COMILLAS
UNIVERSIDAD PONTIFICIA
ICAI

MASTER’S DEGREE IN INDUSTRIAL ENGINEERING

MASTER’S FINAL THESIS

# Analysis of investment strategies in renewable and storage power plants through a multi-stage simulation market model: Application to the Spanish Nuclear Decommissioning Plan

Author: Luis Sarceda Martínez

Director: Tomás Gómez San Román

Co-Director: Orlando Mauricio Valarezo Rivera

Madrid

July 2025

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Analysis of investment strategies in renewable and storage power plants through a multi-stage simulation market model: Application to the Spanish Nuclear Decommissioning Plan

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# *RESUMEN DEL PROYECTO*

Esta tesis desarrolla un modelo de inversión multietapa para evaluar estrategias de inversión en generación renovable y sistemas de almacenamiento, considerando distintos parámetros como el crecimiento de la demanda, los precios del gas y la tasa de descuento. El modelo proporciona información cuantitativa sobre la nueva capacidad instalada, el calendario de inversiones, los costes operativos y el despacho de energía a lo largo de un horizonte de planificación definido. El análisis se aplica al caso del sistema eléctrico español, comparando dos escenarios que difieren en la continuidad o el desmantelamiento de la capacidad nuclear existente. Los resultados permiten comprender los compromisos económicos y técnicos asociados a cada estrategia, aportando evidencia útil para la toma de decisiones en planificación energética.

Palabras clave: PNIEC, multietapa, modelo inversión, desnuclearización, renovables, almacenamiento

## 1. Introducción

La Unión Europea (UE) ha establecido un marco regulador sólido con el objetivo de alcanzar sus metas climáticas. El Pacto Verde Europeo fija objetivos vinculantes para la reducción de emisiones y la integración de energías renovables [1]. A nivel nacional, España ha transpuesto este marco a su normativa mediante el *Plan Nacional Integrado de Energía y Clima* (PNIEC) 2021–2030. Este documento estratégico define una hoja de ruta para alcanzar una participación del 74 % de energías renovables en la generación eléctrica para el año 2030, junto con el despliegue de tecnologías de almacenamiento, el desarrollo de la gestión de la demanda y la retirada progresiva de activos de generación con alta intensidad de carbono. El PNIEC actúa tanto como directriz política como punto de referencia para los inversores que operan en el mercado eléctrico español [2].

## 2. Definición del proyecto

Esta tesis desarrolla y aplica un modelo de simulación del mercado multietapa para analizar estrategias de inversión en plantas de generación renovable y sistemas de almacenamiento. El modelo considera la naturaleza secuencial e incierta de las decisiones de inversión, lo que permite evaluar los resultados a largo plazo bajo distintos escenarios regulatorios y de mercado. A través de este enfoque, se pretende obtener información cuantitativa sobre cómo interactúan el diseño de políticas, los mecanismos de mercado y el comportamiento de los inversores en la configuración del *mix* energético futuro, con un enfoque particular en el sistema eléctrico español bajo el marco del PNIEC.

## 3. Definición del modelo

El modelo de inversión optimiza las inversiones a realizar en distintas etapas dentro de un horizonte de planificación, con el objetivo de minimizar el coste total del sistema (inversiones y operación) conforme evoluciona la demanda. El modelo está diseñado para realizar inversiones en generación renovable (eólica y solar fotovoltaica) y almacenamiento (hidroeléctrico de bombeo y baterías).

En cada etapa, el modelo ejecuta un despacho económico basado en la capacidad instalada existente y la nueva capacidad incorporada, actualizando así la potencia disponible para la siguiente etapa. Este proceso iterativo determina los megavatios de capacidad a instalar en cada periodo.

Se consideran dos escenarios base: P-0 (desmantelamiento nuclear) y N-0 (mantenimiento de la capacidad nuclear). El horizonte de planificación abarca desde 2025 hasta 2040, con etapas de inversión definidas en los años 2025, 2030 y 2035. Para una mayor comprensión, se lleva a cabo un análisis de sensibilidad. El modelo se implementa en Python utilizando Gurobi mediante modelado matricial.

## 4. Resultados

La comparación entre ambos escenarios en términos de nueva capacidad instalada y costes totales permite obtener una visión clara del impacto que tiene la energía nuclear en la planificación a largo plazo. Comenzando por la nueva potencia instalada:

| Etapa | Tecnología | P-0 [MW] | N-0 [MW] |
|---|---|---|---|
| **Etapa 0 - 2025** | Eólica | 3.110 | 3.357 |
| | Solar FV | 7.903 | 7.579 |
| | Bombeo | 6.829 | 6.494 |
| | **Total** | **17.842** | **17.430** |
| **Etapa 1 - 2030** | Eólica | 27.892 | 20.831 |
| | Solar FV | 33.651 | 25.024 |
| | Bombeo | 11.112 | 7.886 |
| | **Total** | **72.654** | **53.741** |
| **Etapa 2 - 2035** | Eólica | 22.649 | 18.231 |
| | Solar FV | 51.591 | 28.345 |
| | Bombeo | 21.051 | 14.885 |
| | **Total** | **95.291** | **61.461** |

Table 1: Casos Base - Nueva Potencia Instalada

A lo largo de todo el horizonte de planificación, la nueva potencia total instalada en el escenario P-0 alcanza los 185.787 MW, mientras que en el escenario N-0 se requieren únicamente 132.632 MW. Esto representa una reducción del 30 % en la nueva potencia instalada, es decir, aproximadamente 53 GW, lo que resalta la influencia significativa que tiene la generación nuclear sobre el dimensionamiento del sistema y las necesidades de inversión.

Al analizar los costes, se observa que, debido a la menor necesidad de nueva potencia instalada en el escenario N-0, los costes de inversión se reducen de forma considerable (aproximadamente 9 mil M€). No obstante, dado que se instala menos capacidad renovable y de almacenamiento, los costes operativos en el escenario N-0 son más elevados, lo que reduce la diferencia total entre escenarios a 6 mil M€.

Al comparar los escenarios con los objetivos de capacidad instalada para 2030 propuestos en el PNIEC, se observa que el escenario P-0 prácticamente alcanza los valores planificados, mientras que en el escenario N-0 se instalan 20 GW menos de capacidad.

<table>
<tr><th></th><th>Tecnología</th><th>PNIEC - [GW]</th><th>P-0 (2030) - [GW]</th><th>N-0 (2030) - [GW]</th></tr>
<tr><td rowspan="4">Generadores</td><td>Nuclear</td><td>3,1</td><td>3,1</td><td>7,1</td></tr>
<tr><td>Solar FV</td><td>76</td><td>75,2</td><td>66,2</td></tr>
<tr><td>Eólica</td><td>62</td><td>63,3</td><td>54,4</td></tr>
<tr><td>Térmica</td><td>26,25</td><td>25,0</td><td>25,0</td></tr>
<tr><td rowspan="2">Alma cen</td><td>Bombeo</td><td rowspan="2">22,5</td><td>23,9</td><td>20,4</td></tr>
<tr><td>Baterías</td><td>0,05</td><td>0,05</td></tr>
</table>

Tabla 2: Comparativa Objetivos PNIEC

## 5. Conclusiones

- Mantener la capacidad nuclear representa una reducción en los costes totales del sistema (6 mil millones de euros) y en los requerimientos de nueva capacidad instalada (renovable y almacenamiento) (53 GW).
- La energía nuclear desempeña un papel clave en la transición energética, ya que permite fijar objetivos menos exigentes para la instalación de renovables y sistemas de almacenamiento.
- El crecimiento de la demanda es un factor clave a la hora de fijar objetivos en los Planes Nacionales de Energía y Clima. Es por ello por lo que, es más adecuado fijar objetivos de instalación de renovables y almacenamiento ligados al crecimiento de la demanda, en lugar de fijarlos en términos absolutos, como lo hace el PNIEC con los fijados para el año 2030.

## 6. Referencias


[1] "The European Green Deal." Accedido el 29 de abril de 2025. Disponible en: https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF

[2] Ministerio para la Transición Ecológica y el Reto Demográfico (MITECO), Plan Nacional Integrado de Energía y Clima (2023–2030), Madrid, septiembre de 2024.

[3] J. M. Ginel, T. G. S. Román, y O. M. V. Rivera, "An investment model for renewable power resources in the context of a fully decarbonized system."

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# *ABSTRACT*

This thesis develops a multi-stage investment model to evaluate investment strategies in renewable generation and storage systems, considering different parameters such as demand growth, gas prices and discount rate. The model provides quantitative information on new installed capacity, investment schedule, operating costs and energy dispatch over a defined planning horizon. The analysis is applied to the Spanish electricity system, comparing two scenarios that differ in the continuation or decommissioning of existing nuclear capacity. The results help to understand the economic and technical trade-offs associated with each strategy, providing useful evidence for decision making in energy planning.Keywords: PNIEC, multiyear, investment model, nuclear decommissioning, renewables, storage

## 1. Introduction

The European Union (EU) has established a robust regulatory framework aimed at achieving this task. The European Green Deal sets binding targets for emissions reduction, and renewable energy integration [1]. At a national level, Spain has transposed this framework into its own regulation through the *Plan Nacional Integrado de Energía y Clima* (PNIEC) 2021–2030. This strategic document defines a roadmap to achieve a 74% share of renewables in electricity generation by 2030, alongside the deployment of storage technologies, the development of demand-side management, and the gradual retirement of carbon-intensive generation assets. The PNIEC serves as both a policy outline and a reference point for investors navigating the Spanish electricity market [2].

## 2. Project Definition

This thesis develops and applies a multi-stage simulation market model to analyse investment strategies in renewable and storage power plants. The model captures the sequential and uncertain nature of investment decisions, allowing for the evaluation of long-term outcomes under varying regulatory and market scenarios. Through this approach, the research aims to provide quantitative insights into how policy design, market mechanisms, and investor behaviour interact in shaping the future energy mix, with a specific focus on the Spanish electricity system under the PNIEC framework.

## 3. Model definition

The investment model optimizes the allocation of investments across multiple stages within a planning horizon, aiming to minimize total system costs (investment and operational) as demand evolves. The model its designed to invest in renewable generation (wind and solar PV) and energy storage (pumped hydro and batteries).

At each stage, the model performs economic dispatch based on, the existing and newly added capacity, updating the installed capacity for the next stage. This iterative process determines the megawatts of capacity to be added at each step.

Two base scenarios are considered: P-0 (nuclear decommissioning) and N-0 (nuclear capacity retained). The planning horizon spans from 2025–2040, with investment stages defined in 2025, 2030, and 2035. For a deeper understanding a sensitivity analysis is conducted. The model is implemented in Python using Gurobi with matrix-based modelling.

## 4. Results

Comparing both scenarios in terms of new installed capacities and total costs, allows for a clear view of the impact on nuclear when planning for the long run. Starting with the new installed capacities:

| Stage | Technology | P-0 [MW] | N-0 [MW] |
|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 3.357 |
| | Solar PV | 7.903 | 7.579 |
| | Hydro Pump | 6.829 | 6.494 |
| | **Total** | **17.842** | **17.430** |
| **Stage 1 - 2030** | Wind | 27.892 | 20.831 |
| | Solar PV | 33.651 | 25.024 |
| | Hydro Pump | 11.112 | 7.886 |
| | **Total** | **72.654** | **53.741** |
| **Stage 2 - 2035** | Wind | 22.649 | 18.231 |
| | Solar PV | 51.591 | 28.345 |
| | Hydro Pump | 21.051 | 14.885 |
| | **Total** | **95.291** | **61.461** |

Table 1: Base Scenarios Installed Capacities

Over the entire planning horizon, the total new installed capacity in the P-0 scenario reaches **185,787 MW**, whereas the N-0 scenario requires only **132,632 MW**. This represents an overall **30% reduction** in newly installed capacity (renewables + storage), or roughly **53 GW**, further emphasizing the substantial influence that nuclear generation has on system sizing and investment needs.

When analysing the costs it can be observed that given the reduction in new installed capacity (in N-0) the investment costs are significantly reduced (approximately 9 billion €). Nevertheless, since less renewable and storage is installed the operational cost for N-0 are higher which brings down the difference between scenarios to **6 billion €.**

When comparing the scenarios to the installed capacity targets for 2030 proposed in the PNIEC, it can be observed that for P-0 the targets are almost the same as the ones prospected but for the N-0 scenarios 20 GW less are installed.

<table>
<tr><th></th><th>Technology</th><th>PNIEC - [GW]</th><th>P-0 (2030) - [GW]</th><th>N-0 (2030) - [GW]</th></tr>
<tr><td rowspan="4">Generators</td><td>Nuclear</td><td>3,1</td><td>3,1</td><td>7,1</td></tr>
<tr><td>Solar PV</td><td>76</td><td>75,2</td><td>66,2</td></tr>
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<tr><td>Batteries</td><td>0,05</td><td>0,05</td></tr>
</table>

Table 2: Base Scenarios Installed Capacities

## 5. Conclusions

- Maintaining nuclear capacity represents a reduction in total costs (6 billion €) and in total new installed capacity requirements in renewables and storage (53 GW).
- Nuclear power plays a key role when addressing the energy transition as it allows for more flexible and less aggressive targets for renewables and storage.
- Demand growth is a key factor when setting targets in National Energy and Climate Plans. For this reason, it is more appropriate to set targets for renewables installation and storage linked to demand growth, rather than setting them in absolute terms, as the PNIEC does with those set for the year 2030

## 6. References

[1] "The European Green Deal." Accessed: Apr. 29, 2025. Available : https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF

[2] Ministerio para la Transición Ecológica y el Reto Demográfico (MITECO), "Plan Nacional Integrado de Energía y Clima (2023-2030)," Ministerio para la Transición Ecológica y el Reto Demográfico (MITECO), Madrid, Sep. 2024.

[3] J. M. Ginel, T. G. S. Román, and O. M. V. Rivera, "An investment model for renewable power resources in the context of a fully decarbonized system".

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# CHAPTER 1: INTRODUCTION

## 1.1. INTRODUCTION

Climate change has become one of the main drivers when it comes to decision and policy making worldwide. A key part of dealing with this problem lies in decarbonizing society, more precisely, decarbonizing the energy sector.

Electrical generation has been historically dependent on fossil fuels, but as renewable technologies increase their penetration in the grid, as well as demand rises, there is a need for a complete transformation. This transformation is not only environmentally imperative but also technologically and economically complex, requiring careful coordination of investment, regulation, and market operation.

The European Union (EU) has established a robust regulatory framework aimed at achieving this task. The European Green Deal sets binding targets for emissions reduction, and renewable energy integration [1]. At a national level, Spain has transposed this framework into its own regulation through the *Plan Nacional Integrado de Energía y Clima* (PNIEC) 2021–2030. This strategic document defines a roadmap to achieve a 74% share of renewables in electricity generation by 2030, alongside the deployment of storage technologies, the development of demand-side management, and the gradual retirement of carbon-intensive generation assets. The PNIEC serves as both a policy outline and a reference point for investors navigating the Spanish electricity market [2].

Within this context, the planning and evaluation of investment strategies in renewable and storage technologies presents significant analytical and engineering challenges. These include dealing with uncertainty in market conditions, policy evolution, technology costs, and the operational behaviour of the power system under high renewable penetration.

To address these complexities, this thesis develops and applies a multi-stage simulation market model to analyze investment strategies in renewable and storage power plants. The model captures the sequential and uncertain nature of investment decisions, allowing for the evaluation of long-term outcomes under varying regulatory and market scenarios. Through this approach, the research aims to provide quantitative insights into how policy design, market mechanisms, and investor behaviour interact in shaping the future energy mix, with a specific focus on the Spanish electricity system under the PNIEC framework.

## *1.2. MOTIVATION*

Spain has set ambitious targets for renewable energy integration and storage deployment in order to undergo the energy transition. Additionally, the Spanish administration has pushed for the decommissioning of the nuclear park, which aggravates even more the need to ensure system reliability and cost-efficiency in the face of retiring baseload capacity and renewable intermittency.

In this context, there is an increasing need for analytical tools that can capture the dynamic and uncertain nature of long-term energy investment.

This thesis is motivated by the desire to contribute to the strategic planning of Spain's energy future by providing a quantitative tool to evaluate investment pathways under complex, evolving conditions. By focusing on the Spanish case, and particularly on the implications of nuclear decommissioning within the PNIEC framework, this work aims to support informed decision-making for policymakers, investors, and system planners working toward a more sustainable and resilient energy system. In Annex I, a more in-depth explanation of the thesis alignment with the SDGs can be found.

## 1.3. OBJECTIVES

- To develop a comprehensive analytical model capable of evaluating long-term energy investment strategies under different policy and economic scenarios.
- To conduct a quantitative assessment of the investment objectives established in Spain's PNIEC, with a focus on renewable generation and storage technologies.
- To quantify the economic and technical implications of nuclear decommissioning on system cost and investment planning.

# CHAPTER 2: STATE OF THE ART OF GENERATION PLANNING

The aim of this chapter is to provide an overview of the key concepts upon which this thesis is built. A clear understanding of these concepts is essential for grasping the overall framework and methodological approach of the investigation.

## *2.1. PLAN NACIONAL INTEGRADO DE ENERGÍA Y CLIMA (PNIEC)*

The commitment made under the Paris Agreement, as adopted by the European Union (EU), outlines a comprehensive strategy to address the climate crisis through decarbonization and the pursuit of climate neutrality by 2050. To operationalize this objective, the EU established binding interim targets for 2030 that must be met by all member states. These include:

- A 40% reduction in greenhouse gas (GHG) emissions relative to 1990 levels.
- A 32% share of renewable energy in total final energy consumption.
- A 32.5% improvement in energy efficiency.

In compliance with these EU mandates, each member state is required to develop a national policy framework to guide the energy transition. Spain has responded with the Plan Nacional Integrado de Energía y Clima (PNIEC), which outlines its strategic goals for the 2021–2030 period [2]. This integrated plan encompasses objectives related to renewable deployment, emissions reduction, and system efficiency, tailored to the national context. In Figure 1, the updated the goals (2023-2030) set out in the PNIEC are shown:

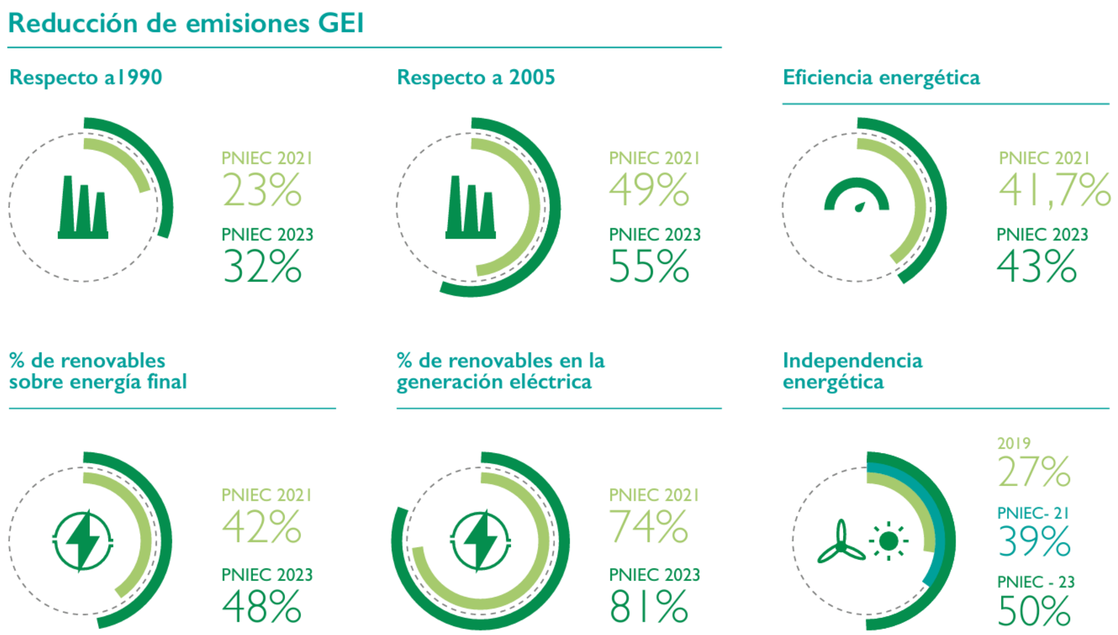


Figure 1: PNIEC 2030 Objectives [2]

Regarding GHG emissions, it is important to note that approximately 75% of Spain's total GHG emissions are linked to the energy sector, underscoring the urgency of decarbonizing power generation. Although Spain's projected 32% emissions reduction is slightly below the EU target, it demonstrates progress in the right direction. Furthermore, the country's expected improvement in energy efficiency surpasses the EU's baseline requirement.

In terms of renewable integration, Spain aims to achieve 81% renewable electricity generation and 48% renewable energy across total consumption by 2030. To realize this ambition, the PNIEC outlines a deployment plan involving approximately 160 GW of new installed capacity (including generation and storage), requiring an estimated 113 billion € in investment. Of this total, 80% is expected to come from the private sector, while 20% will be financed by public funding (5% from the Spanish government and 15% from EU support mechanisms).

In addition to increasing renewable energy capacity, the PNIEC also includes the decommissioning of Spain's nuclear power park. Currently, Spain operates five nuclear power plants with a combined capacity of 7.1 GW, most of which were commissioned during the 1980s and originally designed with a 40-year lifespan. Some plants have received authorizations to extend operation up to 60 years, and discussions have emerged around the possibility of extending operation further to 80 years, provided adequate safety measures are implemented.

However, the Spanish government has firmly committed to a nuclear phase-out, with an official closure schedule defined in the *Séptimo Plan General de Residuos Radiactivos (PGRR)* and incorporated into the PNIEC (*Annex A5.5*). According to this plan, the final operating plant, Trillo, is scheduled to shut down in 2035. The issue of nuclear decommissioning has become increasingly prominent in political and public discourse, sparking debate over energy security, sustainability, and investment priorities.

Even with the planned retirement of nuclear capacity, the PNIEC anticipates a 31% average reduction in marginal generation costs by 2030. However, these savings are dependent on the correct deployment of the investment.

Lastly, the projections and analyses the PNIEC are supported by advanced simulation tools, most notably the TIMES-Sinergia model and the TEPES (Technical-Economic Production and Expansion Simulation) model. However, it is important to note that these models operate within a broader analytical scope than the one addressed in this thesis as they incorporate a wider view of inputs and analyses [2].

## 2.2. ECONOMIC ENERGY DISPATCH

The Spanish electricity market is a complex mechanism with multiple stakeholders involved. The market operates under transparency and freedom of competition principles, where prices are determined hourly through a marginal pricing mechanism, when the intersection of generation and demand sets the clearing price. In order to model this market, lineal optimization models are typically used, where continuous and binary variables are used to represent the different technical and operation constraints upon the market works.

### 2.2.1. STRUCTURE OF SPANISH ELECTRICITY MARKET

As mentioned, the market involves several stakeholders, here are the main ones:

- ***Generators:*** Enterprises in charge of producing the electricity and submitting the generation offers.
- ***Suppliers/Marketers:*** These agents are the ones that buy the electricity from the market and resell them to their final clients.
- ***Market Operator:*** The market operator manages daily operations, determines the hourly clearing price, and oversees all market transactions. In Spain, this role is fulfilled by the *Operador del Mercado Ibérico de la Energía* (OMIE).
- ***Transport System Operator (TSO):*** The TSO oversees the physical operation of the electrical grid, including real-time monitoring and ensuring system stability within defined technical constraints. This function is performed by *Red Eléctrica de España* (REE).
- ***National Regulatory Authority:*** This body ensures that all deals and transactions comply with the best practices associated to sustainability. This role is performed by the *Comisión Nacional de los Mercado y la Competencia* (CNMC).

As for how the market operates on a daily basis. The market operates primarily through a day-ahead auction mechanism. Generators submit their hourly offers indicating the price at which they are willing to sell, while suppliers submit bids representing their willingness to purchase. These bids are cleared using the *EUPHEMIA* algorithm, which is used across the Iberian Electricity Market (*MIBEL*) and harmonized with the rest of Europe, [3].

The resulting price is set by the marginal unit, that is, the most expensive generating unit required to meet the final increment of demand for that hour. All accepted bids, regardless of their individual offer price, receive this market-clearing price for the energy they dispatch.

Additionally, an intraday market operates on the day of delivery, allowing market participants to adjust their positions in real time to accommodate deviations from the day-ahead forecast or sudden changes in system conditions.

Lastly, the system also includes ancillary services such as balancing mechanisms, reserve capacity markets, and frequency regulation services, which enhance the flexibility and reliability of the electricity system, [4], [5].

### 2.2.2. DISPATCH MODELS

Dispatch models are based around two principal components: an economic optimization layer and a technical feasibility layer. From an economic standpoint, accurate forecasting of market bids is essential to ensure profitability and competitiveness. However, the technical dimension introduces significantly greater complexity.

A comprehensive technical dispatch model must consider three hierarchical levels. First, it must determine which generation units will be activated to meet demand. Second, it must enforce fixed technical constraints related to voltage and frequency regulation in the network nodes. Lastly, it must account for a range of variable operational constraints, including ramp rates, minimum up/down times, and reserve requirements.

Due to the inherent complexity of these models, the time horizon is often limited to short-term planning periods (typically day-ahead or intra-day).[6]

Two common modelling approaches are used in practice:

- **Unitary Operator Model (UOM):** This integrated approach solves both economic dispatch and technical feasibility within a single optimization.
- **Optimal Market–Optimal System (OM–OS) Model:** This sequential approach first solves the economic dispatch problem to obtain market-clearing results and then applies technical constraints in a second stage to adjust the solution accordingly.

The Spanish model is based on the OM-OS model as it first solves for the economic problem and afterwards adjusts the results to the technical constraints, [7] .

## 2.3. MULTI-YEAR INVESTMENT MODELS

The design of a national energy system must account for a variety of dynamic factors, including evolving regulatory frameworks and projected economic and electrical demand growth. These and other elements introduce significant levels of uncertainty and risk, requiring the development of flexible modelling tools capable of adapting to changing conditions while providing reliable strategies for resource optimization, regulatory integration, and temporal planning.

A long-term perspective on system development is commonly represented using dynamic multi-stage linear optimization models. Each descriptor in this model type reflects a specific aspect of the investment planning problem.

Dynamic models facilitate the analysis of temporally dependent decisions, where the outcomes of prior actions influence future states across the modelled time horizon. This temporal dependency is essential for capturing the cumulative impact of investment strategies over time.

Linear optimization is typically employed due to the largely linear nature of the constraints that govern the operation of electrical systems, such as power balance, generation limits, and network constraints.

The multi-stage aspect refers to the decomposition of the planning horizon into several decision points. This approach is often adopted to manage the computational complexity inherent in long-term planning, as it allows the model to handle a substantial number of variables more efficiently by breaking the problem into smaller, sequential subproblems.

An additional consideration when formulating these models is whether to adopt a deterministic or stochastic framework. Stochastic models are particularly valuable for incorporating uncertainty and risk. However, this increased realism comes at the cost of significantly greater computational requirements.

This thesis is built as a continuation on the work of Jaime Masjuan Ginel, who developed an investment model for renewable energy resources in his study titled *"An Investment Model for Renewable Power Resources in the Context of a Fully Decarbonized System* [8]. His model focused on identifying the optimal investment strategy under a static, single-stage framework. However, in order to evaluate the long-term strategic implications of Spain's National Integrated Energy and Climate Plan (PNIEC), it is necessary to extend the existing model to a multi-stage framework. This extension enables the analysis of investment decisions over time, incorporating the dynamic effects of future developments. It also requires the integration of temporal variables and the time value of money, both of which are essential for capturing the intertemporal trade-offs inherent in long-term energy planning.

# CHAPTER 3: MULTI-YEAR GENERATION-STORAGE INVESTMENT MODEL

## 3.1. METHODOLOGY

The investment model is designed to determine the optimal allocation of investments across multiple stages, within a defined planning horizon. Its main objective is to minimize total system costs (comprising both investment and operational expenses) as demand evolves over the horizon. The model allows investments in renewable generation technologies, specifically wind and solar photovoltaic (PV), as well as in energy storage systems, more precisely, pumped hydro and battery storage.

The optimization process begins with the definition of the number of decision stages and the duration of each period between them. Once these temporal parameters are set, the model performs an economic dispatch for each stage, taking into account both the existing installed capacity and the additional capacity required to achieve a cost-optimal configuration. The investments made in each stage are added to the installed capacity, thereby determining the initial capacity for the subsequent stage. This iterative process directly yields the amount of capacity, in megawatts, that should be installed at each stage of the planning horizon.

In addition to investment decisions, the model also provides insights into the evolution of operational costs and the extent of renewable energy curtailment across the planning horizon.

To facilitate understanding of the model's structure, the key assumptions upon which it is based are first presented. This is followed by an explanation of the input and economic parameters, and the mathematical formulation that underpins the optimization framework.

### 3.1.1. ASSUMPTIONS

The assumptions incorporated in the model serve to simplify the real-world behaviour of what is inherently a complex energy planning problem. This simplification is intentional, as the primary aim of this thesis is to provide a high-level perspective on the cost-optimal configuration of Spain's generation pool.

The model is developed under the following assumptions:

- **Perfect Information**: The model assumes full knowledge of all relevant variables across the planning horizon, including future demand, costs, and technology performance.
- **Technology Scope**: The system includes four generation technologies: wind, solar PV, thermal generation, and nuclear and two storage technologies: pumped hydro and lithium-ion batteries.
- **Instantaneous Generation Response**: All synchronous generation technologies are assumed to respond instantly to changes in demand. This implies there are no ramping constraints, and generators can be started up or shut down without delay.
- **$CO_2$ Pricing**: Carbon dioxide taxes are incorporated into the effective gas price, reflecting environmental externalities associated with thermal generation.
- **Nuclear Tax Exclusion**: Taxes or fees specific to nuclear power are not considered in the cost analysis.
- **Nuclear Life Extension Cost**: The costs required to extend the nuclear generators life its not considered.
- **No Interconnection Modelling**: Cross-border interconnections are not included in the model; the system is treated as isolated.

- **Construction Times Ignored**: The model does not account for the construction times of new generation or storage facilities, assuming instantaneous deployment upon investment.

- **2025 Investment**: The first stage is set in 2025 and the investment proposed for that year is assumed to be possible even though this study is taking place in the same year.

- **Constant Costs**: All the costs remain the same along the planning horizon. They are just discounted to present value by the discount factor.

These assumptions are adopted to ensure computational tractability and to maintain a focus on identifying long-term optimal investment trends rather than capturing short-term operational dynamics.

### 3.1.2. INPUT PARAMETERS

#### <u>Demand</u>

Electrical demand can be defined as *"the rate at which energy is delivered to loads and scheduling points by generation, transmission, and distribution systems."* [9]. This rate is dynamic and influenced by a wide range of interrelated factors that can be broadly categorized into natural, political, and economic factors.

**Natural factors** include time of day, season, and weather conditions, all of which impact daily and seasonal consumption patterns, such as increased demand during hot or cold weather due to heating and cooling needs.

**Political and social influences** such as regulatory policies, industrial activity, work schedules, and public holidays can also cause significant shifts in demand.

**Economic factors**, including fuel prices (especially natural gas), technological development, and investment in energy infrastructure, further shape demand trends by influencing both consumption behavior and generation choices.

A comprehensive understanding of demand thus requires consideration of these multiple, interconnected drivers. In order to determine the optimal planification of the generation system an in-depth analysis is required.

The most recent update of the PNIEC sets the projected **electricity demand for 2030 at 358 TWh**, representing a 34% increase from 2019 demand. This significant growth is based on the process of societal electrification. Key contributors include the electrification of industrial processes, the transition of climate control systems to electric alternatives and the increasing adoption of electric vehicles. Additionally, emerging factors such as the rising role of hydrogen as an energy vector and the growing energy demand from data centers. [2]

Once the annual demand is defined, the next step is to obtain a representative hourly load profile for a full year. The selected year should reflect normal operating conditions, excluding any extraordinary events or anomalies that could distort typical consumption patterns.

## Generators

As previously mentioned, the generation mix is represented by four distinct technologies: two renewable sources (solar PV and wind power), nuclear energy, and combined cycle gas turbines (CCGT). Due to the intermittent nature of renewable sources, their generation profiles are predefined based on historical data. Nuclear power is modeled as a baseload technology, assumed to be continuously operating but within a defined minimum and maximum output range. Combined cycle gas turbines, on the other hand, are dispatched in fixed output blocks, maintaining a constant generation level over each hourly period.

### *Renewable Generators*

Starting with renewable technologies, both photovoltaic (PV) and wind are considered mature and well-developed, which contributes to their relatively low investment costs. However, their main drawback lies in their inherent intermittency, which poses challenges for grid stability and reliability.

In the model, each technology is defined by a specified number of generators and the initial installed capacity (in MW) for each generator. Once this is established, the generation profiles are assigned. The selection of these profiles follows the same criteria used for defining the demand profile. To better capture average behaviour and enhance realism, multiple historical profiles may be aggregated to construct a composite profile that reflects an average generation scenario.

### *Nuclear*

Nuclear energy plays a critical role in power system dispatch, primarily due to its function as a baseload generation source. In Spain, nuclear power accounts for approximately 20% of total electricity production, despite representing only around 5% of total installed capacity. This disproportionate contribution underscores its importance in ensuring system reliability and stability.

Analogous to the approach used for renewable generators, the number of generating units and the initial installed capacity (in MW) are specified. However, in this case, since the operating profile is assumed to be constant over time, it is only necessary to define the lower and upper operational power limits for each generator. Another important parameter is the decommissioning rate applied to nuclear generators.

### *Combined Cycles*

Thermal generators continue to play a critical role in grid operation due to their high flexibility and rapid response capabilities, which are essential for maintaining stability amidst variable renewable generation. Despite growing concerns over $CO_2$ emissions, thermal technologies remain relevant, particularly when integrated into hybrid systems alongside renewables.

In the model, thermal generation is defined by specifying the number of generators, their capacity, and operational power limits, following a structure similar to that used for nuclear generators.

### *Energy Not Supplied (ENS)*

The term Energy Not Supplied (ENS) refers to the amount of electricity demand that remains unmet under certain conditions, typically due to economic constraints within the system. ENS occurs when the cost of meeting additional demand exceeds the system's willingness to pay, and it becomes more economical, within the model's logic, to curtail the demand and accept the associated penalty cost.

In other words, when the balance between supply and demand cannot be maintained due to limited generation or storage availability, the model allows for demand to remain unmet, resulting in a very high cost. This cost reflects the severe economic and social implications of not delivering electricity and serves as a disincentive for curtailing demand under normal conditions.

Within the model, ENS is implemented through the power balance constraint and is assigned a high penalty cost to accurately represent the critical importance of meeting demand and to minimize the occurrence of unmet energy requirements.

## Storage

Energy storage investment is closely linked to the deployment of renewable energy, as it plays a crucial role in managing the variability and intermittency of renewable generation. By storing excess energy (particularly during midday hours when solar production peaks) storage systems help mitigate the so-called "duck curve" effect, increasing the availability of energy during non-generation hours, especially in the evening.

In addition to shifting energy availability, storage systems contribute to peak shaving, reducing the strain on the grid during periods of highest demand. They also enhance grid stability by providing ancillary services such as frequency regulation and reserve capacity, making them an essential component of a reliable and flexible energy system.

## *Hydro Pump*

Pumped hydro storage operates using two reservoirs at different elevations, generating electricity by releasing water from the upper to the lower reservoir during high demand periods. When there is surplus energy, water is pumped back to the upper reservoir, storing energy as potential energy. This closed-cycle system requires relatively little water and remains one of the most efficient large-scale energy storage.[10]

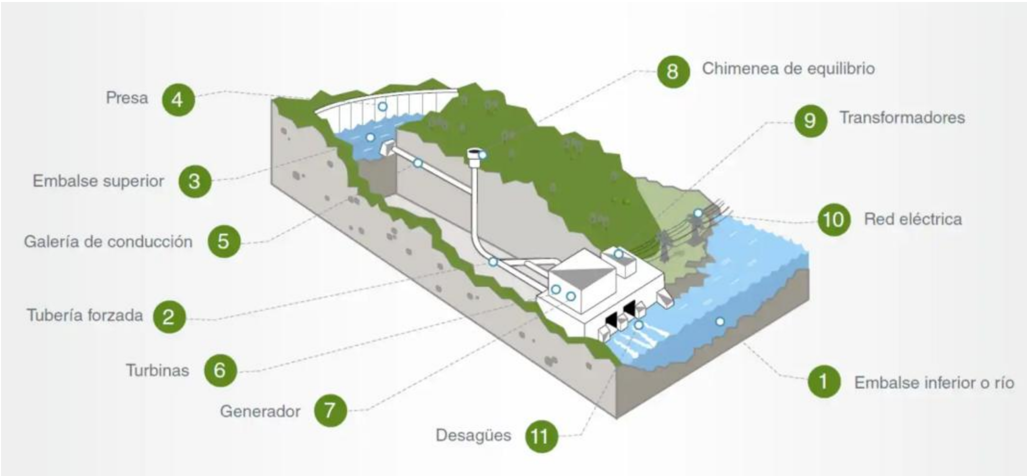


Figure 2:Hydro Pump Storage Schematic [11]

The configuration described is referred to as pure pumped hydro. A variant of this system, known as mixed pumped hydro, allows turbines to also harness the natural flow of a river in addition to the reversible pumping cycle.

## *Lithium Batteries*

Although there are several chemical compositions available for battery storage technologies, lithium-ion batteries have been selected for modelling purposes. This choice is justified by the fact that lithium-ion technology is currently receiving substantial investment and research attention. It is not only the most common storage solution paired with solar PV generation, but it is also widely used in other sectors, such as electric mobility, further reinforcing its relevance and scalability.

Battery storage is expected to experience significant growth in the coming years, not only at the utility scale, but also among residential and small-scale users.[11] However, the technology is still in an early stage of deployment in Spain. According to data from REE, only 50 MW of battery storage capacity is currently installed at the national level.[12]

For both storage technologies, the initial installed power (in MW) and the equivalent storage hours are defined. These two parameters determine the input/output power and the maximum energy storage capacity of each system. An additional key parameter is the round-trip efficiency, which reflects the percentage of energy losses after a full-discharge cycle.

### 3.1.3. ECONOMICAL PARAMETERS

Once the operation of the generators and storage is defined, as any economic dispatch and investment model, costs need to be clearly established.

## Operational Costs

The model distinguishes three main categories of operational costs:

- **Variable Costs:** These are proportional to the amount of energy dispatched and are expressed in €/MWh. They primarily represent operation and maintenance (O&M) expenses.
- **Fixed Costs:** Applied to the installed capacity of each technology, these costs are incurred periodically per installed MW and cover maintenance and related service expenses, regardless of energy output [€/MW].
- **Startup and Shutdown Costs:** These costs (in €) apply exclusively to thermal generators and are introduced to capture the economic impact of changing the operational status (on/off) of these units.

Operational costs are modelled as the discounted sum of the dispatched energy along the period between investment decisions,

## Investment Costs

Given that the model operates over a multi-stage planning horizon, investment costs are modeled using annualized capital expenditures (CAPEX), expressed as annuities per megawatt of installed capacity. This approach enables a consistent comparison of technologies with different lifespans and investment profiles by converting upfront capital costs into equivalent annual payments over the asset's lifetime.

The annuity for each technology is calculated using the standard annuity formula:

$$\boldsymbol{annuity} = \frac{\boldsymbol{CAPEX * r}}{\boldsymbol{1 - (1 + r)^{-n}}} \tag{1}$$

**Annuity:** the constant annual payment over the asset's lifespan [€ /MW-yr]

**CAPEX:** the total investment per MW at present value [€ /MW]

**r**: discount rate [%]

**n**: expected lifespan of technology [years]

## Discount Factor

The time value of money is a decisive factor in shaping the results of the model, as it directly influences the optimal timing and magnitude of investments and operational decisions. To account for this, both investment and operational costs are discounted over time using a discount rate of 7%. However, the treatment of these two cost components differs in accordance with their nature and timing.

Operational costs are assumed to remain constant over the duration of each decision stage. Therefore, the result of the dispatch in a given stage is replicated along a period. Then those cost are discounted to present value and aggregated. This assumes that the dispatch pattern is representative of all years within that stage's interval.

To simplify this calculation, a discount factor for operational costs, denoted as $DF_{OP}[s]$, is defined as follows:

$$\boldsymbol{DF_{OP}[s]} = \sum_{y=s*p}^{s*p+p} \frac{\mathbf{1}}{(\mathbf{1}+\boldsymbol{r})^{y}} \quad \textbf{(2)}$$

$\boldsymbol{DF_{OP}[s]}$**:** operational discount factor for each stage.

**s:** stage

**p:** length of the period

**r:** discount rate [%]

In contrast, investment costs are treated by aggregating all future annuity payments starting from the year in which the investment occurs. If the planning horizon is shorter than the technology's lifespan, only the annuities falling within the horizon are included. A separate investment discount factor, denoted as $DF_{INV}[s]$ is introduced to capture the present value of these future payments:

$$\boldsymbol{DF_{INV}[s]} = \sum_{y=s*p}^{PH} \frac{\mathbf{1}}{(\mathbf{1}+\boldsymbol{r})^{y}} \quad \textbf{(3)}$$

$\boldsymbol{DF_{INV}[s]}$: investment factor for each stage.

**s:** stage

**p:** length of the period

**PH:** planning horizon

**r:** discount rate [%]

## 3.2. MATHEMATICAL FORMULATION

Lastly, to clearly determine how the model operates, the equations are presented as follows. First the objective function is explained and afterward all of the constraints that affect the definition of the problem. All the terms used in every equation are defined at the Annex IV.

### 3.2.1. OBJECTIVE FUNCTION

The objective function is the central equation that characterizes the optimization model. It defines the overall goal of the system, guiding decision-making across all stages of the planning horizon. In this case, the primary objective is to determine the optimal composition of the generation and storage mix through staged investments in renewable and storage technologies, with the aim of minimizing total system costs.

To achieve this, the objective function is formulated to minimize the sum of operational and investment costs across all technologies and all stages. Both cost components are discounted to present value using the appropriate discount factors, as previously defined. This structure ensures that the model considers not only the total magnitude of costs but also their timing, in alignment with the time value of money.

$$
\begin{aligned}
\min \sum_{s=0}^{NS-1} \sum_{t=0}^{NT-1} \Bigg( DF_{OP}[s] \\
&* \Bigg( \sum_{g=1}^{NG_w} p_W[g,s,t] * C_w + \sum_{g=1}^{NG_{PV}} p_{PV}[g,s,t] * C_{PV} + \sum_{g=1}^{NG_N} p_N[g,s,t] * C_N \\
&+ \sum_{g=1}^{NG_{TH}} \left( p_{TH}[g,s,t] * C_{TH}[g] + C_{TH_{SU}}[g,s,t] + C_{TH_{SD}}[g,s,t] \right) + Q_H[s] * CF_H \\
&+ p_{HO}[s,t] * C_H + Q_B[s] * CF_B + p_{BO}[s,t] * C_B + p_{ENS}[s,t] * C_{ENS} \Bigg) \\
&+ DF_{INV}[s] * \left( ip_w[s] * CI_w + ip_{PV}[s] * CI_{PV} + ip_H[s] * CI_H + ip_B[s] * CI_B \right)
\end{aligned}
\qquad (4)
$$

This function is composed of two primary components:

First, the **operational costs**, affected by the operational discount factor $DF_{OP}[s]$ and second the **investment costs**, affected by the investment discount factor $\boldsymbol{DF_{INV}[s]}$. For a further understanding of the equation, the terms are explained below.

The outer summations over stages s=0 to NS-1, and time steps t=0 to NT-1, ensure that the model accounts for all hours across all stages in the planning horizon.

The inner summations iterate over each technology type and generator index:

***Wind Generation*** – [ $\boldsymbol{\sum_{g=1}^{NG_w} p_W[g,s,t] * C_w}$]**:** For each wind generator g, in stage s, and hour t, the wind power dispatched $p_W[g,s,t]$ is multiplied by the variable cost per wind unit $C_w$, yielding the total operational cost for wind energy.

***Solar PV****:* The structure is identical to wind, using the variables $p_{PV}[g,s,t]$ and $C_{PV}$. Also, the number of PV generators is defined by $NG_{PV}$

***Nuclear****:* As for the renewable generators, nuclear its defined in the same way, the variable $p_N[g,s,t]$ accounts for the nuclear powered dispatched for every generator in every stage in every hour, the nuclear cost per unit dispatched its defined as $C_N$ and the number of nuclear generators is $NG_N$.

***Thermal Generation****:* The energy dispatch of thermal generators follows the same structure as the technologies previously described, with dispatch costs modeled as a function of the energy produced by each generator. However, to accurately reflect the operational flexibility and associated costs of thermal units, the model also incorporates startup and shutdown costs. These are represented by the variables $C_{TH_{SU}}[g,\boldsymbol{s},t]$ and $C_{TH_{SD}}[g,\boldsymbol{s},t]$, which capture the startup and shutdown status of each thermal generator g, for each stage s, and for every hour t.

***Hydro Pumped Storage and Batteries****:* For both storage technologies, the model incorporates fixed and variable operational costs. Fixed annual costs are represented by the terms $\mathrm{Q_H[s] * CF_H}$ for pumped hydro storage and $\mathrm{Q_B[s] * CF_B}$for battery storage. Here,

$\mathrm{Q_H}[\mathrm{s}]$ and $\mathrm{Q_B}[\mathrm{s}]$ refer to the total installed capacity of each technology in stage s, accounting for both existing capacity and new investments made during that stage. These are multiplied by $\mathrm{CF_H}$ and $\mathrm{CF_B}$, which represent the fixed annual cost per megawatt (MW) of installed capacity for hydro and battery storage, respectively.

In terms of variable dispatch costs, the model uses $C_H$ and $C_B$ to represent the cost per megawatt-hour (MWh) of energy discharged from pumped hydro and batteries. These costs are applied to the dispatched output in each hour t of stage s, captured by the variables, $p_{HO}[\boldsymbol{s}, t]$ and $p_{BO}[\boldsymbol{s}, t]$ respectively. The subscript "O" stands for output, indicating the energy discharged from storage. Since each storage technology is modelled as a single aggregated unit, there is no summation over multiple generators, which explains the absence of a generator index g in the formulation.

***Energy Not Supplied (ENS)***: Modelled using $p_{ENS}[\boldsymbol{s}, t] * C_{ENS}$, representing the cost of unmet demand, where $C_{ENS}$ is derived from the VoLL and $p_{ENS}[\boldsymbol{s}, t]$ is the unmet demand in MW in every hour t for every stage s.

The **investment component** of the objective function captures the annuity-based capital costs associated with each technology: wind, solar PV, pumped hydro storage, and batteries. Investment decisions made at each stage are represented by the variables $ip_X[s]$, where X∈ {W, PV, H, B} corresponds to wind, solar PV, hydro pump, and batteries, respectively. Each investment variable denotes the amount of capacity (in MW) installed for technology X during stage s. These are multiplied by their respective annuity costs $CI_X$, which reflect the annualized cost per MW of installed capacity, based on CAPEX, lifespan, and the discount rate.

To account for the time value of money, the total investment costs in each stage are discounted using the investment discount factor $\boldsymbol{DF_{INV}}[\boldsymbol{s}]$, ensuring that all capital expenditures are evaluated in present-value terms.

### 3.2.2. CONSTRAINTS

#### Power Balance Constraints

The power balance constraint **(5)**, ensures that the sum of all the power supplied by the different technologies meets the demanded energy for all the time periods in every stage.

$$\begin{aligned}\sum_{g=1}^{NG_w} p_w[g,s,t] + \sum_{g=1}^{NG_{PV}} p_{PV}[g,s,t] + \sum_{g=1}^{NG_{th}} p_{th}[g,s,t] \\ + \sum_{g=1}^{NG_N} p_N[g,s,t] + p_{HO}[s,t] - p_{HI}[s,t] + p_{BO}[s,t] \\ - p_{BI}[s,t] + p_{ENS}[s,t] = Q_D[s,t] \quad \forall\, s,t \in NS, NT\end{aligned} \tag{5}$$

$$Q_D[s,t] = Q_{Dn}[t] * Q_{Ds}[s] \qquad \forall\, s,t \in NS, NT \tag{6}$$

As for equation (6), $Q_D[s,t]$ represents the demand for each stage as a result of multiplying the normalized profile to the peak demand for each stage.

#### Capacity Constraints

The capacity constraints are designed to ensure that the energy dispatched by each technology at any given time does not exceed the available installed capacity. These constraints apply to all modeled generators and are expressed using the dispatch variable $p_X[g,s,t]$, which represents the hourly output of technology X. The upper bound of this variable is determined by the corresponding installed capacity $Q_X[s]$, which may vary across investment stages s. The lower bound in intrinsically set in the definition of the dispatch variable as positive.

$$p_w[g,s,t] \leq Q_{wn}[g,t] * Q_w[s] \qquad \forall\, g,s,t \,\epsilon\, NG_{PV}, NS, NT \tag{7}$$

$$Q_w[s] = Q_w[0] + \sum_{s=0}^{s} ip_w[s] \qquad \forall\, s \,\epsilon\, NS \tag{8}$$

$$p_{PV}[g,s,t] \leq Q_{PVn}[g,t] * Q_{PV}[s] \qquad \forall\, g,s,t \in NG_{PV}, NS, NT \tag{9}$$

$$Q_{PV}[s] = Q_{PV}[0] + \sum_{s=0}^{s} ip_{PV}\,[s] \qquad \forall\, s \in NS \tag{10}$$

$$p_N[g,s,t] \leq Q_N[s] \qquad \forall\, g,s,t \in NG_N, NS, NT \tag{11}$$

$$p_N[g,s,t] \geq 0.9 * Q_N[s] \qquad \forall\, g,s,t \in NG_N, NS, NT \tag{12}$$

$$p_{th}[g,s,t] \leq Q_{th} * u_{on}[g,s,t] \qquad \forall\, g,s,t \in NG_{th}, NS, NT \tag{13}$$

$$p_{th}[g,s,t] \geq 0{,}1 * Q_{th} * u_{on}[g,s,t] \qquad \forall\, g,s,t \in NG_{th}, NS, NT \tag{14}$$

Equations (9) & (11), represent how the investment is aggregated for every stage. The variable $u_{on}[g,s,t]$, is in charge of controlling the status of every thermal generation in every stage for every hour.

## Thermal Start-Up & Shutdown Constraints

The thermal constraints proposed in the above paragraph (13) & (14) are dependent on the status of the generators. Turning on or off from one period to another has its costs attached to it. The impact of these costs is modelled in the following equations.

$$on_{th}[g,s,t] - off_{th}[g,s,t] = u_{on}[g,s,t] - u_{on}[g,s,t-1] \quad \forall g,s\,;\; t > 1 \in NG_{th}, NS, NT \tag{15}$$

$$on_{th}[g,s,t] - off_{th}[g,s,t] = u_{on}[g,s,t] \qquad \forall g,s\,;\; t = 0 \in NG_{th}, NS, NT \tag{16}$$

$$C_{th_{su}}[g,s,t] = C_{th_{su}}[s] * on_{th}[g,s,t] \quad \forall g,s,t \in NG_{th}, NS, NT \tag{17}$$

$$C_{th_{sd}}[g,s,t] = C_{th_{sd}}[s] * off_{th}[g,s,t] \quad \forall g,s,t \in NG_{th}, NS, NT \tag{18}$$

Equations (14) & (15), verify the status and register when a generator is turned on or off with variables $on_{th}[g,s,t]$ & $off_{th}[g,s,t]$ respectively. Once this is done, the start up and shut down costs are defined in $C_{th_{su}}[g,s,t]$ & $C_{th_{sd}}[g,s,t]$.

## Storage Systems Constraints

The modelling of storage operation begins by defining the state of charge $SOC_X$ for each technology *X*, which must remain between the total installed capacity and a minimum threshold of 20%. The investment follows the same formulation as that used for renewable generation technologies.

$$SOC_H[s,t] \leq Q_H[s] * EC_H \qquad \forall\, s,t \in NS, NT \tag{19}$$

$$SOC_H[s,t] \geq 0{,}2 * Q_H[s] * EC_H \qquad \forall\, s,t \in NS, NT \tag{20}$$

$$Q_H[s] = Q_{Hini} + \sum_{s=0}^{s} ip_{PV}[s] \qquad \forall\, s \,\epsilon\, NS \tag{21}$$

$$SOC_B[s,t] \leq Q_B[s] * EC_B \qquad \forall\, s,t \in NS, NT \tag{22}$$

$$SOC_B[s,t] \geq 0{,}2 * Q_B[s] * EC_B \qquad \forall\, s,t \in NS, NT \tag{23}$$

$$Q_B[s] = Q_{Bini} + \sum_{s=0}^{s} ip_w[s] \qquad \forall\, s \,\epsilon\, NS \tag{24}$$

For the charge and discharge process both are limited to the installed capacity in MW.

$$P_{HO}[s,t] \leq Q_H[s] \qquad \forall\, s,t \in NS, NT \tag{25}$$

$$P_{HI}[s,t] \leq Q_H[s] \qquad \forall\, s,t \in NS, NT \tag{26}$$

$$P_{BO}[s,t] \leq Q_B[s] \qquad \forall\, s,t \in NS, NT \tag{27}$$

$$P_{BI}[s,t] \leq Q_B[s] \qquad \forall\, s,t \in NS, NT \tag{28}$$

The state of charge (SOC) is initialized at the beginning of each investment stage at a minimum level of 20% of the installed capacity. The evolution of the SOC over time is then defined recursively, based on the SOC from the previous hour, adjusted by the energy charged or discharged, and accounting for the corresponding efficiency losses of the storage process. The following equations describe the behavior:

$$SOC_H[s,t] = 0{,}2 * Q_H[s] * EC_H \quad \forall\, s \in NS; t = 0 \tag{29}$$

$$SOC_B[s,t] = 0{,}2 * Q_B[s] * EC_B \quad \forall\, s \in NS; t = 0 \tag{30}$$

$$SOC_H[s,t] = SOC_H[s,t-1] - \frac{P_{HO}[s,t]}{\eta_H} + P_{HI}\,[s,t] * \eta_H \quad \forall s \in NS; \forall\, t \geq 1 \tag{31}$$

$$SOC_B[s,t] = SOC_B[s,t-1] - \frac{P_{HO}[s,t]}{\eta_B} + P_{HI}\,[s,t] * \eta_B \quad \forall s \in NS; \forall\, t \geq 1 \tag{32}$$

$$P_{HO}[s,t] + P_{HI}[s,t] \leq Q_H[s] \quad \forall\, s,t \in NS, NT \tag{33}$$

$$P_{BO}[s,t] + P_{BI}[s,t] \leq Q_B[s] \quad \forall\, s,t \in NS, NT \tag{34}$$

Equations (33) & (34), make sure that charge and discharge do not occur at the same time.

# CHAPTER 4: CASE STUDY

## 4.1. CASE DEFINITION

The primary objective of this base case is to determine the optimal investment pathway that minimizes total investment and operational costs by relying exclusively on renewable energy technologies and storage systems. The first scenario, hereafter referred to as **P-0**, is developed in alignment with the decommissioning strategy proposed by the PNIEC, which calls for a reduction in nuclear capacity from 7.1 GW to 3.1 GW by 2030, followed by a complete phase-out by 2035.[2]

This scenario will be directly compared with an alternative case, designated as **N-0**, in which nuclear capacity is maintained at its initial level throughout the entire analysis period. The initial stage of analysis focuses on a comparative assessment of the two scenarios, examining differences in terms of installed capacity and associated costs. Subsequently, the total installed capacities projected for 2030 will be evaluated against the official targets set forth in the PNIEC.

The model spans the period from **2025 to 2040**, covering a **15-year planning horizon** divided into **three investment stages**, each lasting **five years**. To align with the evaluation timeline established by the PNIEC and to assess the impact of nuclear decommissioning, **Stage 0** is set in **2025**, **Stage 1** in **2030**, and **Stage 2** in **2035**.

In order to obtain the results the proposed investment model its implemented using the Python matrix modelling technique of Gurobi, which facilitates the management of variables and constraints, [13]. The code used for the model can be found in Annex II.

## *4.2. INPUT PARAMETERS*

### 4.2.1. DEMAND

The PNIEC projects a demand of 358 TWh for year 2030, to compare this, an additional study conducted by Ernst & Young was consulted. This report analyzes a range of scenarios in which electricity demand growth varies depending on the pace the energy transition takes place. From this analysis, the two most plausible growth scenarios were selected and used to define the boundaries for the model's demand projections. The base scenario is defined as the result of the average growth trajectory derived from the two selected scenarios. All three scenarios are summarized in the following table:

| ***Scenario*** | ***2025 (TWh)*** | ***2030 (TWh)*** | ***2035 (TWh)*** |
|---|---|---|---|
| EY-A (Fast Pace) | 233,5 | 359,8 | 478,7 |
| EY-B (Slow Pace) | 229,4 | 304,8 | 376,3 |
| Base (Average) | **231,5** | **332,3** | **427,5** |

Table 1: Demand Growth 2025-2035

For this study, the 2024 hourly demand profile has been selected, as it provides a recent and representative baseline. According to data from the REE ESIOS platform, electricity demand in 2024 reached a total of 231.5 TWh, with a peak demand of approximately 38 GW. The corresponding hourly profile is presented in the following figure. [14]

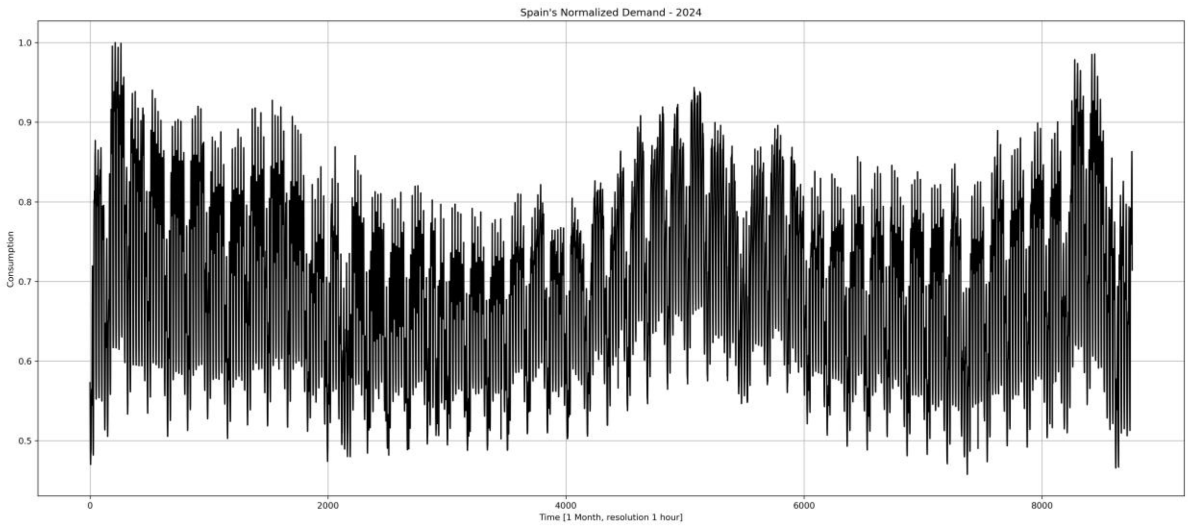


Figure 3: Spain Normalized Demand – 2024

### 4.2.2. GENERATORS

*Solar PV*

Solar PV is currently the most widely deployed generation technology in Spain, with a total installed capacity of 33.63 GW according to the latest data [12]. The PNIEC targets 76 GW of installed solar PV capacity by 2030. [2]

In the model, all solar PV generation is represented as a single aggregated unit reflecting the current installed capacity. The generation profile is based on hourly data from 2024, sourced from the ESIOS platform. During that year, maximum PV dispatch reached approximately 20 GW, with a total annual generation of 43.5 TWh.[14]

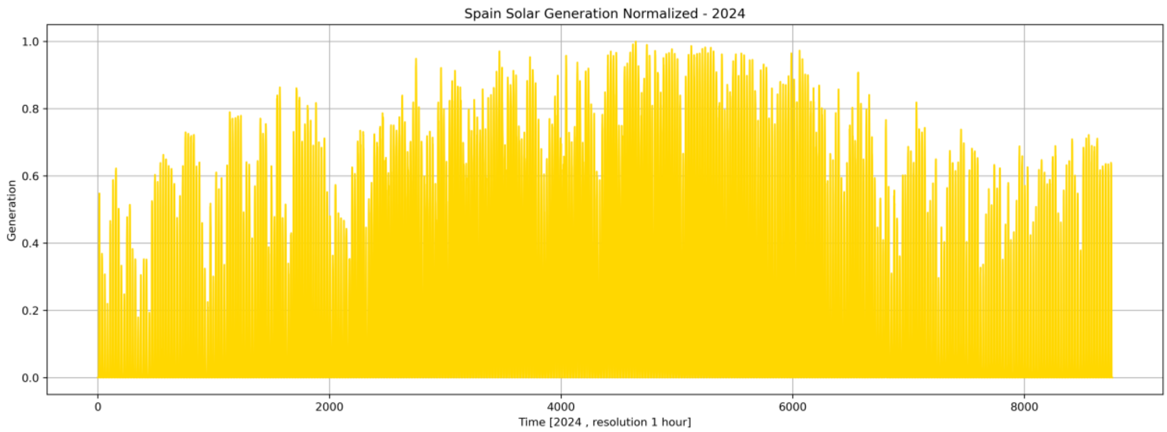


Figure 4: Spain Solar Generation Normalized - 2024

## *Wind*

Wind energy is currently the second most widely deployed electricity generation technology in Spain, with a total installed capacity of 32.25 GW [12]. The PNIEC sets a target of achieving 62 GW of installed wind capacity by the year 2030 [2].

In this model, wind generation is represented as a single aggregated source, corresponding to the stated installed capacity. The generation profile utilized is based on hourly data from the year 2024, obtained from the ESIOS platform. In that year, wind power generation reached a maximum hourly output of approximately 20 GW and produced an estimated total of 59.5 TWh over the course of the year.[14]

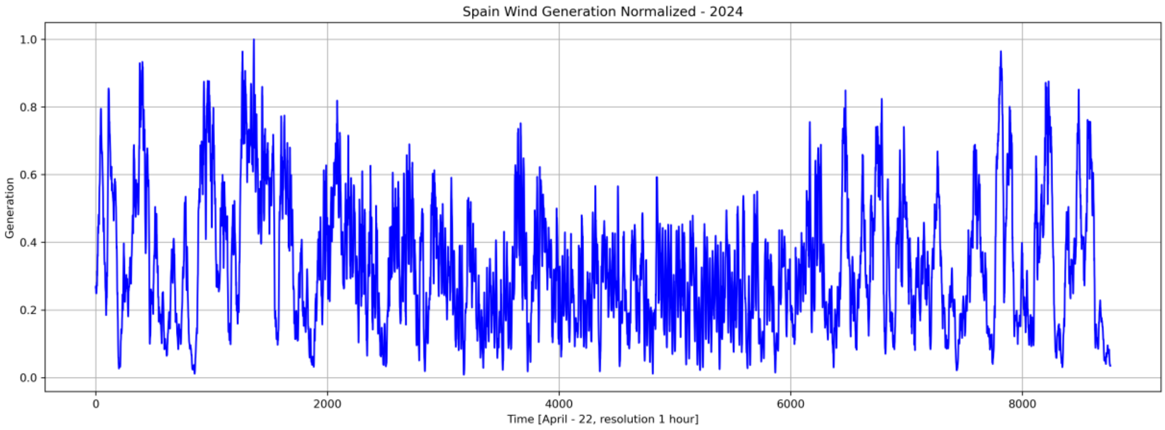


Figure 5: Spain Wind Generation Normalized – 2024

## *Nuclear*

Nuclear generation is modeled as a single, continuously operating (always-on) generation unit with an initial installed capacity of 7.1 GW. Its dispatchable range is constrained between 90% and 100% of its installed capacity, thereby reflecting its operational role as a stable and inflexible baseload power source within the electricity system. In accordance with the decommissioning trajectory outlined in the PNIEC, the model incorporates a gradual phase-out of nuclear power: reducing the installed capacity to 3.1 GW by 2030 and completing the full retirement of nuclear assets by 2035.[2]

## *Thermal*

Spain's electricity system currently includes approximately 26.65 GW of installed thermal capacity [12]. For the purposes of this model, a slightly reduced value of 25 GW is considered, represented by 25 individual units, each with a capacity of 1 GW. Unlike the nuclear generator, thermal generators in the model are fully dispatchable, meaning they can be started up or shut down in response to system needs, thereby reflecting their operational flexibility.

The following table provides a summary of the key input parameters for the four generation technologies represented in the model:

| ***Technology*** | ***Initial Installed Power [MW]*** | ***Nº of generators*** | ***Operation Profile*** |
|---|---|---|---|
| *Solar PV* | 33.630 | 1 | Spain PV gen. 2024 -ESIOS |
| *Wind* | 32.250 | 1 | Spain Wind gen. 2024 -ESIOS |
| *Nuclear* | 7.100 | 1 | Constant - [90%-100% of Total Cap.] |
| *Thermal* | 25.000 | 25 | Fully Dispatchable - On [10%-100% of Total Cap.] |

Table 2: Generation Input Parameters

### 4.2.3. STORAGE

#### *Hydro Pump*

In Spain, pumped hydro is the most prevalent form of energy storage, with approximately 3.5 GW of installed pure pumped hydro capacity and 2.5 GW of mixed systems, totalling in 6 GW of totalled installed capacity [12].

In the model, this technology is represented as a single aggregated unit with a total storage capacity of 180 GWh and a one-trip efficiency of 86.6%. To reflect operational constraints, a minimum reservoir level of 20% of total capacity is imposed, simulating the minimum admissible amount of stored water required for system reliability and technical feasibility [8].

#### *Batteries*

In the model, batteries are represented as a single storage unit with an initial installed power capacity of 50 MW, a total energy storage capacity of 200 MWh, and a round-trip efficiency of 92%. To reflect operational and health-related constraints, a minimum state of charge of 20% is imposed, like the constraint applied to hydro pump storage. This limitation ensures the preservation of battery life and maintains optimal performance throughout the system's operational horizon. [8], [12]

| ***Technology*** | *Initial Installed Power [MW]* | *Storage Capacity [MWh]* | *Efficiency (Roundtrip) [%]* |
|---|---|---|---|
| *Hydro Pump* | 6.000 | 180.000 | 86,6 (75) |
| *Batteries* | 50 | 200 | 92 (85) |

Table 3: Storage Input Parameters

## *4.3. ECONOMICAL PARAMETERS*

### 4.3.1. OPERATIONAL COSTS

The pricing assumptions applied in the model are based on those used in the master's thesis on which this study is based on [8], ensuring consistency and continuity with previous work, as price levels have remained largely stable over the past year. The only exceptions are the updated cost assumptions for thermal generation, and the ENS penalty, which have been revised to reflect more current estimates.

For renewable generation technologies, the model includes only variable O&M costs, calculated per megawatt-hour (MWh) of electricity dispatched. These costs primarily represent maintenance expenses. The cost for solar PV is set at 5 €/MWh, while wind power is associated with a higher cost of 10 €/MWh due to more intensive maintenance requirements.

Nuclear generation is modelled with a constant operational cost of 23 €/MWh, which accounts for both fuel and maintenance. As a baseload generator with limited flexibility, nuclear is expected to operate continuously within a narrow range of capacity output.

Thermal generation, by contrast, is modelled with a more complex cost structure. The system includes 25 identical thermal units, each with a capacity of 1 GW. The O&M cost for these generators increases incrementally by 1 €/MWh for each subsequent unit dispatched, reflecting a merit-order approach. As a result, the operational cost ranges from 105 €/MWh for the first generator up to 130 €/MWh for the last. In addition to variable costs, thermal units incur a fixed cost of 20.000 € for each startup and shutdown event, simulating the additional wear and operational complexity associated with flexible operation.

For storage technologies, the hydro pump storage is assigned an O&M cost of 3 €/MWh, while lithium-ion batteries incur a minimal cost of 0,00025 €/MWh, reflecting their low operating expenditure at this stage of technological maturity. Furthermore, both storage systems are subject to fixed annual costs per megawatt of installed capacity, which are 12.000 €/MW for the hydro pump and 5.500 €/MW for the batteries.

The ENS cost is derived from the Value of Lost Load (VoLL), which in this model is set at 22.879 €/MWh. This high value represents the substantial economic and social impact of unmet demand and is included in the power balance constraint to discourage demand curtailment and prioritize supply adequacy. [15]

| ***Technology*** | ***O&M Cost [€/MWh]*** | ***Fixed Cost [€/MW-year]*** | ***Start-Up & Shut-Down Cost*** |
|---|---|---|---|
| *Solar PV* | 5 | - | - |
| *Wind* | 10 | - | - |
| *Nuclear* | 23 | - | - |
| *Thermal* | 105-130 | - | 20.000 |
| *Hydro Pump* | 3 | 12.000 | - |
| *Batteries* | 0,00025 | 5.500 | - |
| *ENS* | 22.879 | - | - |

Table 4: Operational Input Costs

### 4.3.2. INVESTMENT COSTS

For all four technologies included in the model, a uniform discount rate of 7% is applied.

In the case of renewable generation, PV systems are assigned a CAPEX of €450,000 per MW with an assumed lifespan of 30 years. This results in an annualized cost (annuity) of €36,266 per MW per year. For wind, the CAPEX is higher at €900,000 per MW, also with a 30-year lifespan, yielding an annuity of €72,532 per MW per year.

For energy storage technologies, hydro pump storage is modelled with a CAPEX of €900,000 per MW and a longer lifespan of 60 years, leading to an annuity of €64,106 per MW per year. Lithium-ion batteries, which have a shorter lifespan of 10 years and a CAPEX of €632,122 per MW, result in a comparatively high annuity of €90,000 per MW per year, reflecting their faster depreciation and more frequent reinvestment cycle as technology is not as developed. [8]

These annuity values are used in the investment component of the model's objective function to determine the cost-optimal mix of technologies over the planning horizon.

| ***Technology*** | ***Lifespan [yr]*** | ***Rate [%]*** | ***CAPEX [€/MW]*** | ***Annuity [€/MW-yr]*** |
|---|---|---|---|---|
| *Solar PV* | 30 | 7 | 450.000 | 36.266 |
| *Wind* | 30 | 7 | 900.000 | 72.532 |
| *Hydro Pump* | 60 | 7 | 900.000 | 64.106 |
| *Batteries* | 10 | 7 | 632.122 | 90.000 |

Table 5: Investment Input Costs

### 4.3.3. DISCOUNT FACTOR

Considering the base scenario with the three decision stages, each lasting five years, and a 7% discount rate. The resulting discount factors are presented in the following table:

| ***Cost Type*** | ***DF - Stage 0*** | ***DF - Stage 1*** | ***DF- Stage 2*** |
|---|---|---|---|
| *Operational* | 4,39 | 3,12 | 2,23 |
| *Investment* | 9,75 | 5,36 | 2,23 |

Table 6: Discount Factors (7%- 3 stage-5 yr period)

# CHAPTER 5: RESULTS & SENSITIVITIES

## 5.1. CASE STUDY RESULTS

### 5.1.1. BASE SCENARIOS COMPARISON

To initiate the analysis, Table 7 and Table 8 provide a comparative overview of the two base scenarios, P-0 and N-0. Table 7 outlines the new installed capacity (in MW) by technology and stage for both scenarios, while Table 8 presents the corresponding investment and operational costs associated with each period.

| Stage | Technology | P-0 [MW] | N-0 [MW] |
|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 3.357 |
| | Solar PV | 7.903 | 7.579 |
| | Hydro Pump | 6.829 | 6.494 |
| | Batteries | - | - |
| | **Total** | **17.842** | **17.430** |
| **Stage 1 - 2030** | Wind | 27.892 | 20.831 |
| | Solar PV | 33.651 | 25.024 |
| | Hydro Pump | 11.112 | 7.886 |
| | Batteries | - | - |
| | **Total** | **72.654** | **53.741** |
| **Stage 2 - 2035** | Wind | 22.649 | 18.231 |
| | Solar PV | 51.591 | 28.345 |
| | Hydro Pump | 21.051 | 14.885 |
| | Batteries | - | - |
| | **Total** | **95.291** | **61.461** |

Table 7: Base Case Investments

Beginning with the differences in invested capacities, Table 7shows that maintaining nuclear capacity in the N-0 scenario results in a 26% reduction (approximately 20 GW) in new installed capacity compared to the P-0 scenario by 2030, and a 35.5% reduction (approximately 33.5 GW) by 2035. Over the entire planning horizon, the total new installed capacity in the P-0 scenario reaches **185,787 MW**, whereas the N-0 scenario requires only **132,632 MW**. This represents an overall **30% reduction** in newly installed capacity, or roughly **53 GW**, further emphasizing the substantial influence that nuclear generation has on system sizing and investment needs.

In 2030, to address the expected increase in electricity demand, the model allocates investments in the P-0 scenario with the following approximate distribution: 38% to wind, 46% to solar PV, and 16% to pumped hydro storage. In the N-0 scenario, there are no perceivable differences in how the investments are distributed just the mentioned reduction in capacity in all 3 technologies, what takes place in a proportionate way.

By 2035, the model alters its investment strategy in response to further cost reductions, prioritizing a strong correlation between solar PV and pumped hydro storage. At this stage, investments in wind capacity are reduced, while solar PV and hydro storage capacities are doubled compared to earlier stages.

It's clear that the model defers a significant portion of investment until later stages, capitalizing on cost reductions attributed to the time value of money. Meaning that almost 50% of the investment takes place in the last stage.

Despite the considerably higher storage capacity installed in the P-0 scenario, energy curtailments remain greater than in the N-0 case. In particular, wind curtailment in the P-0 scenario reaches 32.5%, compared to 24,3% in N-0. For solar PV, curtailment is 3.5% in P-0, while only 0.8% in N-0. These results suggest that nuclear energy helps to reduce curtailment rates as it allows for a better integration of the renewables in the system.

Following with the costs and average and marginal costs (expressed in net present value):

| Stage | Technology | P-0 [M€] | N-0 [M€] |
|---|---|---|---|
| **Stage 0 - 2025** | Investment Cost | 9.257 | 9.108 |
| | Operational Cost | 17.908 | 17.972 |
| | Average Cost | [15,47 €/MWh] | [15,53 €/MWh] |
| | Marginal Average Cost | [44,50 €/MWh] | [44,50 €/MWh] |
| | **Stage 0 Total Cost** | **27.165** | **27.080** |
| **Stage 1 - 2030** | Investment Cost | 21.194 | 15.666 |
| | Operational Cost | 17.001 | 17.830 |
| | Average Cost | [10,24 €/MWh] | [10,73 €/MWh] |
| | Marginal Average Cost | [32,57 €/MWh] | [32,12 €/MWh] |
| | **Stage 1 Total cost** | **38.195** | **33.496** |
| **Stage 2 - 2035** | Investment Cost | 10.845 | 7.369 |
| | Operational Cost | 13.153 | 15.292 |
| | Average Cost | [5,51 €/MWh] | [6,70€/MWh] |
| | Marginal Average Cost | [25,58 €/MWh] | [25,53 €/MWh] |
| | **Stage 2 Total Cost** | **23.998** | **22.661** |
| **Total Costs** | Total Investment Cost | 41.296 | 32.143 |
| | Total Operational Cost | 48.062 | 51.094 |
| | **Total Cost** | **89.358** | **83.237** |

Table 8: Base Case Costs

Starting with investment costs, it is evident that a substantial portion of new capacity is deployed by 2035, particularly in the P-0 scenario. In 2030, the difference in total installed capacity between the two scenarios is approximately 19 GW, corresponding to an investment gap of 5.5 billion €. By 2035, the difference in installed capacity increases to 34 GW, with a corresponding investment cost difference of 3.5 billion €.

This trend illustrates how, over time, the time value of money reduces the relative financial gap between the two scenarios. While cost differentials decline, the technical challenge shifts toward the system's ability to manage and integrate larger volumes of installed capacity, rather than the availability of capital itself. This highlights a key insight: beyond a certain point, the feasibility of a high-renewables system is increasingly constrained not by cost, but by technical limitations related to grid integration, storage, and dispatchability.

For the operational costs, as fewer renewable energy technologies are integrated in the nuclear scenario, operational costs in N-0 are comparatively higher, owing to a greater share of demand being met by nuclear generation rather than low-cost renewables. From the marginal costs perspective, both scenarios present almost the same values being the nuclear scenario slightly lower.

When both investment and operational costs are considered together, it becomes clear that investment expenditures dominate the cost structure. As a result, retaining nuclear capacity to accommodate the same projected growth in electricity demand leads to an overall cost saving of approximately 6 billion € over the 15-year planning horizon.

### 5.1.2. 2030 PNIEC COMPARISON

When compared with the targets outlined in the PNIEC, the benefits of extending the operational life of nuclear power plants become apparent, as shown in Table 9.

<table>
<tr><th></th><th>Technology</th><th>PNIEC - [GW]</th><th>P-0 (2030) - [GW]</th><th>N-0 (2030) - [GW]</th></tr>
<tr><td rowspan="4">Generators</td><td>Nuclear</td><td>3,1</td><td>3,1</td><td>7,1</td></tr>
<tr><td>Solar PV</td><td>76</td><td>75,2</td><td>66,2</td></tr>
<tr><td>Wind</td><td>62</td><td>63,3</td><td>54,4</td></tr>
<tr><td>Thermal</td><td>26,25</td><td>25,0</td><td>25,0</td></tr>
<tr><td rowspan="2">Storage</td><td>Hydro Pump</td><td rowspan="2">22,5</td><td>23,9</td><td>20,4</td></tr>
<tr><td>Batteries</td><td>0,05</td><td>0,05</td></tr>
</table>

Table 9: 2030 PNIEC Comparison

As it can be appreciated, even accounting for a slight reduction in thermal generation (by approximately 1,25 GW) and a lower projected demand in the modelled scenarios (332,3 TWh compared to the 358 TWh set in the PNIEC), the results are revealing. The P-0 scenario, which aligns with the nuclear decommissioning path, achieves installed capacities almost identical to those outlined in the PNIEC. However, given that P-0 operates under a lower demand assumption, this alignment suggests that the PNIEC targets may be undersized relative to the actual system requirements if demand projections materialize as expected.

When comparing the N-0 scenario to the PNIEC targets, the benefits of maintaining nuclear generation become more pronounced. The presence of nuclear capacity not only reduces total system costs, as previously discussed, but also significantly decreases the need for additional renewable and storage capacity. Specifically, the N-0 scenario requires 10 GW less solar PV, 8 GW less wind, and 2 GW less pumped hydro storage compared to the PNIEC targets, demonstrating the role nuclear energy can play in alleviating pressure on renewable deployment and grid infrastructure.

When comparing to the targets it can be observed that, marginal costs are within the expected range in the PNIEC [28 – 34,3 €/MWh] for both scenarios and that renewable energy production represents around 80% of the total production.

## 5.2. SENSITIVITY ANALYSIS

To gain deeper insight into the model's behaviour, a series of sensitivity analyses are conducted, focusing on key parameters that influence investment and dispatch outcomes. The factors examined include **demand growth**, **hydro pump cost sensitivity and storage capacity**, **natural gas prices**, and the **discount rate**. These analyses help to evaluate the model's robustness and the relative impact of each variable on system performance and cost.

### 5.2.1. DEMAND

When analysing the results in relation to the objectives outlined in the PNIEC, one critical factor to consider is the projected growth in electricity demand. The PNIEC forecasts a total demand of 358 TWh for the year 2030, while the base scenario used in this model assumes a slightly lower figure of 332.3 TWh.

As previously noted, the base scenarios are built on demand growth rates derived from the average scenario of the Ernst & Young (EY) projections, which assume an average annual growth rate of 7.5% between 2025 and 2030 and 5.2% between 2030 and 2035. Under a lower-growth scenario from the same study, these rates drop to 5.7% and 4.3%, respectively, which would correspond to a 2030 demand of approximately 305 TWh and 376.3 TWh by 2035. The high-growth scenario, more closely aligned with the PNIEC's projections, would result in a 2030 demand of about 360 TWh.

For the purpose of the sensitivity analysis, the lower-growth scenario has been selected. This choice is supported by the historical trend in electricity demand over the past decade. As shown in Figure 5, annual demand growth has remained relatively moderate, reinforcing the motive for exploring a more conservative growth trajectory in this context.

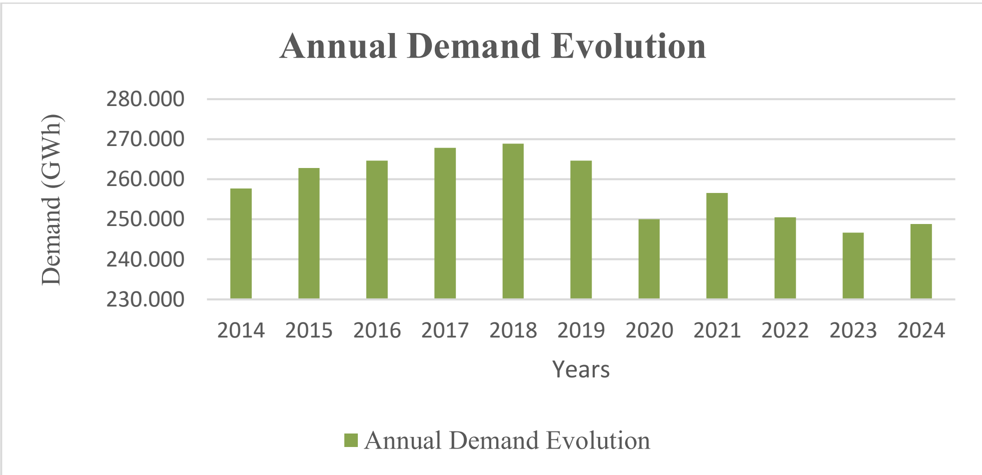


Figure **6**: Annual Demand Evolution 2014-2024

Fuente: REE

As shown in Figure **6**: Annual Demand Evolution 2014-2024, electricity demand over the past decade has not followed a steady upward trend. In fact, the years preceding 2024 experienced negative growth, and although 2024 marked a positive shift, the recorded increase was just 0.9%, which remains significantly below the 7% annual growth rate projected in the base scenario.

This recent trend reinforces the decision to assess the system's performance under a more conservative growth scenario. When the model is run using the lower-demand scenario from the EY study, the investment decisions adjust as follows, the demand cases are noted with an A:

| Stage | Technology | P-0 [MW] | P-A [MW] | N-0 [MW] | N-A [MW] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 4.938 | 3.357 | 3.154 |
| | Solar PV | 7.903 | 6.767 | 7.579 | 7.780 |
| | Hydro Pump | 6.829 | 6.835 | 6.494 | 6.882 |
| | Batteries | - | - | - | - |
| | **Total** | **17.842** | **18.540** | **17.430** | **17.816** |
| **Stage 1 - 2030** | Wind | 27.892 | 20.618 | 20.831 | 15.214 |
| | Solar PV | 33.651 | 27.478 | 25.024 | 18.111 |
| | Hydro Pump | 11.112 | 8.561 | 7.886 | 5.639 |
| | Batteries | - | - | - | - |
| | **Total** | **72.654** | **56.658** | **53.741** | **38.964** |
| **Stage 2 - 2035** | Wind | 22.649 | 18.989 | 18.231 | 14.504 |
| | Solar PV | 51.591 | 26.974 | 28.345 | 20.263 |
| | Hydro Pump | 21.051 | 12.672 | 14.885 | 9.001 |
| | Batteries | - | - | - | - |
| | **Total** | **95.291** | **58.635** | **61.461** | **43.768** |

Table 10: Investments Demand Sensitivity

The comparison between the base case and the lower-demand scenarios reveals several key findings:

A reduction of approximately 30 TWh in projected demand (about 8%) leads to an average decrease of 16% in total installed capacity for both scenarios. In absolute terms, installed capacity in the P-0 scenario drops from 282.7 GW to 231 GW in P-A, and in the N-0 scenario from 236.7 GW to 204.5 GW for N-A. This highlights the strong sensitivity of capacity planning to demand growth assumptions.

As demand growth slows, the difference in capacity between the nuclear-retaining and nuclear decommissioning pathways narrows, decreasing from 53 GW in the base case to 33.5 GW under the low-growth scenario. This reflects that the strategic value of nuclear retention becomes more pronounced under high-demand scenarios, where renewable expansion needs are more aggressive.

From a cost perspective, the total system costs in both adjusted scenarios fall by approximately 11% compared to their base counterparts. However, the cost gap between scenarios remains stable, with the nuclear-inclusive scenario (N-A) consistently resulting in 6 billion € in total savings relative to the decommissioning case (P-A). This suggests that the economic advantage of maintaining nuclear power is robust to variations in demand projections.

### 5.2.2. STORAGE

Storage systems are critical for the successful integration of renewable energy, primarily by mitigating curtailments and enhancing power system flexibility. The model results clearly reflect this, with storage representing approximately 20% of total investment. Over the 15-year planning horizon, the model deploys nearly 40 GW of storage capacity in the P-0 scenario and 30 GW in the N-0 scenario, a substantial increase from the existing 6 GW. All of this storage is modelled as pumped hydro, which justifies further scrutiny of the assumptions used.

To test the robustness and realism of these assumptions, a sensitivity analysis was performed in which the equivalent storage duration for pumped hydro was halved from 30 hours to 15 hours "B1", and the investment annuity was increased from 900 €/kW to 2,500 €/kW "B2", this economic adjustment is obtained from the "Descarbonización del sistema eléctrico en España" [16]

Additionally, a capacity cap of 40 GW was introduced to reflect a more realistic deployment trajectory "B3". This limit aligns with the expected increase from 6 GW to 22.5 GW outlined in the PNIEC between 2025 and 2030, and assumes a linear growth until 2035, ensuring that investment outcomes remain within feasible technical constraints.

This sensitivity allows for a better understanding of the economic and technical feasibility of large-scale storage deployment, and the role that cost assumptions and physical limits play in shaping optimal system configurations.

Starting with the impacts of halving equivalent storage hours.

| Stage | Technology | P-0 [MW] | P-B1 [MW] | N-0 [MW] | N-B1 [MW] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | - | 3.357 | - |
| | Solar PV | 7.903 | 14.491 | 7.579 | 14.529 |
| | Hydro Pump | 6.829 | 11.790 | 6.494 | 11.790 |
| | Batteries | - | - | - | - |
| | **Total** | **17.842** | **26.281** | **17.430** | **26.319** |
| **Stage 1 - 2030** | Wind | 27.892 | 24.900 | 20.831 | 18.492 |
| | Solar PV | 33.651 | 38.650 | 25.024 | 28.825 |
| | Hydro Pump | 11.112 | 14.918 | 7.886 | 11.187 |
| | Batteries | - | - | - | - |
| | **Total** | **72.654** | **78.468** | **53.741** | **58.503** |
| **Stage 2 - 2035** | Wind | 22.649 | 22.450 | 18.231 | 17.344 |
| | Solar PV | 51.591 | 58.293 | 28.345 | 44.374 |
| | Hydro Pump | 21.051 | 50.983 | 14.885 | 32.832 |
| | Batteries | - | - | - | - |
| | **Total** | **95.291** | **131.726** | **61.461** | **94.551** |

Table 11: 15h Storage Hydro Pump Investments

The sensitivity analysis where the equivalent storage hours for hydro pump are halved from 30 to 15 hours (scenarios P-B1 and N-B1) reveals several important effects on investment strategies, generation mix, and system performance.

In Stage 0, the model shifts away from wind investment, reallocating capital toward solar PV and hydro pump, doubling their installed capacities compared to the base cases. For Stage 1, the increase in capacity remains modest across all technologies with a total increase of 5 GW, most of it in pumped hydro storage.

The most notable change appears in Stage 2, where hydro pump storage capacity doubles and PV sees a substantial increase, particularly in the N-B1 scenario, where PV grows from

28 GW to 44 GW. In the P-B1 case, PV increases more modestly (around 5 GW), as it already had a higher baseline integration. Meanwhile, wind capacity is slightly reduced in both scenarios, indicating a shift in system optimization towards storage-PV correlation.

Despite the large changes in installed capacities, especially for storage and PV, the overall costs remain relatively stable. This is expected, as the investment annuity for hydro pump storage was not altered, and the dispatch patterns remain largely unchanged in terms of total energy generation.

The impact of added PV and limited-duration storage is most visible in curtailment levels. Wind curtailments increase sharply in 2035, from 32% to 43% in P-B1, and from 24.3% to 40% in N-B1, due to an oversupply of renewable energy without sufficient long-duration storage to absorb it.

Conversely, solar PV curtailment drops significantly, reaching near-zero levels in 2035. This suggests that the added pumped hydro capacity, despite shorter duration, is well-aligned with PV generation patterns, enabling more effective integration of solar energy.

Overall, the analysis highlights the trade-offs between storage depth and capacity. Reducing the energy duration of storage forces the system to compensate through overbuilding, particularly of hydro pump infrastructure and PV, which in turn increases curtailment for wind. While costs remain stable, system efficiency and renewable integration patterns are notably affected.

Once the behaviour of the storage capacity has been assessed, attention is turned to analysing the impact of pumped hydro investment costs. As with the previous sensitivity, the analysis is structured in three parts: first, examining how changes in cost assumptions affect the investment pattern over time; second, evaluating the implications for total system costs; and finally, assessing the impact on renewable energy curtailments. Starting with the investment in MW. **¡Error! No se encuentra el origen de la referencia.** presents the results of a s ensitivity analysis in which the investment cost of pumped hydro storage is significantly increased. The adjusted scenarios (P-B2 and N-B2) reflect the system's response to this change in terms of capacity deployment across all technologies.

| Stage | Technology | P-0 [MW] | P-B2 [MW] | N-0 [MW] | N-B2 [MW] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 11.238 | 3.357 | 11.686 |
| | Solar PV | 7.903 | - | 7.579 | - |
| | Hydro Pump | 6.829 | - | 6.494 | - |
| | Batteries | - | - | - | 12 |
| | **Total** | **17.842** | **11.238** | **17.430** | **11.698** |
| **Stage 1 - 2030** | Wind | 27.892 | 23.669 | 20.831 | 17.111 |
| | Solar PV | 33.651 | 38.174 | 25.024 | 28.681 |
| | Hydro Pump | 11.112 | 13.293 | 7.886 | 9.133 |
| | Batteries | - | 4.499 | - | 5.529 |
| | **Total** | **72.654** | **79.636** | **53.741** | **60.454** |
| **Stage 2 - 2035** | Wind | 22.649 | 29.223 | 18.231 | 20.320 |
| | Solar PV | 51.591 | 62.398 | 28.345 | 34.585 |
| | Hydro Pump | 21.051 | 17.902 | 14.885 | 14.096 |
| | Batteries | - | - | - | 304 |
| | **Total** | **95.291** | **109.523** | **61.461** | **69.304** |

Table 12: Hydro Pump High-Cost Investments

The results show a notable shift in investment strategy. In Stage 0, where hydro pump storage investment was previously significant, the increased cost leads the model to eliminate PV and pumped hydro investments entirely, replacing them almost exclusively with wind capacity.

In Stage 1, the investment mix begins to rebalance: wind investment is slightly reduced, while both PV and pumped hydro are increased compared to the base scenarios as the model tries to compensate for what wasn't installed in the prior stage. Notably, batteries appear in the investment mix for the first time, with around 5 GW installed, indicating that under certain cost conditions, battery storage becomes competitive.

By Stage 2, investments in both wind and PV increase, reflecting the need to meet growing demand. However, hydro pump investment declines, suggesting the model is substituting storage by oversizing renewable capacity, which leads to increased curtailment.

Continuing with the costs:

| Stage | Cost Type | P-0 [M€] | P-B2 [M€] | N-0 [M€] | N-B2 [M€] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Investment | 9.257 | 7.943 | 9.108 | 8.270 |
| | Operational | 17.908 | 19.410 | 17.972 | 19.269 |
| | **Total** | **27.165** | **27.353** | 27.080 | **27.539** |
| **Stage 1 - 2030** | Investment | 21.194 | 31.470 | 15.666 | 23.603 |
| | Operational | 17.002 | 17.093 | 17.830 | 17.862 |
| | **Total** | **38.196** | **48.563** | 33.496 | **41.465** |
| **Stage 2 - 2035** | Investment | 10.845 | 16.883 | 7.369 | 11.743 |
| | Operational | 13.153 | 12.207 | 15.293 | 14.513 |
| | **Total** | **23.998** | **29.090** | **22.662** | **13.201** |
| | **Total Inv.** | 41.296 | 56.296 | 32.143 | 43.616 |
| **Stages Total** | **Total Op.** | 48.063 | 48.710 | 51.095 | 51.644 |
| | **Total** | **89.359** | **105.006** | **83.238** | **95.260** |

Table 13: High-Cost Pumped Hydro Costs

The increase in hydro pump storage investment costs, significantly affects both the financial structure of the energy system and the integration efficiency of renewables, as observed in scenarios P-B2 and N-B2.

In Stage 0, the reduction in invested capacity logically results in a reduction of the total investment cost for that stage, that reduction its balanced out with the increase of operational costs. However, as demand grows, the system can no longer avoid investment, and by 2030 and 2035, investment costs increase substantially. Overall, the increase in hydro pump investment costs leads to an additional 15 billion € in total system costs compared to the base scenarios. Despite this, operational costs remain relatively stable, indicating that the model delays investment but eventually must compensate for lost flexibility.

One aspect worth mentioning, is that ENS appears in the dispatch results, meaning the model chooses to leave part of the demand unmet rather than incur in higher storage investment.

The reduction in installed storage capacity has a direct impact on renewable energy curtailments. In the P-B2 scenario (nuclear decommissioning), PV curtailment rises from

3.5% to 8.1%, while wind curtailment increases from 32% to 40%. In the N-B2 scenario (with nuclear), PV curtailment increases from 0.8% to 2%, and wind curtailment from 24% to 39%.

These sharp increases highlight the critical role of storage in enabling renewable integration, particularly for wind, where up to 40% of available energy is lost without sufficient storage support.

To complete the analysis of this sensitivity, the effect of imposing a 40 GW cap on pumped hydro storage is examined. This constraint is only relevant to the nuclear decommissioning scenario (P-0), as it is the only case in which total pumped hydro capacity exceeds 40 GW in the final investment stage.

| Stage | Technology | P-0 [MW] | P-B3 [MW] |
|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 3.153 |
| | Solar PV | 7.903 | 7.908 |
| | Hydro Pump | 6.829 | 6.755 |
| | Batteries | - | - |
| | **Total** | **17.842** | **17.817** |
| **Stage 1 - 2030** | Wind | 27.892 | 27.848 |
| | Solar PV | 33.651 | 33.861 |
| | Hydro Pump | 11.112 | 11.549 |
| | Batteries | - | - |
| | **Total** | **72.654** | **73.257** |
| **Stage 2 - 2035** | Wind | 22.649 | 27.807 |
| | Solar PV | 51.591 | 59.692 |
| | Hydro Pump | 21.051 | 15.696 |
| | Batteries | - | 548 |
| | **Total** | **95.291** | **103.744** |

Table 14: Hydro Pump Cap Investments

As shown in Table 14, imposing a 40 GW cap on pumped hydro storage has no significant effect in the first two investment stages. During 2025 and 2030, storage deployment aligns with system needs and remains well below the imposed limit. However, in Stage 2 (2035), the model reaches the cap, preventing the installation of approximately 5 GW of additional hydro pump capacity.

To compensate for this constraint, the system responds by increasing investments in solar PV and wind, as well as by introducing battery storage (548 MW). This adjustment reflects a strategic shift in the generation mix to preserve system flexibility, even under limited long-duration storage availability.

From a cost perspective, the imposition of the hydro pump capacity cap results in only a slight increase in total system costs, which remains largely consistent with those of the base scenario. However, from an energy perspective, the effects are more pronounced in Stage 2 (2035). The model records the appearance of ENS and a rise in curtailments, particularly for wind energy. These values are comparable to those observed in the high-cost storage scenario (P-B2), indicating that even a moderate constraint on storage capacity can lead to reduced system flexibility and lower renewable utilization efficiency.

### 5.2.3. GAS PRICE

Thermal generation plays a significant role in system dispatch due to its flexibility, which allows it to effectively respond to short-term variations in demand. However, it is also a high-cost energy source and a major contributor to $CO_2$ emissions. This dual characteristic makes thermal generation a critical factor in the operational cost structure. For instance, in the 2035 base scenarios, thermal generation accounts for only 4% of total energy production, yet it represents approximately 35% of total operational costs.

Given this disproportionate impact, fluctuations in gas prices can have a direct effect not only on the volume of gas generation, but also on the overall operational and investment costs of the system. To evaluate the sensitivity of the model to this factor, a scenario is proposed in which the range of gas prices is reduced from 105–130 €/MWh to 60–85 €/MWh, allowing for an assessment of how lower gas prices influence dispatch decisions, total costs, and investment patterns.

To assess how investment patterns are influenced by gas prices, Table 15 presents a comparison among the four scenarios. The gas price sensitivity cases are denoted with the letter "C". This allows for a direct comparison between the base scenarios (P-0 and N-0) and their respective low-gas-price counterparts (P-C and N-C), highlighting the effect of reduced gas prices on capacity expansion decisions.

| Stage | Technology | P-0 [MW] | P-C [MW] | N-0 [MW] | N-C [MW] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Wind | 3.110 | 415 | 3.357 | 834 |
| | Solar PV | 7.903 | - | 7.579 | - |
| | Hydro Pump | 6.829 | 1.415 | 6.494 | 1.458 |
| | Batteries | - | - | - | - |
| | **Total** | **17.842** | **1.830** | **17.430** | **2.292** |
| **Stage 1 - 2030** | Wind | 27.892 | 23.587 | 20.831 | 15.638 |
| | Solar PV | 33.651 | 37.343 | 25.024 | 29.917 |
| | Hydro Pump | 11.112 | 16.762 | 7.886 | 13.458 |
| | Batteries | - | - | - | - |
| | **Total** | **72.654** | **77.692** | **53.741** | **59.013** |
| **Stage 2 - 2035** | Wind | 22.649 | 15.975 | 18.231 | 14.436 |
| | Solar PV | 51.591 | 62.403 | 28.345 | 36.221 |
| | Hydro Pump | 21.051 | 24.298 | 14.885 | 14.967 |
| | Batteries | - | - | - | - |
| | **Total** | **95.291** | **102.675** | **61.461** | **65.624** |

Table 15: Investments Gas Price Sensitivity

The results reveal a direct correlation between gas price reduction and investment timing. In both the nuclear decommissioning and nuclear-retention scenarios, the lower gas price leads to a significant shift in investment from the first stage (2025) to the subsequent stages (2030 and 2035). Investment is almost evenly split between these two later stages, suggesting that the reduced cost of thermal generation, combined with existing installed capacity, makes it economically advantageous to postpone new investments. In terms of system sizing, total installed capacities remain relatively stable.

Following with the operational aspect the reduction in price of about 40%, accounts for an increase of gas production as its displayed in Table 16.

| ***Gas Production*** | ***Scenario*** | ***Stage 0 - 2025 [TWh]*** | ***Stage 1 - 2030 [TWh]*** | ***Stage 2 - 2035 [TWh]*** |
|---|---|---|---|---|
| **N-** | 0 - Base Scenario | 59,3 | 91,8 | 99,5 |
| | C - Lower Gas Price | 117,5 | 131,8 | 137 |
| **P-** | 0 - Base Scenario | 58,5 | 100,2 | 92,3 |
| | C - Lower Gas Price | 120,5 | 140 | 124,4 |

Table 16: Gas Production

As renewable technologies increase in installed capacity, the share of thermal generation its reduced. However, the results confirm that the investment shift across stages is largely driven by the substantial rise in thermal generation, particularly in Stage 0, where gas production nearly doubles compared to the base case.

In the subsequent stages, the increase in thermal generation remains significant, averaging around 40% higher than in the original scenarios. Over the entire planning horizon, the average increase in thermal energy production reaches approximately 60%, highlighting the system's increased reliance on gas when prices are reduced, and reinforcing its role as a cost-effective transitional technology.

Lastly and going with the cost analysis, total operation and investment costs are displayed in the following table:

| ***Gas Production*** | ***Scenario*** | ***Investment [M€]*** | ***Operation[M€]*** | ***Total[M€]*** |
|---|---|---|---|---|
| *N-* | 0 - Base Scenario | 32.144 | 51.095 | **83.239** |
| | C - Lower Gas Price | 25.418 | 49.353 | **74.771** |
| *P-* | 0 - Base Scenario | 41.298 | 48.063 | **89.361** |
| | C - Lower Gas Price | 34.462 | 46.374 | **80.836** |

Table 17: Gas Price Total Cost

Despite the reduction in gas prices, the total operational cost experiences only a marginal decrease. This is because the volume of dispatched gas increases substantially, offsetting the cost benefit of the lower fuel price. As a result, operational savings remain limited.

However, the shift in investment timing, enabled by the increased use of gas in earlier stages, results in a notable cost reduction. Specifically, when comparing the low-gas-price scenarios to the base cases, the total system cost is reduced by approximately 7 billion €, primarily due to deferred capital investments. Despite the reduction in costs, increased reliance on gas-fired generation leads to higher $CO_2$ emissions (approximately 67 million tons over the 15-year period). This not only exacerbates environmental impact but also diverges from the core objectives of the PNIEC, particularly the target of reducing greenhouse gas (GHG) emissions.

### 5.2.4. DISCOUNT RATE

The time value of money plays a critical role in cost analysis and long-term planning, acting as a primary driver in investment decision-making. The discount rate used in such models reflects a combination of factors including inflation, cost of capital, and the investor's risk tolerance. Therefore, selecting an appropriate discount rate is essential when designing a multi-year investment strategy, as it significantly influences both the timing and scale of investments.

In the base model scenarios, a 7% discount rate is applied, resulting in total system costs of approximately 89 billion € for the P-0 scenario and 83 billion € for the N-0 scenario. To evaluate the impact of this assumption, a sensitivity analysis is conducted using a higher discount rate of 12%, representing more conservative or risk-averse investor conditions.

This comparison allows for a better understanding of how discount rates influence not only total system costs but also the preferred timing and structure of investments over the planning horizon. The sensitivity cases are defined with the letter "D".

Starting with the analysis of the costs, Table 18 shows the impact of the rate.

| Stage | Cost Type | P-0 [M€] | P-D [M€] | N-0 [M€] | N-D [M€] |
|---|---|---|---|---|---|
| **Stage 0 - 2025** | Investment | 9.257 | 7.178 | 9.108 | 7.227 |
| | Operational | 17.908 | 16.154 | 17.972 | 16.489 |
| | **Total** | **27.165** | **23.332** | 27.080 | **23.716** |
| **Stage 1 - 2030** | Investment | 21.194 | 14.235 | 15.666 | 10.470 |
| | Operational | 17.002 | 12.452 | 17.830 | 13.048 |
| | **Total** | **38.196** | **26.687** | 33.496 | **23.518** |
| **Stage 2 - 2035** | Investment | 10.845 | 6.321 | 7.369 | 4.288 |
| | Operational | 13.153 | 7.666 | 15.293 | 8.913 |
| | **Total** | **23.998** | **13.987** | **22.662** | **13.201** |
| **Stages Total** | **Total Inv.** | 41.296 | 27.734 | 32.143 | 21.985 |
| | **Total Op.** | 48.063 | 36.272 | 51.095 | 38.450 |
| | **Total** | **89.359** | **64.006** | **83.238** | **60.435** |

Table 18: Discount Factor Costs

As observed, a significant reduction in total system costs occurs when the discount rate is increased, affecting both investment and operational cost components. A variation of just 5 percentage points from 7% to 12%, results in an approximately 30% decrease in total projected costs, equivalent to around 25 billion €. This reduction impacts both cost categories in a relatively balanced manner, underscoring the sensitivity of cost optimization models to the discount rate. These findings highlight the critical importance of accurately defining the discount rate, particularly in long-term investment planning where its influence on timing and strategy is substantial.

From an investment strategy perspective, the variation in the discount rate does not significantly alter the investment pattern, either in terms of timing or installed capacities. The model maintains a similar deployment strategy across stages, suggesting that while total costs are sensitive to the discount rate, the optimal allocation of investments remains structurally consistent. In order to be able to make this comparison all costs are brought to present value as operation and investment costs are assumed to be constant along the whole planning horizon.

# CHAPTER 6: CONCLUSIONS

This chapter aims to summarize the key findings from the comparative analysis of the two core scenarios studied, one with nuclear decommissioning and the other with nuclear retention. The analysis is conducted over a 15-year planning horizon, consistent with the scheduled timeline for nuclear decommissioning in Spain and the objectives outlined in the *Plan Nacional Integrado de Energía y Clima* (PNIEC). It also explores the sensitivity of results to demand forecasting, gas prices, storage assumptions, and discount rates. Together, these insights provide a comprehensive understanding of the economic and technical trade-offs involved in investment decisions.

## 6.1. NUCLEAR & 2030 CAPACITY TARGETS

The comparative analysis of both case scenarios (nuclear decommissioning and nuclear retention) over a 15-year horizon highlights several important findings:

- **System Sizing and Investment**: Maintaining nuclear capacity significantly reduces total new installed capacity (renewable + storage) requirements by 26% in 2030 and 35,5% in 2035, resulting in a 30% overall reduction in newly installed capacity (about 53 GW) and 6 billion € in net present value of total system cost savings.
- **Operational Challenges**: The increased renewable deployment in the nuclear decommissioning scenario leads to significantly higher curtailment levels (32.5% for wind and 3.5% for solar PV) despite greater storage capacity. This highlights grid integration and efficiency limitations. In contrast, maintaining nuclear power reduces curtailment to 24.3% for wind and 0.8% for PV, improving overall system performance.

- **PNIEC Alignment**: The projected nuclear decommissioning scenario closely matches the PNIEC investment capacity targets. It does so under a lower demand assumption (332,3 TWh vs 358 TWh), which suggests that the current PNIEC targets may be undersized if demand grows as projected, if analysed strictly from a minimum cost point of view.
- **Nuclear as a Strategic Asset**: By keeping all nuclear power, the projected demand growth for 2030 can be achieved with significantly less renewable and storage capacity (10 GW less PV, 8 GW less wind, and 2 GW less storage), highlighting the nuclear role in easing deployment pressure and improving system balance.

In summary, while both pathways contribute to decarbonization, retaining nuclear power provides clear **economic and technical benefits** and may be critical to achieving a cost-effective and reliable energy transition.

## *6.2. DEMAND FORECASTING*

Forecasting demand growth is a critical component in the analysis of long-term investment strategies and policy target setting. Even small deviations in projected demand can translate into substantial differences, measured in tens of gigawatts of capacity and billions of euros in investment requirements. The following conclusions can be drawn from the demand sensitivity analysis:

- **Demand Growth and System Planning Impact:** A relatively small 8% reduction in electricity demand results in an average 16% decrease in new installed capacity (renewable + storage), emphasizing the importance of accurately defining demand growth.
- **Economic Robustness of Nuclear Retention**: Changes in demand growth do not alter the economic difference between decommissioning and retaining nuclear. Meaning that, independently of the demand growth, the cost advantage of maintaining nuclear capacity remains approximately 6 billion €, although total system costs vary according to the installed capacities requirements.

- **Reduced Sensitivity of Nuclear Under Slower Growth**: As overall installed capacity needs decline with slower demand growth, the relative capacity difference between scenarios with and without nuclear narrows. This suggests that the strategic value of nuclear power becomes more pronounced under high-growth scenarios.

  **Risks of Fixed Planning Targets**: Setting fixed capacity targets in the energy and climate plans based on a single demand projection introduces significant planning risk. A more resilient approach would be to scale targets proportionally to actual demand, assigning technology shares based on demand levels, thereby increasing planning flexibility and realism.

## *6.3. STORAGE ROLE*

Storage technologies play a vital role in enabling the integration of high shares of renewable energy. In all scenarios, the optimization model consistently selects pumped hydro storage due to its favourable investment cost and large storage capacity potential. Even under adverse conditions, such as reduced storage duration or increased investment costs of pumped hydro, battery storage remains largely underinvested, indicating its limited economic competitiveness within the current cost assumptions.

- **Storage Duration of Pumped Hydro (Equivalent Hours):** The required installed capacity is inversely proportional to storage duration. When equivalent operating hours are halved (e.g., from 30 to 15 hours), the system must double the installed capacity to maintain energy balance. However, shorter storage durations reduce system flexibility, leading to higher renewable curtailments, particularly for wind.
- **Investment Cost of Pumped Hydro:** When pumped hydro investment costs are increased, the system shifts away from long-duration storage. Instead, it compensates through overinvestment in renewable generation, which leads to higher curtailment levels. At sufficiently high prices of pumped hydro, the model begins to introduce battery storage, though only in limited quantities.

  Furthermore, excessive investment costs result in an overall decline in installed storage, compromising the system's ability to balance supply and demand effectively. This leads to greater curtailments, higher operational costs, and in some cases, the appearance of ENS events.

These findings underscore the central role of affordable, large-scale storage, particularly pumped hydro, in achieving a reliable and cost-efficient energy transition. The cost and duration of storage capacity are critical parameters that strongly influence system performance, renewable integration, and overall investment strategy.

## 6.4. GAS PRICE EFFECT

Natural gas prices are a significant variable: despite accounting for only 10% of installed capacity in 2035, thermal generation represents approximately 35% of total operational costs and only 4% of the total energy dispatched.

- **Effect of Lower Gas Prices:** Securing lower and stable gas prices leads to a significant increase in thermal generator utilization. While this does not reduce operational costs, since the increase in generation offsets the lower unit price, it results in a shift in investment toward later years, capitalizing on discounting effects and deferring investment expenditures.
- **Quantified Impact:** A 40% reduction in gas prices, from 105 €/MWh to 60 €/MWh, leads to an average 65% increase in thermal generation and delivers a 9 billion € reduction in total system costs, driven primarily by changes in investment behaviour. Although the economic impact is significant, the cost reduction comes at the expense of an increase in $CO_2$ emissions, estimated at approximately 67 million tons over the 15-year period.

## 6.5. DISCOUNT RATE IMPACT

In the context of multistage investment planning, the discount rate is a fundamental parameter that reflects inflation, capital costs and the level of risk investors are prepared to assume.

- **Discount Rate Effect:** A variation from 7% to 12% in the discount rate, used to simulate more conservative investment conditions, results in a total net present value cost reduction of approximately 30%, or 25 billion €, affecting both investment and operational expenditures.
- **Investment Strategy:** Despite this significant cost impact, the structure and timing of investments remain largely unchanged. Meaning a consistent deployment pattern is kept, indicating that the optimal investment strategy is not affected by the discount rate in terms of installed power and timing of the installation.

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# ANNEX I – SDG

Since the project main concerns are about the changes brought by the integration of renewables into the energy mix, as well as the proposed policies to support the energy transition, a clear relationship can be established between this thesis and several of the Sustainable Development Goals (SDGs). The three main ones are defined below:

**SDG 7: Affordable and Clean Energy**

The National Integrated Energy and Climate Plan (PNIEC) is linked to the energy transition, as the criteria outlined in this plan aims, among other things, to facilitate the shift toward more sustainable systems, by reducing GHG emissions and integrating renewables technologies.

**SDG 9: Industry, Innovation, and Infrastructure**

Investment in renewables involves the implementation of new systems and the upgrading of infrastructure to enable a proper transition. The range of impact of the measures that are being evaluated have a great importance on the correct development of the economy, as new jobs and industries are developed.

**SDG 13: Climate Action**

Finally, it is more than evident that since the project addresses issues directly related to the energy transition, there is a clear connection with this SDG, whose main goal is to combat climate change. In this thesis this combat is made via the integration and development of renewables in the generation mix.

# ANNEX II - CODE

```
def economic_dispatch_model1(ND,NE, NG_W, NG_PV, NG_TH, NG_N, NT, C_W, C_PV,
C_TH, C_N, C_ENS, Q_W_h_norm, Q_PV_h_norm, Q_TH_h_norm, Q_D_Y, Q_W, Q_PV, Q_N_e,
Q_TH, Q_H, Q_B, eff_H, eff_B, CI_W, CI_PV, CI_H, CI_B, CF_H, C_H, CF_B, C_B,
EC_H, EC_B, Q_H_max, C_TH_SU, C_TH_SD,FA,FA_INV):

    model = gp.Model("ED_model")
    model.setParam(GRB.Param.MIPGap, 0.001)

  # VARIABLES DEFINITION
    p_w = model.addMVar(shape=(NG_W, NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_w")
    p_pv = model.addMVar(shape=(NG_PV, NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_pv")
    p_th = model.addMVar(shape=(NG_TH, NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_th") # lowercase fro variables--Power dispatch for
each tech.
    p_n = model.addMVar(shape=(NG_N, NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_n")

  # ENS
    p_ens = model.addMVar(shape=(NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_ens") # updated the shape of matrix variable (NT,1)

  # NEW VARIABLES FOR BATTERIES
    p_hi = model.addMVar(shape=(NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_hi")
    p_ho = model.addMVar(shape=(NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_ho")
    soc_h = model.addMVar(shape=(NE,NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="soc_h")

    p_bi = model.addMVar(shape=(NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_bi")
    p_bo= model.addMVar(shape=(NE, NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="p_bo")
    soc_b = model.addMVar(shape=(NE,NT), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="soc_b")

  # NEW VARIABLES FOR INCREASE OF CAPACITY
    ip_w = model.addMVar(shape=(NE), lb=0, ub=GRB.INFINITY, vtype=GRB.CONTINUOUS,
name="ip_w")
    ip_pv = model.addMVar(shape=(NE), lb=0, ub=GRB.INFINITY,
vtype=GRB.CONTINUOUS, name="ip_pv")
    ip_h = model.addMVar(shape=(NE), lb=0, ub=GRB.INFINITY, vtype=GRB.CONTINUOUS,
name="ip_h")
    ip_b = model.addMVar(shape=(NE), lb=0, ub=GRB.INFINITY, vtype=GRB.CONTINUOUS,
name="ip_b")
```

```
  # NEW VARIABLES FOR THERMAL STARTUP AND SHUTDOWN
    c_th_su = model.addMVar(shape=(NG_TH, NE, NT), lb=0, ub=C_TH_SU,
vtype=GRB.CONTINUOUS, name="c_th_su")
    c_th_sd = model.addMVar(shape=(NG_TH,NE, NT), lb=0, ub=C_TH_SD,
vtype=GRB.CONTINUOUS, name="c_th_sd")
    on_th = model.addMVar(shape=(NG_TH,NE, NT),vtype=GRB.BINARY, name="on_th")
    off_th = model.addMVar(shape=(NG_TH,NE, NT), vtype=GRB.BINARY, name="off_th")
    u_on = model.addMVar(shape=(NG_TH,NE, NT), vtype=GRB.BINARY, name="u_on")

  # CAPACITY DEFINITIONS
    # Wind
    Q_W_e = pd.DataFrame({'Investment Wind MW': [0.0] * NE})
    Q_W_e = Q_W_e.astype(object)

    for e in range(NE):
        if e == 0:
            Q_W_e.iloc[e,0] = Q_W + ip_w[e]
        else:
            Q_W_e.iloc[e,0] = Q_W_e.iloc[e-1,0] + ip_w[e]

    # Solar
    Q_PV_e = pd.DataFrame({'Investment Solar MW': [0.0] * NE})
    Q_PV_e = Q_PV_e.astype(object)

    for e in range(NE):
        if e == 0:
            Q_PV_e.iloc[e,0] = Q_PV + ip_pv[e]
        else:
            Q_PV_e.iloc[e,0] = Q_PV_e.iloc[e-1,0] + ip_pv[e]

    # Hydro
    Q_H_e = pd.DataFrame({'Investment Batteries MW': [0.0] * NE})
    Q_H_e = Q_H_e.astype(object)

    for e in range(NE):
        if e == 0:
            Q_H_e.iloc[e,0] = Q_H + ip_h[e]
        else:
            Q_H_e.iloc[e,0] = Q_H_e.iloc[e-1,0] + ip_h[e]

    # Batteries
    Q_B_e = pd.DataFrame({'Investment Hydro MW': [0.0] * NE})
    Q_B_e = Q_B_e.astype(object)

    for e in range(NE):
        if e == 0:
            Q_B_e.iloc[e,0] = Q_B + ip_b[e]
        else:
            Q_B_e.iloc[e,0] = Q_B_e.iloc[e-1,0] + ip_b[e]

  # CAPACITY CONSTRAINTS
    # Wind:
```

```
    for g in range(NG_W):
        for e in range(NE):
            for t in range(NT):
                model.addConstr(p_w[g, e, t] <= (Q_W_h_norm.iloc[g,t] *
(Q_W_e.iloc[e,0])), name="Wind_Capacity_"+ str(g)+"_"+str(t))

    # Solar:
    for g in range(NG_PV):
        for e in range(NE):
            for t in range(NT):
                model.addConstr(p_pv[g, e, t] <= (Q_PV_h_norm.iloc[g,t] *
(Q_PV_e.iloc[e,0])), name="PV_Capacity_"+ str(g)+"_"+str(t))

    # Thermal
    for g in range(NG_TH):
        for e in range(NE):
            for t in range(NT):
                model.addConstr(p_th[g, e, t] <= Q_TH_h_norm.iloc[g,t] * Q_TH *
u_on[g,e,t], name="Thermal_Capacity_"+str(g)+"_"+str(t)) #p_th_g, t ≤
Q_TH_h_norm_g, t * Q_TH
                model.addConstr(p_th[g, e, t] >= 0.1 * Q_TH_h_norm.iloc[g,t] *
Q_TH * u_on[g,e,t], name="Thermal_Capacity_Off"+str(g)+"_"+str(t)) #p_th_g, t ≤
Q_TH_h_norm_g, t * Q_TH

    # Nuclear
    for g in range(NG_N):
        for e in range(NE):
            for t in range(NT):
                model.addConstr(p_n[g, e, t] <= Q_N_e.iloc[e, 0],
name="Nuclear_Capacity_"+ str(g)+"_"+str(t))  #p_W_g, t ≤ Q_W_h_norm_g, t * Q_W
                model.addConstr(p_n[g, e, t] >= 0.9 * Q_N_e.iloc[e, 0],
name="Nuclear_Capacity_Off"+ str(g)+"_"+str(t))  #p_W_g, t ≤ Q_W_h_norm_g, t *
Q_W

   # THERMAL SU & SD CONSTRAINTS
    for g in range(NG_TH):
        for e in range(NE):
            for t in range(NT):
                model.addConstr((on_th[g,e,t] + off_th[g,e,t]) <= 1,
name="Thermal_Verification"+str(g)+"_"+str(t))

                if t == 0:
                    model.addConstr(on_th[g,e,t] - off_th[g,e,t] == u_on[g,e,t],
name="Thermal_Operation"+str(g)+"_"+str(t))

                else:
                    model.addConstr(on_th[g,e,t] - off_th[g,e,t] == u_on[g,e,t] -
u_on[g,e, t-1], name="Thermal_Operation"+str(g)+"_"+str(t))

    for g in range(NG_TH):
        for t in range(NT):
            model.addConstr(c_th_su[g,e, t] == C_TH_SU * on_th[g,e,t],
name="Thermal_Startup_Costs"+str(g)+"_"+str(t))
```

```
            model.addConstr(c_th_sd[g,e, t] == C_TH_SD * off_th[g,e,t],
name="Thermal_Shutdown_Costs"+str(g)+"_"+str(t))

  # STORAGE CONSTRAINTS
    for e in range (NE):
        for t in range(NT):
            model.addConstr(soc_h[e,t] <= (EC_H * Q_H_e.iloc[e,0]) ,
name="SOC_H_capacity_up"+"_"+str(t))
            #model.addConstr(soc_h[t] <= (EC_H * (Q_H + ip_h[e])) ,
name="SOC_H_capacity_up"+"_"+str(t))
            model.addConstr(soc_h[e,t] >= (0.2 * EC_H * Q_H_e.iloc[e,0]),
name="SOC_H_capacity_low"+"_"+str(t))
            #model.addConstr(soc_h[t] >= (0.2 * EC_H * (Q_H + ip_h[e])),
name="SOC_H_capacity_low"+"_"+str(t))

            model.addConstr(p_ho[e, t] <= (Q_H_e.iloc[e,0]), name="P_HO_limit"+
str(g)+"_"+str(t))
            #model.addConstr(p_ho[e, t] <= (Q_H + ip_h[e]), name="P_HO_limit"+
str(g)+"_"+str(t))
            model.addConstr(p_hi[e, t] <= (Q_H_e.iloc[e,0]), name="P_HI_limit"+
str(g)+"_"+str(t))
            #model.addConstr(p_hi[e, t] <= (Q_H + ip_h[e]), name="P_HI_limit"+
str(g)+"_"+str(t))

    for e in range (NE):
        for t in range(NT):
            if t == 0:
                model.addConstr(soc_h[e, t] == (0.2 * EC_H *Q_H_e.iloc[e,0]),
name="SOC_H_constraint"+"_"+str(t))
                #model.addConstr(soc_h[t] == (0.2 * EC_H *(Q_H + ip_h[e])),
name="SOC_H_constraint"+"_"+str(t))
                model.addConstr(p_ho[e, t] == 0, name="P_HO_constraint_" +
str(t))
            else:
                model.addConstr(soc_h[e, t] == soc_h[e, t-1] + ((p_hi[e, t] *
eff_H) - (p_ho[e, t]/eff_H)) * Hr, name="SOC_H_" + str(t))


    for e in range (NE):
        for t in range(NT):
            model.addConstr(soc_b[e, t] <= (EC_B * Q_B_e.iloc[e,0]) ,
name="SOC_B_capacity_up"+"_"+str(t))
            model.addConstr(soc_b[e, t] >= (0.2 * EC_B * (Q_B_e.iloc[e,0])),
name="SOC_B_capacity_low"+"_"+str(t))

            model.addConstr(p_bo[e, t] <= (Q_B_e.iloc[e,0]), name="P_BO_limit"+
str(g)+"_"+str(t))
            model.addConstr(p_bi[e, t] <= (Q_B_e.iloc[e,0]), name="P_BI_limit"+
str(g)+"_"+str(t))

    for e in range (NE):
        for t in range(NT):
            if t == 0:
```

```
                model.addConstr(soc_b[e, t] == (0.2 * EC_B * (Q_B_e.iloc[e,0])),
name="SOC_B_constraint"+"_"+str(t))
                model.addConstr(p_bo[e, t] == 0, name="P_BO_constraint_" +
str(t))
            else:
                model.addConstr(soc_b[e, t] == soc_b[e, t-1] + ((p_bi[e, t] *
eff_B) - (p_bo[e, t]/eff_B)) * Hr, name="SOC_B_" + str(t))

  # POWER BALANCE CONSTRAINT
    for e in range(NE):
        for t in range(NT):
            model.addConstr(sum(p_w[g, e, t] for g in range(NG_W))
                            + sum(p_pv[g, e, t] for g in range(NG_PV))
                            + sum(p_th[g, e, t] for g in range(NG_TH))
                            + sum(p_n[g, e, t] for g in range(NG_N))
                            + p_ens[e, t] + p_ho[e, t] - p_hi[e, t] + p_bo[e, t]
- p_bi[e, t] == Q_D_Y.iloc[e,t], name="Power_Balance_" + str(t))

  # Construir el objetivo
    objective = sum( FA[e]*(sum(
        # Parte 1: Generadores eólicos
        sum(p_w[g, e, t] * C_W for g in range(NG_W))

        # Parte 2: Generadores fotovoltaicos
        + sum(p_pv[g, e, t] * C_PV for g in range(NG_PV))

        # Parte 3: Nuclear
        + sum(p_n[g, e, t] * C_N for g in range(NG_PV))

        # Parte 4: Térmica
        + sum(p_th[g,e,t] * C_TH_array[g] + c_th_su[g,e,t] + c_th_sd[g,e,t] for g
in range(NG_TH))

        # Parte 5: Energía hidráulica y almacenamiento
        + (Q_H_e.iloc[e,0] * CF_H + p_ho[e, t] * C_H)
        + (Q_B_e.iloc[e,0] * CF_B + p_bo[e, t] * C_B)

        # Parte 6: Energía ENS
        + (p_ens[e, t] * C_ENS)
        for t in range(NT)))

        # Parte 7: Inversión
        + FA_INV[e]*(ip_w[e] * CI_W
        + ip_pv[e] * CI_PV
        + ip_h[e] * CI_H
        + ip_b[e] * CI_B)

        for e in range(NE))

    # Establecer el objetivo en el modelo
    model.setObjective(objective, GRB.MINIMIZE)
    model.optimize()
```

```
    if model.status != GRB.OPTIMAL:
        print("Warning: The optimization did not reach an optimal solution.")

    Obj_value = model.objVal
    Q_W_e_df = pd.DataFrame(Q_W_e.iloc[e,0].getValue() for e in range(NE))
    Q_PV_e_df = pd.DataFrame(Q_PV_e.iloc[e,0].getValue() for e in range(NE))
    Q_H_e_df = pd.DataFrame(Q_H_e.iloc[e,0].getValue() for e in range(NE))
    Q_B_e_df = pd.DataFrame(Q_B_e.iloc[e,0].getValue() for e in range(NE))

    #Calculations after optimization
    #Value of generation dispatch
    #p_w_df = pd.DataFrame(p_w.X[0,:,:], index=list(range(NE)),
columns=list(range(NT)))
    #p_pv_df = pd.DataFrame(p_pv.X[0,:,:], index=list(range(NE)),
columns=list(range(NT)))
    #p_th_df = pd.DataFrame(p_th.X, index=list(range(NG_TH)),
columns=list(range(NE), columns=list(range(NT)))
    #p_n_df = pd.DataFrame(p_n.X[0,:,:], index=list(range(NE)),
columns=list(range(NT)))
    #p_ens_df = pd.DataFrame(p_ens.X, index=list(range(NE)),
columns=list(range(NT)))

    #c_th_su_df = pd.DataFrame(c_th_su.X, index=list(range(NG_TH)),
columns=list(range(NT)))
    #c_th_sd_df = pd.DataFrame(c_th_sd.X, index=list(range(NG_TH)),
columns=list(range(NT)))
    #u_on_df = pd.DataFrame(u_on.X, index=list(range(NG_TH)),
columns=list(range(NT)))

    #To compute marginal cost using the power balance constraint
    #marginal_costs=[]#initialization of a list to save the dual variables
    #for c in model.getConstrs(): #get all constraints of the model
    #    if ((c.ConstrName).startswith ("Power_Balance_")): #select only the
constraints of power balance
    #         marginal_costs.append(c.Pi) #Add only dual variables of power
balance constraint in marginal_cost
    #marginal_costs_df = pd.DataFrame(marginal_costs)#marginal cost in dataframe
format


    return Obj_value, p_th.X, p_w.X, p_pv.X, p_n.X, p_ens.X, p_hi.X, p_ho.X,
soc_h.X, p_bi.X, p_bo.X, soc_b.X, c_th_su.X, c_th_sd.X, u_on.X, ip_w.X, ip_pv.X,
ip_h.X, ip_b.X, on_th.X, off_th.X, Q_W_e_df ,Q_PV_e_df, Q_H_e_df, Q_B_e_df
```

# ANNEX III – ABBREVIATIONS

| | |
|---|---|
| **TERMS** | |
| EU | European Union |
| OMIE | Operador del Mercado Ibérico de la Energía |
| REE | Red Eléctrica Española |
| CNMC | Comisión Nacional de Mercados y Competencia |
| MIBEL | Mercado Ibérico de la Electricidad |
| PNIEC | Plan Nacional Integrado de Energía y Clima |
| PGRR | Plan General de Residuos Radioactivos |
| GHG | Green House Gases |
| TSO | Transport System Operator |
| NRA | National Regulatry Authority |
| MW | Megawatt |
| GW | Gigawatt |
| PV | Photovoltaic |
| CCGT | Combined Cycle Gas Turbine |
| ENS | Energy Not Supplied |
| VoLL | Value of Lost Load |
| SoC | State of Charge |
| CAPEX | Capital Expenditure |
| **SCENARIOS** | |
| P- | Decommissioning scenarios |
| N- | Nuclear retention scenarios |
| 0 | Base Case |
| A | Demand Sensitivity |
| B1 | Storage Sensitivity – 15 hour storage |
| B2 | Storage Sensitivity – High Cost CAPEX |
| B3 | Storage Sensitivity – Storage Capacity Limit |
| C | Gas Price Sensitivity |
| D | Discount Rate Sensitivity |

# ANNEX IV – EQUATIONS GLOSSARY

| **Nomenclature** | | | |
|---|---|---|---|
| ***Sets:*** | | | |
| $N_T$ | Set of time simulation periods | $NG_W$ | Set of total number of wind generators |
| $N_S$ | Set of total number of simulation stages | $NG_{PV}$ | Set of total number of solar generators |
| $N_D$ | Set of number of loads | $NG_{TH}$ | Set of total number of thermal generators |
| | | $NG_N$ | Set of total number of nuclear generators |
| ***Nomenclature:*** | | | |
| g | Generator ID | s | Stage |
| t | Period of time | y | Year |
| n | Normalized | | |
| ***Parameters:*** | | | |
| $hp$ | Planned Horizon (Duration) | $p$ | Length between stages (hp / NS) |
| $r$ | Discount rate | | |
| $C_W$ | Cost per MW of wind dispatched [€/MWh] | $C_{TH}^{g}$ | Cost per MW for thermal produced by each generator [€/MWh] |
| $C_{PV}$ | Cost per MW of PV dispatched [€/MWh] | $C_{TH-SU}$ | Cost for turning on the thermal generator [€] |
| $C_N$ | Cost per MW of nuclear dispatched[€/MWh] | $C_{TH-SD}$ | Cost for turning off the thermal generator [€] |
| $CF_H$ | Fixed cost per MW installed of hydro pump storage dispatched [€/MW-year] | $CF_B$ | Fixed cost per MW installed of battery storage [€/MW-year] |
| $C_H$ | Cost per MW of hydro pump dispatched [€/MWh] | $C_B$ | Cost per MW of battery dispatched [€/MWh] |
| $C_{ENS}$ | Cost per MW not supplied [€/MWh] | | |
| $CI_W$ | Cost for new MW of wind installed [€/MW] | $CI_H$ | Cost for new MW of hydro pump installed [€/MW] |
| $CI_{PV}$ | Cost for new MW of PV installed [€/MW] | $CI_B$ | Cost for new MW of batteries installed [€/MW] |
| $EC_H$ | Equivalent capacity hydro. This parameter correlates the storage capacity with the installed power. | $\eta_H$ | Efficiency of the hydro pump system |
| $EC_B$ | Equivalent capacity hydro. This parameter correlates the | $\eta_B$ | Efficiency of the batteries system |

| | | | |
|---|---|---|---|
| | storage capacity with the installed power. | | |
| $Q_{Wini}$ | Existing Wind capacity | $Q_{Bini}$ | Existing Battery capacity |
| $Q_{PVini}$ | Existing PV capacity | $Q_{Hini}$ | Existing Hydro capacity |
| ***Variables:*** | | | |
| $Q_D$ [s] | System total demand (MW) | $Q_{TH}$ [s] | Thermal capacity per generator (MW) |
| $Q_W$ [s] | Total capacity of wind installed (MW) | $Q_H$ [s] | Total capacity of hydro installed (MW) |
| $Q_{PV}$ [s] | Total capacity of PV installed (MW) | $Q_B$ [s] | Total capacity of battery installed (MW) |
| $Q_N$ [s] | Total capacity of nuclear installed (MW) | | |
| $p_W[g,s,t]$ | MW of wind dispatched by generator g in period time t | $p_{HO}[s,t]$ | Output of hydro to the system in period t |
| $p_{PV}[g,s,t]$ | MW of PV dispatched by generator g in period time t | $p_{HI}[s,t]$ | Input of hydro from the system in period t |
| $p_N[g,s,t]$ | MW of nuclear dispatched by generator g in period time t | $p_{BO}[s,t]$ | Output of batteries to the system in period t |
| $p_{th}[g,s,t]$ | MW of thermal dispatched by generator g in period time t | $p_{BI}[s,t]$ | Input of batteries from the system in period t |
| $p_{ENS}[s,t]$ | MW of energy not dispatched in period time t | $soc_H[s,t]$ | Hydro state of charge in period t |
| | | $soc_B[s,t]$ | Battery state of charge in period t |
| $u_{on}[g,s,t]$ | Status of thermal gen. g in period t | $C_{TH-SU}\ [g,s,t]$ | Variable to define whether to apply start-up cost for generator g in period t and its associated cost |
| $on_{TH}[g,s,t]$ | Internal control var. to keep record track of SU | $C_{TH-SD}\ [g,s,t]$ | Variable to define whether to apply shut-down cost for generator g in period t and its associated cost |
| $off_{TH}[g,s,t]$ | Internal control var. to keep record of SD generators | | |
| $ip_w[s]$ | New Installed Wind Power [MW] | $ip_H[s]$ | New Installed Hydro Power [MW] |
| $ip_{PV}[s]$ | New Installed PV Power [MW] | $ip_B[s]$ | New Installed Battery Power [MW] |