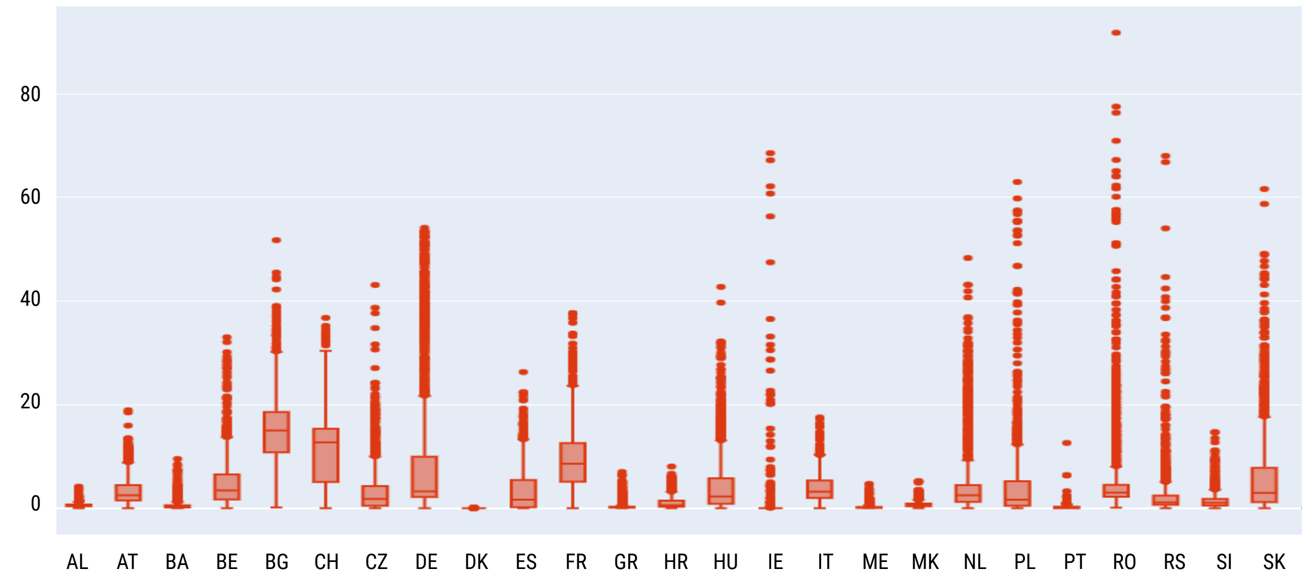

Figure 8: Hourly intraregional price spread for p05–p95 in €/MWh

6 8 weeks x 7 days x 12 hours x 3 climate years

Figure 9 maps the average nodal prices across all simulated climate years, weeks and timestamps. Spreads between average prices mainly occur on country borders, but some spreads are observed within countries.

The nodal prices vary across time and geographical space, mainly in relation to whether the week is congested (e.g. with high infeed of renewables and/or high load) or uncongested. In general, the more congestion in the grid, the more significant the price spreads between individual nodes.

To illustrate this effect, Figure 10 and Figure 11 show the average nodal prices for climate year 1989, week 4 (as an example of a largely uncongested week), and the average nodal prices for climate year 1989, week 31 (as an example of a fairly congested week).

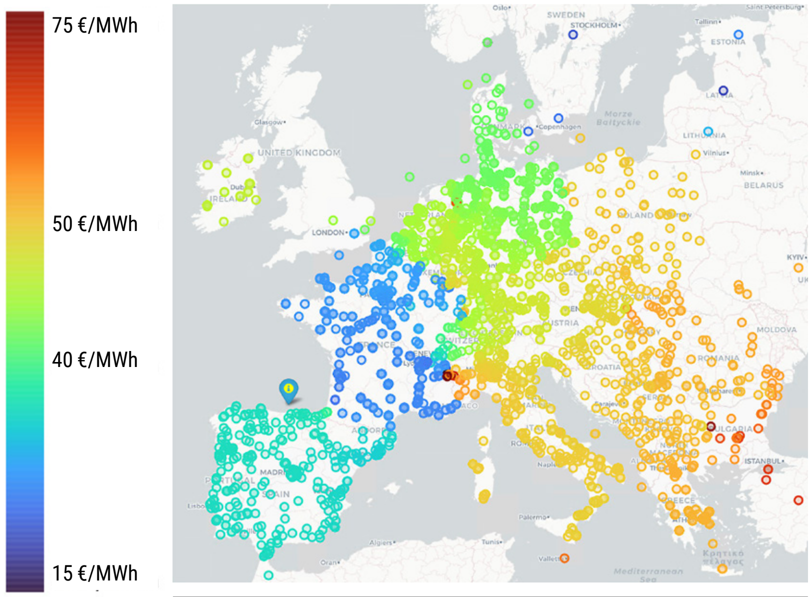

Figure 9: Average nodal prices

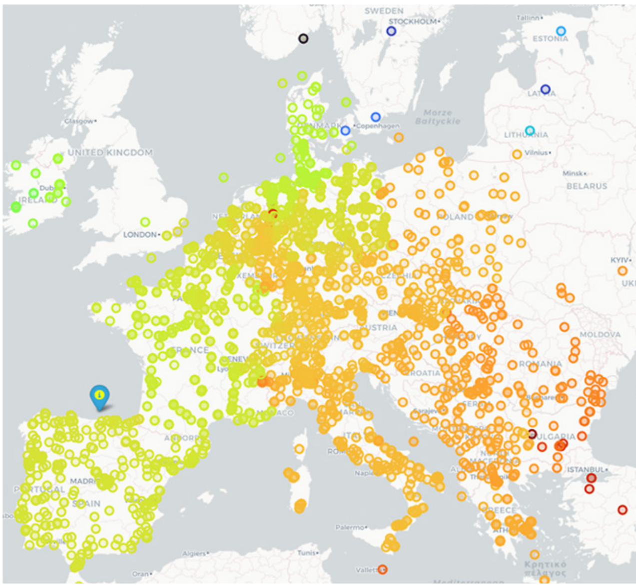

Figure 10: Average nodal prices – uncongested week [1989 w4].

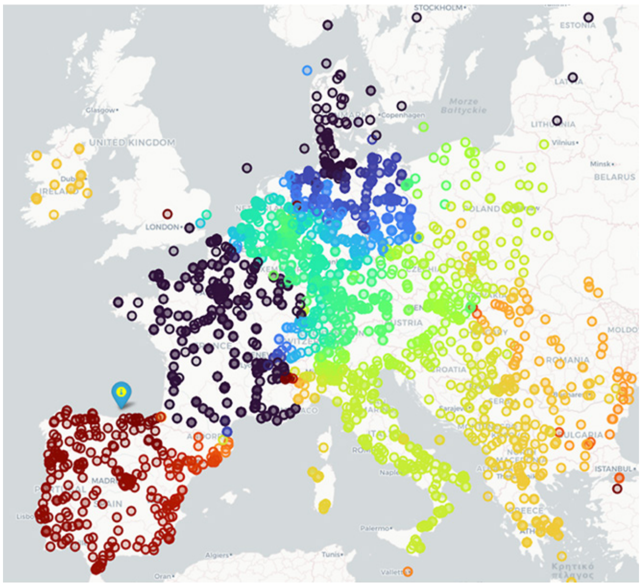

Figure 11: Average nodal prices – congested week [1989 w31]

2.4.2 Sensitivity analyses

Case Relative to Base Run	Integer Model	Sequential Days
Hourly average price per country	≈	≈
Intraregional price spreads	≈	≈
Sum of average hourly shadow prices	≈	≈
Hourly shadow price sum distribution	≈	≈
Conclusion	**Difference insignificant**	**As expected**

Table 11: Overview of the results from the sensitivity analyses

INTEGER two-hour granularity parallel days

Figure 12 provides insight into how the simulation results change where an integer (on the right side) is used instead of a linear model (on the left side) for performing the LMP simulations. The comparison of average nodal prices across all hours within the simulated week shows that the simulation results hardly change when going from a linear to an integer simulation model.

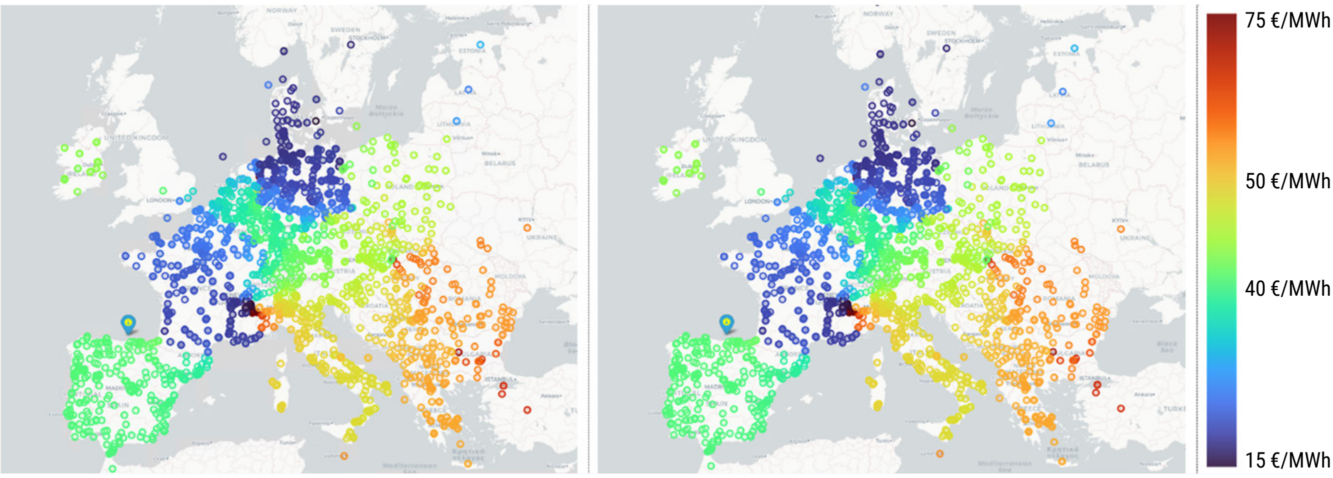

Figure 12: Overall average nodal prices – base model versus integer

LINEAR two-hour granularity sequential days

The integer results from the sensitivity run with the sequential daily optimisation approach do not change significantly from a high-level perspective. However, slight changes in the nodal prices can be identified from Figure 13; in South-East Europe in particular, there are, on average, higher nodal prices (on the right side) compared to the parallel daily simulation run (on the left side). These observations result from the model being more restrictive compared to the base model when the sequential daily optimisation is applied.

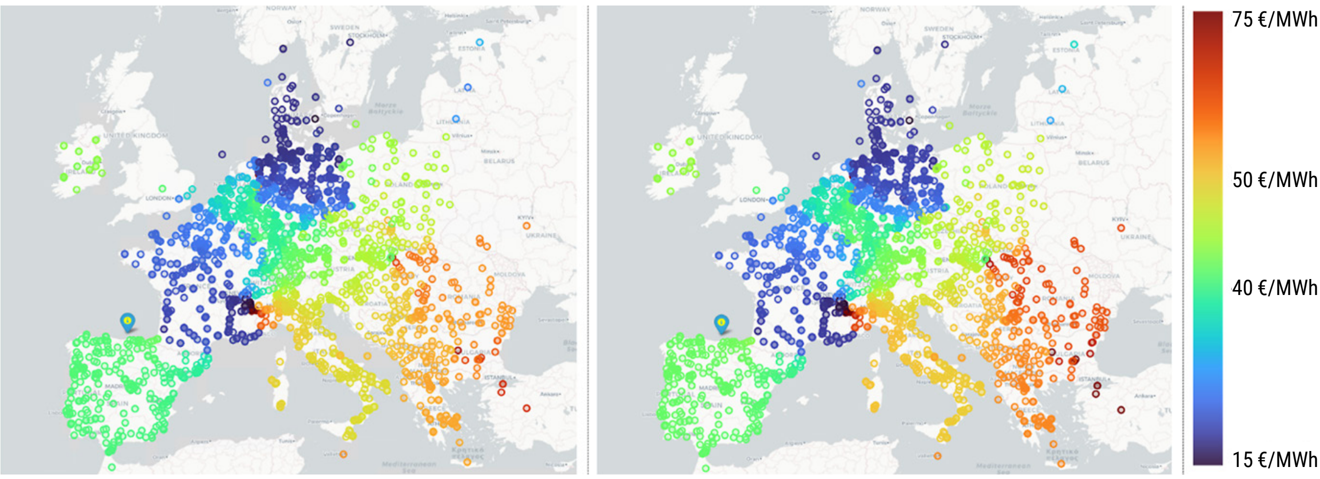

Figure 13: Overall average nodal prices - base model versus sequential daily optimisation

2.4.3 Consideration of TRAs

Impact of TRAs on nodal prices

Simulation results without TRAs are shown on the left side, the ones with TRAs are shown on the right side

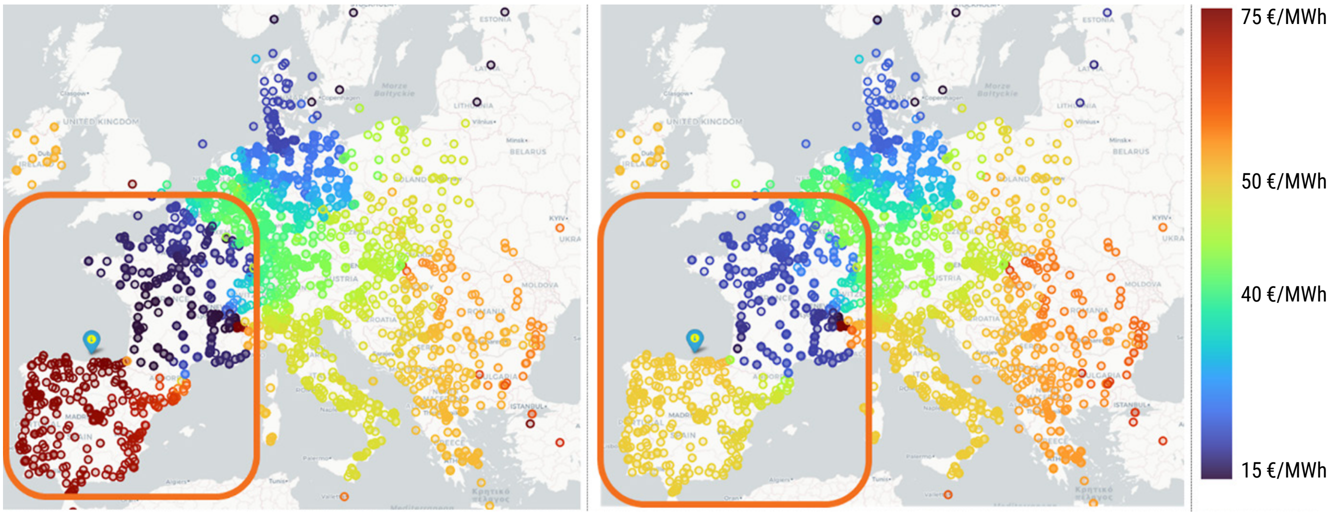

Figure 14: Overall average nodal prices [€/MWh] 1989w31 – comparison without TRAs (left) and with TRAs (right)

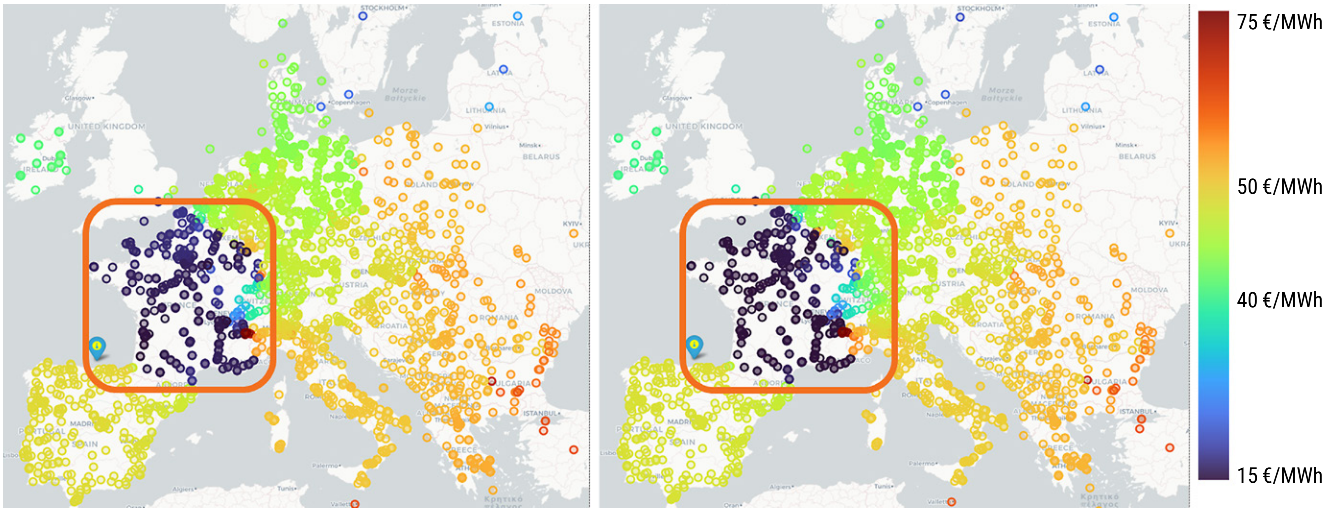

Figure 15: Overall average nodal prices [€/MWh] 2009w31 – comparison without TRAs (left) and with TRAs (right)

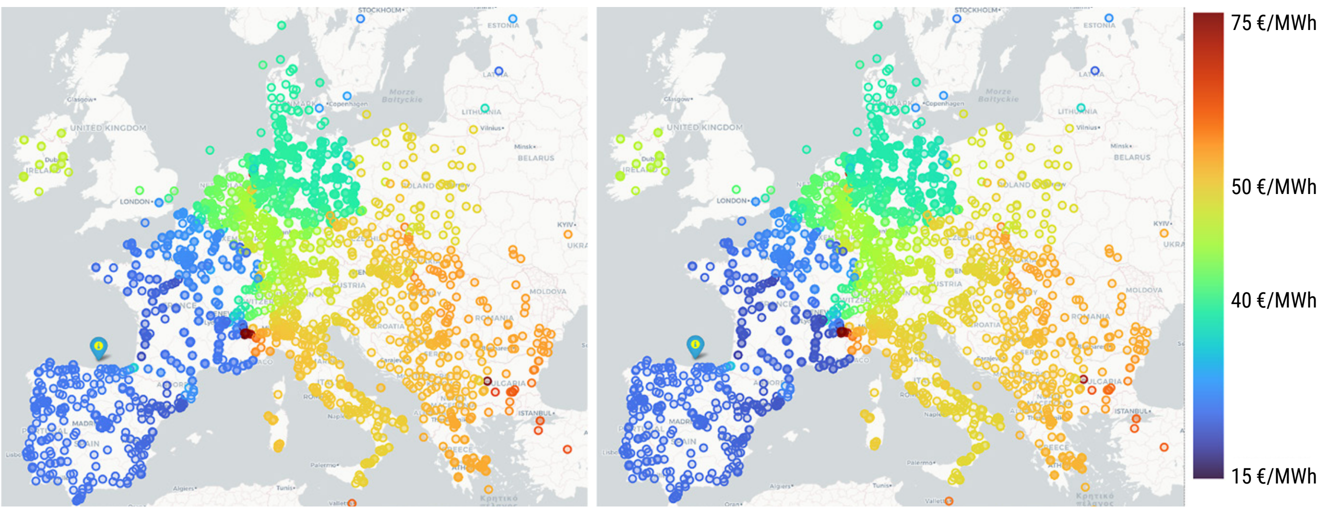

Figure 16: Overall average nodal prices [€/MWh] 2009w48 – with and without TRAs comparison

- › Climate week 1989_w31 – TRA leads to lower average prices in ES & PT, higher prices in FR
- › Climate week 2009_w31 – TRA leads to a slightly lower spread between average prices in FR
- › Climate week 2009_w48 – TRA does not cause any visual difference in average LMPs

Impact of TRAs on shadow prices

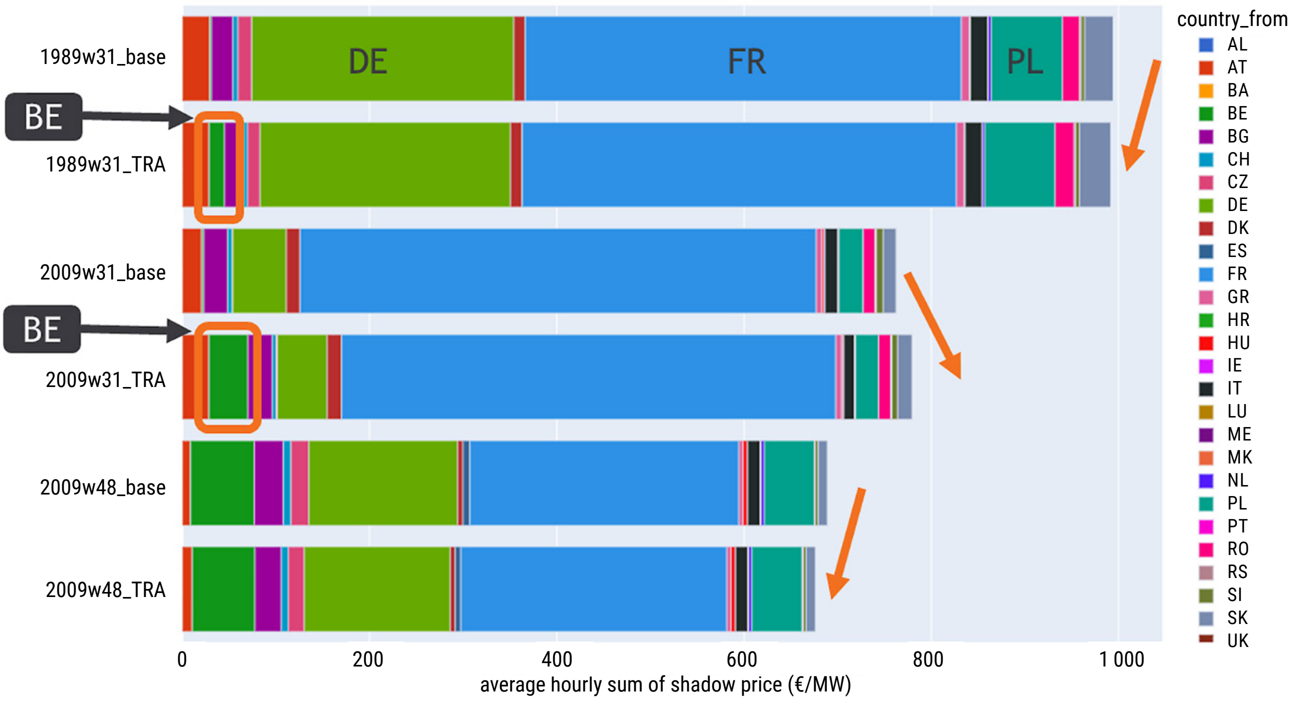

Figure 17: Comparison of the average hourly sum of shadow prices per country of origin for every week pre/post TRA

- › Climate week 1989_w31 – DE & FR slight decrease, BE increase
- › Climate week 2009_w31 – Overall increase, DE & FR slight decrease, BE significant increase
- › Climate week 2009_w48 – Overall decrease

Disclaimer

Each interested TSO provided TRAs to only relieve internal congestions, however some impacts on XB elements were observed.

Normally, the coordination of remedial actions is part of the regional capacity calculation and operational security analysis processes.

As TRAs were not coordinated, impact of applied TRAs may be found in some countries on internal elements. New elements with non-zero shadow prices (due to the application of TRAs by few TSOs) could be found in countries where TSOs have not decided to apply TRAs.

This type of coordination was not foreseen in the TRA methodology.

Energy Cost impact of TRAs

Figure 18 shows the impact on overall costs for consumers of the topological remedial actions application described in Section 2.3.5. For this purpose, the sum of nodal prices is multiplied by the nodal load across all nodes and hours for each of the three weeks simulated.

As can be seen from Figure 18, applying the described topological remedial actions leads to an overall reduction of consumer costs for all the three weeks simulated.

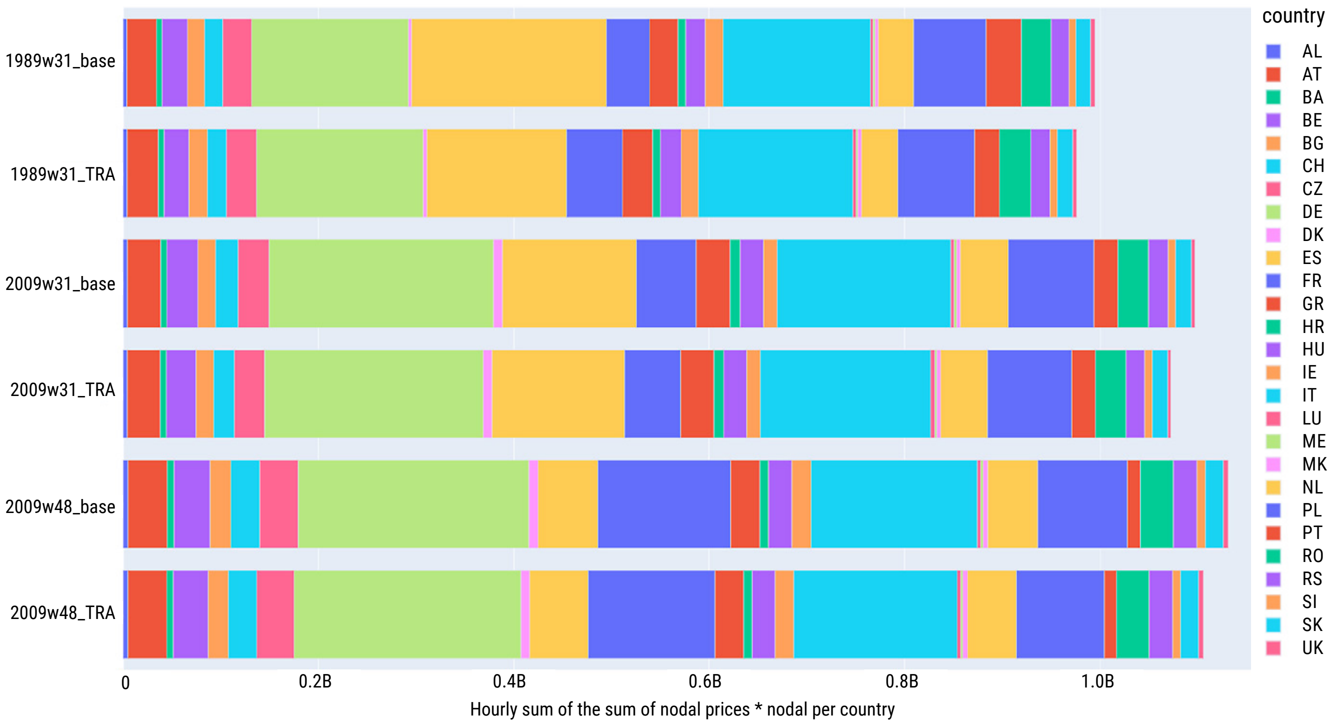

Figure 18: Comparison of the hourly sum of nodal prices nodal load per country for every week pre/post TRA

3. Assumptions, applied simulation chain and results of the LMP calculations in Nordic BZRR

3.1 Market Assumptions

3.1.1 Methodology for selecting Climate Years

In the Nordic region, hydro inflow and temperature (especially during the winter) are particularly important factors for the power system. This is due to the large share in the system of hydropower generation and temperature-sensitive electric heating. Wind power has become increasingly important in recent years and will be even more important in the future as its share in the system increases. Solar power still contributes only a tiny share of the total generation in the Nordic system and is currently less important.

For the LMP analysis, we have used the same climate years in the Nordic analysis as for the Continental Europe LMPs. Please refer to Section 1.2 for more information on the selection process. These years do not represent the full spread of variability for the Nordic system, but the advantage of using the same climate years for all regions is considered more important and is also a requirement of the ACER methodology.

We have compared the three years selected to other years in our database with regard to hydro inflow and temperature. Figure 19 shows how the selected climate years 1989, 1995 and 2009 compare to other years in the period 1989 to 2016 in terms of total hydro inflow in the Nordic system.

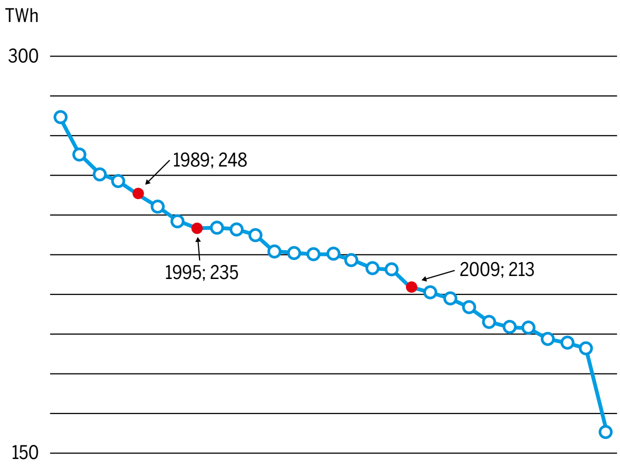

Figure 19: Total hydro inflow in the Nordic power systems for the years in the period 1989–2016.

Figure 19 shows that the selected years have the 5th, 8th and 19th highest inflow in the period. Hence, they are somewhat biased towards the wet side. As the study does not include any particularly dry years, situations with deficits in the Nordic region might have been missed. Ideally, Nordic TSOs would like to include these situations to describe additional price and flow situations. However, including additional years as allowed by the ACER methodology was not an option due to time constraints. Nevertheless, the years are fairly representative, and the Nordic TSOs do not regard the exclusion of particularly dry years as a significant shortcoming of the Nordic LMP study.

3.1.2 Methodology for weeks selected for simulation

For the Nordics, the LMP results include all MTUs for each of the three climate years agreed upon by all TSOs. However, the selected weeks were used to create the ACER-requested snapshots in PSSE. More information on this can be found in Section 2.3.5.

3.1.3 Scenarios used for generation and demand

The basis for the Nordic modelling was the MAF 2020 – National Trends – 2025 scenario. However, some adjustments and improvements were made to reflect the target year in the best possible way, such as:

- Hydropower was disaggregated from the aggregated model database using the most detailed data available to Nordic TSOs. Water courses are not modelled, though each individual plant is modelled with inflow and reservoir size according to that which they would have had access to in the water course.
- Consumption forecasts were updated to reflect the expected increase in power-intensive industry in the northern part of the region.
- Wind power forecasts were updated in line with the most recent Nordic-TSO forecasts by the start of the study.

3.1.4 Short term marginal costs

The prices used in the analysis are:

- CO_2: 23 €/t
- Gas: 23.26 €/$MWh_{thermal}$
- Coal: 13.64 €/$MWh_{thermal}$

The fuel costs in our analysis were inherited from the original MAF 2020 work. The world has significantly changed since those estimates were made for 2025, and the underlying assumptions are no longer as relevant. Results from our analysis, especially the price levels, should be interpreted with this in mind. The extent of price differences is also impacted, as there are hours and regions in our simulations with zero price, and the price difference with neighbouring regions increases if the general price level in the analysis increases.

However, the frequency and location of congestion are not as affected by this discrepancy, and we believe that the results are representative overall.

3.1.5 Implicit and explicit demand side response

A large share of the consumption in the Nordic region is accounted for by power-intensive industry, typically in the aluminium, steel, paper and pulp sectors. This industrial demand is modelled with a high price threshold, which is rarely reached in the simulation results. This explicit DSR is modelled in our model. The price threshold varies between industries, and most have a threshold between 200 and 500 €/MWh.

The remaining consumption is modelled as price elastic but with low price elasticity. The price elasticity is based on Nordic buy curves from the Nord Pool Power Exchange. Hourly buy curves from 2016 to 2020 were analysed, and we calculated the average price elasticity of consumption in the region of +/−10 % from the cleared system price for each hour. The average of these values is our estimate for price elasticity or explicit DSR.

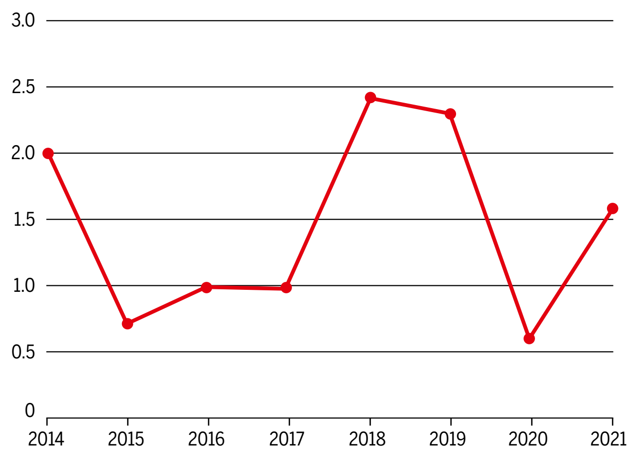

Figure 20: Estimated Nordic elasticity around system price (± 10 % of price), average per year

We selected a value of −3 % price elasticity for the study. The price elasticity begins at 50 €/MWh and ends at 500 €/MWh. This is more than we found from the buy curves we analysed.

We chose a higher value to be conservative with regard to the ACER default value and to account for a long-term price effect not observed in the buy curves.

The elasticity was applied to all the Nordic countries. There are differences between countries, especially since tariffs and the use of electricity for heating vary across the region. The value we found is significantly different from the ACER default value, and we do not have the data necessary to estimate values for individual countries. Therefore, we concluded that using the same estimated value for all countries is the best approach.

This is an estimate for short term price elasticity. Longer-term price sensitivity is also accounted for in the scenario assumptions. Elasticity was modelled as a −0.5 % reduction in demand at: 60, 70, 80, 95, 110, 125, 150, 170, 200, 235, 270, 320, 370, 430 and 500 €/MWh. This means that, in total, demand is reduced by 7.5 % when the price reaches 500 €/MWh.

3.1.6 Reserve modelling

For the Nordics, the reserve modelling is taken into account for FCR and FRR products. RR is not currently in use. The reserves are taken into account in the model by holding constant the generation capacity that is assumed to be contributing to reserves and is thus not available for the day-ahead market dispatch.

In the modelling, the reserve holding is not allocated to specific plants. Instead, the model is given the reserve needed to co-optimize the holding for plants that is available alongside the main dispatch.

Currently, the reserve requirement is fulfilled in some Nordic countries with capacity that is not normally available for the day-ahead market dispatch. The corresponding reserve capacity is not included in the reserve holding requirement in the model; the plants not available for the day-ahead market are also not included in the model. In addition, part of the capacity fulfilling the reserve requirements is assumed to be procured from consumption. This demand contribution is not explicitly modelled, as it is assumed to have only little effect on the day-ahead dispatch.

3.2 Grid Assumption

3.2.1 Grid model

The grid model used as a basis for the Nordic LMP study is the common Nordic planning model in PSSE. This is a power system model for power flow calculations and dynamic simulations used by all Nordic TSOs. The model includes the transmission grid for all the Nordic countries from 420 kV to 50 kV, as well as interconnectors to countries outside the region.

The Nordic planning model represents the current power system in the region. For prospective studies, relevant changes are made to the grid, generation and consumption to reflect the future power system. For the LMP study, the model was updated to reflect the Nordic power system in mid-2025. The study is performed for an intact grid adding N-1 restrictions.

The model was run on a so-called transmission hub level for the LMP calculations. That is, all nodes were assigned to the electrically closest transmission hub (≥ 220 kV), and all the constraints within a transmission hub were relaxed. The full grid is still modelled, but internal constraints within each hub are disregarded. Lines crossing between hubs, regardless of voltage level, are considered and can be included in multi-line constraints.

When the power transfer distribution factors matrix is calculated, it takes the detailed nodal distribution into account via a generation shift key proportional to the installed capacity in each node.

3.2.2 Dynamic line rating

The grid model used in the simulations does not have seasonal/temperature-dependent operational limit events, although this is used in operating the Nordic system. Ideally, temperature-dependent capacity limits should be applied in the simulations, but this step was omitted due to lack of time, and the same capacity limits were used for all simulated hours. Moreover, except for Finland, the capacity limits for the CNECs were based on thermal constraints at a 10-degree ambient temperature, while the capacity limits for single components were based on a 20-degree ambient temperature. For Finland, the CNECs limits were based on 30-degree ambient temperatures.

3.2.3 Topological remedial actions

The calculations for the Nordics were performed with the same grid topology for all MTUs.

3.2.4 Nodal allocation

In the Nordic planning grid model and market simulation tools, generation and consumption are already assigned to specific nodes based on historical values and are updated regularly. We have used this distribution for nodal allocation in Sweden, Norway and Denmark.

As a basis for the nodal allocation of consumption for Finland, Fingrid has used the distribution of consumption in their base case for winter 2021. The base case is a forecast for the situation in the network for the near future. The distribution in 2025 is expected to be similar to that in 2021; however, publicly known changes in the grid are accounted for in the 2025 allocation. Fingrid uses a similar process when allocating nodal consumption in the TYNDP process.

3.3 Simulation Chain

3.3.1 Description for the different steps of the simulation

For the Nordic region, the simulation tool is a hydro-thermal power market simulation software. It models, among other things:

- thermal generation
- hydro generation, reflecting the option value of water
- solar and wind generation, using detailed historical wind speed and solar radiation data
- demand side response

The model solves an optimisation problem by minimising the total costs of the system, considering fuel and emission costs and operational and system constraints. All major power market metrics are calculated on an hourly basis – electricity prices, dispatch of power plants, and flows across interconnectors.

As part of the LMP study, the model was expanded to include detailed power flow calculations to better represent transmission constraints. Including the power flow calculations into the optimisation problem makes available the shadow prices required to calculate nodal prices.

The calculation was performed on the hub level for the Nordic BZRR. The Baltics and DK1 were modelled at the zonal level, while the remaining European bidding zones were modelled with a fixed price; this was an hourly price based on a previous run.

3.3.2 Description of the CNEC selection procedure

A full N-1 analysis has not been performed for various reasons. From a computational-time perspective, it would have been very difficult. In addition, a full N-1 analysis would not necessarily have reflected the capacity in the grid well. In the Nordic region, there are significant restrictions arising from stability considerations not captured by an N-1 analysis, and system protection schemes are used extensively to increase capacity.

Instead, Nordic TSOs chose to only include the most significant contingencies in the study. The CNECs used in the simulations were selected by each Nordic TSO based on the CNECs sent to the Nordic Regional Security Coordinator as part of the Nordic implementation of the new flow-based capacity calculation methodology. Some CNECs for the future grid were also included based on assumptions. Only CNECs relevant for an intact grid were included since the simulations were performed on such a grid.

In the Nordics, there are OSLs and contingencies at voltage levels below 380 kV that are important for the secure operation of the power system. Therefore the Nordic TSOs have chosen to also include in the LMP analysis contingencies on 220 kV network elements. Additional details on the CNEC selection performed by each TSO are presented below.

CNEC selection – Finland

The CNECs for the Finnish grid were selected, as mentioned above, based on the same criteria sent to the Nordic Regional Security Coordinator as part of the Nordic implementation of flow-based capacity calculation methodology. However, only the north to south direction was considered for the CNECs inside Finland. Flow direction from south to north on CNECs was not assumed to be limiting in the model grid. In respect of the future grid, also included in the CNEC selection was the new 400 kV line from Petäjävesi to Oulu (the so-called Forest line, north–south reinforcement) that will be commissioned before 2025 and that is thus assumed to be a CNE for the year 2025. The thermal limits for the CNECs were given based on the 30-degree temperature value used when calculating market capacities.

In addition to the N-1 CNECs for Finland, two Power Transfer Corridors were included as constraints; these are the Cross-Section Central Finland from Central Finland south and the Cross-Section Kemi-Oulujoki representing the flow from northern Finland south.

The shift factors in the model were estimated by PSSE calculation. However, as in the nodal market simulation, only one value is used as the multiplier representing all situations. This value should be taken as an estimation, as the exact values would be dependent on the exact situation in the grid.

The expectation for the CNECs for the year 2025 was that there are few, if any, limitations on the flows due to the CNECs in intact grid. The results were mostly in line with this expectation.

CNEC selection – Norway

Statnett supplied the full database of CNECs used in operations; this is the same source supplied to the flow-based market coupling project. As the analysis is done on an intact grid, only CNECs that applied with intact grids were included.

The database includes thermal constraints and voltage and stability constraints.

There are few grid changes anticipated in the Norwegian system between now and 2025. The changes that will happen are accounted for through manual updates of relevant CNECs.

CNEC selection – Denmark

In the eastern part of Denmark, contingencies were included for CNECs that reflect operational planning. Thus, all transmission lines with a voltage > 100 kV are included where deemed relevant. This means that 132, 220 and 400 kV-lines are used if they are in parallel or influence the CNE in the operational planning.

CNEC selection – Sweden

The original list of CNECs that is used in the flow-based parallel run for the Swedish control area is based on operational experience; i.e. the CNECs are qualitative and statistically chosen based on operational logs. Svenska kraftnät performed some adjustments on the list of CNECs used in the flow-based parallel run, mainly to take into account the changes in the grid until 2025.

3.3.3 Description of the CNEC modelling

The CNECs were implemented in the model by estimating how much flow on the relevant CNE changes when a contingency occurs, thus indicating the limit for the total flow on each CNE. When a contingency happens, the flow from the contingency element is distributed to other elements in the grid. For CNEC modelling, the estimated share of the contingency flow is added to the CNE flow to form a contingency limit. The equation below demonstrates the CNEC formulation in the model:

$$\mathit{Flow\ on\ CNE} + x \cdot \mathit{flow\ on\ contingency\ element} \leq \mathit{thermal\ limit\ of\ CNE}$$

Where *x is the share of contingency element* estimated to be allocated to the related CNE after the contingency, and the contingency-share estimation was done by each TSO. It should be noted that a single value of x was used for the modelling as it was seen to provide enough accuracy for the simulations. However, the actual value of x can vary depending on the situation on the grid.

3.3.4 Power plant modelling

Hydropower is the dominant power source in the Nordic region, especially in Norway and Sweden. For the LMP study, we selected a detailed yet simplified hydropower model. We model hydropower plants as separate power plants, including individual generation capacity, reservoir capacity and inflow. However, hydro cascades are not modelled.

Reservoirs in the cascades were converted from water to energy volumes and allocated to each plant in the cascade according to the fall of each plant. Additionally, the production strategy (water values) of hydropower is determined with an aggregated hydropower module per region and simplified transmission capacities.

For other production plants, the following simplifications were made:

- The simplified approach following Article 9.8 (b) in the ACER methodology was used for modelling all production plants.
- Nuclear power plants were treated as must-runs.
- In the Nordic synchronous system, there are only two thermal plants (excluding nuclear) above 400 MW (in DK2). Those are treated as must-runs in our calculations since they are combined heat and power plants with obligations to deliver heat to the local community.

The reasoning behind these simplifications is that the technical constraints requested in the methodology have a significant impact on the calculation times, and, at the same time, they are not that important for Nordic conditions. Taking into account large share of hydro power in Nordics, we are confident that, being able to obtain the results for the full climate years adds much more value to the process to decide on the alternative configuratons to further study for Nordics rather than modelling the limited number of thermal power plants in the level of detail required by the methodology.

3.3.5 Snapshot creation and selection

PSSE software was used to create the grid model snapshots requested by ACER. A script was built to import hourly market outcome values obtained from the model in an automated fashion, taking various quantities from the LMP results files as input.

In selecting a 24-hour period out of more than 26,000 possible hours for the creation of the snapshots, Nordic TSOs aimed to include the most representative hours possible. Both night- and daytime hours were included to capture hours with high import and export to the Nordics system as well as some hours with high load and others with low load. One hour was selected for each of the agreed climate weeks; see Section 3.1.2.

The changing conditions as a result of the large infeed of renewables and changes in export and import during the period made it very challenging for Nordic TSOs to identify a subset of two or four snapshots as representative of the entire period, all bidding zones, and all power flow scenarios (high, average and low flow) in the power system. However, to meet ACER's request, we have made our best effort to select a good representation, distributing the hours over the year and including hours with both import and export from the Nordic synchronous area. All seasons are covered in the four-hour selections, and there are two export hours and two import hours. The two-hour selection includes one winter/spring hour with export and one summer hour with import.

3.4 Results

3.4.1 Flow patterns

The simulation results reflect flow and price patterns that are familiar in the power system and in simulations using other simulation tools. The main flow pattern is from the surplus areas in Northern Sweden and Norway and Western Norway to the consumption centres in the south. There is also significant export to Continental Europe.

3.4.2 Grid congestions

There are several bottlenecks restricting the flow between the surplus and deficit areas. The most significant AC-grid congestions are illustrated in the map below.

Figure 21: Approximate location of most restricting congestions in the simulation results. Swedish CNECs have been aggregated.

The main bottlenecks, according to the simulation, are between Northern and Southern Sweden, between Northern and Southern Norway, between Eastern Denmark and Southern Sweden, north–south on the west coast of Norway, north–south on the east coast of Sweden and east–west in Eastern Norway. More detailed commentary on congestion for each country is presented below.

Congestion – Finland

In line with expectations, the results did not show structural congestion inside Finland. Only one CNEC was detected as occasionally limiting; however, the limiting effect occurred less than 3 % of the time for each climate year. In addition, there was one thermal single component constraint limiting the flow. However, the effect was only for a few hours for the climate years 1989 and 1995, and the limitation did not occur for climate year 2009.

It may have been expected that the Power Transfer Corridor constraint from Central-Finland south (Cross-Section Central Finland) had some rare hours of limitation. However, this constraint did not show any limitation in the results. The reason for this may lie partly within the occasionally limiting CNEC. This particular CNEC is one of the five lines through Cross-Section Central Finland, and as such, the CNEC is already limiting the flow. However, the limiting effects of these congestions are not shown in the results nor expected to be structural.

Within Finland, prices in all nodes are the same most of the time. This was the expected result. However, there is a price difference between nodes near the current bidding zone SE1 in Sweden and other nodes within Finland. This is caused by the constraint on the border FI – SE1 as well as constraints on the Swedish side of the grid. Very close to the border, the nodal location is important for the impact on these CNECs at the border and inside Sweden.

When the internal N-1 CNEC is limited, prices in Finland diverge. In addition, during the hours when Finland experiences very low prices and is exporting, there is divergence with prices in nearly every node. This does not seem to result from the congestion inside Finland but instead is likely due to the effect of the constraints in the common AC grid. The hours with large price differences within Finland represent only a very small share of time, and Finland has only one price for most hours.

Congestion – Norway

The main bottlenecks identified in the Norwegian system follow known and familiar constraints in the system and typically follow existing bidding borders. Most of the bottlenecks in the Norwegian system can be grouped into the following three groups:

- Southwards out of Northern Norway (approx. today's NO4 – NO3 border)
- Southwards on the west coast of Norway (approx. today's NO3 – NO5 border)
- Eastwards in Eastern Norway (approx. today's NO2 – NO1 border)

In addition, bottlenecks in other parts of the system and, notably, the north–south bottlenecks in Sweden also yield price differences in the Norwegian system. The price differences in the simulation results are generally in line with the current price situation in the Nordic system.

Congestion – Denmark

No major congestion was identified for the eastern Danish grid. There are price differences between the Danish nodes during the summer, but these are most likely due to congestion at the DK2 – SE4 border and not within Eastern Denmark.

Congestion – Sweden

In Sweden the main congestion in 2025 concerns the lines connecting the current bidding zones SE2 and SE3. This north–south congestion is due to operational limitations on single elements between SE2 and SE3 both before and after contingencies, as well as voltage stability constraints for the total transmission on these elements. However, there is a discrepancy between the individual CNECs anticipated to be limiting for north–south flow and those which are actually limiting in the results. This may be due to imperfect modelling of the serial compensators (capacitors) and topological remedial actions. This is unlikely to have a notable effect on the general results with regard to the resulting nodal prices.

There are also internal limitations within bidding zone SE3, mainly due to flows in the east–west direction in case of imports from Finland and export to Denmark and Norway. These limitations occur about 15 % of the time and mostly during the March-May period. This is in line with the current operational experience where elements inside SE3 are often boundary setting for capacities given to the market. However, in current operations, these limitations also occur during other parts of the year. This difference compared to operational experience can be explained by the intact grid assumption used for the LMP study; the thermal limit for these particular CNECs is not temperature-dependent in this model. Limitations in respect of east–west energy flows are expected to occur more frequently towards 2025 when the Finnish balance is strengthened due to additional nuclear and renewable generation. The effect of these new boundary-setting elements in the east–west flow situation is that the north-eastern parts of SE3 receive a price close to the FI price and the south-western parts have a price similar to the DK2 price.

In the Stockholm metropolitan region, the results also show one CNEC on the 220 kV level, which causes very high shadow prices, but for a limited number of hours. This CNEC will likely not be the most limiting element in 2025. Rather, it is likely the result of imperfections in the modelling, for example, the distribution of generation and load, as well as the lack of modelling of remedial actions on the Distribution System Operator (DSO)-level. The same applies to one 220 kV CNEC in SE2 and results in looked in production and very low prices in a cluster of nodes. Another uncertainty is how well shift factors reflect the real flows while implementing the CNECs. This is a method of contingency analysis that is new to Svenska kraftnät and needs to be further evaluated.

In addition, there is a CNEC in SE3 on the 400 kV level that is often limiting in the results but will likely not be limiting in 2025. This is because the rate used in the simulation was significantly lower than the expected rate due to a data collection error.

3.4.3 Nodal prices – average prices

In the nodal price calculation, grid congestion gives rise to price differences between the nodes in the system. The overall price patterns show a clear north to south gradient with higher prices in the south than in the north. There is also an east–west gradient with lower prices in Finland and higher prices in southern Norway. The north–south price difference can also be seen in the current Nordic bidding zones and was especially prominent recent winter. Looking at price differences, the Swedish area SE3 shows the largest internal price difference between the nodes in each of the current bidding zones.

Seasonal pattern – average prices in current bidding zones

The grid congestions and price differences follow a clear seasonal pattern. Generally, there is more grid congestion and larger price differences in the summer than in the winter. Similarly, grid congestion and price differences are much more significant in climate years with large hydro inflow (wet years) than in years with low hydropower surplus.

The easiest way to observe the seasonal patterns is to look at the average prices in each of the current bidding zones. The figure below shows the average price per bidding zone for all the areas in the simulation for the simulated year 1995, with the Norwegian area prices in colour and the other area prices in grey.

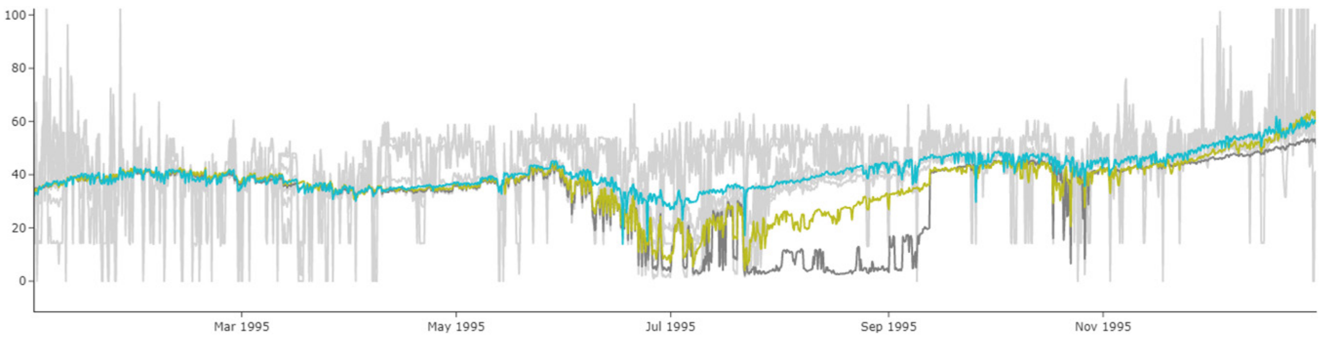

Figure 22: Average prices per current bidding zone for the simulated year 1995. Norwegian price areas highlighted (dark grey: Northern Norway, yellow-green: Mid-Norway, cyan: Northern Norway

Figure 22 clearly shows the seasonal pattern with low prices during the summer, particularly in the north, and increasing prices further south.

In Figure 23 the same data are plotted, but with prices for Swedish areas highlighted.

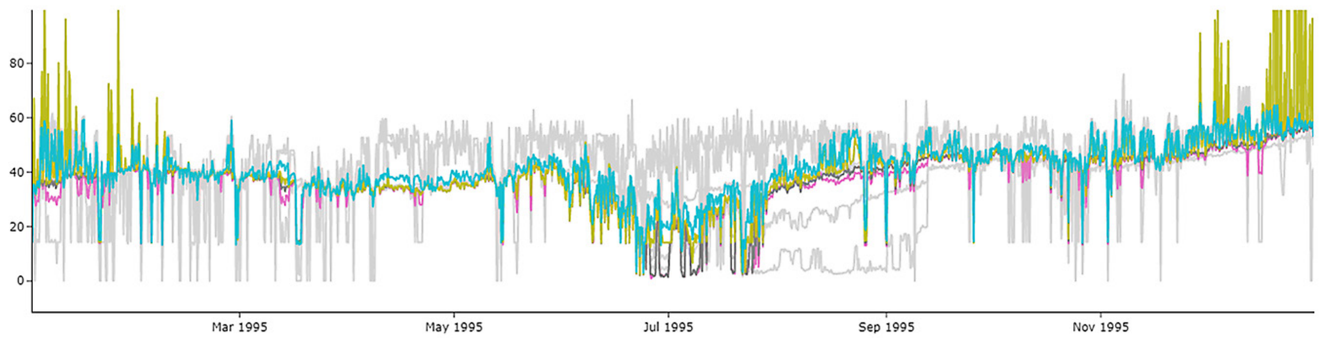

Figure 23: Average prices in each of the current bidding zones for the simulated year 1995. Swedish bidding areas highlighted (pink: SE1, dark grey: SE2, yellow-green: SE3, cyan: SE4)

The figure shows a similar pattern, with lower prices in the summer and prices increasing from north to south. The difference between the average prices for the current bidding zones is, however, much lower than in Norway.

Prices for Finland and Denmark are generally less significantly seasonal than in Norway and Sweden. The nodal prices for Finland and Denmark are included at the end of the next section (as there is only one bidding zone in both Finland and Eastern Denmark, i. e. comparison of bidding zone averages is not relevant).

Seasonal pattern – nodal prices

Figure 24 shows the nodal prices for the simulated year 1995 for all Norwegian nodes in the simulation.

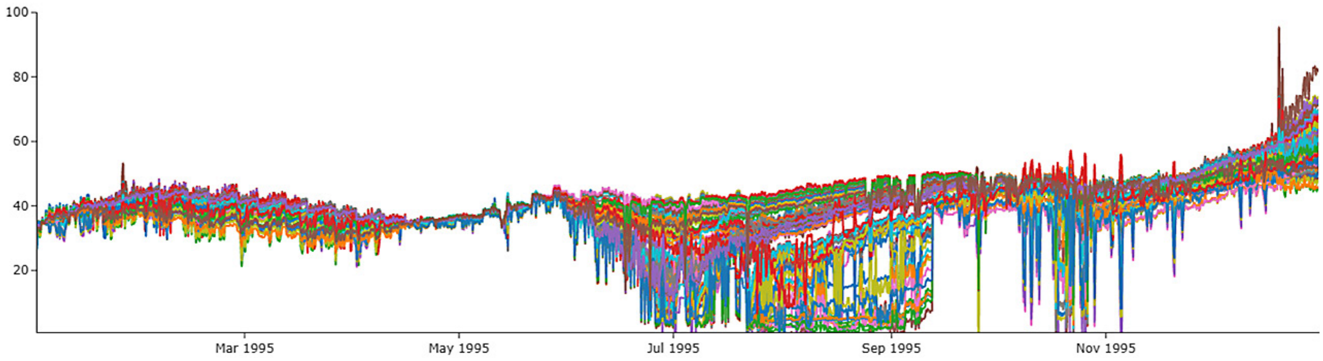

Figure 24: Nodal prices for the simulated year 1995 for all the Norwegian nodes.

The figure shows many of the same patterns as those in Figure 22 but also indicates how the spectrum of prices in the summer from almost zero up to approximately continental prices around 40-50 €/MWh. In some periods, we see clear "clusters" of nodes with similar prices and clear "gaps" between the clusters, while in other periods, the spectrum is almost continuous.

Figure 25 shows the nodal prices for the simulated year 1995 for all the Swedish nodes in the simulation (zoomed in to the y-axis between 0 and 100 €/MWh).

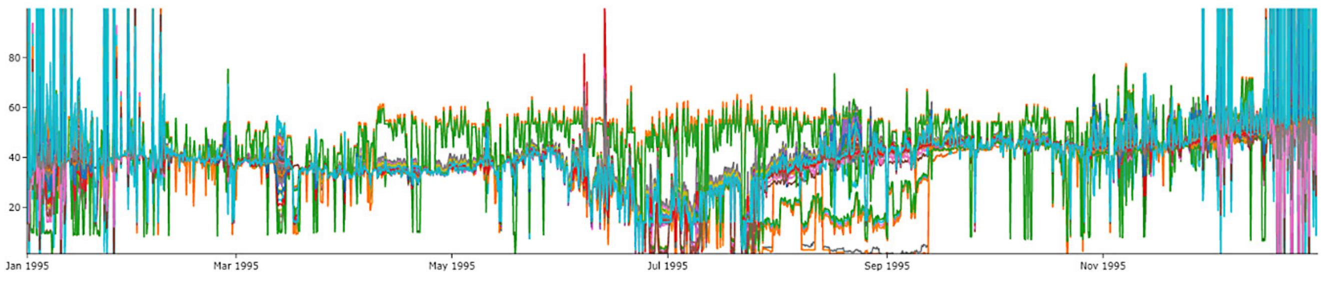

Figure 25: Nodal prices for the simulated year 1995 for all the Swedish nodes (zoomed y-axis).

The figure shows that for most of the year, the Swedish nodal prices are highly concentrated in the main "price cluster", except for a few outliers with either very low prices or high continental prices.

This differs from the pattern in Figure 24, which shows the Norwegian prices on a more continuous spectrum.

Another interesting pattern is visible if we zoom out on the Swedish nodal prices. During the winter, there are periods with extremely high prices at some nodes and simultaneously negative prices at other nodes. This occurs particularly in December, but also in January and February, although with somewhat less extreme prices. This pattern involves a significant number of nodes on a significant number of days (at least 30+ nodes with prices > 250 €/MWh for at least seven days). This probably does reflect a real grid constraint but is currently handled in operations.

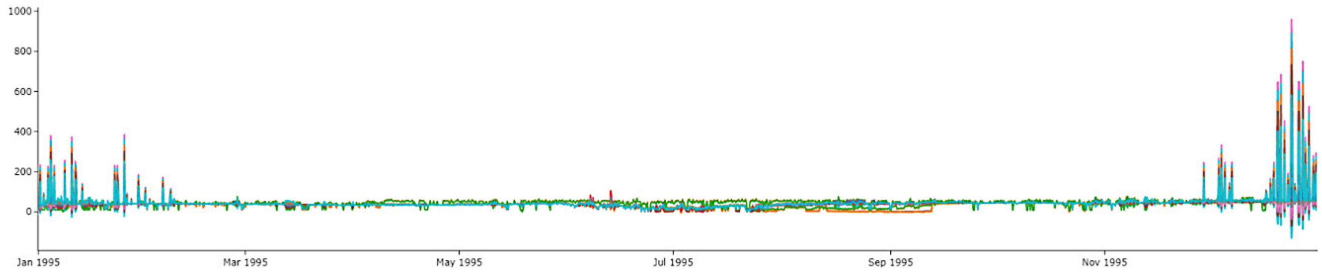

Figure 26: Nodal prices for the simulated year 1995 for all Swedish nodes (entire y-axis).

Figure 27 shows the nodal prices in Eastern Denmark.

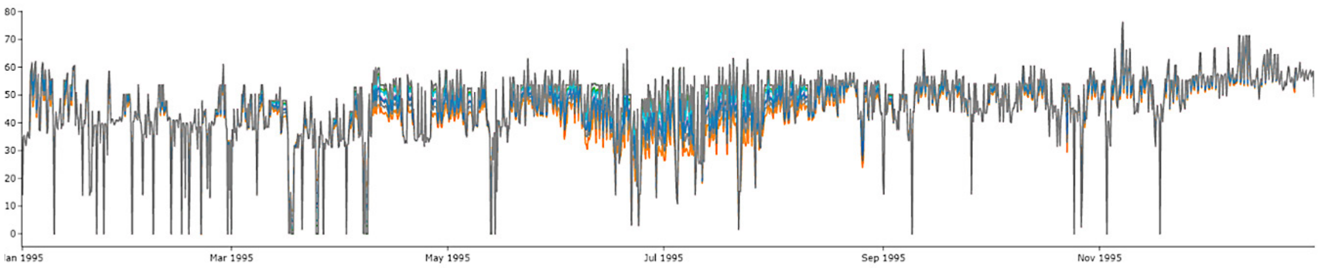

Figure 27: Nodal prices for the simulated year 1995 for all nodes in Eastern Denmark.

As can be seen from Figure 27, the seasonal variation and the price difference among the Danish nodes are generally lower than in Norway and Sweden. There are, however, quite significant price differences in the summer, with price differences between the highest and lowest price nodes being 10–20 € / MWh for several weeks in the summer. However, these price differences are mainly for a few low- and high-price nodes; other nodes have prices that lie within a narrow band around the average price.

Figure 28 shows the nodal prices for the simulated year 1995 for all the Finnish nodes.

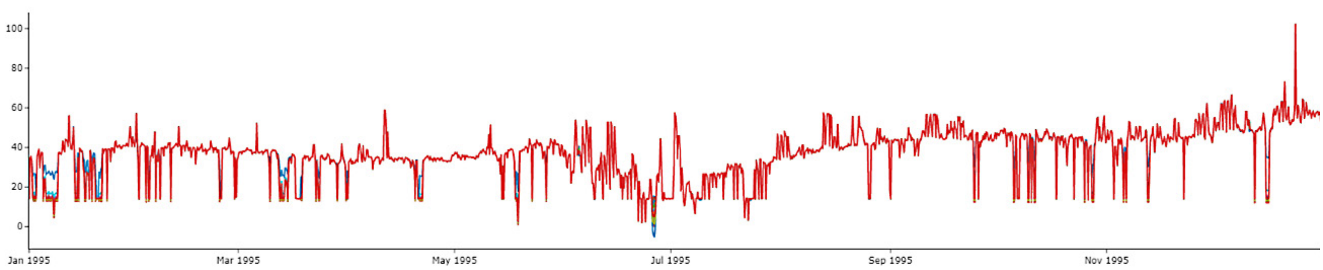

Figure 28: Nodal prices for the simulated year 1995 for all the Finnish nodes

We see that, except for a few short periods, there are no price differences between the Finnish nodes.

4. Appendix

4.1 Annex 1: Climate Year/Week Selection Methodology and Algorithm

4.1.1 Input data and relevant sources

Input datasets

The following variables were identified as relevant for characterising each single climate year and week:

1. **Solar infeed**
2. **Wind infeed (as the sum of the infeed from both offshore and onshore wind farms)**
3. **Hydro inflows**
4. **Load**

Hourly time series

According to the methodological requirements, the assessment input is a detailed dataset of 30 years (1987[7] to 2016) from the Pan European Climate Database (PECD) covering all bidding zones. For each climate year and for each existing bidding zone, hourly profiles are derived according to the following approach:

- **Solar infeed:** the hourly load factor PECD multiplied by the expected total installed solar capacity for the target year 2025 according to the scenario provided by each TSO for the Pan European Market Modelling DataBase (PEMMDB) in 2020.
- **Wind infeed:** the sum of the expected offshore wind infeed and the onshore wind infeed, each computed by multiplying the hourly load factor from the PECD by the expected (offshore/onshore) installed wind capacity for the target year 2025 according to the scenario provided by each TSO for the PEMMDB in 2020.
- **Load:** the hourly demand profiles from the scenarios adopted in the 2020 Mid-term Adequacy Forecast (MAF).
- **Hydro infeed:** For each climate year and for each existing bidding zone from 1987 till 2016, the total yearly inflows (GWh) are computed as the sum of the following components derived from the PEMMDB in 2020:
  - **Run-of-River Hydro Generation** in GWh per day;
  - **Cumulated inflow into reservoirs** per week in GWh; and
  - **Cumulated natural inflow into the pump-storage reservoirs** per week in GWh.

An hourly hydro infeed profile is then derived by allocating the yearly energy among the hours of the year proportionally to the hourly net load (computed as the hourly load netted by solar and wind infeed). In practice, this represents the fact that hydro will be dispatched in a water value approach: more hydro generation in cases when net load is high (high demand and low variable RES infeed) and less generation when net load is low (low load, high variable RES infeed).

Hourly residual load

Finally, for each climate year and for each bidding zone z, the residual load profile for each hour h is computed as follows:

$$V_{residual\ load,z,h} = V_{load,z,h} - (V_{solar,z,h} + V_{wind,z,h} + V_{hydro,z,h})$$

7 Even though data for the period 1982–1986 are available, the methodology requires a 30-year dataset.

Bidding zones are then grouped into relevant macro-regions according to the procedure adopted in the TYNDP (see Table I). The residual load V for each macro-region r is derived as follows:

$$V_{residual\ load,r,h} = \sum_{z \in r} V_{residual\ load,z,h}$$

Macro region	**Zones** (Study Zones may differ from Bidding Zones)
Scandinavia	DKe, DKkf, DKw, FI, NOm, NOn, NOs, SE1, SE2, SE3
Baltic countries	LV, EE, LT
Central west 1	BE, FR, NL
Central west 2	DE, DEkf, AT, CH, LUb, LUf, LUg, LUv
South west	ES, PT
Central east	CZ, SK, HU, PL, RO
GB+IE	GB, IE, NI
South east	GR, CY, BG, MK, ME, MT, HR, SI, RS, AL, BA
South central	ITcn, ITc, ITn, ITs, ITsar, ITsic

Table I: Macro Regions from TYNDP

4.1.2 Methodology for the selection of representative climate years and weeks

The general approach for selecting representative climate years and weeks has three cornerstones, as presented in Figure 29 below. In the following, the approach is presented using the case of climate-year selection.

In defining representative climate years, the approach is as follows:

a. **Definition of hourly** time series of **residual load** on a regional level to capture the temporal and spatial variability of the system state due to climatic conditions;

b. **Computation of delta indicators** to assess how years compare to the 30-year average on a regional level;

c. **Selection of the most representative 3-year combination** (LMP analysis and bidding zone assessment).

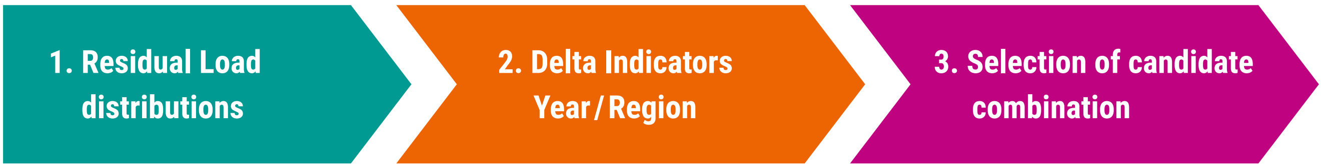

Figure 29. Overview of the approach for the definition of representative years/weeks

a. Residual load distributions

As described in the previous section, the residual load for each region is defined in terms of hourly resolution by deducting the RES infeed from the system load for each hour:

$$V_{residual\ load,r,h} = V_{load,r,h} - (V_{solar,r,h} + V_{wind,r,h} + V_{hydro,r,h})$$

Two key characteristics in this representation are the hourly temporal resolution and the regional level of aggregation. The hourly resolution allows the depiction of the full variability in the system infeeds. The regional representation is needed to retain the information for different regions independent of each other, as aggregation on the European level leads to statistical smoothing of variability. Thus, a dataset of 8,760 values (hourly residual load) is obtained per year and per region.

The following graphs show the histograms of residual load per region and year.[8] Each colour represents the distribution of the 8,760 values for one year. One can see that the variability and shape of the distribution change by year and region, depending on the climatic conditions prevailing in each year. Areas with high variable RES shares (wind and solar), such as CW2 and SW, present high variability and even negative net load. Areas with high hydro resources, such as the Nordics, present significant differences between years due to the yearly hydro-resource availability (e. g. dry versus wet years).

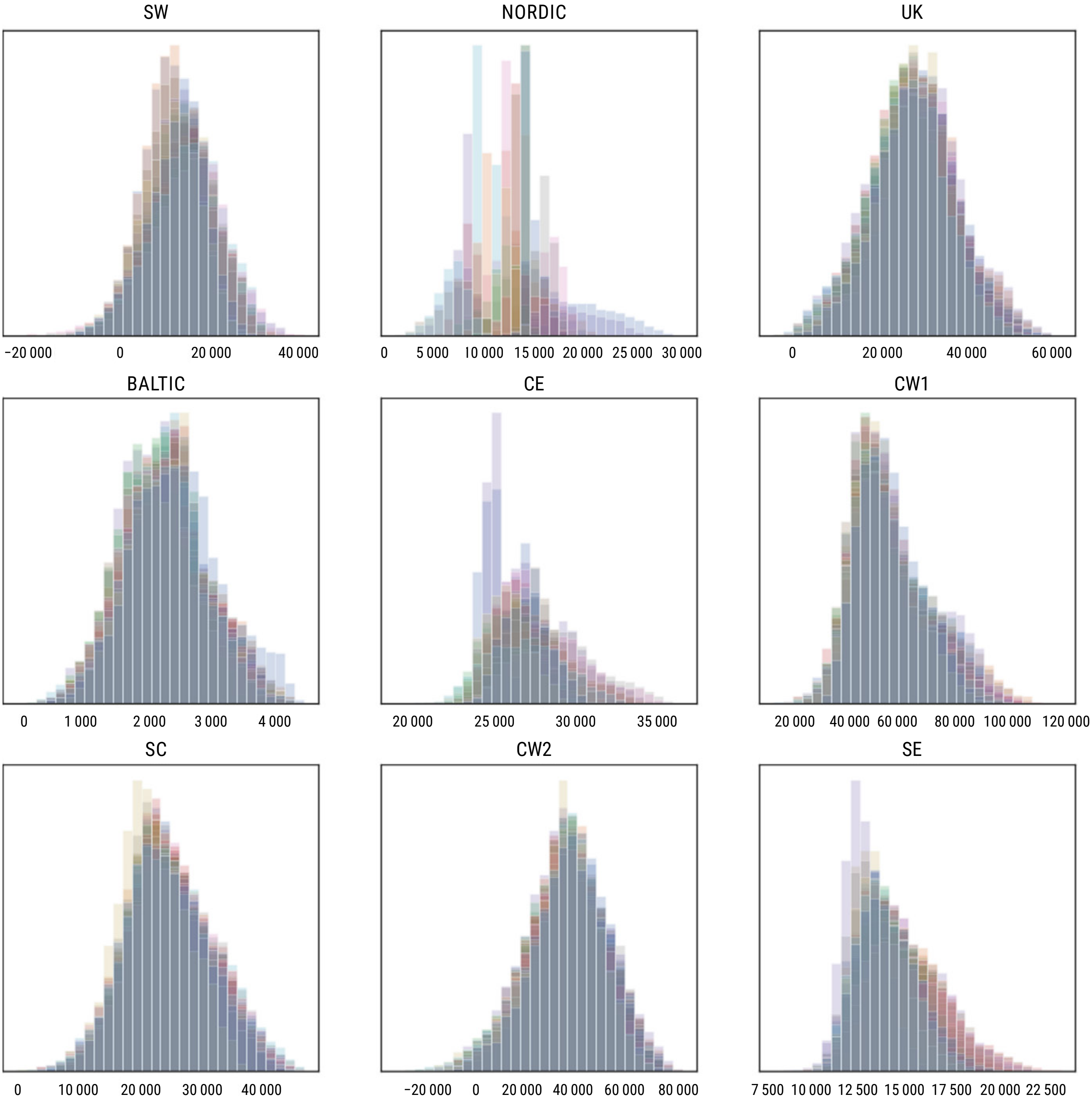

Figure 30: Distributions of residual load per region and year (each year is one color; x-axis: residual load in MW, y-axis: occurrences)

8 These graphs are based on preliminary data, as the PEMMDB dataset is updated at the moment of drafting this report.

b. Delta indicators

The goal of the assessment is to find the 3 years that, in combination, best represent the full 30 years. In this respect, the methodology compares the distributions of each possible 3-year combination to the distribution of the whole dataset (combined 30 years). In the first step, the distributions of all candidate combinations are defined. Indices are then applied to allow comparison of these and the aggregated distributions.

Candidate combinations

In the first step, we construct the datasets of all candidate combinations. In total, with 30 years, there are 4060 different combinations of 3 years to be checked. A combination of 3 years is noted as $g \in G$, and the combined dataset with 3 × 8,760 data points of residual load per region is:

$$\Omega_{r,g} = [V_{load,r,g} - (V_{solar,r,g} + V_{wind,r,g} + V_{hydro,r,g})]$$

Comparison indices

In order to compare the residual load distributions, we use two main indicators, namely the *mean value*, which captures the overall energy content of the yearly distribution, and the *standard deviation (std)*, which captures the variability of the distribution. We assess how well each candidate combination $\boldsymbol{\Omega}_{r\ g}$ depicts the respective characteristics of the aggregate distribution expressed as the difference between the indicator and the corresponding indicator of the aggregate distribution $\boldsymbol{\Omega}_{r,g \in G}$.

$$\Delta\mu_{r,g} = mean(\boldsymbol{\Omega}_{r,g}) - mean(\boldsymbol{\Omega}_{r,g \in G}),$$

$$\Delta\sigma_{r,g} = std(\boldsymbol{\Omega}_{r,g}) - std(\boldsymbol{\Omega}_{r,g \in G})$$

Standardisation and weighting

The indicators are standardised for comparison, which causes the distribution of each indicator to have a mean of 0 and a standard deviation of 1. Thus a transformation of the indicators to the same space and range in magnitude is performed. It is applied as follows:

$$I_{\mu,r,g} = \frac{\Delta\mu_{r,g} - mean(\Delta\mu_{r,g \in G})}{std(\Delta\mu_{r,g \in G})}, I_{\sigma,r,g} = \frac{\Delta\sigma_{r,g} - mean(\Delta\sigma_{r,g \in G})}{std(\Delta\sigma_{r,g \in G})}$$

Further, a regional weighting factor is applied to ensure that the influence of each region is proportional to its relevance to the European electrical load. The applied weighting factor is the share of the region's average load with respect to the European load:

$$w_r = \frac{\sum_{y \in CY} V_{load,r,y}}{\sum_{r \in R} \sum_{y \in CY} V_{load,r,y}}$$

Based on the preliminary data, the weighting factors shown in Figure 31 are as follows:

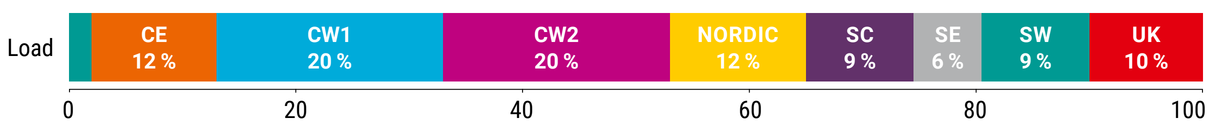

Figure 31: Weighting factors

c. Selection of candidate combination

The selection of the candidate combination is a two-step process, as shown in Figure 32 below.

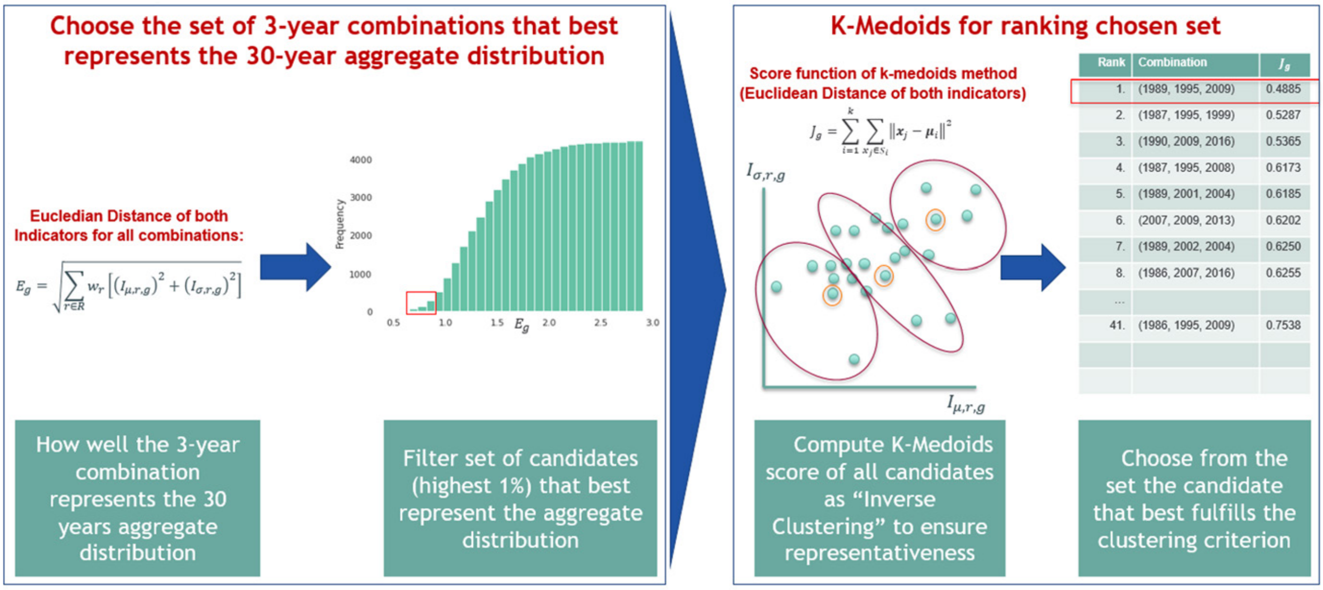

Figure 32: Two step-process for the selection of the representative candidate

Filtering of candidate combinations that represent the aggregate distribution

In the first step, the set of candidates that best represents the aggregated distribution is selected.

For this, the indicators for each combination of three years g are combined and weighted, using the Euclidean distance as shown below:

$$E_g = \sqrt{\sum_{r\in R} w_r \left[(I_{\mu,r,g})^2 + (I_{\sigma,r,g})^2\right]}$$

The assessment operates in 18 dimensions (2 indicators × 9 regions); examples are depicted in the related graphs. Using the indicator E_g, all 3-year-combinations are evaluated as to how well they fit the aggregate distribution. The candidates that ranked best based on E_g (highest 1 % from the 4,600 combinations, referred to as preferred candidates), are kept and are considered representative of the aggregate distribution.

Selection of the best candidate from the preferred candidates

In the next step, each preferred candidate is assessed to see which best represents the 30-year set, using the same indicators (mean and standard deviation). The K-medoids clustering score of all preferred candidates is assessed. The cluster score function, which is the Euclidean distance of each year to the closest medoid, is computed as:

$$J_g = \sum_{i=1}^{k} \sum_{x_j \in S_i} \|\boldsymbol{x}_j - \boldsymbol{\mu}_i\|^2$$

Here, k is the number of clusters (3 for the year selection), $\boldsymbol{x}_j$ is a specific year and $\boldsymbol{\mu}_i$ is the medoid that is closest to $\boldsymbol{x}_j$. The three medoids here are the three years in g.

All preferred 3-year combinations are assessed based on this score function, and the combination with the best clustering score is chosen.

Remark on the assessment of representativeness

The described two-step approach ensures a double depiction of representativeness by ensuring that a) the chosen combination fits the aggregate combination and b) it ranks well in an inverse clustering approach. The combination of the two approaches allows the accumulation of benefits from both assessment methods. **The Euclidean distance indicator ensures that the preferred combinations represent well the aggregated distribution.** However, the aggregated combination may be comprised of three extreme or three mild years, as long as the average is in the centre of all combinations. The application of the K-medoids approach ensures that the final combination is representative in terms of capturing the largest space. It ensures a second layer of representativeness based on a clustering logic. In an example with two dimensions, the following graphs present what would happen if only the first of the two steps were taken. All three combinations satisfy the Euclidean-distance criterion, i.e. their combination is close to the centre represented by the red triangle. **The application of the K-medoids ranking ensures that the selected combination also represents the space** (i.e. not too close to the centre, "mild," or too close to the edges, "extreme").

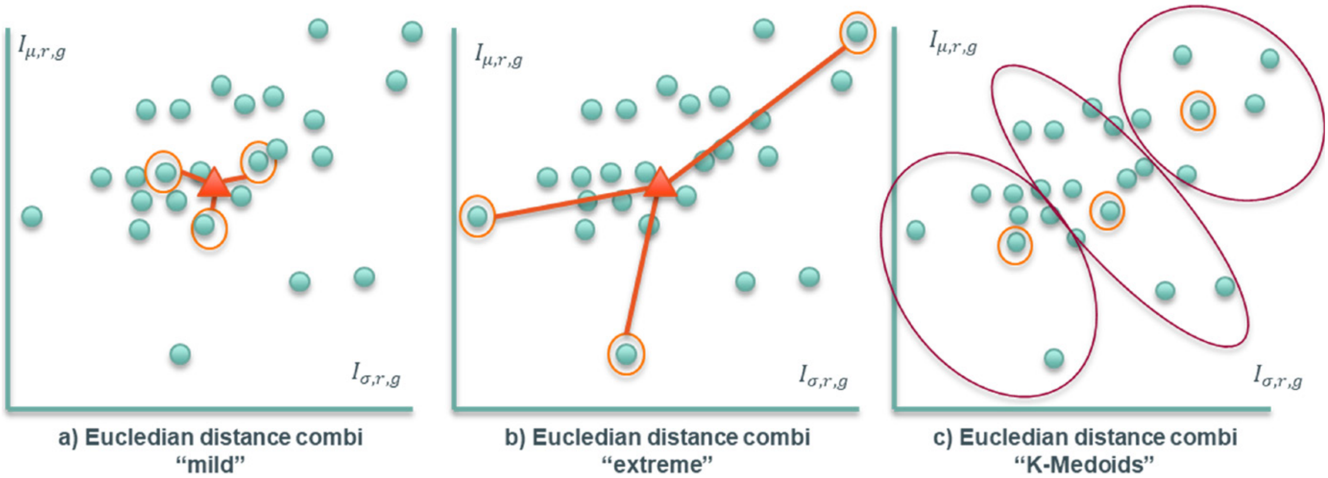

Figure 33: Examples of selection of representative candidates

Application for week selection – specifics

Throughout the previous sections, g represented a combination of three years. For the selection of the week candidates per year, the same methodology is applied, where g now represents a combination of 8 out of 52 weeks. The method is applied using the same logic as in the year selection; the aim is to find the set of 8 weeks that best represents the total set of 52 weeks within a given climate year. In total, more than 752 million combinations for 8 out of 52 weeks exist and are assessed in the selection.

For the week selection, an additional constraint is taken into account in the final step. The winning combination is not the highest ranking, based solely on the K-Medoids score J_g. Instead, the winning combination is the highest-ranking combination that includes at least one week per season. The reason for this constraint is that seasonality is expected in elements that may be missed in the residual load indicator, for example:

- The yearly Hydro dispatch is modelled with a ProRata approach with respect to the residual load. This potentially misses a Hydro seasonality.
- Photovoltaic (PV) production indicates a significant seasonality. Missing summer weeks, for example, would mean missing high PV penetration weeks and vice versa.
- The Dynamic Line Rating (DLR) is temperature-dependent and thus seasonal. Selecting weeks from all seasons ensures a wider range of DLR scenarios are captured.
- The condition of at least one week per season (jointly agreed with ACER) ensures the selected weeks are distributed among all seasons and do not entirely miss the mentioned elements.

The respective week ranges are shown below:

Season	Winter	Spring	Summer	Autumn
Weeks	1–9; 49–52	10–22	23–35	36–48

Table II: Respective week ranges

4.2 Annex 2: Network Projects Excluded from the TYNDP 2025 Reference Case

Project ID	Project Name	Country	Technology Type
16	Biscay Gulf	ES; FR	DC
29	Italy-Tunisia	IT; TN	DC
35	CZ Southwest–east corridor	CZ	AC
40	Belgium-Luxembourg-Germany: long-term perspective	BE; DE; LU	AC
47	Westtirol (AT)–Vöhringen (DE)	AT; DE	AC
82	RIDP I	GB; IE	AC
107	Celtic Interconnector	FR; IE	DC
120	MOG II: connection of up to 2 GW additional offshore wind Belgium	BE	AC
121	Nautilus: multi-purpose interconnector Belgium – UK	BE; GB	DC
130	HVDC SuedOstLink Wolmirstedt to area Isar	DE	DC
132	HVDC Line A-North	DE	DC
150	Italy-Slovenia	IT; SI	DC
153	France-Alderney-Britain	FR; GB	DC
170	Baltic States Synchronization with Continental Europe	EE; LT; LV; PL	AC; DC
174	Greenconnector	CH; IT	DC
179	DKE - DE (Kontek2)	DE; DK	DC
187	St. Peter (AT) – Pleinting (DE)	AT; DE	AC
210	Wurmlach (AT) – Somplago (IT) interconnection	AT; IT	AC
219	EuroAsia Interconnector	CY; GR; IL	DC
225	2nd interconnector Belgium – Germany	BE; DE	DC
227	Transbalkan Corridor	BA; IT; ME; RS	AC
228	Muhlbach – Eichstetten	DE; FR	AC
229	GerPol Power Bridge II	DE; PL	AC
231	Beznau – Tiengen	CH; DE	AC
233	Connection of Aragon Pumping hydro	ES	AC
234	DKE – PL-1	DK; PL	DC
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Grafenrheinfeld	DE	DC
241	Upgrading of existing 220 kV lines between HR and BA to 400 kV lines	BA; HR	AC
243	New 400 kV interconnection line between Serbia and Croatia	HR; RS	AC
244	Vigy – Uchtelfangen area	DE; FR	AC
247	AQUIND Interconnector	FR; GB	DC

Project ID	Project Name	Country	Technology Type
250	Merchant line Castasegna (CH) – Mese (IT)	CH; IT	AC
252	Internal Belgian Backbone Center-East: High Temperature Low Sag (HTLS) upgrade Massenhoven-VanEyck-Gramme-Courcelles-Bruegel-Mercator	BE	AC
253	Upstream reinforcement in France to increase FR-CH capacity	CH; FR	AC
259	HU-RO	HU; RO	AC
260	Project 260 – Multi-purpose HVDC interconnection between Great Britain and The Netherlands	GB; NL	DC
263	Lake Constance East	AT; CH; DE	AC
264	Swiss Roof I	CH	AC
265	Tessin	CH	AC
270	FR – ES project – Aragón – Atlantic Pyrenees	ES; FR	AC; DC
276	FR – ES project – Navarra – Landes	ES; FR	AC;DC
280	FR – BE: study Lonny – Achene – Gramme	BE; FR	AC
283	TuNur	IT; TN	AC; DC
284	LEG1	EG; GR; LY	DC
285	GridLink	FR; GB	DC
286	Greenlink	GB; IE	DC
293	Southern Aegean Interconnector	EG; GR	AC; DC
296	Britib	ES; FR; GB	DC
309	NeuConnect	DE; GB	DC
322	Wullenstetten – Border Area (DE – AT)	DE	AC
323	Dekani (SI) – Zaule (IT) interconnection	IT; SI	AC
324	Redipuglia (IT) – Vrtojba (SI) interconnection	IT; SI	AC
325	Obersielach (AT) – Podlog (SI)	AT; SI	AC
328	Interconnector DE – LUX	DE; LU	AC
329	Stevin – Izegem/Avelgem (Ventilus): new corridor	BE	AC
330	4th 400kV CZ–SK interconnector	CZ; SK	AC
333	PST Foretaille	CH	AC
335	Project 335 – North Sea Wind Power Hub	DE; DK; NL	AC; DC
338	Adriatic HVDC link	IT	DC
339	Italian HVDC tri-terminal link	IT	DC
340	Avelgem-Center: new corridor (Boucle du Hainaut)	BE	AC

Project ID	Project Name	Country	Technology Type
341	North CSE Corridor	RO; RS	AC
342	Central Balkan Corridor	BA; BG; ME; RS	AC
343	CSE1 New	BA; HR	AC
344	Reinforcements Ring NL phase II	NL	AC
346	ZuidWest380 NL Oost	BE; NL	AC
349	MaresConnect	GB; IE	AC; DC
375	Lienz (AT) – Veneto region (IT) 220 kV	AT; IT	AC
376	Refurbishment of the 400 kV Meliti(GR) – Bitola(MK) interconnector	GR; MK	AC
377	Upgrade BE – NL interconnector VanEyck – Maasbracht	BE; NL	AC
1034	HVDC corridor from Northern Germany to Western Germany	DE	DC
1040	LirIC	GB; IE	DC
1041	GREGY Interconnector	EG; GR	AC; DC
1042	Offshore wind integration	LT	AC
1043	Wahle – Mecklar	DE	AC
1047	Emden – Eemshaven	DE; NL	AC
1048	Greece – Africa Power Interconnector (GAP Interconnector)	EG; GR	DC
1049	Cronos Energy Ltd	BE; GB	DC
1050	Tarchon Energy Ltd	DE; GB	DC
1051	Aminth Energy Ltd	DK; GB	DC
1052	Lienz (AT) – Obersielach (AT)	AT	AC
1054	Westtirol (AT) – Zell/Ziller (AT)	AT	AC
1056	Croatian south connection	HR	AC
1057	HVDC CentraLink	DE	DC
1058	HVDC Interconnector DE – CH	CH; DE	DC
1059	Southern Italy	IT	AC
1063	ZuidWest380 West	NL	AC
1066	Bulgaria – Turkey	BG; TR	AC
1067	New AC 400 kV interconnection line Greece – Turkey	GR; TR	AC
1074	Pannonian Corridor	HU; RS	AC
1077	Crete – North Greece – North Macedonia – Bulgaria Interconnector	BG; GR; MK	DC
1081	LAG Interconnector (LAG)	AL; GR; LY	DC
1082	Sea-Socket	IE	AC

Table III: Network projects excluded from the TYNDP 2025 reference case

4.3 Annex 3: Grid Assumptions – Nodal Allocation

4.3.1 Generation database alignment

Highly granular generation information is available in two different databases, the PEMMDB and the Common Grid Model (CGM). Information from both databases is needed for this study, as the PEMMDB includes economic parameters while the CGM contains a model of the entire grid. Therefore, it is necessary to match and align the generation data in both databases such that generation capacities and generation technology types are equal for all modelled generation units. The matching of the capacities is done centrally by ENTSO-E. The general principle is, in the first step, to match the known per-unit generation information in the PEMMDB with the generating units in the CGM. For that purpose, the PEMMDB contains, for each generator, the identifier of the corresponding generator in the CGM. Where the identifier is missing or does not correspond to a correct CGM identifier, the matching is done using the information available in both databases, namely, the generator name, location, installed capacity and fuel category. The resulting matching is checked and validated by the TSOs, with corrections made as needed.

This methodology provides the correct matching for what is represented per unit in the PEMMDB but does not cover the capacity that is aggregated. Correspondingly, there should be generating units in the CGM that do not match with a PEMMDB unit but rather match with the aggregated capacity.

The extent to which this aggregated capacity corresponds to the remaining unmatched capacity is measured by providing an alignment file containing the summary of the capacities per production type to the TSOs to collect the required action in case of a mismatch. For the purpose of the project, the latest CGM available (from TYNDP 2020) was used based on the PEMMDB for which the TYNDP 2020 data collection took place (in 2018). The latest available PEMMDB information corresponding to the one collected for MAF 2020 is used. The data collection took place in 2019. Since the information given in the PEMMDB is more recent than that in the CGM, it is assumed that the capacity in the CGM needs to be aligned with the one given in the PEMMDB. If the capacity in the PEMMDB is higher than what is reflected in the CGM, the TSO has the choice to upscale the generating units in the CGM or create new generating units. If the capacity is lower, the TSO has the choice to downscale the generating units in the CGM or delete some. After this step, the capacity not reflected in per-unit terms (i.e. the aggregated capacity) in the PEMMDB should perfectly match the capacity of the unmatched units in the CGM. Where a TSO does not provide a solution for a gap higher than 3 %, the default action is to remove the difference in the capacities from the load. In this way, the misalignment in the generation is spread among all nodes and not only those where the production type is present. In practice, however, there was no need to apply this default solution, as TSOs provided the necessary information.

The information concerning the aggregated capacity in the PEMMDB can be disaggregated to the generating-unit level in the CGM according to generating capacity. These unmatched units are newly created in the PEMMDB, and the aggregated capacity is deleted to have a perfect unit-by-unit matching between the PEMMDB and the CGM.

4.3.2 Load

The load modelling is based on the zonal load data from the MAF 2020, created with the load forecasting tool TRAPUNTA. The zonal load forecast is disaggregated to the nodal level using a load snapshot from the TYNDP 2020, in which the loads are marked as either unscalable or as scalable. In the case of unscalable load, a constant load is modelled with active power consumption unchanged throughout the LMP study. In the case of scalable load, the ratio derived from the share of a given scalable load in the respective zonal load (from which the zone's total unscalable load is subtracted beforehand) from the TYNDP 2020 snapshot is used. The active power consumption of all scalable loads is then modelled as the product of this ratio and the hourly zonal load forecast data of MAF 2020. Therefore, for all simulated hours, the sum of all individual loads within each zone equals the load given in the respective MAF 2020 zonal-load time series. As the MAF 2020 load time series are climate-dependent, different time series for individual, scalable loads result from the described disaggregation methodology for each of the three selected climate years.

4.3.3 Wind and Solar

In the case of wind and solar, if the generation in the PEMMDB is higher than in the CGM, a third option is proposed to align the disaggregated capacity in the PEMMDB with the CGM. In addition to upscaling or having generators in the CGM as directed by the TSO, ENTSO-E can run an algorithm that optimally creates generators in substations to have the capacity in the Grid Model and in the PEMMDB equal.

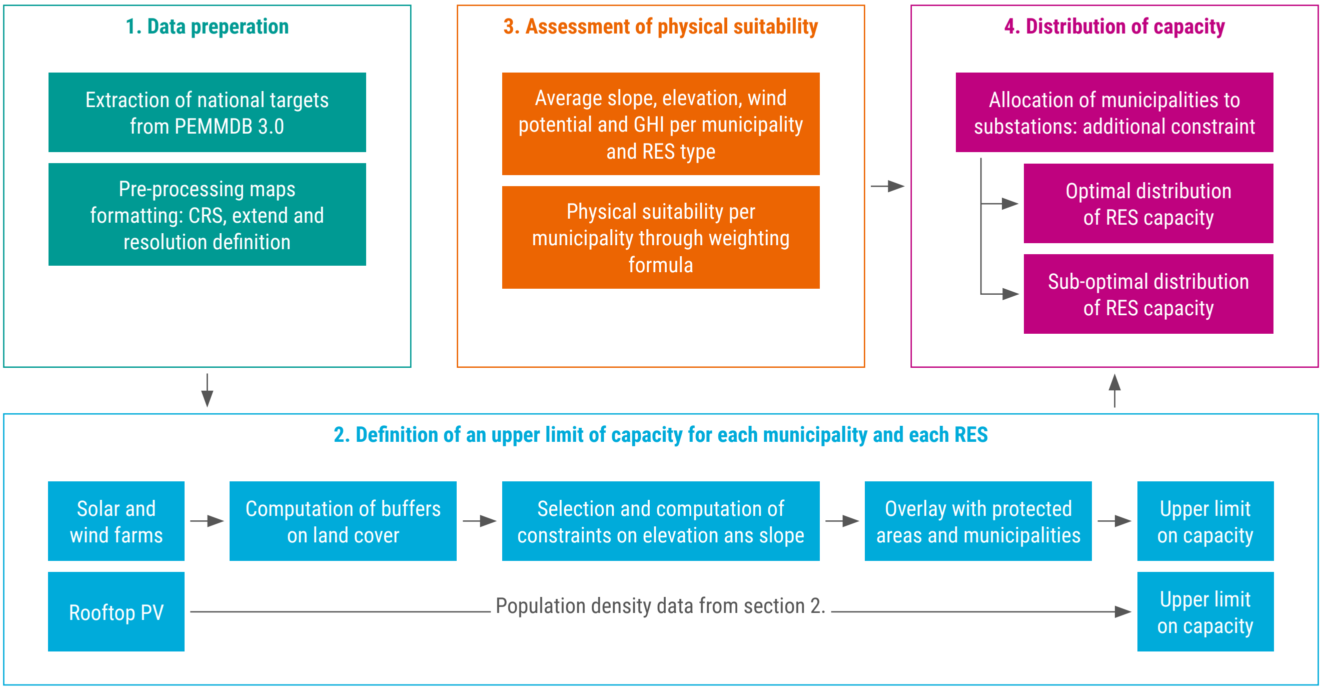

Figure 34. Process to allocate aggregated wind and solar capacities to individual nodes

This algorithm takes into consideration the solar and wind distribution in the country. In addition, it considers information for already existing constructions and facilities and slope and elevation information that prevent the establishment of wind or solar in certain places. Finally, each municipality in the country is given a score for the likelihood of wind or solar generation being installed. Additionally, in each municipality, the available land surface is calculated, and the land use of each technology is considered to obtain the maximum generating capacity that can be built there.

This information is then aggregated per substation, each municipality being allocated to the nearest substation using Voronoi polygons. The Voronoi diagrams represent a way to partition a plane into regions from a set of points. Each point has a region that is the closest for all other points in the region. An optimisation algorithm is then run to optimise the amount of electricity created in each substation according to the maximum-capacity scores for the substation (1) and having in each substation at least the generation of the already installed generators according to the grid model (2). In each substation, the difference between the generation already known at a nodal level and the result of the optimisation is the generators to be created in the grid model.

In the case of solar, the Grid Model does not make a difference between Rooftop PV and PV farms. In order to take into account the already existing solar capacity in the CGM, it was chosen to align what is done in the Grid Model and aggregate the capacities in the PEMMDB for PV farm and Rooftop PV into one single fuel category. In a linear algebra formulation, the problem is then for one fuel type:

For a given country C,

$$\max_{[\chi]_{m \in M_c}} \langle [\chi]_{m \in M_c} \mid [\mu]_{m \in M_c} \rangle$$

Under the constraints:

$$\begin{cases} (1)\ \forall\, m \in M_c, \chi_m \leq \chi_m^{max} \\ (2)\ \forall\, s \in S_c, \sum_{m \in s} \chi_m \geq \chi_s^{CGM} \\ (3)\ \forall\, PECD_{zone} \subseteq C, \sum_{m \in PECD_{zone}} \chi_m \leq \chi_{PECD_{zone}}^{PEMMDB} \end{cases}$$

With

$S_c = \{s \in C\}$	the set of the country's substations
$M_c = \{m \in C\}$	the set of the country's municipalities
$\forall\, m, \mu_m$	the score of the given municipality m
χ_α	the capacity of the geographical area α
$[V]_{a \in \Sigma}$	the vector of coordinates $V(a)\ \forall a \in \Sigma$

Although the methodology and the tools were developed, it has not been requested to disaggregate generation through this tool. The disaggregation of renewable generation has completely been made expert-based by the TSOs.

4.3.4 Hydro

Storage capacity

In the PEMMDB, for the hydro unit listed per unit, it is possible to provide a head reservoir or a tail reservoir if it is relevant to the production type. These reservoirs are also listed per unit, and a single reservoir can feed multiple generating units. Theoretically, the way storage and hydro are modelled in the PEMMDB allows the modelling of cascading, but this was not done since it complicates the way natural inflows are considered. Units that are listed per unit in the PEMMDB are directly matched with the corresponding representation in the CGM. Consequently, in the model for the LMP, these hydro units have the head reservoir indicated in the PEMMDB. These reservoirs have product-type information that should match the information given for the generating unit.

A part of the hydro generating capacity is reported in an aggregated manner, and so it is for the reservoir. The aggregated hydro-generating capacity is matched in a previous step with the generating units in the grid model. Those generating units corresponding to the aggregated capacity in the PEMMDB are not linked with hydro storage listed per unit in the PEMMDB.

In addition, some hydro-generating units in the PEMMDB can be without a link to a reservoir listed per unit. In order to ensure that the zonal information is the same as the sum of the information at a nodal level, the storage aggregated capacity is disaggregated to multiple nodal storages proportionally to the generating capacity of the generating unit for all units without referenced storage.

Natural inflows

Hydro inflows, in addition to some zonal constraints on hydro, are referenced in the PEMMDB, at an aggregated level per study zone and per technology. When attaching this information to the nodal generating units and storage, the information taken is for the technology associated with either the generating unit or storage. The natural inflows, as well as the constraints, are split among the generating units and storage based on their capacity. A bigger generating unit will receive more inflows. This translates the assumption that every plant in a study zone has the same productivity as the average plant in the study zone.

4.3.5 Other RES

Capacities

In the PEMMDB, the production type ´Other RES´ corresponds to five different production types. In the matching of capacities reported in the PEMMDB and CGM, it is impossible (especially for aggregated capacity) to distinguish these types as only a single production type is used in the Grid Model. Hence, the information in the PEMMDB for these five production types is aggregated to obtain the information for a single production type.

For the units that were listed per unit in one of the five production types in the PEMMDB, they are matched with the equivalent CGM unit, and the production type is overwritten with the common production type Other-RES. As for the aggregated capacity, the information is split among the unmatched generating units. The total capacities in the PEMMDB and the Grid Model are guaranteed to be the same following the alignment process.

Time series

The PEMMDB provides for the Other-RES production type time series to describe the available capacity for the generating units hourly throughout the year. Since the production types are aggregated to one, the time series are aggregated proportionally to the installed capacity for each. This averaged time series should be attached to the Other-RES units. In the case of the capacity being removed from the load, this hourly time series should also be considered when taking the capacity for the zonal hourly time series.

4.3.6 Other Non-RES

The Other Non-RES production type in the PEMMDB is given for different bands. Each of these bands is given a market price, a fuel type to meet the technical constraints and the number of units. It is impossible to tell from the units in the CGM which of these bands have aggregated information. These bands are replaced by a single band with the weighted average of the previous elements based on capacity. Additionally, each band has an hourly time series throughout the year to provide the available capacity. For the aggregated band, the time series is the weighted average using the capacities of the time series of the different bands.

The total capacity of the Other Non-RES units in the Grid Model is aligned with the sum of the capacities of the different bands in the PEMMDB. In case the TSO does not provide a solution in the case of misalignment over 3 %, the capacity is removed from the load. In the LMP model, the nodal generators are taken from the CGM, and the information from the aggregated band is attached. Where the capacity is removed from the load, it is necessary to take the information from the aggregated band and from the available capacity time series.

Batteries

The batteries are described in the PEMMDB in an aggregated manner. The capacities given in the PEMMDB and CGM are aligned in the frame of the alignment process. Battery units are created, and the aggregated storage capacity given in the PEMMDB is split among the battery units from the Grid Model according to the generating capacity.

As for power-to-gas, which is another form of storing energy, only the consumption part is considered, and they are modelled as energy purchasers. Again, the aggregated capacity given in the PEMMDB is disaggregated among the CGM units.

DSR

The information about DSR is described in the PEMMDB, but according to the LMP methodology on DSR, they were collected from the TSOs. In the TYNDP load snapshot that is used for the load disaggregation, the information is given whether the load is scalable and unscalable.

Theoretically, explicit DSR is provided by big consumers such as industries. The assumption made in the LMP study is that unscalable loads, meaning their consumption is constant, are industries. Consequently, the DSR in a zone is disaggregated among the nodes with an unscalable load, proportionally to the capacity of this load. The different price bands are represented by creating different generators that can produce when the price becomes higher than the price in the price band. In the case where the TSO in the zone did not implement this logic of scalable and unscalable loads, and all loads are scalable, explicit DSR is split among all nodes.

In the case of implicit DSR, which corresponds to a price elasticity, the assumption is the opposite; the units with a varying consumption would slightly adapt their consumption depending on the price. Hence, the nodal disaggregation of implicit DSR is done among scalable nodes and is proportional to the capacity of these loads.

4.4 Annex 4: Contingency Selection

In particular, for each relevant CNE t, the influence of each (380 kV or above) element in the model r is assessed by computing the following indicators:

$$IF_{r,t}^{pf,f} = \max_{s\epsilon S} \frac{P_{n-r}^{t} - P_{n}^{t}}{P_{n}^{r}} \cdot 100$$

$$IF_{r,t}^{pf,id} = \max_{s\epsilon S} \frac{P_{n-r}^{t} - P_{n}^{t}}{P_{n}^{r}} \cdot \frac{PATL^{r}}{PATL^{t}} \cdot 100$$

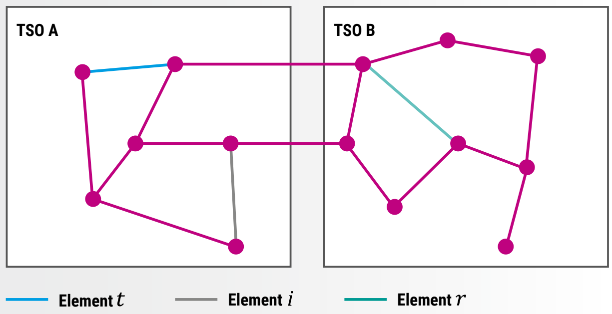

Figure 35: Mathematical description for calculation of power flow identification influence factor ($IF_{r,t}^{pf,f}$) and power flow filtering influence factor ($IF_{r,t}^{pf,id}$)

Where:

- s is the snapshot on which the computation is performed;
- S is a set of 24 snapshots adopted for the scope of identifying relevant contingencies;
- P_{n-r}^{t} is the active power flow through the network element t with the network element r disconnected from the network;
- P_{n}^{t} is the active power flow through the network element t with the network element r connected to the network;
- $PATL^{r}$ is the loading in MVA or MW that can be accepted by network element t in the scenario s for an unlimited duration; and
- $PATL^{t}$ is the loading in MVA or MW that can be accepted by network element r in the scenario s for an unlimited duration.

For each relevant CNE t, each element r having a *"Power flow identification influence factor"* higher than 15 % and a *"Power flow filtering influence factor"* higher than 3 % is identified as a relevant contingency, and the couple r, t creates a relevant CNEC to be included in the "default" list. These values are the most conservative ones, according to the CSAm.

4.5 Annex 5: Results from Additional Sensitivity Analysis

Case relative to base run	1-h granularity	CO_6 price of 90 €/t	New fuel prices	Nuclear must-run deactivated	HVDC DE
Hourly average price per country	≈	↑	↑	≈	DE ↑ AT ↓ DK ↑
Intraregional price spreads	≈	↑	↑	≈	↓
Average hourly sum of shadow prices	≈	↑	↑	≈	↓
Hourly shadow price sum distribution	≈	↑	↑	≈	↓
Conclusion	Difference insignificant	Nothing unexpected	Some new lines with shadow prices detected	Small, minimal difference	As expected

Table IV: Overview of the results of the sensitivity analyses

LINEAR 1-h granularity parallel days

Implementing a one- rather than two-hour granularity does not have a noticeable effect on the average LMP results across the simulated week.

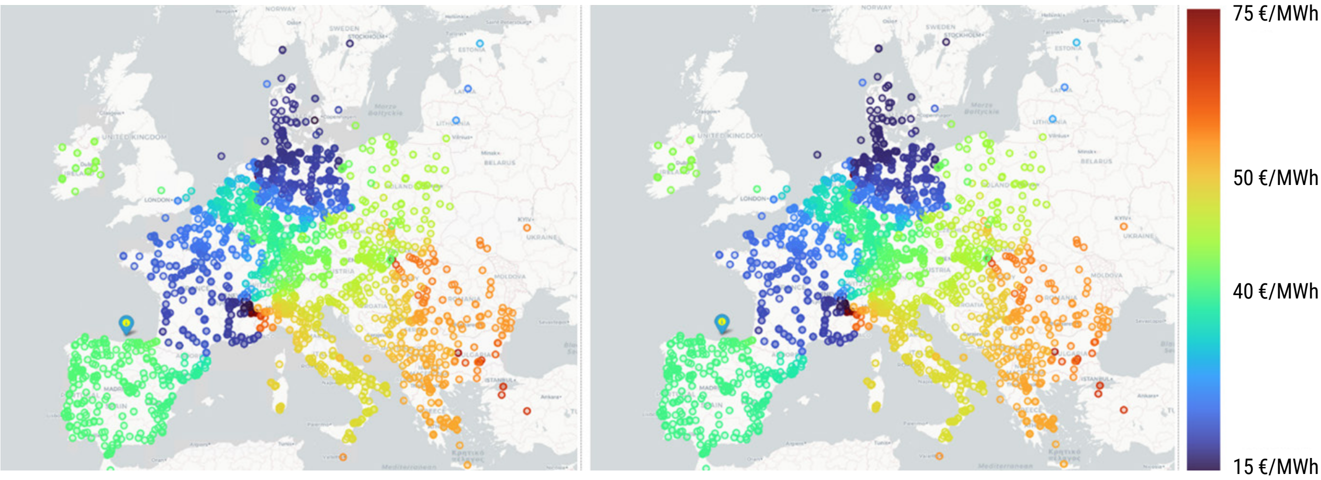

Figure 36: Overall average nodal prices - base model versus 1 h granularity

LINEAR 2-h granularity parallel days & CO_2 price of 90€/t

The assumption of a 90 €/t instead of a 40 €/t CO_2 price leads to an overall increase in the average nodal prices across the simulated week.

Furthermore, slight changes in the location of congested elements can be observed.

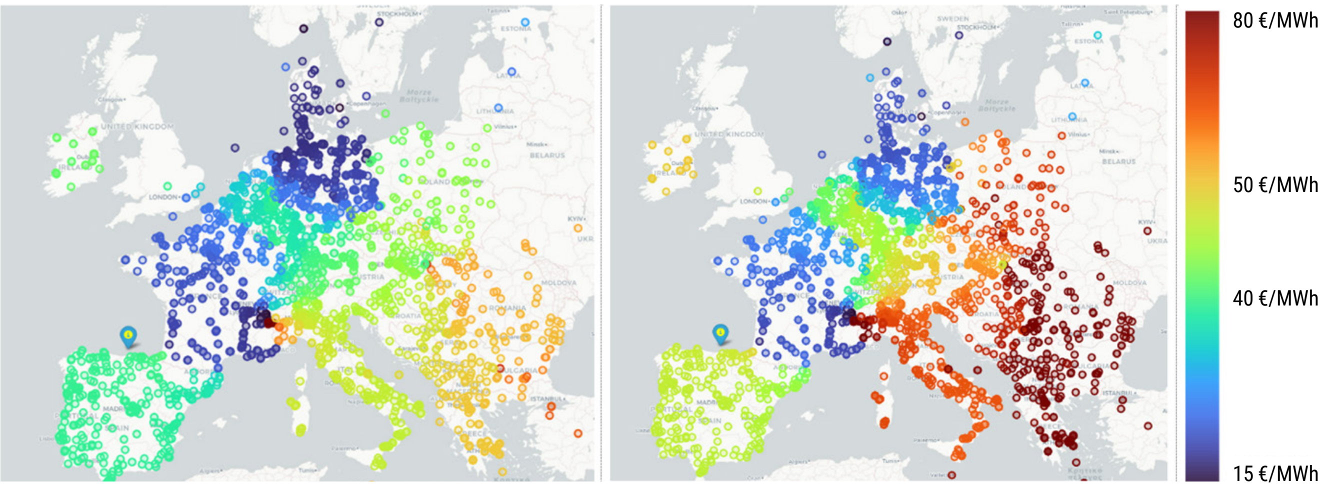

Figure 37: Overall average nodal prices - base model versus increased CO_6 price

LINEAR 2-h granularity parallel days & CO_2 price of 90€/t + increased fuel prices

In case fuel prices are changed to 95€/MWht gas, 90 €/boe brent and 160 €/t coal price together with a CO_2 price of 90 €/t, the average nodal prices increase significantly. Furthermore, additional congested network elements can be observed from the simulation results.

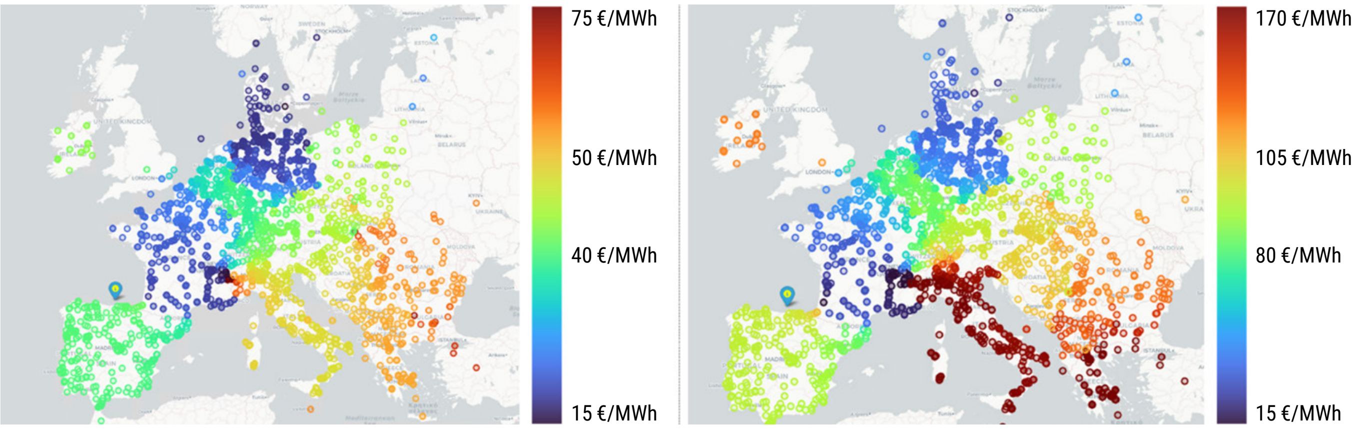

Figure 38: Overall average nodal prices - base model versus increased CO_2 price & new fuel price assumptions

LINEAR 2-h granularity parallel days & nuclear must run constraint deactivated

Deactivating the must-run constraints in the simulation model does not lead to a major change, as can be seen from the average nodal prices across the simulated week.

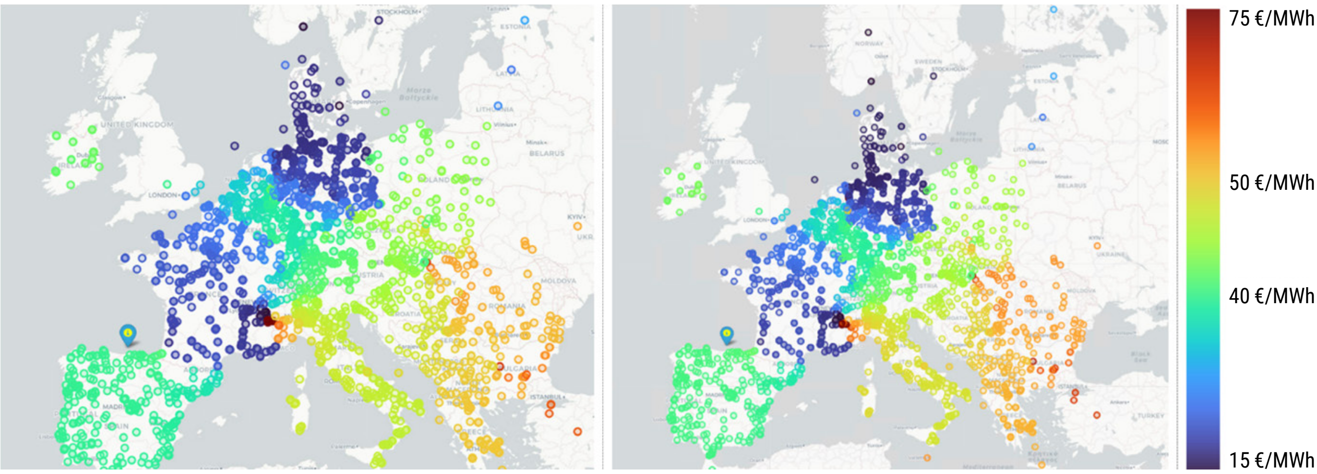

Figure 39: Overall average nodal prices – base model versus deactivated nuclear must run constraints

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BZR	Bidding Zone Review
BZRR	Bidding Zone Review Region
CGM	Common Grid Model
CGMS	Common Grid Model Exchange Standard
CNEC	Critical Network Element with a Contingency
DLR	Dynamic Line Rating
DSO	Distribution System Operator
DSR	Semand Side Response
EC	European Commission
ENTSO-E	European Network for Transmission System Operators in Electricity
ENTSO-G	European Network for Transmission System Operators in Gas
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LMP	Locational Marginal Pricing
MAF	Mid-term Adequacy Forecast
MTU	Market Time Unit
NDP	National Deveopment Plans
OHL	OverHead Line
OSL	Operational Security Limits
PASA	Projected Assessment of System Adequacy
PECD	Pan European Climate Database
PEMMDB	Pan-European Market Modelling Database
PSSE	Power System Simulator for Engineering
PV	Photovoltaic
RES	Renewable Energy Sources
TRA	Topological Remedial Actions
TRAPUNTA	Temperature Regression and LoAd Projection with UNcertainty Analysis
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UCTE	Historical: Union for the Co-ordination of Transmission of Electricity

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