Competition in electricity markets: retailers, generators and technologies

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Contents

Chapter 1

Introduction

For its complexity, relevance and peculiar structure the electricity industry has challenged the researchers in a number of fields. Overtime, many policy interventions have contributed to reshape the electricity industries worldwide, engendering a need for constant updates in the understanding of this sector's dynamics. The process of liberalization, already undertaken in United States and Australia, has been completed in European Union in 2009 with the approval of the Third Energy Package. Generation and retail activities have been opened up to competition and spot electricity markets have been created accordingly. Upstream, the main reform's goal has been to boost efficiency by promoting capacity adequacy and technology mix optimality; downstream, the introduction of competition has been expected to empower final customers lured with better economic deals and a broader product/service range. Alongside with liberalization, the mounting concerns about global warming and climate change have pushed several Countries to rethink about their use of exhaustible resources, such as coal, gas and oil. European Union, the frontrunner in the global environmental battle, has approved in 2009 the Climate and Energy Package which has established compulsory targets for limiting greenhouse gas emissions, enhancing investments in renewable technologies for power generation and improving savings from energy efficiency. Furthermore, a set of publicly financed measures has been put in place to reach the objective of a 20% share of EU energy consumption covered by renewable production within the 2020 time horizon.

Predicting policies' impact on power sector's dynamics is a rather complex task for a number of reasons among which the difficulty of disentangling the effects of single reforms, the pervasive regulatory interventions in a sector considered economically strategic, and the uncertainty about the technological trajectory. For these reasons, several competing approaches for economic analysis may be applied and their results may be fruitfully combined in order to gain a thorough insight into electricity industry. The objective of this thesis is to answer to three questions raised by the waves of reform using in each case a specific methodology: theoretical industrial organization, applied industrial organization and micro-econometrics. The three questions may be synthesized as following:

1. Has retail liberalization achieved its objectives in European Union?

2. How “traditional” and “renewable” generators compete in a liberalized market?

3. What is the impact on congestion and zonal price differences of increased production from renewable intermittent sources in Italy?

The answers to these questions form the object of the three following chapters. As suggested by the title, if the analysis of competition in electricity markets represents the final goal of this thesis, each chapter is devoted to a particular aspect of this issue: the second chapter focuses on retailers, the third on producers and the fourth on technologies.

The second chapter[1] provides a mid-term evaluation of liberalization of electricity retailing in Europe, taking into account four limitations to policy analysis: different and often conflicting theoretical points of view, shortage of routinely collected data, problems in disentangling the effect of retail liberalization from those of other related reforms and pervasive regulatory interventions. Lacking a common analytical framework to assess the costs and benefits of electricity retail competition, a comprehensive theory on retail liberalization has been built and then used to test the consistency of theory and practice in European Union. The analysis of European data on market structure and dynamics highlights the presence of an oligopolistic supply structure, as well as a limited level of customer engagement in the market, which in the case of small consumers is partially justified by the presence of switching costs and informational complexities. Asymmetries in the rate and speed of cost-pass through make the market opaque, challenging the sole reliance on “light-hand” regulation to guarantee a sound market functioning. The situations in which some form of “hard” regulation appear to be necessary to secure the continuity of supply even after the introduction of competition have been identified and several implementation solutions are proposed according to the weight attributed to the objective of supply continuity and customer protection. In the light of evidences about European markets, the attribution of the Default/Last Resort service through an auction mechanism seems the best solution to favor both the development of upstream and downstream competition, without deterring customer switching.

[1]A first version of this chapter has been published as Concettini, S. and Creti, A., “Liberalization of electricity retailing in Europe: what to do next?”, *Energy Studies Review*, Volume 21, Issue 1, 2014.

The third chapter[2] studies the strategic interactions between two electricity generators, the first producing with a "traditional" technology and the second employing a "renewable" technology characterized by the random availability of capacity due to the intermittency of its power source. The competition between "traditional" and "renewable" power producers is examined through a modified version of the *Dixit model* for entry deterrence (Dixit, 1980). I propose two alternative settings for the post entry competition. In the baseline model I employ the Cournot framework and the subgame perfect Nash equilibrium in the investment-production game is found through a two-stage procedure. In the extended model, I adopt the "dominant firm - competitive fringe" setting developed by Carlton and Perloff (2002) and the equilibrium of the game is assessed in three stages. This extension aims at accounting for price taking behaviour of "renewable" firm which represents the competitive fringe in real spot electricity market. The idea behind this extension is that in a stylized model with only two technologies competing in a spot market, the "traditional" generator sets the price knowing that it will face a competitive rival while the "renewable" producer receives the price chosen by marginal "traditional" firm (the dominant firm) despite being competitive in its bid. The analysis suggests that the "renewable" generator exploits merit order rule to invest and produce as if it were a Stackelberg leader; producer's preferences over strategies do not vary with the values of parameters. However, according to the average value of capacity availability, the market may lead to an equilibrium which benefits both the "renewable" producer and the consumers. Given that production of electricity from the renewable source depends on actual weather conditions, the analysis of ex-post pay-offs reveals that "renewable" producer's preferences over strategies may be reversed for small errors in the forecasting of the true value of the average capacity availability factor. In this case, the incentives for strategic behaviour of the "renewable" producer may be even stronger. The main insights of the model seem to be barely sensitive to changes in the market power of competitors: even when the "renewable" generator behaves as a competitive fringe in the spot market, it is able to influence equilibrium outcome to its own advantage through investment choices although to a smaller degree than in the standard setting. In this extension, contrary to the baseline model, the ranking of strategies is sensitive to the choice of parameters'

[2] A first version of this chapter is published as EconomiX Working Paper No. 2014-44.

values. A numerical example shows that when the average value of capacity availability increases, the preferred strategy of "renewable" producer becomes that one implying the largest possible capacity investments.

The fourth chapter[3] studies the impact of increasing intermittent renewable generation on congestion and zonal price differences in Italy. The integration of renewable power plants, especially those exploiting intermittent power sources such as wind and sun, represents a challenge for network operators, market participants and regulators for a number of reasons. First of all, some geographical locations are particularly well suited for the installation of new capacity due to the abundance of natural resources. These locations may not coincide with consumption sites and may, on the contrary, be very far from them. Substantial investments are therefore required to integrate the new facilities and to ease the process of displacement of electricity from production toward consumption sites. Additional investments may be necessary to deal with increasing intermittent generation directly flowing into the network. Secondly, merit order rule and priority dispatch for the electricity generated from renewable power sources have redefined the rules of the game in decentralized spot market: on the one hand renewable supply has partly crowded out the production from mid-merit power plants and on the other hand it has intensified the needs for immediately available, back-up capacity to overcome the intermittency and to guarantee inflows and outflows balance. The economic literature, which has been especially concerned in analysing the impact of increasing renewable production on wholesale electricity prices, has emphasized the likely reductions on equilibrium prices entailed by renewable supply and originated from the displacement of higher variable cost production in the merit order ranking. Nonetheless, when national electricity markets are organized as two or more inter-connected sub-markets with zonal prices, the final impact on equilibrium prices of increased generation from renewable sources may result less straightforward than the existing literature would suggest. As a matter of fact, depending on the location of supply and demand, the renewable output may multiply the incidence of transmission congestions or it may relieve congestion occurrence by reducing transportation needs.

This chapter aims at testing the impact of this phenomenon using Italian electricity market as case study. The Italian Power Exchange is composed of 6 regional sub-

[3] A first version of this chapter has been written in collaboration with Anna Creti and Faddy Ardian.

markets which aggregate in macro-zones all the administrative regions. The hourly electricity price is unique for the whole country when all transmission limits between sub-markets are respected; otherwise a system of zonal pricing applies. The Northern zone, whose generation capacity is the largest of the country, has historically been an exporting zone; as a consequence its zonal prices have been constantly lower than the rest of Italy. The ambitious support policies for the development of renewable power sources have generated a significant amount of new investments in solar and wind power plants: Southern regions have showed the highest growth rate due to the favourable weather conditions. The analysis of inter-zonal transits resulting from the day-ahead auction as well as of the series of paired-price differences between neighbouring zones reveals a changing pattern between importing and exporting regions, with a stronger role for Central and Southern regions as exporters.

To assess the impact of increasing renewable generation on congestion and zonal price differences in Italy, I have built a unique database collecting and matching data with hourly frequency from several sources for the period 2010-2012: GME, the market operator, which publishes the hourly offers in the day-ahead market together with equilibrium prices, quantities end inter-zonal transits; GSE, the state-owned company promoting and supporting renewable energy sources in Italy, which provides information about renewable capacity and generation; Terna, the network operator, which is in charge for the estimation of the demand and the available transmission capacities; REF-E, a consulting group, which has created a list of Italian power plants classified by technology and geographical location; ICE, the American network of exchanges and clearing houses for financial and commodity markets. Then two econometric models performed on five zonal pairings have been estimated: a multinomial logit model, whose dependent variable has three discrete values capturing both the occurrence of congestion and its direction, and an OLS model which seeks to quantify the effects of renewable production on the size of paired-price differences.

The analysis suggests that the effect of increasing renewable generation on congestion remarkably depends on the importing/exporting role played by the zone under consideration. Indeed, if a region is normally importing electricity from its neighbour, the effect of a larger local renewable supply is: 1) to decrease the probability of suffering congestion in entry or 2) to increase the probability of causing a congestion in exit compared to no congestion case. Increasing hydroelectric production in these zones has a similar effect. In terms of price difference, increasing renewable generation seems to have a significant impact on the islander zones, decreasing the level of positive price differences and increasing the level of negative price differences. These results may have substantial implications for the rationalisation of Italian support policy to renewable sources.

Beside the results of the analyses which are extensively discussed in each chapter, it is worthy to mention here that the econometric estimations presented in the fourth chapter have required the set-up of a unique database tracing all the transactions in the Italian day-ahead electricity market from 2009 to 2013. The creation of the database has entailed a significant data-mining effort in order to accede, cross-verify and assemble information from different sources. It is worth to mention also that the construction of the database has posed a favourable basis for other ongoing and future researches on Italian electricity market.

Chapter 2

Liberalization of electricity retailing in Europe: what to do next?

2.1 Introduction

In any industry the role of retailers is to provide final customers with added-value services. The types and magnitudes of the costs and benefits of retailing adding-value activities vary widely across sectors, final customer dimensions and characteristics, periods, geographical locations and market structures.[1] In the electricity industry, retailers perform two main activities: on the one hand, they provide final customers a complex service by aggregating inputs from all upstream actors (generation, transport and distribution); on the other hand, they facilitate upstream firms' sales by finding, arranging and managing relationships with potential and actual buyers. In the liberalization process of power sector, retailing and generation have been opened to competition, whereas grid operation, maintenance and investments have remained under regulatory oversight. In Europe the opening of retail electricity markets has progressively entitled *eligible customers* to freely purchase retail services from a supplier of their choice: this right was first awarded to industrial consumers with annual consumption above a certain threshold[2] and then to all non-household consumers from the 1st of July, 2004, followed by all consumers since the 1st of July, 2007.

Before and during the process of liberalization several arguments have been put forth on the costs and benefits of retail electricity competition. Despite the non negligible academic and political interest on this topic, there has never been a consensus on the theoretical framework that should be used to examine retail activities in this type of market. The lack of a shared vision has challenged the definition of a common set of indicators for assessing the success or the failure of the reform. Two additional limitations have discouraged empirical impact analyses: on the one hand, the scarcity of data on European retail markets which prevents a systematic market oversight; on the other hand, the difficulty of disentangling the effects of retail liberalization from those of other related reforms (e.g. liberalization of generation) when using available data. On top of that, powerful regulatory interventions in this business compound the evaluation of retail competition's outcome. Indeed, liberalization goals of improving

[1]Retailing activities add-value optimizing consumers' allocations of time; increasing consumer awareness of product features, price and quality; offering customer assistance; reducing searching, switching, transportation, transaction and stock-out costs (Joskow, 2000).

[2]See Directive 96/92/EC.

efficiency and effectiveness in electricity retailing have been frequently counterbalanced, both at European and at national level, by the political requirement of ensuring that no consumers were excluded from trade. This objective has often been translated in the co-existence of market prices and regulated tariffs, the latter being kept artificially low with a clear impact on competition's dynamics.

The aim of this chapter is to provide a mid-term evaluation of liberalization of electricity retailing in Europe taking into account the mentioned analytic constraints: different and often conflicting theoretical points of view, shortage of routinely collected data, problems in isolating the impact of a single reform, pervasive regulatory interventions. We focus on European Union experience where a common framework on competition and regulation exists, differently from the US where the extent of liberalization results from State level regulation. Our objective is twofold: drawing the attention to a relevant topic which has been overlooked in recent debates on power markets and suggesting a set of actions that should be undertaken by policy makers in order to give electricity retail business a clearer status. In doing so we essentially compare theory and practice, trying to answering to the question: what to do next?

Our analysis suggest that direct benefits of retail competition have been often overstated, particularly for small and residential customers. Final market has proven to be less dynamic than forecast and new entry in supply more difficult to sustain in the medium-long run, notably for small, non integrated companies. The disappearance of captive market seems to have benefited more integrated generators willing to sell their power to newly attracted customers than pure retailers competing on a retail margin. At the same time, European regulators seem to have proceeded without truly questioning liberalization paradigm, even when some shortcomings have revealed. They have lacked both the courage to let the market freely work and the strength to take a step back when it did not.

Our main conclusion is that it seems unlikely that "light-hand regulation" may fully substitute for "hard regulation"[3] in this sector, especially for small and residential customers. In the light of this limitation, further actions appear to be required to give a thorough organization to this business able to let expected outcomes of other related

[3]By "light-hand regulation", we mean market monitoring and ex-post enforcement, while by "hard regulation", we mean ex-ante regulatory interventions.

reforms (e.g. liberalization of generation) a stronger impact on final customers' welfare. In our opinion, the removal of tariffs, although desirable in a long run, does not appear at present to be the best incentive to boost competition, given possible market power of providers and difficulties in monitoring the market; on the contrary a Default service assigned through an auction mechanism may favor both the development of upstream and downstream competition.

The discussion is organized as follows. Next section summarizes the theory on competition in electricity retailing while the third section provides an overview of European retail electricity markets. Section 4 discusses market characteristics which may undermine the development of a sound retail competition in electricity retailing. The analysis of Default and Last Resort services and the implementation of protection mechanisms for "vulnerable customers" is included in the fifth section with some suggestions about how to improve reform's outcomes. Some final remarks close.

2.2 Retail electricity competition

The expected impacts of competition on electricity retailing are summarized in Table 2.1. Some of the benefits concern efficiency gains, while others are more related to the aspect of differentiation; the remaining benefits are associated with equipment innovation. The academic debate on retail competition has generally been of a qualitative nature[4] although there have been some econometric attempts aimed at examining consumer behaviour and at measuring the impact of retail competition on final prices.

2.2.1 Efficiency

Increasing competitive pressure on electricity retailers is likely to improve the efficiency of retailing. Direct gains have two sources: a more efficient organization of retailing

[4]The contributions of Borenstein and Holland (2005) and Joskow and Tirole (2006) are, to the best of our knowledge, the only attempts to formalize models of retail electricity competition. In these papers, the authors estimate the price distortions arising when competitive retailers are active and settlement obligations for wholesale power purchases are determined on the basis of load profiles when final customers do not react to real time prices. For models of retail competition in the gas industry, see for instance Cremer et al. (2006) and Polo and Scarpa (2011).

Dimension	Expected impact
Efficiency	Direct gains on retail services
	Indirect gains on wholesale, transport and distribution services
	Systemic gains (elimination of double marginalization effect)
Differentiation	New offers and contractual arrangements
	Wider range of services (risk-hedging services, energy management)
Equipment innovation	Innovative measuring and reading devices
	Empowered equipment for quality services

Table 2.1: Expected impacts of retail electricity competition

activities and a larger use of cost-based pricing.[5] The first source of efficiency has proven to be negligible according to the estimates of Joskow (2000) in US, and Ofgem (2004) and Littlechild (2005) in UK.

Using 1996 data, Joskow estimates the potential savings for the average customer in United States from switching to a competitive retailer that is responsible for all retailing services[6] and is able to provide them at a 25% discount compared to distributors. He finds that the average customer's bill might be reduced by less than 1% or approximately 2 dollars per month if the competitive retailer were to pass all of its cost savings through to the customer. In the same vein Ofgem, the British energy regulator, roughly calculates for different payment methods[7] the retail margin on which the entrants are supposed to undercut incumbents. Littlechild provides a downward revision of Ofgem's estimates, mainly reflecting larger than forecast costs for credit cover and initial IT and billing system settlement. The author concludes that the retail margin may be positive only for direct debit contract, regardless the size of the entrant, while is negative (small suppliers) or zero (large and medium sized suppliers) for standard credit contracts. Prepayment contracts may entail negative margins for all types of new entrants.

[5]Real time pricing is one of the possibilities.

[6]It should be noted that, even after full unbundling, distributors will continue to be responsible for, and thus will bear the costs of, some retailing services such as requests to connect, disconnect, or change the level of service, resolve outages and power quality problems, and interface with competitive retailers (Joskow, 2000).

[7]Standard credit, direct debit and prepayment.

According to Littlechild (2000), however, total efficiency gains may be more significant because they originate not only from direct retail operations but also from an improved upstream procurement.[8] Fierce competition for end customers may also place downward pressure on transmission and distribution costs. Moreover in the long run, competition reintroduces the proper incentives for dynamic efficiency: with competition only the best offers from the efficient suppliers can survive and expand at the expense of unwanted contracts or/and inefficient sellers.

A last source of efficiency, which we may call systemic, has been envisioned in the elimination of the double marginalization effect (Goulding et al., 1999). This effect arises as a consequence of the vertical unbundling of supply activities along the value chain when firms in different segments retain some degree of market power. Economic theory states that when vertical relations do not exist, firms can exercise their market power at all successive stages of the value chain, generating a negative impact on aggregate firm profits and on consumer welfare.[9] From this perspective, retail competition *per se* is perceived to be a positive element of liberalization reforms: with retail competition, the double (retail) margin is eliminated or at least reduced.[10]

For the supporters of full retail competition, in principle efficiency gains may be passed through to customers in the form of lower final prices.[11] Some authors have attempted to estimate the impact of reforms such as privatization and liberalization on final prices and efficiency. See for instance Newbery and Pollitt (1997) on British data, Steiner (2001) and Hattori and Tsutsui (2004) on OECD Coutries[12] and Joskow (2006)

[8]Littlechild (2000) provides some quantitative estimations of this effect in the United Kingdom, while recognizing the inherent difficulty of such an exercise.

[9]The double marginalization problem may also be overcome by reestablishing vertical contractual relationships between actors (with some sided-effects) or by using special types of contracts, e.g., two-part tariffs (Motta, 2004).

[10]An empirical paper by von Der Fehr and Hansen (2010) reveals that when fierce competition has been introduced in Norwegian retail electricity market, firms has begun to behave as in a standard Bertrand setting, which has ensured cost-reflective pricing, even in the presence of a small number of competitors.

[11]It is worthy to highlight that a larger use of cost-based pricing to improve efficiency may translate into higher prices for those customers whose consumption has been subsidized through below-cost tariffs before liberalization.

[12]The first paper presents a social cost-benefit analysis, while the others perform regressions using panel data. Both approaches present specific limitations: cost-benefit analyses require the assessment of a credible counterfactual; in the regressions, endogeneity issues are likely to arise.

on US data. Joskow's paper is the only one that properly accounts for retail competition. The author compares changes in real electricity prices between 1996 and 2004 for US states that introduced retail competition and for those that have not. He finds evidence that households in the states where the reform was adopted benefited from larger reductions in prices (with the exception of Texas), while this trend is not apparent for industrial customers. However, this result cannot be attributed *tout court* to retail competition, as in the same period, several other reforms were implemented in the electricity sector (increased competition in generation, improvements in the regulation of distribution and transmission services, etc.).

On the downside, several authors agree that opening the market is likely to produce larger advertising, promotional, transactional, and system duplication (e.g. billing or customer assistance) costs, while there is no consensus on the final balance between these costs and the benefits of competition.[13] For instance, Littlechild (2000) finds that in the long term, efficiency gains may offset increased advertising and promotional costs, whereas Joskow (2000) and Defeuilley (2009) are more skeptical of this prediction.

2.2.2 Differentiation and equipment innovation

Theoretically speaking, retail competition is expected to bring new offers and contractual arrangements to the market and broaden the range of available services, such as risk-hedging or energy management. Furthermore, competitive pressures on retailers may indirectly force other actors, such as distributors or equipment providers, to develop and install new measuring and reading devices and the equipment necessary to improve service quality.

According to Joskow (2000) and Defeuilley (2009), the potential for product differentiation and developments in the range of value-added services for which small and residential customers are willing to pay an additional fee appears constrained in the electricity industry. Empirical evidence in Europe partly contradicts this pessimistic

[13]Advertising and marketing are useful tools for spreading information about products, prices and competitors. However, a general mistrust toward electricity retailers, energy brokers and their advertising campaigns endures, undermining the engagement of consumers and the gains from communication (OFGEM, 2012b). Consumer attitude has been sometimes exacerbated by misleading advertising campaigns which have been fined worldwide by competition authorities (see for instance the cases of ENI in Italy and Airtricity in Ireland).

view on limited scope for product differentiation.[14] Even though additional services such as energy management were primarily demanded by larger customers, competition in electricity retailing also stimulate the demand for new types of products (mainly with green and dual fuel options) and innovative contractual arrangements for pricing (wholesale price plus mark-up contracts, fixed-price contracts, standard variable contracts, time-of-use contracts, and flat contracts) among small and residential customers. The diffusion of these products remains nonetheless heterogeneous.[15]

The installation of smart metering and reading devices seems to represent an essential condition for extending the range of products and services offered by electricity retailers as well as for enabling an active demand side participation. Intelligent equipments may foster the development of contracts with dynamic pricing options and the adoption of more efficient consumption behaviours; moreover they may simplify the process of billing and information exchange between retailers and distributors, with a positive impact on competition dynamics.[16] Even so the adoption of this new technology seems to have been prompted more by binding legal framework than by competitive forces. Indeed it is the European Directive 2009/72/EC which has established that 80% of total consumers should have been equipped with an intelligent metering system by 2020. The decision to roll-out smart metering systems has been subject to a preliminary economic assessment at national level, which has resulted in a variety of coverage choices, technical designs and implementation schedules (ERGEG, 2013). At present only Italy and Sweden have completed their roll-out with a 95% and 100% coverage respectively[17] while Belgium, Czech Republic, Portugal and Lithuania have decided not to invest at all in smart meter deployment. This situation highlights the lack of agreement on the final balance between costs and benefits of smart meter adoption especially in the case of small and residential customers (on this debate see for instance Léautier,

[14]The analysis of the relationship between the numbers and types of available contracts and the ability of consumers to seize the better market opportunities by switching supplier is postponed to section 4.2.

[15]For a survey of newly introduced products, see for instance Von der Fehr and Hansen (2010) on the Norwegian market and Littlechild (2002) on British market.

[16]Littlechild (2005) discusses in details the importance of metering and data communication in the process of entry. For a recent consultation of stakeholders on this topic see CEER (2014).

[17]In both cases the distributor is in charge for the roll-out and the investment is financed through regulated tariffs.

2014).

2.3 Retail markets in Europe

European Union represents an unique case study for the analysis of electricity retail liberalization. All Member States have indeed adopted a common legal framework to open both the wholesale and retail markets to competition. Therefore, if there are country-specific aspects of retail competition, they reflect different realities in terms of generation mix, political and strategic objectives, and consumers' attitudes and awareness vis-à-vis the market. In this section we provide an overview of European retail electricity markets and we calculate a few economic indicators of market structure to test some of the theoretical predictions about liberalization's outcome.

2.3.1 The supply side

Over the whole 2003-2011 period the total number of electricity retailers has decreased from about 3379 to about 3242.[18] The figures for main retailers, i.e. those accounting for at least 5% of total national electricity consumption, reveal that in 2011 only one country, Slovenia, has eight big players, while most of sample Countries show three to six main retailers. From 2003 to 2011 the total number of main retailers has remained relatively constant, from about 102 companies in 2003 to 100 companies in 2011.[19] A relevant indicator of market structure is provided by the cumulative market share of main retailers. The difference between the total market and the cumulative market share of main retailers indicates the size of the residual market, or the market available to minor competitors. The cumulative market share of main retailers in 2011 is reported in Figure 2.1.[20]

According to the size of the residual market, European countries can be classified into three groups:

[18]Source Eurostat.

[19]The relevant market for retailers is the national market. Detailed data are reported in Figures A.1, A.2 and A.3 in the Appendix A.

[20]Denmark, Finland and Greece are excluded because of missing data.

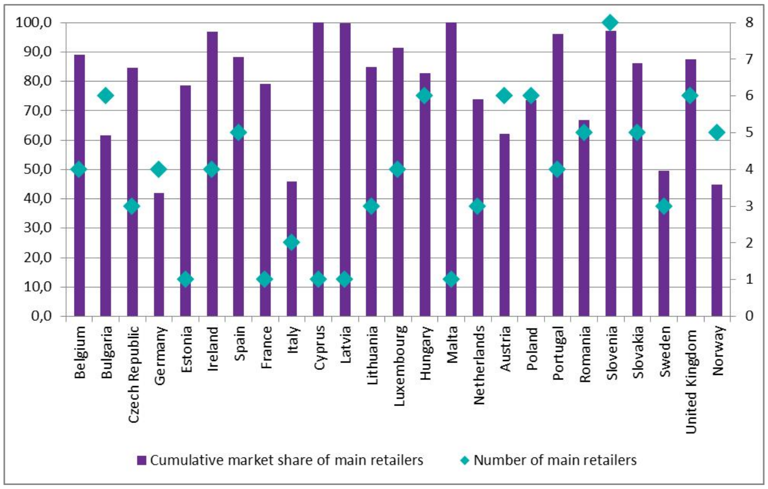

Figure 2.1: Cumulative market share of retailers (%), 2011
Source: Authors' elaboration on Eurostat data

- Countries where the market covered by minor retail companies is large, i.e., between 45% and 60% of the total market: Germany (58%), Norway (55.1%), Italy (54%) and Sweden (50.4%);
- Countries where smaller retailers cover between 45% and 20% of the total market: Bulgaria (38.5%), Austria (38%), Romania (33.1 %), Poland (26.3 %), Netherlands (26%), Estonia (21.4%), France (21%);
- Countries characterized by a small residual market (below 20%):[21] Hungary (17.3%), Czech Republic (15.4%), Lithuania (15.2%), Slovakia (13.8%), United Kingdom (12.4%), Spain (11.7%), Belgium (11%), Luxembourg (8.7%), Portugal (4%), Ireland (3%), Slovenia (2.8%) and Latvia (0.1%).

Although from 2009 to 2011 the cumulative market share of mail retailers has decreased in 17 out of 25 Countries,[22] the market for "minor competitors" remains below 20% in 14 out of 25 Countries in 2011.

[21]Cyprus and Malta have one retailer serving all the market.
[22]The data are reported in Figure A.4 in the Appendix A.

These figures indicate that European electricity retail markets have an oligopolistic structure rather than a competitive one. Small and independent retailers have often experienced unsuccessful entry attempts, horizontal consolidations or acquisitions by larger and vertically integrated firms. Some of the difficulties faced by small companies in running a retail business alone have been highlighted in Littlechild (2005): limited profitability of entry (especially in residential markets) and high cost of credit cover; excessive regulatory and compliance burdens; scarce quality of data and metering services; low liquidity of wholesale markets and large exposure to spot price volatility. The presence of economies between retail and generation activities has also favored the integration of upstream and downstream businesses (Pollitt, 2008): if owning a retail firm has the potential to increase generators' investments by limiting overall business risk, the reduction in the number of independent upstream providers amplifies the risk of foreclosure and facilitates the inflation of retail margin (Jamasb and Pollitt, 2005). Therefore if on the one hand vertical integration may be detrimental to retail competition on the other hand its effects on electricity wholesale and, especially, final prices remain ambiguous (Mansur, 2007; Bushnell et al., 2008; Giulietti et al., 2010).

2.3.2 The demand side

On the demand side, the switching rate of final customers is a commonly used indicator for the level of buyer commitment in a market: it calculates the number of end users who decide to change suppliers when retail services are liberalized. The main idea conveyed by this indicator is that if consumers can easily change service providers when they wish to, producers are less prone to engage in exploitative behaviors, such as imposing high final prices or low quality, and hence the market may be considered more competitive.[23]

Figure 2.2 shows the latest available data on the annual switching rates for household customers.[24] Belgium, Great Britain, Ireland, Spain, Netherlands, Portugal and

[23]The switching rate does not account for the number of customers who have chosen another contract offered by their current supplier. This number also represents an indicator for customer awareness that is not accounted for in official figures which may somehow underestimate customers' market participation.

[24]Switching rates by end user category are reported in the Appendix A (Figures A.5 to A.7). Note that the figures refer to the period 2008-2009 and the source is the European Commission. Large and medium-sized firms generally present higher switching rates than households, indicating a more active

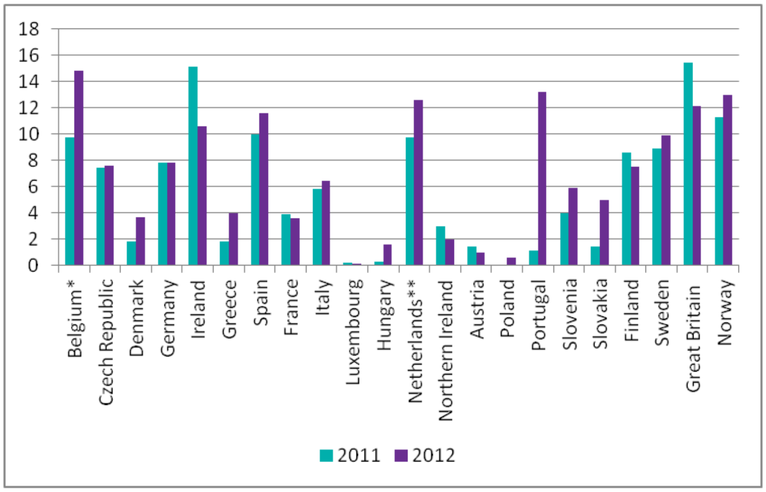

Figure 2.2: Annual switching rate for household consumers (%), 2011/2012
Source: Authors' elaboration on CEER data
Note: For Belgium the 2012 rate is a weighted average for the Flanders and Brussels regions;*
*** Data for Netherlands refer to all segments of retail markets;*
Bulgaria, Estonia, Cyprus, Latvia, Lithuania, Romania and Malta registered zero switchings

Norway present switching rates between 10% and 15%, followed by Czech Republic, Germany, Italy, Slovenia, Finland and Sweden whose rates range between 5% and 10%. The remaining 8 Countries have registered rates below the 5% threshold while other 7 Countries (Bulgaria, Estonia, Cyprus, Latvia, Lithuania, Romania and Malta) have registered no switchings. The trend in the indicator is positive overall, with the exception of a few countries. Interestingly, it is not possible to identify a clear relationship between household switching rates and saving potentials, given the fact that countries with larger gains in moving from the incumbent supplier to the cheapest available option in the market are not systematically characterized by higher switching rates (ACER, 2013). Moreover, only in 6 countries, namely Malta, Cyprus, Ireland, Great Britain, Northern Ireland and Greece, the energy component[25] accounts for more than 50% of the post-tax price for electricity (Eurostat). When competition may have an impact

participation of larger customers in retail electricity markets.

[25] The energy component includes the commodity price and the costs for marketing, billing, other related business costs and a fair margin.

only on a small share of the total bill, the incentives for customers' active participation remain somehow weak.

Three considerations are noteworthy. First, there is no consensus on the level of the switching rate at which the market can be considered "sufficiently competitive". Littlechild (2009) considers a residential customer switching rate of 10% a sufficient threshold to justify the liberalization of retailing. Therefore, according to the data very few countries seem to have developed a sufficient level of competition. To the best of our knowledge, this is the only author providing a basis for comparison with real data. Second, the difference in switching rates between residential and large customers seems to indicate that there exists a two-tier market according to the size of final customers. We address this issue in detail in the next section. Finally, the most recent publicly available figures, from 2012, reveal that 17 countries in the group of EU-27 Member States, Norway and Northern Ireland, keep regulated prices for households, while only 12 do so for small and medium enterprises and 5 for large industry. Where tariffs are available, a large share of residential customers continue to purchase electricity under regulated conditions;[26] moreover the average switching rate in these countries results to be lower than in full liberalized countries (ACER, 2013). It is worthy to note, however, that with very few exceptions, the pre-tax price[27] of electricity in countries where at least 90% of residential consumers were on regulated tariffs has been lower than the EU-27 Member State average in 2012.[28] While it is true that regulation and competition are two sides of the same coin, there is still no general consensus regarding the necessity of eliminating end-user price regulations to allow the retail market to operate effectively. We will further explore this topic in the last section.

2.4 Competition with market imperfections

Some authors have claimed that the presence of market imperfections, such as switching costs, informational complexity and a "consumer preference not to choose", may have

[26]For the proportion of SMEs and large industry on regulated tariffs see EC (2011).

[27]The pre-tax price includes the commodity price, regulated transmission and distribution charges, and retail components (billing, metering, customer services and a fair margin).

[28]Only four Countries without price regulation, namely Finland, Slovenia, Czech Republic and Norway, have pre-tax price below the average (ACER, 2013).

negatively affect the outcomes of competition in the electricity sector, at least regarding small and residential customers (Joskow, 2000; Brennan, 2006; Defeuilley, 2009). Others have found that the introduction of competition may entail a negative externality, namely customer's segmentation (Defeuilley, 2009; von der Fehr and Hansen, 2010). Furthermore, a last group of authors has highlighted the shortfalls of employing traditional measures of competition in this sector, such as the rate and the speed of cost pass trough. In the following paragraphs, we present a summary of the main findings regarding these issues.

2.4.1 Switching costs

Theoretically speaking, in markets characterized by repeated interactions between buyers and sellers, a consumer who has previously purchased a product from a supplier may incur costs when switching to a competitor, despite the firms' products being identical (Klemperer, 1995). Switching costs arise for the following reasons:

- searching costs to identify offers and the suppliers;
- learning costs to become familiar with the supplier;
- transactional costs to sign and resolve a contract.

Switching costs may be real or perceived and lead to a situation in which *"products that are ex ante homogenous become, after the purchase of one of them, ex post heterogeneous"* (Klemperer, 1995). These costs prevent customers from changing suppliers even if they are offered a better priced deal and thus have the same effects on market dynamics as a barrier to entry. In the electricity industry, where consumers have long-lasting supply relationships with the incumbent, switching costs may deter complete consumer mobility, leading to under-switching despite the presence of substantial savings (Defeuilley, 2009). Moreover, the situation may be exacerbated if the switching process is delayed or blocked by suppliers without specific reasons.[29]

Giulietti et al. (2010) analyze the influence of searching and switching costs in the UK retail electricity market by studying the trend in price convergence between new

[29] Compare for instance Ofgem (2012a).

entrants and the incumbent. The authors find that, in line with the general predictions of competition models with switching costs, even after the entry of new competitors, incumbents are able to enjoy a consistent price advantage. Moreover, new entrants, as soon as they are established in the market, tend to exploit the presence of consumer searching and switching costs: over time, new firms' incentives to offer lower prices to gain additional customers are more than offset by the benefits of keeping prices high to increase margins on previously served customers.

2.4.2 Informational complexities

In some sectors, consumers may also be unwilling to change suppliers because they face relevant difficulties in evaluating and comparing suppliers' offers. This might be the case in the electricity industry, where consumers are generally offered two- or multi-part tariffs, which reduce their ability to estimate the per-unit price of the product. This situation might be further complicated if supply contracts contain other advantages that cannot be straightforwardly translated into electricity price savings (e.g., discounts on dual fuel contracts). This limitation may imply the following:

- consumers switch to a more expensive supplier (over-switching);
- consumers switch to a cheaper but not the cheapest available supplier (inaccurate switching).

Errors in consumers' switching decisions damage their welfare both directly, as they cannot obtain the maximum surplus provided by existing retailers, and indirectly, by increasing retailers' market power due to a weakened relationship between firms' sales and surplus provision.

Empirical evidence on electricity sector is provided in Wilson and Waddam-Price (2010). The authors employ a sample of more than five thousand face-to-face surveys of UK households, 16% of which has switched suppliers.[30] They find that nearly 20% of households switched to a more expensive supplier, while inaccurate switching led customers to only obtain half of the gains available on the market. The authors do not find evidence for misselling causing such effects; rather they suggest that complexity and

[30]The sample is biased toward low-income customers.

consumer confusion may cause switching decisions to be less efficient when the number of options in the market is large. As a consequence, while competition may have a positive effect on the total gain available on the market, informational complexity may limit the ability of consumers to appropriate it.

Recently, OFGEM (2012a), the British Regulator, published a package of proposals designed to eliminate, or at least reduce, informational complexities that constrain households' participation in electricity markets. The proposals include a limitation on the number of tariffs that suppliers can offer and the types of tariffs (only two part-tariffs are allowed), and impose specific layouts and contents for communications from suppliers to consumers.

2.4.3 Consumer preference not to choose

In open opposition to the assumptions of the standard economic model, Brennan (2006) attributes the likely scarce success of competition in retail electricity market to the consumer preference for not making a choice, which can be considered a type of market failure. While liberalized markets have forced consumers to make informed choices that in turn presuppose increasing efforts at understanding and comparing contract conditions and terms of trade, the experience in electricity, and previously in telecommunication markets, seems to suggest that consumers in these sectors do not always consider having additional options from which to choose an advantage. Brennan's opinion stems from an accurate analysis of the marketing literature which indicates that consumers generally exhibit a limited propensity to revise their choices or change the goods and services in their consumption bundles.

2.4.4 Customers' segmentation

Some authors note that a possible side-effect of introducing competition in the retail electricity market is the segmentation of active and passive customers (Defeuilley, 2009; von der Fehr and Hansen, 2010). Consumers are active in a market when they exercise their freedom of choice by switching suppliers or by renegotiating their contractual conditions without changing retailer. Differences in customers' willingness to switch suppliers or renegotiate contractual arrangements may create the potential for a twotiered retail market. In this case, active consumers who are consistently involved in market dynamics may benefit from the introduction of competition in retailing because they can obtain access to deals with prices that tend to be more cost-reflective. The inactive customers, conversely, may end up paying prices that are above their pre-liberalization levels, as firms may exploit consumers' reluctance or inability to switch to cross-subsidize their entry to the competitive sub-markets. Empirical evidence from the Norwegian and United Kingdom markets seems to confirm this prediction (OFGEM, 2007; OFGEM 2012b; Von der Fehr and Hansen, 2010).

2.4.5 Speed and rate of cost pass through

The speed and the rate of procurement cost pass through is often used to proxy the level of competitive pressure faced by suppliers when fixing their price. We would expect that in a competitive retail market wholesale cost increases and decreases are passed through customers punctually and symmetrically for positive and negative shocks. Nevertheless, analyzing UK final bills[31] from 2004 to 2010, Ofgem (2011) finds evidence that the speed and the rate of pass-trough results to be higher and the final price adjustment faster in periods of growing wholesale prices compared to falling or stable wholesale prices. As a consequence, downstream competition seems to be tighter when procurement costs are rising and weaker when costs are falling. The British regulator envisages two main possible explanations. First, consumer engagement in the market flags in period of decreasing prices, relaxing competition in the downstream market; second, the vertically integrated companies tend to balance the profits across business: when wholesale prices are low a larger retail margin may compensate for the loss in profits from generation and viceversa. Using data on variable price contracts in Norway from 2000 to 2010, Mirza and Bergland (2012) confirm the presence of an asymmetric speed in the pass-trough of wholesale shocks. They find a stronger evidence of this behavior among suppliers which do not charge a fixed fee as the five dominant national level retailers. The authors claim that these suppliers, albeit apparently cheaper, delay the pass-trough of wholesale price decrease to earn extra-profits. The asymmetric price adjustment strategy is seen therefore as a mean for covertly exerting market power.

[31] The retail price is built using standard regional tariffs.

2.5 Regulation in competitive retail markets

We claim that some regulatory measures which ensure the continuity of supplies remain necessary even after the introduction of competition in electricity retailing. It is worth noting that the need to provide an uninterrupted service may be counterbalanced by the objective of ensuring a certain level of customer protection, especially in terms of price, when the market is not yet sufficiently developed. Three situations are at stake. First, in the aftermath of market opening, customers may decide to switch to a new supplier or can be passive and do nothing. In the latter case, the continuity of supply can be guaranteed by assigning passive customers to a so called Default Supplier (DS).[32]As competition expands and more consumers participate in the market, demand for the Default service should fall and nearly disappear in the long run. Default service may be also employed when competition strives to develop or "light-hand" regulation is difficult to enforce. Second, customers served by a competitive retailer may face the risk of being interrupted if the supplier becomes unable to provide the service, for instance because it is insolvent or bankrupt. In this case, regulators must arrange for the transition of customers to a temporary supplier, the so called Last Resort Supplier (LRS), which ensures service continuity. There may be a third group of customers, often called "vulnerable", that struggles to obtain a counterpart in the market, notably because these customers are not profitable. The lack of profitability may depend on customers' social and economic backgrounds or on the costliness of supply. In the transition to competitive retail markets, these customers face a serious risk of exclusion.

European legislation fails to thoroughly address these issues, a situation that is mirrored in the heterogeneity of national regulations concerning DS, LRS and mechanisms for "vulnerable" customer protection. The term Default Supplier does not appear in the Directives, and ERGEG (2009) reports that most European Countries (11 over 27) do not use this term in their national regulations. When employed, it generally refers to the provider serving passive and "vulnerable" customers. Conversely, the Supplier of Last Resort is explicitly mentioned in European Directives as the provider of Universal Service.[33] The majority of European Countries (20 out of 27) use this label to indicate

[32]An alternative is the immediate disconnection of passive customers, but we do not consider this hypothesis politically feasible.

[33]The Directive 2009/72/EC states, "*Member States shall ensure that all household customers, and,*

the provider of both "vulnerable" customers and consumers whose retailer exited the market. According to ACER (2013), the concept of "vulnerable" customers is present in 18 over 27 countries although with very different interpretations. It is common that the terms DS and LRS are employed synonymously and that a unique supplier is designated to ensure the continuity of supply in each of the three cases examined above. When national regulations do not employ these labels, other forms of interventions are designed to overcome the three possible situations where a retailer is absent. DS and LRS are usually selected by the regulator: commonly the incumbent is the DS, while in the half of the countries it also performs the role of LRS. The length of Default service provision is not temporarily limited in most countries.

More interestingly for the analysis of competition dynamics, Universal Service provision frequently coincides with end-user price regulation for small and residential customers.[34]In this case, the justification for end-price regulation seems to rely on the need to reduce the exploitation of final customers resulting from retailers' market power after the introduction of competition (Littlechild, 2000; OFGEM, 2002; ERGEG, 2007) and thus regulation appears to have similar objectives of DS provision. In our opinion, European regulation may be substantially improved by targeting each of the situations described above with a specific intervention, having made clear in advance the objectives that are to be pursued. We shed some light in this debate by discussing possible interventions and their impact on competition in the next paragraph.

2.5.1 How to improve market functioning?

According to the relative weight placed on the objectives of securing service continuity and protecting customers from exploitation, and considering several possible providers,

where Member States deem it appropriate, small enterprises, enjoy universal service, that is the right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable, transparent and non-discriminatory prices. To ensure the provision of universal service, Member States may appoint a supplier of last resort".

[34]The French government, for instance, in 2010 passed the NOME law, which prescribes the complete removal of tariffs for industrial customers beginning in June 2011 and allows residential customers to choose between signing contracts at market prices or being supplied by the incumbent firm, EDF, at regulated tariffs through to 2015, when all end-user regulated tariffs will disappear. The law also entitles competitive retailers to withdraw a share of EDF nuclear generation at a regulated price to supply final consumers. For further details see Creti et al. (2013).

a wide array of implementation patterns of DS and LRS are feasible (Table 2.2). In addition, three procedures are in principle available to assign these services to a retailer:

1. a direct "ex ante" entitlement, typically granted to the incumbent firm;
2. a periodic rotating obligation imposed on competitive suppliers;
3. a bidding process based on the competitive selection of the provider.[35]

Responsible subject	**Price for electricity**	**Price formation**	**Focus**
Transmission system operator	Imbalance payment	Real time	Supply continuity
Local distributor	Regulated tariff or price cap	Historic (cost)	Consumer protection
	Freely set price	Real time	Supply continuity
Retailer	All retailers (or only the incumbent) offer a tariff	Historic (cost)	Consumer protection
	Supplier resulting from auction	Real time	Supply continuity

Table 2.2: Patterns for the organization of Default and Last Resort services

Each intervention creates however market distortions and has a different level of political and social acceptability, as well as technical feasibility. For instance, when ensuring the continuity of supply is the only regulatory goal and the market seems to be quite competitive, network system operator may provide Last Resort services as part of its balancing activity while the local retailer may freely set the price for the Default service. Price formation for Last Resort Service occurs in real time: the consumers pay an imbalance payment, which is generally burdensome, to discourage imbalances

[35]An empirical application of this measure can be found in Italy, where non-residential customers who temporarily lack a retailer can benefit from a "safeguard service", the supply of which is assigned for a period of two years to the winner of a reverse auction, where the participants offer to provide the service at a mark up with respect to the wholesale price of electricity.

from the day-ahed production plan. Conversely, if a regulator wishes to guarantee a high level of customer protection, Default and Last Resort services may be offered at a tariff and provided by a retailer or the local distributor. Relevant market distortions are created when Default and Last resort services are offered at a tariff that does not reflect its underlying costs (Joskow 2006; EC, 2007): the first is to provide customers with inaccurate price signals for their withdrawals; the second is that the tariff becomes the reference price for market contracts, i.e., the so called *"price-to-beat"*. It is likely that consumers may be deterred from switching and new entry may be hampered if tariffs do not reflect the underlying costs. However, there is no consensus regarding the necessity to withdraw electricity tariffs to allow the market to operate effectively. For instance, Vásquez et al.(2006) maintain that a permanent, well-calculated tariff including a shopping credit which is an extra charge over the regulated tariff that creates a retail margin over which new entrants can compete, achieves the objective of guaranteeing the supply to all customers without deterring consumer switching. Other authors such as Joskow (2000) and Littlechild (2000) are more skeptical on the benefits of including a shopping credit in regulated tariffs.

Evidences from our analysis suggest that, if some form ex-ante regulatory interventions is still required, the assignation of the Default (and/or Last Resort) service through an auction mechanism reduces market distortions and may favor both the development of upstream and downstream competition, while avoiding the problem of deterring customer migration to the market since the tariff is cost-reflective.

Finally, the problem of "vulnerable" customers is slightly different and may be better understood within the Universal Service Obligations (USOs) framework. The primary argument in favor of USOs has been a concern for full market coverage at reasonable prices, including more costly market segments such as rural areas. Accordingly, some obligations have been imposed on network service providers in the form of restrictions on price discrimination ("non-discrimination"constraint) or obligations to provide the service regardless a customer's geographical location ("ubiquity" constraint). Often, the two constraints have been combined, asking the firms to ensure full market coverage at a uniform price. Prior to liberalization, vertically integrated monopolies were able to finance USOs by cross-subsidizing unprofitable and profitable market segments in their customer portfolio.

From a theoretical perspective, when competition is introduced in markets with profitable and unprofitable end users, new entrants only compete with the incumbent for profitable customers, generating the so-called "cream skimming" phenomenon, which challenges the incumbent's ability to finance USOs through cross-subsidies (Laffont and Tirole, 2000). Several authors (see for instance Anton et al., 2002; Choné et al., 2000; Choné et al. 2002; Mirabel and Poudou, 2004) have attempted to assess the welfare effects and distortionary impacts of different regulatory instruments that governments may implement to allocate and finance USOs. However, none of these papers question the economic rationale behind keeping USOs in liberalized markets. In particular, while the "ubiquity" constraint may continue to be imposed on regulated network operators, "non-discrimination" constraint is at odds with the concept of competitive markets with efficient cost-reflective prices.

Panzar (2000) stresses that there is an unavoidable trade-off between competition and universal service provision in liberalized markets. If there is a need for a universal service policy, this means that the competitive market cannot deliver socially acceptable allocations without direct public intervention. We argue that the need for USOs exists if the transition to competitive retail markets may exclude "vulnerable" or unprofitable customers from the trade of an essential good such as electricity. However, in line with ERGEG (2007), we suggest that to avoid the risk of exclusion more targeted and less distortionary interventions are preferable, such as social tariffs[36] or direct transfers to customers.

2.6 Conclusions

Assessing the impact of electricity retailing liberalization is a rather complex task. We identified four main limitations to policy analysis: different and often conflicting theoretical points of view, shortage of routinely collected data, problems in disentangling the effect of retail liberalization from those of other related reforms and pervasive regulatory interventions. Therefore, to provide a mid-term evaluation of the reform, we firstly built a comprehensive theory on liberalization of electricity retailing and then

[36]For instance, the duty of serving customers through social tariffs may be allocated to the local distributor, to all retailers or to the incumbent.

we used European Union data on market structure and its dynamics to test the consistency of theory and practice. We decided to focus on European Union experience where, differently from North America, a common framework on competition and regulation exists.

The analysis of supply has revealed that European retail markets have an oligopolistic structure rather than a competitive one. We identified strong incentives for retailers to horizontal and vertical integrations. The participation of small customers, captured by switching rates, appears scarce, although partially justified by the presence of switching costs and informational complexities which seem to limit the capability of these consumers to fully exploit market benefits. Asymmetries in the rate and speed of cost-pass through make the market opaque, challenging the sole reliance on "light-hand" regulation to guarantee a sound market functioning.

To complete our analysis, we identified also those situations in which some form of "hard" regulation appear to be necessary to secure the continuity of supply even after the introduction of competition. The objective of ensuring supply continuity may be however counterbalanced by the need of protecting customer from exploitation, especially in terms of price. According to the relative weight attributed to these objectives, several implementation solutions are presented. In the light of evidences about European markets, we suggested that the removal of tariffs, although desirable in a long run, does not appear at present to be the best incentive to boost competition, given possible market power of providers, limited awareness of consumers and difficulties in monitoring the market; on the contrary a Default/Last Resort service assigned through an auction mechanism may favor both the development of upstream and downstream competition, without limiting customer switching if the tariff is cost-reflective.

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Appendix A

Figures

Figure A.1: Number of main retailers, 2011
Source: Authors' elaboration on Eurostat data
Note: Denmark is excluded because of missing information

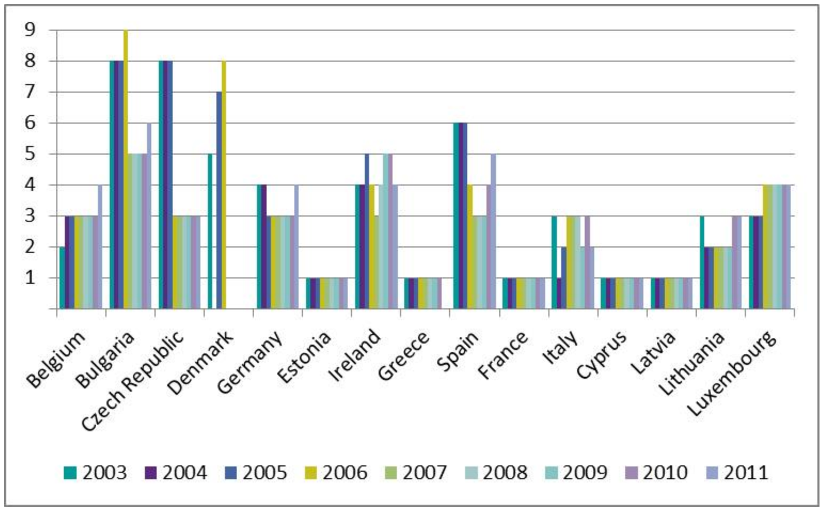

Figure A.2: Number of main electricity retailers, 2003-2011
Source: Authors' elaboration on Eurostat data
Note: Some information about Denmark are missed

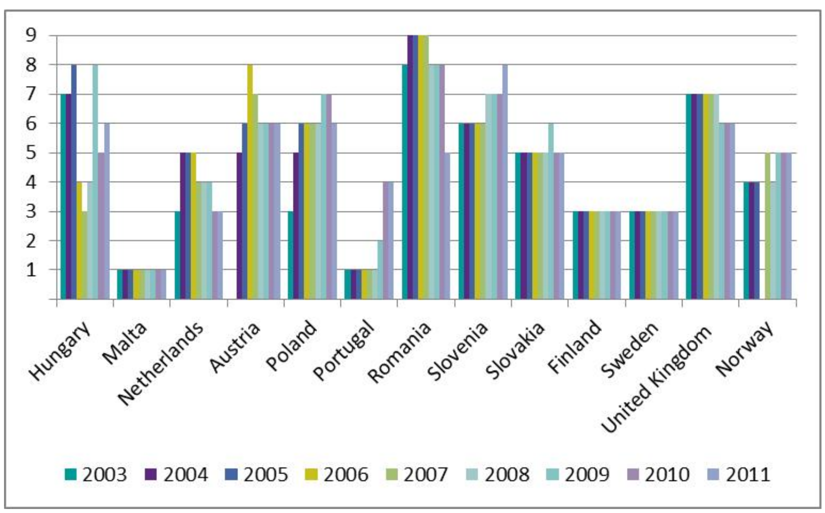

Figure A.3: Number of main electricity retailers, 2003-2011
Source: Authors' elaboration on Eurostat data

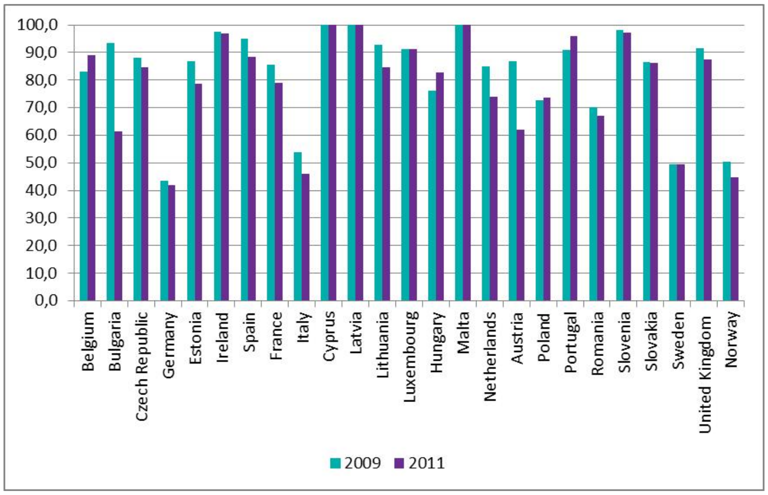

Figure A.4: Evolution of cumulative market share of main retailers (%), 2009-2011

Source: Authors' elaboration on Eurostat data

Note: Denmark, Finland and Greece are excluded because of missing information

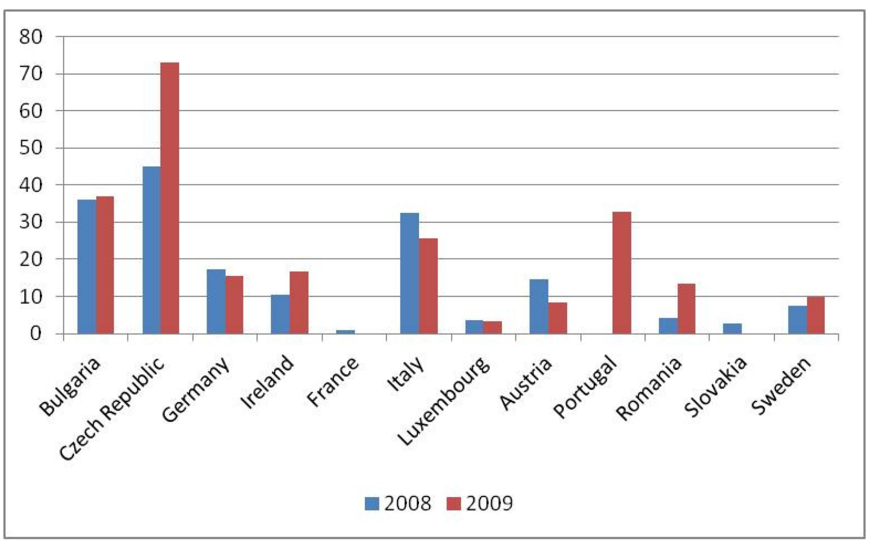

Figure A.5: Annual switching rate for large industry by eligible meter points (%), 2008-2009

Source: Authors' elaboration on European Commission data

Note: Belgium, Denmark, Estonia, Finland, Great Britain, Greece, Hungary, Norway, Poland, Spain and the Netherlands are excluded because of missing data; Cyprus, Latvia, Lithuania, Malta and Slovenia have registered zero switchings

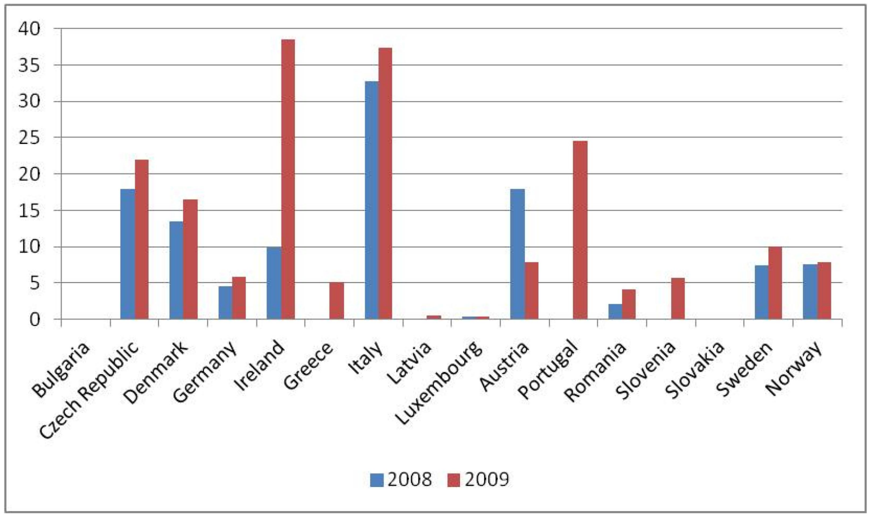

Figure A.6: Annual switching rate for medium sized industry by eligible meter points (%), 2008-2009

Source: Authors' elaboration on European Commission data
Note: Belgium, Estonia, Finland, France, Great Britain, Hungary, Poland, Spain and the Netherlands are excluded because of missing data; Cyprus, Lithuania and Malta have registered zero switchings

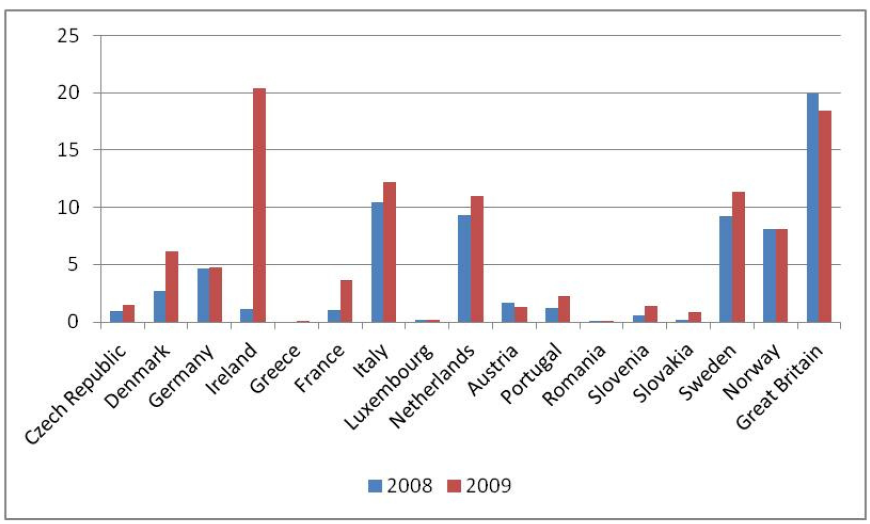

Figure A.7: Annual switching rate for small industry and households by eligible meter points (%), 2008-2009

Source: Authors' elaboration on European Commission data
Note: Belgium, Finland, Hungary, Poland and Spain are excluded because of missing data; Bulgaria, Cyprus, Estonia, Latvia, Lithuania and Malta have registered zero switchings

Chapter 3

Merit order effect and strategic investments in intermittent generation technologies

3.1 Introduction

Overtime a number of policy interventions contributed to reshape electricity industries worldwide. In European Union the process of liberalization was completed in 2009 with the approval of the Third Energy Package. Generation and retail activities have been opened up to competition and spot electricity markets have been created accordingly. One of the reform's goals was to boost sector's efficiency by increasing capacity adequacy and achieving technology mix optimality. The impact of liberalization on production and investments in generation has been extensively analysed within different theoretical frameworks of imperfect competition. The literature may be divided in two main strands: a first strand which investigates bidding behaviours of generators in spot electricity markets (Green and Newbery, 1992; von der Fehr and Harbord, 1993; Federico and Rahman, 2003; Fabra et al., 2006); a second one which analyzes the links between spot market design and incentives to invest in generation capacity (Murphy and Smeers, 2005; Tishler et al., 2008; Milstein and Tishler, 2009; Fabra et al., 2011).

Alongside with liberalization, European Union has approved in 2009 the Climate and Energy Package which establishes compulsory targets for limiting greenhouse gas emissions, enhancing investments in renewable technologies for power generation and improving savings from energy efficiency. A set of publicly financed measures has been put in place to reach the objective of a 20% share of EU energy consumption covered by renewable production within the 2020 time horizon. If strategic behaviours of competing generators have attracted academic attention, the study of interactions between "traditional" and "renewable" power producers remains an almost unexplored field of research (see for instance, Milstein and Tishler, 2011). Nevertheless, competition in generation seems to be substantially animated by new entrants investing in renewable technologies given that photovoltaic and wind capacities represented around the 70% of the 50 GW of new capacity built in European Union between 2010 and 2011 (Terna S.p.A., 2012).

This chapter aims at filling this gap by proposing a model for competition in generation which takes into account the particular features of production and trade of renewable power. Concerning production, the model embeds the randomness which characterizes power generation from renewable sources such as solar and wind. The gap between installed capacity and production possibilities for renewable power plants is a non negligible economic and security issue: it changes investment preferences and influences system security.[1] Concerning trade, whereas real spot markets are organized as uniform price auctions in which firms compete in prices, in a stylized model with a "traditional" and a "renewable" power producers, firms seem rather to compete in quantities because of merit order rule. The merit order is a way of ranking available sources in ascending order of their variable costs: the electricity produced at the lowest variable cost is the first to be brought on line to meet demand, while the one generated at the highest variable cost is the last. Given that electricity from renewable sources has zero or negligible variable production costs, it is always the first to be dispatched, leaving the residual demand to the higher variable cost producer. Because of marginal pricing rule, the market price equalizes the bid submitted by the "traditional" (marginal) producer[2] and is granted to all inframarginal units as well.

The model embeds also a commonly adopted policy mechanisms designed to accelerate investments in renewable technologies, namely the feed-in tariff scheme.[3] In our setting, the tariff is meant to finance the investment cost per kilowatt-hour which, for some renewable technologies, is deemed so large so as to determine a null or insufficient rate of adoption compared to the established target.

The model's objective is to identify the drivers of "renewable" generators capacity and production choices. The analysis of the equilibrium reveals that the "renewable" generator exploits the merit order rule which governs spot electricity markets to invest and produce as if it were a sort of Stackelberg leader. While producer's preferences over strategies seem not to be influenced by the average value of capacity availability, consumer surplus differs substantially according to it. Given that production of electricity from the renewable source depends on actual weather conditions, the analysis of

[1] In Italy for instance the combined photovoltaic and wind capacities represented around 20% of total capacity in 2012 while their production was a 10% share of total power production in the same year. In Germany photovoltaic and wind capacities represented more than 30% of total capacity in 2011 while their production was a 10% share of total power production (Terna S.p.A., 2012. See www.terna.it).

[2] We neglect those rare cases in which low demand coupled with large supply from renewable power plants depresses the spot price to zero.

[3] In general the feed-in tariff rewards the kilowatt-hours produced with renewable technologies by offering to the producers a fixed purchasing price which is generally higher than the market price. For a general discussion on support schemes for renewable technologies see Couture and Gagnon (2010).

ex-post payoffs reveals that "renewable" producer's preferences over strategies may be reversed even for small errors in the forecasting of the true value of the average capacity availability factor when the investment cost in the renewable technology is relatively low. In this case, the incentives for strategic behavior may be even stronger. The main insights of the model are barely sensitive to changes in the relative market power of competitors: even when the "renewable" generator behaves as a competitive fringe in the spot market, it is able to influence equilibrium outcome to its own advantage through investment choices although to a smaller degree than in the standard setting.

The chapter is organized as follows. Section 2 reviews the relevant literature. Sections 3 and 4 are dedicated the baseline model and its resolution. Section 5 presents the ex-post analysis of strategies. Section 6 extends the baseline model to the case in which the renewable producer behaves as a competitive fringe. Section 7 concludes.

3.2 Literature review

A strand of literature on competition in liberalized power markets focuses on firms' short run behaviours (bid strategies in the spot market) while a second strand is concerned with the analysis of long run performances (impact of competition on capacity investments). Often the models in the latter group constitute an extension of those in the former; when this is not the case, it is always possible to envisage such a development: whatever is the selected setting for the second stage competition, this stage is or may be preceded by a first one in which firms make investment decisions. This section summarizes the theoretical models proposed in the literature, provides an overview of their main results and examine the attractiveness of their application in the study of competition between "traditional" and "renewable" generators.[4]

A first approach consists in applying Kreps and Scheinkman (1983) two stage model in which a Bertrand-Edgeworth price competition is preceded by a quantity decision or "capacity choice", yielding the standard Cournot equilibrium outcome. Extensions and refinements of the basic model include the works of Deneckere and Kovenock (1996),

[4]We do not consider those papers in which the spot market is perfectly competitive (or regulated) and the price is fixed to the marginal cost of the last unit called into operation, such as in Meunier (2010).

Reynolds and Wilson (2000) and Fabra and de Frutos (2011). According to von der Fehr and Harbord (1998) the major limit of this approach relates to the fact that firms are paid on the basis of each own bid, rather than on the one of the last unit called into operation, as happens in real power markets. On the other hand, this model provides a formal justification for the elimination of marginal cost bidding strategy in a Bertrand setting when capacity is constrained.[5]

A second approach is based on the Supply function model of Klemperer and Meyer (1989) which has been extended to power markets by Green and Newbery (1992). In this setting firms compete in supply functions, i.e. by setting combinations of price-quantity pairs, given the uncertainty of demand. Although the model closely represents the reality of spot electricity markets where firms' bids combinations of price and quantity (though supply functions are not really continuous), its predictive value is very poor because possible equilibria, when defined, range between the Cournot and the Bertrand solutions. Given the uncertainty of second stage equilibria, the attractiveness of adding a first stage with investments is very low.

The third approach consists in modelling competition in the second stage as a sealed bid, multi-unit auction in which payments to the two competitors are equal to the highest accepted bid in the uniform auction format and to own bid in the discriminatory auction format. The auction is preceded by an investment stage in which firms choose their capacity prior to bid in the market. The auction approach, developed by Fabra et al. (2011) extending the works of von der Fehr and Harbord (1993), von der Fehr and Harbord (1997), Fabra et al. (2006), has been largely appreciated for closely reproducing real market designs and the nature of competition in spot markets. On the other hand the model results difficult to manipulate, for instance by adding technological asymmetries, due to problems of non-uniqueness and non-existence of sub-game perfect pure-strategy equilibria for some values of the demand. Concerning the results, in both types of auction bidding at marginal cost is a Nash equilibrium only when the demand is lower than the capacity of the smaller firm, whereas bidding at price cap is a Nash equilibrium when the demand is larger than the sum of the two capacities. The aggregate capacity in both auction formats results to be smaller compared to the first best's capacity and its distribution is asymmetric although firms are full symmetric

[5]This result is similar to auction model's prediction.

ex-ante.

The last but most appealing approach for our research purpose assumes that power generators compete in quantities. Tishler et al. (2008) study the equilibrium in an oligopolistic two stage game in which firms invest in capacity in the first stage knowing the probability distribution of future demand and select their production in the second stage once the demand reveals.[6] While the first stage is played once, the second stage is repeated a number of independent times over the considered temporal horizon. In the first extension of this model (Milstein and Tishler, 2012) a base-load and a peak-load technologies characterized by a trade-off between capacity and operation costs are available. In a second extension (Milstein and Tishler, 2011) firms may invest in a combined cycle gas turbine (CCGT) plant or in a photovoltaic (PV) plant whose profitability depends on the probability of daily sunshine. In the first extension the authors show that the equilibria differs when firms are allowed or not to invest in both technologies. In particular, when firms can employ both technologies aggregate industry capacity results to be smaller, the share of base-load technology larger and total welfare bigger. In the second extension, the authors demonstrate that the uncertainty of weather conditions reduces the profitability of PV plants and its attractiveness: only when the PV to CCGT capacity cost ratio declines sharply, the adoption of PV becomes positive although it remains limited. The latter setting presents however some limitations: the optimization problem has no closed form solution and must be solved by numerical methods; moreover, the result on the scarce adoption of renewable technology at equilibrium is partly biased by the fact that the authors discard the merit order rule in dispatching.[7]

In the same vein, Murphy and Smeers (2005) study capacity investments when a base load and a peak-load providers compete in an open-loop Cournot setting in which investments and production take simultaneously place and in a closed-loop Cournot model in which investment decisions are taken in the first stage of the game and production levels are chosen in the second stage. The authors show that the total capacity at equilibrium in the closed-loop setting is equal or larger than the capacity chosen in

[6]For a theoretical analysis of such games see Gabszewicz and Poddar (1997).

[7]If on the one hand CCGT investments result to be more profitable than PV investments because CCGT production does not depend on weather conditions, on the other hand CCGT plants have less probability to be dispatched and hence to produce.

the open loop setting: this happens because in the closed loop model the base load producer has an incentive to invest more in the first stage and to produce more in the second stage compared to open loop setting, thus distorting in its favour short run market outcomes.[8] Interestingly, both Murphy and Smeers (2005) and Milstein and Tishler (2012) highlight that base-load investments result to be "strategic" in the sense that they allow to modify short run competition. In the next paragraphs we present our model of competition between "renewable" and "traditional" power producers in which the assumptions of quantity competition and sequential investment-production decisions are maintained although they may have different interpretations. Moreover, our setting differs from Milstein and Tishler (2011) because it takes explicitly into account the relevance of the merit order rule in determining equilibrium investment and production choices.

3.3 The model

In real spot markets, electricity suppliers submit simultaneously and independently bid prices at which they are willing to supply their available capacity. The market operator ranks the bids by merit order defining a supply schedule monotonically increasing in function of price offers. The firms that are called into operation are all paid the system marginal price which corresponds to highest accepted bid. We examine competition between "traditional" and "renewable" power producers using a modified version of the *Dixit model* for entry deterrence (Dixit, 1980). This choice stems from the following reasons.

First of all, because of the merit order rule the power from renewable sources is always the first to be brought on line in spot electricity markets. This favourable ranking may be interpreted as a sort of first mover advantage. As in a standard entry deterrence game the profitability of entry depends on the capacity choices made by the incumbent in previous stages, in power sector the profitability of investments in "traditional" technologies rests on the size of the residual demand, which in turn is determined by the capacity installed by "renewable" producer. In our model the "renewable" power

[8] This "strategic" effect refers to a decrease in rival's production (peak-load provider) due an increase in the market share of firm with smaller marginal costs (base-load provider).

plant is thus the incumbent and the "traditional" producer is the entrant who behaves as a follower in the Stackelberg game for capacity investment.

Secondly, the *Dixit model* is sufficiently flexible to allow for several types of competition in the post entry game: firms may play in a perfect competitive setting (Spence, 1977); in a Cournot setting (Dixit, 1980; Spulber, 1981; Ware, 1984; Bulow et al., 1985; Maskin, 1997); in a Stackelberg setting with the entrant as leader (Dixit, 1980) or follower (Spulber, 1981; Saloner, 1985; Basu and Singh, 1990); in a Bertrand setting (Allen et al., 2000). Moreover in each setting a certain degree of uncertainty about demand and/or cost functions may be introduced (Maskin, 1997). In real power markets firms are supposed to compete in prices. However, in a stylized model with a "renewable" and a "traditional" power producers firms rather play a quantity game since the "renewable" power plant can always bid at zero due to its cost advantage and the "traditional" producer is constantly marginal. We design the post-entry game as a Cournot competition in the baseline model and as quantity competition between a dominant firm and a competitive fringe in the extended model, accounting for the fact that "renewable" producers are price takers in spot markets. Quantity competition presents the additional advantage that both firms receive the same price as in a uniform price auction. Finally, this framework easily allows to introduce uncertainty on the supply side due to the intermittency of production from the renewable power plant.

We propose two alternative structures for the strategic game. In the baseline model (two stage game), firms compete in a two stage game with the following timing:

- in the first stage the "renewable" firm chooses its capacity investment which is irreversible in the sense that capacity already installed cannot be dismissed;

- in the second stage of the game firms compete in quantities: the "traditional" firm selects simultaneously its capacity investment and its production level[9] while the "renewable" firm may increase its capacity prior to compete for production.

[9]For the "traditional" firm capacity and production levels will always be identical given that they are selected simultaneously. Therefore, if in reality capacity investments are already sunk which is very often the case for CCGT power plant, this stage of the game may be interpreted as the one in which the "traditional" firm only adjusts its production.

In the extended model (three stage game), the "renewable" firm is assumed to behave like a price taker fringe in the spot market. Hence the post-entry game is a Stackelberg game with the entrant (the "traditional" firm) playing the role of leader. The timing of the game is the following:

- in the first stage the "renewable" firm chooses its capacity investment which is irreversible in the sense that capacity already installed cannot be dismissed;

- having observed the capacity chosen by its rival, in the second stage the "traditional" firm selects its capacity and its production;

- in the third stage, the "renewable" firm chooses its production level.

We analyze the two stage and the three stage games in sections 4 and 5 respectively. The two stage and three stage games may be interpreted as reproducing two alternative market designs for "renewable" generators participation in the spot market: on the one hand the production from several renewable power plants may be aggregated by a unique entity bidding on behalf of producers;[10] on the other hand, the supply of "renewable" power may be more fragmented and each generator may participate individually in the spot market. As we will see, the qualitatively results of the model hold in both alternative market structures.

3.4 Two stage game

In the baseline model it is assumed that two firms compete in the power market: the first firm, S, manages a photovoltaic power plant (henceforth PV) and the second firm, G, operates a combined cycle gas turbine plant (henceforth CCGT). Production is denoted by q_i, $i = s, g$, and generation capacities by k_i, $i = s, g$. The investment cost per unit of capacity is $I_i > 0$, $i = s, g$. Production gives rise to a variable cost c_i, $i = s, g$, for production levels below capacity while production above capacity is infinitely costly. We assume without loss of generality that $0 = c_s < c_g = c$ and

[10] See for instance the case of Gestore Servizi Energetici in Italy, www.gse.it.

that $c + I_g < I_s$, i.e. firm G has lower average costs.[11] It is further assumed that the availability of photovoltaic capacity for production depends on weather conditions. Therefore for each level of installed capacity k_s the available capacity is xk_s, where x is the realization of a random variable $X \in [0, 1]$. Firms know the continuous distribution function of the random variable X as well as its expected value, $\mathbb{E}[x] = x^*$. Firms face a linear inverse demand function, $p(Q) = a - bQ$, where $Q = q_s + q_g \subseteq (0, xk_s + k_g)$. An amount τ is awarded to the producer for each unit of PV capacity built. The tariff aims at reducing the true investment cost in the renewable technology, I_{pv}, which is deemed so high so as to make entry unprofitable ($I_{pv} > a$). Therefore the tariff verifies the following inequality, $I_{pv} - \tau = I_s < a$.[12]

The structure of the game is the following. In the first stage S chooses its capacity, k_s: the investment is irreversible in the sense that capacity already installed cannot be dismissed. In the second stage of the game firms compete in quantities: G selects simultaneously its capacity, k_g, and its production level, q_g, while S may increase its capacity prior to compete for production. Note that the quantities of electricity produced by G and S are strategic substitute, which means that marginal revenue of each firm is decreasing in rival's output. This assumption is equivalent to assume that both firms' reaction functions are always downward sloping and it is a sufficient condition to ensure that the established firm will never install excess capacity, i.e. it will never install in the first stage of the game a capacity which will be left idle in the final stage (Bulow et al., 1985).

3.4.1 Second stage solutions

The game is solved by backward induction to find the sub-game perfect Nash equilibrium. In the last stage of the game G selects production and capacity which maximize

[11] The concept of average cost may be associated to that of "Levelised Cost of Energy (LEC)" which is a commonly used instrument to compare costs for unit of electricity generated from different sources. The LEC is an economic assessment of unit generation costs over the whole lifetime of a power plant which includes initial investment, operations and maintenance costs, costs of fuel and capital. According to IEA 2012 Annual Energy Outlook, the dollar cost per megawatt-hour of a conventional combined cycle plant entering in service in 2017 is 68,6 dollars while for a solar photovoltaic plant is 156,9 dollars (IEA, 2012).

[12] The role of feed-in tariff here is only to make profitable the adoption of PV technology.

its expected profit:[13]

$$\underset{q_g,k_g}{\text{Max}} \quad \mathbb{E}[\Pi_g] = \mathbb{E}[p(q_s, q_g)q_g - cq_g - I_g k_g] \quad \text{subject to} \qquad q_g \leq k_g \tag{3.1}$$

At the optimum the capacity constraint is binding since G would never invest in a capacity it cannot use for production. Therefore in each equilibrium we will indicate only the quantity produced by G, knowing that the capacity is sized accordingly. The reaction function of G is:

$$R_g(q_s) = q_g = \frac{a - bq_s - c - I_g}{2b} \tag{3.2}$$

The reaction function of S is a kinked curve, whose equation is the solution to the following profit maximization problem:

$$\underset{q_s}{\text{Max}} \quad \mathbb{E}[\Pi_s] = \mathbb{E}[p(q_s, q_g)q_s - C(q_s, k_s)] \quad \text{where} \tag{3.3a}$$

$$C(q_s, k_s) = \begin{cases} 0 & \text{if } q_s \leq x^* k_s \\ \left(\frac{I_s}{x}\right) q_s & otherwise \end{cases} \tag{3.3b}$$

The shape of the reaction curve depends on the capacity choices made by firm S in the previous stage. When in the last stage of the game S selects a production level below or equal to the available installed capacity, $x^* k_s$, it does not incur in any costs given that capacity investment has been already paid and production with renewable technologies is costless. In this case $C(q_s, k_s) = 0$. Contrariwise, if the capacity installed in the previous stage is not sufficient to meet S's optimal production level in the last stage, a new investment may be undertaken bearing the associated cost. S's relevant cost function in this case is $C(q_s, k_s) = \left(\frac{I_s}{x}\right) q_s$. Note that S's expected marginal revenues are decreasing in the quantity of electricity provided by firm G (see Figure 3.1):

$$\mathbb{E}[MR_s] = a - 2bq_s - bq_g \tag{3.4}$$

[13]The randomness in G's profits depends on price's uncertainty which is turn is caused by the uncertainty in S's production level.

For large quantities of q_g, S's expected marginal revenue curves cross expected marginal cost at zero (MR_1). Similarly for small quantities of q_g, S's expected marginal revenue curves cross expected marginal cost at $\frac{I_s}{x^*}$ (MR_3). In the intermediate case expected marginal revenue curves cross expected marginal cost curve at the kink (MR_2).

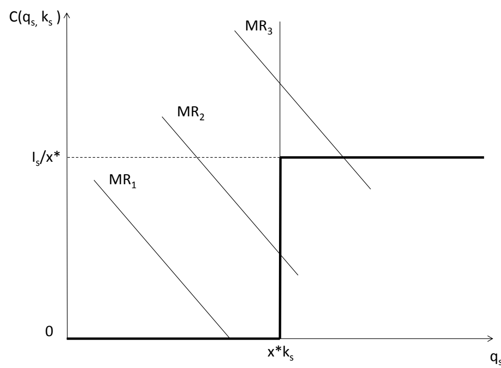

Figure 3.1: Expected marginal revenue and marginal cost curves

It is therefore possible to calculate the thresholds of q_g that make firm S to switch from a cost curve to another, thus changing the relevant reaction function. Let us define:

- $q_g^h = \frac{a-2bx^*k_s}{b}$ as the quantity of q_g such that, $\forall q_g > q_g^h$:

$$\mathbb{E}[MR_s(q_s, q_g)] = 0 \tag{3.5a}$$

$$\tilde{R}_s(q_g) = q_s = \frac{a - bq_g}{2b} \tag{3.5b}$$

- $q_g^l = \frac{x^*(a-2bx^*k_s)-I_s}{bx^*}$ as the quantity of q_g such that, $\forall q_g < q_g^l$:

$$\mathbb{E}[MR_s(q_s, q_g)] = \frac{I_s}{x^*} \tag{3.6a}$$

$$R_s(q_g) = q_s = \frac{x^*a - bx^*q_g - I_s}{2bx^*} \tag{3.6b}$$

- $\forall q_g$ such that $q_g^l < q_g < q_g^h$, firm S produces at (available) capacity:

$$\bar{R}_s = q_s = x^* k_s \tag{3.7}$$

Firm S reaction function is the bold line depicted in Figure 3.2. Note that when relevant marginal costs include investment cost, the reaction function moves inward. According to the capacity installed in the first period, we may observe three different Nash equilibria in the last stage of the game (Case A, Case B and Case C). We firstly calculate each equilibrium in last stage and then we solve backward to find first stage's solutions. Finally we compare the payoffs to estimate S's optimal strategy.

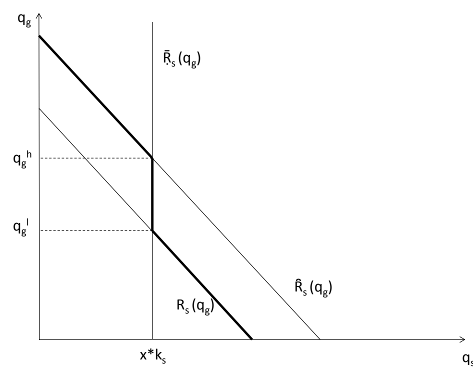

Figure 3.2: Firm S reaction function

Strategy A: small photovoltaic capacity

If firm S has installed a very small level of capacity in the first stage, it would probably like to increase it in the last stage. In this case, Nash equilibrium occurs where the reaction function of firm G crosses the reaction function of firm S in a point on $R_s(q_g)$. The solution of the last stage game is the usual Cournot-Nash equilibrium. Firm S chooses its optimal quantity as the solution to the following profit maximization problem:

$$\underset{q_s}{\text{Max}} \quad \mathbb{E}[\Pi_s] = \mathbb{E}\left[p(q_s, q_g)q_s - \left(\frac{I_s}{x}\right) q_s\right] \tag{3.8}$$

The optimal response is:

$$R_s(q_g) = q_s = \frac{x^*a - bx^*q_g - I_s}{2bx^*} \tag{3.9}$$

Combining S and G reaction functions, we obtain equilibrium quantities, price and profits:

$$q_s^A = \frac{x^*(a + c + I_g) - 2I_s}{3bx^*} \tag{3.10a}$$

$$q_g^A = \frac{x^*[a - 2(c + I_g)] + I_s}{3bx^*} \tag{3.10b}$$

$$p^A = \frac{x^*(a + c + I_g) + I_s}{3x^*} \tag{3.10c}$$

$$\Pi_s^A = \frac{[x^*(a + c + I_g) - 2I_s]^2}{9bx^{*2}} \tag{3.10d}$$

$$\Pi_g^A = \frac{\{x^*[a - 2(c + I_g)] + I_s\}^2}{9bx^{*2}} \tag{3.10e}$$

The equilibrium is represented in Figure 3.3.

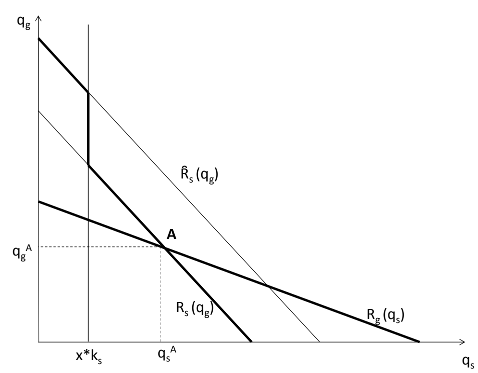

Figure 3.3: Equilibrium in case A

The standard Cournot Nash equilibrium arises in the second stage of the game if in the earlier stage firm S has installed:

$$k_s^A \leqslant \frac{q_s^A}{x^*} = \frac{x^*(a+c+I_g) - 2I_s}{3bx^{*2}} \tag{3.11}$$

Strategy B: large photovoltaic capacity

If firm S has installed a large capacity in the first stage, it presents a cost advantage relative to G in the last stage competition. In this case, the reaction function of firm S moves outward toward $\tilde{R}_s(q_g)$. Firm S determines its optimal quantity as the solution to the following maximization problem:

$$\underset{q_s}{\text{Max}} \quad \mathbb{E}[\Pi_s] = \mathbb{E}[p(q_s, q_g)q_s] \tag{3.12}$$

yielding the reaction function:

$$\tilde{R}_s(q_g) = q_s = \frac{a - bq_g}{2b} \tag{3.13}$$

Again, combining S and G reaction functions gives the optimal quantities, price and profits:

$$q_s^B = \frac{a+c+I_g}{3b} \tag{3.14a}$$

$$q_g^B = \frac{a - 2(c+I_g)}{3b} \tag{3.14b}$$

$$p^B = \frac{a+c+I_g}{3} \tag{3.14c}$$

$$\Pi_s^B = \frac{(a+c+I_g)^2}{9b} \tag{3.14d}$$

$$\Pi_g^B = \frac{[a - 2(c+I_g)]^2}{9b} \tag{3.14e}$$

This equilibrium is represented in Figure 3.4 and arises if firm S has installed in the earlier stage of the game:

$$k_s^B \geqslant \frac{q_s^B}{x^*} = \frac{a+c+I_g}{3bx^*} \tag{3.15}$$

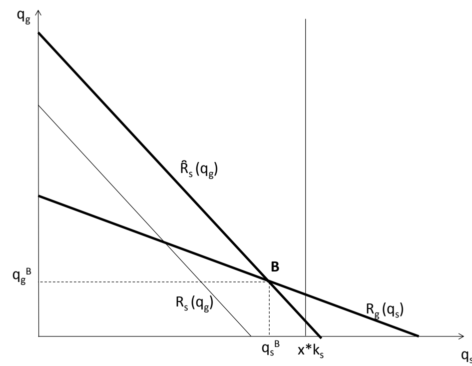

Figure 3.4: Equilibrium in case B

Note that $\Pi_g^B > 0$ if $a > 2(c + I_g)$. If $\Pi_g^B < 0$ firm G prefers not to produce, so we should exclude this opportunity.

Strategy C: intermediate photovoltaic capacity

When S's capacity size is between the thresholds determining equilibria A and B, firm S produces at available capacity, $q_s = x^* k_s$, and firm G behaves as a Stackelberg follower reacting to the quantity produced by its rival. Therefore, G's reaction function described in eqs. (2) may be rewritten as:

$$R_g(k_s) = q_g^C = \frac{a - bx^* k_s - c - I_g}{2b} \tag{3.16}$$

Equilibrium price and profits in implicit form are:

$$p^C = \frac{a - bx^* k_s + c + I_g}{2} \tag{3.17a}$$

$$\Pi_s^C = \left(\frac{a - bx^* k_s + c + I_g}{2} \right) x^* k_s \tag{3.17b}$$

$$\Pi_g^C = \frac{(a - bx^* k_s - c - I_g)^2}{4b} \tag{3.17c}$$

The equilibrium in case C is represented in Figure 3.5.

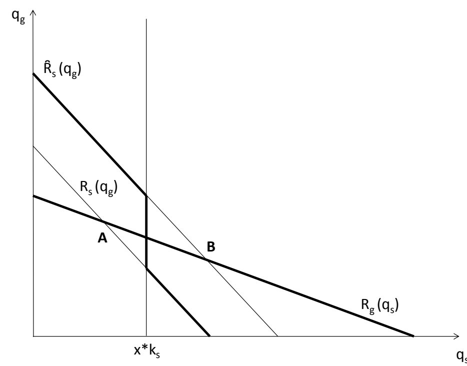

Figure 3.5: Equilibrium in case C

3.4.2 First stage solutions

In order to calculate the explicit pay-off in Case C, the first stage of the game must be solved. In the first stage firm S chooses k_s so as to maximize its expected profits in case C:

$$\underset{k_s}{\text{Max}} \quad \mathbb{E}[\Pi_s] = \mathbb{E}[p(xk_s, q_g)xk_s - I_s k_s] \tag{3.18}$$

Using the reaction function of G and calculating the FOC of the problem, we get equilibrium quantities, price and profits:

$$q_s^C = \frac{x^*(a + c + I_g) - 2I_s}{2bx^*} \tag{3.19a}$$

$$q_g^C = \frac{x^*[a - 3(c + I_g)] + 2I_s}{4bx^*} \tag{3.19b}$$

$$p^C = \frac{x^*(a + c + I_g) + 2I_s}{4x^*} \tag{3.19c}$$

$$\Pi_s^C = \frac{[x^*(a + c + I_g) - 2I_s]^2}{8bx^{*2}} \tag{3.19d}$$

$$\Pi_g^C = \frac{\{x^*[a - 3(c + I_g)] + 2I_s\}^2}{16bx^{*2}} \tag{3.19e}$$

This solution arises if S instals in the first stage of the game the following capacity:

$$k_s^C = \frac{x^*(a+c+I_g) - 2I_s}{2bx^{*2}} \tag{3.20}$$

3.4.3 Optimal strategy selection

Firm S selects its optimal strategy by comparing net profits in each of the three cases regardless if the investment has been paid in the first or the second stage of the game. We indicate net profits with a * to distinguish them from gross profits:[14]

$$\Pi_s^{A^*} = \frac{[x^*(a+c+I_g) - 2I_s]^2}{9bx^{*2}} \tag{3.21a}$$

$$\Pi_s^{B^*} = \frac{(a+c+I_g)((a+c+I_g)x^* - 3I_s)}{9bx^*} \tag{3.21b}$$

$$\Pi_s^{C^*} = \frac{[x^*(a+c+I_g) - 2I_s]^2}{8bx^{*2}} \tag{3.21c}$$

We remark that firm S prefers to invests more in the first stage of the game rather than to postpone investments to the second stage. Indeed strategy A is always dominated by strategy C given that the following inequalities is verified for any value of x^*:

$$\Pi_s^{C^*} = \frac{[x^*(a+c+I_g) - 2I_s]^2}{8bx^{*2}} > \frac{[x^*(a+c+I_g) - 2I_s]^2}{9bx^{*2}} = \Pi_s^{A^*} \tag{3.22}$$

On the other hand, strategy C is preferred to strategy B only when the following inequality holds:

$$\Pi_s^{C^*} = \frac{[x^*(a+c+I_g) - 2I_s]^2}{8bx^{*2}} > \frac{(a+c+I_g)((a+c+I_g)x^* - 3I_s)}{9bx^*} = \Pi_s^{B^*} \tag{3.23}$$

Since both b and x^* are positive the previous condition reduces to:

$$[(a+c+I_g)x^* - 6I_s]^2 > 0 \tag{3.24}$$

Strategy C is then preferred to B when:

[14]Note that $\Pi_s^A = \Pi_s^{A^*}$ and $\Pi_s^C = \Pi_s^{C^*}$

$$\textbf{Case 1:} \quad a + c + I_g < 6I_s \quad \Rightarrow \forall\ x^* \tag{3.25}$$

$$\textbf{Case 2:} \quad a + c + I_g \geq 6I_s \quad \Rightarrow x^* \neq \frac{6I_s}{a + c + I_g} \tag{3.26}$$

When parameters' values are those of Case 1, strategy C is preferred to strategy B for any value of x^*. This means that, regardless of the average value of capacity availability, the photovoltaic generator will exploit the merit order rule to invest and produce as if it were a Stackelberg leader. Notwithstanding, instead of building as much capacity as it would be needed to compete with zero variable costs, the "renewable" producer will prefer to be strategic, restrain the output and leave a larger market share to its competitor because this will result in higher profits. This result is formalized in Proposition 1.

Proposition 1. *Because of merit order rule, the "renewable" producer has a strategic incentive to increase its optimal capacity and production behaving like a Stackelberg leader. However, it will not exploit its "first mover advantage" to its maximum because this may cause the profits to decrease.*

Only when parameters' values are those of Case 2 and the following equality holds:

$$p^B = \frac{2I_s}{x^*} \tag{3.27}$$

the two strategies have exactly the same pay-off and S is indifferent between them, which is clearly a very restrictive case.

Lemma 1. *For most of the parameters' values the average availability of installed capacity does not change the "renewable" producer's preferences between strategies.*

From consumers' point of view, however, strategies B and C differ substantially depending of the value of x^*. Given the monotonicity of demand function it suffices to calculate which equilibrium guarantees the lowest price to assess when consumers' are better off. Equilibrium C leads to a higher consumers' surplus with respect to equilibrium B if and only if:

$$x^* > \frac{6I_s}{a + c + I_g} \tag{3.28}$$

This result seems to indicate that there is some room for welfare improving public interventions. Indeed, if on the one hand the average availability of photovoltaic capacity depends on technology and cannot be modified, on the other hand the value of the right hand side of equation (3.28) is increasing in the investment cost of renewable technology: a policy which reduces such cost increases consumer surplus. We may represent with the help of a graph the preferences over strategies of firm S and consumers for different values of x^* (Figure 3.6). It is worthy to note that if parameters values are those of Case 1 consumers are never better off with strategy C because the right hand side of equation (3.28) is larger than 1 which is not possible.

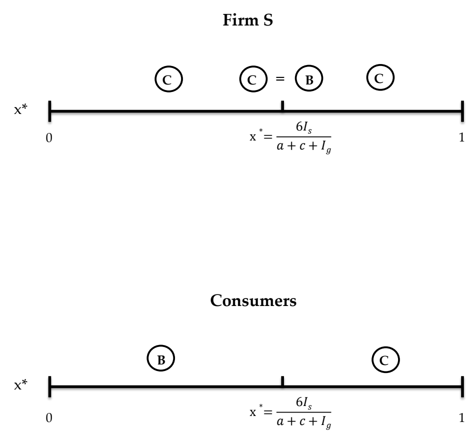

Figure 3.6: Preferences over strategies

The solution of Case 1 above arises when the investment cost of photovoltaic capacity is relatively large. When parameters respect the condition for such equilibrium there is always a conflict between consumers and firm S interest: the former will always prefer equilibrium B, while the latter will always play the strategy leading to equilibrium C. In this case consumers' loss is inversely related to the value of average capacity availability, i.e. the larger is x^* the smaller is the difference between consumer surplus in equilibria C and B. Conversely, when investing in renewable capacity is relatively cheap, there is room for consumers and firm S interests to converge: both may be better off in equilibrium C if the value of average capacity availability is larger than a certain threshold. These results are formalized in Proposition 2 and Lemma 2.

Proposition 2. *Merit order rule may lead to an equilibrium which benefits both the "renewable" producer and the consumers.*

Lemma 2. *A public intervention which reduces investment cost in the "renewable" technology increases the likelihood of a market outcome in which both the "renewable" producer and the consumers are better-off.*

3.5 Analysis of ex post profits

Investment choices are taken on the basis of the average value of capacity availability, x^*, while production firm S may be adjusted according to the realized value of x. G can modify its production as well but it is constrained by the size of its installed capacity. It may be interesting to calculate the ex-post expected profits of firm S, i.e. the profits it gains once it has invested in capacities k_s^C or k_s^B and it produces according to the real value of x. In both cases the pay-off is:

$$\Pi_s = (a - bq_g - bxk_s)xk_s - I_s k_s \tag{3.29}$$

We may substitute in eq. (3.29) the optimal values of k_s^C and k_s^B calculated as functions of x^* and the optimal quantity of firm G.[15] We recall that G produces the lower quantity between its installed capacity and its optimal production given the electricity supplied by S:

$$q_g^{B,C} = \frac{a - b \max(x, x^*) k_s^{B,C} - c - I_g}{2b} \tag{3.30}$$

Calling $A = a + c + I_g$, ex post profits are:

$$\Pi_s^B[x] = -\frac{A}{3bx^*}\left(I_s + \frac{2Ax^2 - 3Axx^* - Ax\max(x, x^*)}{6x^*}\right) \tag{3.31a}$$

[15] All calculations are reported in Appendix B.

$$\Pi_s^C[x] = (Ax^* - 2I_s)\frac{2(x - x^*)(Axx^* - 2I_s(x + x^*)) + x(2I_s - Ax^*)\max(x, x^*)}{8bx^{*4}} \tag{3.31b}$$

To calculate their expected value, we firstly use a generic probability density function, $P(x)$, defined for $x \in [0, 1]$. For a generic function the following condition must hold:

$$\mathbb{E}[f] = \int_0^1 f(x)P(x)dx \tag{3.32}$$

Expected profits are then:[16]

$$\mathbb{E}[\Pi_s^{B,C}] = \int_0^1 \Pi_{B,C}(x)P(x)dx \tag{3.33a}$$

$$\mathbb{E}[\Pi_s^B] = -\frac{AI_s}{3bx^*} - \frac{A^2E[x^2]}{9bx^{*2}} + \frac{A^2}{6b} + \frac{A^2M}{18bx^{*2}} \tag{3.33b}$$

$$\mathbb{E}[\Pi_s^C] = \frac{I_sB}{2bx^{*2}} - \frac{AB}{4bx^*} - \frac{B^2}{4bx^{*4}}E[x^2] + \frac{MB^2}{8bx^{*4}} \tag{3.33c}$$

where:

$$M = \int_0^1 x\max(x, x^*)P(x)dx \tag{3.34a}$$

$$A = a + c + I_g \tag{3.34b}$$

$$B = 2I_s - Ax^* \tag{3.34c}$$

Recalling that $\mathbb{E}[x] = x^*$, we may rewrite the expected profits of strategies B and C using the definition of variance of a random variable, $\mathrm{Var}[x] = \mathbb{E}[x^2] - \mathbb{E}[x]^2$. After some manipulations we get:

$$E[\Pi_B] = \frac{A^2}{18b} - \frac{AI_s}{3bx^*} + \frac{A^2}{18bx^{*2}}(M - 2\mathrm{Var}[x]) \tag{3.35a}$$

$$E[\Pi_C] = \frac{2I_sB - B^2}{4bx^{*2}} - \frac{AB}{4bx^*} + \frac{B^2}{8bx^{*4}}(M - 2\mathrm{Var}[x]) \tag{3.35b}$$

For strategy C to be ex post superior to strategy B the condition $E[\Pi_B] < E[\Pi_C]$ must hold. This condition is equivalent to:

$$\frac{A^2}{18} - \frac{AI_s}{3x^*} + \frac{A^2}{18x^{*2}}(M - 2\mathrm{Var}[x]) < \frac{B^2}{8x^{*4}}(M - 2\mathrm{Var}[x]) \tag{3.36}$$

[16]Note that we have dropped the subscript s for expositional convenience.

The inequality can be reduced to:

$$\hat{x}^2 s(s-1) < \frac{1-6s+5s^2}{4s^2}(M - 2\text{Var}[x]) \tag{3.37}$$

where

$$I = 6I_s \tag{3.38a}$$

$$\hat{x} = \frac{I}{A} \tag{3.38b}$$

$$s = \frac{x^*}{\hat{x}} \tag{3.38c}$$

To get some insights on the effect that the variance of x may have on the ex-post pay-off of strategies we have to specify a distribution function. We performed some simulations using a uniform distribution function defined as:

$$P(x) = \begin{cases} \frac{1}{2\epsilon} & \text{for } x^* - \epsilon \leq x \leq x^* + \epsilon \\ 0 & \text{otherwise} \end{cases} \tag{3.39}$$

With this distribution function we have:

$$M = \frac{\epsilon^2}{6} + \frac{x\epsilon}{4} + x^2 \tag{3.40a}$$

$$\text{Var}[x] = \frac{\epsilon^2}{3} \tag{3.40b}$$

We can finally simplify inequality (3.37) so as to obtain:

$$\hat{x}^2 s < \frac{1}{16s^2}(5s-1)(4\hat{x}^2 s^2 + \hat{x}s\epsilon - 2\epsilon^2) \tag{3.41}$$

We have performed some simulations for different values of $\hat{x}$. The results are reported in Figures 3.7 to 3.14.

Note that the right-hand sided figures show simulation's results when the parameters I_s, a, c_g and I_g have values corresponding to Case 1 in the ex-ante analysis, i.e. relatively large investment cost in renewable technologies, while left-hand sided figures display simulation's results for parameters' values corresponding to Case 2, i.e. relatively small investment cost in renewable technologies. We recall that in the ex ante

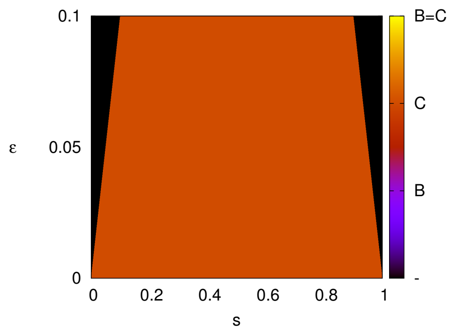

Figure 3.7: $\hat{x} = 1$

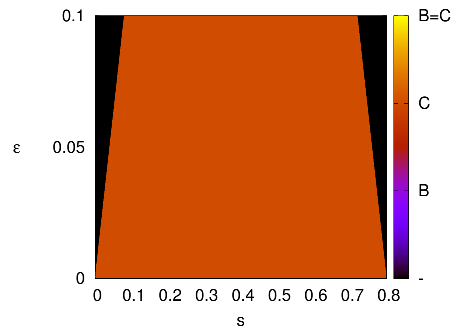

Figure 3.8: $\hat{x} = 1.25$

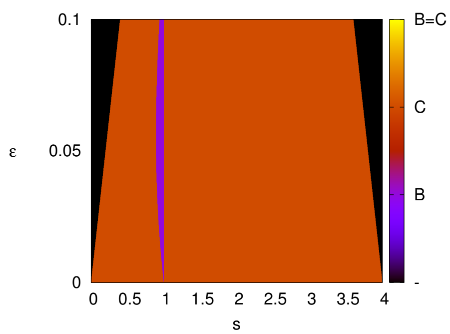

Figure 3.9: $\hat{x} = 0.25$

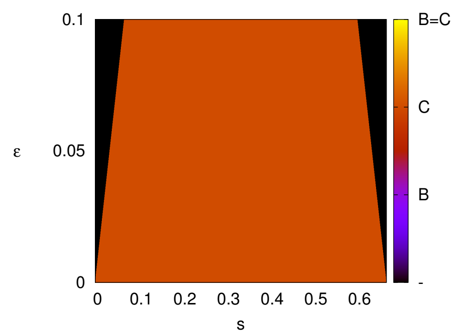

Figure 3.10: $\hat{x} = 1.5$

analysis indifference between strategies B and C is possible only in Case 2 and only for a specific value of x^*. In our simulation, red areas represent the values of parameters for which strategy C is still ex-post preferred, whereas purple areas the values for which strategy B becomes more profitable. We consider that the forecasting of the true value of the average capacity availability is subject to limited errors, i.e. $\epsilon = 0.1$.

We remark that when investment cost in renewable technology is quite large, strategy B is never preferred either ex-ante or ex-post (Figures 3.8, 3.10, 3.12, 3.14). Conversely, when investment cost is relatively low the ex post analysis suggests that strategy B yields greater profits even for smaller values of x^* than those estimated in the ex-ante analysis, thereby increasing the range of parameters' values for which strategy B is preferred by the PV generator (Figures 3.9, 3.11, 3.13). For instance, when $\hat{x} = 0.75$ (see Figure 3.13) strategy B is ex-ante preferred if and only if $x^* = 0.75$ while the ex-post analysis reduces the range to $0.675 < x^* < 0,75$. We formalize these result in Lemma 3 and Proposition 3.

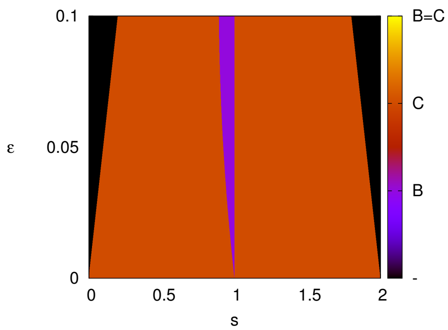

Figure 3.11: $\hat{x} = 0.5$

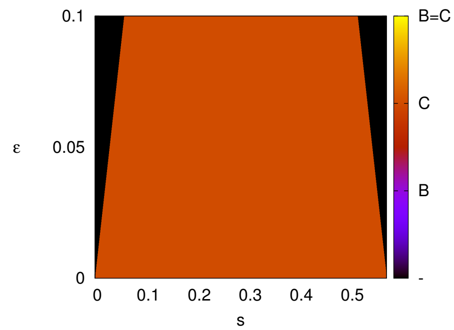

Figure 3.12: $\hat{x} = 1.75$

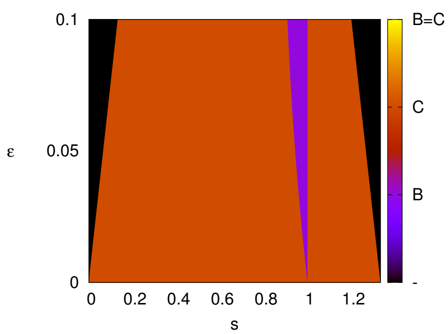

Figure 3.13: $\hat{x} = 0.75$

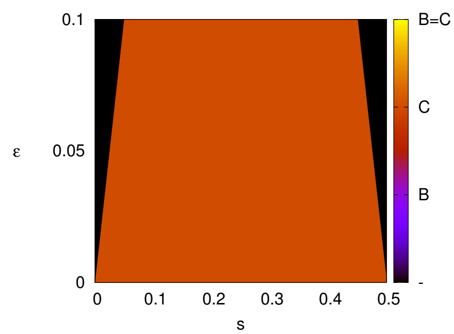

Figure 3.14: $\hat{x} = 2$

Lemma 3. *When investment cost is relatively low, "renewable" producer preferences between strategies may be reversed even for small errors in the forecasting of the true value of capacity availability factor.*

Proposition 3. *According to the ex-post analysis of pay-off the strategic effect of spot market design on investment and production choices of "renewable" producer may be stronger than what suggested by the ex-ante analysis alone.*

3.6 Three stage game

In this section we study the effect on equilibrium outcomes following a change in competition rules in post-investment stage. In particular, we adopt the "dominant firm - competitive fringe" setting developed by Carlton and Perloff (2002) to model competition in production between the "traditional" producer which represents the dominant firm and the "renewable" producer which behaves like a competitive fringe. This extension aims at accounting for price taking behavior of "renewable" firm in real spot electricity markets which are organized as a uniform price auction with all infra-marginal units receiving the system marginal price, i.e. the price bid by the last unit called into operation. The electricity from "renewable" plants is generally bid at zero, while the power from traditional technologies is offered at a positive price which must cover at least the marginal positive cost of production. Therefore, in a stylized model with only two technologies competing in a spot market, the "traditional" generator sets the price knowing that it will face a competitive rival while the "renewable" producer receives the price chosen by the dominant firm despite being competitive in its bid. The results of this analysis are extremely relevant because they show that "renewable" generators are able to influence short run market outcomes with their investment decisions and thanks to merit order rule although they do not make the price in real spot market.[17]

Let us call again S the PV power plant and G the CCGT power plant. Production levels are denoted by $q_i > 0$, $i = s, g$ and generation capacities by k_i, $i = s, g$. Investment cost per unit of capacity is $I_i > 0$, $i = s, g$. S has a convex production cost function for output levels below capacity, $F_s q_s + \frac{c_s}{2} q_s^2$, with $F_s, c_s > 0$, and linear investment cost function, $I_s k_s$. G has linear production and investment cost functions, $I_g k_g + c_g q_g$, with $c_g > 0$. Production above capacity is infinitely costly for both S and G. We assume that $F_s > I_g + c_g$, which means that firm G has the lower minimum average cost. It is further assumed that the availability of PV capacity for production depends on weather conditions. Therefore for each level of installed capacity k_s the available capacity is $x k_s$, where x is the realization of a random variable $X \in [0, 1]$. Firms know the continuous distribution function of the random variable X as well as its expected value, $\mathbb{E}[x] = x^*$. Firms face a linear inverse demand function, $p(Q) = a - bQ$, where $Q = q_s + q_g \subseteq (0, x k_s + k_g)$.

The structure of the game is the following. In the first stage firm S chooses its capacity, k_s: the investment is irreversible in the sense that capacity already installed cannot be dismissed. In the second stage firm G selects simultaneously its capacity, k_g, and its production level, q_g, knowing it that it will face a competitive fringe in the spot market.[18] In the third stage, S chooses its production possibly increasing its capacity

[17]See note 3.

[18]The same reasoning in footnote 10 applies.

prior to compete in the market. The game is solved by backward induction.

3.6.1 Third and second stage solutions

In the last stage of the game S chooses its optimal production level knowing that it may increase its capacity prior to compete in the spot market. As a price taker it sets its quantity by equating expected market price and expected marginal cost of production:

$$\mathbb{E}[a - bq_g - bq_s] = \mathbb{E}[MC(q_s, k_s)] \quad \text{where} \tag{3.42a}$$

$$MC(q_s, k_s) = \begin{cases} F_s + c_s q_s & \text{if } q_s \leq x^* k_s \\ \frac{I_s}{x} + F_s + c_s q_s & otherwise \end{cases} \tag{3.42b}$$

S reaction function is again a kinked curve whose shape depends on the investment decisions that have been taken in previous stages of the game. When the firm has already installed sufficient capacity, its costs in the last stage of the game only consist in production costs thus the first marginal cost curve applies. Conversely, when S's optimal choice of q_s in the last stage of the game is larger than the available capacity, i.e. $q_s > x^* k_s$, the firm must sustain also an investment cost to expand the capacity before producing. In this case the second marginal cost function is the relevant one.

Just like in the two stage game, it is possible to calculate the thresholds f q_g that make the PV producer switching from a reaction curve to another. We remark that the expected inverse demand function is decreasing in the quantity of electricity provided by firm G: $\mathbb{E}[a - bq_g - bq_s]$. We depict these curves for different values of q_g in Figure 3.15. Expected inverse demand curves such as ED_1 emerge when the quantity of electricity produced by G, q_g, is quite large. In this case expected inverse demand curves cross expected marginal cost function $F_s + c_s q_s$. By the same token, small quantities of q_g are associated to expected inverse demand curves such as ED_3 which cross expected marginal cost function at $F_s + \frac{I_s}{x^*} + c_s q_s$. In the intermediate case expected inverse demand curves cross expected marginal cost curve at the kink. Note that if q_g is very large, i.e. $q_g > \frac{a - F_s}{b}$, then $q_s = 0$.

Let us define:

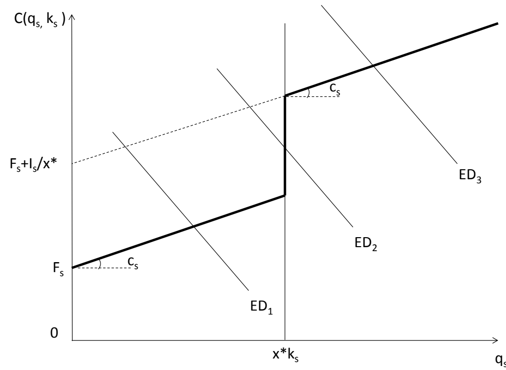

Figure 3.15: Expected inverse demand curves and marginal cost curves

- $q_g^h = \frac{a-(c_s+b)x^*k_s-F_s}{b}$ as the quantity of q_g such that, $\forall q_g > q_g^h$:

$$\mathbb{E}[a - bq_g - bq_s] = \mathbb{E}[F_s + c_s q_s] \tag{3.43a}$$

$$\tilde{R}_s(q_g) = q_s = \frac{a - bq_g - F_s}{c_s + b} \tag{3.43b}$$

- $q_g^l = \frac{x^*[a-(c_s+b)x^*k_s-F_s]-I_s}{bx^*}$ as the quantity of q_g such that, $\forall q_g < q_g^l$:

$$\mathbb{E}[a - bq_g - bq_s] = \mathbb{E}[\frac{I_s}{x} + F_s + c_s q_s] \tag{3.44a}$$

$$R_s(q_g) = q_s = \frac{x^*(a - bq_g - F_s) - I_s}{(c_s + b)x^*} \tag{3.44b}$$

- $\forall q_g$ such that $q_g^l < q_g < q_g^h$, firm S produces at (available) capacity:

$$\bar{R}_s = q_s = x^* k_s \tag{3.45}$$

Firm S reaction function has the same shape as the one depicted in Figure 3.2 with q_g^h and q_g^l corresponding to the new thresholds. Figures 3.16 to 3.19 show all the possible equilibria in the last stage of the game according to the value of k_s installed by S in the first stage. We analyze all possible situations to find the subgame perfect

Nash equilibrium.

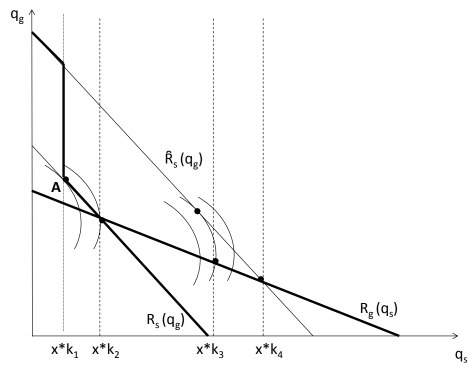

Figure 3.16: $x^*k_s \leq x^*k_1$

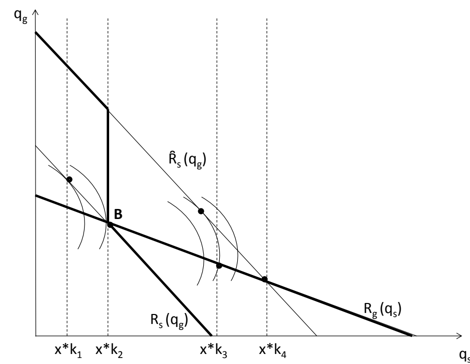

Figure 3.17: $x^*k_s = x^*k_2$

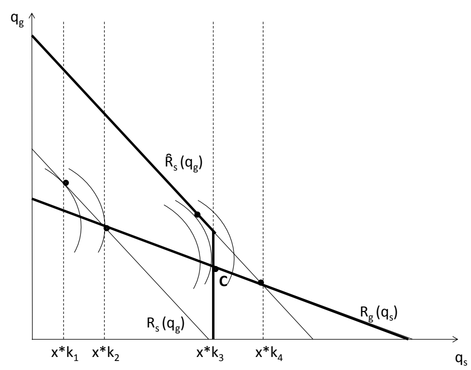

Figure 3.18: $x^*k_2 < x^*k_s \leq x^*k_3$

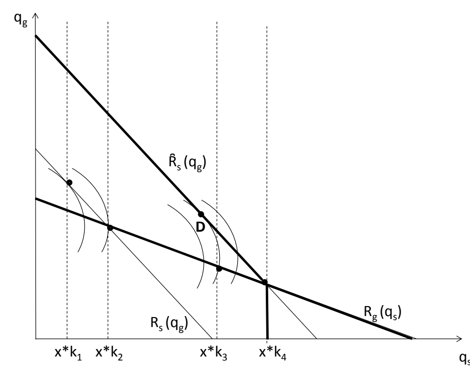

Figure 3.19: $x^*k_s > x^*k_3$

Cases A and B: very small and small photovoltaic capacity

When S has built a small capacity in the first stage of the game it may decide to increase it in the last stage. However in this case it should bear a new investment cost. The optimal quantity of electricity to be produced is selected by equating the expected inverse demand function and S marginal cost function which includes investment cost:

$$\mathbb{E}[a - bq_g - bq_s] = \mathbb{E}\left[\frac{I_s}{x} + F_s + c_s q_s\right] \tag{3.46}$$

The optimal q_s is calculated as a function of q_g:

$$q_s = \frac{x^*(a - bq_g - F_s) - I_s}{(c_s + b)x^*} \tag{3.47}$$

In the second stage, firm G sets its optimal capacity and production. In this setting it behaves as a Stackelberg leader which maximizes its profit over the inverse residual demand, i.e. the inverse market demand minus the supply of the PV producer. G chooses its quantity as the solution to the following maximization problem:

$$\begin{aligned} \underset{q_g, k_g}{\text{Max}} \quad \mathbb{E}[\Pi_g] = \mathbb{E}[p^d(q_g)q_g - cq_g - I_g k_g] \quad \text{subject to} \\ q_g \leq k_g \end{aligned} \tag{3.48}$$

where:

$$p^d = \frac{ac_s x^* + b[I_s + (F_s - c_s q_g)x^*]}{(c_s + b)x^*} \tag{3.49}$$

At the optimimum the constraint is binding and G installs and produces the quantity:

$$k_g^A = q_g^A = \frac{c_s(a - c_g - I_g)x^* + b[I_s + (F_s - c_g - I_g)x^*]}{2bc_s x^*} \tag{3.50}$$

By substituting G's optimal quantity in equations (3.47) and (3.50), we obtain S's optimal quantity and equilibrium price from which we can calculate firms' profits:

$$q_s^A = \frac{c_s(Ax^* - 2I_s) - b(Bx^* + I_s)}{2c_s(c_s + b)x^*} \tag{3.51a}$$

$$p^A = \frac{c_s Cx^* + b(I_s + Dx^*)]}{2(c_s + b)x^*} \tag{3.51b}$$

$$\Pi_s^A = \frac{[c_s(Ax^* - 2I_s) - b(Bx^* + I_s)]^2}{8c_s(c_s + b)^2 x^{*2}} \tag{3.51c}$$

$$\Pi_g^A = \frac{[c_s Ex^* + b(Bx^* + I_s)]^2}{4bc_s(c_s + b)x^{*2}} \tag{3.51d}$$

where:

$$A = a + c_g - 2F_s + I_g = E - 2B > 0$$

$$B = F_s - c_g - I_g > 0$$

$$C = a + c_g + I_g > 0$$

$$D = c_g + I_g + F_s > 0$$

$$E = a - c_g - I_g > 0$$

This equilibrium corresponds to point A in Figure 3.16 and arises in the third stage of the game if in the earlier stage firm S has installed:

$$k_s^A \leqslant \frac{c_s(Ax^* - 2I_s) + b(Bx^* - I_s)}{2c_s(c_s + b)x^{*2}} \tag{3.53}$$

When in the first stage of the game S has invested in a capacity which is larger than k_s^A but still smaller than its optimal choice of production, the firm continues to compete with a reaction function which includes investment cost. In this case the leadership in production of firm G is somehow constrained because the firm should take into account that equilibrium A is unattainable. Therefore to find its optimal quantity and capacity it maximizes its profits over the residual demand as in eq. (3.48): each time the residual demand will be the difference between the market demand and the quantity of electricity provided by S, $q_s = x^* ks$. This equilibrium occurs in a point on the right portion of the segment A-B in Figures 3.16 and 3.17 (excluding point A).[19]

If in the earlier stage S has installed the Cournot capacity the tangency point occurs in B (Figure 3.17) and the optimal response of firm G is to produce exactly Cournot. In this case, the equilibrium outcome is:

$$q_s^B = \frac{Ax^* - 2I_s}{(2c_s + b)x^*} \tag{3.54a}$$

$$q_g^B = \frac{c_s E x^* + b(Bx^* + I_s)}{b(2c_s + b)x^*} \tag{3.54b}$$

$$p^B = \frac{c_s C x^* + b(I_s + F_s x^*)}{(2c_s + b)x^*} \tag{3.54c}$$

$$\Pi_s^B = \frac{c_s(Ax^* - 2I_s)^2}{2(2c_s + b)^2 x^{*2}} \tag{3.54d}$$

[19]The equilibrium is the tangency point between the isoprofit curve of G associated to the highest profit and S reaction function including investment cost.

$$\Pi_g^B = \frac{[c_s E x^* + b(Bx^* + I_s)]^2}{b(2c_s + b)^2 x^{*2}} \tag{3.54e}$$

This equilibrium arises if S has installed in the first stage:

$$k_s^B = \frac{Ax^* - 2I_s}{(2c_s + b)x^{*2}} \tag{3.55}$$

Cases C and D: large and very large photovoltaic capacity

If the photovoltaic producer has installed a large capacity in the first stage of the game, its choice of quantity in the third stage will depend only on production costs. In this case, firm S chooses its optimal quantity as the solution to the equation:

$$\mathbb{E}[a - bq_g - bq_s] = \mathbb{E}\left[F_s + c_s q_s\right] \tag{3.56}$$

which gives the quantity q_s as a function of q_g:

$$q_s = \frac{a - bq_g - F_s}{c_s + b} \tag{3.57}$$

In the second stage of the game the leader in production, firm G, sets its output and its capacity to maximize profits over the residual demand. The problem is the same as in eq. (3.48) but in this case the residual demand is equal to:

$$p^d = \frac{bF_s + c_s(a - bq_g)}{c_s + b} \tag{3.58}$$

At the optimum G installs and produces:

$$k_g^D = q_g^D = \frac{c_s E + bB}{2c_s b} \tag{3.59}$$

Again, by substituting G's optimal quantity in equations (3.56) and (3.57), we obtain S's optimal quantity, equilibrium price and profits:

$$q_s^D = \frac{c_s A - bB}{2c_s(c_s + b)} \tag{3.60a}$$

$$p^D = \frac{c_s C + bD}{2(c_s + b)} \tag{3.60b}$$

$$\Pi_s^D = \frac{[c_s A - bB]^2}{8c_s(c_s+b)^2} \tag{3.60c}$$

$$\Pi_g^D = \frac{[c_s E + bB]^2}{4c_s b(c_s+b)} \tag{3.60d}$$

This equilibrium is represented as point D in Figure 3.19. By constructing the isoprofit curve of G passing through the equilibrium point D we see that it meets firm G reaction function in point C (Figure 3.18). The coordinates of such point are:

$$q_s^C = \frac{E\sqrt{c_s(c_s+b)} - c_s E - bB}{b\sqrt{c_s(c_s+b)}} \tag{3.61a}$$

$$q_g^C = \frac{c_s E + bB}{2b\sqrt{c_s(c_s+b)}} \tag{3.61b}$$

This point ensures to G the same profits of equilibrium D while through the demand function we can calculate the market price and profits of S:

$$p^C = \frac{bB + c_s E + 2\sqrt{c_s(c_s+b)}(c_g + I_g)}{2\sqrt{c_s(c_s+b)}} \tag{3.62}$$

$$\Pi_s^C = \frac{\left\{\left[c_s - \sqrt{c_s(c_s+b)}\right]E + bB\right\}\left\{\left[c_s^2 - c_s\sqrt{c_s(c_s+b)}\right]E + b^2 B + b\left[c_s H - 2\sqrt{c_s(c_s+b)}B\right]\right\}}{2b^2 c_s(c_s+b)} \tag{3.63}$$

where:

$$H = a - 2c_g + F_s - 2I_g$$

Equilibrium D is preferred by CCGT producer when in the first stage S has installed:

$$k_s > \frac{q_s^C}{x^*} = \frac{E\sqrt{c_s(c_s+b)} - c_s E + bB}{x^* b\sqrt{c_s(c_s+b)}} \tag{3.64}$$

while for $k_s = \frac{q_s^C}{x^*}$ firm G prefers the equilibrium at point C.

Case E: intermediate photovoltaic capacity

When in the third stage of the game firm S produces at available capacity, firm G is constrained to behave as a Stackelberg follower.[20] Gas producer's reaction function is the same as the one calculated in the standard setting:

$$R_g(k_s) = q_g^E = \frac{a - bx^*k_s - c_g - I_g}{2b} \tag{3.65}$$

Equilibrium price and profits in implicit form are:

$$p^E = \frac{a - bx^*k_s + c_g + I_g}{2} \tag{3.66a}$$

$$\Pi_s^E = \left(\frac{a - bx^*k_s + c_g + I_g}{2} - F_s - \frac{c_s x^* k_s}{2}\right) x^* k_s \tag{3.66b}$$

$$\Pi_g^E = \frac{(a - bx^*k_s - c_g - I_g)^2}{4b} \tag{3.66c}$$

3.6.2 First stage solutions

To find an explicit form for the equilibrium in case E, we solve the first stage of the game in which S defines its optimal capacity k_s by maximizing its expected profits:

$$\underset{k_s}{\text{Max}} \quad \mathbb{E}[\Pi_s] = \mathbb{E}\left[p(xk_s, q_g)xk_s - \left(\frac{I_s}{x} + F_s + \frac{c_s x k_s}{2}\right) xk_s\right] \tag{3.67}$$

Using the reaction function of G and calculating the FOC of the problem, we get equilibrium capacity, quantities, price and profits in explicit form:

$$k_s^E = \frac{Ax^* - 2I_s}{2(c_s + b)x^{*2}} \tag{3.68a}$$

$$q_s^E = \frac{x^*A - 2I_s}{2(c_s + b)x^*} \tag{3.68b}$$

$$q_g^E = \frac{x^*\left\{b[a - 3(c_g + I_g) + 2F_s] + 2c_s E\right\} + 2bI_s}{4b(c_s + b)x^*} \tag{3.68c}$$

[20]Which means that the first mover advantage in production of firm G is completely lost.

$$p^E = \frac{x^*[b(a + c_g + I_g + 2F_s) + 2c_s C] + 2bI_s}{4(c_s + b)x^*} \tag{3.68d}$$

$$\Pi_s^E = \frac{[Ax^* - 2I_s]^2}{8(c_s + b)x^{*2}} \tag{3.68e}$$

$$\Pi_g^E = \frac{\{x^* \{b[a - 3(c_g + I_g) + 2F_s] + 2c_s E\} + 2bI_s\}^2}{16b(c_s + b)^2 x^{*2}} \tag{3.68f}$$

3.6.3 Optimal strategy selection

Let us firstly qualitatively discuss the possible outcomes of the game with the help of Figures 3.16 to 3.19. The graphics reveal that, when the "renewable" generator prefers to postpone investments and hence presents in the last stage the inner reaction function, between point A in Figure 3.16 and point B in figure 3.17, it will surely prefers the latter equilibrium. Hence the strategy leading to equilibrium A is always dominated by the strategy corresponding to equilibrium B. Likewise, when the "renewable" generator anticipates investments in the first stage of the game and competes in the last stage with the outer reaction function, between equilibrium C in Figure 3.18 and equilibrium D in Figure 3.19 it will always prefer equilibrium at point C. Therefore, although the PV producer is the follower in the production game, it can eliminate strictly dominated strategies leading to points such as A and D at the beginning of the game exploiting its first mover advantage in the investment game. It thus selects its optimal capacity investment on the segment B-C as it does in the two stage game on the segment A-B. The strategic incentives depending on merit order rule still hold. The only difference here is in that the segment B-C is shorter than the segment A-B, which constraints the set of possible capacity choices.

Analytically, firm S selects its optimal strategy by comparing the net profits from each of the five cases, regardless if the investment has been paid in the first or the third stage of the game. As in the baseline model we indicate net profits with a * to distinguish them from gross profits:[21]

$$\Pi_s^{A^*} = \frac{[c_s(Ax^* - 2I_s) - b(Bx^* + I_s)]^2}{8c_s(c_s + b)^2 x^{*2}} \tag{3.69a}$$

[21]Note that $\Pi_s^A = \Pi_s^{A^*}$, $\Pi_s^B = \Pi_s^{B^*}$ and $\Pi_s^E = \Pi_s^{E^*}$.

$$\Pi_s^{B*} = \frac{c_s(Ax^* - 2I_s)^2}{2(2c_s + b)^2 x^{*2}} \tag{3.69b}$$

$$\Pi_s^{C*} = \frac{\left\{(c_s + b)\left[c_s - \sqrt{c_s(c_s + b)}\right] E + bB\right\}\left\{\left[c_s^2 - c_s\sqrt{c_s(c_s + b)}\right] Ex^* - b\left[\sqrt{c_s(c_s + b)}Bx^* - 2c_s(I_s + Bx^*)\right]\right\}}{2b^2[c_s(c_s + b)]^{\frac{3}{2}} x^*} \tag{3.69c}$$

$$\Pi_s^{D*} = \frac{(c_s A - bB)\left[(c_s A - bB)x^* - 4(c_s + b)I_s\right]}{8c_s(c_s + b)^2 x^*} \tag{3.69d}$$

$$\Pi_s^{E*} = \frac{[Ax^* - 2I_s]^2}{8(c_s + b)x^{*2}} \tag{3.69e}$$

Contrary to the baseline case, the ranking of strategies in the extended model depends on the values of parameters. For illustrative purposes, we have calculated the payoffs of the game as a function of x^* and we have reported them in Figure 3.20 using the following parameters' values:

$$c_s = 0.5 \tag{3.70a}$$

$$b = 1 \tag{3.70b}$$

$$I_s = 1 \tag{3.70c}$$

$$F_s = 5 \tag{3.70d}$$

$$c_g = 1 \tag{3.70e}$$

$$I_g = 1 \tag{3.70f}$$

$$a = 50 \tag{3.70g}$$

We remark that the strategy E provides the PV firms with the largest profits whenever x^* has values below 0.9. Strategy B seems to be the second preferred strategy but only when $x^* < 0.25$; indeed after this point strategy C takes over beating even strategy E for very large values of the average capacity availability ($x^* > 0.9$). Strategies A and D follow, with A always preferred to D for any values of x^*. It is interesting to note that in our example strategy D requires an average available capacity larger that 0.3 to produce positive pay-offs.

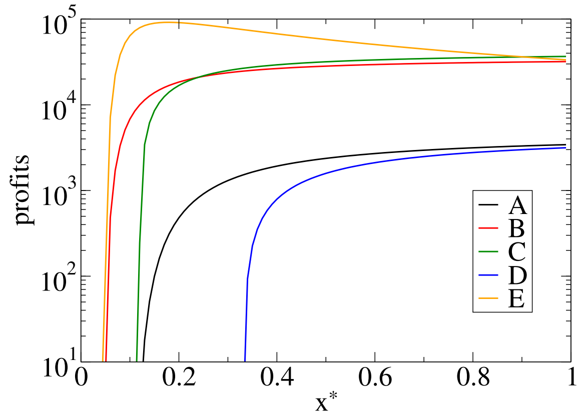

Figure 3.20: Profits

3.7 Conclusions

We proposed a stylized model for the analysis of investment and production incentives in decentralized electricity markets when a traditional power generator faces competition from a producer employing an intermittent technology. Although competition in generation seems to be substantially animated by new entrants investing in renewable technologies, the study of interactions between "traditional" and "renewable" power producers still remains an almost unexplored field of research. Our model is a modified version of the *Dixit model* for entry deterrence with Cournot competition in the post entry stage. This choice stems from two reasons. Firstly, because of merit order rule the power from renewable sources is always the first to be brought on line in spot electricity markets. This favorable ranking may be interpreted as a sort of first mover advantage similar to that one of the incumbent in the Dixit model. Indeed, in power sector the profitability of investments in "traditional" technologies rests on the size of the residual demand, which in turn is determined by the capacity installed by "renewable" producer. Therefore the "renewable" producer is a sort of incumbent and the "traditional" producer is the entrant who behaves as a follower in the Stackelberg game for capacity investment. Secondly, the *Dixit model* is sufficiently flexible to allow for several types of competition in the post entry game and in each setting a certain degree of uncertainty about demand and/or cost functions may be introduced. We have modeled post-entry stage as a Cournot competition and the uncertainty depends on the availability of PV capacity. In real power markets firms are supposed to compete in prices. However, in a stylized model with a "renewable" and a "traditional" power producers firms rather play a quantity game since the "renewable" power plant can always bid at zero and the "traditional" producer is constantly marginal. Quantity competition presents the additional advantage that both firms receive the same price as in a uniform price auction used in real markets.

Our analysis suggests that the "renewable" generator exploits merit order rule to invest and produce as if it were a Stackelberg leader. While including considerations about the average availability of installed capacity does not change preferences over strategies of "renewable" generator for most of the parameters' values, consumer surplus differs substantially according to it. This result seems to indicate that there is some room for welfare improving public interventions: indeed, if on the one hand the average availability of renewable capacity depend on technology and cannot be modified, on the other hand consumer surplus can be increased (regardless to the strategy chosen by the firm) by decreasing investment cost in renewable technology. Interestingly, the ex-post analysis of pay-off reveals that profits ranking, and hence preferences over strategies, may be reversed even for small errors in the forecasting of the average capacity availability factor and so the incentives for strategic behavior may be stronger. This result suggests that the only ex-ante analysis of the game may be misleading and must be always coupled with an ex-post analysis.

An extension of our model has consisted in relaxing the assumptions on market power and dimension of the PV producer. In the extended model, we adopt the "dominant firm - competitive fringe" setting developed by Carlton and Perloff (2002) in the post-entry game. This extension aims at accounting for price taking behavior of "renewable" firm which represents the competitive fringe in real spot electricity market. The idea behind this extension is that in a stylized model with only two technologies competing in a spot market, the "traditional" generator sets the price knowing that it will face a competitive rival while the "renewable" producer receives the price chosen by the marginal "traditional" firm despite being competitive in its bid. This extension transforms the two stage game in a three stage game, in which the PV producer is a follower (competitive fringe) in the production game and a leader in the investment game due to the merit order rule. The main insights of the model seem to be barely sensitive to changes in the market power of competitors: even when the "renewable" generator behaves as a competitive fringe in the spot market, it is able to influence equilibrium outcome to its own advantage through investment choices although to a smaller degree than in the standard setting. In this extension, contrary to the baseline model, the ranking of strategies is sensitive to the choice of parameters' values.

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Appendix B

Analytical calculations

The ex post pay-off of strategies B and C is calculated as:

$$\Pi_s = (a - bq_g - bxk_s)xk_s - I_sk_s \tag{B.1}$$

By substituting in previous equation the optimal values of k_s^C and k_s^B calculated as functions of x^* and the optimal quantity of firm G which is the minimum between its installed capacity and its optimal production given the electricity supplied by S, we obtain:

$$\begin{aligned}\Pi_s^B = \left(a - b\left(\frac{a - b\max(x, x^*)k_s^B - c - I_g}{2b}\right)\right) x \left(\frac{a + c + I_g}{3bx^*}\right) - \\ bx^2\left(\frac{a + c + I_g}{3bx^*}\right)^2 - I_s\left(\frac{a + c + I_g}{3bx^*}\right)\end{aligned} \tag{B.2}$$

$$\begin{aligned}\Pi_s^C = \left(a - b\left(\frac{a - b\max(x, x^*)k_s^C - c - I_g}{2b}\right)\right) x \left(\frac{x^*(a + c + I_g) - 2I_s}{2bx^{*2}}\right) - \\ bx^2\left(\frac{x^*(a + c + I_g) - 2I_s}{2bx^{*2}}\right)^2 - I_s\left(\frac{x^*(a + c + I_g) - 2I_s}{2bx^{*2}}\right)\end{aligned} \tag{B.3}$$

To calculate their expected value, we firstly use a generic probability density function, $P(x)$, defined for $x \in [0, 1]$. The expected value of a generic function $f(x)$ can be rewritten as:

$$\mathbb{E}[f] = \int_0^1 f(x)P(x)dx \tag{B.4}$$

Expected profits are then:[1]

$$\mathbb{E}[\Pi_s^{B,C}] = \int_0^1 \Pi_{B,C}(x)P(x)dx \tag{B.5}$$

For strategy B we have:

$$\mathbb{E}[\Pi_s^B] = -\frac{AI_s}{3bx^*} - \frac{A}{18bx^{*2}}\int_0^1 (2Ax^2 - 3Axx^* - Ax\max(x,x^*))P(x)dx =$$

$$= -\frac{AI_s}{3bx^*} - \frac{A}{18bx^{*2}}\left(2A\int_0^1 x^2P(x)dx - 3Ax^*\int_0^1 xP(x)dx - A\int_0^1 x\max(x,x^*)P(x)dx\right) =$$

$$-\frac{AI_s}{3bx^*} - \frac{A}{18bx^{*2}}\left(2AE[x^2] - 3Ax^{*2} - AM\right)$$

where:

$$M = \int_0^1 x\max(x,x^*)P(x)dx \tag{B.6}$$

Simplifying:

$$\mathbb{E}[\Pi_s^B] = -\frac{AI_s}{3bx^*} - \frac{A^2E[x^2]}{9bx^{*2}} + \frac{A^2}{6b} + \frac{A^2M}{18bx^{*2}} \tag{B.7}$$

For strategy C, let us firstly rewrite the profits as:

$$\Pi_s^C = \frac{I_s}{2bx^{*2}}(2I_s - Ax^*) - \frac{(2I_s - Ax^*)^2}{4bx^{*4}}x^2 + \frac{(2I_s - Ax^*)[(2I_s - Ax^*)\max(x,x^*) - 2Ax^{*2}]}{8bx^{*4}}x =$$

$$= \frac{I_sB}{2bx^{*2}} - \frac{B^2}{4bx^{*4}}x^2 + \frac{B^2\max(x,x^*) - 2ABx^{*2}}{8bx^{*4}}x$$

where $B = 2I_s - Ax^*$. The expected profits are:

$$\mathbb{E}[\Pi_s^C] = \frac{I_sB}{2bx^{*2}} - \int_0^1\left(\frac{B^2}{4bx^{*4}}x^2 + \frac{B^2\max(x,x^*) - 2ABx^{*2}}{8bx^{*4}}x\right)P(x)dx =$$

$$= \frac{I_sB}{2bx^{*2}} - \frac{B^2}{4bx^{*4}}\int_0^1 x^2P(x)dx + \frac{B^2}{8bx^{*4}}\int_0^1 x\max(x,x^*)P(x)dx - \frac{AB}{4bx^{*2}}\int_0^1 xP(x)dx =$$

[1] Note that we have dropped the subscript s for expositional convenience.

Using again the definition of M we obtain:

$$\mathbb{E}[\Pi_s^C] = \frac{I_s B}{2bx^{*2}} - \frac{AB}{4bx^*} - \frac{B^2}{4bx^{*4}}E[x^2] + \frac{MB^2}{8bx^{*4}} \tag{B.8}$$

Recalling that $\mathbb{E}[x] = x^*$, we may rewrite the expected profits of strategies B and C using the definition of variance of a random variable, $\mathrm{Var}[x] = \mathbb{E}[x^2] - \mathbb{E}[x]^2$. After some manipulations we get:

$$E[\Pi_B] = \frac{A^2}{18b} - \frac{AI_s}{3bx^*} + \frac{A^2}{18bx^{*2}}(M - 2\mathrm{Var}[x]) \tag{B.9a}$$

$$E[\Pi_C] = \frac{2I_sB - B^2}{4bx^{*2}} - \frac{AB}{4bx^*} + \frac{B^2}{8bx^{*4}}(M - 2\mathrm{Var}[x]) \tag{B.9b}$$

The condition for $E[\Pi_B] < E[\Pi_C]$ is therefore equivalent to:

$$\frac{A^2}{18} - \frac{AI_s}{3x^*} + \frac{A^2}{18x^{*2}}(M - 2\mathrm{Var}[x]) < \frac{B^2}{8x^{*4}}(M - 2\mathrm{Var}[x]) \tag{B.10}$$

If we call $I = 6I_s$, the previous inequality becomes:

$$\frac{A^2}{18} - \frac{AI}{18x^*} + \frac{A^2}{18x^{*2}}(M - 2\mathrm{Var}[x]) < \frac{(I/3 - Ax^*)^2}{8x^{*4}}(M - 2\mathrm{Var}[x]) \tag{B.11}$$

which we simplify by multiplying both sides by $\frac{18x^{*2}}{I^2}$:

$$\frac{A^2x^{*2}}{I^2} - \frac{Ax^*}{I} + \frac{A^2}{I^2}(M - 2\mathrm{Var}[x]) < \frac{(1 - 3x^*A/I)^2}{4x^{*2}}(M - 2\mathrm{Var}[x]) \tag{B.12}$$

We call $\hat{x} = \frac{I}{A}$ in order to reduce the inequality to:

$$\frac{x^{*2}}{\hat{x}^2} - \frac{x^*}{\hat{x}} + \frac{1}{\hat{x}^2}(M - 2\mathrm{Var}[x]) < \frac{(1 - 3x^*/\hat{x})^2}{4x^{*2}}(M - 2\mathrm{Var}[x]) \tag{B.13}$$

Finally we call s the ratio $x^*/\hat{x}$ and we rewrite previous condition as:

$$s(s-1) < \left(s^2 - \frac{(1-3s)^2}{4}\right)\frac{2\mathrm{Var}[x] - M}{\hat{x}^2} \tag{B.14}$$

By further simplification we obtain:

$$4s(s-1) < (6s + 5s^2 - 1)\frac{2\mathrm{Var}[x] - M}{\hat{x}^2} \tag{B.15}$$

Chapter 4

The effect of intermittent renewable generation on congestion and zonal price differences in Italy

4.1 Introduction and literature review

The interest in alternative energy has sparked in Europe as the climate change problem emerged. The 2009 Climate and Energy package has motivated European governments to stimulate renewable energy penetration through supporting schemes in order to meet the target of a 20% share of EU energy consumption produced from renewable sources by 2020. According to the more recent figures from Eurostat, a Directorate-General of the European Commission responsible for statistical information of its member, the share of renewables in gross final energy consumption has reached 14.1% in the EU-28 in 2012. The integration of renewable power plants, especially those exploiting intermittent power sources such as wind and sun, represents a challenge for network operators, market participants and regulators for a number of reasons. First of all, some geographical locations are particularly well suited for the installation of new capacity due to the abundance of natural resources (e.g. the North for wind and the South for solar in both Germany and Spain). These locations may not coincide with consumption sites and may, on the contrary, be very far from them. Substantial investments are therefore required to integrate the new facilities and to ease the process of displacement of electricity from production toward consumption sites. Additional investments may be necessary to deal with increasing intermittent generation directly flowing into the network: a possible solution are "smart grids" which provide the network operator with an enhanced real-time control over how the electricity is routed within the grid. Secondly, merit order rule and priority dispatch for the electricity generated from renewable power sources have redefined the rules of the game in decentralized spot market: on the one hand renewable supply has partly crowded out the production from mid-merit power plants and on the other hand it has intensified the needs for immediately available, back-up capacity to overcome the intermittency and to guarantee inflows and outflows balance.

If the engineering literature has focused on the topic of integration of renewables and optimal network expansion(see for instance Abdullah et al., 2014; Hemdan et al., 2014; Rathore and Roy, 2014), the economic literature has been especially concerned in analysing the impact of increasing renewable production on wholesale electricity prices. Several authors (Cutler et al., 2011; Gelabert et al., 2011; Ketterer, 2014) have emphasized the likely reductions on equilibrium prices entailed by renewable supply and originated from the displacement of higher variable cost production in the merit order ranking (this phenomenon is referred to as "merit order effect"). Nonetheless, when national electricity markets are organized as two or more inter-connected sub-markets with zonal prices, the final impact on equilibrium prices of increased generation from renewable sources may result less straightforward than the existing literature would suggest. As a matter of fact, depending on the location of supply and demand, the renewable output may multiply the incidence of transmission congestions or it may relieve congestion occurrence by reducing transportation needs.

This chapter aims at testing the impact of this phenomenon using Italian electricity market as case study. For its particular features, Italy serves extremely well our research purpose. The Italian Power Exchange is composed of 6 regional sub-markets which aggregate in macro-zones all the administrative regions. The hourly electricity price is unique for the whole country when all transmission limits between sub-markets are respected; otherwise a system of zonal pricing applies.[1] The Northern zone, whose generation capacity is the largest of the country, has historically been an exporting zone; as a consequence its zonal prices have been constantly lower than the rest of Italy. The ambitious support policies for the development of renewable power sources have generated a significant amount of new investments in solar and wind power plants: between 2010 and 2012 the combined production of solar and wind has increased at a rate of 105% reaching an average hourly generation of about 5100 MWh in 2012.[2] Southern regions have showed the highest growth rate due to the favourable weather conditions. While remaining the larger producer, the contribution of the Northern zone to the average total hourly renewable production has decreased by more than 7% between 2010 and 2012. The analysis of inter-zonal transits resulting from the day-ahead auction as well as of the series of paired-price differences between neighbouring zones reveals a changing pattern between importing and exporting regions, with a stronger role for Central and Southern regions as exporters. The final effect on congestion frequencies and zonal prices remains however to be empirically tested.

[1]The zonal prices are selling prices while buyers all pay the National Single Price (PUN) for the electricity bought in the pool.

[2]In Appendix C we report a full description of the database employed in the analyses.

This chapter aims at contributing to the scant literature on the effect of increasing renewable power production on zonal prices and congestion. Woo et al. (2011) pioneered the discussion by studying the effect of increasing wind generation on zonal price differences in Texas ERCOT power market. The analysis stems from the observation that wind generation is mostly concentrated in the West zone which is scarcely populated, whereas generation capacity in Houston zone falls short of its zonal load. The author firstly estimate a three ordered-logit model on three zonal pairs to capture the effect of total wind generation, zonal loads, nuclear generation and the gas price at Henry Hub on the probability and the direction of grid congestion. Secondly, they estimate a log-linear model to quantify the effect of the same variables on positive and negative zonal price differences. The authors use 15-min market data from January 2007 to May 2010. They show that rising wind supply, nuclear generation, load from non-West zones and gas price increase the likelihood and the size of strictly positive paired-price differences between the West and the other zones;[3] increasing the load in the West zone has exactly the opposite effect since it reduces exporting needs.

Up to our knowledge, Sapio (2014) is the only author applying this type of analysis in Italy to test the effect of larger solar and wind generation on congestion between Sicily and Southern Italy using a binary dynamic logit model and a vector autoregressive model on 2012 hourly data. The regressors in the dynamic logit model are lagged indicator of congestion, demand in Sicily and in the rest of Italy, solar and wind supplies in Sicily and in the rest of Italy, and indicators of market power for Sicily. The binary logit model is designed to take into account alternatively the occurrence of congestion and its direction (congestion from or to Sicily). The likelihood of congestion *tout-court* seems to increase with the demand in Sicily and the supply of solar power supply in the rest of Italy and to decrease with all other regressors (the indicator of market power is not significant). When directional congestion is analysed the author finds that a rise in the demand in Sicily and in the supply of solar in the rest of Italy decreases the likelihood of congestion from Sicily, while a rise in the load in the rest of the peninsula, in the supply of wind and solar in Sicily and in the indicators on market power have the opposite effect; the opposite pattern is found for congestion to Sicily. With the VAR

[3] A strictly positive paired-price difference occurs when the West price is lower than the price in the other zones and vice-versa, meaning that the congestion is “coming from the West”.

model the author validates logit results, additionally proving that congestion indices are characterized by persistence and that they depend on lagged zonal prices but only in the case of congestion to Sicily.

To assess the impact of increasing renewable generation on congestion and zonal price differences in Italy, we have built a unique database collecting and matching data with hourly frequency from several sources for the period 2010-2012: GME, the market operator, which publishes the hourly offers in the day-ahead market together with equilibrium prices, quantities end inter-zonal transits; GSE, the state-owned company promoting and supporting renewable energy sources in Italy, which provides information about renewable capacity and generation; Terna, the network operator, which is in charge for the estimation of the demand and the available transmission capacities; REF-E, a consulting group, which has created a list of Italian power plants classified by technology and geographical location; ICE, the American network of exchanges and clearing houses for financial and commodity markets. We have estimated then two econometric models performed on five zonal pairings: a multinomial logit model, whose dependent variable has three discrete values capturing both the occurrence of congestion and its direction, and an OLS model which seeks to quantify the effects of renewable production on the size of paired-price differences. This chapter originally contributes to previous literature in three ways. Firstly, we enlarge the scope of the analysis by considering all Italian neighbouring zones in order to verify the consistency of the empirical models beyond the specificities of each pair; secondly, we employ a multinomial logit model, instead of a binary model, in order to separately capture the effect of increasing renewable production on the probability of both directional congestions (to and from) compared to the benchmark situation of no congestion; thirdly, we consider zonal figures on production and demand instead of aggregated figures to isolate the contribution of each zone to the occurrence of congestion and to the size of price difference.

Our analysis suggests that the effect of increasing renewable generation on congestion remarkably depends on the importing/exporting role played by the zone under consideration. Indeed, if a region is normally importing electricity from its neighbour, the effect of a larger local renewable supply is to decrease the probability of suffering congestion in entry or at to increase the probability of causing a congestion in exit compared to no congestion case. Increasing hydroelectric production in these zones has a similar effect. In terms of price difference, increasing renewable generation seems to have a significant impact in SICI and SARD, decreasing the level of positive price differences and increasing the level of negative price differences. The opposite effect seems to be played by renewable production in CNOR but only in CNOR-NORD pair.

The chapter is organized as follows. The next section describes the Italian electricity market. The third section analyses the evolution of transits across zones, zonal prices and zonal price differences. The forth section is dedicated to the econometric analysis. The last section concludes.

4.2 Italian electricity market

The Italian Power Exchange (IPEX) is composed by:

- the Spot Electricity Market (MPE) which consists of three sub-markets:
    1. the Day-Ahead Market (MGP - Mercato del giorno prima)
    2. the Intra-Day Market (MI - Mercato Infragiornaliero)
    3. the Ancillary Services Market (MSD - Mercato dei servizi di dispacciamento)
- the Forward Electricity Market (MTE - Mercato a termine);
- the Platform for physical delivery of financial contracts (CDE) concluded on IDEX, the financial derivatives segment of Borsa Italiana S.p.A.

GME, the market operator also manages the OTC Registration Platform (PCE) for registration of forward electricity purchase and sale contracts that have been concluded off the bidding system. The focus of our analysis will be the MGP, the day-ahead market. In the Italian day-ahead market electricity market, transactions take place between the ninth day before the day of physical delivery and the day before the day of delivery. The sellers submit hourly offers for each generating unit specifying the quantity and the minimum price at which they are willing to trade their power. The aggregated supply curve is built according to the merit order which is a way of ranking all available offers in an ascending order of price. In a symmetrical way, the market demand curve is generated through the aggregation of single bids in a descending order of price.[4] The hourly market price is determined by the intersection of the demand and the supply curves: it is unique when all transmission limits between zones are respected; otherwise a system of zonal pricing applies.

The geographical market includes 7 foreign virtual zones, 6 geographical zones and 5 poles of limited production (national virtual zones). A stylized representation of the geographical market with the most relevant links between zones is reported in Figure 4.1. The 20 administrative regions composing the Italian territory are aggregated in the 6 geographical zones (Table 4.1). The poles of limited production are coupled with the closest geographical zone to form 6 large Macro-zones: Monfalcone (MFTV) is associated to North, Brindisi (BRNN), Foggia (FOGN) and Rossano (ROSN) to South and Priolo (PRGP) to Sicily. The determination of market price follows an iterative procedure. Firstly, the geographical market is considered as unique: if the day-ahead production/consumption plan respects all network constraints across zones, then a single price for the whole Country emerges. On the contrary, if a network constraint is saturated then the geographical market is divided in two sub-markets, each one aggregating all the zones above and below the saturated constraint. The market demand and supply curves are rebuilt for the two sub-markets and two zonal prices result. In the event of permanence of constraint saturation, the process of sub-setting the market continues until all constraints are satisfied. The hourly auction is a uniform price auction which means that all accepted units are entitled to receive the system marginal price (or prices when dezoning arises because of transmission congestion).[5] The national bidders pay on the other hand the National Single Price (PUN) for the electricity bought in the pool: the PUN is an average of the zonal prices, weighted for the zonal purchases and net of purchases for pumped-storage units[6] and of purchases

[4]For each day and each offer/bid point, a maximum of 24 bids/offers may be submitted. Three type of offer/bid exist: simple, consisting of a pair of values indicating the volume of electricity offered/bid in the market by a market participant and the price for a given hour; multiple, consisting of the division of an overall volume offered/bid in the market by the same market participant for the same hour; pre-defined, consisting of simple or multiple offers/bids which are daily submitted to GME (GME).

[5]The market splitting mechanism used in Italy represents a non-discriminatory implicit auction for the assignment of transmission rights.

[6]These generating units are classified as mixed offer points since they are authorized to submit both supply offers and demand bids into the day-ahead market.

from foreign zones. The GME publishes all the offers/bids submitted in the market together with equilibrium prices and quantities with a seven day delay.

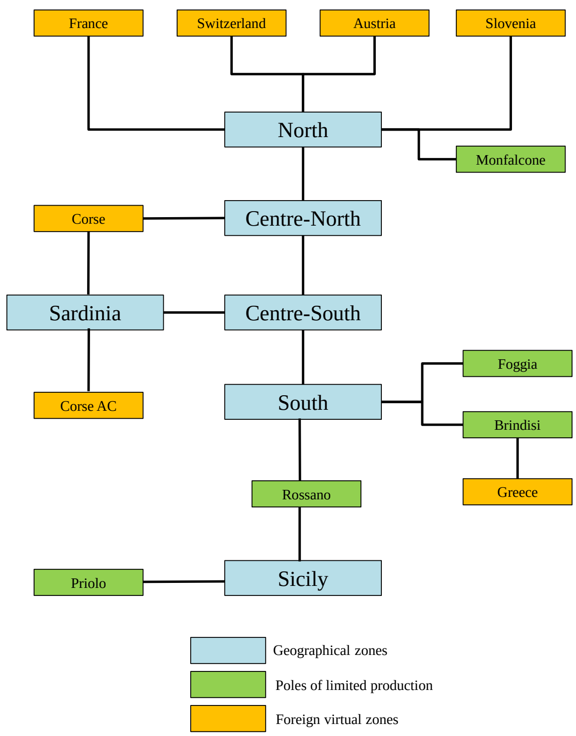

Figure 4.1: A stylized representation of geographical market
Source: Terna

Zone	Regions	Zone Code
North	Valle D'Aosta, Piemonte, Liguria, Lombardia, Trentino, Veneto, Friuli Venezia Giulia, Emilia	NORD
Centre-North	Toscana, Umbria, Marche	CNOR
Centre-South	Lazio, Abruzzo, Campania	CSUD
South	Molise, Puglia, Basilicata, Calabria	SUD
Sicily	Sicilia	SICI
Sardinia	Sardegna	SARD

Table 4.1: Italian geographical zones

To better gauge the relevance of transmission congestion phenomenon in Italy, we have reported in Table 4.2 its frequency in 2010, 2011 and 2012. We observe that overall the grid has been congested for 85.7% of the time. If we look at the changes between the years, we remark that the congestion frequency has increased by 2.6% between 2010 and 2011 and by another 6.9% between 2011 and 2012. It is worthy to note however that some links are more often congested than others. We will come back on this point.

	No congestion	Congestion	N
2010	1527 (17.8%)	7065 (82.2%)	8592
2011	1338 (15.6%)	7254 (84.4%)	8592
2012	834 (9.7%)	7758 (90.3%)	8592
Total	3696 (14.3%)	22080 (85.7%)	25776

Table 4.2: Congestion frequency
Source: Authors' elaboration on GME data

Table 4.3 shows the average number of zonal divisions in the same period. Overall the average number of sub-market caused by congestion is 2.32. Nonetheless, we may observe a decreasing trend in the indicator, with a -4.5% between 2010 and 2011 and -2.6% between 2011 and 2012. Given that the number of congested hours have increased but the number of zonal divisions has decreased toward 2, we may conclude that there is a consolidation towards a two sub-market splitting.

	Mean	Std dev	N
2010	2.411778	0.944578	8592
2011	2.302607	0.82683	8592
2012	2.241155	0.669637	8592
2010-2012	2.318513	0.824433	25776

Table 4.3: Zonal divisions
Source: Authors' elaboration on GME data

4.3 Analysis of physical flows and zonal price series

We present in the next paragraphs the analysis of physical flows across zones, of zonal prices and of zonal price differences for the the period 2010-2012. When studying the flows we consider both geographical zones and poles of limited production, whereas in the analysis of zonal prices and zonal price differences we reduce our scope to the six geographical zones, given that most of the time the zonal prices in the poles of limited production equal the prices in their contiguous geographical zone to which they accrue to form a Macro-zone.

4.3.1 Interzonal transits

Each day and at least 60 minutes before the close of the sittings of the day-ahead auction, Terna notifies GME about the information on the maximum transmission capacity available between all pairs of interconnected zones; these data are published by GME and used to determine market equilibria in each hour. The average admissible interzonal transits have remained largely stable between 2010 and 2012 (Table 4.4), with only two exceptions. From SARD to CSUD the average limit has almost tripled in three year and from CSUD to SARD it has more than doubled: the reason is that from March 2011 a new 1000 MW submarine cable (SAPEI) has been put in operation between the two zones. From MFTV to NORD the average transit has reached its maximum (10000 MWh) in 2012 due to the reduction in the exports of MFTV which has left the transmission capacity idle. Similarly, the variance-to-mean ratios (Table 4.5) have remained steady, apart from the link SARD-CSUD, where the ratios have decreased for both origins but more for flows leaving SARD, and from MFTV to NORD where the indicator has reached zero in 2011.

The physical flows determined through the day-ahead auction, however, have been subjected to relevant changes which highlight an evolution in the relationship between historical exporting and importing zones. The average transits and the variance to mean ratios are reported in Tables 4.6 and 4.7 respectively. The exporting zones are on the vertical header of the tables while the importing zones are on the horizontal header.

From NORD to CNOR, the average flow has plunged of about 50% in size between 2010 and 2012, after an increase in 2011. An opposite trend has characterized the value of the variance-to-mean ratio which has more than doubled between 2010 and 2012 following a decrease in 2011. This result seems to indicate that CNOR, after a first year of larger reliance on imports from NORD, has become less dependent on its

From/To		CNOR	CSUD	NORD	SARD	SICI	SUD	BRNN	FOGN	MFTV	PRGP	ROSN
	2010		1795	1639								
	2011		2002	1596								
CNOR	2012		1922	1672								
	2010	2084			213		10000					
	2011	2186			485		10000					
CSUD	2012	2294			558		10000					
	2010	3264								10000		
	2011	3139								10000		
NORD	2012	3353								10000		
	2010		273									
	2011		612									
SARD	2012		882									
	2010										10000	196
	2011										10000	183
SICI	2012										10000	182
	2010		3883					10000	10000			10000
	2011		3878					10000	10000			10000
SUD	2012		3717					10000	10000			10000
	2010						4969					
	2011						4984					
BRNN	2012						4605					
	2010						1877					
	2011						1884					
FOGN	2012						1888					
	2010			1726								
	2011			1730								
MFTV	2012			10000								
	2010					802						
	2011					795						
PRGP	2012					794						
	2010					164	2035					
	2011					159	2060					
ROSN	2012					167	2082					

Table 4.4: Admissible interzonal transits (Mean), 2010-2012 (MWh)
Source: Authors' elaboration on GME data

neighbour. The flows from MFTV to NORD have progressively decreased to reach 0 in 2012, while the the variance-to-mean ratio has increased in 2011, before touching 0 in 2012 too. These values reveal that NORD has become auto sufficient, reducing its importing needs from MFTV.

The flows from CSUD to CNOR have slightly decreased in 2011 to increase to about the 55% of their initial value in 2012. This result seems to indicate a consolitation in the role of CNOR as importer from CSUD. The variance-to-mean ratio has also slightly increased in 2011 to fall beyond its initial value in 2012. From CSUD to SARD, the average transit, after a substantial increase in 2011, has almost halved in 2012, whereas the variance-to-mean ratio has more than tripled in 2012 compared to 2010, after an initial reduction in 2011. This figure highlights an empowerment of SARD at the expenses of imports from CSUD.

On average the transits from SUD to CSUD have progressively decreased of about 7.8% between 2010 and 2011 and of about 5.6% between 2011 and 2012. CSUD continues to import from SUD but its reliance on import has reduced. The variance-to-mean

From/To		CNOR	CSUD	NORD	SARD	SICI	SUD	BRNN	FOGN	MFTV	PRGP	ROSN
CNOR	2010		0.281	0.365								
	2011		0.210	0.382								
	2012		0.247	0.355								
CSUD	2010	0.202			0.755		0.000					
	2011	0.139			0.372		0.000					
	2012	0.137			0.412		0.000					
NORD	2010	0.186								0.000		
	2011	0.222								0.000		
	2012	0.155								0.000		
SARD	2010		0.667									
	2011		0.473									
	2012		0.284									
SICI	2010										0.000	0.384
	2011										0.000	0.460
	2012										0.000	0.409
SUD	2010		0.106					0.000	0.000			0.000
	2011		0.116					0.000	0.000			0.000
	2012		0.186					0.000	0.000			0.000
BRNN	2010						0.129					
	2011						0.133					
	2012						0.246					
FOGN	2010						0.194					
	2011						0.201					
	2012						0.206					
MFTV	2010			0.040								
	2011			0.000								
	2012			0.000								
PRGP	2010					0.049						
	2011					0.073						
	2012					0.078						
ROSN	2010					0.587	0.158					
	2011					0.633	0.152					
	2012					0.566	0.118					

Table 4.5: Admissible interzonal transits (Variance-to-Mean Ratio), 2010-2012 (MWh)
Source: Authors' elaboration on GME data

From/To		CNOR	CSUD	NORD	SARD	SICI	SUD
CSUD	2010	510			102		
	2011	460			299		
	2012	791			66		
NORD	2010	939					
	2011	1120					
	2012	443					
MFTV	2010			682			
	2011			550			
	2012			0			
SUD	2010		3104				
	2011		2861				
	2012		2698				
BRNN	2010						3418
	2011						3200
	2012						2663
FOGN	2010						633
	2011						725
	2012						624
ROSN	2010					76	911
	2011					79	674
	2012					112	714
PRGP	2010					489	
	2011					440	
	2012					438	

Table 4.6: Interzonal transits resulting from the day-ahead auction (Mean), 2010-2012
Source: Authors' elaboration on GME data

ratio has constantly increased of about 30% in the three year period. The average flows from the poles of limited production BRNN and ROSN to the zone SUD have steadily decreased between 2010 and 2012 with an overall reduction rate of 22% and 20% respectively. The flows from FOGN to SUD have increased between 2010 and 2011 to decrease again to almost their initial levels in 2012. The variance-to-mean ratios in the three year period have rosen of about 35% for ROSN and 45% for BRNN, but has remained substantially constant for FOGN. These figures highlight a weaker reliance of SUD on imports from its neighbouring poles of limited production.

Finally, the average flows from ROSN to SICI have progressively increased between 2010 and 2012 at an overall rate of almost 50%, while imports from PRGP to SICI have decreased of about 10%. In the three year period, the variance-to-mean ratio has increased of about 10% for PRGP and has decreased of about 20% for ROSN. This result seems to indicate that the role of exporter of PRGP for SICI has flagged in favor of ROSN.

From/To		CNOR	CSUD	NORD	SARD	SICI	SUD
	2010	1.834			1.500		
	2011	1.938			0.629		
CSUD	2012	1.268			5.389		
	2010	1.272					
	2011	0.942					
NORD	2012	2.731					
	2010			0.397			
	2011			0.523			
MFTV	2012			0.000			
	2010		0.243				
	2011		0.277				
SUD	2012		0.314				
	2010						0.166
	2011						0.204
BRNN	2012						0.241
	2010						0.543
	2011						0.500
FOGN	2012						0.532
	2010					1.425	0.617
	2011					1.486	0.697
ROSN	2012					1.090	0.831
	2010					0.467	
	2011					0.450	
PRGP	2012					0.528	

Table 4.7: Interzonal transits resulting from the day-ahead auction (Variance-to-Mean Ratio), 2012
Source: Authors' elaboration on GME data

4.3.2 Zonal prices

The series of hourly zonal prices from 2010 to 2012 are shown in Figures 4.2 and 4.3. Table 4.8 below reports the descriptive statistics for the series.

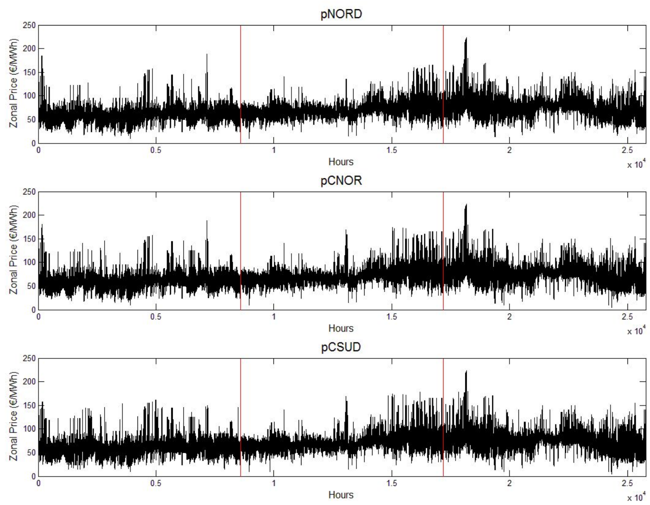

Figure 4.2: Series of zonal prices, 2010-2012

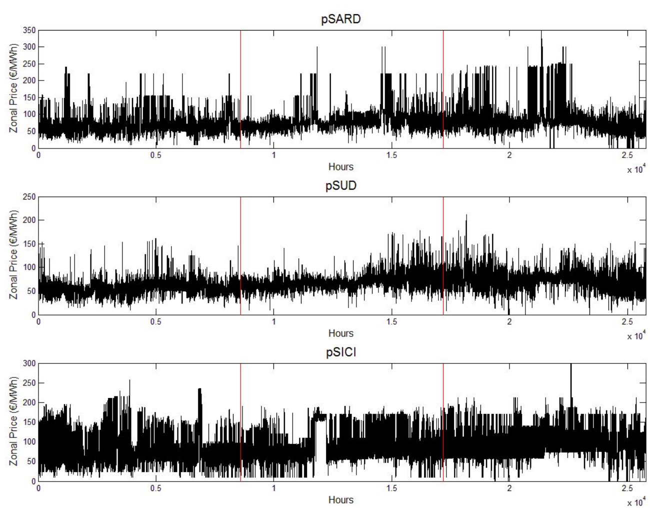

Figure 4.3: Series of zonal prices, 2010-2012

The figures reveal an increasing trend of all zonal prices starting in 2011 and ending in the middle of 2012 where the series seem to start following a decreasing pattern. Summary statistics confirm this result, with all zones showing a rising average price over the three year period with the more significant increases registered between 2010 and 2011. The Sicilian zonal price has the highest average value for the whole period (92.899 €/MWh), followed by SARD (78.369 €/MWh), CNOR (69.149 €/MWh), CSUD (68.933 €/MWh), NORD (68.710 €/MWh) and SUD (66.158 €/MWh). In percentage term, the zonal price in SICI is about 32% larger than the average zonal price calculated with the remaining 5 zones. This figure is 7% for SARD.

Variable	Mean	Std. Dev.	Min.	Max.	N
pNORD					
2010-2012	68.710	19.062	10	224	25776
2010	61.984	17.64	10	189.01	8592
2011	70.161	15.692	10	165.07	8592
2012	73.985	21.392	13	224	8592
pCNOR					
2010-2012	69.149	19.892	5	224	25776
2010	62.477	18.203	10	189.01	8592
2011	71.168	17.61	10	174	8592
2012	73.801	21.805	5	224	8592
pCSUD					
2010-2012	68.933	20.477	5	224	25776
2010	62.703	19.766	10	161.01	8592
2011	71.019	17.838	10	178	8592
2012	73.078	22.109	5	224	8592
pSARD					
2010-2012	78.369	37.557	0	450	25776
2010	73.816	34.866	10	241	8592
2011	80.265	31.785	10	300	8592
2012	81.025	44.438	0	450	8592
pSUD					
2010-2012	66.158	18.721	0	212	25776
2010	59.107	16.946	10	161.01	8592
2011	69.172	15.987	10	178	8592
2012	70.196	20.824	0	212	8592
pSICI					
2010-2012	92.899	46.246	0	3000	25776
2010	90.038	47.878	10	257	8592
2011	93.374	41.471	10	190	8592
2012	95.284	48.891	0	3000	8592

Table 4.8: Summary statistics for zonal prices

Notwithstanding, it is the NORD zone which has experienced the largest increase in prices in percentage terms (19% from 2010 to 2012), closely followed by SUD (18.7%), CNOR (18.1%) and CSUD (16.5%). SARD and SICI present more stable zonal prices with a 9% and a 5% increase respectively. The series of zonal prices in SICI and SARD are characterized by spikes reaching 3000 €/MWh (price cap) and 450 €/MWh respectively in 2012. In the other zones the largest spikes have been registered in the same year although with a weaker intensity. At the same time, SICI, SARD and SUD are the only zones whose price have touched the zero floor in 2012 while NORD presents always the highest minimun price (10 €/MWh in 2010 and 2011 and 13 €/MWh in 2012).

4.3.3 Zonal price differences

By studying the series of zonal price differences, we expect to detect a lasting positive price difference between importing and exporting neighbouring regions. We report the series of paired-price differences for the three year period 2010-2012 (Figure 4.4) for the following pairs: CNOR-NORD; CNOR-CSUD; SARD-CSUD; CSUD-SUD; SICI-SUD. It is worthy to note that for the period 2010-2012 the zonal prices of SUD and ROSN have differed for less that the 2% of the time, while the zonal price differences between SICI-SUD and SICI-ROSN have followed very similar patterns. This result allows us to consider as zonal pair SICI-SUD that are formally non contiguous zones instead of the two pairs SICI-ROSN and SUD-ROSN.

We report in Table 4.9 the descriptive statistics for the same series. On average for the three year period the largest price difference has occurred between SICI and SUD (26.74 €/MWh), followed by SARD-CSUD (9.436 €/MWh) and CSUD-SUD (2.775 €/MWh) while between CNOR-NORD and CNOR-CSUD the price difference has remained on average below 0.5 €/MWh. Between CNOR-NORD an increase in the average price difference between 2010 and 2011 has been followed by a sharp reduction between 2011 and 2012 which has determined a switch from a positive average difference to a negative average difference. This result seems to confirm that after a first year characterized by a larger reliance on import from NORD, the zone CNOR has largely reduced its importing needs in 2012.

In CNOR-CSUD pair the price difference has shown an increasing trend across the three year, revealing a consolidation in the importing role of CNOR from CSUD, whereas the opposite is true for the pair SARD-CSUD, confirming a decreasing reliance of SARD on imports from CSUD. Between CSUD-SUD we observe firstly a reduction in the average price difference between 2010 and 2011 and then an increase between 2011 and 2012, which however does not fully compensate the initial reduction. This trend suggests that while CSUD continues importing from SUD, its reliance on imports from SUD has been subjected to a downward pressure. Finally and interestingly enough, the trend characterizing the paired-price differences between SICI and SUD has been very similar to the one of CSUD-SUD pair, whereas according to the analysis of transits the imports of SICI from the peninsula have constantly increased during the considered period.

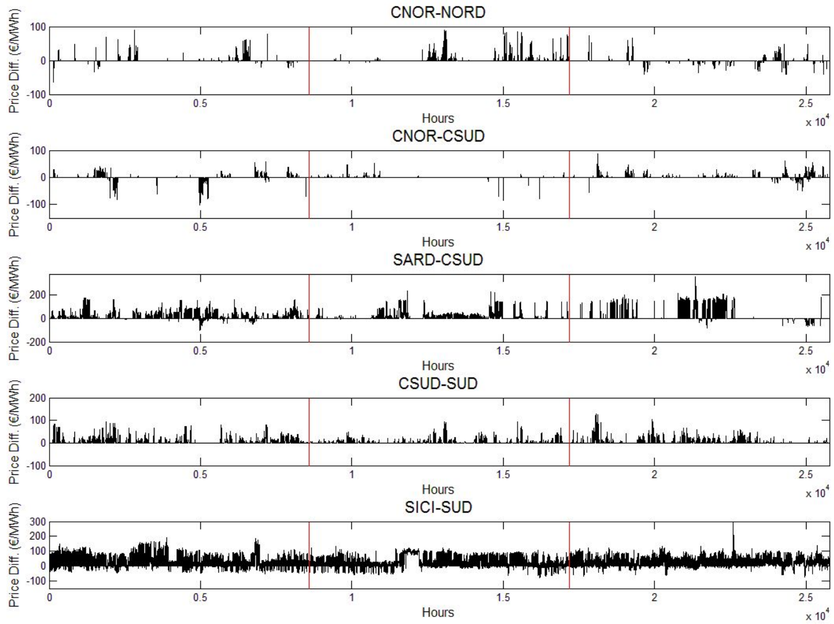

Figure 4.4: Series of zonal price differences, 2010-2012

Variable	Mean	Std. Dev.	Min.	Max.	N
CNOR-NORD					
2010-2012	0.439	5.131	-65	90	25776
2010	0.493	4.811	-65	89.39	8592
2011	1.007	6.45	-9.029	90	8592
2012	-0.184	3.678	-41.51	73.09	8592
CNOR-CSUD					
2010-2012	0.215	5.604	-101.17	88.010	25776
2010	-0.226	7.822	-101.17	57	8592
2011	0.149	2.89	-83.16	51.36	8592
2012	0.723	4.922	-54.66	88.010	8592
SARD-CSUD					
2010-2012	9.436	29.509	-100.17	358	25776
2010	11.113	26.736	-100.17	176.5	8592
2011	9.247	25.477	-7.98	236	8592
2012	7.947	35.265	-80.64	358	8592
CSUD-SUD					
2010-2012	2.775	9.215	0	129.98	25776
2010	3.596	10.281	0	92.040	8592
2011	1.846	7.158	0	94.99	8592
2012	2.883	9.814	0	129.98	8592
SICI-SUD					
2010-2012	26.74	39.367	-75.98	2908.71	25776
2010	30.931	40.807	-50.95	189.38	8592
2011	24.202	34.819	-75.98	134.5	8592
2012	25.088	41.777	-72.75	2908.71	8592

Table 4.9: Summary statistics for paired-price differences

Table 4.10 and 4.11 represent a closer look at the summary statistics for strictly positive and strictly negative paired price differences respectively.[7]

Variable	Mean	Median	Minimum	Maximum	Std.Dev.
CNOR-NORD					
2010-2012	16.322	7.96	0.01	90	19.87
2010	17.259	9.255	0.01	89.39	19.597
2011	15.996	7.1	0.01	90	20.464
2012	15.488	7.635	0.03	73.09	17.263
CNOR-CSUD					
2010-2012	10.714	7.07	0.01	88.01	11.029
2010	11.583	9.59	0.03	57	9.8795
2011	7.3372	3.625	0.02	51.36	10.864
2012	11.296	7.8004	0.01	88.01	11.663
SARD-CSUD					
2010-2012	44.941	26.51	0.01	358	47.922
2010	40.063	31.1	0.01	176.5	34.311
2011	31.926	20.18	0.02	236	38.946
2012	115.14	140.25	0.01	358	63.958
CSUD-SUD					
2010-2012	15.212	9.97	0.01	129.98	16.625
2010	15.78	10.935	0.01	92.04	16.481
2011	11.908	7	0.02	94.99	14.519
2012	17.542	12.495	0.01	129.98	18.141
SICI-SUD					
2010-2012	41.272	30.37	0.01	2908.7	39.078
2010	50.991	39.01	0.01	189.38	37.985
2011	39.521	25.92	0.01	134.5	32.337
2012	34.636	30.02	0.01	2908.7	43.576

Table 4.10: Summary statistic for strictly positive paired price differences

On average in the three year period SARD-CSUD pair has registered the highest price difference (44.941 €/MWh) while CNOR-CSUD pair has registered the lowest one (-24,438 €/MWh). By looking at the yearly average values, we remark that CNOR-NORD, CNOR-CSUD and SICI-SUD pairs have reached their highest price difference in 2010 (17.259 €/MWh, 11.583 €/MWh and 50.991 €/MWh respectively), whereas for the pairs SARD-CSUD and CSUD-SUD the largest yearly average price difference has been reached in 2012 (115.14 €/MWh AND 17;542 €/MWh respectively). The pairs CNOR-NORD and SICI-SUD have been characterized by a decreasing trend in the average positive price difference, while all the remaining pairs have experienced firstly a decrease in the average value of positive price difference between 2010 and 2011, followed by a subsequent increase between 2011 and 2012. Moreover in the pairs SARD-CSUD and CSUD-SUD the final average values have outweighed the original values.

[7] The pair CSUD-SUD is never characterized by a negative price difference so we omit it.

Variable	Mean	Median	Minimum	Maximum	Std.Dev.
CNOR-NORD					
2010-2012	-10.263	-6.88	-65	-0.01	10.075
2010	-9.6334	-6.2	-65	-0.04	10.601
2011	-3.53	-3.07	-9.03	-0.05	2.7632
2012	-10.615	-7.55	-41.51	-0.01	10.06
CNOR-CSUD					
2010-2012	-24.438	-13.925	-101.17	-0.02	24.373
2010	-29.592	-17.65	-101.17	-0.02	26.287
2011	-29.036	-14.86	-83.16	-0.5	29.291
2012	-12.294	-8.965	-54.66	-0.05	11.749
SARD-CSUD					
2010-2012	-21.867	-15.5	-100.17	-0.02	20.243
2010	-19.103	-11.665	-100.17	-0.02	20.7
2011	-2.845	-1.88	-7.98	-1.35	2.5555
2012	-26.467	-21.8	-80.64	-0.17	18.813
SICI-SUD					
2010-2012	-16.995	-11.4	-75.98	-0.01	15.258
2010	-17.784	-16.5	-50.95	-0.01	12.324
2011	-19.597	-10.975	-75.98	-0.01	18.282
2012	-13.101	-9.005	-72.75	-0.01	13.362

Table 4.11: Summary statistic for strictly negative paired price differences

Concerning the negative price differences, we may observe that the lowest average difference has been reached in CNOR-CSUD in 2010, in SICI-SUD in 2011 and in SARD-CSUD and CNOR-NORD in 2012. Across the three years the pairs SARD-CSUD and CNOR-NORD present the same trend: a decrease in the negative price difference between 2010 and 2011 and a subsequent increase between 2011 and 2012, surpassing the initial average values. Between CNOR and CSUD we remark that the average negative price difference has decreased across the years but more markedly between 2011 and 2012. Finally in SICI-SUD pair we remark that after a rise in the average negative price difference between 2010 and 2011, the 2012 has been marked by a reduction in the average negative price difference below its initial value.

4.4 Empirical strategy

The objective of the chapter is to assess the impact of increasing renewable generation on congestion and zonal price differences in Italy. In order to study this phenomenon, we have built a unique database collecting and matching hourly data from four sources:

- GME, the market operator

- GSE, the state-owned company promoting and supporting renewable energy sources in Italy
- Terna, the network operator
- REF-E, a consulting group specialized in energy markets

The empirical strategy consists in estimating two econometric models performed on five zonal pairs using observations from a three year period (2010-2012). The five zonal pairs are:

1. CNOR-NORD
2. CNOR-CSUD
3. SARD-CSUD
4. CSUD-SUD
5. SICI-SUD

The two econometric models that we estimate are a multinomial logit model and an OLS model.

4.4.1 Multinomial logit model

For each zonal pair (ZONE1-ZONE2) the dependent variable in the multinomial logit model, y, may assume three values:[8]

- $y = -1$ when the zonal price in ZONE1 is lower than zonal price in ZONE2: in this case we say that there is "congestion from" ZONE1 or a "negative price difference";
- $y = 0$ when the zonal prices in ZONE1 and ZONE2 are equal, e.g. there is "no congestion" and hence no price difference;

[8] Some zonal pairs are characterized by the occurence of only two outcomes; in these cases we estimate a logit model with a binary dependent variable.

- $y = 1$ when the zonal price in ZONE1 exceeds the zonal price in ZONE2: in this case we say that there is "congestion to" ZONE1 or a "positive price difference".

We report the statistics for the dependent variable in all zonal pairs in Table 4.12.

	2010	%	2011	%	2012	%	Overall	%
CNOR-NORD								
-1	58	0.68%	10	0.12%	295	3,43%	363	1.41%
0	8256	96.09%	8039	93.56%	8197	95,40%	24492	95.02%
1	278	3.24%	543	6.32%	100	1.16%	921	3.57%
CNOR-CSUD								
-1	262	3.05%	18	0.21%	118	1.37%	398	1.54%
0	7828	91.11%	8328	96.93%	7796	90.74%	23952	92.92%
1	502	5.84%	246	2.86%	678	7.89%	1426	5.53%
SARD-CSUD								
-1	270	3.14%	6	0.07%	187	2.18%	463	1.80 %
0	5810	67.62%	6097	70.96%	7769	90.42%	19676	76.33%
1	2512	29.24%	2489	28.97%	636	7.40%	5637	21.87%
CSUD-SUD								
-1	0	0.00%	0	0.00%	0	0.00%	0	0.00%
0	6634	77.21%	7260	84.50%	7180	83.57%	21074	81.76%
1	1958	22.79%	1332	15.50%	1412	16.43%	4702	18.24%
SICI-SUD								
-1	795	9.25%	860	10.01%	736	8.57%	2391	9.28%
0	2302	26.79%	2044	23.79%	1354	15.76%	5700	22.11%
1	5495	63.95%	5688	66.20%	6502	75.68%	17685	68.61%

Table 4.12: Hours and percentage of congestion in zonal pairs

On average, the zonal prices of the neighbouring zones paired for the three year period differ about 26% of the time; however, the average hides important differences across pairs: if on the one hand we may observe that in CNOR-NORD pair the zonal prices differ less than 5% of the time, on the other hand in SICI-SUD pair the prices decouple more than 70% of the time. In general we remark an increasing rate of congestion when moving toward the South and the Islands.

By comparing yearly statistics, we may detect some interesting changes. Between CNOR and NORD, the hours of no congestion have slightly decreased from 2010 to 2012 after an initial larger decrease between 2010 and 2011 partially compensated by an increase between 2011 and 2012; the hours of negative price difference have firstly decreased in 2011 and then they have increased again to reach five times their initial value in 2012. The percentage of hours with a positive price difference has almost doubled from 2010 to 2011 to decrease to less than half of its initial value in 2012. These figures suggest a weaker role for NORD as exporter, a stronger role for CNOR as exporter and an increase of congestion occurrence in the three year period.

Between CNOR and CSUD, the hours of negative price differences have decreased over the three year period but more markedly between 2010 and 2011 (they have increased again between 2011 and 2012). The hours of positive price difference have firstly decreased in 2011 to rise again beyond their initial values in 2012. The hours of no congestion have increased between 2010 and 2011 and they have decreased again to less than their initial value in 2012. By comparing 2010 and 2012 figures, we remark that overall the congestion occurrence has increased and the role of CNOR as importer from CSUD has been consolidated. For the pair SARD and CSUD we observe a progressive increase in the percentage of hours without congestion over the three year period. The hours with negative price difference have decreased significantly between 2010 and 2011 to increase again in 2012 but never reaching their initial value. Positive price differences have instead progressively decreased with a significant reduction between 2011 and 2012. These figures suggest a rising independence of both SARD and CSUD.

In the pair CSUD-SUD, we remark that over the three years the hours without congestion have increased, taking off from the hours of positive price difference. This effect, already in place between 2010 and 2011, is diluted in 2012, where we observe a small increase in hours with congestion and simultaneously a decrease in non congested hours. Overall, the role of CSUD as importer from SUD dims between 2010 and 2012. Finally between SICI and SUD the data show that the occurrence of a negative price difference has decreased over the three year period after an increase between 2010 and 2011. The hours of positive price differences have progressively increased over the three years, while the opposite trend has characterized the number of hours without congestion. We may therefore conclude that the occurrence of congestion has increased overall and that the role of SICI as importer has been consolidated. To sum up we observe the the congestions have decreased for the pairs SARD-CSUD and CSUD-SUD while they have increased for CNOR-NORD, CNOR-CSUD and SICI-SUD.

Our first empirical approach consists in estimating the following equations for each zonal pair:

$$\log \frac{Pr(y=1)}{Pr(y=0)} = \alpha_1 + \rho_1 \boldsymbol{Y} + \sum\nolimits_r \beta_r \boldsymbol{X_r} + \gamma_1 \boldsymbol{G} + \kappa_1 \boldsymbol{C} + \theta_1 \boldsymbol{O} \tag{4.1a}$$

$$\log \frac{Pr(y=-1)}{Pr(y=0)} = \alpha_2 + \rho_2 \boldsymbol{Y} + \sum_r \beta_r \boldsymbol{X_r} + \gamma_2 \boldsymbol{G} + \kappa_2 \boldsymbol{CO} + \theta_2 \boldsymbol{O} \tag{4.1b}$$

where:

- α is the intercept
- Y are dummy variables year (which are present only in multiple year estimations)
- X_r is the matrix of regressors, whose number depends on the geographical position of the pair, and includes:
  - RES generation in the pairing zones and in adjacent zones
  - Hydro generation in the pairing zones and in adjacent zones
  - Forecasted demand in the pairing zones and in adjacent zones
- G and C and O are the vectors of natural gas, CO_2 and oil prices.

Zonal renewable and hydroelectric generation series are built by combining GME bids and REF-E database on unit reference numbers.[9] The zonal forecasted demand is published on GME website. To build natural gas price series we use the daily month-ahead future natural gas price traded at ICE. The series of prices for the CO_2 is constructed by employing the front contract for Phase II EUA prices traded at ECX. For oil price series we use the quotation of Brent crude future (B1) traded at ICE. For all these three series during no-trading days an average between the previous and the following trading day quotations is used. All variables have been converted into euros using the European Central Bank exchange rate. Next section presents the graphic representation of the regressors and their summary statistics.

[9]The series are built by considering the whole Macro-zone production.

4.4.2 Descriptive statistics of the independent variables

Renewable production

The zonal production from renewable power plants is shown in Figure 4.5, followed by the descriptive statistics of the series (Table 4.13).

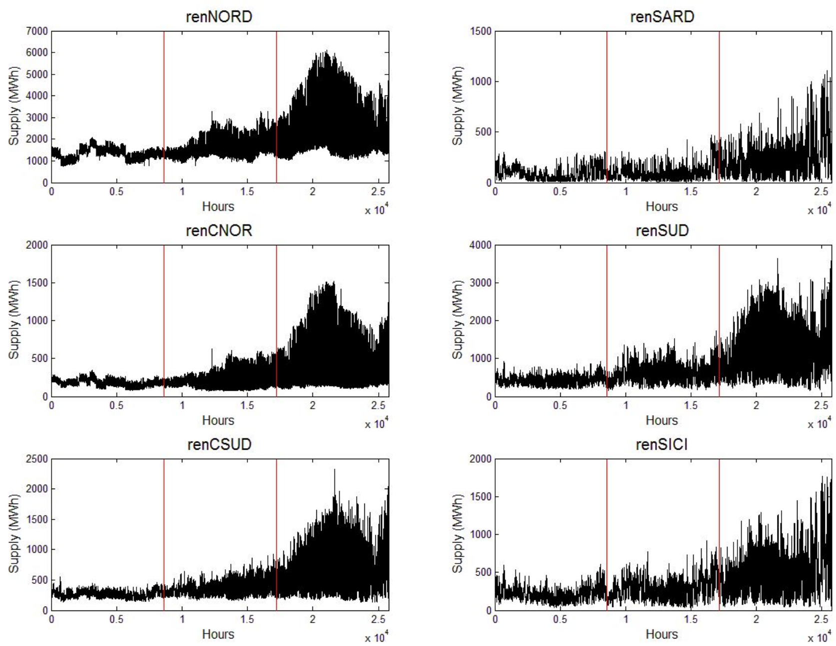

Figure 4.5: Series of zonal renewable generation, 2010-2012

Between 2010 and 2012 the total quantity of electricity produced from renewable sources has increased at rate of 105%; the rise in total production has been particularly accentuated between 2011 and 2012 with a yearly growth rate of 63%. Across regions, SARD has led in terms of penetration growth rate, with a three year rate of 158%, followed by SUD with 152%, CSUD (126%), CNOR (116%) SICI (112%) and NORD (76%). All regions have registered the largest increase between 2011 and 2012: the leading region has been SARD (128%), followed by CNOR (99.9%), SUD (81.8%), CSUD (73.3%), SICI (71%) and NORD (45%). Between 2010 and 2011, on the contrary, has been SUD to register the highest adoption rate with a 38.8% yearly increase, closely followed by CSUD (30.9%), SICI (24%), NORD (21%), SARD (12.9%) and CNOR (9.9%).

In terms of absolute quantities, in the three year period the NORD region has generated the largest average hourly quantity of electricity from RES (1760.403 MWh), while the second and the third producers, SUD and CSUD have recorded an average production of 687.316 MWh and 402.395 MWh, which are far lower figures (e.g. NORD production is 2.5 times SUD production). SARD shows the lowest average RES production with 142.927 MWh, preceeded by CNOR (255.514 MWh) and SICI (314.156 MWh). NORD and SUD have reached their peak production in 2012 with 6107.37 MWh and 3642.153 MWh respectively. The ranking of regions on the basis of hourly production has remained stable across the three years.

Variable	Mean	Std. Dev.	Min.	Max.	N
ren_NORD					
2010-2012	1760.403	856.920	738.341	6107.375	25776
2010	1330.309	257.094	738.341	2073.231	8592
2011	1610.29	456.888	780.200	3286.242	8592
2012	2340.61	1176.454	1032.64	6107.375	8592
ren_CNOR					
2010-2012	255.514	233.671	69.149	1514.11	25776
2010	178.292	48.167	80.676	342.886	8592
2011	196.101	112.951	69.149	631.88	8592
2012	392.149	347.241	94.735	1514.11	8592
ren_CSUD					
2010-2012	402.395	286.38	130.024	2330.159	25776
2010	263.644	60.976	142.265	545.585	8592
2011	345.231	125.319	163.18	920.586	8592
2012	598.312	407.095	130.024	2330.159	8592
ren_SARD					
2010-2012	142.927	141.626	5.758	1108.639	25776
2010	91.033	65.381	5.758	306.612	8592
2011	102.831	77.446	7.413	470.744	8592
2012	234.916	192.723	7.907	1108.639	8592
ren_SUD					
2010-2012	687.316	509.383	155.29	3642.153	25776
2010	419.635	126.786	188.439	931.571	8592
2011	582.688	260.35	156.487	1726.779	8592
2012	1059.625	688.024	155.29	3642.153	8592
ren_SICI					
2010-2012	314.156	227.576	32.862	1765.286	25776
2010	215.75	92.622	38.004	603.999	8592
2011	268.213	140.248	32.862	915.469	8592
2012	458.506	307.41	44.307	1765.286	8592
renewable_all					
2010-2012	3581.992	2085.195	1445.965	14562.555	25776
2010	2498.664	452.737	1445.965	3952.206	8592
2011	3126.673	1004.305	1548.11	7120.804	8592
2012	5120.638	2843.018	1781.142	14562.555	8592

Table 4.13: Summary statistics for zonal renewable generation (MWh)

Hydroelectric production

In Italy, lacking technologies such as nuclear, the base load production has been historically provided by hydroelectric power plants, mostly located in the North regions because of the favourable proximity to the Alps. The zonal production from hydroelectric power plants is shown in Figure 4.6, followed by the descriptive statistics of the series (Table 4.14). By looking at the graphs it is not easy to detect a trend in hydro production as clear as in RES production case. However, the descriptive statistics provide us more with more insights: total hourly average production has decreased at a rate of 21.18% in the three year period, with the larger decrease registered between 2010 and 2011 (12.78%). Apart from SICI which has increased its production at an overall rate of 27%, all the other regions have suffered big reductions in hydro production between 2010 and 2012: CNOR (-50.6%), SARD (49.9%), SUD (-48.37%), CSUD (-43%), NORD (-13.3%). Between 2010 and 2011 SUD, CNOR, SICI and CSUD production have shrunk: -39.05%, 29,35% 26,62% and -26.11% respectively. SARD and NORD have suffered relatively small reductions: -2.7% and 7.6%. Then between 2011 and 2012 the slow down has continued for SUD, CNOR and CSUD (-15.29%, -30%, -23.9% respectively), and also SARD and NORD have experienced more significant reductions (-51% and -6.17%). SICI instead has recovered a 77% of the production.

It is worthy to note that in terms of quantities NORD remains the biggest hydro producer with average hourly production in the three year period of 2942.65 MWh, which is more than ten times the average production of the second region, CSUD (277.33 MWh). The other regions present smaller figures: CNOR (223.5 MWH), SUD (184.52 MWh), SARD (31.76 MWh) and SICI (10.21 MWh). The ranking of regions on the basis of hourly hidro production has remained stable across the three years. NORD has reached its peak production in 2010 with 6956.016 MWh. When we compare hydro and RES production we observe that on the three year period the average total production from the two sources is very closed: 3581.992 MWh for RES and 3669.996 for hydro. However if we take the average yearly production we remark that while in 2010 hydro production was almost the double of RES production (4138.699 MWh versus 2498.644 MWh), in 2012 this figure is reversed with renewable power plants generating 5120.638 MWh against the 3261.837 MWh produced by hydro power plants.

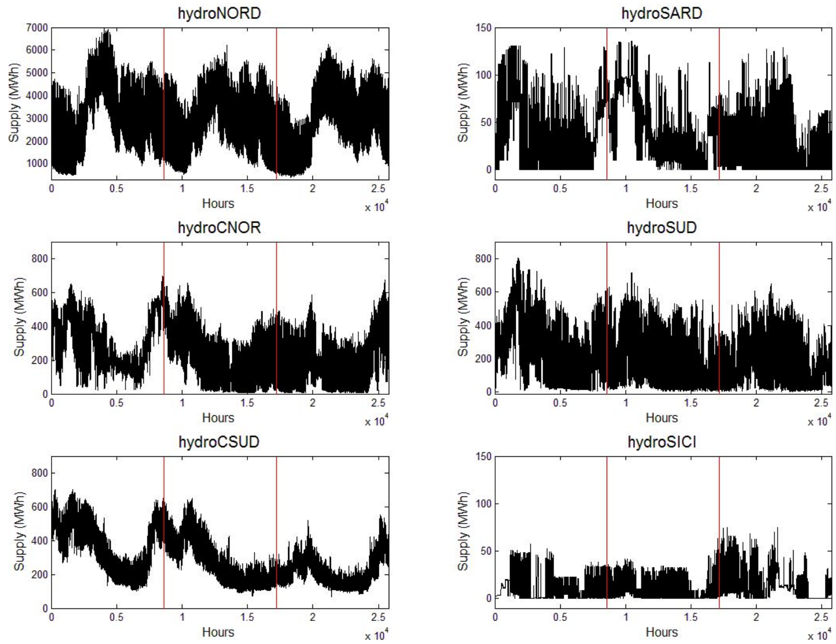

Figure 4.6: Series of zonal hydroelectric generation, 2010-2012

Variable	Mean	Std. Dev.	Min.	Max.	N
hydro_NORD					
2010-2012	2942.656	1385.673	399.749	6956.016	25776
2010	3163.865	1487.59	488.118	6956.016	8592
2011	2922.248	1284.809	522.103	6230.866	8592
2012	2741.857	1344.387	399.749	6252.015	8592
hydro_CNOR					
2010-2012	223.5	163.493	5.339	695.289	25776
2010	304.798	157.85	20.31	695.289	8592
2011	215.318	155.74	5.495	654.736	8592
2012	150.383	137.841	5.339	671.835	8592
hydro_CSUD					
2010-2012	277.336	139.103	69.198	702.75	25776
2010	361.553	145.004	102.321	702.75	8592
2011	267.151	131.56	71.649	652.152	8592
2012	203.305	83.913	69.198	552.723	8592
hydro_SARD					
2010-2012	31.761	34.539	0	135.696	25776
2010	37.687	37.274	0	130.871	8592
2011	38.718	34.992	0	135.696	8592
2012	18.877	26.754	0	128.78	8592
hydro_SUD					
2010-2012	184.524	169.862	0	801.127	25776
2010	260.421	198.676	5.796	801.127	8592
2011	158.715	149.107	4.968	715.373	8592
2012	134.437	126.192	0	645.763	8592
hydro_SICI					
2010-2012	10.218	12.173	0	75.299	25776
2010	10.375	12.029	0	57.699	8592
2011	7.301	9.935	0	63.079	8592
2012	12.98	13.602	0	75.299	8592
hydro_all					
2010-2012	3669.996	1567.905	577.013	8447.365	25776
2010	4138.699	1616.692	1097.931	8447.365	8592
2011	3609.451	1460.818	744.564	7363.584	8592
2012	3261.837	1495.955	577.013	7595.113	8592

Table 4.14: Summary statistics for zonal hydroelectric generation (MWh)

Forecasted demand

Terna provides GME with the information on the predicted load which is used by market participant as reference in order to adjust their production plans and their bids. We report in Figures 4.7 and 4.8 the zonal forecasted demand for the period 2010-2012, followed by the descriptive statistics of the series (Table 4.15). In the graph some seasonal trends appears, although they may be different for each group of zones: we observe indeed that in NORD and CNOR the predicted demand decreased in the middle of the year, while it increase in CSUD, SUD and SICI. This difference is probably due to the fact that the regions in the last group attract tourists during the summer while firms which are mostly located in the Nothern regions close during the same period. In all zones, however, the forecasted demand increases at the end and at the beginning of the year. These patterns are less visible for SARD.

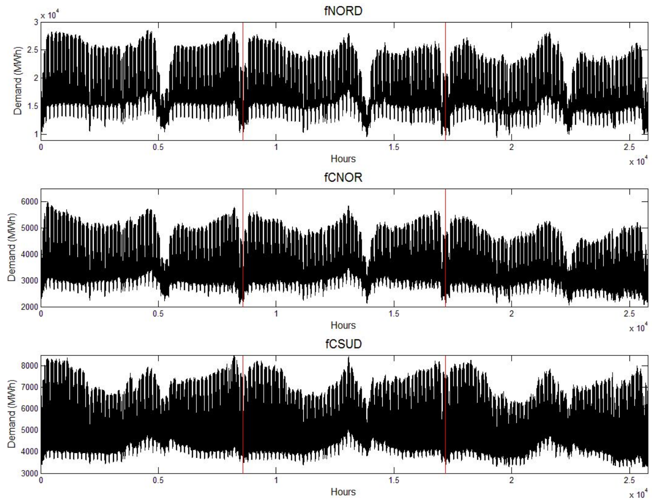

Figure 4.7: Forecasted demand, 2010-2012

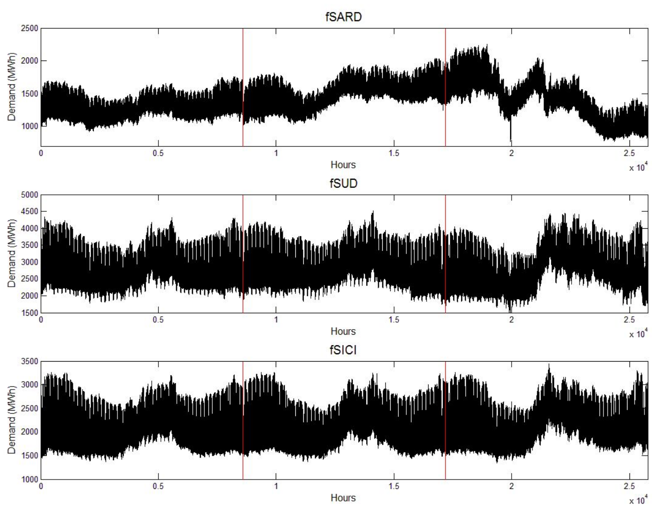

Figure 4.8: Forecasted demand, 2010-2012

The descriptive statistics provide us with further insights. NORD, CNOR, CSUD and SUD have a steadily decreasing demand in the three year period. Between 2010 and 2011, the contraction accounts for -3.32% of demand for NORD, -1.07% for CNOR,

-1% for CSUD and -0.30% for SUD. The shrinkage continues in the same zones between 2011 to 2012 with stronger intensity: NORD (-4.6%), CNOR (-7.3%), CSUD (-4.1%) and SUD (-2.1%). In the three year period CNOR has suffered the largest contraction in the demand (-8.29%), followed by NORD (-7.80%), CSUD (-5.05%) and SUD (-2.42%).

In SICI we may observe a reduction in the forecasted demand of -0.14% between 2010 and 2011 and a subsequent increase in 2012 of 1.48%. SARD shows the opposite trend with a rise in the average predicted demand of 14.76% in 2011 and a contraction in 2012 of -6.6%. Overall in the three year period only SARD and SICI have seen an increase in the demand (7.19% and 1.34% respectively).

In terms of absolute quantity, in the three year period NORD has registered the highest average demand (18747.5 MWh) with a big gap of more than 13 GWh with respect to the second region, CSUD (5600.8 MWh). CNOR (3795.48 MWh), SUD (2899.04 MWh), SICI (2247.93 MWh) and SARD (1433.2 MWh) follows. The ranking of regions on the basis of average predicted demand has remained constant across the three years. NORD has reached its peak demand in 2010 with 28573.2 MWh.

Variable	Mean	Std. Dev.	Min.	Max.	N
fNORD					
2010-2012	18747.568	4362.114	9443.464	28573.215	25776
2010	19469.215	4493.24	10314.038	28573.215	8592
2011	18821.911	4278.465	9646.082	27976.039	8592
2012	17951.579	4175.409	9443.464	28239.637	8592
fCNOR					
2010-2012	3795.487	847.664	2046.885	6005.372	25776
2010	3917.717	882.289	2095.178	6005.372	8592
2011	3875.98	831.541	2126.124	5830.472	8592
2012	3592.765	789.525	2046.885	5486.787	8592
fCSUD					
2010-2012	5600.87	1168.256	3286.27	8584.362	25776
2010	5716.149	1199.497	3416.053	8584.362	8592
2011	5658.896	1157.099	3384.79	8439.956	8592
2012	5427.563	1127.128	3286.27	8258.148	8592
fSARD					
2010-2012	1433.245	252.507	765.725	2255.65	25776
2010	1335.557	168.806	923.834	1758.995	8592
2011	1532.634	204.129	1024.194	2037.167	8592
2012	1431.545	318.912	765.725	2255.65	8592
fSUD					
2010-2012	2899.042	552.537	1487.29	4520.993	25776
2010	2925.548	541.947	1781.872	4337.012	8592
2011	2916.702	517.454	1742.382	4520.993	8592
2012	2854.876	592.901	1487.29	4446.044	8592
fSICI					
2010-2012	2247.933	426.721	1344.612	3445.039	25776
2010	2239.011	429.365	1368.105	3266.204	8592
2011	2235.867	426.343	1369.312	3266.267	8592
2012	2268.92	423.705	1344.612	3445.039	8592

Table 4.15: Summary statistics for zonal forecasted demand (MWh)

Gas, CO_2 and Oil prices

Figure 4.9 reports the series of gas, CO_2 and oil prices, followed by their descriptive statistics (Table 4.16) from 2010 to 2012.[10] The main rationale behind taking into account gas, CO_2 and oil prices in the analysis of congestion is that power production in Italy is dominated by thermal technologies mostly using gas and oil (whereas coal appears in negligible proportion).

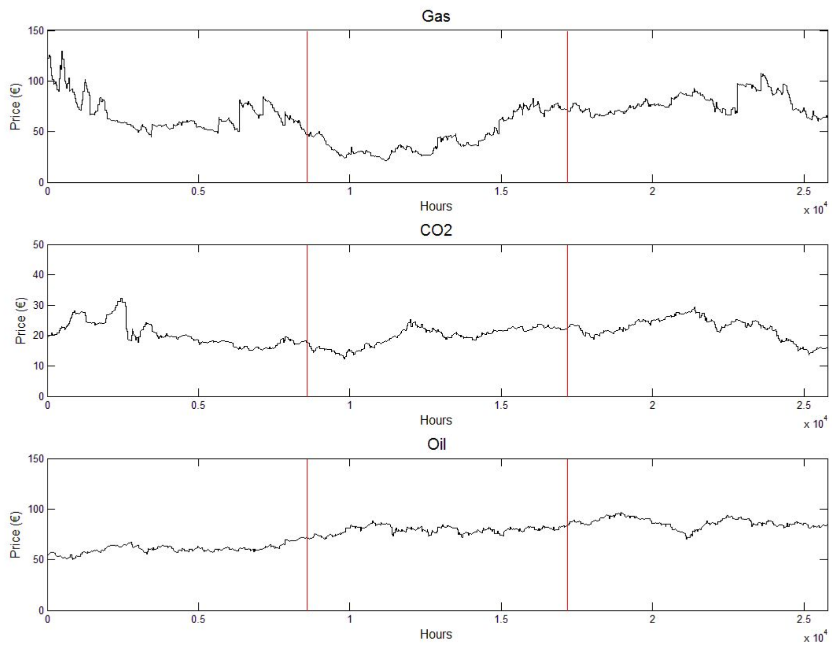

Figure 4.9: Series of Gas, CO_2 and Oil prices, 2010-2012

The average gas price has significantly decreased in 2011 (-33%) to increase again in 2012 (74%). For the three year period, gas price shows an increasing trend of 16.51%. The average price is 63.27 €/thm, the highest spike occurring in the beginning of 2010 and reaching 129.6 €/thm while the lowest price is experienced in 2011 (21.28 €/thm).

Between 2010 to 2011 the average price of CO_2 has also decreased by 3% to increase again in 2012 by 14%. Overall, the price increase has been of 9.52%. The average price

[10]The data are shown with hourly frequency although source data have daily frequency. We believe that the adjustment of power production is not instantaneous, hence the settlement price of the day is used for all 24 hour.

in the observed years is 20.824 €/ton. CO_2 has hit its record high in 2010 (32.25€/ton) and its record low in 2011 (12.25 €/ton).

Contrariwise to gas and CO_2, oil price shows a consistently rising trend between 2010 and 2012. In these three years the price has increased by 42.37%. Between 2010 and 2011, oil price has recorded a significant rise (30.60%) and has continued to increase at a lower rate (9.02%). The average price of oil has reached 75.45 €/bbl, with a peak of 96.38 €/bbl in 2012 and a minimum of 50.462 €/bbl in 2010.

Variable	Mean	Std. Dev.	Min.	Max.	N
Gas					
2010-2012	63.27	20.602	21.286	129.617	25776
2010	67.045	16.558	45.042	129.617	8592
2011	44.648	17.414	21.286	82.756	8592
2012	78.117	10.7	60.332	107.883	8592
CO2					
2010-2012	20.824	3.76	12.25	32.25	25776
2010	20.446	4.034	15.05	32.25	8592
2011	19.632	3.045	12.25	25.15	8592
2012	22.393	3.585	13.72	29.33	8592
Oil					
2010-2012	75.451	11.662	50.462	96.387	25776
2010	60.689	4.321	50.462	71.877	8592
2011	79.259	3.711	69.984	88.233	8592
2012	86.406	4.814	70.447	96.387	8592

Table 4.16: Summary statistics for Gas, CO_2 and Oil prices

4.4.3 Results of multinomial logit model

For each zonal pair we have estimated two models:

1. A two year model for 2010 and 2011 with a year dummy variable for 2010 to be combined with a yearly model for 2012 (henceforth First Model or FM);

2. A three year model with year dummy variables for 2010 and 2011 (henceforth Second Model or SM).

We have summarized the results in Table 4.17 and 4.18 with significant level of 10%, while the detailed estimations are reported in the Appendix D. When a sign is in brackets it means that while a regressor seems to be significant the value of its coefficient is extremely low. The pseudo R^2 is between 0.17 and 0.44 for the first model and 0.22 and 0.30 for the second model; all commonly used measures of goodness of fit are included in the Appendix D as well.

Strictly positive price difference

In general for positive price differences ($y = 1$) we observe that in all pairs (ZONE1-ZONE2), except for CNOR-CSUD pair, the coefficient associated to renewable generation has a negative sign when it is significant. Given that we are estimating a multinomial logit model, this result indicates that a larger renewable generation in ZONE1 is associated with a decrease in the relative log odds of ZONE1 suffering a congestion caused by ZONE2 with respect to no congestion. This result may be explained by the fact that increasing local supply in ZONE1 decreases the importing flows from ZONE2 which are causing congestion. In parallel, we remark that increasing the supply of renewables in ZONE2 has exactly the opposite effect, that is increasing the production in the exporting zone increases the log odds of having congestion to ZONE1 compared to no congestion. Rising renewable production in adjacent zones increases the congestion to ZONE1 in CNOR-CSUD and SICI-SUD, while it relieves congestion in CNOR-NORD pair. In SARD-CSUD, it seems that increasing the production in CNOR relieves the congestion while the opposite is true for RES production in SUD. The evidence is mixed in CSUD-SUD pair. The effect of increasing production in adjacent zones is heterogeneous probably because it depends on the role played by these zones with respect to the pairing regions, e.g. if they are in turn importing or exporting zones, and on their geographical location; so for instance in CNOR-NORD pair, increasing the production of renewables in CSUD decreases the probability of congestion to CNOR caused by flows coming from the NORD because more flows are coming from CSUD; at the opposite in SICI-SUD pair increasing RES generation in CSUD increase the probability of congestion to SICI because the production in SUD is then mostly diverted to SICI.

Increasing hydroelectric generation in ZONE1 decreases the log-odds of having congestion to ZONE1 in CNOR-NORD, CSUD-SUD and SICI-SUD pairs; here the effect of larger hydroelectric production is similar to the one of renewables, that is a larger local production decreases importing needs and incoming flows determining congestion. However, in CNOR-CSUD and SARD-CSUD pairs a larger hydroelectric production seem to increase congestion in entry. Similarly to renewables, rising hydroelectric production in adjacent zones may have different impact: the coefficients are positive in CNOR-NORD, CSUD-SUD and SICI-SUD for all adjacent zones; they are also positive for hydro production in SUD in both CNOR-CSUD and SARD-CSUD pairs. They are on the contrary negative for NORD and CNOR production in CNOR-CSUD and SARD-CSUD pairs respectively, while the evidence is mixed for hydro generation in SARD in the pair CNOR-CSUD.

As expected, rising the forecasted demand in ZONE1 has a positive impact on congestion to ZONE1 in all pairs, whereas rising the demand in ZONE2 has the opposite effect (when this is not the case the positive coefficients are negligible). The demand in adjacent zones seems to positively contribute to the increase in the log-odds of having congestion to ZONE1 relative to no congestion; the only exception is the demand in SARD for CNOR-CSUD pair in the FM and in 2012 for CSUD-SUD pair, probably because in these cases increasing the demand in SARD has contributed in diverting the flows from the congested line. The effects of gas, CO_2 and oil prices on directional congestion to ZONE1 are mixed given that they tend to depend on the pair and on the year. In most cases their coefficients are positive and significant but this is not always true, so we are not able to draw some strong conclusions on this point.

Concerning the year dummies, let us analyse the result on the SM, which are confirmed by the coefficients on the intercept and the year dummy of the FM. Here, we may

Equation 3: y=1																			
	CNOR-NORD				CNOR-CSUD				SARD-CSUD				CSUD-SUD				SICI-SUD		
	FM		SM		FM		SM		FM		SM		FM		SM		FM		SM
	10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12
ren_CNOR	Not	-	Not	ren_CNOR	+	Not	Not	ren_SARD	-	-	-	ren_CSUD	-	Not	Not	ren_SICI	-	-	-
ren_NORD	Not	+	+	ren_CSUD	-	+	Not	ren_CSUD	Not	+	Not	ren_SUD	+	+	+	ren_SUD	Not	(+)	(+)
ren_CSUD	-	-	-	ren_NORD	Not	Not	Not	ren_CNOR	-	Not	-	ren_CNOR	+	-	Not	ren_CSUD	+	+	+
				ren_SUD	+	+	+	ren_SUD	+	Not	+	ren_SARD	+	Not	(+)				
				ren_SARD	Not	+	+												
hydro_CNOR	-	Not	-	hydro_CNOR	+	+	+	hydro_SARD	Not	+	+	hydro_CSUD	Not	-	-	hydro_SICI	-	-	-
hydro_NORD	+	-	(+)	hydro_CSUD	-	-	-	hydro_CSUD	+	Not	+	hydro_SUD	(+)	-	(+)	hydro_SUD	Not	Not	Not
hydro_CSUD	+	Not	+	hydro_NORD	-	(+)	-	hydro_CNOR	-	-	-	hydro_CNOR	+	Not	+	hydro_CSUD	+	+	+
				hydro_SUD	+	+	+	hydro_SUD	Not	+	Not	hydro_SARD	Not	Not	+				
				hydro_SARD	Not	-	+												
fCNOR	+	+	+	fCNOR	Not	+	+	fSARD	+	+	+	fCSUD	Not	+	Not	fSICI	+	+	+
fNORD	(+)	-	(+)	fCSUD	-	-	-	fCSUD	-	-	-	fSUD	-	-	-	fSUD	-	Not	(+)
fCSUD	+	+	+	fNORD	+	(+)	(+)	fCNOR	+	+	+	fCNOR	+	+	+	fCSUD	+	(+)	(+)
				fSUD	+	+	+	fSUD	+	+	+	fSARD	+	-	+				
				fSARD	-	-	Not												
Gas	+	+	+	Gas	Not	-	Not	Gas	-	Not	-	Gas	Not	-	+	Gas	-	+	+
CO2	+	-	+	CO2	-	-	-	CO2	+	Not	+	CO2	-	+	+	CO2	+	-	Not
Oil	+	-	+	Oil	Not	+	Not	Oil	+	-	+	Oil	Not	+	+	Oil	-	+	+
year1	+		+	year1	+		+	year1	+		+	year1	+		+	year1	-		-
year2			+	year2			-	year2			+	year2			+	year2			-
intercept	-	-	-	intercept	+	Not	+	intercept	-	-	-	intercept	-	-	-	intercept	-	-	-

Table 4.17: Multinomial logit estimation summary for positive price differences

find three different evolution patterns. In CNOR-NORD, SARD-CSUD and CSUD-SUD we observe that 2010 and 2011 observations lie above 2012 observations, with the coefficient on the year dummy associated to 2011 being smaller than the one associated to 2010; it seems therefore that the relative log odds of being in a situation of congestion to ZONE1 with respect to the situation of no congestion increase when moving from 2012 to another year, this effect being larger for 2010. We may conclude hence that for these zonal pairs the impact of the regressors on directional congestion to ZONE1 tend to fade out in the three year period. In CNOR-CSUD we observe instead that a positive intercept is coupled with a positive year dummy for 2010 and a negative year dummy for 2011, indicating that after a softer impact in 2011, the effects of the regressors on congestion have strengthened in 2012. Finally in SICI-SUD pair the coefficients on the intercept and on year dummies indicate a progressive consolidation of the previously analysed effects of the independent variables on congestion to SICI.

Strictly negative price difference

In the case of congestion from ZONE1, ($y = -1$), and again with the exception of CNOR-CSUD pair, we observe that the coefficient associated to renewable generation has a positive sign and is almost always significant. This result indicates therefore that a larger renewable generation in ZONE1 is associated with an increase, relative to no congestion, in the log odds of ZONE1 causing a congestion toward ZONE2: increasing local supply in ZONE1 increases the exporting flows to ZONE2 which are causing congestion in exit. In a symmetrical way, we remark that increasing the supply of renewables in ZONE2 has exactly the opposite effect, i.e. it decreases the log odds of having congestion from ZONE1 compared to no congestion in all pairs, CNOR-CSUD included. Rising renewable production in adjacent zones increases the log odds of congestion from ZONE1 relative to no congestion in CNOR-NORD, SARD-CSUD and in CNOR-CSUD but, for this last pair, only in the case of production in NORD while the production in SARD does not seem to be significant. However, it seems that increasing renewable production in SUD for CNOR-CSUD pair and in CSUD for SICI-SUD pair relieves the congestion. Increasing hydroelectric generation in ZONE1 seems to increase the log odds of creating congestion from ZONE1 in all pairs, while the opposite is true for hydroelectric production in ZONE2. The only exception is in

Equation 1: y=-1															
	CNOR-NORD				CNOR-CSUD				SARD-CSUD				SICI-SUD		
	FM		SM		FM		SM		FM		SM		FM		SM
	10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12
ren_CNOR	Not	+	+	ren_CNOR	Not	-	Not	ren_SARD	+	+	+	ren_SICI	+	+	+
ren_NORD	-	-	-	ren_CSUD	-	-	-	ren_CSUD	-	Not	-	ren_SUD	-	-	-
ren_CSUD	+	+	+	ren_NORD	+	+	+	ren_CNOR	+	Not	+	ren_CSUD	-	Not	-
				ren_SUD	Not	-	-	ren_SUD	Not	Not	+				
				ren_SARD	Not	Not	Not								
hydro_CNOR	+	+	+	hydro_CNOR	Not	+	+	hydro_SARD	+	Not	+	hydro_SICI	Not	+	+
hydro_NORD	-	Not	(+)	hydro_CSUD	-	-	-	hydro_CSUD	-	-	-	hydro_SUD	-	Not	-
hydro_CSUD	Not	-	-	hydro_NORD	-	+	-	hydro_CNOR	-	+	Not	hydro_CSUD	Not	-	-
				hydro_SUD	+	-	+	hydro_SUD	+	Not	+				
				hydro_SARD	+	-	Not								
fCNOR	Not	-	-	fCNOR	+	Not	+	fSARD	Not	-	-	fSICI	-	Not	-
fNORD	+	+	+	fCSUD	Not	+	+	fCSUD	-	-	-	fSUD	+	Not	+
fCSUD	-	-	(+)	fNORD	-	-	-	fCNOR	+	Not	+	fCSUD	-	(+)	(+)
				fSUD	+	Not	+	fSUD	+	+	+				
				fSARD	-	-	-								
Gas	+	-	Not	Gas	Not	Not	-	Gas	-	-	-	Gas	Not	-	Not
CO2	-	+	+	CO2	+	-	Not	CO2	+	+	Not	CO2	Not	+	+
Oil	Not	+	+	Oil	+	+	+	Oil	+	-	-	Oil	Not	-	Not
year1	+		+	year1	+		+	year1	+		+	year1	Not		-
year2			-	year2			-	year2			-	year2			-
intercept	Not	-	-	intercept	-	Not	-	intercept	-	+	+	intercept	Not	+	+

Table 4.18: Multinomial logit estimation summary for negative price differences

CNOR-NORD pair in SM but still the coefficient here is extremely low. The signs of coefficients associated to hydroelectric generation in adjacent zones seem to be pretty stable in CNOR-NORD and SICI-SUD pairs (negative) and for hydroelectric production in SUD for SARD-CSUD pair (positive). In the other cases, the impact appears to be dependent on the year and on the selected model.

In line with expectations, rising the forecasted demand in ZONE1 has a negative impact on the log odds of congestion from ZONE1 compared to no congestion in CNOR-NORD and SICI-SUD pairs, whereas the opposite effect is caused by a larger demand in ZONE2 in the same pairs. Nevertheless, in CNOR-CSUD and SARD-CSUD pairs both ZONE1 and ZONE2 forecasted demands have a positive (CNOR-CSUD) and negative (SARD-CSUD) effect on the relative log odds of congestion from ZONE1. Overall, the demand in adjacent zones seems to negatively contribute to the log-odds of having congestion from ZONE1 relative to no congestion in CNOR-NORD and CNOR-CSUD for what concerns the demand in NORD and in SARD. However, the regressors have also positive sign in SARD-CSUD pair and in CNOR-CSUD pair for what concerns the demand in SUD. The evidence in SICI-SUD pair is not conclusive. Increasing gas price seems to reduce the relative log odds of congestion from SARD in SARD-CSUD pair, while in other pairs the results of the estimations are mixed; CO_2 coefficient is overall positive in all pairs but there might be some yearly exceptions; oil price has a positive coefficient in CNOR-NORD and CNOR-CSUD pairs, while in the other two pairs is not possible to draw strong conclusions.

The year dummies have the same behaviour in CNOR-NORD and CNOR-CSUD pairs in both models. In these pairs, we observe that in the second model a negative intercept in 2012 is coupled with a positive year dummy for 2010 and a negative year dummy for 2011, indicating that after a softer impact in 2011, the effects of the regressors on congestion have strengthened in 2012. The same applies to the pair SARD-CSUD altough the intercept in 2012 is positive. This behaviour is confirmed in the FM. Only in SICI-SUD we remark that a positive intercept in associated with a negative coefficient for both 2010 and 2011, whereas the value of the coefficient is larger for 2010. This result seems to indicate there there has been over the years a progressive consolidation of the above discussed effects of the independent variables on congestion from SICI.

4.4.4 Linear Regression

The second empirical approach is to use an OLS model for each paired zone (ZONE1-ZONE2) where the dependent variable is the level of zonal price difference between ZONE1 and ZONE2. The dependent variables are divided in two groups:

- Positive differences (Eur/Mwh), y_p, when there is "congestion to" ZONE1
- Negative differences (Eur/Mwh), y_n, when there is "congestion from" ZONE1

The descriptive statistics of the dependent variables have already been discussed (see Tables 4.10 and 4.11). The linear regression can be written as follow:

$$y_p = \alpha_3 + \eta_3 \boldsymbol{P} + \omega_3 \boldsymbol{W} + \rho_3 \boldsymbol{Y} + + \sum_r \beta_r \boldsymbol{X_r} + \gamma_3 \boldsymbol{G} + \kappa_3 \boldsymbol{C} + \theta_3 \boldsymbol{O} \tag{4.2a}$$

$$y_n = \alpha_4 + \eta_4 \boldsymbol{P} + \omega_4 \boldsymbol{W} + \rho_3 \boldsymbol{Y} + \sum_r \beta_r \boldsymbol{X_r} + \gamma_4 \boldsymbol{G} + \kappa_4 \boldsymbol{C} + \theta_4 \boldsymbol{O} \tag{4.2b}$$

where:

- y_p is the strictly positive zonal price difference and y_n is the strictly negative zonal price difference
- α is the intercept
- P, W, and Y[11] are dummy variables for peak hours, week days and year
- X_r is the matrix of regressors, whose number depends on the geographical position of the pair, and includes:
  - RES generation in the pairing zones and in adjacent zones
  - Hydro generation in the pairing zones and in adjacent zones
  - Forecasted demand in the pairing zones and in adjacent zones
- Natural gas, CO_2 and oil prices

[11] Dummy variables for year are present only in multiple year estimations.

All variables are in log (except for the dummies). As shown in the equation above, dummy variables for peak hours and weekdays are introduced for two reasons. Firstly, unlike in multinomial logit model, these dummies are important to de-trend the dependent variables since prices in peak hours tend to be higher than off-peak, whereas price in the weekdays are more predictable compared to weekend. Secondly, after some trials with and without dummy variables, the model with the dummy variables have shown better statistics performance (R^2, AIC and BIC).

4.4.5 Results of linear regression

As in the previous section 4.4.3, for each zonal pair we have estimated two models:

1. A two year model for 2010 and 2011 with a year dummy variable for 2010 to be combined with a yearly model for 2012 (FM);

2. A three year model with yearly dummy variables for 2010 and 2011 (SM).

Strictly positive price difference

The results of linear estimations for strictly positive price difference are summarized in Table 4.19 with significance level of 10%, while the detailed estimations are reported in the Appendix E. The regressions provide quite good performance. In terms pf R^2, first model display values between 0.08 and 0.45 while the figure is between 0.10 and 0.42 for second model. Finally, our ARCH test result provide no evidence of heteroskedasticity in the residuals.

In the case of strictly positive price difference, we observe that increasing renewable production in ZONE1 for SICI-SUD and SARD-CSUD pairs decreases the positive price gap, given that, due to limited interzonal transit and very low hydro production, an increase in renewable production in SICI and SARD will significantly decrease the equilibrium zonal price in these zones. The opposite effect seems to be generated when the renewable supply increases in CNOR in both CNOR-NORD and CNOR-CSUD pairs. The evidence is mixed for CSUD renewable generation in CSUD-SUD pair: in FM estimations, the variable has a negative sign in the two year regression and a positive sign in 2012 regression, while it is not significant in SM specification.

	Strictly positive price difference (y_p)																		
	CNOR-NORD				CNOR-CSUD				SARD-CSUD				CSUD-SUD				SICI-SUD		
	FM		SM		FM		SM		FM		SM		FM		SM		FM		SM
	10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12
ren_CNOR	+	Not	+	ren_CNOR	+	Not	Not	ren_SARD	-	Not	-	ren_CSUD	-	+	Not	ren_SICI	-	-	-
ren_NORD	-	Not	-	ren_CSUD	Not	+	+	ren_CSUD	+	+	+	ren_SUD	Not	Not	Not	ren_SUD	Not	Not	Not
ren_CSUD	-	-	-	ren_NORD	-	Not	Not	ren_CNOR	Not	-	-	ren_CNOR	+	-	Not	ren_CSUD	+	+	+
				ren_SUD	Not	Not	Not	ren_SUD	-	Not	-	ren_SARD	+	Not	Not				
				ren_SARD	Not	Not	Not												
hydro_CNOR	+	Not	+	hydro_CNOR	Not	+	Not	hydro_SARD	+	+	+	hydro_CSUD	Not	Not	+	hydro_SICI	-	Not	-
hydro_NORD	+	Not	Not	hydro_CSUD	Not	-	Not	hydro_CSUD	-	-	-	hydro_SUD	Not	Not	+	hydro_SUD	+	+	+
hydro_CSUD	-	Not	-	hydro_NORD	Not	-	Not	hydro_CNOR	-	-	Not	hydro_CNOR	-	+	Not	hydro_CSUD	+	+	+
				hydro_SUD	+	+	+	hydro_SUD	Not	Not	Not	hydro_SARD	-	+	-				
				hydro_SARD	Not	Not	Not												
fCNOR	-	+	Not	fCNOR	+	+	+	fSARD	Not	Not	-	fCSUD	-	+	Not	fSICI	-	+	-
fNORD	+	Not	+	fCSUD	-	-	-	fCSUD	Not	Not	-	fSUD	+	-	-	fSUD	+	+	+
fCSUD	+	Not	Not	fNORD	Not	Not	Not	fCNOR	+	Not	+	fCNOR	+	Not	+	fCSUD	+	Not	+
				fSUD	Not	Not	Not	fSUD	Not	+	+	fSARD	-	Not	+				
				fSARD	Not	+	+												
Gas	Not	Not	Not	Gas	Not	+	Not	Gas	Not	Not	Not	Gas	Not	Not	Not	Gas	-	+	-
CO2	Not	Not	Not	CO2	Not	-	-	CO2	+	Not	+	CO2	Not	Not	Not	CO2	+	-	+
Oil	+	Not	+	Oil	Not	Not	Not	Oil	+	-	+	Oil	+	Not	+	Oil	-	Not	-
year1	Not		Not	year1	+		Not	year1	+		-	year1	+		Not	year1	-		-
year2			Not	year2			-	year2			-	year2			-	year2			-
Peak	Not	Not	Not	Peak	Not	Not	Not	Peak	Not	Not	Not	Peak	-	Not	-	Peak	Not	Not	+
Weekdays	Not	Not	-	Weekdays	+	-	Not	Weekdays	Not	-	-	Weekdays	-	-	-	Weekdays	-	Not	-
intercept	-	Not	-	intercept	Not	Not	+	intercept	-	+	-	intercept	-	Not	-	intercept	+	-	+

Table 4.19: Linear estimation summary for strictly positive price difference

Rising renewable production in ZONE2 increases the price difference in SARD-CSUD and CNOR-CSUD pairs, while the opposite is true in CNOR-NORD pair. A larger production in ZONE2 does not appear to have a significant effect in CSUD-SUD and SICI-SUD pairs. Increasing RES production in adjacent zones has negative effect in CNOR-NORD and SARD-CSUD pairs, while it is mostly insignificant in CNOR-CSUD pair. A larger production of renewable in adjacent zones seems to have instead a positive effect in CSUD-SUD and SICI-SUD pairs.

A larger hydro production in ZONE1 seems to trigger larger positive price gaps in most of the pairs: CNOR-NORD, CNOR-CSUD, SARD-CSUD and CSUD-SUD. SICI-SUD is the only exception where rising hydro production shrinks the price difference. Increasing hydro production in ZONE2 seems to increase the positive price difference in CNOR-NORD, CSUD-SUD and SICI-SUD, while the opposite is true in CNOR-CSUD and SARD-CSUD. A larger hydro generation in adjacent zones seems to decrease the price gap in CNOR-NORD and in SARD-CSUD, whereas it seems to trigger larger price gaps in CNOR-CSUD (with some exceptions in 2012) and SICI-SUD pairs. The evidence is mixed in CSUD-SUD pair.

A larger predicted demand in ZONE1 seems to increase the positive price difference in CNOR-CSUD pair while the evidence is mixed in other pairs. Increasing the demand in ZONE2 seems to display negative effects in three pairs: CNOR-CSUD, SARD-CSUD and CSUD-SUD (here with the exception of 2010-2011 estimation). A larger demand in ZONE2 seems however to widen the price gap in CNOR-NORD and SICI-SUD pairs. Increasing the predicted load in adjacent zones has an overall positive effect on price gap, although not all adjacent zones seem to be significant in each pair.

In all observed pairs with the exception of CNOR-CSUD pair the coefficient on weekdays is significant and negative, meaning that the positive price gaps tend to shrink during the week. The dummy variable for peak hours is overall insignificant, with the exception of CSUD-SUD pair where it appears to be negative and significant. Finally, the year dummies seems to be not significant in CNOR-NORD pair in both model specifications. For the other pairs we observe that in the SM the coefficients for 2010 and 2011 are overall negative, indicating an increasing trend in positive price differences in 2012 (the reference year). In the FM, however, the coefficient on the dummy variable for 2010 has a positive sign in CNOR-CSUD, SARD-CSUD and CSUD-SUD, indicating a decreasing trend in positive price difference between 2010 and 2011, while the opposite is true for SICI-SUD pair.[12]

Gas prices are mostly non-significant in determining positive price difference level. The coefficient is significant and positive in CNOR-CSUD in 2012 and it is significant in SICI-SUD pair but the signs show mixed results. CO_2 price coefficient is also not significant in CNOR-NORD and CSUD-SUD pairs, while it is positive in SARD-CSUD pair and negative in CNOR-CSUD pair. Again the results are mixed for SICI-SUD pair. Finally, oil prices seem to have a positive impact on price difference in CNOR-NORD, SARD-CSUD (with the exception of 2012) and CSUD-SUD pairs. However, oil prices seem to decrease the positive price difference in SICI-SUD pair while they are not significant in CNOR-CSUD pair.

Strictly negative price difference

The results of linear estimations for strictly negative price difference are summarized in Table 4.20 with significance level of 10%, while the detailed estimations are reported in the Appendix E. The regressions show very good performance: in terms pf R^2, the first model displays values between 0.23 and 0.54 while the figure is between 0.19 and 0.47 for the second model. The ARCH test provides some evidence of heteroskedasticity in the residuals for 2012 regression in SARD-CSUD, CNOR-CSUD, and CNOR-NORD pairs where we have fewer observations.

Increasing renewable production in ZONE1 seems to increase the negative price difference in SICI-SUD and SARD-CSUD pairs (with the exception of 2010-2011 estimation in SARD-CSUD pair). In CNOR-NORD pair, however, a larger renewable production in ZONE1 seems to reduce the negative price gap, whereas the variable is non-significant in CNOR-CSUD pair. Rising renewable production in ZONE2 seems to increase the negative price gap in CNOR-NORD pair, while the evidence is mixed in SICI-SUD pair. The variable is overall not significant in all remaining pairs. In CNOR-NORD pair increasing the renewable generation from CSUD seems to increase the negative price gap, while the opposite effect is played in SICI-SUD pair, where a larger renewable generation in CSUD seems to reduce the negative price difference. In

[12]These result are confirmed by the statistics on positive price difference with the exception of SICI-SUD pair, see Table 4.10.

Strictly negative price difference (y_n)															
	CNOR-NORD				CNOR-CSUD				SARD-CSUD				SICI-SUD		
	FM		SM		FM		SM		FM		SM		FM		SM
	10-11	12	10-12		10-11	12	10-12		10-11	12	10-12		10-11	12	10-12
ren_CNOR	Not	+	+	ren_CNOR	Not	Not	Not	ren_SARD	+	-	-	ren_SICI	-	-	-
ren_NORD	Not	-	-	ren_CSUD	Not	Not	Not	ren_CSUD	+	Not	Not	ren_SUD	+	-	Not
ren_CSUD	Not	-	-	ren_NORD	-	Not	-	ren_CNOR	-	Not	-	ren_CSUD	-	+	+
				ren_SUD	+	+	Not	ren_SUD	-	+	+				
				ren_SARD	+	Not	Not								
hydro_CNOR	Not	+	-	hydro_CNOR	Not	Not	Not	hydro_SARD	Not	Not	Not	hydro_SICI	-	Not	Not
hydro_NORD	Not	Not	Not	hydro_CSUD	+	Not	+	hydro_CSUD	+	Not	+	hydro_SUD	+	-	+
hydro_CSUD	Not	Not	Not	hydro_NORD	Not	Not	Not	hydro_CNOR	Not	Not	Not	hydro_CSUD	Not	+	+
				hydro_SUD	-	Not	-	hydro_SUD	-	Not	-				
				hydro_SARD	Not	Not	Not								
fCNOR	Not	Not	Not	fCNOR	Not	Not	+	fSARD	+	+	+	fSICI	Not	+	+
fNORD	Not	+	+	fCSUD	Not	Not	Not	fCSUD	Not	-	Not	fSUD	+	-	Not
fCSUD	Not	Not	Not	fNORD	Not	+	Not	fCNOR	-	Not	+	fCSUD	-	-	-
				fSUD	Not	-	Not	fSUD	-	Not	Not				
				fSARD	+	-	+								
Gas	Not	-	-	Gas	Not	Not	+	Gas	-	+	Not	Gas	Not	+	-
CO2	-	Not	Not	CO2	Not	Not	Not	CO2	+	-	+	CO2	+	-	+
Oil	Not	Not	Not	Oil	Not	-	Not	Oil	-	Not	-	Oil	Not	Not	Not
year1	Not		Not	year1	Not		Not	year1	Not		-	year1	Not		-
year2			Not	year2			Not	year2			Not	year2			-
Peak	Not	Not	Not	Peak	+	+	+	Peak	+	Not	+	Peak	-	+	-
Weekdays	Not	Not	Not	Weekdays	Not	+	+	Weekdays	Not	Not	Not	Weekdays	-	+	-
intercept	Not	Not	Not	intercept	Not	+	Not	intercept	Not	-	Not	intercept	-	-	-

Table 4.20: Linear estimation summary for strictly negative price difference

CNOR-CSUD pair, increasing renewable generation from SUD and SARD seems to decrease the price gap, whereas a larger renewable production from NORD tends to widen the negative price gap. As for SARD-CSUD pair, increasing renewable production from SUD tends to reduce the gap, whereas a larger renewable generation from CNOR shows an opposite behavior.

In hydro generation, rising production from ZONE1 seems to have an overall insignificant effect. On the contrary, a larger hydro production from ZONE2 seems to reduce the negative the price gaps in CNOR-CSUD, SARD-CSUD and SICI-SUD (with the exception of 2012) pairs. For what concerns the production in adjacent zones, a larger generation in SUD for CNOR-CSUD and SARD-CSUD pairs widens the negative price difference, while the opposite role is played by hydro production in CSUD for the pair SICI-SUD. In the other cases, the indicator is not significant.

The coefficients on forecasted load in ZONE1 show that increasing the value of this variable tends to decrease the negative price difference in SARD-CSUD and SICI-SUD with some evidence of the same behavior in CNOR-CSUD pair. In the other cases the variable does not seem to be significant. Rising demand in ZONE2 decreases the negative price gap in CNOR-NORD pair while the regressions are inconclusive for the other cases. The regressions provide evidence of larger negative price gap determined by the increase in forecasted demand in CSUD for SICI-SUD pair, while in the other cases the evidence is mixed.

The role of weekdays is non relevant in CNOR-NORD and SARD-CSUD pairs, while it seems to decrease the negative price gap in CNOR-CSUD pair. The evidence is mixed for SICI-SUD where the coefficient is both positive and negative depending on the year. The coefficient of the dummy variable for peak hours is positive in CNOR-CSUD and SARD-CSUD, indicating a shrinking effect on the negative price differences. In the other pairs, it is not possible to draw strong conclusions on this point, either because the variable is not significant or because it changes sign according to the chosen specification. Finally, the year dummy variables are mostly non significant with the exception of SICI-SUD pair where the dummies have a negative sign, indicating a reduction in the negative price gap in 2012 which is the reference year.[13]

CNOR-NORD is the only pair in which gas price seems to play a strong role in

[13] This result is confirmed by the statistics on negative price difference, see Table 4.11.

increasing negative price difference, while in the other pairs the evidence is mixed. CO_2 prices tend to reduce negative price difference in SARD-CSUD and SICI-SUD with an opposite impact in 2012. Finally, oil price seems to widening the negative price gap in CNOR-CSUD and SARD-CSUD, whereas it is non-significant in the other regressions.

4.5 Conclusions

We may sum up our results as following. In general for all ZONE1-ZONE2 pairs, and notably with the exception of CNOR-CSUD, the multinomial logit model provides evidence that increasing renewable production in ZONE1 decreases the probability of congestion in entry and increases the probability of congestion in exit compared to the baseline situation of no congestion. In a symmetric way (with the exception of CNOR-CSUD pair but only in the case of positive price difference), increasing the supply of renewables in ZONE2 has exactly the opposite effect, that it increases the probability of congestion to ZONE1 and decreases the probability of congestion from ZONE1 compared to the no congestion case. The effect of increasing renewable production in adjacent zones is heterogeneous probably because it depends on the role played by these zones with respect to the pairing regions, e.g. if they are in turn importing or exporting zones, and on their geographical location. In the case of congestion to ZONE1, the effect of increasing hydroelectric generation in ZONE1 appears to be similar to the one of increasing renewable in CNOR-NORD, CSUD-SUD and SICI-SUD pairs, while the effect of rising hydro production in ZONE2 is heterogeneous depending on the pair. In the case of congestion from ZONE1, however, increasing hydroelectric generation in ZONE1 seems to increase the probability of congestion in all pairs, while the opposite is true for hydroelectric production in ZONE2. Similarly to renewables, rising hydroelectric production in adjacent zones may have different impact according to the year and the pair.

Overall, rising the forecasted demand in ZONE1 has a positive impact on congestion to ZONE1 in all pairs, whereas rising the demand in ZONE2 has the opposite effect. In the case of congestion from ZONE1, rising the forecasted demand in ZONE1 has a negative impact on the probability of congestion only in CNOR-NORD and SICI-SUD pairs, whereas the opposite effect is caused by a larger demand in ZONE2 in the same pairs. The demand in adjacent zones seems to positively contribute to congestion to ZONE1 and to negatively contribute to congestion from ZONE1, with some exceptions. The effects of gas, CO_2 and oil prices on directional congestion both to and from ZONE1 are mixed given that they tend to depend on the pair and on the year, so we are not able to draw some strong conclusions on this point. Yearly dummies are mostly significant showing that there are important changes across years.

Linear estimation results are less conclusive as follows. The estimations reveal that increasing renewable generation in ZONE1 reduces the level of positive price gaps and increases the level of negative price differences in SICI and SARD. Increasing the predicted demand in ZONE1 seems to reduce the negative price difference in SICI-SUD and SARD-CSUD pairs, while in the case of positive price difference the estimations are not significant for the same pairs. Increasing renewable production in CNOR seems to increase the positive price difference and to decrease the negative price difference in the pairs CNOR-NORD, while in the pair CNOR-CSUD the results of the estimations are inconclusive. A larger renewable production in ZONE2 increases the positive price difference in CNOR-CSUD and SARD-CSUD pairs, while it increases the negative price difference in CNOR-NORD pair. Still in CNOR-NORD pair a larger renewable production in NORD triggers a smaller positive price difference. A larger hydro production in ZONE1 seems to increase the positive price difference in all pairs with the exception of SICI-SUD, while the effect of increasing hydro production in ZONE2 and in adjacent zones may vary widely according to the pair. As for the other regressors, we remark that the dummy on weekdays tends to be significant and negative in the case of positive price difference, indicating that the level of positive price difference is lower during the week.

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Appendix C

Dataset

We have constructed an hourly dataset from January 1, 2010 at 1st delivery period (00:00 -01:00) to December 31, 2012 at 24th delivery period (23:00 - 00:00) totalling 25776 observations for dependent and independent variables. Some observations have been excluded in order to have weekly and hourly consistent series. Notably, we have excluded the 25th delivery period and 12th week every year when there is daylight saving time in Italy. Additionally, we have excluded the observations from February 29, 2012 in order to maintain the same number of observation days in each year: 358. As a result, our dataset consists of 8592 yearly observations. The dataset employed in the empirical analysis has been constructed using three main sources: GME, Italian market operator, REF-E, a consulting group specialized in energy markets, and ICE, the Intercontinental Exchange which is the network of exchanges and clearing houses for financial and commodity markets. The series of zonal prices, interzonal transits and forecasted demands have been downloaded from GME website. The series of the dependent variables have been constructed using the same rough data. Renewable and hydro production series have been built by matching two sources: GME and REF-E databases. By matching GME information on the accepted offers in the day-ahead auction with the list of Italian power plants classified by technology and supplied by REF-E we have extracted two series of hourly renewable quantities: a first one which considers only the production from relevant units (solar and wind power plants with capacity larger than 100 MW); a second one which aggregates the quantity from relevant and non relevant units.[1] We have then compared the yearly production resulting from our extractions to those published by GSE, the state-owned company promoting and supporting renewable energy sources in Italy. The result are reported in Table C.1, where GME R.U. is standing for Relevant Units and GME A.U. is for All Units. Interestingly, GSE figures seem to be somehow in between our two series. To be conservative in our estimations, we have decided to work with the quantity series of relevant units.

Year	GME (R.U.)	GME (A.U.)	GSE
2010	5675411	21856001	11032000
2011	7319418	27371081	20652000
2012	10806853	44880419	32269000

Table C.1: Yearly generation from intermittent renewable sources (MWh)

To extract the hydro quantity we have followed the same procedure. In order to capture the effect of location, all these series have been segmented by Macro-zone: NORD, CNOR, CSUD, SARD, SUD and SICI. Gas, CO_2 and oil price series are built using ICE database with daily observations. The nominal values have been transformed in euros using European Central Bank Exchange rate. Missing observations caused by no-trading days are approximated by averaging two prices between no trading days. It is important to note that the daily price is adopted to hourly frequency.

The econometric exercise has been performed with several model specifications. Following the literature (see Woo et al., 2011), hour dummies have been introduced at the beginning. However, it seemed that these dummies tend to over-fit the results making other independent variables insignificant. Peak and weak dummies are kept in the linear regressions since zonal prices tend to be higher in peak hours and more predictable in weekdays. Concerning the time spam, we have tried at first to run separate yearly regressions but we have finally decided to prefer two year or three year regressions in order to have a larger number of observations for the dependent variables.

[1] It is worthy to note that the non relevant power plants are geographically aggregated by dispatching points and are assigned a single Unit Reference Number to be used in the day-ahead auction. Therefore in the case of bids associated to this type of Unit Reference Number is impossible to distinguish the exact power source.

Appendix D

Multinomial logit tables

D.1 CNOR-NORD

First model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_CNOR	0.005	(0.008)
ren_NORD	-0.004**	(0.002)
ren_CSUD	0.007***	(0.002)
hydro_CNOR	0.003*	(0.001)
hydro_NORD	-0.001***	(0.000)
hydro_CSUD	0.001	(0.002)
fCNOR	-0.001	(0.002)
fNORD	0.001***	(0.000)
fCSUD	-0.001**	(0.001)
Gas	0.024*	(0.013)
CO2	-0.323***	(0.071)
Oil	0.019	(0.045)
year1	2.337***	(0.757)
Intercept	-3.625	(4.073)
	Equation 3 : 1	
ren_CNOR	0.001	(0.001)
ren_NORD	0.000	(0.000)
ren_CSUD	-0.002***	(0.001)
hydro_CNOR	-0.004***	(0.000)
hydro_NORD	0.001***	(0.000)
hydro_CSUD	0.002***	(0.001)
fCNOR	0.001***	(0.000)
fNORD	0.000***	(0.000)
fCSUD	0.001***	(0.000)
Gas	0.013***	(0.003)
CO2	0.099***	(0.015)
Oil	0.092***	(0.012)
year1	0.800***	(0.256)
Intercept	-18.045***	(1.085)
N	17184	
Log-likelihood	-3047.485	
$\chi^2_{(26)}$	1382.276	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-3738.623	$Log - LikFullModel:$	-3047.485
$D(17156):$	6094.969	$LR(26):$	1382.276
		$Prob > LR:$	0
$McFadden'sR2:$	0.185	$McFadden'sAdjR2:$	0.177
$ML(Cox - Snell)R2:$	0.077	$Cragg - Uhler(Nagelkerke)R2:$	0.219
$CountR2:$	0.948	$AdjCountR2:$	0.004
$AIC:$	0.358	$AIC * n:$	6150.969
$BIC:$	-161205.78	$BIC':$	-1128.731
$BICusedbyStata:$	6368.018	$AICusedbyStata:$	6150.969

Table D.1: Estimations for CNOR-NORD with year dummy, 2010-2011

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_CNOR	0.003***	(0.001)
ren_NORD	-0.001***	(0.000)
ren_CSUD	0.003***	(0.000)
hydro_CNOR	0.004***	(0.001)
hydro_NORD	0.000	(0.000)
hydro_CSUD	-0.005***	(0.002)
fCNOR	-0.004***	(0.000)
fNORD	0.001***	(0.000)
fCSUD	-0.001**	(0.000)
Gas	-0.028***	(0.008)
CO2	0.199***	(0.032)
Oil	0.055***	(0.017)
Intercept	-8.231***	(1.894)
	Equation 3 : 1	
ren_CNOR	-0.023***	(0.005)
ren_NORD	0.005***	(0.001)
ren_CSUD	-0.005***	(0.001)
hydro_CNOR	0.000	(0.002)
hydro_NORD	-0.001***	(0.000)
hydro_CSUD	0.003	(0.002)
fCNOR	0.003***	(0.001)
fNORD	-0.001***	(0.000)
fCSUD	0.002***	(0.000)
Gas	0.154***	(0.018)
CO2	-0.306***	(0.050)
Oil	-0.093**	(0.039)
Intercept	-12.611***	(3.465)
N		8592
Log-likelihood		-1294.145
$\chi^2_{(24)}$		1063.2

Significance levels : $*: 10\%$ $**: 5\%$ $***: 1\%$

$Log - LikInterceptOnly:$	-1825.745	$Log - LikFullModel:$	-1294.145
$D(8566):$	2588.29	$LR(24):$	1063.2
		$Prob > LR:$	0
$McFadden'sR2:$	0.291	$McFadden'sAdjR2:$	0.277
$ML(Cox - Snell)R2:$	0.116	$Cragg - Uhler(Nagelkerke)R2:$	0.336
$CountR2:$	0.954	$AdjCountR2:$	0.005
$AIC:$	0.307	$AIC * n:$	2640.29
$BIC:$	-75007.564	$BIC':$	-845.794
$BICusedbyStata:$	2823.814	$AICusedbyStata:$	2640.29

Table D.2: Estimations for CNOR-NORD, 2012

Second model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_CNOR	0.003***	(0.001)
ren_NORD	-0.001***	(0.000)
ren_CSUD	0.002***	(0.000)
hydro_CNOR	0.003***	(0.001)
hydro_NORD	0.000**	(0.000)
hydro_CSUD	-0.003***	(0.001)
fCNOR	-0.004***	(0.000)
fNORD	0.001***	(0.000)
fCSUD	0.000**	(0.000)
Gas	-0.003	(0.006)
CO2	0.078***	(0.020)
Oil	0.049***	(0.014)
year1	1.006**	(0.418)
year2	-1.191***	(0.411)
Intercept	-7.938***	(1.449)
	Equation 3 : 1	
ren_CNOR	-0.001	(0.001)
ren_NORD	0.001***	(0.000)
ren_CSUD	-0.003***	(0.001)
hydro_CNOR	-0.003***	(0.000)
hydro_NORD	0.000***	(0.000)
hydro_CSUD	0.002***	(0.000)
fCNOR	0.001***	(0.000)
fNORD	0.000***	(0.000)
fCSUD	0.001***	(0.000)
Gas	0.015***	(0.003)
CO2	0.045***	(0.014)
Oil	0.079***	(0.010)
year1	2.783***	(0.307)
year2	2.282***	(0.168)
Intercept	-18.712***	(1.052)
N	25776	
Log-likelihood	-4532.867	
$\chi^2_{(28)}$	2669.07	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log-LikInterceptOnly:$	-5867.402	$Log-LikFullModel:$	-4532.867
$D(25746):$	9065.734	$LR(28):$	2669.07
		$Prob > LR:$	0
$McFadden'sR2:$	0.227	$McFadden'sAdjR2:$	0.222
$ML(Cox-Snell)R2:$	0.098	$Cragg-Uhler(Nagelkerke)R2:$	0.269
$CountR2:$	0.95	$AdjCountR2:$	0.001
$AIC:$	0.354	$AIC*n:$	9125.734
$BIC:$	-252441.51	$BIC':$	-2384.668
$BICusedbyStata:$	9370.45	$AICusedbyStata:$	9125.734

Table D.3: Estimations for CNOR-NORD with year dummies, 2010-2012

D.2 CNOR-CSUD

First model

Variable	Coefficient	(Std. Err.)
Equation 1 : -1		
ren_CNOR	0.002	(0.004)
ren_CSUD	-0.011***	(0.003)
ren_SUD	0.001	(0.001)
ren_NORD	0.004***	(0.001)
ren_SARD	0.002	(0.001)
hydro_CNOR	-0.001	(0.001)
hydro_CSUD	-0.010***	(0.001)
hydro_SUD	0.006***	(0.001)
hydro_NORD	-0.001***	(0.000)
hydro_SARD	0.012***	(0.003)
fCNOR	0.006***	(0.001)
fCSUD	0.000	(0.001)
fSUD	0.003***	(0.001)
fNORD	-0.001***	(0.000)
fSARD	-0.005***	(0.002)
Gas	-0.016	(0.010)
CO2	0.123***	(0.031)
Oil	0.214***	(0.033)
year1	7.842***	(0.725)
Intercept	-26.173***	(3.222)
Equation 3 : 1		
ren_CNOR	0.005***	(0.002)
ren_CSUD	-0.003***	(0.001)
ren_SUD	0.003***	(0.000)
ren_NORD	0.000	(0.000)
ren_SARD	0.001	(0.001)
hydro_CNOR	0.001*	(0.000)
hydro_CSUD	-0.001*	(0.001)
hydro_SUD	0.003***	(0.000)
hydro_NORD	-0.001***	(0.000)
hydro_SARD	0.001	(0.002)
fCNOR	-0.001	(0.000)
fCSUD	-0.002***	(0.000)
fSUD	0.001**	(0.000)
fNORD	0.001***	(0.000)
fSARD	-0.002**	(0.001)
Gas	0.002	(0.004)
CO2	-0.227***	(0.017)
Oil	-0.020	(0.013)
year1	1.025***	(0.251)
Intercept	3.300***	(1.092)
N	17184	
Log-likelihood	-2957.1	
$\chi^2_{(38)}$	3073.485	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-4493.84	$Log - LikFullModel:$	-2957.1
$D(17144):$	5914.201	$LR(38):$	3073.485
		$Prob > LR:$	0
$McFadden'sR2:$	0.342	$McFadden'sAdjR2:$	0.333
$ML(Cox - Snell)R2:$	0.164	$Cragg - Uhler(Nagelkerke)R2:$	0.402
$CountR2:$	0.945	$AdjCountR2:$	0.088
$AIC:$	0.349	$AIC * n:$	5994.201
$BIC:$	-161270	$BIC':$	-2702.92
$BICusedbyStata:$	6304.27	$AICusedbyStata:$	5994.201

Table D.4: Estimations for CNOR-CSUD with year dummy, 2010-2011

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_CNOR	-0.010*	(0.005)
ren_CSUD	-0.004**	(0.002)
ren_SUD	-0.003***	(0.001)
ren_NORD	0.004***	(0.001)
ren_SARD	-0.001	(0.001)
hydro_CNOR	0.006***	(0.002)
hydro_CSUD	-0.010***	(0.003)
hydro_SUD	-0.006***	(0.002)
hydro_NORD	0.001***	(0.000)
hydro_SARD	-0.026***	(0.008)
fCNOR	0.000	(0.001)
fCSUD	0.003***	(0.001)
fSUD	-0.001	(0.001)
fNORD	-0.001***	(0.000)
fSARD	-0.003*	(0.001)
Gas	-0.040	(0.027)
CO2	-0.303***	(0.098)
Oil	0.136*	(0.070)
Intercept	-8.604	(6.757)
	Equation 3 : 1	
ren_CNOR	0.000	(0.001)
ren_CSUD	0.001**	(0.000)
ren_SUD	0.001***	(0.000)
ren_NORD	0.000	(0.000)
ren_SARD	0.001***	(0.000)
hydro_CNOR	0.001*	(0.001)
hydro_CSUD	-0.008***	(0.001)
hydro_SUD	0.005***	(0.001)
hydro_NORD	0.000***	(0.000)
hydro_SARD	-0.013***	(0.004)
fCNOR	0.002***	(0.000)
fCSUD	-0.003***	(0.000)
fSUD	0.001***	(0.000)
fNORD	0.000***	(0.000)
fSARD	-0.001*	(0.000)
Gas	-0.050***	(0.008)
CO2	-0.168***	(0.026)
Oil	0.067***	(0.017)
Intercept	1.083	(1.492)
N	8592	
Log-likelihood	-1958.672	
$\chi^2_{(36)}$	2053.947	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-2985.65	$Log - LikFullModel:$	-1958.67
$D(8554):$	3917.344	$LR(36):$	2053.947
		$Prob > LR:$	0
$McFadden'sR2:$	0.344	$McFadden'sAdjR2:$	0.331
$ML(Cox - Snell)R2:$	0.213	$Cragg - Uhler(Nagelkerke)R2:$	0.424
$CountR2:$	0.92	$AdjCountR2:$	0.139
$AIC:$	0.465	$AIC * n:$	3993.344
$BIC:$	-73569.8	$BIC':$	-1727.84
$BICusedbyStata:$	4261.571	$AICusedbyStata:$	3993.344

Table D.5: Estimations for CNOR-CSUD, 2012

Second model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_CNOR	-0.003	(0.002)
ren_CSUD	-0.006***	(0.001)
ren_SUD	-0.001*	(0.001)
ren_NORD	0.003***	(0.001)
ren_SARD	0.000	(0.001)
hydro_CNOR	0.003***	(0.001)
hydro_CSUD	-0.006***	(0.001)
hydro_SUD	0.003***	(0.001)
hydro_NORD	-0.001***	(0.000)
hydro_SARD	0.000	(0.003)
fCNOR	0.006***	(0.001)
fCSUD	0.001***	(0.000)
fSUD	0.003***	(0.000)
fNORD	-0.001***	(0.000)
fSARD	-0.010***	(0.001)
Gas	-0.043***	(0.006)
CO2	-0.013	(0.022)
Oil	0.070***	(0.020)
year1	2.928***	(0.614)
year2	-1.462***	(0.485)
Intercept	-5.708***	(1.999)
	Equation 3 : 1	
ren_CNOR	0.000	(0.000)
ren_CSUD	0.001	(0.000)
ren_SUD	0.001***	(0.000)
ren_NORD	0.000	(0.000)
ren_SARD	0.001***	(0.000)
hydro_CNOR	0.001***	(0.000)
hydro_CSUD	-0.003***	(0.001)
hydro_SUD	0.004***	(0.000)
hydro_NORD	-0.001***	(0.000)
hydro_SARD	0.003**	(0.001)
fCNOR	0.001***	(0.000)
fCSUD	-0.003***	(0.000)
fSUD	0.001***	(0.000)
fNORD	0.000***	(0.000)
fSARD	0.000	(0.000)
Gas	-0.004	(0.003)
CO2	-0.195***	(0.012)
Oil	0.005	(0.009)
year1	0.414*	(0.243)
year2	-1.217***	(0.184)
Intercept	2.460***	(0.824)
N	25776	
Log-likelihood	-5232.792	
$\chi^2_{(40)}$	4625.417	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-7545.5	$Log - LikFullModel:$	-5232.79
$D(25734):$	10465.58	$LR(40):$	4625.417
		$Prob > LR:$	0
$McFadden'sR2:$	0.307	$McFadden'sAdjR2:$	0.301
$ML(Cox - Snell)R2:$	0.164	$Cragg - Uhler(Nagelkerke)R2:$	0.371
$CountR2:$	0.933	$AdjCountR2:$	0.055
$AIC:$	0.409	$AIC * n:$	10549.58
$BIC:$	-250920	$BIC':$	-4219.13
$BICusedbyStata:$	10892.19	$AICusedbyStata:$	10549.58

Table D.6: Estimations for CNOR-CSUD with year dummies, 2010-2012

D.3 SARD-CSUD

First model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_SARD	0.009***	(0.001)
ren_CSUD	-0.010***	(0.003)
ren_SUD	0.000	(0.001)
ren_CNOR	0.014***	(0.003)
hydro_SARD	0.024***	(0.004)
hydro_CSUD	-0.018***	(0.002)
hydro_SUD	0.004***	(0.001)
hydro_CNOR	-0.010***	(0.001)
fSARD	-0.002	(0.002)
fCSUD	-0.003***	(0.000)
fSUD	0.004***	(0.001)
fCNOR	0.001***	(0.000)
Gas	-0.033***	(0.009)
CO2	0.120***	(0.033)
Oil	0.346***	(0.040)
year1	12.407***	(1.099)
Intercept	-30.579***	(3.744)
	Equation 3 : 1	
ren_SARD	-0.010***	(0.000)
ren_CSUD	0.000	(0.001)
ren_SUD	0.002***	(0.000)
ren_CNOR	-0.003***	(0.000)
hydro_SARD	0.000	(0.001)
hydro_CSUD	0.002***	(0.000)
hydro_SUD	0.000	(0.000)
hydro_CNOR	-0.003***	(0.000)
fSARD	0.002***	(0.000)
fCSUD	-0.001***	(0.000)
fSUD	0.002***	(0.000)
fCNOR	0.001***	(0.000)
Gas	-0.013***	(0.002)
CO2	0.070***	(0.006)
Oil	0.042***	(0.005)
year1	1.648***	(0.112)
Intercept	-11.072***	(0.505)
N	17184	
Log-likelihood	-9655.742	
$\chi^2_{(32)}$	4051.109	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-11681.3	$Log - LikFullModel:$	-9655.74
$D(17150):$	19311.48	$LR(32):$	4051.109
		$Prob > LR:$	0
$McFadden'sR2:$	0.173	$McFadden'sAdjR2:$	0.17
$ML(Cox - Snell)R2:$	0.21	$Cragg - Uhler(Nagelkerke)R2:$	0.283
$CountR2:$	0.726	$AdjCountR2:$	0.106
$AIC:$	1.128	$AIC * n:$	19379.48
$BIC:$	-147931	$BIC':$	-3739.05
$BICusedbyStata:$	19643.04	$AICusedbyStata:$	19379.48

Table D.7: Estimations for SARD-CSUD with year dummy, 2010-2011

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_SARD	0.011***	(0.001)
ren_CSUD	0.000	(0.001)
ren_SUD	0.000	(0.000)
ren_CNOR	0.000	(0.001)
hydro_SARD	0.004	(0.007)
hydro_CSUD	-0.008***	(0.002)
hydro_SUD	0.002	(0.001)
hydro_CNOR	0.006***	(0.001)
fSARD	-0.004***	(0.001)
fCSUD	-0.002***	(0.001)
fSUD	0.004***	(0.001)
fCNOR	0.000	(0.000)
Gas	-0.103***	(0.017)
CO2	0.508***	(0.070)
Oil	-0.261***	(0.033)
Intercept	16.018***	(3.444)
	Equation 3 : 1	
ren_SARD	-0.010***	(0.001)
ren_CSUD	0.001*	(0.001)
ren_SUD	0.000	(0.000)
ren_CNOR	-0.001	(0.001)
hydro_SARD	0.029***	(0.002)
hydro_CSUD	-0.001	(0.001)
hydro_SUD	0.001***	(0.001)
hydro_CNOR	-0.006***	(0.001)
fSARD	0.008***	(0.001)
fCSUD	-0.005***	(0.000)
fSUD	0.005***	(0.000)
fCNOR	0.002***	(0.000)
Gas	-0.001	(0.012)
CO2	-0.017	(0.041)
Oil	-0.052***	(0.014)
Intercept	-4.893**	(2.210)
N	8592	
Log-likelihood	-1762.43	
$\chi^2_{(30)}$	2782.65	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log-LikInterceptOnly:$	-3153.76	$Log-LikFullModel:$	-1762.43
$D(8560):$	3524.859	$LR(30):$	2782.65
		$Prob > LR:$	0
$McFadden'sR2:$	0.441	$McFadden'sAdjR2:$	0.431
$ML(Cox-Snell)R2:$	0.277	$Cragg-Uhler(Nagelkerke)R2:$	0.532
$CountR2:$	0.92	$AdjCountR2:$	0.169
$AIC:$	0.418	$AIC*n:$	3588.859
$BIC:$	-74016.6	$BIC':$	-2510.89
$BICusedbyStata:$	3814.734	$AICusedbyStata:$	3588.859

Table D.8: Estimations for SARD-CSUD, 2012

Second model

Variable	Coefficient	(Std. Err.)
Equation 1 : -1		
ren_SARD	0.009***	(0.000)
ren_CSUD	-0.002***	(0.001)
ren_SUD	0.001**	(0.000)
ren_CNOR	0.001**	(0.001)
hydro_SARD	0.007**	(0.003)
hydro_CSUD	-0.010***	(0.001)
hydro_SUD	0.002***	(0.001)
hydro_CNOR	-0.001	(0.001)
fSARD	-0.002***	(0.001)
fCSUD	-0.003***	(0.000)
fSUD	0.005***	(0.000)
fCNOR	0.002***	(0.000)
Gas	-0.065***	(0.006)
CO2	0.022	(0.022)
Oil	-0.065***	(0.019)
year1	2.457***	(0.570)
year2	-1.996***	(0.560)
Intercept	4.769***	(1.808)
Equation 3 : 1		
ren_SARD	-0.010***	(0.000)
ren_CSUD	0.000	(0.000)
ren_SUD	0.001***	(0.000)
ren_CNOR	-0.002***	(0.000)
hydro_SARD	0.004***	(0.001)
hydro_CSUD	0.002***	(0.000)
hydro_SUD	0.000	(0.000)
hydro_CNOR	-0.003***	(0.000)
fSARD	0.003***	(0.000)
fCSUD	-0.002***	(0.000)
fSUD	0.003***	(0.000)
fCNOR	0.001***	(0.000)
Gas	-0.016***	(0.001)
CO2	0.077***	(0.006)
Oil	0.018***	(0.005)
year1	2.501***	(0.148)
year2	1.046***	(0.089)
Intercept	-10.498***	(0.498)
N	25776	
Log-likelihood	-11920.83	
$\chi^2_{(34)}$	7644.667	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log-LikInterceptOnly:$	-15743.2	$Log-LikFullModel:$	-11920.8
$D(25740):$	23841.66	$LR(34):$	7644.667
		$Prob > LR:$	0
$McFadden'sR2:$	0.243	$McFadden'sAdjR2:$	0.241
$ML(Cox-Snell)R2:$	0.257	$Cragg-Uhler(Nagelkerke)$	$R2:0.364$
$CountR2:$	0.786	$AdjCountR2:$	0.097
$AIC:$	0.928	$AIC*n:$	23913.66
$BIC:$	-237605	$BIC':$	-7299.32
$BICusedbyStata:$	24207.32	$AICusedbyStata:$	23913.66

Table D.9: Estimations for SARD-CSUD with year dummies, 2010-2012

D.4 CSUD-SUD

First model

Variable	Coefficient	(Std. Err.)
	Equation 2 : 1	
ren_CSUD	-0.005***	(0.001)
ren_SUD	0.003***	(0.000)
ren_CNOR	0.004***	(0.001)
ren_SARD	0.003***	(0.000)
hydro_CSUD	0.000	(0.000)
hydro_SUD	0.000*	(0.000)
hydro_CNOR	0.003***	(0.000)
hydro_SARD	0.001	(0.001)
fCSUD	0.000	(0.000)
fSUD	-0.002***	(0.000)
fCNOR	0.002***	(0.000)
fSARD	0.003***	(0.000)
Gas	0.000	(0.002)
CO2	-0.015*	(0.008)
Oil	-0.005	(0.007)
year1	1.132***	(0.136)
Intercept	-9.656***	(0.630)
N	17184	
Log-likelihood	-5587.436	
$\chi^2_{(16)}$	5608.018	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-8391.45	$Log - LikFullModel:$	-5587.44
$D(17167):$	11174.87	$LR(16):$	5608.018
		$Prob > LR:$	0
$McFadden'sR2:$	0.334	$McFadden'sAdjR2:$	0.332
$ML(Cox - Snell)R2:$	0.278	$Cragg - Uhler(Nagelkerke)R2:$	0.447
$CountR2:$	0.853	$AdjCountR2:$	0.232
$AIC:$	0.652	$AIC * n:$	11208.87
$BIC:$	-156233	$BIC':$	-5451.99
$BICusedbyStata:$	11340.65	$AICusedbyStata:$	11208.87

Table D.10: Estimations for CSUD-SUD with year dummy, 2010-2011

Variable	Coefficient	(Std. Err.)
	Equation 2 : 1	
ren_CSUD	0.000	(0.000)
ren_SUD	0.001***	(0.000)
ren_CNOR	-0.001***	(0.000)
ren_SARD	0.000	(0.000)
hydro_CSUD	-0.004***	(0.001)
hydro_SUD	-0.004***	(0.000)
hydro_CNOR	0.000	(0.000)
hydro_SARD	0.002	(0.002)
fCSUD	0.001***	(0.000)
fSUD	-0.001***	(0.000)
fCNOR	0.001***	(0.000)
fSARD	-0.001***	(0.000)
Gas	-0.047***	(0.006)
CO2	0.249***	(0.021)
Oil	0.070***	(0.008)
Intercept	-15.178***	(1.090)
N		8592
Log-likelihood		-2680.627
$\chi^2_{(15)}$		2316.475

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly$:	-3838.87	$Log - LikFullModel$:	-2680.63
$D(8576)$:	5361.255	$LR(15)$:	2316.475
		$Prob > LR$:	0
$McFadden'sR2$:	0.302	$McFadden'sAdjR2$:	0.298
$ML(Cox - Snell)R2$:	0.236	$Cragg - Uhler(Nagelkerke)R2$:	0.4
$CountR2$:	0.874	$AdjCountR2$:	0.232
AIC :	0.628	$AIC * n$:	5393.255
BIC :	-72325.2	BIC' :	-2180.6
$BICusedbyStata$:	5506.192	$AICusedbyStata$:	5393.255

Table D.11: Estimations for CSUD-SUD, 2012

Second model

Variable	Coefficient	(Std. Err.)
	Equation 2 : 1	
ren_CSUD	0.000	(0.000)
ren_SUD	0.001***	(0.000)
ren_CNOR	0.000	(0.000)
ren_SARD	0.000**	(0.000)
hydro_CSUD	-0.001***	(0.000)
hydro_SUD	0.000*	(0.000)
hydro_CNOR	0.002***	(0.000)
hydro_SARD	0.005***	(0.001)
fCSUD	0.000	(0.000)
fSUD	-0.001***	(0.000)
fCNOR	0.002***	(0.000)
fSARD	0.001***	(0.000)
Gas	0.003*	(0.002)
CO2	0.044***	(0.007)
Oil	0.045***	(0.005)
year1	2.311***	(0.150)
year2	0.722***	(0.088)
Intercept	-13.941***	(0.528)
N	25776	
Log-likelihood	-8761.379	
$\chi^2_{(17)}$	6966.5	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-12244.6	$Log - LikFullModel:$	-8761.38
$D(25758):$	17522.76	$LR(17):$	6966.5
		$Prob > LR:$	0
$McFadden'sR2:$	0.284	$McFadden'sAdjR2:$	0.283
$ML(Cox - Snell)R2:$	0.237	$Cragg - Uhler(Nagelkerke)R2:$	0.386
$CountR2:$	0.847	$AdjCountR2:$	0.159
$AIC:$	0.681	$AIC * n:$	17558.76
$BIC:$	-244106	$BIC':$	-6793.83
$BICusedbyStata:$	17705.59	$AICusedbyStata:$	17558.76

Table D.12: Estimations for CSUD-SUD with year dummies, 2010-2012

D.5 SICI-SUD

First model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_SICI	0.004***	(0.000)
ren_SUD	-0.001***	(0.000)
ren_CSUD	-0.002***	(0.001)
hydro_SICI	0.005	(0.003)
hydro_SUD	-0.002***	(0.000)
hydro_CSUD	0.000	(0.000)
fSICI	-0.002***	(0.000)
fSUD	0.002***	(0.000)
fCSUD	-0.001***	(0.000)
Gas	0.001	(0.002)
CO2	0.008	(0.010)
Oil	-0.007	(0.009)
year1	-0.143	(0.162)
Intercept	0.542	(0.794)
	Equation 3 : 1	
ren_SICI	-0.004***	(0.000)
ren_SUD	0.000	(0.000)
ren_CSUD	0.004***	(0.001)
hydro_SICI	-0.020***	(0.002)
hydro_SUD	0.000	(0.000)
hydro_CSUD	0.002***	(0.000)
fSICI	0.004***	(0.000)
fSUD	-0.001***	(0.000)
fCSUD	0.001***	(0.000)
Gas	-0.008***	(0.002)
CO2	0.046***	(0.008)
Oil	-0.026***	(0.007)
year1	-0.537***	(0.133)
Intercept	-8.134***	(0.627)
N	17184	
Log-likelihood	-9457.026	
$\chi^2_{(26)}$	10389.102	

Significance levels : $*: 10\%$ $**: 5\%$ $***: 1\%$

$Log-LikInterceptOnly:$	-14651.6	$Log-LikFullModel:$	-9457.03
$D(17156):$	18914.05	$LR(26):$	10389.1
		$Prob > LR:$	0
$McFadden'sR2:$	0.355	$McFadden'sAdjR2:$	0.353
$ML(Cox-Snell)R2:$	0.454	$Cragg-Uhler(Nagelkerke)$	$R2: 0.554$
$CountR2:$	0.78	$AdjCountR2:$	0.369
$AIC:$	1.104	$AIC*n:$	18970.05
$BIC:$	-148387	$BIC':$	-10135.6
$BICusedbyStata:$	19187.1	$AICusedbyStata:$	18970.05

Table D.13: Estimations for SICI-SUD with year dummy, 2010-2011

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_SICI	0.002***	(0.000)
ren_SUD	-0.001***	(0.000)
ren_CSUD	0.000	(0.000)
hydro_SICI	0.017***	(0.003)
hydro_SUD	0.001	(0.001)
hydro_CSUD	-0.010***	(0.001)
fSICI	0.000	(0.001)
fSUD	0.000	(0.000)
fCSUD	0.000***	(0.000)
Gas	-0.044***	(0.007)
CO2	0.101***	(0.021)
Oil	-0.040***	(0.011)
Intercept	6.365***	(1.402)
	Equation 3 : 1	
ren_SICI	-0.005***	(0.000)
ren_SUD	0.000***	(0.000)
ren_CSUD	0.001***	(0.000)
hydro_SICI	-0.006**	(0.003)
hydro_SUD	0.000	(0.000)
hydro_CSUD	0.005***	(0.001)
fSICI	0.004***	(0.000)
fSUD	0.000	(0.000)
fCSUD	0.000***	(0.000)
Gas	0.039***	(0.005)
CO2	-0.062***	(0.015)
Oil	0.034***	(0.008)
Intercept	-10.052***	(1.005)
N	8592	
Log-likelihood	-4401.538	
$\chi^2_{(24)}$	3442.407	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log-LikInterceptOnly:$	-6122.74	$Log-LikFullModel:$	-4401.54
$D(8566):$	8803.076	$LR(24):$	3442.407
		$Prob>LR:$	0
$McFadden'sR2:$	0.281	$McFadden'sAdjR2:$	0.277
$ML(Cox-Snell)R2:$	0.33	$Cragg-Uhler(Nagelkerke)R2:$	0.435
$CountR2:$	0.792	$AdjCountR2:$	0.144
$AIC:$	1.031	$AIC*n:$	8855.076
$BIC:$	-68792.8	$BIC':$	-3225
$BICusedbyStata:$	9038.599	$AICusedbyStata:$	8855.076

Table D.14: Estimations for SICI-SUD, 2012

Second model

Variable	Coefficient	(Std. Err.)
	Equation 1 : -1	
ren_SICI	0.002***	(0.000)
ren_SUD	-0.001***	(0.000)
ren_CSUD	-0.001***	(0.000)
hydro_SICI	0.011***	(0.002)
hydro_SUD	-0.001***	(0.000)
hydro_CSUD	-0.001***	(0.000)
fSICI	-0.001***	(0.000)
fSUD	0.001***	(0.000)
fCSUD	0.000***	(0.000)
Gas	0.000	(0.002)
CO2	0.039***	(0.008)
Oil	-0.010	(0.007)
year1	-0.529***	(0.198)
year2	-0.234**	(0.110)
Intercept	0.904	(0.687)
	Equation 3 : 1	
ren_SICI	-0.005***	(0.000)
ren_SUD	0.000**	(0.000)
ren_CSUD	0.001***	(0.000)
hydro_SICI	-0.016***	(0.002)
hydro_SUD	0.000	(0.000)
hydro_CSUD	0.002***	(0.000)
fSICI	0.004***	(0.000)
fSUD	0.000***	(0.000)
fCSUD	0.000***	(0.000)
Gas	0.007***	(0.001)
CO2	0.006	(0.006)
Oil	0.018***	(0.005)
year1	-1.473***	(0.150)
year2	-1.131***	(0.087)
Intercept	-8.819***	(0.518)
N	25776	
Log-likelihood	-14388.139	
$\chi^2_{(28)}$	13121.216	

Significance levels : $*$: 10% $**$: 5% $***$: 1%

$Log - LikInterceptOnly:$	-20948.7	$Log - LikFullModel:$	-14388.1
$D(25746):$	28776.28	$LR(28):$	13121.22
		$Prob > LR:$	0
$McFadden'sR2:$	0.313	$McFadden'sAdjR2:$	0.312
$ML(Cox - Snell)R2:$	0.399	$Cragg - Uhler(Nagelkerke)$	$R2: 0.497$
$CountR2:$	0.775	$AdjCountR2:$	0.284
$AIC:$	1.119	$AIC * n:$	28836.28
$BIC:$	-232731	$BIC':$	-12836.8
$BICusedbyStata:$	29081	$AICusedbyStata:$	28836.28

Table D.15: Estimations for SICI-SUD with year dummies, 2010-2012

Appendix E

OLS tables

E.1 CNOR-NORD

First Model

2010-2011	CNORNORD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-56.9175	21.1447	***	28.1496	48.4495	
FabCSUD	0.004707	0.002423	*	0.001536	0.010317	
FabNORD	0.002797	0.000955	***	-0.00345	0.002606	
FabCNOR	-0.01276	0.007259	*	0.019376	0.020598	
Gas	0.037515	0.064881		-0.01693	0.224496	
CO2	0.243637	0.28976		-2.29703	1.02484	**
HydCNOR	0.047883	0.008844	***	-0.0031	0.02013	
HydCSUD	-0.02518	0.009807	**	0.039631	0.026334	
HydNORD	0.002409	0.001109	**	-0.0028	0.004535	
RenCNOR	0.111169	0.020058	***	-0.04735	0.097967	
RenCSUD	-0.02206	0.012687	*	-0.02958	0.028408	
RenNORD	-0.02669	0.004346	***	-0.03218	0.021038	
Year1	1.21508	5.01669		6.91931	9.71847	
Peak	2.92393	1.91453		4.44236	7.02353	
Weekdays	-2.83767	2.6541		2.89371	5.033	
Oil	0.639333	0.22358	***	0.471883	0.573479	
Adjusted R-squared	0.175119			0.167204		
P-value(F)	1.42E-28			0.045332		
Akaike criterion	7120.676			508.3758		
Hannan-Quinn	7149.594			522.4468		
Sum squared resid	270180			4390.321		
R-squared	0.190208			0.353651		
Log-likelihood	-3544.34			-238.188		
Schwarz criterion	7196.045			543.888		

Table E.1: Linear Estimation CNOR-NORD, 2010-2011

2012	CNORNORD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-18.3239	69.5945		16.2331	21.9817	
FabCSUD	-0.01116	0.008717		-0.00421	0.002815	
FabNORD	-0.00319	0.002982		0.002784	0.000893	***
FabCNOR	0.036651	0.018946	*	-0.00834	0.005743	
Gas	0.31953	0.268935		-0.24787	0.07866	***
CO2	-0.3746	0.835856		-0.09739	0.294756	
HydCNOR	0.039578	0.026293		-0.02523	0.009473	***
HydCSUD	0.060231	0.046755		-0.00697	0.01606	
HydNORD	-0.00116	0.003054		-0.00041	0.000948	
RenCNOR	-0.08142	0.116303		0.019315	0.006532	***
RenCSUD	-0.02696	0.016153	*	-0.00781	0.003355	**
RenNORD	-0.00813	0.022857		-0.0028	0.001421	**
Peak	-1.60307	5.67552		-0.19138	3.10412	
Weekdays	-2.91097	11.5051		0.202435	1.72944	
Oil	0.171601	0.655018		0.054692	0.21144	
Adjusted R-squared	0.257583			0.191842		
P-value(F)	0.000189			2.54E-10		
Akaike criterion	837.4635			2151.017		
Hannan-Quinn	853.2788			2173.162		
Sum squared resid	18805.93			22902.16		
R-squared	0.362572			0.230325		
Log-likelihood	-403.732			-1060.51		
Schwarz criterion	876.541			2206.322		

Table E.2: Linear Estimation CNOR-CSUD, 2012

Second Model

2010-2012	CNORNORD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-59.1179	20.7809	***	-6.36321	16.197	
FabCSUD	0.002246	0.002229		0.000512	0.002165	
FabNORD	0.001757	0.000856	**	0.001349	0.000571	**
FabCNOR	-0.00262	0.006145		-0.00542	0.004382	
Gas	-0.01021	0.053735		-0.13466	0.058033	**
CO2	0.037513	0.257179		-0.14959	0.22922	
HydCNOR	0.0485	0.008131	***	-0.02996	0.007731	***
HydCSUD	-0.02392	0.009093	***	0.013971	0.010714	
HydNORD	0.000896	0.000873		9.71E-05	0.000828	
RenCNOR	0.098999	0.017975	***	0.016885	0.006093	***
RenCSUD	-0.01927	0.008925	**	-0.01016	0.00315	***
RenNORD	-0.0243	0.004123	***	-0.00282	0.001392	**
Year1	7.40882	5.73655		2.36694	4.59944	
Year2	4.16959	3.03267		0.030868	4.69919	
Peak	1.80447	1.75201		0.379382	2.63725	
Weekdays	-4.39007	2.4928	*	0.636519	1.52775	
Oil	0.675137	0.203645	***	0.104235	0.165127	
Adjusted R-squared	0.170115			0.161819		
P-value(F)	5.70E-31			3.46E-10		
Akaike criterion	7964.892			2659.745		
Hannan-Quinn	7996.194			2686.061		
Sum squared resid	296190.3			29436.25		
R-squared	0.184548			0.198865		
Log-likelihood	-3965.45			-1312.87		
Schwarz criterion	8046.925			2725.95		

Table E.3: Linear Estimation CNOR-CSUD, 2010-2012

E.2 CNOR-CSUD

First Model

2010-2011	CNORCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	11.4287	11.263		-135.119	94.0483	
FabSUD	0.002546	0.004493		-0.014	0.013842	
FabSARD	0.000409	0.007212		0.132243	0.035526	***
FabCSUD	-0.01077	0.002946	***	-0.00383	0.011898	
FabNORD	-0.00095	0.000626		0.001633	0.002922	
FabCNOR	0.015598	0.004558	***	-0.01647	0.016292	
Gas	-0.05121	0.04712		0.09371	0.324229	
CO2	-0.26763	0.172181		0.604806	1.02952	
HydCNOR	0.00097	0.004487		-0.03741	0.027692	
HydCSUD	-0.00824	0.006728		0.093768	0.029074	***
HydNORD	0.000508	0.000931		-0.00092	0.003697	
HydSARD	-0.01852	0.021862		-0.03769	0.066541	
HydSUD	0.015382	0.003325	***	-0.09722	0.013655	***
RenCNOR	0.053518	0.02082	**	0.094154	0.067938	
RenCSUD	-0.00066	0.010844		-0.04628	0.063059	
RenNORD	-0.01004	0.004238	**	-0.04429	0.020581	**
RenSARD	-0.00534	0.006853		0.083652	0.035869	**
RenSUD	-0.00543	0.004291		0.039469	0.023592	*
Year1	6.5575	2.58695	**	32.4323	20.5942	
Peak	2.1138	1.97054		8.43676	4.46268	*
Weekdays	2.55585	1.16029	**	3.84187	5.42873	
Oil	0.217992	0.147453		0.313638	0.884829	
Adjusted R-squared	0.118598			0.431907		
P-value(F)	9.67E-15			1.14E-25		
Akaike criterion	5553.314			2491.151		
Hannan-Quinn	5592.461			2523.226		
Sum squared resid	69211.25			102409.9		
R-squared	0.143376			0.474667		
Log-likelihood	-2754.66			-1223.58		
Schwarz criterion	5654.897			2571.117		

Table E.4: Linear Estimation CNOR-CSUD, 2010-2011

2012	CNORCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	29.0083	18.0466		148.049	79.4501	*
FabSUD	0.002836	0.002566		-0.02858	0.010282	***
FabSARD	0.024219	0.003957	***	-0.02333	0.011021	**
FabCSUD	-0.00858	0.002876	***	0.013178	0.007602	*
FabNORD	-0.00061	0.000509		0.002235	0.001536	
FabCNOR	0.012026	0.004174	***	-0.01257	0.010325	
Gas	0.373279	0.069571	***	0.42512	0.35453	
CO2	-1.84258	0.254221	***	0.141636	1.17284	
HydCNOR	0.029201	0.006095	***	-0.00261	0.016935	
HydCSUD	-0.04037	0.011499	***	-0.01152	0.02548	
HydNORD	-0.00231	0.000767	***	-0.00176	0.002706	
HydSARD	-0.04518	0.034167		0.098217	0.069999	
HydSUD	0.018498	0.007913	**	-0.00431	0.015995	
RenCNOR	-0.00582	0.005601		-0.00417	0.042287	
RenCSUD	0.010133	0.003448	***	0.011245	0.015235	
RenNORD	0.000482	0.001482		-0.01015	0.009446	
RenSARD	0.003078	0.002712		0.002161	0.008331	
RenSUD	-0.00167	0.001934		0.016611	0.007784	**
Peak	-2.85427	2.15104		4.6468	2.64635	*
Weekdays	-4.75412	1.40252	***	13.5433	4.67862	***
Oil	-0.29869	0.190901		-1.62454	0.792955	**
Adjusted R-squared	0.181852			0.450924		
P-value(F)	1.28E-22			1.29E-09		
Akaike criterion	5139.577			864.4433		
Hannan-Quinn	5176.316			888.0678		
Sum squared resid	73117.31			7351.545		
R-squared	0.206022			0.544783		
Log-likelihood	-2548.79			-411.222		
Schwarz criterion	5234.479			922.6277		

Table E.5: Linear Estimation CNOR-CSUD, 2012

Second Model

2010-2012	CNORCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	25.3462	9.25695	***	-79.1816	56.7243	
FabSUD	0.002031	0.001988		-0.0052	0.008357	
FabSARD	0.007495	0.002637	***	0.029535	0.01323	**
FabCSUD	-0.0092	0.001936	***	0.009532	0.007217	
FabNORD	-0.00045	0.000367		0.000518	0.00158	
FabCNOR	0.01204	0.002855	***	-0.0272	0.009572	***
Gas	0.018494	0.034433		0.630431	0.228072	***
CO2	-0.61665	0.130534	***	0.341399	0.584647	
HydCNOR	0.005491	0.003501		-0.02491	0.01657	
HydCSUD	-0.00684	0.005185		0.056484	0.019295	***
HydNORD	-0.00078	0.000494		0.001985	0.002376	
HydSARD	-0.0197	0.015731		-0.02772	0.049935	
HydSUD	0.01599	0.00296	***	-0.07567	0.010013	***
RenCNOR	-0.00628	0.005068		0.058662	0.041459	
RenCSUD	0.014849	0.002969	***	-0.00339	0.02417	
RenNORD	-0.00184	0.001339		-0.02367	0.011664	**
RenSARD	0.002143	0.002356		0.019839	0.012641	
RenSUD	-0.00238	0.001622		0.01267	0.011208	
Year1	-2.17942	2.73675		4.52643	14.0381	
Year2	-6.61951	2.1461	***	-4.12488	9.53934	
Peak	1.42388	1.34686		13.9704	3.84791	***
Weekdays	-0.58969	0.887042		5.49759	2.61102	**
Oil	-0.06873	0.098145		0.492688	0.567889	
Adjusted R-squared	0.099136			0.446261		
P-value(F)	9.35E-25			2.15E-40		
Akaike criterion	10766.95			3458.541		
Hannan-Quinn	10812.16			3494.857		
Sum squared resid	153729.5			123352		
R-squared	0.113044			0.476947		
Log-likelihood	-5360.48			-1706.27		
Schwarz criterion	10887.99			3550.229		

Table E.6: Linear Estimation CNOR-CSUD, 2010-2012

E.3 SARD-CSUD

First Model

2010-2011	SARDCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-106.066	14.7778	***	107.188	80.1661	
FabSUD	0.0023	0.003706		-0.03724	0.012135	***
FabSARD	-0.00179	0.006576		0.122611	0.036536	***
FabCSUD	-0.00179	0.0029		0.01223	0.009392	
FabCNOR	0.005472	0.0026	**	-0.02215	0.008962	**
Gas	-0.02893	0.04155		-0.43311	0.214385	**
CO2	1.55011	0.212479	***	1.83403	0.784801	**
HydCNOR	-0.01417	0.006524	**	0.026161	0.027112	
HydCSUD	-0.05734	0.007687	***	0.080913	0.03226	**
HydSARD	0.449126	0.019079	***	0.01721	0.076699	
HydSUD	-0.00717	0.004496		-0.05313	0.012573	***
RenCNOR	-0.00952	0.012006		-0.26485	0.061574	***
RenCSUD	0.114766	0.014622	***	0.220767	0.050564	***
RenSARD	-0.10793	0.010664	***	0.03669	0.021849	*
RenSUD	-0.02667	0.005008	***	-0.03889	0.019054	**
Year1	33.2103	3.15566	***	-11.7863	22.1737	
Peak	-1.30111	1.50322		12.9128	4.93664	***
Weekdays	-1.55929	1.4699		-3.14968	2.78317	
Oil	1.07491	0.148725	***	-2.91432	0.961966	***
Adjusted R-squared	0.174074			0.433626		
P-value(F)	5.80E-195			1.97E-26		
Akaike criterion	49347.49			2314.981		
Hannan-Quinn	49390.89			2342.584		
Sum squared resid	5606532			61849.16		
R-squared	0.177048			0.470698		
Log-likelihood	-24654.8			-1138.49		
Schwarz criterion	49471.32			2383.768		

Table E.7: Linear Estimation SARD-CSUD, 2010-2011

2012	SARDCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	190.206	94.0801	**	-152.242	71.9765	**
FabSUD	0.051788	0.012204	***	0.006254	0.014087	
FabSARD	0.022408	0.022386		0.10334	0.025252	***
FabCSUD	-0.01257	0.013594		-0.01755	0.009084	*
FabCNOR	0.012621	0.013094		0.005418	0.009386	
Gas	-1.15255	0.79688		1.74941	0.332551	***
CO2	0.215303	2.04476		-6.69076	1.33744	***
HydCNOR	-0.13969	0.031709	***	0.005539	0.01494	
HydCSUD	-0.0968	0.05675	*	0.048173	0.034161	
HydSARD	0.640113	0.06752	***	-0.00908	0.103721	
HydSUD	-0.01209	0.019081		0.016676	0.030002	
RenCNOR	-0.06775	0.029354	**	0.004303	0.008924	
RenCSUD	0.054848	0.033235	*	-0.01248	0.010171	
RenSARD	0.01995	0.042005		-0.10155	0.01442	***
RenSUD	-0.0179	0.015099		0.015306	0.005575	***
Peak	-0.16927	7.38995		-0.22956	5.01286	
Weekdays	-27.721	6.12614	***	1.2864	4.1859	
Oil	-1.50624	0.604982	**	1.19009	0.832033	
Adjusted R-squared	0.436401			0.325482		
P-value(F)	2.53E-69			2.94E-11		
Akaike criterion	6747.21			1571.649		
Hannan-Quinn	6778.346			1595.215		
Sum squared resid	1424795			40346.4		
R-squared	0.451489			0.387132		
Log-likelihood	-3355.61			-767.824		
Schwarz criterion	6827.404			1629.809		

Table E.8: Linear Estimation SARD-CSUD, 2012

Second Model

2010-2012	SARDCSUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-32.4062	16.1247	**	59.8778	50.732	
FabSUD	0.019383	0.002888	***	0.000693	0.007503	
FabSARD	-0.0272	0.005053	***	0.035921	0.014255	**
FabCSUD	-0.00635	0.002889	**	0.00048	0.005919	
FabCNOR	0.009434	0.002657	***	-0.01174	0.005916	**
Gas	-0.04665	0.0433		0.019417	0.14267	
CO2	1.79988	0.221066	***	1.14259	0.400018	***
HydCNOR	-0.00783	0.006588		0.016469	0.013389	
HydCSUD	-0.08786	0.007232	***	0.054329	0.017476	***
HydSARD	0.51847	0.018738	***	-0.01758	0.060432	
HydSUD	-0.0063	0.00458		-0.05824	0.009525	***
RenCNOR	-0.03193	0.010694	***	-0.02432	0.008679	***
RenCSUD	0.095852	0.013071	***	-0.00755	0.010462	
RenSARD	-0.07625	0.010748	***	-0.02491	0.01049	**
RenSUD	-0.02685	0.004793	***	0.011825	0.005726	**
Year1	-32.9608	4.71063	***	-30.2176	13.5796	**
Year2	-60.174	2.83514	***	-10.5831	13.9483	
Peak	0.344932	1.49748		6.655	3.18854	**
Weekdays	-4.50211	1.49255	***	1.1017	2.25109	
Oil	1.0098	0.139861	***	-1.38611	0.628554	**
Adjusted R-squared	0.420471			0.286495		
P-value(F)	0			1.61E-26		
Akaike criterion	56567.49			3962.436		
Hannan-Quinn	56613.73			3995.014		
Sum squared resid	7475703			129525.7		
R-squared	0.422425			0.315839		
Log-likelihood	-28263.7			-1961.22		
Schwarz criterion	56700.23			4045.191		

Table E.9: Linear Estimation SARD-CSUD, 2010-2012

E.4 CSUD-SUD

First Model

2010-2011	CSUDSUD		
	Positive price difference (y_p)		
	Coeff	Std. Error	
const	-77.7882	7.215508	***
FabSUD	0.012146	0.002156	***
FabSARD	-0.00878	0.003936	**
FabCSUD	-0.00517	0.001535	***
FabCNOR	0.012595	0.001348	***
Gas	-0.00277	0.021616	
CO2	0.104264	0.088591	
HydCNOR	-0.01102	0.003422	***
HydCSUD	0.006628	0.004168	
HydSARD	-0.02259	0.009371	**
HydSUD	0.002902	0.002183	
RenCNOR	0.039329	0.00573	***
RenCSUD	-0.01897	0.006605	***
RenSARD	0.02093	0.004346	***
RenSUD	0.000879	0.002377	
Year1	12.84661	1.531869	***
Peak	-2.78087	1.0693	***
Weekdays	-8.10048	1.246711	***
Oil	0.54434	0.079658	***
Adjusted R-squared	0.142186		
P-value(F)	4.24E-99		
Akaike criterion	27023.8		
Hannan-Quinn	27065.29		
Sum squared resid	703017.4		
R-squared	0.146881		
Log-likelihood	-13492.9		
Schwarz criterion	27139.68		

Table E.10: Linear Estimation CSUD-SUD, 2010-2011

2012	CSUDSUD		
	Positive price difference (y_p)		
	Coeff	Std. Error	
const	7.014216	14.94742	
FabSUD	-0.01089	0.002424	***
FabSARD	0.00238	0.003113	
FabCSUD	0.004342	0.002562	*
FabCNOR	0.004014	0.002508	
Gas	-0.03129	0.07512	
CO2	-0.0931	0.284713	
HydCNOR	0.022125	0.006408	***
HydCSUD	0.003919	0.012194	
HydSARD	0.042981	0.02433	*
HydSUD	-0.0055	0.005814	
RenCNOR	-0.00691	0.004047	*
RenCSUD	0.012364	0.004286	***
RenSARD	-0.00196	0.004071	
RenSUD	-0.00268	0.002238	
Peak	-1.31066	2.143382	
Weekdays	-3.43917	1.917842	*
Oil	-0.00458	0.110413	
Adjusted R-squared	0.094336		
P-value(F)	1.74E-24		
Akaike criterion	12069.44		
Hannan-Quinn	12104.77		
Sum squared resid	415463		
R-squared	0.105247		
Log-likelihood	-6016.72		
Schwarz criterion	12163.99		

Table E.11: Linear Estimation CSUD-SUD, 2012

Second Model

2010-2012	CSUDSUD		
	Positive price difference (y_p)		
	Coeff	Std. Error	
const	-43.3696	6.657628	***
FabSUD	-0.00319	0.001297	**
FabSARD	0.004788	0.001805	***
FabCSUD	0.000494	0.001267	
FabCNOR	0.009553	0.001204	***
Gas	-0.0077	0.019678	
CO2	0.067581	0.084902	
HydCNOR	-0.00215	0.002961	
HydCSUD	0.007906	0.003608	**
HydSARD	-0.03015	0.008824	***
HydSUD	0.004006	0.002108	*
RenCNOR	0.003386	0.002757	
RenCSUD	-0.00172	0.00318	
RenSARD	0.004288	0.002777	
RenSUD	-0.00089	0.001484	
Year1	1.406733	1.91164	
Year2	-7.71569	1.148135	***
Peak	-2.03508	0.942151	**
Weekdays	-7.43198	1.055157	***
Oil	0.291852	0.059012	***
Adjusted R-squared	0.098789		
P-value(F)	2.02E-95		
Akaike criterion	39308.45		
Hannan-Quinn	39353.85		
Sum squared resid	1166248		
R-squared	0.102431		
Log-likelihood	-19634.2		
Schwarz criterion	39437.57		

Table E.12: Linear Estimation CSUD-SUD, 2010-2012

E.5 SICI-SUD

First Model

2010-2011	SICISUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	41.4661	7.95082	***	-45.8691	9.14187	***
FabSUD	0.022684	0.00257	***	0.013078	0.003507	***
FabCSUD	0.011014	0.001033	***	-0.00476	0.001568	***
FabSICI	-0.03413	0.003323	***	0.007324	0.004561	
Gas	-0.10318	0.022692	***	0.033857	0.022676	
CO2	1.96832	0.103243	***	1.06765	0.1018	***
HydCSUD	0.013371	0.00289	***	-0.00153	0.00418	
HydSICI	-0.20602	0.028502	***	-0.0864	0.035851	**
HydSUD	0.016696	0.002604	***	0.015508	0.004079	***
RenCSUD	0.012544	0.006111	**	-0.03415	0.008871	***
RenSICI	-0.04142	0.003619	***	-0.0481	0.003276	***
RenSUD	-0.00188	0.002874		0.018612	0.003614	***
Year1	-13.396	1.6488	***	-2.39197	1.80728	
Peak	1.124	0.905348		-10.5394	1.8243	***
Weekdays	-7.40694	0.955249	***	-2.26615	0.710987	***
Oil	-1.08498	0.084332	***	-0.05009	0.097038	
Adjusted R-squared	0.185905			0.314189		
P-value(F)	0			1.00E-125		
Akaike criterion	109127.7			13208.52		
Hannan-Quinn	109167.1			13240.61		
Sum squared resid	11544791			277984.4		
R-squared	0.186999			0.320408		
Log-likelihood	-54547.8			-6588.26		
Schwarz criterion	109244.8			13295.1		

Table E.13: Linear Estimation on SICI-SUD, 2010-2011

2012	SICISUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	-39.7379	15.423	**	-43.0884	13.8655	***
FabSUD	0.005483	0.003182	*	-0.01218	0.00336	***
FabCSUD	-0.00113	0.001629		-0.00508	0.001359	***
FabSICI	0.018483	0.005795	***	0.033954	0.005117	***
Gas	0.342177	0.068666	***	0.290501	0.078592	***
CO2	-0.91314	0.230068	***	-0.47916	0.210271	**
HydCSUD	0.029999	0.010003	***	0.058613	0.012271	***
HydSICI	-0.06339	0.042086		0.00648	0.030516	
HydSUD	0.039096	0.005541	***	-0.02193	0.006931	***
RenCSUD	0.008568	0.004586	*	0.009126	0.00531	*
RenSICI	-0.02118	0.003566	***	-0.02578	0.002614	***
RenSUD	0.000759	0.002839		-0.00498	0.002799	*
Weekdays	1.79684	1.61159		3.64514	0.905771	***
Peak	-1.38187	1.4093		6.72795	2.21974	***
Oil	0.069533	0.12065		0.073844	0.092853	
Adjusted R-squared	0.081371			0.323976		
P-value(F)	1.40E-111			2.39E-55		
Akaike criterion	66998.67			5631.375		
Hannan-Quinn	67033.84			5657.993		
Sum squared resid	11315573			87022.09		
R-squared	0.083349			0.336852		
Log-likelihood	-33484.3			-2800.69		
Schwarz criterion	67100.36			5700.394		

Table E.14: Linear Estimation SICI-SUD, 2012

Second Model

2010-2012	SICISUD					
	Positive price difference (y_p)			Negative price difference (y_p)		
	Coeff	Std Error		Coeff	Std Error	
const	20.9375	7.24692	***	-21.9647	7.61544	***
FabSUD	0.017104	0.001755	***	-0.00064	0.002314	
FabCSUD	0.00663	0.000861	***	-0.00403	0.001048	***
FabSICI	-0.01711	0.002785	***	0.018733	0.003595	***
Gas	-0.05507	0.0219	**	-0.03764	0.020357	*
CO2	1.12952	0.096238	***	0.464584	0.09006	***
HydCSUD	0.023218	0.002914	***	-0.00541	0.003737	
HydSICI	-0.20809	0.023785	***	-0.03104	0.025421	
HydSUD	0.018547	0.002448	***	0.010458	0.003637	***
RenCSUD	0.012095	0.003148	***	0.011921	0.004869	**
RenSICI	-0.02547	0.002373	***	-0.02298	0.001845	***
RenSUD	-0.00307	0.001918		0.000731	0.002353	
Year1	-14.8212	2.05517	***	-7.1683	2.06619	***
Year2	-9.71652	1.26476	***	-7.21856	1.23268	***
Peak	1.81654	0.786928	**	-5.43981	1.51215	***
Weekdays	-4.60026	0.801173	***	-1.26494	0.599809	**
Oil	-0.59366	0.066949	***	-0.09177	0.068487	
Adjusted R-squared	0.130857			0.227101		
P-value(F)	0			1.40E-123		
Akaike criterion	177375.3			19217.74		
Hannan-Quinn	177418.8			19253.49		
Sum squared resid	23449867			427154.4		
R-squared	0.131643			0.232275		
Log-likelihood	-88670.7			-9591.87		
Schwarz criterion	177507.6			19315.99		

Table E.15: Linear Estimation SICI-SUD, 2010-2012