Oxford Energy Comment

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Living with Intermittent Renewable Power:
Challenges for Spain and the EU[1]

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1. Introduction

This note summarizes thirteen policy challenges facing Spain in the context of high penetration of intermittent renewable power. For each challenge, the note offers some thoughts on policy responses.

The Spanish case and proposed policy responses are relevant for the rest of the EU for two reasons. First, all regional markets in the EU with high levels of intermittent renewable penetration will sooner or later have to deal with similar challenges to those now facing Spain. Second, some of the most serious challenges relate to the inconsistency between the EU policy on liberalization of the electricity sector and its policy with respect to climate change.

The note has three parts in addition to the introduction. The first focuses on Spain. It provides background and identifies some general challenges as well as some that are specifically related to renewable energy. The second argues that Spain's main challenges reflect wider problems that face the EU as a result of combining de-carbonization with competitive wholesale electricity markets as they were originally designed. The third suggests a framework for debate on the key economic issues, focusing on the need to reform wholesale markets to reflect the cost structures implied by de-carbonization, and on providing new incentives for innovation in low carbon technologies.

[1] This comment is based on a presentation at the 3rd OMIE International Workshop on the Impact of RES on Wholesale Electricity Markets: The German Case, May 29, 2013, Madrid.

2. Challenges facing Spain and MIBEL

a. Some background

MIBEL comprises the Spanish and Portuguese electricity systems. Spain's electricity system is approximately six times that of Portugal and is the main focus of the summary below.

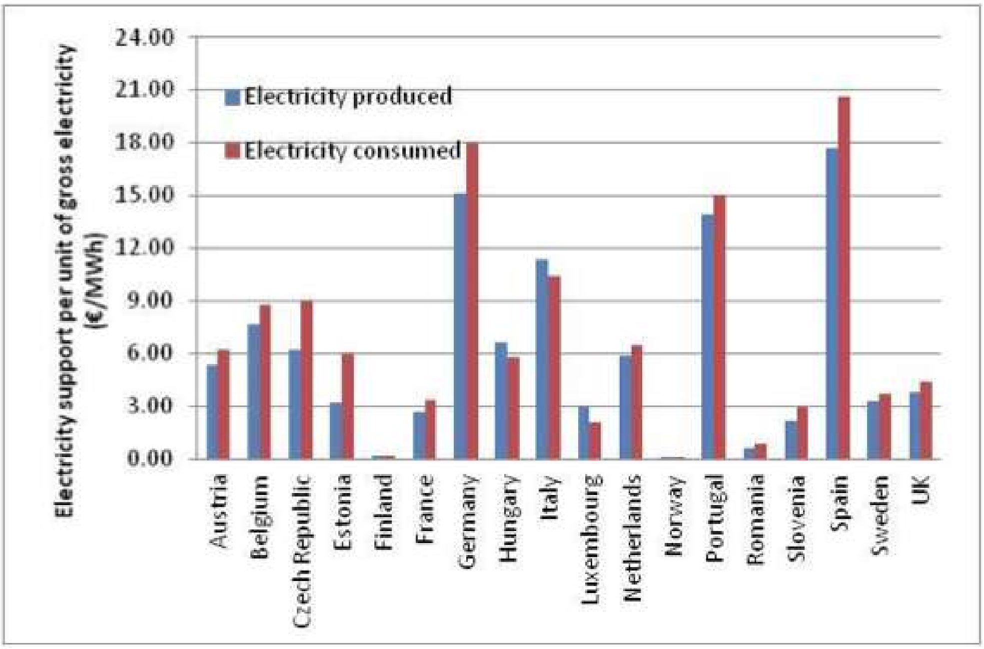
The supply side. Spain has about 100 GW of capacity, which is highly diversified, including (end 2011); CCGT (25%), coal (12%), hydro (19%), wind (21%), nuclear (9%) solar (5%), plus cogeneration and others (9%). Annual production depends very much on weather conditions, demand and regulatory policy, but over time the share of renewable generation and cogeneration has been increasing and the share of conventional generation falling. In particular, the share of gas-fired generation is falling rapidly, with annual operations now averaging closer to 2000 hours a year, compared to the 5000 - 6000 hours a year that were assumed when the CCGT plant were built. Domestic coal has managed to maintain its share of generation because of recent legislation that gives it a priority in dispatch until the end of 2014.

Both Spain and Portugal rely heavily on renewable energy. In 2011, over 30% of Spain's electricity and 50% of Portugal's came from renewable sources, including hydro. In the first five months of 2013, more than 45% of Spain's electricity came from renewable resources, mainly due to heavy wind and rain.

In 2010, about 17% of electricity came from intermittent power (wind and solar PV) in Spain compared to almost 20% in Portugal. The EU expects Spain and Portugal each to generate over 25% of their electricity from these intermittent sources by 2020. Indeed, in Spain, intermittent generation accounted for over 27% of electricity in the first five months of 2013.

The reason for the increased reliance on intermittent renewables is that both countries made political decisions to provide financial support to these sources. Measured in terms of financial support for renewables per kWh consumed in the country, Spain came first in the EU and Portugal third (after Germany) in 2010. In Spain's case, in 2012, the government introduced a moratorium on the approval of new renewable projects eligible for financial support partly because of excess generation capacity on the system and also due to the high costs of financial support at a time of economic hardship.

Graphic 1: Renewable-electricity support per unit of gross electricity produced and per unit of final electricity consumed (2010)[2]

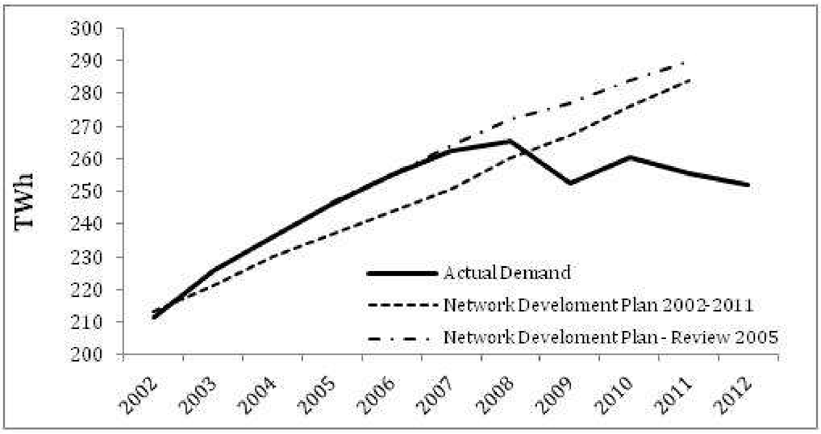


The demand side After many years of growth, Spain and Portugal have experienced electricity demand reductions due to the deep economic recession. Between 2007 and 2011, demand in Spain fell by about 3% and in Portugal a bit less. In the first five months of 2013, demand is a further three percent below the level during the same period of the year before. Electricity demand in Spain is now at 2006 levels.

The combination of declining demand and growing renewable power generation in the context of the regulatory system has contributed to a serious "tariff deficit", in addition to problems of cost recovery related to conventional power stations and rising prices for final customers.

[2] Source: CEER Status Review of Renewable and Energy Efficiency Support Schemes in Europe, 3 December 2012, Revised 19 February 2013, page 20. http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab2/C12-SDE-33-03_RES%20SR_3-Dec-2012_Rev19-Feb-2013.pdf

Graphic 2: Electricity demand in Spain: forecasts and actual 2002-2012[3]



Regulation and the tariff deficit. The regulatory system in Spain differentiates between the costs of energy from the competitive wholesale market, and the so called "access costs", i.e. the remainder of the recognized costs of the system, including regulated network costs, the cost of supporting renewable energy and other costs, for instance the extra costs of providing energy in the islands. The costs of energy from the competitive wholesale market are passed through to all customers in the free market and in the regulated market. The other recognized costs (access costs) should be recovered from all customers through the regulated access tariff. The tariff deficit in any given year refers to the difference between the access costs that are recognized by the government as being recoverable, and the access tariff that has been set to recover them. In any given year, the tariff deficit will be larger, the lower the access tariff compared to the access costs. This can occur for a number of reasons, for instance because government is unwilling to pass on the full costs to customers in the access tariff, or because electricity demand has fallen below the expected level for that year, or because climatic conditions lead to more renewable energy production than expected (which affects the deficit because the renewables receive a feed-in-tariff that is paid in €/kWh). In 2011, the tariff deficit was €3.8 billion and in 2012 it was €5.1 billion.

The accumulated tariff deficit refers to the sum of the annual deficits over a number of years. Most companies (e.g. the transmission company and the renewable energy producers receiving FiTs) recover all their entitlements in the year the costs are incurred, but the largest electricity companies (mainly Endesa, Iberdrola, Gas Natural Fenosa) do not. They finance the tariff deficit and are entitled to charge interest; this adds another cost to the tariff deficit. At the end of 2012, the accumulated deficit was in excess of €25 billion, to be collected from customers over the next 10-15 years.

[3] Source: REE and own elaboration.

The government is very concerned about the tariff deficit. On the one hand, international financial markets treat the deficit as sovereign debt[4] and government naturally wants to avoid increases in the tariff deficit for that reason. On the other hand, the government is reluctant to increase prices to final customers, especially in current economic conditions. Although they have taken measures to limit the deficit, the latter continues to grow. New measures are expected soon and are the subject of much speculation.

CCGT cost recovery. The declining operation of conventional plants makes fixed cost recovery increasingly difficult. A recent study by the regulator, the CNE, estimates that CCGT on average are recovering only 35% of their fixed costs. Some plants are able to recover a larger share of fixed costs because they sell into the constraints market, where prices are higher. However, the situation facing most other CCGT plants is much worse because they rely on declining sales into the day-ahead market. Furthermore, all of the CCGT plants have lost revenue as the result of the end of grandfathered CO2 emission allowances. And they face the imminent loss of their capacity payments.

Economic recession and electricity prices. The economic recession has occurred at the same time as an increase in the price of electricity for final consumers, even after recognizing that these prices do not include the costs that have been differed to future periods. Between the second half of 2010 and the second half of 2012, for instance, the electricity price per kWh for households rose by over 20%. At the same time, wholesale electricity market prices have fallen. The difference is largely due to increasing access costs – especially to support renewable energy – that are only partly captured in the access tariff.

b. Challenges for Spain and MIBEL not caused by renewables

Challenge 1: Political and regulatory uncertainty. Spain has earned a particularly bad reputation in the past ten years for political and regulatory risk. This applies to the electricity sector among other sectors, not just to renewable energy.

Response: It is very hard to rebuild credibility after it has been so seriously damaged. The immediate priority is to reach a "deal" with respect to problems created in the past, including the tariff deficit and badly designed feed-in tariffs. However, it is also important to define the future vision (objectives, market and corporate structure, regulation) for the electricity sector in 2050 and the transition plan. A few other EU countries are well advanced in their thinking on this – notably the UK and Germany – and others are beginning a review – as in France. For all of them, de-carbonization

[4] Some of the tariff déficit has been securitized, and is effectively backed up by government guarantees.

(especially renewable energy) is driving the reform, without forgetting about security of supply and cost. Because Spain and MIBEL have no shortage of capacity and a high

level of renewable penetration, there is a temptation to not think much about the future. But that is a mistake. Now is the right time to be thinking about a sustainable model for the sector, partly because what we do now should take us where we want to go, and also because there is an important debate now beginning in Europe about competition, the internal market and climate change policies. Spain and MIBEL have every reason to want to participate in that debate and to bring their experience to it.

Challenge 2: Excess capacity. Spain currently has generation capacity of about 100 GW, with peak demand of less than 45 GW. If we ignore wind and solar capacity, we are still talking about significant excess capacity, possibly a margin (of peak demand over available firm capacity) of 1.3-1.4 in Spain – compared to REE's target of 1.1. The excess is largely the result of the economic recession, with electricity demand now at the level of 2006. The CNE argues that no new capacity is likely to be needed before 2021 in their central scenario. However, this excess capacity could disappear sooner than expected. Demand will eventually begin to grow. More importantly, we may soon find that a large amount of the fossil capacity is uneconomic due to the incremental costs of meeting the Industrial Emissions Directive, the loss of free CO2 emission allowances (which acted as form of capacity payment until the end of 2012), the imminent loss of capacity payments (which last for the first 10 years of operation for CCGT), and the reduction both in wholesale electricity prices and operating hours. If margins are inadequate, some plants may be mothballed, or dismantled and moved to markets where they will earn higher returns.

***Response**:* We need payment mechanisms to ensure that the economically efficient capacity is available when needed – whether new plant, existing plant or demand response. Meanwhile, mothballing some capacity makes economic sense and is what we should expect in a well functioning market. Mothballing in Spain requires authorization. Generally, generators do not have an incentive to make the first move in this direction since withdrawal of plants will benefit the other generators on the system. In short, excess capacity is a temporary problem and may require some change in legislation to facilitate mothballing. However, it also makes sense to be questioning whether existing wholesale energy markets and capacity payment mechanisms will be "fit for purpose". As explained below, the answer is that they will not be.

Challenge 3: MIBEL as an electricity island: Inadequate interconnector capacity means that MIBEL is not able to export more than 1000 MW to the rest of Europe. Even with the new interconnector capacity being built with France, MIBEL will continue to be an electricity island and have to deal with excess capacity without the benefit of being able to export much more.

Response: This is very difficult to change without strong political support from France. MIBEL should continue to support building interconnector capacity with France, but also consider links with the other countries and allow competition to build and operate new interconnectors. This will be a slow process and MIBEL will have to plan its mid term future as an electricity island.

c. Challenges linked to the Special Regime in Spain

This part of the comment concentrates on the problems of the Spanish Special Regime, which includes new sources of renewable power (e.g. wind, solar PV, solar thermal) as well as cogeneration (fueled by fossil fuels, typically natural gas).

Challenge 4: Low and volatile prices. Heavy reliance on renewable energy, with close to zero marginal costs in the case of wind and solar PV, can lead to frequent and sometimes long periods of zero prices in the wholesale energy market. This is what we have witnessed in recent months in Spain, as the result of significant wind, rain, depressed demand for electricity and excess capacity. In March 2013, for instance, there were 164 hours with zero energy price, with variation from €0-€90/MWh[5]. Furthermore, average prices were 45% lower than in the same period last year. This may be an early indication of the implications of significant penetration of intermittent renewable energies in the power system.

Response: To some extent, these problems are temporary (e.g. excess capacity and depressed demand) and will take care of themselves with time and through reforms such as facilitating mothballing. Furthermore, the regulatory reforms discussed below would change the incentives of some of the special regime generators – discouraging some of them from operating when prices are zero or very low. However, the more fundamental problem here has to do with the growing gap between wholesale energy prices, which reflect the low marginal costs of renewable energy, and the overall costs of the generation on a de-carbonized system, which are increasingly fixed costs. This is a structural issue related to de-carbonization and requires new types of markets and payments. This is discussed later under Challenge 11.

Challenge 5: Poor incentives from feed-in tariffs (FiTs) paid by kWh. Feed-in tariffs paid on output (kWh) give generators an incentive to generate even when their own operating costs are greater than the wholesale market prices. This is most obvious for cogeneration, which has an incentive to run (even though the manufacturing activity has stopped) when electricity prices are zero, as long as their feed-in tariffs are greater than their variable costs, mainly the costs of gas. This was evident in March this year

[5] Note that the range of prices seems high by Spanish standards, but is not nearly as high as it is in other systems, where shortage conditions exist and which have no capacity payments.

when cogeneration maintained an almost constant level of output, in spite of very low electricity prices and so much excess energy on the system that it was necessary to reduce output from nuclear plant. It is also a problem for solar thermal generation, whose operating costs are close to €20/MWh.

Responses. One approach is to introduce FiT price floors to discourage generation when market prices are low. An alternative is to switch the financial support to reward available capacity (kW), rather than output (kWh). In this case, we would still want the generators to base their bids on their variable costs. However, there is a more general question here about the wisdom of feed-in tariffs as a regulatory approach. The note explains later (Challenge 10) that there is a need for a fundamental rethink about how to promote innovation in low carbon technologies, and that FiTs are expensive and now probably getting in the way of innovation.

Challenge 6: Difficulties of providing backup. Intermittent renewables need backup, but at the same time they create a problem of cost recovery (e.g. from low or zero prices, and reduced running) for the conventional plants that provide that backup. CCGT plants provide most of the backup in Spain, but many periods of zero prices, especially with excess capacity, mean that CCGT do not recover their investment costs and, in some cases, will not even recover their annual fixed and variable costs. A recent CNE report[6] provides some evidence of this problem. It is quite possible that many of these plants will shut, or be dismantled and moved elsewhere, unless there is some economic incentive to remain open.

Responses: As mentioned before, mothballing uneconomic CCGT plants makes economic sense and legislation should facilitate it. However, there is still a need to ensure adequate capacity and flexibility to provide backup for intermittent renewables. REE introduced a day-ahead market mechanism to acquire new reserve services for backup. There were apparently some problems with the algorithms and the mechanism is now being revised. The solution is to promote more effective competition in the provision of flexibility services in short term markets, including generation, demand response and storage options. It also makes sense to be considering long term "reliability" auctions or other means of compensating investors for building plants that have low capacity factors but are expected to provide reliable energy when needed. In passing, the author notes that the beneficiaries of backup are final customers and they (not the generators, as some people have suggested) should pay for the service; but customers should also benefit from a more competitive market to provide them.

[6] *Propuesta del Mecanismo por el que se establece elsServicio de garantía de suministro*, CNE, 5 diciembre 2012.

Challenge 7: High costs of de-carbonization. The Spanish regulatory approach to solar energy was badly designed and has paid too much – not least because the quantity of solar being subsidized was not properly limited. On the other hand, de-carbonization involves higher costs everywhere because the technologies are still more expensive than conventional ones. This is not just a Spanish problem, nor is it just a problem of solar; electricity prices in Europe have been rising much faster than in other parts of the world, in part because of the financial support for renewable energy.

Response. The goals should be (a) to design incentives for innovation to minimize de-carbonization costs; (b) to avoid adding new subsidies to the system, for instance in the terms for net metering related to distributed generation; (c) if subsidies are given, to design them as far as possible to minimize distortions to operations; (d) to limit the volume of energy or capacity which will receive support; and (e) to allow these costs to be passed through to customers immediately – no more passing of costs to future consumers in a way that creates a tariff deficit.

Challenge 8: The tariff deficit continues to rise in Spain. An important part of this deficit is related to the way the system pays for renewable energy – in terms of the output (€/kWh). Indeed, the increase in renewable energy production this year (for reasons related to climatic conditions) is well above the government's forecasts, and this is increasing the tariff deficit further, perhaps helping the government to realize some of the problems with the current design of FITs.

Response. We are all waiting to hear what the Ministry is planning to do. The answer is for all parties to sit in a room (now a very big room) and hammer out a solution that will resolve this problem once and for all, and allow everyone to focus on the bigger challenges of the future. What is worrying is that the government and the sector are concentrating most of their efforts on solving a problem of the past. Furthermore, there is a temptation to find quick "solutions" that have the unintended consequence of distorting investment and operation decisions. For instance, this was almost certainly the result of the decision to introduce taxes on the wholesale electricity market; as a result, Spain's prices are higher than they would otherwise be, benefiting producers in countries exporting to Spain (e.g. France and Portugal) at the expense of Spanish customers.

3. Systematic challenges facing Spain, MIBEL and the EU

Many of the challenges mentioned above are symptomatic of a set of EU-wide challenges that directly affect MIBEL and other regional markets.

Challenge 9: Confusion of EU policy objectives. There is confusion between the EU's policies on liberalization and on climate change. This is obvious in two respects.

First, the the EU and Member States now choose specific low carbon technologies, in particular renewable power, rather than letting markets choose the appropriate technology. This tends to raise costs, while undermining the prospects for other low carbon technologies that do not receive special financial support. Second, national policies often clash with EU internal market objectives. For instance, governments wish to introduce capacity payment mechanisms to finance investment in the power stations required to back-up renewable generation; but the Commission objects to these mechanisms on the grounds that they will be inconsistent with the EU internal market.

Response: This is not a Spanish or MIBEL problem. It is a European problem. There is a need to rethink EU policies on liberalization and climate change, and the inconsistency between internal market rules and national policy flexibility. We need consistency across these different objectives and to ensure that the policies favor technological change in favor of low cost de-carbonization, and allow for the creation of new regional wholesale markets that are consistent with the cost structure of de-carbonized sources of energy.

Challenge 10: Economic challenges of de-carbonization – investment. There are at least two fundamental challenges here. One is to provide incentives for innovation and investment in low-carbon technologies. The other is to ensure that the full (external) costs of these technologies for the system are taken into account when investments are made. On the first, the EU has relied very heavily on government selection of technologies and on feed-in tariffs to finance them. This has had one major benefit: creating the market scale that has helped to drive down costs of certain technologies, such as solar PV. However, "picking winners" has proved extremely expensive, especially in Spain, and probably discouraged innovation and the development of low carbon technologies that are not receiving special tariffs. The EU could be considering making a similar and potentially costly technology choice by treating storage as a regulated activity – no doubt with the support of those who will provide that service. This would discourage innovation in an area that is ripe for major technological breakthroughs, for instance new types of batteries.

On the second, de-carbonization introduces technologies whose system-wide impacts are not fully understood and probably not reflected in private investment decisions. For instance, a recent study by the NEA[7] estimated very substantial system-wide impacts of renewable energy, including not only backup costs, but also the costs of balancing, grid connection and grid reinforcement. As the table below for Germany suggests, some of these costs may be small at low levels of renewable penetration, but very large when renewables penetrate to a high level. These estimates vary widely by country and these costs may not be so important now in Spain.

[7] NEA, Nuclear Energy and Renewables, System Effects in Low Carbon Electricity Systems, OECD 2012.,

Responses: On the first topic – incentives for innovation – colleagues at the Oxford Institute for Energy Studies and the author of this note have written a paper[8] with different proposals on how to promote innovation in low carbon technologies, including: (a) central purchasing, (b) reforms to the EU ETS and (c) the introduction of long-term carbon intensity targets, along with trading mechanisms. It is time to think about these and possibly other options in a systematic way.

On the second topic – system wide costs or externalities – it is conceivable that these costs are already reflected in the charges for network connection of specific assets, but more work is needed to determine what these system costs are and who should pay for them. This will be particularly important with the development of offshore wind farms.

System Costs Associated with Different Generation Technologies (Source: NEA, 2012)

Germany												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.04	0.04	0.00	0.00	7.96	8.84	7.96	8.84	19.22	19.71
Balancing costs	0.52	0.35	0.00	0.00	0.00	0.00	3.30	6.41	3.30	6.41	3.30	6.41
Grid connection	1.90	1.90	0.93	0.93	0.54	0.54	6.37	6.37	15.71	15.71	9.44	9.44
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	1.73	22.23	0.92	11.89	3.69	47.40
Total grid-level system costs	**2.42**	**2.25**	**0.97**	**0.97**	**0.54**	**0.54**	**19.36**	**43.85**	**27.90**	**42.85**	**35.64**	**82.95**

Challenge 11: Economic challenges of de-carbonization – markets do not reflect changing cost structure. A central economic issue of de-carbonization has to do with the change in costs implied by the replacement of fossil fuel fired plant by low-carbon or zero-carbon technologies. Wholesale markets were originally designed to reflect and recover the costs of fossil fuel fired plant. System marginal prices reflect the marginal (mainly fuel) cost of the last plant accepted in dispatch; in principle, an energy-only market will enable all the plants on the system to recover their fixed and variable costs, provided the system is "balanced" (no excess capacity). However, most de-carbonized generation has close to zero marginal costs. As the share of decarbonized generation grows and low/zero prices become more common, today's energy-only markets may not permit conventional (e.g. fossil fired) plants to recover their fixed costs. In theory these energy only markets still allow fixed cost recovery for these plants, but investors will need to rely on very uncertain and very high energy prices (up to €10,000/MWh according to some simulations) in few hours in order to compensate for the many hours

[8] Keay, Malcolm, John Rhys and David Robinson, *Decarbonization of the electricity industry – is there still a place for markets?*, Oxford Institute for Energy Studies, November 2012, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2012/11/EL-9.pdf

of zero or low prices. It is very questionable whether investors will be willing to accept this sort of market and political risk. Furthermore, in this sort of market, *most renewable energy plants will not recover fixed costs (without extra-market payments) because when they run, prices are low or zero!* That means that, even if renewable energies were competitive on a levelized cost basis with conventional generation, they would not be able to recover their fixed costs within the current energy-only market systems. This is part of a wider problem, namely that prices in existing wholesale energy markets no longer reflect the level or the structure of costs on the system.

Responses. The way forward is to develop a suite of wholesale markets whose prices together reflect the new structure and level of costs and at least allow for fixed cost recovery. First, if most costs are now mainly fixed and not variable, then it makes sense to be paying generators on the basis of the available capacity they provide to the system, not on the basis solely of the energy they produce. This implies some form of capacity market, for instance reliability auctions that would remunerate capacity for multiple years. In principle, this capacity market should be consistent with a well-designed spot market based on marginal cost principles, along with continuous balancing markets. It should also be consistent with compatible flexibility markets to provide backup for intermittent renewables as well as for other unanticipated changes in supply or demand. In all of these markets, demand should be able to participate actively. Second, although the author of this note thinks that the suite of wholesale markets should include a short-term market that will determine dispatch on the basis of marginal costs, the increased penetration of renewables with zero marginal costs requires new thinking about how the market should optimize the use of these resources in dispatch.

While most EU markets are energy-only, since 1998 Spain has had a combination of energy and capacity payments. This is almost certainly not the moment to move to an energy-only market. Indeed, it looks very likely that the rest of Europe will be moving to energy and capacity markets, although there will be a debate about the extent to which these capacity markets must meet European guidelines.

Challenge 12: Technology changes and the new role of demand. The original wholesale markets were designed on the assumption that customers and demand were basically given (in the long, short and medium term) and generation was built, maintained and scheduled to meet demand. In other words, generation was flexible and demand was not. However, in the de-carbonized world, generation is increasingly inflexible in the sense that it is either non-dispatchable (e.g. renewable wind and solar PV) or runs base load (like nuclear). At the same time, the development of smart technologies and distributed generation enable customers now to be a more flexible part of the market. So the system will be stood on its head. But the wholesale and retail markets are not designed to enable customers to play this role. In Spain, for instance, most residential customers have an incentive to buy their electricity on a regulated tariff rather than in the free retail market.

Response: The challenge is to enable customers to play a more active role – both in the longer-term decisions about resource adequacy, and in the shorter-term decisions about providing flexibility services in competition with generation options. However, this also means rethinking the terms and regulation of network access, so that customers face economically efficient choices (to buy from the system or to generate for themselves) and that distribution companies also have incentives to enable customer participation if that is the least cost solution for the system.

Challenge 13: The internal market. Creating a single European market is a laudable goal, but we are a long way from that today and arguably the proposed "target model" is not well designed to meet the EU challenges of de-carbonization[9]. In particular, this model is designed for an energy-only market and does not even begin to deal with challenge of aligning the new costs of a de-carbonized system with the prices at the interconnectors. We have seen this in the response of the Commission to proposals for capacity markets – they are worried that these mechanisms will distort the energy-only markets. But this is only the beginning of the problem because the existing energy markets themselves are no longer fit for purpose.

Response. This is a further reason to be rethinking EU electricity and climate change policy. This is not just a Spanish or MIBEL issue, but it is certainly one that Spain and MIBEL have good reason to be thinking about.

4. Conclusions

Spain faces important challenges related to high penetration of intermittent renewable power. The rest of the EU will soon have to address similar challenges and should learn from Spain's experience. Furthermore, many of the challenges stem from EU policy decisions and incompatibility between policies. The Spanish case study is therefore of special relevance for the EU, which should be rethinking its policies on climate change and liberalization.

The central economic challenges when thinking about markets for decarbonized power are the same everywhere. One is about providing the right signals for innovation in low carbon technologies (including generation, demand and storage) and in the choice of technology. Another is about designing markets that align the costs of generating electricity with prices in wholesale markets and with the prices that customers are paying.

[9] See Oxford Energy Comment by Malcolm Keay, The EU "Target Model" for electricity markets: fit for purpose? http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/05/The-EU-Target-Model-for-electricity-markets-fit-for-purpose.pdf

Clarifying the economic issues is not easy, but convincing policy makers to think again is harder. Until the EU recognizes the need for a fundamental rethink of energy and climate change policies, it will be difficult to have a sensible conversation about redesigning wholesale electricity markets. It is not easy to change direction when so much momentum has built up and when so many special interests are affected. This would be true for one country, but is even more so for 27. The good bad news is that current policies are so expensive and have been so unsuccessful in terms of their impact on investor appetite that the time is drawing near when it will soon be acceptable to discuss a rethink. We need to help bring forward that moment by explaining what the problem is. Meanwhile, we need to prepare a new vision for European electricity wholesale markets that is consistent with the de-carbonization agenda. And we need to develop a plan for how to get there.