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The Iberian Exception: what was the cost of distorting electricity markets during the 2021-23 European energy crisis?

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Abstract

European wholesale power prices increased to an unprecedented level during the energy crisis in 2022. To tackle the adverse impact on consumers, Spain and Portugal implemented the Iberian Exception (IE) in June 2022, intending to decouple power prices from the rest of Europe to reduce consumer energy bills.

The IE posed challenges and questions, including the impact of foreign demand for Spanish electricity, whether the policy would subsidise French power prices, and whether it would reduce energy bills for consumers. Given that this was a policy implemented in the middle of a continental gas supply crisis, we focus on the direct impact of the policy on gas demand in Spain and in Europe. This is interesting because other aspects of the IE – such as reducing consumer bills - could have been, and in other countries were, addressed by other policies. The 'exception' was allowed by the European Commission (on behalf of the EU27) because it was deemed to be likely to have a limited pan-European impact on electricity prices. By contrast, Spain competes directly with other European countries for LNG supplies on the global gas market and hence large effects in Spain would necessarily spillover to gas prices in the rest of Europe.

Our findings suggested that IE successfully lowered the fossil fuel bids with a secondary effect of decoupling the Spanish power markets from France. Decoupled observations increased by +59.2% compared with our reference period. Even the border between Spain and Portugal was decoupled slightly by +0.9%. Daily net outflow to France increased by 2.3 GWh daily. Daily net outflow to Morocco increased 32 times, and outflow to Andorra increased by 25%. The power outflow increased the domestic electricity price by 24.8%, relative to the effect in the absence of interconnection.

We also simulated the counterfactual scenario by investigating wholesale electricity prices without the subsidy paid to gas generators. Our demand and supply adjustment scenario shows that the subsidy reduced Iberian electricity day-ahead prices by 35.3%. The model was further used to compare the gas-fired generation between June 2022 and February 2023, when the gas price was above the gas cap. Depending on the scenarios, IE increased the Iberian gas burnt by 19.2%; On the EU level, gas burnt also increased by 1.3%. The total Iberian foreign demand also increased gas for power burnt by +5.47% in Iberia (+0.81% across the EU), relative to the effect in the absence of interconnection.

Keywords Iberian Exception, energy crisis, gas price cap, electricity market

JEL Classification L94

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The Iberian Exception: what was the cost of distorting electricity markets during the 2021-23 European energy crisis?[1]

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1. Introduction

Europe was facing a severe energy crisis from 2021-23 (Pollitt et al., 2024). A rapid recovery from the COVID-19 pandemic, the Invasion of Ukraine, outages of the French nuclear plants, and the worst drought in Europe for the past 500 years caused significant shortages in natural gas and electricity while generation fell below sessional averages.[3]

In response to the spike in energy prices causing adverse consequences to Iberian households and businesses, the Spanish government proposed the Iberian Exception (IE) to the European Commission in March 2022 to curb inflation. The proposal was granted by the European Commission in May 2022 and is called an exception as it only applied to the Iberian Peninsula but not to the rest of the European Union (EU). The IE was implemented on 15 June 2022 for one year and extended to the end of 2023.

The IE, also known as the adjustment mechanism or "gas cap", worked by lowering the input cost of fossil-fired power plants in Iberia, ultimately lowering the wholesale electricity price. These power plants received a subsidy, mainly financed by Iberian consumers and partially by the congestion income between Spain and France. This

[1] The authors wish to thank Natalia Fabra for very helpful comments on an earlier draft. All errors are their own.
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[3] https://www.copernicus.eu/en/news/news/observer-2022-year-extremes

adjustment mechanism applied only to fossil fuel generation but not direct gas consumption.

The adverse impact of IE was not been assessed officially by the Spanish National Markets and Competition Commission (CNMC). Robinson et al. (2023) suggested that the Spanish ministry might have overstated the benefit to consumers, such as not considering the increase in Spanish French border flows, which ultimately will increase demand and limit the success of IE. We will extend the analysis from Robinson et al. (2023) on the impact on IE. While there is limited research on the impact of IE from the CNMC, the Royal decree-law and the Spanish electricity market operator have some methodology and market data that allow us to quantify some of the impacts.

Given that this was a policy implemented in the middle of a continental gas supply crisis, we focus on the direct impact of the policy on gas demand in Spain and in Europe. This is interesting because other aspects of the IE – such as reducing consumer bills - could have been, and in other countries were, addressed by other policies. The 'exception' was allowed because it was deemed to be likely to have limited pan-European impact on electricity prices. By contrast, Spain competes directly with other European countries for LNG supplies on the global gas market and hence large effects in Spain do necessarily spillover to gas prices in the rest of Europe.

This paper has eight sections. Section 2 will discuss the fundamentals of the European power markets and relevant energy economics. Section 3 carries out a literature review on the energy crisis and the relationship between gas and power and policy interventions. Section 4 explains how the IE worked and its potential impact on demand, supply and flows. Section 5 states our hypotheses so we can deductively prove or reject them through our empirical study of the Iberian power markets. Section 6 presents our results and findings and discusses their impact. Section 7 makes suggestions for further research. Finally, in Section 8 we present a conclusion.

2. Fundamentals of the Iberian Electricity Markets

The European electricity sector was highly regulated and vertically integrated in the 1990s. Utilities owned generation, transmission, and distribution infrastructure and provided retail services to consumers. They could determine electricity prices without competition. The ownership of the infrastructure created a monopoly and stopped new players from entering the sector.

By 1996, the EU started to liberalise the electricity sector to create a single integrated internal European electricity market across the EU (Pollitt, 2019). This deregulation opened up free competition, reduced overall costs and encouraged specialisation in generation and retail. Over time a genuinely integrated set of day-head wholesale electricity markets emerged across most of the EU. The EUPHEMIA algorithm couples individual wholesale markets such that a single wholesale electricity price can occur across most of Europe in the absence of transmission constraints. If transmission constraints do bind, then zonal prices emerge to reflect supply and demand within the zone, taking into account the flow on the interconnectors. One of the participating markets in EUPHEMIA is the MIBEL market which covers Portugal and Spain.

2.1 The Iberian Electricity Market

Mercado Ibérico de Electricidade (MIBEL) represents the integration of the Spanish and Portuguese electricity systems since 1 July 2007. The convergence of the electricity markets leads to both countries sharing the same legal, economic and energy framework. The OMI Polo Español S.A. (OMIE) is the nominated electricity market operator (NEMO) for the Iberian Peninsula. NEMOs are designated by the European Member States to run the integrated electricity markets. Electricity is considered a good (Cramton, 2017) and is traded on an open exchange.

2.2 Iberian Electricity Day-ahead Market

The daily day-ahead market matches the supply and demand between generators and consumers. The auction is held at 12pm CET for the next day's electricity consumption. Buyers and sellers are matched when the auction is finished.

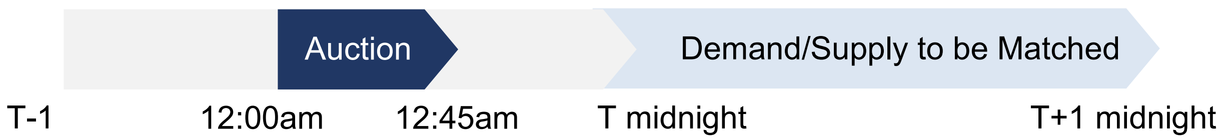


Figure 1: Electricity day-ahead market timeline (CET)

We mainly focus on the electricity day-ahead markets as the NEMOs run the EUPHEMIA algorithm to calculate the market clearing price for each bidding zone and flow between the zones. EUPHEMIA maximises the overall welfare between consumers and producers and ensures efficient capacity allocation. The day-ahead markets thus allow us to quantify the amount of power flow to Morocco and France, and the impact on the Iberian electricity demand curve due to foreign demand from surrounding bidding zones. Actual on the day flows will be different, but not systematically so.

After the day-ahead daily auction, intraday markets (initially six changed to three auctions in June 2024) allow power plants and demand portfolios to adjust production and consumption. There are complex trading rules and restrictions across all these markets, but for simplicity, we assume that the initial supply and demand on the day-ahead curves give the price.

2.3 Demand, Supply Curves and Interconnectors

Demand curves consist of consumers from households, businesses and industry. Demand is seasonal and tends to be lower during the weekend and holiday seasons. It tends to be higher in the winter across all European countries, although heating demand in the summer also has significant impacts on the power systems.

The Iberian generator supply stack comprises renewables, fossil fuels and nuclear. Between January 2020 and December 2023, 50% of Spanish generation came from renewables, 25% from gas, 22% from nuclear, and 3% from coal or oil. In contrast, 57% of Portuguese generation came from renewables, 41% from gas, and 2% from coal or oil. Inframarginal plants such as renewables and nuclear run most of the time and are supposed to have zero or minimal marginal fuel cost. Other fuel technologies can be categorised into different levels, such as gas 1, 2 and 3, due to its efficiency in burning gas to turn the turbine.

By sorting the marginal price of supply bids in ascending order, demand and supply curves interact to obtain the auction result. The auction runs on an hourly granularity, and each hour has a corresponding pair of domestic demand and supply curves within a bidding zone:

$$Domestic\ Demand = Q^D(P) \tag{1}$$

and

$$Domestic\ Supply = Q^S(P) \tag{2}$$

The clearing price (*P*) and quantity (*Q*) are obtained when the demand and supply curves intersect. Quantity and price are matched in the auction:

$$Q^D(P) = Q^S(P) \tag{3}$$

Figure 2 illustrates the matching of 00:00-01:00 on 30 August 2022. The equilibrium price is at €200/MWh.

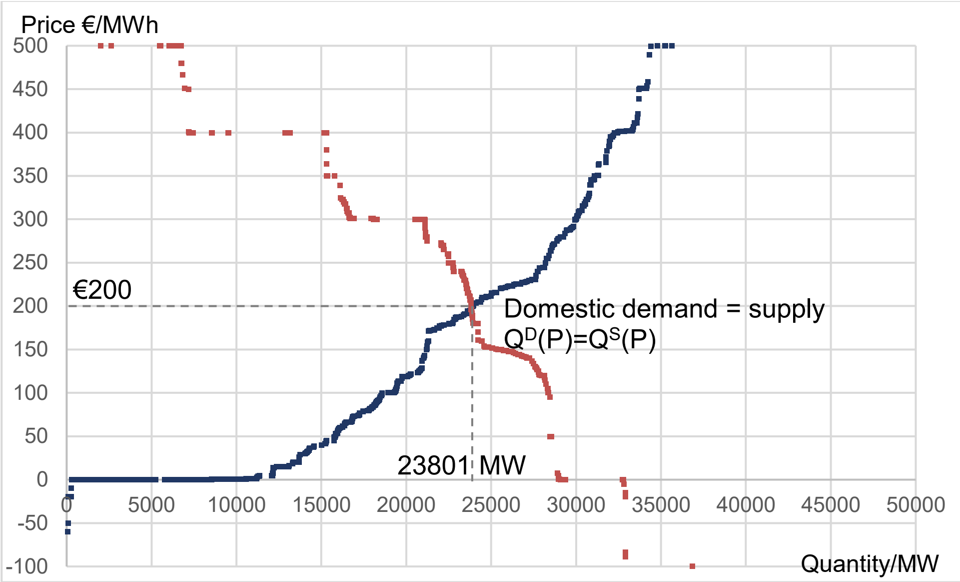


Figure 2: Domestic demand (downward sloping) and supply curve (upward sloping) for Iberian day-ahead electricity markets
(30/08/2022 00:00-01:00) (OMIE, 2023)

On the supply side, fixed costs generally include staffing and labour, routine maintenance, environmental compliance and monitoring, and insurance overhead. Variable costs include fuel handling (receiving, storing, and transporting fuel), waste disposal, such as combustion residuals, and equipment wear and tear. Plants may also incur costs for advanced technology and depreciation. Cold-starting a plant may also require substantial start-up costs. The supply bid has to consider all these costs and the marginal fuel cost.

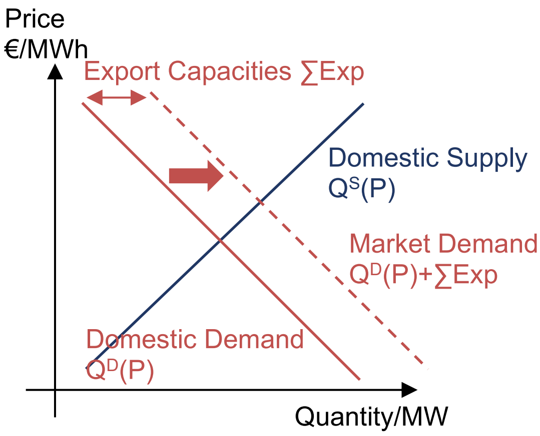
Depending on the direction of the border flow, either the demand curve is shifted for export or the supply curve shifted for import.
The flow direction depends on the price differentials between the two bidding zones. If Spain is cheaper than France, power flows from Spain to France, constituting additional demand in Spain and supply in France.
Figures 3 and 4 show the effect of export/import on the demand and supply curve. Any flows from the interconnector reflect foreign demand/supply within the bidding zone.

$$Market\ Demand = Domestic\ Demand + \Delta Foreign\ Demand = Q^D(P) + \sum Exp \quad (4)$$

and

$$Market\ Supply = Domestic\ Supply + \Delta Foreign\ Supply = Q^S(P) + \sum Imp \quad (5)$$

$$where\ Exp = Export, Imp = Import$$



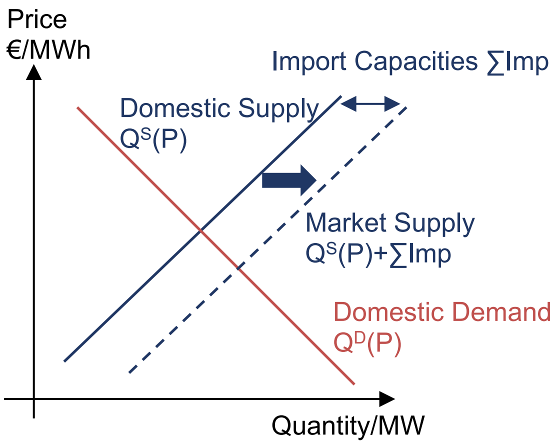


Figure 3 (left): Export capacity shifting domestic demand to market demand

Figure 4 (right): Import capacity shifting the domestic supply curve to market supply

Figure 5 below shows the shifting export flow within the Iberian day-ahead market for 00:00-01:00 on 30 August 2022. The intersection between the market demand and supply curve is the day-ahead price. There is no import flow (no shift of the blue line) as the hour is net export to France.

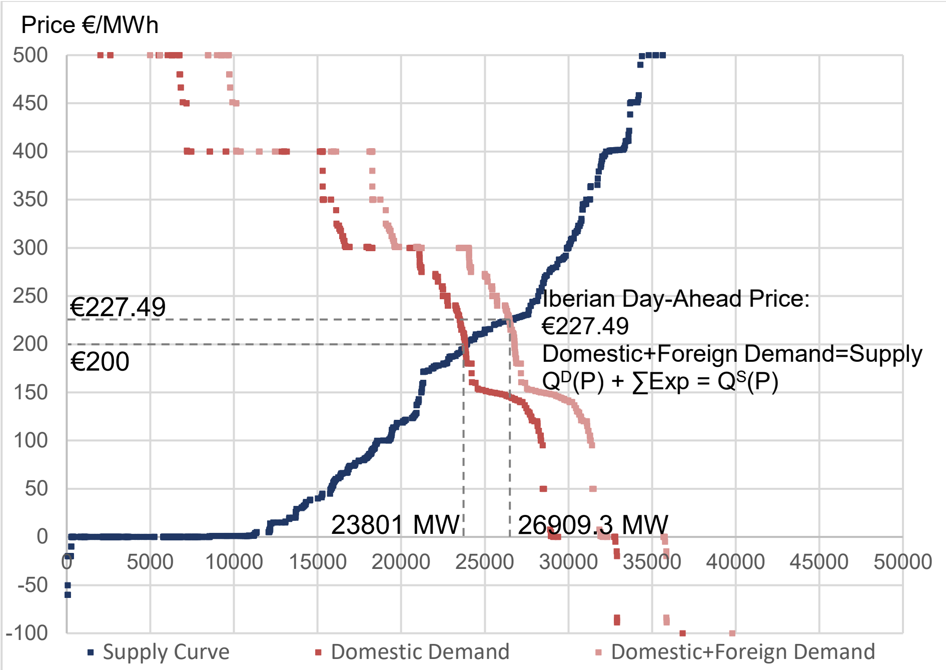


Figure 5: Domestic and foreign demand and supply curve for Iberian day-ahead electricity markets (30/08/2022 00:00-01:00) (OMIE, 2023)

Spain and Portugal have only one bidding zone each, namely in the territories served by Red Eléctrica (REE) and Redes Energéticas Nacionais (REN). Transmission capacities between REE and REN are abundant, where Spain to Portugal has a maximum transfer of 4.2 GW capacity, and Portugal to Spain has 3.5 GW transfer capacity. With 8 GW of peak demand, 5.4 GW wind and 8.2 GW hydro installed capacity, Portugal is generally self-sufficient but may need to import from Spain when renewable generation is low. Hence, we consider Iberia as one zone as they are usually coupled.

If there is no congestion between two bidding zones, for example, Spain and France, import or export capacities will not be exhausted, then we can expect the day-ahead price between the two bidding zones to be the same; hence, the markets are coupled. Otherwise, if the available capacities cannot resolve the congestion and the import or export capacities are all occupied, the two markets are decoupled.

3. Literature Review and Backdrop to the IE

3.1 Energy Crisis

European energy prices surged to an unprecedented level in 2022. The EU imported 83% of its natural gas, of which nearly 50% was supplied by Russia before 2021 (European Council, 2023). Since mid-2021, Russian utility Gazprom has not refilled its European gas storages (Jirusek, 2023). The supply was further manipulated when the Russian gas supply dropped nearly 80% by September 2022 (Heussaff et al., 2022). Europe experienced drought between 2021 and 2022, resulting in less hydro and nuclear power being produced. With a significant supply reduction, consumers were severely impacted when prices spiked by five to fifteen-fold in 2022.

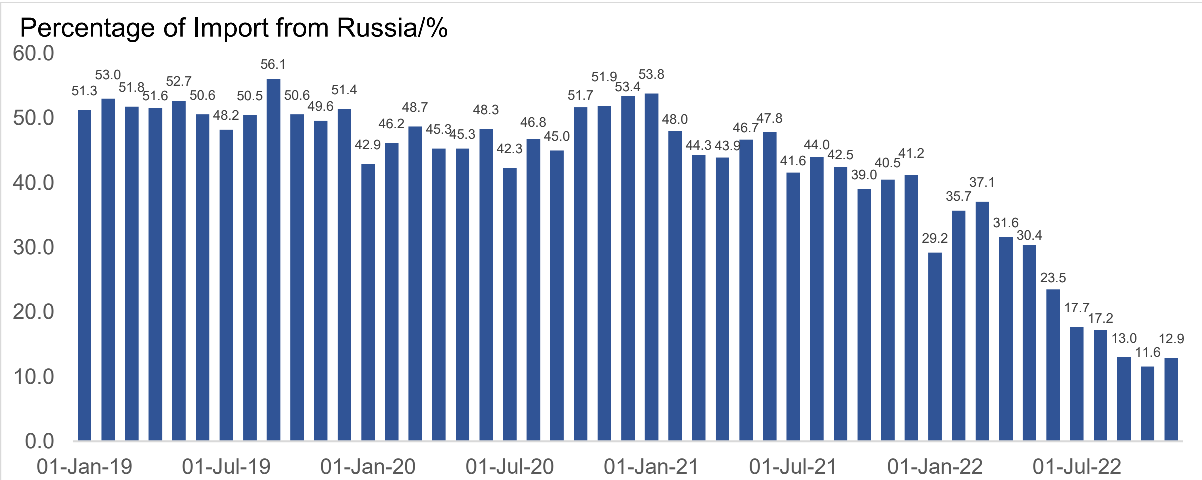


Figure 6: Percentage of EU gas import from Russian (European Council, 2023)

3.2 Relationship between gas and electricity

While households and industrials consume gas directly, power generators can also use gas to generate electricity for a profit. The relationship between gas, electricity and emissions is dictated by the spark spreads. These measure the profitability of a gas plant, and the clean spark spread includes the cost of emissions.

$$Spark\ Spread = Price_{Electricity} - Price_{Gas} \times Heat\ Rate \tag{6}$$

$$Clean\ Spark\ Spread = Spark\ Spread - (Price_{Carbon} \times Emissions\ Intensity) \tag{7}$$

When gas prices increase, electricity prices have to increase to maintain a positive or zero spark spread; otherwise, the gas plants will be switched off as the sale of electricity is not profitable

Any negative supply shock, especially from gas, will have a direct impact on electricity prices due to the direct correlation between gas and electricity prices.

Without policy intervention, less hydro and nuclear generation in Europe and a spike in gas prices created a negative supply shock in the Iberian electricity markets. The cut-off of Russian gas created a negative supply shock, shifting the supply curve as there is less supply available (Perkins and Rainaut, 2023).

Prices balance the equilibrium of demand and supply. Short-term supply is relatively inelastic as it takes 4 to 8 years to build an onshore wind farm (Iberdrola, n.d.), although, in the long run, supply is generally much more elastic.

Spanish and Portuguese inflation rates peaked at 10.7% and 10.6% by July and October 2022 (Gonzalez, 2022). High electricity and gas prices have a dramatic impact on consumers' disposable income, especially on poor households, as their spending on energy bills is greater in proportion than that of affluent households (Perkins and Rainaut, 2023). Housing, water, electricity, gas, and other fuels represented 14.2% of the total CPI weight in 2022 (INE, 2024). A higher Spanish CPI means the Spanish government cannot meet its inflation target while increasing government spending and distorting price levels and long-term macroeconomic goals.

3.3 Policy Interventions

The adverse impact on households and businesses from inflation increases governments’ concern. Several short and long-term interventions were suggested across the EU.

The first price cap introduced was the IE, also called the Adjustment Mechanism. It was proposed by the Spanish government in March 2022 and implemented in Iberia on 15 June 2022. It works by offering subsidies to gas generators with a cap on the Spanish gas price at €40/MWh, thus bringing down the marginal price of the gas generators. The gas cap gradually increases by €5/MWh every month from 1 January 2023 until 30 March 2023 and increases by €1.1/MWh every month from 1 April 2023 onwards and was terminated by 31 December 2023. As the Spanish gas generator stack represents 26% of generation between 2020 and 2023, bringing down the margin fuel price was expected to significantly lower the day-ahead spot price. The IE was supposed to cover both Spain and Portugal, although we understand that the Spanish decree law 10/2022 is significantly more detailed when compared with the Portuguese decree law 33/2022. We will investigate the differences between the two countries in sections 5 and 6 below.

As the mechanism is locally applied to Iberia, it may lead to the export of subsidised electricity to countries who don't pay the subsidy (Heussaff et al., 2022). Robinson (2023) also suggested an increasing flow from Spain to France when the IE was implemented. Heussaff et al. (2022) argued that the same policy could have been implemented across the whole EU, but it would also subsidise non-EU countries such as the UK, which is politically unacceptable. IE also increases gas demand as more gas is burnt to produce electricity by gas plants (Corbeau et al., 2023). Spanish consumers may not have an incentive to reduce power consumption as much as would otherwise be the case if their bills are lower (Corbeau et al., 2023). Industrial consumers who use gas primarily may find themselves subsidising electricity consumers. For instance, steel plants mainly use gas as a source of heat to melt pig iron into steel, and they may end up paying extra for their energy due to increased demand gas from power plants, which were incentivised to burn more gas as a result of IE. The external effect on the whole of Europe of the increase in gas demand in the Spanish generation sector could be significant, although we will be focusing on the supply stack in the electricity markets.

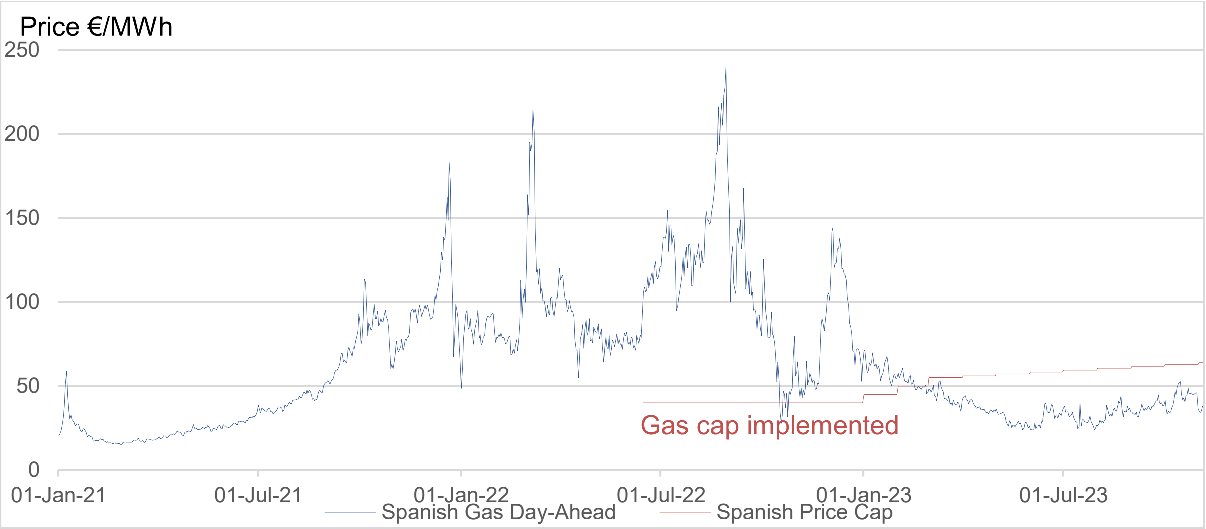


Figure 7: Spanish day-ahead gas price and price cap (MIBGAS, 2023)

A price cap – on gas prices – was suggested when the Title Transfer Facility (TTF) in Amsterdam increased to above €300/MWh by July 2022 (Europa, 2024). A price cap of €180/MWh was agreed by the European Council in December 2022. Gros (2023) argued that price caps subsidise consumption as savings in industry and household gas usage will be offset by an increase in usage for gas plants. The EU Price Cap was further proved to be meaningless as TTF prices dropped quickly after summer 2022 to €60-70/MWh. This was due to the weather being much warmer than expected (McWilliams et al., 2023), the return of French nuclear power plants and high gas saving behaviour by consumers. Thus this cap was never triggered[2].

A price cap on Russian gas was championed by European Commission president Ursula von der Leyen in September 2022. As the Russian gas supply was reduced by 80% in 2022, the impact of the policy was likely to be minimal (Heussaff et al., 2022). Russia might also have retaliated by cutting gas supply completely, which may have intensified the price spike (Heussaff et al., 2022).
Other interventions included revenue caps on renewable and nuclear plants. It was proposed in September 2022 that revenue above €180/MWh would be used to support vulnerable consumers (Europa, 2022). Fabra (2023) disagreed with the cap on the grounds that it was too high to stop inframarginal plants from generating windfall profit. Heussaff et al. (2022) also argued that countries like Poland have little inframarginal production and there would need to be revenue diversion from countries like Germany to revenue-poor countries. Italy implemented a two-way contract-for-difference price cap for power-to-industrials at €210/MWh in early 2023, but was not triggered (Cunnane, 2023). Further energy-saving rules were introduced by Germany where businesses should not open doors when air-conditioning or heating was switched on; Spain limited air-conditioning and heating temperature, and shops had to switch off lights overnight (Llach, 2022).

Before introducing the IE, Spain implemented a gas clawback mechanism of €67/MWh, in which emission-free plants with fixed-price power-purchasing-agreements must return 90% of windfall profit. However, plants awarded from auctions or fixed-price PPA signed before 31 March 2022 were out of scope. The subsequent introduction of the IE incrementally intervened on the supply side. The following section will discuss the impact on the domestic market and border flows, its calculation methods, where and how much consumers paid and who gets the most benefit.

4. Iberian Exception (IE)

4.1 Proposal Introduction

The proposal of IE was first sent by the Spanish government to the European Commission in March 2022 to reduce electricity prices as prices spiked to over €500/MWh after the Ukraine Invasion. Although the European electricity single market was promoted and harmonised from 1996 (Pollitt, 2019), Spain argued that they should be allowed to cap gas prices due to low reliance on Russian gas, and because there are limited interconnector flows to the rest of continental Europe. Due to the distinct pricing tariff in the Iberian Peninsula, it is argued to be an exception as it is different from other tariffs in the rest of Europe.

The Voluntary Price for Small Consumers (PVPC) for Spain before 31 December 2023 consists mainly of the average hourly price of day-ahead and intraday markets (Pmh, below). This was the default tariff which over 10 million residential consumers ended up with during the crisis. REE publishes the hourly price daily at 8:15 pm CET. Day-ahead/intraday prices are directly linked to the PVPC tariff.

$$CPh = Pmh + SAh + OCh \tag{8}$$

CPh: Cost of production to set the PVPC

Sah: Cost of system adjustment and services

OCh: Financing of the market and system operator, capacity mechanism and interruptible services

$$Pmh = \frac{PMDh \times EMDh + \sum_n (PMIh,n \times EMIh,n)}{EMDh + \sum_n EMIh,n} \tag{9}$$

PMDh: Marginal price in the day-ahead market

EMDh: Energy matched in the day-ahead market

PMIh,n: Marginal price in the intraday market with n session

EMIh,n: Energy matched in the intraday market with n session

This methodology exposed Spanish households to very high energy prices in contrast to other European countries where the default tariff is fixed for a multi-month period. Royal Decree 446/2023, dated 13 June 2023, subsequently modified the existing methodology to include forward signals from 2024 to reduce volatility.

Entidade Reguladora dos Serviços Energéticos (ERSE) set Portugal's electricity and gas tariffs. Spain's and Portugal's tariff calculations had subtle differences, as the energy cost calculation includes forward and spot (daily and intraday) prices. Due to the forward component, Portugal's electricity tariffs were less volatile.

As the Spanish electricity day-ahead prices are linked to the retail prices and the inflation index, it was hoped that lower day-ahead prices would reduce inflation. The IE was passed as law on 14 May 2022 (Decree-Law 33/2022). It was implemented on 15 June 2022 for 12 months and extended till December 2023. Affected consumers include PVPC tariffs, consumers with index contracts and wholesale/industrial/large-scale consumers with direct exposure.

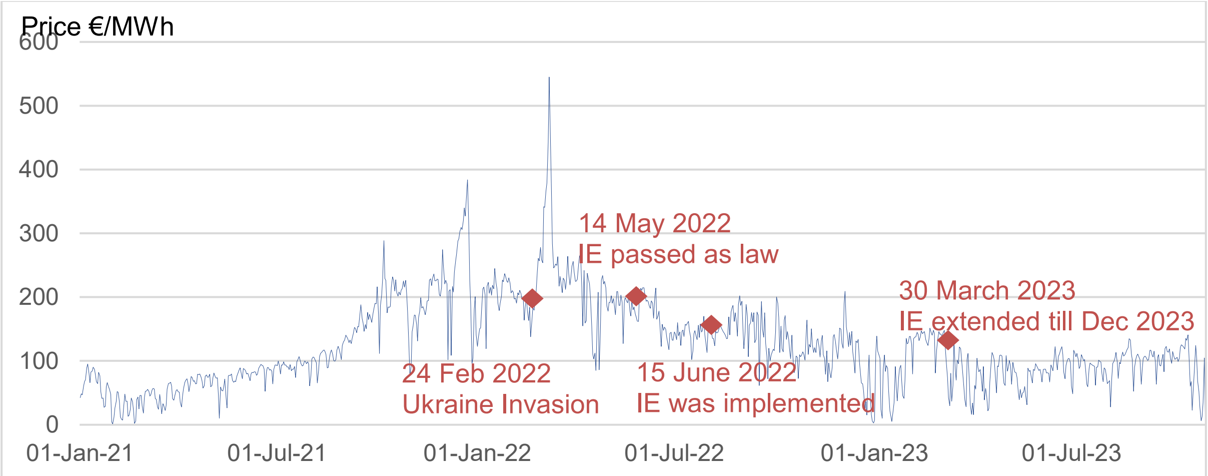


Figure 8: Spanish electricity prices history (OMIE, 2023)

Renewable and nuclear represent 72% of the supply in the Spanish fuel stack. The IE worked by offering subsidies to gas, coal and cogeneration plants as they tend to set the marginal clearing price in the daily auctions. The mechanism was triggered only when the Spanish gas prices exceeded the price cap.

Figure 9 illustrates the impact of the subsidy on the gas plants' supply curve. As the market equilibrium moves from A to B, gas generation should increase from Q_1 to Q_2. However, the difference in market price (P_1 minus P_2) is always smaller than the subsidy paid to gas generators (P_1 minus P_3). B is the new exchange clearing price, and ΔQ_{gas} is the extra electricity generated from gas plants. Wind, solar, and nuclear plants have lower marginal costs than the gas stack; hence, gas plants tend to set the day-ahead price.

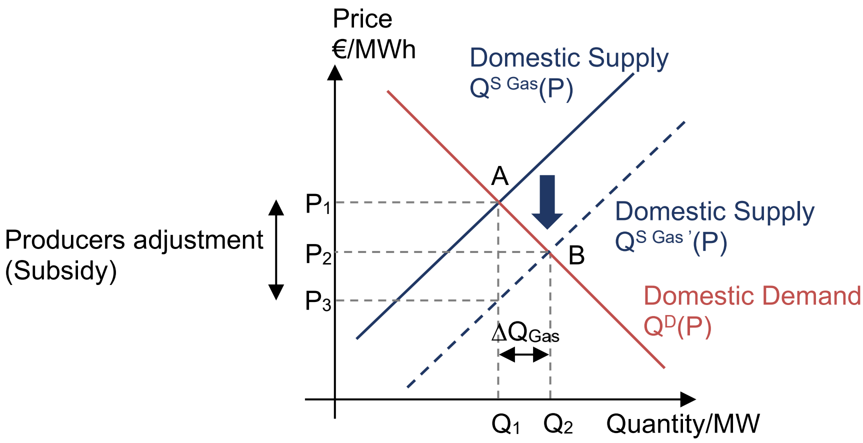


Figure 9: Producers adjustment (subsidy) paid to gas plants to lower exchange offers

4.2 Producers adjustment, congestion income and purchase unit adjustment

The hourly subsidy paid to generators is the *producer's adjustment*. The subsidy is financed mainly by the *purchase unit adjustment*, and partially by the *congestion* *income* obtained from the cross-border electricity trade between REE and RTE. The PVPC and free market consumers who renewed their contracts will share the purchase unit adjustment amount.

$$Purchase\ units\ adjustment\ amount = Producers\ adjustment - (Daily\ congestion\ income\ ES\ FR - Transmission\ rights\ cost) \quad (10)$$

$$Average\ adjustment\ price\ purchase\ units = \frac{Purchase\ units\ adjustment\ amount}{Total\ energy\ purchase\ units} \quad (11)$$

$$Consumer\ Price = DayAhead\ Spot\ Price + Average\ Adjustment\ Price\ Purchase\ Units \quad (12)$$

$$Daily\ Adjustment\ for\ Producer\ Y_i = \frac{P_{GN} - P_{RGN}}{0.55} \quad (13)$$

where Y_i €/MWh is the daily adjustment of production cost for thermal power and cogeneration plants
P_{GN} is the weighted average of daily and weekend gas transactions delivered on the virtual balance point at MIBGAS
P_{RGN} is the reference price cap starting at €40/MWh on 15 June 2022.
0.55 coefficient is the gas burnt efficiency of the representative gas plant

The affected consumer thus ends up paying the power price plus the adjustment amount. This adjustment mechanism will be applied to consumers with their electricity price pegged to the variable day-ahead electricity market or consumers who renewed their fixed-term contract after 26 April 2022 in Spain. Portugal has a slightly different arrangement. The Portuguese decree-law excluded consumers who extended their fixed-price contract from contributing to the IE, implying Spanish consumers paid €600 million more than their Portuguese counterparts (Peña, 2022).
Corbeau, Farfan and Orozco (2023) suggested that the consumer price under IE is lower than the counterfactual, although we believe this is worth further investigation. Figure 10 below shows the daily producers' adjustment (subsidy paid to gas producers) and purchase unit adjustment amount. At the peak of the energy crisis, a staggering €149 million/day was paid to subsidise gas plants on 31 August 2022. This represents a subsidy to intermediate use of gas during a gas supply crisis, which economic theory suggests is inefficient relative to a direct subsidy to support the impact on final consumers which would have economised the use of gas in the production of electricity.

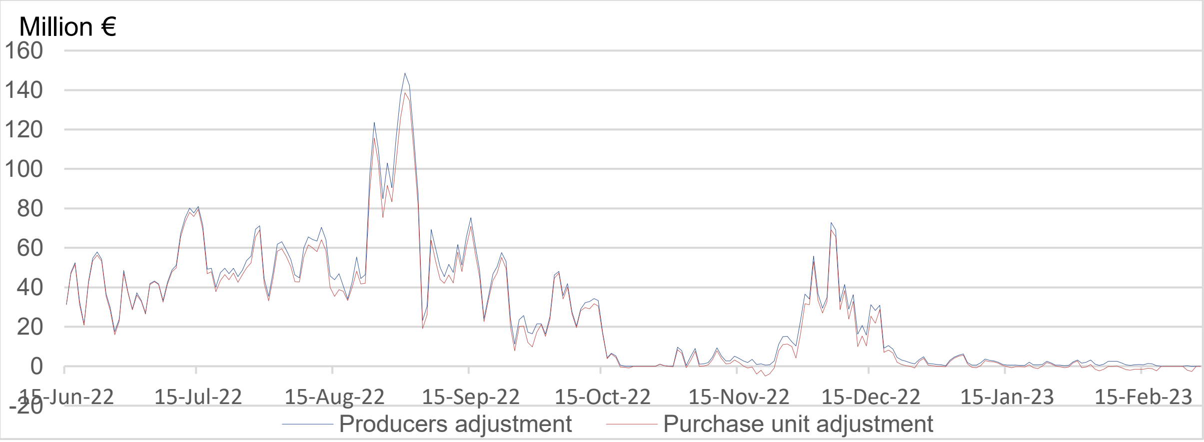


Figure 10: Daily producer adjustment and purchase unit adjustment (OMIE, 2024)

Since the implementation of the IE, a total €7.3 billion of subsidy has been paid to fossil generators, financed by €6.7 billion from the Iberian consumers and €0.6 billion from the Spanish-French transmission income, which is shared equally between REE and RTE. The gas price dropped below the price cap in February 2023; hence, there is no adjustment amount afterwards.

The difference between the producer adjustment and the purchase unit adjustment is the transmission income. The congestion income is relatively small when compared with the producer's adjustment.

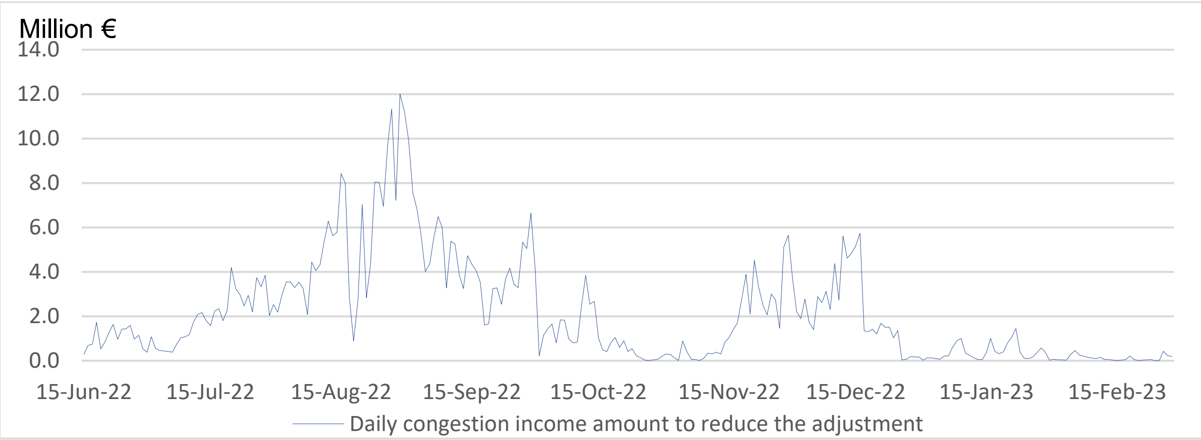


Figure 11: Daily transmission income to subsidise the IE (OMIE, 2024)

Figures 12 and 13 below show the proportion of daily Spanish demand contributing to the IE subsidy. In June 2022, the contribution came from about 55% of Spanish demand. The figure increased to 85% by February 2023.

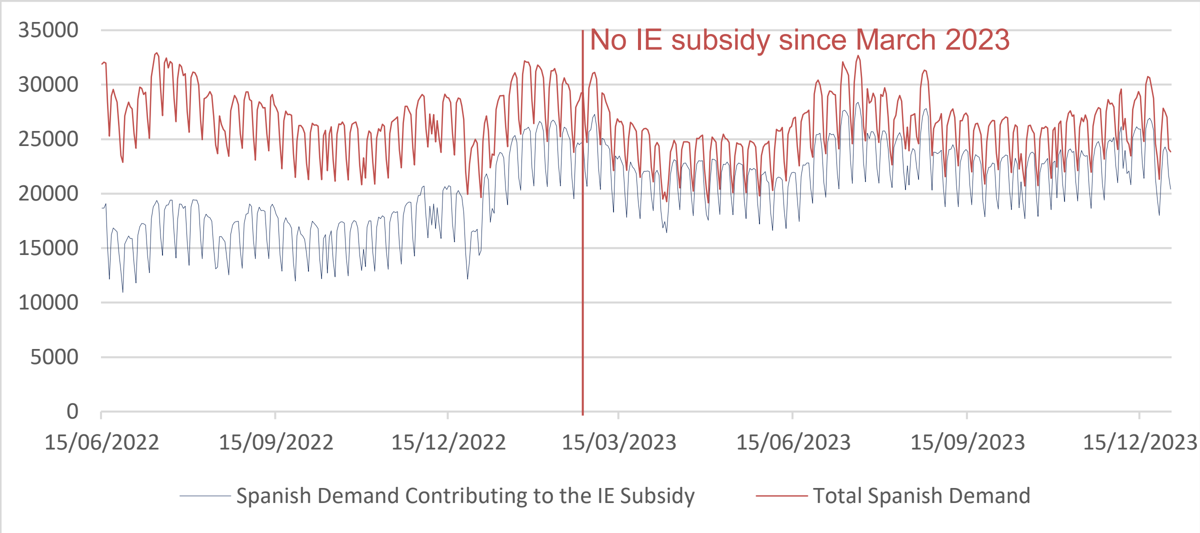


Figure 12: Daily Spanish Demand Contributing to the IE versus Total demand

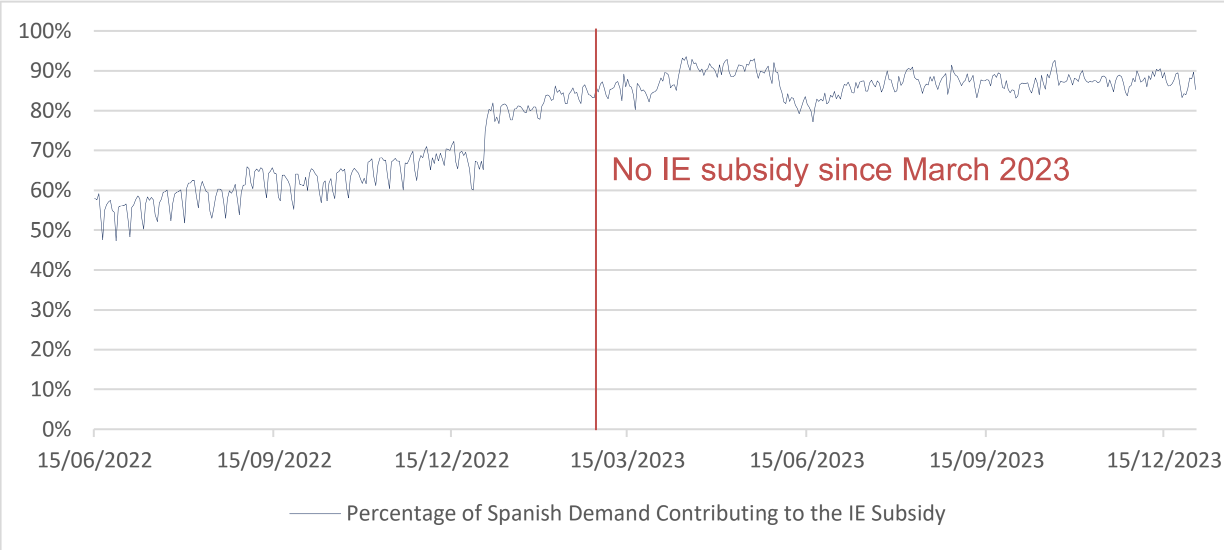


Figure 13: Percentage of Daily Spanish Demand Contributing to the IE

4.3 Implementation differences between Spain and Portugal

Both countries were supposed to follow the same methodology to subsidise their gas generators. As most of the adjustment mechanism is administered by OMIE, which is the Iberian market operator based in Madrid, Spain, it is likely that gas plants in both countries received the same treatment. However, it will be worth investigating if Portugal really kept running their plants as they could simply switch off their generators and buy low-cost electricity from Spain. We will investigate the flows and the market share of gas generation in both countries in sections 5 and 6.

4.4 Impact from Border Flows

European grids are highly interconnected. While Iberia is not as interconnected as Germany, it is still interconnected with France, Morocco, and Andorra. Spain and Portugal are also connected by transmission lines.

As countries surrounding Iberia have not implemented the same policy, electricity may flow from Spain to France and Morocco, thus creating foreign demand inside Iberia. Andorra is a small country with a 139 MW transmission line and is likely to have minimal export flows to Andorra.

$$\begin{aligned} Market\ Demand &= Domestic\ Demand + \Delta Foreign\ Demand \\ &= Q^D(P) + Exp_{France} + Exp_{Morocco} + Exp_{Andorra} \\ where\ Exp_{France} &> 0,\ Exp_{Morocco} > 0, Exp_{Andorra} > 0 \end{aligned} \tag{14}$$

Figure 14 shows the impact of the border flows within Iberia. The demand $Q^D(P)$ has been shifted to $Q^D(P)+Exp_{France}+Exp_{Morocco}+Exp_{Andorra}$. The increase in demand means electricity generated by gas plants increases from $Q_{Domestic\ demand}$ to $Q_{Domestic+Foreign\ Demand}$, implying the IE increases gas burnt to supply electricity to surrounding countries. It also implies that Iberia paid more for electricity because of the border flows, blunting (but not reversing) the intended price impact and paying to subsidise exports when these funds could have been paid more directly to Spanish electricity consumers.

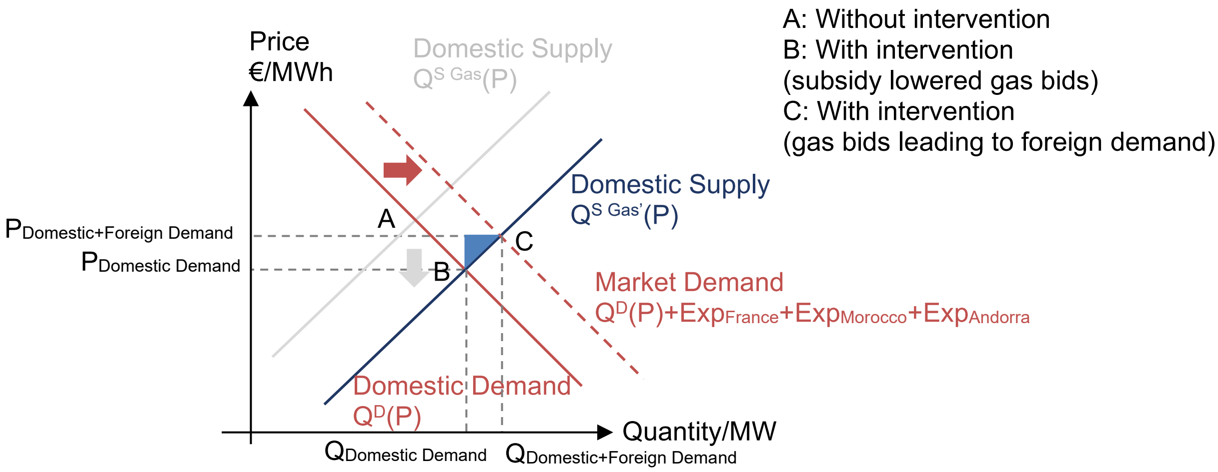


Figure 14: Border flow impacting domestic Iberian day-ahead market

As the flows are netted, we expect that under the decoupled situation, there should be no import flow from France, Morocco and Andorra as long as the day-ahead price in Spain is the lowest in all four bidding zones:

$$\begin{aligned} Market\ Supply &= Domestic\ Supply + \Delta Foreign\ Supply \\ &= Q^S(P) + Imp_{France} + Imp_{Morocco} + Imp_{Andorra} \end{aligned}$$

$$where\ Imp_{France} = 0, Imp_{Morocco} = 0, Imp_{Andorra} = 0 \quad (15)$$

Within the Iberian Peninsula, Spain and Portugal have abundant capacities between the two countries, and are likely to be coupled after IE was implemented. All these assumptions will be reviewed again in section 6.

From the Spanish perspective:

$$Available\ Import_{Portugal} > 0,\ Available\ Export_{Portugal} > 0 \quad (16)$$

From the Portuguese perspective:

$$Available\ Import_{Spain} > 0,\ Available\ Export_{Spain} > 0 \quad (17)$$

As IE was only implemented in Iberia, subsidised electricity flows to surrounding countries, and French/Moroccan consumers would have benefited without paying the subsidy themselves. While the objective is to bring down electricity prices, the effect is partially offset by border flows and increased gas usage and may not achieve the full impact expected by the Spanish (and Portuguese) governments.

Hidalgo-Pérez et al. (2024) have also addressed the Iberian Exception using a different approach to the one adopted in this paper. They employed a Bayesian structural time series to model the causal effect on PVPC, wholesale power price, France export, and gas generation using a TTF/MIBGAS regression approach.

While lower RMSE supports the comprehensive approach, we observed gas price divergence as TTF was decoupled from MIBGAS since April 2022. Hence, they were using historical similar/coupled prices to regress and predict decoupled regions. They could have clarified the choice and weight of TTF and strengthened their model's assumptions.

Our method, suggested in Chapter 5, uses a bottom-up approach. We reverse the subsidy effect on the day-ahead power supply and demand bids, thus addressing the impact on wholesale power price, French power export, and local gas generation. We further enrich our model with quantifiable environmental costs to better frame the trade-off with short-term price relief.

5. Method and Analysis

In this section, we will define the research hypothesis to quantify the effects of the IE. We will first discuss the data sources used in this paper to achieve the outcome. Next, we will carry out our deductive reasoning by formulating hypotheses and conducting experiments to test the hypotheses. The results will be presented in the next section.

5.1 Data Used

5.1.1 Iberia Bid Offer Curves

OMIE is the market operator in Iberia. They published day-ahead aggregated supply and demand curves daily. Each data point has a price, quantity and bid unit. This allows us to identify the market participant, its country of origin and the technology it represents, e.g. hydro, gas, nuclear, etc.

5.1.2 Day-ahead power flows

We obtained the Spanish day-ahead flows from OMIE. We will specifically focus on the borders with France, Morocco, Andorra and Portugal to quantify the effect of IE.

5.1.3 EpexSpot France, OMIE Spain and Portugal day-ahead price

The EU regulation No 543/2013 of 14 June 2013 improved transparency and suggested that price and fundamental data, including the day-ahead prices, should be available publicly at the Entsoe portal. We also use the historical data from EpexSpot to quantify the impact of IE.

5.1.4 MIBGAS gas price and price cap

We understand the price cap from the Spanish decree-law 10/2022. MIBGAS gas price history is available on the Mercado Ibérico del Gas website. We will use these data to calculate the adjustment paid to the fossil fuel plants, which can simulate the counterfactual scenario by removing the subsidy. We would like to understand what it would have been without the IE.

5.2 Hypotheses

We will now formulate our hypotheses to carry out our research. H1 will investigate IE's primary effect on reducing the gas bids during the counterfactual scenario. H2 and H3 will examine the secondary effect if IE decoupled the borders, especially with

France, as the ultimate goal of the policy proposed to the European Commission was to reduce the Spanish wholesale power price. Then, we will look at higher granularity by focusing on the distortions to the border flows of the surrounding bidding zones. We will also focus on the market share of the Portuguese gas plants and explore if Portugal applied the exact adjustment mechanism as their Spanish counterpart. We would like to understand how foreign demand affects domestic Iberian power prices. As IE incentivised more gas generators to run, we will quantify the extra gas burnt for domestic and foreign demand relative to the counterfactual of no IE.

Hypothesis H1: Under IE, the subsidy effect successfully reduced the day-ahead price compared with the counterfactual situation (without IE).

Supply curve

While it is difficult to simulate the European power markets due to the constraints and flows between all the bidding zones, we can model the counterfactual by removing the subsidy and rebuilding the supply curve. The subsidy S paid to fossil plants is measured as:

$$S = \frac{Spanish\ DayAhead\ Gas\ Price - Reference\ Gas\ Cap}{0.55} \tag{18}$$

We will perform the following procedures:

1. Identify all Iberian gas plants receiving subsidies on the supply stack.
2. Add the subsidy S to the marginal fuel price of the gas plants identified.
3. Re-order the stack in ascending order as plants with lower marginal cost are filled first.
4. Apply the domestic and domestic+foreign demand to find the intersections.

We will run the simulation since the IE was implemented. This “pure stack effect” model will be used below to measure further scenarios of IE versus the counterfactual. Our model takes into account the monthly price cap revision since January 2023.

Demand curve

We cannot simply adjust the entire demand curve as it comprises various market participants such as:

1. IE exposed consumers.
2. Non-IE consumers.
3. Power plants and traders were buying back from forward sales.
4. Pump-storage purchases for peak-time resale.

Generic Unit	35,009	1.1%
Last resort marketer	63,497	2.0%
Marketing purchases	830,055	25.8%
Marketer	1,319,649	40.9%
Qualified customer	158,156	4.9%
Direct consumption purchases	429,301	13.3%
Producer consumption	35,190	1.1%
Rep. of direct consumers	11,904	0.4%
Non-resident marketer	3,861	0.1%
Auxiliary consumption purchases	20,276	0.6%
Mixed pumping consumption	155,964	4.8%
Pumping consumption	93,980	2.9%
Pure pumping consumption	19,998	0.6%
Direct consumption purchases Balance	10,739	0.3%
Marketer balance purchase	35,270	1.1%
Storage purchase	210	0.0%
Total	3,223,059	100%

Table 1: Spanish Hourly Demand bids between 15 June 2022 and 26 February 2023

The majority of the bids from Table 1 proved to be marketers/marketing purchases, yet they can be IE-exposed consumers, non-IE consumers, traders from proprietary firms, and power plants. Spanish law stated that hedging deals executed before the

IE were not liable for the IE contribution; hence, a large proportion of demand bids were excluded from the IE.

Our scenario for the demand adjustments underscores the potential influence of IE-exposed consumers on the demand adjustment. We first calculate the percentage of demand buyers who contributed to the IE fund over the whole Iberian demand. The percentage allows us to adjust the demand curve, as only 40-70% of consumers contributed to the IE in 2022.

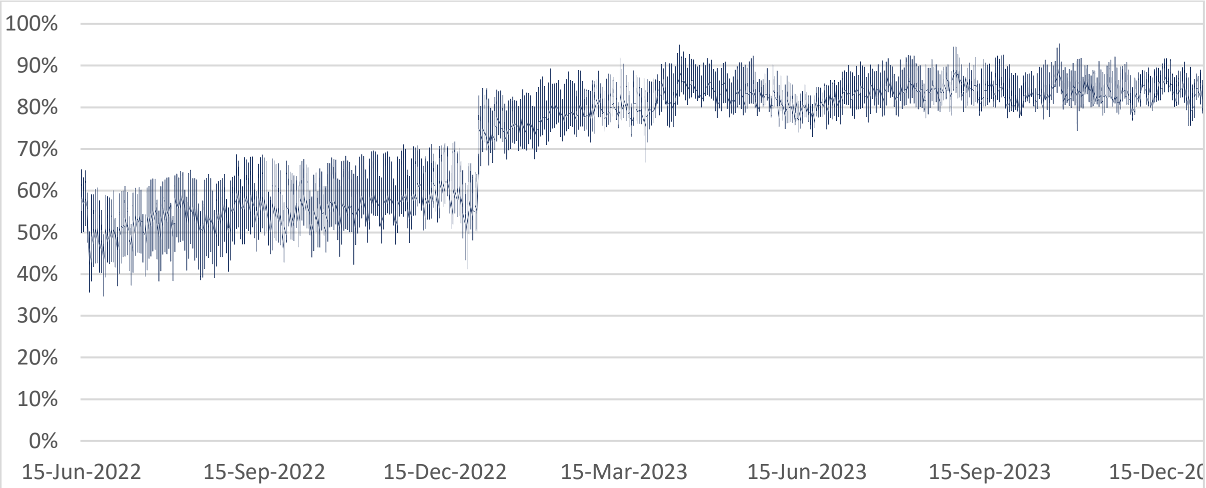


Figure 15: Hourly percentage of Iberian demand contributing to the IE fund

We then applied the hourly percentage of demand adjustment on each hourly demand curve when IE was triggered. Since the start of the IE, many wholesale consumers have obtained their power from the forward markets. Such contracts can be monthly, e.g., July 2022, quarterly, e.g., October to December 2022, or yearly, e.g., January to December 2022. As the bilateral agreements expired, more consumers paid for the IE.

The contribution percentage will not reach 100% as pumped storage bought power when prices were low overnight or mid-day. Similarly, proprietary traders buy and sell between different markets and do not contribute.

By working out our counterfactual power prices, we can further estimate the counterfactual flows and compare them with the French day-ahead prices. We expect more coupled scenarios, and in some cases, Spanish prices are higher than French prices.

Hypothesis H2: IE decoupled the Spanish and French day-ahead electricity markets.

We first examine if the IE decoupled the Spanish electricity markets from France and to what extent it was decoupled. We will measure the impact between 1 January 2021 and 31 December 2023. There are likely significant decoupling effects due to the subsidy paid to gas generators.

Hypothesis H3: IE did not decouple the Spanish and Portuguese day-ahead electricity markets.

We will focus on the Portuguese electricity market. We will not investigate Morocco and Andorra as they are not open markets, and no market participants can participate in the auctions.

As there are abundant capacities between Spain and Portugal (ES>PT: 4.2GW and PT>ES: 3.5GW), depending on the peak demand and supply of the day, there should be no decoupling effect.

We will investigate all four interconnectors separately. Flows are generally available to surrounding borders for most European countries under the energy transparency regulation in 2013.

Hypothesis H4: IE increased Spanish-French day-ahead outflows

We expect a large outflow to France as Spanish gas-fired plants were heavily subsidised. The flow is likely unidirectional to France when the IE was first implemented, but it remains to be investigated whether flows were altered by the IE.

Hypothesis H5: IE increased Spanish-Morocco day-ahead outflows

Similar to France, export flows to Morocco are likely unidirectional. It implies the EU is running fossil fuel plants to supply electricity to Africa.

Hypothesis H6: IE increased Spanish-Andorra day-ahead outflows

Despite the small power demand and minimal transfer capacities, there should be increase in export outflow to Andorra.

Hypothesis H7: IE increased Spanish-Portugal day-ahead outflows

If Spain and Portugal both applied the IE subsidy to their gas plants, we expect minimal changes in the flows.

Hypothesis H8: Under IE, Portugal is applying the subsidy payment to their gas generators.

Spain suggested that the IE be applied to the whole of Iberia. Notably, the Portuguese decree is significantly shorter than the Spanish one. Does Portugal apply the subsidy to their gas plants as well? Or does the Portuguese buy subsidised low-cost electricity from Spain instead?

While the exact producers' adjustment split is unavailable, we will inspect the gas plants' market share before and during IE. Suppose the Portuguese gas generators do not receive the subsidy or do not dispatch their generators to reduce subsidy payment; their generation should drop off from the market as their marginal fuel cost is too high compared with the Spanish counterpart, and we should observe a significant reduction in the Portuguese market share

Hypothesis H9: Foreign Demand Increased Spanish Electricity Price.

If Spain was decoupled, the foreign demand from France and Morocco would dramatically increase the Spanish electricity price. The increase can be measured by shifting the domestic demand curve in Figure 16 to the domestic+foreign demand curve by adding the export-occupied capacities.

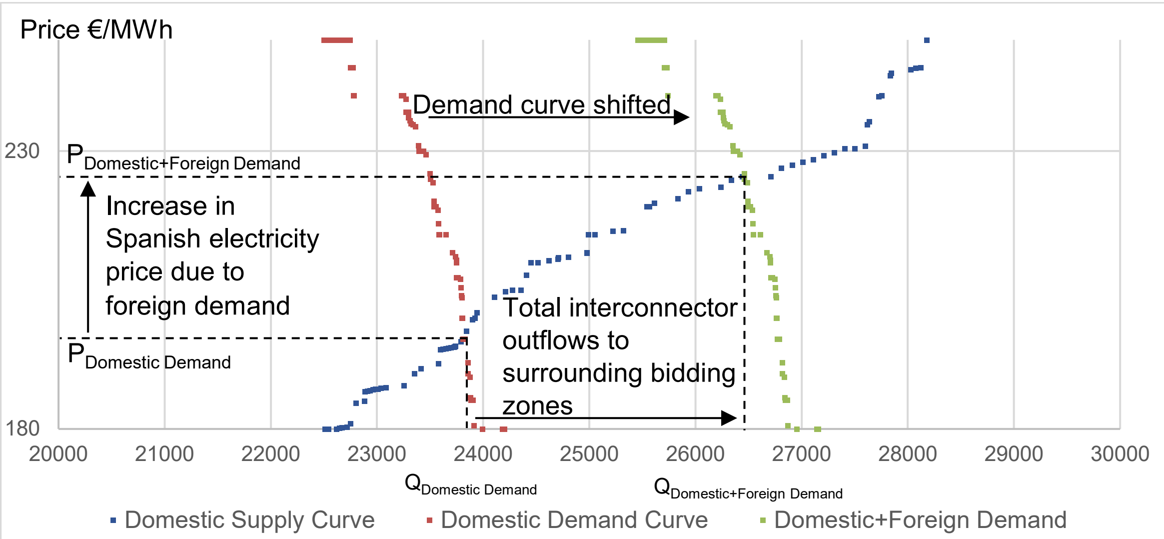


Figure 16: Demand-Supply curve for Spanish day-ahead market 00:00-01:00 30/08/2022 (OMIE, 2023)

As day-ahead products are traded by hour, each hour will have different demand and supply curves. Since the implementation of IE, there were 565 trading days between 15 June 2022 and 31 December 2023, resulting in ~13,560 pairs of hourly curves. The periods are denoted as t=1,…,n, where n=13,560.

In practice, the IE was triggered between 15 June 2022 and 26 February 2023. No subsidy was triggered afterwards as the gas price did not exceed the reference price cap. Hence, the dataset is reduced to 257 trading days with ~6,168 hourly observations.

$$\Delta P_{Foreign\ Demand\ n} = P_{Domestic+Foreign\ Demand\ n} - P_{Domestic\ Demand\ n} \quad (19)$$

$$where\ n\ is\ between\ 1\ and\ 6{,}168\ observations$$

Hypothesis H10: Under IE, more gas was burnt to satisfy domestic demand than in the counterfactual scenario (without IE).

We can compare mega-watt hour generated by gas plants under the pure stack effect (counterfactual) versus IE. As gas plants receive subsidies, their position in the merit order is shifted (to the left) so they are likely to generate more power and burn more gas. It is assumed that 11.52 mmBtu of gas is required to generate 1 MWh of electricity (Singh et al., 2022).

Hypothesis H11: Under IE, extra gas was burnt to satisfy foreign demand.

If Spain was decoupled and export capacities were occupied, more gas plants are required to supply both domestic and foreign consumers. This section will measure the amount of gas burnt to supply electricity to France and Morocco. Under the counterfactual, France is likely to have more generation from coal and gas; We also expect Morocco to have more coal generation.

Hypothesis H12: Under IE, when compared with the counterfactual scenario, significantly more foreign (French) generators are displaced due to the extra Spanish-French day-ahead flows.

We will first compare the flows between IE versus counterfactual. It's essential to delve into the flows. The additional Spanish-French flows under IE could artificially displace the French generators, a critical aspect we want to understand. If there are significantly more coupled scenarios, then we will next focus on the French fossil-fuel generators and inspect if there are any spare capacities.

Hypothesis H13: Under IE, there is a significant impact on the TTF gas price.

Although some French gas generators might be displaced from the previous hypothesis, leading to less demand for TTF/PEG, a few French gas plants suffered from gas supply issues in 2022 and may not run at all. This section inspects the displacement effect and French gas plant availability.

We will inspect the relationship between MIBGAS, TTF and the LNG markets. If Spain competes with France/the Netherlands in the LNG markets, we can prove that IE introduced additional Spanish gas demand, raising the TTF prices.

6. Results and Discussion

We will present our results and models from section 5. Our empirical study uses various energy market data and microeconomics concepts to examine the impact of IE. The results will be presented with statistics to prove the hypotheses for decoupling Spanish power markets and flows to surrounding countries. We will also focus on modelling the simulation between the IE and the counterfactual scenario by removing the gas plant subsidy.

Hypothesis H1: Under IE, the subsidy successfully reduced the day-ahead price compared with the counterfactual situation (without IE)

The primary effect of IE was to lower the generators' bid on the supply stack. We created a model to run a simulation when subsidy was removed.

Figure 17 shows the IE (green line) versus the counterfactual (yellow line) when we adjust the coal, gas and cogeneration supply bid. We also adjusted the demand based on the hourly percentage of contribution. The IE reduced the counterfactual by 35.3% or 67.61 €/MWh. Spanish power prices would have been much higher at 191.53 €/MWh compared to IE at 123.92 €/MWh, while numerous hours will be coupled with or flows even reversed between Spain and France.

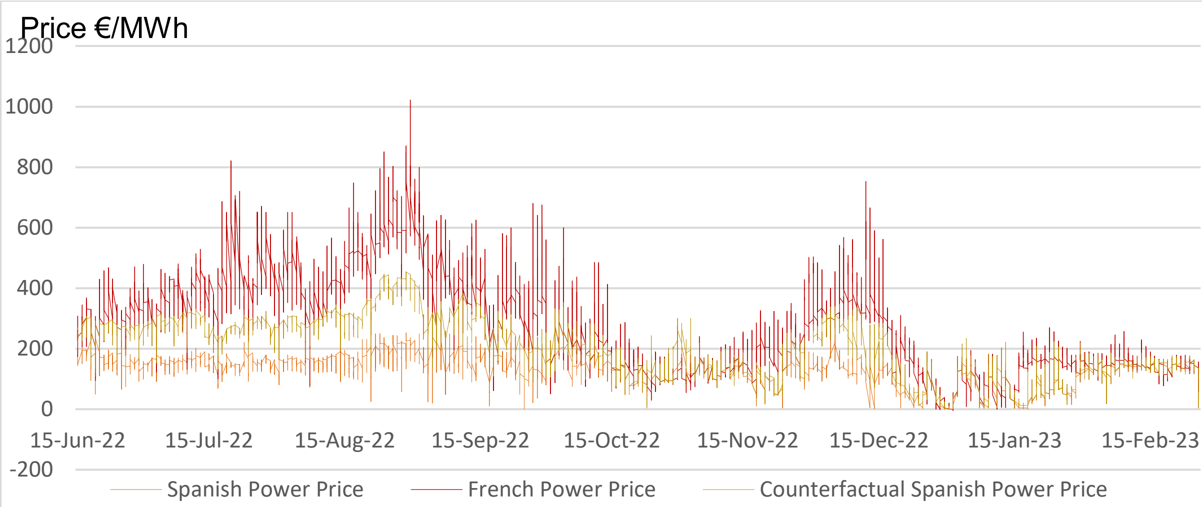


Figure 17: Pure stack effect with arbitrary demand adjustment

The impact of IE diminished quickly from October 2022, when the French nuclear generations came back gradually, and the weather was warmer than expected. The gas bids were lowered again when Spanish gas prices spiked to above €140 by early December 2022. However, the impact was minimal afterwards and wholly disappeared in March 2022.

The impact due to subsidy is illustrated below. The subsidy reduced the day-ahead price by about €100 to €150 between June and July 2022. As the demand contribution spiked to nearly €400 by August 2022, the impact from IE on the Spanish spot price increased to almost €300 without demand adjustment. The subsidy was reduced to a minimum as the Spanish gas prices dropped near the reference price cap. The subsidy stopped entirely in March 2023 as the gas price was always below the reference price.

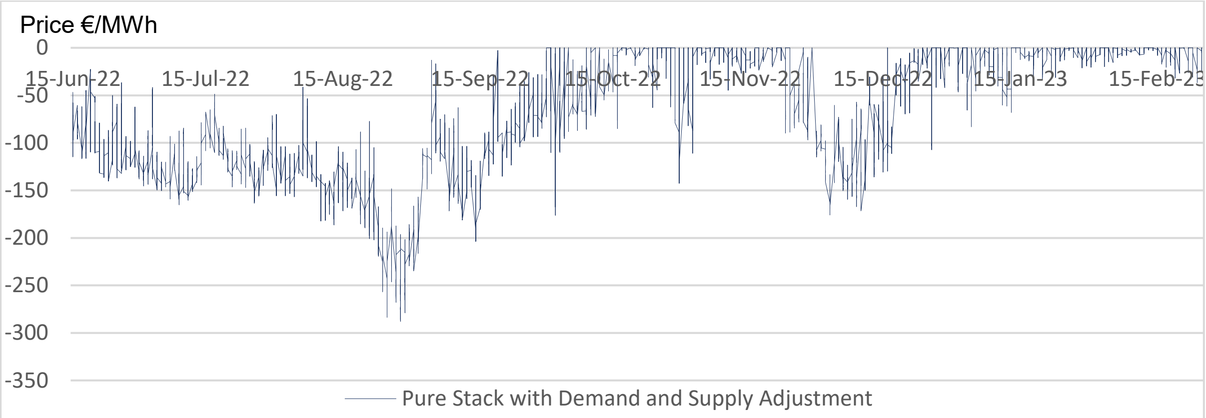


Figure 18: Hourly spot price reduction from IE

Statistics		
15 June 2022 to 26 February 2023	IE	CF
Observations Hourly n	6,144	6,144
Average Spot Price (€/MWh)	123.92	191.53
Average Reduction (%)		-35.3%
Average Decrease (€)		-67.61
Maximum Decrease (€)		-287.93

Table 2: Comparison between IE and counterfactual

Flows

Our analysis gains value as we simulate the counterfactual flows and compare them with IE, providing a comprehensive understanding of the subsidy's impact on flows from interconnectors.

Overall, the observations with exports to France reduced by 10.7%. Imports from France increased by 65.7%, while coupled observations also increased by 44.1%. Hence, IE yields 10.47 TWh net export to France, while counterfactual introduced a 14.9% reduction of export to 8.91 TWh to France.

Statistics		
15 June 2022 to 26 February 2023	IE	CF
Observations Hourly n	6,144	6,144
Import from France Only	283	469 (+65.7%)
Coupled	820	1182 (+44.1%)
Export to France Only	5,113	4,565 (-10.7%)
Decoupled (Export Only) (%)	83.2%	74.3%
Export to France / TWh	11.80	10.42
Import from France/ TWh	1.33	1.52
Net Export to France /TWh	10.47	8.91
% Change of Export to France		-14.9%

Table 3: Flows between IE and counterfactuals scenarios

Hypothesis H2: IE decoupled the Spanish and French day-ahead electricity markets.
The Spanish and French power prices are highly correlated before the IE. Figure 19 shows the day-ahead daily power price in both countries. The outlier on 4 April 2022 was due to 07:00-08:00 and 08:00-09:00 in France spiking to 2,713 and 2,987.8 Euro/MWh, respectively, during the invasion of Ukraine.

The IE was last triggered on 26 February 2023. As the Spanish gas price was always below the reference price, the IE was not triggered anymore, and the two markets are closely correlated again. Figure 20 shows the decoupling result from IE.

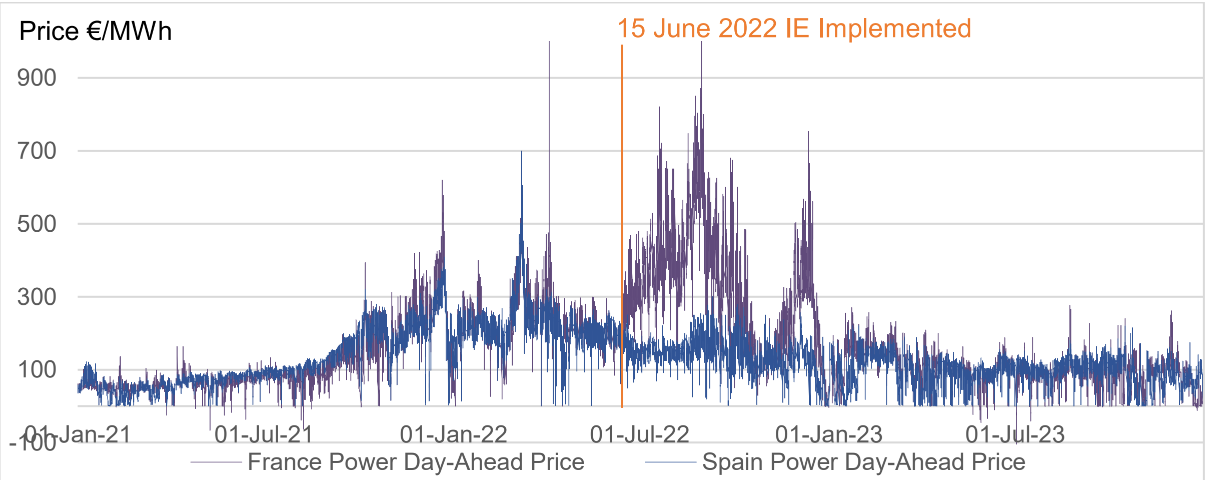


Figure 19: French and Spanish day-ahead power price (OMIE, 2023)

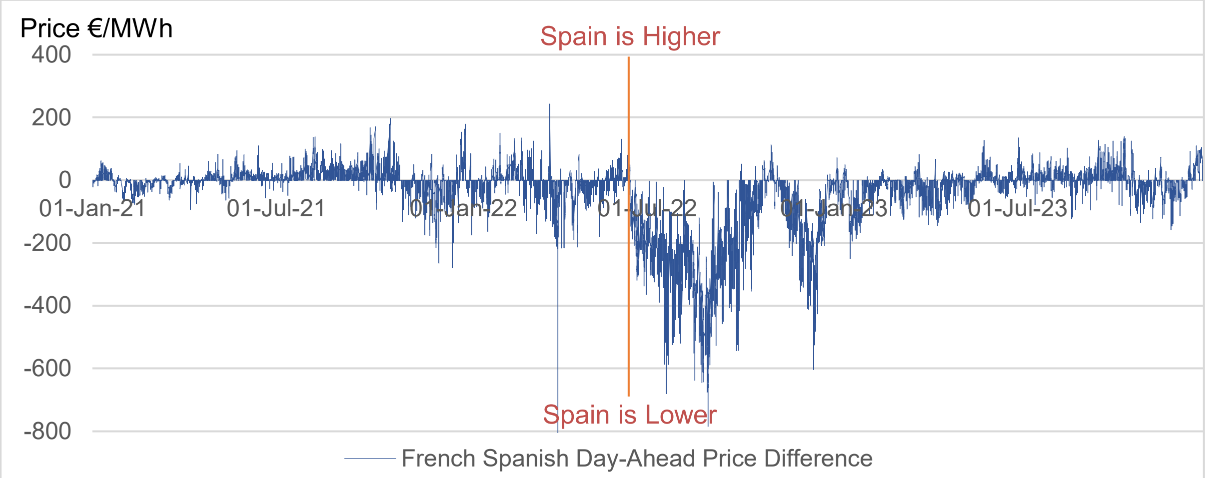


Figure 20: French and Spanish day-ahead price difference (EpexSpot, 2024)

Overall, there were 5,808 hourly observations when IE was triggered. With a mean of €165.56 and a standard deviation of €144.18, H2 is proven as IE successfully decoupled the Spanish and French day-ahead power markets with an increase from 26.4% to 85.7%, yielding an increase of +59.2% in decoupled scenarios. The minimum decoupling value €784.73 was obtained on 27 August 2022.

However, IE produces illogical and not economic decisions for consumers. There were 650 observations (11.2%) that Spain and France were coupled, yet IE subsidy was triggered for gas plants. Iberian consumers could have bought their electricity from France while the government could have paid less subsidy until the capacities were exhausted. Figure 21 shows the Spanish government paid €138 million for gas plants to lower their bids even when hourly results from Spain and France were coupled.

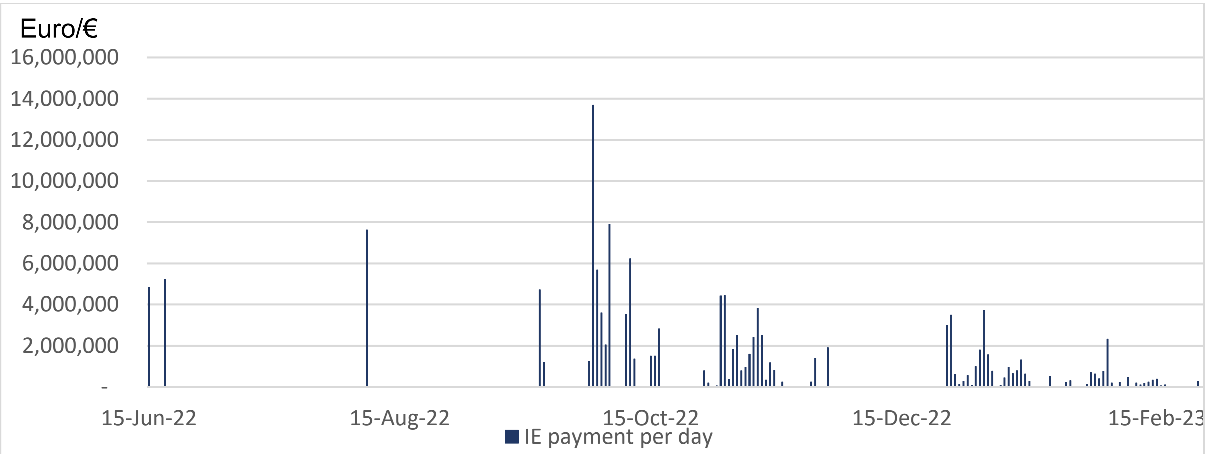


Figure 21: IE payment per day when Spain and France Hourly Day-Ahead results were coupled

Statistics		
	Pre-IE	IE Triggered
Observations n	12,720	5,808
Mean (€)	-1.20	-165.56
Standard Deviation (€)	49.59	144.18
Spain is below France	3,363 (26.4%)	4,975 (85.7%)
Spain equals France	4,879 (38.4%)	650 (11.2%)
Spain is above France	4,478 (35.2%)	183 (3.2%)
∆Spain is below France	+59.2%	

Table 4: IE decoupled the Spanish-French electricity markets

Hypothesis H3: IE did not decouple the Spanish and Portuguese day-ahead electricity markets

The Spanish and Portuguese power markets are highly correlated due to their abundance of installed transfer capacities. Figure 22 shows the Spanish and Portuguese day-ahead power results since 2021. During the pre-IE period, 97.6% (12,410) of observations were coupled. When the IE was triggered, 96.5% (5,582) of observations were coupled. The number of decoupled scenarios increased from 1.4% to 2.5%, and the mean changing from €-0.12 to €-0.36, suggesting although the effect is minimal, there is still some decoupling effect on Portugal.

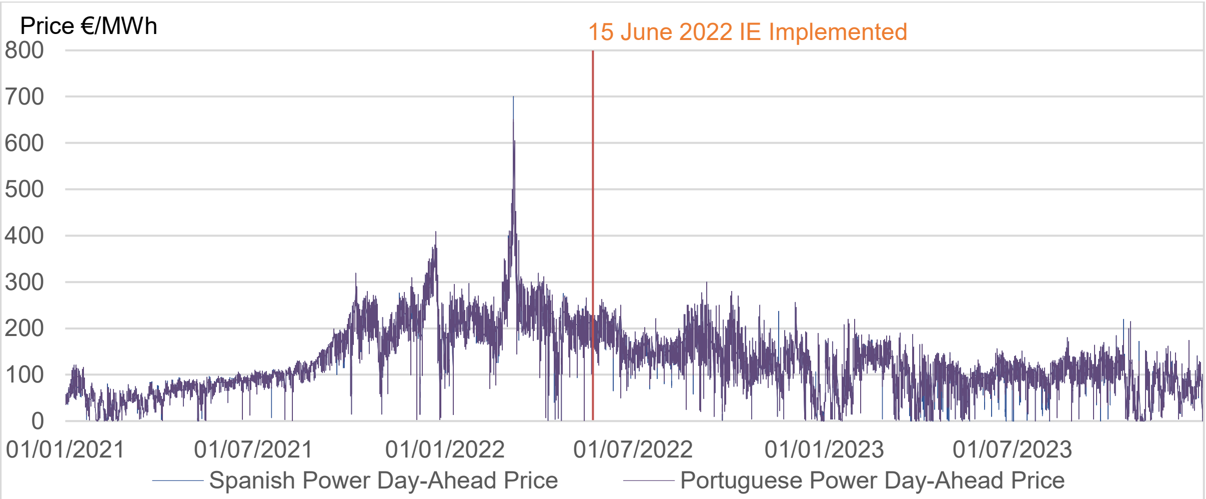


Figure 22: Spanish and Portuguese day-ahead power price

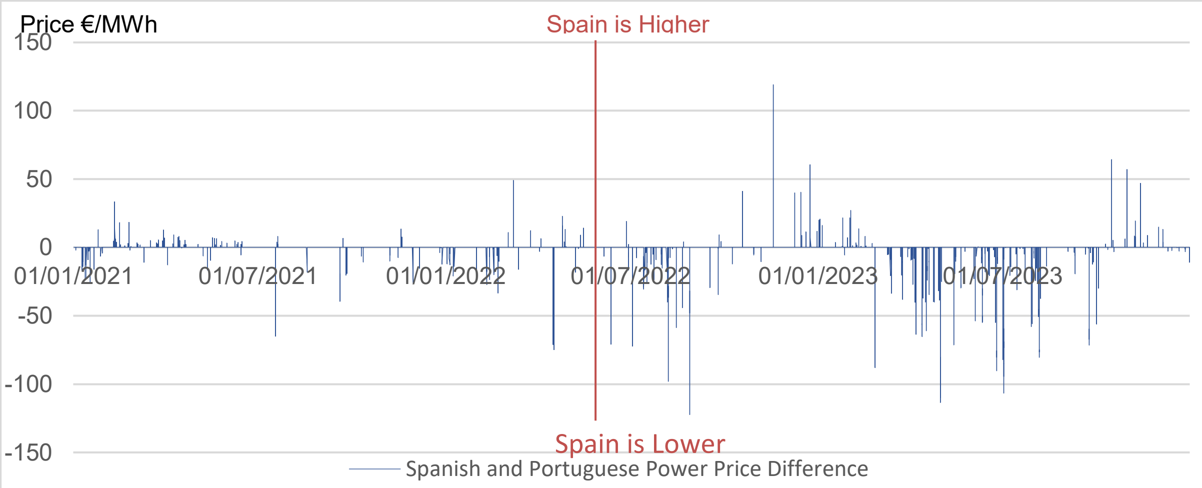


Figure 23: Spanish and Portuguese day-ahead price difference

Statistics		
	Pre-IE	IE Triggered
Observations n	12,719	5,784
Mean (€)	-0.12	-0.36
Standard Deviation (€)	2.41	5.36
Spain is below Portugal	177 (1.4%)	146 (2.5%)
Spain equals Portugal	12,410 (97.6%)	5,582 (96.5%)
Spain is above Portugal	132 (1.0%)	56 (1.0%)
∆Spain is below Portugal	+0.9%	

Table 5: IE slightly decoupled the Spanish-Portuguese electricity markets

Hypothesis H4: IE increased Spanish-French day-ahead outflows

Flow data in Figure 24 shows the hourly import/export flows between France and Spain. The pre-IE period had a net *import* of 6.6 terra-watt-hours from France (i.e. Spain's day-ahead prices were much higher than France's) as Spain imported 16.8 terra-watt-hour and exported 10.2 terra-watt-hours of power.

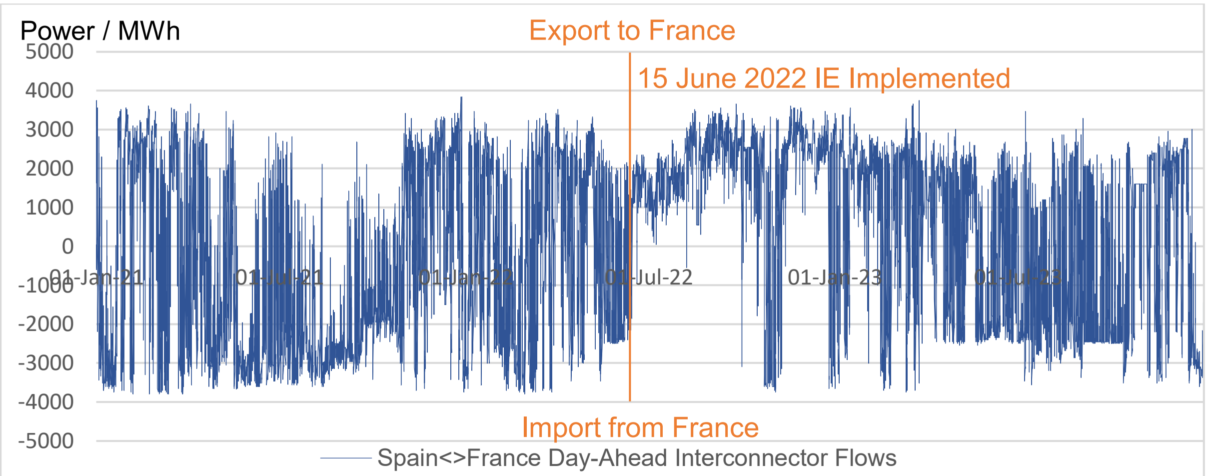


Figure 24: Import and export flows between Spain and France (OMIE, 2024)

During the IE, the total export to France was 11.33 TWh, while the import was 0.96 terra-watt-hours, yielding a net export of 10.37 TWh. Due to the warm weather and the return of French nuclear plants, Spanish gas prices dropped below the reference price cap briefly in November 2022, and the flow was reversed. The subsidy was triggered again in December 2022. Spanish day-ahead gas prices were consistently below the reference price after 26 February 2023; hence, there were bi-directional flows again.

We must understand if the decoupling effect was due to the French generation outages. Figure 25 shows the generation history of French hydro and nuclear plants. Between 1 April and 14 June 2022, the aggregated generation was 33.4 GW, yet between 15 and 30 June 2022 it was 32.7 GW. As the generations were quite similar, the decoupled effect in June 2022 appears to be due to the IE.

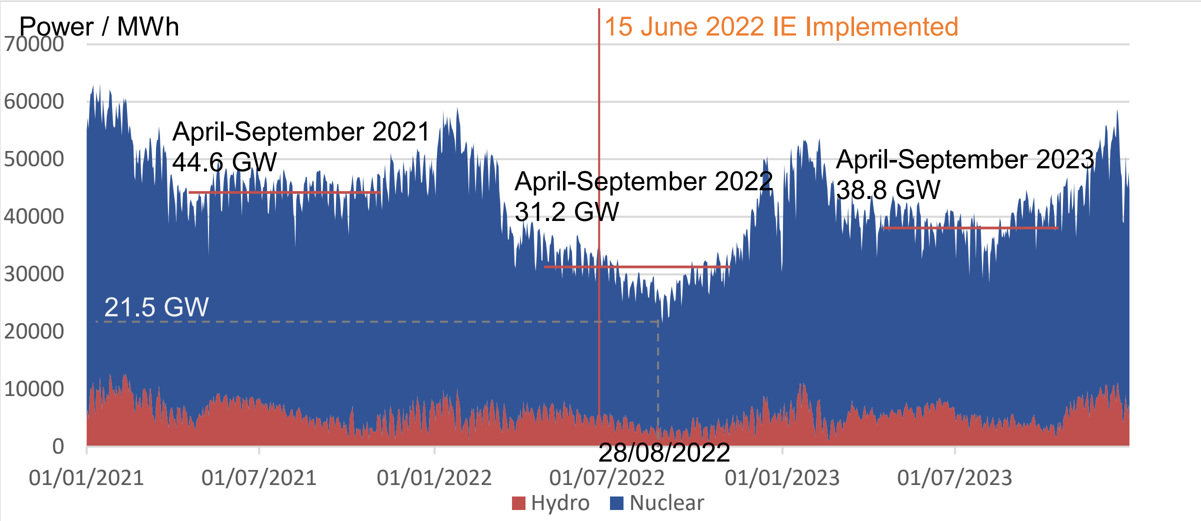


Figure 25: French hydro and nuclear aggregated generation history (Entsoe, 2024)

The aggregated generation kept deteriorating since July and dropped to 21.5 GW on 28 August 2022. The increase in Spain/France price spread was partially due to the French generations, especially during the peak of the energy crisis when aggregated generation dropped y-o-y by 52% (44.6 GW to 21.5 GW). However, the gas cap also partially contributed to the magnitude of the decoupling when Spanish gas prices spiked to €240/MWh by 29 August 2022.

Overall, Spain imported pre-IE from France daily by 0.51 GWh and flipped to a daily export of 1.79 GWh. By comparing the net export between pre-IE and during IE, the average daily net export increased by +2.3 GWh; hence H4 is proven as IE increased outflow.

Statistics		
	Pre-IE	IE Triggered
Observations n	12,720	5,808
Export to France (TWh)	10.2	11.3
Import from France (TWh)	16.8	1.0
Net Export to France (TWh)	(-6.6)	10.4
Average Net Daily Export (GWh)	(-0.51)	1.79
∆Net Daily Export (GWh)	+2.3	

Table 6: Export flow to France

Hypothesis H5: IE increased Spanish-Morocco day-ahead outflows

Figure 26 shows the day-ahead flows between Spain and Morocco. The flows are organised by the TSOs and not by any explicit allocations by market participants or implicit allocations by the day-ahead algorithm.

The pre-IE period has minimal export flow at 96.5 GWh. During IE, the outflow increased to nearly 750 MW/hour with a total net export of 1,483 GWh. The daily average export changed from 0.0076 to 0.255 GWh, representing a 32.6 times increase on a daily basis.

The flow continued in March 2023 suggesting there are long-term contracts between the TSOs. It means IE unleashed an opportunity to burn gas and supply electricity to Morocco for the foreseeable future.

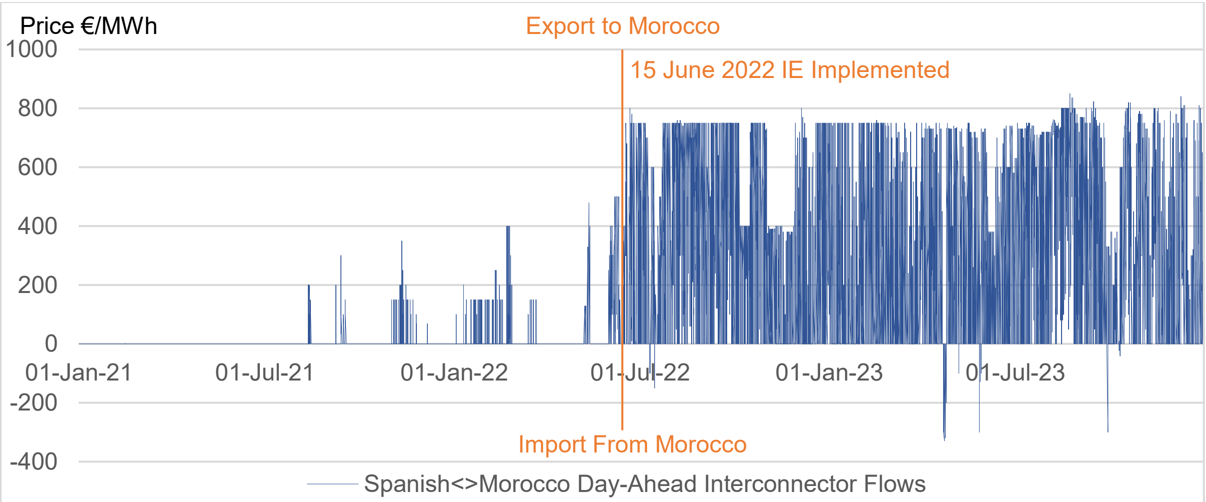


Figure 26: Export flow from Spain to Morocco (OMIE, 2024)

Statistics		
	Pre-IE	IE Triggered
Observations n	12,720	5,808
Export to France (GWh)	96.5	1,485
Import from France (GWh)	0.0	1.45
Net Export to France (GWh)	96.5	1,483
Average Net Daily Export (GWh)	0.0076	0.255
∆Net Daily Export (GWh)	+0.248	

Table 7: Export flow to Morocco

Hypothesis H6: IE increased Spanish-Andorra day-ahead outflows

The flow between Spain and Andorra is negligible, as the maximum export capacity is only 139 MW/hour. Average daily export increased from 0.028 to 0.035 GWh during IE. Despite a slight increase of only 0.007 GWh, it represents a 25% increase in flows.

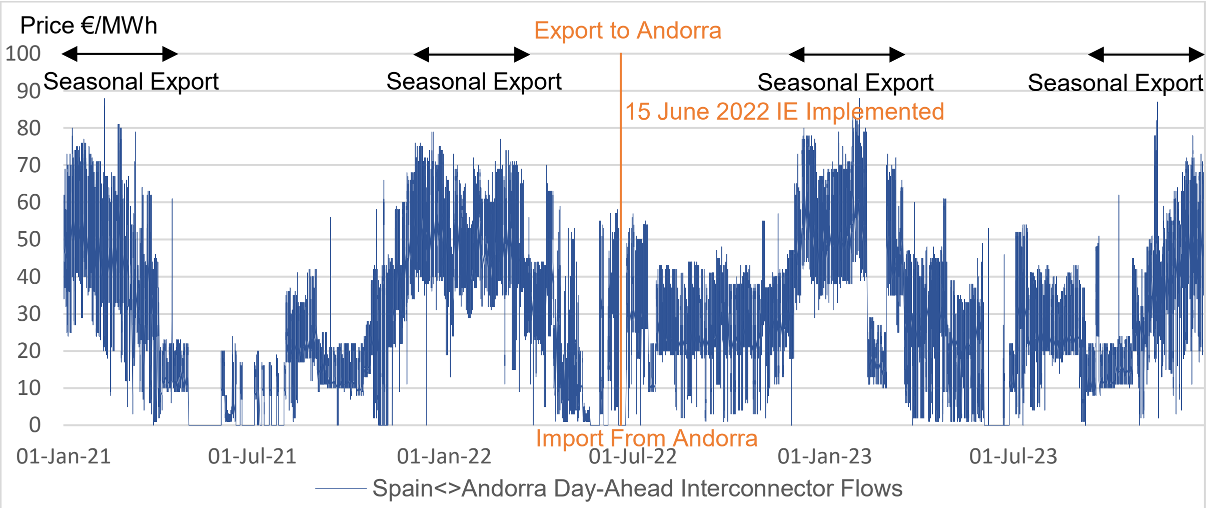


Figure 27: Export and import flow between Spain and Andorra (OMIE, 2024)

Statistics		
	Pre-IE	IE Triggered
Observations n	12,720	5,808
Export to France (GWh)	357.6	205.7
Import from France (GWh)	0.0	0.0
Net Export to France (GWh)	357.6	205.7
Average Net Daily Export (GWh)	0.028	0.035
∆Net Daily Export (GWh)	+0.007	

Table 8: Export flow to Andorra

Hypothesis H7: IE increased Spanish-Portuguese day-ahead outflows

Figure 28 shows the flows between Spain and Portugal. Spain was exporting power daily pre-IE with 0.64 giga-watt-hours. There is seasonal import during winter when Spanish demand is high. Overall, the average daily export flow reduced from 0.64 to 0.56 giga-watt-hour as Spain imported more power from Portugal during the winter of 2022; hence, Portugal partially helped Spain during the energy crisis.

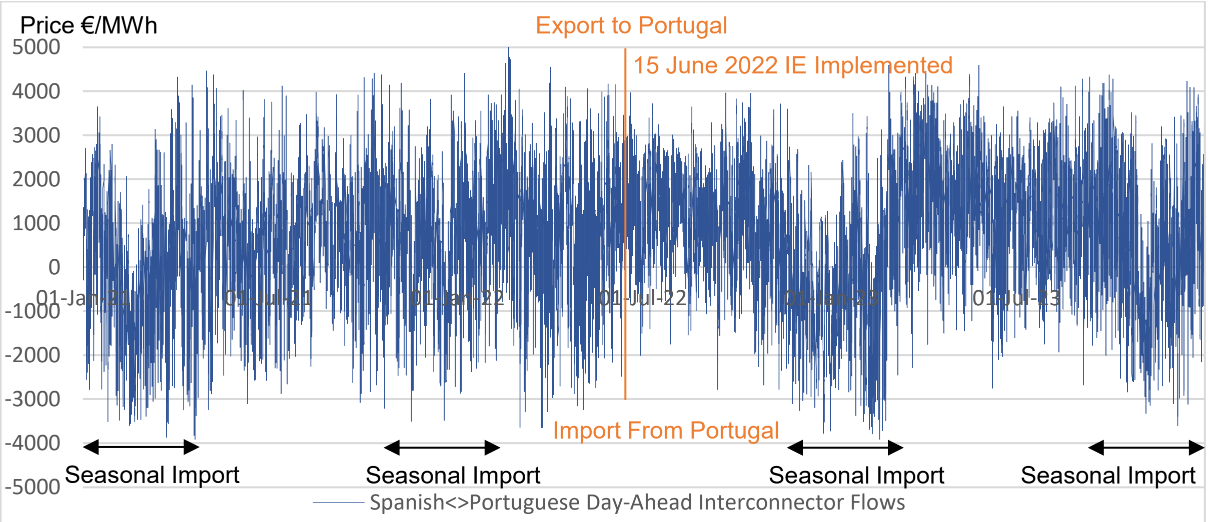


Figure 28: Day-ahead flow between Spain and Portugal (OMIE, 2024)

Statistics		
	Pre-IE	IE Triggered
Observations n	12,720	5,808
Export to Portugal (TWh)	12.4	5.5
Import from Portugal (TWh)	4.2	2.3
Net Export to Portugal (TWh)	8.2	3.2
Average Net Daily Export (GWh)	0.64	0.56
∆Net Daily Export (GWh)	(-0.08)	

Table 9: Export outflow to Portugal

Hypothesis H8: Under IE, Portugal is applying the subsidy payment to their gas generators.

H7 suggested that Spain was importing from Portugal, indicating that there could be equal subsidy treatment to the Portuguese gas plants as they are unlikely to be switched off. In this section, we will directly compare the gas generation between Spain and Portugal and investigate if there are any discrepancies between the pre-IE and IE periods.

Figure 29 below shows the Spanish and Portuguese actual gas generations.

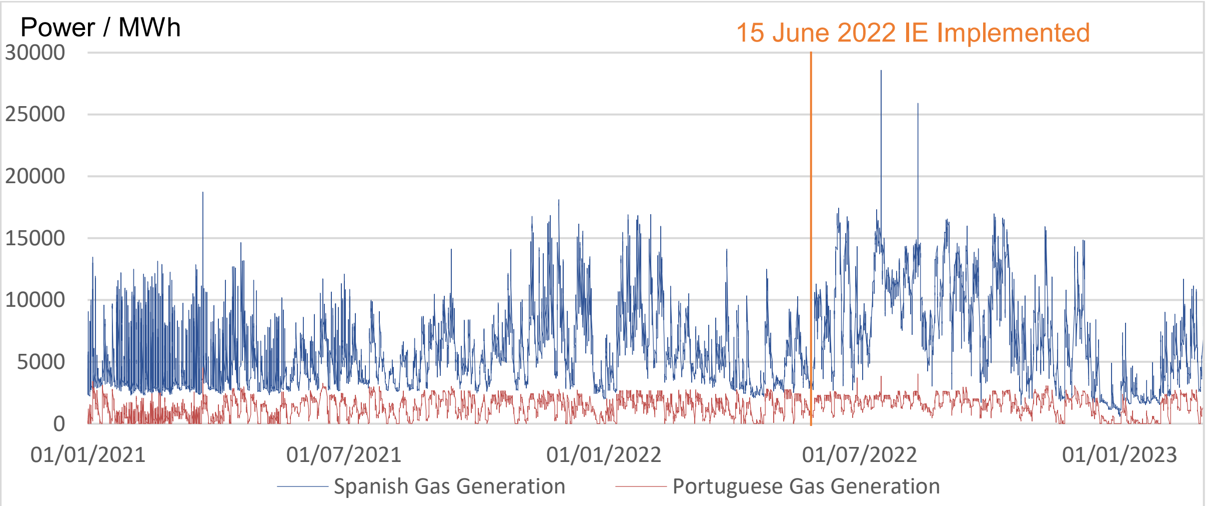


Figure 29: Spanish and Portuguese gas generations history (Entsoe, 2024)

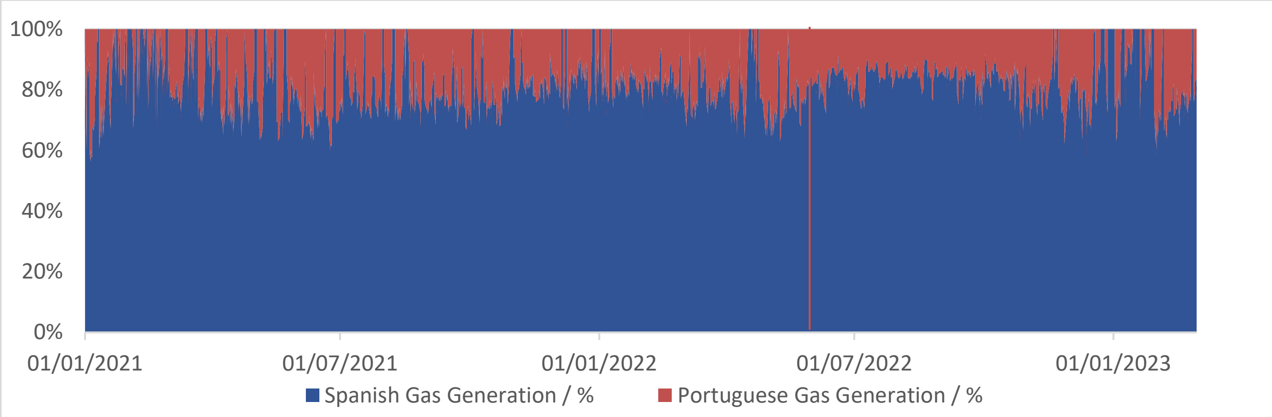


Figure 30: Spanish and Portuguese gas generations percentage

The Portuguese gas generation was quite stable and averaged at 1.3 GWh pre-IE, while Spain generated 5.7 GWh hourly on average, representing 17% and 83% of market share, respectively.

During IE, the average hourly generations in both countries increased to 1.5 GWh and 7.5 GWh, representing 16% and 84% of generations across Portugal and Spain. Hence both countries are incentivised to run more gas plants. However, the Spanish hourly gas generations are pretty volatile and range from 3 GWh to 15 GWh, and it is noticeable that they are slightly more incentivised to run than their Portuguese counterparty. There were also a few periods when Portuguese generations dropped to zero by late 2022, probably because power prices were below their marginal fuel cost; hence, they switched off their plants.

As OMIE administered the day-ahead market and producer adjustment, they applied the same methodology to both Spanish and Portuguese gas generators.

Overall, both countries were incentivised to run more gas generators, although the Spanish market share was 1% more than the pre-IE period. It is proven that Portuguese did not switch off their plants to buy subsidised electricity from Spain.

Statistics		
	Pre-IE	IE Triggered
Observations n	12,718	6,216
Spanish Gas Generation (GWh)	5,752	7,504
Portuguese Gas Generation (GWh)	1,303	1,500
Spanish Gas Generation (%)	83.0	84.0
Portuguese Gas Generation (%)	17.0	16.0

Table 10: Spanish and Portuguese gas generation market share

Hypothesis H9: Foreign Demand Increased Spanish Electricity Price

As H4, H5, and H6 are proven, the extra export outflow to France, Morocco and Andorra constituted foreign demand within Iberia.

We measure the change in power price due to foreign demand by placing a) domestic demand curve and b) domestic+foreign demand curve on the supply stack when n is between 15 June 2022 and 26 February 2023.

$$\Delta P_{Foreign\ Demand\ n} = P_{Domestic+Foreign\ Demand\ n} - P_{Domestic\ Demand\ n} \quad (20)$$

Figure 31 shows the impact of the foreign demand in Spain. When gas plants were subsidised, leading to the decoupling effect in H2, the foreign demand pushed the Spanish day-ahead electricity price €10 to €40 euro above its domestic price, representing a 10% to 25% premium to satisfy the foreign demand.

By the end of December 2022, energy prices dropped to below €10, and another €10 impact due to foreign demand could mean a +100% premium. Overall, foreign demand poses a 24.8% increase in Spanish energy prices with an average normal difference of €18.85.

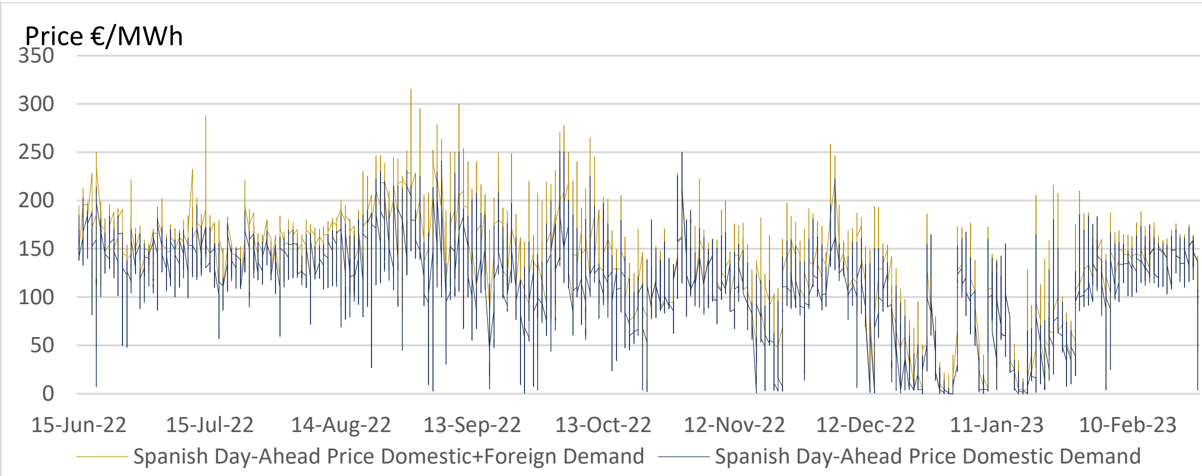


Figure 31: Daily Spanish day-ahead price with and without foreign demand

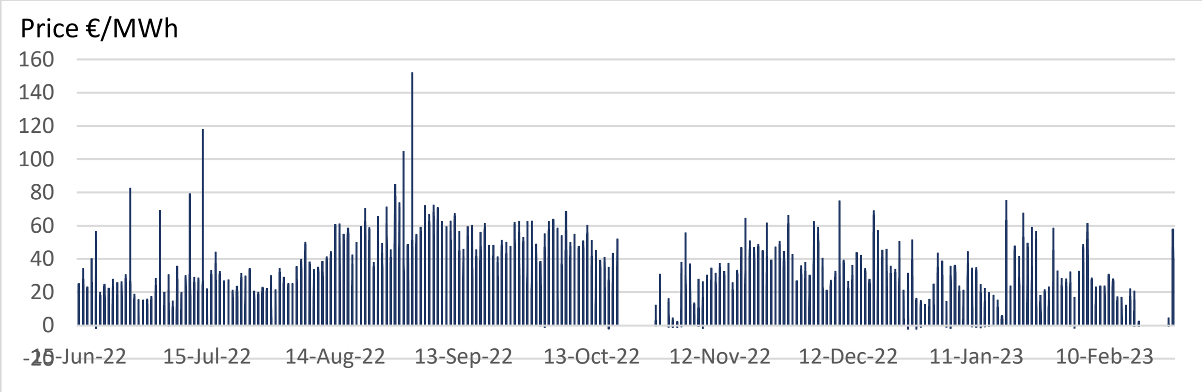


Figure 32: Price difference due to foreign demand

Statistics	
Observations Daily n	6,168
Average Increase (€)	18.99
Maximum Increase (€)	152.17

Table 11: Impact from foreign demand

Hypothesis H10: Under the IE, more gas was burnt to satisfy domestic demand than in the counterfactual scenario (without IE)

Using the pure stack effect model from H1, we can identify all gas-fired generations between IE versus the counterfactual. This allows us to quantify the increase in gas generation within Iberia due to IE.

Figure 33 shows the extra Spanish gas burnt to satisfy domestic demand between IE and the counterfactual scenario. IE incentivised an extra 1.06×10^8 mmBtu gas burnt between the IE and counterfactual. By comparing with gas burnt under IE and counterfactual, it constituted a +19.2% increase. The EU generated 387.5 TWh of gas-fired electricity (Eurostat, 2024). During the same period, IE induced 5.2 TWh of extra gas-fired electricity versus our counterfactual, representing a +1.3% increase on the EU level.

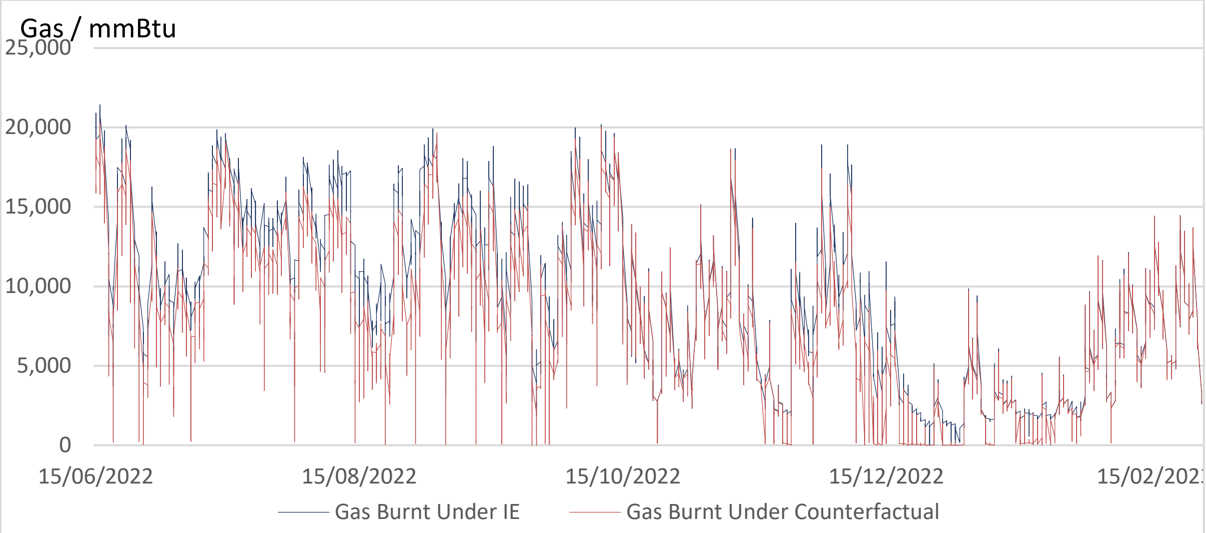


Figure 33: Hourly gas burnt for domestic consumers (IE vs counterfactual)

Figure 34 shows the Spanish gas burnt difference between IE versus different counterfactual scenarios. The significant difference appeared in late August 2022 when consumer adjustment peaked at €410.20 on 31 August 2022.

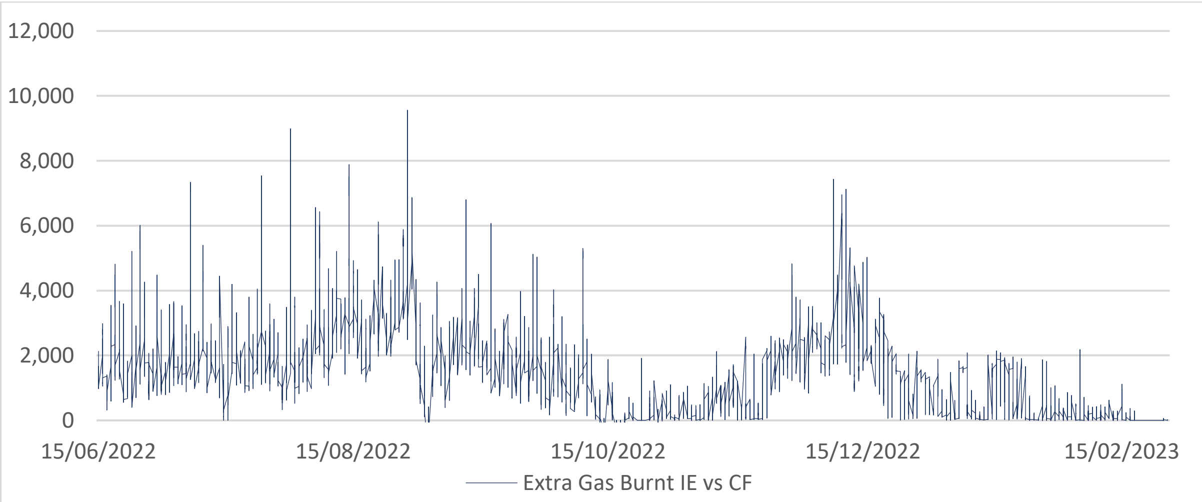


Figure 34: Difference of extra hourly gas burnt for domestic consumers between IE vs CF

Statistics	
Observations Daily n	6,168
IE gas burnt (mmBtu)	657,779,194
CF gas burnt (mmBtu)	551,629,329
Extra gas burnt from IE (mmBtu)	106,149,865
Extra gas burnt (Iberia) (%)	19.2%
Extra gas burnt (EU) (%)	1.3%

Table 12: Extra gas burnt for domestic customer (IE vs counterfactual)

Hypothesis H11: During IE, more gas was burnt to satisfy foreign demand

The flow from H4, H5 and H6 represents foreign demand. Figure 35 shows the extra gas burnt required for those foreign flows. Overall, 3,125 GWh extra gas generation was required for France, Morocco and Andorra, representing extra gas burnt of 3.6×10^7 mmBtu. The outflows from foreign demand increased the gas generation within the Iberia and across the EU by +5.47% and +0.81%, respectively.

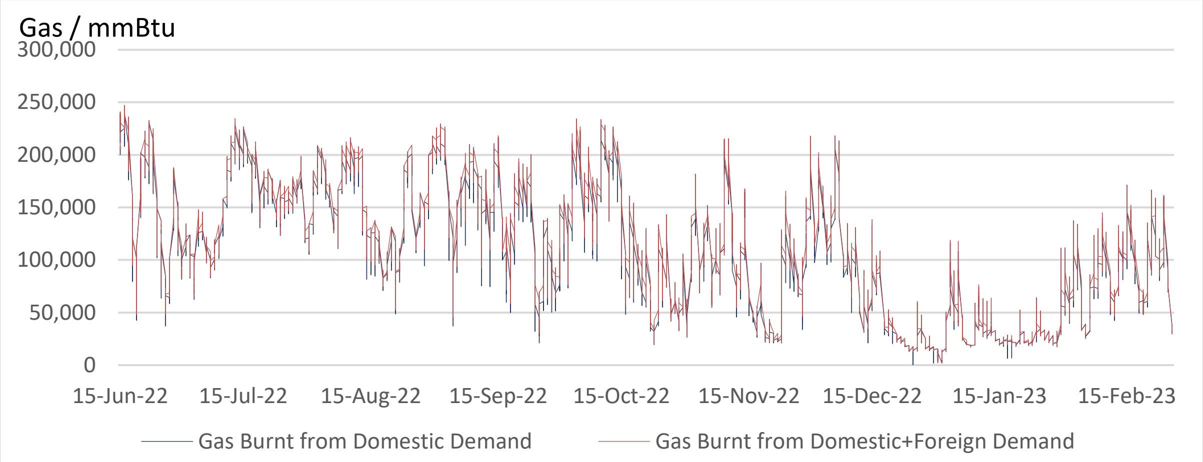


Figure 35: Extra hourly gas burnt from foreign demand

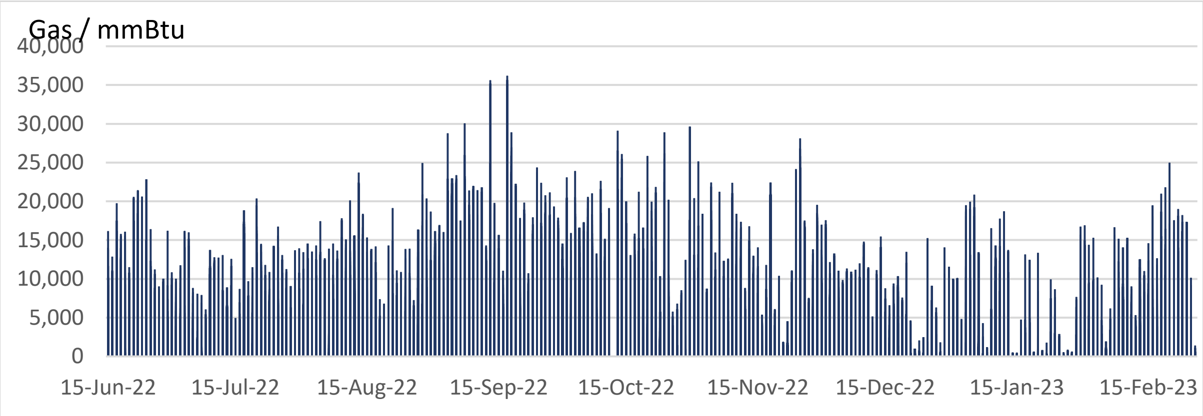


Figure 36: Gas burnt differences due to foreign demand

Statistics	
Observations n	6,168
Extra gas burnt (mmBtu)	36,033,170
Extra gas burnt (Iberia) (%)	+5.47
Extra gas burnt (EU) (%)	+0.81

Table 13: Extra gas burnt for foreign demand

Hypothesis H12: Under IE, when compared with the counterfactual scenario, significantly more foreign (French) generators are displaced due to the extra Spanish-French day-ahead flows.

Since most European bidding zones are interconnected, simulating the day-ahead flows will require re-running the EUPHEMIA algorithm, capacities constraints, and supply and demand curves in all countries. Re-running the day-ahead bidding is infeasible as not all data are widely available, and the EUPHEMIA algorithm is highly confidential.

The Pure Stack effect from H1 proved that counterfactuals reduced the export to France by 14.9%; hence, flows are still primarily unidirectional from Spain to France. The displacement effect will likely be small as the extra flow is minimal.

French Generators

RTE stopped publishing the aggregated available capacities; so we can only inspect the individual plants' availability capacities. We manually scaled the gas and biomass availability capacities below as some plant data are missing.

French gas generation has significantly dropped since early 2022, falling from 8 GW to 4GW by mid-2022. This was not due to IE but rather a supply-chain issue that resulted in fewer French gas generators being available.

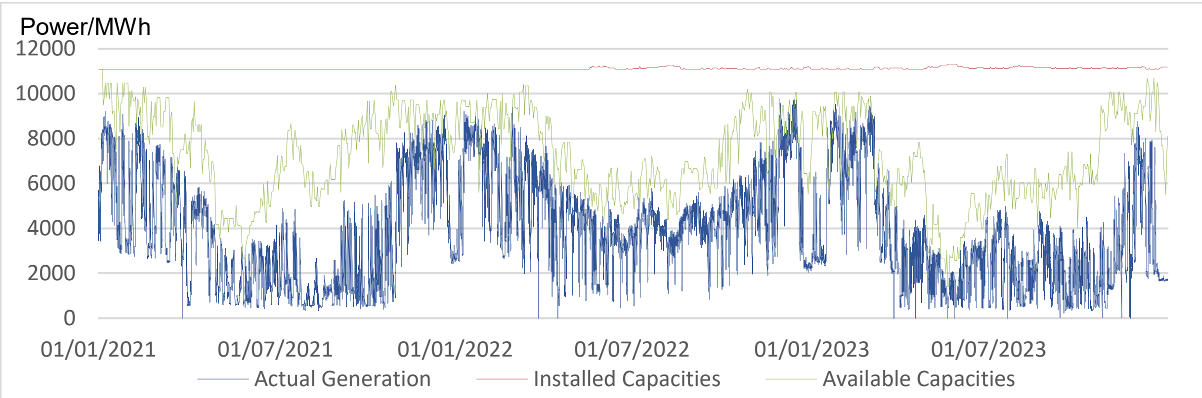


Figure 37: French gas actual generation, installed and available capacities

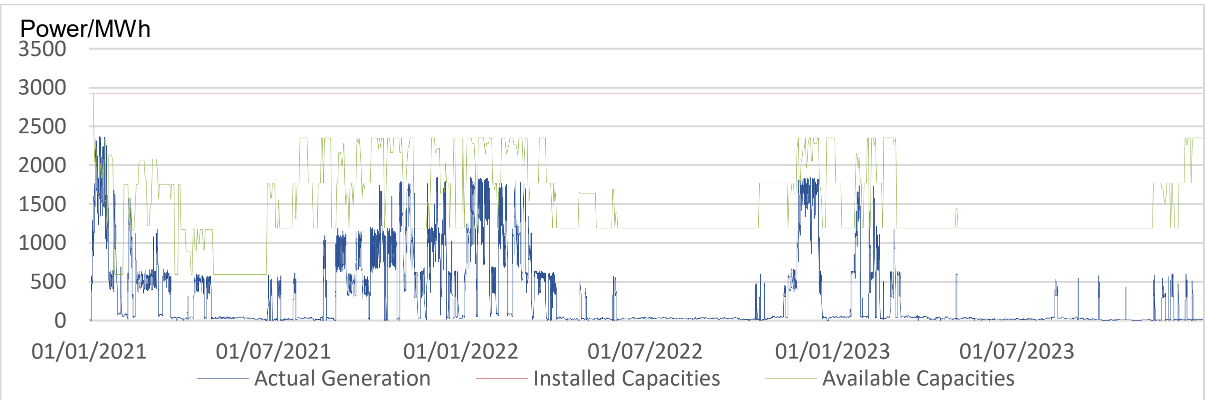


Figure 38: French coal actual generation, installed and available capacities

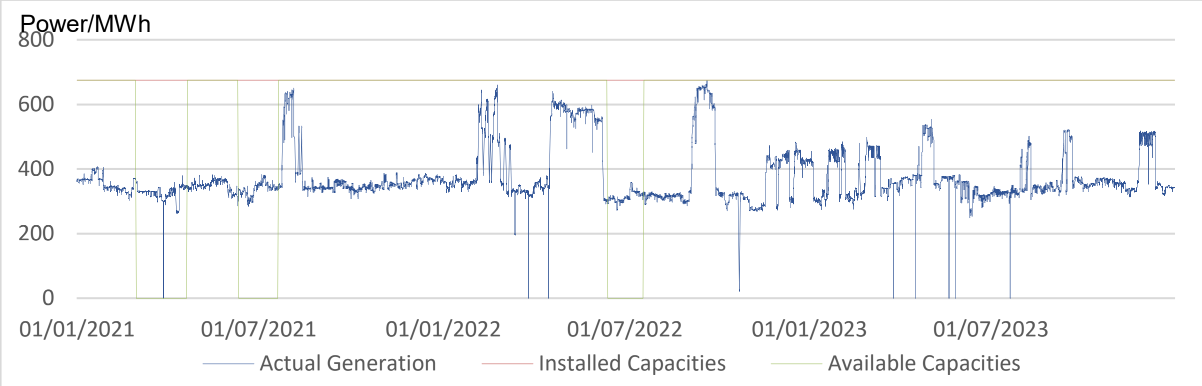


Figure 39: French biomass actual generation, installed and available capacities

In contrast to the French gas generators, 300 MW of French biomass and 1.2 GW of coal plants have spare capacities that can run in 2022. We can conclude that a slight reduction in French exports may lead to a minimal displacement effect in France.

Hypothesis 13: Under IE, there is a significant impact on the TTF gas price.
Spain has six operational LNG terminals, while the Netherlands has only one in Rotterdam. Before August 2022, Spain was awash with LNG, and because of the bottlenecks between the Dutch and Spanish pipelines, Spain could not send more regasified LNG to the rest of the Continent.

Name	Country	Year in Operation
Barcelona	Spain	1968
Huelva	Spain	1988
Cartagena	Spain	1989
Bilbao	Spain	2003
Sagunto	Spain	2006
Mugardos	Spain	2007
Sines	Portugal	2004
Fos Tonkin	France	1972
Montoir de Bretagne	France	1980
Fos Cavaou	France	2010
Dunkerque	France	2016
Zeebrugge	Belgium	1987
Rotterdam	Netherlands	2011

Table 14: Major LNG terminals in the Central Western Europe before 2022

Figure 40 shows the history of TTF, MIBGAS, and JKM LNG. In 2022, the correlation between TTF and MIBGAS decreased from 0.98 to 0.85 due to potential winter gas supply concerns for the Central European hubs. The bottleneck between MIBGAS and TTF also contributed to the decoupling.

Since September 2022, due to the unseasonably mild weather and demand destruction, Spain has not competed with TTF for LNG cargoes, and MIBGAS is below JKM LNG.

Overall, IE did not drive up TTF gas prices. Instead, Europe's limited pipeline interconnectivity and lack of LNG terminals in Central Europe led to the spike in TTF prices and the breakdown of the correlation between TTF and MIBGAS.

Figure 40: TTF, MIBGAS and JKM history

Statistics			
	Pre-IE(before 14/06/2022)	During-IE (15/06/2022-26/02/2023)	End of IE (27/02/2023-31/12/2023)
Observations n	530	257	308
Correlation	0.98	0.85	0.88

Table 15: Daily TTF and MIBGAS correlations

This section summarises our findings. To conclude, we accepted most of our hypothesis. The only rejected hypotheses include H3, when IE decoupled the Spanish-Portuguese power markets slightly despite abundantly available capacities, and H7, when Spain imported more power from Portugal, especially during winter 2022.

Hypothesis	Accepted/Rejected	Summary
H1	Accepted	The power price was reduced by €131 on average for the first three months.
H2	Accepted	Number of decoupled observations increased by +59.2%.
H3	Rejected	Number of decoupled observations increased by +0.9%.
H4	Accepted	IE increased outflow to France by 2.3 GWh per day.
H5	Accepted	IE increased outflow to Morocco by 32.6 times compared with pre-IE.
H6	Accepted	IE increased outflow to Andorra by 25%.
H7	Rejected	Spain was importing power from Portugal with 0.08 GWh per day.
H8	Accepted	Portuguese gas plants received subsidies, and the gas market share was reduced from 17% to 16%.
H9	Accepted	Spanish domestic power price increased by 24.8% due to foreign demand.
H10	Accepted	Gas burnt increased 19.2% (Iberia) and 1.3% (EU) under IE than counterfactual.
H11	Accepted	Gas burnt increased by 5.47% (Iberia) and 0.81% (EU) to satisfy foreign demand.
H12	Rejected	The counterfactual only increased French power exports by 14.9%. There is minimal displacement effect on biomass and coal plants.
H13	Rejected	The correlation between TTF and MIBGAS broke down due to central Europe's lack of gas infrastructure. IE did not drive up the TTF prices.

Table 16: Hypotheses summary

Comparing our results with Hidalgo-Pérez et al. (2024) we get broadly similar results for the reduction in wholesale power prices, the increase in gas consumption for electricity generation and the increase in exports to France caused by the IE.

7. Suggestions and Further Research

7.1 Limitations

7.1.1 Forward market

We focus on the day-ahead markets as we can quantify the distortions on the day-ahead flows and the impact on demand, supply, and gas burnt. However, it is understood that the volume of the Spanish futures market in 2021 was 233.8 TWh (Martinez and Pacce, 2023). Our results are limited to the day-ahead markets and actual generation only. There could be an impact as utilities and generators can voluntarily buy or sell their power on the forward market.

7.1.2 Seasonal Patterns

We only present the flow data since 1 January 2021, and there were seasonal patterns for the interconnectors. Investigating further into the past could calculate the seasonal import and export flows, which can work out the impact of IE against the seasonal average.

7.2 Flows

7.2.1 France day-ahead flow

We understand that 86.2% of observations (5,008 out of 5,808) from Spain was decoupled and lower than France, we discovered that 10.7% of observations (619 out of 5,808) were coupled yet gas subsidy was paid. A partial subsidy could have been saved as Spanish consumers could have bought their electricity from France instead, thus consumer unit adjustment and gas burnt could be reduced.

7.2.2 Morocco day-ahead flow

After the price cap was last triggered, there was still substantial flow to Morocco. The flow participation is rather opaque as it is organised by the TSOs. However, further research can potentially help understand why there is still substantial flow to Morocco even after IE.

7.3 Demand

7.3.1 Portugal purchase unit adjustment

We have the aggregated producer and consumer adjustment amount across Iberia. However, the breakdown across Spain and Portugal has yet to be investigated. Peña (2022) suggested that Spain paid €600 million more than Portugal for the IE as most Portuguese consumers were on a fixed-term contract. Spanish consumers who extended their fixed-term contract after May 2022 were liable for extra contributions. However, it will be beneficial to understand the split of the amount paid by the Portuguese consumers from the grid and market operator perspective.

8. Conclusion

The unprecedented energy crisis from 2021 to 2023 caused massive grief in Europe, leading to a sharp rise in the cost of living. Several short- and long-term interventions were suggested and implemented by the EU to counter the adverse impact on households and businesses.

Due to the main Spanish regulated consumer tariff directly linked to the day-ahead electricity spot price, limited interconnector capacities to the rest of continental Europe and low reliance on the Russian gas supply, it was argued that IE should only be applied to Iberia and not the rest of EU.

We discussed the fundamentals in the European power markets and how microeconomics could be applied to the day-ahead auctions. We discussed the adjustment mechanism's calculation methodology and how it was financed. We later devised hypotheses and used various market data from the grids and market operators to quantify the effects of IE.

Our results suggested that IE successfully lowered the gas bids with a secondary effect of decoupling the Spanish markets from France during the period that the IE was binding. The distortions were large. The power flows to Morocco and Andorra increased massively, and Iberia subsidised the power price of bordering countries. The IE further produced a partially uneconomic scenario for Iberian consumers as they could have purchased their electricity from France while saving some of the subsidy levied on the consumers. Portugal also applies the exact adjustment mechanism to its generators and does not merely buy subsidised power from Spain.

We further quantify the size of the extra purchases of gas. By modelling the counterfactual scenario, a simulation was run to remove the subsidy on gas plants. We worked out some adverse impacts, including extra gas being burnt to supply electricity to foreign countries, including France and Morocco, and how much extra gas was burnt to supply domestic electricity.

The Spanish government did not emphasise the cost of the IE and the EU did not consider the adverse impact of IE on European gas demand and prices. While the IE has successfully reduced the day-ahead spot price in Iberia, consumers must finance most of the producer adjustment. The effectiveness of IE was further reduced by the outflow to surrounding countries when the flows increased domestic power prices and European gas burnt. A better policy of subsidising infra-marginal electricity consumption could have had the same effect on average bills at much lower societal cost.

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