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Projects of common interest? Evaluation of European electricity interconnectors

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ABSTRACT

This paper evaluates the new electricity interconnection projects on the fifth list of Energy Projects of Common Interest. A cost-benefit analysis is carried out with electricity market modelling. The results show that out of the 13 planned lines, 12 are socially beneficial. Moreover, the sensitivity checks highlight that most projects remain beneficial despite differing market assumptions. In those scenarios, where Europe's average wholesale electricity price is relatively higher, the projects yield greater social benefits. A complementarity index is also calculated, showing that PCI projects are generally weak competitors to each other.

1. Introduction

In November 2021, the European Commission published the fifth list of Projects of Common Interest (PCI). These are key infrastructure projects to complete the European internal energy market and help the EU achieve its energy and climate policy objectives. The projects are selected partly based on market modelling, which evaluates the benefits of the planned electricity interconnectors for European market players, such as power producers and consumers. However, the market modelling and the assessment process are not fully transparent in many respects, and the Commission's final decision is often criticised. Therefore, assessing the costs and benefits of the recently labelled PCI projects in line with the evaluating guidelines is relevant, as it may validate or discredit the final selection.

This study focuses on planned cross-border electricity projects and measures their future social profitability. The analysis covers the most important cost and benefit categories included in the latest version of the ENTSO-E CBA Guideline (ENTSO-E, 2021), most precisely quantified through modelling. We estimate the investment and the operational costs of the interconnector projects based on cost information published for current and past PCI projects. Furthermore, the effect of the projects on interconnectivity targets is analysed.

The European Electricity Market Model (EEMM) is used to carry out the quantitative analysis, which market model is operated by the Regional Centre for Energy Policy and Research (REKK). It is a partial equilibrium microeconomic model that covers the entire European power system and simultaneously optimises the production of more than 3000 power plant units and trades on more than 100 interconnectors hourly. EEMM can be used to quantify the welfare changes caused by the realisation of PCIs for different market participants, including traders, system operators, consumers, and producers, across the 43 markets modelled. Net present value (NPV) and social profitability index (benefit-cost ratio) calculations assume a 25-year lifetime. Different groups of projects are modelled together (PINT and TOOT assessment, explained later in detail) to capture the interaction and the significant effects projects have on one another. Several sensitivity cases with different price environment assumptions are analysed to account for the uncertainty of the European power sector. After taking these steps, we can comprehensively assess all the electricity interconnector projects on the fifth PCI list.

The analysis extends the methodology applied through the PCI selection with a new indicator, the complementarity index, which measures the degree of complementarity or competitiveness between projects, which is a novel addition to the existing methodology and can be incorporated into the future PCI selection process.

The paper is structured as follows. The next section summarises the relevant literature, mainly focusing on different interconnector evaluation solutions and the evolution of the PCI selection process. Section 3 introduces the electricity interconnector projects of the fifth list and presents the main input values related to the lines applied in the analysis. Section 4 presents the applied methodology, the indicators applied for the welfare analysis, and a detailed description of the European

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Electricity Market Model used in the analysis. Section 5 summarises the main results, including the sensitivity assessments, while Section 6 draws the analysis's main conclusions and policy implications.

2. Literature review

This section presents the evolution of evaluations similar to our analysis. We begin by addressing the more general aspects: we introduce the different approaches of electricity interconnector evaluation techniques, explain why it is important to carry out such analyses, and then show why using a Europe-wide, detailed electricity market model is one of the best options. In the second part, we show concrete analyses of previous PCI projects, highlighting the concerns and presenting how the pitfalls are avoided in our work. Finally, we summarise the history of the official PCI selection process, highlighting how it developed and improved over the past decade and the remaining weaknesses of the approach that make evaluations such as our work still useful and important.

2.1. Interconnector evaluation

The European Union aims to create a well-functioning internal market, known as the Energy Union, in the electricity and natural gas sectors, providing secure, sustainable, competitive and affordable energy for all consumers (European Parliament, 2018). Thus, barriers hindering internal trade and market integration need to be removed. One of the most important preconditions is the requisite infrastructure. Pach-Gurgul (2017) stated that integrating national electricity markets is limited by the inadequate possibility of energy transmission between them. Increasing trade possibilities between countries can bring us closer to the Energy Union. Brunekreeft and Meyer (2018) also pointed out that EU cross-border interconnector capacity is scarce and, more importantly, the progress of interconnector capacity expansion is too slow.

Interconnectivity not only integrates markets but is also crucial for the green energy transition in Europe (Andersen, 2014; Schittekatte et al., 2020; Newbery et al., 2019) and around the world, e.g. China (Xu et al., 2020) or Central Asia (Qadir & Dosmagambet). Spiecker et al. (2013) found that system flexibility needs resulting from high shares of stochastic generation (e.g. wind and hydro) can be reduced by boosting interconnection capacities. In its latest annual progress report (European Commission, 2021), the Commission also emphasised the importance of removing grid bottlenecks to speed up the green energy transition, further demonstrating the magnitude and timeliness of the topic.

Based on the above, it seems that constructing more and more interconnectors can eventually lead to the desired integration of European markets. However, these projects are usually very costly with long lead times (Sovacool et al., 2014). Thus, it is important to choose the optimal group of projects under the right policy framework and market design to deliver sufficiently integrated electricity markets at the lowest cost. This task, however, is complex and challenging, with several different approaches and analytical choices. In the following, we show different methods and try to justify our methodological choice based on the listed approaches.

Several researchers analysed the effects of increased trading capacity on specific borders as a result of new interconnector projects or other market design elements (such as market coupling) either empirically (ex-post) or theoretically (ex-ante) using different benefit categories. Most of the research attempted to capture the changes in overall social welfare resulting from the newly available capacities, while some focused on TSO costs and incomes (congestion revenues). However, the latter would lead to more biased decision-making. According to De Nooij (2011), an investment decision based solely on evaluating changes in congestion revenues is unlikely to lead to socially optimal investment decisions.

Abadie and Chamorro (2021) quantified the transmission revenues of a new interconnector between Spain and France. They built a price forecasting model for 2020–2022 and use Monte Carlo simulation to generate hourly prices and flows and calculate transmission income. However, this approach fails to consider all social welfare categories and quantify the producer and consumer welfare changes. It solely focuses on the foreseeable income of the TSO. Kimura and Ichimura (2019) took a similar approach for two lines (Japan-Russia and Japan-South Korea). They calculated the investment recovery solely from the investor's perspective (the TSO), quantifying the future estimated transmission revenues.

The interconnectors between the UK and the EU are particularly interesting; several studies have been conducted in recent years to examine the effects of existing and planned infrastructure on these borders. Newbery et al. (2019) analysed the effect of market coupling on the UK-EU borders based on historical prices and trade data, finding it successful. They asserted that additional investment in interconnectors is likely socially desirable due to their utilisation and the resulting price integration with increased renewables penetration and harmonised carbon pricing policies across the EU. This approach, however, can only be applied ex-post and thus cannot be used to evaluate future projects.

Doorman and Frøystad (2013) assessed the profitability of a potential HVDC cable between the UK and Norway from the social and merchant investors' perspectives. The two cases differ in terms of the rate of return, the considered lifetime and the calculation method of the benefits. They argued that the line is not profitable from the investor's point of view, but from the standpoint of social welfare, it is.

Guo and Newbery (2021) estimated the social cost associated with the uncoupling of the UK market from the EU Integrated Electricity Market as a consequence of BREXIT. They quantified social costs as the growth in generation costs resulting from inefficient trade caused by replacing lower-cost imports with costlier domestic generation. The results suggest that the loss in congestion revenue due to uncoupling is about €31 m/yr, carrying a social cost of around €28 m/yr. This approach might capture the changes in consumer and producer welfare but say nothing about the effects on congestion rent.

MacIver et al. (2021) used a European scale unit commitment model to analyse how British-EU interconnectors and the changing generation mix across Europe may impact the British electricity sector. They modelled three years (2020, 2025, and 2030) based on ENTSO-E TYNDP scenarios. They found that under certain policy parameters, the new British-EU interconnectors may result in an overall increase in European carbon emissions. This research underlines the importance of conducting detailed analysis for welfare gains and assessing the impacts on emissions. While welfare is not calculated directly, the authors quantified interconnector utilisation and modelled prices on the different markets to calculate TSO revenues.

Zakeri et al. (2018) conducted a cost-benefit analysis for an interconnector project between the UK and the Nordic power markets. They used a multi-area hourly deterministic operation and dispatch model to monetise social welfare that covers Nordic power and heating sectors, making it possible to capture CHP producer behaviour more accurately. Their results indicate that the total benefit of a new link would exceed the cost due to lower prices in the UK, higher prices in the Nordic market, and a significant congestion revenue. However, this outcome can change if new wind capacities are realised in the UK market, pushing down British power prices. In this scenario, the overall benefits are lower than the costs due to lower grid revenues. This result highlights the importance of assumptions about future renewable developments. Such modelling can provide a broader picture of the effects of a new interconnector through hourly modelling and monetisation of social welfare.

Purvins et al. (2021) conducted a cost-benefit analysis for the Trans-Asia line from Turkey through Georgia and Azerbaijan to Kazakhstan. Welfare was monetised using a techno-economic electricity system model that optimises generation dispatch and power flows, providing an asset performance valuation in terms of electricity prices.

The authors modelled one year (2040) to extrapolate welfare gains over 40 years and monetised CO_2 emission reduction based on EU ETS prices, which they compared with investment costs. The limitation of this approach is the modelling of a single year: as the European power sector is constantly evolving, the effect of a transmission line in different future years might vary significantly.

Spiecker et al. (2013) emphasised that the increasing share of variable RES poses great challenges for evaluating the benefits of increased interconnection capacities. They applied a stochastic European electricity market model (E2M2s) for the economic valuation of specific interconnector capacities (mostly between the northern European countries and the European mainland). This model assumes well-functioning competitive markets and determines optimal market results for 12 reference hours for 12 days. As a result, cost-efficient power plants cover (price-inelastic) demand. The model determines the optimal operation of power plants that leads to minimum total system costs considering load restrictions, detailed technical limitations of power system components, and endogenous investments in new conventional power generation capacities. The authors stressed the importance of the stochastics of the model as it reflects the benefits of generation and transmission flexibility.

While our model takes a deterministic approach, several similarities exist with the analysis above. Both models cover the whole of Europe (critical in such a strongly interconnected market), assume competitive markets, determine cost-efficient power plant dispatch, and model the investments in new conventional power generation capacities endogenously. Applying a (simplified) deterministic model helps us to unlock some of the limitations: e.g. we are modelling 12 weeks on an hourly basis, which means more than 2000 h in each year, and several years are modelled, with evolving input setups. From an economic point of view, another relevant aspect is introducing the introduction of an elastic demand function that allows the modelling of prices and the calculation of all the important socio-economic welfare categories (consumer surplus, producer surplus and change in congestion rent). Based on the literature, the best approach seems to be applying such a Europe-wide partial equilibrium economic power system model.

2.2. Previous analysis of the PCI lists

The TEN-E Regulation (European Parliament, 2013) was established to facilitate energy market integration for the European Union. Based on this regulation, key energy infrastructure projects essential to the single energy market are selected every two years. For a project to be labelled as a "project of common interest" (PCI), it must benefit at least two Member states, foster market integration and competition, enhance the security of supply and reduce CO_2 emissions (Carlini et al., 2019). Selected projects will have better access to funding and can benefit from accelerated planning and permitting processes and an improved regulatory regime (Selei and Tóth, 2022). The Fifth PCI list was published in November 2021.

As demonstrated above, the selection process is a complex undertaking. There are several critics of the evaluation practices employed, which is why the European Commission continuously updates its methodology.

De Nooij (2011) warned that the cost-benefit analysis carried out by TSOs and regulators could be flawed. Regulators may use negative assumptions in their CBAs to ensure the NPV remains positive and apply different discount factors that lead to poor comparability. The author called for a uniform cost-benefit analysis methodology for TSOs and regulators to avoid under and overinvestments and help identify optimal projects. Although this assessment gained the attention of policymakers, heterogenity in the ENTSO CBA Guidelines persists, and the decision-making process is not based on a single, joint modelling approach.

Schmidt and Lilliestam (2015) elaborated further on the biases associated with CBA. They highlighted that the analyst's perspective influences value judgements and suffers from non-comparability of interpersonal utility and the arbitrariness of social discount rates, using flawed data from willingness-to-pay/willingness-to-accept methods. Therefore, a pan-European transmission CBA cannot generate neutral information and provide unbiased outcomes. Echoing De Nooij (2011), they called for including non-transmission solutions in domestic grid investment projects. They proposed a collective and participatory approach involving stakeholders and TSOs in the CBA process.

Most of the concerns are related to the different interests of the parties involved to some extent in project development, which is not the case for the authors of this analysis. To perform an independent and comparable analysis of the PCI projects, we use the social discount rate suggested by ENTSO-E and consider the welfare changes of all European market participants.

2.3. Evolution of the PCI selection process

Since the first PCI selection process in 2012–2013, the selection and evaluation methodology has improved in several areas. Observing the implemented changes since the first list in 2013, it is clear that the PCI selection procedure is becoming more and more standardised (ACER, 2013; ACER, 2015; ACER, 2017; ACER, 2019; ACER 2021). In the case of the first and second lists (in 2015), only projects included in ENTSO-E TYNDPs were eligible, which allowed for the harmonisation of CBA methodologies (ACER, 2015).

The evaluation methodology is linked to ENTSO-E TYNDPs mostly as input data for calculations; however, cooperation between producers became more common, and TYNDP evolved to provide a basis for the calculations related to PCI selection. For example, CBA rules were harmonised for the third list in 2017, and from the fourth list in 2019 onwards, submitting sub-sections of TYNDP clusters was mostly not permitted, creating more consistency among listed projects (ACER, 2019).

The harmonisation and uniformisation were further improved by introducing the identification requirement by the Regional Groups (ACER (2017)). Previously, the selection was mostly based on country-level indicators and calculations, which reduced the reliability of the selection in the third to fifth lists. Thus, ACER argued that a univariate, quantified border-wise requirement calculation conducted by ENTSO-E (ACER 2017; ACER 2019; ACER 2021) should be applied. Such detailed calculations only became available with ENTSO-E – ENTSOG, 2022; ENTSO-E, 2021). However, the modelling results were not applied in the fifth PCI selection process (ACER, 2021).

Thus, although there has been a significant improvement, there is still room for developing the selection process. ACER has several suggestions related to the fifth PCI list selection procedure. Most importantly, CBAs are still not transparent enough, which allows NRAs to use inconsistent methods. Furthermore, the final decision is based on multi-criteria selection rather than a ranking based solely on monetised costs and benefits. As a final point, ACER proposed a different evaluation methodology for well-advanced and non-advanced projects since the latter category carries significantly more uncertainty (ACER, 2021).

Thus, independent evaluation reports such as this analysis are of great value and are an important mean of cross-checking the official PCI selection process's robustness, in a continuously changing market environment. The need for this research is particularly urgent in turbulent times, as witnessed over the past 1.5 years. To our knowledge, no such assessment has yet been conducted for the fifth PCI list.

3. Introduction of fifth list PCI projects

3.1. Analysed projects

In November 2021, the European Commission published the fifth PCI list, which featured significantly fewer cross-border electricity interconnector projects than the fourth PCI list due to three main factors.

Firstly, most projects from the fourth PCI list were commissioned or were very close to completion, rendering their inclusion in the new list unnecessary. Secondly, the exit of the United Kingdom from the European Union resulted in the exclusion of associated PCIs. Lastly, projects that failed to demonstrate sufficient economic value or faced delays in the implementation process were omitted from the list, probably because of the above-mentioned factors.

Table 1 summarises the characteristics of the cross-border electricity projects[1] included in the fifth PCI list. Less than half of them are expected to be commissioned by 2025, with the Southwest-East corridor in the Czech Republic, Fontefría (ES) – Ponte de Lima (PT) line and LitPol Link Stage 2 closest to completion, by 2024, Aragón-Atlantic Pyrenees & Navarra- Landes lines between France and Portugal the furthest, by 2030.

The Westtirol (AT) - Zell/Ziller (AT) internal line is the smallest, which increases the German-Austrian cross-border capacity by 600-600 MWs in both directions. The largest development is expected on the French-Spanish border, increasing the cross-border capacity with 5200-5200 MWs in both directions, to be accomplished in two stages by 2028 and 2030.

As the map of the projects shows, several member states are included in at least one PCI project, but the majority are concentrated in four countries: Spain, France, Germany and Portugal. Belgium, Netherlands and Slovakia have no projects on the fifth list but have completed PCI projects from previous lists.

3.2. Associated costs

The welfare analysis's PCI investment and operational costs are based on ENTSO-E – ENTSOG, 2022. They are summarised in Table 2.

The Westtirol - Zell/Ziller, a domestic Austrian line, has the lowest capital expenditure, at 45 million EUR. The two proposed lines between France and Spain are the most expensive, with planned commissioning in 2030. Together they will cost approximately 2.64 billion EURs.

3.3. Effects on interconnectivity

Member states must reach a 10% interconnectivity threshold by 2020 to advance the single EU electricity market and achieve 15% by 2030. Interconnectivity is measured by the ratio of total import transmission capacity to total installed electricity generation capacity. PCIs should facilitate the achievement of these targets. This subsection investigates how ongoing PCI projects will contribute to the 2030 interconnectivity target in all Member States (see Fig. 1).

Fig. 2 shows the current interconnectivity of member states and the contribution of these PCIs. According to the figures, eight member states will fail to reach the minimum 2030 interconnectivity requirement with the realisation of current PCIs: Italy, Spain, Greece, France, Ireland, Poland, Germany and Romania. Italy has the lowest projected value at 5%, while Romania is just below the 2030 threshold at 14%.

Even without reaching the 15% target, all PCI projects contribute significantly to the interconnectivity of Member States except Greece, where new import transmission capacities are outside the scope of PCIs. Thus, further investments will be necessary beyond this PCI list to facilitate a well-connected European electricity system.

In other member states, past and present PCIs matter to making or breaking the 2030 interconnectivity target. Without current and future PCIs, the Netherlands would be at 10% instead of the projected 15%, Portugal at 9% instead of the planned 16%, and Belgium at 13% instead of 19%.

Finally, several Member States will be well above the 15% interconnectivity threshold, with three countries- Estonia, Lithuania, and Luxembourg - exceeding 100%. For the first two, PCIs are important in synchronising the Baltic States with the main European grid.

4. Methodology

4.1. Electricity market modelling

This section briefly describes the model, the main input assumptions, and the different analysed scenarios. With modelling up to 2050, sensitivity testing is essential over such a long timeframe, especially for a sector undergoing significant transformation.

4.1.1. The European Electricity Market Model

The European Electricity Market Model (EEMM) is a partial equilibrium microeconomic model that covers the entire power sector of the European region and maximises overall welfare (consumer surplus + producer surplus + congestion rent) across all countries for each modelled hour. It simultaneously models the electricity markets of 43 countries over 2016 separate (and independent) hours in each modelled year, all 168 h of 12 representative weeks. This approach is similar but far more granular than Spiecker et al. (2013), which modelled 12 representative hours of 12 representative days. Each non-modelled hour is represented by exactly one modelled hour, so the results for 2016 h can be extrapolated to 8760 h, from which annual values are calculated. Each year between 2025 and 2050 is modelled to more accurately incorporate installed capacities, interconnectivity, and other important market developments (e.g. carbon pricing from a specified future date). The supply and demand curve for each market is based on exogenous assumptions (i.e. installed capacities, commodity prices and predicted demand developments), with trade possibilities constituted by future interconnector capacities. An aggregated linear demand function is assumed for each country and a constant marginal cost (independent of the production level) for each producer in each hour. With all these factors accounted for, the model produces the welfare-maximising equilibrium wholesale prices, the trade at each border, and the hourly output of each modelled power plant unit. The modelling logic is summarised in Fig. 3 and described in more detail in the next subsection.

4.1.2. Main inputs and assumptions of the modelling

The three main inputs to the modelling are installed capacity, demand, and commodity prices. The assumptions and the sources of these inputs are briefly described below.

The installed capacity values for each country are based on the latest data publicly available on the websites of TSOs and national regulatory authorities (NRAs). The model includes unit-level information for nuclear and fossil plants and planned decommissioning dates, where available, which is particularly relevant to national phase-out plans for coal and lignite plants. There is much uncertainty about these plans, especially lately in light of the recent very high gas price environment, but we still believe that sooner or later, these plans will be implemented; thus they are incorporated into the modelling. For future fossil capacity developments, a built-in investment module determines the expansion of natural gas power plants (with or without carbon capture and storage technology) based on expected profitability from country to country.

Regarding the investments in the modelling, we apply a two-step approach. Investors "look ahead" and see how the profitability of a given power plant technology will evolve over the next years. Thus, an initial "test" will run for the future. Based on the results, it is decided whether the fossil investment is necessary, and if yes, the power plant will be included in the second (final) modelling round. This two-step approach is carried out for each modelled year, with information on future power plant decisions in previous years always fed into the modelling for the following year. This approach is also similar to that of Spiecker et al. (2013), wherein renewable capacities are exogenous, and fossil developments are endogenous. The reference scenario uses the module, and the resulting fossil capacity developments are applied in all other scenarios. This approach makes the comparative analysis of the

[1] Some internal lines have a cross-border impact by increasing NTC.

Table 1
List of modelled PCI projects based on the Fifth PCI list.

Code	PCI number	Name	Length (km)	Type (AC/DC)	Country-1	Country-2	Expected commission date[a]	Expected NTC increase (1–2/2 to 1), MW
PCI-1	1.6	Celtic Interconnector	575	DC	France	Ireland	2027	700/700
PCI-2	2.14	Green-connector	165	DC	Switzerland	Italy	2027	1000/1000
PCI-3	2.17	Fontefría (ES) – Ponte de Lima (PT)	125	AC	Spain	Portugal	2024	1900/1000
PCI-4	2.7	Biscay Gulf	394	DC	France	Spain	2028	2200/2200
PCI-5	3.1.1 & 3.1.2	Isar/Altheim/Ottenhofen (DE) - St. Peter (AT)	90	AC	Austria	Germany	2025	2000/2000
PCI-6	2.27.1 & 2.27.2	Aragón-Atlantic Pyrenees & Navarra-Landes	605	AC & DC[b]	France	Spain	2030	3000/3000
PCI-7	3.1.4	Westtirol (AT) - Zell/Ziller (AT)	105	AC	Germany	Austria	2027	600/600
PCI-8	3.11	CZ Southwest-east corridor & CZ Northwest-South corridor	321	AC	Germany	Czech Republic	2024,2029	500 + 500/500 + 500
PCI-9	3.14	GerPol Power Bridge I	325	AC	Germany	Poland	2026	1500/500
PCI-10	3.22.1	Mid Continental East Corridor	522	AC	Romania Romania	Serbia Hungary	2026	844/600 617/335
PCI-11	4.5.2	LitPol Link Stage 2	108	AC	Poland	Lithuania	2024	1000/500
PCI-12	4.8	Baltic States Synchronisation with Continental Europe	1948	AC & DC[c]	Lithuania	Poland	2026	500/1000
PCI-13	4.10.1	Third AC Finland-Sweden north	379	AC	Finland	Sweden	2025	900/800

[a] Dates refer to when the new line first enters the modelling, In many instances, if the expected commission date is at the end of a given year, the next year considered.
[b] Both type of lines is included within the project cluster.
[c] Both types of lines are included within the project cluster.
Source: Fifth PCI list & technical documentation, ENTSO-E – ENTSOG, 2022

Table 2
Estimated investment and operation costs of projects on the Fifth PCI list.

Code	Name	CAPEX (mEUR)	OPEX (mEUR/year)
PCI-1	Celtic Interconnector (FR-IR)	930	8.4
PCI-2	Greenconnector (CH-IT)	630	2
PCI-3	Fontefría (ES) – Ponte de Lima (PT)	113	1.1
PCI-4	Biscay Gulf (FR-ES)	1750	10.2
PCI-5	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	384	3
PCI-6	Aragón-Atlantic Pyrenees & Navarra-Landes (FR-ES)	2640	16.5
PCI-7	Westtirol (AT) - Zell/Ziller (AT), (DE)	45	1
PCI-8	CZ Southwest-east corridor & CZ Northwest-South corridor (DE)	691	0.9
PCI-9	GerPol Power Bridge I (DE-PL)	251	1.8
PCI-10	Mid Continental East Corridor (RS-RO-HU)	189	1.3
PCI-11	LitPol Link Stage 2 (PL-LT)	80	1
PCI-12	Baltic States Synchronisation with Continental Europe (LT-PL)	1820	10.5
PCI-13	Third AC Finland-Sweden North (FI-SE)	297	0.3

Source: ENTSO-E – ENTSOG, 2022

different sensitivity scenarios easier, but it may also mean that in some scenarios, we have slightly more or less natural gas-based capacities than the optimal level.

The model includes aggregate values per country for renewable plants and storage for eight different technologies. The pathways are based on the EU's REPower Europe plan of May 2022 (European Commission, 2022). The main developments are summarised in Fig. 4.

The power sector constantly changes and evolves, with several new technologies becoming available. Different storage technologies are incorporated into the modelling to capture at least part of this. On the one hand, these are battery storage, pumped storage and hydro storage (reservoir) technologies with capacities exogenously set independently of demand developments. On the other hand, Demand Side Management (DSM) is also assumed in the model, up to a given (increasing year by year) percentage of the yearly average load. Thus, this element changes when different power demand pathways are assumed. Both are modelled the following way: they consume (more) in hours expected to be the cheapest and produce (/consume less) in hours expected to be the most expensive. These expectations are based on the level of projected residual demand, i.e. the difference between demand and zero marginal cost renewable production. The higher the residual demand, the higher the expected prices are. All market participants are assumed to have perfect foresight, with no uncertainty about future hourly RES production and demand. That is a simplification, but including a stochastic approach to these two factors is beyond the scope of this research.

Electricity demand is assumed to grow by an average of 1.2% per year in the EU-27 until 2030, driven by increased electrification somewhat offset by energy efficiency. Thereafter, a lower annual growth rate of 0.7% is envisaged, in line with the Fit for 55 Reference scenario.

The most important commodity prices are related to natural gas, coal and carbon allowances. For the country-specific values of natural gas prices, we use the REKK European Gas Market Model (see Selei and Tóth (2022)). The TTF price, representative of the overall price level across Europe, is presented in Table 3. Both coal and carbon allowance price assumptions are based on our best estimate using various international forecasts (IEA, 2021; Worldbank, 2021; European Commission, 2020; Reuters, 2021; Aurora, 2021), as well as the latest developments on the short and long-term markets. Most Energy Community Contracting Parties enter the EU ETS by 2030, and those that do not are assumed to introduce carbon pricing at a slightly later date. The table below also shows the commodity price assumptions of the ENTSOs (ENTSO-E – ENTSOG, 2022).

The fourth important element in evaluating PCIs is the development pathway for interconnectivity. We use the historical NTC values on each border as a baseline and then add the projects listed in the latest final TYNDP2020 (excluding those in the fifth PCI list).

4.1.3. Scenarios

The reference scenario embodies the most likely installed capacity mix, demand and commodity price pathways from the ones described above. The evaluation of the projects is carried out using two different approaches: TOOT (which means that only the analysed project is removed from a grid containing all planned PCIs) and PINT (which means that only the analysed project is inserted into the reference grid)

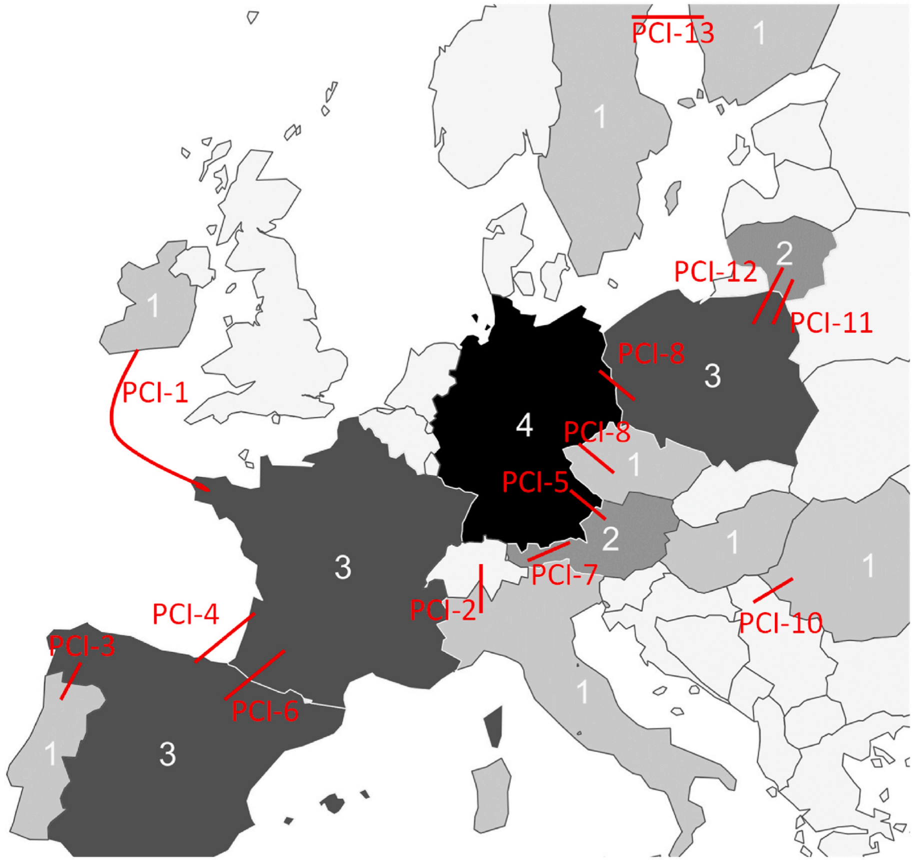

Fig. 1. Mapping the Fifth PCI list
Source: Own map based on the Fifth PCI list.

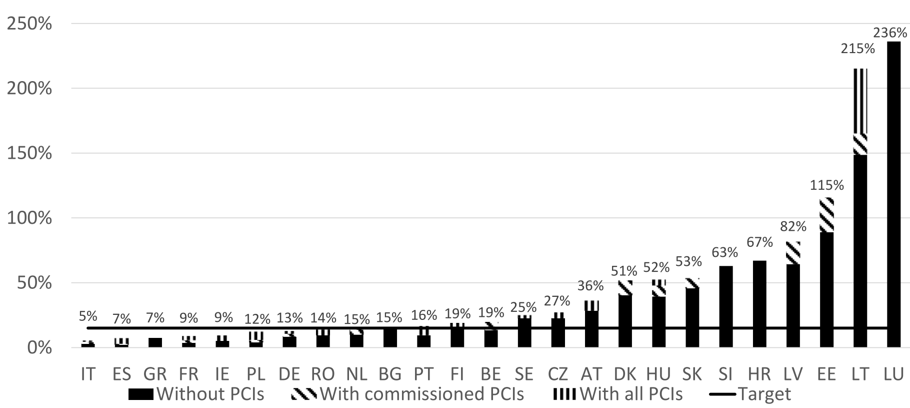

Fig. 2. Member state interconnectivity with PCIs
Source: Own calculation based on EEMM model inputs and PCI lists.

methodologies, explained below in more detail, which allow us to measure the effects of adding and removing PCI projects in the system. In addition to the Reference scenario, several sensitivity cases are analysed, testing for different commodity prices, power consumption and uptake of renewable capacities. These are summarised in Table 4, where "REF" indicates that the same value is used as in the Reference scenario. One of the ENTSO-E – ENTSOG, 2022 scenarios (Global Ambitions) is also modelled. This scenario assumes a much higher demand growth due to hydrogen production (2.9% annual consumption growth between 2030 and 2050) and higher intermittent RES generation. This ENTSO scenario assumes 1.1 TW of wind and 1.2 TW of solar capacity in 2050, while in our REF scenario, these values are 0.84 TW and 0.79 TW, respectively. However, ENTSO calculates with a much lower gas price level (~15 €/MWh from 2030) and an increasing CO2 price trajectory, with prices rising from 40 €/t to 168 €/t by 2050.

4.2. Indicators measuring social welfare

A cost-benefit analysis is carried out to determine whether the new projects benefit Europe, quantifying and comparing the welfare changes associated with implementing the new lines. The cost-benefit analysis uses two important indicators: the net present value (NPV) and the

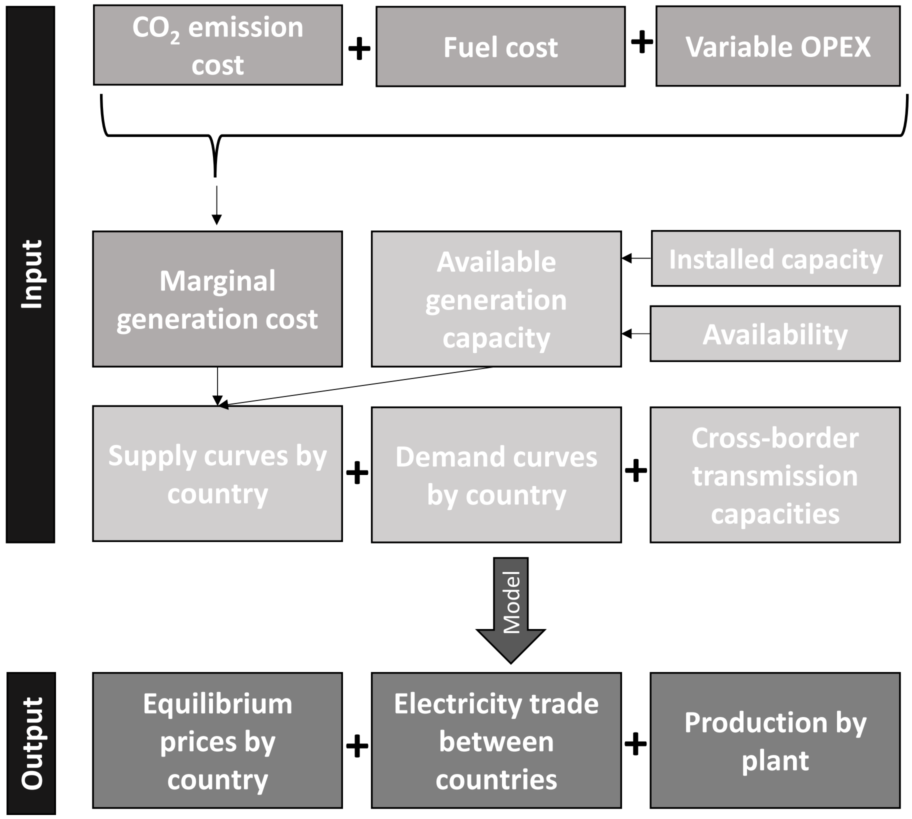

Fig. 3. Logic and structure of the modelling
Source: own Figure.

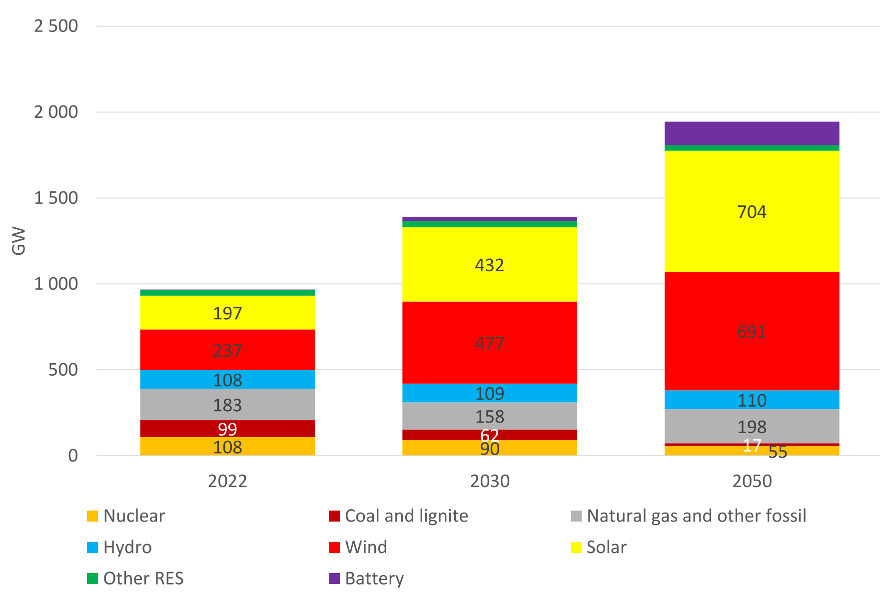

Fig. 4. Development of EU-27 installed capacity
Source: REKK modelling based on TSO and NRA data and REPower Europe plan.

benefit-cost ratio (B/C), which can also be considered a profitability index. The project NPV is the sum of discounted costs and benefits (considering all the costs and benefits incurred in each year over the 25-year lifetime of the project), and the B/C is the ratio of the total discounted benefits of the project to the total discounted costs. For the costs, it is assumed that the total CAPEX is incurred in the first year, and then the same OPEX (in real terms) arises in each year.

The advantage of the NPV indicator is that it shows exactly how beneficial a project is for European electricity market participants in monetary terms. Its disadvantage is that large projects with high costs and potentially higher benefits tend to have significantly higher NPVs in absolute terms than small projects, making their comparison difficult. In

Table 3
Commodity price assumptions.

		2025	2030	2040	2050
Gas price, €/MWh	REF	31.8	30.7	31.1	31.1
	High	47.7	46.0	46.7	46.7
	Low	15.9	15.3	15.6	15.6
	Very high	106.0	102.2	103.7	103.7
	ENTSOs GA[a] scenario	20.1	14.5	14.7	14.7
CO2 price, €/t	REF	90.0	90.0	90.0	90.0
	High	150.0	150.0	150.0	150.0
	Low	30.0	30.0	30.0	30.0
	ENTSOs GA scenario	40.0	78.0	123.0	168.0
Coal price, $/t	REF	76.9	57.0	52.0	52.0
	ENTSOs GA scenario	73.3	62.8	61.2	59.6

[a] ENTSO-E's Global Amibition (GA) scenario.

some cases, the benefits of a project with a relatively low (absolute) NPV can still be significantly higher than the associated costs, making it worth implementing. That is where the B/C ratio comes into play, which accounts for the relative profitability of the project.

4.2.1. Benefits

Three categories of benefits are calculated using the EEMM model: producer surplus, consumer surplus, and congestion rent.

Producer surplus is the difference between the market electricity price and the total average variable cost of production multiplied by the quantity produced. Consumer surplus is the difference between the price the consumer is willing to pay and the actual market price, aggregated over total demand. Congestion rent is calculated as the price difference between two markets multiplied by the traded quantity. Each can be calculated for all modelled hours and aggregated over the entire period. Mathematically, the indicators are formulated as follows,

$$PS = \sum_{pp=1}^{pp_{max}} \sum_{t=1}^{t=25} \sum_{h=1}^{8760} \frac{\left(P_{t,h} - AVC_{pp,t,h}\right) * QP_{pp,t,h}}{(1+\sigma)^{t-1}}$$

$$CS = \sum_{cc=1}^{cc_{max}} \sum_{t=1}^{t=25} \sum_{h=1}^{8760} \frac{\left(RP_{cc,t,h} - P_{t,h}\right) * QC_{cc,t,h}}{(1+\sigma)^{t-1}}$$

$$TSO = \sum_{t=1}^{25} \sum_{h=1}^{8760} \sum_{s=0}^{C_{max}} \sum_{n=0}^{C_{max}} \frac{\left(P_{s,h,t} - P_{n,h,t}\right) * QT_{s,n,h,t}}{(1+\sigma)^{t-1}}$$

$$B = PS + CS + TSO$$

where CS is the consumer surplus, PS is the producer surplus, TSO is the congestion rent, and B is the total benefit. Additionally, *pp* represents the different power plants, *cc* the consumers, *t* the years, *h* the hours within a year, while *s* and *n* are the country identifiers. P is the wholesale market price, QP is the quantity produced, QC is the quantity consumed, and QT is the quantity traded. AVC denotes the average variable cost of the power plant, RP is the reservation price of the consumers, and σ is the real discount rate.

All three categories are associated with positive welfare effects; however, implementing a PCI project may result in negative welfare changes in one or more categories. It is important to highlight that welfare effects are calculated at the European level, including all modelled countries, which can result in a net positive welfare effect for the bloc, with individual countries affected negatively.

4.2.2. Costs

PCI costs are based on ENTSO-E – ENTSOG, 2022, with the total cost calculated as,

$$TC_i = I + \sum_{t=1}^{t=25} \frac{OC_i}{(1+\sigma)^{t-1}}$$

where *i* stands for the different analysed PCI projects, I is the investment expenditure (CAPEX), and OC denotes the operational cost (OPEX).

4.2.3. TOOT & PINT

The social benefits of the projects are always evaluated against a reference grid. In both calculations, the relative welfare changes associated with the new PCI project (relative to the reference grid) are considered against the costs of implementing and operating the project.

Following the third ENTSO-E Guideline for cost-benefit analysis (ENTSO-E, 2020), the two approaches used in this paper are the "Put in one at the time" (PINT) and the "Take out one at the time" (TOOT).

The PINT methodology reference scenario is the same as the EEMM baseline in the previous section. The welfare effect is the difference between an alternative scenario and the reference scenario, which is then compared to the project's cost. A similar approach is followed in the TOOT methodology, with the difference that the reference case includes the full PCI project list, excluding the project being evaluated. In the alternative scenario, the assessed PCI project is also included. In both the PINT and TOOT scenarios, the calculation of NPV and B/C can be written as the following,

Table 4
Sensitivity cases.

	RES scenario	Load scenario	Gas price in 2030 (TTF, €/MWh)	CO_2 price (€/t)
Reference	REF	REF	REF	REF
Very high gas	REF	REF	Very high	REF
High gas	REF	REF	High	REF
Low gas	REF	REF	Low	REF
High CO_2	REF	REF	REF	High
Low CO_2	REF	REF	REF	Low
High consumption	REF	+0.5% yearly growth rate	REF	REF
Low consumption	REF	−0.5% yearly growth rate	REF	REF
High RES	+25% wind&PV	REF	REF	REF
Low RES	−25% wind&PV	REF	REF	REF
High price	REF	REF	High	High
Low price	REF	REF	Low	Low
Absolute high	−25% wind&PV	+0.5% yearly growth rate	High	High
Absolute low	+25% wind&PV	−0.5% yearly growth rate	Low	Low
ENTSOs' Global Ambitions	High	Very high consumption growth	~low	Increasing trend, low in the first years, and high at the end of the period

$$NPV_i = B_i - B_0 - TC_i$$

$$B/C_i = \frac{B_i - B_0}{TC_i}$$

where B_i is the total benefit when the assessed project is connected to the grid (either in a PINT or TOOT setup), and B_0 denotes the benefits in the reference setup.

To simplify the calculations, we assumed that all the assessed PCI projects will be commissioned by 2025, so the evaluation timeframe is 2025–2049. A real discount rate of 4% is applied, as suggested by the ENTSO-E Third CBA Guideline (ENTSO-E, 2020) and used in the literature (e.g. Purvins et al., 2021).

The PINT and TOOT approaches differ considerably under the baseline assumptions, thus leading to different results for the same project. In the PINT setup, all the other projects are not part of the reference case, so the interaction of planned PCIs is not measured. It is easily conceivable that some of these will not be completed or commissioned with significant delays, and ignoring this could lead to potential bias in the TOOT results. On the other hand, with the TOOT approach, all PCIs are accounted for, so that complementarity can be measured. The simultaneous completion of two lines may result in their competition, lowering the associated benefits, or synergy, creating more social benefits than the sum of the benefits in isolation.

A complementarity index is calculated for some sensitivity scenarios, measured as the ratio of the sum of the welfare benefits when both projects are connected to the grid simultaneously relative to the sum of the benefits if they are connected separately. Thus, the complementarity index between project i and j can be calculated as,

$$CI_{i,j} = \frac{(B_i - B_0)_{i,j} + (B_j - B_0)_{i,j}}{(B_i - B_0)_i + (B_j - B_0)_j}$$

where, i and j indicate which line is included in the alternative (PINT or TOOT) scenario, meaning both projects are completed when both i and j are included in the formula. This calculation can also be applied to more than two projects, mutatis mutandis.

If the complementarity ratio exceeds 1 (100%), simultaneous completion would lead to welfare synergies. If it is less than 1, the proposed lines are (at least partly) competitors.

5. Results and discussion

5.1. Reference scenario

5.1.1. Wholesale price development for 2030 and 2050

First, the wholesale price effect of the PCI list was analysed in aggregate by comparing the scenario of all commissioned projects with none. The results are summarised in Fig. 5.

The maps on the left represent 2030, and the maps on the right-hand side represent 2050. The maps at the top show the baseload wholesale prices for all European countries, and those below show the relative price change when all the PCI projects are commissioned.

Three distinct price zones will emerge in 2030 in the no PCI list scenario. The lowest prices will occur in Western and Southwestern Europe, mainly France, Spain, Portugal, Ireland and UK, with an average baseload price of 50–70 EUR/MWh. The second price region will include Northern and some Western and Central European countries, including

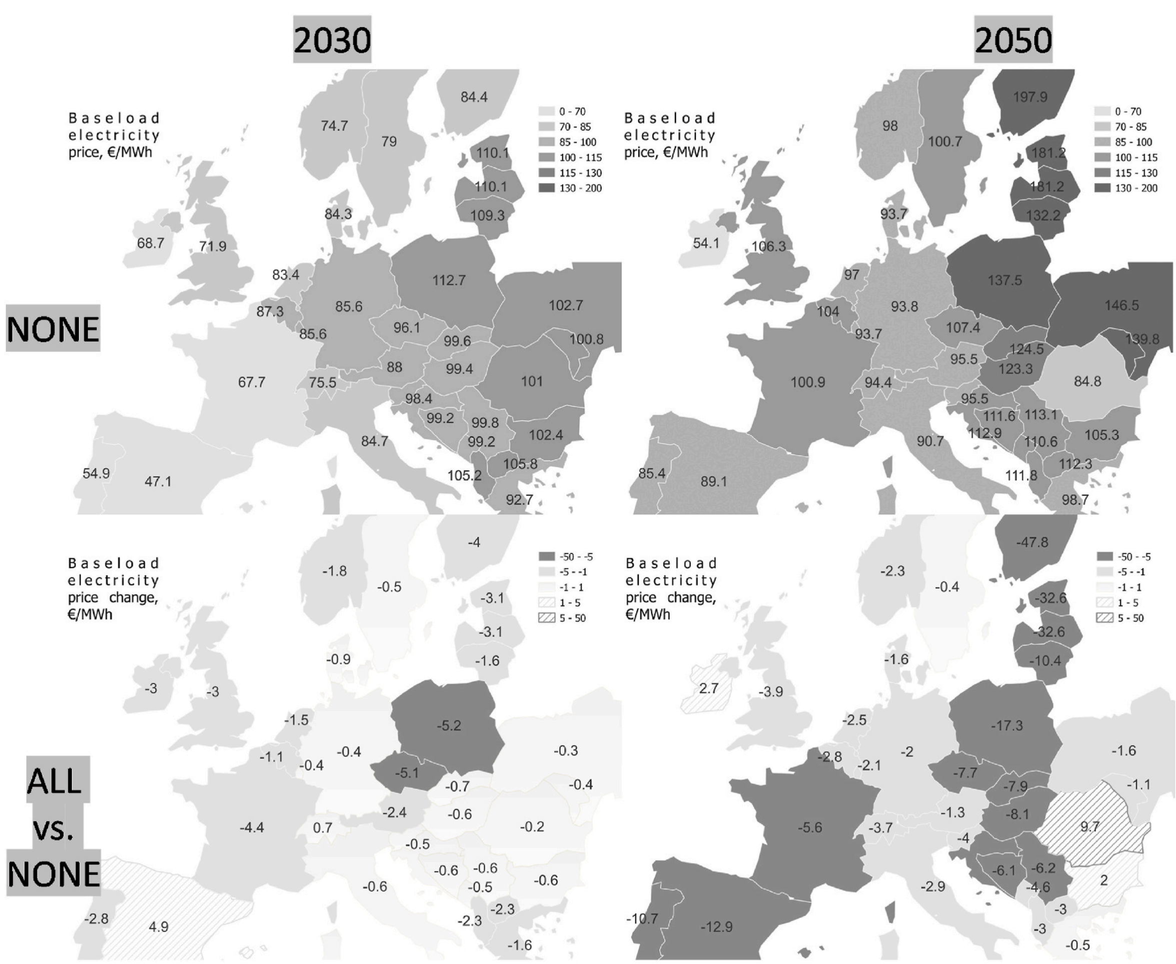

Fig. 5. Wholesale baseload electricity prices in 2030 and 2050 with PCI projects (bottom maps) and without (upper maps).

the Benelux states, Germany, Italy and Austria, with prices around 75–85 EUR/MWh. The remaining countries in South-East Europe will have the highest average prices at around 100 EUR/MWh.

In 2050, even without PCIs, some price convergence will take place, with higher prices on average. Two main price zones will divide the West and the East, with Austria and the Czech Republic the bordering countries. In the Western region, the average baseload price will be 90–100 EUR/MWh, while in the Eastern part, it will be 110–125 EUR/MWh. Ukraine, Poland and the Baltic states will reach even higher prices at around 140–150 EUR/MWh. With the PCI list commissioned, the average wholesale prices will fall across Europe in 2030 and 2050 relative to the reference case. The price-dampening effect will be more moderate in 2030, approximately 1 EUR/MWh in most Member States, with the Czech Republic and Poland achieving a sizable decline (more than 5 EUR/MWh) along with Estonia and Latvia (more than 3 EUR/MWh). Only Spain will experience a price increase in 2030 (5 EUR/MWh) due to the implementation of the Spanish-French interconnector, which opens the lower price zone of the Iberian region. In 2050, the effect will be much more significant in the Baltic states (approximately 30 EUR/MWh reduction), Central Europe (around 10 EUR/MWh) and Western Europe (5 EUR/MWh). Romania and Bulgaria are the only two countries experiencing higher prices than the reference. Fig. 7 summarises the B/C ratio of the PCI list based on the methodology introduced in the previous section.

Although at first glance, it seems counterintuitive that a new line between two countries leads to a baseload price drop in both countries, this could happen because the depicted values do not reflect the price for only 1 h, but the average of the modelled hours. Let us assume that in half of the hours in a given year, market A is cheaper, while in the other half, market B is cheaper. Building a new transmission line between these two countries could result in more electricity being exported to country B during the hours when country A is cheaper, but the prices in country A do not change, while prices in country B fall. This effect can also be imagined in the opposite direction. In this situation, the average baseload prices decline in both countries.

It is not only the annual baseload electricity price that will change significantly between 2030 and 2050 but also the shape of the hourly electricity price curves. In 2050, hourly prices will be more volatile than in 2030. Fig. 6 presents the hourly price curves for Germany in 2030 and 2050. It shows that while in 2030 there will be about 1000 h with a zero wholesale electricity price, this number will double by 2050. On the other hand, the number of hours with high prices also increases significantly. While in 2030, there will be only 54 h when the price exceeds 150 €/MWh, in 2050, this number will increase to 140.

5.1.2. PINT and TOOT results

The B/C ratio is greater than 1 for all projects (except PCI-12, the Baltic synchronisation to the European grid), meaning they are socially beneficial for Europe regardless of using the PINT or TOOT approach. The highest B/C ratio is observed for the Germany-Poland interconnector, with a value of 17–19.

The Baltic synchronisation project is an outlier, as its actual welfare effect is difficult to capture. It is a costly project, and the modelling may not measure all the associated benefits, as it only captures the welfare gains associated with higher NTC. The synchronisation of two zones could also provide additional welfare gains.

It is evident that the PINT approach results in higher B/C values for all projects than the TOOT, but only by a small margin. This finding suggests that the PCIs are, to some extent, competitors. However, the substitution effect between them is not strong enough to make either of them socially unprofitable in the TOOT analysis.

5.2. Sensitivity runs

Sensitivity runs are carried out to determine which factors are the most important for the profitability of the PCI projects from a social point of view. In addition to the reference (REF) scenario, 14 sensitivities are modelled. When considered in aggregate, all sensitivities have a cost/benefit ratio well above 1, indicating that the projects benefit society.

Fig. 8 shows the B/C ratio based on the total costs and benefits if all PCI projects are included in the grid, compared to when the projects are not implemented. The Figure shows that for sensitivities with higher average wholesale electricity prices than in the reference case, the profitability of the PCIs is also higher, and vice-versa. Scenarios with higher gas prices, CO_2 prices and consumption, and lower RES all lead to higher wholesale electricity prices on average, and in all these scenarios, the benefit is higher compared to the reference scenario. The largest impact occurs in the non-combined scenarios with high consumption (7.7 B/C) or very high gas prices (7.6 B/C). The lowest B/C index is 1.9 in the absolute low scenario, with low consumption, low natural gas and CO_2 prices, and high renewable penetration. The ENTSOs GA scenario

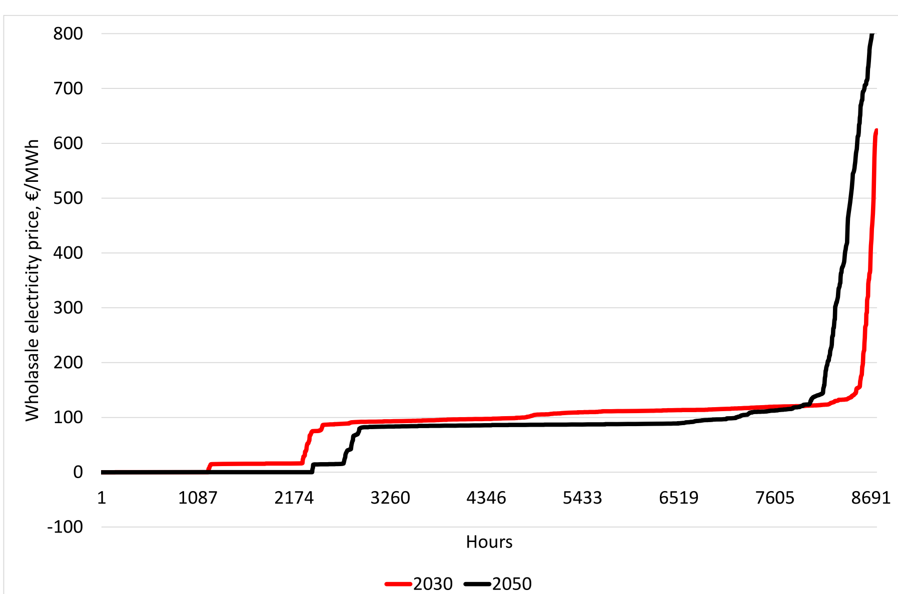

Fig. 6. Hourly electricity price development in Germany in 2030 and in 2050, REF, ALL scenario, €/MWh.

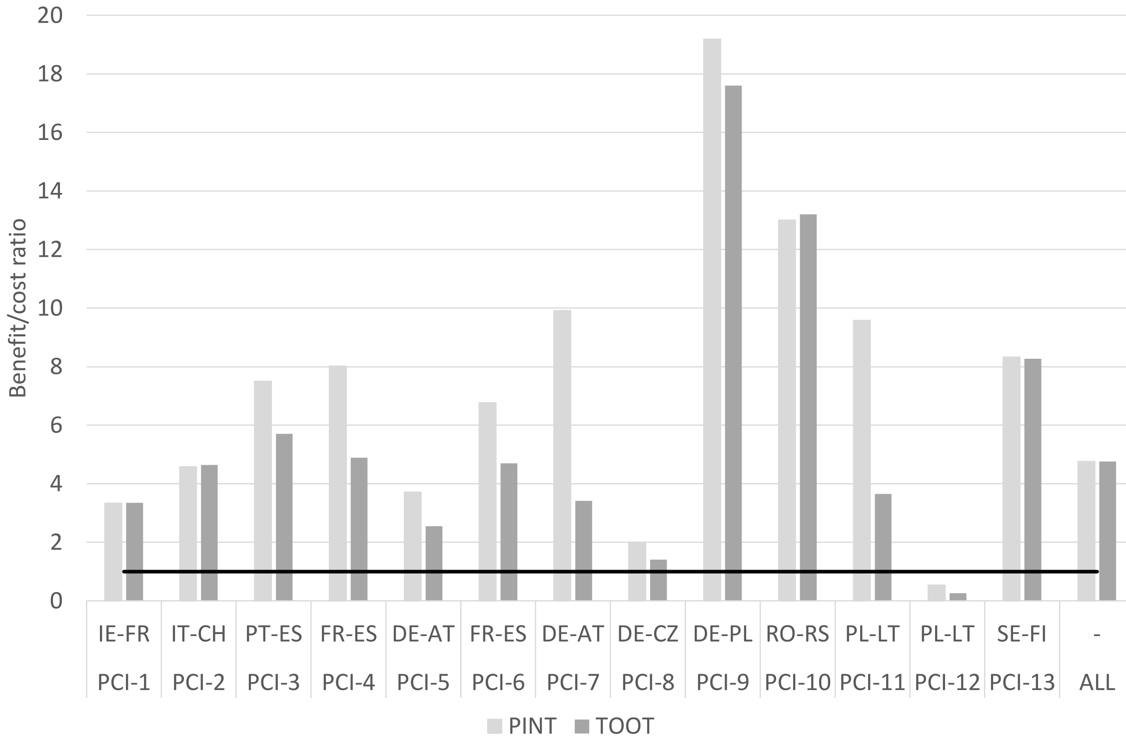

Fig. 7. B/C ratio for PCIs in the reference scenario.

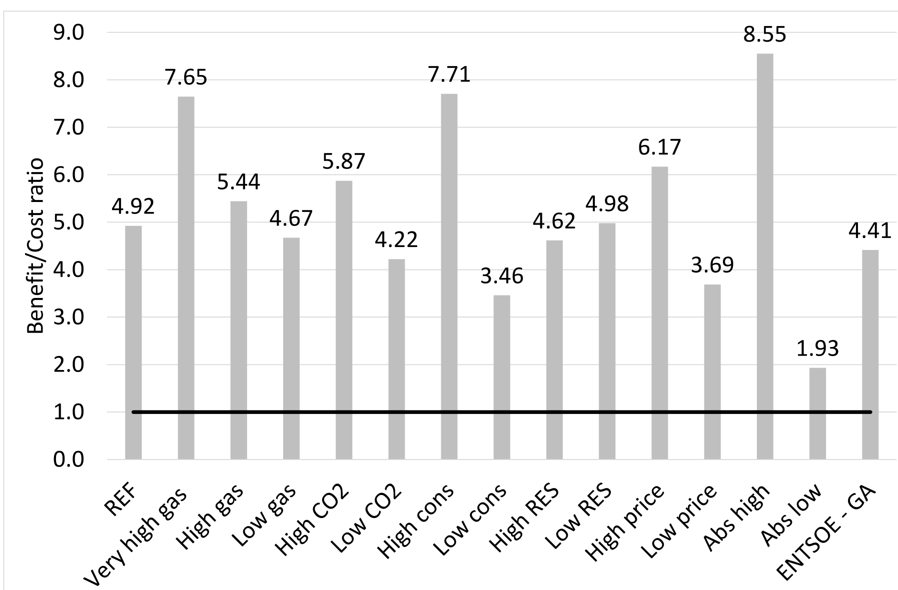

Fig. 8. Overall B/C ratio of the PCIs across different sensitivity runs.

gives similar results to the REF scenario, with a slightly lower B/C ratio, but still well above 1.

The above-mentioned results are based on the NPV of costs and benefits for all PCIs between 2025 and 2049. However, the benefits are highly variable over this period. In the Reference scenario, the lowest social benefit will occur in the earlier years, followed by a small increase until the mid-2030s, when growth rates increase significantly. The highest social welfare will be reached in the early 2040s, after which it stagnates or declines slightly. Due to the higher consumption, higher RES share, and phase-out of coal, lignite and gas generations in the later years, the price of electricity is more volatile, which increases the profitability of the new interconnector lines.

Fig. 9 depicts extreme price scenarios where social benefit trends are similar to the Reference scenario. The lowest social benefits will occur in 2025 and then increase until the early 2040s before stagnating or declining slightly in most scenarios. The notable exception is the absolute high price scenario, where a peak will not occur in the early 2040s, but the benefits continue to grow until the end of the analysed period.

It holds, not just in aggregate, that the higher the average wholesale electricity price, the higher the net social gain. The lowest gain each year

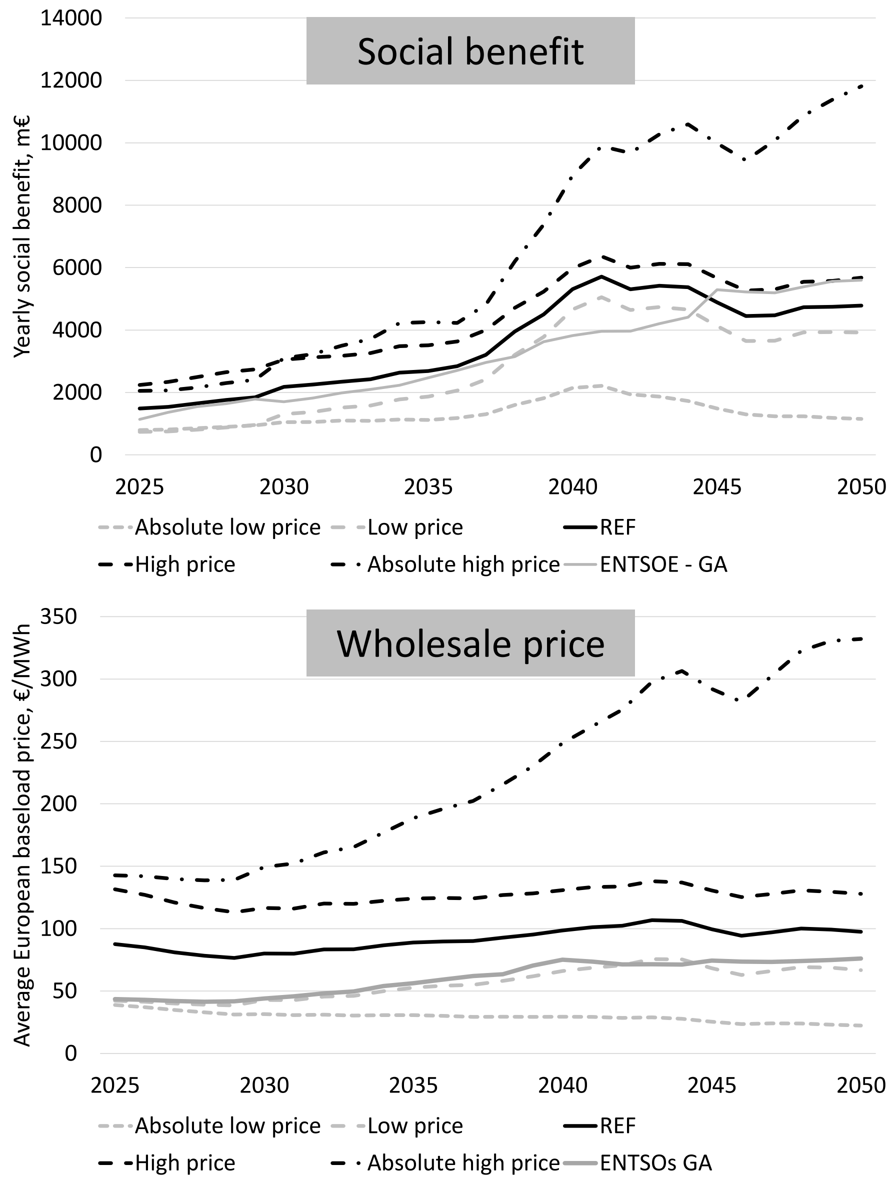

Fig. 9. Yearly social benefit (upper) and simple average wholesale electricity price in the modelled countries (bottom) in five scenarios, 2025–2049.

is in the absolute low price environment, where the electricity price is, on average, the lowest, while the second lowest gain occurs in the low price environment with the second lowest average price in the five scenarios. A similar correlation can be observed when the price exceeds the Reference scenario.

5.3. Absolute low-price scenario

The aggregated results show that the lowest social benefit from PCIs happens in the absolute low-price scenario, where the average wholesale electricity price is the lowest. That is the only case where some projects have a negative NPV, which is analysed in more detail.

Fig. 10 shows the individual B/C ratio for all 13 PCIs. According to the modelling results, in addition to the above-mentioned PCI-12 Baltic synchronisation project, another 2–3 projects are on the border of social welfare profitability. The most critical project is the PCI-8 (DE-CZ interconnector), where the B/C ratio is below 1 using the PINT and TOOT methods. For the two DE-AT projects (PCI-5 and PCI-7), the B/C ratio is below 1 with the TOOT method and above 1 using the PINT method.

These three projects are analysed more thoroughly, focusing on whether their interactions are complementary or competing. If the Complementarity Index (CI) presented above is higher than 1, then the projects are complementary, and if it is lower than 1, they are competitors.

Table 5 presents the B/C ratios and the discounted total benefits (excluding costs) of the three projects for the cases evaluated separately (first three rows in the table) and together (last four rows in the table). The CI is below one in all combinations, indicating that the projects are competitive rather than complementary. The lowest CI is between the two DE-AT projects (PCI-5 and PCI-7). Individually, the PCI-5 project has a discounted total benefit of 533 m€, while the PCI-7 project has a discounted total benefit of 212 m€. The aggregate benefit of these two projects for the whole period is 609 m€ with a CI of only 81,8% (609 m€/(533 m€+212 m€)). In contrast to this pair, the CI of PCI-7 and PCI-8 is close to 1.

6. Conclusion and policy implications

In this paper, we analyse the changes in social benefits in Europe due

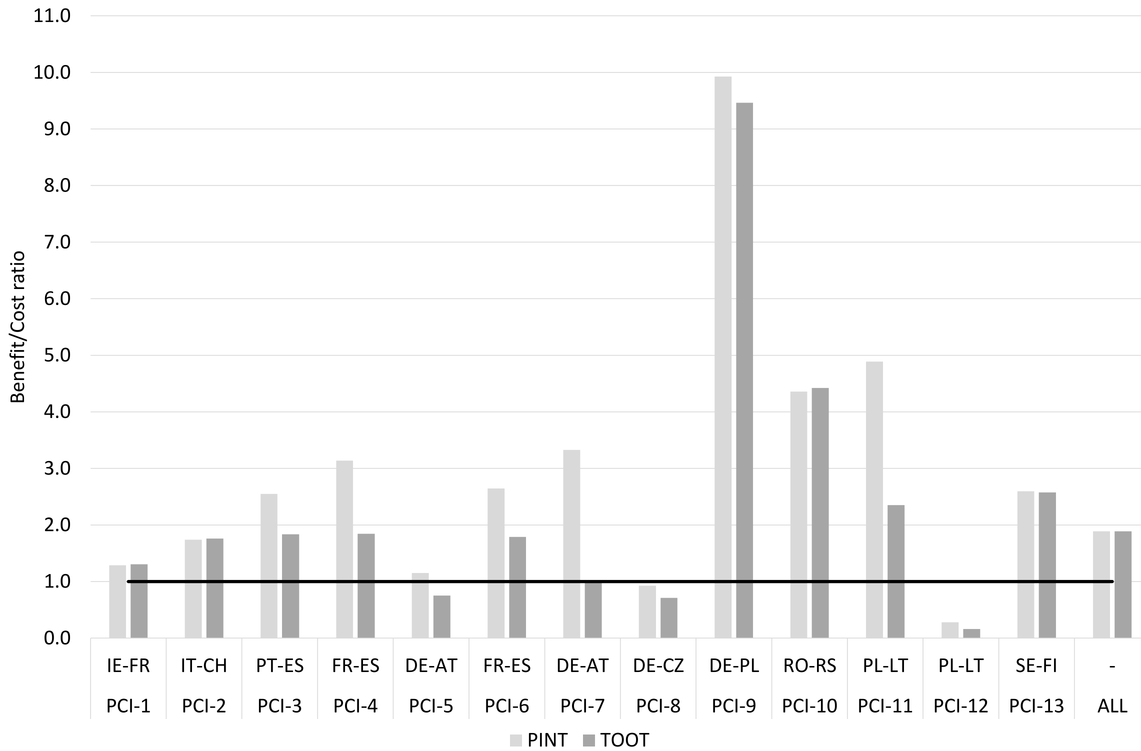

Fig. 10. B/C ratio for PCIs in the absolute low-price scenario, PINT and TOOT methods.

Table 5
Individual and aggregated discounted benefits and complementary indices of three PCIs (PCI-5, PCI-7, PCI-8).

	Benefit/cost ratio	Discounted aggregated benefit, m€	Discounted aggregated individual benefit, m€	Complementarity index
PCI-5	1.24	533	–	–
PCI-7	3.49	212	–	–
PCI-8	0.85	599	–	–
PCI-5+PCI-7	1.24	609	745	81.8%
PCI-5+PCI-8	0.93	1052	1133	92.9%
PCI-7+PCI-8	1.03	787	811	97.0%
PCI-7+PCI-8+PCI-9	0.93	1111	1345	82.7%

to implementing the electricity interconnection projects of the fifth PCI list. This issue is timely and relevant to ensuring a well-functioning, integrated common energy market (the so-called Energy Union). Our analysis confirms that the interconnector projects facilitate efficient trade between countries, increase the overall benefits for market participants, and, as demonstrated above, are important for individual Member States to achieve their 2030 interconnectivity targets.

To our knowledge, this is the first joint evaluation of these projects, even though quantifying the benefits of former PCI projects has always been a popular topic. We use a Europe-wide electricity market model to estimate the future effects of these projects in each year between 2025 and 2049 and formulate different indicators to measure their profitability and overall social benefit for Europe, represented by NPVs and B/C ratios. To account for future uncertainties, we conduct several sensitivity case analyses considering different trends in commodity prices, demand, and renewable penetration.

Based on the modelling, we conclude that the list is well-positioned. In the Reference scenario, all analysed projects are socially beneficial, except for the Baltic synchronisation, which stands out as a unique case. In other words, the total welfare gains in Europe exceed the investment costs of these projects. Thus, the Commission should proceed with facilitating their implementation.

We find that a higher price environment consistently leads to greater net benefits,[2] whereas in a lower price environment, the net benefits of some projects may become negative. Benefits also tend to grow with increasing demand and renewable penetration in later years. Consequently, these projects are expected to remain valuable assets with a low risk of becoming stranded.

Additionally, we assess the effect of the different projects on one another by comparing the results of the PINT and TOOT assessment methods and introducing the Complementarity Index. Our findings indicate that all PCI projects compete with each other to some extent, but mostly only to the extent that this does not impair their profitability. The only exceptions are the scenarios of very low wholesale prices, where some projects (DE-AT & DE-CZ) may become socially suboptimal due to the competition between projects. This result highlights the importance of conducting comprehensive project evaluations that consider all future projects simultaneously to explore these interactions.

[2] Higher prices usually lead to higher prices differences between to connected countries, which may drastically increase congestion rent. One such example is the record high congestion rent of Norway in 2022.

The applied modelling methodology has several limitations. Concerning the welfare analysis, this paper only considers the costs and benefits that are easy to monetise (investment and operation costs, changes in the consumer surplus, producer surplus and congestion rents). However, several other significant indicators are not covered in our analysis but can influence the results, such as the contribution to RES integration, reduction in grid losses, or CO_2 emission reductions. Due to the difficulty in monetising these aspects, they were excluded from the analysis to ensure the comparability of results.

Furthermore, the applied electricity market model also has certain limitations. Firstly, the model is deterministic, using pre-defined input values rather than incorporating distributions and probabilities (e.g. in the case of variable renewable production or demand). Moreover, all market participants are assumed to have perfect foresight (even in the long run, in the case of the investment module). While introducing a stochastic approach could make the analysis more sophisticated and potentially provide more robust results under varying circumstances, it is beyond the scope of this research. On the other hand, greater uncertainty regarding future demand and renewable production could result in less correlated prices across countries, thereby generating higher gains from implementing interconnectors. From this perspective, the benefits derived from our modelling can be considered conservative estimates, and we still observe very positive results.

Additionally, the model does not consider physical power line constraints, focusing solely on cross-border net transfer capacities available for trade, and thus, neither inland lines nor flow-based optimisation is incorporated into the tool. However, the current model is well suited for the presented estimations and can be further improved to address the identified limitations in the future.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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