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Executive Summary

This deliverable D6.12 of the EU-SCORES project presents a market price assessment of different electricity sources – primarily offshore wind – across three key European electricity markets: Iberia (Spain and Portugal), Ireland, and the Benelux region (Netherlands, Belgium, Luxembourg), with Germany included for broader context. The objective is to evaluate the market behaviour and potential revenues of offshore renewable energy parks under projected 2030 conditions. The analysis supports the business case development for hybrid renewable energy parks by simulating how different energy sources interact with market dynamics, regional demand, and flexibility options.

Three advanced regional simulation models were employed: CEVESA for the Iberian Peninsula, MaREI PLEXOS for Ireland, and the DMEC MultiORE and price model for Benelux and Germany. These models were fed with scenarios based on projections from the latest National Energy and Climate Plans (NECPs), historical weather and market data, and future demand assumptions. A wide range of scenarios were explored, including variations in offshore and onshore wind capacities, hydrogen demand, and system flexibility.

Results show that increasing offshore wind capacity generally lowers electricity prices due to its high-capacity factor (compared, for example, to the same onshore wind capacity) and low marginal cost.

In Iberia, high offshore wind penetration significantly reduces market prices, especially when flexible demand (e.g. hydrogen production) is present to absorb surplus generation avoiding spillages. Without flexibility, overgeneration leads to high renewable spillage and reduced capture prices (i.e. unitary incomes), potentially undermining investment viability unless supported by long-term contracts or policy incentives.

Similar trends were observed in the Benelux and Germany, where a strong linear relationship between residual load and electricity price was used as a simplified future price modelling. Capture prices differ among technologies, with wave and offshore wind often achieving slightly higher values than solar due to more uniform hourly generation profiles, better temporal alignment with demand and therefore a lower cannibalization effect. Solar capture prices become notably low when flexible demand is insufficient, underscoring the importance of demand-side flexibility to counteract the non-dispatchable renewable generation cannibalization and maintain economic viability in a system with large non-dispatchable renewable generation.

In Ireland, the transition towards a more renewable grid by 2030 – with an emphasis on wind, including offshore – shows clear benefits, such as reduced gas dependency, lower and more stable electricity prices, and reduced-price volatility. Offshore wind complements the daily and seasonal generation patterns of solar, contributing to grid stability. However, as in other regions, increased wind capacity depresses capture prices due to surplus generation during low-demand periods,



posing economic challenges for unsubsidized projects when the system lacks enough flexibility.

Across all regions, the study finds that decarbonizing the electricity system through offshore and hybrid renewable energy sources seems technically feasible from a market perspective, since investment costs were not assessed, further analysis is required to fully determine economic viability from an investor standpoint. Capture prices reduction and potential revenue cannibalization can boost investments in flexible technologies such as hydrogen production or batteries storage systems that would profit from low prices, smoothing the hourly price profiles. In addition, well designed capacity markets and supportive regulatory frameworks, and further developing interconnections can also counteract the cannibalization effect and contribute to further non-dispatchable renewable generation penetration, contributing also to a better operation of the system. Indeed, these elements are key to ensure that renewable investments remain attractive, and that the energy transition delivers both sustainability and market stability. The findings can provide guidance for policymaking, investment strategies, and future research aimed at optimizing the integration of offshore renewables into European energy systems.



Acronyms and abbreviations

ACP	Average Captured Price
aFRR	Automatic Frequency Restoration Reserve
BTM	Behind-The-Meter
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DA	Day Ahead (market)
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity
ERA5	Fifth generation ECMWF atmospheric reanalysis of the global climate
EUA	European Union Allowance (CO ₂ emissions trading)
LCOE	Levelized Cost of Energy
MIBEL	Iberian Electricity Market
NECP	National Energy and Climate Plan
NSE	Not Supplied Energy
NTC	Net Transfer Capacity
P2G	Power to Gas
P2H	Power to Heat
PV	Photovoltaic
RES	Renewable Energy Source
SEM	Single Electricity Market (Ireland)
SNSP	System Non-Synchronous Penetration
TSO	Transmission System Operator
TTF	Title Transfer Facility (Dutch gas trading point)
V2G/V2GR	Vehicle to Grid/Vehicle to Grid with Reserve



1 Introduction

1.1 Objectives

The increasing drive towards decarbonization and energy diversification in Europe necessitates a deeper understanding of how emerging renewable technologies can be integrated into regional electricity markets. Within this context, Task 6.6 of the EU-SCORES project focuses on assessing the market potential of offshore wind energy parks in three distinct regional electricity markets: Iberia, Ireland, and the Benelux region. This task, executed collaboratively by DMEC, INESC TEC, and EXCEEDENCE over months 32 to 48 (M32–M48) of the project, leverages three advanced market modelling tools to simulate the hourly electricity prices projected for 2030.

The primary goal of Task 6.6 is to evaluate the achievable revenues and market behaviour of offshore wind parks under future grid and market conditions. By analysing how these systems interact with regional demand and supply dynamics throughout the day, this task offers insights into the economic viability and strategic value of integrating multiple renewable sources offshore.

Deliverable D6.12 directly supports this task by providing a detailed market price assessment of electricity generated from different energy sources, with a focus on offshore wind across the Iberian Peninsula, Ireland, and the Benelux countries, with Germany included for a broader market view. Results serve as critical inputs for the business case analysis in Work Package 7 (WP7), where the competitiveness of multi-source parks versus single-source installations will be thoroughly evaluated.

Through the combined use of regional market models and technology-specific simulations, this work aims to inform policymakers, investors, and developers on the value proposition of offshore renewable diversification – highlighting how market will respond in the future.

1.2 Scope and limitations

This study leverages three dedicated regional market models:

- CEVESA for the Iberian market (Spain and Portugal),
- MultiORE plus the DMEC residual load-based Price Model for the Netherlands, Belgium and Germany plus Luxembourg.
- MaREI PLEXOS for Ireland,

The focus lies on modelling electricity prices for 2030 under a variety of scenarios that reflect plausible energy mixes, renewable capacities, and demand-side flexibilities. These simulations help assess the capture price for each technology and time-based pricing patterns critical to the economic viability of hybrid parks.

However, the analysis is subject to several limitations:



- **Input Data Uncertainty:** The projections are based on existing NECPs, historical weather data, and market assumptions. Future deviations in policy, fuel costs, CO₂ prices, and infrastructure development could significantly affect outcomes. The DMEC Price Model is a simplified simulation model using a linear correlation between the residual load and the electricity price. This provides the opportunity to perform multitudes of simulations to study the input data uncertainty.
- **Temporal Scope:** The market simulations focus on a single target year (2030). While this allows for a high-resolution analysis of intra-annual variation, long-term volatility or trends beyond 2030 are not considered.
- **Technology Representation:** While offshore wind technologies are included in the methodology, real-world performance data and large-scale deployment assumptions are still evolving. Therefore, results should be interpreted with caution for these emerging technologies.
- **Flexibility and Storage Assumptions:** While flexible load modelling is included, battery storage and hydrogen dynamics are simplified or absent in some cases, which may underestimate potential system balancing benefits.
- **Only Power Sector Modelled** in detail: models do not fully simulate interactions with other sectors as heating, transport, or industry sectors beyond electrification of loads.
- **Grid constraints are not modelled:** only system-wide curtailment is considered, and while some additional constraints can be considered (e.g., SNSP limits, inertia, minimum units) models do not represent the physical transmission grid in detail and do not compute any load flow analysis.
- **Capital costs:** investments costs, financing, and retail price impacts are outside scope.



2 Methodology

This section outlines some aspects of the methodological approach employed to assess market prices of different electricity sources across Iberia, Ireland, and the Benelux region (plus Germany). The methodology includes the models used, and the main common modelling assumptions, inputs and parameters, and outputs.

2.1 Models

This study leverages three dedicated regional market models:

- CEVESA for the Iberian market (Spain and Portugal), includes plant-level technical parameters (e.g. ramp rates, min/max generation, reserve requirements), and is described in more detail in section 3.1.
- MultiORE plus the DMEC residual load-based Price Model for the Netherlands, Belgium and Germany plus Luxembourg, that calculates renewable outputs via location-based capacity distributions and uses a residual load-based price regression method, described in more detail in section 4.1.
- MaREI PLEXOS for Ireland, that models operational constraints like SNSP limits and interconnector flow, and described in more detail in section 5.1.

Each model has its own methodological approach which are described in the referred sections.

2.2 Common assumptions

The simulations conducted across all regions are built upon a consistent set of fundamental assumptions to ensure coherence and comparability:

- **Target Year:** All simulations target the year 2030, chosen as a key milestone aligned with national and European decarbonization goals.
- **Time Resolution:** Market prices and system behaviours are analysed on an hourly basis to capture daily variability and intra-day patterns crucial for non-dispatchable renewable technologies.
- **Scenario Design:** Scenarios are based on projections in the latest NECPs and consider variations in renewable energy capacity, demand-side flexibility, and fuel/CO₂ prices.
- **Market Structures:** Day-Ahead (DA) electricity markets are simulated, reflecting the central pricing mechanism for electricity in Europe. Flexibility in demand (e.g., hydrogen production) and non-dispatchable supply (e.g., solar PV, offshore wind) are included where applicable.
- **Geographical Scope:** Each model reflects specific regional characteristics:
 - Iberia: CEVESA zonal market model
 - Ireland: MaREI PLEXOS model
 - Benelux and Germany: DMEC residual load-based linear model



- **Decarbonisation:** All models assume phase-out or reduction of coal and fuel oil capacity by 2030, replaced by increased renewable energy penetration and flexible loads.

2.3 Inputs

Each regional model is fed with comprehensive data sources, harmonised where feasible across the different geographic contexts:

Parameter	Unit	Description	Origin
Installed power capacities of different renewable energy technologies	MW	The cumulative (or regional) installed capacity of renewable energy technologies exploiting different resources	NECPs and ENTSO-E
Share of flexible load	%	Share of total demand that is flexible load (e.g. storage capacity, electrolysers)	ENTSO-E
Interconnection capacities	MW	Capacities of the interconnectors between countries	ENTSO-E and national TSOs
Resource profile	MWh p.u.	Timeseries of resource available in different locations over a range of years (hourly resolution)	ERA5 Copernicus, Solcast and WavEC
Demand profile	MWh	Timeseries of cumulative demand on national or grid level	National TSO
CO2 emission price	Euro	Historic and projected EUA price	Sendeco2 and NECPs
Gas price	Euro	Historic and forecasted Dutch TTF-based natural gas prices	Investing.com and TenneT

Each model can have specific inputs depending on the methodology behind and the level of detail, that are described in the corresponding model sections.



2.4 Outputs

The key outputs from the simulations are hourly electricity price time series for each country/region, which form the basis for assessing the revenue potential and capture prices for different technologies.

Main outputs include:

- **Hourly DA Market Prices:** Capturing the impact of RES generation and demand profiles across seasons and times of day.
- **Average Annual and Seasonal Prices:** Used to derive cost-recovery potential and compare across scenarios.
- **Technology-Specific Capture Prices:** Reflects the average price received by each technology, calculated as a weighted average over their hourly production.
- **RES Spillage and Non-Supplied Energy (NSE):** Quantifies curtailment and reliability gaps.
- **CO₂ Emissions Profiles:** Highlights environmental impact of each scenario and technology mix.

The output of this task helps to understand the electricity price at different daytimes and to assess the potential revenues of the technologies under study, needed for the business case in WP7.



3 Iberian market prices assessment

3.1 CEVESA Iberian market model

3.1.1 Model overview and main features

CEVESA, is a long-term planning and operation model of single-price zones interconnected with implicit capacity allocation for market coupling and market splitting computation.

The version used for this work implements the Iberian Electricity market (MIBEL) zones. There are academic versions that also include France (one zone) and Italy (several zones) that are in testing phase and have not been considered for the current work. However, the energy exchanged through the interconnections with France and Morocco are considered in a simplified way.

CEVESA can run a system costs minimization or a conjectural variations equilibrium problem (with an equivalent quadratic minimization problem that simplifies its resolution), where the strategies and market power of the market agents are represented by their conjectures [1], [2], and considers the joint dispatch of energy and secondary reserve (aFRR) capacity reservation. Secondary reserves can be computed endogenously from the expected renewable production and the demand. The version used for this project is based on the cost minimization approach, commonly used for long term market assessments.

CEVESA can represent the transportation sector by modelling the impact of electric and fuel cell vehicles on the market and can compute the evolution of the share of vehicles considering also internal combustion engine vehicles (CEV), taking into account infrastructure deployment, fuel, and social and environmental costs of transportation technologies [2]. No transport sector has been considered since the impact expected for 2030 simulations is not significant enough.

CEVESA optimizes the operation of the dispatchable resources (operation mode) and can also compute investments (investments mode) in utility-scale facilities (conventional thermal generation plants, renewable generation, and centralized storage) and behind-the-meter distributed generation (local PV panels and batteries) using a single-level equilibrium formulation for investment and operation decisions [3], driven by a constraint, for each single-price zone, to guarantee a system firm capacity set annually as a margin over the annual peak demand of the zone. In this sense, each generation facility contributes to the firm capacity of the system in proportion to its installed capacity times its firm capacity factor which is technology dependent. The firm capacity constraint allows to obtain a price signal for the capacity remuneration needed to meet the firm capacity required. Since, as the methodology describes, the capacity expansion is based on the expected generation capacity planned in the NECPs, only the operation mode of CEVESA was used.



CEVESA's main features (see Figure 1) are:

- Operation and dynamic investment decisions in utility-scale and behind-the-meter generation. Investments are computed by technologies.
- Hourly detail, with chronological joint energy and aFRR capacity reservation cost-minimization or conjectural equilibrium-based dispatch [1].
- Thermal units are represented individually in the model by their main technical features such as their efficiency, specific emissions, technical minimum, maximum capacity and ramps.
- Hydro and pump-storage units are also represented in the model. Dispatchable units are represented individually and dispatched based on a simplified weekly approach based on historical energy and reserve historical commitments and maximum and minimum values.
- Non dispatchable hydro, CHP generation and wind and solar technologies are characterised by their generation profiles. If needed different profiles can be represented for each technology, for example to simulate plants located in different geographical zones with different generation profiles.
- Batteries can be represented in the model by their capacity, power and efficiency.
- Demand is inelastic, but its reaction in terms of self-consumption based on behind-the-meter (BTM) resources such as PV panels and batteries are considered, which allows to assess demand reaction base on self-consumption activities. While utility scale investments are based on market agents profits maximization, BTM investments are based on the cost minimization of customers clusters considering the tariffs they have to face.
- Hydrogen electrolyzers can be represented in the model by their capacity, power and efficiency, [4], [5], although modelling is currently evolving.
- Transport sector impact is represented by modelling vehicle fleets of combustion, electrical (dummy, optimal, V2G and V2GR charging strategies) and hydrogen vehicles, [2], [6].
- Optimal allocation of single-price zones interconnections for energy and reserve commodities is currently under development.
- The model does not represent grid constraints based on electrotechnical magnitudes.



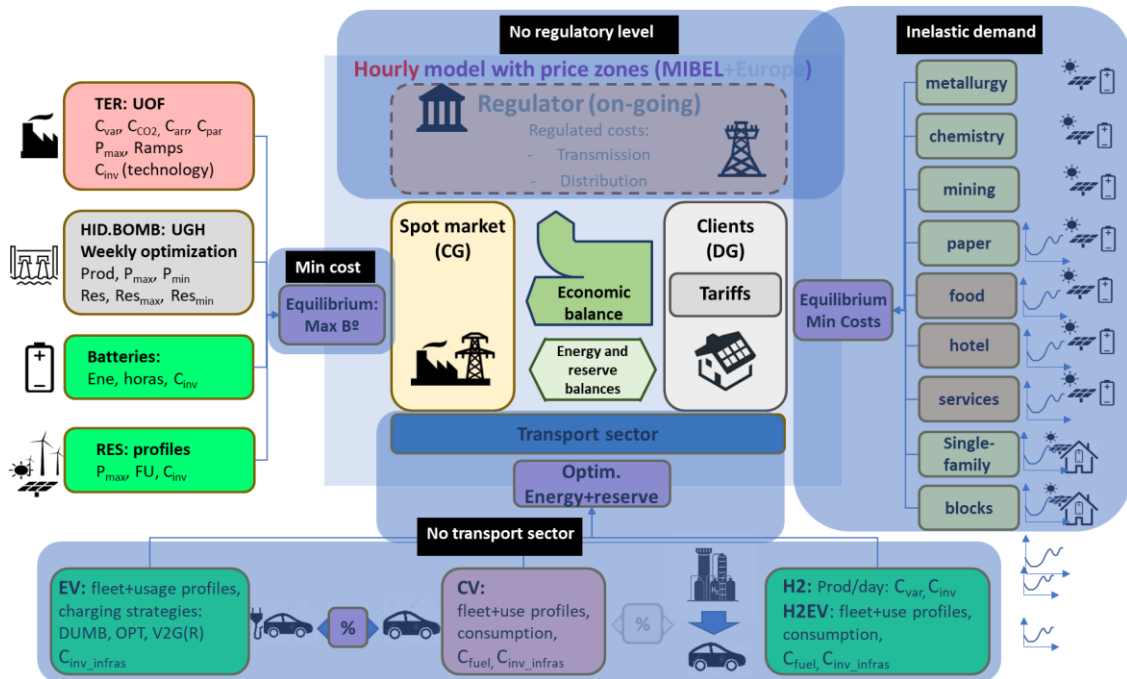


Figure 1 – CEVESA Model overview

Summarizing, for the purposes of the EU-Scores project, CEVESA was run with the operation mode with system cost minimization and without considering the interactions with the transport sector, still with low impact on the electrical system.

3.1.2 Inputs

CEVESA main inputs are characterized by the following:

- **Thermal units:**
 - Costs:
 - Variable cost (VC) – fuel cost
 - CO₂ cost
 - Startup cost
 - Shutdown cost
 - Investment costs (only when using the investments mode)
 - Ramps
 - Installed Capacity (MW)
 - Decommissioning date
- **Hydro and pump-storage units:**
 - Historical weekly hourly market data:
 - Minimum weekly generation/pumping
 - Maximum weekly generation/pumping
 - Minimum weekly upward/downward reserve
 - Maximum weekly upward/downward reserve
- **Batteries:**
 - Current and forecasted installed capacity



- Investments costs (only investments mode)
- **Solar and Wind:**
 - Historical hourly generation profiles
 - Current and forecasted installed capacity
 - Investments costs (only investments mode)
- **Other technologies:**
 - Considered as non-dispatchable
 - Hourly generation profile (historical/forecasted)
- **Demand, 2 options:**
 - a) Inelastic
 - b) With BTM DG expansion (investments costs and tariffs)
- **Interconnections:**
 - Lines installed capacities

3.1.3 Outputs

CEVESA main outputs are the following ones:

- Hourly energy and aFRR capacity reservation market prices
- Hourly energy and aFRR capacity reservation dispatches for the dispatchable units
- Thermal units, including startup and shutdown
- Hydro and pump-storage
- Batteries cycle
- CO₂ emissions of thermal units
- Energy surplus and non-supplied energy
- Technologies capture prices (technology average energy price)
- Technologies investments if running investment mode.

3.2 Simulated scenarios

3.2.1 Input data

CEVESA uses public data available from different sources. The main data sources for the different inputs are specified in Table 3.1.

Table 3.1 – Input data sources for CEVESA model.

DATA	SOURCE
Thermal UOF decommission years	[7] and news articles [8], [9]
Historical Net Transfer Capacity (NTC) values	ENTSO-E [10]
Forecasted NTC	NECPs [11], [12]
CO ₂ allowances	Portuguese NECP [11], Sandeco2 [13] and [14]
Dutch TTF spot prices	[15] (up until 2023, excluding December)



Historical Hourly Demand	[16]
Forecasted Demand	NECPs [11], [12]
Historical Hydro data	PHOF program [17] and P48 program [18]
Installed Capacities for renewable energy sources (RES) and other (non-thermal and hydro)	NECPs [11], [12]
Historical data for RES profiles (solar, solar thermal, wind onshore, small hydro plants, cogeneration, and other technologies)	OMIE [19] and SIMEE [20]
Historical data for wind offshore profile	Viana do Castelo normalized profile (in p.u.) made available by WavEC

The 2023 hourly profile of the demand was adjusted to reflect the anticipated increase in system electrification by 2030 – particularly driven by industrial sectors and constant-load consumers such as data centres. The approach used for this modification is detailed in , consists of decomposing the 2030 forecast demand into two components – a “base” demand that follows the historical hourly shape and an “industrial” demand that is assumed to be flat throughout the year – and then recombining them via a weighting factor to produce a new hourly profile, using:

$$DEM_{h,y}^{ADJUST} = DEM_{h,y}^{HIST} \cdot (1 - \alpha_y) + \frac{\sum_{h \in y} DEM_{h,y}^{HIST}}{\sum_{h \in y} 1} \cdot \alpha_y \quad (1)$$

$$DEM_{h,y} = \frac{DEM_{h,y}^{ADJUST} \cdot DEM_y^{FORECAST}}{\sum_{h \in y} DEM_{h,y}^{ADJUST}} \quad (2)$$

where $DEM_{h,y}$ is the final hourly demand used by CEVESA, $DEM_{h,y}^{ADJUST}$ the historical hourly demand profile with industrial component correction, $DEM_{h,y}^{HIST}$ the hourly historical demand, $DEM_y^{FORECAST}$ the forecasted demand for a given year y , and $\alpha_y \in [0,1]$ the percentage of the industrial demand in year y , which is assumed to be constant throughout the year. Figure 2 shows the original demand and the adjusted demand for a sample year.

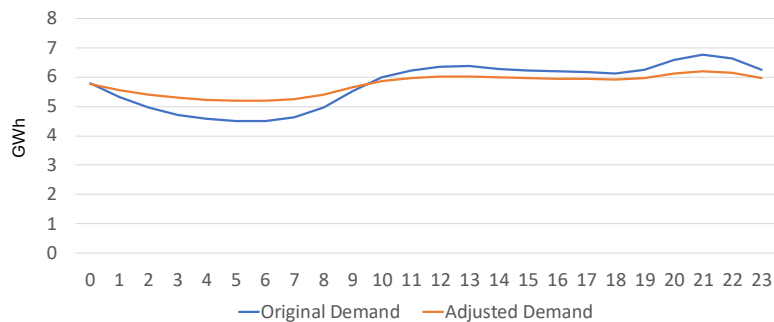


Figure 2 – Hourly average adjusted and original demand (2022) for an example year, for Portugal.

Similarly, historical data on CO₂ allowance prices and fuel costs were updated to the latest available figures as of 2024, following the methodology outlined in [21]. Projections for future CO₂ allowance prices through 2030 were also derived using



this same methodology, based on trends observed in the historical data. This methodology is summarized by the following steps:

1. Bringing historical data up to date

- **Fuel (TTF) spot prices:** Monthly TTF prices from 2018 through 2024 were collected, but the extreme price spikes driven by the Russia–Ukraine war in late 2021 and throughout 2022 were treated as outliers and set aside. The remaining data then yielded a single “current” average price for 2024.
- **CO₂ allowances:** Examination of EUA (European Union Allowance) prices from 2019 to 2024 showed no consistent seasonal swings. Therefore, the most recent observed level – 80 €/tCO₂ in 2023 – was adopted as the “current” price.

2. Extending those prices out to 2030

- **Gas price projections:** The overall 2024 average was preserved while re-imposing the typical month-to-month shape seen in earlier years. In practice, a simple curve was fitted to capture how TTF prices tend to rise or fall in each calendar month, and that pattern was then “draped” over the 2024 average so that every future year shares the same annual mean but still reflects familiar seasonal highs and lows. The results of this approach, averaging 34.34 €/MWh for 2030, align closely with the European Commission's recommendations for the development of NECPs (9 €/GJ, equivalent to 32.40 €/MWh) [11]. The monthly values used can be found in Table 3.2.

Table 3.2 – Used monthly gas price projections for 2030 (€/MWh).

MONTH / YEAR	2030
M1	58.23
M2	45.34
M3	35.01
M4	27.25
M5	22.05
M6	19.42
M7	19.35
M8	21.84
M9	26.90
M10	34.53
M11	44.72
M12	57.47
2030 AVERAGE	34.34
EC RECOMMENDATION	32.40



- **CO₂-allowance projections:** Since no clear seasonality emerged from the historical EUA data, the flat 80 €/tCO₂ level observed in 2023 is simply held constant through every year up to 2030, which is in line with the NECPs assumptions [11].

3.2.2 Methodology and scenarios

The scenarios used for this study are based on the most recent NECPs submitted by Portugal and Spain [11], [12]. These documents provide the foundation for constructing consistent scenarios aligned with the policies currently in place and projected for 2030.

To build the 2030 base scenario, key data extracted from the NECPs were the expected electricity and green hydrogen demands, and installed capacities of thermal, hydro, and renewable energy sources (RES). Combined with historical generation and reserve profiles for technologies such as hydro and RES, this information enables CEVESA to estimate how the energy market is expected to perform by 2030.

Since the primary focus of this study is to assess the impact of offshore wind technologies on several electricity markets, it is essential to gather relevant data on the current installed capacity and generation profiles of this technology to support future projections.

Offshore wind production in the MIBEL system is still in its early stages, with limited capacity installed. In particular, there is an ongoing project of 25 MW of offshore wind generation capacity near the coast of Viana do Castelo, in northern Portugal, for which generation profile data were generated by WavEC and used in this study.

However, as the generation profile reflects data from a single specific site rather than the entire MIBEL region, its profile cannot directly be used for larger installed capacities corresponding to several different sites, since the averaging that takes place in practice would be lost. Therefore, additional adjustments were made to better approximate the expected performance of offshore wind technology across the broader system. The methodology used for this adjustment is detailed in the next section.

3.2.2.1 Methodology for smoothing the offshore profile

Departing from the hourly time-series of normalized (in p.u.) generation data from 2023 from the offshore wind generation site of Viana do Castelo, a resampling algorithm was designed and applied to generate a time series that should better represent a hypothetical generation profile resulting from the aggregation of all possible wind offshore generation sites along the coast of the Iberian Peninsula.

The result is a smoothed generation profile that maintains some properties of the original profile, such as its average value (guarantying a same capacity factor, and therefore, a same energy production for a same installed capacity), but reducing the frequency of extreme values (i.e., maximum and minimum, 1 and 0 respectively).



Since nearby offshore sites often experience similar wind conditions but at slightly different times, we created 48 variations of the original profile by shifting it forward and backward in time by up to 24 hours in hourly steps. These variations represent how other offshore sites might behave under similar weather conditions. In each hour, 10% of these profiles were randomly excluded to incorporate the impact of short-term irregularities or noise. The final smoothed profile was then calculated as the average of the remaining profiles. This approach provides a more realistic picture of how aggregated wind power from multiple offshore sites would behave, showing a more stable and consistent pattern over time.

Figure 3 presents a simplified version of the smoothing process using only four time-shifted permutations (in different shades of grey) of the original offshore wind profile (in blue). The smoothed result (in orange) is obtained by averaging the original and permuted profiles, illustrating how aggregation across multiple offshore sites can reduce variability:

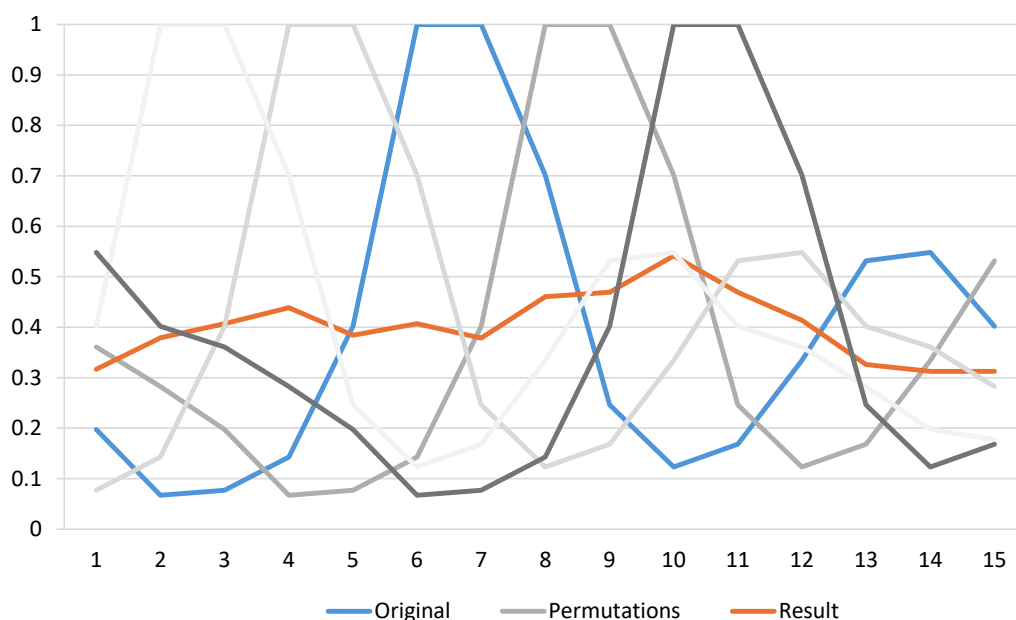


Figure 3 – Offshore wind smoothing algorithm (for illustration purposes)

Figure 4 compares the initial (source) profile and the smoothed profile of the offshore wind generation with the normalized historical profiles of onshore generation from 2023 of all the Spanish (ESP) and Portugal (PT) wind generators, respectively:



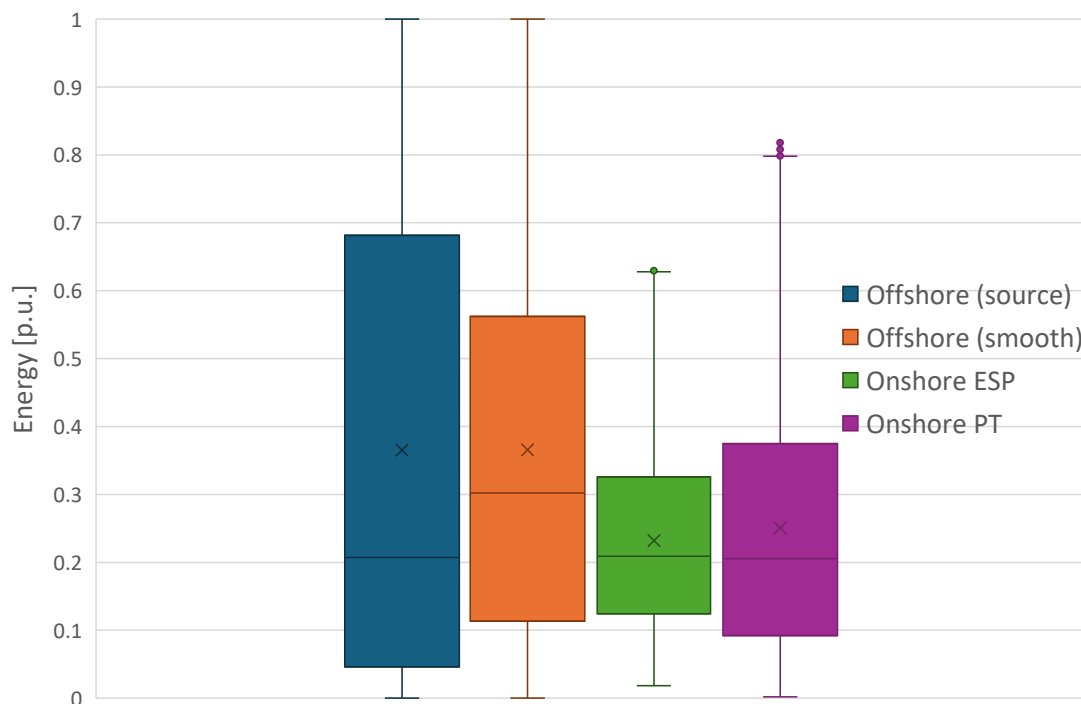


Figure 4 – Wind profiles comparison

As Figure 4 shows, the resulting smoothed profile has the same average value as the source profile, which is about a 50% higher than the onshore profiles average. However, the source profile has a higher unrealistic spread of its 2nd and 3rd quartiles, whereas the smoothed profile has a more realistic lower spread, closer to both onshore profiles. The median value of the smoothed profile is closer to its average, showing a similar distribution to the historical onshore wind profiles of Spain and Portugal.

3.2.2.2 Simulated scenarios

For this study, three sets of scenarios were defined – one set for basic scenarios, another for extreme scenarios, and one for an in-depth offshore profile analysis. The basic scenarios are described in Table 3.3, the extreme scenarios are described in Table 3.4. and the in-depth offshore profile scenarios are described in Table 3.5

Table 3.3 – Basic scenarios.

SCENARIO NAME	DESCRIPTION
■ NECP	<ul style="list-style-type: none"> ▪ Based on the latest NECPs for Portugal and Spain ▪ With offshore profile smoothing (specified on section 3.2.2.1) ▪ With hydrogen demand for 2030 ▪ Wind offshore installed capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 2 GW ○ Spain – 3 GW ▪ Wind onshore capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 10.4 GW ○ Spain – 59.044 GW



■ High offshore	<ul style="list-style-type: none"> ▪ Based on the latest NECPs for Portugal and Spain ▪ With offshore profile smoothing (specified on section 3.2.2.1) ▪ With hydrogen demand for 2030 ▪ Wind offshore installed capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 4 GW ○ Spain – 6 GW ▪ Wind onshore capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 10.4 GW ○ Spain – 59.044 GW
■ Low offshore	<ul style="list-style-type: none"> ▪ Based on the latest NECPs for Portugal and Spain ▪ With offshore profile smoothing (specified on section 3.2.2.1) ▪ With hydrogen demand for 2030 ▪ Wind offshore installed capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 1 GW ○ Spain – 1.5 GW ▪ Wind onshore capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 10.4 GW ○ Spain – 59.044 GW
■ High offshore w/o H2	<ul style="list-style-type: none"> ▪ Same as “High offshore” scenario ▪ Without hydrogen demand for 2030

Table 3.4 – Extreme scenarios.

SCENARIO NAME	DESCRIPTION
■ NECP	<ul style="list-style-type: none"> ▪ Same scenario as Basic NECP scenario. ▪ Used as base scenario for comparison with the other scenarios
■ All offshore	<ul style="list-style-type: none"> ▪ Based on the latest NECPs for Portugal and Spain ▪ With offshore profile smoothing (specified on section 3.2.2.1) ▪ With hydrogen demand for 2030 ▪ Wind offshore installed capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 12.4 GW ○ Spain – 62.044 GW ▪ Wind onshore capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 0 GW ○ Spain – 0 GW
■ All onshore	<ul style="list-style-type: none"> ▪ Based on the latest NECPs for Portugal and Spain ▪ With offshore profile smoothing (specified on section 3.2.2.1) ▪ With hydrogen demand for 2030 ▪ Wind offshore installed capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 0 GW ○ Spain – 0 GW ▪ Wind onshore capacity for 2030: <ul style="list-style-type: none"> ○ Portugal – 12.4 GW ○ Spain – 62.044 GW

Table 3.5 – In-depth offshore profile scenarios.

SCENARIO NAME	DESCRIPTION
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■ **All offshore**

- Same as Extreme All offshore scenario
- With offshore profile smoothing (specified on section 3.2.2.1)

■ **All offshore w/o smoothing**

- Same scenario as Extreme All offshore scenario
- Without offshore profile smoothing (specified on section 3.2.2.1)

Figure 9 shows the onshore and offshore wind installed capacity, for 2030, per scenario, as defined in the previous tables.

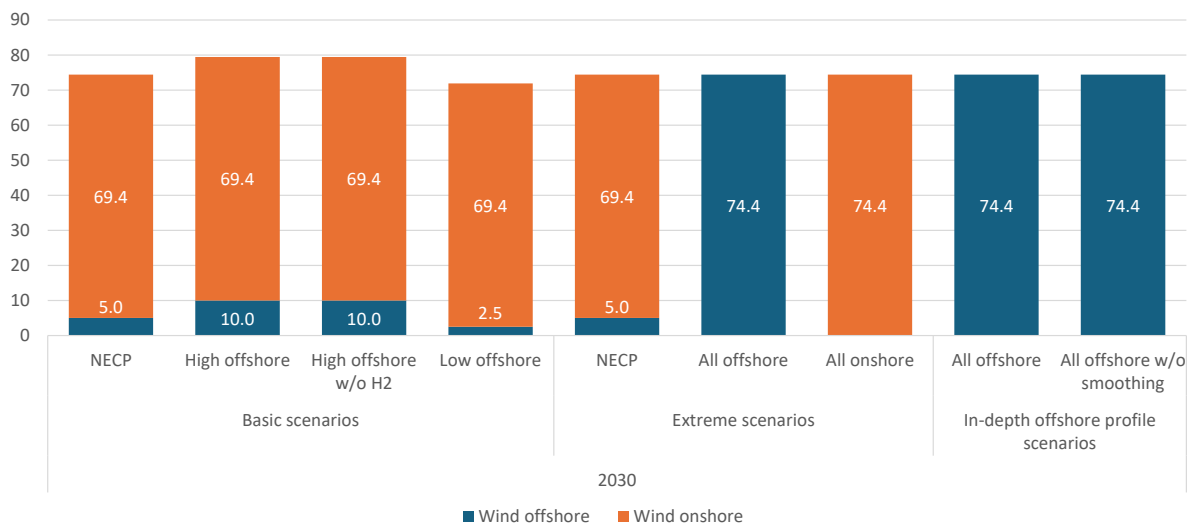


Figure 5 – Onshore and offshore wind installed capacity for 2030 per scenario.

3.3 Results analysis

This section shows the main results of the CEVESA simulations for the three set of scenarios defined in section 3.2.2. The more specific results for each set of scenarios (basic, extreme and in-depth offshore) are in sections 3.3.1, 3.3.2 and 3.3.3, respectively.

3.3.1 Basic scenarios results

This section entails the results for the basic scenarios defined in section 3.2.2.2, and summarized as:

- “NECP” – baseline scenario to be used for comparison.
- “High offshore” – higher installed capacity of wind offshore when comparing to the baseline scenario.



- “Low offshore” – lower installed capacity of wind offshore when comparing to the baseline scenario.
- “High offshore w/o H2” – same as “High offshore” scenario but without considering hydrogen demand for 2030.

Figure 6 shows the total electricity demand (in blue) and electricity demand for H2 production (in orange) by type and year for the basic scenarios.

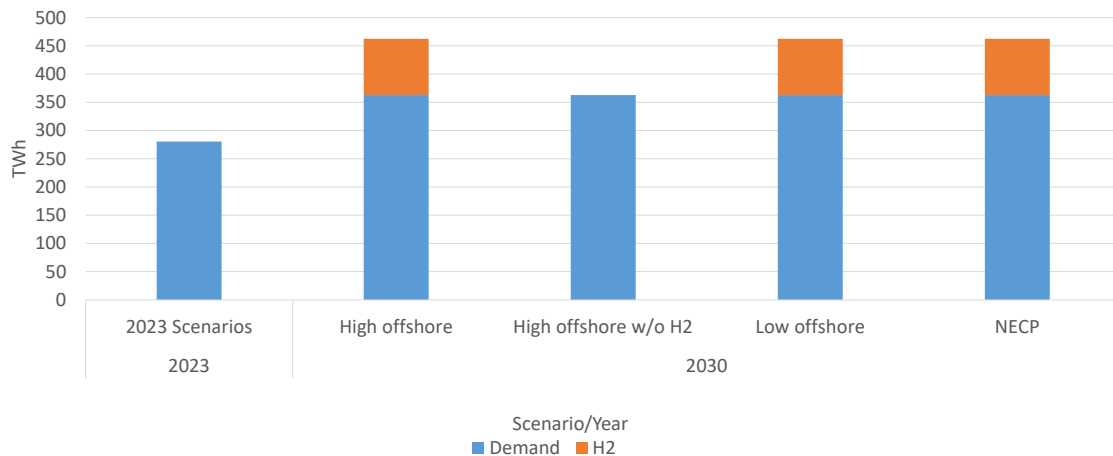


Figure 6 – Aggregated demand by type and year for basic scenarios.

The electricity demand for 2023 is the same for all scenarios and corresponds to its historical value. For 2030, “NECP”, “High offshore” and “Low offshore” scenarios have the same electrical and hydrogen demand, in line with the NECPs for both Portugal and Spain, while the 2030 “High offshore w/o H2” scenario does not have electricity demand for green hydrogen production.

Figure 7 shows the hourly average market price for 2023 and 2030 for the basic scenarios.

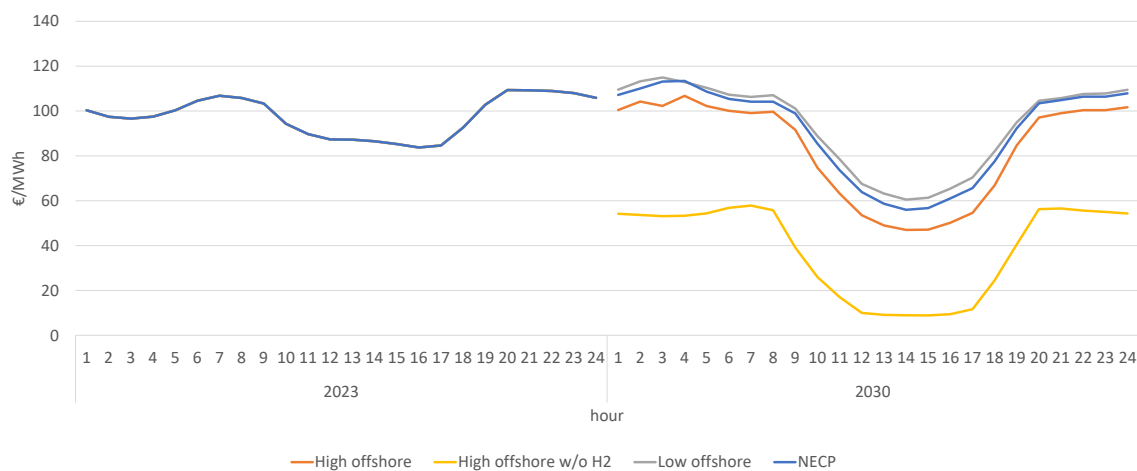


Figure 7 – Hourly average market price for basic scenarios.



In 2023, the average market price profile remains relatively stable throughout the day, with only minor fluctuations – primarily during the midday hours when solar irradiance is highest.

By 2030, significant differences appear between the scenarios, driven by variations in offshore wind capacity and electricity demand.

In the “Low offshore” scenario:

- Offshore wind capacity is reduced to 2.5 GW, compared to 5 GW in the reference case.
- This results in lower installed renewable capacity, and significantly less electricity production from renewables.
- Because offshore wind has a higher capacity factor than other technologies (e.g. solar PV or onshore wind), this reduction leads to a disproportionate decline in actual generation.
- With reduced renewable output, the system becomes more reliant on costlier conventional generation, pushing market prices higher.

In the “High offshore” scenario:

- Offshore wind capacity is expanded to 10 GW, compared to 5 GW in the reference case, enhancing the total renewable installed capacity.
- Given offshore wind’s high and stable capacity factor, this results in greater renewable generation, especially during windy periods.
- The increased availability of low-marginal-cost electricity from offshore wind puts downward pressure on market prices, particularly during hours of high offshore output.

In the “High offshore w/o H₂” scenario:

- Offshore wind capacity remains high at 10 GW, as in the previous scenario.
- However, electricity demand is lower because hydrogen production (a major source of flexible demand in the “High offshore” scenario) is not present.
- With high renewable generation and reduced demand, there is less need for dispatchable generation, intensifying the price-suppressing effect.

Figure 8 shows the annual average market price for 2023 and 2030 for the basic scenarios.



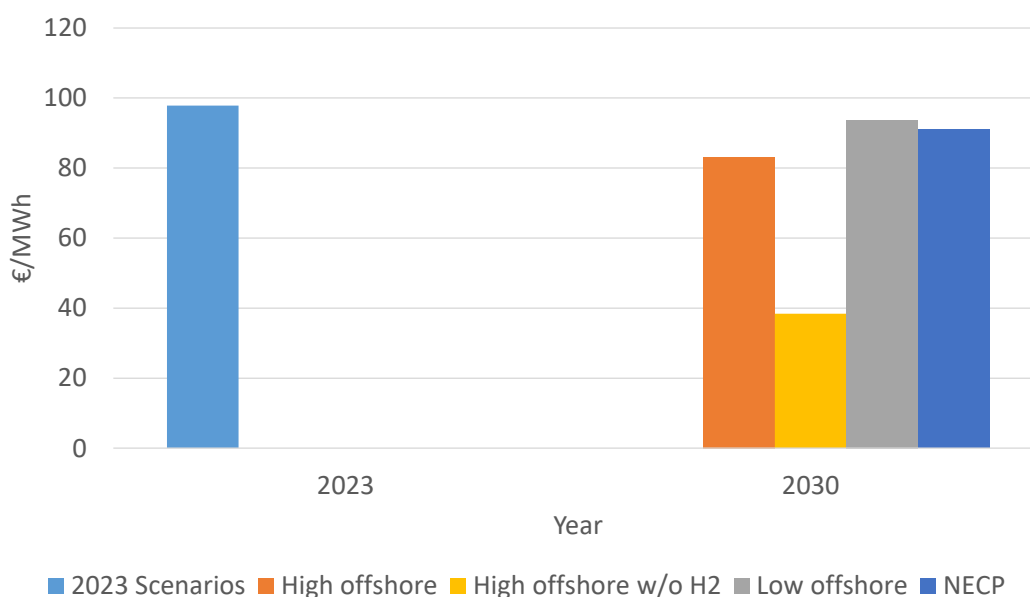


Figure 8 – Annual average market price for basic scenarios.

In 2023 all scenarios are identical and have a same price of approximately 98 €/MWh.

In the “High offshore w/o H₂” scenario:

- Electricity prices drop below 40 €/MWh, representing the most significant decline among all scenarios.
- This is driven by reduced electricity demand, due to the absence of hydrogen production as a flexible consumer.
- At the same time, the system faces high levels of renewable generation from the 10 GW offshore capacity, creating periods of overgeneration.
- The mismatch between high supply and lower demand leads to increased spillage of renewable energy, reducing the system's efficiency but further suppressing prices.

In the “High offshore” scenario:

- Prices also decrease, but the reduction is less dramatic than in the “High offshore w/o H₂” case.
- The combination of high offshore capacity and higher demand (due to hydrogen production) absorbs a larger share of the renewable generation.
- This limits spillage and stabilizes prices at a moderately lower level, reflecting the price-dampening effect of increased zero-marginal-cost supply.

In the “Low offshore” scenario:

- Market prices increase compared to the “NECP” reference case.
- The lower offshore capacity (2.5 GW vs 5 GW in NECP) reduces the amount of available RES generation.



- As a result, there is a greater reliance on conventional generation, which drives prices upward.

Figure 9 shows the hourly average market price by season for 2023 and 2030, for each of the basic scenarios.

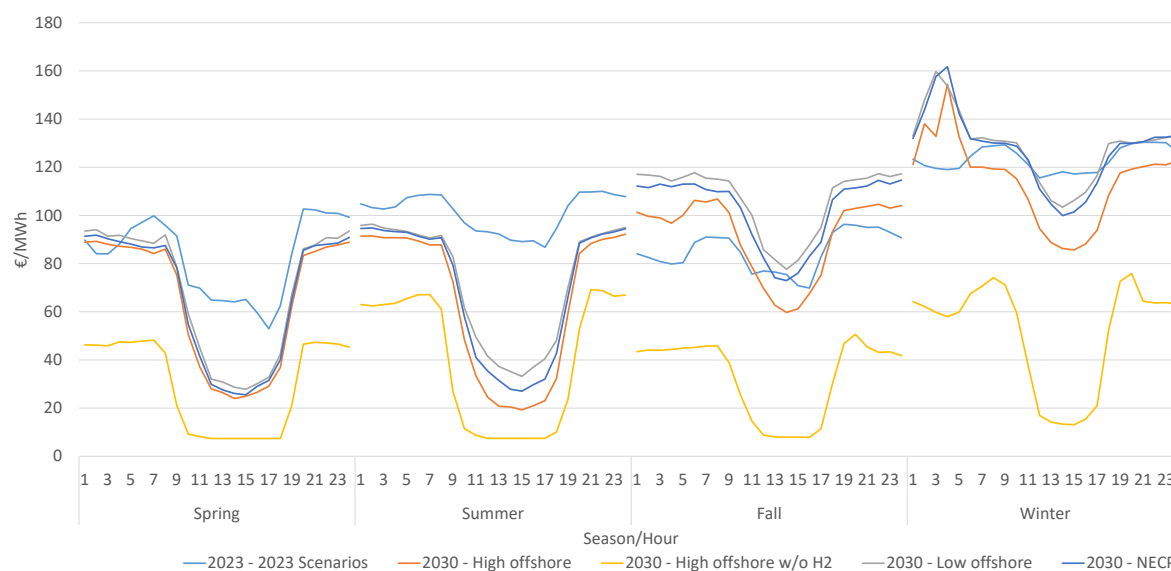


Figure 9 – Hourly average market price by season for basic scenarios.

As expected, only a single curve is shown for 2023, reflecting the absence of scenario differentiation in that year.

In contrast, the 2030 projections display distinct curves for each scenario, following a consistent pattern observed in Figure 7.

The “High offshore w/o H₂” scenario:

- Experiences the lowest market prices across all seasons, frequently dropping below 40 €/MWh.
- Driven by high offshore capacity (10 GW) and lack of hydrogen demand, leading to significant overgeneration and high renewable spillages.
- Spring and Summer show a deep U-shaped curve, as midday solar and wind coincide, strongly depressing prices.
- Fall and Winter curves are also relatively low but take on a shallower V-shape, reflecting reduced solar input and increased reliance on wind.

The “High offshore” scenario:

- Also shows lower prices than the “NECP” scenario, though not as steep as in the “High offshore w/o H₂” case.
- The inclusion of hydrogen production as flexible demand helps absorb midday overgeneration, reducing spillage and moderating price drops.
- Spring and Summer maintain a U-shaped curve, though less pronounced than in “High offshore w/o H₂” due to demand flexibility.



- Fall and Winter transition to a V-shape, where offshore wind fills in during non-solar hours, maintaining price stability but with higher evening peaks than in summer.

The “Low offshore” scenario:

- Results in higher market prices compared to the NECP baseline, due to reduced offshore capacity (2.5 GW) and therefore lower RES generation.
- Increased dependency on conventional generation raises marginal costs, especially during low-solar hours.
- Spring and Summer curves are flatter, with a shallow U-shape, since solar output is less effective without offshore wind support.
- Fall and Winter show a muted V-shape, but with elevated prices throughout the day, indicating weaker renewable contributions and more conventional dispatch.

The “NECP” scenario:

- Reflects moderate market prices, serving as the reference with 5 GW offshore wind capacity.
- Balances renewable generation and demand without hydrogen-specific demand drivers.
- Spring and Summer show a balanced U-shaped pattern, shaped by solar input but limited by offshore capacity.
- Fall and Winter follow a moderate V-shape, with price stability during midday and peaks in the morning and evening.

Figure 10 shows the seasonal average market price for the basic scenarios for 2023 and 2030.

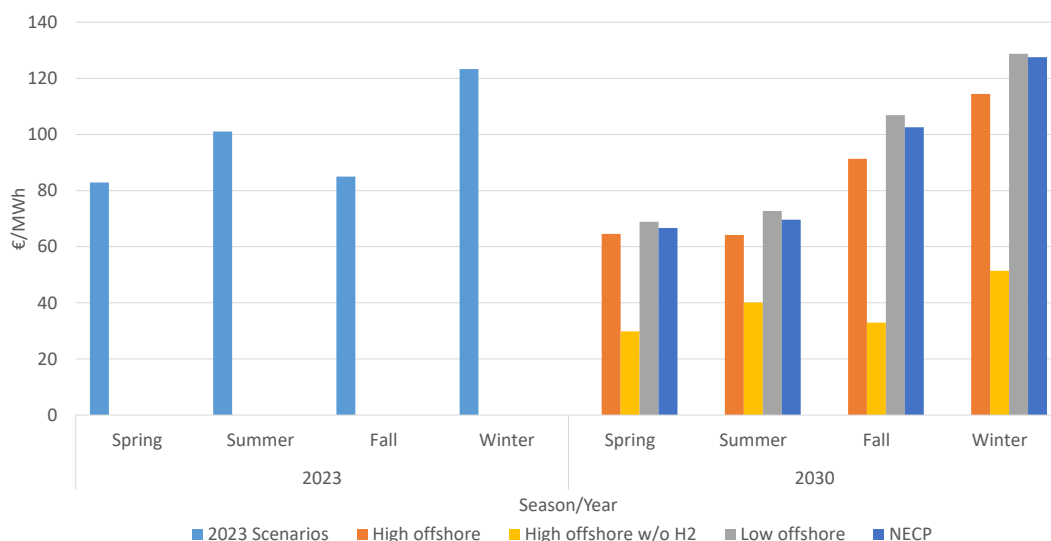


Figure 10 – Seasonal average market price for basic scenarios.

The “High offshore w/o H₂” scenario:



- Experiences the lowest market prices across all seasons, with summer and spring particularly suppressed due to overgeneration.
- Driven by high offshore capacity (10 GW) and the absence of hydrogen demand, leading to significant renewable spillage and price depression.
- Summer and spring prices fall well below those in other scenarios, reversing the typical seasonal order.
- Fall and winter remain the costliest seasons in this scenario but still register prices significantly below other scenarios due to surplus wind output.

The “High offshore” scenario:

- Also shows lower prices than the “NECP” and “Low offshore” scenarios, though not as steep as in the “High offshore w/o H₂” case.
- The presence of hydrogen production as a flexible load absorbs excess renewable generation, reducing spillage and stabilizing prices.
- Seasonal price pattern follows the expected trend: spring and summer are the lowest, followed by fall, with the highest prices in winter, when demand is stronger.
- Winter prices are notably reduced compared to NECP and Low offshore, benefiting from peak offshore wind production.

The “Low offshore” scenario:

- Results in higher market prices across all seasons compared to both “High offshore” scenarios and NECP.
- The limited offshore capacity (2.5 GW) reduces renewable generation potential, increasing reliance on CCGT generation with higher marginal costs.
- Shows the highest seasonal prices, particularly in fall and winter, when solar is weak and offshore wind is insufficient to offset demand.
- Spring and summer still display lower prices relative to colder seasons but are less affected by solar-driven price suppression due to weaker renewable output.

The “NECP” scenario:

- Reflects moderate price levels, serving as the reference case with 5 GW of offshore wind and no hydrogen flexibility.
- Follows a typical seasonal pattern with lowest prices in spring and summer, moderate in fall, and highest in winter.
- The balance between renewable generation and demand produces smoother seasonal variations, though prices remain above both “High offshore” cases.
- Winter remains the costliest season, where both demand and CCGT generation play a dominant role.

Figure 11 shows the annual aggregated generation by technology for 2023 and 2030, for the basic scenarios. The legend of the figure is as follows:



C	Coal	NU	Nuclear
CC	Combined Cycle Gas Turbines	Others	Other technologies
CHARG	Batteries charge	Pump	Hydro pumps
Cog	Cogeneration	Solar	Solar PV
DCHARG	Batteries discharge	Solar T	Solar Thermal
NSE	Not supplied energy		Renewable spillage (excess generation that is not used or stored)
Excess	Generation excess	Wind Onshore	Onshore wind generation
FG	Fuel Gas	Wind Offshore	Offshore wind generation
Hydro	Hydro generation		

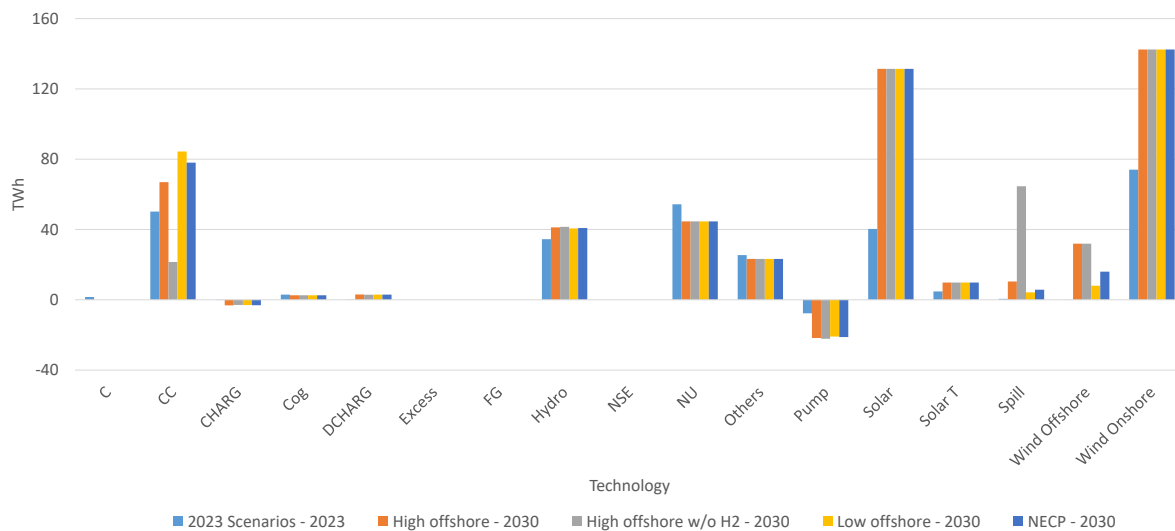


Figure 11 – Annual aggregated generation by technology for basic scenarios.

Again, 2023 scenarios are identical and with same generation mix. However, by comparing 2023 to 2030 it is possible to observe, as expected, that coal generation and fuel gas disappears totally from the generation mix, since these units decommission are expected before 2030 in line with the NECP strategy to decarbonise the electrical sector. This fact, together with the higher demand for 2030 increases CCGT generation, even though there is higher RES penetration in the system in all 2030 scenarios.

The “High offshore w/o H₂” scenario:

- Shows a significant reduction in CCGT generation, driven by lower overall electricity demand due to the absence of hydrogen production.
- The combination of reduced demand and high renewable installed capacity leads to substantial renewable energy spillage, as excess energy cannot be fully absorbed.
- This scenario highlights a system imbalance where overgeneration exceeds available flexibility options, resulting in curtailed RES output.



The “High offshore” scenario:

- Displays a notable decrease in CCGT generation compared to the “NECP” scenario, as increased renewable generation meets more of the demand.
- RES spillages are higher than in “NECP”, but lower than in the “High offshore w/o H₂” scenario, thanks to hydrogen acting as a flexible demand sink.
- Demonstrates the benefits of combining high offshore capacity with demand-side flexibility to reduce CCGT generation while managing surplus renewables.

The “Low offshore” scenario:

- Results in the highest CCGT generation among the 2030 scenarios, due to limited renewable capacity (2.5 GW offshore) unable to meet demand.
- RES spillage remains low, as renewable output is modest and mostly absorbed by the system.
- Emphasizes that lower offshore capacity limits both renewable contributions, the risk of spillage and increases dependency on CCGT generation.

Figure 12 shows the annual capture price by RES technology for 2023 and 2030, for the basic scenarios.

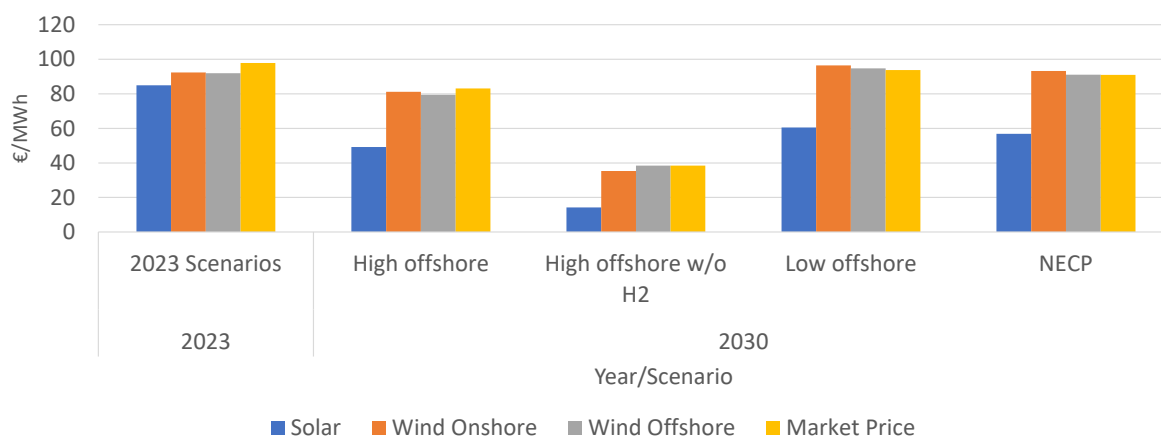


Figure 12 – Average annual capture price by RES technology for basic scenarios.

The figure shows that as offshore wind capacity increases, the capture price for offshore wind technology declines – a pattern driven by the cannibalization effect. This market dynamic occurs when technologies with low marginal costs, such as RES, achieve significant market share and begin to suppress their own prices.

In the "High offshore" scenario, the capture price for offshore wind falls below the average market price. While this illustrates reduced market revenues, it is important to emphasize that investment viability should be assessed by comparing capture prices with the Levelized Cost of Energy (LCOE), not merely with the average market price. Therefore, no definitive conclusions about investment profitability can be drawn solely from this price comparison.



This situation also points to a potential mismatch between the planned increase in offshore wind capacity and the expected financial returns. This mismatch could imply either that actual investments might be lower than planned if investors react to the declining revenue outlook, or that the targeted capacity levels will require supplementary remuneration mechanisms – such as capacity payments or long-term contracts – to remain financially viable. Moreover, revenues from services like secondary reserves, which are not included in this analysis, could also contribute to investment returns and should be considered in a more comprehensive evaluation.

Figure 13 shows the hourly aggregated CO₂ equivalent emissions for the basic scenarios.

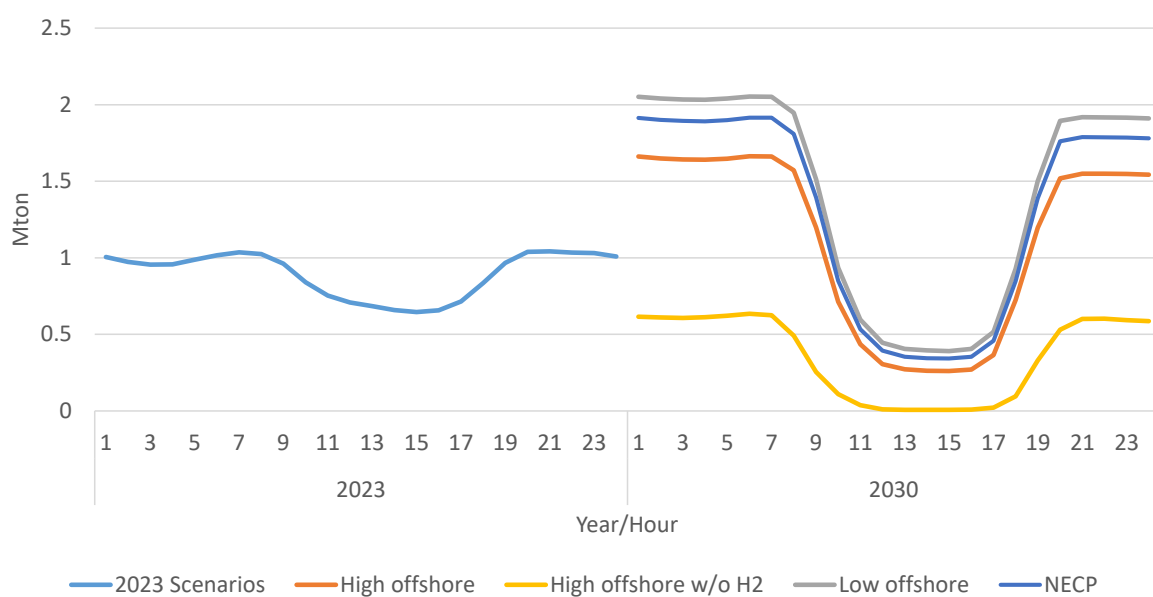


Figure 13 – Hourly aggregated CO₂ equivalent emissions for basic scenarios.

By 2030, the reduced electricity demand in the “High offshore w/o H₂” scenario results in lower CCGT generation, the unique CO₂ emitting technology, making it the scenario with the lowest CO₂ equivalent emissions. In contrast, the scenario with the highest CO₂ equivalent emissions is “Low offshore”, which has the lowest level of offshore wind capacity installed. Conversely, the scenario with higher offshore installed capacity, “High offshore”, has the lower CO₂ equivalent emissions, mainly in the hours with high wind offshore generation (hours 1 to 8 and 19 to 24).

3.3.2 Extreme scenarios results

This section reports the results obtained for the extreme scenarios defined in section 3.2.2.2, and summarized as:

- “NECP” – baseline scenario to be used for comparison.
- “All offshore” – all wind installed capacity is offshore, i.e. there is no wind onshore in the system.
- “All onshore” – all wind installed capacity is onshore, i.e. there is no wind offshore in the system.



Figure 14 shows the aggregated demand by type and year for the extreme scenarios. Notice that the demand for the NECP scenario is the same as the previous section.

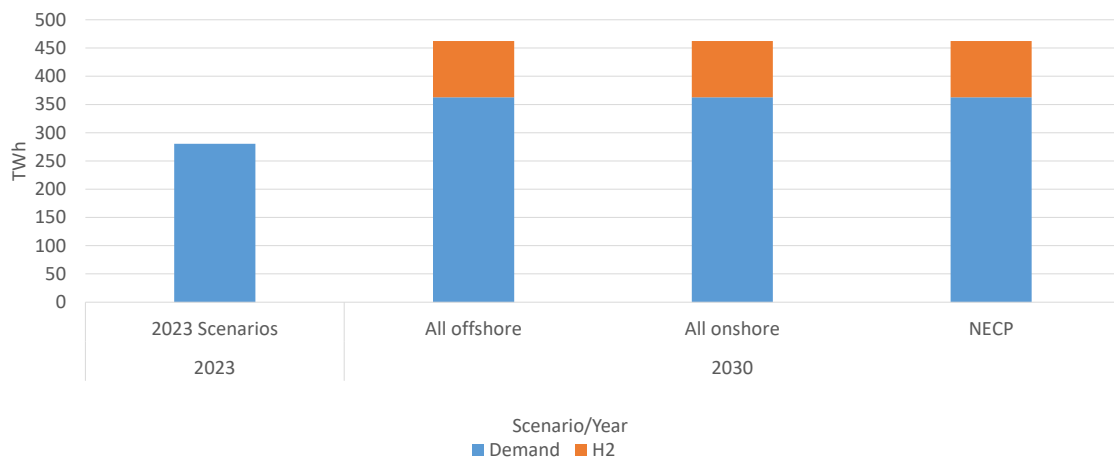


Figure 14 – Aggregated demand by type and year for extreme scenarios.

It is possible to observe that, for 2023 and 2030, the demand is constant throughout the different scenarios in this section.

Figure 15 shows the hourly average market price for 2023 and 2030 for the extreme scenarios.

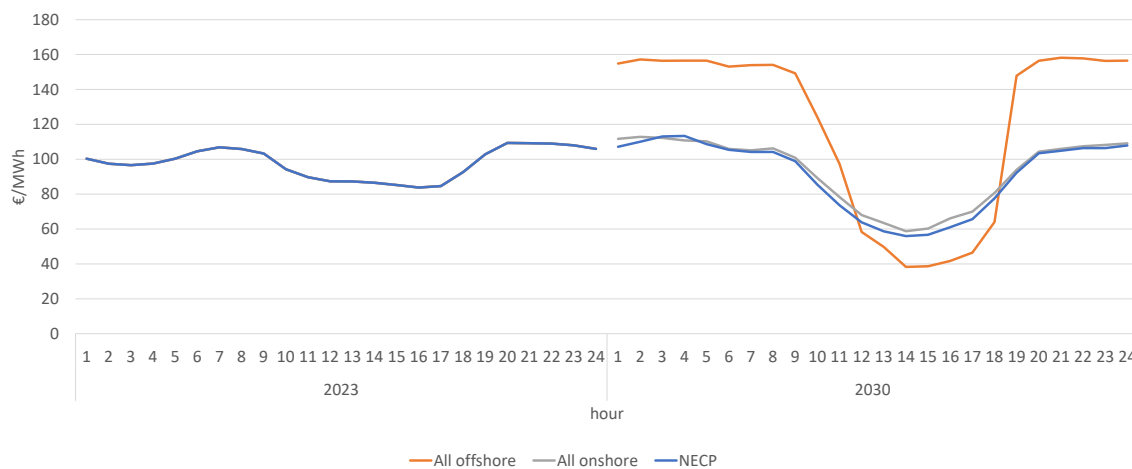


Figure 15 – Hourly average market price for extreme scenarios.

The figure shows that in the “All offshore” scenario, market prices are lower during the intermediate hours of the day but higher during other periods. This result appears inconsistent with expectations, given that offshore wind typically has a higher capacity factor than onshore wind, which should translate into higher renewable generation and, consequently, lower market prices.

However, the input data used to model offshore wind generation are based on a single site profile extrapolate for the whole system. As a result, and as explained next, extreme scenarios may be strongly affected by distortions or misleading conclusions, even when using the profile smoothing described in section 3.2.2.1.



Indeed, when analysing the seasonal hourly average market prices for the extreme scenarios in Figure 16, it can be observed that, for all seasons except Winter, the price curves for the “All offshore” scenario lie below those of the other scenarios. This aligns with expectations, as higher penetration of RES – given the high capacity factor for offshore wind when compared to onshore wind – typically leads to lower market prices.

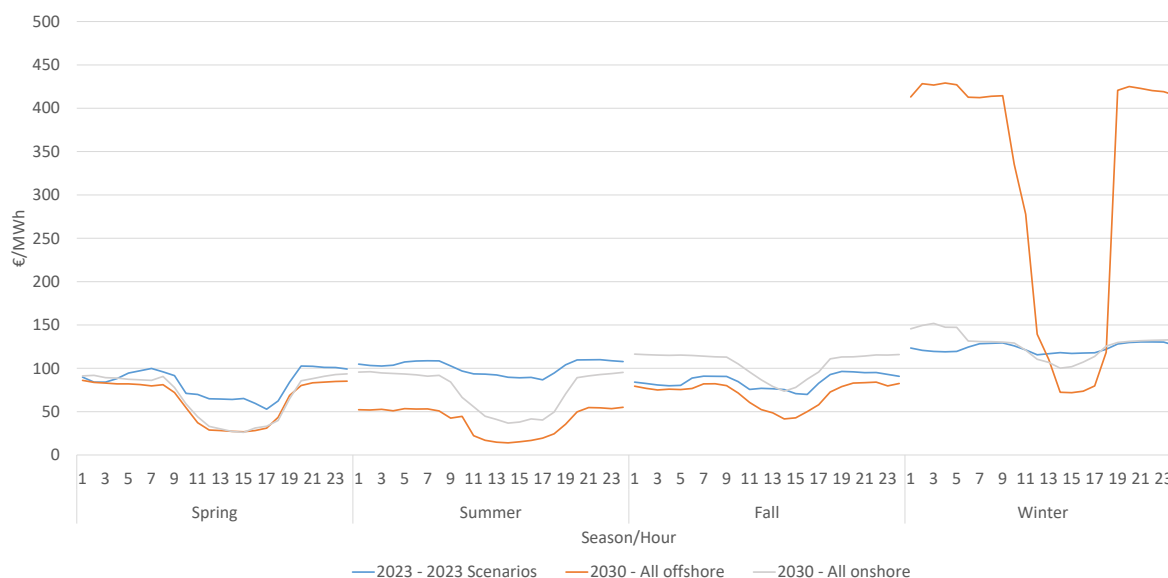


Figure 16 – Hourly average market price by season for extreme scenarios.

The results observed for the “All offshore” scenario during the winter season can be attributed to two key factors:

- First, the offshore wind generation profile used – derived from a single site – includes several hours with zero output, which does not accurately represent the behaviour of a more geographically diverse offshore wind fleet across the MIBEL system. In a system-wide context, low generation at individual sites is often compensated by output from other sites, resulting in a more stable and continuous supply.
- Second, winter is also characterized by higher electricity demand, which amplifies the impact of these generation gaps on market prices. In fact, winter market prices for the “All offshore” scenario are unusually high due to the high number of hours with NSE (not supplied energy), when there is not enough generation to meet the demand. Figure 17 shows the amount of NSE by season and hour for 2030.



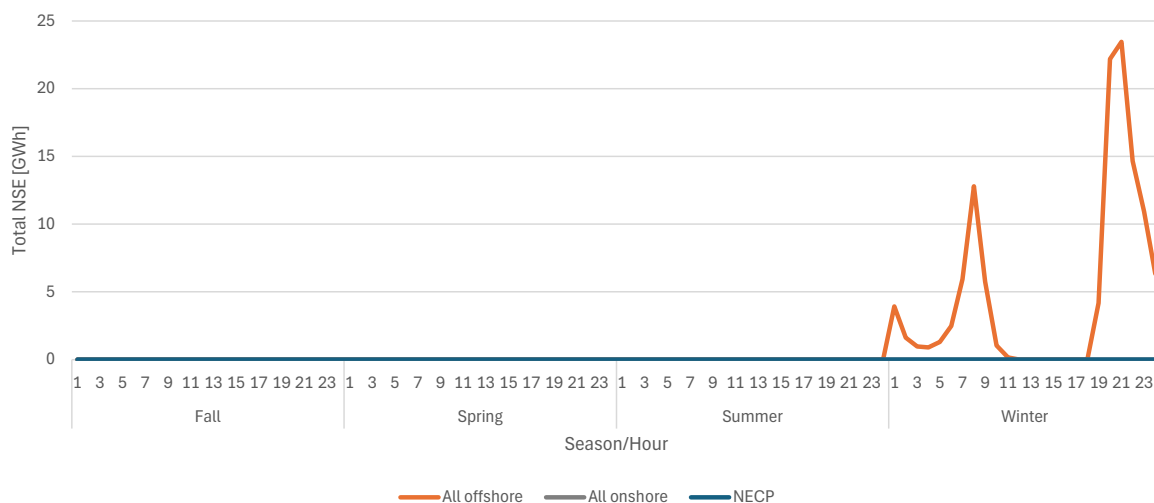


Figure 17 – Total NSE by season and hour for 2030 for extreme scenarios.

It is possible to observe that outside the intermediate hours of the day, for scenario “All offshore” there is significant amount of NSE with makes the system cost equal to the NSE cost, set to 4000 €/MWh in the simulations. Since the price is set to the system marginal cost, this effect the high prices obtained for the winter season of Figure 16 and Figure 18.

Together, these factors highlight the need for using aggregated, system-representative input data to ensure robust and realistic scenario analyses.

Figure 18 shows the seasonal average market price for extreme scenarios.

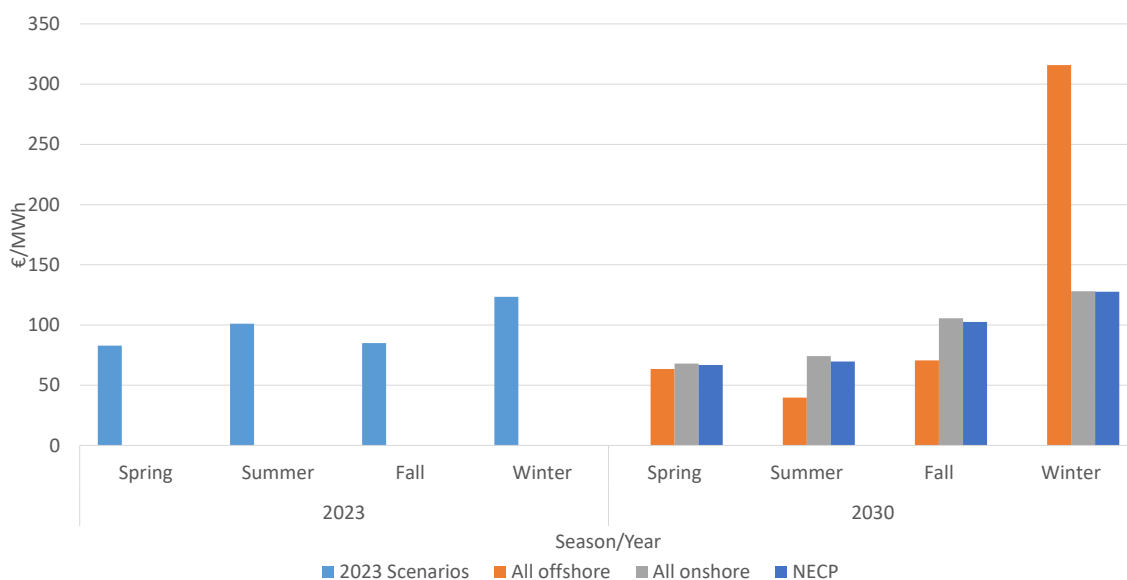


Figure 18 – Seasonal average market price for extreme scenarios.

The “All offshore” scenario:



- Results in generally lower market prices across Spring, Summer, and Fall of 2030, with the most notable reduction occurring during Summer, due to high offshore wind output.
- Exhibits a sharp and anomalous price spike in Winter 2030, driven by the limitations of using a single-site offshore wind profile, as previously explained.

The “All onshore” scenario:

- Shows market prices similar to the “NECP” scenario across all seasons, with only slight variations.
- Reflects a system dominated by onshore wind, with slightly higher onshore wind capacity than “NECP” and no onshore capacity but minimal impact on price due to the similar renewable mix.

Figure 19 shows the annual aggregated generation by technology for the extreme scenarios.

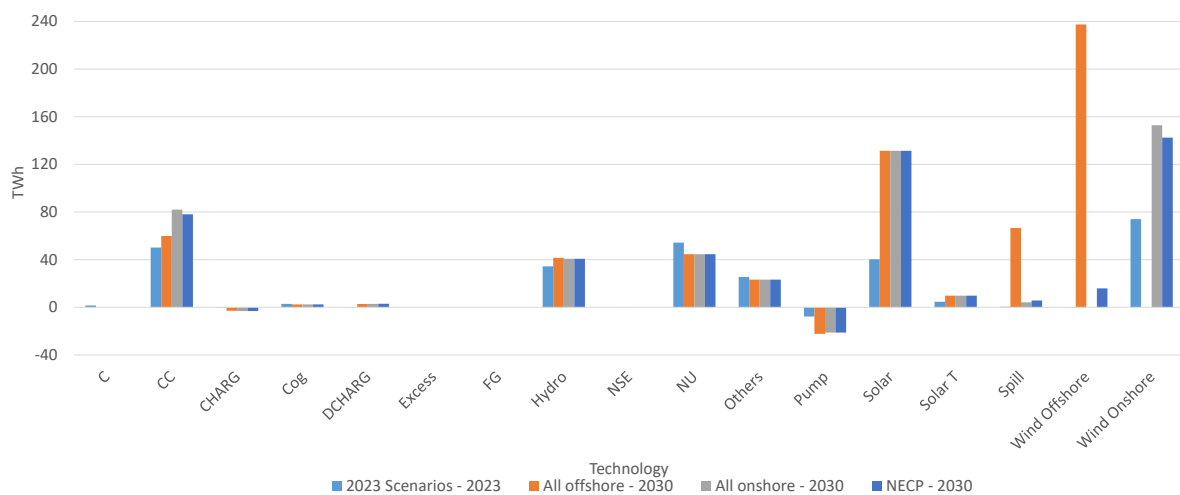


Figure 19 – Annual aggregated generation by technology for extreme scenarios.

The “All offshore” scenario:

- Shows the lowest level of CCGT generation among the scenarios, due to the high capacity factor and output of offshore wind, which displaces fossil generation.
- Experiences the highest level of RES spillage, as the large offshore wind output exceeds system absorption capabilities, leading to energy waste.

The “All onshore” scenario:

- Relies more heavily on CCGT generation than the offshore scenarios, as onshore wind, despite being the dominant RES, has a lower capacity factor.
- Exhibits relatively low spillage, indicating that most of the RES generation is effectively utilized within system limits.

The “NECP” scenario:



- Also features low CCGT generation, benefiting from a balanced mix that includes some offshore wind capacity, though less than in the “All offshore” scenario.
- Shows moderate spillage – higher than the “All onshore” scenario but lower than “All offshore”.

Figure 20 shows the average annual capture price by RES technology for the extreme scenarios.

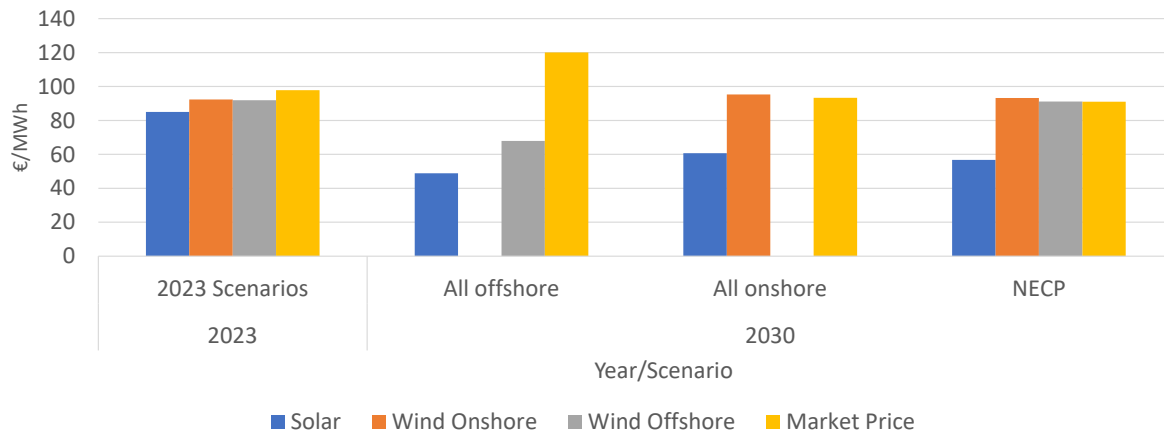


Figure 20 – Average annual capture price by RES technology for extreme scenarios.

When comparing the “All offshore” and “All onshore” scenarios, it appears that the capture price for offshore wind is higher than that for onshore wind. However, this observation should be interpreted in the context of earlier findings. The elevated market prices in the “All offshore” scenario are driven by NSE in the system, which indicates a supply shortfall. As a result, the higher capture price for offshore wind in this scenario does not reflect a realistic market outcome. Instead, it is artificially inflated due to the technology benefiting from an unrealistic scarcity in supply. Therefore, the capture price in this case should be considered with caution, as it does not represent a plausible or stable investment environment.

Figure 21 shows the hourly aggregated CO₂ equivalent emissions for extreme scenarios.



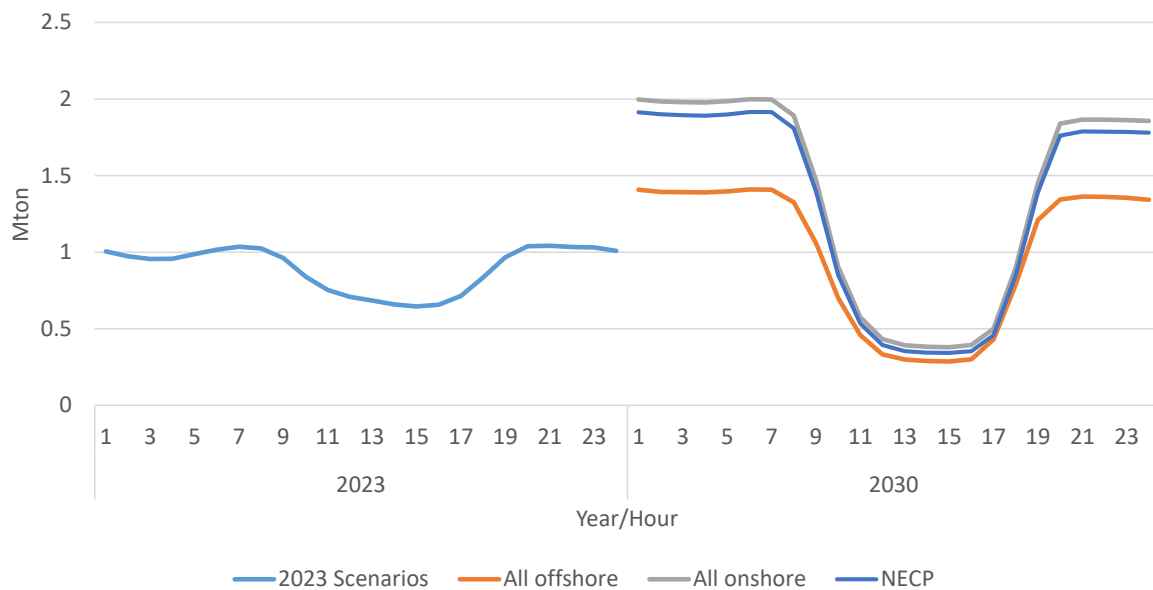


Figure 21 – Hourly aggregated CO₂ equivalent emissions for extreme scenarios.

Consistent with the earlier conclusion that offshore wind has a higher capacity factor than onshore wind – comparing “All offshore” to “All onshore”, respectively – , a system relying solely on offshore capacity leads to reduced CCGT generation. Consequently, this results in lower CO₂ equivalent emissions from the electricity system.

3.3.3 In-depth offshore profile scenarios

This section presents the results for the “All Offshore” scenario, which was discussed in the previous section, as well as the “All Offshore w/o Smoothing” scenario. The latter scenario utilizes the normalized profile of the Viana do Castelo offshore unit without any adjustments to scale the profile to the MIBEL system level.

Figure 22 presents the aggregated demand by type and year for both the “All offshore” and “All offshore w/o smoothing” scenarios. Since both scenarios assume the same total demand for 2030, no differences are observed between them in this regard.



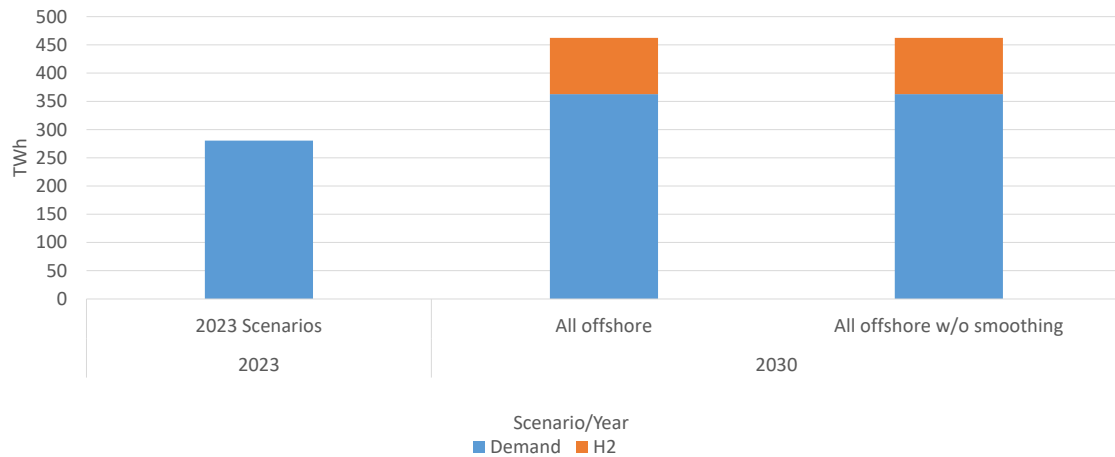


Figure 22 – Aggregated demand by type and year for in-depth offshore profile scenarios.

Figure 23 shows the hourly market price for the in-depth offshore profile scenarios.

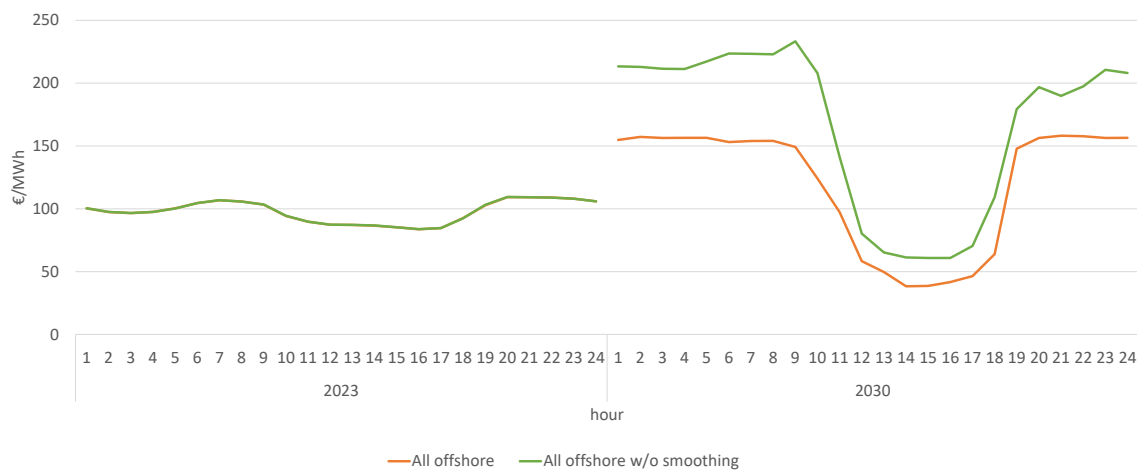


Figure 23 – Hourly average market price for in-depth offshore profile scenarios.

It is important to note that both scenarios are affected by the previously explained NSE effect, which artificially raises market prices due to the supply shortage in meeting demand. However, the scenario without smoothing is more susceptible to this effect, as no adjustment was made to scale the offshore wind profile to the MIBEL system level.

As illustrated in Figure 24, the scenario without smoothing results in slightly higher market prices across all seasons. Notably, the winter season exhibits a more significant disparity between the two scenarios, due to the limited supply available to meet demand during that period, as previously mentioned which leads to much more NSE hours for the non-smoothed scenario.



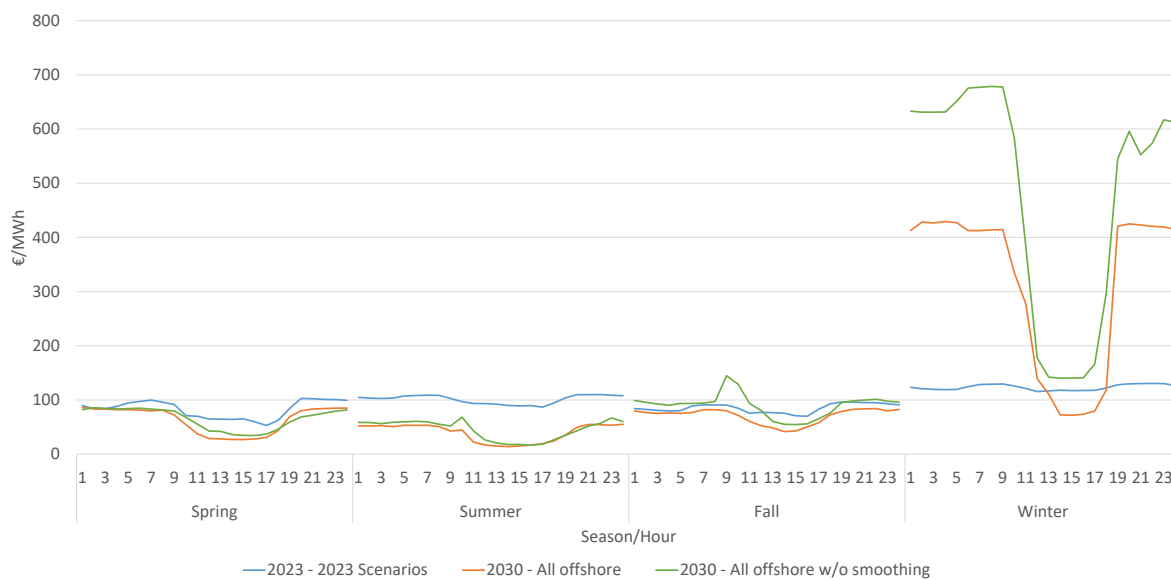


Figure 24 – Hourly average market price by season for in-depth offshore profile scenarios.

Figure 25 shows the total NSE by season and hour for 2030 for in-depth offshore profile scenarios.

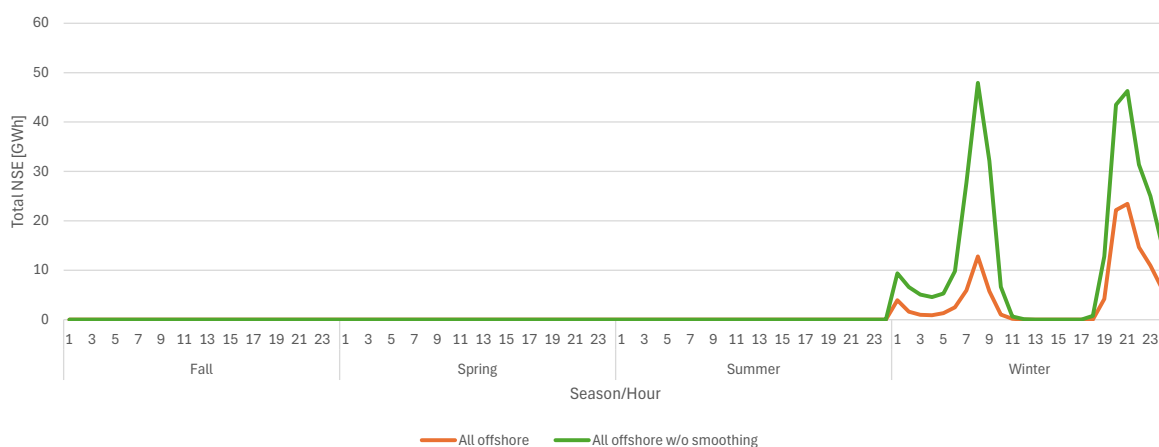


Figure 25 – Total NSE by season and hour for 2030 for in-depth offshore profile scenarios.

As concluded earlier, the winter season shows high NSE values, especially outside intermediate hours, highlighting the supply side’s inability to meet demand under the given scenarios. Although these scenarios are intentionally extreme and not meant to reflect real-world conditions, they help illustrate how different offshore wind profiles affect system performance. Specifically, when the offshore wind profile considers a single-site generation – as in the “All offshore w/o smoothing” scenario – NSE values rise significantly, with notable impacts on market prices.

Figure 26 shows the annual aggregated generation by technology for the in-depth offshore profile scenarios.



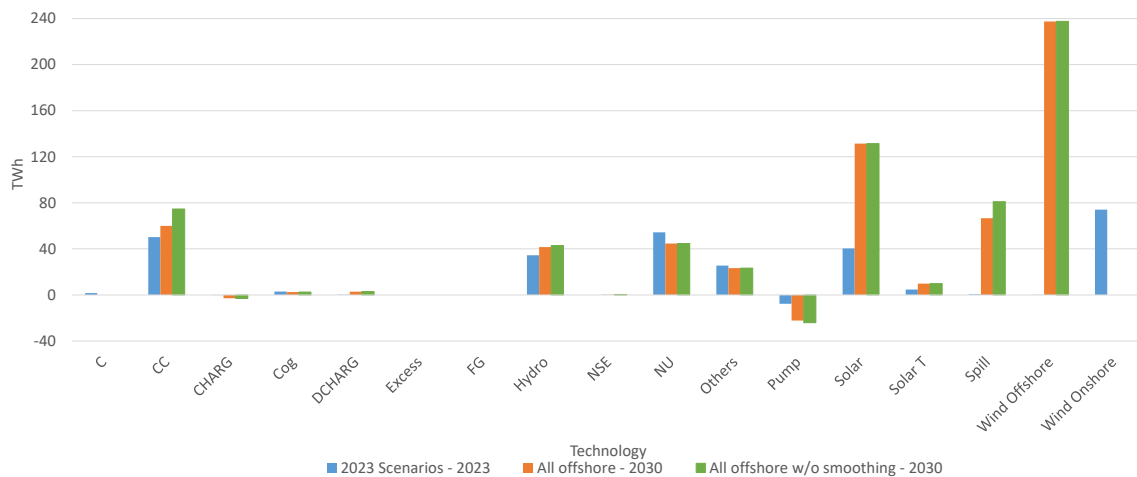


Figure 26 – Annual aggregated generation by technology for in-depth offshore profile scenarios.

In 2030, CCGT generation is higher in the scenario without smoothing compared to the scenario with smoothing. This occurs because, when no adjustment is made to the offshore wind profile, there are fewer hours of 100% offshore generation and more hours with 0% offshore generation. As a result, there is less offshore generation available during peak hours when CCGT are mainly needed to compensate the lack of generation.

In contrast, the "All offshore w/o smoothing" scenario has higher spillages than the scenario that considers offshore smoothing, given the fact that without smoothing, there are more periods of excess offshore generation that cannot be absorbed by the system. This leads to greater curtailment of wind energy, resulting in higher spillages, whereas smoothing helps to better align generation with demand, reducing the need for curtailment.

Figure 27 shows the annual capture price by RES technology for in-depth offshore profile scenarios.

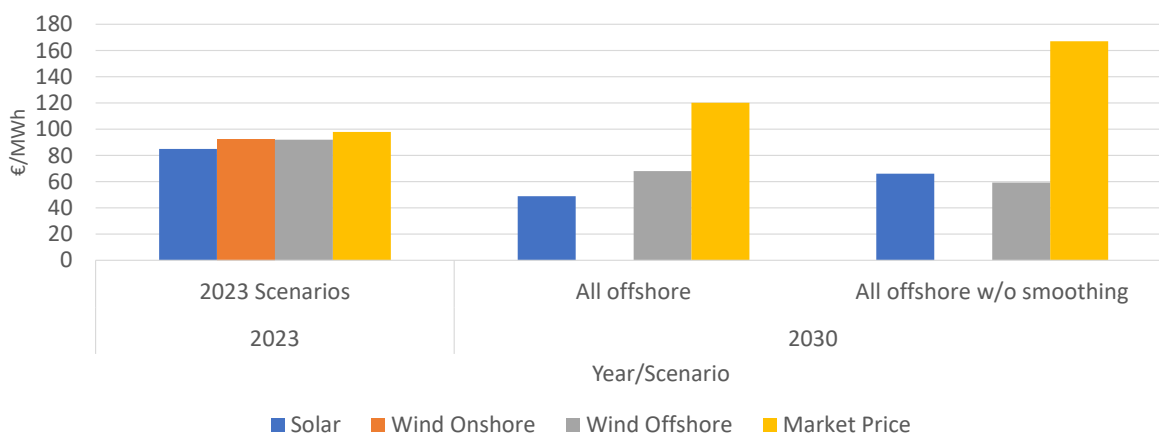


Figure 27 – Average annual capture price by RES technology for in-depth offshore profile scenarios.

By comparing both scenarios, it can be concluded that the "All offshore" scenario results in a higher annual average capture price than the scenario without smoothing. This is primarily due to the lower market prices and the increased



hourly offshore availability in the "All offshore" scenario – which does not reflect real-world conditions. These factors contribute to a more realistic representation, where the capture price for offshore wind tends to be lower than the market price, reflecting the higher availability of offshore wind during certain periods and the cannibalization effect of RES penetration.

This figure demonstrates that the cannibalization effect on offshore wind revenues is more pronounced when smoothing is not considered.

Figure 28 shows the hourly aggregated CO₂ equivalent emissions for in-depth offshore profile scenarios.

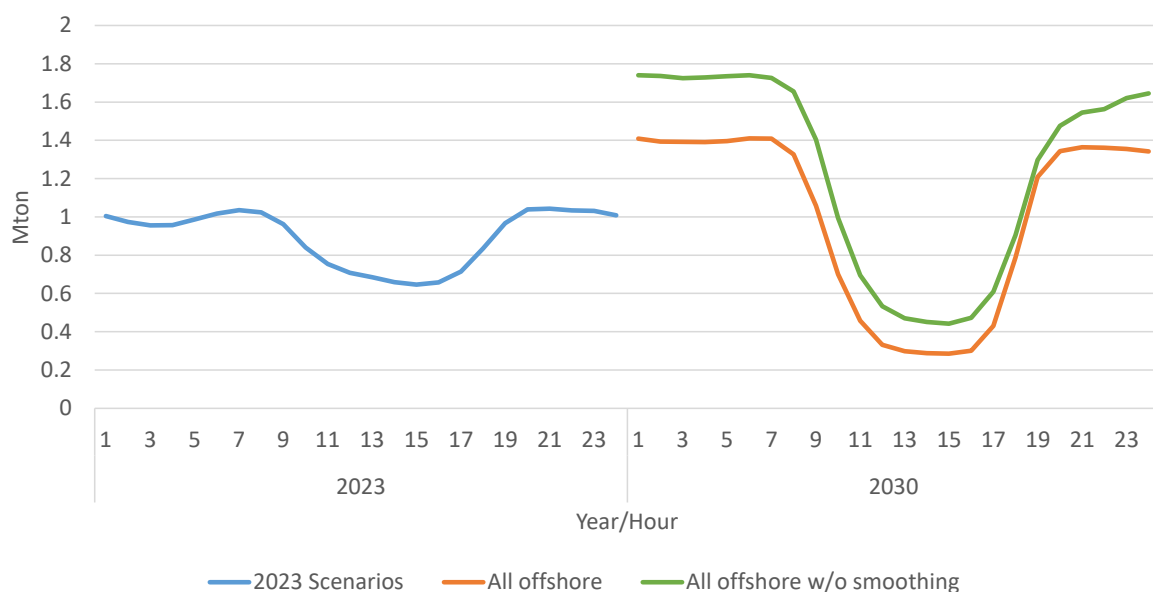


Figure 28 – Hourly aggregated CO₂ equivalent emissions for in-depth offshore profile scenarios.

In line with Figure 26, the scenario without smoothing has higher CCGT generation than the scenario with smoothing. This results in higher CO₂ equivalent emissions in the "All offshore w/o smoothing" scenario compared to the "All offshore" scenario. This indicates that the offshore wind profile used as input data can significantly influence the results. Therefore, it is crucial to ensure an accurate representation of the MIBEL system rather than relying on extrapolated unit data, as this can lead to misleading conclusions and potentially underestimate the environmental impact.



4 Netherlands, Belgium and Germany (plus Luxembourg) market prices assessment

4.1 Model overview and main features

In a renewable electricity system, based predominantly on wind and solar power, the Day Ahead (DA) electricity price will fluctuate with the weather. In the Netherlands this effect is now already visible, since there are hours that the production of wind and solar power is higher than the total load (see Figure 29). The figure presents the hourly DA electricity price for the Netherlands for the year 2023 as a function of the residual load. The residual load is the hourly load (demand) minus the weather dependent production of solar and wind. The price data are downloaded from the EU energy transparency platform ENTSO-E for the bidding zone of the Netherlands [22]. The residual load is calculated based on the ENTSO-E load over 2023 minus the solar and wind production over the hours provided by NED.NL [23].

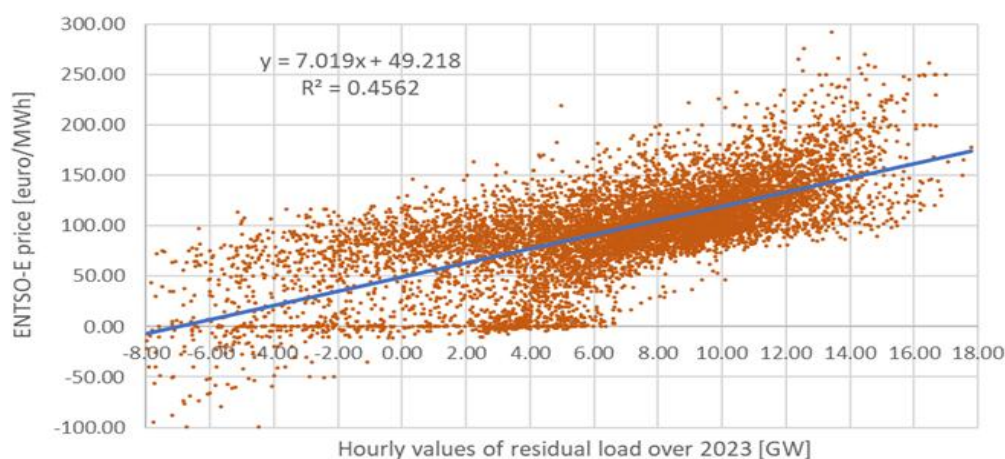


Figure 29 – Hourly day ahead electricity price as a function of the residual load (load minus solar plus wind power) over 2023

Around maximum residual-load the prices can make very high spikes. These spikes are due to scarcity of installed capacity. Also, at the other end of the graph very low (sub-zero) prices occur, which are mainly due to renewable production units that have no incentive to switch off at below zero price levels, like rooftop solar or wind farms with a fixed subsidized rate per MWh. These price spikes up and down have not much influence on the general price level, as long as they are incidental. In the future, these market disturbing methods of subsidizing production when prices are below zero, will be phased out [24].

Because of the very fast increase in renewable production, the year 2023 was chosen for our simulations, since it resembles the future better than previous years. The year 2024 was not finished yet when we started the research. There are certain differences between the years, concerning; windspeed, solar irradiation, ambient temperature, wave heights and demand. Therefore, using a single year only, has its



limitations. For specific projects (task 7), more than 1 year should be studied, as well as the effects of climate change.

There is a linear correlation appearing between the data points with an R2 of 0.46. So, 46% percent of the variance in the day ahead electricity price can be explained by the linear relation and about 55% of the variation is not related to the linear relation. As will be clear, there are a large number of external influences on the electricity price like electricity import and export, ambient temperature, day versus night, amongst others. However, if we are interested in the revenues of wave, tidal, solar and wind production over a whole year the linear relationship is a good approximation. Moreover, the uncertainty in the input data, like the future installed capacities of wind and solar or the price of natural gas, is much bigger than the uncertainty in this linear relationship. Moreover, the future weather is not known, so there will always be a weather-related uncertainty.

In other countries, a comparable linear relationship between day ahead electricity prices and the residual load is emerging. See for example the graph for Germany presented by Energy-Charts (see Figure 30) [25]. We see that there is an even better linear relationship than for the Netherlands in 2023. Sub-zero residual load values are still rare by 2023 in Germany.

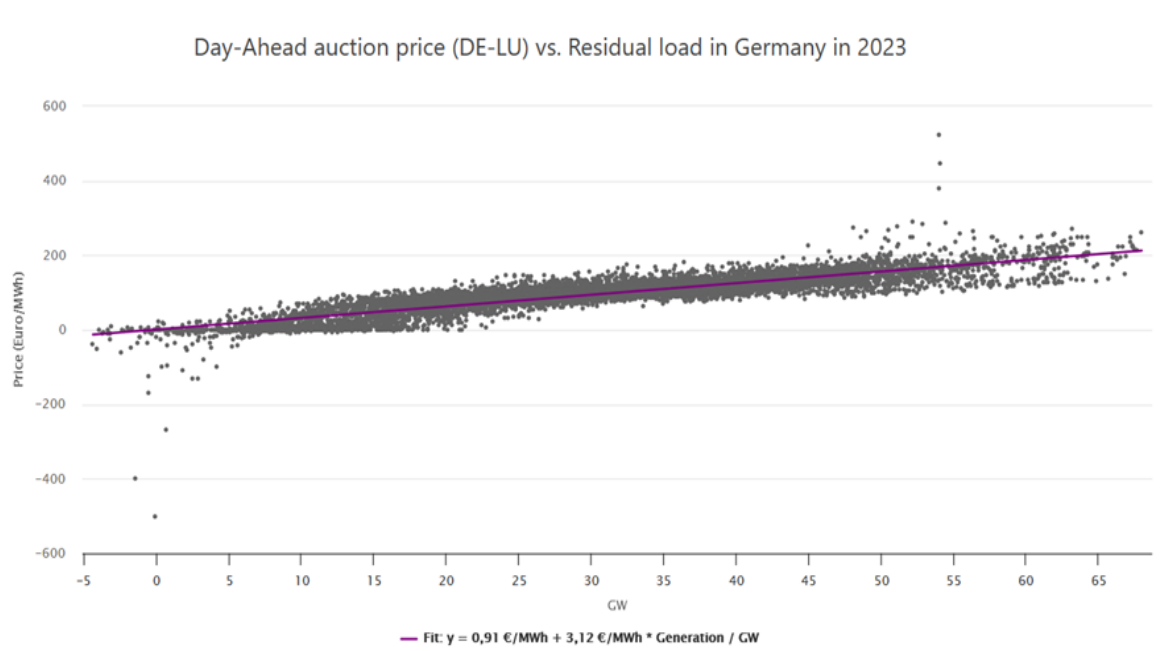


Figure 30 – Day-Ahead auction price (DE-LU) vs Residual load in Germany in 2023.

Based on this linear relation between the electricity price and the residual load, we can construct a linear price model for the future renewable electricity system (see Figure 31).



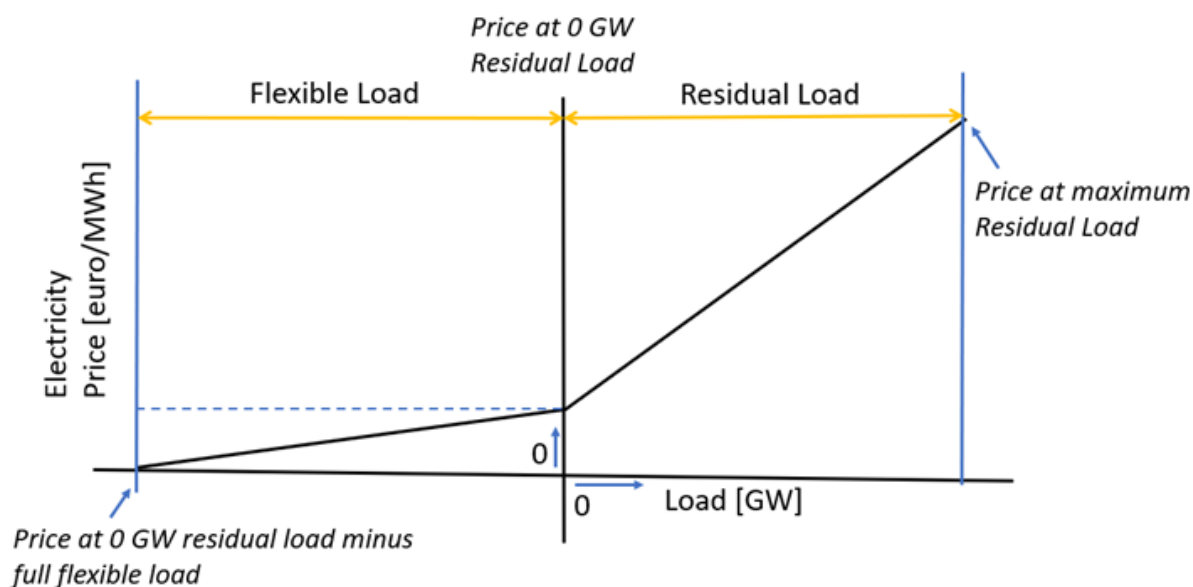


Figure 31 – Linear electricity price model between the residual load and the electricity price, consisting of two linear parts, one for the non-flexible load and one for the flexible load.

In the future there will not only be non-flexible load but also flexible load due to electrification of sectors like industry, mobility and heating. The flexible load will be switched on and off depending on the hourly electricity prices. Examples of upcoming flexible loads are charging of electric cars, heat pumps, electric boilers in industry and the production of hydrogen. In the current electricity system, there is hardly any flexible load, and the pricing scheme of the energy companies is not yet suited for the stimulation of flexible loads, although electricity companies that are offering dynamic hourly prices are picking up speed. However, flexible loads are an essential element in a renewable electricity supply, to accommodate surplus production of solar and wind.

The flexible load is switched on whenever the prices are below a certain threshold for cost effective operation. This depends on the type of flexible load like electricity export, vehicle charging, H2 production or direct heat production. The installed capacity of flexible load will follow the developments at the supply side of the market. The more solar and wind capacity will be installed, the lower the electricity prices will become, and the more flexible load capacity will be added, to profit from the low prices.

In our 2023 EWTEC paper, we used the “demand coverage ratio” parameter instead of the “residual load” parameter as it is a common methodology applied to assess daily prices [26]. The two methodologies were later compared, and the findings were that the use of the "residual load" parameters was giving more accurate results. The residual load is a better parameter since the prices are related to the actual electric power in the system and not to the relative powers in the system, as is the case with the demand coverage ratio parameter. The residual load parameter was first introduced by Von Roon in 2010 [27]. Von Roon showed that there was a good correlation between the residual load and the day ahead market price for Germany. Simpson (2019) elaborated further on the possibilities of the



application of the residual load method to determine the value of electricity in the design of renewable energy systems [28]. While Ruhnau (2022) shows the effect of adding flexible load (in his case flexible hydrogen electrolysers) to the electricity prices [29]. He shows that, once high shares of variable renewables are reached, flexible electrolysers help increase the market share of renewables even further. This means that they disproportionately consume renewable electricity that would otherwise have been curtailed. This leads to a distinct section of the price graph: at very high contribution of variable renewables (so at values of the residual load below zero), the demand from the flexible loads will keep the electricity price above zero and thus bend the price curve upwards (Ruhnau, figure 10).

The DMEC price simulation model consists of two parts: the first part is the DMEC MultiORE multi-source renewable production simulation model. The model calculates the electricity production of solar, wind and wave power devices for any geographic location. The production profile is calculated by multiplying the resource available from historical time-dependent datasets with the performance characteristics of the different technologies included in the energy mix [30]. The second part is the Price Model. This is based on the residual load calculated for each hour for the applied weather year (in this study 2023). The demand profile is computed through adaptation from the historical hourly demand dataset for the same weather year (see Figure 32).

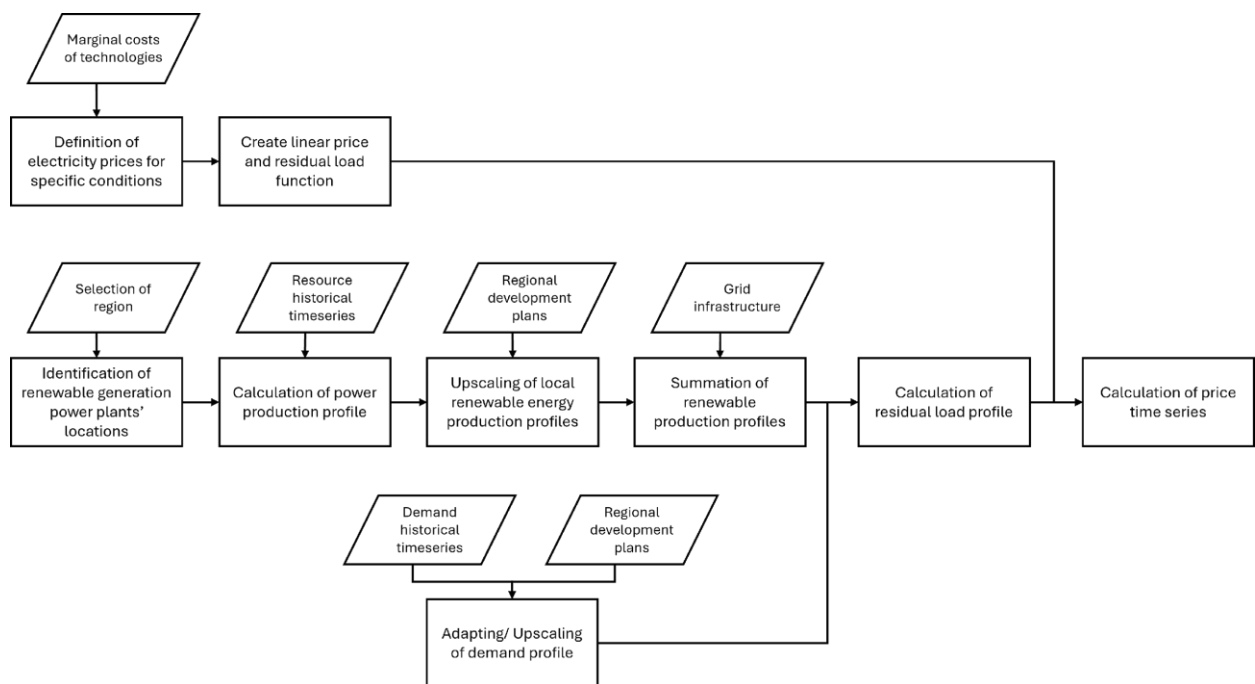


Figure 32 – DMEC Price Model following the linear regression method

With this Price Model DMEC can perform large amounts of simulations, to provide an overview of all possible future price developments.



4.1.1 Geographic distribution of the installed wind and solar capacity

For Germany especially, but also for smaller countries like Belgium and the Netherlands, there is an effect of the geographic location on the hourly solar, wind and wave production. This geographic distribution of the renewable generation has a direct influence on the electricity price through the residual load relationship. The Netherlands, Belgium and Germany (plus Luxembourg) all have a single day ahead electricity market (BZN = Bidding Zone), so all the renewable production is aggregated to a total renewable production over the land and sea area per country. To be able to calculate this total production we have made a geographic distribution over the land and sea area for all three bidding zones.

Geographic distribution for the Netherlands

The geographic distribution should be detailed enough to eliminate the effect of local weather patterns, but the amount of simulations should be limited also for practical reasons. For the Netherlands we designed a geographic distribution with twelve locations of which seven are located onshore and five offshore (see Figure 33). All the renewable production capacity is concentrated in these 12 locations. Onshore the distribution follows the subdivision in provinces and the locations are chosen at KNMI (Dutch meteorological institute) weather stations, so that we have the most optimal weather data available for validation purposes. Offshore the distribution follows the main wind farm areas. Governmental and CBS figures were used to construct this geographic distribution [31], [32], [33].



Figure 33 – Geographic distribution for the Netherlands consisting of twelve locations in which the renewable production is concentrated

Table 4.1 shows the twelve locations with the expected installed capacities (in percentage of the total) per location. This provides the possibility to change the total installed capacity without having to change the distribution. A geographic distribution was made for 2030 and for 2050.



Table 4.1 – Geographic distribution of the installed renewable production capacity for 2030 (locations in degrees).

	Location	KNMI station	North	East	Wind onshore	Wind offshore	Solar onshore	Solar offshore
1	Groningen, Drenthe	Eelde	53.120	6.580	16.9%		13%	
2	Friesland	Leeuwarden	53.220	5.520	9.2%		5%	
3	Noord Holland	De Kooy	52.930	4.780	10.3%		9%	
4	Overijssel, East Gelderland	Twenthe	52.270	6.880	3.2%		14%	
5	Utrecht, West Gelderland, Flevoland	De Bilt	52.100	5.180	31.9%		18%	
6	West Brabant, Zeeland, South Holland	Woensdrecht	51.540	4.350	26.1%		22%	
7	Limburg, East Brabant	Eil	51.200	5.770	2.4%		17%	
8	Northern part of territorial waters	A12-CPP	55.399	3.810		0%		0%
9	Ten Noorden Waddeneilanden	Gemini BG OHVS2	54.037	6.042		17%		0%
10	Nederwiek, Lagelander, IJmuiden ver	K13-A	53.218	3.219		61%		0%
11	Hollandse Kust	Hoorn A	52.918	4.150		15%		100%
12	Borssele wind farm	Euro platform	51.998	3.275		8%		0%

The percentages give the distribution of this installed capacity over the land or sea area. Until 2030, these are the planned capacities and locations of the Dutch government. For 2050 an estimation is made where the extra capacity would be installed. Table 4.2 shows the distribution over the twelve locations for the year 2050.

Table 4.2 – Geographic distribution of the installed renewable production capacity for 2050 (locations in degrees).

	Location	KNMI station	North	East	Wind onshore	Wind offshore	Solar onshore	Solar offshore
1	Groningen, Drenthe	Eelde	53.120	6.580	16.9%		13.5%	
2	Friesland	Leeuwarden	53.220	5.520	9.2%		5.1%	
3	Noord Holland	De Kooy	52.930	4.780	10.3%		9.5%	
4	Overijssel, East Gelderland	Twenthe	52.270	6.880	3.2%		14.0%	
5	Utrecht, West Gelderland, Flevoland	De Bilt	52.100	5.180	31.9%		18.3%	
6	West Brabant, Zeeland, South Holland	Woensdrecht	51.540	4.350	26.1%		22.4%	
7	Limburg, East Brabant	Eil	51.200	5.770	2.4%		17.2%	
8	Northern part of territorial waters	A12-CPP	55.399	3.810		50%		0%
9	Ten Noorden Waddeneilanden	Gemini BG OHVS2	54.037	6.042		10%		5%



10	Nederwiek, Lagelander, IJmuiden ver	K13-A	53.218	3.219		26%		50%
11	Hollandse Kust	Hoorn A	52.918	4.150		10%		40%
12	Borssele wind farm	Euro platform	51.998	3.275		4%		5%

Geographic distribution for Belgium

Belgium is a smaller country than the Netherlands with especially a much smaller sea area. Therefore, we designed a geographic distribution with 7 locations in total, of which two are offshore. Onshore the distribution follows the subdivision in provinces and the locations were chosen at KMI stations (Belgium national meteorological institute), offshore the locations were chosen at the two wind farm zones. For the Western wind farm-zone the location of the Elia substation was chosen (Elia OSY MOG). For the other location the offshore Princess Elisabeth Island was chosen, that is under construction. Governmental figures were used to construct the geographic distribution of the installed capacities [34], [35], [36].



Figure 34 – Geographic distribution for Belgium consisting of 7 locations in which the renewable production is concentrated.

Table 4.3 – Geographic distribution for Belgium consisting of 7 locations in which the renewable production is concentrated.

	Location	KMI station	North	East	Wind onshore	Wind offshore	Solar onshore	Solar offshore
1	East and West Vlaanderen	Zeebrugge	51.3474	3.2018	28%		34%	
2	Antwerpen	Retie	51.2214	5.0272	16%		17%	
3	V. and W. Brabant, Hainaut, Brussel	Ukkel	50.7969	4.3579	23%		24%	
4	Liege, Limburg	Mont Rigi	50.5108	6.0734	21%		20%	
5	Luxembourg, Namur	Buzenol	49.6204	5.5872	12%		5%	
6	Elia OSY MOG		51.5824	2.8686		46%		0%
7	Princess Elisabeth island		51.5280	2.4980		54%		0%



Geographic distribution for Germany

Germany (plus Luxembourg) is a far bigger country than Belgium and the Netherlands, therefore we have chosen more geographic locations (13 onshore and 4 offshore). The offshore area of Germany is relatively smaller than that of the Netherlands. The distribution over the land area follows the areas of the Bundesländer and the specific locations are at a DWD (German weather service) location. Offshore the locations are at the main wind areas. Governmental figures were used to construct the geographic distribution of the installed capacities [37], [38], [39].



Figure 35 – Geographic distribution for Germany (plus Luxembourg; not on the map) consisting of 17 locations in which the renewable production is concentrated.

Table 4.4 – Locations data for Germany (plus Luxembourg) consisting of 17 locations in which the renewable production is concentrated.

	Location	KMI station	North	East	Wind onshore	Wind offshore	Solar onshore	Solar offshore
1	Schleswig-Holstein, Hamburg	Schleswig	54.528	9.549	14.3%		3.9%	
2	Mecklenburg-Vorpommern	Schwerin	53.642	11.387	6.1%		4.3%	
3	Niedersachsen, Bremen	Bremen	53.045	8.798	20.5%		8.9%	
4	Brandenburg, Berlin	Berlin Tempelhof	52.468	13.402	14.2%		8.0%	
5	Sachsen-Anhalt	Magdeburg	52.103	11.583	8.7%		4.8%	
6	Nordrhein-Westfalen	Düsseldorf	51.296	6.769	12.0%		12.0%	
7	Hessen	Giessen	50.591	8.655	4.2%		4.5%	
8	Thuringen	Erfurt	50.992	11.057	3.0%		2.9%	
9	Sachsen	Dresden	51.056	13.727	2.2%		4.7%	
10	Rheinland Pfaltz, Saarland, Luxemburg	Trier	49.748	6.658	7.7%		6.5%	



11	Bayern Nord	Nürnberg	49.503	11.055	2.1%		13.4%	
12	Bayern Sud	München	48.217	11.517	2.1%		13.4%	
13	Baden-Württemberg	Freudenstadt	48.454	8.409	2.9%		12.5%	
14	N-14 up to and including N-20		54.900	5.300		0%		0%
15	N-5 up to and including N-13		54.500	6.000		58%		0%
16	N-1 up to and including N-4		53.800	6.900		29%		50%
17	O-1 up to and including O-3		54.800	14.000		13%		50%

All offshore locations are used to calculate the wave energy generation as well. The results of wave energy presented in the following chapters use the mean power production of all offshore locations in each country to show an average captured price for waves.

4.1.2 Installed capacities solar and wind

In the model, the installed capacities per location are multiplied with the normalized power output of each technology to generate hourly time series of renewable energy production that are used further to calculate the residual load in hourly resolution.

For the Netherlands the future installed capacities onshore and offshore solar and wind were derived from several relevant scenarios. Two PBL studies [40], [41], the NECP for 2030 [32] and the I13050 study [42]. The figures of all these scenarios were averaged to come to the values for offshore and onshore solar and wind in 2030. For 2050 we applied the average values of the scenarios of the I13050 study.

For Belgium for 2030, we applied the NECP for 2030 [36], the planning for the Princess Elizabeth offshore wind zone [43] and Zonneplan Vlaanderen [44]. The values of these scenarios were averaged for onshore and offshore wind and solar.

For Germany for 2030, we applied the NECP for 2030 [39] for solar and onshore wind. For offshore wind we also applied the German offshore wind energy act [45] as well as the total planned capacity offshore wind for 2030 [38]. The values of these scenarios for offshore wind were averaged.

4.1.3 Demand

In the model, the demand hourly timeseries per country is taken from historical data corresponding to the same duration and year of the resource data used to calculate the renewable power production (2023). The timeseries is multiplied by a defined factor in order to reach the total fixed energy demand defined in the future scenarios. The time series is used further to calculate the residual load in hourly resolution.



For the demand in the Netherlands in 2030 and 2050 we applied the I13050 study of Netbeheer Nederland [42]. The average value of the three scenario's was used. For Belgium and Germany for 2030 we have applied the NECP plans [36] and [39].

4.1.4 Flexible loads

The estimation of the installed capacity flexible loads is difficult, since it not only consists of centrally controlled large investments like the interconnection with surrounding countries, but also on investments on household level like the amount of (flexibly charged) electric cars. Other forms of flexible loads are Demand Side Response (DSR), Power to Gas (P2G) and Power to Heat (P2H). We applied different references to come to an estimation of the installed capacity flexible loads in 2030. For the Netherlands we used the I13050 study of Netbeheer Nederland [42]. For Germany we applied the NECP plan [39] plus the Penta flexibility study [46]. The Penta region is a regional cooperation between BeNeLux, Germany, France, Austria and Switzerland. For Belgium the Penta study plus the NECP was applied [36]. See Table 4.5 for the resulting values.

Table 4.5 – Assumptions for the installed capacity flexible loads in 2030.

Country	Interconnection [GW]	Other flexible loads [GW]	Total flexible loads [GW]
Germany/Luxembourg	28.4	40.0	68.4
Netherlands	12.8	10.1	22.9
Belgium	8.6	3.7	12.3

There will also be a certain capacity of batteries installed in the system. Batteries are not included as flexible loads, since they also deliver the power back to the system. Batteries can be regarded as price dampening actors on the electricity market. In these simulations batteries were not considered, yet.

4.1.5 Price at maximum residual load

In the Netherlands in 2023 the electricity price at the maximum residual load in 2023 (at 18 GW), was 175.6 €/MWh, according to the linear regression line (see Figure 29). The main price drivers for the maximum residual load price point are the fuel costs plus the costs of emitting or removing CO₂. At the EPEX SPOT Day-Ahead market, the fuel-based dispatchable plants generally offer to produce at or just above their marginal costs, which consist mainly of these fuel costs and CO₂ costs. If the price, at the closing of the market, is settled higher than their marginal costs, they make a margin with which they have to earn back their CAPEX and make a profit. The fuel can be natural gas but can also be a bio-fuel or, when 2050 is nearing, it could be hydrogen or other renewable power-based fuels (P2G: Power to Gas). The type of fuel-based technology used, will affect the marginal costs at the maximum residual load.



In 2023 the natural gas price level (52 €/MWh) was exceptionally high due to the closure of the pipelines from Russia and the scarcity of LNG. Transmission System Operator (TSO) Tennet expects that the LNG scarcity will be solved by 2030 and the price will be lower at 27 €/MWh for The Netherlands [47]. INESC TEC however is calculating with a gas price of 41 euro per MWh for Iberia for 2030. The European CO2 price was around 90 €/ton in 2023 and will be around 113 €/ton in 2030 according to Tennet [47]. The maximum residual load price for 2030 is assumed to stand in the same relation to the natural gas plus CO2 costs per MWh as in 2023. The price level at the year 2050 is an estimation based upon the fact that by then all CO2 must be removed from the fuel gasses or the fuel should emit no nett CO2. These maximum residual load price levels are comparable to the price level that we derived in our 2023 EWTEC paper of 150 €/MWh for 2050 [26].

Table 4.6 – Price level at maximum residual load in 2030 and 2050 based on the main cost driver (the fuel and co2 costs) for the Netherlands.

The Netherlands	Year	2023	2030	2050
Fuel and CO2 costs [€/MWh]		122.9	86.5	103.9
Price at max. residual load [€/MWh]		175.6	123.6	148.3

Since the natural gas and CO2 price in Belgium and Germany are at about the same level as in the Netherlands, we used the same method to derive the maximum residual load prices for Belgium and Germany.

For the Netherlands the price level at zero residual load is kept at 50 euro per MWh for 2030 and 2050, according to the regression line for 2023 (Figure 29). The most important flexible load in the system in 2023 is the import and export of electricity. The price-effect of adding other flexible loads to the system (DSR, P2G, P2H) is not known yet, so there is no information available to set this price at a different level than for 2023. For Germany and Belgium we have made the same assumption and set the price level at 50 €/MWh for 2030.

4.1.6 Other Inputs

In addition to the above-described assumptions, other input parameters as well as timeseries are necessary to calculate the hourly price of the different countries.

To calculate the produced power for each location and technology in each country, the **resource timeseries** is necessary and for the **demand timeseries** the historical data on the country's demand is required. As the validation case was performed with 2023 historical data, both resource and demand timeseries are taken for that year.

Solcast is used for the wind and solar data and ENTOS-E's transparency platform provided the demand timeseries. The power produced by each technology in each location of the defined geographical distribution is normalized and multiplied by



the total **installed capacity of the technology** in the chosen locations of the country.

After calculating the price timeseries, also the power produced by wave devices in the different offshore locations is calculated; for this ERA5 data from the same timeframe is used. The wave device is characterized by a power matrix. As for all other technologies assessed, the average power output of all wave technologies in the different offshore locations is taken to calculate the results per technology (e.g. captured price and capacity factor).

The demand timeseries is multiplied by a factor based on the ratio between total demand of the historical timeseries and the **total fixed demand** defined for the future scenario of the country.

As mentioned above, the **electricity price at maximum residual load** and the **electricity price at zero residual load** need to be defined in addition to the **maximum residual load capacity** and the **maximum flexible load capacity** to define the three price-points that define the linear price model assumptions.

Based on the assumptions and inputs defined, the price timeseries can be calculated. The values taken for the input parameters for the different scenarios simulated are summarized and described in the next section (Section 4.2).

4.1.7 Outputs

The initial result of the model is the **hourly time series of DA electricity prices** for the total timespan defined with the input time series.

Based on this main result, further assessments can be made through post-processing and defined metrics.

The price time series can be grouped in order to give significant mean values per hour of the day; the **mean electricity price** for each hour of the day throughout the year can be depicted. The same approach can be used to calculate the average electricity price for each hour of the day for each season. The seasons are defined to be spring (March, April, May), summer (June, July, August), fall (September, October, November), and winter (January, February, December).

Furthermore, the **coefficient of variance** of the hourly price time series can be calculated:

$$CoV = \frac{\sigma}{\mu},$$

Where σ is the standard deviation of the price time series and μ is its mean. This metric helps understand the fluctuations between hourly prices throughout the year.

The most interesting metrics are calculated when the price time series is assessed in connection to the performance of the different technologies.

The **average captured price** (ACP) per technology (tec) can be defined as:



$$ACP_{tec} = \frac{\sum_t Revenue_{tec}}{\sum_t Power_{tec}}$$

t being the timestep of the timeseries of hourly resolution. This metric gives a weighted average of the captured prices for each technology based on the amount of power produced and sold in each timestep. Depending on the timestep chosen seasonal and hourly differences can be studied.

4.2 Simulated scenarios

The price model has been used to assess the future prices of multiple scenarios; three base case scenarios are defined to compare the Netherlands, Belgium and Germany + Luxembourg pricing zones. The input parameters for the installed capacities of the different countries used for these cases are summarized in Table 4.7.

Table 4.7 – Installed capacities for 2030 scenarios for the three separate countries.

Input parameter	Unit	NL	BE	DE + Lux
Installed capacity wind	GW	28.6	10.2	143
Installed capacity onshore wind	GW	8.6	5.2	115
Installed capacity offshore wind	GW	20	5.0	28
Installed capacity solar (onshore)	GW	48.3	14.7	215
Total fixed demand	TWh	153.5	60.8	476.4
Maximum flexible demand	GW	22.9	12.3	68.4

An initial focus on the Netherlands gives a detailed explanation of how the model works by considering different potential input scenarios for which the input parameters change slightly, depending on the reports and documents used to describe the plans for future renewable energy installations (Table 4.8).

Table 4.8 – Installed capacities for four scenarios in the Netherlands region.

Input parameter	Unit	2023	2030	2030 NECP	2050
Installed capacity wind	GW	9.9	28.6	26	64.1
Installed capacity onshore wind	GW	6.4	8.6	9	13.8
Installed capacity offshore wind	GW	3.5	20	17	50.3
Installed capacity onshore solar	GW	24	48.3	59	144.6
Installed capacity offshore solar		-	-	-	1
Total fixed demand	TWh	109	153.5	153.5	153.5
Maximum flexible demand	GW	3.7	22.9	11	68.1

The three price-points that create the linear regression price model for each scenario are defined in Table 4.9. With these inputs, the price models depicted in Figure 36 are created and applied to the base case scenarios. The price points are changed only in the full factorial analysis and this is described more in detail in Section 4.3.1.1.



Table 4.9 – Price-point assumptions for 2030 scenarios.

	Unit	NL	BE	DE + Lux
Maximum fixed demand	GW	28.2	9.8	75.7
Price at maximum residual load (maximum fixed demand)	€/MWh	123.6	119.7	149.2
Price at zero residual load	€/MWh	50	50	50
Maximum flexible demand	GW	22.9	12.3	68.4
Price at minimum residual load (maximum flexible demand)	€/MWh	0	0	0

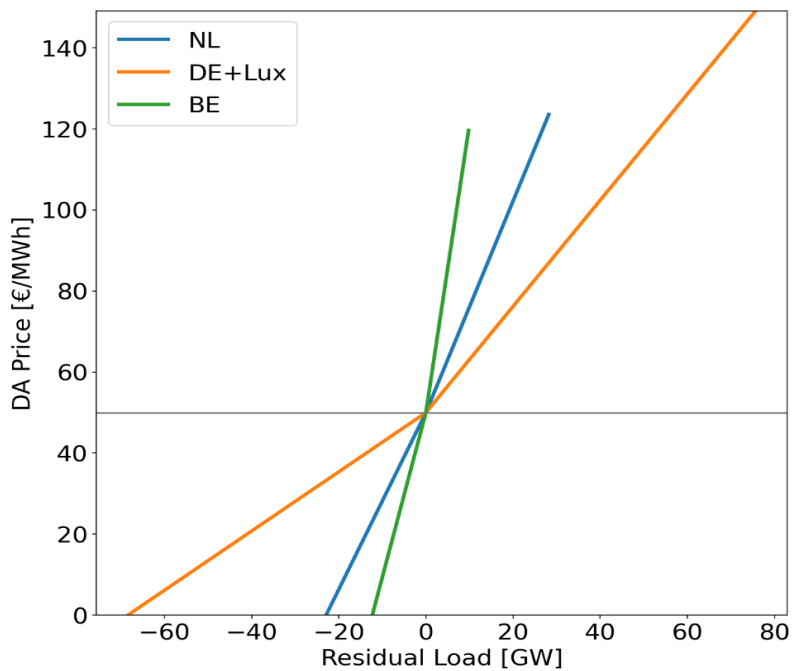


Figure 36 – Price curves (Day Ahead price versus residual load) for Netherlands, Belgium and Germany (plus Luxembourg).

4.3 Results analysis

With the price model, the Netherlands, Belgium, and Germany (plus Luxembourg) are assessed. The 2030 base case scenarios are defined and compared between these countries.

The first in-depth study is performed for the Netherlands. It includes scenarios of three different years (2023, 2030, and 2050) and the use of two different references to define the input parameters for the 2030 scenarios. This shows the uncertainty of input parameters and how possible changes to regional, national and European plans could affect future electricity prices. Furthermore, a full factorial study on the six input parameters is performed with a three-level sensitivity to give additional insights into the effects of changing certain input parameters onto the results.



For the remaining countries, the base case is assessed and, finally, the main results of the three countries are compared.

4.3.1 Netherlands

For the Netherlands, the scenarios are extended to include 2023 and 2050 in addition to the 2030 base case in order to contextualize the results and give a broader overview. The 2023 scenario was used for model validation. The 2050 scenario is included as it shows significantly higher renewable energy penetration and offshore solar installations. 2050 is also relevant for renewable project business cases. Furthermore, two different scenarios for the year 2030 are selected to highlight the differences between the NECP which is updated less frequently and other relevant scenarios that are updated more consistently.

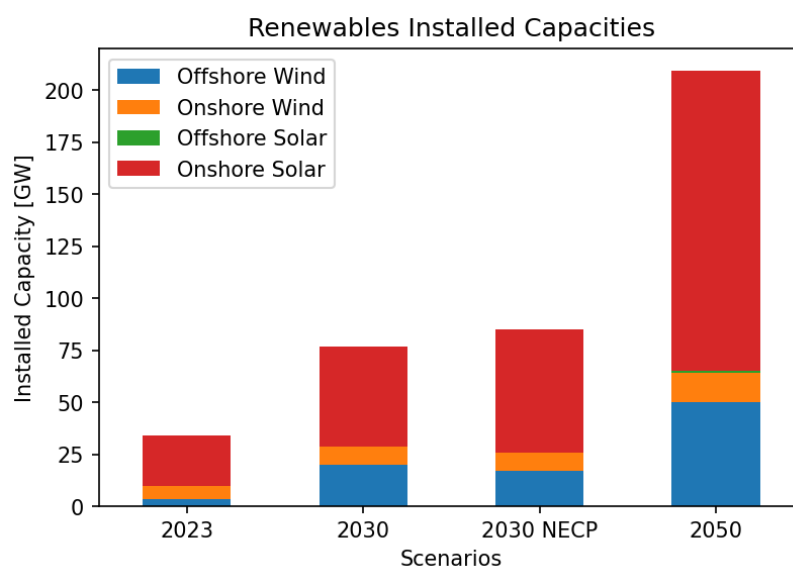


Figure 37 – Installed capacities solar and wind for the Netherlands, with two scenarios for 2030.

For 2030, no installed capacity for offshore solar and wave power is included, because the Netherlands has no official goal anymore for these two technologies. Last year there was an official goal of 3 GW offshore floating solar in 2030, but it was erased by the new government. Both technologies are also not included in relevant base case future scenarios; the same holds for Germany and Belgium. For the 2050 scenario, a small amount of offshore solar is included in order to show potential differences between performance and captured prices of onshore and offshore solar technologies. The amount depicted is no reflection on the much larger potential offshore solar could hold by 2050.

Between 2023 and 2030 the installed capacity of renewable energy technologies more than doubles; while in the NECP scenario a large amount comes from solar energy, in the base case scenario defined by more recent reports, such as the I13050, the total renewable energy capacity is slightly lower as well as the solar capacity, while wind (especially offshore wind) capacity is higher. The Dutch plans for 2050 show a total installed capacity of renewables of more than 200 GW; the majority of which comes from onshore solar power. Having an outlook towards



2050 is important for investors, banks and insurance companies, because projects that start their development now, will be realised around 2030 and will still be running after 2050.

It is worth mentioning that the ratios of installed capacities do not necessarily coincide with the ratios of total energy produced per technology, this is assessed more in detail further below.

The DA prices and the captured prices per technology are used to assess and compare different cases. The average values give an initial assessment; seasonal and hourly metrics can be used to give more detailed information about the effects of different renewable energy technologies on the results.

The total average DA price, the coefficient of variance (CoV) of the price and the average captured prices per scenario of the Netherlands are summarised in Table 4.10.

Table 4.10 – Total average DA price, CoV and average capture prices per scenario of the Netherlands.

The Netherlands	Unit	2023	2030	2030 NECP	2050
Average electricity price	€/MWh	101	53	45	37
CoV of price	-	0.34	0.47	0.86	0.76
Average captured price per technology					
Onshore wind	€/MWh	86	37	26	24
Offshore wind	€/MWh	91	40	30	25
Onshore solar	€/MWh	64	34	4	12
Offshore solar	€/MWh	N/A	N/A	N/A	12
Wave	€/MWh	N/A	43	34	27
CO2 emissions	Mton	24	15	21	N/A

While the average electricity price does not change significantly between the 2030 and 2030 NECP cases, it shows significant differences in the captured prices of the technologies, especially the solar technology. The solar price is very low, because of the too small amount of flexible load in the NECP scenario; leading to more frequent and higher negative prices. Such a price is not realistic (no business case for solar). So, there will be less solar installed or more flexible load (and batteries).

Although the total renewable energy installed is higher in the 2030 NECP scenario, due to the larger amount of solar capacity installed and the lower flexible load capacity, the total CO2 emissions are slightly higher than in the 2030 base case scenario.

The CoV of the DA price shows that with increasing share of one specific renewable energy technology the fluctuations between hourly price points increase significantly (2030 NECP and 2050 scenarios). A high amount of flexible load is necessary to avoid negative prices (2050 scenario).



Considering the captured prices of the different technologies, the differences are slim, but it is worth highlighting that solar energy shows lower captured prices in all scenarios compared to wind and wave energy. Furthermore, wave energy captures slightly higher prices than wind energy (onshore and offshore). The differences in captured electricity prices become smaller with increasing renewable energy capacity installed.

The effects are also visible in duration curves in Figure 38. The crossing of the price curves at 50 €/MWh DA electricity price shows the total amount of hours in the year in which the renewable energy generation is higher than the fixed demand, thus, the use of flexible load. When the price curve dips below 0 €/MWh the renewable energy generation is higher than the fixed and flexible load combined.

Between the NECP and base case scenario, a strong difference becomes visible after reaching the 50 €/MWh threshold, meaning that the lack of flexible demand causes a fast decrease of prices and a more frequent and lower negative price.

These results show that it is important to consider the uncertainty of the input parameters and give an initial understanding of the input parameters' effects on the resulting price timeseries and captured prices.

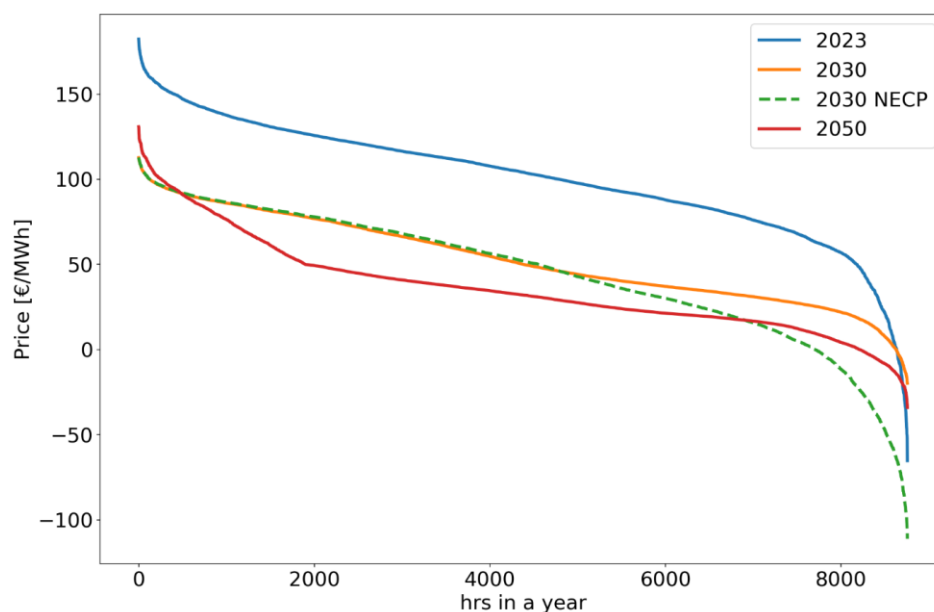


Figure 38 – Price duration curves over the whole year for 2023, 2030 (two scenarios) and 2050.

In the figure below (Figure 39), the total power produced by renewable technologies and the total fixed and flexible demand are summarised. Although more than 60% of the installed capacity is onshore solar, most of the renewable energy produced originates from offshore wind. The renewable energy production cumulatively nearly reaches the fixed demand but due to the timeliness of the generation, residual load still occurs, and flexible load is necessary to absorb the additional renewable energy production in timesteps with high production and low fixed demand.



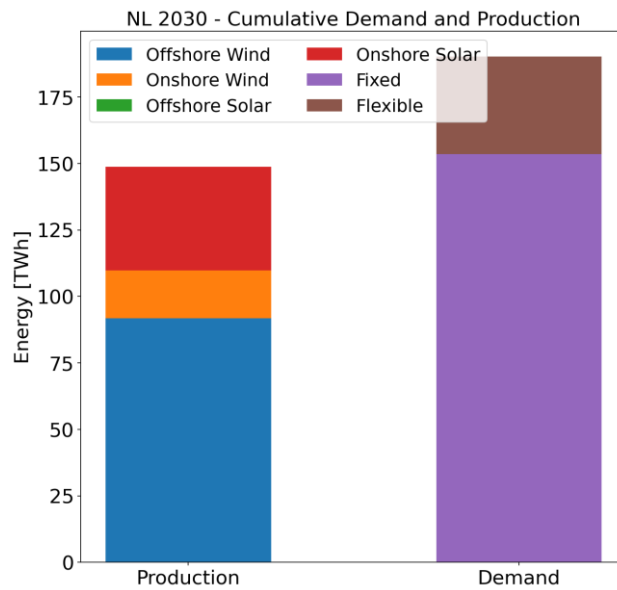


Figure 39 – The production of wind and solar as well as the fixed and flexible demand for the base case of 2030.

In general, the average DA market price shows significant 'duck'-shaped behaviour. Similarly, also the captured prices of the technologies follow this pattern but with smaller differences between highest and lowest captured price (except for solar energy). The average capture price per technology shows that in most cases the captured price is below the average market price, except solar energy in the early hours of the day. Figure 40 shows the average prices and captured prices over the entire year; below the seasonality effects are assessed which might cause the higher prices for solar in the early hours of the day.

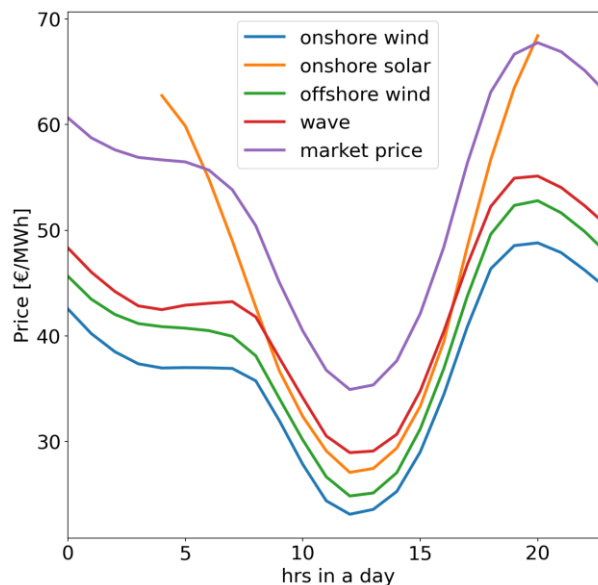


Figure 40 – The average price of wind, solar and wave power as well as the market price as a function of the time of day (base case 2030).

Solar technologies do not produce any electricity during dark hours, thus, not showing captured prices during the night hours. Wave energy shows higher



captured prices than both onshore and offshore wind, and offshore wind shows higher captured prices than onshore wind. It seems as though solar will have a better capture price over the year than wind and wave, but that is not the case as shown in Table 4.10. Solar makes most of its turnover around noon, when prices are low, while the turnover of wind and wave is more distributed over the day. Around noon wind and wave receive even lower prices than solar, because prices are driven even lower when there is high production from both solar and wind at the same time.

The importance of seasonality of production and demand profiles can be analysed through the differences in average hourly electricity prices and average hourly captured prices by technologies in the different seasons. From Figure 41, we can see the effects of seasonality on the DA electricity prices.

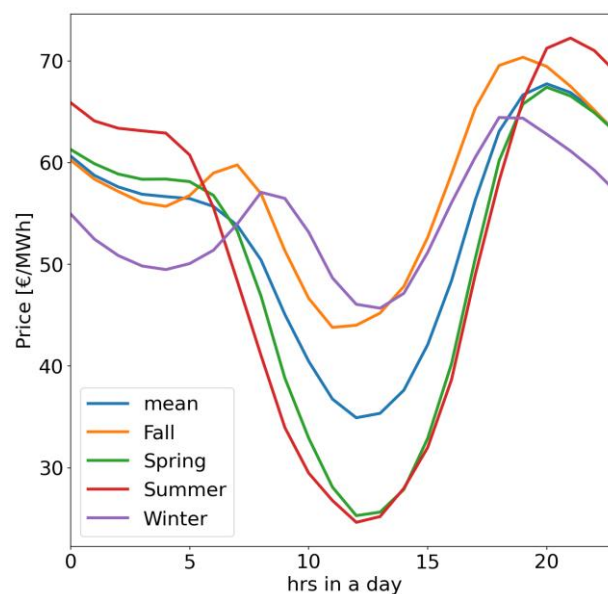


Figure 41 – The average capture price over the seasons as a function of the time of day (base case 2030).

In summer and spring, the duck curve shows significantly lower prices during the midday hours, while in fall and winter months the prices show a strong increase compared to the summer and spring months due to lower solar contribution. In winter, the prices are lower during the night hours due to strong wind power production, especially compared to summer. Furthermore, the summer season shows the highest and lowest average hourly prices overall while in winter and fall the prices fluctuate less throughout the day and two local valleys can be seen around 5 am and 12 pm. These effects are highlighted more clearly in the subsequent figures showing the captured prices of the different technologies in the seasons.

The overall average price per season only shows slight differences and in fall the highest average price can be found. While in spring and summer wind and wave technologies show higher average capture prices, in fall and spring the situation is reversed. The difference in capture prices between seasons is higher for solar technology compared to changes in the captured prices of wind and wave



technologies. Offshore wind captures slightly higher prices than onshore wind and wave technologies capture slightly higher prices than wind in spring and summer. These results are summarised in the below table (Table 4.11).

Table 4.11 – Seasonal results for different metrics (base case 2030)

The Netherlands	Spring	Summer	Fall	Winter
Average electricity price	50	51	58	54
Average capture price per technology				
Onshore wind	35	37	40	36
Offshore wind	38	38	42	41
Onshore solar	31	31	45	47
Offshore solar	N/A	N/A	N/A	N/A
Wave	44	41	45	41

Figure 42 and Figure 43 show the hourly average capture price per technology and their capacity factor for each season; combining these information shows how the captured price is affected by the average DA price or the technologies' performance. With low-capacity factors, a lower amount of timesteps is included in the average price calculation.

The average hourly captured prices for all technologies except of solar energy show similar shapes as the seasonal mean electricity price. This can be explained by the average hourly capture factors of the different technologies; throughout the hours of the day, wind and wave energy shows more constant output. The capacity factors increase in fall and winter for wind and wave energy but the trend and behaviour of the prices throughout the day does not change.

For solar energy, as depicted in Figure 42 (second graph from the left), in winter the period in which it does not capture any prices is longer than in summer and spring (seen as a gap in the hourly price curves).



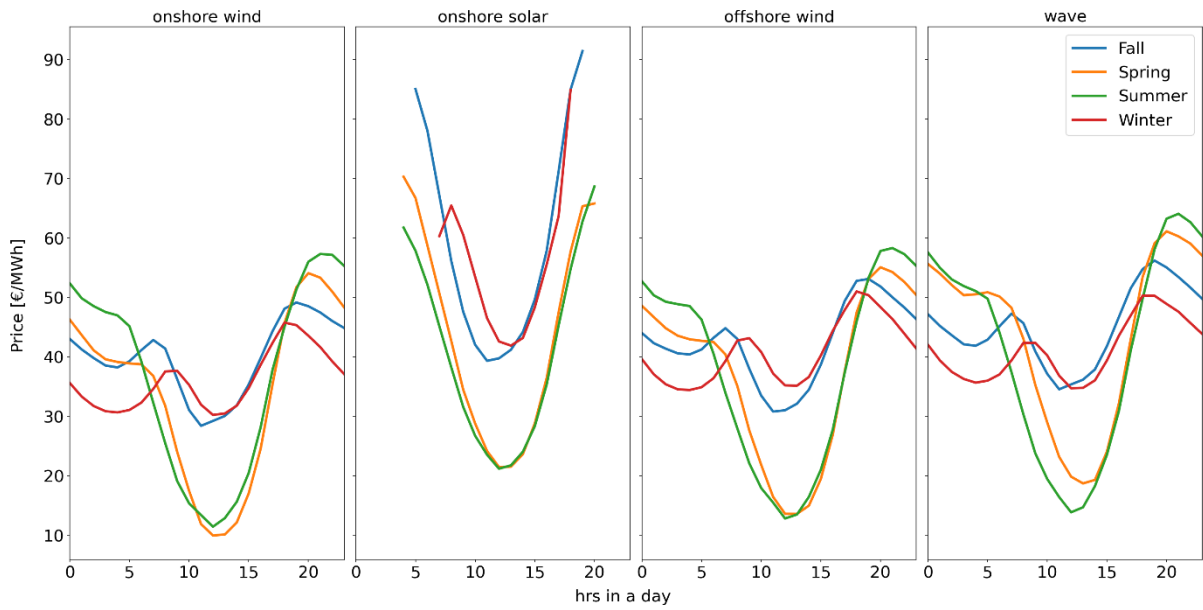


Figure 42 – The average capture price over the seasons as a function of the time of day per technology (base case 2030)

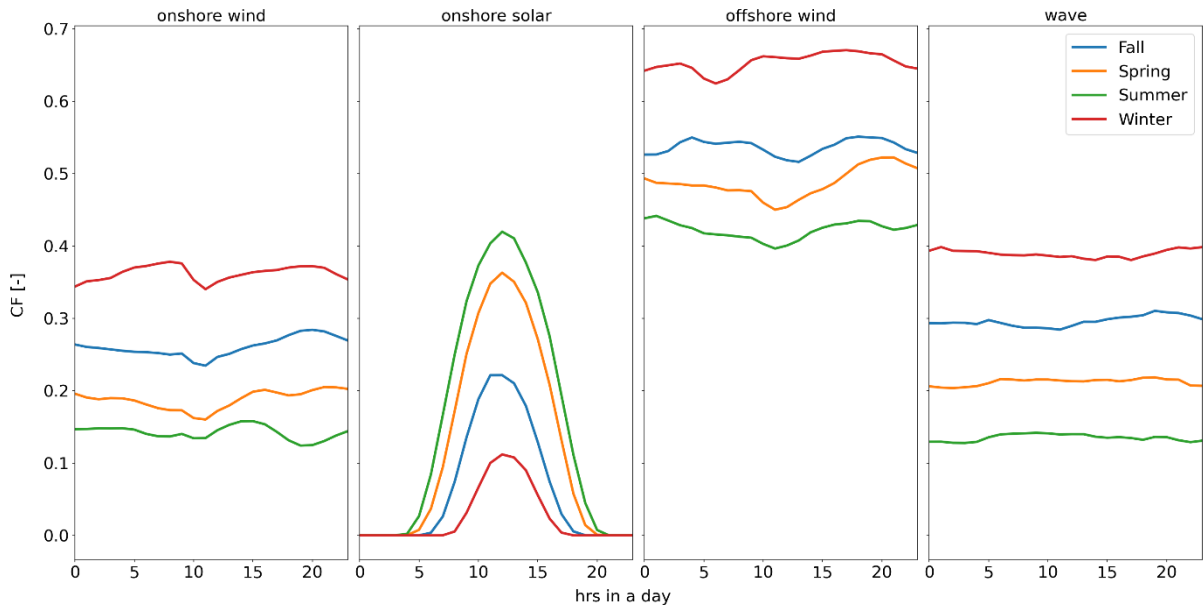


Figure 43 – The average capacity factor for the different technologies as a function of the time of day (base case 2030).

These simulations are also performed for the Belgium and Germany plus Luxembourg in the sections further below.

4.3.1.1 Full factorial study of Base Case scenario 2030

Most studies on future electricity prices use a limited number of scenarios to study the uncertainty in the input data; uncertainty in the future solar and wind installed capacities, the price of natural gas, the fixed electricity demand and the installed



capacity of flexible demand, for example. However, these input variables are essentially all independent variables. Political decision-making, international political developments and economic circumstances can all influence these parameters separately. Therefore, the organisation of these parameters in a limited number of scenarios greatly reduces the possible outcomes of the study.

An important question for investors in solar, wind and wave farms will not only be; how much profit the project will make, but also under what circumstances the project could potentially make a loss. For banks, that lend money to a project, this question will even be the most important question. This will also be the case for insurance companies. Therefore, all possible outcomes should be studied and not only a limited number of scenarios.

Based on the base case scenario of the 2030 Netherlands region, a full factorial assessment is performed considering the most relevant input parameters. This means that (in this case) six variables have been varied separately with a minimum, average and maximum value. The base case input parameters (the average) are separately multiplied by 0.71 for the minimum value and multiplied by 1.4 for the maximum value. This gives a difference between minimum and maximum value of about a factor of two. This is also what we see in the II3050 scenarios for The Netherlands, especially for the year 2050 [42].

The total amount of full simulations was 729 (3 to the power 6). The effects of the installed capacities of solar, wind, demand and flexible load plus the selection of the price points are presented in Figure 44. Throughout the 729 simulations, each parameter's effect is assessed by keeping the one parameter constant while all other parameters are included within minimum, average, and maximum values. As an example, in the top left graph in Figure 44, the effect of changing the solar installed capacity is assessed by calculating the mean DA price over the 729 simulations; when the solar installed capacity is at its minimum, the 243 simulations in which this parameter is at its minimum are used to calculate the mean DA price. The same approach is taken for the other levels of that parameter and the other parameters' effects. The main effects assessment shows what effects single input parameters independently of the selection of the other parameters (e.g. whatever values are selected for wind installed capacity, total fixed demand, maximum flexible demand, price at maximum and zero residual load) can have. The solar installed capacity could influence the mean electricity price by +/- 4 €/MWh).



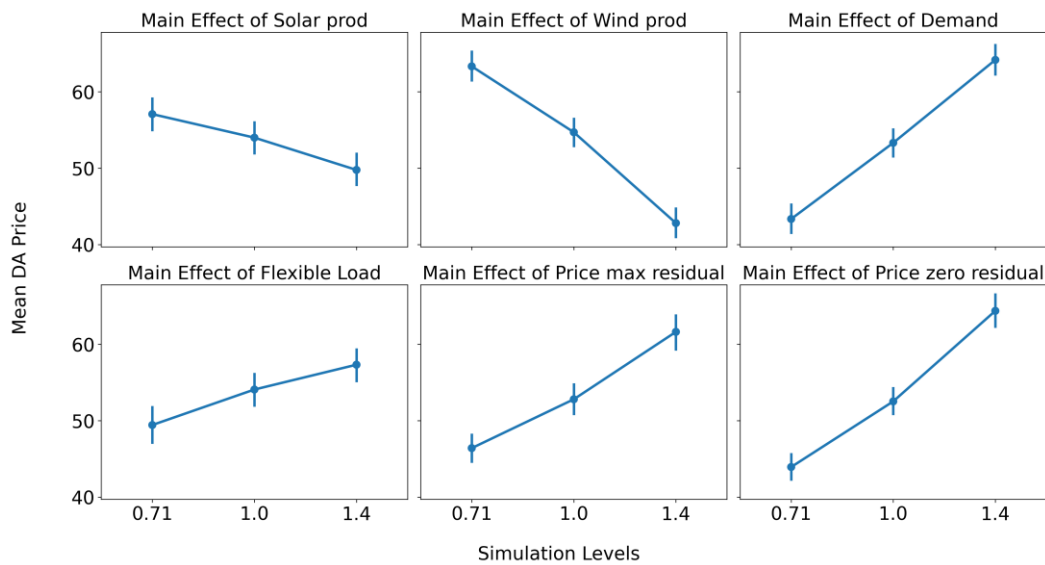


Figure 44 – The main effects on the mean electricity price of the minimum (average times 0.71), average and maximum (average times 1.4) value for six parameters (DA is Day Ahead), base case 2030

Because of the capacity factor of solar, the effect of changes in the installed capacity of solar energy is lower than that of the installed capacity of wind energy. The effect of changes in the fixed demand are higher than the effect of changes in the flexible load capacity, because the electricity price is higher in the range of the fixed demand.

The average electricity price shows a range between 10 to 100 €/MWh throughout the 729 simulations (Figure 45). We see that there is an enormous range of possible outcomes based on the variation in the input variables. More detailed project-specific studies should give investors, banks and insurers more insight in the specific risks for their project. This can be performed in work package 7. The captured prices for combined onshore and offshore wind and solar energy show similar ranges with a slight shift to higher prices for wind energy compared to solar (Figure 46 and Figure 47 respectively).



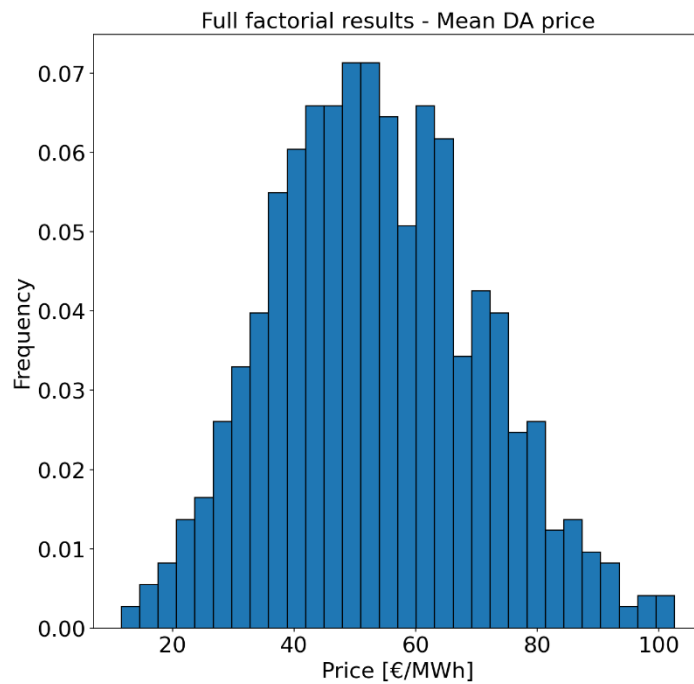


Figure 45 – Mean day ahead electricity price histogram over 729 simulations expressed as the relative frequency of occurrence for the base case 2030.

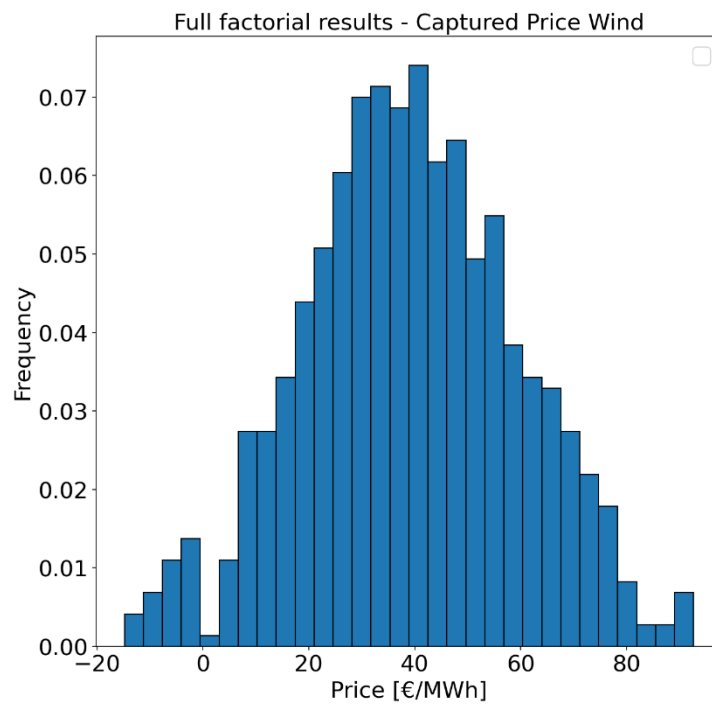


Figure 46 – Captured price for combined onshore and offshore wind power histogram over 729 simulations expressed as the relative frequency of occurrence for the base case 2030.



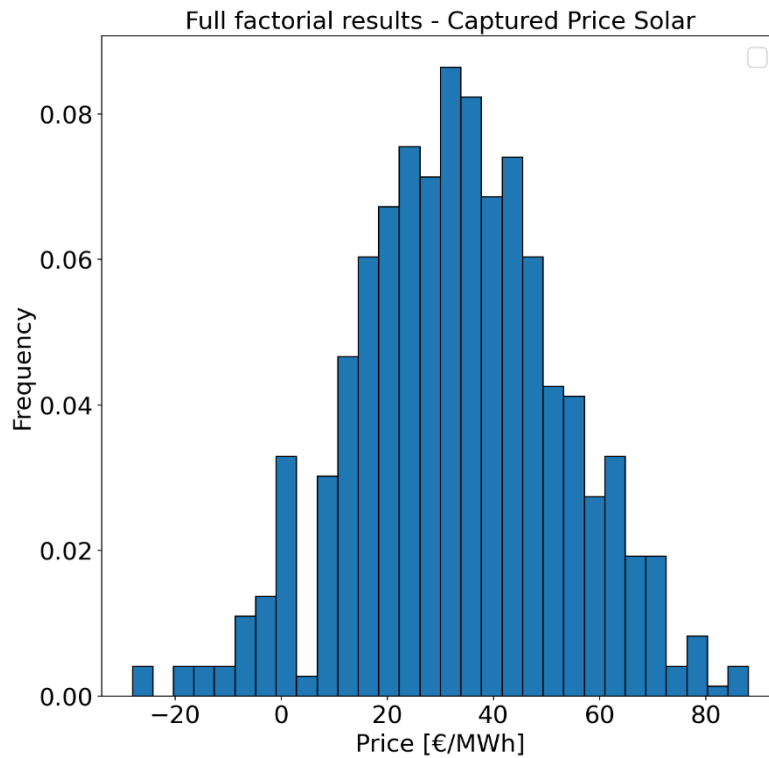


Figure 47 – Captured price for solar power histogram over 729 simulations expressed as the relative frequency of occurrence for the base case 2030.

4.3.2 Belgium

Belgium is smaller than the Netherlands assessed above. The total assumed installed capacity of renewable energy in the year 2030 is below 25 GW but the share of the different technologies is similar to the Netherlands (Figure 48).

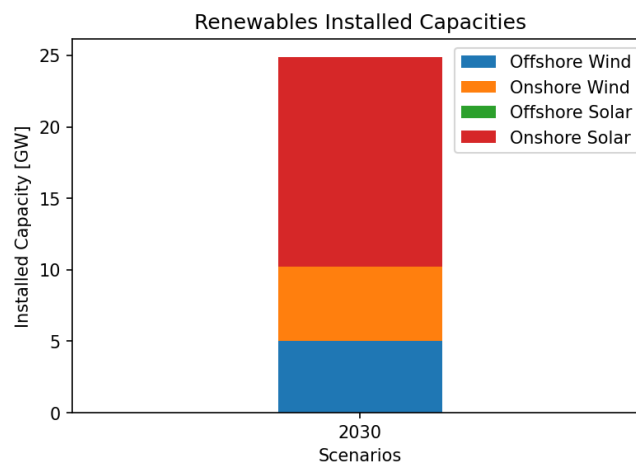


Figure 48 – Installed capacity of renewables in Belgium for 2030.

The total generated energy from renewables is lower than the total fixed demand suggesting that also the residual load is less likely to be negative, thus, the use of flexible demand is less likely as well (see Figure 49).



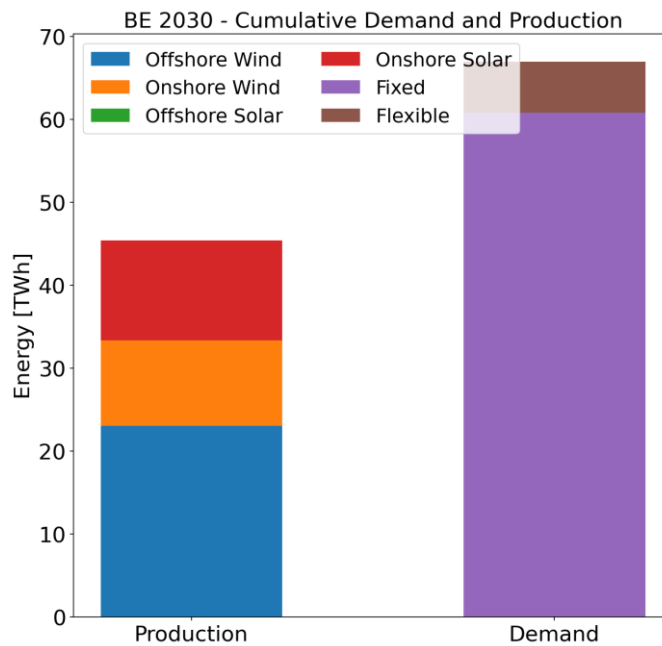


Figure 49 – Renewable solar and wind production in Belgium compared to the fixed and flexible demand for 2030.

Similarly to the Netherlands, also in this country the captured price per technology is below the average market price. The lower total energy produced leads to less smooth average market and captured price curves compared to the Netherlands (see Figure 50).

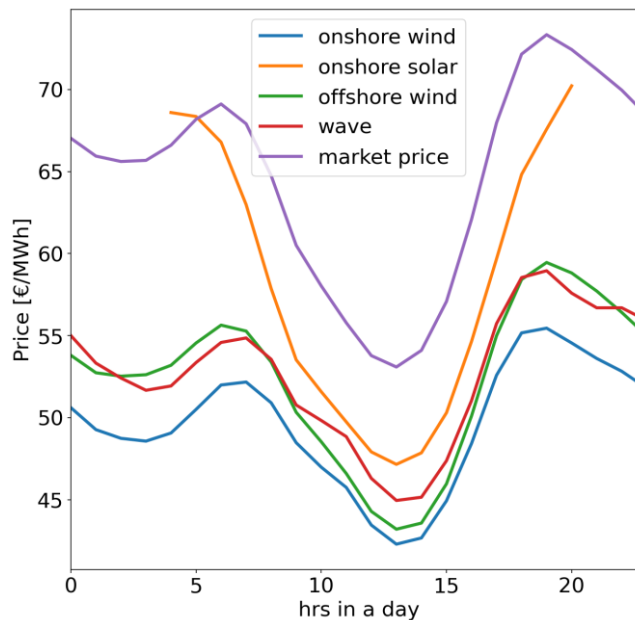


Figure 50 – Mean market price and the mean captured price of the renewable technologies over the time of day for the year 2030.

The average captured prices of the different technologies in the seasons show small differences between technologies (see Table 4.12).



Table 4.12 – Average captured prices of the different technologies by season (2030)

Belgium	Spring	Summer	Fall	Winter
Average electricity price	64	60	66	68
Average capture price per technology				
Onshore wind	51	46	51	49
Offshore wind	53	50	53	54
Onshore solar	50	48	58	68
Offshore solar	N/A	N/A	N/A	N/A
Wave	57	49	53	51

Interestingly and different to the results of the Netherlands, in this country, the average hourly electricity price in spring is higher than in the summer. Additionally, the winter prices are slightly higher in the middle of the day (see Figure 51). This might also be due to differences in the weather patterns over 2023.

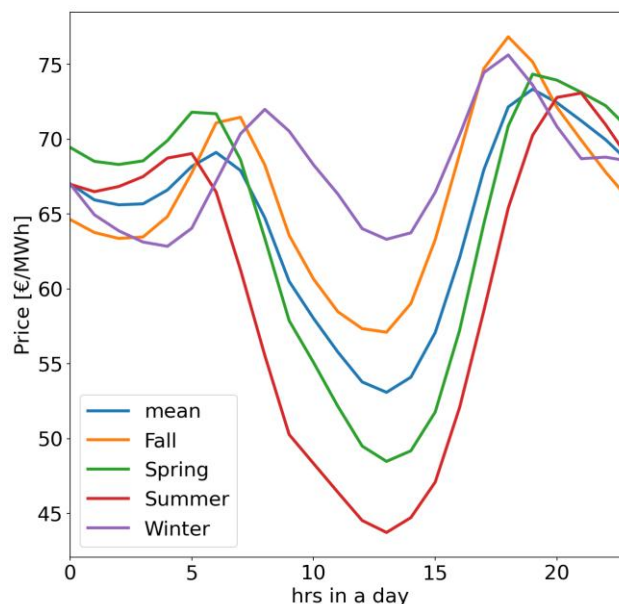


Figure 51 – The average capture price over the seasons as a function of the time of day for Belgium (2030).

Combining the average hourly capacity factors of the technologies with their average capture prices, it appears that offshore wind energy decreases significantly during midday in the summer and fall seasons, but it does not affect the captured price significantly (see Figure 52 and Figure 53). The average capture price for all technologies is higher in the spring season than in the summer season. While in the Netherlands the capture price of solar in the winter months is comparable to the captured price in fall, in this country there is a significant increase between fall and winter prices. This also might be due to the weather patterns of 2023.



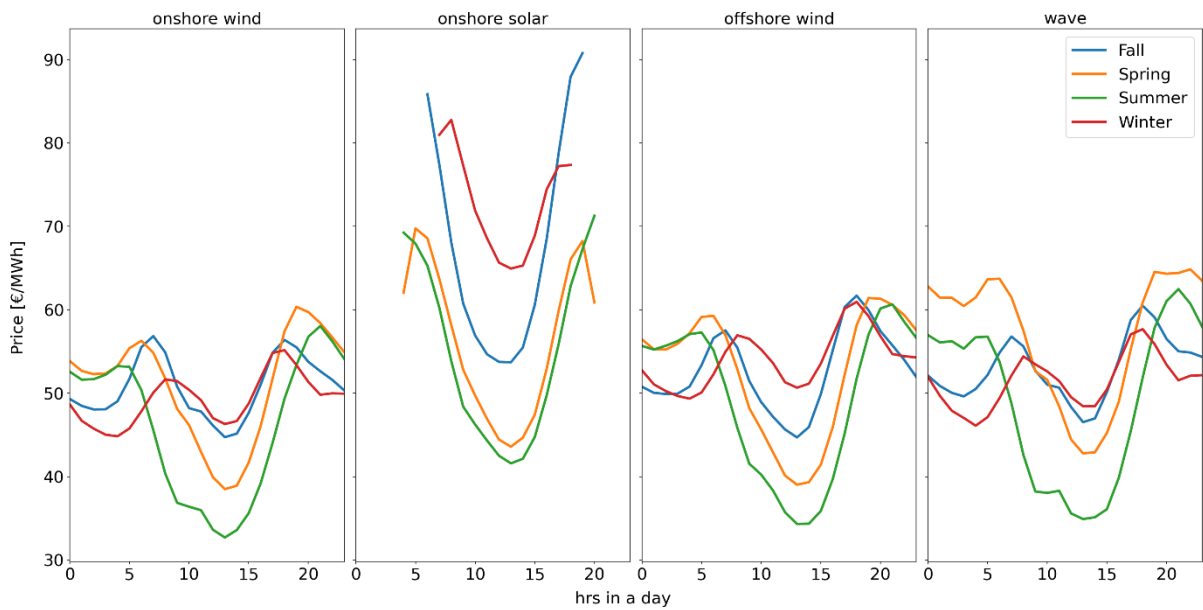


Figure 52 – The average capture price over the seasons as a function of the time of day per technology for Belgium (2030).

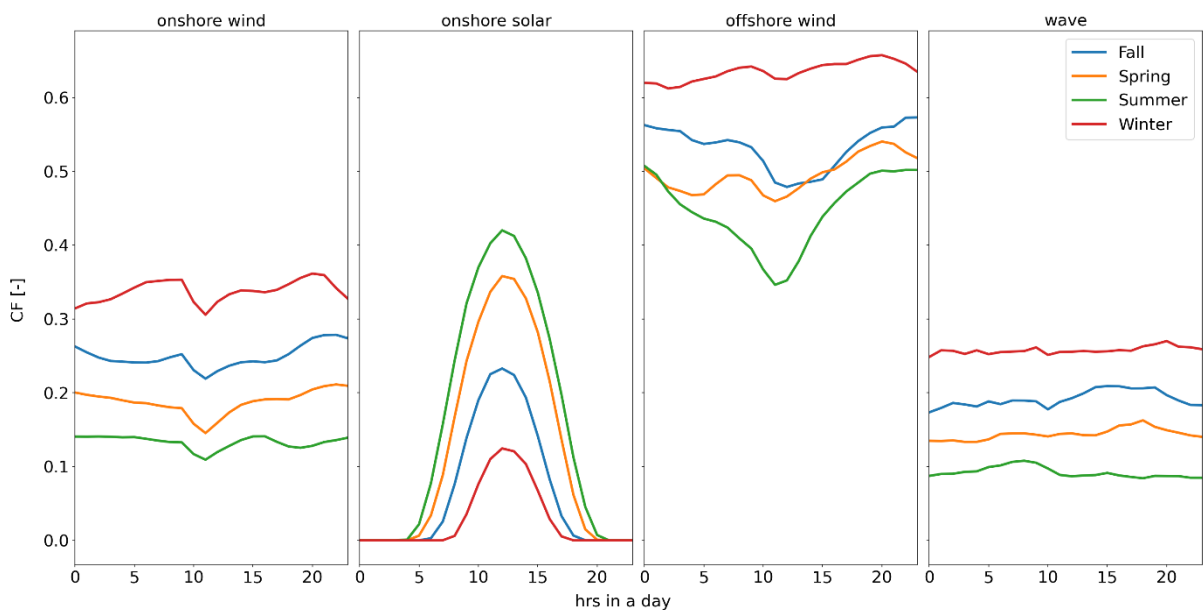


Figure 53 – The average capacity factor for the different technologies as a function of the time of day for Belgium.

4.3.3 Germany & Luxembourg

For Germany plus Luxembourg, the installed capacity is significantly larger, but the share of solar energy is comparable to the other countries (Figure 44). As the total country is significantly larger also the fixed demand is larger, thus, it appears that the total energy generated by renewable energy resources is comparable to the cumulative fixed demand (similar to the Netherlands base case). The share of offshore wind compared to onshore wind is significantly lower than in the



Netherlands which is also evident in the share of offshore wind in the cumulative energy produced which appears to be approximately equally distributed over the three technologies (Figure 55).

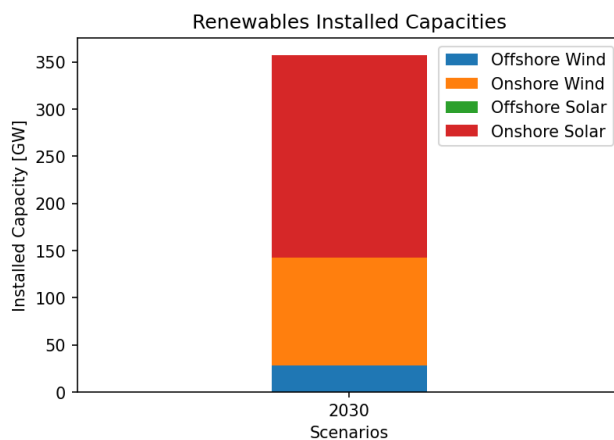


Figure 54 – Installed capacity of renewables in Germany and Luxembourg for 2030.

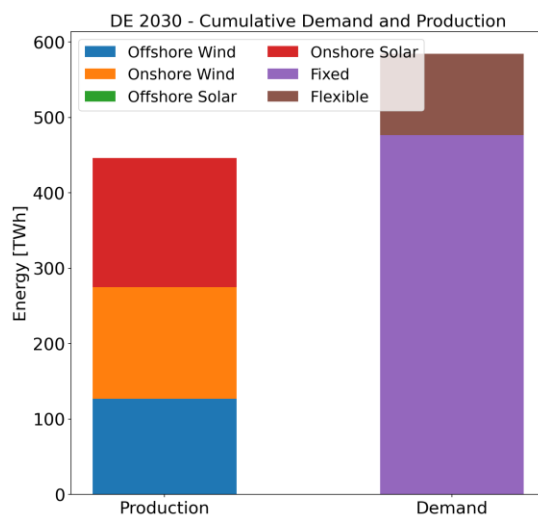


Figure 55 – Renewable solar and wind production in Germany and Luxembourg compared to the fixed and flexible demand for 2030.

Over the different seasons, the average electricity price remains similar and the captured electricity price for wind is higher in spring and fall, while for solar energy it is lower in spring and summer (Table 4.13). The captured electricity price for wave energy shows the same trends as wind but with slightly higher values.



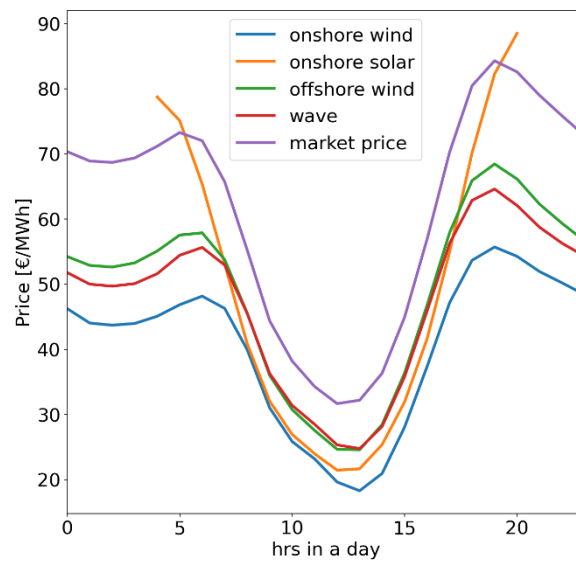


Figure 56 - Mean market price and the mean captured price of the renewable technologies over the time of day for the year 2030 in Germany and Luxembourg.

Table 4.13 – Average captured prices of the different technologies by season in Germany and Luxembourg.

	Spring	Summer	Fall	Winter
Average electricity price	58	57	66	66
Average capture price per technology				
Onshore wind	47	39	46	34
Offshore wind	50	45	52	49
Onshore solar	29	26	40	58
Offshore solar	N/A	N/A	N/A	N/A
Wave	51	42	51	45

Comparable to the other countries, the hourly average market price per season shows strong 'duck' shape in the spring and summer season (Figure 57). The same shape is visible more strongly also in the fall season compared to the NL base case scenario. Comparable behaviour to the NL base case can be seen in the average captured prices of the technologies.



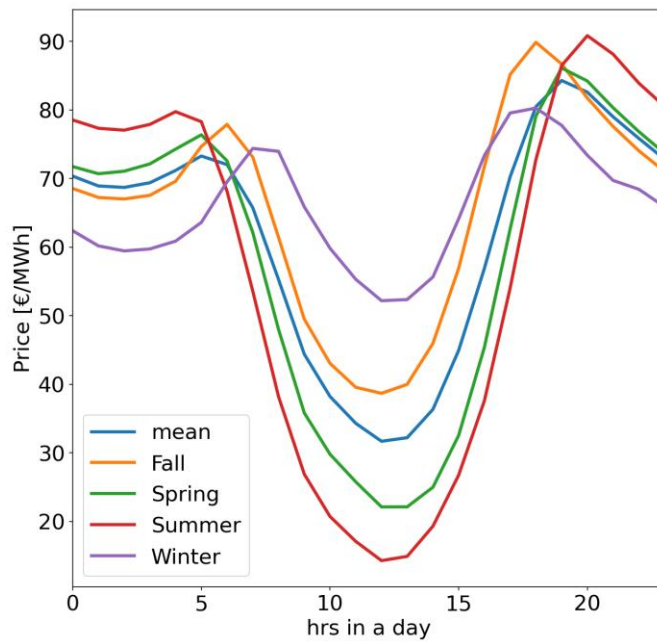


Figure 57 – The average capture price over the seasons as a function of the time of day in Germany and Luxembourg.

Figure 58 shows the average capture price for all technologies. The captured price is higher in the spring season than in the Netherlands. Furthermore, the total difference between peaks and valleys of the wind and wave technologies are larger.

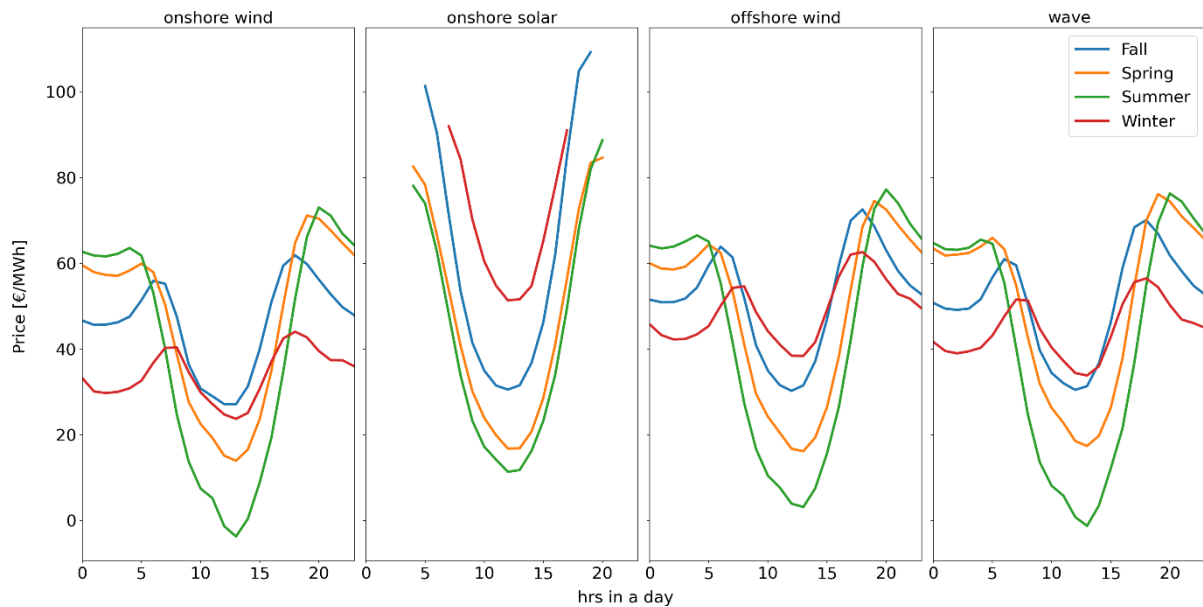


Figure 58 – The average capture price over the seasons as a function of the time of day per technology in Germany and Luxembourg.

The capacity factor of the offshore wind technology shows a decrease in the midday hours in spring, that is more predominant when compared to the more linear capacity factor in fall. This could also be due to the weather patterns of 2023.



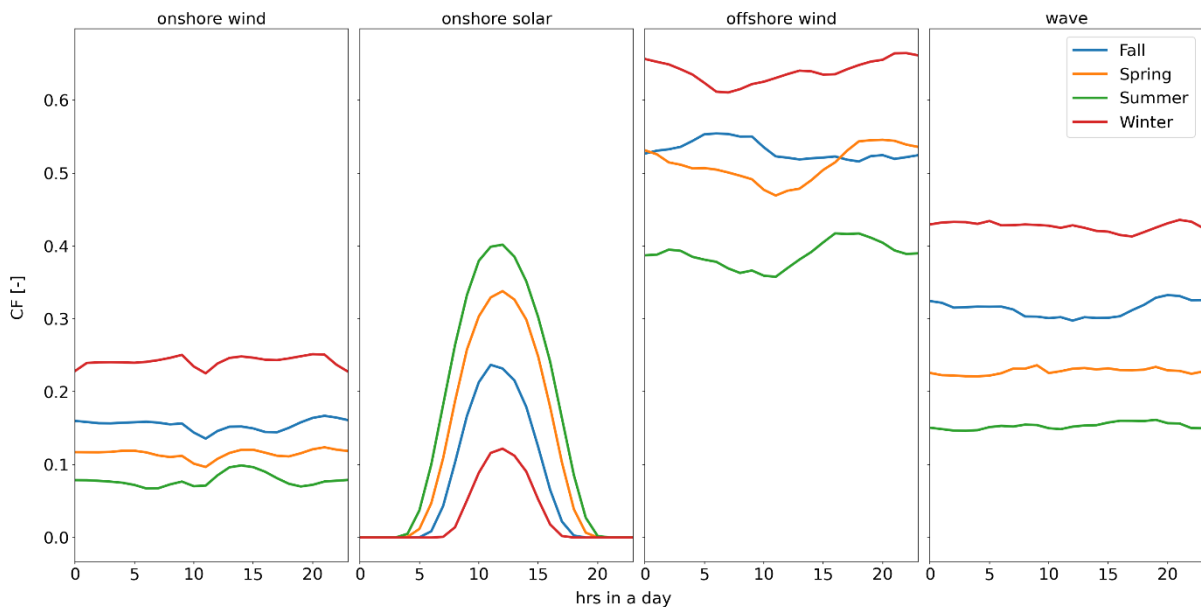


Figure 59 – The average capacity factor for the different technologies as a function of the time of day in Germany and Luxembourg (2030).

4.3.4 Comparison between Countries

This section compares the different countries (NL, BE, DE+LU) for the scenario of 2030. Comparing the input and results at a high level can give insights into the potential advantages of combining the countries into one overarching electricity market.

The installed capacities of the three countries are shown in Figure 60. While in all countries the share of installed solar capacity is approximately 60%, the ratio between onshore and offshore wind capacity differs. In Germany + Luxembourg less than 20% of the total wind capacity is offshore; in Belgium approximately 50% is defined to be offshore wind; and in the Netherlands approximately 70% of the total installed wind capacity is offshore. Relatively speaking, Germany has a lower installed capacity of offshore wind than the Netherlands, so the solar and wind mix will also have a lower capacity factor.



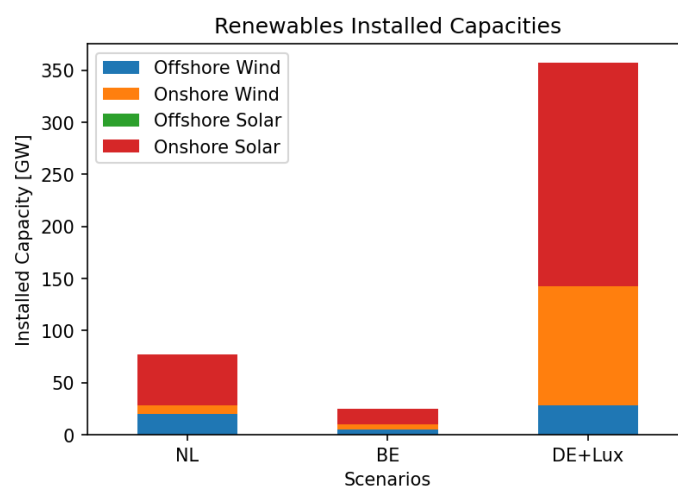


Figure 60 – Installed capacity of renewables in 2030 in the Netherlands, Belgium, and Germany + Luxembourg.

Comparing the overall averages of market and captured prices show that the Netherlands shows slightly lower values in all metrics, while Belgium and Germany (plus Luxembourg) are more comparable. This is summarized in Table 4.14.

Table 4.14 – Total average DA price, CoV and average capture prices for 2030 in the Netherlands, Belgium, and Germany + Luxembourg.

	Unit	NL	BE	DE + LU
Average electricity price	€/MWh	53	65	62
CoV of price	-	0.47	0.33	0.55
Average capture price per technology				
Onshore wind	€/MWh	37	50	41
Offshore wind	€/MWh	40	53	49
Onshore solar	€/MWh	34	52	32
Offshore solar	€/MWh	N/A	N/A	N/A
Wave	€/MWh	43	53	47
CO2 emissions	Mton	15	5	53

Considering the total power curves (Figure 61) and average hourly electricity prices (Figure 62), stronger peaks and valleys can be found in Germany, which could be caused by higher fixed demand and renewable energy capacity installed.



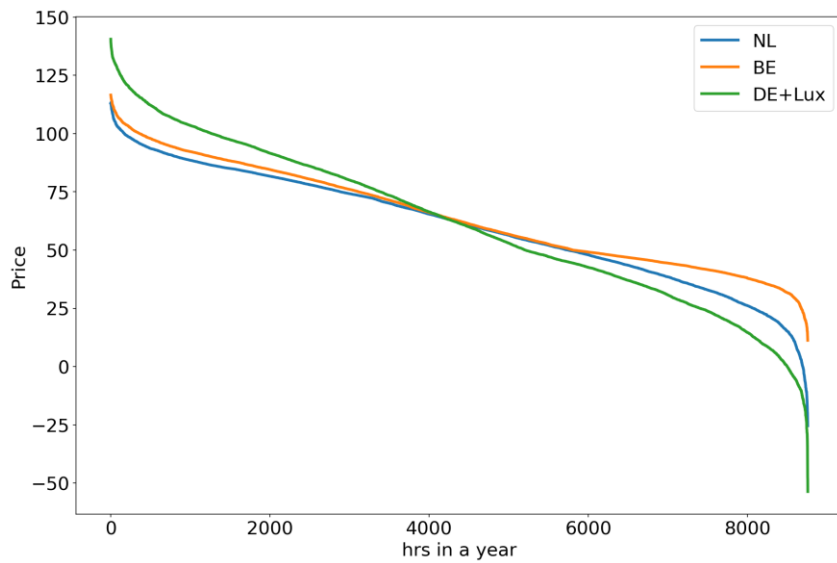


Figure 61 – Comparison of price curves for 2030 in the Netherlands, Belgium, and Germany + Luxembourg.

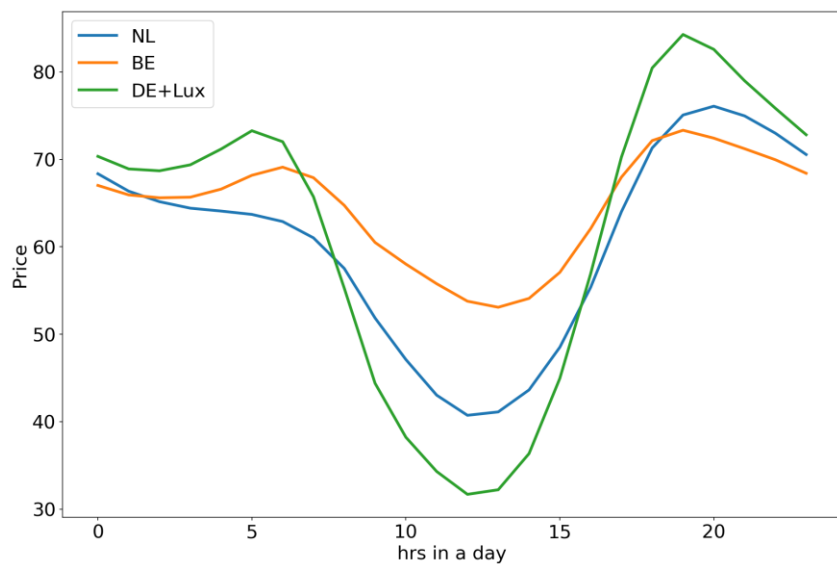


Figure 62 – Comparison of mean market price over the time of day for the year 2030 in the Netherlands, Belgium, and Germany + Luxembourg.

5 Ireland market prices assessment

The power system on the island of Ireland is one of the most agile in Europe. The system is All-Island and covers both the Republic of Ireland and Northern Ireland and operates under the Single Electricity Market (SEM), a unified electricity market that ensures a coordinated supply and demand balance across the island. Established in 2007 the Single Electricity Market operates with dual currencies (Euro and Sterling) and was the first market of its kind in the world when it opened.



Any modelling on the Irish Grid system must model the All Island system and thus must take account of both Irish and Northern Irish policies and targets as well as acknowledging that the system is interconnected to mainland UK. The TSO in Ireland is Eirgrid and in Northern Ireland it is SONI.

This system has a strong emphasis on the integration of renewable energy sources, with ambitious targets for decarbonization by 2030. The All-Island system aims to achieve 70% renewable electricity by 2030, driven primarily by wind and solar power. This transition aligns with the broader European energy decarbonization goals and Ireland's commitment to reducing greenhouse gas emissions. Achieving this vision will require continuous investment in grid flexibility, energy storage, and infrastructure to ensure a stable, reliable, and decarbonized electricity system. A map of the current transmission system for the island is shown below in Figure 63. This is taken from the live transmission system dashboard operated by Eirgrid which tracks demand, generation, renewable generation and other metrics such as fuel mix, market price and carbon intensity.



Transmission System Map

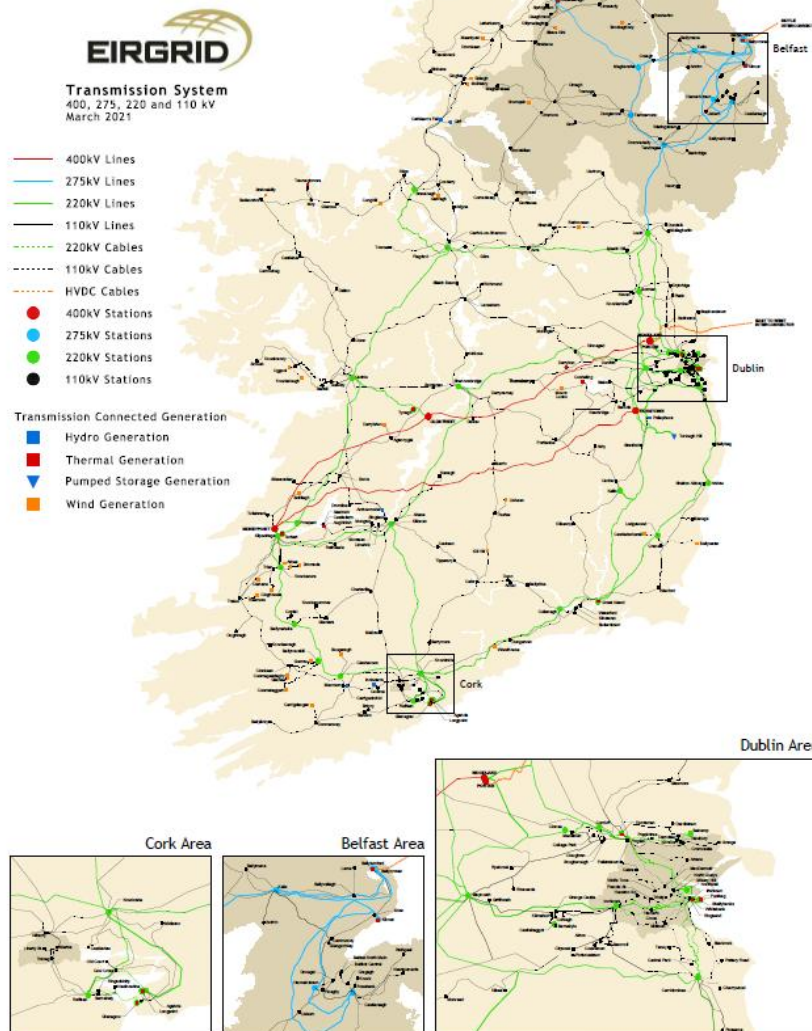


Figure 63 – Ireland's Transmission Network [48].

The distribution of generation around the country is also mapped below with hydro, pumped storage, wind and thermal plants shown in Figure 64. This demonstrates a good spread of generation with a slight bias of wind to the West. This requires a strong transmission network as the load centres are predominantly in the East in and around Dublin. The latest round of offshore wind developments are planned for the east coast in the Irish Sea and will be built out in the coming years.



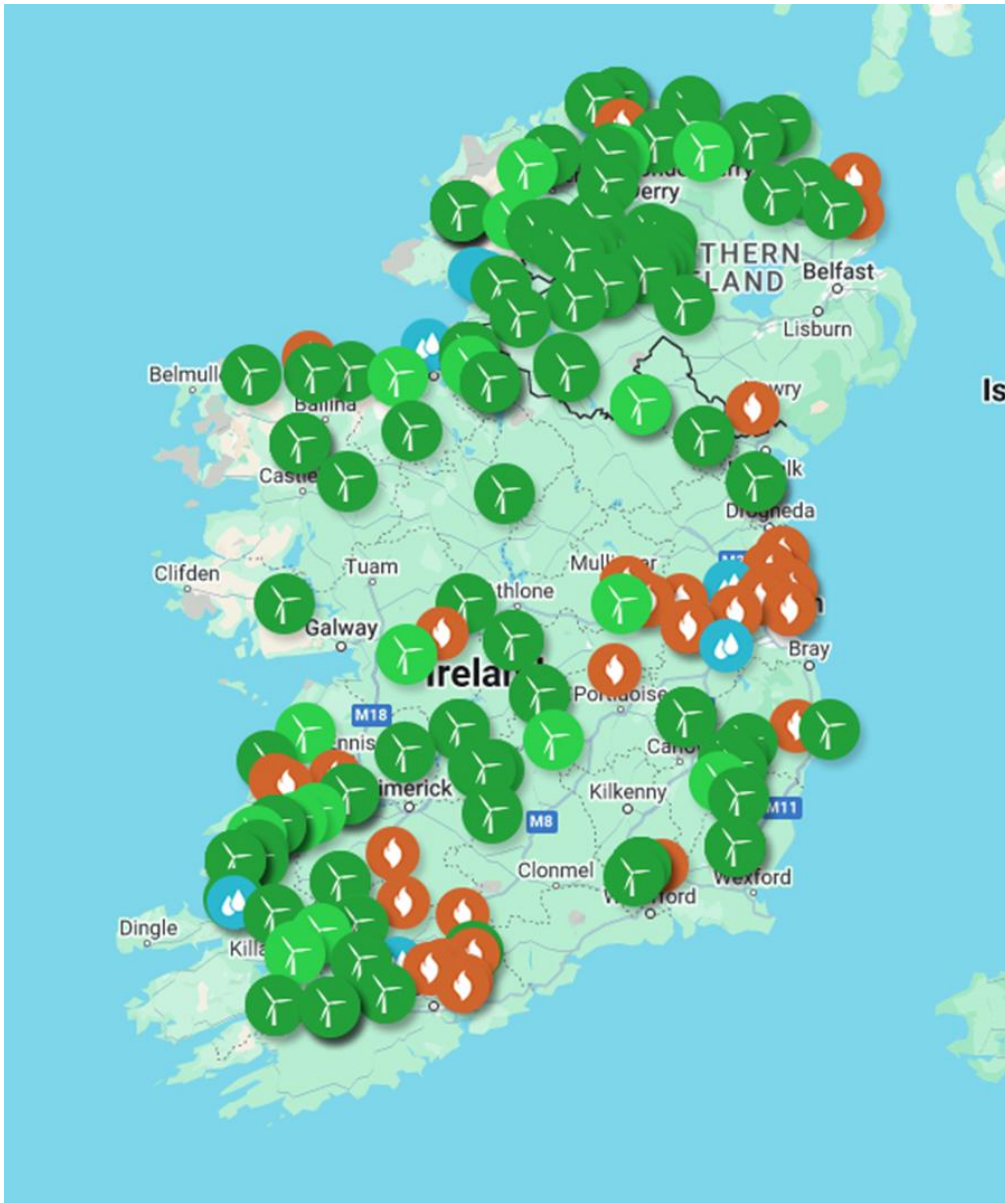


Figure 64 – All Ireland Generation Geographical Spread.



Sustainable Energy Authority of Ireland - Wind Atlas

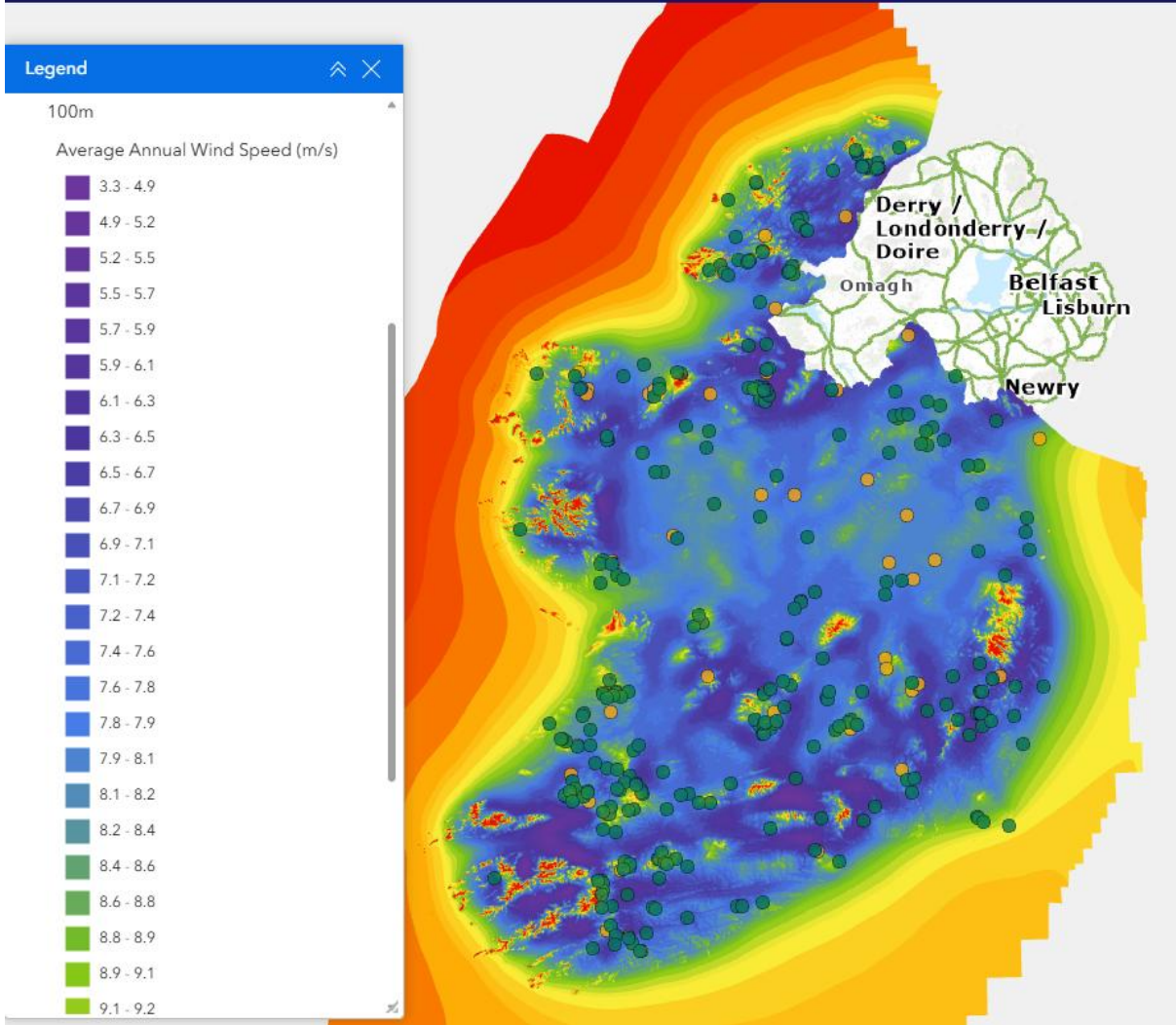


Figure 65 – Ireland's Typical Wind Resource [49].

The SEAI Wind Atlas [49], in Figure 65, shows the distribution of wind speeds around Ireland and although there are some hotspots for onshore farms it is clear the future resource lies offshore.

5.1 Model overview and main features

The MaREI PLEXOS model is used to simulate the future All-Island power system, projecting how the grid will operate in 2030 with high levels of renewable energy integration. This work is produced with the thanks to Dr Paul Deane and Laura Mehigan from the Energy Policy and Modelling Group [50] of University College Cork and comes from the re-analysis of a number of the data sets produced by UCC for a number of publications including notably, Our Zero eMission Future [51].

This model is designed to assess the technical, economic, and operational aspects of the energy system while considering policy goals, such as decarbonization, and operational realities, like system reliability and grid stability.



The model encompasses the entire All-Island electricity system, covering both the Republic of Ireland and Northern Ireland. It also includes interconnected markets such as the United Kingdom and continental Europe (EU27, Norway, etc.), simulating cross-border electricity flows. However, the resulting outputs in reanalysis have been tailored only with the Republic of Ireland data.

5.1.1 Inputs and constraints

The model draws from a wide range of inputs to create a realistic and detailed simulation of the 2030 power system. A full description of the setup is given in Our Zero eMission Future [51]. Key inputs include:

- **Hourly demand profiles:** Projected electricity demand across different hours, reflecting both daily and seasonal fluctuations.
- **Fuel prices:** Assumed costs for various energy sources, particularly gas, which will continue to play a role in the generation mix.
- **Generation portfolios:** Detailed capacity of different energy technologies, including wind, solar, gas, and other forms of generation.
- **Renewable energy profiles:** Historical and projected data on wind and solar output, reflecting their intermittent nature.
- **Interconnection capacity:** The model accounts for electricity flows between Ireland and neighbouring countries, adjusting for planned new interconnectors and their capacities.

The demand profile for the year is as follows Figure 66. This shows hourly demand and average daily demand.

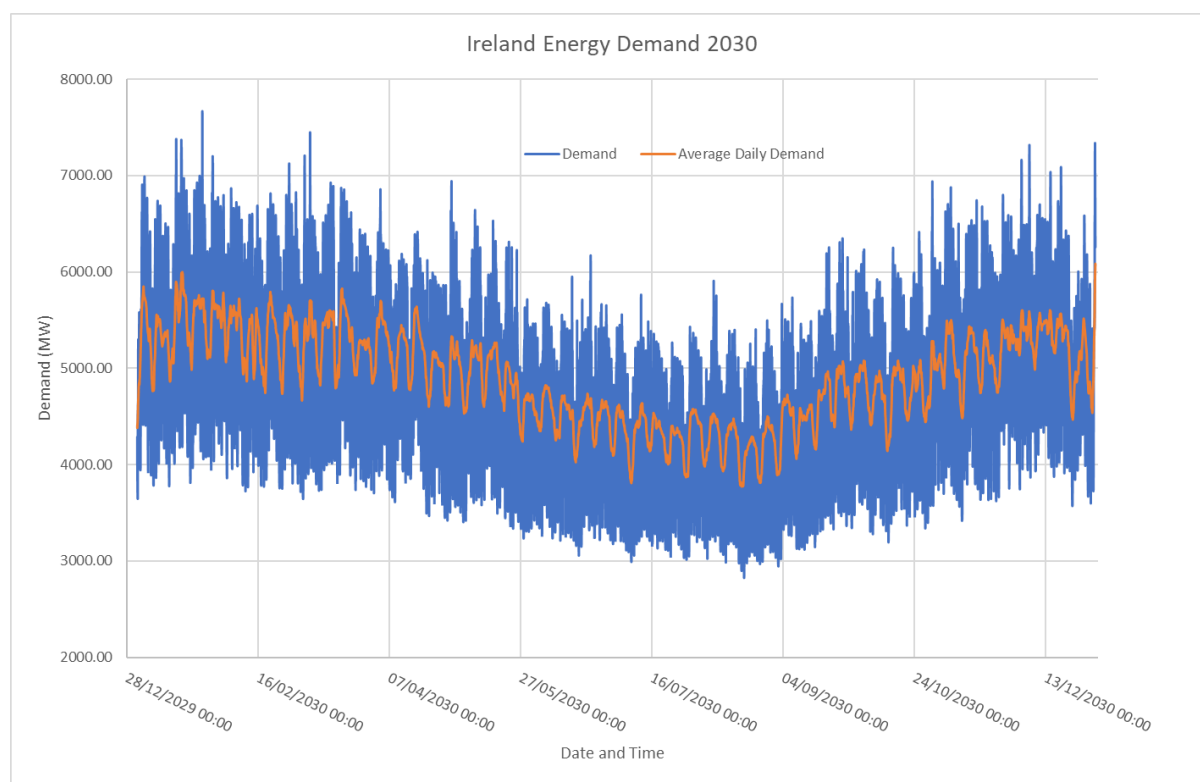


Figure 66 – Irelands' Energy Demand 2030.

This profile has also some seasonal variation as can be seen in the chart of Figure 67.

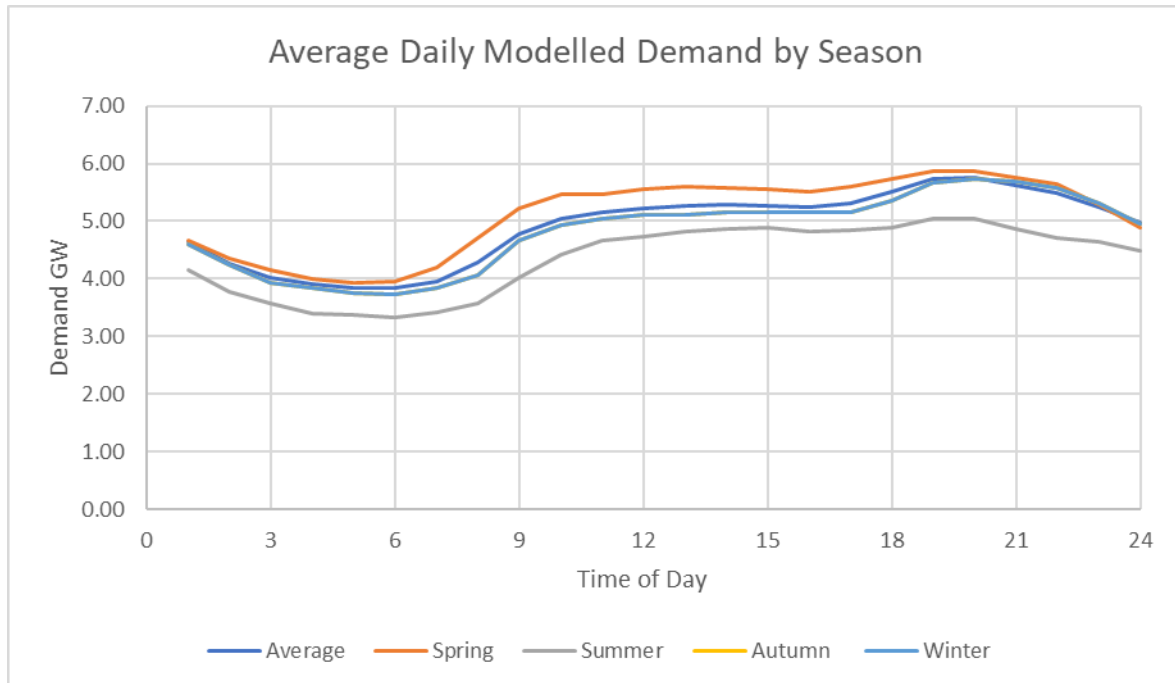


Figure 67 – Irelands' Seasonal demand profile 2030 for modelling purposes.

The generation profile is also variable and seasonal. Figure 68 shows the PV generation profile for both summer and winter for the 2030 case.

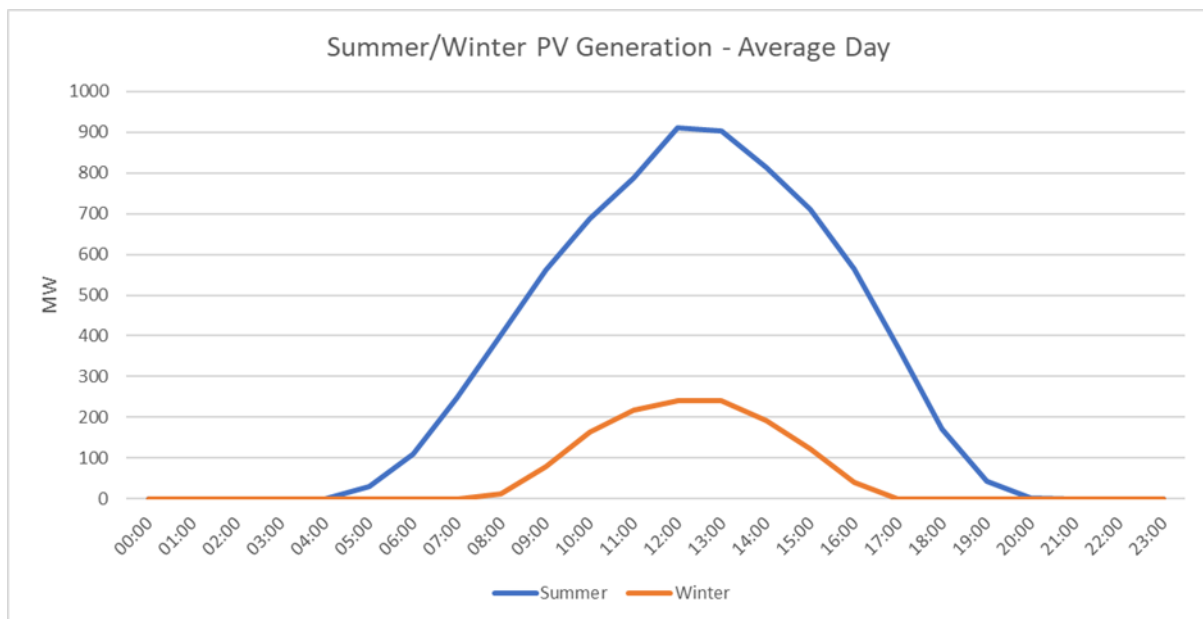


Figure 68 – Difference in PV generation from Summer to Winter.



Operational Constraints:

- **Generator technical constraints:** The model simulates the operation of power plants based on their technical capabilities, such as ramp rates (how quickly they can increase or decrease output), start-up times, minimum generation levels, and fuel efficiency.
- **System Non-Synchronous Penetration (SNSP) Limit:** The model incorporates this critical operational limit, which controls how much of the system's generation can come from non-synchronous sources (wind and solar) at any given time. By 2030, the SNSP limit is expected to increase to around 95%, meaning the system must be able to manage times when 95% of electricity comes from non-synchronous sources.
- **Minimum generation levels:** The model considers constraints on the minimum amount of generation that must come from synchronous sources (such as gas plants) to maintain grid stability and inertia.

These constraints will be shown in the scenarios table.

5.1.2 Outputs

The MaREI PLEXOS model provides a detailed analysis of how the All-Island power system will operate under different conditions, producing outputs such as:

- **Electricity prices:** Hourly electricity price forecasts based on least-cost dispatch optimization.
- **Dispatch schedules:** Simulated operation of each generation unit, showing when and how much each plant generates, including wind and solar curtailment levels.
- **CO2 emissions:** The model tracks emissions reductions as fossil fuel generation is displaced by renewables. These are available in summary for the scenarios but not as time series outputs in the data set shared for re-analysis.
- **System reliability metrics:** Measures like **Loss of Load Expectation (LOLE)**, which estimates the number of hours per year when electricity demand might not be met.

5.2 Simulated scenarios

There are 2 modelled scenarios presented along with the base case of actual data from 2023. The modelled scenarios are for a target 70% penetration of renewables by 2030 and the variation is an 80% penetration by adding more offshore wind. These are shown in Table 5.1.

Table 5.1 – Scenarios modelled for Ireland.

Scenarios		2023	2030 Base	2030 Increased Offshore Wind
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		Actual (GW)	Modelled (GW)	Modelled (GW)
	Installed Capacities			
Generation	Coal/HFO	0.75	0	0
	Gas	4.196	3.116	3.116
	Other Non RES	0.67	0.365	0.365
	Hydro	0.222	0.231	0.231
	Solar	0.786	2.1	2.1
	Onshore Wind	4.595	8.2	8.2
	Offshore Wind	0.025	1.05	2.7
	CHP	0.159	0.161	0.161
	Biomass	0.142	0.121	0.121
Demand	Electricity	31.5 TWh	42.9 TWh	42.9 TWh
	Flexible Load		1.1	1.1
External	Interconnectors		2.2	2.2
	CO2 Price (average)		€33.5/t	€33.5/t
	Wholesale gas price (average)	3.9c/kwh (see figure)	56p/Th (approx. 2.27c/kwh) [52]	56p/Th (approx. 2.27c/kwh) [52]
SNSP Limit		~75%	95%	95%
Min Synchronous Units			4	4
Target Renewables Penetration		~50%	70%	80%

The rationale behind the base case is in keeping with climate targets specifically the Paris Agreement. It also aligns with the Northern Ireland ambition to have a 73% RES-E target as well as contemporary publications [53]. Figure 69 clearly shows some of the changes from 2023 to 2030 base.

Older thermal plants are planned to be retired [54]. Electricity demand will increase due to [54] Electrification of heat (e.g., heat pumps) and transport (e.g., EVs) and this is modelled. There is less reliance on gas plant and these units will be more modern. There is an increase in wind, offshore wind and grid connected solar and the SNSP will be raised to up to 95%.



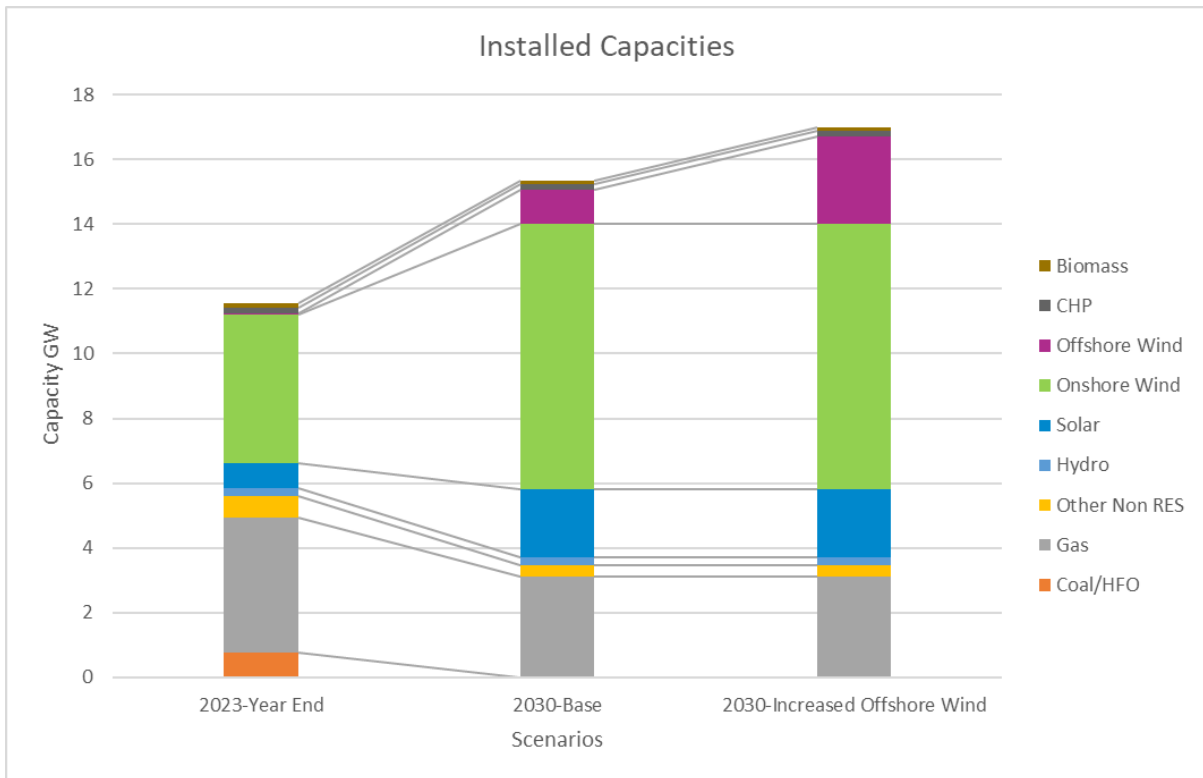


Figure 69 – Actual and Future modelled installed capacities.

The 2nd scenario increases the wind capacity even further by adding more offshore wind in line with a number of projects already consented and entering the build phase.

5.3 2023 Context

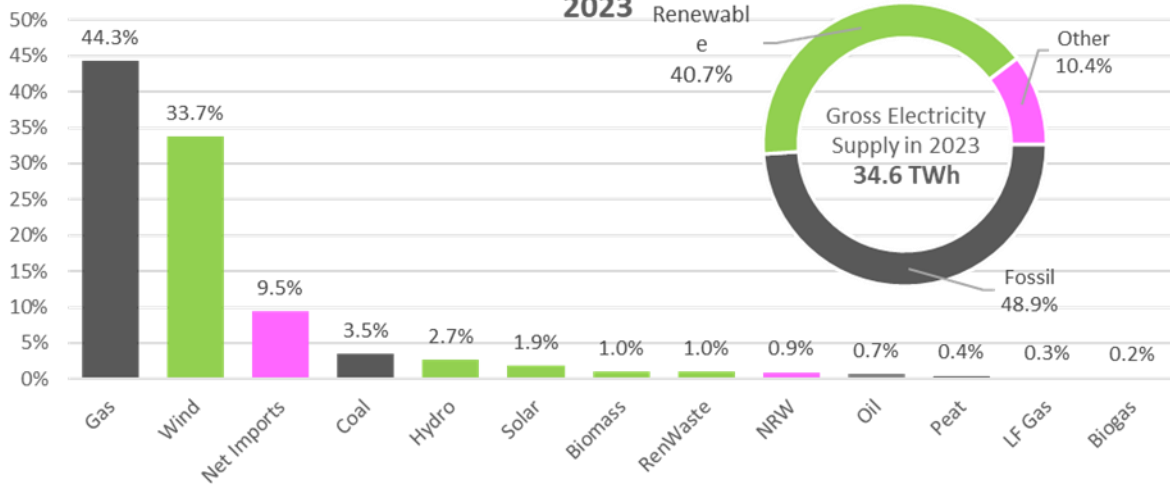
To put the modelled scenarios into context, as much actual published data that is available for the most recent year is presented. This is collated and cross checked from a number of reference sources.

The installed capacities come from the EirGrid Generation Capacity Statement 2023 2024 [55].

The generated power by type and the demand come from an SEAI annual report [56] and data workbook [57] and is shown in Figure 70.



Percentage Breakdown of Ireland's Gross Electricity Supply in 2023



Time Series Percentage Breakdown of Gross Electricity Supply

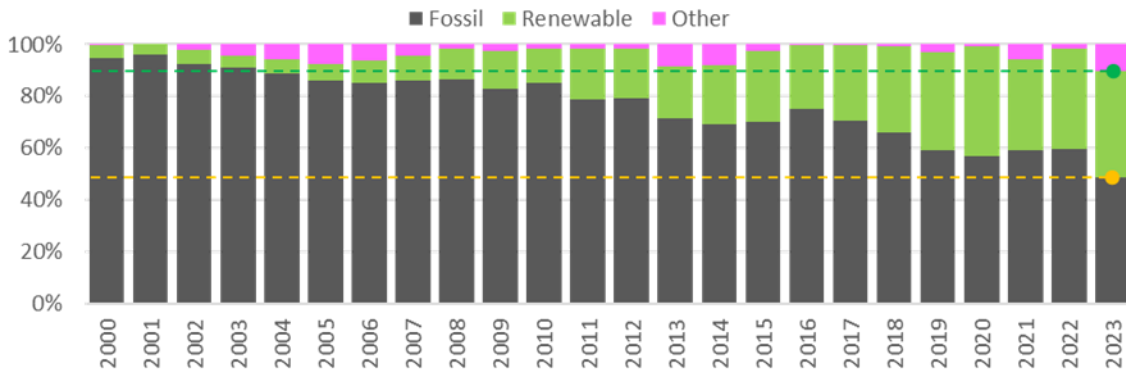


Figure 70 – Irelands' electricity supply by source 2023.

Historical wholesale gas prices come from a database maintained by Utilityfair [58] and wholesale electricity prices come from Kilowatt.ie [59] and is shown in Figure 71.

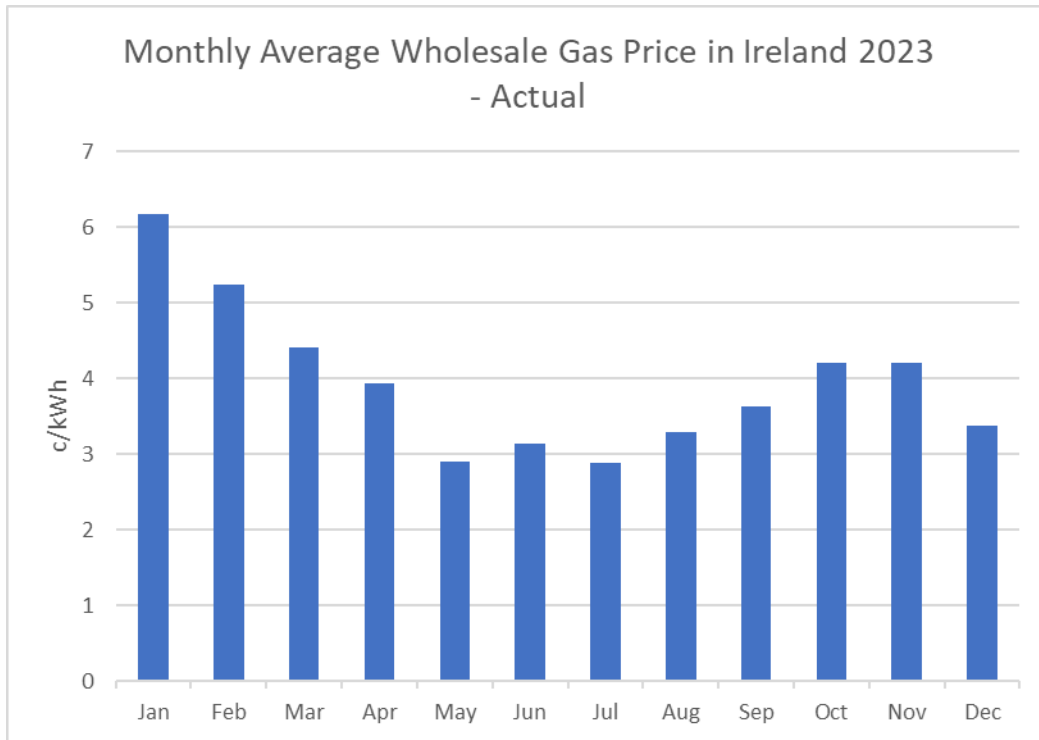


Figure 71 – Wholesale Gas Price in Ireland 2023.

It should be noted that the 2023 gas price is on average higher than the 2030 modelled price but still seen as reasonable given that 2023 was still recovering from global instability in market prices [60] as shown in Figure 72.



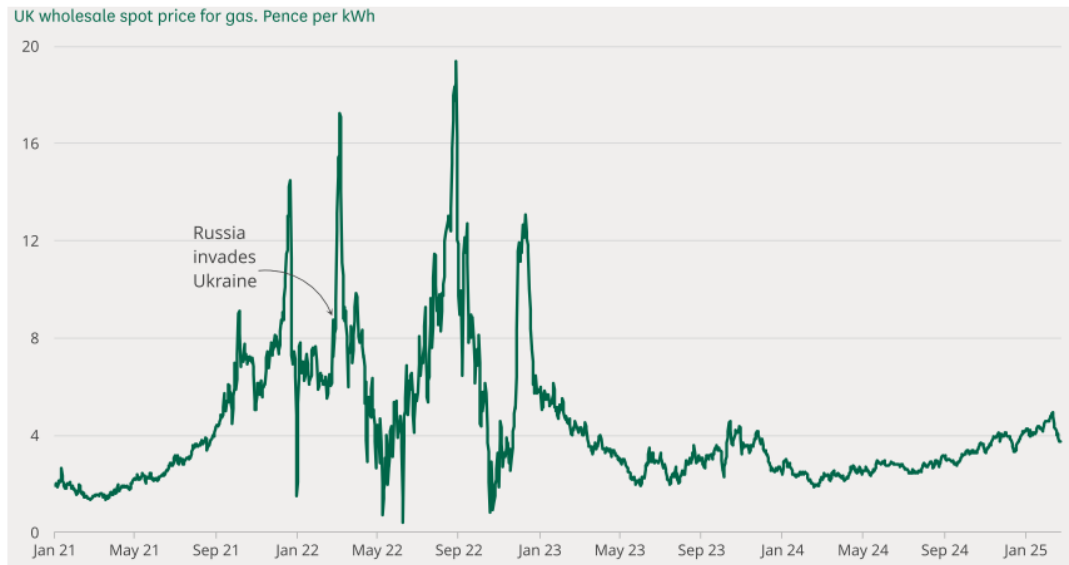


Figure 72 – UK Historical gas spot price.

The influence of this on the consumer price is shown in Figure 73.

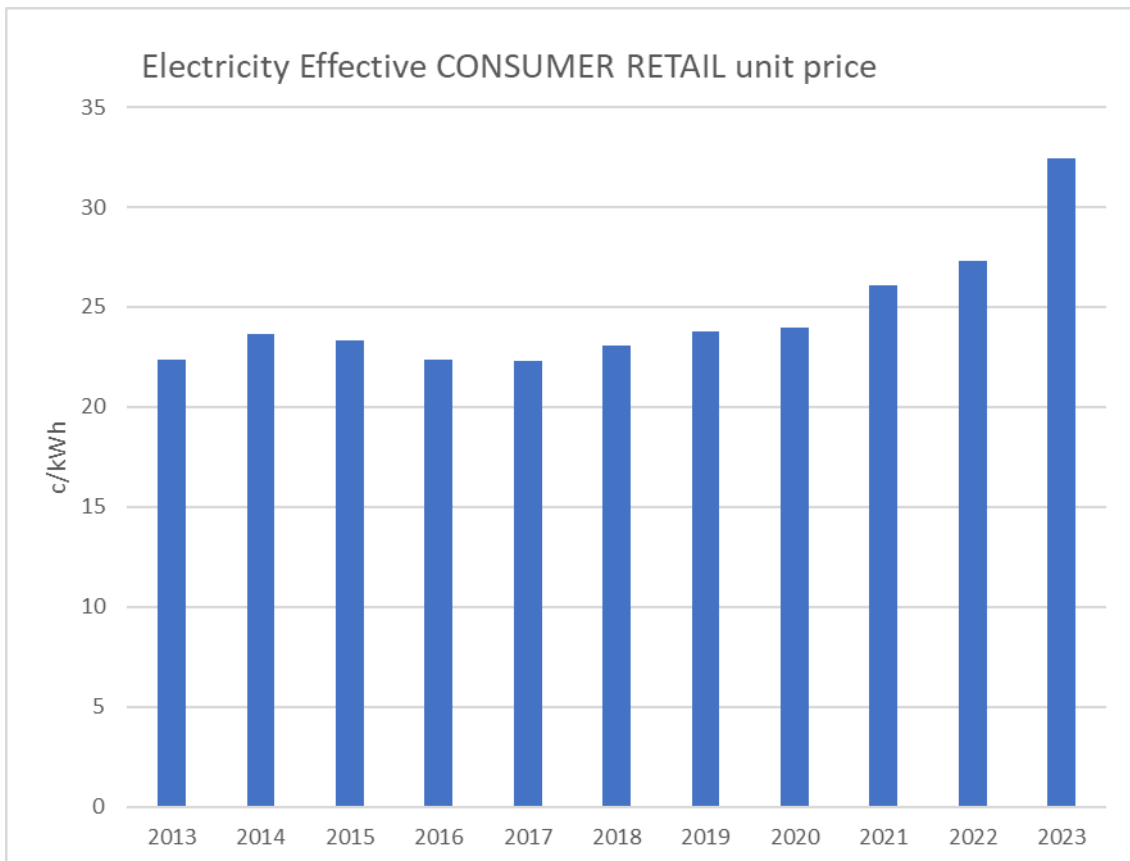


Figure 73 – Ireland's effective average consumer electricity price.



5.1 Results analysis

A first step in the analysis is to look at the relative generation mix by type. Figure 74 shows 2023 mapped against both the 2030 modelled scenarios. Some clear changes are the reduction of gas generation and the increase in onshore, offshore and solar. Increasing the offshore wind installed capacity further reduces gas without reducing solar, showing that they are complementary.

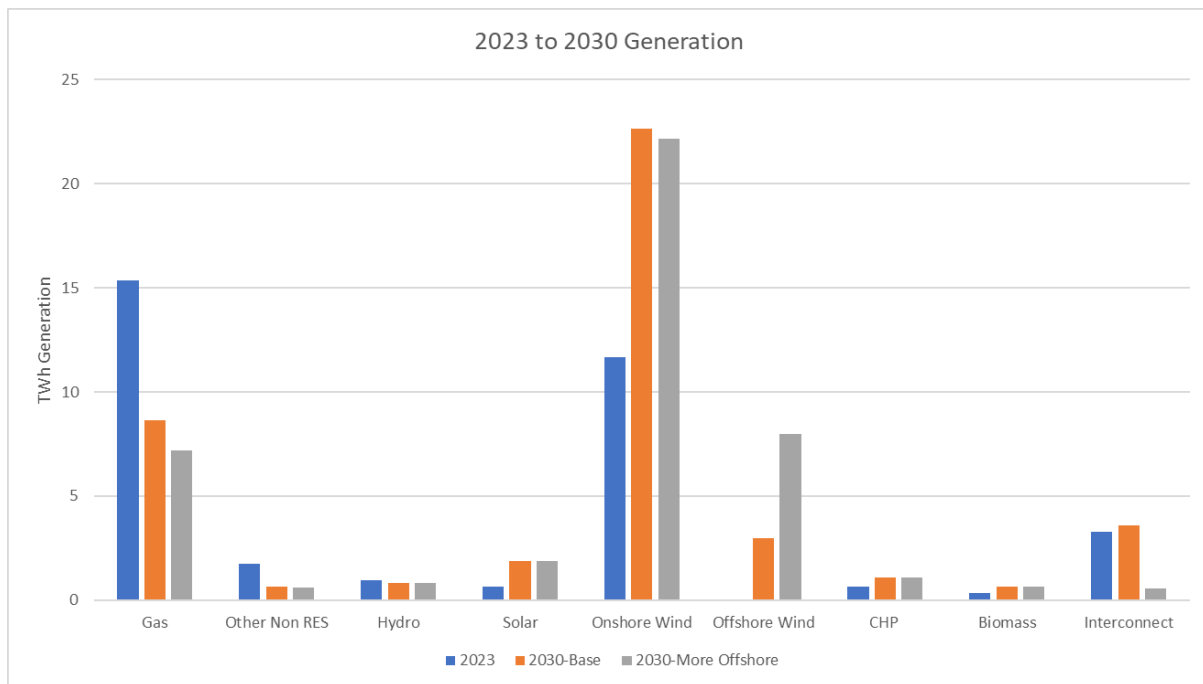


Figure 74 – Generation by type, actual and modelled.



Price Analysis

Figure 75 shows the monthly average market price per unit of electricity in Ireland in both the 2023 reality and the 2030 model scenarios. Although this is useful to visualise monthly averages further breakdown into price duration and seasonality will help to understand each case. It is also useful to bear in mind the delta between the modelled scenarios as they only have minor differences in inputs and hence conclusions can be solid.

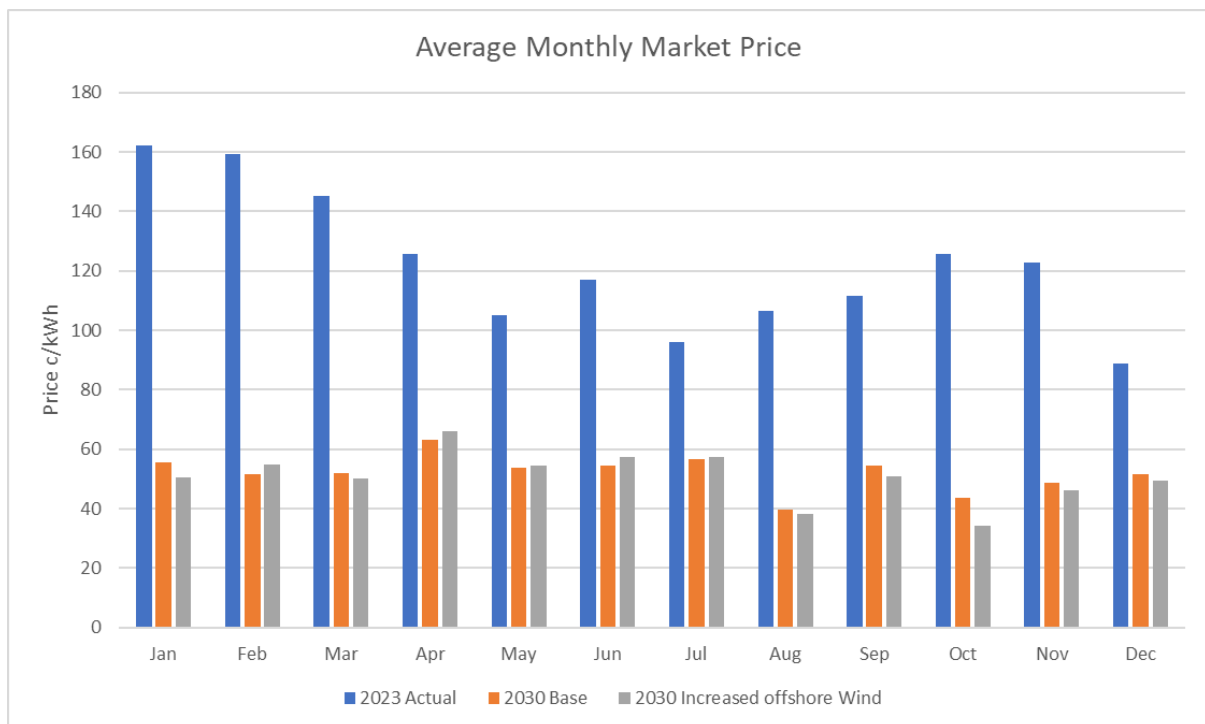


Figure 75 – Average monthly market price.



Hourly pricing data was available for both scenarios and the 2023 case. These were binned and sorted for the hours they occurred and cumulated for the year of 8760 hours. This results in the price duration curves shown in Figure 76.

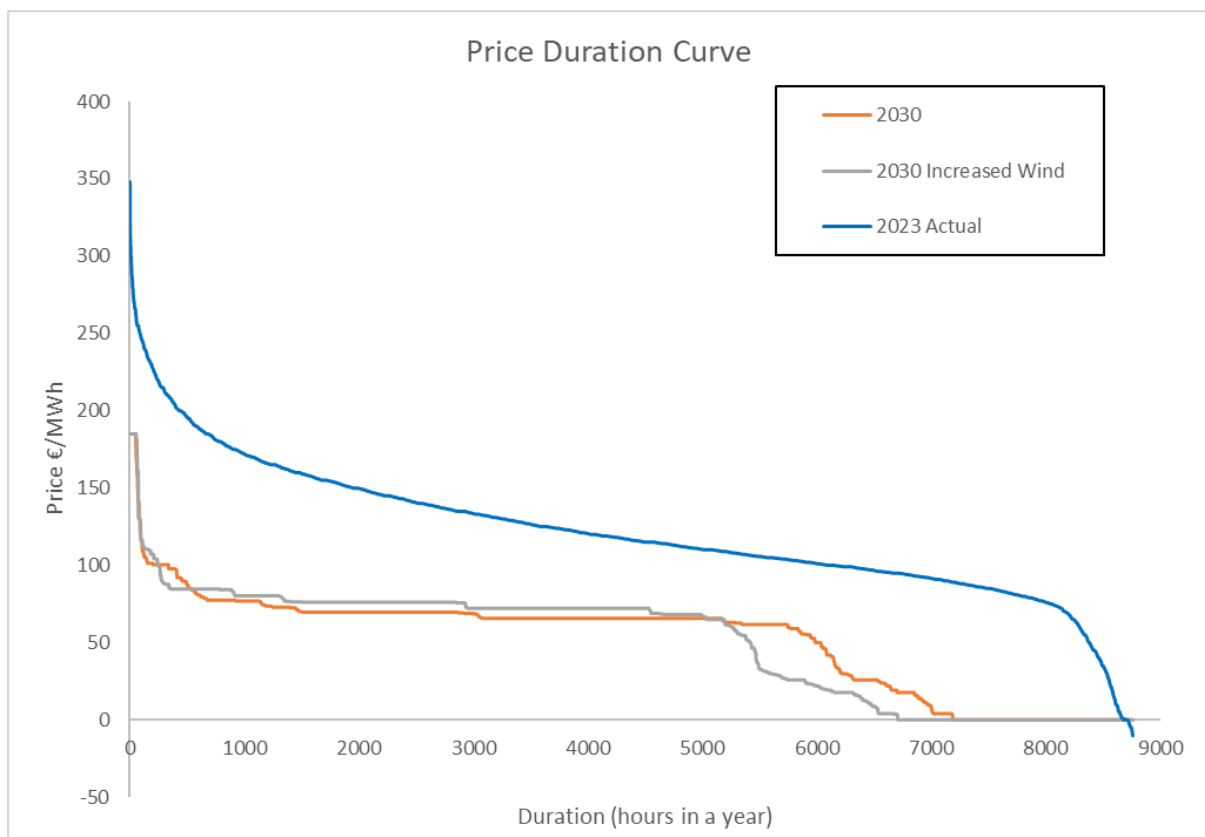


Figure 76 – Price duration curves.



Overall, this shows that a move to higher RES penetration reduces price volatility. The price swings are not as large and this is as a result in a reduction in gas dependence coupled with good wind capacity factor throughout the year complemented by PV. As reference, 2 snapshots of the Eirgrid market price dashboard at time of writing 19th May 2025 (Figure 77) and 20th May (Figure 78) shows a large variation between max and min pricing.

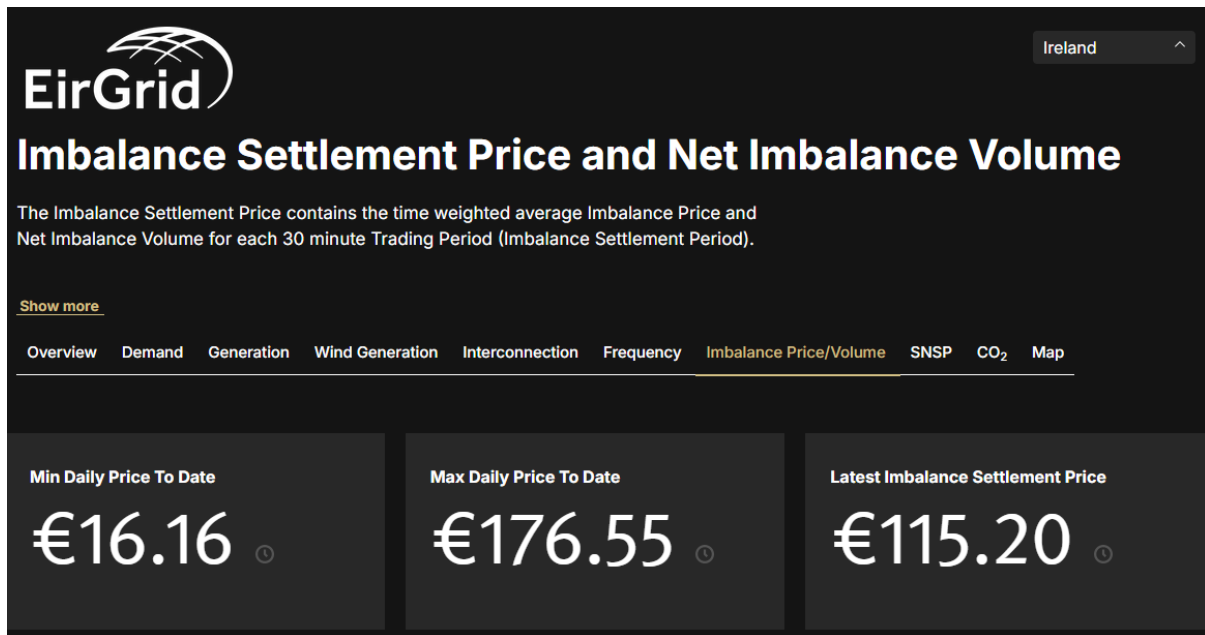


Figure 77 – Pricing Dashboard for Ireland 19th May 2025.



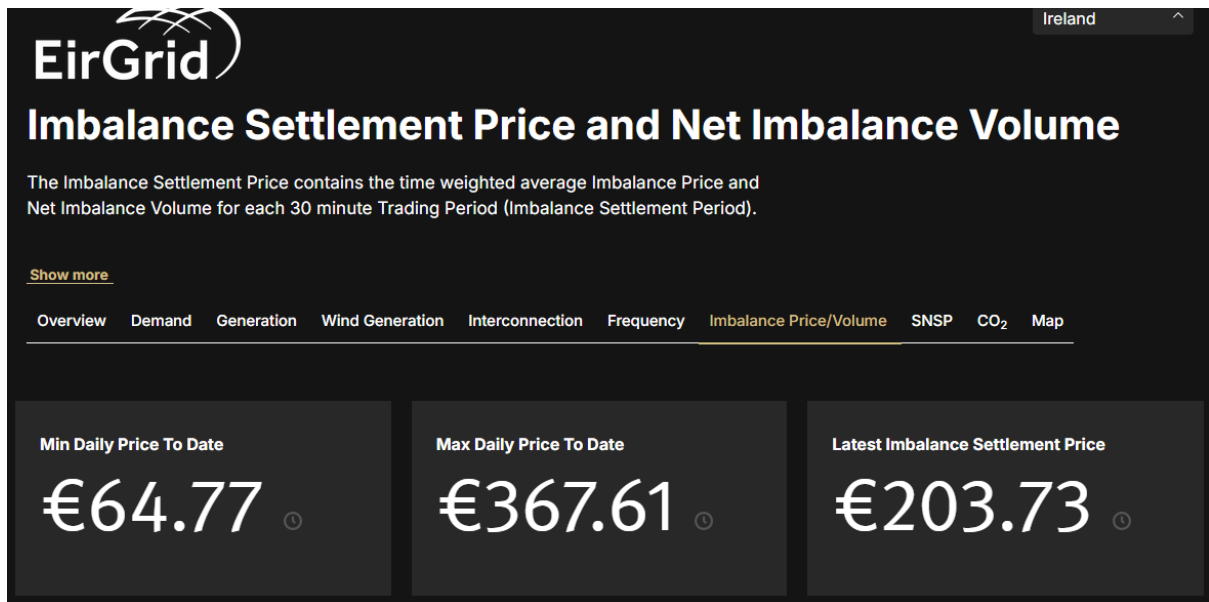


Figure 78 – Pricing Dashboard for Ireland 20th May 2025.

Since the data sets were available as hourly timestamped, it was possible to sort it into seasons and compare each scenario. Met Éireann, Ireland's national meteorological service divides the year into four equal parts, each comprising three full months [61]

Winter: December, January, February

Spring: March, April, May

Summer: June, July, August

Autumn: September, October, November

Each price point was sorted into season and then further broken down by time of day. The average price per time of day per season is presented for each scenario in the following 3 graphs.



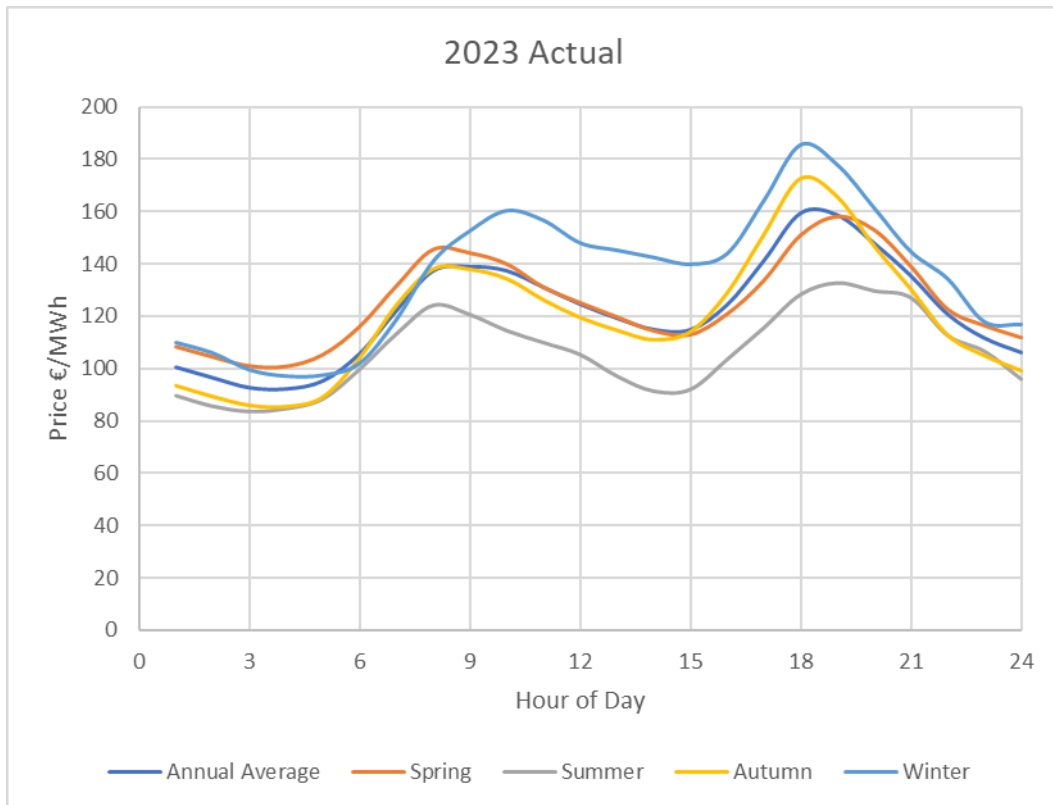


Figure 79 –Time of Day Price variation by season – 2023 Actual.



The real data for 2023, in Figure 79, shows that in Ireland there are 2 daily peaks in the morning and then again in the evening. We can also see that the winter peak price is much higher than that of summer. In Ireland, home air conditioning units are not widespread so this trend is as expected.

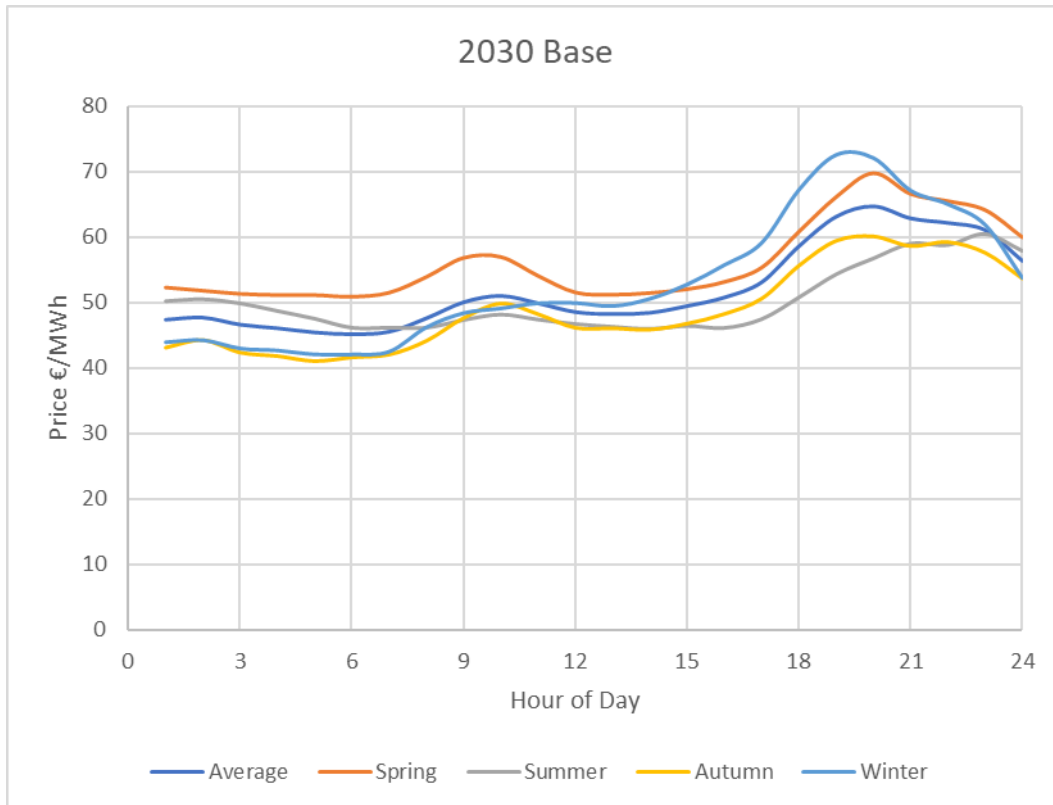


Figure 80 – Time of Day Price variation by season – 2030Base.



The 2030 base case, in Figure 80, follows a similar pattern to that of the real 2023 data. However, the % change between trough and peak is not as extreme, neither is the delta between summer and winter.

The 2030 increased wind case, in Figure 81, has a further reduction in volatility and a narrowing of the extremes.

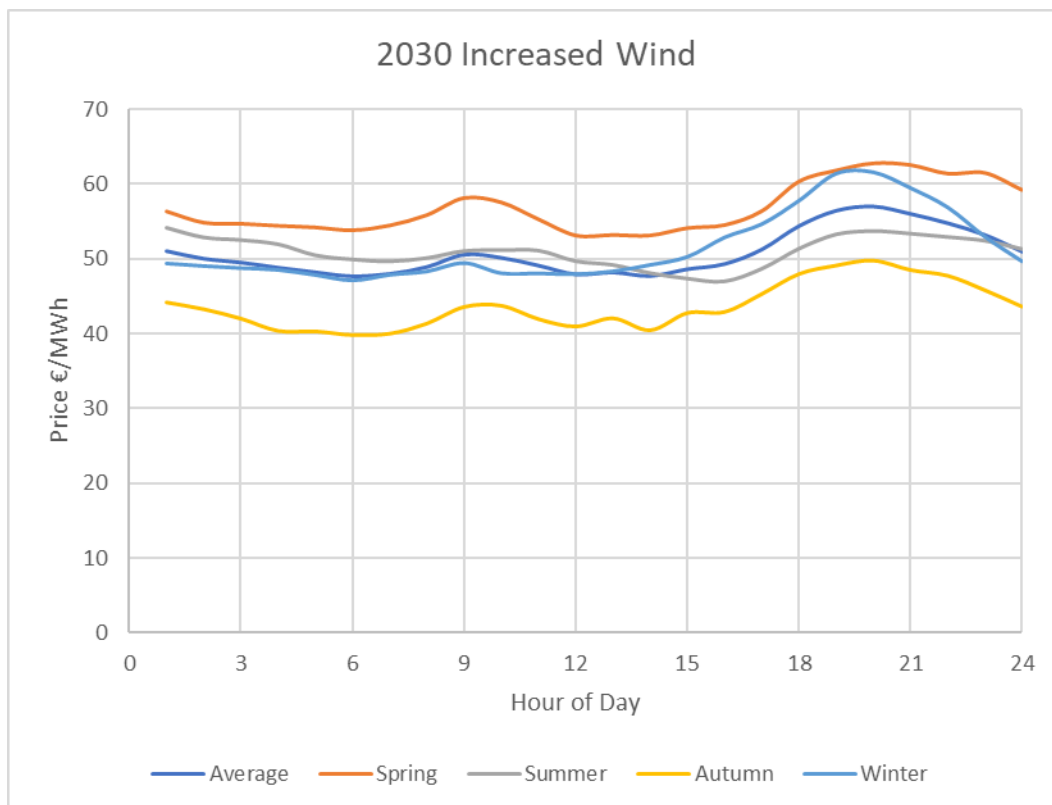


Figure 81 – Time of Day Price variation by season – 2030 Increased Wind.

For the 2 modelled cases, further analysis and breakdown can be done as not only is the price available per hour over the year, but the MWh generated by each renewable type in that hour is also available. This allows the calculation of the Average weighted capture price per technology. In this case we calculated this from the dispatched energy per technology as this reflects what the generator would be paid.

Table 5.2 breaks it down by model, by technology and by season. For comparison the average market price in that period is also shown.

Table 5.2 – Average Market prices vs Average Capture by technology and season.

Base Case 2030	Spring	Summer	Autumn	Winter
Average electricity price	€56.18	€50.19	€48.90	€52.94



Average dispatched weighted captured price per technology				
Wind	€36.60	€30.36	€28.94	€34.22
Solar	€56.06	€48.58	€48.11	€55.13
2030 Increased Offshore Wind	Spring	Summer	Autumn	Winter
Average electricity price	€56.74	€51.02	€43.69	€51.42
Average dispatched weighted captured price per technology				
Wind	€34.62	€27.53	€21.41	€30.52
Solar	€58.25	€51.39	€43.84	€53.85



The trends shown are as expected. Wind has a lower than market price as it generates through the day but also at night during low periods of demand. PV is much better matched to the daily demand profile and hence performs better. Adding more offshore wind also tends to further reduce the capture price.

Conclusions for Ireland

The direction of travel that Ireland is on from 2023 towards 2030 shows that building out a more renewables focussed grid has many benefits. Looking only at price, it can be seen that a more renewables focussed system can reduce overall price volatility, lessen spikes and also improve seasonal variation which is good for both consumer and generator. The dependence on gas fired generation is greatly reduced having significant carbon reductions. It also shows that increasing electrification through heat and transport can be answered through renewables. It happens that in Ireland, PV, wind and offshore wind are complementary not only in time of day but also looking at seasonal variation. This has the effect of lowering the overall system price. This further strengthens the case of EU SCORES for future co-located farms that offer complementary renewable generation.

However, there is a price to be paid for this. Adding more wind tends to lower the average capture price since much of the generation is at times of lower demand. From the generators' perspective, this may reduce overall profitability of a new farm IF that farm is not on a subsidy scheme. The system operator also needs to raise the SNSP limit to enable this.

For Ireland to go further in its decarbonisation journey there will need to investment in storage, flexibility and interconnection overall highlighting the trade-offs between higher renewable ambition, system operability, investment needs, and policy design.



6 Conclusions

This deliverable has provided a comprehensive market price assessment of different electricity sources – particularly offshore wind – across several European electricity markets: the Iberian Peninsula, Ireland, the Netherlands, Belgium and Germany (plus Luxembourg). The analysis was designed to evaluate how varying levels of offshore renewable deployment, system flexibility, and regional differences in energy policy and infrastructure could impact electricity market dynamics by the year 2030.

Offshore Wind as a Market Stabilizer

Across all modelled regions, increasing offshore wind capacity consistently resulted in lower average electricity prices. This trend is driven by offshore wind's higher capacity factor and its low marginal costs. However, this price suppression also introduces challenges for investors: higher renewable penetration often leads to capture price cannibalization, where technologies reduce their own revenue potential by driving market prices downward during peak generation periods.

In scenarios with very high offshore wind penetration (e.g., the Iberian “All Offshore” scenario), this effect becomes particularly pronounced, leading to increased renewable spillage and reduced economic viability unless compensated by flexibility mechanisms or policy support. Therefore, while offshore wind contributes to market decarbonization and price stability, its rapid expansion must be balanced with sufficient demand-side and system flexibility.

Role of Demand-Side Flexibility

The simulations clearly demonstrate that flexible demand – particularly for applications such as green hydrogen production, electric vehicles, and industrial load management – is essential to maintain the economic sustainability of renewable investments. In scenarios where flexible demand was included (e.g., “High Offshore” in Iberia), market prices stabilized and spillage was reduced, allowing better utilization of zero-marginal-cost generation.

Conversely, scenarios lacking flexibility (e.g., “High Offshore w/o H₂”) exhibited both lower market prices and higher spillage, reducing the value captured by generators. These results emphasize the urgent need for regulatory and market design measures that promote demand-side participation, price-responsive loads, storage development and smart electrification.

Regional Highlights

- **Iberia:** Offshore wind significantly reduces market prices, especially when paired with hydrogen demand. Without flexible demand, overgeneration



leads to inefficient system operation and diminished capture prices. The Iberian simulations also reveal that some kind of offshore profile smoothing, when aggregated realistic profiles are not available, is needed to adjust single-site data to the total system to produce more realistic estimates of market impacts.

- **Netherlands, Belgium and Germany (plus Luxembourg):** A strong linear correlation between residual load and electricity price enabled a simplified yet robust modelling approach. The results show that while solar dominates installed capacity, wind and wave technologies yield higher capture prices due to better alignment with system demand. Wave energy also shows promising market performance. A factorial study for The Netherlands for 2030 showed that variations in the input parameters (like the installed capacities of wind and solar) can cause big changes in the electricity prices.
- **Ireland:** The All-Island power system benefits from increased offshore and onshore wind, achieving lower price volatility, reduced gas dependency, and stable pricing patterns. However, the decline in capture prices for wind highlights economic pressures for unsubsidized projects. Seasonal and daily generation complementarity between wind and solar is particularly beneficial.

Market Design and Policy Implications

The findings across all regions highlight a critical inflection point for European electricity markets:

- The **renewable cannibalization effect** poses a significant challenge to the economic sustainability of variable renewable energy sources, particularly for unsubsidized offshore wind projects. As renewable penetration grows, technologies begin to undermine their own capture prices by saturating the grid during peak production hours. This, if not properly addressed, will disincentivize future investments in renewable energy.
- **Flexible demand** and **grid interconnections** are essential to mitigate price volatility and reduce curtailment. However, while hydrogen production and storage are promising sources of flexibility, regulation can provide additional support and allow these new technologies to participate in different system services to increase their revenues streams and incentivize investments.
- **Well-designed capacity markets, long-term contracts,** and **supportive regulatory frameworks** will be necessary to maintain investment signals in a zero-carbon electricity system.
- **Integrated energy planning** that considers sector coupling (e.g., electrification of transport, heating, and industry) will further enhance system flexibility and reduce CO₂ emissions.



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