Impacts of Investment in Cross-border High Voltage Electricity Transmission Interconnections

Filip Klein

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Abstract

Integration and connection of renewable electricity generation into the electricity grid to meet climate goals requires investment in high voltage electricity transmission systems. Limited cross-border transmission capacities constrain allocative efficiency gains from expansions of wholesale electricity markets across large geographical areas. Since the electricity transmission system is the only conduit for trade, a transmission line connecting adjacent areas operating at its capacity constrains trade between them, and creates differences in wholesale electricity prices between them. Quantifying and understanding the impacts of increased cross-border transmission capacity on trade volumes, wholesale market prices, and stakeholder surplus is an essential step in designing policy incentivizing market delivered investment in transmission systems. I enumerate the impacts of the first major increase in transmission capacity in decades across the Spain - France border, a notorious and persistent bottleneck in the European transmission network. Hourly electricity flows between the two countries double following the line opening compared to 1,000 MWh before the expansion. The new interconnection decreases the absolute value of price differences between Spain and France by 5 Euros per MWh, from a baseline of 15 Euros per MWh. The resulting aggregate benefits amount to 93 million Euros per year, compared to the investment cost of 700 million Euros. However, changes in buyer expenditures and generator profits provide mixed evidence of incentives to build the line. Generator profits and buyer expenditures do not change in Spain. In France, both generator profits and buyer expenditures increase following the line commissioning. Consequently, despite substantial aggregate benefits not all stakeholders benefit from the transmission expansion, demonstrating the need to consider the distribution of transmission expansion benefits in addition aggregate impacts.

1 Introduction

Although high voltage electricity transmission lines account for only a small fraction of all the lines carrying electricity around us, nearly all electricity passes through the transmission system. Indeed, the transmission system is the only conduit of trade in electricity between any two places. The transmission system capacity between any two places determines the maximum volume of trade between them. Furthermore, if demand and supply of electricity do not exactly match at any given time, then a collapse of the system and a blackout are inevitable. Electricity must be produced at the very same moment as it is consumed, and vice versa. There must be a feasible path to carry the electricity through the transmission system between generator and demand locations.

Most current transmission systems in developed countries were built in the middle of the 20^{th} century, under different circumstances, industry structure, and demands than exist today and are likely to exist in the future. The transmission system must be adapted to the new circumstances. Existing transmission capacity between areas with greatest renewable generation opportunities and large demand centers is insufficient for efficient large scale integration of renewable resources. Already, with the existing generation portfolio, large and persistent differences in wholesale electricity market prices exist between adjacent points of the grid (Cicala, 2021). Price differences correspond to differences in marginal cost, and thus imply inefficient generation allocation. Wholesale price differences exist because the transmission capacity between these adjacent points is fully utilized.

Climate commitments, decarbonization of the electricity system, and increasing deployment of renewable generation require investment in the transmission system. The switch from a central command and control authority operating the electricity system across a small geographical area to wholesale market based operations integrated across greater geographical regions allows for more efficient infrastructure and system operations (Cicala, 2022). A greater role for markets spanning large geographical regions in electricity system operations also necessitates investment in the transmission system. Indeed, the need to massively invest in transmission infrastructure has been an important topic in policy debate in the last decade. Both the Inflation Reduction Act in the USA, and the European Green Deal in the EU are calling for, and devoting resources to transmission system expansion. Doubling of transmission capacity across many European borders, costing tens of billions Euros, will be needed in the next few decades (Joskow, 2021; ENTSO-E, 2021). Several questions immediately surface. If the claimed needs and benefits are there, why are we not seeing more investment in electricity transmission systems? Are there incentives such that the market will deliver the investment when, where, and in the volumes needed?

What are the ex-post benefits of increased transmission capacity between two places? How do these benefits compare to investment costs? Is the cross-border transmission capacity the dominant constraint on trade or is there another significant factor constraining trade? Most evaluations of new transmission projects happen ex-ante, before the transmission line is built. Entities directly involved and impacted by the investments frequently conduct these evaluations. Their interests might not align with global interests. Even though the evaluations must follow regulation, the results can be significantly influenced due to usage of highly complex, stylized and proprietary engineering models and assumptions. There is a lack of thorough empirical evaluation of realized impacts of investment in transmission networks, with a few exceptions, such as Doshi (2024) and Gonzales et al. (2023). In other words, there is little rigorous evidence on the realized benefits of transmission expansion. Consequently, it is very difficult to validate the ex-ante studies, which might be subject to great errors. I am the first to evaluate the impacts of a large new transmission interconnection between Spain and France.

The interconnection between Spain and France has been persistently congested, that is operating at its capacity, for years. Indeed, the Iberian Peninsula has been referred to as an "energy island" due to a lack of cross-border transmission capacity limiting trade in electricity between Spain and France (European Commission, 2018; Arroyo Gonzalez, 2024) . A new high voltage direct current (HVDC) line between Baixas in France and Santa Llogaia in Spain was commissioned on October 5th, 2015. This interconnection resulted in the first significant change in cross-border transmission capacity between Spain and France in decades. The project was built as a joint venture between Spanish and French transmission system operators (TSO). The TSOs estimated that the new line would double the cross-border transmission capacity between the two countries. I utilize, for the economics literature, a novel data set containing detailed hourly operational data on the Spanish and French electricity systems to empirically estimate the impacts of this new transmission line.

Wholesale market electricity price differences indicate congestion across a border, because price differences across a border occur if and only if the cross-border transmission capacity is fully utilized, or congested[1]. The absolute value of price difference between two places then measures the distance between the respective marginal cost curves. The day-ahead price differences between Spain and France were substantial. The mean and median absolute value of price differences were both approximately 15 Euro per MWh, roughly a third of the mean price in each country preceding line opening. The day-ahead price differences were also persistent - they were greater, in absolute value, than 1 Euro cent per MWh for more than 89% of hours before the expansion.

The border between Spain and France is an interesting empirical setting to study impacts of transmission investment not only due to the presence and degree of congestion both before and after the line commissioning, but also due to the rich set of load, generation, market and regulatory characteristics present. Typically, in connection to transmission investment, we think about the need to connect a renewable rich area with a low demand level to a large load center with a (relatively) low renewable generation potential, as is the case in Doshi (2024) and Gonzales et al. (2023). In these cases, electricity trade and flows are mostly in one direction - from the renewable rich area to the demand center. In contrast to this, trade and thus congestion across the border between Spain and France change direction based on demand and generation conditions following seasonal patterns. Both Spain and France have high demand levels. France has a very high share of, mostly nuclear, zero carbon generation. Spain has had a large, and increasing share of, and even greater potential for, solar and wind generation. Consequently, this would seem to offer large opportunities for trade in low carbon electricity.

Using the time series variation in the data and a rich set of controls, I find that the hourly absolute value of net flows, corresponding to trade volumes, across the Spain-France border increased by 93%, or 912 MWh, within a year of the new line starting operations. The increase in trade volume is equal to approximately 2%, and 1%, of highest peak (maximum) hourly demand level in Spain, and France, respectively. Using the same approach, I find that the hourly absolute value of price differences decreased by 5.25 Euros per MWh following the line commissioning, from a baseline mean of slightly above 15 Euros per MWh. Based on a back of the envelope calculation, the mean net hourly aggregate benefits of the increased transmission capacity across the border are approximately 10,653 Euros, or 93 million Euros a year. The line cost around 700 million Euros to build, and the estimated lifespan of a transmission interconnection is measured in decades.

However, when it comes to transmission investment aggregate benefits might not give us the whole picture regarding incentives to build a line. Any transmission line has two ends. The aggregate benefits are the sum of benefits occurring at each end of the line. Impacts of the increased interconnection capacity might not be distributed equally between the two sides. If the new transmission line crosses any kind of administrative, regulatory, or market border, it is almost inevitable that the size and type of impacts on each side of the transmission line, or border, will differ. As a result, in aggregate, the parties at each end of the line are likely to have different, or at least different levels of, interests in (not) building the line.

Since a new line needs to be connected to the existing transmission network on each side of the border, cooperation of transmission system operators (TSOs) and regulators on both sides of the line is required to build a new interconnection. If most of the benefits occur on one side of the border, then that side of the border has much higher incentives to build the line. It is possible that, despite an aggregate welfare gain, the increased transmission capacity causes a net welfare loss on one side of the border. In such case, one party might not want to build the line at all. A well designed system of transfers could address the incentive compatibility issues. However, to design those transfers, and to determine whether the transfers are even needed, one needs to know the division of the benefits between the two sides of the border.

The electricity system consists of multiple entities - consumers, or buyers of electricity in wholesale markets, generators, and TSOs. Since increased interconnection capacity affects market outcomes, all these

[1] It is difficult to determine whether an interconnection is operating at capacity just from quantity data, because capacity oscillates a little bit all the time due to unobserved operational conditions.

different stakeholders are impacted (Davis et al., 2023). For example, increased exports can lead to higher wholesale prices on the exporting side, and lower prices on the importing side. Generators able to export more, and at higher prices, will increase their profits, while generators on the importing side will see their profits decrease due to lower prices and production levels. In this example, buyers on the exporting side will lose from the line, while the buyers on the importing side will gain. Each of these stakeholders has different interests in (not) constructing the transmission line.

While many of these stakeholders might not be directly participating in the decision making process connected to construction of the new line, ample opportunities are available, and have been utilized by incumbents, to delay and derail transmission projects through lobbying and a lack of cooperation with parties which are part of the decision making, such as different regulators, governments and government agencies (Joskow, 2021, 2020; Borenstein and Kellogg, 2021; Cicala, 2021). Consequently, when evaluating the benefits of transmission expansion and determining how to incentivize investment, the distribution of impacts must be taken into account. What is the welfare distribution of impacts of the increased transmission interconnection across the different stakeholders - consumers (buyer expenditures), generators (profits), system operators (congestion revenue)?

The organization of European electricity system, markets and regulatory boundaries largely, and in case of France and Spain exactly, follow national borders. Most importantly for me, each country corresponds to one wholesale electricity market bidding zone, an area with an equal wholesale electricity price. Consequently, unless noted otherwise, I use the terms country, control area, price and bidding zone interchangeably. This alignment of institutional, administrative, and regulatory borders, combined with the data being at country level, allows me to estimate the impacts of the new transmission interconnection at each side of the border. I estimate the impacts of the new line on the different stakeholders in each country utilizing data on load, day-ahead prices, and generation.

Using data on day ahead prices, realized load and generation, I find the expansion of transmission capacity between Spain and France does not lead to statistically significant changes in either buyer expenditures or generator profits in Spain. In contrast to that, buyer expenditures and generator profits in France both increase following the line commissioning. The changes in buyer expenditures and generator profits in France cancel each other out, thus resulting in no aggregate welfare change in France. The two TSOs see a combined increase in revenue resulting from trade across the border.

I demonstrate large aggregate net benefits, and returns, of the new interconnection between Spain and France. Yet, I empirically show that aggregate benefits of transmission investment do not necessary imply that all stakeholders benefit from the investment. French electricity buyers, essentially consumers, are harmed by the new interconnection with Spain. Furthermore, I show that impacts on two sides of the border can differ substantially. As a result, when it comes to evaluating impacts of transmission investment, it is not sufficient to look at aggregate impacts, as is commonly done. The distribution of impacts across the various stakeholders must also be analyzed, and it might be the key to making the transmission investment process more efficient.

I contribute to several strands of literature analyzing the electricity industry and markets. Despite documented large benefits resulting from moving electricity production decisions from command and control authorities governing small geographical areas to a market based mechanism covering a large geographical area, in the US context, over 90% of electricity consumed in the legacy control areas is still generated within their boundaries (Cicala, 2022). The question whether congestion of transmission interconnections between the areas prevents even greater benefits arises. Theoretical literature has shown that transmission congestion enables generation, and in some instances load, to exercise market power, thus creating incentives for these stakeholders to induce congestion (Joskow and Tirole, 2000; Borenstein et al., 2000). A relatively small increase of transmission capacity can alleviate the market power issues (Borenstein et al., 2000). Furthermore, ability of the TSOs to derive revenue from congestion can lead to a withdrawal of transmission capacity and under-investment in transmission infrastructure (Joskow and Tirole, 2005; Oggioni and Smeers, 2013).

Empirical literature has acknowledged, but largely excluded from analyses, the importance of transmission congestion in electricity markets (Sweeting, 2007; Hortaçsu and Puller, 2008; Cicala, 2022). While a growing body of empirical literature has identified substantial anti-competitive behavior of generators during periods of congestion (Wolak, 2015; Davis and Hausman, 2016; Ryan, 2021), the literature treats congestion and the transmission system as exogenous. Even though I do not explicitly model market conduct, I account for impacts of the new transmission line on buyer welfare, because I am using wholesale market prices, rather than commonly used generation cost, as monetary outcomes.

Impacts of transmission lines operating at capacity go beyond direct market outcomes. There has been extensive discussion of insufficient transmission capacity limiting deployment, and production, of renewable resources, in particular wind and solar generation, (Cicala, 2021; Hausman, 2024; Bloom et al., 2022; Borenstein and Kellogg, 2021; Joskow, 2020; Gonzales et al., 2023). Indeed, empirical setting in the sparse existing literature on empirical, ex-post impacts of transmission expansion has mostly been on interconnecting renewable rich areas with large demand centers, in Texas (LaRiviere and Lyu, 2022; Doshi, 2024; Fell et al., 2021), and in Chile (Gonzales et al., 2023). I account for market value of impacts on carbon dioxide emissions, which are priced in generation bids and thus wholesale market prices due to the presence of carbon dioxide emissions markets in Europe.

Impacts of transmission expansion are going to be significant as long as congestion was present before the expansion, no matter what generation resources are involved. With the exceptions of Hausman (2024); Ryan (2021), there is a lack of investigation in empirical literature on how improved interconnection affects profits of incumbent generators. In contrast to these two papers, which analyze impacts of *potential, complete* elimination of congestion, I enumerate impacts of a realized change improvement in interconnection capacity. Furthermore, my setting is much closer to a realistic investment scenario, because congestion is only reduced, rather than completely eliminated.

My paper is the first to conduct an ex-post empirical investigation of transmission expansion within continental Europe. The only other similar peer-reviewed study in the European context is (Newbery et al., 2019), who analyze interconnection between continental Europe and Great Britain. A largely simulation based, ex-ante, and illustrative engineering and operations research literature studying the European transmission network and its expansion, is more extensive (Bertsch et al., 2016; Oggioni and Smeers, 2013; Domínguez et al., 2020; Orgaz et al., 2019; Huppmann and Egerer, 2015; Di Cosmo et al., 2020).

I also contribute to literature studying the Spanish electricity system and markets. There is substantial research evaluating various effects of renewable generation (Petersen et al., 2024; Fabra and Imelda, 2023; Ciarreta et al., 2020; Cahana et al., 2022; Peña et al., 2022), as well as market conduct of Spanish power plants (Reguant, 2014; Fabra and Reguant, 2014; Fabra and Imelda, 2023). However, with the exception of Costa-Campi et al. (2021), I am the only one in economics investigating the Spanish transmission system. In addition, I am the first to jointly empirically analyze the French and Spanish electricity systems in a comprehensive manner using operational data.

2 Background

2.1 Industry Structure and Its History

Electricity systems in developed countries were built and conceived in an era when a single vertically integrated entity built, owned and operated the electricity system - from generation, transmission and distribution systems, to retail sales within a certain geographical area, known as a control area. A control area typically corresponded to a country in Europe. Since utility companies developed, sited, usually constructed, owned, and operated the transmission system and power plants, development of the entire system was in theory part of a joint optimization problem of the same entity.

Utilities, private or government owned, mostly satisfied demand within their territory with their own generation. Trade volumes between neighboring control areas were limited, because potential cost savings from increased trade with neighboring control areas were not substantially rewarded under regulation. Transmission interconnections between neighboring control areas were built to maintain system stability, rather than to facilitate large trade volumes[2]. Most of the trade was based on long term bilateral agreements.

[2] In the USA, the only exception are lines built to bring power from very large generators, such as hydro or nuclear plants, which were shared by multiple balancing authorities. I cannot think of such examples in Europe.

In Europe, as well as in the USA, the industry has undergone several substantial changes that interplay with the transmission system, and in particularly with cross-border interconnections. The most important changes are a substantial vertical and horizontal restructuring of the industry, an increasing share of renewable generation, and a shift to a market based dispatch system covering multiple control areas from a central command and control mechanism over a single control area.

In what follows, I describe the industry restructuring in the European context, although many of the principles are the same in the USA. The vertically integrated monopolies were broken up into separate entities, with competition introduced at several levels. The newly vertically separate companies must be "functionally" independent, in other words they cannot coordinate their decisions even if they have the same owner. Electricity consumers can freely choose their retail supplier. Retail suppliers buy electricity from generators, sell it to, and bill, their customers for it[3]. Retailers must buy the correct amount of electricity to meet demand of their customers or face fines otherwise.

Distribution system operators (DSO) own, maintain, and operate the vast majority, in terms of distance, of electricity lines. All of the lines running alongside streets and directly connecting to consumers are part of the distribution system. DSOs are also in charge of metering in most places. In the European context, all low and high voltage lines, essentially anything below 110kV AC, are part of the distribution system. DSOs are regulated natural monopolies within their areas.

The distribution system is connected to the electricity system through the very high voltage transmission system. In the European context, the transmission system operator (TSO) owns and operates the transmission system, as well as dispatches generation, balances and maintains the reliability of the entire system. In comparison, the independent system operator (ISO), consisting of multiple TSOs, operates the system in the USA. In order to prevent the legacy utility companies from exercising market power by preferring their own generators by either dispatching them more, or preventing access of generation entrants to the transmission system, transmission was spun off into an functionally independent company.

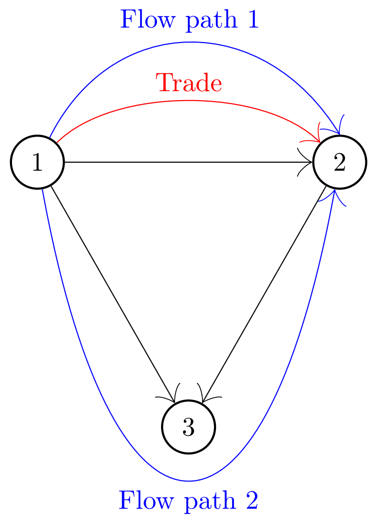
In most instances, TSOs recoup the costs and returns allowed under regulation through imposition of regulated surcharges on transmission customers (electricity consumers and generators). Ownership of the TSOs in Europe varies from fully government owned, to publicly listed companies. Each country in Europe, with the exception of Germany and Austria, corresponds to a control area of one TSO[4]. Before restructuring, there were around 100 control areas, known as balancing authorities, in the USA.

Large generators directly connect to the transmission system. Generation competition was introduced with the goal of achieving lower electricity prices. To foster the competition, free entry of generators was allowed, conditional on ability to connect to the transmission network. While there is free entry, generation in most European countries is still dominated by so called "national champions," or companies that took on generation portfolios of the formerly vertically integrated utilities. An important aspect of the restructuring process for transmission system development is that the decision on where and when to build power plants and transmission lines is not controlled by the same entity.

Large generators, mainly fossil fuel coal and later natural gas power plants dominated electricity generation in the not so distant past, with nuclear generation also playing a major role. Generator locations and transmission system topology could be determined in conjunction with each other, and with respect to locations of major demand centers within the control area. In contrast to fuel being relatively easily deliverable to legacy plants by rail, water, and pipelines, renewable generation resources, especially wind and solar, must be built in areas which are suitable for them. Most areas with high potential for renewable generation are in different locations than legacy generation and major load centers. Consequently, a transmission system with a different topology is needed to accommodate an electricity system with a large share of renewable generation.

[3]In many instances, they sell other services to their customers - for example EV charging solutions.
[4]There are 4 large TSOs in Germany. There is one large and one small TSO in Austria.

Figure 1: Simple Network Illustration



2.2 Electricity Markets

The biggest change in electricity generation came from how generation dispatch, or production, is determined. In the central command and dispatch system, the TSO decided the optimal generation allocation, considering both generation costs and grid operations. Both the USA and Europe have been moving from the central command and dispatch system to a system in which generation is determined based on outcomes in competitive wholesale markets.

Wholesale electricity markets operate as second (or uniform) price auctions. Both generators, and load (buyers purchasing on behalf of their customers) submit price and quantity pair bids to a centralized marketplace. Power plants are called upon to produce in ascending order of their bids until demand and supply intersect. Due to the highly inelastic demand, it is typical in the literature to consider demand to be fixed (see section 3 for details). The market clearing price received by all the dispatched generators is then equal to the cost of meeting the next unit of demand.

The most consequential part of the shift to market based dispatch mechanism for operation of transmission systems comes not from the introduction of markets per se, but from the geographical expansion of the area under the common dispatch mechanism. The switch was accompanied by multiple control areas joining together to create common marketplaces spanning large geographical areas. For example, PJM Interconnection, the largest jointly operated system in the USA, covers territory of 20 legacy transmission system operators, spanning parts of 13 states and the District of Columbia. Today, all European Union countries are part of the same day ahead, as well as intraday market place[5]. France and Spain have been part of a common day ahead market clearing since May 2014.

In terms of the spatial dimension, the area that is part of the single market is divided into separate pricing locations. Market participants supply bids at the pricing location corresponding to their physical location in the electricity system. Generators are paid, and load pays, the prevailing price at the location where they inject electricity to, and withdraw electricity from the grid, respectively. For example, in the 3 location, or node, network diagram in figure 1, a generator at location 1 is always paid the price at, and can only inject electricity at node 1, no matter where the electricity is consumed.

From a physics perspective, it is impossible to identify the source of each "electron" consumed, and the destination of each "electron" produced. Consequently, only the net position (generation minus demand) at

[5]Cyprus is the only exception.

each location matter. Continuing with the example from above, assume that the generator at node 1 and a customer (load) at node 2 agree on a bilateral transaction. During operations, it will not be possible to determine whether the actual electricity consumed by the customer at node 2 was produced by the generator at node 1. Only the fact that they withdrew, and injected, the electricity, combined with their locations, matters.

Electricity system operations, and flows, are governed by Kirchhoff's Laws. Kirchhoff's Voltage Law implies that power traded between two nodes flows through all available paths connecting the two nodes[6]. In the example above, the trade depicted by the red curve flows through both blue curves - that is through the line directly connecting nodes 1 and 2, as well as through the lines connecting nodes 1 and 3, and nodes 3 and 2. Kirchoff's Current Law states that supply and demand must be equal at every node. In other words, generation plus imports must equal to load plus exports at every node. Since the balance holds at every node of the network, generation equals load in the overall network.

The transmission system enters market clearing in the form of transmission constraints on trade, or flow, volumes between locations. If there was infinite transmission capacity between all nodes, then prices at all nodes would be the same. Generators from the entire area that is part of the common market would be dispatched in the global ordering of their bids from the cheapest to the most expensive. The ordering of generators from cheapest to the most expensive is called merit order.

In reality, transmission constraints are frequently binding during market clearing. Assume that during market clearing in the example from figure 1, generator in the global merit order that would be used to meet the next unit of load at node 2 is located at node 1. In addition, assume that the transmission capacity of the line directly connecting nodes 1 and 2 is already fully utilized. Consequently, the generator at node 1 cannot be used to meet the next unit of load at node 2. Similarly, a generator at node 3 cannot be dispatched to meet the next unit of load at node 2, because the trade would need flow through the congested line. Instead, a generator at node 2 will be used to meet the next unit of load at node 2.

Since the costs, in terms of bids, of meeting the next unit of demand at node 2 are higher than at node 1, the market clearing price at node 2 will be higher than at node 1. A more costly generator at node 2 must be dispatched because the transmission path from the lower cost generator at node 1 is congested.

In mathematical terms, market clearing corresponds to global constrained cost minimization to meet demand, where the constraints are that net balance of the entire system must equal zero, and resulting flows through each transmission line must not exceed its capacity. Since the flows are determined as a function of net balance at each node, the set of constraints nests constraints on demand at each node being met.

The two most prevalent markets are the day-ahead, and real time markets (called intraday market in Europe). I am going to focus on day-ahead markets throughout my paper. Day-ahead market clears a day before delivery - in Europe at noon for all time periods in the next calendar date. The market time unit, or the time period over which the electricity in bids is supplied (consumed), was equal to one hour during my period of analysis. Since then some markets have shifted to 30 and 15 minute delivery frequencies. Generators, and load, must supply, and withdraw, the quantities allocated to them in day ahead market clearing. If a generator cannot supply its allocation, it can either purchase the power on the real time markets, or face fines. Analogous principles apply to load. If the TSO cannot dispatch the allocated quantity of a generator for any reason, it must compensate the generator for the forgone profits.

It is important to note that the wholesale market price is not equal to the price final electricity consumers pay. The final per unit of consumption price contains components in the form of fees and surcharges, in addition to the pure cost of energy. For example, there are transmission and distribution fees, used to compensate the TSOs and DSOs for investment into the grid and maintenance, the TSO is also compensated for various ancillary services it procures, such as frequency and load balancing, to maintain grid stability. Furthermore, most retail consumers enter into contracts with retail suppliers at negotiated prices for energy, which typically would not equal the wholesale market prices.

[6]It states that the sum of voltage drops across all elements around any closed loop must equal zero.

2.2.1 Distinction between Nodal and Zonal Markets

In nodal markets, common in the USA, each pricing or bidding location typically corresponds to a connection of the distribution system, or of large generators and load, to the transmission system. All transmission lines enter as constraints in market clearing. Consequently, the market outcomes convey accurate price signals of any transmission congestion present. Any congestion happening on the distribution side of the system does not enter market clearing. The example above, from figure 1, corresponds to a nodal market.

Europe uses a zonal market set up. In contrast to nodal markets, several transmission nodes are grouped together to form one price or bidding zone. The transmission system is also represented only by a subset of transmission lines. In zonal markets, only the net position of the entire zone, rather than of each node within the zone, enters the market clearing process. For example, let's imagine that the the French zone consists of nodes 1 and 2 in figure 1, while node 3 is the Spanish zone. Since only the net position of the entire zone enters market clearing, any internal trade within the French zone does not translate to flows through any transmission lines in the market clearing process. In other words, during market clearing, it would not play any role whether electricity is consumed (or generated) at node 1 or 2, only the fact that it is consumed (or generated) in France would matter.

Consequently, there are no impacts of internal trade on transmission congestion, and in particular on internal transmission congestion. Furthermore, during my analysis period cross-border transmission capacity available to the market was represented only by a single number, or one transmission line, rather than at individual line line . This accounting for capacity is called net transfer capacity (NTC) market coupling. As a result, the actual triangular network from figure 1 becomes a radial network, two zones (nodes) connected by one line (path), in market clearing. Even though Europe has moved to using individual cross-border, and some internal, lines in market clearing, only the net position of the entire zone enters the process.

Zonal markets do not convey an accurate price signal for transmission congestion, because the actual dispatch must satisfy constraints of the nodal representation of the network. If the zonal market outcome doesn't satisfy these constraints, that is it cannot be dispatched, the TSO must engage in so called redispatching to correct the dispatch. The TSO must compensate the plants that were scheduled to generate under the market outcome but cannot be called upon to generate due to network constraints. At the same time, the TSO must call upon more expensive plants, that were not scheduled to produce under the market outcome, to generate in order to satisfy demand.

While the fact that zonal market outcome does not follow physical, or nodal, network constraints is a general problem of zonal markets, it is particularly pronounced in Europe. A bidding zone in Europe corresponds to one country, with a few exceptions[7]. Yet, there is no reason for congestion to follow national borders, which are administrative by nature.

2.3 Background on the Project and the Spain-France Interconnection

The journey to commissioning the high voltage direct current (HVDC) interconnection between Baixas in France and Santa Llogaia in Spain was long and treacherous. Prior to this interconnection, Spain and France were connected by 4 transmission lines, with the last one, between the Arkale substation in Oyarzun, Spain and Argia in France, completed 1982 (Inelfe, 2011).

The economical and technical need to further bolster the transmission capacity between the two countries had long been known, and widely acknowledged. Indeed, the interconnection between Spain and France has been included among priority energy corridors in the European Union since the 1990s (European Commission, 1996). Several new transmission interconnections, in varying stages of planning and construction, were abandoned in the 1990s (Sánchez Sánchez, 2016; Francos et al., 2012). A prime example is the 400kV alternating current line between Aragon in Spain and Cazaril in France, which was unilaterally canceled by the French government in 1996, despite over three quarters of the work on the Spanish portion of project

[7] Italy has 6 bidding zones (there were changes in 2021). Sweden has four and Norway has five. Luxembourg is part of the German zone. Austria used to be a part of the DE-LU bidding zone until October, 2021. Denmark has two bidding zones - one for Eastern Denmark, which is synchronized with the rest of Scandinavia, and one for Western Denmark, which is synchronized with continental Europe.

being completed at the time (European Commission, 1996; Red Eléctrica de España, 1998). The cancellation lead to renegotiation of long term power supply contracts between France and Spain, as well as to large monetary compensation from the French TSO to the Spanish TSO (Red Eléctrica de España, 1998, 2001).

The biggest obstacle to construction of new interconnections across the Spain-France border was local opposition on both sides of the border (De Clercq, 2015; Euractiv, 2008). There were large protests against the projects in the 1990s, especially in France (Sánchez Sánchez, 2016; Lagendijk, 2015). The opposition of local interest groups, trickled to opposition by local and national governments, in particular in France, leading to stalling of the permitting process, and of the projects in general (Francos et al., 2012; European Commission, 1996; Boselli, 2008). While most of the opposition was, on paper, based on environmental concerns, if one reads between the lines it is questionable how much of a role aesthetic concerns, given the setting of Pyrenees Mountains, actually played (Euractiv, 2008; Sánchez Sánchez, 2016). The opposition was fierce - for a example a Spanish citizen, Manuel Escola Hernando, wrote in his 1998 letter to the European Commission that "[s]ince the early 1990s the inhabitants of Bal de Chistau, in the Aragón Pyrenees, have used every possible legal argument in their fight against the construction of a high-tension power line between France and Spain ... [i]n their efforts to protect what is virtually an unspoiled valley ...;" he continued in the next paragraph "the local people fear that [the line] could jeopardise the development of tourism in the area on account of the serious impact it would have on health conditions, the environment and the landscape." (European Commission, 1998).

Despite the insurmountable opposition to new overhead AC lines, plans of French and Spanish TSOs for increasing the interconnection capacity, in various versions, called for construction of new AC lines well into the early 2000s (Red Eléctrica de España, 2001; Francos et al., 2012). The European Commission appointed the former EU Competition Commissioner Mario Monti to act as a mediator in the stalemate in September 2007 (Euractiv, 2008; Francos et al., 2012). The resulting efforts lead to a signing of a memorandum of understanding between the French and Spanish governments to increase the cross-border transmission capacity in January 2008.

The Zaragoza Agreement, signed in June 2008, lead to creation of INELFE (INterconexión ELéctrica Francia-España), a joint venture between the French, RTE, and Spanish, RED Electrica (REE), TSOs, and to the selection of the HVDC interconnection between Baixas and Santa Llogaia (Inelfe, 2011; Francos et al., 2012). The 64.5km long line is fully underground, and largely follows pre-existing highway and railway corridors to minimize the environmental impact (Inelfe, 2011; Red Eléctrica de España, 2025). The line also contains an 8.5km long tunnel underneath the Albera massif. The interconnection consists of two $\pm 320kV$ DC cables, with each having a capacity of 1,000MW. Focus on mitigating environmental impacts, as well as on engagement with local stakeholders, during the construction is mentioned throughout most official documents on the project (Inelfe, 2024; Red Eléctrica de España, 2025).

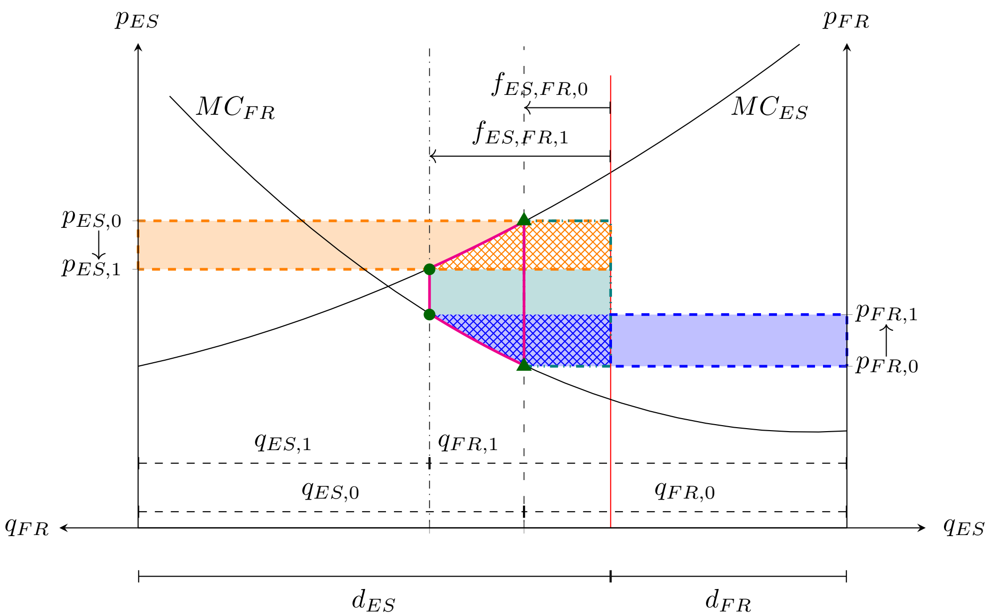
The reported construction costs of the project were 700 million Euros, and they were equally split between REE and RTE (de LADOUCETTE et al., 2015; Wright, 2015; Francos et al., 2012; De Clercq, 2015). The European Commission awarded the interconnection status of Project of Common Interest (PCI), thus making it eligible for fast-tracked permitting process and EU funding. The interconnection received a 225 million Euro grant under the European Energy Programme for Recovery from the EU, as well as a 350 million loan from the European Investment Bank (European Investment Bank, 2011).

Initially, it was anticipated that the project would enter service in 2014 (Inelfe, 2011; European Investment Bank, 2011). The project received the necessary permits at the end of 2010 (Inelfe, 2024). Construction contracts were awarded in 2011, with work commencing in early 2012. The construction phase was completed by the end 2014. The testing period started in February 2015, and the anticipated start of commercial operation was set to June 2015 (European Investment Bank, 2015; De Clercq, 2015). However, the project did not commence commercial operations until the 5th of October, 2015.

3 Conceptual Impacts of Transmission Investment

Several features of electricity systems and markets enable me to illustrate conceptual effects of expanding transmission capacity between two nodes using figure 2, under the assumption that the demand and load

Figure 2: Impacts of Transmission Expansion



are the same before and after the expansion. First, power plants are dispatched and paid based on the day-ahead market outcomes in the order of their bids. Since day-ahead markets in Spain and France are second price auctions with a large number of participants, it is optimal for the power plants to bid marginal costs. Consequently, the equilibrium price in each country corresponds to the marginal costs of the power plant that is going to meet the next unit of demand in that country. Second, since markets in the two countries are cleared jointly, the market clearing mechanism utilizes all beneficial trade up to the transmission capacity. Third, generation must always equal demand.

Fourth, retail consumers do not directly purchase electricity in the wholesale market, with the exception of large industrial loads. They contract with utility companies, at negotiated rates, who purchase the required amount of electricity on their behalf in wholesale markets. As a result, it is better to refer to entities purchasing electricity in wholesale markets as buyers of electricity, rather than as consumers. Furthermore, the buyers do not exert control over consumption since that is determined by consumers. Combined with the fact that the markets are second price auctions, these bidders bid their valuation.

Even though some large industrial loads might be more exposed to the wholesale market, their technology frequently limits short term output adjustment, and thus adjustment of electricity consumption. Consequently, in line with the majority of literature (Cicala, 2022; Doshi, 2024; Gonzales et al., 2023; Petersen et al., 2024; Fabra and Reguant, 2014), I assume that in the short run demand is perfectly price inelastic and exogenous, and largely determined based on observables such as weather, hour of the day, and day of the week. Even in the span of a few years demand is likely to be relatively stable, conditional on observables in the absence of significant change in technology or behavior.

The two vertical axes in figure 2 represent per unit prices - for Spain on the left axis, and for France on the right axis. The horizontal axis represents quantity at a given point in time. Quantity is equal to zero for each country at the point where its respective vertical axis interesects the horizontal axis. Quantity for Spain is increasing from left to right. Quantity for France is increasing from right to left. The distance between the two y-axes equals to combined demand of Spain and France. The red vertical line represents demand for Spain, and France, denoted d_{ES}, and d_{FR}, respectively. For simplicity, assume no trade with third countries, thus:

$$d_{ES} + d_{FR} = q_{ES,t} + q_{FR,t} \; \forall \; t$$

Note that, electricity flow, $f_{i,j,t}$, is a vector variable, so it has a directional component. The first index,

i, denotes the source of the flow, while the second index, j, denotes the destination (or sink). Direction of flow then translates into sign of flow:

$$f_{i,j,t} \begin{cases} > 0 & \text{if flow is } i \to j \\ < 0 & \text{if flow is } j \to i \\ = 0 & \text{if there is no flow} \end{cases} \tag{1}$$

No matter what the flow direction is $f_{i,j,t} = -f_{j,i,t}$.

The black upward sloping curves represent marginal costs of generating electricity in each country. Under autarky, prices would equal to intersections of the marginal cost curves with the vertical red line, and generation in each country would be equal to its demand. Let the transmission capacity between Spain and France at time t be denoted by $f^{\max}_{ES,FR,t}$, and the same for both directions, that is $f^{\max}_{ES,FR,t} = f^{\max}_{FR,ES,t}$. The figure depicts a situation when France has lower marginal cost than Spain, corresponding to summer months in real life, so the flow is going to be from France to Spain, that is $f_{ES,FR,t} < 0$ both before, $t = 0$, and after, $t = 1$, the expansion.

The existing interconnection between Spain and France was operating at its capacity before the expansion, that is $f_{ES,FR,0} = -f^{\max}_{ES,FR,0}$, leading to different prices in France, $p_{FR,0}$, and in Spain, $p_{ES,0}$. The before expansion equilibrium outcomes are denoted by the green triangles in figure 2. Volume of trade, or flows, before the expansion is equal to the distance between the red (demand) and the dashed vertical lines. The dashed vertical line represents generation outcomes:

$$f_{ES,FR,t} = q_{ES,t} - d_{ES} = d_{FR} - q_{FR,t}$$

Staying in line with the real world conditions across the border between Spain and France, congestion is still present after the transmission capacity expansion:

$$f_{ES,FR,1} = -f^{\max}_{ES,FR,1} \ , \ f^{\max}_{ES,FR,1} > f^{\max}_{ES,FR,0} \ , \ |f_{ES,FR,1}| > |f_{ES,FR,0}|$$

Since the demand levels and marginal cost curves are the same before and after the expansion, only the generation allocation, and consequently prices, change following the expansion. French generation output and price increase following the expansion, while the Spanish generation and price decrease. The post-expansion equilibrium is represented by the green dots in figure 2. Consequently, the price difference, in absolute value, between Spain and France decreases:

$$\begin{aligned} q_{FR,1} > q_{FR,0} \qquad & q_{ES,1} < q_{ES,0} \\ p_{FR,1} > p_{FR,0} \qquad & p_{ES,1} < p_{ES,0} \\ |p_{FR,1} - p_{ES,1}| < & |p_{FR,0} - p_{ES,0}| \end{aligned}$$

The net aggregate benefits, or the net social welfare change, of the transmission expansion are represented by the area of the magenta trapezoid, which is equal to the change in costs of serving the combined load of the two countries. Since the market clearing prices are equal to marginal costs, in the absence of cost data, the area can be approximated by using the prices differences and flows before and after the transmission expansion:

$$\widetilde{\Delta SWF} = \frac{|p_{FR,0} - p_{ES,0}| + |p_{FR,1} - p_{ES,1}|}{2} \times (|f_{ES,FR,1}| - |f_{ES,FR,0}|) \tag{2}$$

Note that this specification is applicable no matter what the flow direction prior to expansion is, as long as the marginal costs curves and demands do not change in response to expansion and prices.

3.1 Distribution of Transmission Investment Impacts

Since the demand is perfectly inelastic and retailers purchase electricity in wholesale markets, which they sell consumers under negotiated rates, the relevant measure of transmission expansion impacts on the load, or consumer, side is the change in buyer expenditures. The change in buyer surplus equals the negative value of the change in expenditures, because the buyers prefer lower prices or decreased expenditures of serving load. The change in buyer expenditures in node i is defined as:

$$\Delta BE_i = d_i \times (p_{i,1} - p_{i,0}) \tag{3}$$

The sign of change in buyer expenditures is the same as for change in prices. As a result, Spanish buyers benefit from the expansion in this example, due to a decrease in price resulting in lower expenditures. To the contrary, French buyers lose from the investment, because the increased transmission capacity between France and Spain causes higher prices, and thus expenditures in France. Changes in expenditures of French, and Spanish, buyers are of opposite direction and equal to the areas inside the orange, and blue dashed rectangles, respectively, in figure 2.

Transmission investment affects generator profits in each country in two ways: by changing price, and quantity generated. The two changes go in the same direction within each country, affecting profits in the same direction. In the example depicted in figure 2, the increased transmission capacity decreases generator profits in Spain, equal to the non-crosshatched orange area, while increasing generator profits in France, equal to the blue area, including the crosshatched area.

The net impact of the transmission expansion for each country across both buyers and producers equals to the cross-hatched area, orange for Spain, and blue for France, in figure 2. Since a decrease (negative change) in expenditures is a desired outcome for the buyers, the net impact at node i equals to the difference between changes in generator profits, $\Delta\pi_i$, and buyer expenditures at that node:

$$\Delta SWF_i = \Delta\pi_i - \Delta BE_i \tag{4}$$

In this example, the exporting French generators receive the French price, and the importing Spanish buyers pay the Spanish price for the traded electricity. Since the two prices are not equal during congested periods, the trade results in so called congestion revenue that neither the French, nor the Spanish generators receive. Congestion revenue is defined as:

$$CR_{ES,FR,t} = f_{ES,FR,t} \times (p_{FR,t} - p_{ES,t}) \tag{5}$$

Note that in jointly cleared markets on a radial network, congestion revenue is always positive, because the directions (signs) of flow and price difference are the same[8]. Congestion revenue before, and after, the expansion is the area inside the teal dashed rectangle, and teal shaded area, respectively, in the example in figure 2 . The sign of the change in congestion revenue induced by transmission expansion is ambiguous, because flow increases, while the price difference decreases. Congestion revenue, or the proceeds from sales of rights to congestion revenue, is split between the two transmission system operators in a predefined manner.

The aggregate net benefits of the transmission expansion between two places can then be calculated as the sum of net impacts at the two affected nodes from equation (4) and the change in congestion revenue:

$$\begin{aligned}\Delta SWF &= (CR_{ES,FR,1} - CR_{ES,FR,0}) + \sum_{i\in\{ES,FR\}} \Delta SWF_i \\ &= (CR_{ES,FR,1} - CR_{ES,FR,0}) + \sum_{i\in\{ES,FR\}} \Delta\pi_i - \Delta BE_i\end{aligned}$$

Under the assumption that the marginal costs curves are locally linear, the net social welfare change equals the approximation in equation (2).

4 Data

My main source of data is the European Network of Transmission System Operators in Electricity Transparency Platform (ENTSO-E Transparency). A total of 40 TSOs, from 36 countries, including all TSOs from

[8]In a non-radial network with loop flows, that is when there is more than one transmission path between between any two nodes, the directions of price differences and flows between any two nodes might not be the same.

EU member countries, are ENTSO-E members[9]. The Transparency Platform is a centralized data disclosure system mandated by EU legislation. Transparency started operating on the 5th of January 2015. My primary data sample goes from January 2015 to October 2016.

The data is published at the so called market time unit, that is at the same frequency at which the electricity market is cleared. Day ahead markets in Spain and France operated at an hourly frequency during my sample period. I utilize data aggregated at the control area level, the territory of one TSO, which matches in case of France and Spain bidding (price) zone, and country boundaries. Cross-border variables, such as physical flows, are reported at the level of the border between areas of the same type. I convert quantity data, except capacities, reported in megawatts to megawatt hours, so every observation corresponds to energy over time rather than to instantaneous values. Further description of the data is in appendix A.

To extend the time-series of day-ahead prices and cross-border flows I use data from IESOE, or Electricity Interconnection in South-Western Europe, an organization founded by French, Spanish and Portuguese TSOs to promote increased transmission capacity in the region. Data from Transparency and IESOE match in nearly all instances when available from both sources.

To control for weather related impacts on system operations, I obtained hourly mean country level data from the EU Commission's and ECMW's Copernicus Climate Change Service (Copernicus Climate Change Service, 2020) [10]. I use ambient air temperature, rainfall, wind speed and solar radiation, the exact description is in appendix A.

Natural gas and coal generators are very frequently marginal, or price setting, generators, thus their input prices are going to have substantial impact on market outcomes, especially prices. To control for exogenous changes input prices, I use natural gas and coal price indexes obtained from Bloomberg. I use a day-ahead price index for natural gas, and a month ahead price index for coal. While the generators might purchase fuel through long term contracts and hedge fuel prices, generators can at any time trade fuel in the short term markets. Thus the short term prices represent the opportunity cost of the fuel, the economically relevant price, at the time the generation decision. Natural gas and coal price indexes are frequently used to proxy for fuel prices in literature when plant level cost data is not available (Cicala, 2022; Doshi, 2024; Gonzales et al., 2023; Petersen et al., 2024; Fabra and Reguant, 2014).

For natural gas prices, I use the European Energy Exchange (EEX) PEGAS exchange day-ahead price index, which prices natural gas at the Title Transfer Facility (TTF) Virtual Trading Point in the Netherlands. I utilize the Bloomberg OECM API2 month ahead coal price index to proxy for coal prices, which is based on the Argus/McCloskey's Coal API2 Price Index, the primary price reference for physical and over-the-counter coal contracts in northwest Europe. Further details about the construction of fossil fuel prices are in appendix A.1.

4.1 Sample Specification

The complexity of electricity system operations makes the selection of the data sampling window, or the time span of data, used for estimation an important, albeit challenging, exercise. The estimates cannot be confounded by coincident events. At the same time, the data must have sufficient variation in system conditions and operations, both before and after the line enters service, to capture the effect of transmission investment.

While a very narrow sampling window around the date of line commissioning can eliminate impacts of longer term coincident changes, even a very short term event, such as a sudden transmission line outage, or a change in weather, can cause a significant deviation from typical system operations and thus confound the estimates. In addition, the transmission line comes into service in the beginning of October, a time of mild weather and thus, compared to summer and winter, lower demand. Due to the typically highly increasing

[9] National Grid, the TSO in the United Kingdom of Great Britian, was a member of ENTSO-E until Brexit. SONI, the TSO in Northern Ireland, is still a ENTSO-E member.

[10] Neither the European Commission nor ECMWF is responsible for any use that may be made of the Copernicus information or data it contains.

slope of marginal cost of electricity generation in quantity generated[11] and more frequent congestion, effects of the new transmission line are likely to be largest during times of high demand (Wolak, 2015).

A slightly extended window would capture operations in the summer and winter peaks, as well as during milder fall. However, load and generation patterns within a day differ a lot between summer and winter for each country. Unobserved generation availability can also vary a lot between seasons. While the weather controls dampen the bias from seasonal changes coincident with treatment, they do not completely eliminate it.

Seasonal changes tend to average out in a sample with a longer time span. At a same time, a wide sampling window is more likely to contain other significant long term changes, such as further transmission improvements, generator retirement, or new generation coming online. Combined with the fact that most data is only available from January 2015, I define the main analysis sample as starting in January 2015, and ending on the 4th of October 2016 - a year after the transmission line became operational.

The new interconnection between Spain and France started operations on the 5th of October, 2015. However, transmission capacity was increased gradually over a span of several weeks, rather than made available to the market immediately. Testing, maintenance and preparation work were conducted in the weeks before, and to some extent after, the line commissioning. I utilize a donut hole around the commissioning date to avoid bias from the capacity being artificially low right around line commissioning compared to normal operations. In my main specification, I exclude 30 days on each side of treatment from the sample. The pre expansion part is thus 2015/01/01 through 2015/09/04, and the post expansion part contains data from 2015/11/04 to 2016/10/04.

There is also a significant difference in electricity demand, generation, and price levels and patterns between weekdays and weekends. The electricity system, and thus the grid overall, is under much more strain during weekdays than on weekends due to higher demand. As a result, congestion is more costly during weekdays. To control for this, I only use weekdays in my analysis.

4.2 Data Summary and Patterns

4.2.1 Electricity Prices and Price Differences

The French and Spanish day ahead electricity markets have been coupled (or integrated) since May 2014. In other words, the French and Spanish price zones have been jointly cleared as a part of the same market clearing mechanism since then. The market clearing mechanisms exploits all feasible and beneficial trade opportunities between the two countries. Furthermore, large volumes of electricity are traded in the day ahead market in both countries. Consequently, I use the day-ahead prices as the relevant prices throughout the paper. The day ahead market clearing takes places at noon Central European Time for each hour of the following date.

I present summary statistics of day ahead prices in France and Spain, and of day ahead price differences for my preferred analysis sample in table 1. Since the new transmission line started operations on the 5th of October, 2015, I define the pre, and post expansion sample periods as 2015/01/01 - 2015/09/04, and 2015/11/04 - 2016/10/04, respectively (see section 4.1 for further details). Summary statistics at annual level for 2014 through 2016, as well as broken down by the Cartesian product of pre and post line commissioning with calendar year are in table 11 in appendix C.

Overall, French day-ahead electricity prices were lower than Spanish, defined as $\mathbb{1}\left(p_{FR,t} - p_{ES,t} < -0.01\right)$, specifically during 72%, and 61% of hours before, and after line commissioning, respectively, as shown in the second column of table 2. Day-ahead prices in Spain and France converged, that is they were within less than 1 cent of each other, during 11%, and 26%, of hours in the pre, and post expansion samples, respectively (31% in 2016 overall). The increased price convergence following the expansion, and France being cheaper in general, is also evident in price differences, shown in table 1. Mean and median hourly price differences are both negative at all times. The mean price differences were -11.44 EUR/MWh (median -14.02 EUR/MWh) before the line started operating, and -6.23 EUR/MWh (median -4.48 EUR/MWh) afterwards.

[11] Marginal costs of electricity generation are highly convex in quantity.

Table 1: Summary Statistics for Flows and Prices

Variable	Time Period	Mean	Sd	Percentile					N
				1st	10th	50th	90th	99th	
Prices [EUR/MWh]									
$p_{ES,t}$	*Pre*	52.49	11.94	20.00	36.59	53.75	66.60	71.66	4,248
$p_{ES,t}$	*Post*	39.65	12.60	8.50	22.69	40.11	56.70	68.98	5,760
$p_{FR,t}$	*Pre*	41.07	12.05	15.01	24.94	41.60	55.47	69.94	4,200
$p_{FR,t}$	*Post*	33.43	11.11	10.06	21.39	32.50	46.99	65.79	5,760
Price Differences [EUR/MWh]									
$p_{FR,t} - p_{ES,t}$	*Pre*	-11.44	14.30	-37.40	-27.94	-14.02	7.25	24.63	4,200
$p_{FR,t} - p_{ES,t}$	*Post*	-6.23	9.77	-30.63	-19.61	-4.48	2.31	17.68	5,760
$\|p_{FR,t} - p_{ES,t}\|$	*Pre*	15.15	10.29	0	0	15.84	28.23	37.76	4,200
$\|p_{FR,t} - p_{ES,t}\|$	*Post*	8.21	8.17	0	0	6.57	20.07	31.14	5,760
Cross-border Flows [MWh]									
$f_{ES,FR,t}$	*Pre*	-585	795	-1,314	-1,216	-964	982	1,124	4,248
$f_{ES,FR,t}$	*Post*	-1,132	1,494	-2,830	-2,575	-1,667	1,638	2,429	5,759
$\|f_{ES,FR,t}\|$	*Pre*	937	311	55	387	1,028	1,216	1,314	4,248
$\|f_{ES,FR,t}\|$	*Post*	1,726	731	38	591	1,877	2,584	2,838	5,759

Data for 2014 is from IESOE, data from 2015 onward is from ENTSO-E Transparency. Observations are for weekdays at hourly level.
The time periods for Pre/Post expansion align with my main analysis sample, and are defined as: *Pre* is 2015/01/01 - 2015/09/04, *Post* is 2015/11/04 - 2016/10/04, see section 4.1 for further details.

However, raw price differences can lead to a false perception that the price differences are low if both negative and positive price differences are observed. Electricity is cheaper in Spain than in France approximately 15% of the time. The important factor is the existence of a price difference and its magnitude, rather than its sign. Consequently, the absolute value of price differences is a better measure than the raw value. The mean hourly absolute price difference was 15.15, and 8.21 Euros per MWh, before, and after the transmission expansion, respectively, (medians were 15.84, and 6.57 EUR/MWh). For reference, the pre, and post expansion mean day-ahead prices in Spain were 52.49, and 39.65 EUR/MWh, respectively, and 41.07, and 33.43 EUR/MWh, respectively, in France.

In summary, there are large day-ahead wholesale electricity price differences across the border between Spain and France. The price differences are in particular large in comparison to prices in both countries - the mean absolute price difference before expansion is 28.9% of mean pre-expansion Spanish price, and 36.9% of French price[12]. The difference in prices is not driven by a few hours with particularly large magnitudes - the 99th percentile of absolute price difference was 37.76, and 31.14 EUR/MWh, pre, and post expansion, respectively. The price difference between Spain and France is also present during vast majority of hours, and persistently large. Consequently, there is strong suggestive evidence for large aggregate benefits from increased cross-border electricity trade across the border between Spain and France.

4.2.2 Cross-border Physical Flows

Realized hourly net cross-border physical flows provide an accurate representation of trade volumes across the border between Spain and France. Price differences between two price zones with jointly cleared markets exist only when the transmission path between the two locations is congested - in other words, as long as the transmission capacity along at least one path between the two price zones is fully utilized. In general, in the presence of multiple physical paths between two locations, known as loop flows, any line, along any path between the two places, rather than just the line directly connecting them, can constrain trade during

[12] Calculating summary statistics for relative price difference is challenging due to presence of 0 and close to zero prices.

Table 2: Summary Statistics for Direction of Flows and Prices

Time Period	Mean			
	$\mathbb{1}$ (Prices Converged)	$\mathbb{1}$ (FR Cheaper)	$\mathbb{1}$ (Flow to ES)	$\mathbb{1}$ (Directions Aligned)
Calendar Year:				
2014	0.064	0.64	0.67	0.95
2015	0.135	0.73	0.80	0.99
2016	0.315	0.49	0.69	0.99
Pre/Post Expansion:				
Pre	0.114	0.72	0.78	0.99
Post	0.264	0.61	0.79	0.99

Data for 2014 is from IESOE, data from 2015 onward is from ENTSO-E Transparency. Observations are for weekdays at hourly level.
I define the columns as $\mathbb{1}\,(\text{Prices Converged}) \equiv \mathbb{1}\left(|p_{FR,t} - p_{ES,t}| < 0.01\right)$, $\mathbb{1}\,(\text{FR Cheaper}) \equiv \mathbb{1}\left(p_{FR,t} - p_{ES,t} < -0.01\right)$, $\mathbb{1}\,(\text{Flow to ES}) \equiv \mathbb{1}\left(f_{ES,FR,t} < 0\right)$, and $\mathbb{1}\,(\text{Directions Aligned}) := \mathbb{1}\left(|p_{FR,t} - p_{ES,t}| < 0.01 \vee sgn\left(p_{FR,t} - p_{ES,t}\right) \equiv sgn\left(f_{ES,FR,t}\right)\right)$. That is the flow and price difference have the correct direction (or are aligned) when either the prices have converged, since then flow can go in either direction, or when flow and price difference have the same sign. The denominator for the last column is the number of observations for which either prices have converged, or both price difference and flows are not missing.
The time periods for Pre/Post expansion align with my main analysis sample, and are defined as: *Pre* is 2015/01/01 - 2015/09/04, *Post* is 2015/11/04 - 2016/10/04, see section 4.1 for further details.
In 2014, the vast majority of misalignment occurs prior to May, that is during the time when the two price zones were not jointly cleared.

market clearing.

Trade between Spain and France does not involve loop flows. First, all transmission paths between Spain and France go directly across the border between them. Second, due to the nature of zonal market set-up used in Europe the cross-border, or cross-zone, net flow is determined as the aggregate flow across all transmission lines across the border, directions, and measurement sub-intervals. As a result, the net cross-border flows between the two countries correspond to trade volumes. Net flow, $f_{ES,FR,t}$, is considered to be positive if it is from Spain to France and negative otherwise, as defined in equation (1). Further details on how I construct the net flows from the raw data are in appendix A.

Electricity flowed from France to Spain at least 78% of hours in my main analysis sample, and at least 67% of time at annual level between 2014 and 2016, as reported in the third column of table 2, leaving a substantial amount of time when flows were positive - or from Spain to France. Consequently, similarly to price differences, the absolute value of net cross-border physical flows is a better measure of cross-border trade volumes than flows per se. Mean absolute hourly flows before the expansion, reported in table 1, were 937 MWh. There was a large increase in absolute cross-border trade volumes following the line commissioning, with the mean increasing to 1,726 MWh in each hour.

The change in the tails of the hourly net physical flows across the border provides a good proxy for impact of the new line on the cross-border transmission capacity[13]. Assuming that transmission capacity is the same in both direction, the increase of the 99th percentile of hourly absolute flows from 1,314, to 2,838 MWh suggested that the capacity more than doubled after the expansion. Tails of the (raw) net physical flows distribution proxy direction specific capacities. The first percentile of the hourly net flow distribution, a proxy for France to Spain capacity, decreased from -1,313 MWh to -2,830 MWh following the expansion, and to -3,267 MWh in 2016 overall. The transmission capacity from Spain to France appears to increase as well, with 99th percentile increasing from 1,124 to 2,429 MWh. The approximate doubling of capacity and flows, and the lower capacity for the Spain to France direction, match ex-ante predictions of the two TSOs.

[13]I use the tails, rather than the minimum and maximum, to proxy for the capacity of the transmission interconnection. Capacity of a transmission line can vary even within a very short time period, because it is dependent on environmental factors, operational and system conditions. An equipment outage can cause transmission capacity to decrease. Capacity also tends to be lower during extremely hot periods. A line might also be operated over its capacity rating during short periods of time.

Given the zonal electricity markets and the lack of loop flows for trade between Spain and France, the flow and price direction alignment measures how well the trade implied by day-ahead market outcomes aligns with realized flow, or trade. I define the state of alignment as:

$$\mathbb{1}\,(\text{Directions Aligned}) := \mathbb{1}\left(|p_{FR,t} - p_{ES,t}| < 0.01 \vee sgn\left(p_{FR,t} - p_{ES,t}\right) \equiv sgn\left(f_{ES,FR,t}\right)\right)$$

The net cross border physical flow and the day ahead price difference have the correct directions (or are aligned) when either the prices have converged, since then flow can go in either direction, or when flow and price difference have the same sign. The fourth column in tables 2 and 12 shows that flow and day-ahead price difference directions are aligned in at least 99% of hours in all sample definitions for 2015 and afterwards[14]. When comparing the difference of columns 2 and 3 in table 2, which is equal to the share of time when flows were from France to Spain and France was not cheaper, to column 1, the share of time when prices were the same, one sees that France was exporting to Spain during the majority of time when prices were equal.

4.2.3 Demand and Production Data

I use the actual total load reported in Transparency for load, or demand. It is defined as net generation minus balance with neighboring areas (imports minus exports), minus absorbed (stored) energy for the given area and hour. Where net generation is the generation output of all generators in the area minus any consumption by these generators. Note that net load includes any transmission and system losses. For production, or generation data, I utilize net generation from Transparency for a given area and time period aggregated at the level of 16 production types. A production type is the source of energy, or fuel, used for generation. Net generation, in this case, is equal to net output generators are feeding into the transmission system. That is the gross generation output minus any energy consumed by the generators. In contrast to construction of net load data, electricity used for storing energy is included in generators' consumption. If a generator is a net consumer, I define its net generation to be negative. To create country level net generation, I sum generation and consumption for all production types in a given hour and then subtract the resulting consumption from generation. I include further description of how I construct generation and load data in appendix A.

5 Empirical Strategy

I utilize the high frequency time series variation in the data, combined with a rich set of controls to estimate a range of impacts of the new transmission line between Spain and France. My outcomes of interests can be split into two groups - country level, and border level - based on the unit of observations. The specification for estimating effects on cross-border outcomes is:

$$\begin{aligned} y_t = {} & \beta_1 \mathbb{1}\,(t \geq \text{2015-10-05}) + \beta_2 D_{ES,t} + \beta_3 D_{FR,t} + \alpha_{ES} X_{ES,t} + \alpha_{FR} X_{FR,t} \\ & + \gamma_1 PCoal_{d(t)} + \gamma_2 PGas_{d(t)} + hour_t + dow_t + \varepsilon_t \end{aligned} \tag{6}$$

where: t denotes date-hour, $d(t)$ is the date component of t, y_t is the outcome of interest, $\mathbb{1}\,(t \geq \text{2015-10-05})$ is an indicator variable for post line commissioning, D_{it} is demand in country i at time t, X_{it} is a vector of weather controls, $PCoal_{d(t)}$, and $PGas_{d(t)}$ are the coal, and natural gas price indexes, respectively for date $d(t)$; $hour_t$, and dow_t are the hour of day, and day of the week fixed effects, respectively, and ε_t is the unobserved heterogeneity. The parameter of interest is β_1, which represents the change in y_t after commissioning of the new transmission line.

I analyze three cross-border outcomes - absolute value of net flow across the border, $|f_{ES,FR,t}|$, absolute value of day ahead price difference between the two countries $|p_{FR,t} - p_{ES,t}|$, and congestion revenue, as defined in equation (5).

Recall that flow is vector variable - it represents the volume of electricity flowing across the border, as well as the direction. For a given set of system conditions in a radial network, transmission expansion does not affect direction of trade, only the magnitude. A seasonal change of trade direction coincident with line

[14]In 2014, the vast majority of misalignment occurs prior to May, that is during the time when the two price zones were not jointly cleared.

opening, would bias the estimate of line opening on flows towards zero. The absolute value of flows is thus the relevant outcome to measure impacts of the reinforced transmission interconnection on trade volumes between the two countries.

Price difference measures the distance between marginal costs in the two countries. A large difference in marginal costs implies inefficient allocation of generation. The price difference corresponds to per unit cost of the inefficiency. Similarly to flows, any coincident changes in direction of price differences biases the estimate. Thus, the absolute value of price differences is the relevant outcome.

I control for demand in each country. Load levels indicate the level of strain the grid is under in each country. Furthermore, since the prices and generation quantities are determined as the intersection of demand with the marginal cost curve, demand proxies for the position on the marginal cost curve in each country under autarky.

Natural gas and coal power plants are most likely to be the marginal, or price setting, generators during the time period under study. Changes in coal and gas prices then affect wholesale market prices, and thus opportunities for trade. Controlling for fuel input prices disentangles coincident changes in fuel prices from the effects of the new line being brought into service.

Electricity demand and other system operating conditions have a significant and persistent pattern, and large variation, over time. For example, demand is typically very low during the night and it rapidly increases in the early morning. Friday might see a decrease in industrial load earlier than on other weekdays. I include an hour of day fixed effects, *hod*, and day of the week, *dow*, fixed effects, to account for the within day, and between days patterns and variation, respectively.

Weather has a large impact on nearly all parts of the electricity system. Demand is high during very hot (cold) days due to high air conditioning (heating) load. Cooling of thermal generators is more challenging on hot days, thus reducing generation capacity. Coal piles can freeze during cold spells. Solar generation is dependent on sun shine. Very high temperatures can lead to transmission lines sagging, equipment overheating, and thus reducing transmission capacity. I control for weather in equation (6) using:

$$\begin{aligned}\alpha_i X_{it} = \alpha_{i1} Temp_{it} + \alpha_{i2} Temp_{it}^2 + \alpha_{i3} Rain_{it} + \alpha_{i4} Temp_{it} \times Rain_{it} + \alpha_{i5} Temp_{it}^2 \times Rain_{it} + \\ \alpha_{i6} Rain24h_{it} + \alpha_{i7} Wind10m_{it} + \alpha_{i8} Wind100m_{it} + \alpha_{i9} GHI_{it}\end{aligned} \tag{7}$$

All of the weather controls are mean values for country i at date-hour t. $Temp_{it}$ is temperature in degrees Celsius. I also control for squared temperature, because a change in temperature is going to have a greater impact during already hot or cold weather, than during mild days. I control for hourly rainfall accumulation using $Rain$. On one hand, rain can have a cooling effect, especially since it is correlated with cloudy weather. On the other hand, rain is going to increase the amount of moisture in the air, and thus humidity. Heating is less energy intensive during humid weather, while air conditioning is more energy intensive. I interact the hourly rainfall with temperature, and temperature squared to proxy evaporation and humidity, as well as to account for the interaction of humidity and temperature. I also include rain accumulation over the last 24 hours in millimeters, represented by $Rain24h$, to account for a broader stock of moisture.

Wind and solar generation output is highly dependent on weather. Wind and solar generation have a significant impact on prices, and thus trade, because they have close to zero marginal cost. The line starts operating in October, so I need to isolate any coincidental impacts of weather patterns from the impact of the transmission project on wind and solar generation. Transmission expansion can affect production of wind and solar resources, however, holding generation capacity constant, it is not going to affect the potential renewable output. I control for wind speed at 10, and 100 meters above ground using $Wind10m$, and $Wind100m$, respectively. To account for potential solar generation, I control for global horizontal irradiance, GHI, or solar radiation. I describe the weather data in more detail in appendix A.

To obtain impacts of the transmission expansion on country level outcomes, such as buyer expenditures and generator profits, I estimate following regression separately for each country i:

$$\begin{aligned}y_{it} = \beta_1 \mathbb{1}\left(t \geq \text{2015-10-05}\right) + \beta_2 D_{it} + \alpha X_{it} \\ + \gamma_1 PCoal_{d(t)} + \gamma_2 PGas_{d(t)} + hour_t + dow_t + \varepsilon_{it}\end{aligned} \tag{8}$$

The only difference between this specification and the one in equation (6) for cross-border outcomes is that I do not control for weather and load in the other country here. Note that when I estimate impacts on buyer expenditures, I do not include the load, D_{it}, as a control because it appears on the left hand side. When estimating the nominal, and relative effect on buyer expenditures, I define the outcome as $y_{it} = D_{it}p_{it}$, and $y_{it} = \log(D_{it}p_{it})$, respectively.

5.1 Estimating Impacts on Generator Profits

In the absence of detailed cost data, I can neither directly calculate generator profits, nor directly estimate impacts of the transmission investment on generator profits. However, I can estimate bounds on changes in generator profits by using features of the electricity system and markets operations, described in section 3, weak assumptions, and by decomposing changes in generator revenues.

5.1.1 Derivation of Bounds on Generator Profits Changes

First, generation and load must always match exactly in the entire interconnected system, and there must always be a feasible transmission path between generation and load. Second, assume that trade with 3rd countries does not change significantly after line commissioning. Third, assume that, given weather, generation technology and generator availability do not change following the line commissioning. Hence, absent changes in fuel prices, the marginal cost curves in both countries remain unchanged after the transmission line commissioning. Consequently, for the same demand, weather, and fuel prices before and after the expansion, the increased transmission capacity only impacts how the, unchanged, total quantity generated is split between the two countries.

If there was no congestion before the line started operating, under the assumptions above, generation allocation and prices remain unchanged after the expansion. If congestion was present before line commissioning, the unchanged marginal cost curves imply that the interconnection reinforcement must increase the magnitude of flows, and that flow direction is not impacted. The cheaper region exports, and generates, more after the expansion. Generations decreases in the importing region after line commissioning due to increased imports. In the setting depicted in figure 2 this is equivalent to:

$$q_{FR,1} > q_{FR,0} \quad \text{and} \quad q_{ES,1} < q_{ES,0}$$

I decompose the observed change in revenue due to transmission expansion into changes in quantities and prices in two ways:

$$\Delta R_i = q_{i,0}\left(p_{i,1} - p_{i,0}\right) + p_{i,1}\left(q_{i,1} - q_{i,0}\right) \tag{9}$$

$$\Delta R_i = q_{i,1}\left(p_{i,1} - p_{i,0}\right) + p_{i,0}\left(q_{i,1} - q_{i,0}\right) \tag{10}$$

The change in profits for Spain, and France, is equal to the orange, and blue area, respectively in figure 3.

I use the decomposition in equation (9) to derive the lower bound on changes in profits. The first term in equation (9) holds the quantity generated fixed at the pre-expansion level and it assumes only prices change. It equals the area inside the orange dotted, and blue dashed-dotted rectangle in figure 3a, for Spain, and for France, respectively. The second term holds the price fixed at the post expansion level and assumes that only quantities change. It is depicted by the area inside the dark red rectangle for Spain, and by the light blue dotted area for France. The first term in equation (9) is the lower bound on changes in profits:

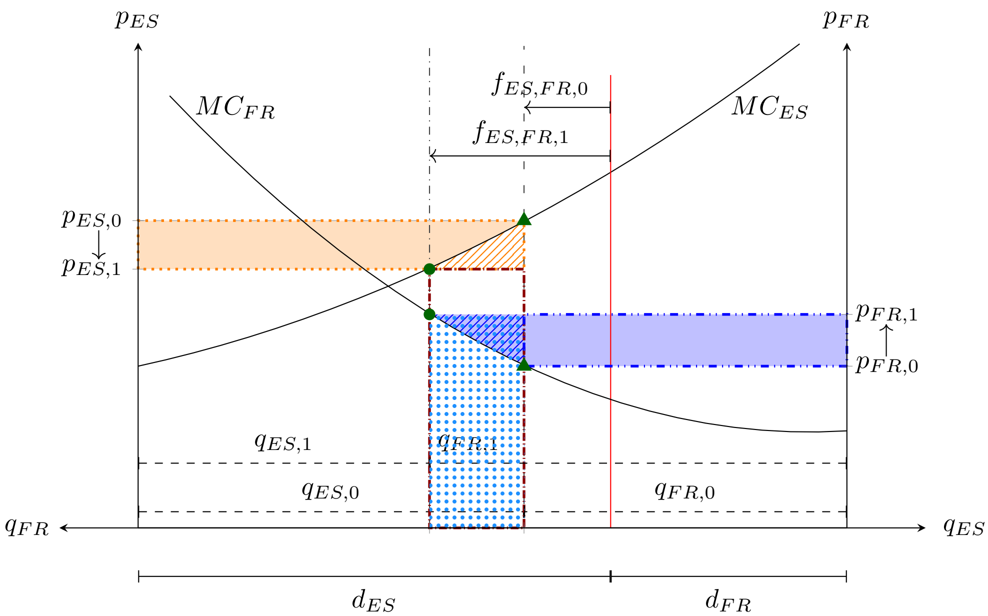
$$\Delta\pi_i^{LB} = q_{i,0}\left(p_{i,1} - p_{i,0}\right) \tag{11}$$

The time periods at which the quantity and price are held fixed are reversed in equation (10). The first term in equation (10) equals the upper bound on changes in profits:

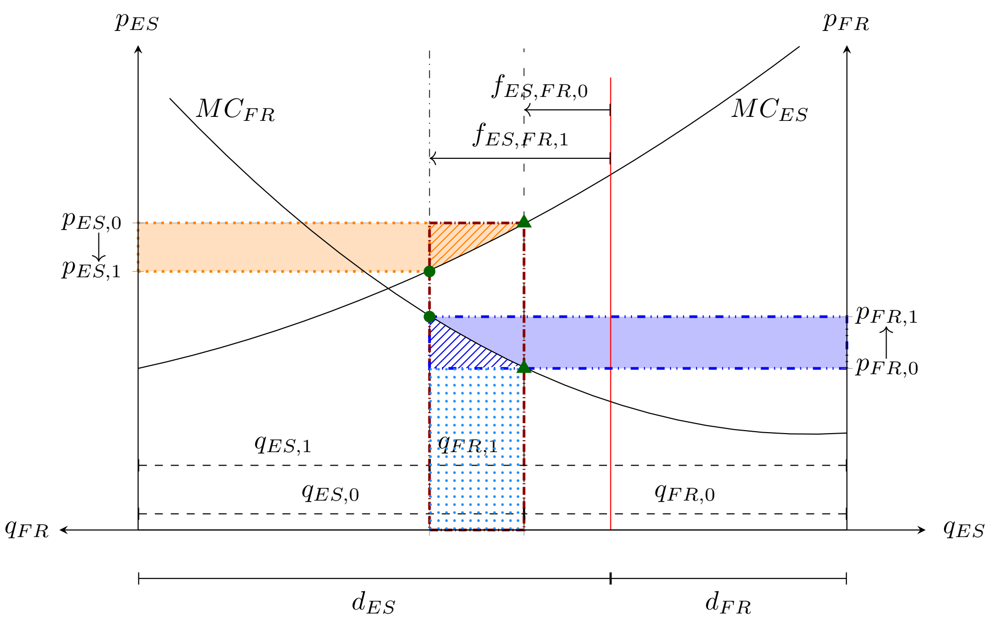
$$\Delta\pi_i^{UB} = q_{i,1}\left(p_{i,1} - p_{i,0}\right) \tag{12}$$

The upper bounds for Spain, and France are equal to the areas inside the orange dotted, and blue dashed-dotted rectangles in figure 3b, respectively. The areas inside the dark red dashed, and blue dotted rectangles represent the remaining parts of revenue changes in Spain, and France, respectively.

Figure 3: Impacts of Transmission Expansion on Generation Profits



(a) Lower Bound



(b) Upper Bound

The derivation showing that equation (9) is the lower bound follows. Decomposing the change in profits into changes in revenues and cost, and using the revenue change decomposition in equation (9):

$$\begin{aligned}\Delta\pi_i &= q_{i,0}\left(p_{i,1}-p_{i,0}\right)+p_{i,1}\left(q_{i,1}-q_{i,0}\right)-C_i(q_{i,1})+C_i(q_{i,0}) \\ &= q_{i,0}\left(p_{i,1}-p_{i,0}\right)-\int_{q_{i,0}}^{q_{i,1}} MC_i(q)-p_{i,1}dq \\ &= \Delta\pi_i^{LB}-\int_{q_{i,0}}^{q_{i,1}} MC_i(q)-p_{i,1}dq\end{aligned} \tag{13}$$

Given that equilibrium price is equal to the marginal cost of the most expensive generators:

$$\begin{cases} p_{i,t}\geq MC_i(q) & \forall\ q\leq q_{i,t} \\ p_{i,t}< MC_i(q) & \forall\ q> q_{i,t}\end{cases}$$

Since, for a given system state, the directions of changes in quantity generated and prices due to transmission expansion in each country are known, for the importing country (Spain in the example):

$$\begin{aligned}&q_{ES,1}<q_{ES,0} \implies \\ &\int_{q_{ES,0}}^{q_{ES,1}} \underbrace{MC_{ES}(q)-p_{ES,1}}_{>0\ \forall\ q>q_{ES,1}} dq<0 \implies \\ &\Delta\pi_{ES}>\Delta\pi_{ES}^{LB}\end{aligned}$$

and for the exporting country (France in the example):

$$\begin{aligned}&q_{FR,1}>q_{FR,0} \implies \\ &\int_{q_{FR,0}}^{q_{FR,1}} \underbrace{MC_{FR}(q)-p_{FR,1}}_{<0\ \forall\ q<q_{FR,1}} dq<0 \implies \\ &\Delta\pi_{FR}>\Delta\pi_{FR}^{LB}\end{aligned}$$

The lower bound on profit change in the importing location contains the orange lined triangle in figure 3a, with its area equal to the the integral in equation (13), which was part of costs rather than profits before the expansion.

The lower bound on change in profits of the exporting region does not contain the blue lined triangle in figure 3a, with area equal the negative value of the integral equation (13).

The derivation for the upper bound is in appendix B. Intuitively, the bound for Spain does not contain orange lined area in figure 3b, which is part of changes in profits. The upper bound for France contains the blue lined area, in addition to changes in profits.

5.1.2 Estimation of Bounds on Generator Profits Changes

Let q_{it}^0, and q_{it}^1, denote the counterfactual quantity that would be generated in country i at time t, if there *were not*, and *were*, respectively, transmission expansion at time t. For now, assume that I know the counterfactual quantities. I estimate the following two regressions for each country i:

$$\begin{aligned}q_{it}^0 p_{it} &= \beta_1^{LB}\mathbb{1}\left(t\geq \text{2015-10-05}\right)+\beta_2^{LB}D_{it}+\beta_3^{LB}D_{-it}+\alpha^{LB}X_{it} \\ &\quad +\gamma_1^{LB}PCoal_{d(t)}+\gamma_2^{LB}PGas_{d(t)}+hour_t^{LB}+dow_t^{LB}+\varepsilon_{it}^{LB}\end{aligned} \tag{14}$$

$$\begin{aligned}q_{it}^1 p_{it} &= \beta_1^{UB}\mathbb{1}\left(t\geq \text{2015-10-05}\right)+\beta_2^{UB}D_{it}+\beta_3^{UB}D_{-it}+\alpha^{UB}X_{it} \\ &\quad +\gamma_1^{UB}PCoal_{d(t)}+\gamma_2^{UB}PGas_{d(t)}+hour_t^{UB}+dow_t^{UB}+\varepsilon_{it}^{UB}\end{aligned} \tag{15}$$

These equations include the term D_{-it}, representing load of the other country, on the right hand side in addition to the right hand side of equation (8) for general country level outcomes. Load of the other country is included, because it influences imports and exports, and thus quantities and prices. By definition, the transmission expansion is not going to affect the counterfactual quantities. Therefore, the regressions for country i yield the bounds on profit changes in country i as defined in equations (11) and (12):

$$\beta_1^{LB} = \mathbb{E}\left[\Delta\pi_i^{LB}\right]$$
$$\beta_1^{UB} = \mathbb{E}\left[\Delta\pi_i^{UB}\right]$$

Since, holding everything else constant, the expansion only affects how generation in each country responds to changes in load in both countries, I obtain the counterfactual quantities generated using the following regression for each country i:

$$\begin{aligned} q_{it} = {} & \beta_1 Post_t + \beta_2 D_{it} + \beta_3 D_{-it} + \beta_4 Post_t \times D_{it} + \beta_5 Post_t \times D_{-it} + \\ & + \alpha X_{it} + \gamma_1 PCoal_{d(t)} + \gamma_2 PGas_{d(t)} + hour_t + dow_t + \varepsilon_{it} \end{aligned} \tag{16}$$

where $Post_t = \mathbb{1}\left(t \geq \text{2015-10-05}\right)$, everything else is the same as before. I calculate the counterfactual quantities used in equations (14) and (15) as fitted values with $Post_t$ set to the appropriate value.

I set $Post_t = 0$ for all times t to obtain q_{it}^0, the counterfactual quantity that would be generated in country i at time t, if there was no transmission expansion at time t:

$$q_{it}^0 = \widehat{\beta_2} D_{it} + \widehat{\beta_3} D_{-it} + \widehat{\alpha} X_{it} + \widehat{\gamma_1} PCoal_{d(t)} + \widehat{\gamma_2} PGas_{d(t)} + \widehat{hour_t} + \widehat{dow_t}$$

Similarly, I obtain q_{it}^1, the counterfactual quantity that would be generated in country i at time t, if there was transmission expansion at time t by setting $Post_t = 1$ for all times t:

$$q_{it}^1 = \widehat{\beta_1} + \left(\widehat{\beta_2} + \widehat{\beta_4}\right) D_{it} + \left(\widehat{\beta_3} + \widehat{\beta_5}\right) D_{-it} + \widehat{\alpha} X_{it} + \widehat{\gamma_1} PCoal_{d(t)} + \widehat{\gamma_2} PGas_{d(t)} + \widehat{hour_t} + \widehat{dow_t}$$

6 Results

The effect of the new transmission line on the absolute value of hourly net cross-border physical flows, denoted $|f_{ES,FR,t}|$, estimated using the specification in equation (6), is shown in table 3. Physical flows, $f_{ES,FR,t}$, measure the realized net trade direction, and the net trade volume between Spain and France. Flows across the border regularly switch direction, and there is no theoretical reason, given the zonal markets, for the increased transmission capacity to affect flow direction. Consequently, the relevant measure of trade volumes between the two countries is the absolute value of net cross-border physical flows.

Panel A of table 3 shows the nominal effects. I prefer the estimate from column 6 - with a sampling window from the 1st of January 2015, to the 4th of October, 2015, and a 30 day donut window on each side of treatment (a total of 60 days excluded), details regarding preferred sample selection are in section 4.1. The coefficient shows that the increased transmission capacity between Spain and France results in 912 MWh (Megawatt-hour) increase in absolute flows across the border for any given hour. That represents a significant increase in flows compared to the pre-expansion baseline absolute hourly flows of approximately 1,000 MWh. I report Driscoll-Kraay standard errors using 6 lags at daily (date) level in parentheses. Driscoll-Kraay standard errors allow me to control for both within day (between hours of the day) and across days (auto-correlation) correlation of residuals.

The 912 MWh increase in absolute flows represents about 3.3%, and 1.8%, of mean hourly load in Spain, and France, respectively. The annual peak (maximum) hourly load in Spain, and France, is on the order of 40,000 MWh, and 90,000 MWh, respectively. Thus, the coefficient equals to approximately 2.5%, and 1.1% of Spanish, and French peak load, respectively. While these numbers might appear small, one must keep in mind that marginal cost curves tend to be very steep at periods of very high demand.

To put the increase in flows into further perspective, in Spain the aggregate mean, and peak, hourly generation in 2015 from natural gas amounted to approximately 5,500 MWh, and 10,700 MWh, respectively, and from hard coal to 5,500 MWh, and 8,100 MWh, respectively. In France, the mean hourly generation from natural gas, and hard coal, was in the order 3,000 MWh, and 1,100 MWh, with peaks of 7,500 MWh, and

Table 3: Effects on Cross-Border Flows

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- ≈ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Panel A - Nominal Changes						
Dependent Variable			$\lvert f_{ES,FR,t} \rvert$ $[MWh]$			
$\mathbb{1}\,(t \geq \text{2015-10-05})$	558.5***	1,111.4***	628.8***	972.7***	633.1***	912.1***
	(191.1)	(179.1)	(147.5)	(115.4)	(148.4)	(109.7)
Observations	6,126	5,126	9,264	8,264	10,837	9,837
Adjusted R^2	0.478	0.528	0.410	0.440	0.391	0.412
Within Adjusted R^2	0.470	0.521	0.405	0.436	0.380	0.402
Panel B - Relative Changes						
Dependent Variable			$\log\left(\lvert f_{ES,FR,t} \rvert\right)$			
$\mathbb{1}\,(t \geq \text{2015-10-05})$	0.5084**	0.9386***	0.4956***	0.7058***	0.4946***	0.6552***
	(0.2092)	(0.1713)	(0.1431)	(0.1144)	(0.1478)	(0.1142)
Observations	6,125	5,125	9,263	8,263	10,836	9,836
Adjusted R^2	0.250	0.276	0.187	0.194	0.186	0.191
Within Adjusted R^2	0.238	0.266	0.181	0.190	0.176	0.182

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are for weekdays at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

3,300 MWh, respectively. Because these resources are most likely to be marginal (price setting) generators, and thus displaced by imports, at any given time, the 912 MWh increase in flows across the border is substantial.

I also presents results with two additional sampling windows - 180 days (columns 1 and 2), and 9 months (columns 3 and 4). The length of the sampling window corresponds to the amount of time on each side of treatment date. For each sampling window, I present results for two donut windows, the number of days excluded from analysis on each side of the line commissioning date - the full sample (the full window is used), and for a 30 day donut window (a total of 60 days excluded). In general, the coefficients for different sampling windows are quantitatively similar for a given donut hole. Results with different donut holes become closer as the overall sample window increases. The estimated impacts range from 912 MWh (1 year window, col. 6) to 1,111 MWh (180 day window, col. 2) with a 30 day donut window, and 558 MWh (180 day window, col. 1) to 633 MWh (1 year window, col. 5) without a donut window.

Panel B in table 3 contains results for relative changes in cross-border flows between Spain and France caused by the transmission investment, with the dependent variable specified as $\log\left(\lvert f_{ES,FR,t} \rvert\right)$. My preferred estimate from column 6, 0.655, translates to an average 92.55% increase in net volume of absolute cross-border flows between the two countries for any given hour[15]. The near doubling of flows closely corresponds to the doubling of cross-border transmission capacity that was reported by the project investor, although the investor claimed the capacity was going to increase from 1,400 MWh to 2,800 MWh (Inelfe, 2024). I consider the fact that my estimate matches the ex-ante prediction, in relative terms, to be remarkable.

The large increase in hourly flows implies that there was, on average, a significant room for improving generation allocation by increasing trade between France and Spain. The difference between day-ahead wholesale market electricity prices in France and Spain corresponds to the difference in marginal costs of meeting load in the two countries. A large price difference indicates inefficient generation allocation between

[15] A coefficient in a log-linear regression can be transformed to relative changes using the formula: $\exp(\beta_1) - 1$.

Table 4: Effects on Cross-Border Price Differences

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Dependent Variable	$\lvert p_{FR,t} - p_{ES,t} \rvert$					
$\mathbb{1}\,(t \geq$ 2015-10-05)	-3.700	-2.202	-5.006**	-3.804**	-5.390***	-5.249***
	(2.789)	(2.208)	(2.027)	(1.789)	(1.953)	(1.814)
Observations	6,126	5,126	9,264	8,264	10,837	9,837
Adjusted R^2	0.457	0.496	0.375	0.400	0.380	0.399
Within Adjusted R^2	0.445	0.486	0.367	0.395	0.368	0.389

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are for weekdays at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

the two countries. It also points to large potential benefits from increasing trade. The change in price differences indicates how much closer the per unit costs of electricity in the two countries became due to the transmission expansion[16]. It is also indicative of the steepness of marginal cost curves for the two countries. The relevant measure for price (cost) differences between the two countries is the distance, or absolute value, of price differences, because it is not influenced by exogenous switching of price difference sign.

Impacts of the transmission investment on the absolute value of day-ahead wholesale market price differences between France and Spain, based on specification in equation (6), are shown in table 4. My preferred estimate in column 6 implies that the new transmission line decreased the absolute value of the price differences by 5.25 Euros per MWh for an average hour. For comparison, the mean, and 99th percentile, absolute price difference were 15.15 EUR/MWh, and 37.76 EUR/MWh, respectively, in the period from January through September 2015, and 16.28, and 49.97 EUR/MWh, in 2014. Medians were approximately the same as means. Consequently, the increased transmission capacity causes the absolute value of price difference to decrease by about a third, and a tenth, of the pre-expansion mean, and 99th percentile, respectively.

The decrease in price differences is also large when compared to prices in Spain and France. The mean day-ahead electricity prices in Spain were 44.64, and 52.49 EUR/MWh, in 2014, and in January through September 2015, respectively. In France, the mean price was 38.11, and 41.07 EUR/MWh in those two time periods. Median prices were approximately the same as mean. The impact of the reinforced interconnection thus corresponds to about 10 to 13% of mean prices before expansion. Considering the fact that the annual mean absolute price differences stay in the range of 7 to 10 Euros per MWh in the following years, both the price difference and impact of the transmission expansion on it, are substantial compared to prices in each country.

6.1 Cost Benefit Analysis of The Investment

Impacts of the new transmission interconnection on cross-border flow volumes between Spain and France, and cross-border price differences are sufficient for estimating the aggregate net benefits of the investment, even in the absence of detailed data on generation technology and costs. The net-benefits are equal to the magenta lined area in figure 2, which is equal to the cost savings of serving the demand in Spain and France.

Under the assumption that marginal costs are linear between the pre and post-expansion equilibrium points for each country, the magenta area can be estimated as an area of an isosceles trapezoid using equation (2). Using the estimated 912 MWh change in cross-border trade volumes, or flows, between Spain and France from column 6 in table 3, combined with the 15.15 EUR/MWh, and 8.21 EUR/MWh, mean absolute

[16]The exact benefits depend on the relative shapes of the marginal cost curves in the two countries.

Table 5: Aggregate Welfare Impacts and Cost Benefit Analysis

Panel A: Static Benefits and Costs:				
Hourly Benefits [Euro]	10,653.33			
Annual Benefits [million Euro]	93.323			
Construction Cost [million Euro]	700			
Panel B: Returns for Different Discount Rates:				
Discount Rate	1 %	4 %	5 %	10 %
Years to achieve parity	7.75	8.68	9.06	12.02
Present value of benefits after 25 years [million Euro]	2,075	1,516	1,381	931
Panel C: Returns for Different Lifespans:				
Lifespan [Years]	25	50	75	100
Internal Rate of Return	14.83 %	15.37 %	15.38 %	15.38 %
Present Value of Benefits with 4% Discount Rate [million Euro]	1,516	2,085	2,298	2,378

Benefits are calculated using the 2015/01/01-2016/10/04 sampling window and a 30 day donut window. Observations are for weekdays at hourly level.

I calculate the present value of the investment as $PV(T,\rho) = \sum_{t=0}^{T} (1+\rho)^{-t}\, \widetilde{\Delta SWF}$ where T stands for total number of years the benefits are calculated for, and rho for the discount rate. Years to achieve parity is the solution of $PV(T,\rho) = c$ for T given ρ, where c equals the construction costs. Internal Rate of Return is the solution for ρ for a given T.

price differences in same pre, and post expansion samples, respectively, from table 1, I calculate that the transmission expansion results in average benefits of 10,653 Euros per hour.

The hourly net benefits translate to 93.3 millions Euros annually. I present a cost-benefit analysis of the new HVDC interconnection between Spain and France at the aggregate level in table 5. I perform the analysis under the assumption that the annual benefits remain the same throughout life-cycle of the transmission line. Consequently, my estimates are a lower bound on the gains over the life cycle of the project, because the increased transmission capacity is likely to result in more efficient investment in generation (Gonzales et al., 2023), as well as increased reliability. I also assume that costs occur only during the construction of the project, a reasonable assumption given that operating costs tend to be related mainly to maintenance. The reported construction costs of the project were 700 million Euros (de LADOUCETTE et al., 2015; Wright, 2015; Francos et al., 2012; De Clercq, 2015).

I calculate how many years, T, it takes for the present value of the project to reach parity to the construction costs for a range of discount rates, ρ, in Panel B of table 5 with the present value defined as:

$$PV(T,\rho) = \sum_{t=0}^{T} \frac{1}{(1+\rho)^t} \widetilde{\Delta SWF}$$

where $\widetilde{\Delta SWF}$ stands for the annual benefits, as defined above. With a 1%, and 10%, discount rate it takes 7.75, and 12.02 years, respectively, for the benefits to exceed costs. Using the 4% discount rate for cost benefit analyses of investment in electricity transmission infrastructure in the pan-European, bi-annual Ten Year Network Development Plan (TYNDP) (ENTSO-E, 2024), the present value of the investment in the new interconnection exceeds the construction costs after operating for 8.68 years. In comparison, operational lifespan of transmission infrastructure is frequently over half a century.

Following Gonzales et al. (2023), I compute the internal rate of return on the investment, defined as the highest discount rate such that the present value of the investment reaches parity with investment costs over a given time period. The internal rates of return, as well as present values of the benefits with a 4% discount rate for different lifespans of the project are in table 5, Panel C. For the purposes of TYNDP, the economical lifespan of an investment, that is the duration over which benefits are calculated, should be at most 25 years, even if the technical lifespan of the infrastructure is longer (ENTSO-E, 2024). The internal rate of return for this time horizon is 14.83%. For longer time horizons, the internal rate of return does not increase by much,

Table 6: Effects on Congestion Revenue and Buyer Expenditures

Change in	**Congestion Revenue**	**Buyer Expenditures**			
	(1)	(2)	(3)	(4)	(5)
Type of Change	Nominal	Nominal		Relative	
Unit	Euro	Euro		Log-points	
Dependent Variable	$(p_{FR,t} - p_{ES,t}) \times f_{ES,FR,t}$	$p_{i,t} \times d_{i,t}$		$\log(p_{i,t} \times d_{i,t})$	
Level	Cross-border	Spain	France	Spain	France
$\mathbb{1}(t \geq \text{2015-10-05})$	10,264.4***	-46,321.0	566,726.2***	-0.0408	0.2859***
	(2,864.7)	(126,496.3)	(149,518.2)	(0.1058)	(0.0670)
Observations	9,837	9,976	9,950	9,976	9,950
Adjusted R^2	0.328	0.771	0.798	0.738	0.794
Within Adjusted R^2	0.308	0.639	0.726	0.582	0.673

Significance Codes: ***: 0.01, **: 0.05, *: 0.1. Observations are for weekdays at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. The sample is defined as pre-expansion period from 2015/01/01 to 2015/09/04 and post-expansion period from 2015/11/04 to 2016/10/04, see section 4.1 for further details. Results for additional sample definitions are in appendix D - in table 13 for congestion revenue, and in tables 14 and 15 for expenditures in Spain, and France, respectively.

because the present value of benefits becomes very small for large t - for example it is only 0.55 percentage points higher, 15.38%, for a 100 year long time horizon.

6.2 Welfare Distribution of the Effects

The large estimated aggregate benefits of the project indicate that building the new transmission interconnection between Spain and France was important. It is reasonable to ask then - why did it take over 30 years (since the 1980s) to build it? It takes two to dance, and it takes two to build a cross-border transmission line. The French and Spanish TSOs had to jointly site the line, and connect it to their systems. They had to decide how to split the construction costs. Regulators in both countries had to approve and permit the project. Each TSO, and national government, must benefit from the project in order to support it. Construction costs are passed onto transmission customers over time through fees, and we usually want the beneficiary to bear the cost. If either the buyers of the electricity (who represent consumers) or the generators in a country are harmed by the project, they can exert political pressure on regulators and governments in order to derail the project. Consequently, it is important to know how the transmission investment affects the different stakeholders in each country, as well as each country in aggregate.

If there are non-zero flows and congestion (price differences) between two adjacent pricing points, the prices paid for the traded quantity at the exporting and importing nodes are different. The money "left on table" from the trade is called congestion revenue, defined in equation (5). It is split between the two TSOs. Since the only transmission path between Spain and France crosses their border[17], the directions (signs) of price differences and flows are always the same in jointly cleared markets. Consequently, congestion revenue is always non-negative. Congestion revenue before, and after the expansion, is represented by the area of teal dashed, and teal shaded rectangle, respectively, in figure 2.

In order to be concise, I only present results for my preferred sample specification in the main text, defined as 1st of January, 2015, to the 4th of October, 2016, with 30 days excluded on each side of 5th of October, 2015. Results for the full set of sample specifications are in appendix D. The transmission expansion increased congestion revenue by 10,264 Euros for an average hour, as specified in equation (6) and shown in the first column of table 6, compared to a pre-expansion mean of 15,188 Euros. The large increase in congestion revenue implies that the the increase in flows across the border outweighed the decrease in price differences.

I estimate impacts on buyer expenditures using equation (8), with the exception that I do not include

[17] In other words there are no loop flows, or paths going through other price zones.

Table 7: Effects on Generation Quantities

Country	(1) Spain	(2) France
Dependent Variable [MWh]	$q_{ES,t}$	$q_{FR,t}$
$\mathbb{1}\,(t \geq \text{2015-10-05})$	-1,354.2**	-109.5
	(688.4)	(0.0497)
$d_{ES,t}$	0.9125***	0.1154
	(0.0264)	(0.1116)
$\mathbb{1}\,(t \geq \text{2015-10-05}) \times d_{ES,t}$	-0.0466*	0.1357
	(0.0257)	(0.0885)
$d_{FR,t}$	0.0265**	0.8537***
	(0.0131)	(0.0497)
$\mathbb{1}\,(t \geq \text{2015-10-05}) \times d_{FR,t}$	0.0345**	-0.0597
	(0.0161)	(0.0401)
Observations	9,972	9,971
Adjusted R^2	0.944	0.950
Within Adjusted R^2	0.853	0.942

Significance Codes: ***: 0.01, **: 0.05, *: 0.1. Observations are for weekdays at hourly level. Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. The sample is defined as pre-expansion period from 2015/01/01 to 2015/09/04 and post-expansion period from 2015/11/04 to 2016/10/04, see section 4.1 for further details. Results for additional sample definitions are in appendix D.

demand, D_{it}, on the right hand side. I find a negative, but statistically insignificant, effect on buyer expenditures in Spain in both nominal, and relative terms, shown in table 6, columns 2 and 4, respectively. The estimate remains insignificant in all, but one, of the other sample specifications found in table 14. In contrast to Spain, I find that the transmission expansion increases the hourly cost of purchasing the electricity to meet load in France by 566,726 Euros, or 33% in my preferred specification in columns 3 and 5 of table 6.

I estimate bounds on impacts of the transmission expansion on generation profits in each country, rather than impacts on profits due to data limitations, as discussed in section 5.1. In summary - as a first step, I estimate the effects on generation quantities, as well as on generation response to changes in load in each country, using the regression in equation (16). I then utilize the obtained coefficients to compute counterfactual production in each country, defined as the quantity that would have been generated if the transmission line had (not) been in service at any given time. With the counterfactual quantities in hand, I estimate the lower and upper bound on changes in generation profits for each country, as specified in equations (14) and (15), respectively.

The changes in generation quantities due the transmission expansion are in table 7, for my preferred sample, and in table 16 for the full set of samples. Following the transmission expansion, generation in Spain, in column 1, increases by 0.05 MWh less than before in response to a 1 MWh increase in domestic demand. Furthermore, Spanish generators produce 0.035 MWh more per every 1 MWh increase in French demand after the expansion, in addition to a pre-expansion response of 0.027 MWh. Note that, one cannot interpret the coefficient on post line opening as a, on average, 1,354 MWh decrease in Spanish generation due to the transmission expansion, because we never observe demand levels equal to zero. I do not find any significant impact of the new transmission line on French generation output, as displayed in column 2. Furthermore, French generation does not exhibit a statistically significant response to changes in Spanish demand before the expansion.

The estimated lower and upper bounds on changes in generator profits for the preferred sample are in table 8, and for all samples in tables 17 and 18 for Spain, and France, respectively. The two bounds are very close to each other (within less than one standard error) in all instances. I do not find statistically significant impacts on generator profits in Spain, columns 1 and 2, in either nominal (Panel A), or relative terms and

Table 8: Effects on Generation Profits

	(1)	(2)	(3)	(4)
Country	Spain		France	
Bound	Lower	Upper	Lower	Upper
Panel A - Nominal Profit Changes [EUR]				
Dependent Variable	$q^0_{ES,t} \times p_{ES,t}$	$q^1_{ES,t} \times p_{ES,t}$	$q^0_{FR,t} \times p_{FR,t}$	$q^1_{FR,t} \times p_{FR,t}$
$\mathbb{1}\,(t \geq 2015\text{-}10\text{-}05)$	11,383.0	14,162.5	552,234.5***	555,985.1***
	(105,807.8)	(58,037.1)	(166,474.0)	(167,665.8)
Observations	9,972	9,972	9,934	9,934
Adjusted R^2	0.868	0.866	0.854	0.852
Within Adjusted R^2	0.795	0.792	0.801	0.795
Panel B - Relative Profit Changes [log-points]				
Dependent Variable	$\log\left(q^0_{ES,t} \times p_{ES,t}\right)$	$\log\left(q^1_{ES,t} \times p_{ES,t}\right)$	$\log\left(q^0_{FR,t} \times p_{FR,t}\right)$	$\log\left(q^1_{FR,t} \times p_{FR,t}\right)$
$\mathbb{1}\,(t \geq 2015\text{-}10\text{-}05)$	0.0133	0.0143	0.2174***	0.2164***
	(0.0853)	(0.0852)	(0.0625)	(0.0624)
Observations	9,972	9,972	9,934	9,934
Adjusted R^2	0.816	0.813	0.846	0.844
Within Adjusted R^2	0.712	0.708	0.758	0.751

Significance Codes: ***: 0.01, **: 0.05, *: 0.1. Observations are for weekdays at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. The sample is defined as pre-expansion period from 2015/01/01 to 2015/09/04 and post-expansion period from 2015/11/04 to 2016/10/04, see section 4.1 for further details. Results for additional sample definitions are in appendix D. Counterfactual quantities used in the estimation and the impacts on profits are estimated on the same analysis sample.

(Panel B).

In contrast to the results for Spain, I find a large and statistically significant increase in hourly profits of French generators following the increase in cross-border transmission capacity, with the lower, and upper bound, equal to 552,234, and 555,985 Euros per hour, respectively, for an average hour as shown in table 8, Panel A, columns 3 and 4. The bounds on relative changes in hourly French generation profits, in Panel B, are both equal to a 24% increase.

I summarize the decomposition and distribution of welfare impacts in table 9. The country level welfare impact of the project is computed as the change in generator profits minus the change in buyer expenditures (since buyers prefer lower expenditures, or prices) as per equation (4). The transmission expansion leads to a 57,704 Euro per hour increase in welfare in Spain, although neither of the two components is statistically significantly different from zero.

The individual welfare impacts, and thus the welfare decomposition, are much more precise and interesting for France. The estimated increases in hourly buyer expenditures, and generator profits due to the new transmission interconnection are almost completely equal, approximately 552,000 Euros. Combined, the aggregate impact of the transmission line on French stakeholders is close to negligible, despite highly economically and statistically significant impacts on individual stakeholders in France.

Consequently, the French transmission system operator, the project investor on the French side, and to some extent the French government, must have faced an interesting conundrum when it comes to proposing and building the project, even if we do not consider which transmission customers pay for the expansion. On one hand, French generators, who are customers of the TSO and pay taxes, greatly benefit from the expansion through increased profits. On the other hand, French consumers, who are also customers of the TSO and who vote in elections, are harmed by the project almost as much as the generators benefit from it. Whether a project gets build is going to depend on which group has more leverage to push through its interests. A system of welfare transfers could alleviate some of these conflicting impacts, but that is area left

Table 9: Summary of Decomposition of Welfare Changes

Country	(1) Spain	(2) France
Change in Buyer Expenditures	-46,321.0	552,196.9***
	(126,496.3)	(149,518.2)
Change in Profits (Lower Bound)	11,383.0	552,234.5***
	(105,807.8)	(166,474.0)
Country Level Change in Social Welfare	57,704	37.6
Change in Congestion Revenue	10,264.4***	
	(2,864.7)	

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . All dependent variables are in Euros. Data is weekdays at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses, where available. Numbers with standard errors reported are coefficients from corresponding regressions using a sample with a 2015/01/01-2016/10/04 sampling window and a 30 day donut window. Country level change in social welfare is calculated as per equation (4).

for further research.

7 Conclusion

Areas most suitable for renewable electricity generations are frequently different from locations of legacy fossil fuel generation resources, and far away from major load centers. Hence, large scale investment in high voltage electricity transmission infrastructure connecting renewable rich areas to demand centers is crucial in order to efficiently deploy renewable energy resources at the scale needed to meet decarbonization goals.

Wholesale electricity markets covering large geographical areas increase allocation efficiency of electricity generation by enabling trade. Large and persistent price differences between adjacent pricing locations have been omnipresent. These large price differences exists if and only if the transmission interconnection between the two locations is operating at its capacity. Congested transmission links thus prevent efficient generation allocation. In other words lower cost plants are available, and could be dispatched if higher transmission capacity was available.

It frequently takes decades from the identification of a need to increase transmission capacity to the construction start. Many projects fail long before getting close to the construction phase. Newly built transmission interconnections oftentimes reach their full operational capacity shortly after commissioning, and thus (again) constrain trade, despite the low marginal cost of capacity and high fixed costs involved in transmission investment. Efficient incentives are needed for market delivered investment, where, when, and at the levels needed. Knowing the benefits, and their distribution across the various stakeholders, is the first step in designing policy incentivizing transmission investment. In addition, better understanding of benefit distribution can aid in determining who to target with the regulatory fees in cost recovery of the transmission expansion.

I am the first to empirically evaluate the impacts of the first large increase in cross-border transmission capacity between Spain and France since the 1980s. This border offers an excellent opportunity to study impacts of transmission investment for multiple reasons. It has been a significant congestion point in the European electricity transmission system for decades. Indeed, the Iberian Peninsula has been frequently labeled as an "electrical island" isolated from the rest of Continental Europe due to the severity of congestion. Furthermore, both countries have a high share of, and in Spain great potential for, zero carbon electricity generation, specifically from wind and solar in Spain, and from nuclear generation in France. Differences in generation and load patterns in the two countries seemingly create room for trade in zero carbon electricity. Importantly, the lack of loop flows through third countries involved in trade between Spain and France greatly simplifies the analysis. Yet, in contrast to other settings with radial network arrangements used in the literature, both countries have rich demand and generation patterns.

I estimate impacts of a new high voltage direct current interconnection between Spain and France, commissioned on the 5th of October 2015, using a novel data set with a comprehensive high frequency coverage of electricity system and market operations in Spain and France. I find that, within a year of the line starting operations, the hourly absolute cross-border flows between the two countries, equivalent to trade volumes, nearly doubled. They increased by 92.55%, or 912 MWh. The increase corresponds to approximately 3.3%, and 1.8%, of mean Spanish and French load. The doubling of cross-border flows matches ex-ante prediction of the project investor.

The transmission expansion decreased the absolute value of day ahead price differences between the two countries, a measure of the distance between marginal costs, by 5.25 Euros per MWh, from a baseline of approximately 16 Euros per MWh. The impact is equal to approximately 10 to 13% of mean day ahead prices in Spain and France before the expansion. Thus, the decrease in price differences is substantial.

The aggregate benefits of the project are estimated at 93 million Euros a year. The investment costs were 700 million Euros. At an annual discount rate of 4%, used to evaluate investment in transmission infrastructure in Europe, the benefits of the project exceed costs in 8.7 years from the start of operations. A 25 year long economical lifespan is used in cost benefit analysis of transmission investment in Europe. The internal rate of return on the investment for a 25 year long period, that is the discount rate that would make the present value of benefits over the 25 years equal to cost, is 14.8%. The investment in the cross-border capacity between Spain and France appears to have high aggregate returns.

At a finer level, the Spanish and French transmission system operators see a combined ten thousand Euro per hour increase in congestion revenue, or revenue from the cross-border trade, due to the expansion. I do not find the investment resulting in a statistically significant impact on either expenditures of Spanish buyers, or on profits of Spanish generators. However, I find a statistically and economically significant increase in buyer expenditures as well as in generator profits in France. The nominal increase in expenditures is nearly equal to the increase in profits, so in total they essentially cancel each other out within France.

Consequently, it is understandable if there was opposition from the French consumers against building the new transmission link between the two countries. Although the buyers, or consumers, are not directly part of the investment process, they can influence the outcome through political pressure, essentially their votes, and throughout the permitting process. Activist groups have derailed transmission projects through pushing overly expensive measures due to environmental, or even visual appeal reasons, in the past. Similarly, generator owners might lobby in line with their interests - they pay taxes, and are frequently large employers.

In summary, I demonstrate that even what might appear as small increase in transmission capacity can lead to substantial aggregate benefits. But at the same time, I also show that it is necessary to consider not only the aggregate benefits of a transmission project, but also how the different stakeholders - generators, buyers (consumers), and TSOs - are affected by the project. It is also important to know who these stakeholders are, and where they are located, in order to reduce opposition to, and gather support for, investment in transmission infrastructure. Direct engagement with stakeholders, or perhaps even transfers between beneficiaries and losers might be part of the solution. Knowledge of the benefit distribution also enables targeting of investment cost recovery from beneficiaries, rather than recovering the cost uniformly from all transmission customers. Design of exact solutions, and policies to alleviate roadblocks investment in transmission infrastructure faces due to the distribution of impacts is an area left for further research.

There are several additional interesting dimensions to heterogeneity of the impacts that I would like to analyze in future work, in addition to the aggregate country level outcomes on generators, buyers, and TSOs across the two countries I analyze in this paper. There are large differences in electricity demand, generation, and generator availability patterns between different seasons of the year. Analyzing the heterogeneity of effects across different seasons can thus be informative about when the impacts are the greatest. Furthermore, different generators are going to be affected differently depending on the part of merit order cost curve at which they are located. It is important to consider which generators are affected the most and in what way.

The data is suitable for analysis of how generation aggregated at fuel type level, and for large generators at unit level, is affected by the increased trade. Of particular interests are the effects on fossil fuel (coal and natural gas), and renewable (wind and solar) resources. I am also interested in whether there are any spillovers on secondary borders - borders of France, and Spain, with their other neighbors. Impacts on pollution, and in general on emissions, from power generation and where the changes occur are also of great importance and interest. These are all areas I am planning to focus on next. I also want to improve the analysis on generation impacts, in particular profits, by obtaining data on costs, and bidding in the day ahead market.

The border between Spain and France is not the only border in Europe with significant congestion and issues with construction of new transmission lines. The vast majority of the data is available for all European countries. I can thus expand the analysis to other borders in Europe. The interesting aspect of other European borders is the fact that Europe has highly meshed, or interconnected, transmission network. Due to physical properties of electricity flows, increased capacity across one border is going to affect many other borders as well. For example, a change on the border between Germany and Poland is also going to affect the borders between Germany and Czechia, and between Czechia and Poland since flows between Germany and Poland go through all transmission paths between them. These cross-border spillovers are important in other transmission systems as well. However, they have largely not been empirically studied.

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A Further Details on Data

Some data is published at 15-minute frequency on ENTSO-E Transparency. I aggregate any data on quantities published at 15-minute frequency to hourly level. Most of the data on quantities is reported in MW, so I convert the 15-minute data for hour h to hourly data in megawatt hours as $x_h = \sum_{t=1}^{4} 0.25 \times x_{t(h)}$ where t stands for a 15-minute interval falling in hour h. In terms of cross-sectional dimension, most of the data is available aggregated at bidding (price) zone, control area, and country levels. Bidding zone corresponds to the area in which there is the same wholesale market price, and control area is the territory of a particular TSO. In case of France and Spain, bidding zone, control area and country are equal to each other, so I use data for control areas. Data values for the different cross-sectional units are identical for all, but a handful of observations. Quantities are typically reported in megawatts, and calculated as an average of instantaneous values available over the given time interval.

ENTSO-E Transparency and IESOE provides data on realized hourly net cross-border physical flows. The flows are across the border between the two areas, rather than the trade volume between them, which can involve loop flows. Net flow means that electricity flow is summed (integrated) across all transmission lines crossing the border, directions, and measuring intervals (if they are smaller than the data reporting frequency) for the given time period. The flows are reported for each direction - the value is positive for one direction and zero for the other one. I convert the data into net flows in the few instances when positive flows are reported for both directions. I then assign net flow, $f_{ES,FR,t}$, to be positive if is from Spain to France and negative if it is in the opposite direction, as defined in equation (1).

In definition of net load, absorbed energy is equal to the energy all storage units in the area utilized to store energy during the particular hour. Since in my sample period, 2015 - 2016, storage units primarily consisted of hydro pumped storage (battery storage is not listed specifically), absorbed energy would equal to the electricity hydro pumped storage units used to pump water into storage during the given time interval.

During my sample period the production types present in Spain and France are Biomass, Fossil Brown coal/Lignite, Fossil Gas, Fossil Hard coal, Fossil Oil, Hydro Pumped Storage, Hydro Run-of-river and poundage, Hydro Water Reservoir, Nuclear, Other, Other renewable, Solar, Waste, and Wind Onshore. If a generator is a net consumer, zero net generation and a positive consumption linked to generation is reported in the data. Similarly, if a generator ends up being a net producer, generation reported is positive and consumption is zero. In the few observations where both values are positive, I convert them to net values. I define net generation for my purposes as net generation minus consumption of the generator. Consequently, net generation is negative if the generator produces less than it consumes in any given hour.

At the most granular level, generation is reported for at unit level for generation units with nameplate capacity of at least 100 MW. While one might think that a generation unit is what we call power plant, a power plant can have multiple generation units. A generation unit is the generator in the power plant that is connected to the transmission system, essentially a turbine in steam based or hydro power plants. Consequently, output at generation unit level is only available for power plants with large generation units. For example, I observe all nuclear generation at generation unit level. However, a large hydro power plant with a total nameplate capacity well over 1,000 MW can be easily composed entirely of turbines (or generation units) with nameplate capacity of less than 100 MW.

For the weather data, the data directly contains hourly mean country level values. Each value is calculated as the mean area average across the entire country. I use the air temperature at a height of 2 meters, total accumulated precipitation on a flat, horizontal and impermeable surface, wind speed (horizontal air velocity) at heights of 10 and 100 meters, and solar radiation. Solar radiation is called surface downwelling shortwave radiation in the data description and it is also known as global horizontal irradiance, or GHI - the amount of solar radiation that reaches a horizontal plane at surface level.

A.1 Construction of Fossil Fuel Prices

For natural gas prices, I use the European Energy Exchange (EEX) PEGAS exchange day-ahead price index, which prices natural gas at the Title Transfer Facility (TTF) Virtual Trading Point in the Netherlands. I select the last price in a given trading day to represent the relevant price for that date. The TTF trading hub is considered to be the dominant and most relevant natural gas exchange in Europe. It is utilized in literature as the relevant natural gas price for Spain (Petersen et al., 2024). Spanish and French natural gas exchanges are considered to be immature in many dimensions (Heather, 2023, 2020, 2015). The TTF is thus a good proxy for the natural gas prices Spanish and French generators are facing. The index is in Euros per megawatt hour. Note that my period of analysis is not affected by the impact of increased LNG imports, which became important after Russian invasion of Ukraine in 2022.

The ticker for the European Energy Exchange (EEX) PEGAS exchange day-ahead natural gas price index is *EEDATTF1.* The index based on the day-ahead natural gas price for contracts for physical delivery through the transfer of rights in respect of natural gas at the Title Transfer Facility (TTF) Virtual Trading Point, operated by Gasunie Transport Services (GTS), the natural gas transmission system operator in the Netherlands. For days when I do not observe the index, I use the Bloomberg OECM Index for day-ahead TTF natural gas price, ticker TTFGDAHD. In cases when I observe neither index, I linearly interpolate for the price.

I utilize the Bloomberg OECM API2 month ahead coal price index to proxy for coal prices, which is based on the Argus/McCloskey's Coal API2 Price Index, the primary price reference for physical and over-the-counter coal contracts in northwest Europe. I use the settlement price, in Euros per metric ton, for a particular day as the relevant price. The ticker for the Bloomberg OECM API2 month ahead coal price index is API21MON. The index represents the price of a 1 month ahead future coal contract, that is for coal delivered in the next calendar month. The index adjust for the fact that as the next calendar month nears the price for the calendar month after next becomes more relevant. In other words, on the 30th of August the price of a contract for delivery October might be more relevant than the price of a contract for delivery in September. The index is based on the Argus/McCloskey's Coal API2 Price Index, which is the primary price reference for physical and over-the-counter coal contracts in northwest Europe. It reflects the price of coal, including cost of insurance and freight (CIF), delivered into the Amsterdam, Rotterdam region in the Netherlands, and Antwerp region in Belgium. I use the settlement price, in Euros per metric ton, for a particular day as the relevant price. If the settlement price is missing, I use the last price index for a given day. When both price indexes are missing I linearly interpolate.

B Derivation of Upper Bound on Generator Profit Changes

Decomposing profit changes:

$$\begin{aligned}\Delta\pi_i &= q_{i,1}\left(p_{i,1}-p_{i,0}\right)+p_{i,0}\left(q_{i,1}-q_{i,0}\right)-C_i(q_{i,1})+C_i(q_{i,0})\\ &= q_{i,1}\left(p_{i,1}-p_{i,0}\right)-\int_{q_{i,0}}^{q_{i,1}} MC_i(q)-p_{i,0}dq\\ &= \Delta\pi_i^{UB}-\int_{q_{i,0}}^{q_{i,1}} MC_i(q)-p_{i,0}dq\end{aligned} \tag{17}$$

Now, for the importing area (Spain):

$$\begin{aligned}& q_{ES,1} < q_{ES,0} \implies\\ &\int_{q_{ES,0}}^{q_{ES,1}} \underbrace{MC_{ES}(q)-p_{ES,0}}_{<0\ \forall\ q<q_{ES,0}} dq > 0 \implies\\ &\Delta\pi_{ES} < \Delta\pi_{ES}^{UB}\end{aligned}$$

The area of the orange lined triangle in figure 3b, which is part of the change in profit for Spain but not of the upper bound, equals the negative value of the integral in equation (17). For the exporting area (France):

$$
\begin{aligned}
& q_{FR,1} > q_{FR,0} \implies \\
& \int_{q_{FR,0}}^{q_{FR,1}} \underbrace{MC_{FR}(q) - p_{FR,0}}_{>0 \ \forall \ q > q_{FR,0}} dq > 0 \implies \\
& \Delta\pi_{FR} < \Delta\pi_{FR}^{UB}
\end{aligned}
$$

The area of the blue lined triangle in figure 3b, which is part of the upper bound but not of the change in profit for France, equals the value of the integral in equation (17).

C Additional Summary Statistics

Table 10: Additional Summary Statistics for Flows

Variable	Time Period	Mean	Sd	Percentile					N
				1st	10th	50th	90th	99th	
Cross-border Flows [MWh]									
Calendar Year:									
$f_{ES,FR,t}$	*2014*	-383.22	856.93	-1,295.98	-1,200.40	-851.85	1,014.97	1,132.04	6,264
$f_{ES,FR,t}$	*2015*	-779.00	992.43	-2,698.72	-2,086.81	-1,004.26	967.14	1,478.40	6,264
$f_{ES,FR,t}$	*2016*	-756.02	1,742.58	-3,266.64	-2,640.54	-1,314.83	2,174.00	2,572.95	6,260
$\lvert f_{ES,FR,t}\rvert$	*2014*	877.67	332.84	52.84	277.03	990.75	1,200.67	1,296.87	6,264
$\lvert f_{ES,FR,t}\rvert$	*2015*	1,115.78	588.80	53.93	368.89	1,077.54	2,090.36	2,698.72	6,264
$\lvert f_{ES,FR,t}\rvert$	*2016*	1,727.26	790.15	28.43	534.28	1,841.22	2,650.74	3,266.64	6,260
Calendar Year × Pre/Post Expansion:									
$f_{ES,FR,t}$	*2015 Pre*	-584.78	794.86	-1,313.88	-1,216.06	-963.58	981.64	1,123.77	4,248
$f_{ES,FR,t}$	*2015 Post*	-1,861.82	1,133.56	-2,883.92	-2,644.77	-2,186.74	-242.48	1,943.41	1,008
$f_{ES,FR,t}$	*2016 Post*	-976.96	1,515.27	-2,813.65	-2,535.25	-1,490.19	1,756.79	2,471.15	4,751
$\lvert f_{ES,FR,t}\rvert$	*2015 Pre*	936.53	310.72	55.33	387.05	1,027.54	1,216.06	1,313.88	4,248
$\lvert f_{ES,FR,t}\rvert$	*2015 Post*	2,103.66	570.11	176.91	1,412.17	2,186.74	2,644.77	2,883.92	1,008
$\lvert f_{ES,FR,t}\rvert$	*2016 Post*	1,645.81	735.82	31.56	523.03	1,744.20	2,554.78	2,821.77	4,751

Data for 2014 is from IESOE, data from 2015 onward is from ENTSO-E Transparency. Observations are for weekdays at hourly level.
The time periods for Year × Pre/Post expansion are defined as: *2015 Pre* is 2015/01/01-2015/09/04 , *2015 Post* is 2015/11/04-2015/12/31 , *2016 Post* is 2016/01/01-2016/10/04
The time periods for Pre/Post expansion are defined as: *Pre* is 2015/01/01-2015/09/04, *Post* is 2015/11/04-2016/10/04

Table 11: Additional Summary Statistics for Prices

Variable	Time Period	Mean	Sd	Percentile					N
				1st	10th	50th	90th	99th	
Prices [EUR/MWh]									
Calendar Year:									
$p_{ES,t}$	*2014*	44.64	18.26	0	16.00	46.58	65.00	75.72	6,264
$p_{ES,t}$	*2015*	52.75	11.45	21.00	37.70	54.16	65.75	71.89	6,264
$p_{ES,t}$	*2016*	41.90	13.99	9.00	23.48	42.00	63.00	71.49	6,264
$p_{FR,t}$	*2014*	38.11	13.48	9.19	19.90	38.51	54.76	69.44	6,264
$p_{FR,t}$	*2015*	41.58	12.37	14.26	25.07	41.98	56.19	70.99	6,216
$p_{FR,t}$	*2016*	40.07	26.84	11.82	22.15	34.50	67.01	102.53	6,264
Calendar Year × Pre/Post Expansion:									
$p_{ES,t}$	*2015 Pre*	52.49	11.94	20.00	36.59	53.75	66.60	71.66	4,248
$p_{ES,t}$	*2015 Post*	54.95	10.94	26.02	39.27	57.00	66.72	73.91	1,008
$p_{ES,t}$	*2016 Post*	36.41	10.34	8.00	21.50	38.01	47.69	56.10	4,752
$p_{FR,t}$	*2015 Pre*	41.07	12.05	15.01	24.94	41.60	55.47	69.94	4,200
$p_{FR,t}$	*2015 Post*	40.91	14.49	9.47	23.00	40.38	58.94	76.92	1,008
$p_{FR,t}$	*2016 Post*	31.84	9.53	10.17	21.19	31.55	44.02	55.78	4,752
Price Differences [EUR/MWh]									
Calendar Year:									
$p_{FR,t} - p_{ES,t}$	*2014*	-6.53	19.22	-38.55	-28.90	-8.56	19.51	49.43	6,264
$p_{FR,t} - p_{ES,t}$	*2015*	-11.19	13.40	-36.46	-27.35	-12.44	4.47	23.30	6,216
$p_{FR,t} - p_{ES,t}$	*2016*	-1.83	21.84	-24.08	-15.08	0	8.31	40.94	6,264
$\|p_{FR,t} - p_{ES,t}\|$	*2014*	16.28	12.12	0	1.03	15.30	32.03	49.97	6,264
$\|p_{FR,t} - p_{ES,t}\|$	*2015*	14.11	10.27	0	0	14.27	27.57	37.35	6,216
$\|p_{FR,t} - p_{ES,t}\|$	*2016*	7.85	20.46	0	0	4.98	17.72	40.94	6,264
Calendar Year × Pre/Post Expansion:									
$p_{FR,t} - p_{ES,t}$	*2015 Pre*	-11.44	14.30	-37.40	-27.94	-14.02	7.25	24.63	4,200
$p_{FR,t} - p_{ES,t}$	*2015 Post*	-14.05	11.46	-34.96	-26.98	-15.53	0	13.79	1,008
$p_{FR,t} - p_{ES,t}$	*2016 Post*	-4.57	8.49	-24.26	-15.86	-2.68	3.70	18.34	4,752
$\|p_{FR,t} - p_{ES,t}\|$	*2015 Pre*	15.15	10.29	0	0	15.84	28.23	37.76	4,200
$\|p_{FR,t} - p_{ES,t}\|$	*2015 Post*	15.01	10.16	0	0	15.88	27.34	35.92	1,008
$\|p_{FR,t} - p_{ES,t}\|$	*2016 Post*	6.77	6.87	0	0	5.35	16.45	25.29	4,752

Data for 2014 is from IESOE, data from 2015 onward is from ENTSO-E Transparency. Observations are for weekdays at hourly level.
The time periods for Year × Pre/Post expansion are defined as: *2015 Pre* is 2015/01/01-2015/09/04 , *2015 Post* is 2015/11/04-2015/12/31 , *2016 Post* is 2016/01/01-2016/10/04
The time periods for Pre/Post expansion are defined as: *Pre* is 2015/01/01-2015/09/04, *Post* is 2015/11/04-2016/10/04
The significantly higher means than medians in 2016 for variables including French prices are due to a handful of hours with very high prices in France in late 2016.

Table 12: Calendar Year × Pre/Post Summary Statistics for Direction of Flows and Prices

Time Period	Mean			
	$\mathbb{1}$ (Prices Converged)	$\mathbb{1}$ (FR Cheaper)	$\mathbb{1}$ (Flow to ES)	$\mathbb{1}$ (Directions Aligned)
Calendar Year × Pre/Post Expansion:				
2015 Pre	0.114	0.72	0.78	0.99
2015 Post	0.137	0.82	0.91	1.00
2016 Post	0.291	0.57	0.76	0.99

Data for 2014 is from IESOE, data from 2015 onward is from ENTSO-E Transparency. Observations are for weekdays at hourly level.

I define the columns as $\mathbb{1}\,(\text{Prices Converged}) \equiv \mathbb{1}\left(|p_{FR,t} - p_{ES,t}| < 0.01\right)$, $\mathbb{1}\,(\text{FR Cheaper}) \equiv \mathbb{1}\left(p_{FR,t} - p_{ES,t} < -0.01\right)$, $\mathbb{1}\,(\text{Flow to ES}) \equiv \mathbb{1}\left(f_{ES,FR,t} < 0\right)$, and $\mathbb{1}\,(\text{Directions Aligned}) \equiv \mathbb{1}\left(|p_{FR,t} - p_{ES,t}| < 0.01 \vee sqn\left(p_{FR,t} - p_{ES,t}\right) \equiv sgn\left(f_{ES,FR,t}\right)\right)$. That is the flow and price difference have the correct direction (or are aligned) when either the prices have converged, since then flow can go in either direction, or when the signs of flow and price difference are the same.

The time periods for Calendar Year × Pre/Post expansion are defined as: *2015 Pre* is 2015/01/01-2015/09/04 , *2015 Post* is 2015/11/04-2015/12/31 , *2016 Post* is 2016/01/01-2016/10/04

The time periods for Pre/Post expansion are defined as: *Pre* is 2015/01/01-2015/09/04, *Post* is 2015/11/04-2016/10/04

D Additional Results for Welfare Distribution

Table 13: Effects on Congestion Revenue

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Dependent Variable	$(p_{FR,t} - p_{ES,t}) \times f_{ES,FR,t}$					
$\mathbb{1}\,(t \geq \text{2015-10-05})$	6,921.0	16,177.3***	5,893.2	12,199.6***	5,832.0	10,264.4***
	(5,029.4)	(5,284.3)	(3,806.2)	(2,946.9)	(3,736.7)	(2,864.7)
Observations	6,126	5,126	9,264	8,264	10,837	9,837
Adjusted R^2	0.376	0.417	0.295	0.333	0.292	0.328
Within Adjusted R^2	0.360	0.401	0.282	0.321	0.271	0.308

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

Table 14: Effects on Buyer Expenditures in Spain

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Panel A - Nominal Changes						
Dependent Variable			$p_{ES,t} \times d_{ES,t}$			
$\mathbb{1}\,(t \geq \text{2015-10-05})$	93,458.9	287,521.9***	-14,795.9	22,721.8	-43,915.3	-46,321.0
	(69,619.9)	(89,882.8)	(75,908.7)	(121,798.4)	(77,570.8)	(126,496.3)
Observations	6,179	5,171	9,364	8,356	10,984	9,976
Adjusted R^2	0.838	0.852	0.799	0.801	0.774	0.771
Within Adjusted R^2	0.720	0.757	0.680	0.692	0.633	0.639
Panel B - Relative Changes						
Dependent Variable			$\log(p_{ES,t} \times d_{ES,t})$			
$\mathbb{1}\,(t \geq \text{2015-10-05})$	0.0087	0.0580	-0.0032	-0.0011	-0.0206	-0.0408
	(0.0548)	(0.1015)	(0.0624)	(0.1078)	(0.0638)	(0.1058)
Observations	6,179	5,171	9,364	8,356	10,984	9,976
Adjusted R^2	0.787	0.793	0.758	0.757	0.740	0.738
Within Adjusted R^2	0.654	0.675	0.613	0.620	0.577	0.582

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

Table 15: Effects on Buyer Expenditures in France

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Panel A - Nominal Changes						
Dependent Variable	$p_{FR,t} \times d_{FR,t}$					
$\mathbb{1}\,(t \geq$ 2015-10-05)	714,404.1***	1,016,745.3***	629,673.0***	696,353.9***	552,196.9***	566,726.2***
	(168,488.1)	(188,720.5)	(117,093.3)	(143,417.8)	(127,417.7)	(149,518.2)
Observations	6,189	5,182	9,381	8,374	10,957	9,950
Adjusted R^2	0.726	0.719	0.801	0.803	0.795	0.798
Within Adjusted R^2	0.566	0.573	0.723	0.734	0.715	0.726
Panel B - Relative Changes						
Dependent Variable	$\log\left(p_{FR,t} \times d_{FR,t}\right)$					
$\mathbb{1}\,(t \geq$ 2015-10-05)	0.3619***	0.5103***	0.3190***	0.3518***	0.2809***	0.2859***
	(0.0847)	(0.0737)	(0.0570)	(0.0594)	(0.0647)	(0.0670)
Observations	6,189	5,182	9,381	8,374	10,957	9,950
Adjusted R^2	0.735	0.735	0.795	0.799	0.788	0.794
Within Adjusted R^2	0.502	0.517	0.674	0.690	0.655	0.673

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

Table 16: Additional Results for Effects on Generation Quantities

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Panel A - Spain						
Dependent Variable	$q_{ES,t}$ [MWh]					
$\mathbb{1}\,(t \geq$ 2015-10-05)	-2,981.2***	-3,183.4***	-943.4	-1,299.9*	-1,106.4*	-1,354.2**
	(732.4)	(859.0)	(652.4)	(737.9)	(612.2)	(688.4)
$d_{ES,t}$	0.8854***	0.9216***	0.9060***	0.9139***	0.9026***	0.9125***
	(0.0458)	(0.0475)	(0.0288)	(0.0307)	(0.0255)	(0.0264)
$\mathbb{1}\,(t \geq$ 2015-10-05) $\times\, d_{ES,t}$	-0.0785*	-0.1084**	-0.0617**	-0.0657**	-0.0467*	-0.0466*
	(0.0463)	(0.0543)	(0.0286)	(0.0306)	(0.0247)	(0.0257)
$d_{FR,t}$	-0.0221	-0.0413*	0.0289**	0.0257*	0.0296**	0.0265**
	(0.0241)	(0.0249)	(0.0129)	(0.0141)	(0.0120)	(0.0131)
$\mathbb{1}\,(t \geq$ 2015-10-05) $\times\, d_{FR,t}$	0.1032***	0.1276***	0.0386**	0.0415**	0.0345**	0.0345**
	(0.0260)	(0.0308)	(0.0170)	(0.0178)	(0.0156)	(0.0161)
Observations	6,178	5,170	9,363	8,355	10,980	9,972
Adjusted R^2	0.941	0.940	0.942	0.941	0.945	0.944
Within Adjusted R^2	0.829	0.833	0.851	0.852	0.852	0.853
Panel B - France						
Dependent Variable	$q_{FR,t}$ [MWh]					
$\mathbb{1}\,(t \geq$ 2015-10-05)	-7,619.0***	-5,951.5***	-2,037.5	-1,428.6	-506.8	-109.5
	(1,559.0)	(1,594.9)	(1,380.0)	(1,617.1)	(1,567.2)	(1,674.9)
$d_{FR,t}$	0.6018***	0.6172***	0.9262***	0.9136***	0.8776***	0.8537***
	(0.0559)	(0.0538)	(0.0535)	(0.0505)	(0.0513)	(0.0497)
$\mathbb{1}\,(t \geq$ 2015-10-05) $\times\, d_{FR,t}$	0.2340***	0.1694***	-0.0594	-0.0820*	-0.0495	-0.0597
	(0.0676)	(0.0639)	(0.0455)	(0.0462)	(0.0406)	(0.0401)
$d_{ES,t}$	0.2891***	0.1919**	0.1565*	0.1299	0.1471	0.1154
	(0.0895)	(0.0913)	(0.0940)	(0.1129)	(0.1016)	(0.1116)
$\mathbb{1}\,(t \geq$ 2015-10-05) $\times\, d_{ES,t}$	-0.0681	0.0402	0.1888**	0.2278**	0.1154	0.1357
	(0.0886)	(0.0873)	(0.0899)	(0.0980)	(0.0832)	(0.0885)
Observations	6,178	5,171	9,365	8,358	10,978	9,971
Adjusted R^2	0.941	0.946	0.943	0.945	0.946	0.950
Within Adjusted R^2	0.925	0.933	0.931	0.934	0.936	0.942

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date.

Table 17: Effects on Generation Profits in Spain

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Nominal Profit Changes						
Panel A1 - Lower Bound						
Dependent Variable	$q^0_{ES,t} \times p_{ES,t}$					
$\mathbb{1}(t \geq \text{2015-10-05})$	126,177.8***	281,569.0***	109,957.9*	146,878.5	37,221.6	11,383.0
	(47,867.2)	(59,635.3)	(56,861.9)	(89,735.5)	(62,855.3)	(105,807.8)
Observations	6,178	5,170	9,363	8,355	10,980	9,972
Adjusted R^2	0.922	0.931	0.893	0.892	0.869	0.868
Within Adjusted R^2	0.874	0.894	0.833	0.836	0.792	0.795
Panel A2 - Upper Bound						
Dependent Variable	$q^1_{ES,t} \times p_{ES,t}$					
$\mathbb{1}(t \geq \text{2015-10-05})$	148,044.6***	329,000.1***	113,425.3*	150,617.7	40,462.7	14,162.5
	(54,970.3)	(70,694.1)	(58,037.1)	(92,251.0)	(64,357.3)	(108,322.0)
Observations	6,178	5,170	9,363	8,355	10,980	9,972
Adjusted R^2	0.914	0.921	0.891	0.890	0.867	0.866
Within Adjusted R^2	0.857	0.875	0.830	0.832	0.789	0.792
Relative Profit Changes						
Panel B1 - Lower Bound						
Dependent Variable	$\log\left(q^0_{ES,t} \times p_{ES,t}\right)$					
$\mathbb{1}(t \geq \text{2015-10-05})$	0.0578	0.0850	0.1034**	0.1082	0.0500	0.0133
	(0.0384)	(0.0746)	(0.0473)	(0.0775)	(0.0530)	(0.0853)
Observations	6,178	5,170	9,363	8,355	10,980	9,972
Adjusted R^2	0.866	0.872	0.831	0.830	0.815	0.816
Within Adjusted R^2	0.793	0.810	0.736	0.739	0.705	0.712
Panel B2 - Upper Bound						
Dependent Variable	$\log\left(q^1_{ES,t} \times p_{ES,t}\right)$					
$\mathbb{1}(t \geq \text{2015-10-05})$	0.0615	0.0931	0.1042**	0.1095	0.0508	0.0143
	(0.0381)	(0.0735)	(0.0472)	(0.0773)	(0.0529)	(0.0852)
Observations	6,178	5,170	9,363	8,355	10,980	9,972
Adjusted R^2	0.856	0.858	0.828	0.827	0.812	0.813
Within Adjusted R^2	0.773	0.786	0.732	0.735	0.701	0.708

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date. Counterfactual quantities used in the estimation and the impacts on profits are estimated on the same analysis sample.

Table 18: Effects on Generation Profits in France

	(1)	(2)	(3)	(4)	(5)	(6)
Sample Window	2015/04/08-2016/04/02		2015/01/04-2016/07/05		2015/01/01-2016/10/04	
Window Length	+/- 180 days		+/- 9 months		+/- $\approx$ 1 year	
Donut Window Days	0	+/- 30	0	+/- 30	0	+/- 30
Nominal Profit Changes						
Panel A1 - Lower Bound						
Dependent Variable	$q^0_{FR,t} \times p_{FR,t}$					
$\mathbb{1}(t \geq \text{2015-10-05})$	387,820.7**	559,579.3***	670,160.2***	738,939.6***	558,036.8***	552,234.5***
	(184,936.4)	(183,938.8)	(149,409.5)	(153,788.6)	(171,810.7)	(166,474.0)
Observations	6,178	5,171	9,365	8,358	10,941	9,934
Adjusted R^2	0.792	0.808	0.839	0.854	0.835	0.854
Within Adjusted R^2	0.645	0.685	0.774	0.800	0.770	0.801
Panel A2 - Upper Bound						
Dependent Variable	$q^1_{FR,t} \times p_{FR,t}$					
$\mathbb{1}(t \geq \text{2015-10-05})$	459,186.8**	659,485.1***	691,189.6***	762,056.9***	561,436.7***	555,985.1***
	(219,572.8)	(220,344.8)	(154,169.6)	(157,295.9)	(173,369.0)	(167,665.8)
Observations	6,178	5,171	9,365	8,358	10,941	9,934
Adjusted R^2	0.797	0.811	0.837	0.851	0.833	0.852
Within Adjusted R^2	0.660	0.692	0.766	0.793	0.764	0.795
Relative Profit Changes						
Panel B1 - Lower Bound						
Dependent Variable	$\log\left(q^0_{FR,t} \times p_{FR,t}\right)$					
$\mathbb{1}(t \geq \text{2015-10-05})$	0.1585*	0.2143**	0.2683***	0.2925***	0.2213***	0.2174***
	(0.0891)	(0.0865)	(0.0617)	(0.0546)	(0.0735)	(0.0625)
Observations	6,178	5,171	9,365	8,358	10,941	9,934
Adjusted R^2	0.784	0.807	0.825	0.843	0.823	0.846
Within Adjusted R^2	0.581	0.635	0.724	0.759	0.717	0.758
Panel B2 - Upper Bound						
Dependent Variable	$\log\left(q^1_{FR,t} \times p_{FR,t}\right)$					
$\mathbb{1}(t \geq \text{2015-10-05})$	0.1612*	0.2168**	0.2669***	0.2908***	0.2205***	0.2164***
	(0.0893)	(0.0862)	(0.0616)	(0.0545)	(0.0735)	(0.0624)
Observations	6,178	5,171	9,365	8,358	10,941	9,934
Adjusted R^2	0.789	0.811	0.823	0.841	0.821	0.844
Within Adjusted R^2	0.595	0.642	0.715	0.749	0.710	0.751

Significance Codes: ***: 0.01, **: 0.05, *: 0.1 . Observations are at hourly level.
Driscoll-Kraay HAC corrected standard errors with 6 daily lags are in parentheses. Sample Window is the time span of the analysis sample. Window Length is the approximate length of the sample window on each side of treatment date (2015/10/05). For results in columns 5 and 6, the sample goes 9 months before, and 1 year after treatment. Donut Window Days stands for the number of days excluded from the analysis sample on each side of the treatment date. Counterfactual quantities used in the estimation and the impacts on profits are estimated on the same analysis sample.