TESIS DOCTORAL

PROSPECTIVE LONG-TERM OVERALL ECONOMIC AND ENVIRONMENTAL IMPACT OF A COUNTRY'S ENERGY POLICIES. A BEHAVIORAL DYNAMIC SYSTEMS THINKING APPROACH

TESIS DOCTORAL
PARA LA OBTENCIÓN DEL
TÍTULO DE **DOCTOR**

NOVIEMBRE 2017

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POLITÉCNICA

POLYTECHNIC UNIVERSITY OF MADRID

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Submitted in fulfilment of the requirements for the degree of Doctor of Philosophy

Madrid, 2017

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By

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Submitted to the Polytechnic University of Madrid
on October, 2017 in Fulfillment of the
Requirements for the Degree of Doctor of Philosophy

ABSTRACT

The structure of a country’s electric power mix has deep technical, environmental and economic implications.

From the technical point of view, issues such as the recent fast deployment of renewable power generation capacity, with its high degree of production variability, which has taken place during the last decades are introducing new challenges in power system planning and operation. Also, the deployment of specific technologies has an impact on the technologies themselves as they mature and increase their competitiveness with their installed capacity due to a “learning curve” effect.

From the environmental point of view, the power generation mix impacts environment not only through CO_2 emissions but also through additional air emissions such as NO_X, and SO_X as well as liquid and solid waste.

From the economic point of view, the power generation mix impacts not only power system costs (which include costs such as power production, T&D, CO_2 emission allowances, incentives and capacity payments) but also macroeconomic variables such as trade balance, industrial production, internal economic flows, employment, taxes and budget deficit, which ultimately impact the nation’s socio-economic performance and well-being.

While in regulated markets decisions on the power mix were basically an optimization problem (system cost minimization subject to specific restrictions) to be centrally addressed by the regulator, the transition to liberalized markets, which has been taking place worldwide during the last decades has entailed (i) the transition from a system cost minimization to an investor profit maximization problem and (ii) the transfer of investment decisions from the regulator to private investors. Therefore, the perceptions and behaviors of private investors play now a key role on the evolution of the power generation mix so that behavioral models have become increasingly relevant.

Also, liberalized markets show a higher degree of uncertainty than regulated ones so that the use of stochastic planning assessment methodologies, able to simulate the random behavior inherent to specific system variables becomes very useful.

Finally, the electric power industry is very capital intensive and subject to long planning, development and construction lead times, required to bring new power generation assets into commercial operation. Decisions made today may not have an effect before several years and their impact may last for many decades. Because of these facts, power systems show a large inertia so that dynamic considerations become very relevant.

Because of the fact that the power industry impacts so many different and deeply interconnected fields and disciplines, its assessment fits very well with the Systems Thinking discipline, which is precisely focused on analyzing very complex systems.

The abovementioned points have relevant consequences on the power mix optimization process nowadays:

i. Assessments must include behavioral considerations which take into account private investors' perceptions and decisions.

ii. Not only power system costs but the overall net impact on a country's economy, environment and system reliability must be assessed.

iii. Assessments must be done on a long-run basis and must include cumulative ratios and measures.

iv. Dynamic considerations must be taken into consideration in order to properly model issues such as system's inertia, delays and feedback loops.

v. Stochastic approaches must be used in order to properly take into account the random behavior of specific system variables.

The goal of the present research is to provide a methodological framework aimed at the optimization of the power generation mix while taking into account the abovementioned considerations. The methodology here suggested includes a combination of:

i. System Dynamics techniques: used to model the dynamic characteristics of power systems, investors' behavior and soft variables such as public opinion, market perceptions or administrative barriers.

ii. Supply – demand market equilibrium models: used in order to simulate the operation of the country's wholesale power market and compute final power prices.

iii. Stochastic techniques: used in order to account for the uncertainty inherent to specific exogenous variables such as fossil fuel prices or final power demand.

iv. Input – Output macroeconomic models: used to assess the overall impact of the power system on the country's economic performance.

Therefore, the methodological framework here presented can be used by a country's power system regulator as an additional tool aimed at the assessment of the overall long-run impact that his energy policies (e.g. capacity payments, alternative energy incentives or regulatory barriers) may have on multiple variables and, ultimately on the overall socio-economic well-being of the country.

Finally, the methodological framework here presented is applied to two case studies of special relevance for Spain's power system:

i. Assessment of the long-run impact of alternative energy incentives and capacity payments on system reliability, environment and costs.

ii. Assessment of the long-run impact of Spain's new competitive auction-based alternative energy support scheme on wind capacity development and overall system costs.

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RESUMEN

La estructura del mix de generación eléctrica de un país tiene profundas implicaciones a nivel técnico, medioambiental y económico.

Desde el punto de vista técnico, aspectos tales como el rápido desarrollo de las tecnologías renovables, con su consiguiente variabilidad de producción, que ha tenido lugar en las últimas décadas están introduciendo nuevos desafíos en los procesos de operación y planificación de los sistemas eléctricos de potencia. Además, el propio despliegue comercial de las tecnologías de generación tiene impacto en las propias tecnologías ya que éstas maduran y aumentan su competitividad conforme aumenta su potencia instalada, debido al efecto "curva de aprendizaje".

Desde la perspectiva medioambiental, el mix de generación eléctrica tiene impacto en el medioambiente no sólo a través de las emisiones de CO_2 sino también a través de emisiones atmosféricas adicionales tales como NO_X o SO_X, así como a través de emisiones líquidas y sólidas.

Desde el punto de vista económico, el mix de generación eléctrica tiene impacto no solamente en los costes del sistema eléctrico (que incluyen costes tales como la producción de energía, el transporte y la distribución, los créditos de CO2, los incentivos y los pagos por capacidad) sino también en variables macroeconómicas tales como la balanza de pagos, la producción industrial, los flujos económicos internos, el mercado laboral, la fiscalidad y el déficit presupuestario, que a su vez afectan el bienestar socioeconómico general del país.

Mientras en mercados regulados la toma de decisiones relativas al desarrollo del mix de generación consistía básicamente en un problema de optimización (minimización de los costes del sistema sujeto a ciertas restricciones) que debía ser resuelto de forma centralizada por el regulador, la transición hacia mercados liberalizados que ha venido teniendo lugar durante las últimas décadas a nivel mundial ha supuesto (i) la transición desde un problema de minimización de costes del sistema hacia un problema de maximización de los beneficios de los inversores privados y (ii) la transferencia de las decisiones de inversión del regulador hacia los inversores privados. Por estos motivos, las percepciones y comportamientos de los inversores han pasado a jugar un papel transcendental en el desarrollo del mix de generación. Por ello, los modelos de simulación de comportamientos ("behavioral models") han pasado a jugar un papel muy relevante.

Adicionalmente, los mercados liberalizados muestran un grado de incertidumbre mayor que el de los mercados regulados de forma que el uso de metodologías estocásticas de planificación, capaces de simular la aleatoriedad de ciertas variables del sistema, adquiere especial relevancia.

Finalmente, el sector eléctrico es altamente intensivo en capital y está sujeto a largos plazos de planificación, desarrollo y construcción, requeridos para la puesta en servicio de activos de generación eléctrica. Las decisiones tomadas hoy pueden no tener efecto antes de varias décadas y su impacto puede prolongarse también a lo largo de muchas décadas. Por estos motivos, los sistemas eléctricos

de potencia presentan grandes inercias por lo que las consideraciones dinámicas toman especial relevancia.

El hecho de que el sector eléctrico tenga un profundo impacto en múltiples sectores íntimamente ligados entre sí hace que su análisis se ajuste muy bien a la disciplina de Systems Thinking, que precisamente está enfocada al análisis de sistemas de gran complejidad.

Los puntos arriba mencionados tienen importantes implicaciones en los procesos de optimización de sectores eléctricos liberalizados hoy en día:

i. Los estudios deben incluir consideraciones de comportamiento que tengan en cuenta las percepciones y procesos de toma de decisión de los inversores privados.

ii. No solamente el impacto en los costes del sistema eléctrico sino también el impacto global en la economía nacional, medioambiente y la fiabilidad del sistema deben ser analizados.

iii. Los estudios deben realizarse con una perspectiva de largo plazo e incluir mediciones e indicadores acumulados.

iv. Las componentes dinámicas deben ser incluidas con el fin de modelar adecuadamente aspectos tales como la inercia del sistema, plazos temporales y lazos de realimentación.

v. Métodos estocásticos deben ser utilizados con el fin de tener en cuenta el comportamiento aleatorio de variables exógenas específicas.

El objetivo del presente trabajo de investigación es el de proporcionar un marco metodológico enfocado a la optimización del mix de generación eléctrica teniendo en cuenta los puntos arriba mencionados. La metodología aquí propuesta incluye una combinación de:

i. Modelos de Dinámica de Sistemas, utilizados para simular las características dinámicas de los sistemas eléctricos de potencia, el comportamiento de los inversores y variables “suaves” tales como opinión pública, percepciones de mercado o barreras administrativas.

ii. Modelos de equilibrio oferta – demanda, utilizados para simular la operación del mercado mayorista de energía eléctrica del país considerado así como para el cálculo del precio de la electricidad.

iii. Técnicas estocásticas, utilizadas para simular la aleatoriedad inherente a variables exógenas específicas tales como los precios de los combustibles fósiles o la demanda final de energía eléctrica.

iv. Modelos macroeconómicos Input – Output, utilizados para valorar el impacto del sistema eléctrico en el rendimiento económico global del país.

Por lo tanto, el marco metodológico aquí presentado puede ser utilizado por el regulador del sistema eléctrico de un país como una herramienta adicional enfocada a la valoración del impacto global a largo plazo que sus políticas energéticas (p.ej. pagos por capacidad, incentivos a las tecnologías renovables o barreras regulatorias) tienen en múltiples variables así como su impacto en el bienestar socio-económico del país.

Finalmente y a modo de ejemplo del uso del marco metodológico aquí desarrollado, se presentan dos casos prácticos de especial interés para el sistema eléctrico español:

i. Análisis del impacto a largo plazo de los incentivos a las energías renovables y los pagos por capacidad en el medioambiente, costes y fiabilidad del sistema.

ii. Valoración del impacto a largo plazo de la nueva política de incentivos a las energías renovables en España, basada en subastas competitivas, en el desarrollo de la energía eólica y en los costes globales del sistema.

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Acknowledgments

The present thesis would not have happened without the support from many people.

First and foremost, I would like to express my deepest gratitude and thanks to my thesis supervisors, José María Martínez-Val and Yolanda Moratilla for their continuous support, guidance, motivation and wise advice during these three years, as well as for finding time in their busy schedules to help me. Special thanks to Yolanda Moratilla and José Ignacio Linares for the opportunity to teach at the Comillas Pontifical University, for their help during my time as a lecturer, for encouraging me to become a student again in order to write this thesis and, most importantly, for their friendship since more than nine years ago.

I also want to thank my professor and Master's Thesis advisor at MIT, Professor Henry Birdseye Weil, for his help, guidance, amazing advice on energy markets, and for introducing me to the fascinating world of Systems Thinking, which is at the core of this research. Thanks as well to Stephen Sacca, ex-director of the MIT Sloan Fellows Program, for believing in me and giving me the opportunity to go through the life-changing Sloan Fellows experience at MIT, which opened to me a whole new world full of amazing and exciting opportunities.

I am also very thankful to Andres Feijoo, my Master's Thesis advisor at the University of Vigo, who introduced me to the world of power systems and with whom I have kept a long lasting friendship. His advice and knowledge on power systems, shared during our multiple discussions, has been very valuable for this research as well.

I am indebted to the institution that has funded my graduate studies. Thanks to the "Barrie de la Maza" Foundation for believing in me and allowing to conduct my M.Sc. studies overseas, where the seed of this research was first planted. I hope my work can contribute to their amazing mission so that I can return to some extent the trust and resources they put on me.

Thanks to my colleagues both in the academic and corporate worlds for their help in many different forms, advice and general guidance regarding how to make the present research useful from both the academic and the more practical corporate perspectives. Special thanks to Tanya Bodell for her support, guidance, mentorship and advice during my time with her at Energyzt, which sparked my curiosity and allowed me to dramatically increase my knowledge on energy markets.

Thanks to all my amazing friends, both the new ones in the US and the old ones back in Spain, for their unconditional support and friendship. I feel extremely gifted for being able to count on them.

Last but definitely not least, I would like to thank my family: my parents and Tai for their unconditional and unwavering support and love. They mean the world to me and I would have never made it without them. Thanks to my parents for their motivation and honest critics to my work which, as outstanding professors, have provided me with on a continuous basis. Thanks to Tai for her understanding, endless

patience, and for the time which, while more than deserved, I did not spend with her while working on this research. I am extremely indebted for this and promise to make it up to her right away.

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List of Acronyms

ABM:	Agent based modeling
AES:	Alternative energy source
ARIMA:	Autoregressive integrated moving average
CAPEX:	Capital expenses
CC:	Combined cycle
CGE:	Computational general equilibrium
COD:	Commercial operation date
CPI:	Consumer price index
CSP:	Concentrated solar power
DCF:	Discounted cash flow
Dmnl:	Dimensionless
EOH:	Equivalent operating hours
EU:	European Union
EUR:	Euro
FIT:	Feed-in tariff
GDP:	Gross domestic product
GHG:	Greenhouse gas
IRR:	Internal rate of return
ITC:	Investment tax credit
MOPP:	Merit order power pricing
NEP:	National Energy Plan
NFFO:	Non-fossil fuel obligation
NPP:	Nuclear power plant
NPV:	Net present value
O&M:	Operation and maintenance
OM:	Ministry order
OPEX:	Operation expenses
PI:	Profitability index
PIRR:	Perceived rate of return
PPA:	Power purchase agreement

PTC:	Production tax credit
PV:	Photovoltaic
RAET:	Reference average electric tariff
RD:	Royal decree
RDL:	Royal decree-law
REC:	Renewable energy certificate
REP:	Renewable energy plan
ROI:	Return on investment
RPP:	Reference power plant
SD:	System dynamics
SRPG:	Special regime for power generation
SRR:	Specific remuneration regime
TD:	Tariff deficit
TFC:	Total energy final consumption
TPES:	Total primary energy supply
TSO:	Transmission system operator
T&D:	Transmission and distribution
VOLL:	Value of lost load
WPM:	Wholesale power market

Chapter 1
Introduction

1.1 The problem

Long term power generation system planning is a complex task: it impacts multiple variables in different areas such as economics, environment and technology; it shows great capital intensity as well as investment irreversibility; it requires advanced planning because of the long lead times required for permitting, developing and building power generation assets, and it involves externalities such as environmental impacts which are challenging to assess and often neglected.

In addition, the ongoing worldwide power industry liberalization trend is contributing to the growing complexity of the planning process. While under previous regulated centralized models regulators had the power to set the power mix composition in order to meet specific goals (e.g. renewable penetration, CO_2 emissions, energy dependence, etc.), the current shift to liberalized models is transferring investment decisions from regulators to investors. Therefore, instead of planning and executing, now regulators face the challenge of setting the right incentives for investors in order to drive the power generation mix in the desired direction. This a challenging task as regulators must be able to predict how investors will react to energy policies and changing market conditions so that behavioral considerations must be introduced in the forecasting models.

From the economic perspective, the power system impacts variables such as:

i. System costs: They include the costs related to power production, T&D, CO_2 emission allowances, technology-specific incentives and capacity payments.

ii. Trade balance: For example, fossil fuel technologies have a negative impact on trade balance due to fossil fuel imports.

iii. Industrial production: For example, those technologies locally manufactured (e.g. wind power in the case of Spain) have a positive impact on industrial production while imported technologies do not. Also, those technologies which entail high power prices have a negative impact on the economics of power intensive industries[1].

iv. Employment: In a similar way, those technologies which are locally manufactured will have a more positive impact on employment and job creation than technologies which involve capital equipment imports.

v. Government's deficit: For example, subsidized technologies will have a negative impact on Government's accounts.

The abovementioned variables ultimately impact GDP through its three different components: direct, indirect and induced.

The power generation mix has also a very significant impact on environment as it is an important source of air emissions[2] (e.g. CO_2, NO_X and SO_X) as well as of solid and liquid waste. Environmental impact assessment is challenging as emissions show the public goods properties (Dahl, 2004) and their economic impact is very difficult to assess. Some works have been aimed at quantifying their economic impact, finding values in a range as wide as \$10 - \$95 / t CO_2 depending on the number of years and discount rates considered (Interagency Working Group on Social Cost of Carbon, 2015). Although in many cases these externalities are not taken into account when assessing power system costs, attempts to partially value and monetize these externalities have been done for example through the introduction of CO_2 emission allowance markets (ICE Futures Europe, 2015).

Technology is an interesting variable as it both impacts and is impacted by the evolution of the power generation mix. Mature and cost-competitive technologies will entail greater economic returns for investors

---

[1] E.g. aluminum production.

[2] It is for example one of the largest sources of CO_2 emissions worldwide.

and will therefore be deployed faster. This fact will lead to their further maturing, increasing competitiveness and further faster deployment through a reinforcing feedback loop due to technology learning curves.

Many power policies worldwide have been enacted with specific economic goals such as the reduction of power price, control of unemployment[3], development or discontinuation of specific technologies[4], control of emissions or compliance with supranational regulations (such as in the case of the EU directives). Nevertheless, while these policies may meet the partial goals they were designed for, it is not clear that they will have a net country-wide positive impact due to the complexity, system interlinks and feedback loops inherent to power systems.

The power industry is subject to very long planning, development and construction lead times, required to put new power generation assets in commercial operation. Power generation assets have long lifetimes which may spread over several decades. Therefore, decisions made today may not have an effect before several years and their impact may last for many decades. Because of these facts, power systems show a large inertia and dynamic considerations become very important. While policymakers have often based their decisions on short term assessments limited to the term they are in office, power policies must be assessed by taking into account their cumulative long term impact on the power system, due to the abovementioned large inertia effect.

Finally, liberalized markets show a higher degree of uncertainty than regulated ones[5] so that the use of stochastic models able to simulate the random behavior inherent to specific variables (e.g. commodity prices, power demand, etc.) acquires special relevance.

The fact of the power industry having an impact on so many different fields as well as the way all these fields are deeply intertwined among them, makes its assessment fall within the Systems Thinking discipline, which is precisely focused on analyzing large complex systems.

The goal of the present research is to provide a methodological framework aimed the optimization of the power generation mix in a holistic way, taking into account the abovementioned considerations (i.e. assessment of the overall economic impact, long term cumulative assessment and inclusion of dynamic, behavioral and stochastic considerations). The methodological framework presented here is a combination of several modelling techniques:

i. Input – Output models are used to assess the overall impact of the power generation mix on the country's GDP through its direct and indirect components.

[3] E.g. Spain incentivized the use of indigenous coal in order to benefit the local mining industry (Kreiser, et al., 2012).

[4] E.g. the promotion of renewables or the cancellation of nuclear projects in Spain (Organisation for Economic Co-operation and Development, 2001).

[5] E.g. power price is not fixed by the regulator anymore.

ii. SD models are used in order to simulate the evolution of the power generation fleet across time. This methodology is very useful in order to model the dynamic considerations inherent to the power system (e.g. delays and feedback loops) as well as to model soft variables (e.g. public opinion) as well as behavioral considerations.

iii. Supply – demand market equilibrium models are used in order to simulate the operation of the country's WPM and compute final WPM prices.

iv. Monte Carlo simulations are used in order to account for the uncertainty inherent to variables such as fossil fuel and power demand, which are modeled as Random Walks[6].

Therefore, the present research provides a methodological framework which enables the assessment and definition of optimum energy policies by taking into account all relevant system variables, feedback loops and long term considerations so that the overall economic well-being of the country can be maximized.

1.2 Motivating case: Spain's Power Sector

The present research focuses on the specific case of Spain's electric power sector, which shows some unique characteristics such as high energy dependency, limited electric interconnection capacity and large AES penetration, which are described in detail in Chapter 2 below.

Spain's power industry has gone through turbulent times during last years, being two of the most controversial topics the TD and the retroactive AES incentive cuts which took place between 2009 and 2013 (Head of State, 2009; Ministry of Industry, Tourism and Commerce, 2010b; Head of State, 2010; Head of State, 2012; Head of State, 2013a).

The TD was caused by a structural unbalance between the revenues and the expenses of the power industry's regulated activities (i.e. T&D), which entailed a growing cumulative debt. This unbalance was mainly due to the fact that distribution companies had to purchase power at the WPM, which very often showed increasing prices, and sell it to end users based on regulated retail tariffs, which were often capped by the regulator mostly due to political reasons.

AES incentives contributed as well to the TD as retail tariffs had to pay also for said incentives, which were ultimately being paid to AES generators by the distribution companies (Ministry of Economy, 2001a). Therefore, the TD problem was greatly worsened by the solar PV investment boom cycle which led to 3,207 MW of solar PV installed capacity in 2008 (Red Electrica de España, 2013), largely overshooting the 400 MW target set for 2010 (Instituto para la Diversificación y Ahorro de la Energía, 2005) as well as the 371 MW capacity cap set by RD 661/2007 (Ministry of Industry, Tourism and Commerce, 2007c).

[6] Random walk processes are a particular case of ARIMA (p, d, q) processes where p = 0, d = 1 and q = 0.

This solar PV investment boom cycle was mainly due to poorly designed incentives, which provided investors with unreasonably high economic returns on their solar PV investments.

Because of this long lasting and growing financial unbalance, the Government of Spain started enacting new regulations in 2008 aimed at reducing system costs by limiting AES capacity additions and reducing the incentives to be received by existing AES plants. This last measure was extremely controversial as it introduced for the first time the concept of retroactivity, which meant a total break with the previous stable remuneration framework.

These measures ultimately led to a brand new AES incentive regulatory framework introduced by RD 413/2014 (Ministry of Industry, Energy and Tourism, 2014b) and based on the concept of “reasonable return on investment” as well as on a competitive process for incentive allocation, which totally broke with the previous FIT / premium based support scheme.

This new regulatory framework was fully retroactive as it was applicable to both existing and projected power plants. So, following RD 413/2014, Ministry Order (OM) IET/1045/2014 (Ministry of Industry, Energy and Tourism, 2014a) set the equivalences between the legacy regulatory technology groups and the RPPs to be allocated to existing AES plants.

The retroactive character of this new regulation was very controversial as it dramatically changed the expected ROIs of the plants already in operation. Because of this fact, having an exposure of about 13 billion EUR to renewable energy assets as of 2016, international investment funds started a series of legal actions against the Government of Spain. This fact made Spain rank first in terms of number of AES claims faced under the Energy Charter Treaty (de la Hoz, et al., 2016). Similar problems, involving overinvestments in PV power and retroactive incentive cuts have also occurred in countries such as Italy, the Czech Republic, Bulgaria and Greece (de la Hoz, et al., 2016).

The present research presents a methodological framework aimed at assessing and designing optimum energy policies in order to meet specific goals in terms of variables such as reserve margin, system costs or environmental impact while avoiding the abovementioned problems. This is done by accurately forecasting the long run evolution of the power generation mix and costs based on levers such as incentive policies and exogenous variables such as market conditions. This way, regulators can assess the long run impact and set the right incentive policies in order to meet their capacity goals and minimize over or underinvestment risks.

1.3 Dissertation original contributions

SD has been widely used in order to assess and simulate power systems. Compilations of the most relevant references can be found in (Ford, 1997), (Bunn, et al., 1997) and (Teufel, et al., 2013). A detailed review of the most recent literature on the application of SD to power systems is included in section 4.4. Also, Input-Output modeling has been widely used in order to assess the power system’s impact on a country’s economy. A detailed review of the most recent literature on the application of Input – Output modeling to energy markets is included in section 4.10.

The present research builds on top of existing literature by introducing the following novel aspects:

i. The combination of the SD methodology with a full MOPP model and an Input – Output economic model, which allow to assess the overall impact of the power industry on system costs and the country's economic output.

ii. The combination with stochastic methods (Monte Carlo and random walk simulations) in order to introduce the uncertainty inherent to variables such as commodity prices or power demand.

iii. The assessment of the overall impact on technical (e.g. reserve margin and reliability), economic (e.g. system costs and economic output) and environmental (e.g. CO_2 emissions) variables.

iv. The application of the models developed to Spain's power system.

In addition, some additional improvements over the existing literature include: the consideration of the full generation technology range (while some previous works consider just a few technologies or groups of technologies (Olsina, et al., 2006; Arango, 2007; Hasani & Hosseini, 2011; Bunn & Larsen, 1992; Assili, et al., 2008)), the consideration of power demand long run price elasticity, the calculation of power plant decommissioning rates as a function of actual economic return, and the inclusion of soft variables (e.g. market perceptions and regulatory barriers). Finally, while similar studies have focused mostly on the impact of capacity payments on the power generation mix composition (Hasani & Hosseini, 2011) this work focuses on the impact of both AES incentives and capacity payments on capacity additions, system costs and environment.

1.4 Dissertation structure

The present dissertation is structured as follows:

Chapter 2 "Overview of Spain's power system" provides a background and context for this work. It presents an overview of Spain's electric power sector including the main characteristics from both the technical and economic perspectives, a description of the historical evolution of the sector including the transition from a regulated to a fully liberalized market and a description of the main AES incentive policies enacted by the Government of Spain. Finally, a short description of the most popular AES incentive policies worldwide is included in order to compare them with the ones implemented in Spain.

Chapter 3 "Problem definition" provides a detailed description of the problem tackled by the present research by deep diving into the different power system planning methodologies (regulated vs. liberalized), the main challenges entailed by the power system planning process and the goals of the present research.

Chapter 4 "Modeling approach and literature review" includes a review of power system and economic impact modeling techniques as well as a review of the relevant literature. The reasons behind the selection of specific modeling techniques are described and the chosen techniques are described in further detail both from the theoretical and practical perspectives, by including simplified examples. Finally, modeling software package options are discussed.

Chapter 5 “Model overview” provides a high-level overview of the models developed for the present research. The models’ causal diagrams are presented and the feedback loops, reference modes and expected system behavior are described, therefore providing a high level description of the dynamics of each subsystem considered.

Chapter 6 “Model structure” provides a detailed description of the models used in the present research. This includes the detailed description of all stock & flow diagrams, the market equilibrium model used in the MOPP, the Input-Output model and the random walk methodology. The models’ equations are presented and explained in detail. Finally, the models’ limitations and potential future enhancements and expansions are discussed.

Chapter 7 “Model validation and calibration” describes the main data sources, discusses the different techniques and approaches for SD model calibration and presents the calibration results. The chosen calibration approach is justified and described in detailed. The calibration results in terms of fit with historical data are assessed through statistical techniques and thoroughly discussed.

Chapter 8 “Case study 1: Capacity payments vs. renewable incentives” applies the methodological framework developed in the present research to the assessment of the long run impact of incentive and capacity payment policies as tools aimed at keeping sufficient system reserve margins, therefore guaranteeing system reliability. The long run impact of both policies from the technical, environmental and economical perspective is assessed and the pros and cons of each policy are discussed.

Chapter 9 “Case study 2: Assessment of Spain’s new auction-based AES incentive” applies the methodological framework developed in the present research to the long-run assessment of the impact of Spain’s new competitive auction-based wind incentive system on wind capacity additions through dynamic stochastic simulations. Different incentive policies along their long-run cumulative overall cost are assessed and their pros and cons are discussed. Also, the optimum incentive levels in terms of overall economic benefit are computed and discussed.

Chapter 10 “Original contributions and future research” summarizes the key insights, implications and contributions of the present research and discusses its limitations and potential enhancements, expansions and future lines of research.

0 “Appendices” includes data on historical commodity prices, macroeconomic indicators, power supply and demand, power mix composition and power plant performance, capital, and O&M costs which has been used for the development and calibration of the models used in the present research.

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Chapter 2
Overview of Spain’s power system

2.1 Introduction

Spain’s power system has some unique characteristics which make power generation planning significantly challenging. The most relevant characteristics are described in the present chapter.

2.2 Main characteristics

2.2.1 Energy dependency

Figure 2-1 shows the total primary energy dependency of the EU-28 countries as well as the averages for the EU-28 and EU-19 country groups. With a 72.9% total primary energy dependency in 2016, Spain is one of the largest primary energy importers in Europe being its energy dependency well above the EU-28 and EU-19 average values.

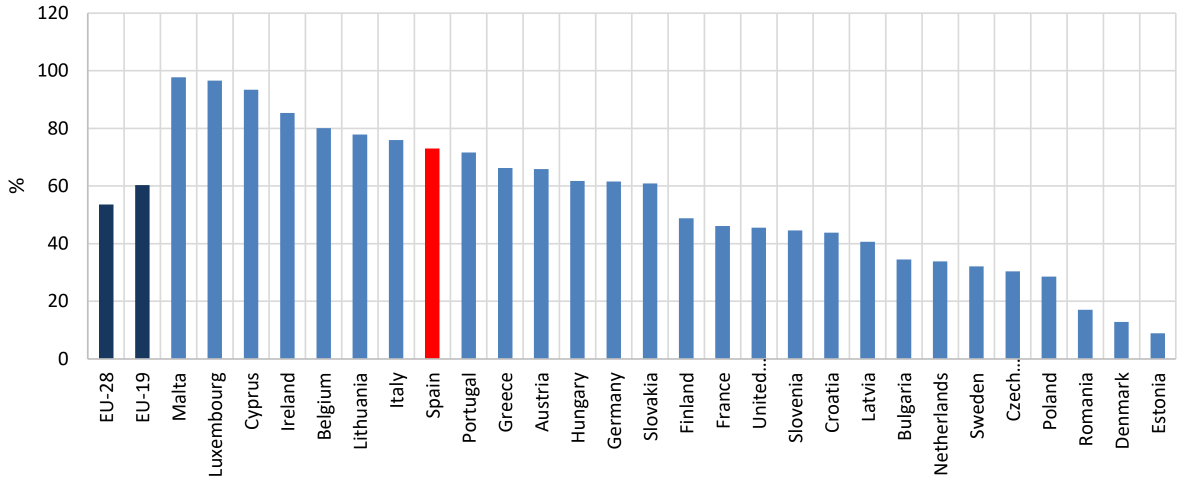

Figure 2-1: Primary energy dependency by country in Europe in 2016[7]

Figure 2-2 shows the historical evolution of the primary energy dependency in Spain. Primary energy dependency shows a growing trend since 1990 due to the increasing GDP and the resulting growth in power and transportation fuel demand (see section 2.3). In the case of power, the only renewable resources available in the early 90s (i.e. hydro) were quite exhausted[8] and nuclear deployment was put on hold by the so-called "nuclear moratorium" so that most new capacity additions were fossil fuel-based.

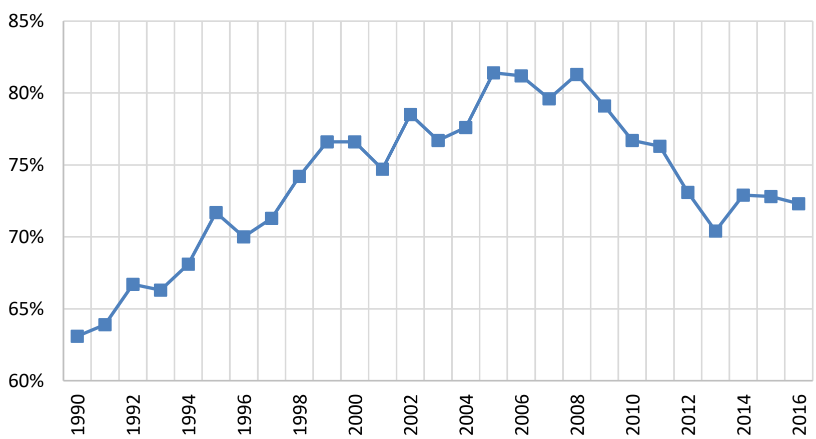

Figure 2-2**:** Spain's historical primary energy dependency[9]

[7] (Eurostat, 2016)

[8] There were very limited available river sites for new hydro power plants

[9] (Eurostat, 2016; Club Español de la Energia, 2017)

This trend started to revert in the mid-2000s due to the inception and fast growth of AES technologies, mostly wind and solar PV, which led to a high renewable energy penetration by the end of the decade as described in section 2.3 below. Despite this fact, the country still showed a primary energy dependence of 72.9% in 2016 which still makes Spain one of the largest primary energy importers in Europe.

High energy dependence levels have relevant geopolitical implications. Most fossil fuel reservoirs lie within politically unstable regions, which entails a significant supply disruption risk. Importing countries must make sure to count on a diversified portfolio of energy supplying countries so that supply disruption risk is minimized and no political power can be exercised on the grounds of energy supply. This fact makes energy policy-making more challenging in those countries with a high primary energy dependence.

2.2.2 Spain, a power Island

Electricity storage requires expensive infrastructures and heavy investments. Even though distributed power storage capacity is currently being fostered and growing in some countries, its contribution to power system stability is still marginal. Therefore, most power demand fluctuations must be covered either by local production or real-time imports / exports. Limited international interconnection capacity adds technical complexity as it limits a country's capacity to cover demand fluctuations, which may ultimately lead to power shortages and even blackouts.

The Interconnection Ratio of a specific country is defined as the ratio between the interconnection capacity with its neighboring countries and the total installed capacity within the country. Figure 2-3 and Table 2-1 show the interconnection ratios for the EU Member States. The European Commission has set a 10% interconnection ratio goal for all its Member States for 2020 (European Commission, 2015a) as well as an indicative target of 15% for 2030 (ENTSOE, 2015). This policy aims at facilitating internal power trade and at enabling the Iberian Peninsula to fully participate in the internal electricity market. It has been estimated that around 40 billion EUR will be needed during the present decade in order to meet the 10% interconnection goal (European Commission, 2016).

Nevertheless, as of 2014 Spain just showed a 3% interconnection ratio, well below the required target, being this fact mostly due to Spain's geographical location, mostly surrounded by sea and sharing borders just with France, Portugal and Andorra. Figure 2-4 shows the commercial power exchange capacities as of 2016, once the new 2,400 MW interconnection with France has been put in service.

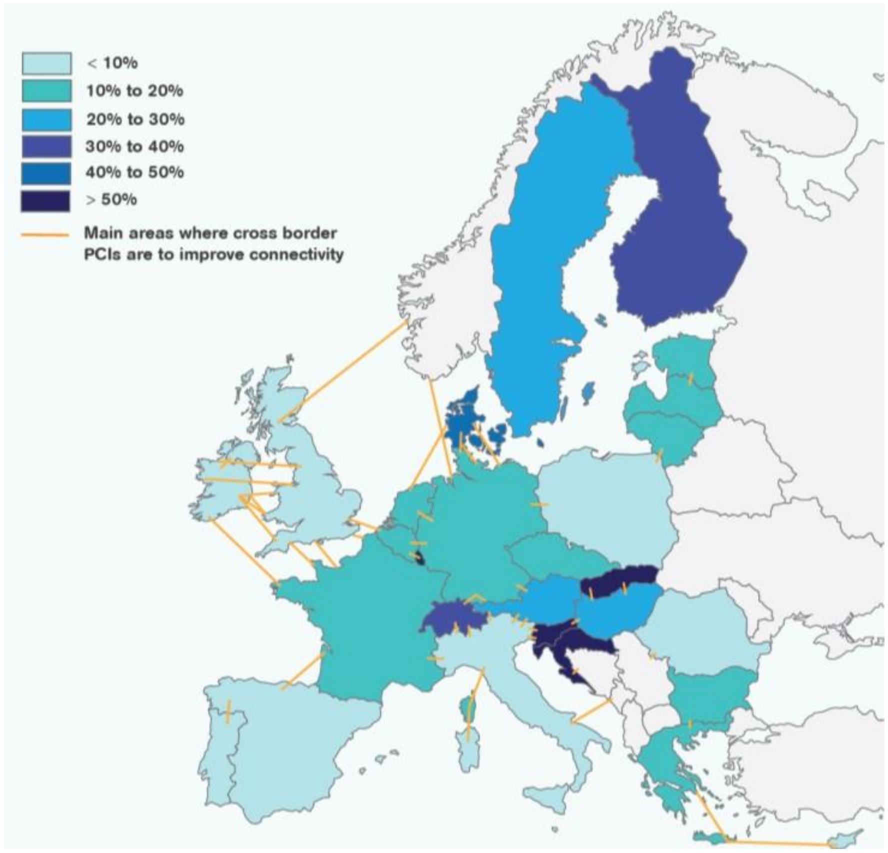

Figure 2-3: Electrical interconnection levels in EU countries as of 2014[10]

It is because of the facts above that Spain is regarded as a “Power Island”. This low electrical interconnection level entails potential issues such as:

- Lower reliability and greater blackout risk: due to the fact that international interconnections act as an immediate real-time back up system in case of power plant outages.
- Necessity for additional back-up capacity: Because of the same reasons mentioned above.
- Complicated variable renewable power generation management: The intermittency of local renewable energy sources may be offset by international power exchanges. The lack of enough capacity makes the management of these variable, non-dispatchable technologies more challenging

[10] (Monforti, et al., 2016; Eurelectric, 2015)

- Higher power price: The lack of interconnection capacity entails system bottlenecks which complicate power trading so that the optimum, cheapest generation resources may not be readily available making power generation more expensive.

Country	***Interconnection ratio***	***Country***	***Interconnection ratio***
Luxembourg	245%	Germany	10%
Croatia	69%	France	10%
Slovenia	65%	Ireland	9%
Slovakia	61%	Italy	7%
Denmark	44%	Romania	7%
Finland	30%	Portugal	7%
Austria	29%	UK	6%
Hungary	29%	Estonia	4%
Sweden	26%	Lithuania	4%
Belgium	17%	Latvia	4%
Czech Republic	17%	Spain	3%
Netherlands	17%	Poland	2%
Belarus	11%	Cyprus	0%
Greece	11%	Malta	0%

Table 2-1: Electrical interconnection levels in EU countries as of 2014[11]

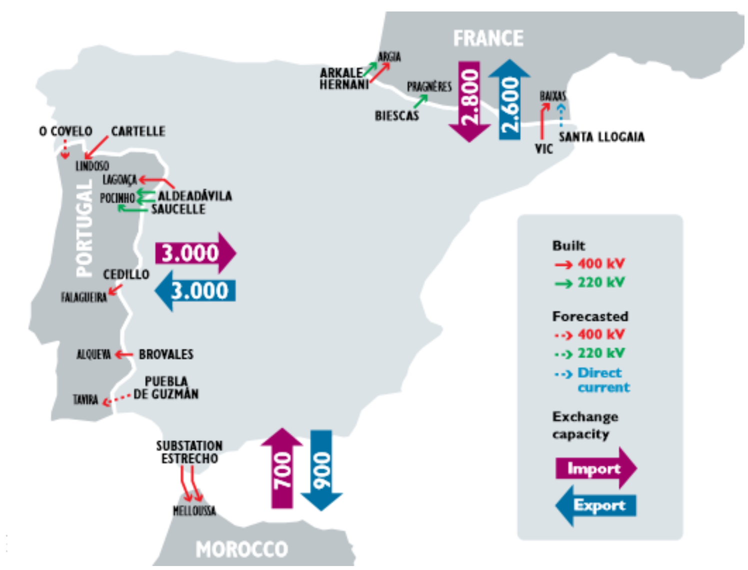

Figure 2-4: Spain's commercial interconnection capacities as of 2016[12]

[11] (European Commission, 2015b)

[12] (Red Electrica de España, 2012b)

Therefore, systems with limited interconnection capacity require careful system planning as issues such as intermittent generation or plant outages entail greater risks than in systems with large interconnection capacities. This means that countries with limited interconnection capacity in general must plan greater reserve margins so that additional capital investments are required.

2.2.3 Variable AES penetration

With 22,864 MW of installed wind capacity in 2016 (Red Electrica de España, 2017), Spain is one of the countries with the largest wind penetration worldwide (22.8% in terms of installed capacity and 19.9% in terms of power generation as of 2016). Table 2-2 shows the installed capacity by technology in Spain as of 2016. Table 2-3 shows the power generation by technology in 2015 and 2016.

	MW	***%***
Hydro - Large	18,020	18.0%
Nuclear	7,573	7.6%
Coal	9,536	9.5%
Gas peak	0	0.0%
Gas CC	24,948	24.9%
Wind	22,864	22.8%
Solar PV	4,425	4.4%
Small Hydro	2,333	2.3%
CSP	2,300	2.3%
Cogeneration	6,670	6.7%
Biomass	1,420	1.4%
Total Renewables	**51,362**	**51.3%**
TOTAL	**100,089**	**100.0%**

Table 2-2: Spain's Installed capacity by technology as of 2016[13]

Renewable power generation hit a remarkable 43.7% share in 2016, increasing from 38.2% in 2015 mostly at the expense of coal, which declined from 21.4% in 2015 to 14.2% in 2016. Wind power has been successively breaking records in terms of power generation for example reaching a value of 352.087 MWh/day (46.9% of total demand) on March 25th, 2014 (Revista eólica y del vehículo eléctrico, 2015)

Due to the intermittent nature of most renewable technologies, high renewable energy penetration levels introduce complexity in power system operation and planning. In the specific case of Spain, this adds to the country's limited interconnection capacity, making power system planning and operation even more challenging.

[13] (Red Electrica de España, 2017)

	2015		2016	
	GWh	**%**	**GWh**	**%**
Hydro - Large	25,733	10.1%	33,049	13.5%
Nuclear	56,796	22.3%	55,546	22.7%
Coal	54,553	21.4%	34,740	14.2%
Gas peak	0	0.0%	0	0.0%
Gas CC	26,086	10.3%	26,186	10.7%
Wind	47,948	18.8%	48,507	19.9%
Solar PV	7,861	3.1%	7,570	3.1%
Small Hydro	5,659	2.2%	6,000	2.5%
Solar CSP	5,158	2.0%	5,102	2.1%
Cogeneration	26,845	10.5%	25,843	10.6%
Biomass	4,921	1.9%	6,489	2.7%
Generation consumption	-7,087	-2.8%	-4,846	-2.0%
Total Renewables	**97,280**	**38.2%**	**106,717**	**43.7%**
TOTAL	**254,473**	**100.0%**	**244,186**	**100.0%**

Table 2-3: Spain's power generation by technology in 2015 and 2016[14]

2.2.4 Incentives, PV overinvestment and the Tariff Deficit

The large renewable energy penetration described above has been achieved through an aggressive incentive policy initiated with the adoption of Law 54/1997 of the Electric Power System (Head of State, 1997) and the approval of RD 2818/98 (Ministry of Industry and Energy, 1998b) aimed at fostering AES technologies by the implementation of a support scheme based on both FITs and premium payments.

Subsequent regulations introduced changes aimed at refining RD 2818/98 in order to tackle with issues such as overpayments to renewable technologies because of too high WPM prices, or underpayments to CHP units because of increasing fuel prices. Nevertheless, all these changes stuck to the initial FIT / price premium scheme which guaranteed a reasonable degree of stability for investors.

In general terms, this system was successful as it allowed the country to comply with the renewable energy requirements set by EU Directives (The European Parliament and the Council of the European Union, 2001; The European Parliament and the Council of the European Union, 2009) and to become one of the top countries worldwide in terms of wind installed capacity and penetration, as described in the previous section. As an example, wind power became the second most important electricity source after nuclear in 2013 (Red Electrica de España, 2013).

Nevertheless, the system was not exempt of problems such as the overinvestment in solar PV technology (de la Hoz, et al., 2010) that took place in 2008 due to erratic and excessively high incentives which made PV power largely overshoot the 400 MW target set for 2010 (Instituto para la Diversificación y Ahorro de la

[14] (Red Electrica de España, 2017)

Energía, 2005) by reaching an installed capacity of 3,207 MW in 2008 (Red Electrica de España, 2013). Figure 2-5 shows the historical wind and solar PV installed capacities in Spain.

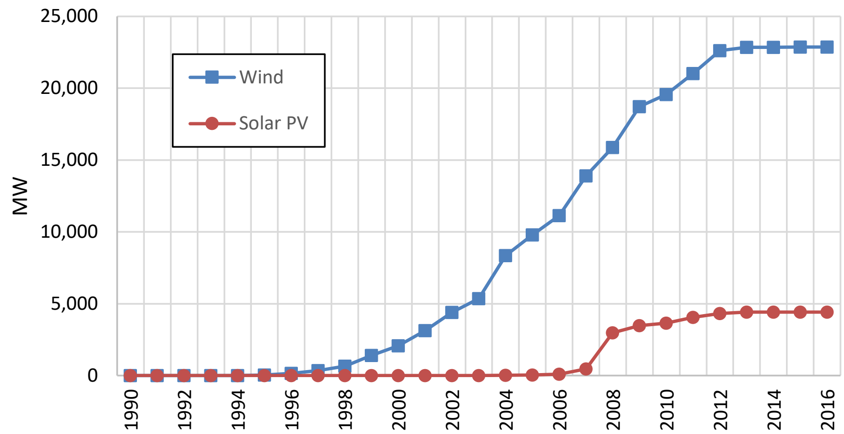

Figure 2-5: Spain's historical wind and PV installed capacity[15]

These problems contributed to the controversial TD, which had been for many years a recurrent problem in Spain's power system and that basically consisted of a structural unbalance between the revenues and the expenses of the regulated industry activities (i.e. T&D), which was the cause of a growing cumulative debt. This unbalance was mainly caused by the fact that distribution companies had to purchase power at the WPM at free market prices and sell it to end users based on regulated tariffs which were limited by the regulator mostly because of political reasons.

Also, regulated retail tariffs were not only paying for generation, T&D costs but also for additional system costs such as system operation, the regulator, the nuclear moratorium and, most importantly, the AES incentives that were being paid by the distribution companies to the AES generators (Ministry of Economy, 2001a).

So, the TD problem was further worsened by increasing AES incentive expenses due to booming capacity additions which, added to quasi-constant retail tariffs, entailed declining profits for the regulated industry activities.

Because of this long lasting and increasing unbalance, the Government of Spain started to approve new regulations in 2008 aimed at reducing system costs by limiting new AES capacity additions and the incentive levels to be received by new AES plants, setting annual goals for TD, restructuring system costs and, most importantly, by reducing the incentives to be received by existing AES plants. This last measure turned out to be extremely controversial as it introduced for the first time the concept of retroactivity in Spain's AES

[15] (Asociacion Empresarial Eolica, 2017; Red Electrica de España, 2017)

support scheme, which meant a total break with the previous stable remuneration framework. Figure 2-6 shows the evolution of the wind power incentives in Spain.

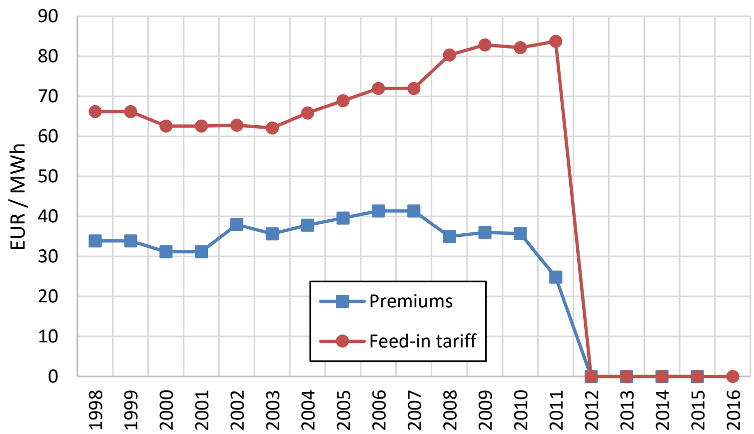

Figure 2-6: Evolution of the wind FIT and price premium in Spain[16]

Ultimately, all these measures led to a brand new AES regulatory framework based on the concept of "investor reasonable profitability" as well as on a competitive process for incentives allocation, which totally broke with the previous FIT / premium based support scheme.

The facts above illustrate the challenges that AES incentives entail for regulators in the sense that they must carefully assess the right level of incentives to be set as well as set the right control mechanisms to avoid under or overinvestment in specific technologies, which may result in financial unbalances as it was the case in Spain's PV power industry.

2.2.5 Public opinion and political issues

Public opinion and political issues have historically played a major role in energy planning in Spain both before and after the liberalization of the power industry. This fact has been clearly evident in the case of the nuclear industry, where investment decisions have been influenced by public opinion and political issues.

Figure 2-17 shows Spain's historical nuclear capacity additions. As it can be observed, the construction of the NPPs currently in operation[17] took place between 1971 and 1988, with a total capacity added of 7.8 GW. Three other NPP projects (Lemoniz I and II, Valdecaballeros I and II and Trillo II) were canceled by the Government of Spain in 1984 when the so-called "nuclear moratorium" was enacted (Organisation for

[16] Prepared by the author based on the analysis of historical incentive systems and premium / FIT values.

[17] With the exception of the Zorita nuclear plant (466 MW) which has been already decommissioned.

Economic Co-operation and Development, 2001). This Nuclear Moratorium actually put on hold the construction of new NPPs and was due both to the fact that power demand was not growing as fast as initially forecasted and to public opposition to nuclear power (Costa Campi, 2016).

Significant investments had already been done by power utilities at the time the projects were canceled so that the Government was forced to compensate the sponsoring utilities through a premium introduced in retail power tariffs which is still being charged to consumers nowadays.

This case illustrates the significant impact that public opinion and politics has had on Spain's power system design and shows that public opinion, although being a "soft" variable, it is a very relevant aspect that regulators must consider when assessing the potential impact of energy policies on the future evolution of the power mix. Also, this case illustrates again how suboptimum or erratic energy policy designs may lead to greater system costs which ultimately lead to greater retail power prices to end users, so reducing the overall well-being of the country.

2.2.6 Hydro capacity

In addition to being a renewable energy source, hydro power has the important advantage of being dispatchable[18], on the contrary to most wind or solar technologies. Therefore, hydro capacity additions contribute to declining CO_2 emissions while not introducing complexity in terms of system planning and operation.

Nevertheless, Spain shows very limited room for additional hydro capacity. Figure 2-16 shows Spain's historical hydro capacity additions since 1900. Earlier power plants show small capacities, with most of the plants larger than 50 MW having been built after 1940. The largest capacity additions took place between the 60s and the 90s and sharply declined after so that hydro capacity grew from 16.5 GW in 1998 to just 17.5 GW in 2011. This decline is mostly due to the fact that most of the river sites suitable for large hydro power plants have been already taken. In the case of smaller hydro plants, there are still sites available but many of them are located within environmentally protected areas such as national parks, fishing sites or in the upper course of the rivers (Martinez Montes, et al., 2005), which are either not suitable for the development of additional capacity or very challenging in terms of environmental permitting.

Figure 2-7 shows the hydro capacity additions forecasted in the 2000 – 2010 (Instituto para la Diversificación y Ahorro de la Energía, 1999) and 2010 – 2020 (Instituto para la Diversificación y Ahorro de la Energía, 2011) REPs as well as the actual historical development of hydro capacity.

As it can be observed, small hydro capacity has been steadily growing since 2000 although with a declining rate. Large hydro capacity has stayed practically constant except for some capacity additions in 2010. Not only actual growth rates are low but also the capacity additions forecasted in the REPs are very limited as

[18] In the case of impoundment facilities.

it can be observed in Figure 2-10. Moreover, the forecasted small hydro capacity was revised downwards in the 2010 – 2020 REP.

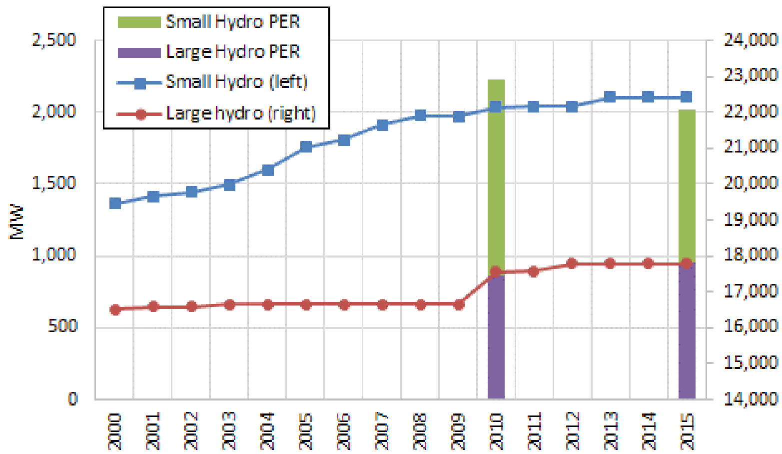

Figure 2-7: Spain's historical vs. planned (PER) hydro installed capacity[19]

Finally, some existing literature claims that hydro resources in Spain are expected to decline in the upcoming decades so that the expected hydro power generation will decline as well (Hamududu & Killingtveit, 2012). Figure 2-8 shows graphically the results of one of these studies.

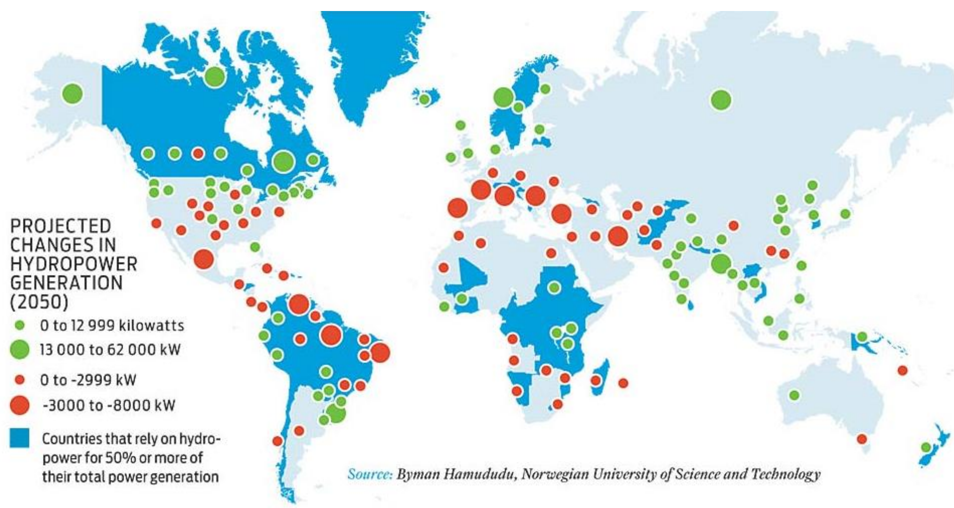

Figure 2-8: Forecasted changes in hydro power generation – 2050[20]

[19] (Instituto para la Diversificación y Ahorro de la Energía, 2005; Instituto para la Diversificación y Ahorro de la Energía, 2011; Red Electrica de España, 2017)

[20] (Hamududu & Killingtveit, 2012)

Because of these reasons, no relevant hydro capacity additions are expected in the future so that, in order to comply with the EU Renewable Energy Directives and, on the contrary to other northern European countries, Spain will not be able to rely on hydropower and will have to deploy AES technologies such as wind or solar.

2.2.7 The EU directives

As a Member State of the EU, Spain is subject to the regulations and directives enacted by the EU, which must be transposed into national legislation. The EU has passed several sets of laws focused on energy efficiency, renewable energy and environmental issues that have been transposed into national regulations. This EU directives have had a deep impact on policy making as governments were required to meet their requirements in order to avoid fines from the EU. Table 2-4 includes a list with the most relevant EU directives regarding renewable energy, energy efficiency and environment recently passed.

Directive	***Field***	***Main goals***
EU plan on climate change	Environment	20% reduction GHG emissions in EU by 2020 20% increase in energy efficiency in EU by 2020 20% renewables in GFC in EU by 2020
2009/28/EC	Renewable Energy	20% renewable in GFC in EU by 2020 10% renewable in transport GFC in EU by 2020 20% renewable in GFC in Spain
2012/27/EU	Energy efficiency	20% increase in energy efficiency by 2020
2030 climate & energy framework	Environment	40% reduction GHG emissions in EU by 2030 27% increase in energy efficiency in EU by 2030 27% renewables in GFC in EU by 2030

Table 2-4: Relevant EU directives on renewable energy, energy efficiency and environment

EU directives on climate, renewable energy and energy efficiency entail additional constraints for the governments of the EU Member States as they have to design energy policies which balance the national goals and interests with the restrictions and goals imposed by said directives.

2.3 Historical evolution

Spain's GDP has experienced a significant growth between 1998 and 2008, when the global financial crisis hit Spain's economy. Figure 2-9 shows the historical evolution of Spain's real GDP and peak power demand.

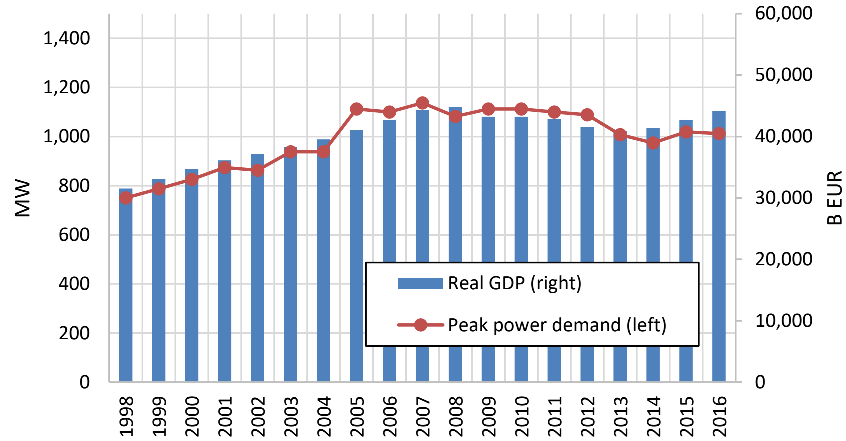

Figure 2-9: Spain's historical real GDP and peak power demand[21]

As it can be observed, peak power demand and real GDP are strongly correlated. So, there has been a significant increase in power demand between 1998 and 2008, when demand started to decline due to Spain's real GDP decline.

Figure 2-10 shows the historical evolution of total installed capacity vs. peak power demand. It can be observed that the absolute reserve margin[22] increases sharply after 2004 due to the following two factors:

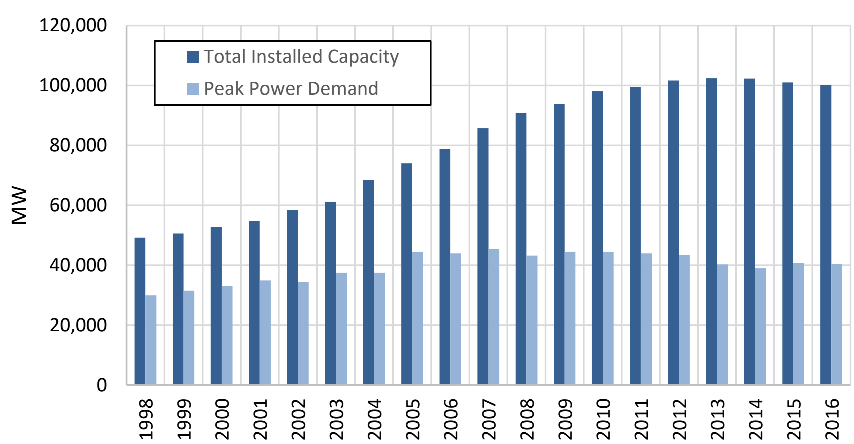

Figure 2-10: Spain's historical total installed capacity and peak power demand[23]

[21] (International Monetary Fund, 2017; Red Electrica de España, 2017)

[22] The absolute reserve margin is here considered as the absolute difference between the total installed capacity and the peak power demand. As it will be described in subsequent sections, installed capacity is modified (derated) in the case of specific technologies in order to take into account their capacity factors and intermittency

[23] (Red Electrica de España, 2017)

- Demand side – GDP correlation: The 2008 global economic crisis impact on Spain's economy, which drove the country's real GDP down. As peak power demand is strongly correlated with GDP, it declined as well, therefore contributing to an increasing reserve margin.
- Demand side – energy efficiency: The deployment of energy efficiency measures, fostered by EU directive 2012/27/EU and Spain's own regulations also contributed to declining power demand.
- Supply side: The massive deployment of gas CC plants and wind power[24] in the mid-2000s greatly contributed to the increasing reserve margin as well. Also, because of the inertia and sunk costs inherent to power plant deployment, some of the projects that already were at an early development stage were finalized regardless of the forecasted shrinking demand.

Figure 2-11 shows Spain's historical conventional power generation capacity since 1998. The most relevant changes during this period have been the decommissioning of the gas / fuel peak power plants and the massive deployment of gas CC power plants. The remaining technologies' (i.e. coal, nuclear and large hydro) installed capacity has stayed roughly constant.

Figure 2-12 shows Spain's historical AES installed capacity since 1998. As it can be observed, the most relevant change is the massive deployment of wind power, which in 2016 showed an installed capacity of 22,864 MW. Solar PV and solar CSP power have experienced a significant deployment as well while small hydro, cogeneration and biomass have experienced very moderate growths.

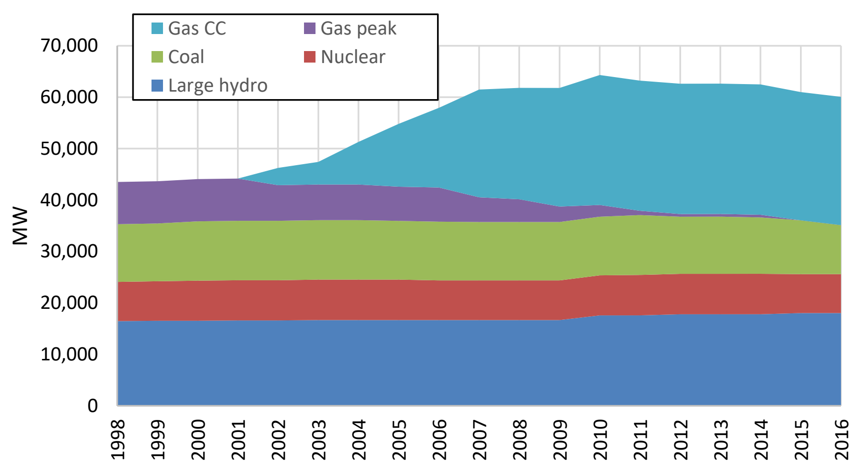

Figure 2-11: Spain's historical installed capacity – conventional technologies[25]

[24] Wind power contributed to a lesser extent due to its limited contribution to reserve margin computation.

[25] (Red Electrica de España, 2017)

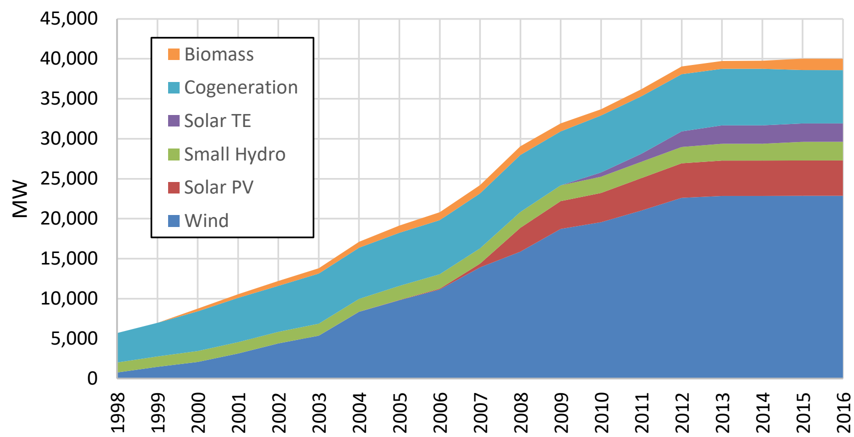

Figure 2-12: Spain's historical installed capacity – AES technologies[25]

Apart from the changes in the physical infrastructure, Spain's power industry has also experienced deep changes from the market structure point of view as the country has shifted from fully centralized and regulated model to a liberalized one. The liberalization process started in 1998 with the enacting of Law 54/1998 (Head of State, 1997) which established the rules for the implementation of a WPM and the progressive liberalization of the retail market. Generation was immediately liberalized while the retail side of the market was progressively deregulated so that initially, only the largest consumers were entitled to participate in the liberalized market, while the smaller ones were still subject to regulated retail tariffs. A detailed description of the liberalization process can be found in section 2.5.1.

Despite this liberalization process, AES generators were still regulated in the sense that they were allowed to sell their power either under regulated FITs or at the WPM where they were entitled to an additional regulated price premium (Ministry of Industry and Energy, 1998b). Figure 2-13 graphically shows the structure of the WPM right after deregulation.

Conventional power generators had two options for selling their production:

i. Through bilateral contracts (PPAs): Signed between power generators and final consumers and in general used only by very large final consumers.
ii. Through trading at the WPM: Most of the power produced in Spain is actually traded at the WPM.

AES technologies had an additional option (dotted red line in Figure 2-13) which consisted of directly selling their production to power distribution operators. In this case, the generators received a regulated FIT. AES generators which traded their production at the WPM were entitled to a regulated price premium on top of the WPM price.

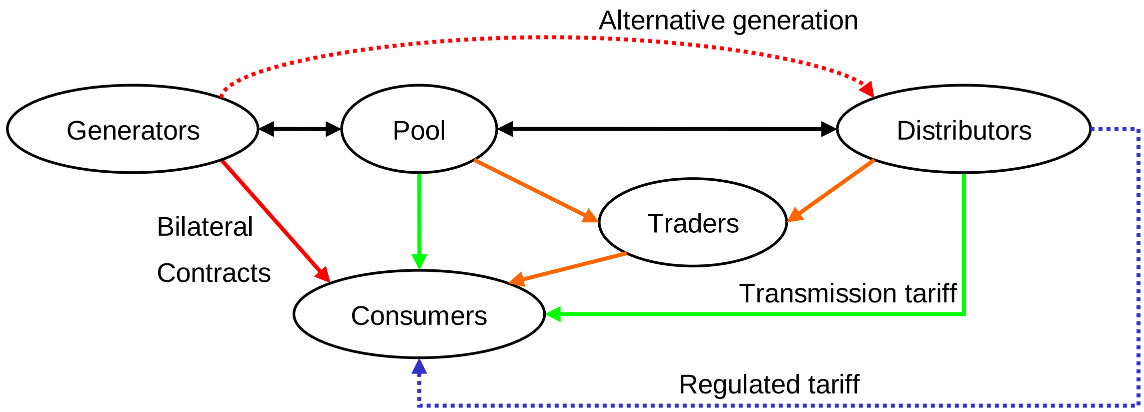

Figure 2-13: Structure of Spain's WPM after deregulation

Final consumers could purchase power in four different ways:

i. Through bilateral contracts (PPAs) directly signed with the generation units
ii. Outright acquisition at the WPM.
iii. Acquisition from power traders. This option was used by small consumers which did not have the resources to operate at the WPM.
iv. Acquisition from distribution operators based on regulated tariffs. This option was used by small retail consumers.

The WPM price is set on an hourly basis in the so-called "daily market". Participants have to submit their sell and buy energy bids one day in advance and for each hour of the following day. Subsequently, the system operator announces the plants actually dispatched as well as the value of the hourly marginal price. Figure 2-14 shows an example of the demand / supply curves and the marginal price calculation.

The final dispatching schedule is defined once the technical restrictions are solved (for example, it may happen that a generating unit cannot produce power because of an overload in the transmission system (bottleneck) even though the bidding price is low enough to be scheduled for production).

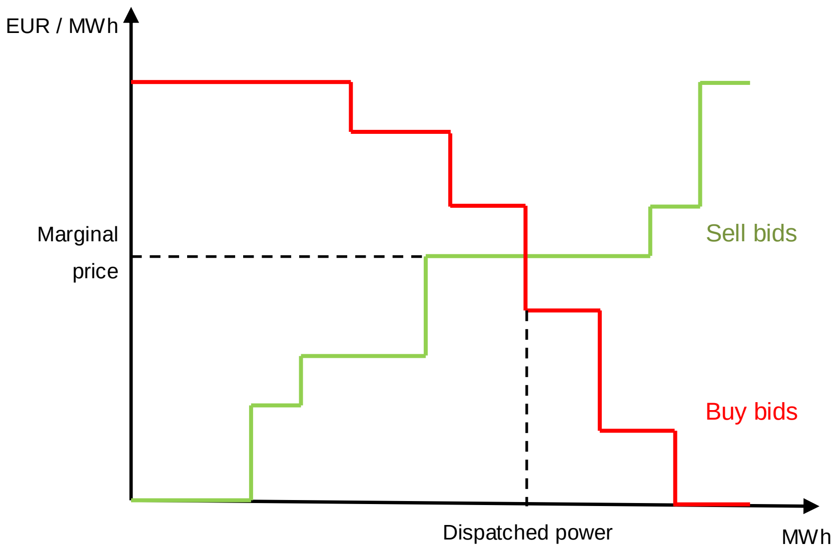

Figure 2-14: Hourly marginal power price calculation

The historical evolution of the WPM price since its inception in 1998 as well as of fossil fuel prices are shown in Figure 2-15.

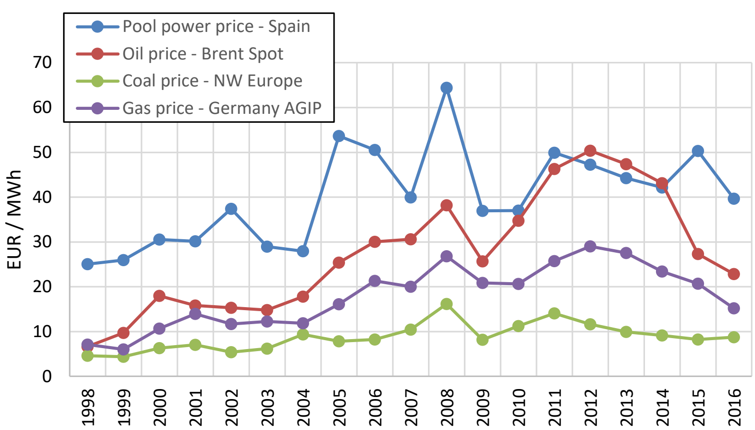

Figure 2-15: Historical WPM and fossil fuel prices[26]

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[26] (BP, 2017a; BP, 2017b; US Energy Information Administration, 2017c; OMIE, 2017)

2.4 Technologies involved

2.4.1 Hydro

Hydro power is a mature technology so that no relevant performance improvements are expected in the short run. Figure 2-16 shows Spain's historical hydro capacity additions vs. plant capacity. As described in section 2.2.6 capacity additions have declined in the last decades due to the fact that most of Spain's available river sites have been already taken. Because of these reasons, no large capacity additions are expected in the near future.

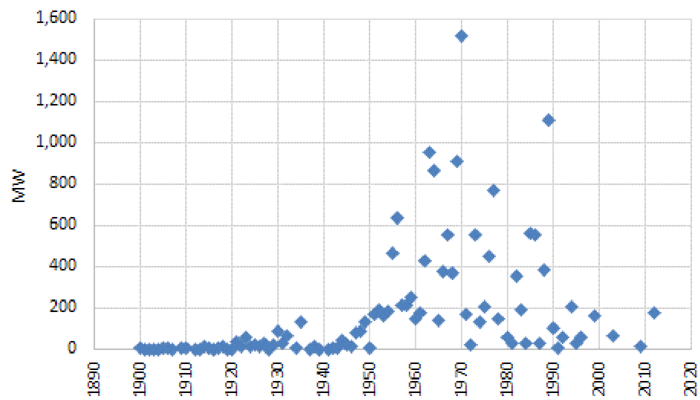

Figure 2-16: Historical hydro capacity additions in Spain[27]

2.4.2 Nuclear

Figure 2-17 shows Spain's historical nuclear capacity additions vs. plant capacity. The construction of the plants currently in operation took place between 1970 and 1988 with no capacity additions after due to the "Nuclear Moratorium", as described in section 2.2.5.

There has been a historical significant public opposition to nuclear power in Spain. Therefore, none of the governments in office has strongly pushed in favor of its further development after the "Nuclear Moratorium" was enacted in 1984. In addition, current denuclearization trends in Europe such as Germany's decision to phase out nuclear power after Japan's Fukushima accident (Hayashi & Hughes, 2013) are not to helping to the reactivation of the industry in Spain. Indeed, Spain's oldest NPP (Jose Cabrera NPP, 160 MW) was taken out of service in 2006, when its decommissioning process started. Vandellos NPP's unit 1 (508 MW) was shut down in 1990 following a fire in one of its two turbo-generators in October 1989, with no reactivation plans as of today. Finally, Santa Maria de Garona NPP (466 MW) was shut down on December

[27] (Ministry of Energy, Tourism and Digital Agenda, 2017c)

2012 and, while a final decision has not yet been made, it seems that the plant will not be put back into commercial operation.

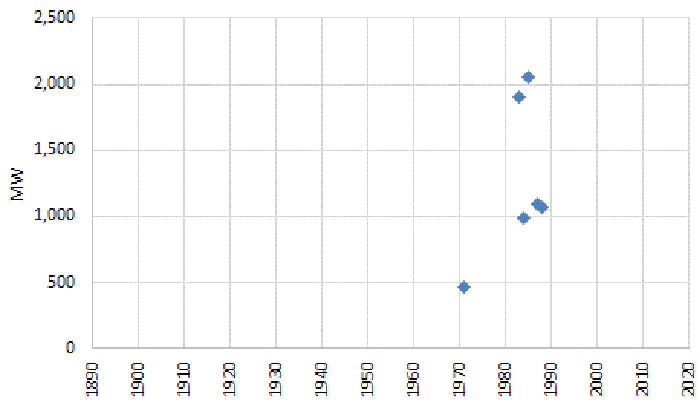

Figure 2-17: Historical nuclear capacity additions in Spain[28]

Therefore, it does not seem very likely that nuclear power will play a major role in terms of capacity addition in the near future so that, in order to limit CO_2 emissions, Spain will have to rely mostly on AES technologies.

2.4.3 Coal

Figure 2-18 shows Spain's historical coal capacity additions vs. plant capacity. Coal installed capacity has stayed practically constant at a level of about 11.5 GW since 1998 because of two reasons:

i. The emergence of the more efficient gas CC power plants, which became more competitive from the economic perspective than the older and more inefficient coal units
ii. The implementation of the European CO_2 trading mechanism (ETS). Coal power plants are more polluting than gas CC plants in terms of CO_2 emissions. The European CO_2 trading mechanism assigned emission quotas by industry so that all emissions exceeding said quotas had to be offset by means of the acquisition of CO_2 emission allowances. This fact entailed significant additional operation costs for coal plants and drove their profitability further down, thus discouraging operators to invest in this technology.

Therefore, significant coal capacity additions seem quite unlikely, unless some disruptive technology changes take place. Operators are therefore expected to invest in the more competitive gas CC technology instead. Nevertheless, for the sake of this work and as it will be described in further detail

[28] (Ministry of Energy, Tourism and Digital Agenda, 2017c)

in subsequent sections, investors will be considered as risk-adverse so that they are willing to have a diversified power generation portfolio, which includes coal.

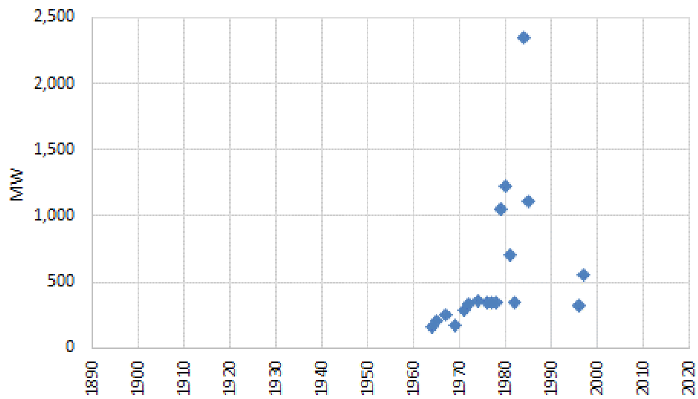

Figure 2-18: Historical coal capacity additions in Spain[29]

2.4.4 Gas Peak

Figure 2-19 shows Spain's historical gas peak capacity additions vs. plant capacity. Gas peak installed capacity has stayed virtually constant at a level of 8.2 GW from 1998 to 2002, and has steadily declined since, until it was fully phased-out in 2015. This was also due to the emergence of the gas CC technology, which is more efficient and provides a degree of flexibility similar to the one of gas peak technology. Therefore, gas peak units were either converted to CC units or decommissioned during the last decade.

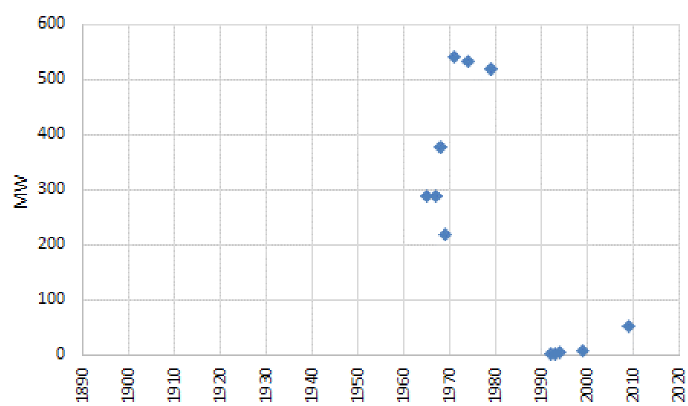

Figure 2-19: Historical gas peak capacity additions in Spain[29]

[29] (Ministry of Energy, Tourism and Digital Agenda, 2017c)

2.4.5 Gas Combined Cycle

Figure 2-20 shows Spain's historical gas CC capacity additions vs. plant capacity. Along wind, gas CC has been one of the most successful technologies in the last two decades in terms of capacity additions. The first units started commercial operation in 2002 and the installed capacity reached a maximum of 25.4 GW in 2012. This fast deployment has been attributed not only to profitability reasons but also the so-called "dash for gas" phenomenon by which operators were willing to strategically position themselves in the industry even at the risk of system overcapacity (Gary & Larsen, 2000), which is what actually happened. The massive deployment of wind and gas CC power, the dispatch priority of RES technologies and the decreasing power demand due to the global economic crisis in 2008 have led to a situation where gas CC power plants are running on low capacity factors and intermittent operation (Basanez Llantada & Lorenzo Garcia, 2012).

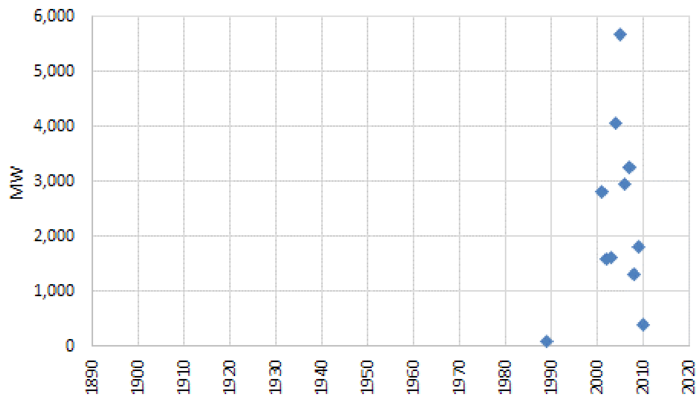

Figure 2-20: Historical gas CC capacity additions in Spain[30]

Despite all these issues and because of the gas CC technology's high efficiency, flexibility and limited emissions, new capacity additions are expected in the future once demand grows again, reserve margin declines, and WPM price becomes attractive enough for investors.

2.4.6 Small Hydro

Figure 2-12 shows Spain's historical small hydro installed capacity. This case is very similar to large hydro. Small hydro technology is very mature so that no relevant efficiency improvements nor cost redictopm are expected in the near future.

[30] (Ministry of Energy, Tourism and Digital Agenda, 2017c)

Regarding the availability of hydro resource, on the contrary to the case of large hydro power, where most of Spain's suitable river sites have been already taken, there are still river sites available for small hydro. Nevertheless, getting the required environmental permits may be challenging as described in section 2.2.6.

2.4.7 Wind

Figure 2-12 shows Spain's historical wind installed capacity. Along gas CC, wind has experienced the greatest growth during the last decades in Spain, having reached a maximum of 22,864 MW in 2016. During the early 2000s, Spain has been the 3rd country in terms of wind installed capacity worldwide[31] having subsequently been surpassed by countries such as the US, China or India. Spain was the 5th country in terms of wind power installed capacity in 2015 (Global Wind Energy Council, 2017).

While wind power deployment in Spain showed an exponential growth during the first years after its inception, it abruptly slowed down by 2012 due to the reduction and eventual phase out of AES incentives. This measure was taken by the Government of Spain in order to (i) tackle with the TD issue which had been present in Spain's power system for many years and (ii) to limit the overcapacity situation the power system was going through, as described in detail in section 2.4.5.

2.4.8 Other renewable

This category includes those technologies which are at an early stage of development such as wave or tidal power. Due do the very limited impact of these technologies in the power generation mix as well as on the WPM price so far and also due to the fact that they are not expected to have a very relevant development in the short run, they have not been included in the models used in the present research.

2.4.9 Biomass

Figure 2-12 shows Spain's historical biomass installed capacity. Biomass has had a limited growth since the liberalization of the power sector in 1998, having reached a maximum installed capacity of 1,420 MW in 2016 and well below the goals set in Spain's REPs (see section 2.5.2. This has been mainly caused by an erratic incentive policy which provided biomass investors with limited economic returns.

Because of its limited historical growth rate, limited impact of in the power generation mix, limited forecasted growth rate (Instituto para la Diversificación y Ahorro de la Energía, 2011) and also for the sake of simplicity[32], biomass power has not been included in the models used in the present research.

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[31] After Germany and Denmark

[32] Historical incentive schemes for biomass have been very complex and have not had the required impact on the energy mix as biomass deployment has turned out to be relatively insignificant

2.4.10 Solar PV

Figure 2-12 shows Spain's historical solar PV installed capacity. PV power experienced a limited growth until 2008 when the extremely high incentives set by the controversial RD 661/2007 (Ministry of Industry, Tourism and Commerce, 2007c) made solar PV capacity largely overshoot the 400 MW target set by the 2000 – 2010 REP (Instituto para la Diversificación y Ahorro de la Energía, 2005) for 2010 as well as the 371 MW capacity cap set by RD 661/2007. Solar PV power reached an installed capacity of 3,207 MW as early as in 2008 (Red Electrica de España, 2013).

This huge overinvestment in solar PV power had a significant effect on the TD problem (de la Hoz, et al., 2010) as the incentives allocated to the new PV power plants directly contributed to increasing it. As a result, solar PV incentives were eventually phased out by the Government of Spain so that new investments were discontinued and PV capacity additions stopped abruptly.

Despite the facts above, PV power has experienced a dramatic cost reduction during last years, having its costs declined from about 4 MEUR/MW in 2012 to about 0.6 MEUR/MW in 2017 so that it has become increasingly competitive with other technologies. Because of this fact, PV is expected to significantly contribute to new capacity additions in Spain once power demand goes back to the pre-crisis levels and new capacity is required.

2.4.11 Solar CSP

Figure 2-12 shows Spain's historical solar CSP installed capacity. Although not as much as solar PV, solar CSP has experienced a significant growth in Spain since the late 2010s having reached a maximum installed capacity of 2,300 MW in 2013. This fact has greatly contributed to the development of Spain's solar CSP industry making it one of the leading countries in terms of solar CSP OEM companies, with corporations such as Abengoa Solar, Acciona or Sener, which are industry leaders.

Because of its technical complexity, solar CSP technology is currently being outpaced in terms of economic competitiveness by technologies such as solar PV and wind, and seems to have a more limited cost reduction potential.

Nevertheless, when combined with thermal storage, solar CSP shows the great advantage of being dispatchable, on the contrary to other AES technologies such as wind or solar PV, which show intermittency issues. This is a very relevant technical advantage which may offset the cost disadvantage in systems with limited international connections where system stability is a concern, such as in the case of Spain.

Because of these reasons, solar CSP shall not be discarded as it may still play a relevant role in Spain's future power generation mix.

2.4.12 Cogeneration

Figure 2-12 shows Spain's historical cogeneration installed capacity. Cogeneration technology experienced a significant growth in Spain after RD 907/82 (Ministry of Industry and Energy, 1982) was passed in 1982, even before the liberalization of Spain's power industry in 1998. A cumulative capacity of 2,728 MW existed at the beginning of 1998, when the new RD 2818/98 (Ministry of Industry and Energy, 1998b) was passed in order to regulate AES power generation. The rate of addition of new CHP capacity significantly declined after 2000 mainly due to increasing natural gas price.

On the contrary to renewable energy sources, cogeneration is not subject to EU renewable energy directives but to energy efficiency ones. Therefore, the Government of Spain is expected to enact the required incentives to foster investments in new CHP capacity so that the EU goals are met. Therefore, cogeneration is expected to play a significant role in Spain's future power generation mix.

2.5 Long term planning of electric generation capacity in Spain

2.5.1 From a regulated market to a liberalized one

Following the trend initiated by countries such as Chile, Norway and UK, which first introduced competition in their electricity markets (Gary & Larsen, 2000), Spain liberalized its power industry in 1998 with the adoption of law 54/1997 (Head of State, 1997). Prior to the liberalization, the history of Spain's power industry can be divided in two different periods: the NEPs (1975 – 1983) and the legal stable framework 1988 - 1997 (Costa Campi, 2016).

THE NATIONAL ENERGY PLANS (1975 – 1983)

The 70s was a time of significant political changes and economic growth in Spain so that power demand also experienced a significant increase. This fact added to the 1973 oil crisis, entailed the need for significant changes in Spain's power industry. The situation was worsened by the fact that, while most European countries decided to foster energy efficiency in order to fight the 1973 oil crisis, the Government of Spain decided to tackle the crisis by not transferring the growing oil prices to the end consumers, which distorted the market as this created an unrealistically high oil demand.

Spain's 1975 NEP was aimed at tackling these issues. It set Spain's energy policies for the next ten years and focused on the substitution of oil for alternative energy sources. Therefore, one of the main consequences of the 1975 NEP was the partial substitution of oil power generation for coal and nuclear. Also, collateral consequences were significantly growing system costs and overcapacity due to unrealistic growing demand forecasts.

Given the disappointing results of the 1975 NEP, a new NEP was enacted in 1978. It set the energy policies for the next nine years (1978 – 1987). The main action lines in this new NEP were similar to the ones in the previous one, with the difference that it considered smaller capacity additions, more consistent with the reality of demand growth, and it finally transferred the real energy costs to the end consumers.

The final outcome of the 1975 and 1978 NEPs was a huge installed capacity increase of about 10,000 MW (mostly coal and nuclear), which entailed significant investments by the vertically integrated power utility companies. These huge investment efforts entailed financial distress for the power utilities because of three reasons: (i) their need to rely on third party financing, in most cases by foreign institutions (which was caused by the difficulty to access to local funding), (ii) increasing interest rates and (iii) recurrent devaluations of Spain's currency, which made the repayment of the debt more difficult.

Due to the abovementioned problems, the 1978 PEN was replaced in 1983 by a new PEN which set the energy policies for the 1983 – 1992 period. This new PEN focused on the long-run planning of the power industry, the unified and coordinated operation of the power system and the update of the tariff rates in order to make the industry financially viable. Also, this new PEN fostered energy efficiency for the first time and canceled generation projects (mostly nuclear, initiating the so-called "nuclear moratorium") in order to tackle the system overcapacity problem. The unified operation of the power system was achieved by means of the nationalization and transfer of the transmission assets, which at that time were owned by the vertically integrated utilities, to the newly created Red Electrica de España, Spain's TSO. The power industry's financial problems were tackled by means of a series of agreements between the Government of Spain and the industry's stakeholders, which included a viability plan involving company mergers as well as an increase of the retail power rates.

THE LEGAL STABLE FRAMEWORK 1988 - 1997

The Legal Stable Framework was a new policy which focused on the continuation of the policies included in the 1983 PEN. Its main contribution was the agreement and enacting in 1987 of a new stable tariff framework which aimed at reflecting the system's real costs and was in force until 1997. The Legal Stable framework aimed as well at improving the power system's planning process, fostering the general efficiency of the industry, reducing uncertainty and guaranteeing to some extent the return on the investments.

This policy succeeded at solving the industry's financial problems as well as at meeting most of its secondary goals. During the Legal Stable Framework period, capacity additions were significantly smaller than in the PEN era due to the resulting overcapacity entailed by the PENs.

THE LIBERALIZATION

EU regulations enacted in the 90s (The European Parliament and the Council of the European Union, 1997) focused on the liberalization of the power industries of the Member States, in order to further increase efficiency, optimize the system, reduce system costs and ultimately create an integrated European market. These regulations set the following goals: (i) full liberalization of power generation, (ii) guaranteed access to the power grid, (iii) segregation of the generation, T&D activities and (iv) progressive liberalization of the retail business.

Spain's power industry was liberalized by means of Law 54/1997 of the electric power sector (Head of State, 1997). This regulation introduced full competition in the generation and trading activities but did not deregulated the T&D ones due to their natural monopoly characteristics. Also, OMEL and Red Electrica de España where appointed as the WPM operator and TSO respectively.

Spain's WPM was organized as a spot market composed mainly of one daily and several intra-daily markets where power prices are bid on an hourly basis. The WPM operator is in charge of dispatching the generation units and setting the final WPM price based on their bids and on the technical constraints.

The EU further accelerated the liberalization process by enacting Directive 2003/54/CE (The European Parliament and the Council of the European Union, 2003b), which required the legal separation of the transmission operators, distribution operators and other system agents, granted unlimited access to the power generation market, and required the full liberalization of the retail market by 2007. This directive was transposed into Spain's regulation by means of law 17/2007 (Head of State, 2007) although some of the requirements of Directive 2003/54/CE had been previously introduced in Spain (e.g. the retail market was fully liberalized by 2003 when all retail users where given the option to choose their power supplier).

In 2006 Spain's and Portugal's WPMs were integrated into one single WPM, the "Mercado Iberico de Electricidad" (MIBEL). This fact led to a further integration (in line with the goal of a single European market), the fostering of long-term contracting, the increase of the security of supply and the reduction of costs.

From the system planning perspective, Spain's transition from a regulated to a liberalized system has entailed two relevant changes as (i) utilities had to switch from traditional optimization-based planning to strategy-based planning and (ii) the planning capacity expansion process has been reformulated from a cost-minimization problem, where the goal was to determine the right level of generation capacity, the optimal mix of technologies and the timing of investments at a minimum cost and adequate level of reliability to a profit-maximization problem. Further details on this transition as on the ways and tools to deal with it are described in section 4.2.

2.5.2 The goals. EU regulations and the REP 2020

National energy policies in EU Member States are driven by and subject to higher rank EU directives. The most relevant EU directives on electric power were described in section 2.2.7. Once enacted, EU directives are transposed to national regulations. Therefore, in the case of Spain multiple regulations have been enacted in the past in order to comply with EU energy directives.

EU energy directives have not only been the origin of new laws but also of Spain's so-called "National Renewable Energy Plans", the first of which was enacted in 1999 and covered the 2000 – 2010 period

(Instituto para la Diversificación y Ahorro de la Energía, 1999). The ultimate goal of this REP was a 12% renewable energy share in TPES in 2010.

Table 2-5 shows the prevailing situation at the time the 2000 – 2010 REP was enacted as well as the goals set for 2010.

	1998 Initial situation		***Goals 2010***	
	Capacity MW	***Production GWh***	***Capacity MW***	***Production GWh***
Small hydro < 10 MW	1,510	4,680	2,230	6,912
Large hydro 10 – 50 MW	2,801	5,603	3,151	6,303
Large hydro > 50 MW	13,420	24,826	13,420	24,826
Wind	834	2,002	8,974	21,538
Biomass	189	1,139	1,897	13,949
Biogas	0	0	78	546
Solar PV	8.7	15.3	144	218
Solar CSP	0	0	200	459
Waste	94	586	262	1,846
Total	**18,856**	**38,851**	**30,355**	**76,956**

Table 2-5: REP 2000 – 2010. Initial scenario and goals[33]

This plan was repealed in 2005 by the 2005 – 2010 REP (Instituto para la Diversificación y Ahorro de la Energía, 2005) which set a more ambitious goal for AES. There were three reasons for this:

i. Spain's TPES grew faster than expected so that, in order to reach the planned share of renewable energy, a more aggressive AES capacity addition plan was required.
ii. EU Directives 2001/77/CE (The European Parliament and the Council of the European Union, 2001) and 2003/30/CE (The European Parliament and the Council of the European Union, 2003a) were passed after Spain's first 2000 – 2010 REP was enacted. While the first directive focused on the promotion of renewable electricity the second one focused on the promotion of biofuels. Both directives entailed an additional push in both fields so that Spain's initial AES targets had to be revised upwards.
iii. Finally, Spain's first National Plan on Emission Rights (Ministry of the Presidency, 2004) was passed in 2004. This plan entailed CO_2 emission quotas for specific sectors nationwide. Renewable technologies were seen as an additional instrument in order to meet the CO_2 emission goals. Therefore, the National Plan on Emission Rights itself stated the convenience of revising the goals set in the first 2000 – 2010 REP.

[33] (Instituto para la Diversificación y Ahorro de la Energía, 1999)

As a consequence, most renewable energy goals were revised upwards by the 2005 – 2010 REP. Table 2-6 shows the actual figures at the time the new 2005 – 2010 REP was enacted as well as its goals.

	2004 Initial situation		***Goal 2010***	
	Capacity MW	***Production GWh***	***Capacity MW***	***Production GWh***
Small hydro < 10 MW	1,749	5,421	2,199	6,692
Large hydro 10 – 50 MW	2,897	5,794	3,257	6,480
Large hydro > 50 MW	13,521	25,014	13,521	25,014
Wind	8,155	19,571	20,155	45,511
Biomass	344	2,193	2,039	14,015
Biogas	141	825	235	1,417
Solar PV	37	56	400	609
Solar CSP	0	0	500	1,298
Waste	189	1,223	189	1,223
Total	**27,032**	**52,852**	**42,494**	**102,259**

Table 2-6: REP 2005 – 2010. Initial scenario and goals[34]

Table 2-7 shows the comparison of the actual figures in 2010 vs. the targets set in the 2005 – 2010 REP. The goals which were met are highlighted in green while the goals which were not met are highlighted in light brown.

As it can be observed, the overall goal was practically met as the total renewable installed capacity was slightly higher than the target and the total renewable energy produced was slightly lower.

	2010 Actual figures		***% fulfillment***	
	Capacity MW	***Production GWh***	***Capacity MW***	***Production GWh***
Small hydro < 10 MW	1,922	6,234	87.4%	93.2%
Large hydro > 10 MW	16,651	39,087	123.1%	156.3%
Wind	20,744	43,708	102.9%	96.0%
Biomass	533	2,820	26.1%	20.1%
Biogas	177	745	75.3%	52.6%
Solar PV	3,787	6,279	946.8%	1,031.0%
Solar CSP	632	691	126.4%	53.2%
Waste	115	663	60.8%	54.2%
Total	**42,494**	**102,259**	**104.9%**	**98.0%**

Table 2-7: REP 2005 – 2010. Results and degree of fulfillment[35]

[34] (Instituto para la Diversificación y Ahorro de la Energía, 2005)

[35] (Ministry of Teritorial Policy and Public Administration, 2011; Instituto para la Diversificación y Ahorro de la Energía, 2011)

The classification of hydro technologies changed in the meantime so that the comparison is not straightforward. Anyway, the great large hydro increase seems to offset the low small hydro increase so that hydro seems to have met its goals. Wind power met its goal in terms on installed capacity and almost did in terms of power generation. The big “losers” were biomass, biogas and waste, which failed to meet their respective goals by far. Solar CSP met the installed capacity goal but missed the power production one. Finally, solar PV clearly overshot the 400 MW target by reaching 3,787 MW as a consequence of erratic incentive policies as described in section 2.2.4.

A new REP covering the 2011 – 2020 period was enacted in 2011 (Instituto para la Diversificación y Ahorro de la Energía, 2011). It set goals in line with the recently enacted EU Directive 2009/28/CE (The European Parliament and the Council of the European Union, 2009), which set a global target of a 20% renewable energy share in TFC both for the whole EU and Spain by 2020, as well as a 10% renewable energy share in transport final energy consumption for all Member States by 2020. This directive also required all Member States to develop their own national plans in order to reach the abovementioned goals.

Therefore, Spain’s new 2011 – 2020 REP included the main guidelines of the plan to be submitted to the EU and even set a slightly more challenging overall goal of a 20.8% renewable energy share in TFC.

With regards to the power generation mix, the plan not only set final goals for 2020 but also intermediate indicative goals for 2015 as shown in Table 2-8.

	2010 Actual data		***2015 forecasted***		***2020 forecasted***	
	Capacity MW	***Production GWh***	***Capacity MW***	***Production GWh***	***Capacity MW***	***Production GWh***
Hydro	13,226	31.614	13.548	31.371	13.861	32.814
Small hydro < 1 MW	242	601	253	744	268	835
Small hydro 1 - 10 MW	1,680	4.068	1.764	4.803	1.917	5.692
Large hydro > 10 MW	11,304	26.946	11.531	25.823	11.676	26.287
Pumping hydro	5,347	3,106	6.312	6,592	8.811	8,457
Geothermal	0	0	0	0	50	300
Solar PV	3,787	6,279	5.416	9,060	7.250	12,356
Solar CSP	632	691	3.001	8,287	4.800	14,379
Wave / tidal / etc.	0	0	0	0	100	220
Wind on-shore	20,744	42.337	27.847	55.538	35.000	70.734
Wind off-shore	0	0	22	66	750	1.822
Biomass	825	4,228	1.162	7,142	1.950	12,200
Solid biomass	533	2,820	817	4,903	1.350	8,100
Waste	115	663	125	938	200	1,500
Biogas	177	745	220	1,302	400	2,600
Total	**39,214**	**85.149**	**50.996**	**111.464**	**63.761**	**144.825**

Table 2-8: REP 2011 – 2020. Actual figures and forecast[36]

[36] (Instituto para la Diversificación y Ahorro de la Energía, 2011)

Table 2-9 shows the comparison of the actual figures in 2015 vs. the goals set in the 2011 – 2020 REP for 2015. Those goals which were met are highlighted in green while the goals that were not met are highlighted in light brown.

	2015 Actual figures		***% fulfillment***	
	Capacity MW	***Production GWh***	***Capacity MW***	***Production GWh***
Small hydro < 10 MW	*2,333*	*5,659*	*16%*	*2%*
Large hydro > 10 MW	18,019	25,733	56%	0%
Wind on-shore	22,864	47,948	-18%	-14%
Wind off-shore	0	0	-100%	-100%
Biomass	1,419	4,921	22%	-31%
Solar PV	4,420	7,861	-18%	-13%
Solar CSP	2,300	5,158	-23%	-38%
Total	**51,355**	**97,280**	**1%**	**-13%**

Table 2-9: REP 2011 – 2020. Actual figures and degree of fulfillment[37]

As it can be observed, overall capacity goals have been met (1% over the expectations) while overall production goals have not (13% below expectations). Hydro (both small and large) and biomass show the greatest degree of fulfillment although the growth goals for both technologies were very modest. On the contrary, solar and wind show the lowest degrees of fulfilment.

This section has been included in order to emphasize how and why power system planning in the EU is constrained and must comply with higher rank EU directives, which entails an additional constraint for power system planning.

2.5.3 The historical AES incentive scheme

While most of Spain's power industry was liberalized in 1998 as described in the previous section, parts of it remained regulated. This was the case of power T&D which stayed regulated because of its natural monopoly nature. This was also the case of AES technologies which stayed regulated to some extent as they were subject to a regulated remuneration framework, which aimed at fostering their development by providing them with additional revenues so that they were able to compete with conventional technologies while they were moving down the learning curve and reducing their costs.

The AES incentive scheme started with the adoption of RD 2366/1994 (Ministry of Industry and Energy, 1994), which set the so-called "Special Regime for Power Generation" which included all AES technologies. Basically, only new cogeneration capacity was added under this AES regulation.

[37] (Instituto para la Diversificación y Ahorro de la Energía, 2011; Red Electrica de España, 2017)

Renewable energy deployment actually started to boom in 1998 with the adoption of Law 54/1997 of the Electric Power Sector, the liberalization of Spain's power industry and the adoption of RD 2818/1998 which assigned AES technologies specific remuneration levels, provided them with different options for selling their production and granted them specific rights in terms of grid access and dispatch priority.

RD 2818/1998 gave AES generators two options for selling their production. The first one consisted of a technology-specific FIT while the second one consisted of a technology-specific price premium to be added on top of the WPM price so that the final price was computed as follows:

$$FinalPrice = AVWPMPrice + Premium + RPComplement \qquad (2.1)$$

Where: FinalPrice = Final power price to be received by the producer (EUR/MWh)

AVWPMPrice = Average WPM price (EUR/MWh)

Premium = Technology-specific price premium (EUR/MWh)

RPComplement= Reactive power complement (EUR/MWh)

RD 2818/1998 was subsequently modified by RD 841/2002 (Ministry of Economy, 2002a). This new regulation focused on incentivizing the participation of AES plants in the WPM. It did so by forcing AES plants larger than 50 MW to participate in the WPM and by providing the rest of AES plants with a new additional remuneration option which allowed them to receive a final power price computed as follows:

$$FinalPrice = WSMPrice + Premium + SysServices + CapPayment \qquad (2.2)$$

Where: FinalPrice = Final power price to be received by the producer (EUR/MWh)

WPMPrice = WPM price (EUR/MWh)

Premium = Technology-specific price premium (EUR/MWh)

SysServices = System services premium (EUR/MWh)

CapPayment = Capacity payment (EUR/MWh)

The first significant change to the regulatory scheme in force was introduced in 2004 by RD 436/2004 (Ministry of Economy, 2004). This new rule aimed at setting a more stable and predictable support scheme by indexing all remuneration parameters (including FITs and premiums) to the so-called "Reference Average Electric Tariff" which had been previously defined by RD 1432/2002 (Ministry of Economy, 2002b). The RAET update methodology was clearly set as a function of specific macroeconomic indicators so that it provided a clear, predictable and stable way for calculating and forecasting the remuneration parameters of AES producers.

RD 661/2007 (Ministry of Industry, Tourism and Commerce, 2007c) updated once more the support scheme and repealed RD 436/2004. It decoupled incentive levels from the RAET and set new specific FIT and premium values based on three different variables (technology, capacity and age). It also introduced lower and upper caps for the final price to be received by pure renewable technologies (Group b) such as wind. This was done in order to avoid windfall profits in case of high WPM prices (e.g. due to high fossil fuel prices) as well as to guarantee a minimum profitability in case the WPM price fell below a specific threshold value.

After several regulation changes aimed at reducing the incentive levels in order to limit the TD, this scheme was eventually phased out in 2012 with the adoption of RDL 1/2012 (Head of State, 2012) and substituted in 2013 by a new system based on competitive auctions, which was set by RD 413/2014 (Ministry of Industry, Energy and Tourism, 2014b).

Under this new system, AES generators are entitled to a remuneration regime aimed at guaranteeing a "reasonable ROI"[38], which has two components:

i. A capacity-based payment component (Remuneration to the investment, Rinv) aimed at covering the investment costs that cannot be recovered from the revenues coming from the sale of electricity at the WPM.
ii. An operation component (Remuneration to the operation, Ro) which covers the difference between the actual operation costs and the proceeds from the sales of power at the WPM.

The main difference with the previous system is that now the remuneration regime is set by a competitive bidding processes in which participants bid the specific investment value (EUR/MW) based on which the remuneration parameters are computed.

2.6 AES incentive schemes worldwide

While section 2.5.3 describes the historical evolution of Spain AES incentive scheme, this section describes the AES support systems currently in use worldwide. This section is included in order to have a clear picture of the incentive systems potentially available as well as of their pros and cons.

AES support schemes may be classified in the following three categories: fiscal incentives, public finance and regulations. This section describes in detail the specific support mechanisms within each category (International Renewable Energy Agency, 2012a; Lund, 2007; International Energy Agency, 2017; KPMG International, 2015).

[38] The 'reasonable ROI' was set as the average return of Spain's 10-year government bonds increased by 300 basis points

2.6.1 Fiscal incentives

i. Grants: They consist of monetary assistance by the Government, usually a percentage of the total initial investment, which must not be repaid by the recipient. They basically reduce the initial investment costs, so increasing project's IRR. They have been used in countries such as Austria, Finland, Norway, UAE or the US.
ii. Energy production payments: Financial assistance from the Government in the form of cash that instead of being paid as a percentage of the total initial investment, is paid per unit of power produced. They improve the project's cash flows, therefore improving its IRR.
iii. Rebates: They are similar to grants with the only difference that the outlay is made after project completion while grants are disbursed before the project starts construction.
iv. Tax credits: They consist of tax credits that are computed as a function of either the total investment (Investment Tax Credit – ITC) or the power actually produced (Production Tax Credit – PTC). These credits improve the project's P&L account therefore improving its IRR. In some cases when project sponsors do not have enough tax credit appetite, specific financial instruments are used in order to monetize and trade the tax credits. This system has been used with significant success in countries such as Colombia, India, Madagascar and US.
v. Tax reduction or exemption: They consist of specific tax (e.g. VAT, sales tax, carbon tax, etc.) reductions applicable to the purchase, production, sale or investment in AES. This system has been used in countries such as Albania, Australia (carbon tax), New Zealand (carbon tax) and Tunisia.

2.6.2 Public finance

i. Investment: Government's equity investment in a power company or SPC (Special Purpose Company) in charge of a specific AES project. They are usually done through a government managed fund that directly invests in projects' and companies' equity.
ii. Guarantee: The Government takes part of the project risk in order to facilitate financing from commercial banks. The Government covers the risk of part of the loan not being repaid (typically 50 – 80%). This mechanism has been used often in infrastructure projects such as toll roads in Spain.
iii. Loan: "Soft financing" (i.e. preferential interest rates or security requirements) provided by the Government or a development bank. This mechanism has been used in countries such as Brazil where banks such as the BNDES or the BNB have been providing soft financing for specific power projects.
iv. Public procurement: Public entities preferentially purchase AES power and/or RE equipment. Mechanism used for example in Sweden in order to foster the deployment of heat pumps or in the US in order to foster the deployment of efficient lighting.

2.6.3 Regulations

i. Quantity driven:

- Renewable portfolio standard (RPS): This mechanism obliges power distributors to supply a specific quantity of renewable power so that they must acquire renewable power from AES producers. Acquisition transactions are documented through RECs, which are usually traded at specific markets where their price is set. This system has been used with significant success in countries such as Belgium, Chile, Mexico, Norway, Poland, Romania, South Korea, Sweden, UK, and US.
- Auctions: Public authorities organize tenders for specific amounts of renewable energy or capacity. Winning bids are usually remunerated at prices above regular WPM prices. This system is claimed to be one of the least expensive for consumers because of its competitive nature. It has been used in many cases with significant success in countries such as Argentina, Brazil, Cost Rica, Egypt, El Salvador, Ethiopia, France, Germany, Guatemala, Bolivia, Jordan, Kenya, Mexico, Panama, Peru, Poland, Russia, Tanzania, Uganda, Zambia and, since very recently, in Spain.

ii. Price driven:

- FIT: AES generators are remunerated by means of a regulated fixed price per MWh, higher than the WPM price, which usually depends on the technology involved, plant capacity and plant age. This system has been used, in many cases with great success, in countries such as Algeria, Armenia, Austria, Belarus, Bosnia and Herzegovina, China, Croatia, Denmark, Ecuador, Egypt, France, Germany, Ghana, Greece, Hungary, Hungary, Indonesia, Israel, Italy, Japan, Jordan, Kazakhstan, Latvia, Lithuania, Malaysia, Mongolia, Montenegro, Namibia, Nigeria, Philippines, Portugal, Serbia, Slovenia, Spain, Switzerland, Thailand, Turkey, Ukraine, Uruguay, and Vietnam
- Premium payments: AES generators are remunerated by means of a regulated premium to be added on top of the WPM price. This premium usually depends on the technology involved, plant capacity and plant age. This system has been used, in many cases with great success, in countries such as Estonia, Finland, Netherlands and Spain.

iii. Quality driven:

- Green energy purchasing: This mechanism promotes the voluntary purchases of AES power by consumers, beyond existing RE obligations.
- Green labelling: By means of this mechanism, the Government facilitates renewable energy labelling so that consumers can easily choose to buy certified green power. This policy has been used in countries such as Denmark or UK.

iv. Access:

- Net metering: This mechanism is mostly used in distributed generation next to consumption points (e.g. residential solar generation). It allows a two-way power flow so that when generation exceeds demand, the excess power is injected into the grid and the meter counts backwards so that in fact the power is remunerated at the prevailing retail price. This system is used in countries such as Costa Rica, Honduras and Pakistan.

- Priority grid access: This mechanism grants AES generators preferential access to the power grid and is often used in combination with one or more of the incentive mechanism described above in multiple countries.
- Priority dispatch: This mechanism grants AES generators dispatch priority against conventional technologies and is often used in combination with one or more of the incentive mechanism described above in multiple countries.

Table 2-10 shows the most relevant AES support policies used by a selection of countries.

	FIT / Premium	*RPS*	*Net metering*	*RECs*	*Auctions*	*Grants/Rebates*	*Tax Credits*	*Tax reduction*	*Energy payment*	*Public investment, loans or grants*
Albania	√	√		√	√		√	√	√	√
Algeria	√				√	√				√
Andorra	√								√	
Angola										√
Argentina	√		√		√	√	√	√	√	√
Armenia	√									
Australia	√	√		√	√	√				√
Austria	√			√		√	√			√
Azerbaijan										√
Bahrain										√
Bangladesh					√	√		√		√
Barbados			√					√		√
Belarus	√	√						√		√
Belgium		√	√	√	√	√	√	√		
Belize					√					
Bosnia and Herzeg.	√				√	√				
Botswana						√		√		
Brazil			√		√		√	√		√
Bulgaria	√									√
Burkina Faso					√		√	√	√	
Cabo Verde			√		√		√		√	
Cameroon								√		
Canada	√	√	√		√	√	√	√		√
Chile		√	√		√	√	√	√		√
China	√	√			√	√	√	√	√	√

`	FIT / Premium	RPS	Net metering	RECs	Auctions	Grants/Rebates	Tax Credits	Tax reduction	Energy payment	Public investment, loans or grants
Colombia			√				√	√		√
Costa Rica	√		√		√			√		
Cote d'Ivoire					√			√		
Croatia	√									
Cyprus	√		√		√	√				
Czech Republic				√		√	√	√		√
Denmark	√		√	√	√	√	√	√		√
Dominican Republic	√		√		√	√	√	√		√
Ecuador	√				√			√		√
Egypt	√		√		√	√		√		
El Salvador					√		√	√	√	√
Estonia	√								√	√
Ethiopia								√		√
Fiji							√	√		
Finland	√			√		√		√	√	
France	√			√	√	√	√	√		√
Gambia								√		
Germany	√					√	√	√		√
Ghana	√	√		√		√		√		√
Greece	√		√			√	√	√		√
Grenada			√					√		
Guatemala			√		√		√	√		
Guinea								√		
Guyana								√		
Haiti										√
Honduras	√		√		√		√	√		
Hungary	√					√		√		√
India	√	√	√	√	√	√	√	√	√	√
Indonesia	√	√			√	√	√	√		√
Iran	√						√		√	√
Ireland	√			√	√					
Israel	√	√	√		√			√		√
Italy	√		√	√	√	√	√	√		√
Jamaica			√		√		√	√		
Japan	√	√	√	√	√	√				√
Jordan	√		√		√			√		√
Kazakhstan	√			√		√				
Kenya	√				√			√	√	√
Kuwait					√					

`	FIT / Premium	RPS	Net metering	RECs	Auctions	Grants/Rebates	Tax Credits	Tax reduction	Energy payment	Public investment, loans or grants
Kyrgyz Republic		√				√		√		
Latvia	√		√		√			√		
Lebanon			√					√		√
Lesotho			√		√	√	√		√	√
Liberia								√		
Libya								√		
Liechtenstein	√									
Lithuania	√	√								√
Luxembourg	√					√				
Macedonia	√									
Madagascar								√		
Malawi								√		√
Malaysia								√		√
Maldives	√				√					
Mali								√		√
Malta	√		√			√		√		
Marshall Islands								√		
Mauritius					√	√		√		√
Mexico			√		√		√			√
Micronesia			√							
Moldova	√									√
Mongolia	√				√					
Montenegro	√									
Morocco			√		√					√
Mozambique								√		√
Myanmar								√		
Namibia										
Nepal	√			√	√	√	√	√		√
Netherlands	√		√	√		√	√	√	√	√
New Zealand						√				√
Nicaragua	√							√		
Niger								√		
Nigeria	√					√		√		√
Norway		√		√	√	√		√		√
Pakistan	√		√	√		√		√		√
Palau		√								
Palestinian territories	√		√					√		
Panama	√		√		√		√	√	√	
Paraguay								√		

`	FIT / Premium	RPS	Net metering	RECs	Auctions	Grants/Rebates	Tax Credits	Tax reduction	Energy payment	Public investment, loans or grants
Peru	√	√			√			√		√
Philippines	√	√	√		√	√	√	√	√	√
Poland	√	√		√	√		√	√		√
Portugal	√	√	√		√	√		√		√
Romania		√		√						√
Russia	√				√	√				
Rwanda	√				√		√	√		√
San Marino	√									
Senegal	√	√	√		√			√		
Serbia	√					√				
Seychelles			√				√	√		√
Singapore			√		√					√
Slovakia	√			√				√		
Slovenia	√			√	√	√	√	√		√
South Africa		√			√	√		√		√
South Korea		√	√	√		√	√	√		√
Spain			√	√		√	√		√	
Sri Lanka	√	√	√			√		√	√	√
St. Lucia			√					√		
St. Vincent			√							
Sudan										
Sweden	√	√		√		√	√	√		√
Switzerland	√					√		√		
Syria	√		√		√		√			
Tajikistan	√							√		√
Tanzania	√					√		√	√	√
Thailand	√							√	√	√
Togo								√		
Trinidad and Tobago							√	√		
Tunisia			√			√		√		√
Turkey	√					√				√
Uganda	√				√	√		√		√
Ukraine	√		√			√		√		√
United Arab Emirates		√			√				√	√
United Kingdom	√	√		√		√		√	√	√
United States	√	√	√	√		√	√	√		√
Uruguay	√		√		√	√		√	√	√
Uzbekistan					√					
Vanuatu								√		

`	***FIT / Premium***	***RPS***	***Net metering***	***RECs***	***Auctions***	***Grants/Rebates***	***Tax Credits***	***Tax reduction***	***Energy payment***	***Public investment, loans or grants***
Vietnam	√			√		√	√	√		
Zambia						√		√		√
Zimbabwe								√		√

Table 2-10: Main AES incentive policies by country[39]

[39] (KPMG International, 2015)

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Chapter 3
Problem definition

3.1 Introduction

This Chapter describes in detail the characteristics of the problem to be solved as well as the main challenges to be addressed in order to choose the most adequate modeling techniques.

3.2 Power planning in liberalized markets

Long term power generation system planning in liberalized markets is a challenging task. The transition from regulated to liberalized markets has entailed dramatic changes in the planning process, as the industry has evolved from a monopoly to an unregulated model, which is mainly driven by supply and demand market forces.

Power system planning's main goal is to provide a reliable service (i.e. keeping stable and adequate reserve margins) while keeping costs as low as possible. In addition, other targets such as emissions, energy dependency, etc. are often taken into consideration as well (e.g. CO_2 regulations in the EU).

While centralized planning allowed to meet these goals relatively easily, liberalized markets entail additional challenges. For example, there is extensive research (Bunn & Larsen, 1992; Ford, 1999; Ford, 2001a; International Energy Agency, 2014b) showing that supply-demand market forces by themselves may not be enough to keep the required investment levels necessary to maintain safe reserve margins nor to achieve specific environmental targets (Lund, 2007). This is due to the fact that, is some cases, AES technologies are not yet competitive with conventional ones in terms of costs while in other cases, environmental externalities are not properly accounted for, which unfairly harms AES technologies.

While some of the main characteristics of the power industry during the monopoly era were stable prices, full information, easily forecasted demand and co-operative regulation, liberalization has introduced new characteristics such as uncertainty (for example, monopolistic utilities had a constant 100% market share while in liberalized markets this variable is uncertain), price volatility (monopolistic utilities used to have an accurate forecast of the future tariffs as they were allowed to charge constant rates, while liberalized markets entail free pricing) and limited information (Dyner & Larsen, 2001; Gary & Larsen, 2000).

Also, as described in the previous sections the electric power industry is experiencing changes never seen before which are adding complexity to the planning and forecasting processes. These challenges include the inception of renewable technologies such as wind and solar with their associated variability, the introduction of the electric vehicle with its associated power demand increase, the inception of distributed generation, the potential introduction of distributed power storage (Castelvecchi, 2015) and the obsolescence of assets such as the NPPs built in the 60s and 70s, which will need replacements in the near future.

In liberalized markets, the regulator does not have the power to decide which technologies to deploy anymore as private investors are now the ones making these decisions. Therefore, the regulator's power is limited to setting the right incentives for investors in order to drive the power generation mix into the desired direction.

For example, the regulator may introduce capacity payments in order to encourage investment in baseload capacity aimed at keeping safe and stable reserve margins. In the same line of thinking, the regulator may introduce incentives for specific technologies in order to make them attractive to investors and foster their deployment. This is for example the case of AES incentives.

Defining accurate policies is a key issue in order to avoid over or underinvestment as it has been the case in Spain in the past (Prieto & Hall, 2013). Therefore, in liberalized markets the regulator must predict how investors will react to energy policies so that the behavioral component becomes a key issue, which must be taken into account when developing forecasting models.

In addition to the challenges inherent to the transitions from regulated to a liberalized market models, there are other important topics that are often overlooked by policymakers.

In many cases, policymakers have focused their policies on specific economic variables such as power cost, power-related employment (for example by fostering coal power and so the associated coal mining industry), economic development (for example by fostering locally produced technologies), etc. Nevertheless, the power system is deeply interlinked with many parts of a country's economy, with multiple and complex feedback loops, and impacts multiple variables in many sectors. Therefore, the assessment of the power system's impact must not be constrained to just one ore a few economic variables but must consider the overall net impact on a country's economy. This way, the country's overall economic well-being can be maximized.

Power systems show a large inertia due to facts such as the long planning and development lead times, the time required for investors to form expectations and investment irreversibility which, in some cases, makes investors delay investment decisions in order to take advantage of the value of their option to invest. Development lead times for some technologies may take several decades and the lifetime of power generation assets spreads over several decades. Therefore, the impact of decisions made today will last for several decades. In many cases the assessments done by policy makers on the impact of their policies is restricted to the short run, being in many cases just focused on the period the current government is in office. This may lead to suboptimal policies because of the abovementioned high power system inertia. Therefore, it is necessary to assess the impact of energy policies on the long run and from a cumulative perspective. Only doing it this way, it is guaranteed that the overall impact is assessed and the overall country's economic wellbeing is properly maximized. As a consequence, dynamic models become extremely interesting for these assessments as they are able to capture the long run effect, system inertia, delays, feedback loops and all other dynamic considerations.

Finally, liberalized power systems show a greater degree of uncertainty than regulated ones. Legacy deterministic assessment methodologies must be adapted in order to take this point into account. The use of stochastic models able to reproduce the uncertainty inherent to variables such as commodity prices, power demand, etc. as well as to provide results in the form of confidence intervals becomes extremely important.

3.3 Research objectives

The present research presents a novel methodological framework aimed at tackling the abovementioned challenges. The models here presented can be used to forecast the evolution of the power generation mix and its long run technical, environmental and economic impacts based on exogenous variables such as fossil fuel prices and levers such as incentive polices, while taking into consideration the abovementioned constraints (i.e. behavioral considerations, stochastic approach, overall long run net cumulative economic impact and dynamic considerations):

i. Behavioral considerations: As discussed in previous sections, on the contrary to regulated markets where the evolution of the power generation mix depends on the regulator's decisions, in liberalized markets it depends on private investors' decisions. Therefore, Investors' behavior is modeled in order to simulate their reaction to exogenous variables such as commodity prices and levers such as incentive policies, so that capacity additions are computed and the evolution of the power generation mix and its economic impact is assessed. Aspects such as decision-time, risk aversion and soft variables such as public opinion or investors' market perceptions are considered.

ii. Stochastic approach: Not only deterministic but also stochastic techniques are used in order to model the greater uncertainties inherent to liberalized markets and the random behavior of specific variables such as fossil fuel prices or power demand, which are modeled as random walks through Monte Carlo simulations.

iii. Long-run cumulative assessment: The impact of energy policies on the power generation mix and its economic impact is assessed from a long run cumulative perspective in order to take into account the inertia and long lead times inherent to power systems. Additional dynamic considerations such as delays and feedback loops are considered as well.

iv. Assessment of the overall net economic impact on the country's economy: The assessment of the economic impact of the power generation mix is not limited to power cost. As previously discussed, the power generation system is deeply interlinked with multiples areas of a country's economy. It impacts areas such as trade balance (e.g. through fossil fuel imports), the job market (e.g. through equipment manufacturing) and industrial output (e.g. through power price), which ultimately impact the country's economic performance, which is measured through the country's real GDP.

The methodological framework here presented consists of a combination of the following modeling techniques:

i. SD models are used in order to describe the evolution of the power generation fleet across time. This methodology is very useful in order to model the dynamic considerations inherent to power systems (e.g. delays and feedback loops) as well as to model soft variables (e.g. public opinion) and behavioral considerations.

ii. Stochastic methodologies are used in order to reproduce the uncertainty inherent to specific variables such as fossil fuel prices and power demand, which are modeled as Random Walks.

iii. Input – Output models are used to assess the overall economic impact of the power generation system on the country's GDP through its direct and indirect components.

iv. Supply – demand market equilibrium models are used in order to simulate the operation of the country's WPM and compute final WPM prices.

Therefore, the present research provides a methodological framework which enables the assessment and definition of optimum energy policies by taking into account all relevant system variables, feedback loops and long term considerations, so that the overall economic well-being of the country can be maximized.

For the sake of this work, well-being is measured in economic terms through real GDP so that all impacts of power policy design (environmental, financial, and technical) are “translated” into economic terms and factored in the real GDP variable.

The environmental impact of the power industry comprises air emissions (CO_2, NO_X, SO_X, N_2O, particles, etc.), liquid waste (boiler drains, etc.) and solid waste (biomass sludge, ashes, etc.). It also includes consumption of resources such as water. For the sake of this work, only CO_2 emissions will be considered as they are currently the most important pollutant from the power industry and one of the main causes of the Greenhouse effect. Special care has to be taken regarding this impact as it is often not internalized in the costs of power and energy consumption as it will be discussed in subsequent chapters.

The financial impact of the power industry reflects the cost of energy supply which is composed of investment and operation costs. Power producers need to cover their variable operation costs as well as to get the required return on their investments. Other system costs such as T&D are not considered in this work as, for the sake of simplicity, they are considered as irrespective of the power generation technologies considered.

Finally, technical impact involves system reliability which is transformed into economic impact by means of the expected VOLL, which measures the value that end consumers put on lost power in case of outages in EUR/MWh.

So, the present research presents a methodological framework aimed at forecasting the long-run evolution of the power generation mix and its impact on the overall country’s economic well-being based on exogenous variables (e.g. fossil fuel prices, GDP growth, CO_2 emission credit price, etc.) as well as on regulator’s levers (e.g. AES incentives, capacity payments, administrative barriers, etc.). Therefore, this will allow the optimum design of the energy policies aimed at meeting specific goals (e.g. specific AES share, maximum air emissions, maximum WPM price, etc.).

3.4 Main challenges

3.4.1 Industry complexity and Systems Thinking approach

There is no doubt the world in increasingly becoming more interconnected almost from any points of view so that interdependences are increasing: International trade links nations through strong feedback loops, policy or economic changes in one nation impact other nations’ economies, technology contributes to growing interdependences as it helps to further interconnect the world (Internet, power grids, utility systems, etc.). Systems which in the past were isolated, are steadily moving towards interconnectedness as the world moves towards a globalized future (Arnold & Wade, 2015).

The Systems Thinking discipline, whose name was first coined by Barry Richmond in 1987, precisely aims at better understanding the causes of complex system behaviors in order to better predict them and, ultimately design policies in order to meet specific goals. Many researchers on the Systems Thinking field agree that this discipline will become increasingly relevant as the world exponentially becomes more complex and interconnected (Meadows, 2008; Sterman, 2000).

Surprisingly, the Systems Thinking discipline has been redefined by different authors across time, therefore existing some disagreement regarding its precise definition. Some of the most relevant definitions define Systems Thinking as: "the art and science of making reliable inferences about behavior by developing an increasingly deep understanding of underlying structure" (Richmond, 1994), "a discipline for seeing wholes. It is a framework for seeing interrelationships rather than things, for seeing patterns of change rather than static snapshots" (Senge, 2006), "a discipline with the goal to improve our understanding of the ways in which an organization's performance is related to its internal structure and operating policies, including those of customers, competitors, and suppliers and then to use that understanding to design high leverage policies for success" (Sterman, 2000) and "a set of synergistic analytic skills used to improve the capability of identifying and understanding systems, predicting their behaviors, and devising modifications to them in order to produce desired effects. These skills work together as a system" (Arnold & Wade, 2015).

Power system planning falls into the Systems Thinking space because of the many different variables it involves, which are strongly intertwined and affect very different fields such as economics, environment, politics, finance and technology.

On the technology side, in a country of the size of Spain, the power system comprises thousands of power plants of different technologies which must deliver enough power to meet the demand of millions of consumers with very demanding reliability standards. This requires a vast power grid composed of thousands of kilometers of high, medium and low voltage power lines as well as thousands of substations. As electricity storage is still limited with the currently available technology, the system must operate in real time so that production matches demand at any point in time, with all the technical challenges this fact entails.

Regarding the economics field, decisions on the power mix impact variables such as power price and imports and exports of fossil fuels. Power price may have a direct impact on a country's GDP as companies will base their investment and operation decisions on their production costs, where power price is included. If this price becomes too high, companies may decide to discontinue their operations (as it was about to happen with the Aluminum industry in Spain in 2012 with Alcoa's aluminum plants (Europa Press, 2012)) or to cancel additional investments. Power price may impact other areas such as the transportation one through the deployment of the electric vehicle, which will be fostered by lower power prices. Also, the way capital is invested in power generation assets has an impact on GDP through trade balance, national savings and direct GDP.

Imports and exports impact the country's trade balance, which impacts national savings, ultimately having an impact on GDP through capital accumulation. Also, decisions on the technologies deployed may impact a country's GDP as some technologies may be manufactured locally while others must be imported because of the lack of local technical skills. For example, in the case of Spain, wind power tends to increase local GDP (Asociacion de Productores de Energias Renovables, 2009) due to the well-developed wind power industry while technologies such as gas CC or nuclear must be acquired or licensed from foreign suppliers.

Energy impacts politics as well, mostly through the geopolitical implications related to fossil fuel imports and exports. Countries such as Spain, which has a large fossil fuel dependency, rely on foreign supplies in order to meet their energy demand. This fact entails a risk for the country, which can see its international political decisions influenced by this external dependency. So, it becomes critical for the country to minimize fossil fuel imports and / or to have a diversified pool of international fossil fuel suppliers.

Finally, the power system has a deep impact on environment as it has been the main CO_2 producer worldwide during last years (Intergovernmental Panel on Climate Change WG III, 2014). As it will be discussed below, pollution can be defined as an externality as emissions from one source affect other stakeholders. Also, emission abatement fits within the definition of Public Goods (Dahl, 2004), which makes it more difficult to tackle, as described in section 3.4.4.

Because of the reasons above, power generation system planning must be looked at from a broad system-wide perspective, taking into account all the variables affected as well as all the feedback loops, non-linearities and delays embedded in the system. This is why, a Systems Thinking approach must be used in order to obtain the right results and design the optimum policies.

3.4.2 What to optimize

As described above, the power industry is a complex system which is heavily intertwined with other fields and industries, and which has a significant impact on diverse economic, political and environmental variables which are also interrelated through different reinforcing and balancing loops.

As so many variables are affected, system optimization becomes a challenge and the question about which variables should be optimized raises. Should policies be aimed at obtaining the lowest power price for consumers at the expense of all other variables? Should policies be aimed at minimizing the environmental impact? Should policies be aimed at improving the economic performance of power utilities? Should policies be aimed at maximizing system reliability?

In most cases in the past, policies have been aimed at optimizing one or, at most, a subset of these variables. For example, governments have taken actions in order to limit the power price to be paid by consumers[40], which has been used as a political tool for attracting voters. In other cases, policies encouraging the deployment of renewable technologies aimed at reducing emissions and/or energy dependency have been implemented (Instituto para la Diversificación y Ahorro de la Energía, 1999).

Nevertheless, these policies are focused on a specific subset of variables and do not take into account the whole picture. National energy policies should be aimed at optimizing the overall well-being of a country as the fact of optimizing just a subset of variables may lead to a suboptimal outcome. Therefore, now the main question is how to measure overall well-being. Shall it be measured as consumer surplus? Shall it be measured as declining pollution? Answers to these questions are required in order to set specific policy goals.

GDP per capita is often used as a proxy for the average wealth of a country's individuals. Despite some studies argue that GDP per capita is not fully correlated with the happiness or well-being of the population (The New York Times, 2011), in many other cases this variable is considered a good indicator of well-being and happiness (The Economist, 2010). So, for the sake of this study, real GDP per capita has been taken as the main target variable. Further details on the selection on GDP as a measure of well-being can be found in section 4.8.

Therefore, in order to have an objective and consistent well-being measure, all impacts considered in this study are transformed into monetary terms by assigning a cost to them. While in some cases this is an easy task (e.g. power generation costs, investment costs, etc.) in other cases this is a more challenging task. For example, this is the case of the social costs of environmental pollution. No agreement seems to have been reached yet on the real economic cost that CO_2 emissions entail for countries so that they have to be roughly estimated as it will be discussed in subsequent sections (Interagency Working Group on Social Cost of Carbon, 2015). Also, atmospheric emissions fall within the definition of "Public Goods" so that their valuation becomes even more challenging.

3.4.3 Temporal issues. Lead times and delays

Power generation projects require very long planning and execution times. For example, the planning, permitting and construction of a wind farm can take up to 4 - 5 years while the planning, permitting and construction of a NPP can take up to 10 years (Bozzuto, 2006). This fact entails large lead times between the moment a plant is planned and its actual COD. Policies must take into account this fact in order to avoid suboptimal investment decisions.

Temporal issues are also related to investment irreversibility and capital intensity. Power generation assets are costly to dismantle or modify once built. Also, because of their large capital intensity, additional capital for alternative projects may be difficult to find. This has two relevant implications:

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[40] As it has been the case in Spain. See sections 2.2.4 and 2.5.3

i. Power systems show a significant inertia: if a power generation technology becomes more profitable than other, it will take a while for the least profitable one to be removed from the system because of its sunk costs as well as because of the costs associated to dismantling and / or modifying it (e.g. converting it from an open gas cycle to a gas CC unit). So, changing the composition of the energy mix by measures such as technology-specific incentives, has no immediate effects.
ii. Investors are prone to delay investment decisions in order to take advantage of the value of their option to invest as per the real options theory (Dixit & Pindyck, 1994).

Both implications entail delays which, in complex systems, usually lead to oscillating patterns (Sterman, 2000). When present in power systems, oscillating patterns may lead to boom and bust investment cycles which may ultimately lead to low reserve margins and large power price spikes (Ford, 1999).

3.4.4 Pollution abatement and public goods

Public goods are defined as those which their consumption by one person does not influence or reduce another person's consumption (i.e. there is no rivalry in consumption) (Dahl, 2004). Also, public goods do not allow to exclude anyone from benefitting from them. One clear example is the light from a lighthouse: consumers are not affected for other users' consumption decisions and nobody can be excluded from benefitting from it.

One relevant characteristic of public goods is that markets are expected to produce public goods below the theoretical optimum level due to the fact that each producer is expecting other producers to supply the good so that the first one can take a free ride by producing less. (Dahl, 2004)

Pollution abatement has the exact characteristics of public goods: nobody can be excluded from benefitting from it and there is no competition for it. Also, pollution producers are expecting other producers to invest in pollution abatement so that they can take a free ride and benefit from this fact.

This is why free markets are not expected to produce the optimum level of pollution abatement so that regulatory entities must step in in order to set the right incentives for achieving the optimum pollution abatement goal. This fact, adds another layer of complexity into the power system planning problem.

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Chapter 4
Modeling approach and literature review

4.1 Introduction

The main underlying problem to be addressed by the present research involves basically long run dynamic forecasting. The future composition of the energy mix and its impact on environment, economics, etc. must be forecasted in the long run based on current policy levers and exogenous variables, taking into account additional considerations such as system inertia, delays, uncertainty, behavioral aspects and dynamic system interactions. As a second derivative, the present problem involves optimization as well: once it is known how the system is expected to evolve based on policy levers, it is required to find those policies which allow to meet the desired goals (e.g. specific share of renewable energy, maximum CO_2 emissions, minimum reserve margin, etc.). Finally, the present problem requires the use of supply-demand equilibrium models in order to simulate the operation of WPMs as well as of economic Input – Output models in order to assess the overall economic impact of the power system.

This chapter discusses the modeling techniques usually applied to power system planning, their pros and cons and their suitability to address the present problem. Also, the selection of the SD and Input – Output methodologies for the present research is explained and justified.

4.2 Discussion on modeling techniques

Diverse optimization techniques such as linear and integer programming, game theory, real options, decision trees, forecasting, etc. have been traditionally used under regulated market environments in order to optimize investment decisions on power generation capacity additions (Dyner & Larsen, 2001; Kagiannas, et al., 2004). Also, econometric methods have been widely used in order to describe the statistical relations between economic variables and provide forecasts in power markets.

The transition from regulated to deregulated markets has entailed two relevant changes in the capacity expansion process as (i) utilities had to switch from traditional optimization-based planning to strategy-based planning and (ii) the planning capacity expansion process has been reformulated from a cost-minimization problem, where the goal was to determine the right level of generation capacity, the optimal mix of technologies and the timing of investments at a minimum cost and adequate level of reliability (Olsina, et al., 2006), to a profit-maximization problem (Kagiannas, et al., 2004; Hasani & Hosseini, 2011). This transition entails the necessity to switch from "hard" modelling techniques (e.g. optimization) to models which include "soft" variables such as market perceptions, public opinion, politic interests and bundled rationality (Larsen & Bunn, 1999; Gary & Larsen, 2000; Dyner & Larsen, 2001; Olsina, et al., 2006; Assili, et al., 2008). In addition, the use of econometric methods based on large historical datasets becomes difficult as new liberalized power markets have had a short life so that there is not much historical data available for model calibration.

This fact does not mean that legacy optimization models must be discarded. Instead, optimization models are still useful in deregulated environments for short term planning (e.g. WPM price bidding) or as benchmark models. Nevertheless, behavioral dynamic simulation methods, which provide an explanation of how industry players behave and how the market will evolve, have become increasingly interesting in the case of long term analysis.

Different kinds of mathematical methods have been under development during the last years in order to facilitate investors' decision making on power generation capacity expansion. Short and medium-term models are the ones which have experienced the largest development (Sanchez, et al., 2012). On the other hand, long term models are still a more unexplored area (Kagiannas, et al., 2004), being this probably due to the fact that, at the beginning of their deregulation processes, most European power markets were in a state of overcapacity inherited from the previous regulated expansion periods. Because of this fact, investors and operators were more concerned about optimizing the allocation of the existing assets instead of planning for new capacity. As reserve margins declined due to the increasing demand, long term capacity planning has become a concern for investors again.

The sections below, describe in further detail the modeling techniques which have been traditionally most often used for power system planning and discuss their suitability for the present research.

4.2.1 Forecasting techniques

HISTORICAL TRENDS

Historical trends are one of the simplest forecasting tools. They basically extrapolate past historical trends into the future by using the functions (e.g. lineal, exponential, logarithmic, etc.) which best fit historical data series.

This technique may be effective for modeling short run, business-as-usual scenarios where steady growth rates and no disruptive events are expected. Nevertheless, this technique does not predict well turning points, disruptive events or long run forecasts.

Due to the long run approach of the present study and because of the complexity of the power system where, for example, large non-linearities are present, this forecasting tool has been only considered in order to assess the future evolution of a few exogenous variables, combined with stochastic random walk modeling in those cases where uncertainty is present.

TIME SERIES ANALYSIS

This technique is a more sophisticated extrapolation procedure which consists of computing the future value of a variable either based on its past values (univariate time series analysis) or on its past values and the past values of other variables (multivariate time series analysis). In both cases an error term (ε) modeled by a random variable is introduced in order to introduce randomness in the model.

Univariate models are used when the evolution of the variable under study depends only on its past values so that for example cyclic behaviors can be reproduced. Multivariate models are used when the evolution of the variable under study depends not only on its past values but also on the past values of other variables.

The univariate model is formulated as:

$$X_t = \sum_{i=1}^{n} \alpha_i \cdot X_{t-i} + \varepsilon_t \qquad (4.1)$$

Where: X_t = Variable analyzed value at time t

n = Number of past values considered

α_i = Constant coefficients

ε_t = Random error term

The multivariate model is formulated as:

$$X_t = \sum_{i=1}^{n} \alpha_i \cdot X_{t-i} + \sum_{i=1}^{m} \beta_i \cdot Y_{t-i} + \varepsilon_t \sum_{i=1}^{o} \gamma_i \cdot Z_{t-i} + \varepsilon_t \tag{4.2}$$

Where: X_t = Variable analyzed value at time t

Y_{t-1}, Z_{t-1} = Variable analyzed value at time t

n, m, o = Number of past values considered for each variable

α_i, β_i, γ_i = Constant coefficients

ε_t = Random error term

Statistical techniques are used to compute the constant coefficients (α, β, γ) as well as the number of lags (n, m, o) which make the model best fit to the historical data series.

This technique may model a wider range of cases as it is able to model not only constant growth rate scenarios but also cyclic patterns. It works well for modeling systems with consistent structural regimes with significant variation in the variables on the right side of the equations.

Nevertheless, this technique is in general more suitable for short-term modeling as it does not forecast turning points or disruptions well. Also, it needs a significant amount of historical data in order to properly compute the constant coefficients as well as the time lags. Finally, time series analysis requires the accurate forecasting of the exogenous variables on the right side of the equations.

ECONOMETRIC TECHNIQUES

Econometric techniques are similar to time series analysis but more attention is put on the variables that should be included in the model and data may be more cross sectional. When only small datasets are available, this technique is preferred over time series analysis as in the case of the second one, it is difficult to accurately compute the constant coefficients and lags. So, economic theory is used as an additional tool for designing the model structure.

Econometric model still rely on statistical techniques for model calibration (i.e. computation of the constant coefficients) and when used for forecasting purposes, requires an accurate forecasting of the exogenous variables driving the model.

BAYESIAN TIME SERIES ANALYSIS

Bayesian time series analysis allows the introduction of subjective estimations when computing the constant model's coefficients. These estimations may be based on issues such as the modeler's experience in the specific industry. If these subjective values are correct, the model's output may be more accurate than in the case of using only historical data for its calibration.

For example, in the univariate time series equation below, it can be considered, that based on the modeler's experience, α_i follows a Normal distribution with mean 5 and standard deviation 1:

$$X_t = \sum_{i=1}^{n} \alpha_i \cdot X_{t-i} + \varepsilon_t \qquad \alpha_i \sim \mathrm{N}(5,1) \tag{4.3}$$

SCENARIO ANALYSIS

Scenario analysis is not a pure forecasting technique. It is rather a what-if analysis which assess the system outputs by assuming that exogenous variables follow a preconceived path. This does not involve any dynamic assessment of how endogenous variables will evolve over time. Instead, some endogenous system variables have to be assumed as exogenous while the computation of the remaining endogenous variables is directly made by running "snapshot" models[41] on the preconceived scenarios.

This technique is useful in order to assess the effect of disruptive events that usually cannot be simulated just by applying sensitivity analysis to forecasted exogenous variables. The scenarios generated are then used to assess different strategies and policies.

The main drawback of this technique for the present research is its inability to forecast the dynamic evolution of the system based on exogenous variables. For example, in case one scenario assumes a sharp decline of natural gas prices the share of gas CC power plants in the power mix is expected to grow. Nevertheless, scenario analysis is not able to determine by how much, so that this has to be assumed by the modeler. On the other hand, SD would be able to forecast this growth as the exact mechanisms driving power generation investment based on fossil fuel price (amongst many other exogenous variables) are modeled.

4.2.2 Optimization techniques

Optimization techniques aim at finding the optimum solution (i.e. the one that maximizes the value function) in large multivariate problems. Optimization problems consist of three elements (Bradley, et al., 1977):

i. An objective function that must be maximized (e.g. profit) or minimized (e.g. cost)
ii. The decision variables, which are the variables under the modeler's control and whose value will be the result of the optimization problem, along with the final value of the objective function
iii. Constraints: Additional equations that restrict the choices for decision variables

[41] For example, accounting models such as energy balances, input-output, end-use or process models.

Optimization has been widely used in the power industry prior to its liberalization. The fact of the regulator having full (or almost full) access to information, the capability to calculate the optimum scenarios as well as to plan and develop the power mix accordingly made optimization a widely used modeling technique before market liberalization.

A wide array of optimization techniques are used depending on the nature of the problem. Some of the most widely used techniques are described below:

LINEAR PROGRAMMING

Linear programming (also known as linear optimization) is a specific case of an optimization problem where both the objective function and constraints are linear equations. This technique has gained much attention during the last decades because of its applicability (many real world applications may be modeled as linear problems) and its solvability (there are several efficient techniques for solving large scale problems). The linear programming problem can be expressed in its canonical form as:

Maximize: $c^T x$

Subject to: $Ax \leq b$

$x \geq 0$

Where "x" represents the vector of decision variables, "c" and "b" are the vectors of known coefficients and "A" is a matrix of known coefficients.

There are several algorithms useful for solving this optimization problem being the Simplex method one of the most widely used.

NONLINEAR PROGRAMMING

Nonlinear programming (also known as nonlinear optimization) is a more generic optimization problem where either the objective function or any of the constraints are nonlinear equations. The nonlinear programming problem can be expressed in its canonical form as:

Maximize: $f(x)$

Subject to: $g_i(x) \leq 0$

$h_j(x) = 0$

Depending on the characteristics of the objective function (concave, convex, a combination of both or quadratic) different computation algorithms (quadratic programming, fractional programming, branch and bound techniques, etc.) are used for solving the problem.

INTEGER PROGRAMMING

Integer programming is a particular case of either linear or nonlinear optimization problems where all decision variables are constrained to be integers. This is useful for example when binary (yes / no) solutions are required as it may be the case when it must be decided whether a specific power generation unit must operate or not. This problem can be expressed in its canonical form as:

$$
\begin{aligned}
&\text{Maximize:} && f(x) \\
&\text{Subject to:} && g_i(x) \leq 0 \\
& && h_j(x) = 0 \\
& && x \in Z
\end{aligned}
$$

Specific algorithms (e.g. cutting plane methods, branch and bound methods, heuristic, etc.) are used to solve this particular optimization case.

MIXED INTEGER PROGRAMMING

Mixed integer programming is another particular case of either linear or nonlinear problems where just some of the decision variables are constrained to be integers, being the rest of decision variables allow to be real numbers only constrained by the equations specific to the problem.

DYNAMIC PROGRAMMING

While all previous optimization techniques are "static" (i.e. the optimize systems by finding the optimum decision variable values, regardless of the time where these decision variables must be enacted), many optimization problems (such as the power generation capacity expansion) require a sequence of decisions to be made at specific points in time (e.g. the decision to start planning a project, the decision to invest in the permitting & design of a project or the decision to invest in in the actual construction of the project).

Dynamic programming is an analytical framework aimed at solving problems where time is an additional constraint, so that different optimum solutions must be adopted at different points in time depending on the evolution of the system. Dynamic programming has been described in the literature as the most general optimization technique because in general, it can solve the widest array of problems.

STOCHASTIC OPTIMIZATION

While all previous optimization models are based on deterministic approaches (i.e. all equation coefficients and constants are known in advance), the stochastic programming methodology is a probabilistic approach which is useful for optimization under uncertainty. This approach assumes that probability distribution governing random variables are known or can be estimated. The problem can be expressed in its canonical form as:

Maximize: $f(x)$

Subject to: $g_i(x) \leq 0$

$h_j(x) = 0$

$x \sim N(a, \sigma^2)$

This technique aims a finding a solution which is feasible for all the possible data instances and maximizes the expected value of some function of the decision and random variables. Stochastic optimization has been applied in multiple disciplines including for example finance, transportation and energy.

ROBUST OPTIMIZATION

This technique is similar to stochastic optimization in the sense that it involves uncertainty regarding specific variables. Its main difference is that while the stochastic optimization technique assumes that the probability distributions of random variables are known in advance or can be estimated, robust optimization assumes that only the boundaries of random variables are known in advance. Robust optimization has been applied to fields such as operations research, finance, portfolio management, manufacturing, energy, etc.

Robust optimization techniques are often solved by means of Monte Carlo simulation approaches. When the computational requirements are demanding, diverse techniques (e.g. out-of-sample validation) are applied in order to reduce the number of simulations.

4.2.3 Decision theory

On the contrary to optimization, the goal of decision theory is not to find the optimum final state but to find the most robust and flexible plan (decisions to be taken at each moment in time) in order to reach a specific final state. So, it does not aim at analyzing equilibriums, policies or strategies under different scenarios but at choosing the most efficient decisions to meet specific goals. Robustness can be seen as how close the system's parameters are to the optimum ones in each system state while flexibility measures the capacity of the system to adapt to unexpected changes of exogenous system variables.

Therefore, other techniques such as scenario analysis, optimization, etc. are usually used in order to assess the effect of different policies and strategies. Then, a target scenario is chosen and decision theory is used in order to find the optimum decisions for achieving the chosen outcome.

Classical decision theory approaches include the Wald procedure, which minimizes the maximum cost, the Savage procedure, which aims to minimize the maximum regret (i.e. to minimize the difference between the proposed solution and the best solution of each scenario), and the Hurwicz procedure, which represents intermediate situations between the one of greater optimism (to maximize the best result) and the one with the smaller pessimism (to minimize the worst result).

4.2.4 Investment valuation under uncertainty

REAL OPTIONS

The real options theory is used as an alternative to the standard DCF approach for investment valuation. It provides information not only about the value of the investment but about the right moment to do it. It is an adaptation of the financial options theory to the case of tangible assets such as power plants.

While standard DCF analysis assume a static view of investment decisions, projected cash flows and discount rates, real options entail a more dynamic approach which incorporates not only the value of flexibility and expansion opportunities but also of competitive strategies in an uncertain environment (Smit & Trigeorgis, n/a). For example, a project that shows a negative NPV based on standard DCF analysis, may have a positive total strategic value when the value of flexibility is factored in.

In order to do so, real options theory makes an equivalence between financial options and the option to invest in a tangible asset, such as a power plant. Then, the real option is valued by using the same techniques applied to financial option valuation (stochastic dynamic programming, etc.), which assume that some of the underlying variables with an impact on the investment are random.

The fact of explicitly considering uncertainty makes this method very useful in uncertain scenarios and in the presence of investment irreversibility, as it is the case of liberalized power generation markets. On the other hand, the fact of assuming a power generation asset as an equivalent to a financial asset is highly debatable because of the technical simplifications it entails as well as because of the difficulty of assigning specific random distributions to variables such as the WPM.

So, rather than a pure dynamic simulation methodology, the real options theory provides an investment valuation framework with a more dynamic approach than the standard DCF analysis. An exhaustive review of the application of the real options theory to power generation capacity expansion problems can be found in (Botterud, 2003).

MONTE CARLO SIMULATIONS

Monte Carlo simulation is a methodology that can be combined with other techniques in order to model uncertainty and random behavior. It is a stochastic approach which assigns probability distributions to the variables which show uncertainty, and simulates a number of cases so that probability distributions for the output variables are computed. This way, confidence intervals for the trajectories over time of the selected output variables can be obtained. Monte Carlo simulations may be univariate (only one random variable involved) or multivariate (several random variables involved).

4.2.5 Equilibrium techniques. Game theory

Game theory is a set of mathematical models which describe conflict and cooperation between intelligent rational decision makers. It provides a framework for analyzing competitive scenarios where the outcomes of each competitor's decisions depend not only on the decision but also on the reaction of the rest of the competitors to the decision.

This theory leads to eventual equilibrium states which depend on the strategies chosen by competitors being the main ones the Cournot equilibrium (competition on quantities), the Bertrand equilibrium (competition on prices), the Stackelberg equilibrium (quantities set by a leader and competition on quantities by the rest), and Nash equilibrium (when no competitor can improve its situation by any unilateral decision he may make).

Different mathematical techniques are used in order to solve this models, being the main ones iterative methods, mathematical programming with equilibrium constraints, equivalent quadratic problem and mixed complementary problem.

Because of its characteristics, game theory is often used under competitive environments as a modeling tool for short term static problems such as operation planning. Its use in long term dynamic problems has been much more limited, having it also been restricted to small size problems (Sanchez Dominguez, 2008).

4.2.6 Simulation techniques

AGENT BASED MODELING

This technique explicitly represents and simulates the behavior of each single system agent, who makes his own decisions in order to reach specific goals (e.g. profitability, etc.). This technique is suitable for modelling problems where agents are in continuous interaction, decisions are taken continuously and the strategies are adapted frequently. So, this technique has been widely applied in short-term models, mainly in the analysis of bidding strategies in spot markets (Sanchez Dominguez, 2008). This methodology has been rarely used in long term planning problems because they lack most of the characteristics mentioned above.

SYSTEM DYNAMICS

SD is a method which was first established at MIT by Jay W. Forrester in the 50s with the goal of studying and understanding the long-term behavior of complex systems. It is based on the construction of a descriptive model composed of variables related through equations and feedback loops which aims at replicating the behavior of a real system along time. This is the main technique chosen for the present work and it has been combined with additional modelling techniques as it will be described below. Section 4.5 includes a detailed description of the SD methodology.

4.3 Justification for the use of the System Dynamics methodology

As previously described, the main underlying problem to be addressed by the present research involves basically long run forecasting. Power system regulators must be able to properly forecast the evolution of the power generation mix and its overall economic impact based on exogenous variables and external levers such as energy policies and incentives.

While in principle the forecasting techniques described in section 4.2.1 (e.g. econometric, time series analysis, etc.) seem the most suitable ones for addressing the present problem, there are some arguments against their utilization. The liberalization of Spain's power market took place in 1998, just 19 years ago so that the amount of historical data available necessary to calibrate econometric models is limited. Also, Spain's power industry has gone through dramatic changes during this period: the country has experienced the inception and booming of AES technologies, the inception of the electrical vehicle, there have been investment boom cycles, a global economic downturn has made power demand to shrink, distributed generation is growing, etc.

Standard forecasting techniques such as time series analysis or econometric models are more suited to stable frameworks with no relevant structural changes so that they can be calibrated against historical data in order to forecast future scenarios. In scenarios where structural changes take place, such as Spain's power system, these techniques lose relevance while simulation techniques focused on understanding the structure and operation of the system become increasingly interesting.

Also, while techniques such as game theory, microeconomic models (e.g. Cournot and Bertrand) or operational research are useful for modelling markets under equilibrium conditions, behavioral dynamic models are well suited for describing non equilibrium conditions. This kind of conditions is often present in power markets due to their dynamic nature, mostly caused by long time delays and investor behavior, which often leads to boom and bust cycles so that the system does not always remain on its optimal trajectory at every point in time (Larsen & Bunn, 1999; Ford, 1999; Ford, 2001a; Ford, 2001b; Kadoya, et al., 2005; Assili, et al., 2008; Hasani & Hosseini, 2011). Also, non-equilibrium conditions may exist in markets in transition, such as the case of power markets under deregulation processes where strategic imbalances may exist. Therefore, static models based on equilibrium conditions are not the most appropriate ones for analyzing long-term fluctuations in complex systems as they do not take into account the interplay of variables with time but just provide a static picture which does not provide much information about the trajectory and evolution of a system towards its equilibrium state (Assili, et al., 2008).

Two simulation techniques are especially suited for addressing the abovementioned issues: SD and ABM. Both methodologies belong to the group of dynamic models that focus on understanding the interdependencies of the different variables in a system, focusing on feedback loops and so allowing the simulation of non-equilibrium, changing conditions. Also, on the contrary to optimization models, these methodologies allow the introduction of bounded rationality and "soft" variables such as market perceptions, public opinion or management aspirations which are present in deregulated markets.

The main difference between ABM and SD is that, while ABM models individual industry players at a highly detailed micro level, SD models systems from a more aggregated macro perspective. While SD has been extensively used for both short and long term power system modeling, ABM has been mostly applied to short term modelling problems so far (Garcia Alvarez, et al., 2008). For the sake of the present research, there is no need to model power plants from an individual perspective as the system can be modelled in an aggregated way, just broken down by power generation technology and age, and characterized by average variable values.

The following differential factors of SD make this technique very suitable for the power capacity expansion problem discussed in the present research (Teufel, et al., 2013):

i. Capability to implement delays: This is a key issue in the case of power generation capacity expansion problems. This is due to the long lead times required for planning, permitting and executing power generation project.

ii. Capability to implement soft variables and bounded rationality considerations: While other "hard" modeling techniques such as optimization assume perfect information in order to find the optimum solution, SD allows to model the so-called "imperfect foresight", by which industry players have limited information and have to base their decisions on the available market information. While under regulated systems, the regulator was assumed to have full (or almost full) information (e.g. rates, power generation costs, etc.), liberalized markets entail limited information (e.g. players don't know how competitors will react to their decisions or to market changes). In addition, SD allows the introduction of soft variables such as investor's perceptions or public opinion on specific generation technologies.

iii. Dynamic approach: While other methodologies assume that the system instantly evolves to equilibrium states, SD allows the simulation non-equilibrium trajectories from an initial equilibrium point to a new equilibrium point (which may be reached or not). This is possible because of the dynamic nature of the technique and its capability to simulate delays, system inertias, non-linearities, etc. This fact is of special importance in the case of power systems as they (i) show large inertias and (ii) have gone or are going through deep transformation processes which make them stay away from equilibrium points. For example, if there is a shock in demand by which it increases sharply, the long lead times required for building new power plants will prevent the system from reaching an equilibrium point immediately.

iv. Causal relation approach: While other techniques such as econometric models are based on statistical approaches, SD is based on causal relations which allow to incorporate to the model qualitative influences that may be present in the system although not reflected in past historical data.

v. Aggregated approach: While other techniques such optimization or ABM usually focus on specific system actors at a micro level, SD usually considers systems from a more aggregated perspective. For example, an SD model's agent may be a country's whole industry or even have a cross-industry approach. Therefore, SD models can often reach beyond what is usually included in traditional analytical methods in terms of scope.

Therefore, SD is the underlying modelling methodology chosen for the present research. There is extensive literature on the application of SD to power markets: compilations of the most important contributions on SD for long term power generation capacity planning can be found in (Ford, 1997), (Bunn, et al., 1997) and (Teufel, et al., 2013). Section 4.4 includes a compilation of the most relevant references of the application of SD to power markets.

Finally, forecasting models can be either deterministic or probabilistic. Deterministic models provide just one specific output value as a function of specific exogenous variables. On the contrary, probabilistic models do not provide just one specific output value but a probabilistic distribution based on exogenous variables which are modeled as random variables. This is useful in the case where the evolution of exogenous variables is not know in advance such as in the case of the power industry, where the future evolution of variables such as oil price, CO_2 price, etc. is not known in advance.

Therefore, while SD is by itself a deterministic technique, it can be combined with stochastic methodologies such as Monte Carlo simulations in order to properly model the uncertainties inherent to variables such as commodity prices or power demand. So, the model developed for the present research combines the SD methodology with Monte Carlo simulations where stochastic variables are assumed to follow random walks as described in section 6.6.

4.4 System Dynamics applied to energy planning. Literature review.

The use of SD for the simulation of energy markets can be traced back to the early 70s when research on world dynamics and natural resource depletion was being done at MIT and Dartmouth. Subsequent studies on energy resources followed and a number of energy models such as COAL2, FOSSIL2, etc. were developed.

There is extensive literature on energy modelling. (Weijermars, et al., 2012) provide a high level summary of general energy modelling techniques. (Dyner & Larsen, 2001) discuss the evolution of power capacity planning methods due to the transition from regulated to unregulated markets. (Kagiannas, et al., 2004) present a comprehensive review of power generation planning methods for competitive markets as well as a review of the models previously used under regulated environments.

There is also extensive literature on the application of SD to energy markets: (Bunn, et al., 1997) present a model aimed at getting insight into the market power that a dominant power generator might get from its size and ability to operate both in the gas and power spot markets. (Wu & Xu, 2012) present a SD model combined with multi-objective programming in order to predict energy consumption at a regional level. (Shrestha, et al., 2012) use SD in order to assess the energy requirements and their associated footprint to move water from water sources to consumption points in California. (Abbas Seifi, 2013) use SD in order to assess the energy consumption and CO_2 emissions of the Iranian cement industry under different production and export scenarios. (Robalino-Lopez, et al., 2014) present a SD model aimed at predicting the impact that changes in the energy matrix and GDP growth will have on a country's CO_2 emissions and apply it to the specific case of Ecuador.

Finally, there is also extensive literature on the application of SD to power markets: compilations of the most important contributions on SD and long term power generation capacity planning can be found at (Ford, 1997), (Bunn, et al., 1997) and (Teufel, et al., 2013). (Bunn & Larsen, 1992) provide insights regarding how investments in generation capacity may evolve according to different regulatory conditions, economic assumptions, degrees of competition and strategic behavior of utilities in England and Wales. (Bunn, et al., 1993) show that optimization techniques are more suited for simulating rate of return, capital structure and tax implications due to the deregulation of power systems while SD is more useful for simulating the regulatory, uncertainty and competitive effects. (Ford, 1999) and (Ford, 2001a) uses SD in order to assess the impact of capacity payments on investment boom and bust cycles and analyses California's 2000 and 2001 power market crises. (Gary & Larsen, 2000) discuss the advantages of dynamic simulation models such as SD over equilibrium models for the simulation of markets in transition. (Kadoya, et al., 2005) assess the impact of deregulation on generation capacity growth and show that deregulation is a driver for the boom-and-bust cycles that occurred in the US in the nineties. (Olsina, et al., 2006) present a mathematical formulation for modelling generic power markets under the SD framework, (Ford, 2006) presents an interdisciplinary approach that combines SD and engineering methods in order to simulate a cap and trade market aimed at controlling the emissions in the US western electricity system. (Arango, 2007) uses SD in order to evaluate alternative regulation schemes regarding capacity payments for the Colombian electricity market. (Sanchez, et al., 2008a) combine a SD model with an oligopoly model for forecasting reserve margin and power price. (Garcia Alvarez, et al., 2008) describe a model of Spain's power industry aimed at assessing whether the market price and current capacity payments are enough for achieving the required reserve margin. (Assili, et al., 2008) simulate and explore an improved mechanism for capacity payment in a competitive environment. (Hasani & Hosseini, 2011) present a model aimed at examining the performance of electricity markets under different capacity payment mechanisms. (Pereira & Saraiva, 2011) present a model aimed at solving the generation expansion planning problem in competitive electricity markets by using a combination of SD and Genetic Algorithms. (Hsu, 2012) uses a SD approach for assessing the impact of incentives on the development of PV power, on system costs and on CO_2 emissions in Taiwan. (Sanchez, et al., 2012) combine a SD model with a MOPP model in order to forecast the future investments in CCGT and wind power. (Alishahi, et al., 2012) use a SD model in order to evaluate innovative and improved incentive mechanisms for wind power investment. (Qudrat-Ullah, 2013) introduces a SD model with the goal of assessing the impact of exogenous variables on the evolution of the Canadian power generation mix as well as on the power price and capacity gap. (Kunsch & Friesewinkel, 2014) uses a SD model for assessing the impact of the Belgian phase-out law on the power generation mix, power price, oil dependency, CO_2 emissions and power demand under different energy policy scenarios.

4.5 Description of the System Dynamics methodology

4.5.1 Introduction

The SD methodology aims at simulating the evolution of complex systems over time based on the system's internal structure, its initial state and the evolution of exogenous variables.

The model's structure is composed of system variables[42] and connecting links, which represent the mathematical relations between them. The evolution of the system across time is determined by the system structure as well as by the exogenous variables, which in the case of power systems may be commodity prices or levers such as incentive policies. As an example, a simplified SD model for power capacity additions consisting of only one technology (gas CC) is presented. It includes the following variables:

- Installed capacity
- WPM price
- Natural gas price
- Power demand
- Profitability
- Incentive policies

In this case, the links between variables include the direct relation between profitability and installed capacity, the direct relation between installed capacity and technology efficiency, the inverse relation between installed capacity and WPM price, the direct relation between efficiency and profitability, the direct relation between WPM price and profitability, the direct relation between power demand and WPM price, the direct relation between incentive policies and profitability and the inverse relation between natural gas price and profitability.

Finally, in this specific example the exogenous variables driving the behavior of the model along its structure are natural gas price[43], power demand[44] and incentive policies. Figure 4-1 shows a simplified conceptual diagram for this model.

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[42] Both level and auxiliary variables

[43] Assuming as a simplification that global market price is inelastic to gas consumption in the country under assessment

[44] Assuming as a simplification that it is fully inelastic to price

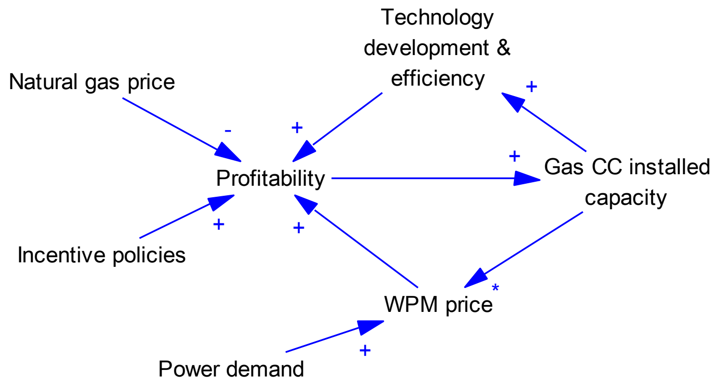

Figure 4-1: Simplified capacity expansion SD model diagram

4.5.2 Development of a System Dynamics model

The development of a SD model is based on a structured process which entails the following steps (Albin, 1997; Randers, 1980; Sterman, 2000):

i. Problem articulation
ii. Formulation of dynamic hypothesis
iii. Formulation of a simulation model
iv. Testing & Calibration
v. Policy design and evaluation

PROBLEM ARTICULATION

The problem articulation phase involves answering questions such as: what is the purpose of the model? What is the nature of the problem to be solved? Why there is a problem? This phase includes tasks such as the definition of key variables, model boundaries, and time horizons.

The definition of key variables entails the identification of the required output variables, the identification of exogenous variables, which will be considered as "given" and will be driving the behavior of the model as well as the required endogenous auxiliary variables. Exogenous variables can be either parameters outside of the model boundaries (e.g. natural gas price in the present example) or policy levers used to modify the behavior of the system (e.g. incentive policies in the present example). Endogenous auxiliary variables are neither outputs nor inputs to the model but internal variables required to perform the computations (e.g. profitability in the present example)

Time horizon definition is also a key issue as it has to extend far back enough in order to show how the problem emerged and describe the symptoms. Also, the time horizon must extend far enough into the future in order to capture the effects of delays and business cycles, both of which are very relevant in power systems simulation.

The definition of boundaries involves the distinction between what is internal and what is external to the model. Because of the complexity of some systems (such as the power industry) models can easily get too complex by extending their boundaries far beyond the specific area or problem to be analyzed. Therefore, boundaries must be set in order to constrain the problem to the specific set of variables relevant to the problem under assessment. For example, in the present example it could be considered that the price of natural gas depends on the country's actual gas power generation so that an additional supply-demand model should be included in order to assess the impact of national natural gas consumption on international natural gas markets. Nevertheless, the boundaries of the model have been set so that natural gas price is considered as an exogenous variable[45] so that this additional model is not required.

FORMULATION OF DYNAMIC HYPOTHESIS

This phase involves the definition of the reference modes and the nature of the basic mechanisms to be considered in the problem.

Reference mode definition involves the analysis of the historical behavior of key concepts and variables as well as the formulation of hypothesis regarding how they may behave in the future.

The definition of the basic mechanisms involves the design of the mechanisms that enable the model to generate the desired or expected reference modes. These basic mechanisms represent the smallest set of cause and effect relations capable of generating the reference mode. The basic mechanisms may also be thought of as the simplest story that explains the dynamic behavior of the system. These mechanisms are basically composed of feedback loops which may be either balancing or reinforcing.

Model mechanisms are based on dynamic hypothesis made by the modeler. Dynamic hypothesis are explanations of the reference mode behaviors present in the system and should be consistent with the model purpose. Based on these hypothesis the mechanisms are drafted and tested. These relations and feedback loops are graphically represented in the so-called "causal diagrams". Figure 5-3 shows the causal diagram of the present example.

[45] Which is a reasonable hypothesis as the natural gas demand of a relatively small country is not expected to have a huge impact on the global natural gas trade

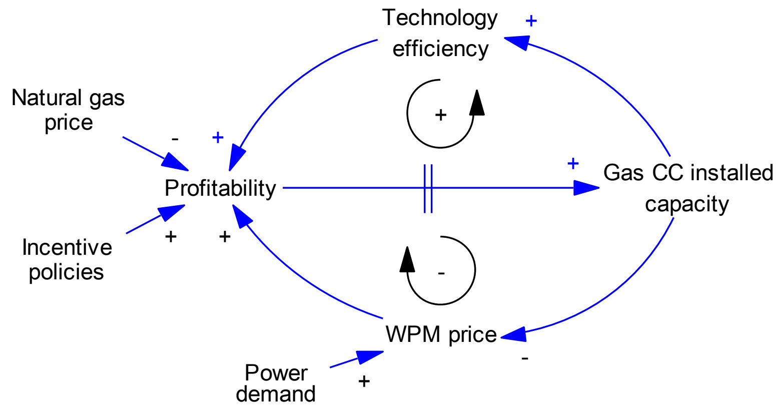

Figure 4-2: Simplified capacity expansion SD model causal diagram

Causal diagrams are the simplest graphic representation of the system structure and include all of their basic elements: variables, relations between variables (including their polarity: direct or inverse), delays and feedbacks (including their type: balancing or reinforcing).

Variables are represented by their names. Relations between variables are represented by arrows pointing from the input variable to the output one. A positive sign next to the arrowhead means that the relation between the variables is direct (i.e. the output variable increases with the input one) while a negative sign means that the relation is inverse (i.e. the output variable decreases with the input one). Feedback loops are represented by circular arrows with a "-" or "+" sign inside in the case of balancing and reinforcing feedback loops respectively. Finally, delays are represented by a double short straight line crossing the linking arrows. Exogenous variables are those who do not have any "system cause" (i.e. no input arrow). In our example, natural gas price, incentive policies and power demand are exogenous variables.

In the example, the feedback loop involving WPM price is a balancing one: gas CC installed capacity increases with gas CC profitability which makes WPM price decrease[46]. This makes gas CC profitability decrease leading to declining ("balancing") installed capacity.

The second feedback loop, involving technology efficiency is a reinforcing one. Gas CC installed capacity increases with gas CC profitability. Technology efficiency increases with gas CC installed capacity and profitability increases with technology efficiency, which leads to a further increase of gas CC installed capacity.

The independent effects of the balancing and reinforcing loops described above are shown in Figure 4-3 through Figure 4-6. If only the reinforcing feedback loop is present, increasing installed capacity leads to improved efficiency which entails greater profitability so that installed capacity increases further. This leads

[46] Because of the supply-demand balance and assuming constant power demand

to the exponential growth in the commissioning rate and installed capacity shown in Figure 4-3 and Figure 4-4 respectively.

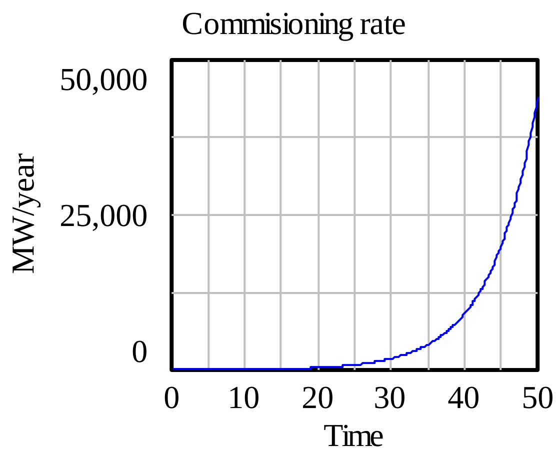

Figure 4-3: Commissioning rate – Reinforcing loop only

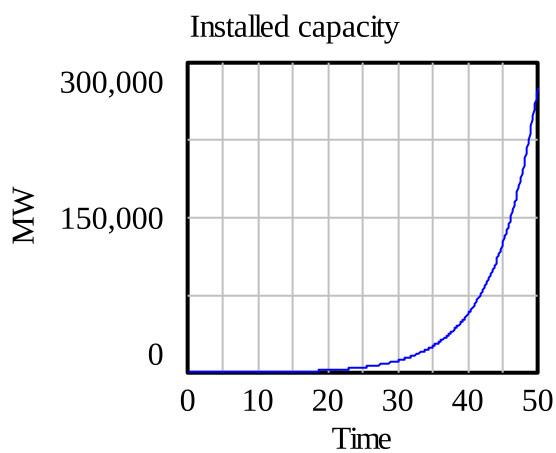

Figure 4-4: Installed capacity – Reinforcing loop only

The outcome when the only the balancing loop is present is very different. Increasing gas CC installed capacity leads to declining WPM price[47] because of the supply-demand balance. This leads to declining WPM price and so to declining investments in new capacity. This process iterates over time until the commissioning rate becomes zero. The evolution of the commissioning rate and installed capacity under this scenario are shown in Figure 4-5 and Figure 4-6 respectively.

[47] Assuming constant power demand

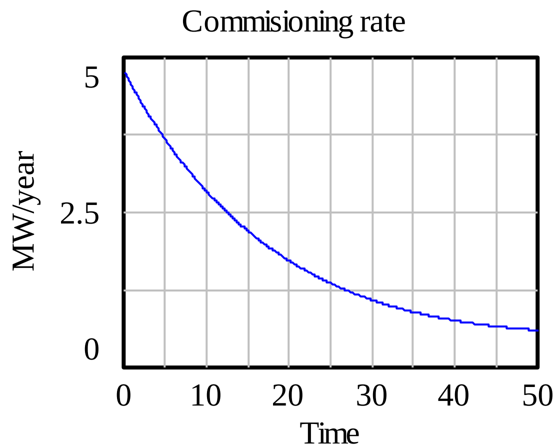

Figure 4-5: Commissioning rate – Balancing loop only

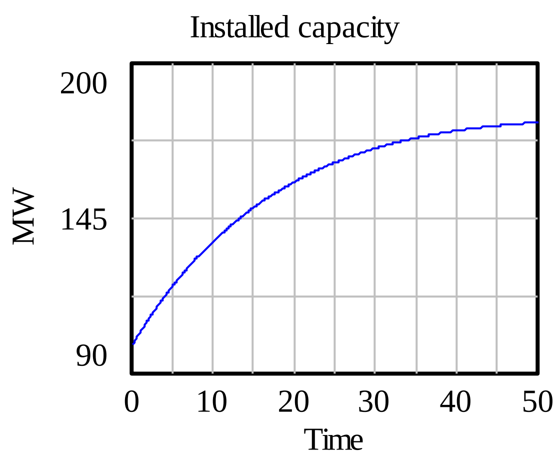

Figure 4-6: Installed capacity – Balancing loop only

Feedback loops are the basis of the SD modeling methodology. The number, polarity and strength of feedback loops in a model leads to well-studied specific behaviors such as S-shaped growth curves, bell growth curves, exponential growth and decay, oscillating patterns, etc.

Figure 4-7 and Figure 4-8 show the evolution of the commissioning rate and installed capacity when both the balancing and reinforcing loops are active. As it can be observed, the reinforcing loop prevails at the beginning of the simulation so that the commissioning rate and the installed capacity grow exponentially. Nevertheless, as the simulation goes on, the balancing loop becomes stronger and ends up prevailing over the reinforcing loop. The effect of declining WPM prices on profitability is greater than the effect of increasing efficiency. So, the commissioning rate finally becomes zero and the installed capacity remains constant.

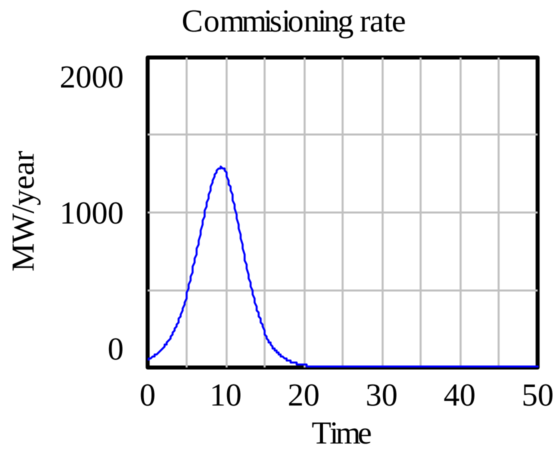

Figure 4-7: Commissioning rate – Balancing and reinforcing loops

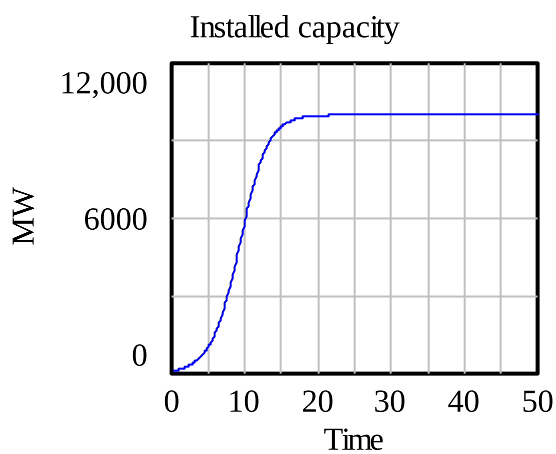

Figure 4-8: Installed capacity – Balancing and reinforcing loops

Once the causal diagrams have been defined, the next modeling step is the definition of the stock & flow diagrams. While causal diagrams emphasize the feedback structure of the system, stock & flow diagrams emphasize the underlying physical structure. They also enable to differentiate which variables represent a state of the system (stock variables) from those which set the rates at which stock variables change and from those which are just auxiliary variables required for intermediate computations.

Stocks are inventory variables such as products, population, money or installed capacity in our example. Flows are the rates of increase or decrease of stocks such as production, birth and deaths, payments or power plant commissioning and decommissioning rates in our example. Figure 4-9 shows the stock & flow diagram for the example system under discussion.

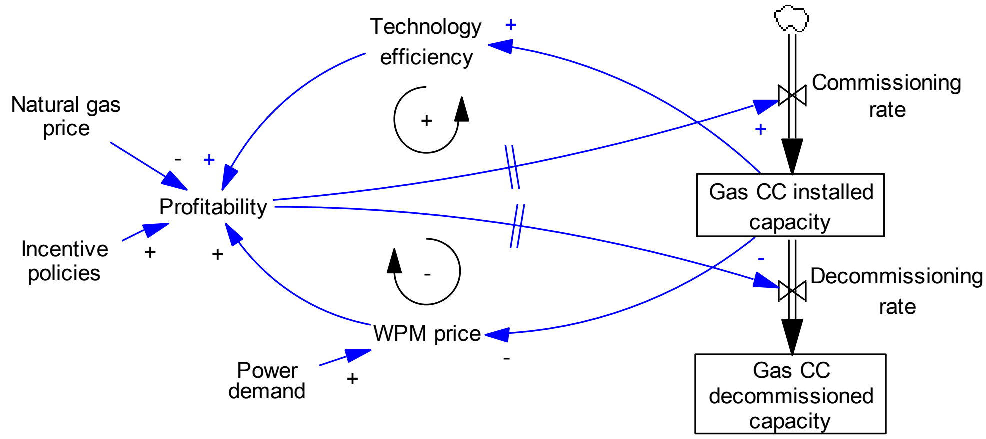

Figure 4-9: Simplified capacity expansion SD model stock & flow diagram

Stock & flow diagrams are in general more detailed than causal diagrams and force the modeler to think more specifically about the system structure. In general, the relations between the components of a stock & flow diagram are more strictly defined than in a causal diagram. Although more complex and more time consuming to draft, stock & flow diagrams are in general more informative than causal diagrams.

Level variables in stock & flow diagrams show a cumulative behavior. They are required in order to simulate the dynamics of the system over time. If no levels variables are included in the model, the loop dynamics would be instantaneous and no behavior over time would exist to examine (Albin, 1997). Causal diagrams in fact cannot be considered as models. They are however easy to understand and easy to use. It is important to understand the limitations of causal loop diagrams and restrict their use to the basic description of the model's behavior.

FORMULATION

The formulation phase involves the translation of the stock & flow diagrams into equations as well as the parametrization of the model through the definition of equation coefficients, initial conditions of stock variables and lookup tables. Formulation involves the transformation of the vaguer casual loop and stock & flow diagrams into a fully specified model that can be actually run on a computer. Model formulation involves the following elements:

- Formulation of stock variables: Stock variables are formulated as integral equations with an initial value. Input flows are added within the integral operator while output flows are subtracted. Formulation of stock variables involves the specification of the units. In the present example the Gas CC installed capacity variable is defined as follows:

$$Gas\ CC\ Installed\ Capacity(t) = \int_0^t (Commissioning\ rate(t) - Decommissioning\ rate\ (t)) \cdot dt + Gas\ CC\ Installed\ Capacity\ (0) \quad (4.4)$$

- Formulation of flow and auxiliary variables: These variables are formulated by using any kind of mathematical function (e.g. exponential, lineal, logarithmic, polynomic, etc.). In some cases where no straightforward mathematical function describes the relation between two variables, modeler-defined custom lookup tables may be used. Units must be included in the definition of flow and auxiliary variables. The formulation of flow and auxiliary variables may also entail the definition of initial conditions when delays are present. As an example, a possible formulation for the commissioning rate would be a linear function of profitability with a constant delay as shown below:

$$Commissioning\ rate(t) = DELAYFIXED(a + b \cdot Profitability, Delay) \quad (4.5)$$

Where:	a, b	= Pre-set coefficients of the linear function
	Delay	= Delay time
	DELAYFIXED	= Delay function

- Lookup table / chart definition: As described above, in those cases where relations cannot be easily described by mathematical functions, custom-made lookup tables can be used. Figure 4-10 shows an example of a lookup table generated with the Vensym software package (Ventana Systems, 2017).

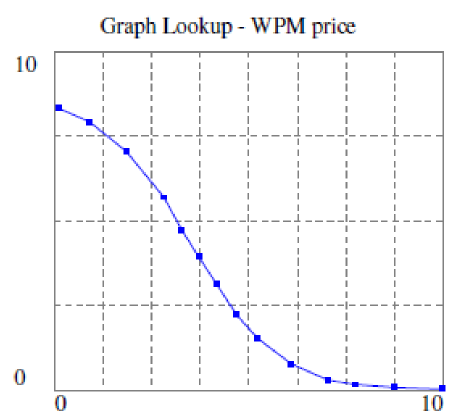

Figure 4-10: Lookup table example

- Model settings: Once the model's structure has been fully specified, additional general simulation parameters must be set. This includes parameters such as time units, the length of time steps for numerical integration, initial and final time as well as the selection of the numerical integration technique (Euler, Differences, etc.).

TESTING

Once the previous steps are finalized, the model is ready to be run on a computer and tested. The testing phase basically aims at finding flaws, checking the dynamic hypothesis, the model's assumptions, the model's behavior and its sensitivity to perturbations. Model calibration is performed as well during the testing stage by assigning final values to the model's coefficients. Model testing may involve some or all of the following checks (Sterman, 2000; Qudrat-Ullah & Seo Seong, 2010):

- Boundary adequacy: The goal of this test is to confirm that all relevant variables required for addressing the problem are endogenous to the model. Boundaries are modified in order to check whether either model behavior or policy recommendations change significantly. For example, in the basic model used in this section boundaries could be extended in order to make natural gas price[48] endogenous to the model and check how results change.
- Structure assessment: This test aims at checking that the model is consistent with the relevant descriptive knowledge of the system and that it does not break any basic rules which apply to the real system (e.g. physical laws such as material or energy conservation). Global and partial model tests are conducted by changing assumptions and scenarios in order to check that this rules are not violated. For example, the fact of obtaining a negative Gas CC installed capacity in our example model, would be a clear sign of a structural problem.
- Dimensional consistency: The goal of this test is to check whether all equations are properly formulated by checking their dimensional consistency. This may be done either by directly inspecting the equations and checking their units or by using dimensional analysis applications which, in some cases, are embedded in SD software packages (Ventana Systems, 2017).
- Parameter assessment: As it will be described later, model calibration entails the estimation of equations coefficients. This is usually done by means of a combination of statistical techniques (e.g. ordinary least squares regression, generalized least squares regression, maximum likelihood, Kalman filtering, etc.), which try to find the best fit of the model to historical data series, as well as of judgmental methods. The parameter assessment test aims at checking whether the parameter values used in the model are consistent with relevant descriptive and numerical knowledge of the system as well as whether all parameters have real word counterparts. In our example, the coefficients "a" and "b" should be estimated from historical data. It should be after confirmed that

[48] By assuming that the national natural gas consumption significantly impacts the global supply – demand balance and so, the global natural gas price

the values obtained are consistent with the real relation between new investments (commissioning rate) in new gas CC capacity and the profitability of this technology.

- Extreme conditions: The goal of this test is to check that the model works well not only in the business-as-usual scenario but also when the values of the system variables reach their upper and lower limits. This is done in order to check whether the model's output stays realistic when subject to extreme conditions, policies and shocks. This test is carried out by assigning said extreme values to specific variables and checking the models' output. In the present example, it could be checked what happens if profitability falls to zero. In this case, the commissioning rate should fall to zero as well and the decommissioning rate should increase sharply although never exceeding a maximum value which depends on the actual installed capacity.

- Integration error: The goal of this test is to check whether the results are sensitive to the time step or integration method (Euler, differences, etc.) chosen for the simulation. This test is performed by changing both parameters and directly assessing whether there are differences in the results.

- Behavior reproduction: This test aims at checking whether the model accurately reproduces the behavior of the real system from both the quantitative and qualitative points of view. It is important to highlight that the ultimate goal of this test is not to "validate" the model[49] but to uncover flaws in the structure of parameters of the model.

  From the qualitative point of view, this test checks that the reference modes present in the real system are correctly replicated in the model. From the quantitative point of view, it checks that the model's output values (oscillation size, etc.) are similar to the real values. This is done by visual inspection and comparison between the model output and the real data as well as by the application of descriptive statistical techniques (e.g. R^2, MAE, MAPE, RMSE, Theil's inequality statistics) which provide an objective measure of how well the model output fits the historical data. A good model should show patterns which are similar to the ones in real data. Oscillations should have the same frequencies and amplitudes, leads and lags should be similar, etc.

  Therefore, in the present example, it should be checked for example that the simulated past values of gas CC installed capacity, WPM price and gas CC decommissioned capacity fit the historical real data.

- Behavior anomaly: This test is aimed at assessing how strong specific relations within the model are and how their removal impacts results. This is done in order to check that the strength of the relations or feedback loops are in line with their real counterparts.

[49] For any given of historical scenario, there is an infinite number of models which are able to replicate it and which lead to different future outcomes (Sterman, 2000)

This test is usually carried out by means of the so-called "loop knockout analysis" by which specific relations or complete loops are removed in order to check its impact on the results and assess their strength. This test becomes particularly interesting when combined with the extreme conditions test as there may be loops that are inactive under standard conditions but become active under extreme conditions. Figure 4-11 shows an example on how a loop knockout analysis could be performed on the example model, by removing the technology efficiency loop.

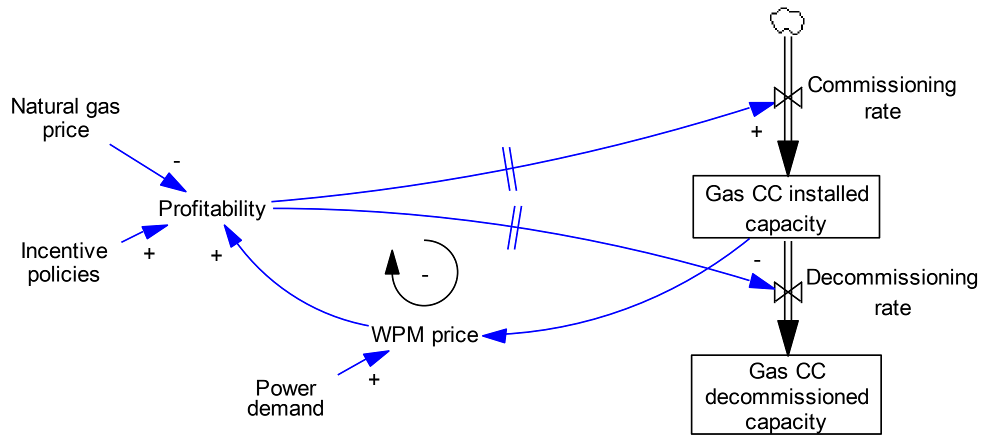

Figure 4-11: Simplified capacity expansion SD model loop knockout analysis

- Family member: The goal of this test is to assess whether the model is able to reproduce the behavior of systems in the same class as the system it is intended to simulate. For example, a corporate growth model should be able to simulate not only the growth of a specific corporation but the growth of any other corporation. The same happens in the present example: the model should be able to simulate not only the capacity expansion process of a specific country (e.g. Spain) but also the capacity expansion process of any other country. This test is performed by calibrating the model to the widest range of related systems and assessing how well the model reproduces each system's behavior.

- Surprise behavior: The goal of this test is to assess whether the model is able to reproduce unexpected behaviors absent in preliminary mental models but that are present in the system even though unobserved so far. Unexpected behaviors may be due to the fact that they are not in the preliminary mental models because they have not been observed yet but also because of model flaws. So, this test is passed when unexpected model behavior happens and this behavior is afterwards analyzed and confirmed as inherent to the real system. This test may be trickier in the sense that there is no formal way to perform it. It has to be carried out by assessing many different simulations and scenarios, observing the behavior of multiple variables and searching for unexpected variable behaviors.

- Sensitivity analysis: The goal of this test is to assess whether the system behavior and simulation results change significantly when assumptions change over the plausible range of uncertainty. Sensitivity analysis include numerical, behavior and policy sensitivity.

  Numerical sensitivity occurs when varying assumptions entail changes in the numerical results of the model. Although all models show numerical sensitivity, it is convenient to assess its degree as larger or smaller than expected sensitivities may be caused by model flaws.

  Behavior sensitivity occurs when varying assumptions entail changes in the system's behavior. The presence of behavior sensitivity does not have to be bad by itself as, for example, stable patterns may evolve into oscillatory ones when delays are introduced, which is a true reflection of reality.

  Finally, policy sensitivity occurs when varying assumptions entail changes in the impacts of a suggested policy. For example if our capacity expansion model shows increasing installed capacity with increasing incentives under specific conditions but the opposite under other conditions, policy sensitivity exists. Again, policy sensitivity is not bad by itself. It just has to be assessed and the reasons for its existence checked in order to make sure that they correctly reflect the reality.

  This analysis is usually performed by means of Monte Carlo simulations, by which probability distributions are assigned to specific input variables and a number of cases are simulated so that probability distributions for the output variables are obtained. This analysis may be univariate (only one variable is changed) or multivariate (several variables are changed). The final outcome of this analysis are confidence intervals for the trajectories of specific model variables.

  Figure 4-12 and Figure 4-13 show a sensitivity analysis applied to the present example. In this case, incentive policies (in the form of an increase in profitability) are the random input variable, which has been assigned the following normal distribution:

$$Incentive\ policies \sim N(1, 0.04) \tag{4.6}$$

  As it can be observed, in the case of the Commissioning rate both numerical and behavior sensitivity exist. Not only the output values change but also the shape of the curves (behavior) changes for the extreme upper Incentive policies values. In the case of the Gas CC installed capacity, only numerical sensitivity seems to exist as the shape of the curves does not change significantly.

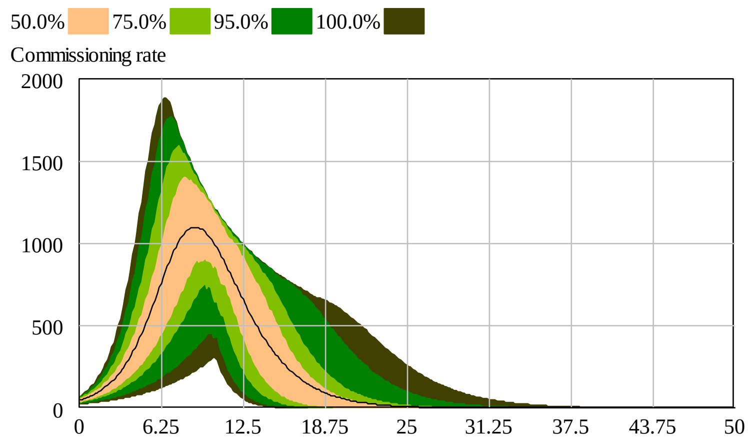

Figure 4-12: Commissioning rate. Sensitivity analysis

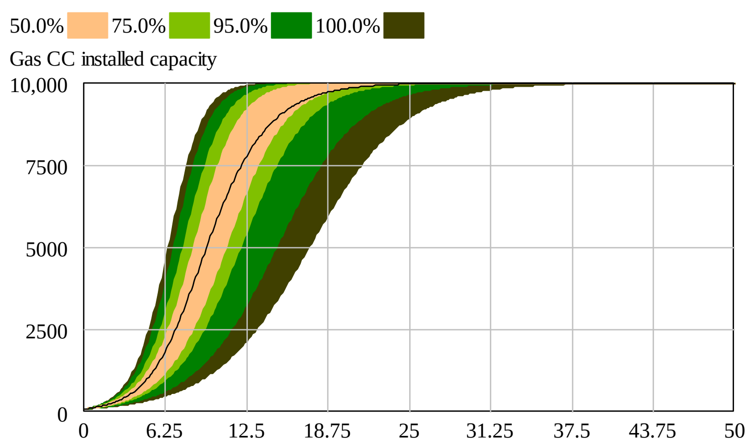

Figure 4-13: Gas CC installed capacity. Sensitivity analysis

CALIBRATION

Model calibration is performed both during and after the testing stage. The goal of the calibration stage is to assign final values to the model's coefficients. There are different approaches on model calibration in the literature. While some authors argue that SD models are aimed at assessing just the qualitative behavior of systems, others argue that SD models may be calibrated in order to perform quantitative system assessments as well (Arango, 2007), and in order to test the the model's accuracy (Oliva, 2003).

As the goal of the present research is to go beyond the pure qualitative behavioral analysis by quantitatively forecasting the evolution of the power generation mix and its overall impact on Spain's economy, the model has been calibrated based on Spain's 1998-2015 historical power system data series. The reason for having chosen this period is the fact that Spain's power industry was regulated and the construction of new power plants was centrally planned until 1998, when the industry was liberalized and investment decisions were made available to private investors. So, dates previous to 1998 cannot be simulated with the models developed in the present research. The accuracy of the model and the calibration process is assessed in a qualitative way by visually inspecting how the simulation outputs fit the historical data series, and in a quantitative way by means of standard goodness-of-fit measures such as R^2, MSE, RMSE, RMSPE, etc. as well as by Theil's inequality statistics, which become specially interesting in the case of dynamic simulations.

Theil's inequality statistics aims at decomposing error in order to facilitate the identification of its sources (noise vs. systematic). Therefore, mean square error (MSE) is decomposed in three components: bias (U^M), unequal variation (U^S) and unequal covariation (U^C) as per the equations below (Sterman, 1984):

$$MSE = \frac{1}{n}\sum_{t=1}^{n}(S_T - A_T)^2 = \left(\overline{S} - \overline{A}\right)^2 + (S_S - S_A)^2 + 2(1-r)\cdot S_S \cdot S_A \qquad (4.7)$$

Where:	MSE	= Mean square error
	n	= Number of samples
	S_T	= Simulated value at time t
	A_T	= Actual value at time t
	$\overline{S}$	= Mean of S
	$\overline{A}$	= Mean of A
	S_S	= Standard deviation of S
	S_A	= Standard deviation of A
	r	= correlation coefficient between S and A

Therefore, Theil's inequality statistics are given by the following equations:

$$U^M = \frac{\left(\overline{S} - \overline{A}\right)^2}{\frac{1}{n}\sum_{t=1}^{n}(S_T - A_T)^2} \qquad (4.8)$$

$$U^S = \frac{(S_S - S_A)^2}{\frac{1}{n}\sum_{t=1}^{n}(S_T - A_T)^2} \qquad (4.9)$$

$$U^C = \frac{2(1-r)\cdot S_S \cdot S_A}{\frac{1}{n}\sum_{t=1}^{n}(S_T - A_T)^2} \qquad (4.10)$$

$$U^M + U^S + U^C = 1 \tag{4.11}$$

U^M measures the bias between the simulated and the actual data. Large biases are identified through large U^M and large MSE. Bias entails a systematic difference between the model and reality. A large bias may entail serious issues with the model which may be caused by structural or calibration errors. U^S measures the difference in the variance between the simulated and the actual data. It measures the degree of unequal variation between the two data series. Finally, U^C measures the covariation between the simulated and the actual series and provides the degree to which the changes in the simulated series fail to match the changes in the actual series on a point-by-point basis. Based on the weights of these three error components it becomes easier to identify whether the errors are systematic or just noise.

POLICY DESIGN AND EVALUATION

Once that the model has been built and tested so that enough confidence on it has been developed, it may be used for policy design and evaluation. This last step of the SD modeling process involves not only changing specific model parameters such as incentive levels, etc. but also trying new rules, decision making strategies and even system structures that may arise because of relevant policy changes[50], and assessing the impact on the model's output. This is done in order to find the right policies to meet the desired goals. Once a specific policy is chosen it may also be tested for robustness by performing different tests (sensitivity, extreme conditions, etc.) on it.

For example, different incentive policies (incentive values in this case) might be used in our model example in order to reach the desired gas CC installed capacity.

The policy design phase may be combined with optimization techniques in order to find in a systematic way, the values of the parameters that maximize or minimize specific system variables (e.g. system costs, pollutant emissions, reliability, etc.). Some SD software packages have these optimization modules embedded in the main SD platform (Ventana Systems, 2017).

4.6 Combination of System Dynamics with alternative modeling techniques

While SD is becoming increasingly popular for power system simulation (Teufel, et al., 2013), there is also a a growing trend involving the combination of SD with other modeling techniques.

The SD methodology has been combined in recent literature with techniques such as decision trees (Tan, et al., 2010), real options (Arango, 2007; Botterud, 2003), genetic algorithms (Pereira & Saraiva, 2011), analytical hierarchy processes (Pasaoglu, 2006), game theory (Sanchez Dominguez, 2008) or iterative algorithms (Dyner, et al., 2011), to cite some examples.

[50] For example, regulating specific parts of the power industry may lead to totally new system structures that must be assessed

Also, the use of stochastic variables in SD models is becoming a common trend as more and more research contributions are relying on Monte Carlo simulations in order to get system insights (Botterud, 2003; Olsina, et al., 2006).

In the present work, the SD methodology is combined with the following modeling techniques:

i. Forecasting: Historical trends and time series analysis are used in order to set hypothetical future scenarios for the main SD model's exogenous variables.

ii. Optimization: Optimization techniques embedded in the SD modeling software are used during model calibration in order to find the model parameters which entail the best fit with historical data series. Also, optimization techniques are used during policy design and evaluation in order to find the optimum policies for achieving specific goals (e.g. minimization of system costs, minimization of pollutant emissions, maximization of reliability, etc.)

iii. Stochastic modeling: Monte Carlo simulations are used in order to introduce the uncertainty inherent to specific variables of liberalized power markets. Uncertain variables such as fossil fuel prices or power demand are modeled as random paths with drift based on past historical values. This approach allows to compute confidence intervals for the forecasted evolution of the output variables.

iv. Supply – demand equilibrium models: Supply – demand equilibrium modeling is used in order to simulate the operation of the spot WPM. The model reproduces the non-lineal supply curve, the hourly bidding approach (through the load duration curve) and includes the simulation of potential price spikes caused by potentially low reserve margins.

v. Economic input-output models: Input-output economic modeling is used in order to assess the impact of the power generation mix and related policies on the country's GDP through its direct and indirect components.

4.7 Modeling software

A wide spectrum of software can be used for SD modeling, ranging from plain spreadsheet to specialized SD software such as Vensim, Stella, Powersim or Dynamo (Ford, 2009).

Although spreadsheets are potentially useful for SD modeling and show the advantage of popularity and easy-to-read visual interfaces, they are more suitable for supporting dynamic modeling with specialized software or to provide a convenient way to display or analyze outputs from dynamic simulations.

Regarding specialized SD modeling software, Vensim, Stella and Powersim are the most popular software packages and show multiple similarities. All of them are icon-based and allow the drafting of stock & flow diagrams, which provides visual clarity when modeling.

Dynamo is the original software package developed for running SD models in the 60s. It was widely used through the 60s and 80s, having been used for example to implement the World3 model used in The Limits to Growth work (Meadows, et al., 1972). It shows an older command-line user interface where equations are written. Its use has declined in favor of more modern and user-friendly software such as Vensim, Stella or Powersim.

Finally, there is a third group of software packages focused on general-purpose modeling which can be used for SD modeling. This group includes software packages such as Simulink, Goldsim and Simile. These software packages are icon-based and use a notation which is similar to the stock & flow diagrams used by specialized SD software, although not exactly the same. Simulink is the dynamic modeling component of Matlab, a general modeling software package which has become the standard for engineering applications. Goldsim is a general dynamic modeling software which puts special focus on probabilistic and stochastic simulations. Simile is a dynamic modeling software with close resemblances and similar capabilities to Vensim, Stella and Powersim, although with a broader simulation scope, in many cases beyond the SD methodology.

In general, SD modeling is faster, more intuitive and straightforward when using specialized SD modeling software, which allows the outright drafting of stock & flow diagrams and provides specific tools aimed at developing, testing, calibrating and operating SD models.

Therefore, the Vensim software package (Ventana Systems, 2017) has been chosen for the present research. Some of it most relevant characteristics include the following:

- It allows model subscription so that the same model structures (although differently parametrized) can be used to simulate the behavior of different system agents. This is very useful in the present research as the same model structure can be used to model the dynamic evolution of different power generation technologies.
- It has an embedded optimization module which can be used for model calibration by optimum fitting to historical data. This optimization module also allows optimum policy design by computing the policies with maximize or minimize specific outputs (e.g. system costs).
- It has an embedded Monte Carlo simulation module which allows the simulation of stochastic variables and so the introduction of uncertainty considerations in SD models.
- It provides multiple features aimed at facilitating SD model developing, testing, calibration and operation. This includes features such as unit consistency checks, reality checks, sensitivity tests, runs comparisons, and partial and gaming simulations.
- It provides multiple convenient visualization tools such as custom charts, sensitivity graphs, causes strip charts, bar charts, histograms, statistical analysis, etc.

- It is based on an icon-based user-friendly interface with allows the outright drafting and visualization of stock & flow diagrams.
- It provides import and export data connectivity in multiple formats, including Excel spreadsheets, which have been used in the present research both as data sources and data analytics tools.

4.8 Socio-economic impact modeling

4.8.1 Introduction

As previously discussed, energy policies do not have only technical and environmental implications but also socio-economic ones. The way the power system is developed impacts variables such as job creation, trade balance, economic flows, technological development, energy independence etc., being all this variables important for policy makers.

Socio-economic valued added is challenging to quantify and its components can be structured based on different frameworks. One of these potential frameworks classifies socio-economic impact into the following four categories (International Renewable Energy Agency, 2014):

i. Macroeconomic impact: This category includes the measures most often used for macroeconomic impact assessment as per the traditional macroeconomic theory: Output, GDP, value added, employment, welfare, personal income and trade balance (Weisbrod & Weisbrod, 1997). This assessment can be limited to specific sectors (e.g. AES industry or the whole power industry) or to the country's economy as a whole. In the first case the assessment is referred to as "gross" impact while in the second case it is referred to as "net" impact.

ii. Distributional impact: This category deals with the distribution of costs and benefits and the assessment of the economic flows among the economy's agents, being taxation on of the most relevant components.

iii. Power system-related impact: This category includes the impact on the power industry itself, including indicators such as VOLL, and power generation, T&D, balancing, incentive and CO_2 emission allowance costs. In summary, this category covers the impact on power system operations costs as well as on some environmental externalities.

iv. Additional effects: This section covers all remaining impacts caused by the power industry. It includes the impact on issues such as geopolitics, safety and security of supply.

The present research focuses on macroeconomic effects and explores in detail the power system-related impact in order to better understand the causes of the macroeconomic effects. The reason for focusing on macroeconomic effects is because they provide a quite broad assessment of the socio-economic impact and they are relatively easy to quantify due to the well-developed macroeconomic theory and well established, accepted and available macroeconomic indicators.

Distributional effects are not considered in the present research as the economic impact is assessed from an aggregated perspective. Also, additional effects such as geopolitical, safety or security of energy supply are out of the scope of the present research as they are very difficult to quantify from an economic perspective and empirical quantitative analysis on these variables is still limited.

The macroeconomic impact may be measured by means of different indicators, being the most relevant the following ones (International Renewable Energy Agency, 2014; Weisbrod & Weisbrod, 1997):

i. Economic Output: This is the broadest measure of economic activity. It includes the gross level of the economy's revenue. This can be a misleading measure of economic development benefit, since it does not distinguish between high and low value added economic activities.

ii. Value added: This indicator is computed as the value of the goods and services produced by an industry less the value of intermediate goods and service used as production inputs. Value added is equal to the sum of wage income and corporate profit in a closed economy. It can be computed at company level (micro level), industry level (meso level) and country level (macro level), being in this last case equivalent to the country's GDP. While valued added is in most cases the most appropriate and accurate economic impact measure, it may overestimate economic performance as it considers all business profits, including those which may be paid out as dividends to foreign investors, who will most probably reinvest the profits abroad.

iii. GDP: This indicator measures the country's overall value added. GDP is the most often used indicator of a country's economic performance. It is also a commonly used benchmark for comparison between countries. GDP may be computed by using three different methodologies: production, expenditure and income (Eurostat, 2014).

iv. Employment: This indicator reflects the industry's impact on job creation. Jobs are classified as "direct" (those employees directly working in the relevant industry (e.g. wind industry)), "indirect" (those employees working in supporting industries (e.g. steel industry)) and "induced" (those employees working for sectors benefiting from macroeconomic feedbacks (e.g. retail consumption expenditures done by the employees of "direct" or "indirect" industries). This is the most popular measure of economic impact because it is tangible and very easy to understand. Nevertheless, it has two major limitations: (i) it does not necessarily reflect the quality of the jobs created and (ii) it cannot be easily compared to the public cost of attracting those jobs (through subsidies, tax breaks, public investments, etc.).

v. Aggregated personal income: This ratio measures the income of the workers hired by an economy, which will rise with wages and the number of workers hired. Although this is a reasonable measure of the personal income benefit of an industry or a country, it is still an underestimate of the true economic impact as it is not taking into account business profits, which may be paid out as dividends, or reinvested locally, further contributing to the economic development.

vi. Welfare: There are different measures for welfare. While sometimes pure economic indicators such as GDP are used as a proxy for welfare, alternative measures which take into account parameters beyond the pure economic considerations are also used. One example of these alternative measures is the Human Development Index (HDI) (Organisation for Economic Co-operation and Development, 2015). These alternative indicators acknowledge the limitations of economic indicators such as GDP to measure well-being. Nevertheless, they are not often used in socio-economic impact assessments because they are difficult to quantify and empirical analysis on them is relatively limited (International Renewable Energy Agency, 2014).

The selection of the most appropriate indicator depends on the goal of the analysis. GDP is sometimes claimed to be a poor proxy for a country's well-being. Its critics claim that it does not take into consideration important issues such as wealth equality, health, education levels, freedom, crime, security or institutional development. Also, while GDP is an aggregate indicator, alternative well-being indicators often take into account distribution issues and material household level variables such as income, wealth, jobs, earnings, housing conditions as well as subjective variables such as work-life balance, civil engagement, social issues and subjective well-being (International Renewable Energy Agency, 2014). One of the most popular alternative well-being indicators is HDI which, in order to assess well-being, takes into account three different aspects: health, education and living standards, based on the corresponding life expectancy, years of schooling and GDP per capita indicators.

Alternative well-being indicators clearly show some advantages over GDP but also some drawbacks. They are difficult to quantify (e.g. education levels) and the empirical experience with them is relatively limited, as discussed above. Also, they require consistency in terms of units and in the way different dimensions are weighted (e.g. health, education and living standards in the case of HDI).

Regarding employment, while it is a well-established indicator and very important from the political perspective, it is tricky in the sense that the total number of jobs does not provide information regarding neither the quality of the jobs nor the income level.

On the positive side, GDP is a very well established indicator with plenty of historical data available through official statistical offices and easily comparable between countries and across time. Also, most alternative well-being indicators are clearly influenced by the country's economic output. For example, indicators of health, life expectancy or personal security are strongly correlated with income (Organisation for Economic Co-operation and Development, 2015).

Therefore, because of the abovementioned reasons, GDP has been chosen as the key variable for assessing the economic impact in the present research.

4.8.2 Socio-economic impact assessment techniques

Different modeling techniques are currently available in order to assess socio-economic impact, each one of them with its own advantages and disadvantages. They differ in complexity, accuracy and input data requirements.

As previously discussed, socio-economic impact assessment may be done from a gross or a net perspective. Gross impact assessment considers just a part of the economy (one or a few economic sectors) while net impact assessment considers the country's economy as a whole. Techniques for gross socio-economic impact assessment include gross Input – Output models, supply chain analysis and employment factors (International Renewable Energy Agency, 2014).

As previously discussed, the present research focuses on the overall impact of the power system on the economy as a whole, so that more focus is put on net analysis, which can be carried out by means of the following methodologies.

NET INPUT – OUTPUT

The Input – Output methodology focuses on the relations between the country's different productive sectors and studies the economic flows between them. It can be used to directly estimate the full income and job effects of changes in industry activity levels.

This method is based on the data in the national Production, Uses and Input – Output tables, based on which the structure of the productive system is analyzed.

The basic versions of this method assume that the productive structure is constant over time so that it does not take into account changes in productivity, technology or consumer preferences. Also, it does not take into account price considerations (wage levels, property prices, etc.) nor capital accumulation processes. Therefore, its critics argue that Input – Output is not a perfect methodology as it fails to capture all feedbacks across the whole country's economy, although relevant improvements and extensions have been made in order to tackle this issues (Rose, 1995).

COMPUTABLE GENERAL EQUILIBRIUM MODELS

CGE models provide a more comprehensive assessment of a country's economy than Input – Output models by including the supply side and taking into account government consumption, international trade and households which, in this case, act as producers by providing labor and capital to other productive sectors.

CGE models combine the Input – Output functions with supply – demand equilibrium equations derived from neoclassical economic theory and make assumptions such as the perfect rationality of the actors in the economy, perfect information, equilibrium markets and the fact that households and companies maximize their utility and profits respectively. Based on these supply – demand equilibrium modeling, CGE models are able to compute prices. Other models tend to be more grounded on the Structuralist tradition, paying more attention to institutions and political economy, market power and disequilibrium (Mercado, 2003).

Like Input – Output models, CGE models can be used to directly estimate the full income and job effects of an industry (Grant, et al., 2008). Unlike Input – Output models, they may also be used to estimate the impacts over time of variables such as costs, prices, productivity, business competitiveness, and migration.

Although being in principle more accurate than Input – Output models because of the reasons mentioned above, CGE modeling presents some challenges (Rose, 1995): (i) it is arguable whether neoclassical economic theories are always valid in practice, (ii) CGE models cannot reproduce large structural changes as they are usually based on static SAM matrices, (iii) they need data that may be difficult to obtain or estimate (e.g. substitution elasticities) and (iv) in many cases the market equilibrium assumption does not hold. Finally, CGE models are complex and require highly specialized know-how. Therefore they require a large amount of resources and are expensive to develop.

MACROECONOMETRIC MODELS

Econometric models are based on advanced statistical analysis and are most suited to short and mid-term economic analysis. On the contrary to Input – Output or CGE models they do not make any assumptions regarding the country's productive structure nor model the economy based on economic theories. Instead, they are based on the pure statistical analysis of historical values and assume that historical correlations between variables hold in the future. Because of this fact, macroeconometric modeling is more suited for short-term analysis while Input-Output and CGE modeling can be used for both short and mid/long term modeling.

One of the most important strengths of macroeconometric models is their capability to reproduce market imperfections (which are neglected in CGE models). On the other hand, one of their most relevant weaknesses is the fact that historical statistical relations may not hold in the future, especially if economic structural changes occur. Macroeconometric models require large amounts of historical data as well as advanced statistics skills, which make them demanding in terms of resources required and development costs.

ECONOMIC SIMULATION MODELS

On the contrary to Input – Output and CGE models and in a similar way to macroeconometric models, economic simulation models are not based on any specific macroeconomic theory. On the contrary, they are based on relations between variables which modelers believe to occur in reality. Economic simulation models are also demanding in terms of resources and costs. Some of their most relevant drawbacks include their mixed character (as they combine different theoretical frameworks) and the difficulty to obtain or estimate some of their parameters, being these two factors sources for reduced model transparency.

4.9 Justification of the use of the Input – Output technique

In general and due to the reasons explained in the previous section, it is generally assumed that Input – Output models provide a more limited analysis scope as they mostly focus on the supply side and overlook to some extent the demand side as well as price considerations. Nevertheless they present some clear advantages such as more limited data requirements, the fact that the required data is readily available (Input – Output tables are at the core of the almost universal System of National Accounts, and today, Input – Output tables exist for more than 100 countries), and the fact of being less demanding in terms of development resources, time and cost.

Macroeconometric modeling is not considered as suitable for the present research as the amount of available data since the liberalization of Spain's power system is limited (just 19 years: 1998 – 2017). Finally economic simulation and CGE modeling have been also discarded due to their high development time, resource and cost requirements, beyond the scope and resources of the present research as well as to the difficulty for finding or estimating the required data (e.g. substitution elasticities, etc.).

Therefore, because of the abovementioned reasons, the Input – Output methodology is the socio – economic impact modeling tool chosen for the present research. Future lines of research could involve the combination of the methodologies developed in the present research with other socio – economic impact modelling methodologies such as CGE or economic simulation.

4.10 Input-Output modeling applied to energy markets

Input – Output modeling has been widely used in order to assess the impact of the energy industry on multiple variables. For example, (Cruz, 2002) and (Cruz, 2004) assess the impact of the energy industry on CO_2 emissions in Portugal, (Ciorba, et al., 2004) assess the impact of the PV industry on Morocco's economy, (Allan, et al., 2005) assess the impact of the power industry on Scotland's economy, (Stoddard, et al., 2006) assess the impact of CSP deployment on California's economy, (Madlener & Koller, 2007) assess the impact of biomass heating on the economy and CO_2 emissions of the Austrian federal province of Vorarlberg, (Allan, et al., 2007) assess the impact of changes in the power generation mix through the introduction of AES technologies on Scotland's economy, (Lehr, et al., 2008) assess the impact of AES deployment on Germany's job market, (European Wind Energy Association, 2009) assesses the impact of wind power development on the EU's job market and (de Arce, et al., 2012) assess the macroeconomic impact of AES deployment in Morocco.

In the specific case of Spain, (Caldes, et al., 2009) assess the impact of CSP deployment on Spain's economic flows and job market and (Asociacion de Productores de Energias Renovables, 2009) assess the macroeconomic impact of AES deployment. Also, in the case of Spain, Input – Output modeling has been used not only to assess the impact of the energy industry but also of other multiple sectors. For example, (Morilla, et al., 2009) assess the impact of Spain's productive sectors on environmental damage, (Polo & Valle, 2007) assess the impact of tourism on the economy of the Balearic Islands, (Robles Teigeiro & Sanjuan Solis, 2005) perform an assessment of the evolution of Spain's economic flows through the analysis of the historical Input – Output tables, (Munoz Alamillos, et al., 2012) assess the impact of youth unemployment on Spain's economy,

4.11 Description of the Input-Output method

INTRODUCTION

The Input-Output methodology (Leontief, 1986) started to be developed by the Russian economist Wassily Leontief in the late 1930s. This methodology is based on the production data of the different sectors which form the country's economy. This data is included in the so-called "Production" and "Uses" tables, which are the pillars of the country's national accounts. The data in these tables is used to compile the so-called "Input-Output" tables, which are the main inputs for this methodology (Miller & Blair, 2009; O'Connor & Henry, 1975).

Three main tables are necessary for the Input – Output analysis:

i. A transactions table (Input – Output table)

ii. A technical coefficients table

iii. An interdependence coefficients table (often called total coefficients)

The transactions table shows the economic flows within the country's economy, which is broken down into a number of specific sectors. The rows of the table show the outputs of each sector while the columns show the inputs to each sector.

Table 4-1 shows an example of a highly simplified Input-Output table, for illustrative purposes.

	Sector 1	Sector 2	Sector 3	Export	Domestic Demand	Total Demand	Output
Sector 1	3	2	1	15	45	60	**66**
Sector 2	4	7	6	15	45	60	**77**
Sector 3	20	5	3	5	30	35	**63**
Intermediate inputs	**27**	**14**	**10**	**35**	**120**	**155**	**206**
Value Added	36	45	47	0	0	0	**128**
Imports	3	18	6	0	0	0	**27**
GDP Contribution	**36**	**45**	**47**	**35**	**120**	**0**	**128**
Total Inputs	**66**	**77**	**63**	**70**	**240**	**155**	**361**

Table 4-1: Simplified Input-Output table example

In the example shown in Table 4-1, the country's economy is broken down in just three sectors. The first row of the table shows the uses of the output of Sector 1 in this specific year. It must be highlighted that productive sectors use part of their output as inputs to their own productive processes. This is shown for example in the "3" entry in the first row, which shows that Sector 1 uses 3 of its own output units as inputs.

The rest of the first row is read as follows: Sector 2 uses 2 output units from Sector 1 and Sector 3 uses 1 output unit from Sector 1. The remaining production of sector 1 is used for exports (15 units) and domestic demand (45 units). Therefore, total final demand for Sector 1 is 60 output units (45 + 15) and the total output of Sector 1 is 66 units (60 + 3 + 2 + 1). The next two rows are read the same way.

Column 1 shows the inputs to Sector 1 which, as described before, uses 3 units from its own production as inputs. In addition, Sector 1 used 4 output units from Sector 2 and 20 output units from Sector 3. Therefore, total intermediate inputs to Sector 1 are 27 output units. In addition, Sector 1 required 36 units of value added and 3 units of imports so that total inputs to Sector 1 were 66 units (27 + 36 + 3).

Row 5 (value added) includes items such as wages, salaries profits or depreciation. Row 6 (imports) includes the flow of imports required by each productive sector. Row 7 (GDP contribution) shows the contribution to the country's GDP of each productive sector, which is computed as total inputs less intermediate inputs, less imports, being in this simplified case the result equal to the value added. The country's total GDP is shown in row 7 and column 7 and is equal to 128 units.

Finally, row 8 (total inputs) shows the total inputs required by each productive sector which are equal to the sum of the Intermediate inputs and the primary inputs (value added and imports), and match the total output values. Based on these relations, it can be observed, the Input – Output system is intimately related to the country's national accounts.

The Input – Output table is divided by a bold vertical line into two parts. The outputs used as inputs to the productive sectors are shown on the left of the bold vertical line while the final uses of the outputs are shown on the right. Also, the Input-Output table is divided by a bold horizontal line. The intermediate inputs are shown on top of the bold line while the primary inputs are shown below it. Therefore, the Input – Output table is divided into four quadrants, highlighted in different colors in Table 4-1.

The first quadrant (top left) shows the interindustry flows (sometimes called intermediate demand). The second quadrant (top right) shows the flows of each production sector to final demand. The third quadrant (bottom left) shows the primary inputs used by each production sector. Finally, the fourth quadrant (bottom right), shows the primary inputs that are directly used by final demand. Quadrant 1 is always symmetric as both its rows and columns include the number of productive sectors. The symmetric Input – Output coefficient tables are derived from the first quadrant of the Input – Output table.

IMPACT ANALYSIS

The Input – Output system is a very useful tool in order to assess the impact of changes of specific variables in the country's economy. The first step of impact analysis involves the computation of the so-called "technical" and "interdependence coefficients". Table 4-2 shows a simplified Input – Output table where said coefficients will be derived from.

	Sector 1	**Sector 2**	**Sector 3**	**Total Demand**	**Output**
Sector 1	x_{11}	x_{12}	x_{13}	Y_1	$\mathbf{X_1}$
Sector 2	X_{21}	X_{22}	X_{23}	Y_2	$\mathbf{X_2}$
Sector 3	X_{31}	X_{32}	X_{33}	Y_3	$\mathbf{X_3}$
Primary inputs	Z_1	Z_2	Z_3		
Total Inputs	$\mathbf{X_1}$	$\mathbf{X_2}$	$\mathbf{X_3}$		

Table 4-2: Technical coefficients

Technical coefficients ($a_{i,j}$) describe the unit structure of the productive system and the first order effects of changes in final demand. They are computed by dividing the entries in quadrant 1 of the Input – Output table by the total input of each industrial sector (i.e. the column sums) as follows:

$$a_{i,j} = \frac{x_{i,j}}{X_j} \tag{4.12}$$

Based on Table 4-2, total output can be computed as follows:

$$\begin{aligned} X_1 &= x_{1,1} + x_{1,2} + x_{1,3} + Y_1 \\ X_2 &= x_{2,1} + x_{2,2} + x_{2,3} + Y_2 \\ X_3 &= x_{3,1} + x_{3,2} + x_{3,3} + Y_3 \end{aligned} \tag{4.13}$$

Introducing equation (4.12) in equations (4.13) total output may be expressed as:

$$\begin{aligned} X_1 &= a_{1,1} \cdot X_1 + a_{1,2} \cdot X_2 + a_{1,3} \cdot X_3 + Y_1 \\ X_2 &= a_{2,1} \cdot X_1 + a_{2,2} \cdot X_2 + a_{2,3} \cdot X_3 + Y_2 \\ X_3 &= a_{3,1} \cdot X_1 + a_{3,2} \cdot X_2 + a_{3,3} \cdot X_3 + Y_3 \end{aligned} \tag{4.14}$$

In order to use matrix formulation, the following matrices are defined and denoted with bold characters:

$$A = \begin{bmatrix} a_{1,1} & a_{1,2} & a_{1,3} \\ a_{2,1} & a_{2,2} & a_{2,3} \\ a_{3,1} & a_{3,2} & a_{3,3} \end{bmatrix} \tag{4.15}$$

$$X = \begin{bmatrix} X_1 \\ X_2 \\ X_3 \end{bmatrix} \tag{4.16}$$

$$Y = \begin{bmatrix} Y_1 \\ Y_2 \\ Y_3 \end{bmatrix} \tag{4.17}$$

Therefore, equation (4.14) can be expressed in matrix form as follows:

$$\boldsymbol{X} = \boldsymbol{A} \cdot \boldsymbol{X} + \boldsymbol{Y} \tag{4.18}$$

Impact analysis is often used in order to assess how changes in final demand impact inter-industry flows and total output. In order to do so, equation (4.15) can be transformed using basic matrix algebra as follows (where **I** is the identity matrix):

$$\boldsymbol{X} = \boldsymbol{A} \cdot \boldsymbol{X} + \boldsymbol{Y} \;\Rightarrow\; (\boldsymbol{I} - \boldsymbol{A})\boldsymbol{X} = \boldsymbol{Y} \;\Rightarrow\; \boldsymbol{X} = (\boldsymbol{I} - \boldsymbol{A})^{-\mathbf{1}}\boldsymbol{Y} \tag{4.19}$$

The (**I** - **A**)$^{-1}$ matrix is the Leontief Matrix and its elements are the so-called “interdependence coefficients” ($z_{i,j}$). The Leontief matrix is therefore defined as follows:

$$(\boldsymbol{I} - \boldsymbol{A})^{-\mathbf{1}} = \begin{bmatrix} z_{1,1} & z_{1,2} & z_{1,3} \\ z_{2,1} & z_{2,2} & z_{2,3} \\ z_{3,1} & z_{3,2} & z_{3,3} \end{bmatrix} \tag{4.20}$$

For the sake of clarity the set of equations describing the matrix equation (4.19) are shown below:

$$\begin{aligned} X_1 &= z_{1,1} \cdot Y_1 + z_{1,2} \cdot Y_2 + z_{1,3} \cdot Y_3 \\ X_2 &= z_{2,1} \cdot Y_1 + z_{2,2} \cdot Y_2 + z_{2,3} \cdot Y_3 \\ X_3 &= z_{3,1} \cdot Y_1 + z_{3,2} \cdot Y_2 + z_{3,3} \cdot Y_3 \end{aligned} \tag{4.21}$$

While technical coefficients described just the first order effects of changes in final demand, interdependence coefficients describe the total effect of changes in final demand. Interdependence coefficients can be interpreted as the increment of a sector's total output per unit increase of this same sector's final demand.

EXAMPLE

A simplified example of the assessment of the impact of the deployment of power generation technologies is described below. Spain's productive and energy structures are taken as an approximate reference. For the sake of simplicity, only three productive sectors are considered: machinery, fuel extraction and construction. Only wind and gas CC power generation technologies are considered. While most of the inputs for wind are local, gas CC requires a significant amount of imports both from the fuel perspective[51] and the capital equipment perspective[52]. Table 4-3 shows the Input – Output flows for this case. 10 and 12 units of machinery output are used by the fuel extraction and construction sectors respectively. 15 units are exported and 50 are used to meet the domestic demand. Therefore the total output of the machinery sector is 90 units. The remaining sectors can be read in the same way. Total GDP is 188.0 units.

	Machinery	Fuel Extraction	Construction	Exports	Domestic Demand	Total Demand	Output
Machinery	3.0	10.0	12.0	15.0	50.0	65.0	**90.0**
Fuel Extraction	4.0	2.0	6.0	15.0	60.0	75.0	**87.0**
Construction	15.0	20.0	4.0	5.0	70.0	75.0	**114.0**
Intermediate inputs	**22.0**	**32.0**	**22.0**	**35.0**	**180.0**	**215.0**	291.0
Value Added	65.0	37.0	86.0	0.0	0.0	0.0	**188.0**
Imports	3.0	18.0	6.0	0.0	50.0	50.0	**77.0**
GDP Contribution	**65.0**	**37.0**	**86.0**	**0.0**	**0.0**	**0.0**	**188.0**
Total Inputs	**90.0**	**87.0**	**114.0**	**35.0**	**230.0**	**265.0**	**556.0**

Table 4-3: Simplified Input-Output table. Impact of the power industry example

Table 4-4 and Table 4-5 show the technical and interdependence coefficients respectively.

	Machinery	Fuel Extraction	Construction
Machinery	0.033	0.115	0.105
Fuel Extraction	0.044	0.023	0.053
Construction	0.167	0.230	0.035

Table 4-4: Technical coefficients

[51] Almost all natural gas consumed in Spain is imported

[52] The main gas CC plant's equipment (e.g. gas turbine, etc.) is most often imported.

	Machinery	Fuel Extraction	Construction
Machinery	1.063	0.154	0.124
Fuel Extraction	0.059	1.045	0.063
Construction	0.198	0.276	1.073

Table 4-5: Interdependence coefficients

In order to assess the impact of wind or gas CC capacity additions, it is necessary to assess the demand induced by each technology in each productive sector as well as the share of the demand which is imported. Also, as the power generation sector has not been included by itself in the first quadrant of the Input – Output table (as it is the case in Spain's Input – Output tables), the demand induced by the power generation deployment is considered as final domestic demand.

Table 4-6 and Table 4-7 show the suggested demand allocations per sector and estimated imports for wind and gas CC respectively.

	Machinery	Fuel Extraction	Construction
Sector Allocation	70.0%	3.0%	27.0%
Imports	10.0%	100.0%	0.0%
Domestic Demand	**63.0%**	**0.0%**	**27.0%**

Table 4-6: Suggested sector allocation and imports for wind power

	Machinery	Fuel Extraction	Construction
Sector Allocation	25.0%	70.0%	5.0%
Imports	80.0%	100.0%	0.0%
Domestic Demand	**5.0%**	**0.0%**	**5.0%**

Table 4-7: Suggested sector allocation and imports for gas CC power

Wind shows a small allocation to the fuel extraction sector as virtually no fuel is used during the operation phase. Most demand is allocated to the machinery sector, which has the largest weight in windfarm costs. Wind machinery imports are very limited as most of the wind power supply chain elements are present in Spain. Gas CC shows a significantly higher fuel extraction allocation share as well as higher machinery imports due to the fact that most of the main equipment (e.g. gas turbines, etc.) is usually imported. In both cases, the whole allocations to fuel extraction are considered as imported, due to Spain's high energy dependency.

Two scenarios have been simulated four illustrative purposes. The first one assumes the addition of 100 output units in wind farms, while the second one assumes the addition of 100 output units of gas CC power plants. Table 4-8 shows the increase in domestic demand due to 100 units of wind and gas CC.

	Machinery	Fuel Extraction	Construction
Wind power (100 units)	63.0	0.0	27.0
Gas CC (100 units)	5.0	0.0	5.0

Table 4-8: Domestic demand increase by sector

Table 4-9 shows the economic flows resulting from the addition of 100 output units of wind power.

	Machinery	Fuel Extraction	Construction	Exports	Domestic Demand	Total Demand	Output
Machinery	5.6	10.7	16.5	15.0	120.0	135.0	**167.8**
Fuel Extraction	7.5	2.1	8.3	15.0	60.0	75.0	**92.8**
Construction	28.0	21.3	5.5	5.0	97.0	102.0	**156.8**
Intermediate inputs	**41.0**	**34.1**	**30.3**	**35.0**	**277.0**	**312.0**	**417.4**
Value Added	121.2	39.5	118.3	0.0	0.0	0.0	**278.9**
Imports	5.6	19.2	8.3	0.0	60.0	60.0	**93.1**
GDP Contribution	**121.2**	**39.5**	**118.3**	**0.0**	**0.0**	**0.0**	**278.9**
Total Inputs	**167.8**	**92.8**	**156.8**	**35.0**	**337.0**	**372.0**	**789.4**

Table 4-9: Input-Output table. Addition of 100 units of wind power

With respect to the base case, the addition of 100 units of wind capacity entails a significant increase in machinery sector output and a smaller increase in the construction sector output. The impact on the fuel extraction sector is very limited due to the assumption on wind industry's fuel demand. The increase in total output includes the direct effect due to the direct demand of the wind power generation sector plus the indirect effect due to the induced demand in all other productive sectors. Table 4-10 shows the breakdown between the direct and indirect effects on total output.

	Direct Effect	Indirect Effect	Total effect
Machinery	70.0	7.8	**77.8**
Fuel extraction	0.0	5.8	**5.8**
Construction	27.0	15.8	**42.8**

Table 4-10: Indirect vs. direct effect breakdown

Exports stay constant while imports increase slightly from 50 to 60 units due to the machinery and limited fuel imports, which are considered to flow directly to final demand (power generation). The addition of 100 units of wind capacity entails a 90.9 units GDP growth, from 188.0 to 278.9 units.

Table 4-11 shows the economic flows resulting from the addition of 100 output units of Gas CC power. In this case, the machinery and constructions sectors output increase is much more limited due to the greater import share assumed for this technology. Imports used as final demand (fourth quadrant) increase significantly from 50.0 to 140.0 units due to the imports of natural gas required for running the plants. GDP growth is lower than in the wind case, showing an increase of just 28.2 units, from 188.0 to 216.2.

	Machinery	Fuel Extraction	Construction	Exports	Domestic Demand	Total Demand	Output
Machinery	3.9	10.2	13.1	15.0	75.0	90.0	**117.2**
Fuel Extraction	5.2	2.0	6.5	15.0	60.0	75.0	**88.8**
Construction	19.5	20.4	4.4	5.0	75.0	80.0	**124.3**
Intermediate inputs	**28.6**	**32.7**	**24.0**	**35.0**	**210.0**	**245.0**	**330.3**
Value Added	84.6	37.8	93.8	0.0	0.0	0.0	**216.2**
Imports	3.9	18.4	6.5	0.0	140.0	140.0	**168.8**
GDP Contribution	**84.6**	**37.8**	**93.8**	**0.0**	**0.0**	**0.0**	**216.2**
Total Inputs	**117.2**	**88.8**	**124.3**	**35.0**	**350.0**	**385.0**	**715.3**

Table 4-11: Input-Output table. Addition of 100 units of gas CC power

Table 4-12 shows the breakdown between the direct and indirect effects on total output.

	Direct Effect	Indirect Effect	Total effect
Machinery	70.0	7.8	**77.8**
Fuel extraction	0.0	5.8	**5.8**
Construction	27.0	15.8	**42.8**

Table 4-12: Indirect vs. direct effect breakdown

Chapter 5
Model overview

5.1 Introduction

The model presented in the present research is a combination of several modeling techniques and is aimed at forecasting the evolution of a country's power generation mix and its overall environmental, technical and economic impact based on the evolution of exogenous variables such as fossil fuel prices and power demand, as well as on policy levers such as incentive policies.

The present research builds on top of the work described in (Ibanez-Lopez, 2013) by including economic and environmental considerations, introducing uncertainty and behavioral aspects, by coupling the main SD model to an actual MOPP model and by deeply refining the underlying dynamic structures.

The model counts on different submodules which make use of different techniques and aim at modeling different parts of the power system:

i. Power generation asset lifecycle model: This is the main underlying model. It uses the SD methodology due to its suitability for modeling the dynamic considerations inherent to the power generation system (e.g. delays and feedback loops) as well as to model soft variables (e.g. public opinion) and behavioral considerations.

ii. The MOPP model: This model is used to simulate the operation of the country's WPM. It is a supply – demand equilibrium model which endogenously computes the WPM price based on inputs such as the power mix composition, the demand level and power plant operating marginal costs.

iii. The system cost model: This sub-model is an integral part of the main SD power generation mix lifecycle dynamics model. It computes the overall power system costs based on variables such as power mix composition, commodity prices, incentive policies, power plant dispatching, power demand and CO_2 emissions.

iv. The environmental impact model: This sub-model is also an integral part of the main SD power generation mix lifecycle dynamics model. It computes the overall system-wide CO_2 emissions based on variables such as power mix composition, power plant dispatching and power demand.

v. The economic impact model: The goal of this model is to compute the overall net economic impact of the power system and the related energy policies. It uses the Input – Output methodology in order to compute the net impact in the country's GDP through its direct and indirect components.

The following sections describe in further detail the basic structure of the abovementioned models and describes the causal diagrams in those cases were SD is used.

5.2 Power generation asset lifecycle dynamics

The main objective of this model is to simulate and forecast the dynamic evolution of a country's complete power generation mix based on specific exogenous variables such as commodity prices [53] or macroeconomic variables, as well as on policy levers such as incentive policies or capacity payments. A general preliminary description of the modeling philosophy can be found in (Ibanez-Lopez, 2013).

Figure 5-1 shows a simplified causal diagram, which describes the dynamics of capacity additions and decommissioning. The diagram is subscripted (i.e. each technology considered is described by the same structure although differently parametrized) so that most variables are technology-specific while the rest (e.g. wholesale power price or CO2 price) are system-wide. Variables are represented as follows:

[53] While some models in the literature (Gary & Larsen, 2000) assume that fuel prices are a function of the country's fuel demand, they have been considered as exogenous variables for the present work. This is because the present model is going to be used to simulate Spain's power industry and it has been assumed that Spain's fuel consumption is relatively small compared to the whole world's one, so that a change in fuel demand in Spain will not significantly impact global fuel markets.

- White hexagon variables: Exogenous, technology-specific
- Grey hexagon variables: Exogenous, system-wide
- Box grey variables: Endogenous, system-wide
- Rest of variables: Endogenous, technology-specific

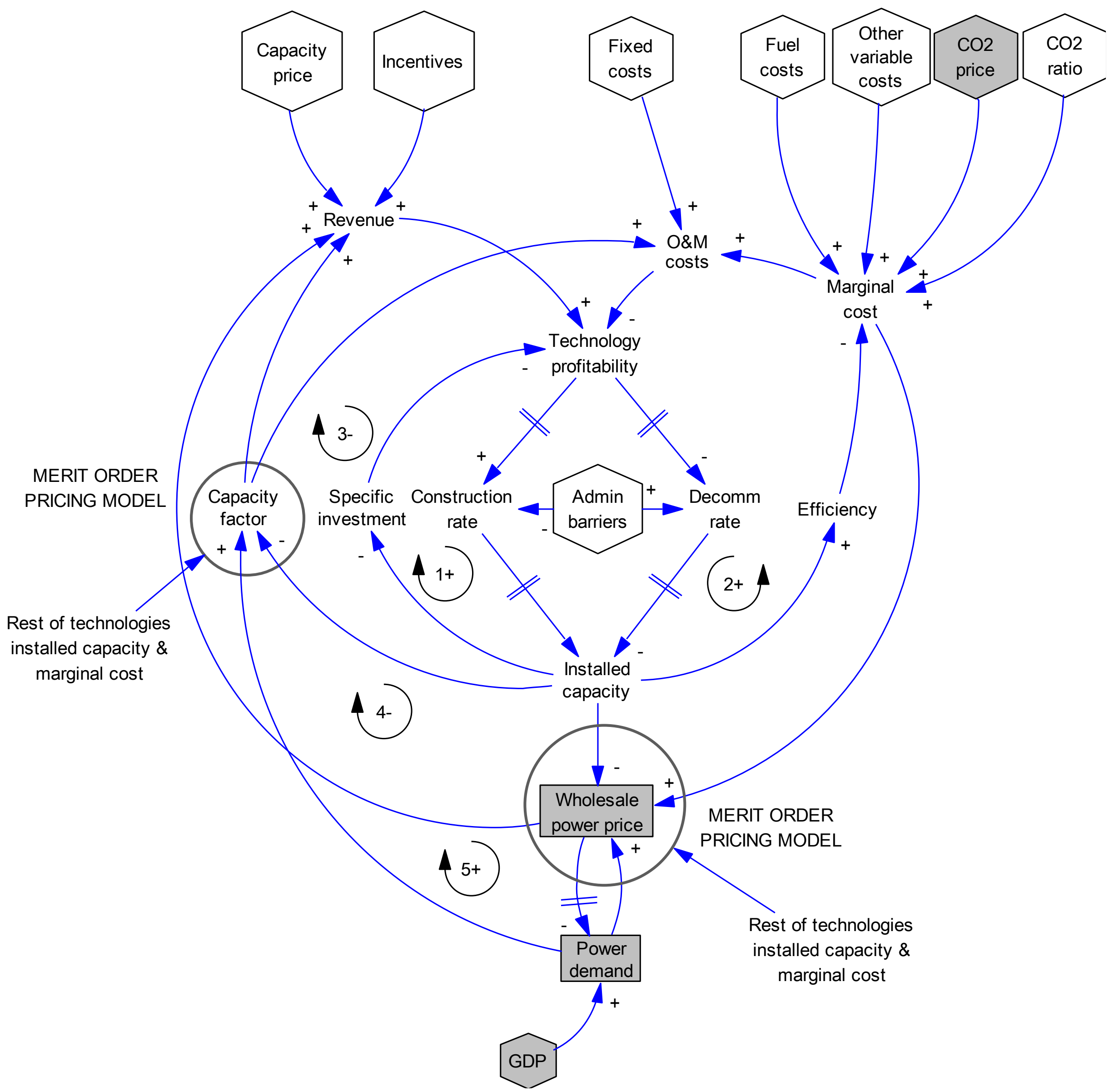

Figure 5-1: Causal diagram. Power generation asset lifecycle dynamics

Variables linked by arrows with positive signs (+) are directly related while variables linked by arrows with negative signs (-) are inversely related. Feedback loops are numbered. Reinforcing and balancing loops are represented with positive and negative signs respectively.

Capacity factor and WPM price are computed by means of a MOPP model which is described in detail in Sections 5.3 and 6.2, and which takes as inputs data from all technologies involved, as shown in the diagram. The variables computed by the MOPP are represented enclosed by a circle.

The dynamics of all technologies are as follows: Installed capacity increases with construction rate and decreases with decommissioning rate[54]. Both functions include delays which represent the time required to plan, build, start up and decommission a power generation asset.

Construction rate and decommissioning rate are direct and inverse functions of technology profitability respectively. Both functions include delays which represent the time required by investors to form expectations and make investment decisions. Construction rate decreases with administrative barriers[55] while the opposite happens to decommissioning rate. Administrative barriers represent the obstacles that the Administration may put when trying to limit the development of specific technologies. Examples of such barriers are Spain's "Nuclear Moratorium" in the 80s (Organisation for Economic Co-operation and Development, 2001) and the ban by the Government of Spain on new solar PV capacity additions in 2009 and 2010 because of the large overinvestment that took place in 2008 (Prieto & Hall, 2013).

Technology profitability increases with revenue and decreases with O&M costs and specific investment[56].

Revenues increase with capacity price[57], incentives, WPM price and capacity factor. Capacity price and incentives are exogenous variables. WPM price and capacity factor are computed by means of the MOPP model. Capacity factor increases with power demand and decreases with installed capacity, as increasing capacity or decreasing demand entail shorter annual operation times for plants. Power demand increases with the country's GDP and decreases with WPM price in the long run[58]. This relation includes a delay which represents the fact that consumers cannot immediately switch from power to alternative energy sources. No final consensus seems to have been reached in the literature regarding whether GDP drives power consumption or the opposite (Jamil & Eatzaz, 2010). So, power demand has been considered as an exogenous variable driven by GDP. While it has been assumed that demand is inelastic in the short run, given the difficulty in quickly switching energy sources for final consumers (He, et al., 2008; Garcia Alvarez,

[54] "Decomm rate" in Figure 5-1

[55] "Admin barriers" in Figure 5-1

[56] Investment cost in EUR per MW of installed capacity.

[57] Profitability is computed on a per unit (EUR/MW) basis so that no total capacity data is required.

[58] Due to the long run power demand elasticity to price

et al., 2008; Assili, et al., 2008), a certain degree of price elasticity has been considered in the long run (Hasani & Hosseini, 2011).

GDP is an exogenous variable. WPM price increases with power demand and generation marginal cost, and decreases with installed capacity. This is because the MOPP model gives dispatch priority to the cheapest technologies so that as power demand increases, more expensive technologies will be dispatched and WPM price will increase. Marginal cost increases with fuel costs, other variable costs, CO_2 price and CO_2 ratio[59], which are all exogenous variables, and decreases with efficiency. Efficiency increases with installed capacity because of a learning curve effect[60].

O&M costs increase with fixed costs, which are an exogenous variable, and marginal cost. Specific investment decreases with installed capacity because of a learning curve effect[60]. The feedback loops in the system are described below:

- Reinforcing loop 1: As installed capacity increases, specific investment decreases and technology profitability increases so that construction rate increases and decommissioning rate decreases which leads to increasing installed capacity.
- Reinforcing loop 2: As installed capacity increases, efficiency increases so that marginal cost decreases, O&M costs decrease and technology profitability increases so that construction rate increases and decommissioning rate decreases which leads to increasing installed capacity.
- Balancing loop 3: As installed capacity increases, capacity factor decreases, revenue decreases, and technology profitability decreases so that construction rate decreases and decommissioning rate increases which entails decreasing installed capacity[61].
- Balancing loop 4: As installed capacity increases, WPM price decreases, revenue decreases, and technology profitability decreases so that construction rate decreases and decommissioning rate increases which entails decreasing installed capacity[61].
- Reinforcing loop 5: As installed capacity increases, WPM price decreases, power demand increases, capacity factor increases, revenue increases, and technology profitability increases so that construction rate increases and decommissioning rate decreases which leads to increasing installed capacity[61].

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[59] Tons of CO_2 produced per MWh generated.

[60] Efficiency and specific investment change with total built capacity in the actual model. This includes both installed operating capacity and decommissioned capacity and is simulated as a fraction of total capacity built worldwide. For the sake of simplicity installed capacity is used in the causal model.

[61] Additional loops similar but opposite to loops 3 and 5 involve O&M costs instead of revenue. Nevertheless only the balancing / reinforcing effect of loops 3 and 5 is here described as it is assumed that revenues will be always higher than variable costs (otherwise the plant will not operate).

5.3 Wholesale power market dynamics

The goal of the MOPP model is to replicate the operation of the country's WPM. It is basically a market equilibrium model which matches supply with demand and computes power plant dispatching and WPM price based on input variables such as the composition of the power generation mix, the demand level and power generation marginal costs.

As described in the previous section the causal diagram of the MOPP model is embedded and deeply interlinked through feedback loops with the power generation mix lifecycle dynamics model, which is shown in Figure 5-1. Further details regarding the operation of the MOPP model can be found in section 6.2.

5.4 System cost dynamics

The goal of this model is to compute the overall power system costs based on variables such as power mix composition, commodity prices, incentive policies, power plant dispatching, power demand and CO_2 emissions. Figure 5-2 depicts the causal diagram showing the relations between system costs and their causal variables. Total system costs increase with capacity, CO_2, incentive, investment and power use costs. Capacity cost increases with installed capacity and capacity price, which is an exogenous variable. CO_2 costs increase with CO_2 price (exogenous variable) and CO_2 emissions. CO_2 emissions increase with CO_2 factor (exogenous variable) and the actual power generation which increases with installed capacity and capacity factor. Incentive costs increase with incentive prices (exogenous variable), and the actual power generation. Investment costs increase with construction rate and specific investment. Finally, power use costs increase with WPM and the actual power generation.

5.5 Environmental impact dynamics

The goal of this model is to compute the overall system-wide environmental impact based on variables such as power mix composition, power plant dispatching and power demand. Figure 5-3 shows the causal diagram of this model.

Environmental impact is measured through CO_2 emissions. Other environmental impacts such as water consumption, additional air emissions (e.g. NO_X and SO_X) or solid and liquid waste are not considered in the present research and could be considered as an additional line for further research.

Total CO_2 emissions grows with the power produced by CO_2 emitting technologies and with their respective CO_2 emission coefficients. The power produced by each generation technology depends on its installed capacity and its capacity factor, which is determined by the MOPP model, as described in previous sections. CO_2 emission coefficients are constant, exogenous, technology-specific parameters which represent the amount of CO_2 emitted per each unit of power produced.

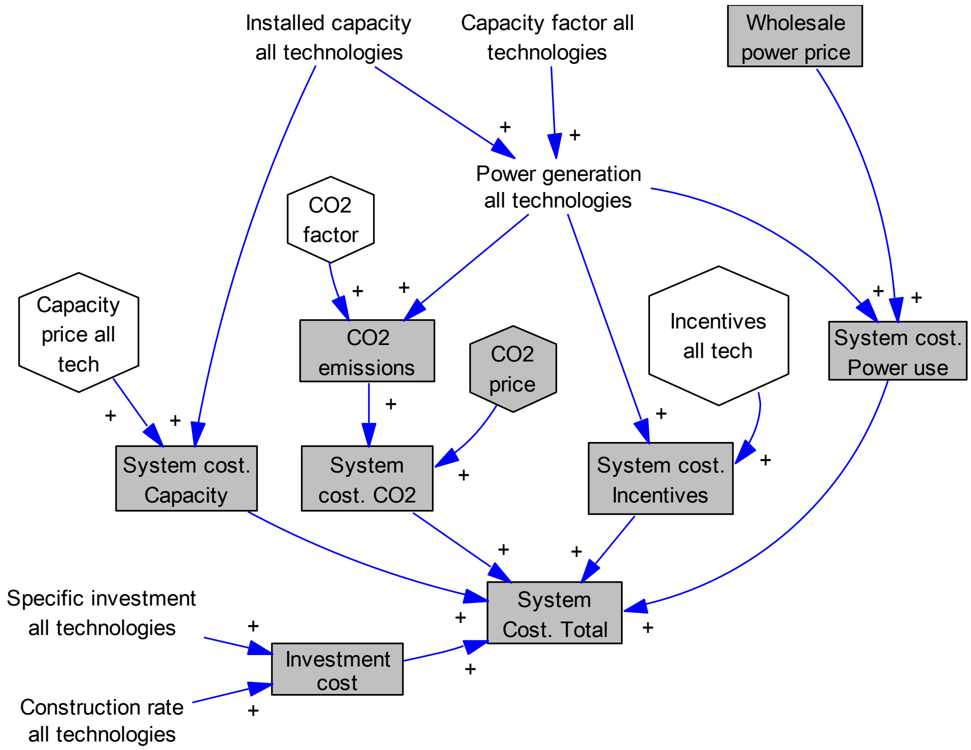

Figure 5-2: Causal diagram. System costs

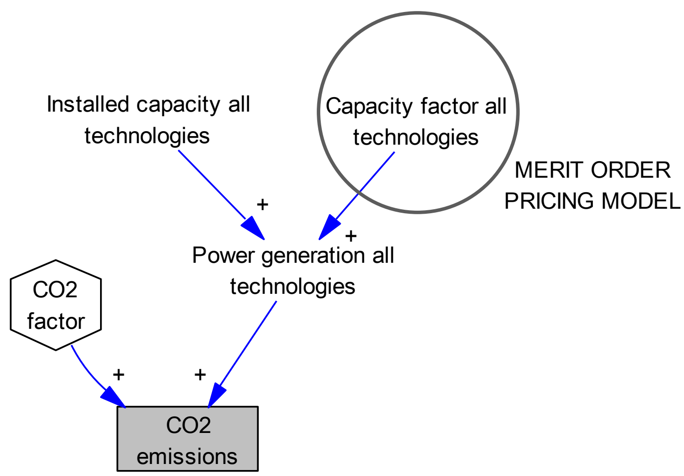

Figure 5-3: Causal diagram. Environmental impact

5.6 Socio-economic impact dynamics

The goal of this model is to compute the net impact of the power system and policies on the country's overall well-being. The energy system impacts the country's society and economy in different ways due to the multiple and complex interlinks and feedback loops involving energy, economy and society.

5.6.1 Impact of the power industry on GDP

GDP is defined as (Mankiw & Ball, 2011):

$$GDP = I + C + G + E - M = I + C + G + NX \tag{5.1}$$

Where: GDP = Gross Domestic Product

I = National Investment

C = National consumption

G = Government spending

E = National exports

M = National imports

NX = National net exports

National savings are defined as:

$$S = Y - C - G = I + NX \tag{5.2}$$

Where: S = National savings

Finally, according to the classic economic theory, GDP may be defined as a function of capital and labor accumulation by the Solow growth model (Mankiw & Ball, 2011):

$$GDP = f(K, L) \tag{5.3}$$

Where: K = capital accumulation

L = labor force

Therefore, in light of the previous equations, the power sector impacts a country's GDP in the following ways:

- National power industry direct output: The power generation mix has a direct impact on the local manufacturing industry. For example, when a country invests in technologies produced locally (for example wind turbines in the case of Spain), this has a positive impact on the country's GDP as it increases the national output at the expense of imports. On the contrary, when a country invests in technologies which must be imported (for example gas turbines or nuclear reactors in the case of Spain), this has a negative impact on the country's GDP.
- National non-power industry direct output: Power price directly impacts the industrial activity of a country. Industrial production costs increase with power price especially in power intensive industries (e.g. aluminum production). So, increasing power prices have a negative impact on industrial output and discourage investments in new productive assets.
- Indirect and induced output: Both national power direct industry output and national non-power direct industry output have indirect and induced effects on output. Indirect output account for the output of industries supporting the power industry (e.g. the steel industry, which for example produces wind turbine towers). Induced output accounts for the output of those industries benefiting from macroeconomic feedbacks (e.g. retail consumption expenditures done by the employees of a power plant) (Deloitte, 2011).
- National savings and capital accumulation: As per the Solow's growth model mentioned above, a country's output is a direct function of the accumulation of capital and labor. Investment grows with national savings (Savings = Local investment + Net exports). Therefore, the power industry impacts capital accumulation through national savings in two different ways:
    - Through savings in power generation costs: Being everything else equal, the lower the CAPEX requirements for capacity expansion and power generation costs, the greater the national savings (S) and so the capital available for additional productive assets (I).
    - Through the trade balance: National savings grow with a positive trade balance. For example, national savings (S) decline with oil imports (M), which leads to lower capital accumulation. So, in the case of an oil-importing country, greater renewable penetration will lead to a reduction in oil imports, which will entail a positive impact on the trade balance. This positive impact will ultimately increase the national savings so that more national income will be available for investment in capital goods, which will positively impact GDP in the long run.

- Final electric power consumption: End use power consumption is a GDP component by itself[62]. Therefore, the country's GDP grows with end use power demand. For the sake of the present research, total power demand is assumed to be directly correlated with real GDP, is totally inelastic in the short run, and shows limited long run price elasticity.

Figure 5-4 shows the causal diagram of the GDP model, which graphically shows the points above. Total national GDP is a direct delayed function of capital stock accumulation[63] and grows with power-related industrial production, end use power demand, end use alternative energy demand and non-power industry-related GDP, which is an exogenous variable (as described in section 5.2).

Capital stock accumulation grows with national savings, which grow with a positive trade balance and decline with increasing power generation costs. The trade balance declines with imports, which include services and fuel required for power plant operation as well as equipment and services required for capacity additions.

Services and fuel imported for power plant operations increase with installed capacity, the share of services and fuel imported, and total power production. Installed capacity grows with capacity additions, which are endogenously computed by the power generation mix lifecycle dynamics model and grow with power cost and total power demand. Power cost is endogenously computed by the MOPP model and grows with total power demand and declines with installed capacity because of the supply-demand equilibrium.

Total power demand grows with end use power demand and industrial use power demand. End use power demand and industrial use power demand are both assumed to be directly correlated with non-power GDP and inverse delayed functions of power cost, due to the long-run price elasticity assumed.

The share of services and fuel imported for power plants operations is a function of the power mix composition. Equipment and services required for capacity additions grow with capacity additions and with the share of equipment and services locally produced, which depends on the technology of the capacity added. Power generation costs grow with total power production and power cost. Total power production grows with total power demand.

Power industrial production grows with capacity additions and with the share of equipment and services required for capacity additions locally produced.

End use alternative energy demand and industrial use alternative energy demand grow with non-power GDP and with power cost as they are expected to substitute power when its price increases.

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[62] While power used as an intermediate for the production of final goods is not accounted for when computing GDP, the final use of electric power is.

[63] As per the Solow growth model.

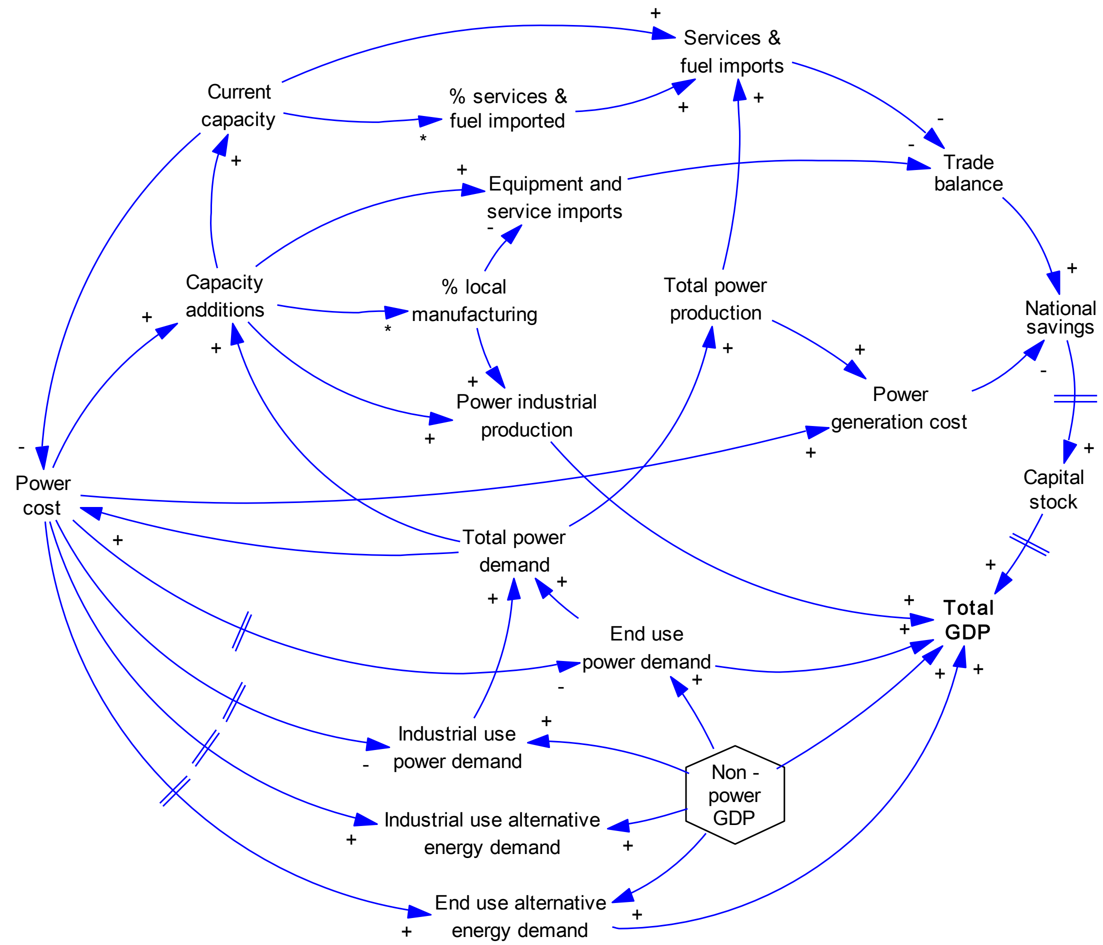

Figure 5-4: Causal diagram: Impact on GDP

The present research assumes industrial production and national savings as the main contributors to GDP. The main component of industrial production is power-related industrial production, which focuses on the supply of the equipment and services required by the power generation industry. Power-related industrial production has an indirect impact on the rest of the country's productive sectors as well as an induced effect on the country's economy, as previously discussed. In the present research, these impacts are assessed by means of Input-Output economic modelling.

For the sake of simplicity, national savings are directly added to the country's annual GDP, so that the uncertainty related to the estimation of the parameters of the Solow growth model is avoided. Trade balance is computed by assessing the share of imports in power-related capital equipment and fuels.

Finally, end use power demand is not considered as an input to the country's GDP because for the sake of the present research, power demand is considered as an exogenous variable, therefore beyond the model's boundaries. Figure 5-5 shows a simplified causal diagram of the power system's impact on GDP based on the abovementioned simplifying assumptions.

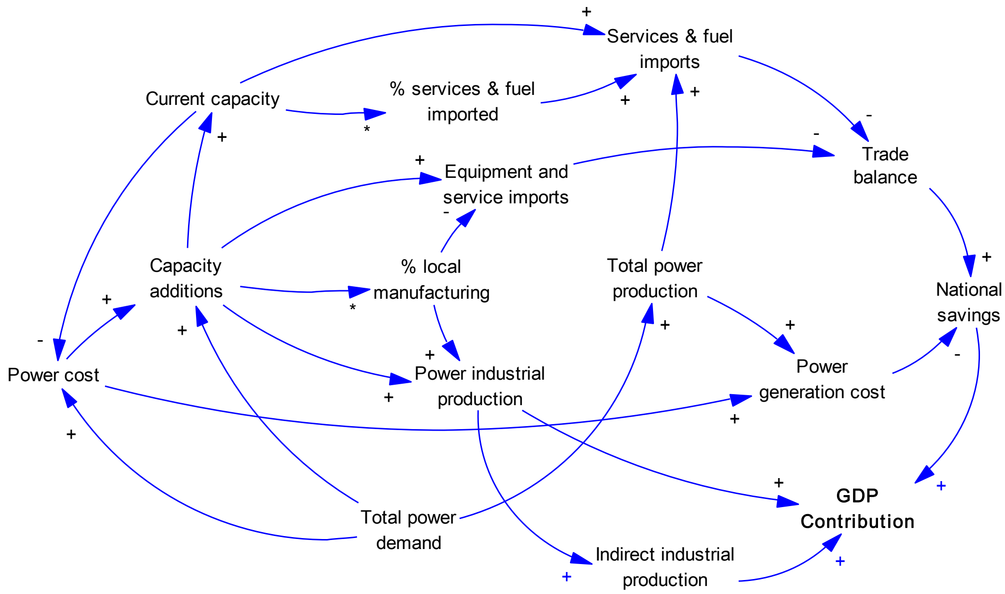

Figure 5-5: Causal diagram: Simplified impact on GDP

Chapter 6
Model structure

This section includes the detailed description of the models, including the description of the stock & flow diagrams, the feedback loops and the equations involved.

As described in previous sections, the main objective of the model developed for this work is to forecast the evolution of a country's power generation mix and its technical, environmental and socio-economic impacts, given specific exogenous variables, with a special focus on incentive policies and capacity payments. The model is driven by exogenous variables such as fossil fuel prices, macroeconomic variables, etc. as well as by levers such as incentive levels for specific technologies and capacity payments.

The model is composed of four sub models:

- <u>The power generation asset lifecycle model</u>: This model simulates the power generation capacity which is under planning, construction, operation, and decommissioned stages.

- The MOPP Model: This model simulates the operation of the country's WPM and computes the WPM price.
- The system cost model: This model computes the overall power system costs.
- The environmental impact model: This model computes the overall system-wide CO_2 emissions based on variables such as power mix composition, power plant dispatching and power demand.
- The economic impact model: This model computes the economic impact of the power sector in terms of inter-industry flows, production sector outputs and, ultimately GDP.

6.1 The power generation asset lifecycle model

This model simulates the power generation capacity by technology which is at each different stage of its lifecycle, including development, construction, operation, and decommissioning. The model is based on an aging chain structure (Sterman, 2000) which simulates the evolution of power plants through the different stages of their lifetime by technology. Operating capacity is assigned to five different capacity vintages in order to simulate each technology's evolving characteristics, by means of coflow structures (Sterman, 2000). Figure 6-1 shows a simplified stock & flow diagram of the model, which like the causal diagram, is subscripted. Permitted capacity enters the construction stage as investment decisions are made and goes online once construction finishes. Then, operating capacity goes through five different vintages until it is finally decommissioned. Capacity may be also decommissioned from any vintage due to low profitability.

The model's main underlying assumption is that technology-specific investment rates are a direct function of technology profitability, which is measured by its IRR. Decommissioning rates are a function of capacity aging as well as an inverse function of technology profitability. Additional relevant assumptions include:

i. Investors are rational. They invest in those technologies with the greater economic returns
ii. Investors are willing to diversify their risk by holding a diversified power generation portfolio
iii. Investors take time to form expectations about the future profitability of power technologies. The time taken depends on the technology considered and on the direction of the trend[64].
iv. Investors hold a pipeline of fully permitted projects that start construction when the required IRR threshold is reached.

[64] Investors are assumed to be risk-adverse so that it takes a while for them to make investment decisions when market conditions improve but they cancel investments rapidly when market conditions deteriorate.

v. Soft variables such as regulatory constraints driven by negative public opinions may delay or even completely ban capacity additions[65].

vi. There is a maximum non-dispatchable AES[66] penetration level which, once reached, refrains the regulator from issuing new construction permits for these technologies.

vii. Some energy resources are limited.

viii. There is a technology-specific maximum construction rate which is defined by the construction resources available in the country.

Assumption (i) implies that the installation rate of each specific technology will increase with its profitability. On the contrary to other models in the literature where investors are assumed to follow different strategies based on profitability, market share, etc. (Gary & Larsen, 2000) the present model assumes that all investors follow the same strategy, based on pure economic return. Assumption (ii) implies that new investments will not be done just in the most profitable technology but on every technology with an economic return greater than a technology-specific threshold value so that generation companies hold a diversified generation portfolio. Assumption (iii) implies information delays between the technologies' actual economic return and the investors' willingness to invest in them.

As a result of assumption (vii) an "available resource" variable has been considered for each technology in order to model the physical energy resource constraints. The available resource may be unlimited, such as in the case of natural gas, coal or nuclear (these energy resources are considered unlimited from a single country's perspective), or limited such as in the case of wind and hydro, where there is a limited number of river sites available for hydro power plants, a limited amount of available land for the installation of wind farms, etc.

While for example (Assili, et al., 2008) and (Saysel & Hekimoglu, 2013) consider the time required for permitting and developing the projects until they reach the ready-to-build stage, the present works assumes that investors hold a pipeline of fully permitted projects which commence construction once the profitability threshold is reached, in a way similar to (Olsina, et al., 2006) and (Arango, 2007). This is a common practice for specific technologies (mostly alternative) in the industry where investors are waiting for economic conditions to be good enough to start construction. For the sake of simplicity, this assumption has been extended to all technologies.

[65] These regulatory constraints have been introduced for example in the case of nuclear power where a moratorium banning new capacity additions was enacted in 1984 in Spain.

[66] Non-dispatchable AES include wind and solar PV.

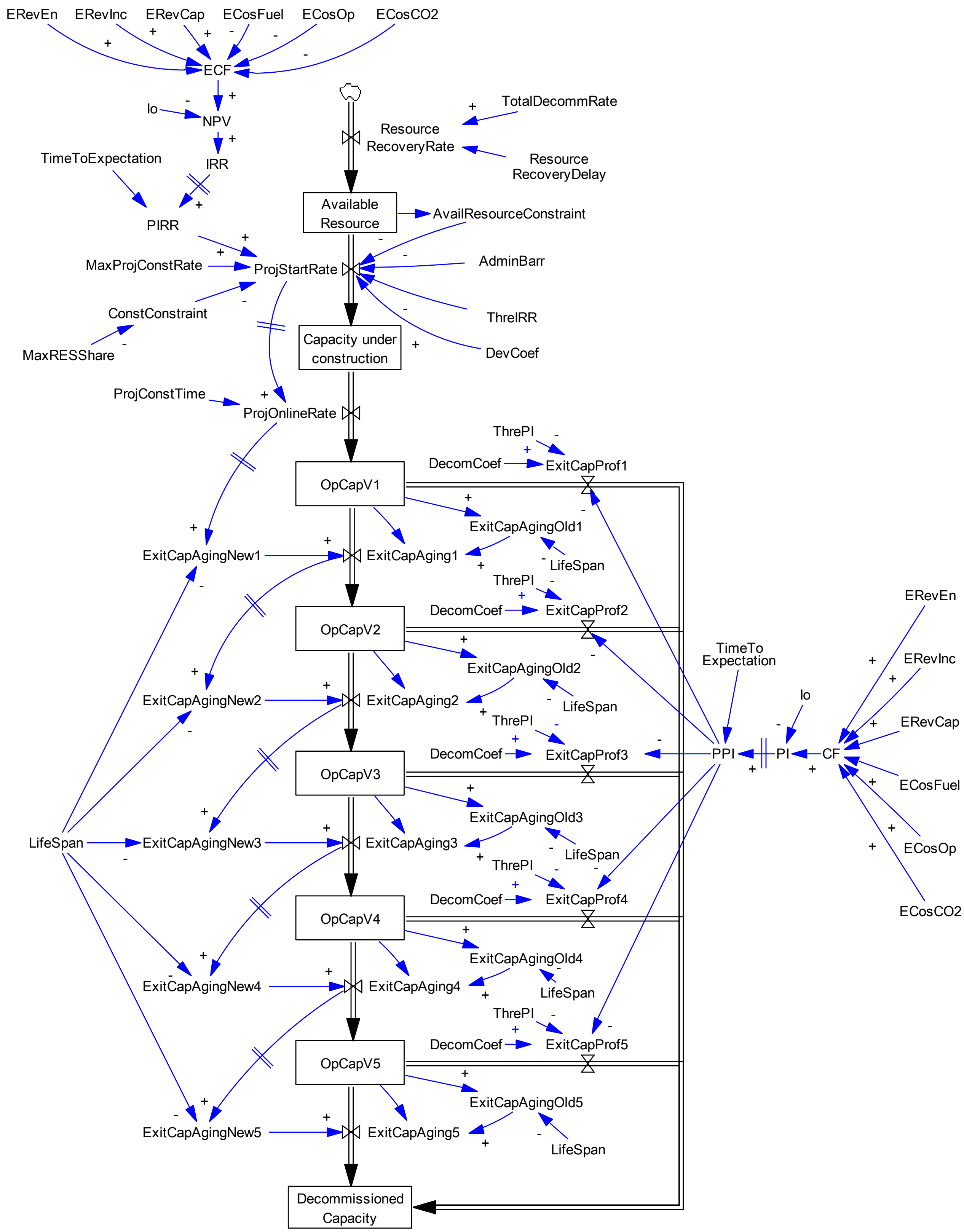

Figure 6-1: Simplified stock & flow diagram of the power generation asset lifecycle model

Several economic return ratios such as NPV, IRR, PI or ROI are commonly used in the power industry. Corporations often choose a specific ratio or a combination of ratios to make their investment decisions. For the sake of the present research, IRR has been chosen because it provides a clear and easy way for benchmarking relative economic returns as it is (i) independent of the project size and (ii) independent of the discount rate considered by different corporations. IRR is computed as follows:

$$NPV = 0 = -I_0 + \sum_{n=1}^{N} \frac{ECF_n}{(1+IRR)^n} \tag{6.1}$$

Where: IRR = Internal Rate of Return (dmnl)

I_0 = Initial investment (EUR)

n = Economic life of the power plant (years)

ECF_n = Expected cash flow in year n (EUR/year)

Different to the real lifespan, the economic lifespan of a power plant is defined as the time period while a power plant can operate without additional investments or major overhauls.

IRR depends on the stream of cash flows that investors expect to get in the future. Expected future cash flows are a function of expected future revenues (energy sales, capacity payments and incentives) as well as of the expected operating costs (fuel, variable, fixed, CO_2 credits, capacity etc.). So, expected cash flows are computed as follows:

$$\begin{aligned} ECF_n = ERevEn_n + ERevInc_n + ERevCap_n - ECosFuel_n - ECosOp_n \\ - ECos\ CO2_n \end{aligned} \tag{6.2}$$

Where for year n:

ECF_n = Expected cash flow (EUR/year)

$ERevEn_n$ = Expected energy revenue (EUR/year)

$ERevInc_n$ = Expected incentive revenue (EUR/year)

$ERevCap_n$ = Expected capacity payment revenue (EUR/year)

$ECosFuel_n$ = Expected fuel cost (EUR/year)

$ECosOp_n$ = Expected non-fuel operating cost (EUR/year)

$ECosCO2_n$ = Expected CO_2 credit allowance cost (EUR/year)

There are different approaches in the literature regarding how to model expected cash flows, revenues and costs which include trend functions based on the bounded rationality hypothesis, smoothing techniques, etc. (Hasani & Hosseini, 2011). For example, (Bunn & Larsen, 1992) and (Bunn, et al., 1993) include specific degrees of foresight in their models ranging from 0 (myopic) to 4 years while (Kadoya, et al., 2005) include trend extrapolations of past average values.

For the sake of the present research, an approach by which expected cash flows depend just on current market conditions and keep constant throughout the power plant lifetime has been considered.

This is a relatively myopic approach as, while real life investors do not enjoy perfect foresight either, they perform more sophisticated assessments such as trend analysis and extrapolation or sensitivity analysis based on which they produce their feasibility assessments and ultimately make their investment decisions. Also, while this approach is accurate in the case of technologies subject to secured FITs, it may be more arguable in technologies whose profitability depends on market conditions.

While historical trends are accurately replicated by this approach, as described in section 7.3, more sophisticated approaches regarding investors' rationality could be embedded in the model, being this a potential line of future research.

As future expected cash flows have been assumed constant across the power plants' lifetimes, IRR can be computed as follows:

$$NPV = 0 = -I_0 + ECF\left(\frac{1-(1+IRR)^{-n}}{IRR}\right) \tag{6.3}$$

Where: NPV = Net present value (EUR)

I_0 = Initial investment (EUR)

n = Economic life of the power plant (years)

ECF = Expected annual cash flow (EUR/year)

IRR = Internal rate of return (dmnl)

The IRR above computed is the one that investors expect go get from future cash flows which are based on current market conditions. However, it usually takes time for investors to adapt their market perception to the actual market conditions, especially when said market conditions are improving. So, a delay between the perceived IRR (PIRR) and the actual IRR has been considered. Similar to (Assili, et al., 2008), this delay has been modelled as a first order smoothing function (i.e. information delay).

The delay time has been assumed as different depending on whether market conditions improve or deteriorate because of risk aversion issues, so that an asymmetric approach has been considered. When market conditions improve, investors usually tend to be cautions and wait to check if this improvement is going to be transient or steady. So, a non-zero positive delay time has been considered in this case. In case market conditions deteriorate, investors are expected to be risk adverse and immediately adapt their expectations to reality so that in this case the delay time has been considered to be zero[67]. Therefore, PIRR is computed as:

$$\begin{aligned} PIRR_{n,i} &= \\ & IF\ \left(IRR_{n,i} > IRR_{n-1,i}\right) \\ & \qquad = \ \left(SMOOTH\left(IRR_{n,i}, Time\ ToExpectation_i\right)\right. \\ & ELSE \\ & \qquad = \ IRR_{n,i} \end{aligned} \tag{6.4}$$

Where for year n and technology i:

$PIRR_{n,i}$	= Perceived IRR (dmnl)
$IRR_{n,i}$	= IRR (dmnl)
$IRR_{n-1,i}$	= IRR in year n-1 (dmnl)
$TimeToExpectation_i$	= Time to form expectations (year)

One of the main challenges of the present model is the simulation of the relation between the perceived IRR (PIRR) and the actual capacity which enters the construction stage (ProjStartRate) in MW per year. (Assili, et al., 2008; Olsina, et al., 2006) model the investment rate as a function of PIRR by means of S-shaped logistic curves. (Botterud, 2003) considers an investment rate which is fully proportional to the PI. (Hasani & Hosseini, 2011) use S-shaped logistic curves applied to the required capacity additions and decommissioning rates. For the sake of the present research, a fully proportional approach has been considered so that the project start rate is a function of both a technology-specific threshold minimum IRR ($ThreIRR_i$), below which no investments are done, and a technology-specific constant proportionality coefficient ($DevCoef_i$). Also, a maximum installation rate (MaxProjConstRate), which sets a technology-specific limit for the installation rate and takes into account physical limitations such as the equipment manufacturing capacity, construction company availability, materials availability, etc., has been considered. Figure 6-2 shows graphically the relations described above.

[67] This assumption is based on multiple observations and discussions with FIT based renewable energy investors, where this behavior was most often confirmed. This assumption may be more arguable in the case of conventional technologies although the results of the simulation seem to confirm that they are not far away from reality

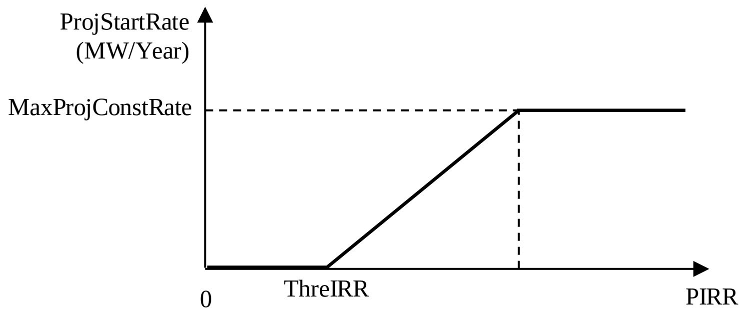

Figure 6-2: Functional relation between the expected IRR and the actual project start rate

An additional constraint regarding the maximum renewable non-dispatchable capacity share allowed in the system (MaxRESShare) has been included in the model. Only wind and solar PV technologies have been included in the non-dispatchable category as solar CSP and hydro in some cases are dispatchable. Therefore, the system operator is expected to stop granting construction permits for solar PV and wind power projects when the share of non-dispatchable capacity reaches a specific threshold. This limit is modelled by the ConstConstraint binary variable. It has also been considered that once the system operator has stopped granting permits, this situation will continue until the share of non-dispatchable capacity falls below a specific threshold.

The fact that that the regulator may limit or even completely ban the development of specific technologies because of any political reason has been modelled by including the administrative barriers variable (AdminBarr) which limits the project start rate.

Finally, the project start rate is also a function of the available energy resource so that if not enough resource is available, projects will not be executed. So, the project start rate is computed as:

$$\begin{aligned} & ProjStartRate_i(t) = \\ & \quad IF\ (AvailResourceConstraint_i(t) = FALSE\ AND\ ConstConstraint_i(t) \\ & \qquad = FALSE) \\ & \qquad MIN(\mathrm{MaxProjConstRate}_i, MAX(0, DevCoef_i \\ & \qquad\qquad \cdot (PIRR_i(t) - ThreIRR_i)) \cdot (1 - AdminBarr_i(t)) \\ & \quad ELSE \\ & \qquad = 0 \end{aligned} \tag{6.5}$$

Where for technology i:

$ProjStartRate_i$	= Project start rate (MW/year)
$AvailResourceConstraint_i$	= Available resource constraint (binary)
$ConstConstraint_i$	= Regulatory construction constraint (binary)

$MaxProjConstRate_i$ = Maximum project construction rate (MW/year)

$DevCoef_i$ = Proportionality factor (MW/year)

$PIRR_i$ = Perceived IRR (dmnl)

$ThreIRR_i$ = Minimum threshold IRR (dmnl)

$AdminBarr_i$ = Administrative barriers (dmnl)

In contrast to other works where a single overall threshold IRR is set based on estimated industry ROI requirements (Olsina, et al., 2006; Hasani & Hosseini, 2011), different threshold IRRs and proportionality factors by technology are empirically determined, based on historical values as described in section 7.3. (Bunn, et al., 1993) provides examples of required IRRs required by both the public and the private sector as well as a description on how these requirements have evolved with the privatization of the power industry. Technology-specific threshold IRRs aim at reflecting the different risk profiles inherent to each technology. Setting these two parameters is one of the key points of this model and is done based on historical values as described in section 7.3.

The rate at which new power plants come online has been modelled as a fixed delay (material delay) of the project start rate. This delay takes into account the actual technology-specific time required to build a power plant. Therefore, the project online rate (ProjOnlineRate) is computed as:

$$ProjOnlineRate_i(t) = DELAYFIXED(ProjStartRate_i(t), ProjConstTime_i) \qquad (6.6)$$

Where for technology i:

$ProjOnlineRate_i$ = Project online rate (MW/year)

$ProjConstTime_i$ = Project construction time (year)

The operating capacity has been allocated to five different vintages in order to take into account the evolution across time of plant characteristics such as efficiency, capacity factor, etc. Said vintage structure is shown in Figure 6-1.

Therefore, once power plants are built, they enter into commercial operation and go through five different vintages and are ultimately decommissioned. This methodology is used in order to assess the impact on the system of each technology vintage as well as its profitability along its useful life. For example, older thermal plants will have lower efficiencies than more modern ones; new wind farms will have lower capacity factors than older ones (as the best sites are already used), etc. In the specific case of incentive premiums or FITs associated to each generation technology, it has been considered that, once assigned, they stay constant across the plant's whole lifetime. The operating capacity in each vintage at time t is given by:

$$OpCapV_{i,v}(t) = \int_0^t EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitCapV_{i,v}(t) \cdot dt + OpCapV_{i,v}(0) \qquad (6.7)$$

Where for technology I and vintage v:

$OpCapV_{i,v}$ =	Operating capacity in the vintage (MW)
$EntCapV_{i,v}$ =	Capacity enter rate (MW/year)
$ExitCapV_{i,v}$ =	Capacity exit rate (MW/year)

The vintage characteristics (i.e. maximum capacity factor, efficiency and applicable premiums) are simulated by means of a coflow structures (Sterman, 2000) and computed as follows:

$$CFV_{i,v}(t) = \frac{\int_0^t EntCFV_{i,v}(t) \cdot EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitCFV_{i,v}(t) \cdot ExitCapV_{i,v}(t) \cdot dt + CFStock_{i,v}(0)}{\int_0^t EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitCapV_{i,v}(t) \cdot dt + OpCapV_{i,v}(0)} \qquad (6.8)$$

$$EffV_{i,v}(t) = \frac{\int_0^t EntEffV_{i,v}(t) \cdot EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitEffV_{i,v}(t) \cdot ExitCapV_{i,v}(t) \cdot dt + EffStock_{i,v}(0)}{\int_0^t EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitCapV_{i,v}(t) \cdot dt + OpCapV_{i,v}(0)} \qquad (6.9)$$

$$Prem_{i,v}(t) = \frac{\int_0^t EntPrem_{i,v}(t) \cdot EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitPrem_{i,v}(t) \cdot ExitCapV_{i,v}(t) \cdot dt + PremStock_{i,v}(0)}{\int_0^t EntCapV_{i,v}(t) \cdot dt - \int_0^t ExitCapV_{i,v}(t) \cdot dt + OpCapV_{i,v}(0)} \qquad (6.10)$$

Where for technology I and vintage v:

$EntCapV_{i,v}$	= Capacity entering the vintage (MW/year)
$ExitCapV_{i,v}$	= Capacity exiting the vintage (MW/year)
$CFV_{i,v}$	= Average capacity factor (dmnl)
$EntCFV_{i,v}$	= Capacity factor of the plants entering the vintage (dmnl)
$ExitCFV_{i,v}$	= Capacity factor of the plants exiting the vintage (dmnl)
$CFStock_{i,v}$ (0)	= Cumulative product CF times Operating capacity at time 0 (MW)
$EffV_{i,v}$	= Average efficiency (dmnl)
$EntEffV_{i,v}$	= Efficiency of the plants entering the vintage (dmnl)
$ExitEffV_{i,v}$	= Efficiency of the plants exiting the vintage (dmnl)

$EffStock_{i,v}$ (0) = Cumulative product Eff times Operating capacity at time 0 (MW)

$PremV_{i,v}$ = Average premiums (EUR/MWh)

$EntPremV_{i,v}$ = Premiums entering the vintage (EUR / MWh – year)

$ExitPremV_{i,v}$ = Premiums exiting the vintage (EUR / MWh – year)

$PremStock_{i,v}$ (0) = Cumulative product Prem times Op. cap. at time 0 (EUR/h)

While $EntCF_{i,v}$ is equal to the actual capacity factor of the capacity entering the vintage, $ExitCF_{i,v}$ is equal to the average capacity factor in the vintage. Capacity enter rate is equal to project online rate in case of the first vintage and equal to the previous vintage's exit rate for the other vintages.

Capacity exit rate is the sum of the exit rate due to plant aging and the decommissioning rate due to low profitability.

$$ExitCapV_{i,v}(t) = ExitCapAging_{i,v}(t) + ExitCapProf_{i,v}(t) \tag{6.11}$$

Where for technology i and vintage v:

$ExitCapV_{i,v}$ = Total capacity exit rate (MW/year)

$ExitCapAging_{i,v}$ = Capacity exit rate due to plant obsolescence (MW/year)

$ExitCapProf_{i,v}$ = Capacity decommissioning rate due to low profitability (MW/year)

ExitCapAging is the sum of the exit rate of the plants which entered the vintage plus the exit rate of the plants already in the vintage at the start of the simulation and is computed as follows:

$$ExitCapAging_{i,v}(t) = ExitCapAgingOld_{i,v}(t) + ExitCapAgingNew_{i,v}(t) \tag{6.12}$$

Where for technology i and vintage v:

$ExitCapAging_{i,v}$ = Total aging exit rate (MW/year)

$ExitCapAgingNew_{i,v}$ = Exit rate of the plants which entered the vintage (MW/year)

$ExitCapAgingOld_{i,v}$ = Exit rate of the plants already in the vintage (MW/year)

The capacity outflow of each vintage depends on two different parameters. The first one is the aging rate, which depends on the useful life of each technology. So the time that each technology stays in each one of the vintages is given by:

$$TimeInVint_{i,v} = \frac{LifeSpan_i}{5} \tag{6.13}$$

Where for technology I and vintage v:

$TimeInVint_{i,v}$ = Time of the technology in the vintage (year)

$LifeSpan_i$ = Lifespan of the technology (year)

The exit rate of the plants which entered the vintage is equal to the capacity enter rate delayed (fixed material delay) by the useful life of the technology as follows:

$$ExitCapAgingNew_{i,v}(t) = DELAYFIXED\left(EntCapV_{i,v}(t), TimeInVint_{i,v}\right) \tag{6.14}$$

Where for technology I and vintage v:

$EntCapV_{i,v}$ = Capacity entering the vintage (MW/year)

$TimeInVint_{i,v}$ = Time of the technology in the vintage (year)

The exit rate of the legacy plants already in the vintage at the beginning of the simulation is computed as follows:

$$ExitCapAgingOld_{i,v}(t) = \frac{\mathrm{OpCapOldV}_{i,v}(t)}{TimeInVint_{i,v}} \tag{6.15}$$

Where for technology i and vintage v:

$OpCapOldV_{i,v}$ = Legacy capacity already in the vintage (MW)

$TimeInVint_{i,v}$ = Time of the technology in the vintage (year)

The decommissioning rate due to low profitability depends on the actual profitability of each technology in each vintage. In case profitability falls below a specific threshold, investors will opt to decommission the plant. In this case, the profitability does not depend on the initial investment as, once already done, it is a sunk cost. So, the profitability is measured by the actual cash flow divided by the initial investment in order to have normalized values. So, the profitability index for decommissioning purposes is defined as:

$$PI_{i,v}(t) = \frac{CF_{i,v}(t)}{I_{0.i,v}} \tag{6.16}$$

Where for technology i and vintage v:

$PI_{i,v}$ = Decommissioning profitability index (dmnl)

$CF_{i,v}$ = Annual cash flow (EUR/year)

$I_{0,i,v}$ = Initial investment (EUR/year)

The perceived profitability index (PPI) is a delayed function of the profitability index and is computed the same way as PIRR, by means of a SMOOTH (information delay) function. So, the decommissioning rate due to low profitability is computed in a similar way to the project start rate:

$$ExitCapProf_{i,v}(t) = MAX\Big(0, DecomCoef_i \cdot \big(PPI_{i,v}(t) - ThrePI_i\big)\Big) \tag{6.17}$$

Where for technology i and vintage v:

$PPI_{i,v}$ = Perceived profitability index (dmnl)

$ExitCapProf_{i,v}$ = Decommissioning rate due to low profitability (MW/year)

$DecomCoef_i$ = Decommissioning coefficient (MW/year)

$ThrePI_i$ = Threshold profitability index (dmnl)

Finally the resource recovery rate (MW/year) for those technologies where it is finite, is given by:

$$ResourceRecoveryRate_i = ExitCapAging5_i + \sum_{v=1}^{5} ExitCapProf_{v,i} \tag{6.18}$$

Where for technology i and vintage v:

$ExitCapAging5_i$ = Energy resource recovery rate (MW/year)

$ExitCapAging5_i$ = Exit rate due to plant aging from vintage 5 (MW/year)

6.2 The merit order power pricing model

This model is used to simulate the operation of Spain's WPM (OMIE) where hourly spot prices are set on a daily basis.

The MOPP assumes a fully liberalized market where the whole power produced is traded at a WPM where producers and consumers bid their respective production and demand. Both the power produced (and consumed) and the clearing price are set by the intersection between the power supply and demand curves. All generators and consumers who are awarded with any amount of energy get the same marginal price regardless of the price they actually bid.

While works such as (Alishahi, et al., 2012) propose a perfect competitive market model where power generating firms bid their marginal generation costs and cannot strategically influence the clearing price, other works such as (Kadoya, et al., 2005) consider sometimes-opportunistic bidding strategies so that bids depend not only on marginal costs but on biding strategies which may reflect sporadic market power. For the sake of this work a perfectly competitive market has been assumed while the reserve margin keeps over a specific threshold value but once this threshold is reached, market power has been considered by means of a scarcity price as described below in this section.

The following assumptions have been made regarding the MOPP:

i. The whole power production is traded at the WPM. No other instruments (such as PPAs, etc.) exist.
ii. The WPM sets the WPM price by constructing the power supply and demand curves and finding their intersection point.
iii. The market is uniform and perfect in the sense that power generators are assumed to bid their actual marginal cost, no complex bidding strategies have been considered and power generators cannot strategically influence the price while reserve margin stays over a specific level.
iv. When reserve margin goes below a specific threshold, power generators start to exercise market power, which is modelled by a "scarcity price".
v. Power demand is a function of GDP, is price-inelastic in the short run but shows some price-elasticity in the long run.
vi. Costs other than generation such as T&D or system operation are not considered so that consumers are assumed to pay just the generation cost which is composed of the power marginal price and the scarcity price.

The supply curve is built by sorting all involved power generation technologies (10) and vintages (5) by increasing marginal price. So, a supply curve made up of 50 (10 technologies and 5 vintages) horizontal segments is obtained. Marginal costs are set on the Y-axis while the available capacity is set on the X-axis. Therefore, the X axis shows the cumulative capacity which is offered in the market, sorted by increasing marginal price. As a result, the technologies located to the left side are the cheapest ones and the technologies on the right side are the most expensive ones. The marginal price (MargPrice) for each technology i and vintage v is computed as:

$$MargPrice_{i,v}(t) = ECosFuel_{i,v}(t) + ECosOp_{i,v}(t) + ECosCO2_{i,v}(t) \tag{6.19}$$

Where for technology i and vintage v:

$MargPrice_{i,v}$	= Marginal price (EUR/MWh)
$ECosFuel_{i,v}$	= Fuel cost (EUR/MWh)
$ECosOp_{i,v}$	= Non-fuel O&M cost (EUR/MWh)
$ECosCO2_{i,v}$	= CO_2 emission allowance cost (EUR/MWh)

The available capacity by technology (AvaCapacity) for each technology and vintage is calculated as:

$$AvaCapacity_{i,v} = InstCapacity_{i,v} \cdot BiddingCF_{i,v} \tag{6.20}$$

Where for technology I and vintage v:

$AvaCapacity_{i,v}$	= Available capacity (MW)
$InstCapacity_{i,v}$	= Installed capacity (MW)
$BiddingCF_{i,v}$	= Capacity factor considered for bidding (dmnl)

While the model uses historical and calculated capacity factors in order to assess and forecast plants' profitability and dispatching, the full available capacity factor is used for the calculation of the supply curve. This is because plant operators are assumed to bid each plant's whole capacity although the final energy output (and CF) will depend on the amount of energy actually sold at the WPM.

WPMs usually work on an hourly basis so that using annual averages for calculations can be misleading due to the large non-linearity introduced by the supply and demand curves. So, instead of using annual average demand values, a model based on the load duration curve has been introduced. For the sake of simplicity, the load duration curve has been considered as linear, being its maximum the annual peak power demand and its minimum the lowest annual power demand. Figure 6-3 shows an example of such a curve.

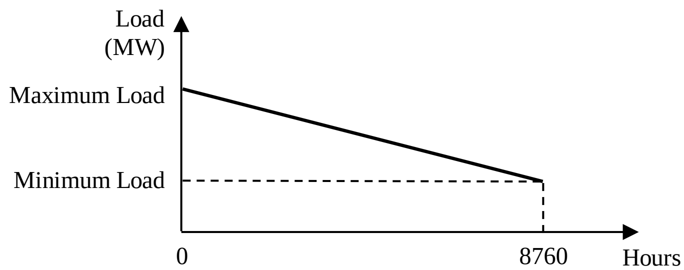

Figure 6-3: Load duration curve example

The load duration curve is divided into ten sections and a WPM price is calculated for the demand corresponding to each section. The resulting WPM price (FinalMarginalPrice) is calculated as the average of the ten calculated marginal price values.

The WPM price is set by the intersection of the supply and demand curves as shown in Figure 6-4. The capacity located to the left of the intersection point will be dispatched and will receive the WPM price regardless of the price actually bid. The capacity located to the right of the intersection point will not be dispatched.

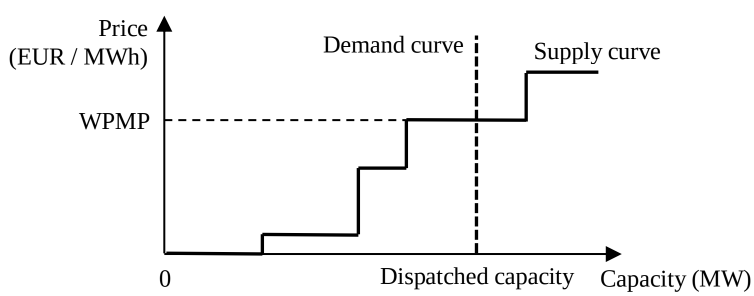

Figure 6-4: Marginal price computation

Large price spikes far beyond the regular marginal generation costs have occurred historically for example in the case of the California electricity crisis in 2000 and 2001 (Olsina, et al., 2006) or the Chilean electricity crisis (Galetovic & Fischer, 2000). These price spikes may be due either to the use of very expensive power generation units or to the opportunistic bidding behavior of generation operators during scarcity times that, in the case of Spain, may be amplified by the significant horizontal integration of the power generation industry, where the two largest power generation utilities accounted for about 50% of the market share in 2004 (Garcia Alvarez, et al., 2008).

In order to capture this effect, an additional scarcity price component has been introduced in the model and added on top of the power marginal price. This scarcity price is a nonlinear function of the reserve margin. It is equal to zero for reserve margin values over a specific threshold and increases sharply when the reserve margin falls below said threshold, reaching a maximum value which depends on the market considered. Theoretically, this maximum value should be equal to the VOLL[68], which has been extensively described in the literature, minus the actual marginal price. However, from a practical point of view it has been considered that the regulator will impose a price cap in case the final power price becomes too high (Ford, 1999). So, the final WPM price is computed as follows:

$$FinalWPMP(t) = MIN\left(PriceCap, WPMP(t) + ScarcityPrice(RerveMargin(t))\right) \quad (6.21)$$

Where: FinalWPMP = Final WPM price (EUR/MWh)

WPMP = WPM price obtained from the supply-demand curves (EUR/MWh)

ScarcityPrice = Scarcity price (EUR/MWh)

ReserveMargin = System reserve margin (dmnl)

PriceCap = Final WPMP cap set by the regulator (EUR/MWh)

The reserve margin (ReserveMargin) is defined as follows:

$$ReserveMargin = \frac{DeratedInstCapacity}{PeakPowerDemand} \quad (6.22)$$

Where: DeratedInstCapacity = Total installed capacity corrected by technology-specific derating factors which take into account each technology's specific availability to meet demand (MW)

PeakPowerDemand = Annual system wide maximum power demand (MW)

[68] Which, as described in the literature (Hasani & Hosseini, 2011; Ford, 1999; Bunn & Larsen, 1992), may reach values as high as 1,000 to 3,000 EUR/MWh.

Figure 6-5 shows an example of the scarcity price vs. reserve margin curve. While in some cases only dispatchable technologies (i.e. coal, nuclear, gas and impoundment hydro) are considered for the calculation of the reserve margin, in other cases alternative technologies are considered to some extent as well (The Brattle Group, Astrape Consulting, 2013). So, wind and solar PV have been considered although limited by the derating factors shown in Table 7-1.

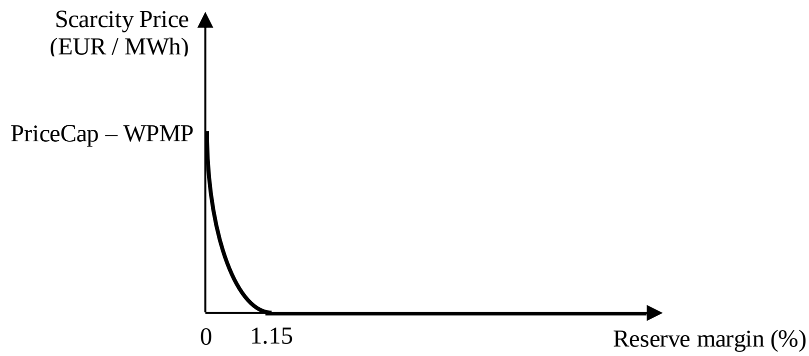

Figure 6-5: Scarcity price vs. reserve margin curve example

There is extensive literature on the causality between power demand and GDP (Guttormsen, 2004; Wolde-Rafael, 2006; Yoo, 2006). However, no final consensus seems to have been reached regarding whether GDP drives power consumption or the opposite (Jamil & Eatzaz, 2010). Therefore, for the sake of the present research power demand has been considered as an exogenous variable driven by GDP. While it has been assumed that demand is inelastic in the short run given the difficulty in quickly switching energy sources for final consumers (He, et al., 2008; Garcia Alvarez, et al., 2008; Assili, et al., 2008), a certain degree of price elasticity has been considered in the long run (Hasani & Hosseini, 2011). So, peak power demand is computed as per the formula below, where a specific time delay is introduced in order to account for the long run characteristic mentioned above.

$$FinalPeakDem_n = ForPeakDem_n \left(\frac{ForPowPrice_n}{RefPowPrice_0}\right)^{PriceElast} \quad (6.23)$$

Where: $FinalPeakDem_n$ = Calculated peak power demand in year n (MW)

$ForPeakDem_n$ = Forecasted (based on GDP) peak power demand in year n (MW)

$ForPowPrice_n$ = Computed power price in year n (EUR/MWh)

$RefPowPrice_0$ = Power price at the beginning of the simulation (EUR/MWh)

$PriceElast$ = Power demand elasticity to price (dmnl)

6.3 The system cost model

Although usually system costs include components such as generation, T&D, system management, system operation, trading and regulation costs, incentives, etc. for the sake of the present research and in order to be able to benchmark the impact of the power generation mix on system costs, only power purchase outlays, incentives, capacity payments, CO_2 costs and total investment have been considered.

While, as described in section 2.6 incentives can take many different forms such as grants, FITs, price premiums, tax credits or green certificates, at the end of the day, they are paid by end users through either higher power bills or higher tax rates. On the contrary to systems such as green certificates, which entail the operation of a parallel trading exchange or tax credits which sometimes require complex financial instruments in order to monetize tax savings, premiums are a very simple and intuitive incentive scheme which allows straightforward quantification. Because of these reasons, premiums have been chosen as the reference incentive scheme in the present research. Total incentive cost is calculated as the product of the power produced and the annual average premium price in EUR/MWh. Figure 6-6 shows the simplified stock & flow diagram of the system cost model.

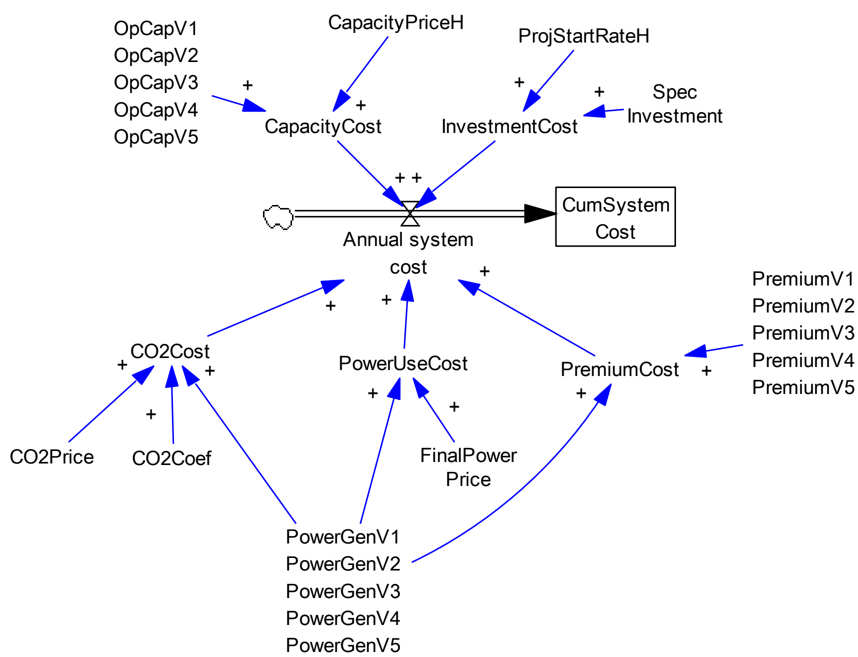

Figure 6-6: Simplified stock & flow diagram of the system cost model

As described in previous sections, power systems show large inertia due to the long lead times required for planning and building power generation assets as well as to their long lifetimes. Investment decisions made today may have an impact on system costs during many decades from now. Energy policy decisions must be done by taking into account their cumulative long term impact on the power system.

Therefore, for the sake of the present research, systems costs are assessed from a long run, cumulative perspective. Cumulative system costs (CumSystemCosts) are computed as follows:

$$\begin{aligned} &CumSystemCost(t) \\ &\quad = \sum_i \sum_v \int_0^t \big(PowerGen_{i,v}(t) \\ &\quad \cdot \big(FinalWPP(t) + Premium_{i,v}(t) + CO2Coef_i(t) \cdot CO2Price\ (t)\big) \\ &\quad + OpCapV_{i,v}(t) \cdot CapacityPriceH_i(t)\big) \cdot dt + CumSystemCost(0) \end{aligned} \tag{6.24}$$

Where for technology i and vintage v:

CumSystemCost	= Cumulative system cost (EUR)
$PowerGen_{i,v}$	= Instant power generation (MW)
FinalPowerPrice	= Final WPM (EUR/MWh)
$Premium_{i,v}$	= Price premium (EUR/MWh)
$CO2Coef_i$	= CO_2 production (t/MWh)
CO2Price	= CO2 emission allowance price (EUR/t)
$CapacityPriceH_i$	= Capacity price (EUR/MW - h)

Cumulative average power price (CumAvgPowerPrice) is computed as follows:

$$CumAvgPowerPrice = \frac{CumSystemCosts}{\sum_{y=2017}^{2030} AnnPowerGen} \tag{6.25}$$

Where: AnnPowerGen = Annual power generation (MWh/year)

6.4 The CO_2 emission model

The goal of this model is to calculate the cumulative CO_2 emissions caused by the power generation industry. Figure 6-7 shows the simplified stock & flow diagram of this model. Cumulative CO_2 emissions depend on the actual annual power generation and on the technology-specific CO_2 coefficients.

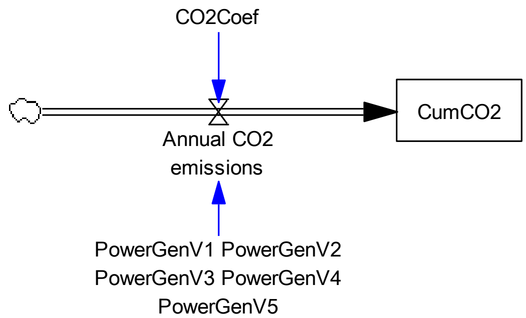

Figure 6-7: Simplified stock & flow diagram of the CO_2 emission model

Cumulative CO_2 emissions are computed as follows:

$$CumCO2(t) = \sum_i \sum_v \int_0^t PowerGen_{i,v}(t) \cdot CO2Coef_i(t) \cdot dt + CumCO2(0) \tag{6.26}$$

Where for technology i and vintage v:

CumCO2 = Cumulative CO_2 emissions (t)

$PowerGen_{i,v}$ = Instant power generation (MW)

$CO2Coef_i$ = CO_2 production coefficient (t/MWh)

6.5 The socio-economic impact model

As discussed in previous sections, the socio-economic impact of the power system will be assessed through its impact on the country's GDP and savings. The impact on GDP is computed through the Input-Output methodology, as described in section 4.11. The impact on savings is computed by assessing the impact of the power system on the country's trade balance in accordance to section 5.6.1.

6.5.1 Practical implementation of the Input-Output model

Spain's symmetric Input-Output tables (Instituto Nacional de Estadistica, 2017) include the 73 productive sectors listed in Table 6-1.

#	Sector	#	Sector
1	Agriculture, livestock and hunting	38	Manufacture of furniture; manufacturing n.e.c.
2	Forestry, logging and related service activities	39	Recycling
3	Fishing	40	Construction
4	Mining of coal and lignite; extraction of peat	41	Sale and retail of motor vehicles; retail sale of automotive fuel
5	Extraction of crude petroleum and natural gas; mining of uranium and thorium ores	42	Wholesale trade and commission trade
6	Mining of metal ores	43	Retail trade; repair of personal and household goods
7	Other mining and quarrying	44	Hotels
8	Manufacture of coke, refined petroleum products and nuclear fuel	45	Restaurants
9	Production and distribution of electricity	46	Railway transport
10	Manufacture of gas; distribution of gaseous fuels through mains; steam and hot water supply	47	Other land transport; transport via pipelines
11	Collection, purification and distribution of water	48	Water transport
12	Manufacture of meat products	49	Air transport
13	Manufacture of dairy products	50	Support and auxiliary transport activities
14	Manufacture of other food products	51	Travel agencies activities
15	Manufacture of beverages	52	Post and telecommunications
16	Manufacture of tobacco products	53	Financial intermediation, except insurance and pension funding
17	Manufacture of textiles	54	Insurance and pension funding, except compulsory social security
18	Manufacture of wearing apparel; dressing and dyeing of fur	55	Activities auxiliary to financial intermediation
19	Manufacture of leather and leather products	56	Real estate activities
20	Manufacture of wood and wood products	57	Renting of machinery, personal and household goods
21	Manufacture of pulp, paper and paper products	58	Computer and related activities
22	Publishing and printing	59	Research and development
23	Manufacture of chemicals and chemical products	60	Other business activities
24	Manufacture of rubber and plastic products	61	Market education
25	Manufacture of cement, lime and plaster	62	Market health and social work
26	Manufacture of glass and glass products	63	Market sewage abd refuse disposal, sanitation and similar activities
27	Manufacture of ceramic products	64	Market activities of membership organization n.e.c.
28	Manufacture of other non-metallic mineral products	65	Market recreational, cultural and sporting activities
29	Manufacture of basics metals	66	Other service activities
30	Manufacture of fabricated metal products	67	Public Administration
31	Manufacture of machinery and equipment n.e.c.	68	Non-market education
32	Manufacture of office machinery and computers	69	Non-market health and social work
33	Manufacture of electrical machinery and apparatus n.e.c.	70	Non-market sewage and refuse disposal, sanitation and similar activities. Public Administration
34	Manufacture of electronic equipment and apparatus	71	Non-market activities of membership organization n.e.c. NPISHs
35	Manufacture of medical, precision and optical instruments	72	Non-market recreational, cultural and sporting activities
36	Manufacture of motor vehicles, trailers and semi-trailers	73	Private households with employed persons
37	Manufacture of other transport equipment		

Table 6-1: Productive sectors in Spain's official Input-Output tables

When used for assessing specific industries, Input-Output tables are usually grouped or broken down into specific sub-sectors order to facilitate the analysis. In the present case some sectors with no direct links to the power one may grouped in to broader groups in order to facilitate the analysis. Table 6-2 shows a suggested sector aggregation, in line with (Caldes, et al., 2009).

#	***Sector***
1	Agricultural products, livestock, hunting, forestry and fishing
2	Fuels and extractive activities
3	Carbon, refinery products and nuclear fuel
4	Electricity, gas and water production and distribution services
5	Foodstuffs, drinks, textiles, clothes and footwear
6	Wood, paper, cardboard, edition products
7	Chemical products, plastics and rubber
8	Cement, lime, plaster, glass and other no-mineral products
9	Metallurgical products
10	Metal products, except machinery and equipment
11	Machinery and equipment
12	Office equipment, computing devices and electronic material
13	Electronic devices, radio, precision, TV and communication equipment
14	Motor vehicles and trailers
15	Furniture, other manufactured products and material recovering
16	Construction: building and civil engineering
17	Hotel industry, commerce and vehicle and motorcycle repairing, and fuel selling to small consumers
18	Transport services
19	Telecommunication services, financial services, insurance and auxiliary services to financial mediation
21	Building services, machinery renting, computing and R&D
21	Other business and service activities (health and social work, recreational activities, etc.)
22	Other no market personal services and public administration services

Table 6-2: Aggregated Input-Output sector breakdown

Therefore, in order to assess the impact of the power system on the economic flows, each power production technology must be allocated to the sectors in Table 6-2. Investment and O&M costs must be broken down and each line must be allocated to a sector in Table 6-2. In addition, the share of imports must be defined. For example, wind power could be broken down as follows (Black & Veatch, 2012):

#	**% of total investment**	***% imported***
Wind turbine	68.0%	20.0%
Distribution	10.0%	5.0%
BOP / Erection	13.0%	10.0%
EPC	4.0%	0.0%
Owner’s cost	5.1%	0.0%

Table 6-3: Suggested wind power cost breakdown and import allocation

Then, the wind turbine line could be broken down into the different sectors in Table 6-2 approximately as follows:

#	% of total investment
Sector 7	5.0%
Sector 10	25.0%
Sector 13	10.0%
Sector 18	5.0%
Sector 21	5.0%
TOTAL	**100.0%**

Table 6-4: Suggested wind turbine item allocation by aggregated sector

Once each technology has been allocated to each productive sector and the share of imports has been defined, the capacity increase of each technology in MW can be translated into an increase of final demand in terms of output units (EUR). The last step involves the computation of the Leontief matrix based on the 22-Sector simplified Input-Output table described above. Table 6-5 shows the interdependence coefficients in this Leontief matrix.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1	1.12	0.01	0.00	0.00	0.29	0.04	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.05	0.00	0.00	0.01	0.01
2	0.00	1.01	0.01	0.05	0.00	0.00	0.01	0.04	0.03	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
3	0.02	0.05	1.08	0.05	0.01	0.01	0.05	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.01	0.00	0.01	0.01
4	0.03	0.09	0.02	1.19	0.03	0.04	0.04	0.08	0.05	0.04	0.03	0.04	0.02	0.02	0.03	0.02	0.03	0.02	0.03	0.01	0.02	0.02
5	0.18	0.02	0.01	0.01	1.30	0.02	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.02	0.05	0.01	0.02	0.16	0.01	0.00	0.02	0.02
6	0.02	0.04	0.01	0.02	0.04	1.24	0.03	0.04	0.05	0.03	0.02	0.03	0.02	0.02	0.22	0.04	0.02	0.02	0.03	0.02	0.09	0.03
7	0.04	0.09	0.01	0.03	0.05	0.07	1.14	0.07	0.09	0.06	0.05	0.09	0.03	0.07	0.06	0.04	0.02	0.03	0.02	0.01	0.02	0.02
8	0.00	0.01	0.00	0.00	0.01	0.00	0.01	1.10	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.14	0.01	0.01	0.01	0.01	0.00	0.00
9	0.01	0.02	0.00	0.01	0.01	0.03	0.01	0.03	1.05	0.24	0.09	0.14	0.03	0.09	0.07	0.03	0.01	0.01	0.01	0.00	0.01	0.00
10	0.02	0.05	0.01	0.03	0.03	0.02	0.01	0.04	0.09	1.08	0.12	0.07	0.03	0.05	0.13	0.08	0.01	0.01	0.01	0.01	0.01	0.01
11	0.01	0.03	0.01	0.02	0.01	0.01	0.01	0.03	0.02	0.02	1.04	0.03	0.01	0.02	0.01	0.02	0.01	0.01	0.01	0.00	0.00	0.01
12	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.04	1.07	0.09	0.02	0.01	0.03	0.00	0.00	0.01	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	1.07	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.01	0.01	0.00	0.01	1.11	0.01	0.00	0.04	0.01	0.01	0.00	0.00	0.01
15	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.14	0.03	0.02	0.02	0.01	0.01	1.03	0.01	0.00	0.01	0.01	0.00	0.01	0.01
16	0.01	0.03	0.01	0.02	0.02	0.01	0.01	0.03	0.01	0.01	0.02	0.01	0.01	0.01	0.01	1.30	0.03	0.02	0.02	0.10	0.03	0.02
17	0.07	0.05	0.01	0.05	0.08	0.08	0.04	0.07	0.07	0.06	0.06	0.04	0.04	0.04	0.08	0.08	1.05	0.07	0.01	0.02	0.03	0.03
18	0.01	0.07	0.03	0.02	0.05	0.06	0.05	0.12	0.05	0.05	0.03	0.03	0.02	0.02	0.05	0.04	0.03	1.02	0.03	0.01	0.02	0.02
19	0.02	0.08	0.02	0.03	0.04	0.03	0.04	0.07	0.05	0.04	0.03	0.04	0.03	0.03	0.03	0.03	0.05	0.08	1.01	0.03	0.06	0.02
20	0.03	0.06	0.02	0.05	0.06	0.04	0.04	0.06	0.04	0.04	0.05	0.05	0.03	0.03	0.04	0.07	0.10	0.06	0.01	1.13	0.06	0.03
21	0.04	0.08	0.04	0.08	0.09	0.09	0.08	0.11	0.08	0.08	0.09	0.10	0.13	0.06	0.07	0.05	0.10	0.05	0.03	0.07	1.10	0.06
22	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.04	0.01	0.03	1.03

Table 6-5: Spain's aggregated 22-Sector Leontief matrix

Once the Leontief Matrix has been computed and each technology's capacity additions translated into output units, the impact on the country's total output by sector can be computed by using Equation (4.19), as described in section 4.11.

It is very important to highlight that the allocation of each expense line of each power generation technology to each productive sector is not straightforward. A detail breakdown of each line into all its components and subcomponents must be done. The computation of the imported shares is even more challenging as, at the time of writing the present document, no public data is available.

Therefore, both the breakdown by sector and the imported share must be estimated, being a line of future research the collection of this information based on a deep industry analysis.

6.6 Uncertainty. The Monte Carlo / random walk methodology

As discussed in previous sections, the models presented in this research simulate and forecast the dynamic evolution of the power system and its impact based on a set of exogenous variables, which includes variables such as fossil fuel prices, GDP growth, power demand, as well as policy levers such as AES incentives and capacity payments.

The values of some of these exogenous variables can be easily predefined, as in the case of policy levers (e.g. incentive levels). Nevertheless, in the case of variables which show significant uncertainty, their values may not be easy to predefine. This is the case of variables such as commodity prices or power demand.

Therefore, variables showing uncertainty have been modeled through an stochastic approach, which involves Monte Carlo simulations and "random walk" modeling.

Random walk processes are a particular case of ARIMA (p, d, q) processes where p = 0, d = 1 and q = 0. Random walks may or may not show drift. In the present case, random walk with drift models have been considered. Therefore, random walk variables are modeled as follows:

$$y_t = y_{t-1} + a + \varepsilon_t, \quad \varepsilon_t \sim N(0, \sigma^2), \quad t = 2, \dots, n \tag{6.27}$$

Where: y_t = Variable value at time t

a = Drift coefficients

ε_t = Volatility coefficients

σ = Standard deviation of the volatility component

The volatility and drift coefficients have been computed by taking the historical mean and standard deviation of the 1st difference of each variable. Normality tests (e.g. Q-Q, etc.) are performed on the 1st difference of the variables in order to verify that they follow a Normal distribution. As an illustrative example of a random walk, Figure 9 shows a 100-runs-only random walk simulation of the natural gas price variable.

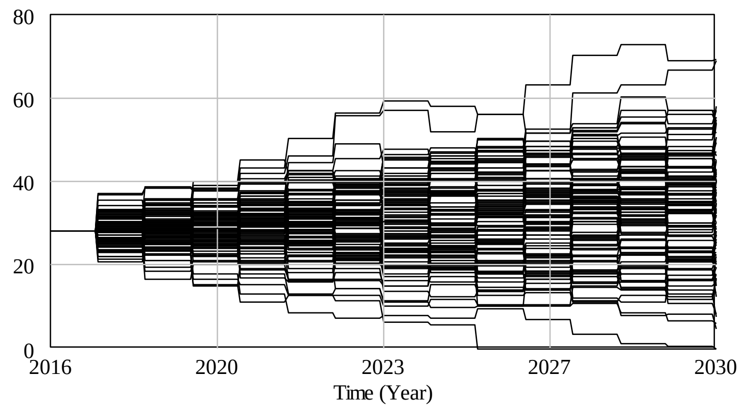

Figure 6-8: Random walk example. Natural gas price (100 simulations)

6.7 Model limitations and future expansions

Multiple assumptions have been made during the development of the models used in the present research, being some of them significant simplifications of reality. As an example, the threshold IRRs and the level of investment vs. IRR have been assumed to stay constant across time while this may not necessarily hold in the long run. For example, as technologies mature, investors may perceive less risk so that the threshold IRR for investing may decrease and the level of investment vs. IRR may increase. Other factors may affect the risk perceived by investors so having an impact as well on the threshold IRR and level of investment vs. IRR variables.

Also, for computing the projects' IRR, it has been assumed the project cash flows stay constant across time. This assumption may not always hold as often investors base their IRR computations on cash flow forecasts produced by themselves and which may be based on forecasts regarding competitors' actions, macroeconomic variables, etc. These forecasts may be developed through different methodologies (e.g. trend functions based on the bounded rationality hypothesis, smoothing techniques, etc.). Therefore, the approach used in the present research is relatively myopic as it does not consider any investor foresight at the time of computing project IRRs.

One of the model's main underlying assumption is that investors invest in those technologies with the greater economic returns regardless of any other consideration, hence neglecting potential decision-making variables such as strategy considerations. Although in the real world economic return is of course one of the main variables considered for investment decision-making, other aspects may have an impact as well. For example this is the case of the “dash for gas” phenomenon by which, after deregulation, utilities invested heavily in gas CC power plants not only because of profitability reasons but also because of strategic considerations (Gary & Larsen, 2000).

The present models also assume that investors hold a pipeline of fully permitted projects which commence construction once the profitability threshold is reached, in a way similar to (Olsina, et al., 2006) and (Arango, 2007). While this is a common practice in the case of AES technologies where in many cases, projects have a smaller size, this assumption does not always hold in the case of conventional technologies, where projects may be significantly larger and more complex. For example, NPPs are developed on a case by case basis and no power utility holds a pipeline of fully permitted projects.

Regarding the MOPP model, it assumes that that the country’s whole power generation is traded at the WPM. Nevertheless, while in the case of Spain this is true for most of the power produced, a small share of the production is traded through PPAs so that the WPM prices computed by the models may slightly differ from reality.

Also, while the MOPP model assumes that the WPM is uniform and perfect in the sense that generators bid their actual marginal costs and no complex bidding strategies are considered, bidding strategies and even competitor collusion occur in the real world. Therefore, because of this assumptions the MOPP here introduced may underestimate the real WPM price.

Finally, two considerations regarding the socio-economic impact modeling must be mentioned. The first one involves the use of the Input – Output methodology, which presents some limitations, described in detail in section 4.8. The second one involves the availability of data required for the Input – Output models. Additional data decomposition including the allocation to the different productive sectors of the different power generation technologies as well as the share of imports for each one of them is required. Therefore, the Input – Output methodology is just described in the present work and the economic impact is limited to system costs in the cases studies. Additional macroeconomic data should be gathered by the regulator in order to fully implement the methodology here described.

Some of the abovementioned simplifying assumptions have been made with goal of limiting the number of calibration variables in order to limit model overfitting risk. Like in the case of any fitting problem (e.g. regression, neural networks, etc.) the use of a large number of calibration variables may improve the fitting to the historical trends but may refrain the model from properly generalizing, therefore leading to inaccurate forecasts. In any case, after calibration, the model accurately replicates Spain’s power system historical data series, even with the limited number of calibration variables used.

Therefore, model enhancements and extensions are possible but must be carefully assessed in order to avoid overfitting risk. Also, potential improvements in terms of macroeconomic data requirements are not only possible but necessary in order to use the full potential of the methodology here described.

Chapter 7
Model validation and calibration

7.1 Model validation

Before the actual parameter calibration the model has been validated from the structural and behavioral points of view (Sterman, 2000) by performing the recommended boundary adequacy, structure verification, dimensional consistency, extreme conditions, behavior reproduction, behavior anomaly and behavior sensitivity tests (Sterman, 1984; Qudrat-Ullah & Seo Seong, 2010) described in section 4.5.2.

Structure tests have been performed by checking that the model's structure is consistent with the descriptive knowledge of the system and by partial model testing in order to verify that physical constraints are not violated (e.g. negative installed capacities, negative capacity flows and WPM price out of the zero – PriceCap range). Dimensional consistency has been automatically checked by the Vensim software package. Extreme condition tests have been performed by assigning to specific variables their maximum and minimum values and by checking that the model's response is consistent. For example, when extreme power demand increase and decrease rates have been tested, the model has responded with large WPM price spikes and investment boom and bust cycles in the first case and with extremely low WPM price in the second case, which are the expected outcomes. Behavior reproduction tests have been performed during the calibration phase in order to check that the model reproduces the behavior of the real system both from the quantitative and qualitative points of view. Finally, behavior anomaly and sensitivity test have been performed in order to check how strong internal relations are (e.g. by removing specific loops) and to check whether there is any behavior change when the parameter values change over their plausible level of uncertainty (e.g. the IRR threshold values obtained after model calibration). For example, these tests have found that feedback loops 1 and 2 are significantly weaker that the rest of the loops.

Regarding parameter calibration, the model has been calibrated based on Spain’s power system 1998-2013 historical data series. The reason for having chosen this period is the fact that Spain’s power industry was regulated and the construction of new power plants was centrally planned until 1998 when the industry was liberalized and investment decisions were made available to private investors. So, dates previous to 1998 cannot be simulated with the models developed in the present reseach.

7.2 Data sources and main assumptions

Spain’s power system historical data series have been collected for each power generation technology. These variables can be classified in the following groups:

7.2.1 Commodity and incentive prices

- Oil price (US Energy Information Administration, 2017c)
- Coal price (BP, 2017a)
- Natural gas price (BP, 2017b)
- Nuclear fuel price (US Energy Information Administration, 2017a)
- WPM price (OMIE, 2017)
- CO_2 emission allowance price (ICE Futures Europe, 2015; World Bank Group, 2014)
- Capacity payment levels (Ministry of Industry and Energy, 1997; Ministry of Industry and Energy, 1998a; Ministry of Industry and Energy, 1999; Head of State, 2000; Ministry of Economy, 2002a; Ministry of Industry, Tourism and Commerce, 2007a; Ministry of Industry, Tourism and Commerce, 2011)
- AES incentives (Ministry of Industry and Energy, 1998b; Ministry of Industry and Energy, 1998c) (Ministry of Industry and Energy, 1999; Ministry of Economy, 2000; Ministry of Economy, 2001b; Ministry of Economy, 2002c; Ministry of Economy, 2003; Ministry of Economy, 2004; Ministry of Industry, Tourism and Commerce, 2004; Ministry of Industry, Tourism and Commerce, 2005), (Ministry of Industry, Tourism and Commerce, 2006; Ministry of Industry, Tourism and Commerce,

2007c; Ministry of Industry, Tourism and Commerce, 2007b; Ministry of Industry, Tourism and Commerce, 2008b; Ministry of Industry, Tourism and Commerce, 2009; Ministry of Industry, Tourism and Commerce, 2010a)

7.2.2 Power system's technical parameters

- Peak power demand, energy demand, installed capacity, power generation and capacity factor by technology (Red Electrica de España, 2003; Red Electrica de España, 2004; Red Electrica de España, 2005; Red Electrica de España, 2006; Red Electrica de España, 2007; Red Electrica de España, 2008; Red Electrica de España, 2009; Red Electrica de España, 2010; Red Electrica de España, 2011; Red Electrica de España, 2012a), (Red Electrica de España, 2013; Red Electrica de España, 2014; Red Electrica de España, 2015; Red Electrica de España, 2016; Red Electrica de España, 2017).
- Plant age and average capacity (Ministry of Energy, Tourism and Digital Agenda, 2017a; Ministry of Energy, Tourism and Digital Agenda, 2017c)

7.2.3 Investment, operation costs and other

- Technology efficiency (US Energy Information Administration, 2016b; Nyberg, 2014; International Renewable Energy Agency, 2012b)
- Overnight capital costs (Krohn, et al., 2009; US Energy Information Administration, 2010; Black & Veatch, 2012; Tegen, et al., 2012; Lantz, et al., 2012; US Energy Information Administration, 2013; Energy and Environmental Economics, Inc, 2014; International Renewable Energy Agency, 2015; US Energy Information Administration, 2016a)
- O&M variable and fixed costs (US Energy Information Administration, 2017d) and diverse commercial databases.
- Project development time (Bozzuto, 2006)
- Inflation (International Monetary Fund, 2017)
- Foreign exchange rates (OANDA, 2017; Fxtop, 2017)
- Interest rates (Global-rates.com, 2017)
- Economic and real plant lifespan (International Renewable Energy Agency, 2015; Asian Development Bank, 2012; Voosen, 2016; Ujam & Diyoke, 2013; Bloomberg Business, 2011; US Department of Energy, 2003; Flury & Frischknecht, 2012)
- CO_2 emission factors by technology (US Energy Information Administration, 2017b)

Table 7-1, Table 7-2 and Table 7-3 show additional data and assumptions considered for the calibration process and case studies below.

	Available Resource (MW)	***Specific investment 2014 (MEUR/MW)***	***CO_2 coefficient $kgCO_2$ / MWh***	***Derating factor***
Wind	100,000	1.44	0.0	0.13
Solar PV	200,000	2.50	0.0	0.40
Small Hydro	3,000	3.42	0.0	1.00
Solar CSP	200,000	3.85	0.0	0.40
Gas CC	Infinite	0.70	311.9	1.00
Gas peak	Infinite	0.74	603.1	1.00
Hydro	2,000	2.23	0.0	1.00
Nuclear	Infinite	4.20	0.0	1.00
Coal	Infinite	2.23	978.7	1.00
Cogeneration	Infinite	1.90	502.6	1.00

Table 7-1: Selected model data and assumptions (1)

(years)	***Time to form expectations (yr)***	***Construction time (yr)***	***Economic life (yr)***	***Real life (yr)***	***Max installation rate (MW/yr)***
Wind	0.2	1.0	25	30	6,000
Solar PV	0.2	0.1	25	30	5,000
Small Hydro	0.2	1.0	30	90	2,400
Solar CSP	0.2	1.5	25	30	2,000
Gas CC	2.0	1.5	25	40	10,000
Gas peak	2.0	1.0	25	40	1,000
Hydro	1.0	2.0	30	130	2,000
Nuclear	2.0	8.0	40	60	3,000
Coal	2.0	3.0	30	50	2,000
Cogeneration	2.0	0.5	25	30	2,000

Table 7-2: Selected model data and assumptions (2)

While construction time, economic and real life spans and maximum installation rates are widely known in the industry or easy to estimate, the time to form expectations is more challenging and the following assumptions have been made: In the case of alternative technologies it has been considered only one year because of the fact that power prices have been historically set by regulated guaranteed FITs or price premiums which investors considered safe since their inception. For the rest of technologies, a 3-year time to form expectations has been considered as investors may take some time in order to confirm improving market trends.

Variable	*Value*
Power demand elasticity to price[69]	-0.2
Power cap price (EUR/MWh)	200.00
CO_2 emission credit price (EUR/t)	15.00
Maximum RES share in system	30.0%
Long run elasticity delay (years)	1.0

Table 7-3: Selected model data and assumptions (3)

Administrative barriers have been introduced for Nuclear and Solar PV power in order to simulate the political reality in the 1998 – 2013 period. In the case of nuclear power, a 100% administrative barrier has been introduced in the whole period in order to simulate the total reluctance of the Government of Spain to the construction of new NPPs after the so-called “nuclear moratorium” was enforced in 1984. In the case of Solar PV, a spike in installed capacity took place in 1998, when more than 2,500 MW were built due to an erratic incentive policy. Because of this fact, the Government introduced artificial control mechanisms in order to limit the installation rate of this technology. So, large administrative barriers of about 90% have been considered in 2009, 2010 and 2011.

7.3 Model calibration

SD models are usually calibrated manually rather than automatically (Kadoya, et al., 2005; Oliva, 2003). One of the main reasons for this is that by doing it this way, each discrepancy allows to verify not only the appropriateness of the parameter value but also the model structure. So, the present model has been manually calibrated being the goal of the calibration to reproduce Spain’s installed capacity historical data series by setting the following variables for each technology i:

i. Proportionality factor between the perceived IRR (PIRR) of each technology and its corresponding investment rate ($DevCoef_i$).

ii. The IRR threshold value over which investments take place ($ThreIRR_i$).

iii. The proportionality factor between the perceived PI (PPI) of each technology and its corresponding decommissioning rate ($DecomCoef_i$).

iv. The PI threshold value below which decommissioning takes place ($ThrePI_{i,v}$).

Table 7-4 shows the resulting values for these variables after model calibration.

[69] (Hasani & Hosseini, 2011)

	Development Coef. (MW/year)	***Threshold IRR (dmnl)***	***Decomm. Coefficient (MW/year)***	***Threshold PI (dmnl)***
Wind	22,500	1.0%	1.00	-0.10
Solar PV	57,000	3.5%	1.00	-0.10
Small Hydro	2,000	0.0%	1.00	-0.10
Solar CSP	16,000	7.5%	1.00	-0.10
Gas CC	32,400	6.0%	1.00	-0.10
Gas peak	15,000	6.0%	0.75	-0.10
Hydro	20,000	0.0%	1.00	-0.10
Nuclear	25,000	3.0%	1.00	-0.10
Coal	30,000	6.0%	1.00	-0.10
Cogeneration	7,000	5.0%	1.00	-0.10

Table 7-4: Model calibration results

The accuracy of the model once calibrated can be observed in Figure 7-1 through Figure 7-11, which show the comparison of historical versus simulated installed capacity by technology and historical versus simulated final wholesale power WPM price. Table 7-5 shows the summary statistics as well as Theil's inequality statistics (Oliva, n.a.; Sterman, 1984) for historical fit.

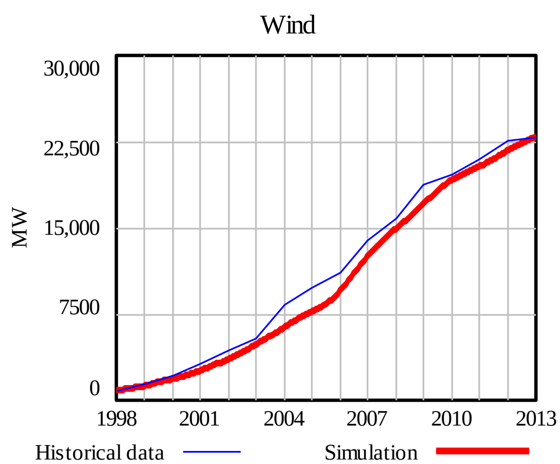

Figure 7-1: Historical vs. simulated data. Wind

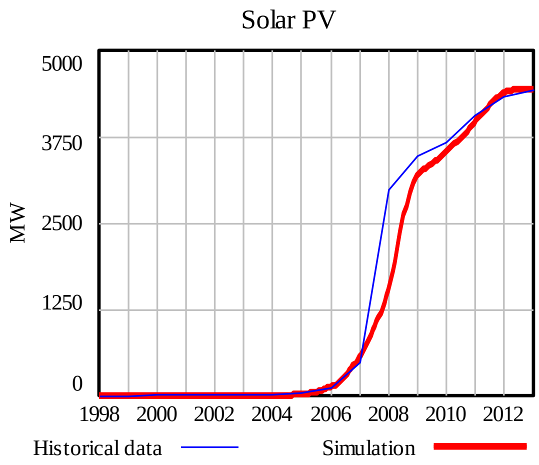

Figure 7-2: Historical vs. simulated data. Solar PV

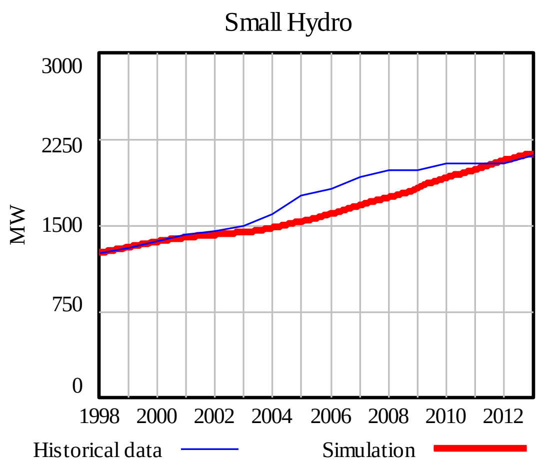

Figure 7-3: Historical vs. simulated data. Small hydro

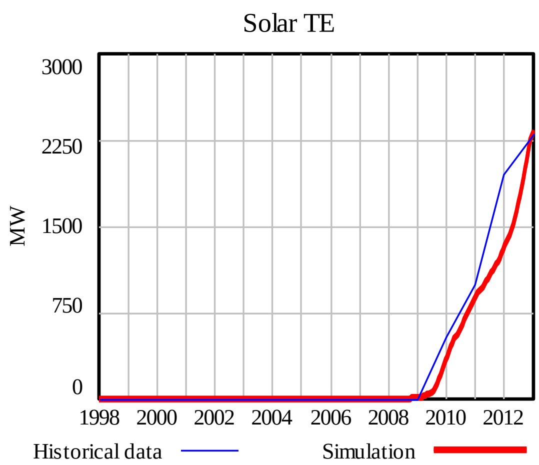

Figure 7-4: Historical vs. simulated data. Solar CSP

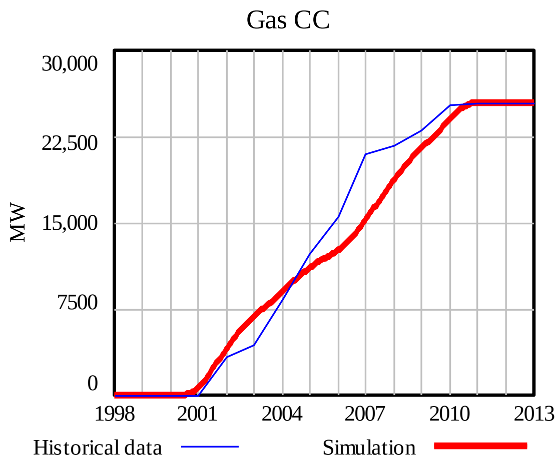

Figure 7-5: Historical vs. simulated data. Gas CC

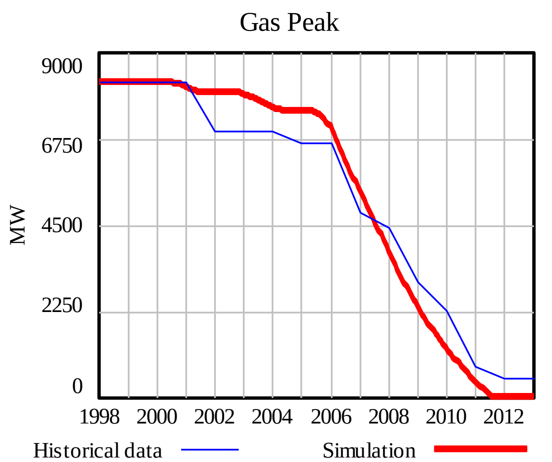

Figure 7-6: Historical vs. simulated data. Gas peak

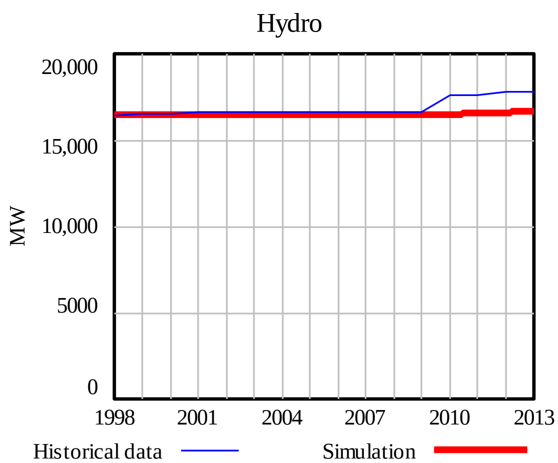

Figure 7-7: Historical vs. simulated data. Hydro

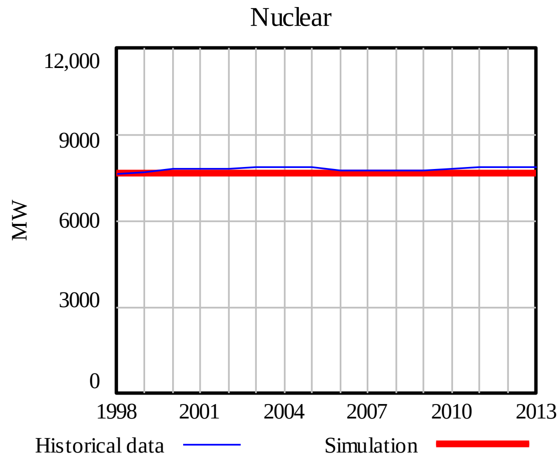

Figure 7-8: Historical vs. simulated data. Nuclear

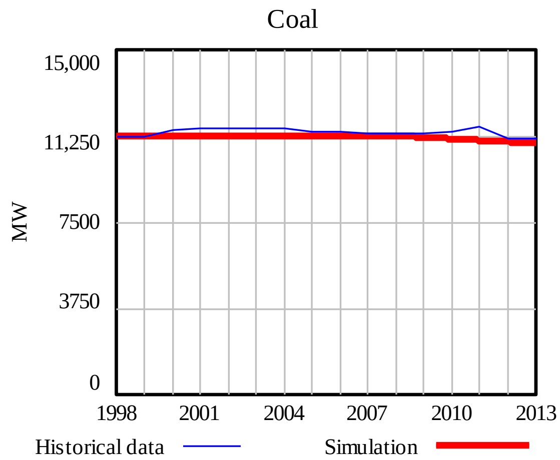

Figure 7-9: Historical vs. simulated data. Coal

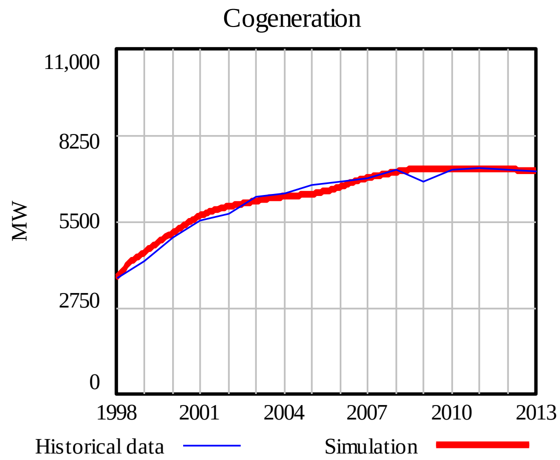

Figure 7-10: Historical vs. simulated data. Cogeneration

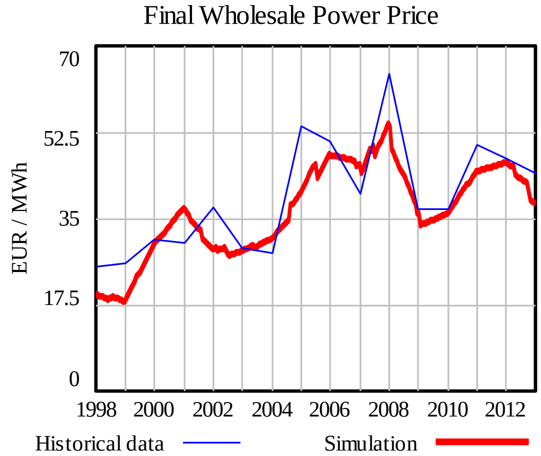

Figure 7-11: Historical vs. simulated data. WPM price

	R^2	*MAPE*	*RMSE*	U^M	U^S	U^C
Wind	0.993	0.13	1,197.7	0.73	0.00	0.27
Solar PV	0.971	0.47	331.5	0.15	0.04	0.79
Small Hydro	0.894	0.06	139.1	0.56	0.04	0.41
Solar CSP	0.976	0.09	172.0	0.19	0.54	0.27
Gas CC	0.970	0.12	2,007.5	0.16	0.14	0.70
Gas Peak	0.980	0.23	614.4	0.01	0.53	0.45
Hydro	0.651	0.02	564.3	0.49	0.48	0.03
Nuclear	0.000	0.02	174.5	0.83	0.16	0.00
Coal	0.219	0.02	280.6	0.80	0.19	0.18
Cogeneration	0.975	0.02	163.73	0.02	0.12	0.86

Table 7-5: Summary statistics for historical fit & Theil's inequality statistics

As it can be observed, the model accurately reproduces the historical data series, being the largest discrepancies in those technologies where the actual changes in their installed capacity have been very tiny (i.e. hydro, nuclear and coal) so that slight differences between the real and the simulated values are magnified in the summary statistics through low R^2 values.

MAPE and RMSE provide the mean absolute percent error and the root mean square error respectively. While having very low R^2 values, hydro, nuclear and coal show low MAPE values which confirm the point made above. Theil's inequality statistics decompose mean square error in three components: bias (U^M), unequal variation (U^S) and unequal covariation (U^C). The bias component, which may be due to systematic errors, prevails in those cases with tiny variations (small and large hydro, coal and nuclear) and it is also the most relevant component in the case of wind. This is because historical average wind investment rates have been greater than the ones forecasted by the model possibly because of strategic considerations similar to the "dash for gas" case described below.

By visually inspecting the charts, it can be also observed a significant difference in gas CC as actual investments seem to take place sooner than the model forecast. This may be due to the "dash for gas" phenomenon by which, after deregulation, utilities invested heavily in gas CC power plants not because of profitability reasons but because of strategic considerations (Gary & Larsen, 2000) as well as for the increasing interest in low capital investment technologies which are less penalized by the increasing discount rates required by the private sector (Bunn, et al., 1993).

Regarding the final WPM price, although quite accurate, differences are greater as it can be observed in Figure 7-11. This may be due to the fact that this variable is influenced by additional historical factors such as market power and behavioral issues related to bidding strategies not included in the model. Historical prices have on average been greater than the simulated ones and this can be a consequence of the market power exercised by generators.

Regarding the output coefficients shown in Table 7-4, the low IRR project development threshold values obtained for wind, small hydro and hydro may be surprising. These low values may be due to the fact that investors find these technologies safer because they are not subject to fuel price volatility and because they are already mature (even onshore wind power). All fossil fuel technologies show greater threshold values, in the 5.0 – 6.0% range. Finally, solar PV and solar CSP show values of 3.5% and 7.5% respectively, being this fact attributable to their more recent inceptions and thus, limited technological maturity.

Regarding the Development coefficient, a significant divergence can be observed as well. The largest value (57,000 MW/year) corresponds to Solar PV. This may be due to the fact that a large share of the solar PV project pipeline is composed of small power plants (average size = 100 kW) that are built massively by residential or commercial users when profitability threshold values are reached. On the other hand, small hydro shows the lowest value being this fact attributable to the difficulty of finding new suitable river sites in Spain.

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Chapter 8
Case study 1: Capacity payments vs. renewable incentives

8.1 Introduction

This case study analyzes three different scenarios with the goal of assessing the impact of AES incentives and capacity payments on environment, system costs and reliability. The first one presents a "business as usual" scenario where capacity payments stay at 2014 levels and no AES incentives are introduced. The second one, "increased capacity payments", introduces greater capacity payments aimed at keeping system reliability and WPM price over specific levels in the long run. Finally, the third scenario, "AES incentives", introduces incentives for AES projects with the goal of achieving a specific AES share. Total system costs, reserve margin and CO_2 emissions have been calculated in all three scenarios. The simulations cover the 1998 – 2050 time frame. Table 7-1 through Table 7-3 show some of the main assumptions common to all scenarios.

8.2 The "business as usual" scenario

The following assumptions have been made for this scenario:

- No AES incentives
- No changes in the current capacity payments (26,000 EUR/MW-year)
- No regulatory constraints for any technology
- 3.0% annual increase in power demand
- Constant fossil and nuclear fuel prices
- Constant power plant characteristics except:
    - Wind: 0.5% annual declining specific investment
    - Solar PV: 0.5% annual declining specific investment

As it can be observed in Figure 8-1 and Figure 8-2, both installed capacity and reserve margin are adequate until 2028 so that final WPM price (Figure 8-3) stays at reasonable levels set only by the marginal generation cost. This situation changes after 2028 as the reserve margin declines dramatically (reaching a minimum value of 0.99) causing significant WPM price spikes between 2042 and 2048. These price spikes drive the profitability of power plants up again so that new investments take place and the reserve margin increases, starting an investment boom and bust pattern driven by WPM price spikes and by the long lead times required for bringing power plants online. This fact makes installed capacity oscillate after 2030.

Figure 8-4 shows the evolution of the generation mix. It can be observed that, under a scenario with no alternative energy incentives, all alternative technologies show declining market shares even completely vanishing such is the case of solar PV, solar CSP and cogeneration. Wind is the only technology with a relevant market share by 2050, although smaller than in 2014. Coal share declines to a very low value by 2038. Gas peak technology is discontinued by 2011. Cogeneration is discontinued by 2030. The largest share increase corresponds to gas CC, being the predominant technology by far in 2050. Nuclear shows a slightly declining market share. Hydro shows a declining market share due to the limited hydro resource available in Spain, being future capacity additions, mostly replacements for the old power plants that must be decommissioned.

A first conclusion of this case study is that the current policy scenario provides reasonable results in the short run, mostly due to the current large overcapacity, but does not work in the long run as it entails capacity deficits and large power price spikes. Table 8-1 shows the system cost breakdown and Table 8-2 shows the CO_2 emissions and renewable energy share for this scenario.

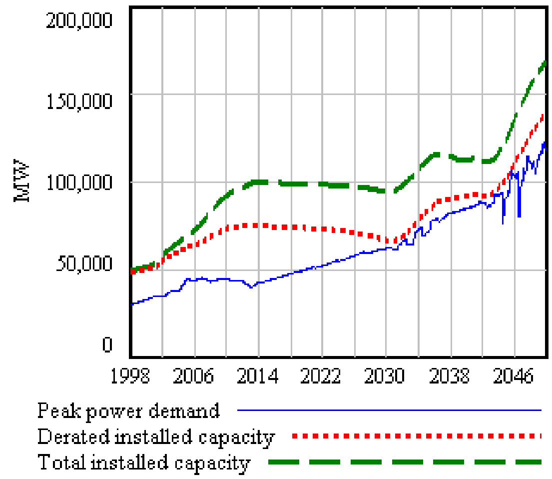

Figure 8-1: Peak power demand and installed capacity. “Business as usual” scenario

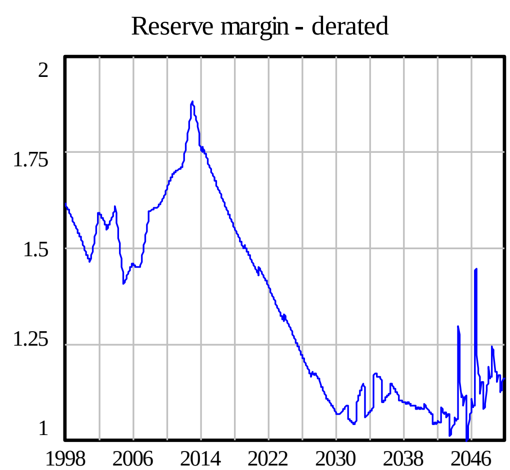

Figure 8-2: Reserve margin. “Business as usual” scenario

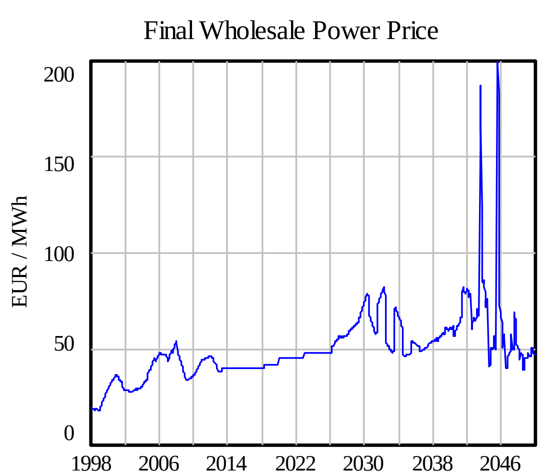

Figure 8-3: Final WPM price. “Business as usual” scenario

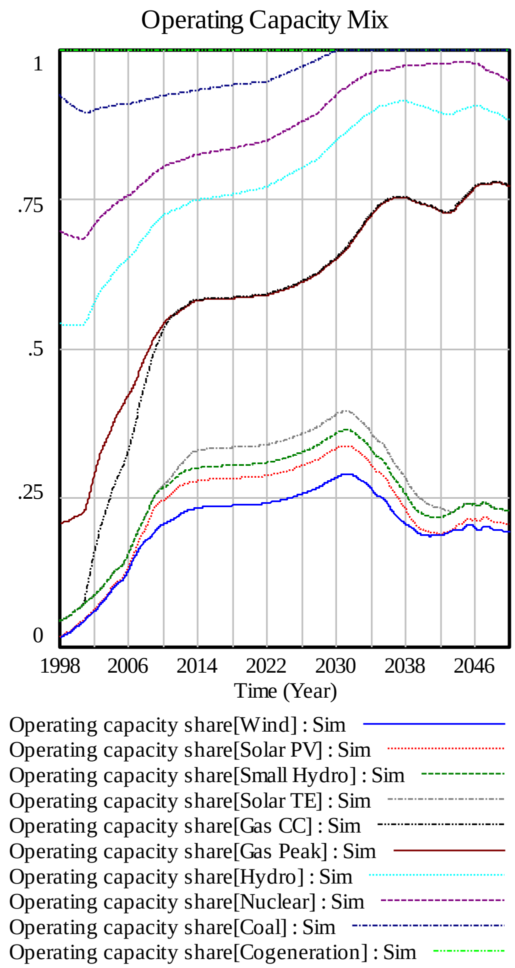

Figure 8-4: Installed capacity mix. “Business as usual” scenario

Billion EUR	***Business as usual***	***Increased capacity payments***	***AES incentives***
Incentive cost	100.60	100.40	160.00
Capacity payment cost	71.23	356.70	71.53
Investment cost	178.10	161.70	237.60
CO_2 credit cost	42.51	40.80	37.45
Power generation cost	800.10	687.50	855.30
Total system cost	**1,193.00**	**1,347.00**	**1,362.00**

Table 8-1: Cumulative system cost breakdown (year 2050)

	Business as usual	***Increased capacity payments***	***AES incentives***
Cumulative CO_2 emissions (billion ton)	2.853	2.738	2.515
RES production share (%)	25.0%	16.8%	52.3%

Table 8-2: Cumulative CO_2 emissions and renewable energy share (year 2050)

8.3 The “increased capacity payments” scenario

The goal of this scenario is to assess whether increased capacity payments may solve the reserve margin problem described in the previous scenario as well as their impact on system costs and CO_2 emissions.

Therefore, the assumptions in this case are the same as the ones in the “business as usual” scenario with the exception of the capacity payments, which have been adjusted in order to achieve a minimum reserve margin of 1.10. This goal is met with a new capacity payment of 120,000 EUR/MW.

As it can be observed in Figure 8-5, derated installed capacity is now enough to keep reserve margin (Figure 8-6) over the 1.10 level previously set. This makes the final WPM price (Figure 8-7) not to be impacted by the scarcity price so that it is a function of just the marginal cost of production, there are no price spikes and capacity oscillations are avoided.

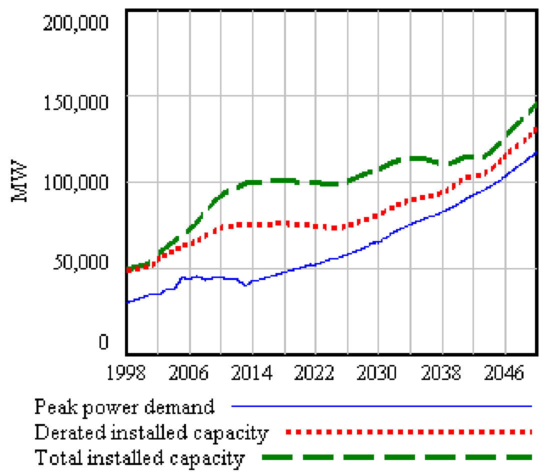

Figure 8-5: Peak power demand / capacity. “Increased capacity payments” scenario

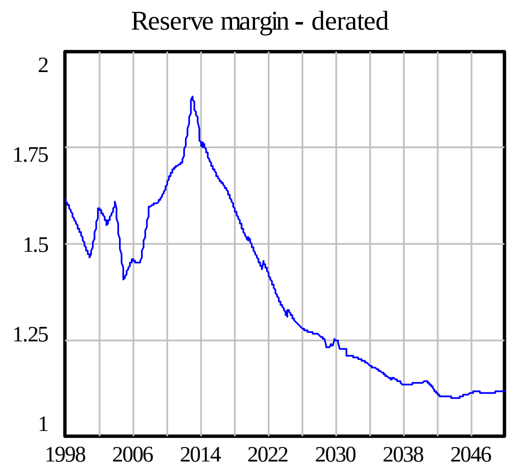

Figure 8-6: Reserve margin. “Increased capacity payments” scenario

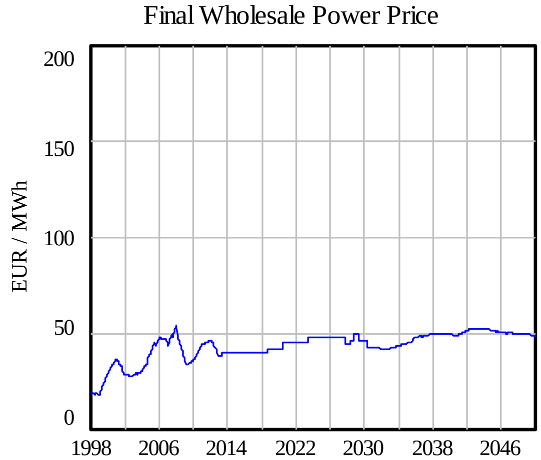

Figure 8-7: Final WPM price. "Increased capacity payments" scenario

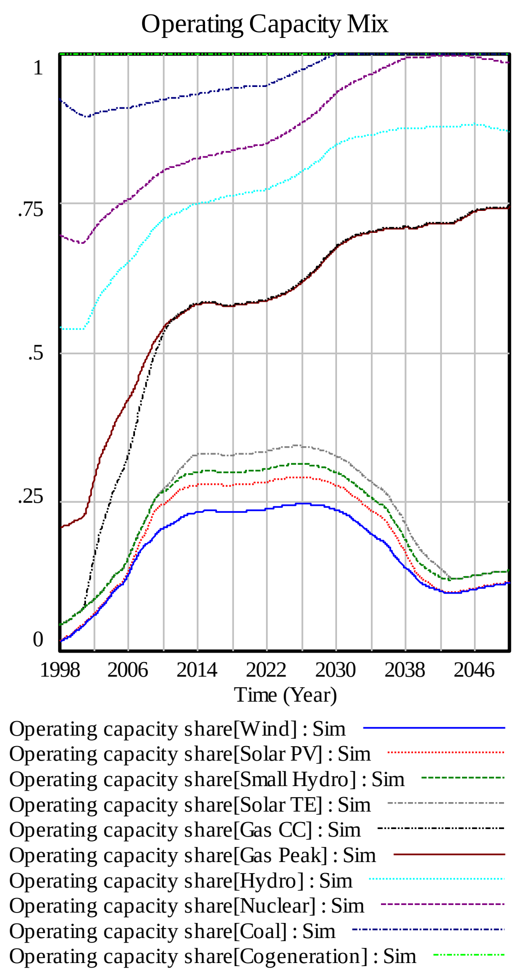

Figure 8-8: Installed capacity mix. "Increased capacity payments" scenario

Figure 8-8 shows the evolution of the power generation mix. Again, it can be observed that, under a scenario with no AES incentives, all alternative technologies show declining market shares with the difference that in this case wind shows a larger decline which is offset by a larger increase of Gas CC. This is because capacity payments benefit dispatchable technologies (such as Gas CC) but do not positively impact non-dispatchable technologies such as wind. Gas peak and cogeneration are discontinued at the same time as in the previous case. On the contrary to the "business as usual" scenario, coal is fully discontinued by 2038 and offset by gas CC which again, is the predominant technology in 2050. The remaining technologies behave in a similar way to the previous case. Table 8-1 shows the system cost breakdown and Table 8-2 shows the CO_2 emissions and renewable energy share for this scenario.

8.4 The "AES incentives" scenario

The goal of this last scenario is to assess the impact on reserve margins and system costs of a wind capacity share increase from 0.23 in 2014 to 0.35 in 2050 through wind power incentives. Therefore, all assumptions in this case are the same as in the "business as usual" scenario with the exception of the wind power incentive, which has been set to 26 EUR/MWh in order to meet the wind capacity share target.

As it can be observed in Figure 8-9 and Figure 8-10 derated installed capacity shows larger oscillations and reserve margin shows lower values than in the "business as usual" scenario. These low reserve margins entail greater final WPM price spikes between 2032 and 2036 and from 2044 on (Figure 8-11) which are the cause of the mentioned capacity oscillations.

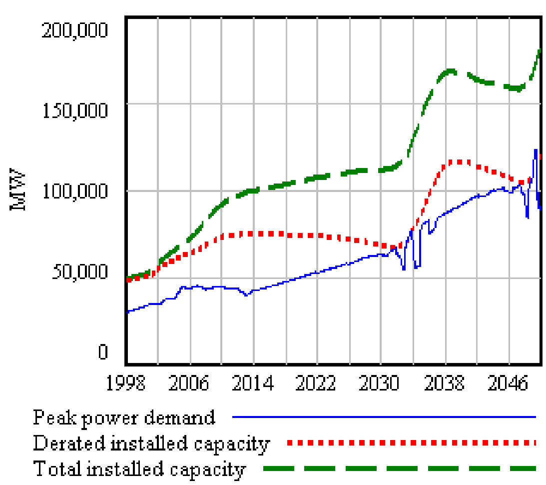

Figure 8-9: Peak power demand / capacity. "AES incentives" scenario

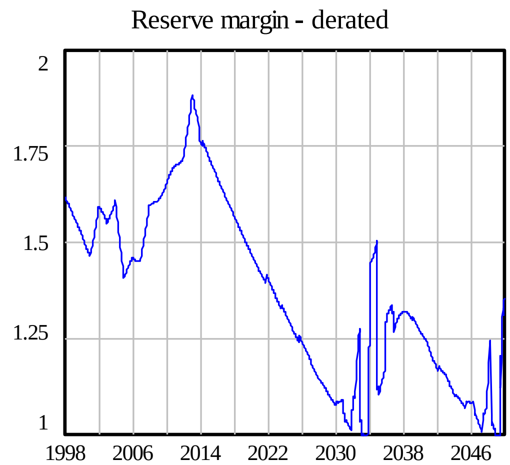

Figure 8-10: Reserve margin. “AES incentives” scenario

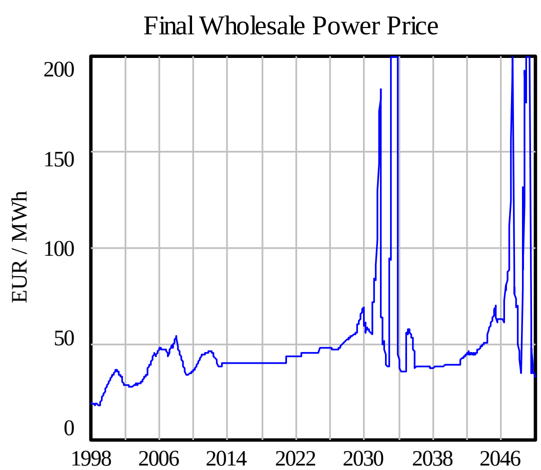

Figure 8-11: Final WPM price. “AES incentives” scenario

Figure 8-12 shows the forecasted evolution of the generation capacity mix. The results are similar to the ones of the “business as usual” scenario with the difference that, as intended, the final wind capacity share is greater and also there is a slight increase in the gas peak share between 2034 and 2038 due to the high power prices obtained in this period. This larger wind share is offset by a lower gas CC share with respect to the “business as usual scenario”. Table 8-1 shows the system cost breakdown and Table 8-2 shows the CO_2 emissions and renewable energy share for this scenario.

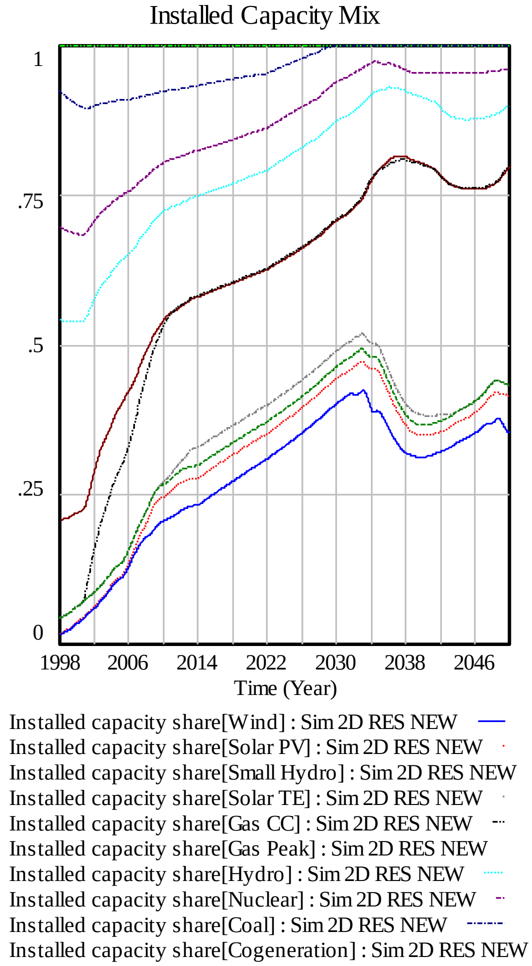

Figure 8-12: Installed capacity mix. “AES incentives” scenario

8.5 Discussion

The first conclusion derived from the case studies above is that free market supply and demand forces are not enough to keep adequate reliability (reserve margin) levels in the long run in Spain. Administrative actions such as increasing capacity payments or any other investment incentive are required in order to guarantee reliability in the long run and to avoid the boom and bust investment cycles that take place in the “business as usual” scenario as it can be observed in Figure 8-1 and Figure 8-2.

These investment boom and bust cycles can be observed in Figure 8-1 and Figure 8-9 where derated installed capacity dramatically oscillates reaching values equal or even below peak power demand, which is an unacceptable situation for a power system as it will lead to blackouts or load shedding. On the contrary, in the “increased capacity payments” scenario (Figure 8-5), investors’ expected profitability is stable and reasonable, which leads to steady investment rates. So, derated installed capacity and peak power demand grow at similar rates, reserve margin stays stable and WPM price spikes are avoided.

This behavior is caused by the fact that the revenues due to the WPM price and the current capacity payment price are not enough for investors to build new capacity. This leads to declining reserve margin (because of demand increase and asset aging) which leads to increasing WPM price and so to new investments. Nevertheless, due to the long lead times required for building power generation assets, installed capacity does not increase fast enough so that reserve margin reaches critically low values and great WPM price spikes occur. Great WPM price spikes entail great revenues and profitability for operators, which lead to investment boom cycles. These investment boom cycles entail future overcapacity which leads to depressed WPM price prices and investment bust cycles afterwards.

This deregulated power system behavior has been extensively described in the literature. Further details on this specific topic can be found in (Ford, 1999; Ford, 2001a; Ford, 2001b; Kadoya, et al., 2005; Hasani & Hosseini, 2011; Assili, et al., 2008). The results obtained in this case study are consistent with the ones in the abovementioned references.

Another relevant conclusion is that administrative actions are required in order to achieve specific power generation mix structures and CO_2 emission limits.

As shown in Table 8-1, the “increased capacity payments” scenario entails smaller investment and power generation costs than the “business as usual” base case. Smaller investment costs may seem strange at first glance as capacity payments are precisely intended to encouraging investment. Nevertheless, this can be explained by the fact that capacity payments encourage investment in base load technologies which greatly contribute to the reserve margin while the lack of capacity payments in the base case entails power price spikes which lead to investment boom and bust cycles. As a result, the total installed capacity in 2050 is greater in the “business as usual” scenario than in the “increased capacity payments” scenario but the installed capacity of base load technologies contributing to the reserve margin computation is greater in the “increased capacity payments” scenario so that total investment costs are greater in the “business as usual scenario”. The lower power generation costs in the “increased capacity payments” scenario is explained by the absence of WPM price spikes.

As expected, the share of AES is smaller in the “Increased capacity payments” scenario because fossil fuel baseload technologies are fostered at the expense of renewable technologies, mainly wind. The fact that cumulative CO_2 emissions are lower may seem initially contradictory but it is explained by the fact that the most pollutant coal plants are discontinued by 2038 in the “increased capacity payments” scenario while some of them stay online until 2050 in the “business as usual” scenario.

The positive effect of investment costs, CO_2 credit costs and power generation costs is not enough to offset the negative effect of the increased capacity payment costs so that the “increased capacity payments” scenario total costs are greater than the “business as usual” scenario total costs by 154BEUR.

The “AES incentives” scenario shows the greatest incentive costs and the smallest CO_2 emissions and CO_2 costs, as expected. Capacity payment costs are very similar to those of the “business as usual” scenario. Investment costs are the greatest among the three case studies assessed due to overinvestment in wind and the boom and bust cycles that take place after 2030. Finally, power generation costs are also the greatest among all three scenarios. These costs could be initially expected to be lower as renewable technologies push fossil technologies, with greater production marginal costs, to the right side of the supply curve. Nevertheless, the greater costs due to the WPM price spikes happening between 2030 and 2038 and from 2044 on offset this effect so that the resulting power generation costs are higher. As a result, this scenario shows greater total system costs than the “business as usual” scenario.

It may be surprising that, while renewable production share increases from 25.0% to 52.3% in 2030, cumulative CO_2 emissions decline just from 2.853 to 2.515 billion tons. This is due to the fact that wind power incentives entail low reserve margins which lead to WPM price spikes that make coal technology profitable enough so that its installed capacity increases. So, coal share is slightly greater in the “renewable incentives scenario” and, because of coal’s greater CO_2 factor, this effect offsets to some extent the CO_2 emissions reduction entailed by greater renewable power generation. In the case of the “increased capacity payments” scenario, the difference is very small and mostly due to a slightly greater gas share and a smaller coal share.

By having considered just total system costs figures, it might be inferred from this analysis that the “business as usual scenario” is the optimum one as it shows the lowest total costs. Nevertheless, there are three relevant considerations to be taken into account. The first one is the fact that the wholesale power price cap has been assumed to be set by the regulator at 200 EUR/MW (Table 7-3) (Ford, 1999; Ford, 2001a) while the real cost of the lack of supply is given by the VOLL which, according to different sources, may be as high as 1,000 - 3,000 EUR/MWh (Hasani & Hosseini, 2011; Bunn & Larsen, 1992; Ford, 1999). So, the introduction of a price cap by the Administration is actually distorting the results as the “business as usual” scenario could be potentially more costly if the WPM price was allowed to be freely set by the market. As an example, an additional “business as usual” scenario simulation has been done with a price cap set to 2,000 EUR/MW and the resulting total system cost is 1,541BEUR, the largest among all three cases studied.

The second consideration involves the boundaries of the model in terms of system cost calculations. So far, this model includes the system-specific costs described in section 6.3. However, it is true that there additional impacts at a country level such as the impact on the trade balance due fossil fuel imports, the impact on GDP due to local equipment manufacturing (which depends on the technologies being deployed), etc., as described in section 5.6. The collection of additional macroeconomic data is required in order to properly quantify the environmental cost, as per the process described in section 6.5.1.

The third and final consideration involves environmental costs. While for the sake of this case study a 15 EUR/t CO_2 price (Table 7-3) has been considered as a reasonable value according to historical market data, this is not necessarily the real economic cost of CO_2 emissions. Some works have been aimed at quantifying said impact, setting values for CO_2 emissions in the range of $10 - $95 / t depending on the number of years and discount rates considered (Interagency Working Group on Social Cost of Carbon, 2015). Further research is required in this field in order to properly quantify the environmental cost.

Finally, it is interesting to observe that, on the contrary to what would be initially expected, reserve margins decline with AES incentives. This is due to the fact that AES incentives foster technologies which do not contribute to reserve margin as much as the fossil fuel baseload technologies, which they are substituting.

8.6 Conclusions and policy implications

As a result of the assessments performed above, the following conclusions and policy implications can be derived:

- SD is a useful tool for dynamic simulations of power systems. Once calibrated against historical data, the model here presented accurately reproduces the past evolution of Spain's power system and enables to produce forecasts about its future evolution.
- Said forecasts may be of great interest for planners and policy makers in order to take the right actions aimed at achieving an optimal power generation mix from the technical (reliability), environmental (CO_2 emissions) and economic (system costs) point of view.
- In the specific case of Spain's power system, administrative actions are required in order to guarantee adequate reserve margins (and thus reliability) and avoid investment boom and bust cycles in the long run. Increased capacity payments for base load technologies are a useful instrument for achieving this goal and they do not significantly increase CO_2 emissions although they entail greater total system costs.
- Although significantly decreasing CO2 emissions, the implementation of higher AES incentives at the present time do not help in terms of system reliability and costs as they entail lower reserve margins, large price spikes and greater total system costs in the long run. AES incentives have a negative overall effect on costs.
- In any case and despite declining investment costs, incentive policies will still be required in the short and mid run in order to increase the share of alternative technologies.

Chapter 9
Case study 2: Assessment of Spain's new auction-based AES incentive

9.1 Introduction

Wind power hesitantly started its deployment in Spain in 1995 and boomed after 1998 (Figure 9-1 and Figure 9-2) with the liberalization of the power industry and the adoption of a new regulation aimed at fostering AES technologies through the implementation of a support scheme based on both FITs and premium payments.

In general terms, this system was successful as it allowed Spain to meet the renewable capacity goals set by EU Directives (The European Parliament and the Council of the European Union, 2001; The European Parliament and the Council of the European Union, 2009) and become one of the top countries worldwide in terms of wind power penetration. As an example, wind showed the second largest power generation share after nuclear in 2013 (Red Electrica de España, 2014). Nevertheless, the system showed drawbacks such as the solar PV overinvestment which took place in 2008 due to excessively high incentives (de la Hoz, et al., 2010).

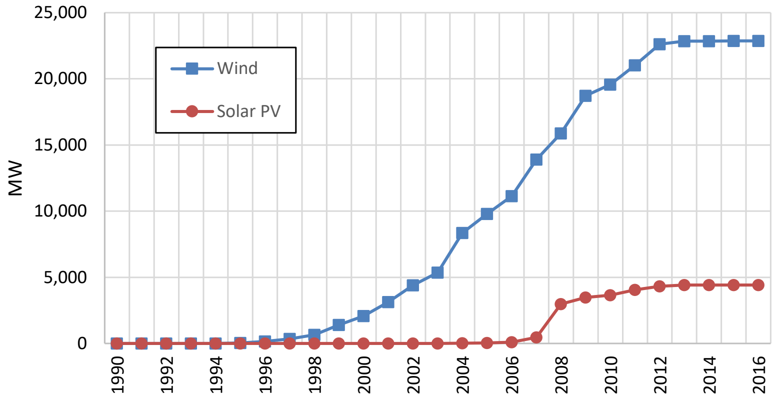

Figure 9-1: Spain’s historical wind and PV installed capacity[70]

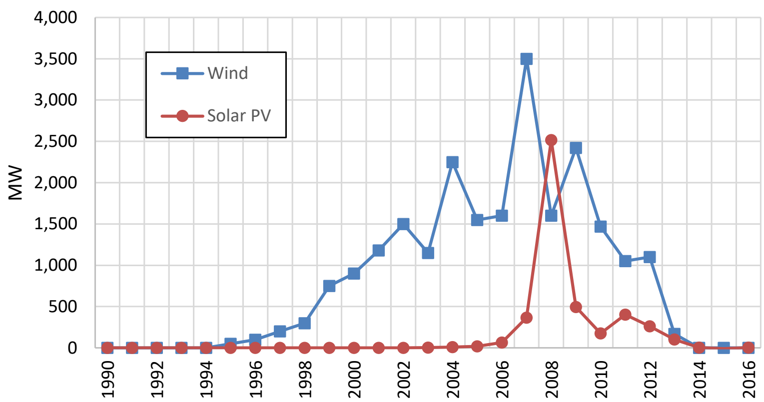

Figure 9-2: Spain’s historical wind and PV installation rate[70]

These issues contributed to the controversial “Tariff Deficit” problem. The TD was caused by a structural unbalance between the revenues and the expenses of the power industry’s regulated activities (i.e. T&D), which entailed a growing cumulative debt. This unbalance was due to the fact that distribution companies had to purchase power at the WPM, which very often showed increasing prices, and sell it to end users based on regulated retail tariffs, which were often capped by the regulator mostly due to political reasons. AES incentives contributed as well to the TD as they had to be covered by retail tariffs, which were ultimately paid to generators by the distribution operators (Ministry of Economy, 2001a).

[70] (Red Electrica de España, 2017; Asociacion Empresarial Eolica, 2017)

Therefore, the Government of Spain started enacting new regulations in 2008 aimed at reducing system costs by limiting AES capacity additions and reducing the incentives to be received by existing AES plants.

These measures ultimately led to a new AES regulatory framework based on the concept of “reasonable ROI” as well as on a competitive process for incentive allocation, which totally broke with the previous FIT / premium based support scheme. Since its inception in 2016, this incentive scheme has resulted in no incentives being allocated to any new wind farm.

The present case study analyzes the historical evolution of wind power support schemes in Spain, assesses the impact of the incentive levels resulting from the newly adopted regulatory scheme on the future evolution of wind capacity and system costs from a long run perspective, and computes the incentive levels required to meet specific goals in terms of installed capacity and system costs. This is done through the application of the methodologies developed in the present research.

Most existing literature on power AES support schemes in Spain focuses on general comparisons between the structure and costs of AES support schemes (Batlle, et al., 2012; Ortega, et al., 2013; Abdmouleh, et al., 2015; Cansino, et al., 2010; Ortega-Izquierdo & del Rio, 2016; Nicolini & Tavoni, 2017; Schallenberg-Rodriguez, 2017; Schallemberg-Rodriguez, 2014), on the past efficiency of support schemes (Folsland Bolkesjø, et al., 2014; Garcia-Alvarez & Mariz-Perez, 2012; Prados, 2010), on the evolution of solar PV incentives (Avril, et al., 2012; Sarasa-Maestro, et al., 2013; de la Hoz, et al., 2014; Ming-Zhi Gao, et al., 2015; de la Hoz, et al., 2010; Heras-Saizarbitoria, et al., 2011; del Rio & Mir-Artigues, 2012), on the impact of incentives on power price and system costs (Burgos-Payan, et al., 2013; Lopez-Peña, et al., 2012; Mendes & Soares, 2014), and on the description of the general evolution of the AES industry (Jäger-Waldau, et al., 2011; Montoya, et al., 2014; del Rio & Gual, 2007; Martinez Alonso, et al., 2016). A comprehensive assessment of the evolution of AES incentives for all technologies during the 1998 – 2007 period can be found in (del Rio Gonzalez, 2008).

The literature on Spain’s wind industry is more scarce; (Saenz de Miera, et al., 2008) and (Gallego-Castillo & Victoria, 2015) analyze the impact of wind power in WPM price both empirically and through simulation, (Martinez Montes, et al., 2007) describe the evolution of Spain’s wind power industry during the 1986 – 2007 period, (del Rio & Unruh, 2007) assess the drivers and barriers for both PV and wind power development and (Perez & Ramos-Real, 2009) analyze the reasons for the success of the wind FIT support scheme during the 1986 – 2007 period. (de la Hoz, et al., 2016) assess the impact of the new competitive auction-based AES support scheme introduced in 2016 on expected ROI, focusing on PV systems and on the general incentive structure but neither considering the results of any auctions nor the potential impact on the wind industry.

9.2 Evolution of Spain's wind power support scheme

Wind power started its deployment in Spain by 1995 (Figure 9-3) prior to the liberalization of Spain's power industry. At that time, the AES source regulation in force was RD 2366/1994 (Ministry of Industry and Energy, 1994) which among other things, had set the so-called "special regime for power generation" which included all AES technologies.

9.2.1 RD 2818: The beginning of the AES stable regulatory framework

Wind power development boomed after 1998 with the adoption of Law 54/1997 of the Electric Power Sector, the liberalization of Spain's power industry and the adoption of RD 2818/1998, which developed the guidelines set by Law 54 regarding AES by classifying technologies in different groups, assigning them specific remuneration levels, providing them with additional options for selling their power other than the WPM, granting them specific rights in term of grid access and dispatch priority and ultimately, setting a general regulatory framework that was in force until 2013.

Regarding the remuneration scheme, RD 2818/1998 provided AES generators with two options for selling their production. The first one consisted of a technology-specific fixed FIT while the second one consisted of a technology-specific price premium to be added on top of the WPM price which was computed as follows:

$$FinalPrice = AVWPMPrice + Premium + RPComplement \qquad (9.1)$$

Where:	FinalPrice	= Final power price to be received by the producer (EUR/MWh)
	AVWPMPrice	= Average WPM price (EUR/MWh)
	Premium	= Technology-specific price premium (EUR/MWh)
	RPComplement	= Reactive power complement (EUR/MWh)[71]

In the specific case of wind power the prices set by RD 2818/1998 for the FIT and the premium were 66.23 and 31.61 EUR/MWh respectively. Figure 9-3 shows the historical evolution of both parameters along time. These incentive prices were updated every year based on the evolution of the WPM price and every 4 years based on the evolution of power price and on the actual penetration of AES technologies at the Government's discretion, being this fact a source of uncertainty for investors (Asociacion de Productores de Energias Renovables, 2002).

[71] RPComplement was calculated as a percentage of the selling price based on the generator's power factor.

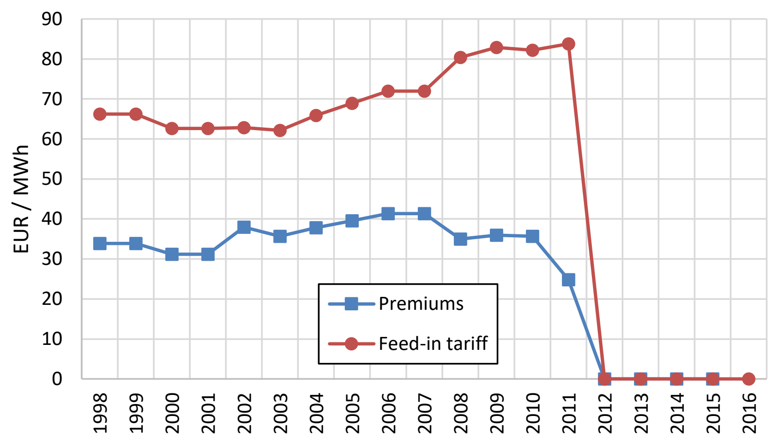

Figure 9-3: Spain's historical wind FIT and price premium

RD 2818/1998 was modified in 2002 by RD 841/2002 (Ministry of Economy, 2002a). This new regulation was focused on incentivizing the participation of AES plants in the WPM. It did so by forcing AES plants larger than 50 MW to participate in the WPM and by providing the rest of AES plants with a new additional remuneration option which allowed them to receive a final power price computed as:

$$FinalPrice = WPMPrice + Premium + SysServices + CapPayment \tag{9.2}$$

Where: FinalPrice = Final power price to be received by the producer (EUR/MWh)

WPMPrice = WPM price (EUR/MWh)

Premium = Technology-specific price premium (EUR/MWh)

SysServices = System services (EUR/MWh)

CapPayment = Capacity payment (EUR/MWh)

The main difference is that now AES producers would be submitting bids to the WPM and so, receiving the real market price (instead of the average one, considered in RD 2818/1998). In addition, producers were entitled to the same premiums set in RD 2818/1998 plus the remuneration for system services (i.e. ancillary services, transmission constraints, etc.) plus a capacity payment in the amount of 9.015 EUR / MWh. The result was that, because of these additional payments, this option became more competitive than the average pool price plus premium option set by RD 2818/1998 so that producers opted just for the option here described or the FIT option set by RD 2818/1998. The incentive price updating method stayed unchanged so that it remained a cause of uncertainty and risk for investors.

9.2.2 RD 436/2004: The first significant change to the AES regulatory framework

The first significant change to the regulatory scheme in force was introduced in 2004 by RD 436/2004 (Ministry of Economy, 2004). This new rule aimed at setting a more stable and predictable support scheme by indexing all remuneration parameters (i.e. FITs, premiums, system services, etc.) to the RAET which had been previously defined by RD 1432/2002 (Ministry of Economy, 2002b). The RAET update methodology was set as a function of specific macroeconomic indicators so that it provided a clear, predictable and stable way for calculating and forecasting the remuneration parameters of AES power producers.

RD 436/2004 kept the main characteristics of the two support schemes set by previous regulations (i.e. FITs and price premiums) but introduced significant changes in the way the remuneration parameters were computed. Now, the FIT was computed as a percentage of the RAET and the final power price under the Price Premium option was computed as follows:

$$\begin{aligned} FinalPrice = WPMPrice + Premium + WPMIncentive + CapPayment \\ + RPComplement + VoltDipComp - DevCost \end{aligned} \tag{9.3}$$

Where: FinalPrice = Final power price to be received by the producer (EUR/MWh)

WPMPrice = WPM price (EUR/MWh)

Premium = Technology-specific price premium (EUR/MWh)

WPMIncentive = Additional incentive for participation in the WPM (EUR/MWh)

CapPayment = Capacity payment (EUR/MWh)

REComplement= Reactive energy complement (EUR/MWh)

VoltDipComp = Premium for voltage dip resistance (EUR/MWh)

DevCost = Penalties for deviations from the forecasted generation schedule (EUR/MWh)

Premiums, WPM participation incentives, voltage dip complements and reactive energy complements were computed as a percentage of the RAET with values of 40%, 10%, 5% and a range from -4% to 8% respectively in the case of wind power. Capacity payments were computed in the same way as for conventional power plants. The RAET value was set at 72,072 EUR/MWh when RD 436/2004 was adopted and subsequently updated on a yearly basis based on the evolution of specific macroeconomic parameters.

Producers still had the FIT option, being its value computed as a percentage of the RAET as well. In the specific case of wind power, RD 436/2004 set a declining value starting at 90% for the first five years of operation, 85% for the next 10 years and 80% for rest of the plant’s life span.

RD 436/2004 introduced for the first time payments to wind farms for their capacity to withstand specific voltage dips. This was a cause of major concern at that time because the oldest asynchronous technology-based wind farms tripped under voltage dips so contributing to make the voltage dip larger which could lead to a total system black out. These new payments were aimed at encouraging investors to use technologies able to deal with voltage dips (e.g. full converter synchronous, doubly fed induction generator or specific control systems added to older squirrel cage generator wind turbines, etc.) (Engstrom, 2011; Jauch, 2006)

Finally, and in order to deal with the growing concern about the potential network instability introduced by wind power variability, RD 436/2004 introduced for the first time the requirement for wind farms to pay for the deviations from their power generation forecasts. This measure was aimed at facilitating the system operation by encouraging wind power generators to provide accurate forecasts.

RD 436/2004 achieved its goal of fostering AES participation in the WPM as 96% of wind power generation was already traded in the WPM by 2008 (del Rio Gonzalez, 2008).

9.2.3 RD 661/2007: The second significant change to the AES regulatory framework

RD 661/2007 (Ministry of Industry, Tourism and Commerce, 2007c) updated once more the incentive scheme in 2007. It repealed RD 436/2004 and stayed in force until 2013, when the largest regulatory change in the short history of AES power generation regulation took place. The main idea behind this new rule was the fact that the cost of some renewable technologies such as wind, solar, etc. was not actually correlated with the WPM price which was the main reference for setting the RAET. So, this new regulation decoupled the incentive levels from the RAET, set new specific values based on three different variables (technology, capacity and age) and based the incentive price updating process on the evolution of the CPI (CPI minus 0.25% until 2012 and CPI minus 0.5% afterwards).

In addition, RD 661/2007 introduced lower and upper caps for the power price to be received by pure renewable technologies such as wind. This was done in order to avoid windfall profits for these technologies when the WPM price was high due to high fossil fuel prices (which was the case at the time the RD was passed) as the production costs of said technologies is not correlated with fossil fuel prices. On the other hand, the lower cap guaranteed a minimum profitability for these technologies in the unlikely case (at that time) that the WPM price fell below a threshold value. Also, the introduction of this lower cap helped to alleviate the controversy caused by the introduction of this new rule among the AES producers which were concerned about their profitability being limited by the upper caps.

9.2.4 RD 1578/2008: Dealing with the PV power overinvestment problem

Although not directly related to wind power but in order to have the whole picture and understand the regulatory evolution of Spain's AES industry, it is necessary to mention the controversial overinvestment effect that RD 661/2007 had on PV power. This RD set a much more stable framework and significantly increased PV incentive levels (del Rio & Mir-Artigues, 2012). This entailed an investment boom cycle which led to 3,207 MW of solar PV installed capacity in 2008 (Red Electrica de España, 2013), which largely overshot the 400 MW target set for 2010 (Instituto para la Diversificación y Ahorro de la Energía, 2005) as well as the 371 MW capacity cap set by RD 661/2007.

As a result, the next relevant regulatory change, RD 1578/2008 (Ministry of Industry, Tourism and Commerce, 2008a), focused on PV power. It set a reduction of the applicable incentive prices as well as the adoption of a pre-allocation registry for new capacity additions in order to keep the capacity growth under control. Each annual quota was assigned a specific incentive that was calculated based on the fulfillment of the previous year quota according to the following equation:

$$
\begin{aligned}
&IF\ P \geq 0.75 \cdot P_0 \\
&\qquad T_n = T_{n-1}\left[(1-A)\cdot\frac{P_0 - P}{0.25 \cdot P_0} + A\right] \\
&IF\ P < 0.75 \cdot P_0 \\
&\qquad T_n = T_{n-1}
\end{aligned}
\tag{9.4}
$$

Where: P = Registered capacity in period n-1 (MW)

P_0 = Capacity quota in period n-1 (MW)

T_{n-1} = Incentive awarded to the capacity registered in period n-1 (EUR/MWh)

T_n = Incentive to be awarded to the capacity registered in period n (EUR/MWh)

A = $0.9^{1/m}$, being m the number of capacity calls in period n (dmnl)

Although in general this procedure sought a declining incentive price when capacity quotas were met or exceeded, a mechanism for increasing the incentive in case capacity additions were not large enough was set as well. Therefore, the regulator had the option to increase the incentive value in case the approved capacity was below 50% of the quota.

RD 1578/2008 was an important milestone for AES regulation in Spain as it was the first step aimed at slowing down the deployment of specific technologies and reducing incentive expenses because of the large system costs being incurred, which added pressure on the already growing TD.

9.2.5 RDL 6/2009 and subsequent: The incentive cuts

While AES incentives were still growing because of the increasing AES installed capacity and production, the 2008 global economic crisis further increased the pressure on system costs making the Government of Spain more concerned about the TD problem. So, RDL 6/2009 (Head of State, 2009) set a binding decreasing annual deficit target for the upcoming years and a zero-deficit target for 2013. It also set the

“Fondo de Titulizacion del Déficit del Sistema Eléctrico” (FADE), a financing mechanism for the existing cumulative debt.

In order to achieve these goals, RDL 6/2009 introduced additional measures such as the suppression of the few remaining retail tariffs (with the exception of the last resource one, which focused on low income end power users) so that the only remaining regulated tariffs where the grid access ones, which were designed to cover the industry regulated activities’ costs. In addition, RDL 6/2009 decoupled the expenses related to radioactive waste management and NPP decommissioning from said grid access tariffs and charged them to the State General Budget instead.

Finally and most importantly, in order to avoid new overinvestment issues such as the one that happened with PV power in 2008, RDL 6/2009 added new control mechanisms by extending the pre-allocation registry to all AES technologies, emphasizing that the incentives would be discontinued once the installed capacity reaches the goals previously set and stating that, once the installed capacity goals are achieved a new support scheme will be set.

RD 1565/2010 (Ministry of Industry, Tourism and Commerce, 2010c) introduced further changes aimed at decreasing the AES incentive costs, being the most relevant one a further reduction in the incentives for PV power, both by removing them for plants older than 25 years and by applying the following reduction coefficients to the incentives to be approved in the next call for capacity:

- Type I.1 (Rooftop PV ≤ 20kW): 0.95
- Type I.2 (Rooftop PV > 20kW): 0.75
- Type II (Rest of plants): 0.55

All previous measures were not enough to alleviate the pressure on the financials of the country’s power industry, being the problem worsened by the effects of the global economic crisis which was still affecting Spain’s economy. So, RD 1614/2010 (Ministry of Industry, Tourism and Commerce, 2010b) was passed in 2010 in order to introduce further measures aimed at further decreasing the TD. This decree was a new important milestone in Spain’s AES regulation as, it introduced for the first time the concept of retroactivity, therefore becoming a controversial measure.

The basic idea behind RD 1614/2010 was to further cut wind and solar CSP incentive expenses by (i) limiting the number of EOHs in which the generators are entitled to incentives and (ii) by reducing the price of the incentives. In the case of wind power, the EOHs were limited to 2,589 hours / year (only in case the country’s average wind EOHs are greater than 2.350) and the incentive price was reduced by 35%. In the case of solar CSP, the limit EOHs were reduced to a 2,350 – 6,450 range depending on the technology considered while the incentive price remained unchanged.

In this case, retroactivity was temporary as these measures were expected to be in force until 2013, when the incentive price would go back to its initial value. Even though with significant controversy, industry players accepted these temporary measures in exchange of a new stable framework from 2013 on, which unlocked the situation of the wind power industry (Asociacion Empresarial Eolica, 2011).

RDL 14/2010 (Head of State, 2010) introduced further retroactive changes with the goal of reducing AES support spending in order to limit the still growing TD as previous measures had not successful. Power demand was decreasing because of the global economic crisis so that the income from the network access tariffs was decreasing too. In addition and because of climate issues, the production from AES technologies was reaching all-time maximums so that the incentive outlays were growing and the TD binding limits set by RDL 6/2009 were largely exceeded.

RDL 14/2010 is considered as the third large AES incentive cut. It was focused on PV power as, at that time, it was the major source of imbalance in the system because of the high values of the prevailing incentives. This new regulation introduced a cap for the EOHs in which solar PV power plants were entitled to incentives. This cap was in the 1,232 – 2,367 hours / year range depending on the geographic area where the power plant was located as well as on the type of plant (fixed, 1-axis, 2-axis). This reduction was even greater for the period comprised between the time the Decree was passed and the end of 2013. In order to offset this negative effect, the deadline for receiving the incentives was extended from 25 to 28 years.

Finally this RD requested an additional effort from all industry players in the form of new generation tax in the amount of 0.5 EUR/MWh and increased the TD limit set by RDL 6/2009 in order to deal with the tough industry conditions prevailing at that time.

9.2.6 RDL 1/2012: The AES moratorium

The termination of the support framework that had been in force since the adoption of RD 2818/1998 and that was key for the successful deployment of AES in Spain took place in 2012 with the adoption of RDL 1/2012 (Head of State, 2012). This decree entailed the discontinuation of the support scheme based on FITs and premiums as well as of the pre-allocation registry for all technologies setting the beginning of the so-called "AES moratorium". On the contrary to the two previous Decrees, this one had no retroactive effect as it was aimed just at new AES plants.

The reasons given by the Government for passing this RD at that time were that all previous measures were not enough in order to get rid of the TD (its value was about 2,000 MEUR in 2012 and was expected to increase by the same amount for 2014), the fact that the installed capacity goals set by the 2010 REP had been largely exceeded in the case of wind, solar PV and solar CSP power, the fact that the reserve margin at that time was enough to meet the future demand for several years and the fact that the Government had plenty of margin in order to comply with the recently approved 2020 REP in terms of the capacity path to follow.

In 2013, the unbalance between system revenues and expenses was still increasing because of higher-than-expected AES power generation, the indexation of the FIT and premium to oil price (which was high at that time) and the decreasing demand due to the global economic crisis.

Therefore, RDL 2/2013 (Head of State, 2013b) updated the FIT update methodology. While these updates where initially linked to the standard CPI, they were subsequently linked to a modified CPI which was not considering the evolution of oil price for its calculation. In addition, the option for selling power at the WPM price plus the regulated premium was discontinued, so that all AES generators were forced to use the FIT option. According to the Government, this was done in order to reduce the volatility of the price to be received by AES generators so that both the minimum reasonable ROI could be guaranteed and windfall profits avoided.

9.3 The new regulatory framework

The changes introduced in the power regulation described in the previous section, greatly contributed to growing regulatory complexity while the structural problems were not being solved. So, in 2013 the Government decided to start from scratch by repealing all previous regulation and passing a new comprehensive law aimed at simplifying the system as well as at solving the TD issue once and for all.

This process started with RDL 9/2013 (Head of State, 2013c) which was aimed at setting “new measures for guaranteeing the financial stability of the electric system”. This new regulation repealed the most important existing regulations on AES incentives in force at that time, RD 1578/2008 for PV power and RD 661/2007 for the rest of technologies, and enabled the Government to set a brand new framework to be fully developed in subsequent regulations, aimed at providing AES investors with reasonable ROIs as well as enabling AES technologies to compete with conventional ones on equal terms. For the first time in the history of Spain’s AES regulation, RDL 9/2013 defined the concept of reasonable ROI, which was set as the average return of Spain’s 10-year government bonds increased by 300 basis points.

The new electric power sector Law 23/2013 (Head of State, 2013a) repealed law 54/1997 and set a brand new framework for AES, integrating the preliminary directives set in RDL 9/2013. In addition, Law 23/2013 discontinued the differentiation between conventional and SPGR technologies with the goal of making AES technologies converge with the conventional ones after they reach their maturity stage. Law 23/2013 also obliged all AES technologies to participate in the WPM and granted incentives aimed at allowing them to compete against conventional technologies on equal terms.

In addition, it entitled the Government to approve specific remuneration regimes (SRR) for those technologies that need to be fostered (e.g. renewables, cogeneration and waste) and set its main guidelines:

- SRRs will be determined by competitive processes in which the bidding parameter will be the specific investment based on which the remuneration parameters will be computed.

- SRRs will have two components. A capacity-based component (Remuneration for the investment, Rinv) aimed at covering the investment costs that cannot be recovered from the revenues from power sales at the WPM, and an operation component (Remuneration for the operation, Ro) which will cover the difference between the actual operation costs and the revenues from power sales at the WPM.
- In order to avoid future TD problems, it will have to guarantee the financial sustainability of the power system and will be, in any case, limited to the capacity targets set by the Government.
- Different RPPs will be defined based on variables such as technology, capacity, age, interconnection system, etc.
- Specific SRRs will be allocated to each RPP based on (i) the standard electricity sales revenue, (ii) the standard operation costs and (iii) the standard initial investment.
- SRR will be allocated to each RPP based on (i) the standard electricity sales revenue, (ii) the standard operation costs and (iii) the standard initial investment, for the life span of each RPP considering that it is being operated by an efficient and well-managed company.
- The SRR will be updated every 6 years.

Law 23/2013 guidelines were further developed by RD 413/2014 (Ministry of Industry, Energy and Tourism, 2014b). It defined the concept of the RPP and stated that each existing or new power plant will be assigned an RPP based on its characteristics and that specific SRR will be assigned to each RPP. It also specified how Rinv and Ro are to be computed based on the characteristics of each RPP. The details are described in the next section.

This new regulatory framework is fully retroactive as it is applicable to both existing and projected power plants. So, following RD 413/2014, OM IET/1045/2014 established the equivalences between the old technology groups in RD 661/2007 and the new RPPs to be assigned to all existing AES power plants. So, a total of 576 RPPs were defined for the existing power generation portfolio.

The retroactive characteristic of this new regulation was very relevant as it dramatically changed the expected ROIs of the generation assets already in operation. Therefore, international investment funds started a series of legal actions against the Government of Spain, which had an exposure of about 13 billion EUR to renewable energy assets as of 2016. This fact made Spain rank first in terms of number of AES claims faced under the Energy Charter Treaty (de la Hoz, et al., 2016).

OM IET/1459/2014 was the first practical implementation of the new regulatory regime as it set the mechanisms for the allocation of the SRR for new AES plants to be subsequently added to Spain’s power systems out of Spain’s mainland.

9.4 Detailed description of the new regulatory regime

According to the new support scheme defined by Law 23/2013 and RD 413/2014 the remuneration of all power plants in Spain's mainland[72] will be composed of (i) the WPM price, (ii) the ancillary services payments, (iii) the capacity payments and (iv) the SRR, as per the following equation:

$$TotRem = (WPMPrice + ASPay) \cdot AnnPowGen + CPay + SRRP \qquad (9.5)$$

Where: TotRem = Total remuneration (EUR/year)

WPMPrice = WPM payments (EUR/MWh)

ASPay = Ancillary services payment (EUR/MWh)[73]

AnnPowGen = Annual power generation (MWh/year)

CPay = Capacity payment (EUR/MW/year)[73]

SRRP = SRR payment (EUR/year)

The SRRP is only applicable to AES technologies. The idea behind it is to guarantee AES power plants a reasonable ROI based on the required initial investment and future cash flows as well as their ability to compete with conventional technologies on equal terms.

So, as described above all AES power plants either existing or projected will be assigned an RPP based on their characteristics (technology, age, capacity, operating costs, etc.) and each RPP will be assigned an SRRP which is calculated on the economic parameters of each RPP (initial investment, performance, capacity factor, etc.) as well as on projected economic variables (power price, etc.) in order to achieve the "reasonable ROI" goal.

The difference between existing and projected plants is that, while for existing plants the SRRP was set by Ministry Order OM IET/1459/2014 (Ministry of Industry, Energy and Tourism, 2014c), in the case of projected plants it will be set based on a competitive process by which participants must bid a reduction on the initial expected investment per MW based on which the SRRP will be calculated.

The SRRP is composed of Rinv and Ro, being both components calculated for each RPP as described below.

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[72] In the case of Spain's territories other than the mainland, an additional remuneration complement which takes into account potential power production cost savings is considered

[73] Wind farms are neither entitled to capacity payments (Ministry of Industry, Tourism and Commerce, 2011) nor to ancillary service payments (Ministry of Industry, Energy and Tourism, 2014b).

$$SRPP_{j,a} = \left(Rinv_{j,a} \cdot P + Ro \cdot E\right) \cdot d \qquad (9.6)$$

Where: $Rinv_{j,\ a}$ = Remuneration for the investment in each year of semi period j for a standard plan authorized in year a (EUR/MW - year)

P = Plant capacity (MW)

Ro = Remuneration for the operation in the current year (EUR / MWh)

E = Annual power production in (MWh/year)

d = Adjustment coefficient based on the actual EOHs (dmnl)

The adjustment value, d is computed based on several threshold values described in RD 413/2014 that, for the sake of brevity, are omitted[74].

$Rinv_{j,a}$ is computed as follows:

$$Rinv_{j,a} = C_{j,a} \cdot VNA_{j,a} \frac{t_j \cdot (1 + t_j)^{VR_j}}{\left(1 + t_j\right)^{VR_j} - 1} \qquad (9.7)$$

Where: $C_{j,a}$ = Adjustment coefficient in semi period j for a standard facility authorized in year a

$VNA_{j,a}$ = Net asset value at semi period j of a standard facility authorized in year a (EUR/MW)

t_j = Discount rate

VR_j = Residual plant life span (year)

Basically, the previous equation computes the future value of the VNA at the end of the life of the plant and computes the stream of cash flows which equates said future value at a t_j discount rate.

The adjustment coefficient Cj,a represents the percentage of investment costs that cannot be recovered by the proceeds of power sales at the WPM based on the current net asset value and the forecasted operating cash flows. It is computed as follows:

[74] Basically, this adjustment entails the reduction or elimination of the SRRP in case the EOHs fall below specific thresholds

$$C_{j,a} = \frac{VNA_{j,a} - \sum_{i=p}^{a+VU-1} \frac{Ingf_i - Cexpf_i}{\left(1+t_j\right)^{i-p+1}}}{VI_a} \quad (9.8)$$

Where: p = First year of regulatory period j (year)

a = Authorization year for the standard facility (year)

VU = Regulatory life span of the standard facility (year)

$Ingf_j$ = Estimated future operating revenues of the standard facility (EUR/year)

$Cexpf_j$ = Estimated future operating costs of the standard facility (EUR/year)

t_j = Discount rate (dmnl)

$Ingf_j$ and $Cexpf_j$ are computed based on forecasted variables such as the WPM price, standard operation costs, EOHs, etc. (Table 9-1). In the specific case of the forecasted WPM price, it will be computed as the 6-month average price of the power futures contracts traded before the regulatory period.

The net asset value, $VNA_{j,a}$, is computed according to the following equation[75]:

$$VNA_{j,a} = \left[VNA_{j-1,a}\left(1+t_{j-1}\right)^{p-a-1} - \sum_{i=a+1}^{p-1} \left(Ing_{i,j-1} - Cexp_{i,j-1} - Vadj_{i,j-1}\right)\left(1+t_{j-1}\right)^{p-i-1} \right] \quad (9.9)$$

Where: $Vadj_{j,j-1}$ = Adjustment value due from deviations from the forecasted WPM market price in regulatory period j-1

The adjustment value, $Vadj_{j,j-1}$ takes into account the deviation from the forecasted WMP price and computed based on several threshold values described in RD 413/2014 that, for the sake of brevity, are omitted here[76]. The remuneration (Ro) for the operation will be computed so that the operating revenues equals the operating expenses, always considering that the facility is operated by an efficient and properly managed company.

[75] In the first regulatory period, $Vadj_{j-1}$,a is equal to the investment cost

[76] Upper and lower WPM price caps are defined so that if the limits are exceed a positive or negative balance is accrued in order to have it offset during the remaining plant life.

So, Rinv and Ro are computed based on a series of forecasted market and technical variables (Table 9-1) as well as on the regulatory parameters specific to each RPP (Table 9-2). Rinv and Ro will be updated every 3 years based on the evolution of the remuneration variables as described below:

- The investment per MW[77] and the regulatory lifespan will remain unchanged along the plant´s lifetime.
- The forecasted WPM price and the forecasted EOHs will be updated every 3 years.
- Ro will be updated annually based on the current plant fuel price evolution.
- The rest of the remuneration parameters, including the "reasonable ROI" will be updated every 6 years.

Technical & market parameters
Investment cost of the RPP
Forecasted daily and intra-daily WPM price
Forecasted EOHs
Forecasted proceeds from power sales
Forecasted additional proceeds
Forecasted operation costs

Table 9-1: Technical and market parameters for SRR calculation [78]

Regulatory parameters
Regulatory plant life span
Upper and lower EOHs caps
Upper and lower WPM price caps
Technology-specific market participation adjustment coefficient
Discount rate (equal to "reasonable" ROI)

Table 9-2: Regulatory parameters for SRR calculation[78]

9.5 Wind capacity auctions

In 2015 the Government of Spain acknowledged the necessity to increase wind and biomass capacity in Spain's mainland in order to facilitate the compliance with EU 2009/28/CE Directive (The European Parliament and the Council of the European Union, 2009). Therefore, an auction for 500 MW of wind and 200 MW of biomass was announced by RD 947/2015 (Ministry of Industry, Energy and Tourism, 2015c).

[77] This is the final investment cost value resulting from the bidding process

[78] (Ministry of Industry, Energy and Tourism, 2014b)

Subsequently, OM IET/2212/2015 (Ministry of Industry, Energy and Tourism, 2015a) approved the remuneration parameters for the RPPs to be considered in the bidding contest and set the basic rules. Table 9-3 shows the remuneration parameters for wind power RPPs Table 9-4 shows the main assumptions considered by the Government for their calculation.

Operation authorization year	***Regulatory lifespan (years)***	***Investment cost (EUR/MW)***	***Operating eq. hours (hour)***	***Operating costs 1st y (EUR/MWh)***	***Min eq. op hours (hours)***	***Threshold Eq. op. hours (hours)***	***Rinv 2017-2020 EUR/MW***
2015	20	1,200,000	2,800	24.95	1,400	840	63.243
2015	20	1,200,000	2,800	24.96	1,400	840	63.275
2017	20	1,200,000	2,800	25.29	1,400	840	63,384
2018	20	1,200,000	2,800	25.50	1,400	840	64,010
2019	20	1,200,000	2,800	25.71	1,400	840	64,643
2020	20	1,200,000	2,800	25.93	1,400	840	65,282

Table 9-3: RPP remuneration parameters considered in the 2016 auction[79]

Main Assumptions
WPM price (2015) = 49.52 EUR/MWh
WPM price (2016) = 49.75 EUR/MWh
WPM price (2017) = 52.00 EUR/MWh
Technology-specific market adjustment coefficient = 0.8889
Reasonable ROI = 7.503%
Operating cost annual increase rate = 1%
Performance decrease rate = 0.5%/year from year 16
Generation schedule deviation costs (2015) = 0.80 EUR/MWh
Generation schedule deviation costs (2016 on) = 0.60 EUR/MWh

Table 9-4: 2016 auction remuneration parameters computation assumptions[80]

The products to be auctioned were the wind and biomass capacity entitled to the SRR. The quantities to be auctioned were 200 MW and 500 MW for biomass and wind power respectively. The result of the auction will be the capacity awarded to each participant as well as the final percentage reduction of the investment cost for the RPP.

The participants in the capacity auctions had to bid reductions of the initial investment cost so that the final Rinv to be received by the winning wind farms was to be computed based on the reduced investment cost as well as on the rest of remuneration parameters of their associated RPP.

[79] (Ministry of Industry, Energy and Tourism, 2015a)

[80] (Ministry of Industry, Energy and Tourism, 2015a)

The computation of Rinv based on RD 413/2014 turned out to be very complex as even some of the assumptions were not clearly disclosed, which was a cause of concern for investors. Therefore, in order to solve this issue, OM IET/2212/2015 provided the following simplified equation for the calculation of Rinv for the period 2015-2020:

$$Rinv_a = Rinv_{RPP,a} - m_{RPP,a} \cdot Red_{RPP} \tag{9.10}$$

Where: $Rinv_a$ = Remuneration for the investment for the plant authorized in year a

$Rinv_{RPP,a}$ = Remuneration for the investment for the RPP authorized in year a

Red_{RPP} = Percentage reduction of the RPP investment cost resulting from the auction

$m_{RPP,a}$ = Coefficient for the calculation of Rinv (Table 9-5)

RPP code	***Operation authorization year***	***Group code***	***ARPP code***	***$m_{RPP,a}$***
ITR-0102	2015	b.2	IT-04007	117,737
	2016	b.2	IT-04008	117,737
	2017	b.2	IT-04009	117,737
	2018	b.2	IT-04010	117,737
	2019	b.2	IT-04011	117,737
	2020	b.2	IT-04012	117,737

Table 9-5: 2016 auction mRPP coefficient[81]

The Resolution dated November 30th 2015 (Ministry of Industry, Energy and Tourism, 2015b), scheduled the auction for January 14th 2016 and set the final details and mechanisms regarding the bidding process which was based on a sealed-bid marginal price system by which all winning wind farms were to be assigned the same marginal percentage investment cost reduction and so, the same Rinv regardless of the specific percentage investment cost reduction they bid. Figure 9-4 shows graphically this procedure.

[81] (Ministry of Industry, Energy and Tourism, 2015a)

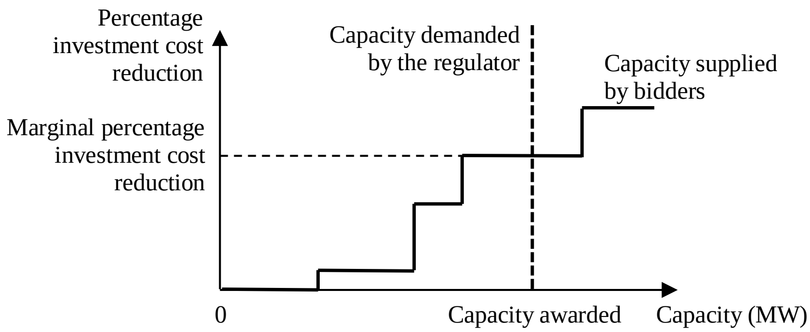

Figure 9-4: 2016 wind power auction awarding procedure[82]

The Government resolution dated 01/18/2016 (Ministry of Industry, Energy and Tourism, 2016b) released the auction results and showed that the resulting marginal percentage reduction of the initial investment cost was 100% so that the resulting Rinv was null. This fact meant that no SRR was allocated to any of the wind projects that participated in this auction, which was a big surprise for the industry players.

A second auction took place in May, 2017. RD 359/2017 (Ministry of Energy, Tourism and Digital Agenda, 2017d) scheduled the auction, OM ETU/315/2017 (Ministry of Energy, Tourism and Digital Agenda, 2017b) approved the bid parameters and set the basic rules, and Government Resolutions dated 04/10/2017 (Ministry of Energy, Tourism and Digital Agenda, 2017e; Ministry of Energy, Tourism and Digital Agenda, 2017f) set the final rules and the maximum discount to be applied by technology.

While the first auction included just wind and biomass, this second one was technology-agnostic and introduced a cap for the maximum discount on the investment cost. 2,980 MW of wind, 1 MW of solar PV and 19 MW of other AES technologies were awarded. Like in the 2016 auction, all wind capacity was awarded with the maximum discount so that again, no incentives were allocated to any wind farm. Nevertheless, the fact of including a cap for the maximum discount entailed a lower cap of 42 EUR/MWh for the price to be received by wind farms, hence hedging to some extent the WPM price volatility risk.

Auctions have proven to be a challenging support scheme as, while they are good at keeping power prices and system costs low, they may entail underpricing risk due to the so-called “winner’s curse” (GIZ, 2015). Peru, Brazil, the UK and France are some examples where AES auctions have been used with mixed results. The UK pioneered the usage of auction-based AES support schemes by introducing the NFFO in 1989. Nevertheless, the outcome was not positive as of the 2,659 MW awarded while the NFFO was in force until 1998, only 391 were effectively built. The NFFO was discontinued and substituted by a Renewable Purchase Obligation system in 2002 and, ultimately, by a premium system (Elizondo Azuela, et al., 2014; ECOFYS, 2014). France is another example where auctions have not been successful as a

[82] (Ministry of Industry, Energy and Tourism, 2015b)

realization rate of just 20% was achieved (ECOFYS, 2014). In the case of Brazil, after the introduction of wind power auctions in 2009, wind power prices reached all-time minimums reaching a 2009-2013 average value of 69 USD/MWh, which is about 60% lower than the final price set by the previous FIT-based support scheme (PROINFA). It is yet unclear whether these prices are sustainable or whether bidders have made overoptimistic or strategically low bids which may entail low project realization rates (GIZ, 2015). All in all, the heavy delays incurred by the projects which took place in these auctions are a cause of concern (ECOFYS, 2014).

Some authors claim that the bids in the most recent auctions are below sustainable values given current financing conditions and investment and operation costs (Elizondo Azuela, et al., 2014). On the contrary, despite its AES auction-based support scheme not having been fully proven yet, Peru seems to be obtaining good results; out of 27 projects awarded in the first auction, 21 are operating on schedule (ECOFYS, 2014). The reason for this is possibly the strict compliance guarantees set by the Peruvian auction rules.

9.6 Assumptions

Table 9-6 through Table 9-8 show the main assumptions considered in the simulations in this case study.

	Available Resource (MW)	***Specific investment (MEUR/MW)***	***CO_2 coefficient $kgCO_2$ / MWh***
Wind	100,000	1.10	0.0
Solar PV	200,000	0.80	0.0
Small Hydro	3,000	3.50	0.0
Solar CSP	200,000	4.50	0.0
Gas CC	Unlimited	0.80	311.9
Gas peak	Unlimited	0.85	603.1
Hydro	2,000	2.60	0.0
Nuclear	Unlimited	5.41	0.0
Coal	Unlimited	2.90	978.7
Cogeneration	Unlimited	1.90	502.6

Table 9-6: Main assumptions (1)

Regarding the Monte Carlo simulations, coal price, gas price and peak power demand have been modeled as random walks with drift (Nau, 2014). Table 9-9 shows the statistics for the first difference of said variables. Figure 9-5 shows the historical evolution of coal and natural gas prices. Figure 9-6 through Figure 9-8 show the Q-Q normality tests for the first difference of all three variables. 1,000 cases have been simulated under a multivariate model (i.e. all variables changed at the same time).

(years)	*Construction time (yr)*	*Economic life (yr)*	*Real life (yr)*	*Max installation rate (MW/yr)*
Wind	1.0	25	30	500
Solar PV	0.1	25	30	5,000
Small Hydro	1.0	30	90	2,400
Solar CSP	1.5	25	30	2,000
Gas CC	1.5	25	40	10,000
Gas peak	1.0	25	40	1,000
Hydro	2.0	30	130	2,000
Nuclear	8.0	40	60	3,000
Coal	3.0	30	50	2,000
Cogeneration	0.5	25	30	2,000

Table 9-7: Main assumptions (2)

Variable	*Value*
Power demand elasticity to price[83]	-0.2
Power cap price (EUR/MWh)	200.00
CO_2 emission credit price (EUR/t)	15.00
Maximum AES share in system	30.0%

Table 9-8: Main assumptions (3)

Variable (1st difference)	*Mean*	*Standard deviation*
Oil price USD/bbl	1.43	16.71
Coal price USD/t	1.60	24.91
Gas price EUR/MWh	0.91	3.24
Peak power demand MW	669	1,994

Table 9-9: Random input variables 1st difference Statistics

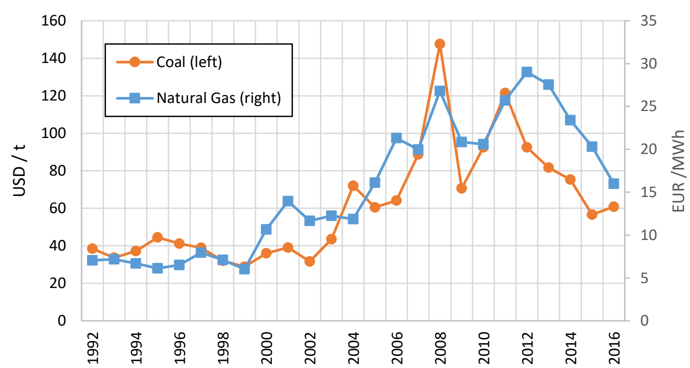

Figure 9-5: Historical natural gas and coal prices[84]

[83] (Hasani & Hosseini, 2011)

[84] (BP, 2017a)

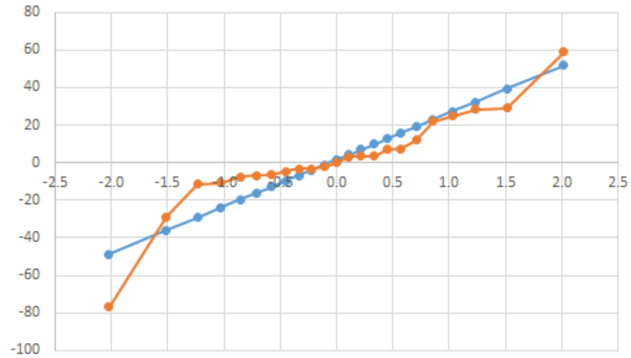

Figure 9-6: Normality test (QQ Plot) Coal price (1st difference)

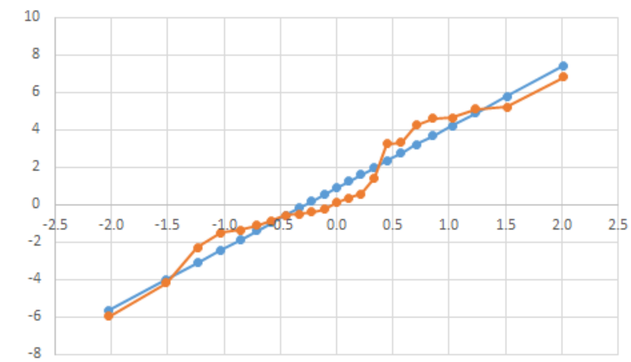

Figure 9-7: Normality test (QQ Plot) Gas price (1st difference)

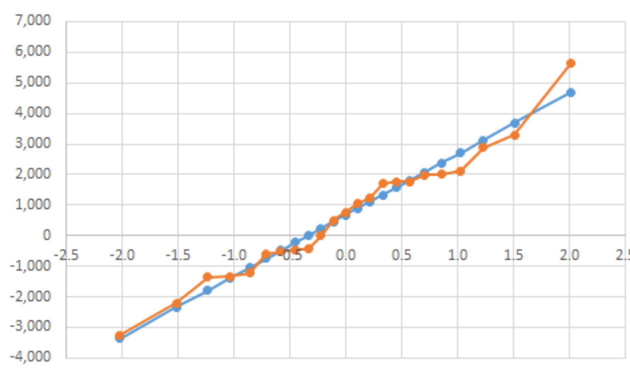

Figure 9-8: Normality test (QQ Plot) peak power demand (1st difference)

Multiple scenarios have been simulated in order to assess the impact of wind incentives on the evolution of wind power capacity and system costs. Special focus has been put on the no incentives and 42 EUR/MWh price floor scenario (Scenario 1) and on the 25 EUR/MWh scenario (Scenario 2). Scenario 1 represents the actual outcome of the wind auctions held so far while Scenario 2 is the one with minimum cumulative system costs.

9.7 Results

Figure 9-9 through Figure 9-12 show the results of the simulations for Scenario 1. Figure 9-9 shows the forecasted evolution of wind power capacity between 2017 and 2030. 50%, 75%, 95% and 100% confidence intervals are shown in different colors while the solid line shows the average (expected) value. Results show that the expected wind capacity increase is limited, starting at about 23 GW in 2017 and reaching 28.9 GW in 2030. The 35 GW goal set by Spain's REPt for 2020 is not achieved. This goal wind capacity is reached with just a 9.5% probability in 2030. Figure 9-10 shows the forecasted evolution of the wind capacity addition rate in the same format. Results show an increasing trend consistent with growing WPM price. Capacity addition rate spikes overlap with WPM price spikes, as expected.

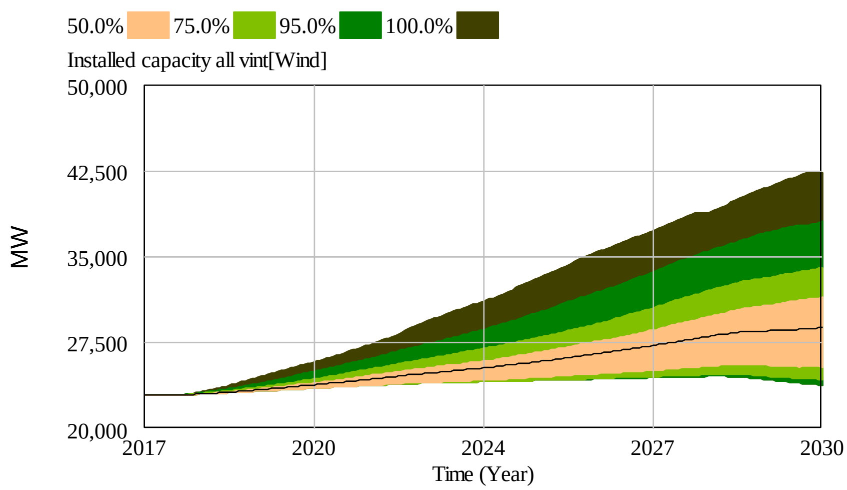

Figure 9-9: Forecasted wind installed capacity. Scenario 1

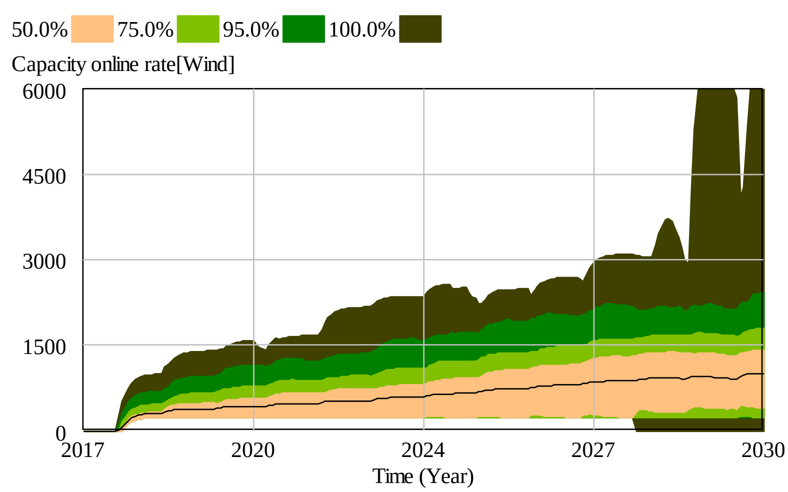

Figure 9-10: Forecasted wind capacity addition rate. Scenario 1

Figure 9-11 shows the forecasted evolution of WPM. Large price spikes are present after 2028 although with a very low probability (last 5% confidence interval).

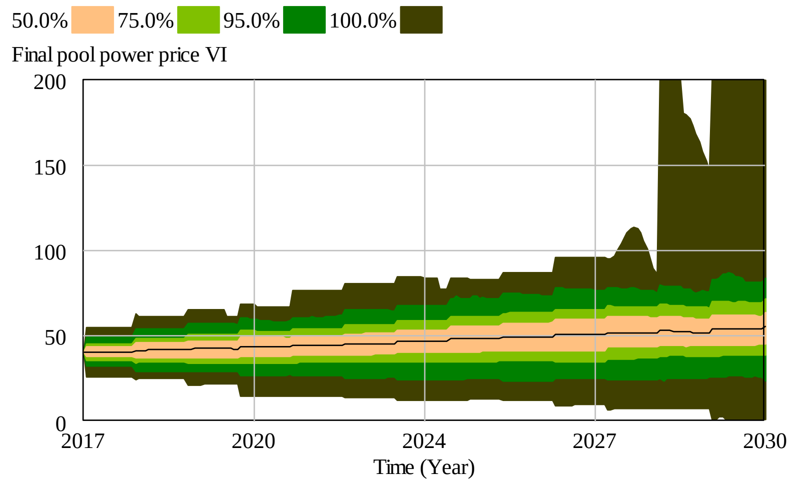

Figure 9-11: Forecasted WPM price. Scenario 1

Finally, Figure 9-12 shows the forecasted evolution of the reserve margin, whose lowest values overlap with the WPM price spikes.

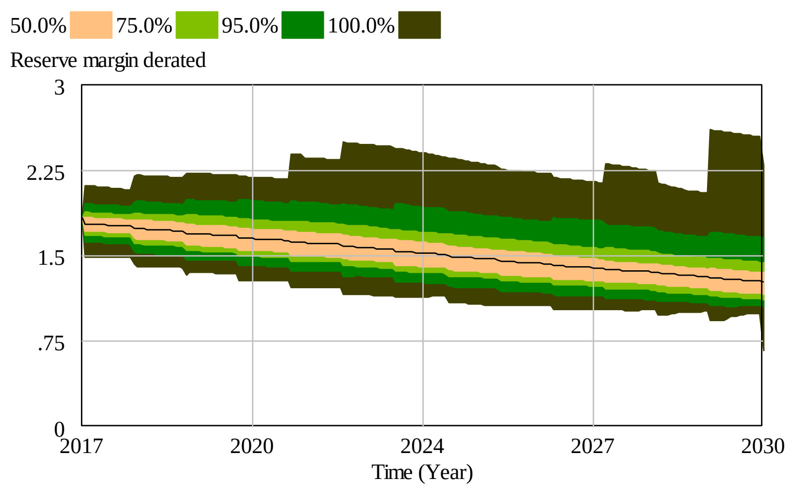

Figure 9-12: Forecasted derated reserve margin. Scenario 1

Figure 9-13 shows the year when the expected wind capacity reaches 35 GW as a function of wind incentives.

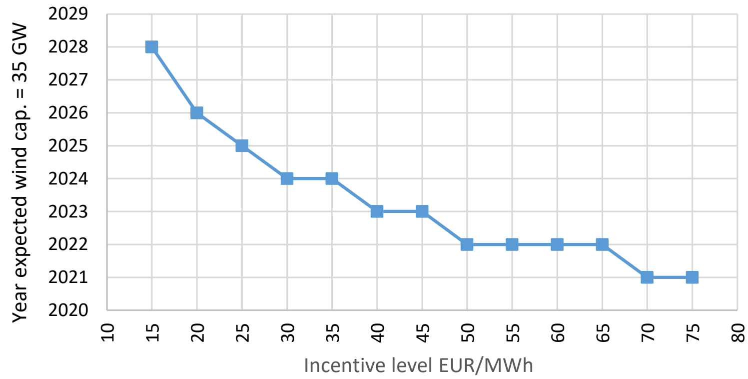

Figure 9-13: Year when expected wind capacity reaches 35 GW vs. wind incentives

Figure 9-14 through Figure 9-16 focus on power system costs. Figure 9-14 shows the evolution of cumulative average power costs as a function of wind incentive levels for the 2017 – 2025 and 2017 – 2030 time periods. Minimum system costs are obtained with 25 EUR/MWh incentives in both cases.

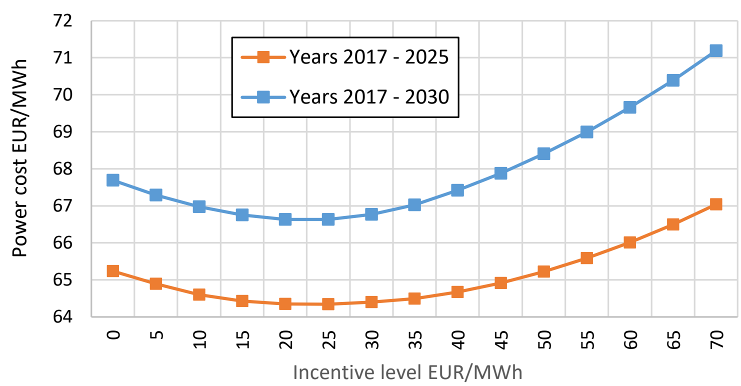

Figure 9-14: Cumulative average power cost vs. wind incentives

Figure 9-15 shows the cumulative (2017-2030) average power cost breakdown into its four components (i.e. WPM power acquisition cost, incentive cost, capacity payment cost and CO_2 credit cost) as a function of wind incentives. Results show a declining trend for WPM power acquisition cost and an increasing trend for incentive costs. Capacity and CO_2 costs have a very limited impact on overall system costs.

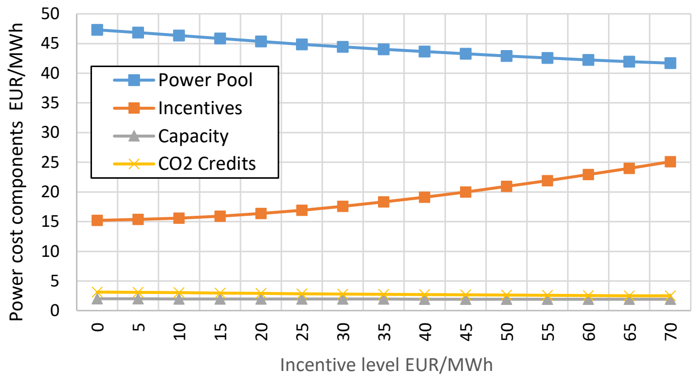

Figure 9-15: Cumulative (2017 – 2030) average power cost components vs. wind incentives

Figure 9-16 shows the cumulative total power system savings. Consistently with the results discussed above, savings reach a maximum of about one billion EUR with wind incentive levels of 25 EUR/MWh.

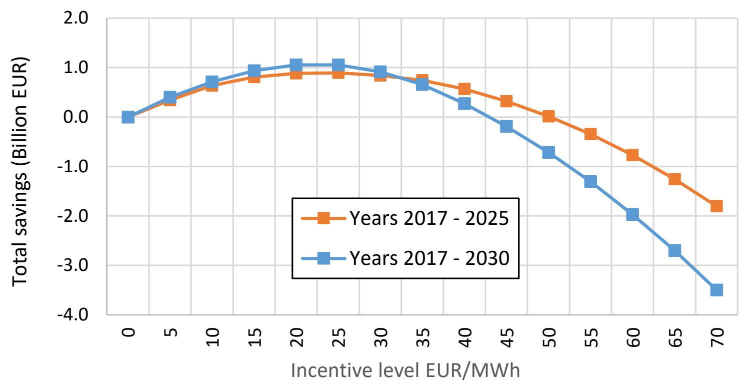

Figure 9-16: Cumulative power system savings vs. wind incentives

Figure 9-17 shows the probability of wind capacity being equal or greater than 35 GW in 2030. As it can be observed, an expected (p = 50%) wind capacity of 35 GW is achieved with an incentive level of 10 EUR/MWh.

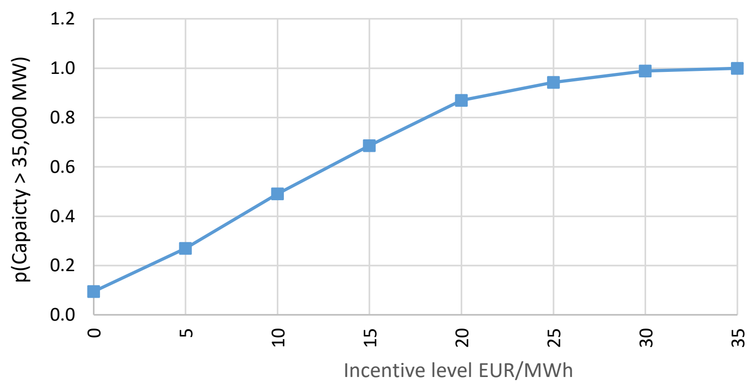

Figure 9-17: Probability of wind capacity equal or greater than 35 GW in 2030 vs. wind incentives

Figure 9-18 through Figure 9-21 show the results of the simulations for Scenario 2. Wind capacity growth rate is significantly greater than in Scenario 1, showing a quite stable average value of about 1,700 MW/year and low probability (last 5% confidence interval) spikes after 2028, which overlap with WPM price spikes. WPM price shows a pattern very similar to the one in Scenario 1 although with lower average values as previously discussed.

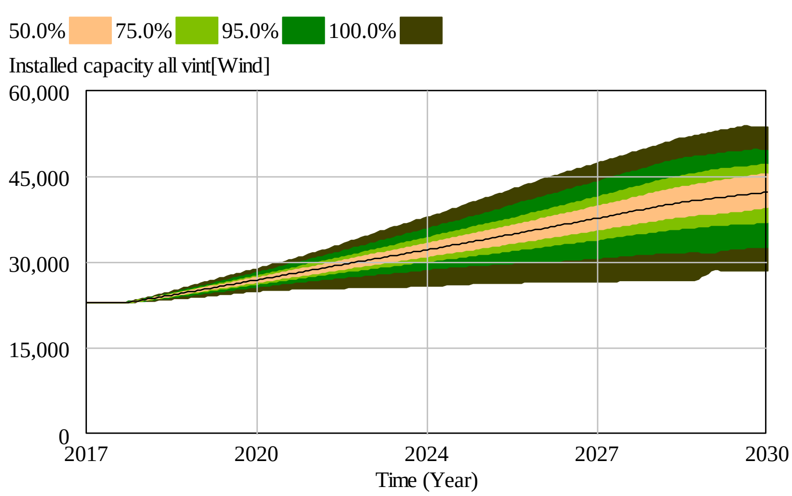

Figure 9-18: Forecasted wind installed capacity. Scenario 2

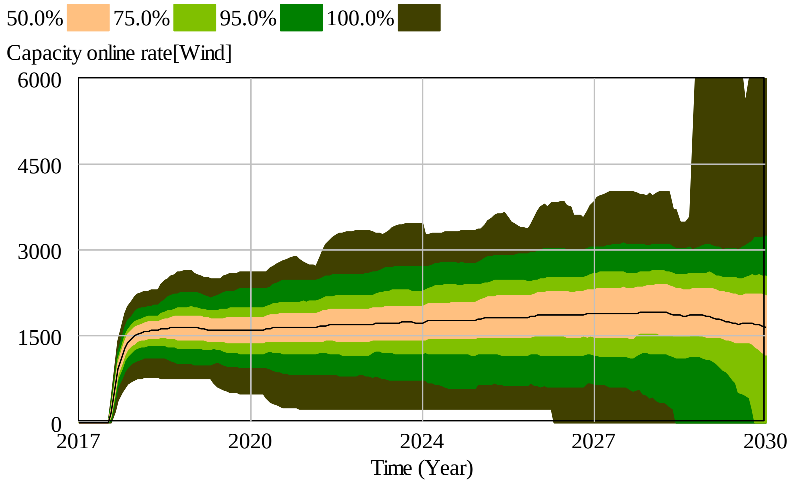

Figure 9-19: Forecasted wind capacity addition rate. Scenario 2

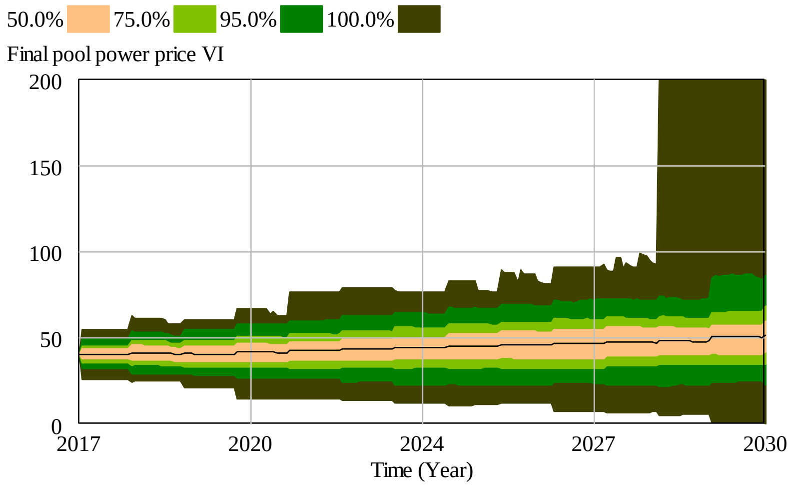

Figure 9-20: Forecasted WPM price. Scenario 2

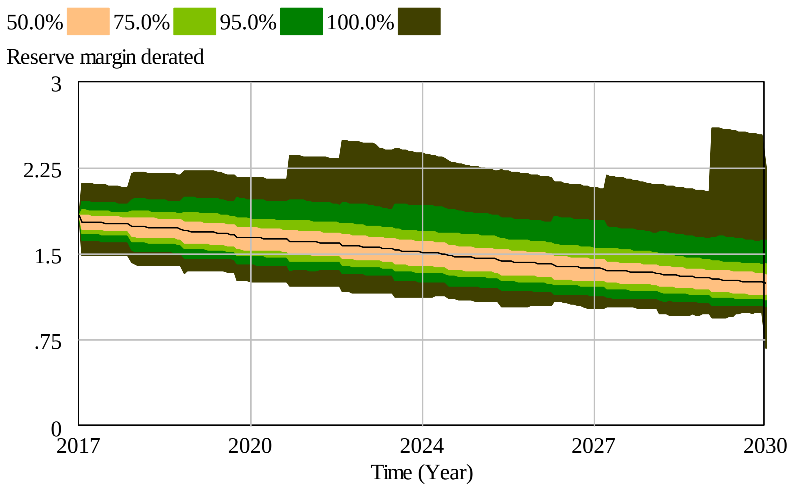

Figure 9-21: Forecasted derated reserve margin. Scenario 2

Finally, in order to understand the global impact on the whole power generation mix, Figure 9-22 shows its forecasted evolution in Scenario 2 and with average constant values assigned to the random walk variables.

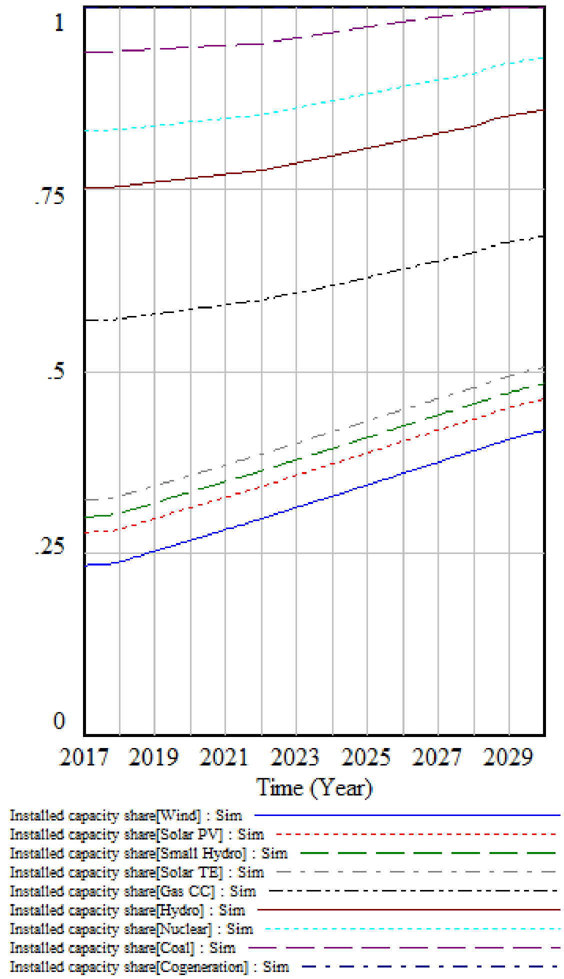

Figure 9-22: Forecasted power generation mix. Scenario 2

9.8 Discussion

In order to understand the effect of wind incentives on the power generation mix and system costs, it is necessary to first understand the reasons behind the evolution of system variables in Scenario 1.

Results clearly show that with no wind incentives, wind IRR is not enough for investors to deploy large amounts of new capacity. WPM price shows a low value in 2017 due to the large initial overcapacity (reserve margin = 1.84%) and shows a quite stable increasing trend consistent with the assumptions on forecasted fossil fuel prices and the declining endogenously computed reserve margin. Large price spikes are present after 2028 due to the scarcity price described in section 5.2, which takes into account the fact that industry players may exercise market power when supply is scarce. This is the case in this scenario due to endogenously computed limited investments in new capacity and the assumptions on growing demand, which entail a consistently declining reserve margin.

WPM price spikes are a cause of concern as they not only entail greater costs for consumers but they may also be the cause of investment boom and bust cycles as it has been extensively described in the literature (Ford, 1999; Ford, 2001a). The lack of investments in new capacity is due to depressed WPM prices caused by initial system overcapacity. Power system marginal pricing may not be enough to keep sufficient investment levels so that incentives or capacity payments[85] are required. So, it seems clear that in Scenario 1, the regulator should take measures such as capacity payments in order to keep a reasonable reserve margin and avoid future WPM price spikes.

Results also show that the 35 GW wind capacity goal is not going to be met in 2020 under any reasonable wind incentive scenario (Figure 9-13) and that the impact of wind incentives declines with their value. This effect can be observed in Figure 9-13, where the curve becomes less steep as wind incentives increase. This effect is due to (i) the existence of maximum wind capacity addition rates which depend on the country's resources (e.g. contractors, equipment, manufacturing capacity, etc.) and (ii) the lead times assumed for wind power deployment, which include investors' decision making and plant construction times.

Although wind capacity additions in Scenario 2 are significantly greater than in Scenario 1, the evolution of the reserve margin is practically the same in both scenarios. This is due to i) the limited contribution of wind power to reserve margin computation (The Brattle Group, Astrape Consulting, 2013) [86] and ii) other technologies' limited capacity additions due to depressed WPM prices.

Wind incentives obviously entail greater wind IRR and speed up wind capacity deployment but they also lead to additional outlays. Interestingly, the present case study shows that wind incentives may entail lower overall system costs. Indeed, system costs decrease with wind incentives for values of up to 25 EUR/MWh, when system costs hit their minimum (Figure 9-14). This is due to the fact that WPM power acquisition costs decrease faster than wind incentive costs increase with wind incentives. WPM power acquisition costs decrease with wind capacity additions because, having very low marginal costs, wind shifts more expensive technologies to the right of the supply curve, which leads to lower WPM clearing price (Figure 6-4). On the contrary, incentive costs increase with wind capacity additions as they obviously entail greater incentive outlays. CO_2 credit costs decline with wind incentives because the fossil fuel share in the power generation mix declines with wind capacity. Capacity payment costs decline with wind incentives because of the

[85] Usually incentives are used in the case of AES and capacity payments in the case of baseload conventional technologies.

[86] Baseload technologies are the greatest contributors to reserve margin.

increasing weight of wind power and so decreasing weigh of baseload technologies[87] in the power generation mix. Both capacity and CO_2 costs have a limited impact on overall system costs.

The necessity of additional investments in baseload capacity in order to absorb the variability of added wind capacity is a recurrent discussion topic in the power industry. Nevertheless, reserve margin results in Scenario 2 are very similar to the ones in Scenario 1. Therefore, similar backup power is required in both cases so that no significantly greater investments in baseload capacity are required in Scenario 2.

Figure 9-22 shows that wind shows the greatest share growth in Scenario 2, mostly at the expense of cogeneration[88] as well as of gas CC and coal. Nuclear share shows a slight decrease while the rest of technologies' share stays almost constant.

Regulators and policymakers may use the results from the present research in order to set the incentive policies required to meet their goals in terms of either wind deployment timing or system costs.

Incentive policies can take many forms including grants, tax credits, FITs, premiums, green certificates, etc. (International Renewable Energy Agency, 2012a) which, at the end of the day, aim at providing investors with a higher IRR through increasing cash flow streams. It is not the goal of the present research to assess how incentive policies should be designed but to determine what their outcome should be in terms of actual incentive levels in order to meet specific goals. So, for example in case the regulator's goal is to minimize system costs, this could be achieved by any policy which provides wind investors with a 25 EUR/MWh premium over the WPM price. These policies may include any of the instruments above, provided that their economic outcome is equivalent to a 25 EUR/MWh price premium.

9.9 Conclusions and policy implications

As discussed in the Introduction section, the goal of this case study is to analyze the historical evolution of wind power support schemes in Spain, and to assess the impact of wind incentives on the future evolution of the power generation mix and system costs through a behavioral stochastic SD approach which models investors' decisions based on market conditions and regulatory levers.

While the former FIT / premium payment support scheme has proven to be effective as it enabled the country to meet its AES goals, the outcome of the new competitive auction based support system has entailed null incentive levels.

The methodological framework developed in the present research has been used in order to simulate the impact of incentives on (i) wind capacity additions, (ii) reserve margin, (iii) WPM price and (iv) system costs.

[87] Baseload technologies are the ones entitled to capacity payments.

[88] Which vanishes from the generation mix by 2028.

Results show that the outcome of the AES auctions held so far in Spain will entail limited wind capacity growth. Greater incentive levels are required in order to (i) meet wind capacity goals and (ii) minimize system costs. Additional results show that:

i. Wind incentives do not necessarily entail greater system costs. In fact, system costs decrease with wind incentives for values below 25 EUR/MWh, when system costs hit their minimum.

ii. The efficiency of wind incentives in terms of capacity deployment declines with their value due to capacity addition constraints and project lead times.

iii. Wind capacity additions do not necessarily entail additional investments in backup baseload capacity in the scenarios considered.

The results of the auctions held so far in Spain and other countries suggest that this methodology will most probably lead to low or even null incentive levels which will limit wind capacity additions.

Regulators can use the methodologies hereby described in order to compute the incentive levels required to meet specific goals in terms of capacity additions or system costs. Regulators can use this information at the moment of designing incentive polices, by making sure that they provide investors with the abovementioned required incentive levels.

Chapter 10
Original contributions and future research

10.1 Original contributions

The goal of the present research was to develop a methodological framework aimed at systematically assessing the long-run technical, environmental and economic impact of a country's power system.

While most of the existing literature and research on Spain's power system economic implications shows a short-term approach and uses methodologies such as equilibrium models, the present research presents a methodological framework which allows to assess the power system's technical, economic and environmental impact from a long run perspective. Also, while most of the existing literature focuses on specific variables such as CO_2 emissions, power price, etc. the present research assess the economic impact from a holistic perspective, by including the most relevant direct and indirect economic impacts.

From a methodological perspective, the present research contributes to the existing literature by using the following combination of modeling techniques:

i. SD: Used as the main underlying technique in order to take into account dynamic considerations and behavioral considerations.

ii. Market equilibrium modeling: Used in the MOPP for the simulation of Spain's WPM in order to compute power plant dispatching and the WPM clearing price.

iii. Stochastic methods: Monte Carlo simulations / Random walks have been used in order to introduce the uncertainty component inherent to variables such as commodity prices or power demand.

iv. Input – Output modeling: Used to assess the overall impact on the country's economy.

The methodological framework here presented is not limited to the pure economic assessment as it also considers the impact on areas such as environment (CO_2 emissions) and system reliability (through reserve margin). Finally, additional contributions include modeling refinements such as the consideration of the full generation technology range, the consideration of power demand long run price elasticity, the calculation of power plant decommissioning rates as a function of actual economic return, the inclusion of soft variables (such as investors' market perceptions and regulatory barriers), the use of technology-specific threshold IRRs and development coefficients, as well as the consideration of technology learning curves.

This methodological framework has been applied to two case studies. The first case study focuses on the assessment of the impact of capacity payments on long-run system costs, reliability and environment. Results show that (i) higher capacity payments are required in order to keep safe reserve margins and system stability and (ii) that capacity payments are a better instrument than AES incentive policies in order to keep safe reserve margins.

The second case study focuses on the assessment of the impact of Spain's new competitive, auction-based AES incentive system on the future development of wind power. Results show that incentive levels higher than the ones obtained in the 2016 and 2017 auctions are required in order meet the wind capacity goals. Also, the values of the incentives which minimize cumulative long-run system costs were computed.

Therefore, the framework here presented can be used by a country's regulator in order to assess the overall long-run impact that his energy policies (e.g. capacity payments, incentive policies, regulatory barriers, etc.) may have on multiple variables and, ultimately on the overall economic well-being of the country. Hence, the methodological framework here presented may be used in order to optimize the country's energy policies.

10.2 Future research

Future lines of research fall into two different categories:

i. Methodological framework enhancement an extensions

ii. Application of the methodological framework to additional scenarios.

Section 6.7 describes the main simplifying assumptions considered in the present research as well as the derived potential model limitations. Therefore, future enhancement and extensions of the present methodological framework could be focused but not limited to tackling the points described in section 6.7 including:

i. The consideration of “dynamic” model parameters. For example, time-changing IRR thresholds and level of investment vs. IRR values could be considered. This would allow to reflect the changes in investor behavior (in terms of the perceived technology risk) across time, so that the model could better reflect the reality. Nevertheless, this enhancement would make the model more difficult to calibrate and potentially introduce overfitting risk.

ii. The addition of investors’ foresight, by which they become “smarter” and are able to foresee the future performance of their potential investments to some extent. This enhancement could make the models better replicate the reality in the sense that they replicate investors’ behavior in a more realistic way.

iii. The consideration of parameters other than pure economic return when assessing potential investments. These additional parameters could include topics such as strategy considerations or the risk level entailed by incentive schemes other than the premium / FIT ones considered in the present research. Nevertheless, these considerations are very difficult to quantify, model and, ultimately “translate” into investment levels making this a challenging future line of research.

iv. The Introduction of actual project development and permitting times in the case of conventional power generation technologies, which would more accurately reflect the reality of large conventional power generation projects in terms of project development timing.

v. The consideration of power traded through PPAs as well as of complex bidding strategies and even stakeholder collusion, which would better reflect the reality of the WPM operation so that the WPM price results could be more accurate. Nevertheless, as in the case of investment strategy considerations, the quantification and modeling of these aspects is not straightforward, making this a challenging future line of research.

vi. The combination of the plant lifecycle dynamic models with a CGE macroeconomic model instead of with an Input – Output model. Input – Output models have the limitations described in section 4.8.2. Although more challenging from the computational, data requirements and development time perspectives, CGE models overcome many of these limitations. Therefore, the combination with CGE models would allow to take into consideration variables such as costs, prices, productivity, competitiveness, migration, etc.

vii. Accurate definition of relevant variables such as CO_2 or VOLL pricing, which have a very relevant impact on the output of the model and show high variability in the existing literature.

viii. Finally, additional macroeconomic data disaggregation (including the allocation to the different productive sectors of the different power generation technologies as well as the share of imports for each one of them) is required. Additional macroeconomic data must be gathered by the regulator in order to fully implement the macroeconomic analysis here described

From the application to additional scenarios perspective, future lines of research are at the discretion of the users of this framework. Potential suggested applications could include:

i. Assessment of the economic, environmental and technical impact of the deployment of the electric vehicle from the power system perspective and at a country level.

ii. Assessment of the overall impact of the deployment of residential scale distributed power generation.

iii. Assessment of the overall impact of the implementation of demand response policies.

iv. Assessment of the overall impact of the denuclearization of the country's power system.

v. Assessment of disruptive events such as fossil fuel price shocks, supply constraints or the commercial deployment of distributed power storage.

vi. Assessment of the optimum timing of policy actions as only policy actions taken at the present time have been considered in the case studies here presented.

vii. Etc.

Appendices

Appendix A. Data

This Appendix includes the most relevant historical data used in order to calibrate the models to the specific case of Spain's power industry

A-1 Macroeconomic data

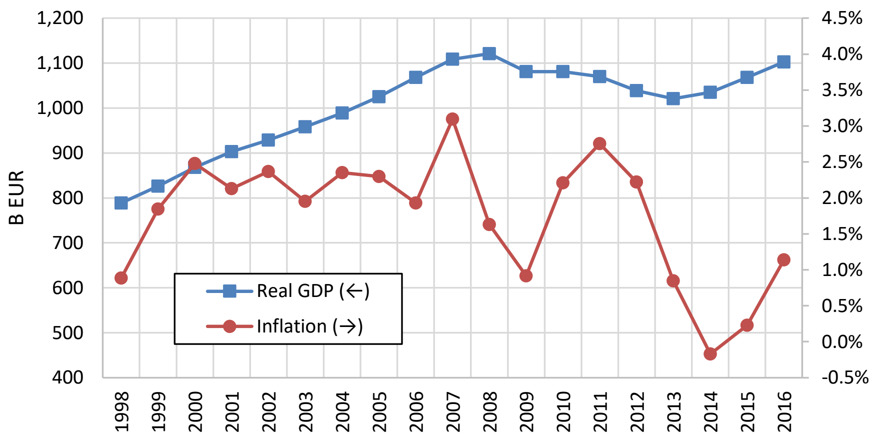

Figure A-1-1: Spain's historical real GDP and Euro area inflation rate[89]

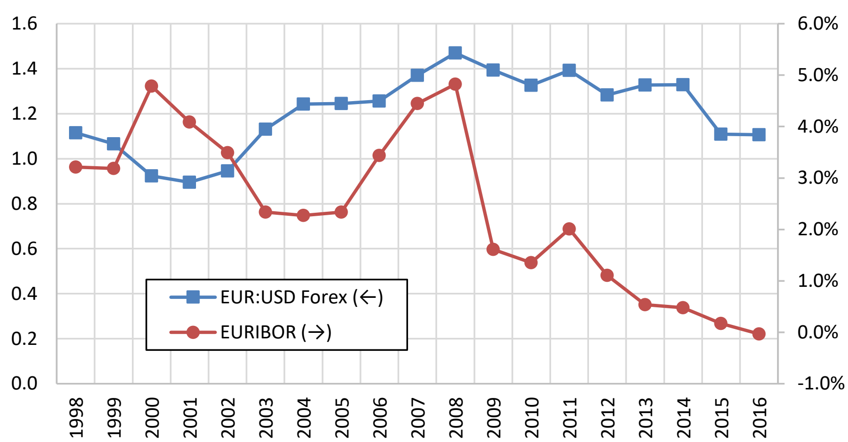

Figure A-1-2: Historical EUR:USD Forex and EURIBOR rates (12-month maturity)[90]

89 (International Monetary Fund, 2017)

90 (Global-rates.com, 2017; Fxtop, 2017)

A-2 International commodity prices

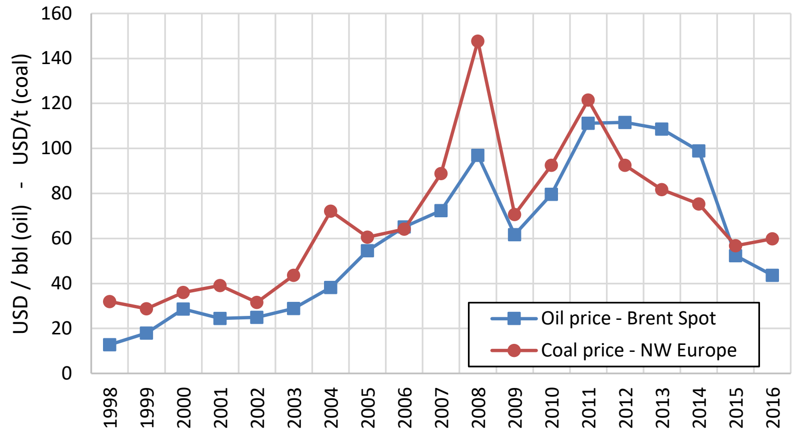

Figure A-2-1: Historical Brent spot oil price and NW Europe coal price[91]

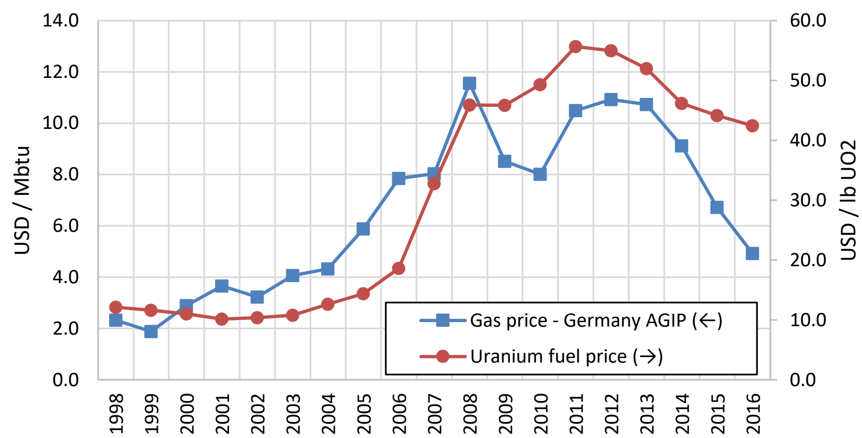

Figure A-2-2: Historical Germany's AGIP natural gas price and international uranium fuel price[92]

[91] (US Energy Information Administration, 2017c; BP, 2017a)

[92] (BP, 2017b; US Energy Information Administration, 2017a)

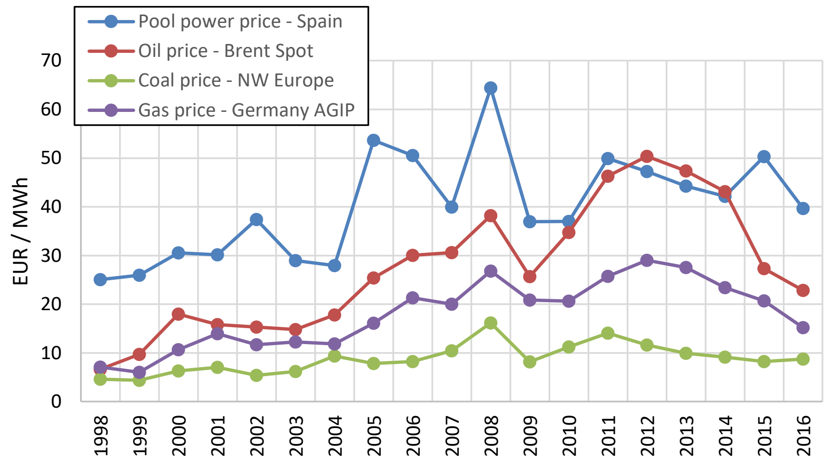

Figure A-2-3: Historical energy commodity prices in EUR/MWh[93]

A-3 Technology characteristics and parameters

POWER PLANT EFFICIENCY BY TECHNOLOGY DATA

This section describes the data gathered on power plant efficiency by technology. For this matter, power generation technologies can be divided in three groups:

- Renewable energy sources: The efficiency has been considered constant equal to one (International Energy Agency, 2014a)
- Nuclear power: The thermal efficiency has been considered constant and equal to 0.33 (International Energy Agency, 2014a)
- Fossil fuel technologies: Historical data has been collected regarding power plant efficiency for each specific technology.

In those cases where there is no info for the whole time period considered (1998 – 2016) the data has been extrapolated based on the trends of the existing data.

Figure A-3-1 through Figure A-3-4 show the efficiency historical data for nuclear, coal, gas peak, gas CC and cogeneration plants in the US (US Energy Information Administration, 2016b) as well as in California (Nyberg, 2014) in specific cases.

[93] (BP, 2017a; BP, 2017b; US Energy Information Administration, 2017c; OMIE, 2017)

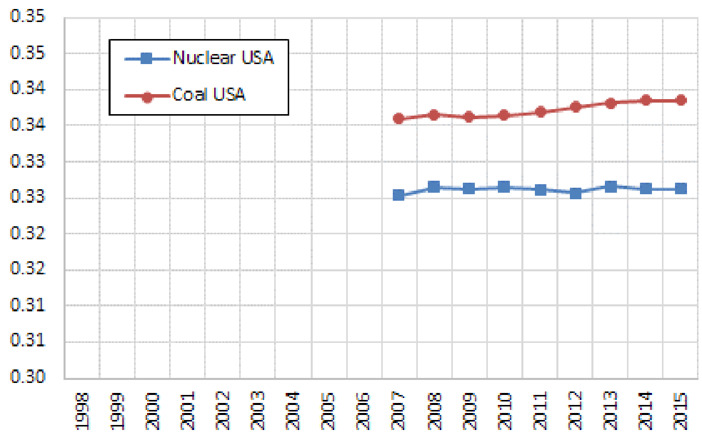

Figure A-3-1: US historical NPP efficiency[94]

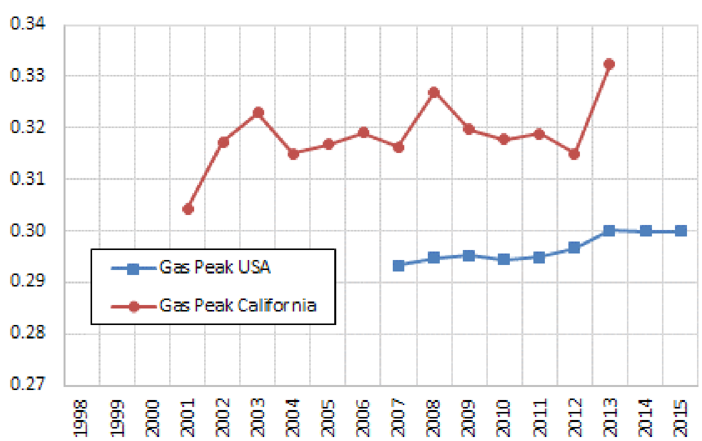

Figure A-3-2: US and California's historical gas peak power plant efficiency[95]

[94] (US Energy Information Administration, 2016b)

[95] (US Energy Information Administration, 2016b; Nyberg, 2014)

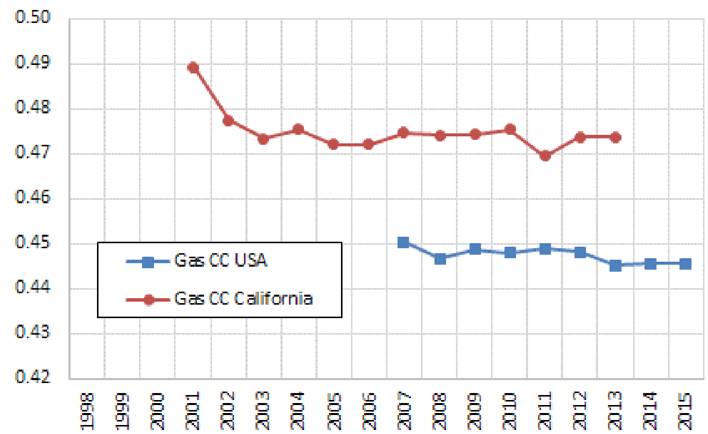

Figure A-3-3: US and California's historical gas peak power plant efficiency[96]

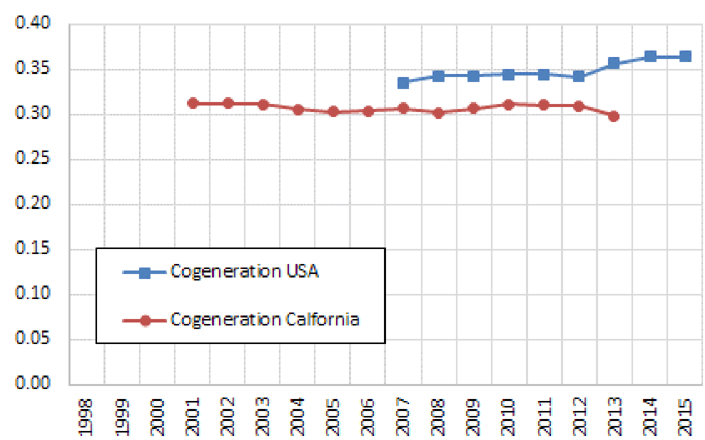

Figure A-3-4: US and California's historical cogeneration plant efficiency[96]

A-4 Generation plant fuel costs

This section describes how the fuel costs for power plants have been computed based on fuel prices and technologies' efficiencies.

[96] (US Energy Information Administration, 2016b; Nyberg, 2014)

In the case of fossil fuel - fired power plants, the fossil fuel prices computed based on the data described in appendix A-2 have been converted from USD/MBtu into EUR/MWh and divided by the standard technology efficiencies computed based on the data described in appendix A-3 as per the next equation:

$$PlantFuelCost\left(\frac{EUR}{MWh}\right)=\frac{FossilFuelPrice\left(\frac{EUR}{MWh-f}\right)}{TechnologyEfficieny\left(\frac{MWh-f}{MWh}\right)} \tag{10.1}$$

In the case of nuclear technology the data included in Table A-4-1 has been used in order to compute the fuel costs per MWh of electricity:

Component	***Quantity***	***Price USD***	***Total USD***	***%***
Uranium	8.9 kg U_3O_8	97	862	46%
Conversion	7.5 kg U	16	120	6%
Enrichment	7.3 SWU	82	599	32%
Fuel fabrication	per kg (approx.)		300	16%
Total			**1,881**	

Table A-4-1: Nuclear fuel price components[97]

In order to obtain the power generation fuel cost, the UO_2 price shown above has been converted to EUR(kg) and the required amount UO_2 has been obtained by using the data in Table A-4-1 according to the formula below (World Nuclear Association, 2017):

$$Nuclear\ fuel\ cost\left(\frac{EUR}{MWh}\right)=\frac{UO2\ price\left(\frac{EUR}{kg\ UO2}\right)\cdot 8.9\left(\frac{kg\ UO2}{kg\ Nuclear\ fuel}\right)}{0.46\left(\frac{\%UO2}{\%\ Fuel}\right)\cdot 360\left(\frac{MWh}{kgNuclear\ fuel}\right)} \tag{10.2}$$

[97] (World Nuclear Association, 2017)

A-5 Capital costs

Figure A-5-1 through Figure A-5-3 show the historical evolution of the capital costs for selected generation technologies. Additional data has been taken from (US Energy Information Administration, 2010), (US Energy Information Administration, 2013), (US Energy Information Administration, 2016a) and (Black & Veatch, 2012).

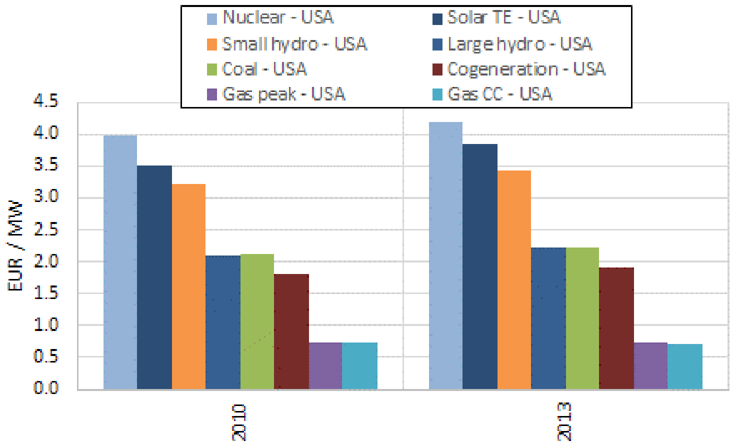

Figure A-5-1: US historical power plant capital costs[98]

Figure A-5-2 shows the evolution of wind power capital cost. Data has been gathered from several sources for different geographic areas. Although there is a significant dispersion in the period 1998- 2002, the series converge after 2002.

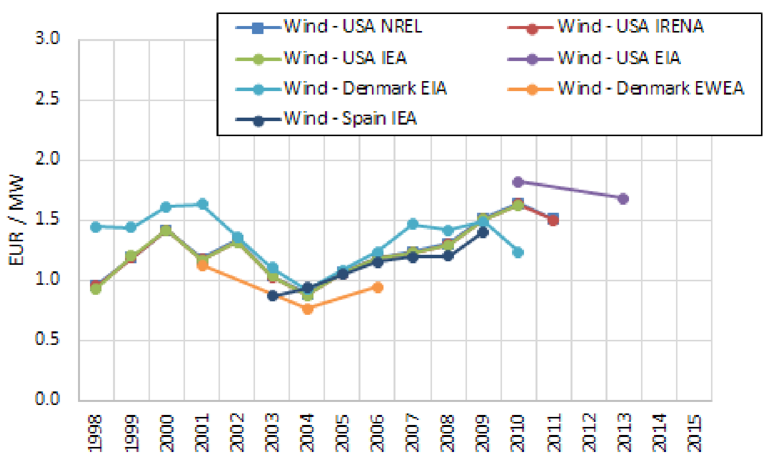

Figure A-5-2: Historical wind power capital costs[99]

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[98] (US Energy Information Administration, 2013)

[99] (Krohn, et al., 2009; Lantz, et al., 2012; Tegen, et al., 2012; US Energy Information Administration, 2013; International Renewable Energy Agency, 2015)

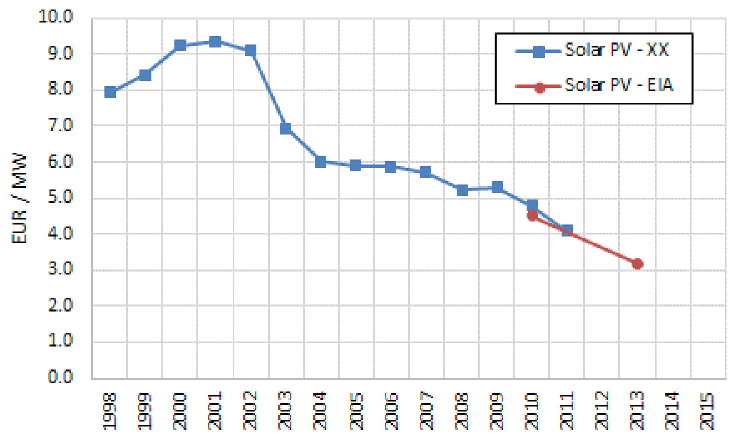

Figure A-5-3: Historical PV power capital costs[100]

A-6 Fixed and non-fuel variable generation costs

This section describes the historical data series collected regarding power generation costs (fixed and non-fuel variable costs) for each technology. Most of the data gathered belongs to power plants located in the US. Data has been adjusted by using the relevant currency exchange and inflation rates.

Fuel costs have already been discussed in appendices A-2, A-3 and A-4 so that, only non-fuel variable costs and fixed costs are described and analyzed in this section.

WIND

The commercial databases from where O&M costs were obtained assume that all operating costs are fixed, in the case of wind power. Therefore, variable costs are null for this technology, as can be observed in Figure A-6-1 and Figure A-6-2, which show the variable O&M costs as a function of the online year and the plant capacity respectively.

[100] (US Energy Information Administration, 2013)

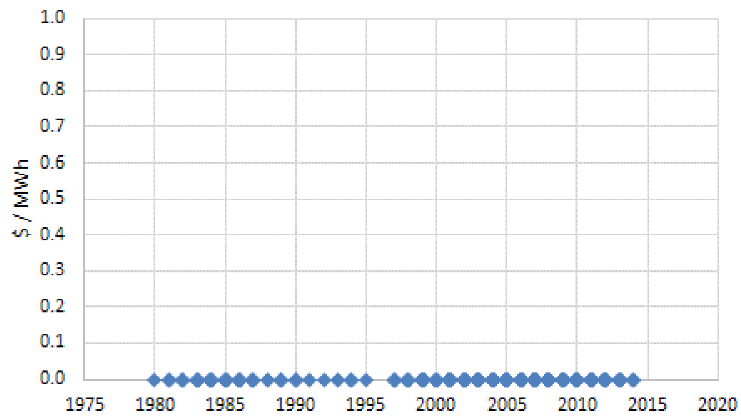

Figure A-6-1: Wind O&M variable costs vs. plant online year[101]

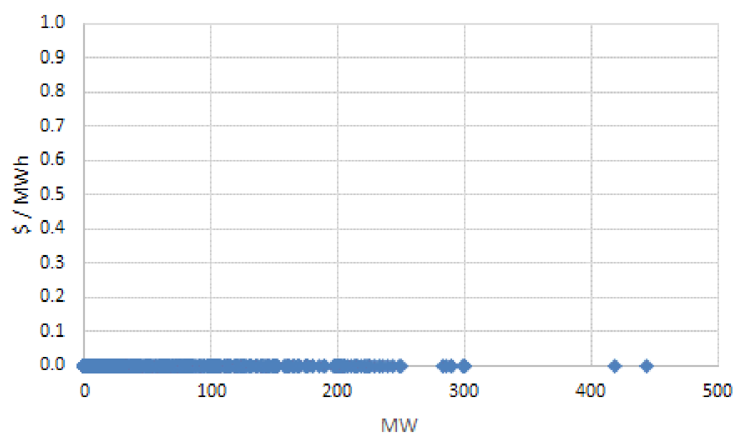

Figure A-6-2: Wind O&M variable costs vs. plant capacity[101]

[101] Prepared by the authors based on diverse commercial databases

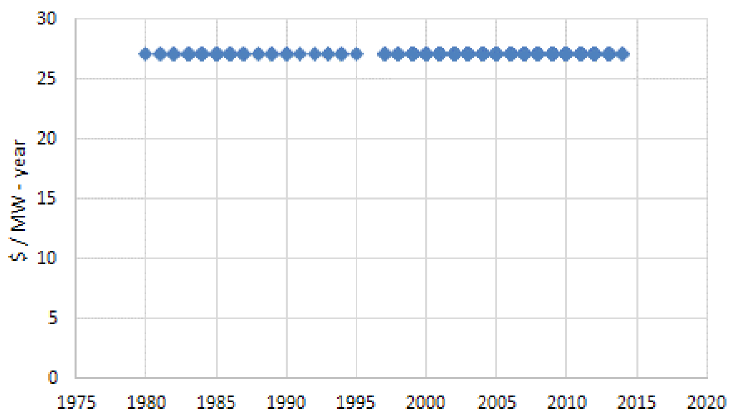

Figure A-6-3: Wind O&M fixed costs vs. plant online year[102]

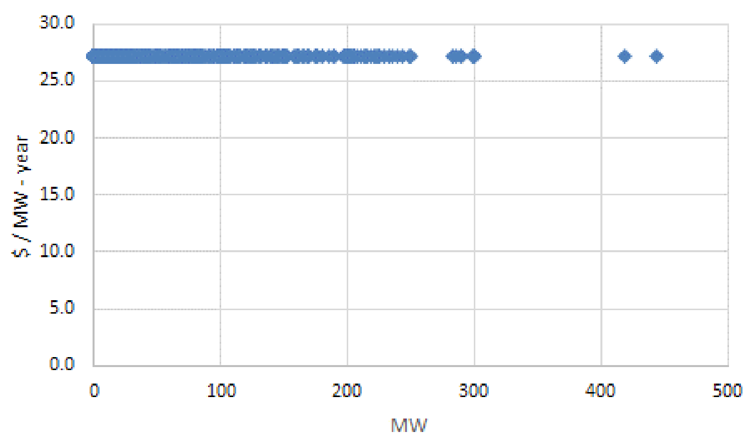

Figure A-6-4: Wind O&M fixed costs vs. plant capacity[102]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	0.00	0.00	0.00	0.00
Fixed O&M $/kW-yr	27.14	27.14	27.14	0.00

Table A-6-1: O&M cost analysis - Wind

[102] Prepared by the authors based on diverse commercial databases

The EUR values taken for the simulations are:

- Variable O&M: 0.00 EUR/MWh
- Fixed O&M: 22,600 EUR/MW - year

SOLAR PV

Figure A-6-5 and Figure A-6-6 show the variable O&M costs as a function of the online year and the plant capacity respectively.

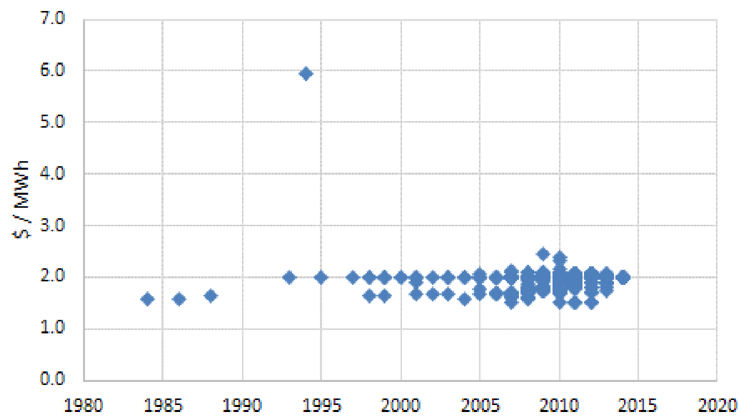

Figure A-6-5: Solar PV O&M variable costs vs. plant online year[103]

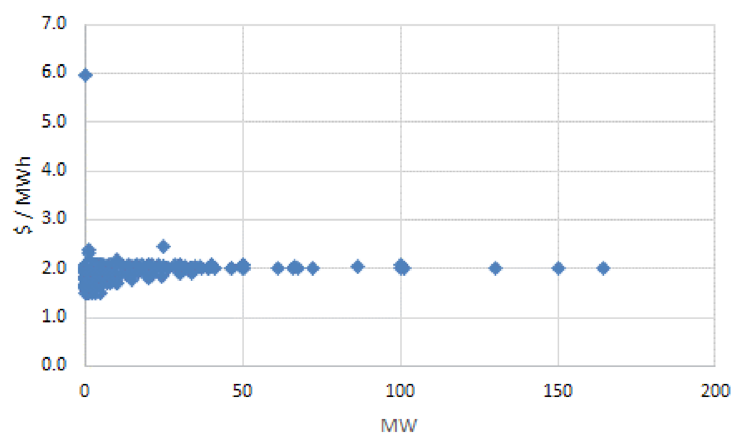

Figure A-6-6: Solar PV O&M variable costs vs. plant capacity[103]

[103] Prepared by the authors based on diverse commercial databases

Figure A-6-7 and Figure A-6-8 show the fixed O & M costs as a function of the online year and the plant's installed capacity respectively.

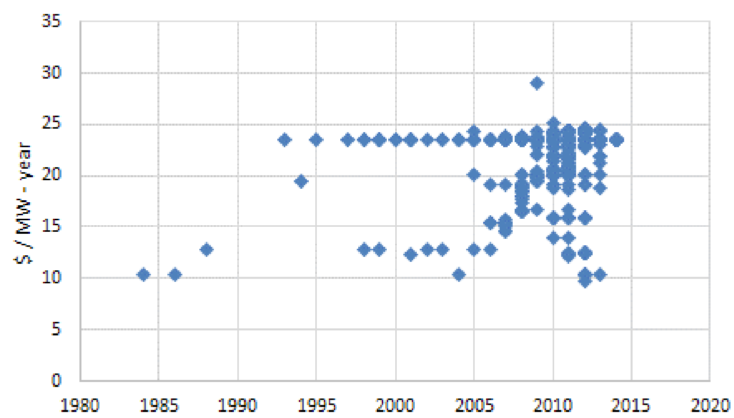

Figure A-6-7: Solar PV O&M fixed costs vs. plant online year[104]

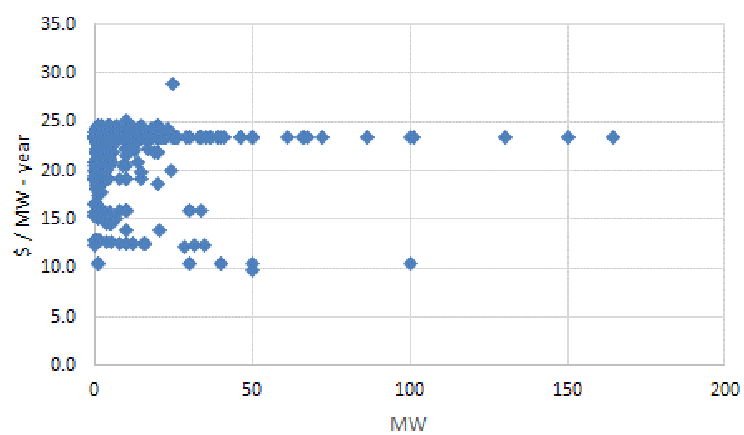

Figure A-6-8: Solar PV O&M fixed costs vs. plant capacity[104]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	5.95	1.99	1.50	0.13
Fixed O&M $/kW-yr	28.95	22.79	9.74	2.23

Table A-6-2: O&M cost analysis – Solar PV

[104] Prepared by the authors based on diverse commercial databases

Solar PV shows quite constant variable O&M costs across both time and plant capacities showing an average value of $1.99 and a standard deviation of 0.13. Regarding the fixed costs, they show larger variability in the case of smaller plants (as expected) as well as in the plants more recently built.

The EUR values taken for the simulations are:

- Variable O&M: 1.65 EUR/MWh
- Fixed O&M: 19,000.00 EUR/MW - year

SMALL HYDRO

Figure A-6-9 and Figure A-6-10 show the variable O&M costs as a function of the online year and the plant installed capacity respectively.

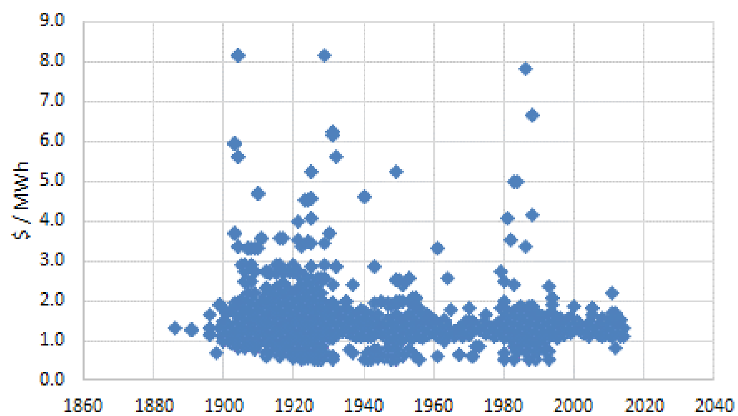

Figure A-6-9: Small hydro O&M variable costs vs. plant online year[105]

[105] Prepared by the authors based on diverse commercial databases

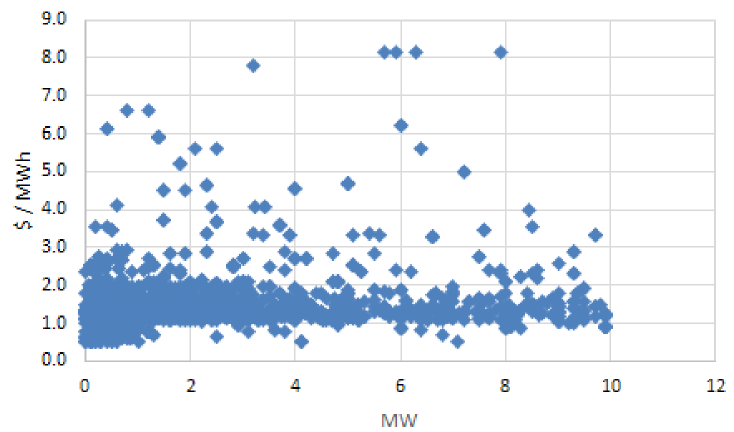

Figure A-6-10: Small hydro O&M variable costs vs. plant capacity[106]

Figure A-6-11 and Figure A-6-12 show the fixed O&M costs as a function of the online year and the plant capacity respectively.

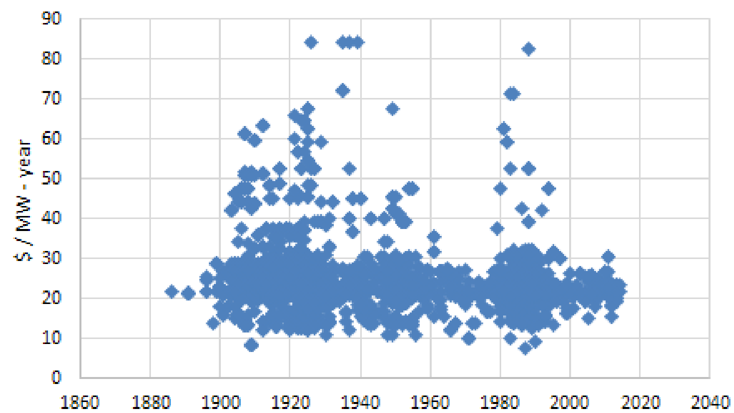

Figure A-6-11: Small hydro O&M fixed costs vs. plant online year[106]

[106] Prepared by the authors based on diverse commercial databases

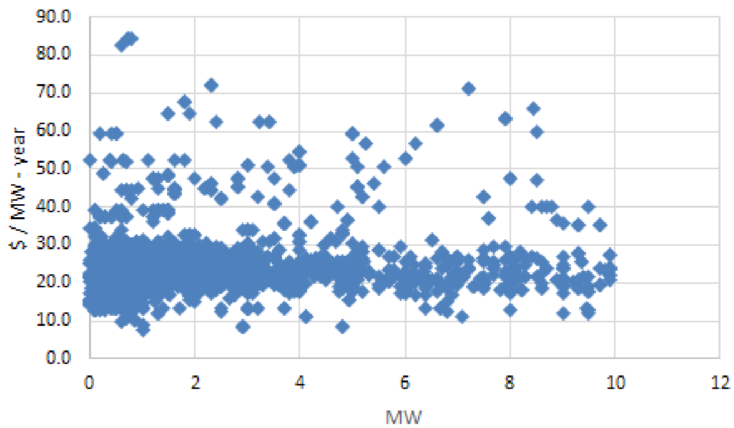

Figure A-6-12: Small hydro O&M fixed costs vs. plant capacity[107]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	8.14	1.44	0.51	0.65
Fixed O&M $/kW-yr	84.22	24.18	7.48	7.93

Table A-6-3: O&M cost analysis – Small Hydro

Small hydro shows a quite constant variable O&M cost trend with most values between 1 and 2 USD/MWh with some outliers mostly on the upper side which entail a significant standard deviation of 0.65 USD/MWh, being the average value 1.44 USD/MWh. Regarding fixed O&M costs, these ones show larger variability in the case of smaller and older plants.

The EUR values taken for the simulations are:

- Variable O&M: 1.20 EUR/MWh
- Fixed O&M: 20,100.00 EUR/MW - year

SOLAR CSP

Figure A-6-13 and Figure A-6-14 show the variable O&M costs as a function of the online year and the plant capacity respectively.

[107] Prepared by the authors based on diverse commercial databases

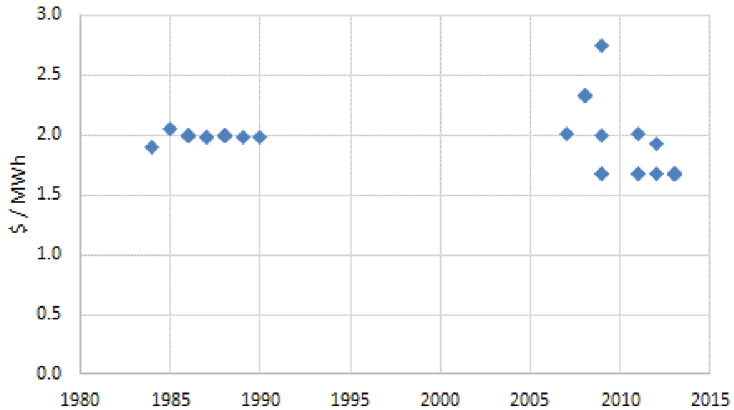

Figure A-6-13: Solar CSP O&M variable costs vs. plant online year[108]

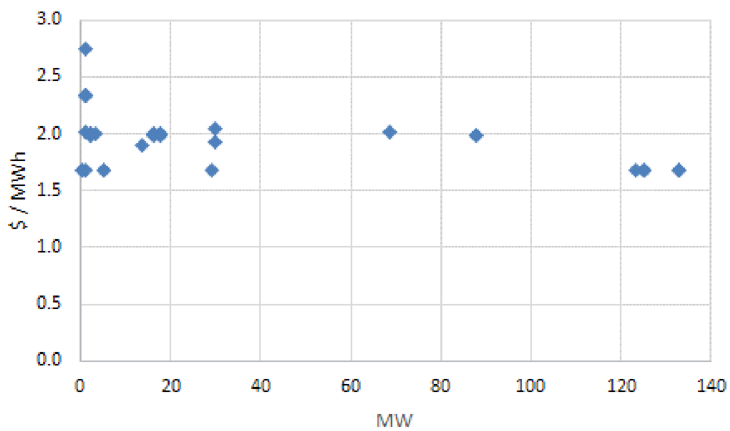

Figure A-6-14: Solar CSP O&M variable costs vs. plant capacity[108]

Figure A-6-15 and Figure A-6-16 show the fixed O&M costs as a function of the online year and the plant capacity respectively.

[108] Prepared by the authors based on diverse commercial databases

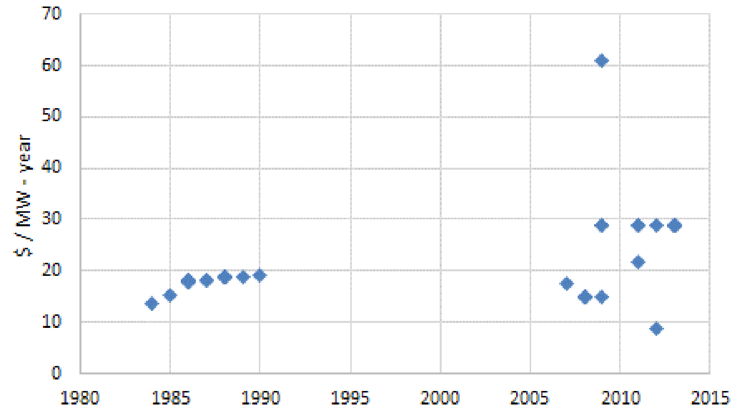

Figure A-6-15: Solar CSP O&M fixed costs vs. plant online year[109]

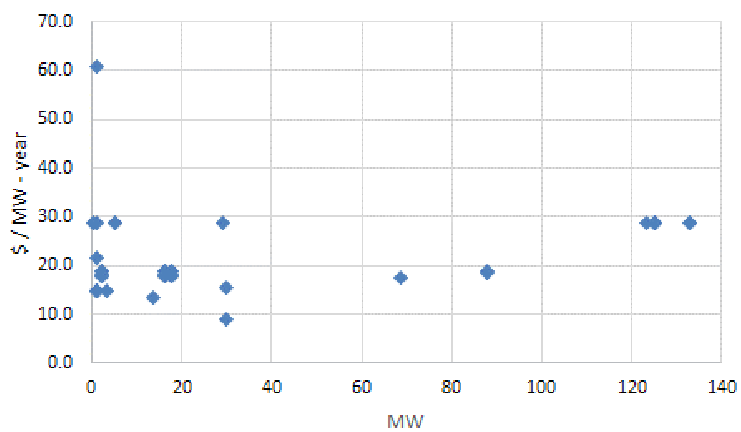

Figure A-6-16: Solar CSP O&M fixed costs vs. plant capacity[109]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	2.75	1.91	1.68	0.23
Fixed O&M $/kW-yr	60.84	25.13	8.83	8.40

Table A-6-4: O&M cost analysis – Solar CSP

[109] Prepared by the authors based on diverse commercial databases

There is not much data available in the case of Solar CSP technology. In the specific case of the US, a few plants were built in the late eighties / early nineties while a new batch of plants has started to become online since 2006. In the case of these newer plants, variable O&M costs oscillate around 2 USD/MWh averaging 1.91 USD/MWh. The dispersion is clearly larger in the case of smaller plants.

Regarding fixed O&M costs, there is a larger dispersion mostly in case of newer and smaller plants as well.

The EUR values taken for the simulations are:

- Variable O&M: 1.60 EUR/MWh
- Fixed O&M: 21,000.00 EUR/MW – year

GAS CC

Figure A-6-17 and Figure A-6-18 show the variable O&M costs as a function of the online year and the plant capacity respectively.

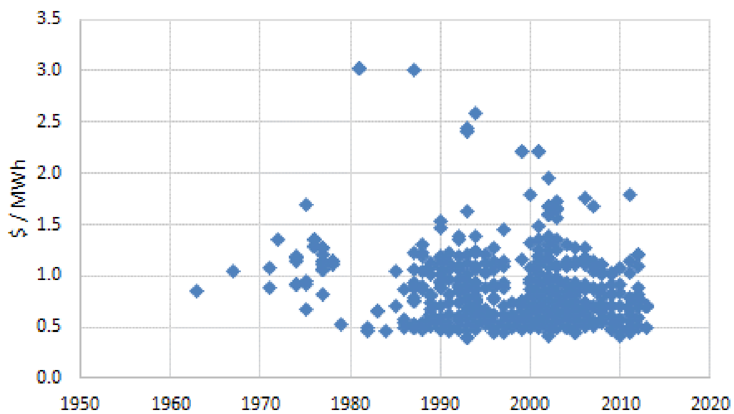

Figure A-6-17: Gas CC O&M variable costs vs. plant online year[110]

[110] Prepared by the authors based on diverse commercial databases

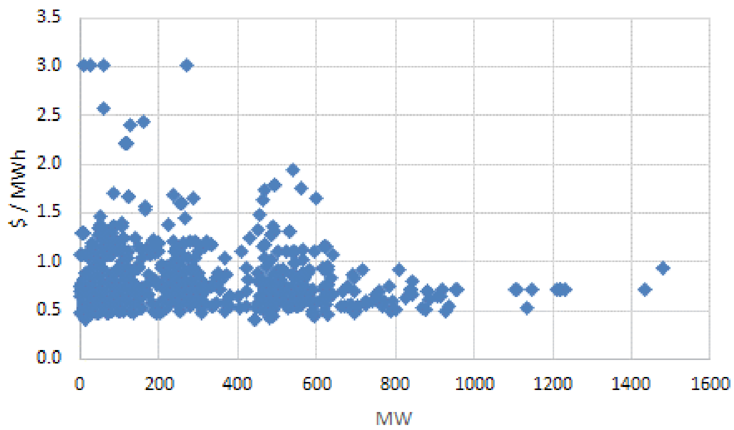

Figure A-6-18: Gas CC O&M variable costs vs. plant capacity[111]

Figure A-6-19 and Figure A-6-20show the fixed O&M costs as a function of the online year and the plant capacity respectively.

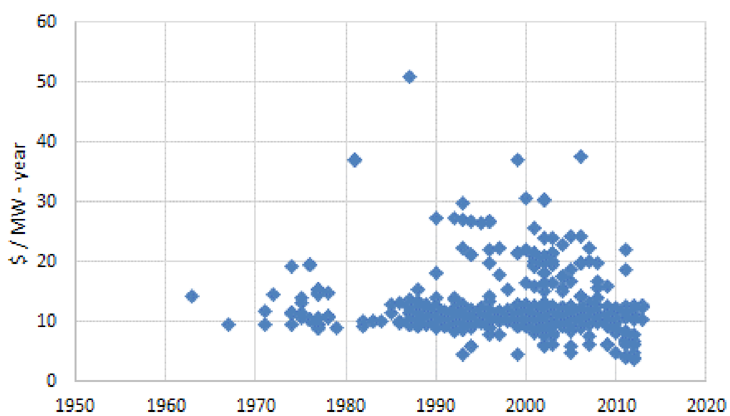

Figure A-6-19: Gas CC O&M fixed costs vs. plant online year[111]

[111] Prepared by the authors based on diverse commercial databases

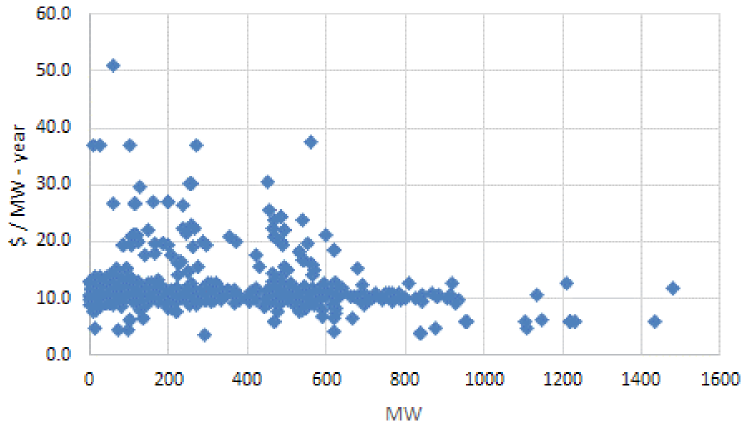

Figure A-6-20: Gas CC O&M fixed costs vs. plant capacity[112]

Variable	Max	Avg	Min	Std. Dev.
Variable O&M $/MWh	3.02	0.83	0.40	0.35
Fixed O&M $/kW-yr	50.99	11.98	3.60	4.61

Table A-6-5: O&M cost analysis – Gas CC

Gas CC technology shows variable costs in the range from 0.5 to 1.5 USD/MWh in most cases, with a significant number of outliers on the upper side. There is no clear trend regard the dispersion as a function of the online date. On the other hand, dispersion and average values are significantly larger in case of smaller plants.

Fixed O&M costs follow exactly the same pattern, with outliers on the upper side, no clear trend pattern regarding dispersion as a function of the online date and larger dispersion in case of smaller plants.

The EUR values taken for the simulations are:

- Variable O&M: 0.70 EUR/MWh
- Fixed O&M: 10,000.00 EUR/MW – year

[112] Prepared by the authors based on diverse commercial databases

GAS PEAK

Figure A-6-21 and Figure A-6-22show the variable O&M costs as a function of the online year and the plant installed capacity respectively.

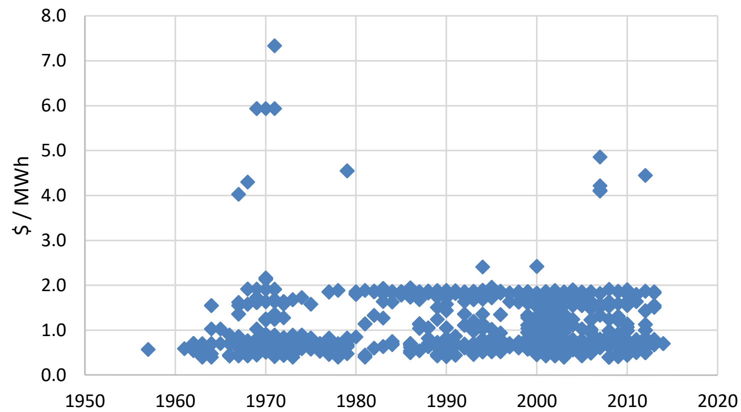

Figure A-6-21: Gas Peak O&M variable costs vs. plant online year[113]

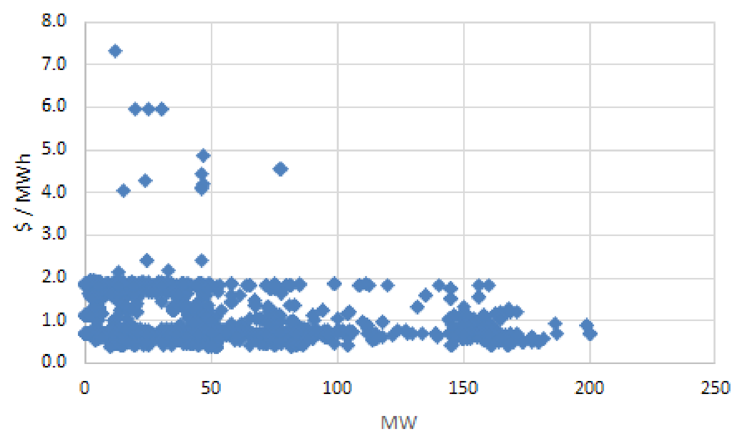

Figure A-6-22: Gas Peak O&M variable costs vs. plant capacity[113]

[113] Prepared by the authors based on diverse commercial databases

Figure A-6-23 and Figure A-6-24show the fixed O&M costs as a function of the online year and the plant capacity respectively.

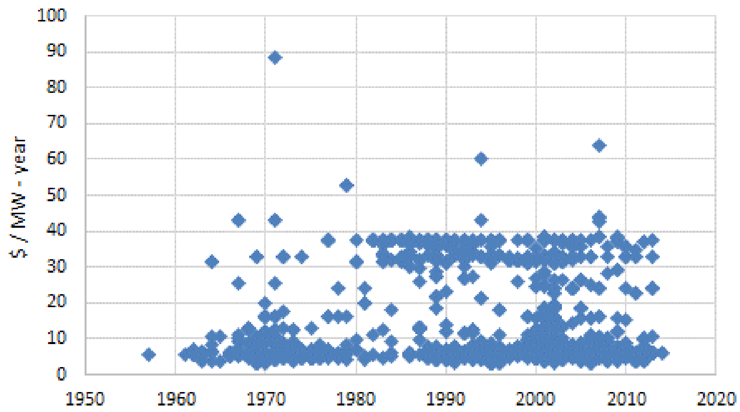

Figure A-6-23: Gas Peak O&M fixed costs vs. plant online[114]

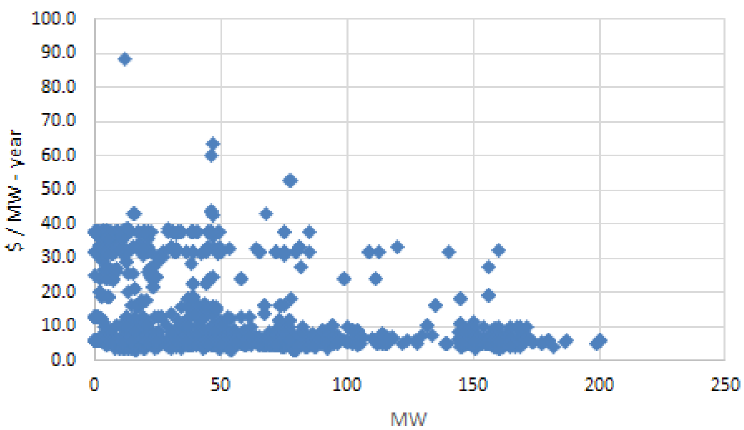

Figure A-6-24: Gas Peak O&M fixed costs vs. plant capacity[114]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	7.34	1.00	0.40	0.57
Fixed O&M $/kW-yr	88.55	11.75	3.18	11.25

Table A-6-6: O&M cost analysis – Gas Peak

[114] Prepared by the authors based on diverse commercial databases

The EUR values taken for the simulations are:

- Variable O&M: 0.84 EUR/MWh
- Fixed O&M: 9,800.00 EUR/MW – year

HYDRO

Figure A-6-25 and Figure A-6-26 show the variable O&M costs as a function of the online year and the plant capacity respectively.

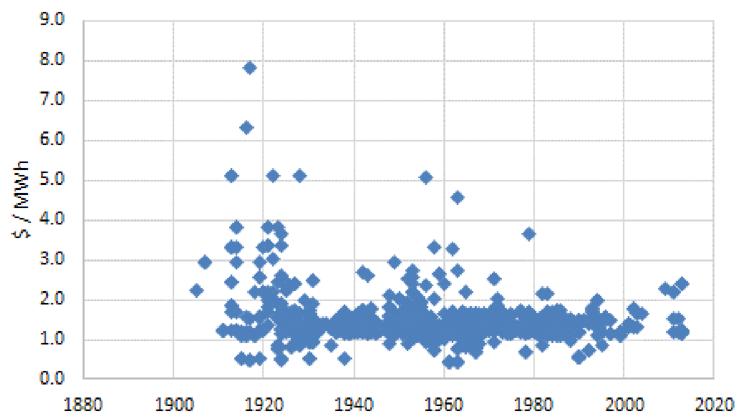

Figure A-6-25: Hydro O&M variable costs vs. plant online year[115]

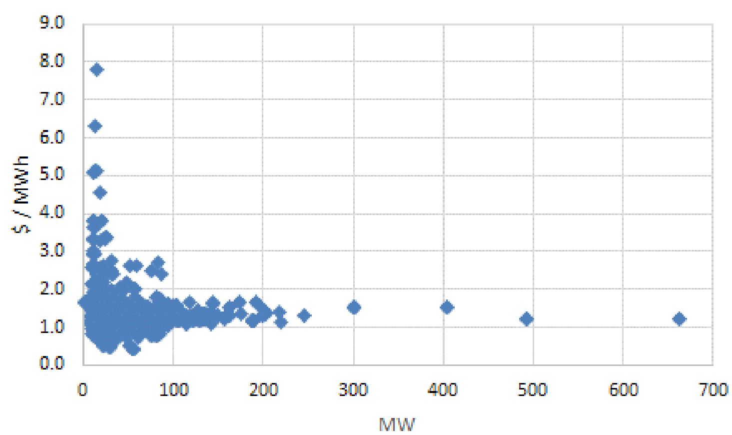

Figure A-6-26: Hydro O&M variable costs vs. plant capacity[115]

[115] Prepared by the authors based on diverse commercial databases

Figure A-6-27 and Figure A-6-28 show the fixed O&M costs as a function of the plant's online year and installed capacity respectively.

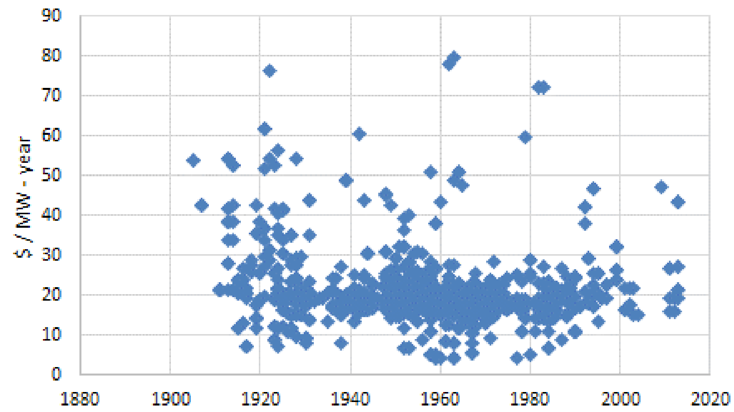

Figure A-6-27: Hydro O&M fixed costs vs. plant online year[116]

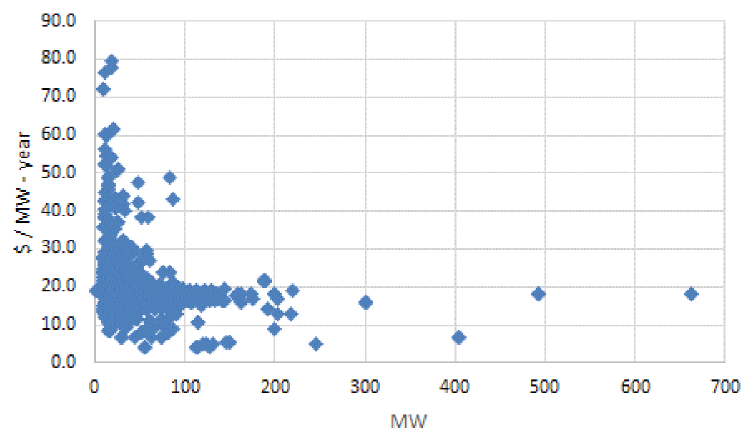

Figure A-6-28: Hydro O&M fixed costs vs. plant capacity[116]

Variable	Max	Avg	Min	Std. Dev.
Variable O&M $/MWh	7.82	1.40	0.43	0.51
Fixed O&M $/kW-yr	79.44	20.07	4.13	7.98

Table A-6-7: O&M cost analysis - Hydro

[116] Prepared by the authors based on diverse commercial databases

Large hydro technology shows variable costs in the range from 1.0 to 2.0 USD/MWh for all plants over 100 MW. In the case of smaller plants, the variability increases and shows a trend of increasing variables costs with lower plant capacities. Regarding the evolution in time, variability declines in the case of newer plants. There are outliers on the upper side in both cases.

Fixed O&M costs follow a very similar pattern, with outliers on the upper side and larger dispersion and larger values in case of smaller plants.

The EUR values taken for the simulations are:

- Variable O&M: 1.16 EUR/MWh
- Fixed O&M: 16,800.00 EUR/MW – year

NUCLEAR

Figure A-6-29 and Figure A-6-30 show the variable O&M costs as a function of the plant's online year and installed capacity respectively.

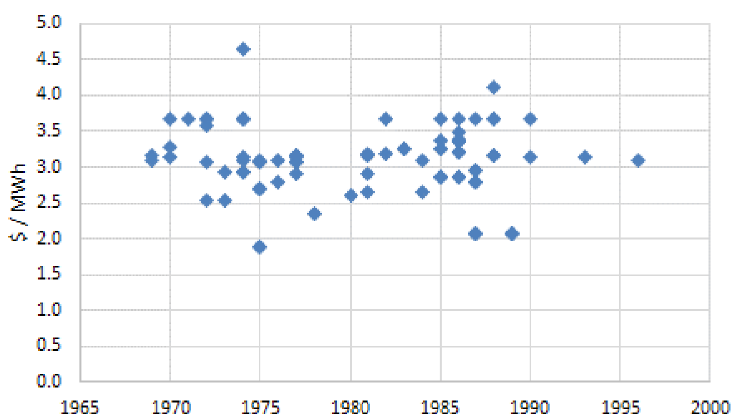

Figure A-6-29: Nuclear O&M variable costs vs. plant online year[117]

[117] Prepared by the authors based on diverse commercial databases

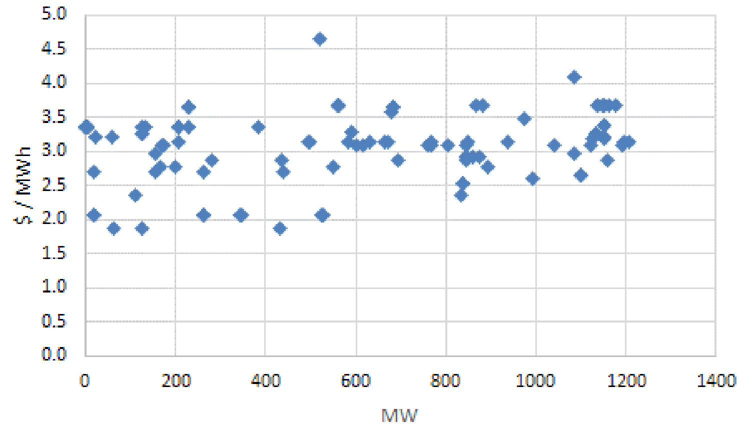

Figure A-6-30: Nuclear O&M variable costs vs. plant capacity[117]

Figure A-6-31 and Figure A-6-32 show the fixed O&M costs as a function of the plant's online year and installed capacity respectively.

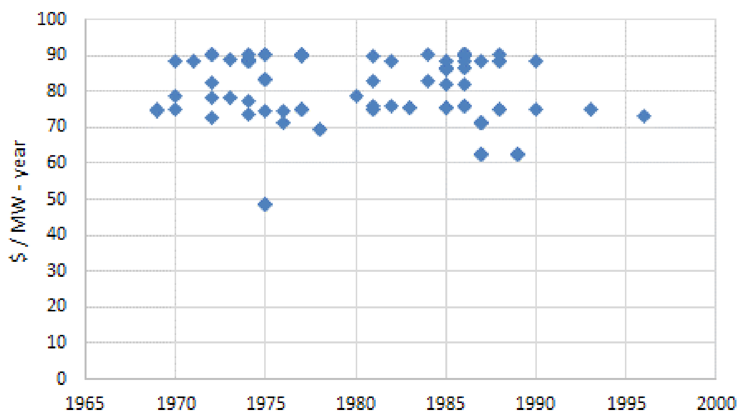

Figure A-6-31: Nuclear O&M fixed costs vs. plant online year[118]

[118] Prepared by the authors based on diverse commercial databases

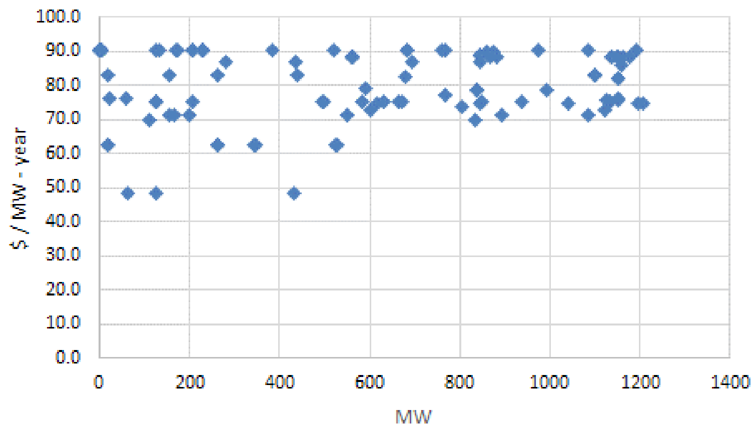

Figure A-6-32: Nuclear O&M fixed costs vs. plant capacity[118]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	4.65	3.08	1.88	0.50
Fixed O&M $/kW-yr	90.43	80.47	48.48	10.18

Table A-6-8: O&M cost analysis - Nuclear

Nuclear technology shows quite constant costs, both fixed and variable, across time and plant capacities. There are no clear cost trends depending on time or plant capacity. The data show a quite large constant variability as well.

The EUR values taken for the simulations are:

- Variable O&M: 2.60 EUR/MWh
- Fixed O&M: 67,000.00 EUR/MW – year

COAL

Figure A-6-33 and Figure A-6-34 show the variable O&M costs as a function of the plant's online year and installed capacity respectively.

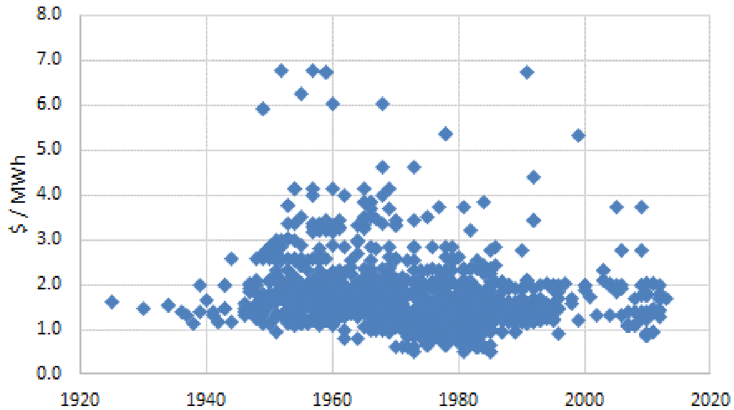

Figure A-6-33: Coal O&M variable costs vs. plant online year[119]

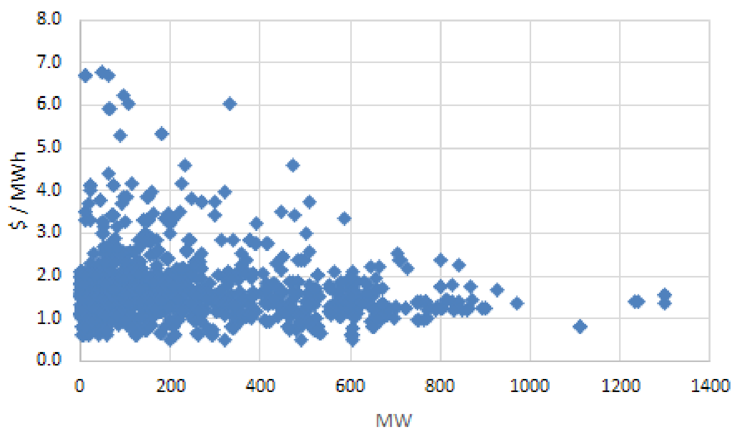

Figure A-6-34: Coal O&M variable costs vs. plant capacity[119]

Figure A-6-35 and Figure A-6-36 show the fixed O&M costs as a function of the plant's online year and installed capacity respectively.

[119] Prepared by the authors based on diverse commercial databases

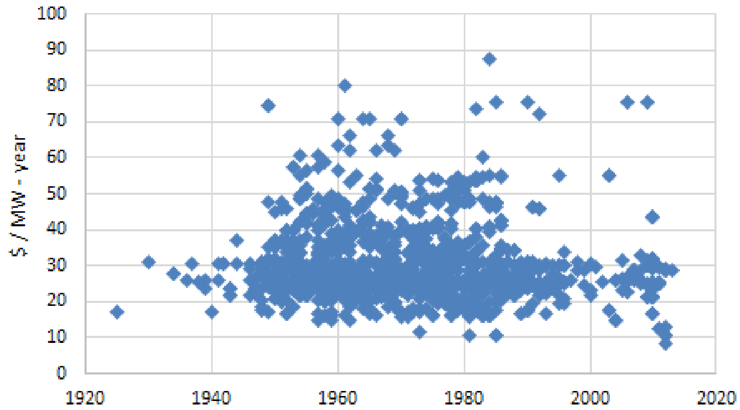

Figure A-6-35: Coal O&M fixed costs vs. plant online year[120]

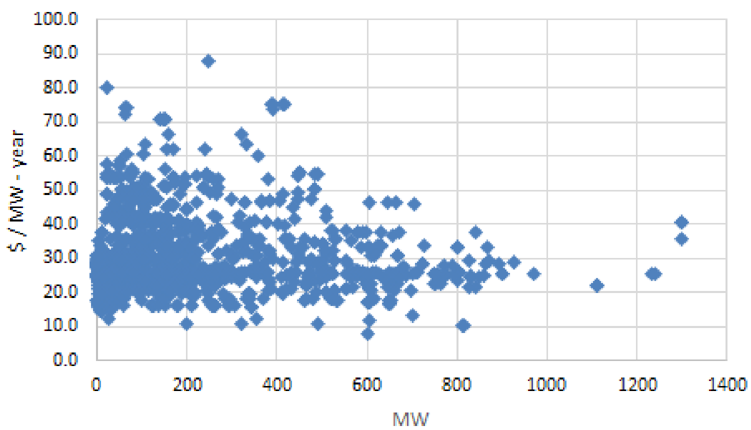

Figure A-6-36: Coal O&M fixed costs vs. plant capacity[120]

Variable	***Max***	***Avg***	***Min***	***Std. Dev.***
Variable O&M $/MWh	6.76	1.70	0.50	0.76
Fixed O&M $/kW-yr	87.71	30.37	8.13	10.64

Table A-6-9: O&M cost analysis - Coal

[120] Prepared by the authors based on diverse commercial databases

Coal shows variable O&M costs comprised between 0.5 and 3.0 USD/MWh in most cases with outliers on the upper side. While there is no clear correlation between variable O&M costs and online date, variable O&M costs become larger and more disperse as the plant capacity declines.

The EUR values taken for the simulations are:

- Variable O&M: 1.41 EUR/MWh
- Fixed O&M: 25,300.00 EUR/MW – year

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