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Study S14

Wholesale market prices, revenues and risks for producers with high shares of variable RES in the power system

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1 ABBREVIATIONS AND DEFINITIONS

1.1 ABBREVIATIONS

Abbreviation	Definition
CCGT	Combined Cycle Gas Turbine
CRM	Capacity remuneration mechanism
NTC	Net transfer capacity
OCGT	Open Cycle Gas Turbine
PPA	Power Purchase Agreement
PV	Photovoltaic
DSR	Demand Side Response
RES	Renewable Energy Sources
vRES	Variable RES

1.2 METIS CONFIGURATION

The configuration of the METIS model used to evaluate the impacts of the MDI policy measures is summarised in Table 1.

Table 1 - METIS Configuration

METIS Configuration	
Version	METIS v1.4
Modules	Power system and demand modules
Scenario	METISS1-2050 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

2 EXECUTIVE SUMMARY

Renewable energy sources (RES) are nowadays considered as a key element in the overall strive for power sector decarbonisation. At the same time, dropping technology costs and increased market integration make RES investments becoming increasingly competitive and lead to a progressive phase-out of support mechanisms.

In a decarbonised power sector with a high share of variable RES generation, price volatility will be much more important than today, which incorporates a price risk for RES investments but also for other production or storage technologies. This risk may translate into an increased risk premium which prevents actual investments despite a per se profitability of the projects. This study has for aim to shed further light on the potential amplitude of such risks for different types of investors and to evaluate the effectiveness of different risk hedging strategies.

The analysis builds upon METIS-S1-2050 scenario from the METIS S1 study (focussing on optimal flexibility portfolios for a high-RES 2050 scenario), assuming a fully decarbonised power sector. That is the scenario is in line with the European Commission's 2050 long-term strategy[1]. In the scenario, the RES share exceeds 80% in European power generation and all gas burnt is biogas or synthetically generated via power-to-gas. A part of the gas consumption in the industry and transport sectors is electricity-based (via electrolysis and methanation) and power demand is highly flexible thanks to the price-elastic power demand of electric vehicles, heat pumps, domestic hot water boilers and power-to-gas.

The study shows that in a context where most of the generation is weather-dependent with almost no variable cost, market prices are often set by the demand. When all flexible power demand is met by renewable production, the market prices are close to zero and when it is partially supplied, price-elastic customers (e.g. electrolysis) set the price. The frequency of zero prices and the price volatility tend to increase but vary significantly across countries, depending on the interconnection level, the share of variable RES and the access to large hydro capacities. Based on these characteristics, four clusters of countries are proposed and analysed in more detail in the study.

While, by construction, average revenues equal fixed cost assumptions, weather-related revenue risks affect in particular peak generation units (up to 50% surplus variation) and RES (in particular solar PV). Storage units are much less concerned as long as price spreads remain unchanged. Risks related to changes in the power system (investment stress cases) are evaluated for five sensitivities, with varying RES, interconnector and storage capacities (all else equal). It is noted that:

- An accelerated increase in RES generation capacities deteriorates market prices and revenues for RES and gas-based power generators. Solar PV suffers particularly from cannibalisation, as additional solar capacities drive down market prices during sunny days. This effect is much less pronounced for storage units which also benefit from low market prices.
- A cannibalisation effect is also observed for batteries: with the addition of alternative sources of flexibility (competing storage or demand response with similar characteristics), price spreads and opportunities for arbitrage decrease rapidly. Investments in storage only based on market revenues are therefore very risky as it is difficult to forecast flexibility development.
- Electrolysis (as representative of flexible consumers) benefit from lower prices – in contrast to generation units. They thus offer an opportunity for risk hedging.

As part of the revenue risk is triggered by government decisions (e.g. with respect to phase-out decisions, introduction of a carbon price, or set-up of renewables targets), public authorities could play a role to cover this risk.

Besides, the analysis reveals that hedging RES investments with load-following supply contracts works well but does not cover the cannibalisation effect (market prices drop during hours of high RES generation). Combining a RES investment with a flexible power supply contract (e.g. electrolysis) appears to be a more effective hedging strategy.

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[1] https://ec.europa.eu/clima/policies/strategies/2050_en

3 INTRODUCTION

National support policies, a significant reduction in project costs as well as clear commitment and target setting by European and national policy makers have triggered important investments in renewable energies (RES) for power generation over the past years. Renewable energy sources are nowadays considered as a key element in the overall strive for power sector decarbonisation.

With respect to the European energy system in the year 2050, it is conceivable that a power mix relying primarily on RES and with necessary assets for flexibility can be cost-optimal from a system point of view. Yet, there is a strong questioning on how wholesale power markets will behave in such a context. On the one hand, RES generators featuring near-zero variable costs will increasingly often set the clearing price and thus lead to very low (or even negative) market prices. On the other hand, rising shares of variable renewable power generation will entail important hourly variations in wholesale prices and exhibit relevant interannual differences due to varying weather conditions. Besides, the development of flexible demand and power-to-X applications will change the paradigm of price setting at wholesale markets: from a situation where producers set the price (facing a relatively price inelastic demand), the market will evolve to a situation where flexible consumers are going to set the price, depending on the price they are ready to pay for a certain energy service or power-to-X application.

Considering a new world where most of the costs are CAPEX-related (vs low CAPEX and high variable costs in historical systems), it can be that the increasing uncertainty in wholesale market prices implies a volatility in revenues from the day-ahead market which would lead to insufficient revenues or high risk premia. An increased risk premium may in the end prevent the market actor from undertaking the actual investment. Hence, private and public risk hedging measures are necessary to reduce revenue risks and facilitate investments in the future power market that guarantee a continuous supply-demand balance at low total cost.

Based on a literature review, this report provides an overview of existing revenue risks and details risk hedging strategies that proof in particular effective to tackle price risks (cf. Section 4). Subsequently, future prices and revenue risks are analysed for a given 2050 scenario with a high share of renewable power generation, flexible consumers and Power-to-X applications representing a relevant part of electricity consumption. The assessment reveals the evolution of future power prices in four reference countries and compares them to the current situation (Section 5). Based on the observed prices, the weather-related revenue risks are derived for 10 different weather years, analysing the impact on revenues for renewable power generators, as well as flexibility providers (Section 6). The study also addresses the impact of investment stress cases on revenues, simulated as changes in the power system, for five sensitivities featuring varying degrees of RES penetration, interconnection, flexibility availability and fuel prices (Section 7). This assessment is complemented by a quantitative analysis of the potential effectiveness of different risk hedging strategies to overcome the previously identified risks. The study closes with a set of concluding remarks on the most promising actions and gives an outlook for further analysis.

4 Revenue risks and risk hedging strategies – A literature review

This section provides an overview of potential revenue risks faced by investors and existing risk-hedging strategies, based on (IRENA, 2016; Gatzert & Kosub, 2015; BNEF, 2013).

4.1 Revenue risks

This introductory section provides a typology of risks associated with power generation projects, relying on a global classification in five classes of risk.

- **Volume risk:** refers to the risk of unanticipated variations in the level of power generation or in the level of customers' consumption, which potentially makes the producer short or long of power and thus exposed to price move in the end. For renewable energy production, this risk mostly stems from the uncertainty of resources (wind, irradiance, rainfall, etc.).
- **Price risk:** is the risk that the value of investments and/or revenues of business activities will change due to unexpected variation in prices. Typical market risk factors for a power producer include an increase in the price of fuels and other inputs (e.g. CO_2 price), or a decrease in the price of the electricity sold. This risk and the evolution of price is the focus of the study, which we will detail in Sections 6 and 7.
- **Counterparty risk:** is the risk of loss due to a counterparty defaulting in the performance of a contract (default of payment, of goods delivery, etc.). More generally this is the risk of change in the credit quality ("rating") of a counterparty. For RES generators, the risk is related to the default by the power off-taker (e.g. the utility).
- **Financial structure risk:** this class refers to the risk of being short of the financial resources required to develop and maintain a profitable activity. The concern is twofold: first ensuring access to stable funds (equity and debt) consistent with the viability of the project in the long run; secondly, treasury needs in the short and medium term must be carefully assessed and covered.
- **Operational structure risk:** by its very nature this class encompasses ubiquitous risks arising from running operations. This refers to the risk of loss resulting from inadequate or failed internal processes, people and systems, or from external events. Political and regulatory risk include for instance a change in public policy or regulation, for instance taxes or subsidies policy.

Table 2 further details each risk class.

Table 2 - Overview of risk types

Risk type	Potential sources[2]	Primary random variables[3]
Volume risk	• Clients' consumption level • Availability of "supplies" (internal and third-party providers) • Availability of transmission and distribution network, congestion	1. Weather variables (irradiation, wind speed, temperature, rainfalls, water inflows) 2. Equipment reliability (electrical, mechanical) 3. Global context (overall economic perspective, changes in geographical distribution of consumption)
Price risk	• Selling price (clients, markets) • Supply and production costs (fuels prices, price of power purchased to others or on the market, operation and maintenance costs)	1. Fuel prices 2. Currency exchange rates 3. Power demand and supply mix characteristics (level and structure) in the area and in the interconnected areas. 4. Energy management (by other producers)
Counterparty risk	• Electricity clients/consumers (default of payment) • Electricity suppliers (default of delivery) • Suppliers of general services (poor quality of hardware or maintenance service) • Purchases and sales on the market or OTC	1. Country risk 2. Financial and operational evaluation of each counterparty (individual rating)
Financial structure risk	• Stability of shareholders and partners • Equity level • Anticipation of cash flow needs	1. General economic and specific business context 2. Monetary policies
Operational structure risk	• Separation of duties • Setting up appropriate skills and procedures for the considered activity • Ensuring legal enforceability of contracts	1. Political and legal context 2. Internal management

In this study, the focus is set on the price risk[4], as the evolution of wholesale prices and the power output of power generators are subject to particularly high uncertainty and potentially represent a challenge for investors different from other sectors of investment.

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[2] A potential source refers to a source of uncertainty that directly makes a risk arising. For example, the uncertainty of the actual consumption of clients is a major source of volume risk for an energy provider.

[3] This refers to the uncertainty factors that may be more or less strong drivers of the variability of the previous sources. For example, weather variables like temperature or rainfall are primary factors that may influence both consumption level and production costs

[4] Investments risks are also subject to a number of additional factors, such as imperfect market competition or market power. However, such analyses are not included in the scope of this study, as the impact of imperfect

4.2 INTRODUCTION OF PRICE BUILDING AT WHOLESALE MARKETS

For a better comprehension of the risks related to price volatility and potential risk-hedging strategies, it is useful to recall the general functioning of the wholesale day-ahead market (i.e. the merit order) and the major levers that may affect the wholesale price.

4.2.1 PRINCIPLE OF MERIT ORDER

Although electricity is often referred to as a commodity, one has to take into account its specific physical characteristics in order to fully understand why electricity markets do not behave like other energy markets, such as natural gas or oil. Indeed, what is most critical about electricity is its inability to be stored in large quantity without conversion and the parallel requirement that supply and demand need to be balanced at all time. Network operators are in charge to avoid any imbalance as the latter may cause significant damage to physical facilities and put at risk system stability.

The actual equilibrium between demand and supply is determined at wholesale markets[5], where a pool of power generators bid their production and are awarded a contract until the demand is met. This functioning is typically illustrated via the so-called *merit order* (cf. Figure 1). Every asset places a bid at the market for a given capacity and at a specific price, which equals in theory its variable production costs (which are driven by the asset technology). One may distinguish two main asset categories. Firstly, renewable energy sources which do not rely on a fuel (such as solar PV, wind turbines, or run-of-the-river hydro power) and only feature operational expenditures and thus near-zero production costs. Secondly, fossil-fuelled assets, nuclear plants and biomass, which convert energy from an input fuel into power. As such, their variable costs depend on the fuel price, technology characteristics (e.g. conversion efficiencies), operational costs and the EU-ETS CO_2 price.

To ensure demand is met at the lowest cost and at every time-step, competing generation assets are sorted by the prices they bid, which structures the merit order. The merit order is then matched with the demand level, and assets are awarded a contract consequently until demand-supply equilibrium is met. As a consequence, low variable costs technologies will run most of the year at their maximum capacity, and high variable costs assets will operate only a few hours along the year. At every time-step, the most expensive running asset sets the market price.[6]

As vRES generation, storage and assets availabilities as well as demand levels fluctuate, so does the merit order structure and thus power market prices. At every time-step, as they are selected to produce, assets featuring a unitary variable cost lower than the market price earn the difference in price, for every MWh they serve, also referred to as *infra-marginal rent* or *unit* margin. Near-zero variable costs assets thus benefit from higher differences with market prices. On the contrary, marginal peakers, which produce only at a few moments in the year, may find difficulty recovering their fixed costs unless they are able to capture scarcity prices when demand is close to or exceeds supply capacities, or if their annual surplus is complemented by capacity market payments.

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competition on the outcome will mainly depend on assumptions on market liquidity by country which are difficult to project at 2050 horizon.

[5] Different markets exist at different time scales. The focus in this study is set on the day-ahead market.

[6] The above explanation considers perfect market functioning based on marginal prices and is as such represented in the METIS model. However, actual markets may be imperfect, or specific market products (e.g. block bids) may create non convexity ; price setting may thus deviate, see for instance (Gribik, Hogan, & Pope, 2007).

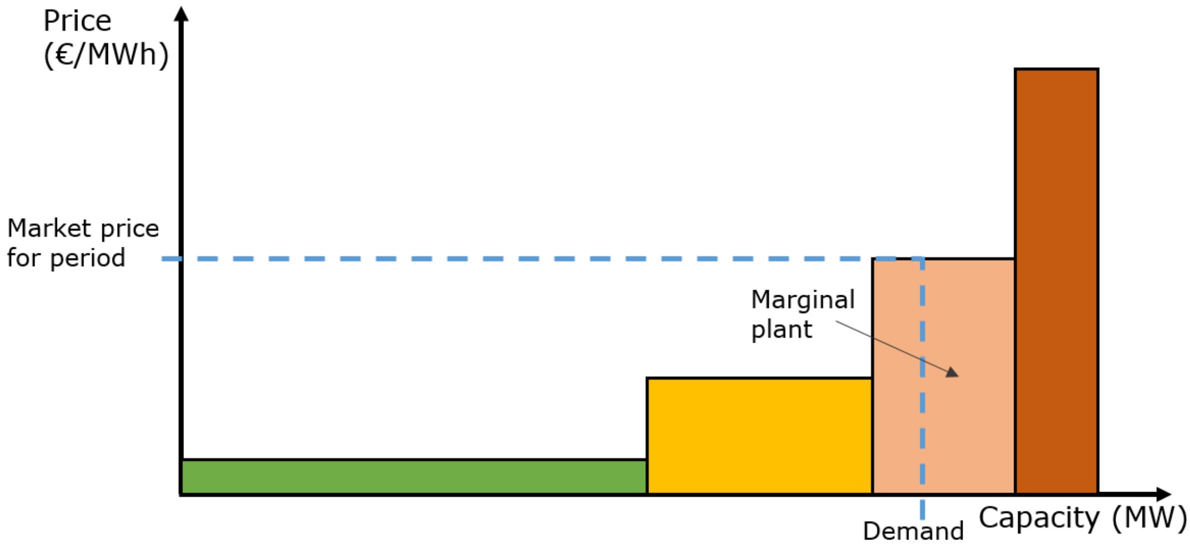

Figure 1 - Principle of merit order (in the case of 4 technologies available)

4.2.2 DRIVERS OF ELECTRICITY PRICES

In order to fully understand where market price fluctuations and uncertainty may come from, we analyse here different levers affecting the structure of the merit order.

Fuel costs

In the first place, fossil-fuelled and nuclear generation assets need to source their input on commodity markets as price-takers and have limited margin to control their supply cost. Varying variable costs for a technology can have different impacts. In situations when the technology is marginal, the market price is affected. At times when the technology is selected to produce without setting the clearing price, its infra-marginal rent is affected. More generally, the technology's position in the merit order may change since its variable costs change.

For instance, in the case of rising natural gas prices, the price increase will drive up the asset's variable costs. In a stylised example (cf. Figure 2), if the concerned asset is the marginal plant, the asset's variable cost will rise and so will the power price. Furthermore, if the rise of this gas-powered asset's variable costs is sufficient, this plant could become even more expensive to run than the ones it used to take precedence over on the merit order scale.

Figure 2 – Flip of the merit order in the wake of fuel costs variations

Carbon price

The EU-Emissions Trading Scheme imposes to all power producers to purchase (cf. Figure 3 - Emissions Allowances price evolution) carbon Emissions Allowances (EUAs, issued for one ton of CO_2 each) in quantities that match their actual yearly emissions due to power (and possibly heat) generation.

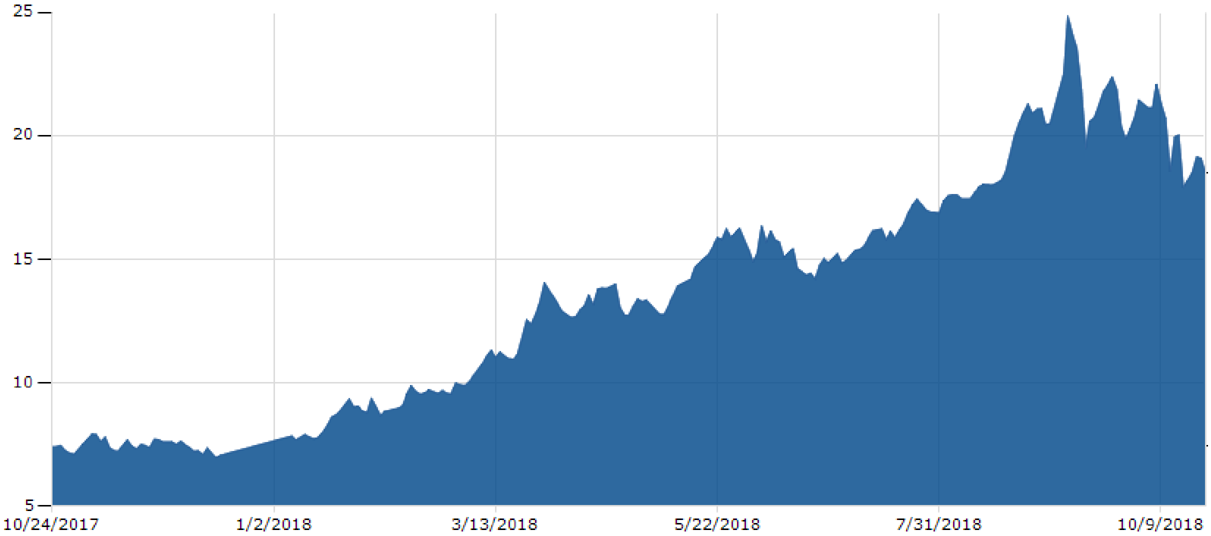

Figure 3 - Emissions Allowances price evolution (Business Insider, 2018)

Carbon emissions depend on the fuel's carbon content (which differs between gas, coal, lignite and oil) and the technology's conversion efficiency. Hence, carbon price affects technologies to varying degrees, if any.

That is, the EU-ETS carbon price induces an additional layer in fossil-fuelled power producers' variable costs, leading the system's marginal cost to increase in times when these technologies are required to meet high demand. Secondly, if a certain level is reached, it may flip[7] the merit order, favouring technologies whose high running costs may be offset by low emissions.

RES deployment

Additional commissioning of variable renewable power generation capacities may imply significant changes in market prices. As they feature near-zero variable costs for power generation, the merit order principle grants them precedence over other technologies, pushing more expensive generators potentially out of the market (so-called *merit order effect)*. Variable RES (vRES) in particular have a specific impact on prices. Solar and wind power production are intrinsically linked to weather conditions. As a result, the marginal unit may significantly change from one hour to another. On sunny days, for instance, solar panels will account for a wide band within the merit order, while this band is inexistent at night.

If vRES capacity increases, conventional producers' opportunity to sell electricity becomes increasingly unlikely, since they do not only depend on demand levels any more, but also compete with vRES production at near-zero variable costs at the same time. They are then only responsible for coping with the *residual load* resulting from the difference between vRES generation and demand.

[7] According to Carbon Tracker, under certain assumptions in terms of technologies efficiency rates, a carbon price over 20€/t_{CO2} can lead gas to take precedence over coal in many areas (Carbon Tracker – Carbon Clampdown, 2018)

A second impact of vRES deployment is the *cannibalisation effect*. Above certain thresholds of vRES installed capacities, assuming favourable weather conditions, there are times when units with near-zero variable costs cover most of the demand. Electricity prices and vRES technologies' infra-marginal rent will therefore decline, to varying degrees depending on the situation.

When generation of assets with near-zero variable costs is not sufficient to reach supply-demand equilibrium, the system still needs additional producers that feature non-zero variable costs, which translate into a reduced but still positive infra-marginal rent for near-zero cost producers (cf. Figure 4 - Merit order shift in the wake of vRES generation rise).

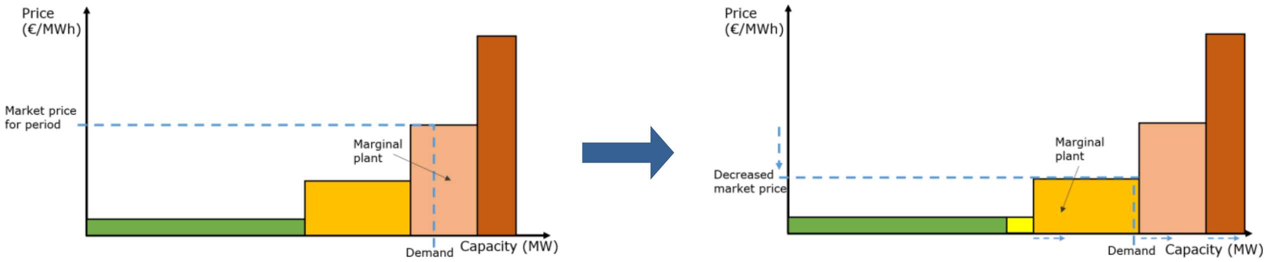

Figure 4 - Merit order shift in the wake of vRES generation rise

If generation with near-zero costs equals or exceeds demand, all demand can be met at no cost, and market prices reach zero or even negative values. As a consequence, infra-marginal rent is zeroed as well and producers may be incapable to recover their fixed costs (cf. Figure 5). As this price reducing effect occurs particularly in hours with high RES generation, it drives down the market value of RES capacities, i.e. RES capacities are said to cannibalise each other.

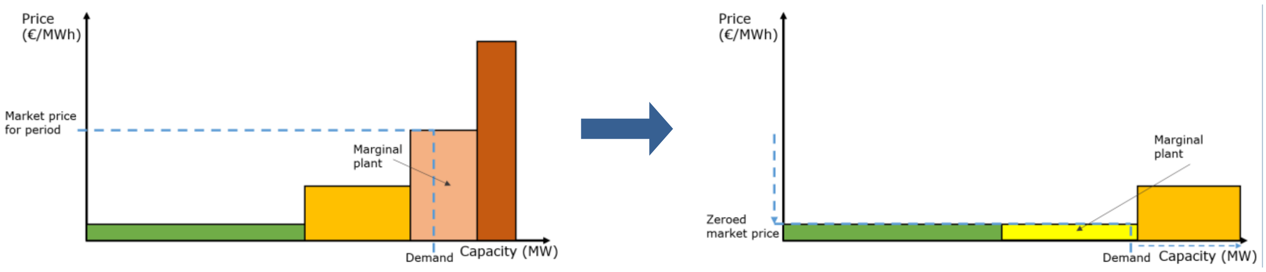

Figure 5 - Cannibalisation effect due to over-dimensioning of vRES capacities

Decommissioning of coal and nuclear capacities

For environmental or political reasons (JRC, 2018), the early decommissioning of coal and/or nuclear generation capacities may take place in several countries across Europe. These events represent potential shifts of the merit order, as base and semi-base capacities may disappear. As a result, the gap between low and high costs technologies will widen, enhancing price volatility and thresholds effects.

Demand flexibility

Technical breakthroughs in the domain of demand-side response (DSR) technologies (e.g. smart meters, monitoring technologies, smart electric vehicle charging algorithm) make power demand increasingly flexible and price-elastic. Hence, power prices could not only be set by producers meeting a static demand, but result from dynamic supply and demand, as the latter will be able to shift consumption, with noticeable impacts on power prices.

Indeed, flexibility technologies may thereby intensify demand in periods of low prices and load shedding in periods of high prices.

Generally speaking, enhanced price elasticity of demand through DSR implies that price fluctuations are expected to smooth and price spreads to narrow. Overall, this reduces the utilisation of expensive technologies and hours of scarcity prices decline.

Interconnections

Reinforced interconnectors tend to intermingle the merit orders from neighbouring countries, thus resulting in an apparent unique transnational merit order. The resulting proliferation of demand profiles and generation assets may have diverging impacts. If the neighbouring country features higher power prices, there is a chance for additional exports and thus higher revenues for national generators. In contrast, if power prices are lower in the neighbouring country (e.g. due to high vRES generation), then there is a risk of higher competition for national producers, possibly implying decreasing prices.

4.3 PRIVATE RISK HEDGING STRATEGIES

While most RES projects in Europe today benefit from support schemes that limit or even eliminate price risks, the phasing out of support schemes will make sales on the wholesale market the main source of income. As investments require stable return projections, de-risking projects will become increasingly important. In the following, different risk hedging strategies are introduced, based on (The Brattle Group, 2017; Gatzert & Kosub, 2015; Australian Government - Productivity Commission, 2013). A quantitative, model-based evaluation of these strategies is carried out in Section 7.4.

4.3.1 POWER PURCHASE AGREEMENT

The most common strategy for RES projects to tackle revenue risks consists of entering a power purchase agreement (PPA) with a utility or a large commercial or industrial customer that wants to increase the share of green electricity in its supply. The contract stipulates a fixed price, typically covering the full lifetime of the project, that is 15 to 20 years or even more. The PPA typically represents a take-or-pay agreement whereby the customer is obliged to pay for consumed electricity as well as electricity that was provided but not consumed.

With PPAs, the market price risk is supported by the customer who has to buy remaining electricity demand and sell electricity surplus on the market. With the growing share of renewables and the increasing market price risk (cf. Section 5.2), it is expected that PPAs become less popular as large electricity consumers will ask the RES developer, or a third party, to bear this risk. Moreover, PPAs are often offered at prices with heavy discounts compared to forward prices, which can be detrimental to the value captured by developers.

4.3.2 ELECTRICITY AND GAS SWAPS

An increasing share of renewables, especially wind resources, are being developed on a merchant basis without PPAs. Merchant projects sell their power at the spot market and thus face substantial market risk due to price fluctuations, which could impact developers' ability to fulfil debt obligations and the level of investment returns. Price risk may also affect willingness, size, or timing of market entry. Using standardised financial contracts

(e.g. electric or gas swaps) as a hedging instrument can be a cost-effective way to manage market risk[8] and achieve the level of revenue certainty needed[9].
At short-term (1-3 years), an electricity swap can hedge most of the market risk. The project company sells its power to the market at a floating clearing price and swaps its floating payments for a fixed electricity price per kWh. Electricity swaps are typically established for a fixed quantity of power projected for a year. The counterparty of the swap is typically a buyer in the electricity market.
For longer time horizons, electricity swaps are not available. However, as natural gas is the prevalent source for electricity generation in many countries, there is a strong correlation between gas and electricity prices. A well-traded gas market allows generators to use gas swaps to hedge the electricity price for longer periods, such as 10 years[10]. The project company has to estimate the market heat rate, that is to say the ratio between gas and electricity prices, by projecting the thermal efficiency of the marginal gas units. It will then perform the following transactions:

- It sells RES production on the wholesale electricity market and receives a floating income.
- Based on these revenues, it buys gas on the wholesale market and sells it at the floating price to the counterparty of the swap (typically a gas consumer). If there is no cannibalisation and the heat rate is unchanged, these operations are neutral for the company
- Finally, it receives a fixed price from the counterparty of the gas swap.

In addition, the company can buy a spark spread option to hedge the risk that the heat rate changes (unplanned coal plant retirements, new efficient gas units or even CO_2 price evolution can alter heat rates).
In both cases, the gas and electricity swaps are based on spot prices, while the RES project revenues on the market are volume-weighted. The project company is therefore exposed to the correlation between wind or PV output and spot prices (so-called cannibalisation effect).

4.3.3 RES + STORAGE

Outside Europe, for low interconnected areas with good weather conditions (for instance, North Chile, Africa, Australia), there is already today a high risk of price collapse during periods of high RES generation. The current practice is generally to couple wind or PV projects with storage facilities (typically pumped hydro or batteries).

In continental Europe, at short term, the high level of interconnection between countries reduces the needs for such coupled projects and RES / storage projects are often managed separately. Yet, at long term, coupling RES and storage projects could de-risk the exposition to the correlation between wind or PV output and spot prices. For instance, for a PV plus battery project:

- If the spot prices during the daylight period collapse, the spread between peak and off-peak widens and the storage increases its income
- On the contrary, if the spot prices during the daylight period remain high, storage revenues remain limited but the PV project gets high revenues

As it is often difficult for a single company to manage both projects, the common practice is to find a counterparty and sign a financial contract such as (in the following, company A owns the RES project and company B owns the storage project):

- PPA: company A sells electricity to company B at a fixed price. In this case, company B covers its supply risk but still support its selling price risk

[8] Literature suggests that power price risks may add a risk premium of 3-5% on top of the cost of capital for investors (FTI Consulting, 2018).
[9] For further information about the functioning of SWAPs, see (EY, 2016; Bolinger, Wiser, & Golove, 2004; EIA, 2002)
[10] This only holds true as long as gas-based power generation is available in the power system.

- Peak/off-peak spread option: if the difference between peak and off-peak exceeds a strike price, company B pays out the difference. In the opposite case, company B receives a fixed revenue from company A thanks to the option premium.
- Tolling Contract: for an upfront payment (the tolling fee), company A gets the right to operate and control the scheduling of the plant.

In addition, an electricity or gas swap is still necessary as the storage project does not cover the risk associated to low market prices.

4.4 PUBLIC RISK HEDGING STRATEGIES

While phasing out support schemes at mid-term, governments could also play a key role to hedge RES investments. Indeed, national governments have a better grasp of the future evolution of their power mix, as decommissioning of coal or nuclear capacities and the development of new electricity demand and flexible usages are often triggered by national policies. Hence, public authorities could set-up hedging instruments to bear the market risk and de-risk private RES investments. On the other side, governments can limit their own market risk by developing a sound national energy and climate plan.

Among others, the following mechanisms can be mentioned:

- Develop power purchase agreements for power consumption of public services: while the purchase price can reflect current market conditions, the market risk is borne by the public authority
- Emit electricity price swaps: a public authority becomes the counterparty to swap floating market clearing prices for a fixed electricity price (typically based on current market conditions)
- Long-term CO_2 floor price: as the CO_2 price represents a major source of market price uncertainty, a CO_2 floor price could reduce price risk for investors
- Develop sufficient flexibility in the power system, by developing interconnections and promoting demand response and storage. A more flexible power system eases RES integration and reduces market risks associated to cannibalisation.

5 EVALUATION OF FUTURE WHOLESALE PRICES

5.1 INTRODUCTION OF THE UNDERLYING SCENARIO

The assessment is conducted with the hypothesis of a fully decarbonised power system in 2050. To reach such a level, the METIS-S1-2050 scenario was built on the grounds of the EUCO30-2050 scenario (E3MLab & IIASA, 2016) and complemented with additional assumptions.[11]

- Coal and lignite capacities are completely phased-out. In the original scenario, these two fossil fuels still represent 48 TWh of yearly power generation. In the new environment, high CO_2 prices hamper economic relevance of new coal. Moreover, existing coal-fuelled assets which could still be in function in 2050 are mainly located in countries who pledged phase-out by 2040.

- Gas assets are fuelled with decarbonised gas. The bulk of original gas capacities is directly replaced by RES technologies. Remaining plants are then fuelled with either synthetic gas produced by power-to-gas installations (electrolysis, methanation) or biogas, assumed to be carbon-free.

- The industry and transport sector are partially decarbonised via electricity-based fuels. 28 TWh of the direct hydrogen use reported in the EUCO30-2050 scenario is assumed to be generated by electrolysis, 70 TWh of fossil fuels demand is met by power-to-liquids transformations and 100% of heat pumps gas back-up consumption is produced by electrolysis and methanation.

- Apart from power-to-X, selected end uses provide additional system flexibility. All electric vehicles are charged in an optimal manner (50% at home, 50% at work). Heat pumps (and domestic hot water in some countries) may shift power demand within the day and the first rely on gas and electricity back-up capacities for peak heat demand.

Overall, this fossil fuel phase-out makes the power system independent from the CO_2 price. Together with the additional power demand related to the introduction of power-to-X systems, power generation from solar and wind power sums up to 2970 TWh, with an overall RES share of more than 80% in power generation.

Since the EUCO30-2050 scenario is chosen as a starting point, most power generation installed capacities are considered exogenous, including solar and wind fleets. However, key technologies to reach the goal of a decarbonised and flexible power system are optimised using the METIS Capacity Optimisation module (see textbox below):

- OCGT and CCGT,
- Pumped hydro storage, lithium-ion batteries,
- Interconnector capacities
- Electrolysis and methanation facilities.

As detailed in Section 6.1, a specific weather year (Test Case 5[12]) is selected to run the capacity optimisation and thus dimension the power system, once and for all.

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[11] A detailed description of the scenario and the underlying methodology and assumptions is available in the METIS study S1 (Artelys, 2018).

[12] Test Case 5 is represented by relatively severe weather conditions implying low RES generation and high demand. Dimensioning the flexibility of the power system for such a "worst case" test case ensures limited loss of load in all other test cases. In reality, several weather years would be taken into account for the dimensioning. For the purpose of reduce complexity and computation times this multi test case optimisation is not carried out in the present study.

In order to reduce price risk for peakers, scarcity prices are capped at the maximum variable generation cost observed, 670 €/MWh, and a capacity remuneration mechanism (CRM) is assumed to pay for the remaining missing money[13].

The METIS Capacity Optimisation module[14]

METIS is an energy modelling software covering in high granularity (in time and technological detail, as well as representing each Member State of the EU and relevant neighbouring countries) the whole European power system and markets. METIS includes its own modelling assumptions, datasets and comes with a set of pre-configured scenarios. These scenarios usually rely on the inputs and results from the European Commission's projections of the energy system, for instance with respect to the capacity mix or annual demand. In the present case, this information includes RES generation capacities and demand, subsequently updated according to the assumptions listed above. METIS allows to perform a joint optimisation of capacity investment and hourly dispatch (for the length of an entire year, i.e. 8760 consecutive time-steps per year). In this study, the result consists of the capacities for the previously listed flexibility solutions as well as the hourly utilisation of all national generation, storage, cross-border capacities and demand side response facilities.

The capacity optimisation determines the cost-optimal dimensioning of the assessed technologies, taking into account capital expenditures (CAPEX) and fixed operation and maintenance costs (FOC). The METIS optimisation module determines the capacity investments and dispatch that maximizes the annual welfare of the total European power system.

5.2 PRICE ASSESSMENT

5.2.1 INTRODUCTION OF COUNTRY CLUSTERS AND REFERENCE COUNTRIES

The analysis of the hourly wholesale prices of the 2050 scenario on a country-by-country level reveals four major country clusters with respect to the future price characteristics (cf. Figure 6). In the remainder of this document, the results will be detailed for a representative country of each cluster.

[13] The question of weather-related price risk for peakers and solutions to mitigate them has been studied in METIS study S16 (Artelys, 2016). This is consequently out of the scope of this report.

[14] Further information about the METIS tool is available at the METIS website: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

Figure 6 – European countries clustering

The country clustering was realised on the basis of a set of indicators. For each country, the shares of solar and wind power in the generation mix are calculated, the first and third quartiles, mean price over the year as well as the number of hours when prices reach 0 €/MWh (cf. Table 3). The four country clusters are defined as follows.

- The *Sunny cluster* groups southern countries with an important solar share, a relevant number of hours with prices below 1 €/MWh as well as limited interconnection with neighbouring countries. Spain functions as reference country for this group. Indeed, 40% of its power consumption is generated by solar panels (cf. Table 3) and its end-of-line position, due to its peninsula localization, will help identifying key messages for that type of supply-side environments.

- The *Windy cluster* is built on the same logic, but with wind power dominating the power mix. Similar to the Sunny cluster, the first quartile of prices in all countries (except for Malta and Romania) is below 10 €/MWh (cf. Table 3, Q1 column). As explained above (see Section 5.2.3), in a high vRES environment, times of favourable weather conditions lead to low electricity prices. The reference country Ireland exhibits a 90% wind share in power demand. PV generation plays a minor role in the generation mix.

- The *Nordic cluster* incorporates the Scandinavian and Baltic countries, which enjoy relatively high shares of hydro power generation in their power mix. In contrast, vRES generation is more limited, implying that the number of hours with power prices under 1€/MWh do generally not exceed 400 (except for Denmark). Price levels in the countries of the Nordic cluster are well aligned due to high interconnection. Sweden is the reference country, with virtually 30% hydro power in the power mix.

- The *Connected cluster* gathers well-interconnected Central European countries, whose power generation mixes generally rely on intermediate RES shares. Consequently, the first price quartile is comparable to the Nordic cluster. However, mean prices are more elevated and can be rather compared to the Sunny and Windy cluster. Hungary represents the cluster as its bulk power production relies on conventional technologies (55%) and its central position reflects a high degree of interconnection with neighbouring countries.

Table 3 - Statistical description of price characteristics by country (RES shares in % of demand)

	Country	Q1 (€/MWh)	Mean (€/MWh)	Q3 (€/MWh)	Hours below 1 €/MWh	Solar	Wind	vRES
Sunny	BG	9	83	145	936	24%	40%	63%
	CY	1	74	145	2195	68%	35%	103%
	ES	8	70	100	846	40%	40%	80%
	GR	8	80	145	1931	50%	56%	106%
	MT	145	144	145	561	18%	10%	27%
	PT	8	70	96	434	22%	48%	70%
Windy	DE	8	76	120	1434	26%	67%	94%
	FR	8	73	118	903	17%	43%	60%
	GB	8	78	145	1248	2%	65%	67%
	IE	8	75	145	1725	3%	90%	92%
	RO	21	85	145	780	14%	49%	63%
Nordic	DK	43	75	98	818	2%	95%	96%
	EE	43	74	90	371	0%	76%	76%
	FI	43	70	86	238	0%	23%	23%
	LT	43	74	90	331	9%	42%	51%
	LV	43	74	90	381	8%	53%	61%
	NO	43	70	82	387	0%	10%	10%
	SE	43	68	82	357	0%	28%	28%
Connected	AT	40	84	138	655	17%	29%	46%
	BA	43	99	145	433	0%	12%	12%
	BE	34	81	145	939	23%	37%	60%
	CH	42	84	138	569	6%	2%	8%
	CZ	38	84	145	13	11%	16%	27%
	HR	43	89	145	556	41%	37%	78%
	HU	42	89	145	544	21%	24%	45%
	IT	35	86	145	1703	45%	31%	77%
	LU	13	78	120	980	12%	12%	24%
	ME	44	100	145	433	0%	10%	10%
	MK	43	94	145	476	0%	2%	3%
	NL	31	80	145	1103	5%	74%	79%
	PL	53	99	145	328	1%	40%	41%
	RS	43	99	145	433	0%	13%	13%
	SI	42	89	145	647	19%	7%	26%
	SK	40	83	138	13	2%	2%	4%

Figure 7 depicts the 2050 power generation mixes of all reference countries. As 2050 these generation mixes feature high shares of vRES and vRES production varies throughout the year, due to seasonal weather variations, this will also affect the monthly generation and prices in each country. Figure 8 shows that, compared to 2020, 2050 generation and price profiles feature much wider fluctuations. In Spain and Hungary, solar generation is substantially higher in 2050 compared to 2020, in particular in summer. Wind fleets appear to generate more power in winter, when average winds are stronger. On the monthly level, it is noticeable that solar and wind fluctuations tend to compensate each other, leading to relatively stable power prices in Spain for instance (except for the high-demand months).

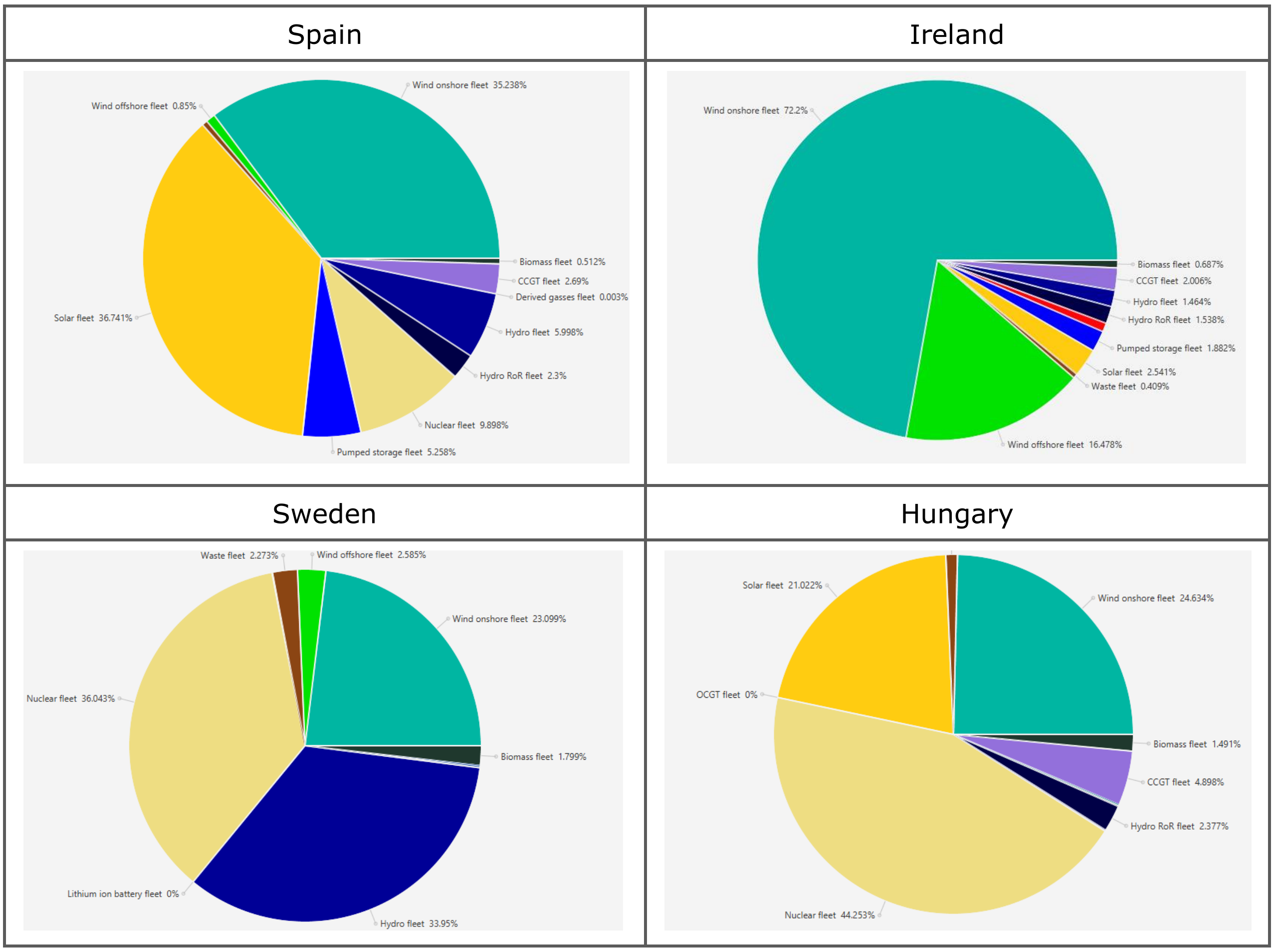


Figure 7 – Power generation mixes

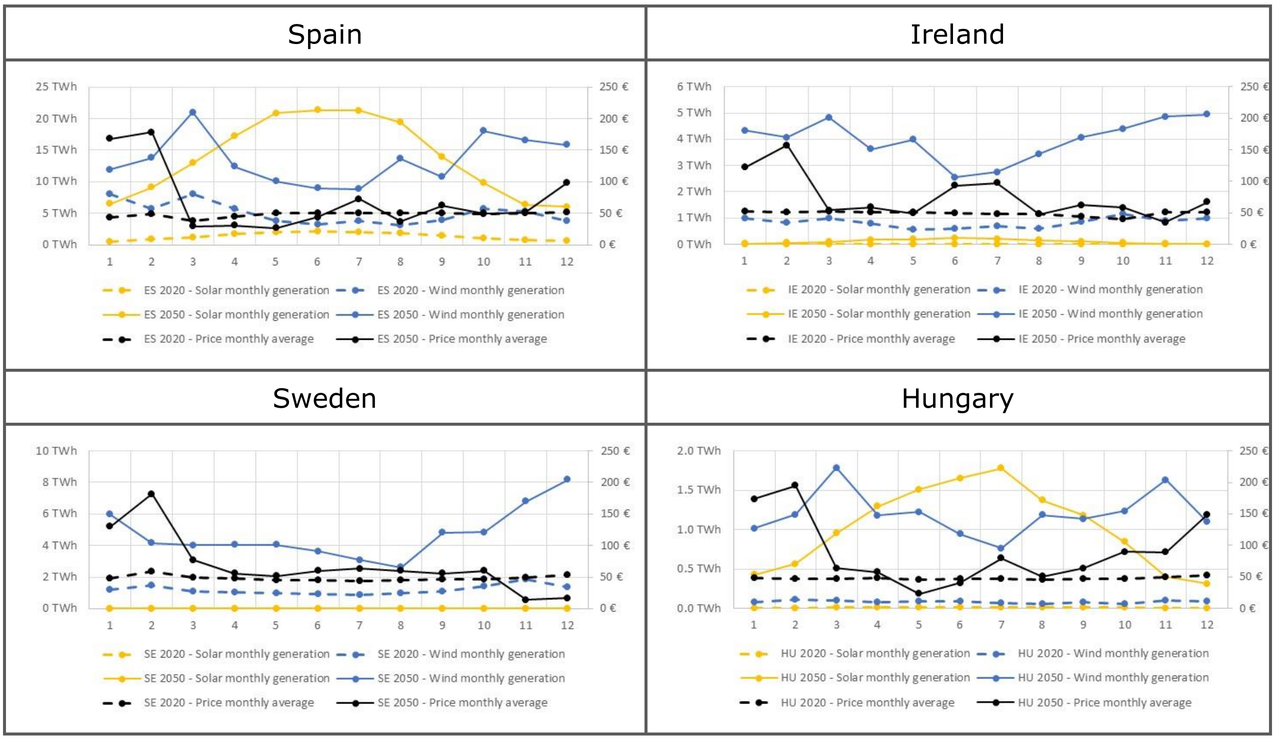


Figure 8 - Monthly averages of vRES generation and wholesale prices

5.2.2 Distribution of prices

As shown before, reference countries stand for clusters that do not feature the same power system structures. Figure 9 depicts the load-weighted average price as well the price spread, distinguishing minimum and maximum price as well as the first and third price quartile in each reference country. Although the number of hours with very low prices may vary substantially, in each reference country there are times when prices reach 0 €/MWh. Higher power prices appear in Hungary that features the lowest share of vRES. Lowest prices are experienced in Spain and Ireland (where the first quartile is equal to 8 €/MWh). In addition, Sweden's price variation remains limited thanks to its hydro power capacities.

In all four countries, load-weighted average prices (red dots in Figure 9) are higher than median prices, indicating that most power sold is more expensive than the median price. This recalls that, in most cases, periods of high consumption do not fully coincide with low variable costs power generation, thus leading to higher wholesale prices during periods of higher demand.

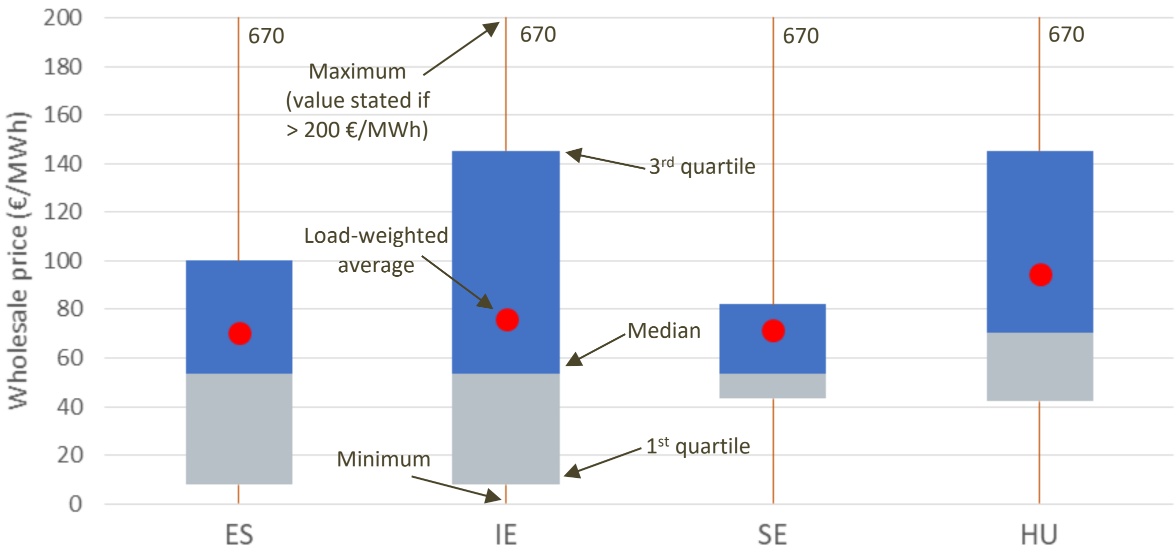


Figure 9 – Power price variation – values between 200 and 670 €/MWh are cut

2050 price duration curves exhibit pronounced differences in price variation and levels. Spain and Ireland experience high numbers of hours when prices are below 10 €/MWh, as illustrated by the relatively near-zero price plateaus in Figure 10. While both countries feature high vRES penetration, the Irish power prices spread (cf. Figure 9) is wider than in Spain. Figure 10 shows that 2050 prices in Ireland take off the 50 €/MWh threshold and reach the 150 €/MWh plateau in a higher number of hours, thus raising the third quartile upper boundary. In Sweden, the larger 50 €/MWh plateau translates into less variance (cf. Figure 9). Hungary, where prices occur least under the 50 €/MWh threshold, experience the highest prices.
2020 price duration curves (cf. Figure 10, dotted lines) appear to be very similar across countries and much flatter. Hours with near-zero prices are virtually inexistent and mean prices appear lower.

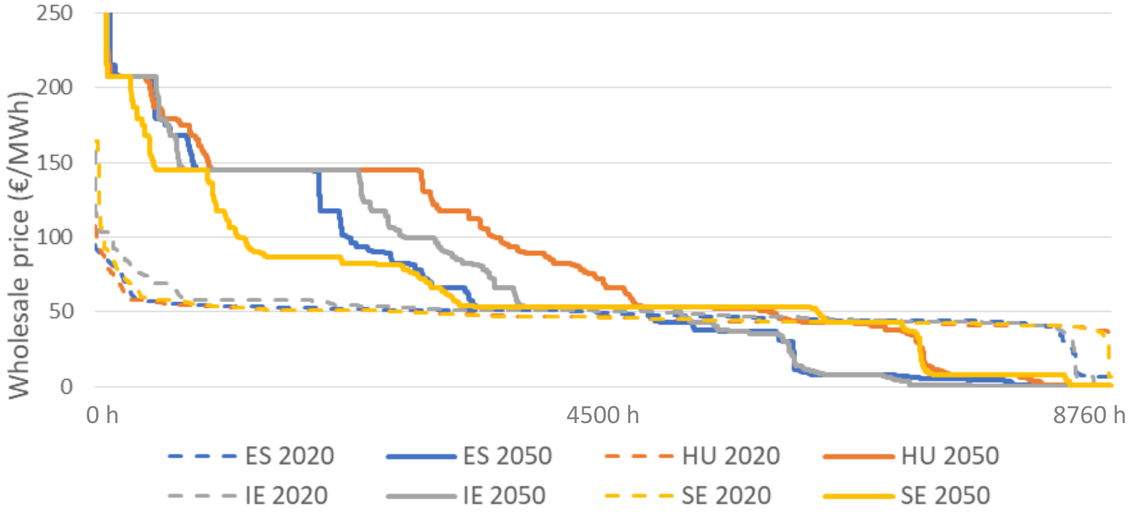


Figure 10 – Price duration curves

While price duration curves differ substantially between countries, price plateaus coincide perfectly. They are determined by technologies and fuel prices (see Section 4.2.2) and are thus largely independent of the country. Figure 11 displays the distribution of price events throughout the year and matches price spikes with the corresponding main technologies (or price echoes due to storage, materialising through smaller peaks).

Near-zero wholesale prices occur when vRES or nuclear fleets are marginal and set the clearing price. As long as power prices allow to produce synthetic gas cheaper than biogas (90 €/MWh$_{biogas}$ in the model), electrolysis and methanation facilities intensify demand, leading prices to rise. The arbitrage is economic until the 50 €/MWh threshold (given the electrolysis and methanation efficiency), which is why such a spike is clearly observable. Beyond, main price levels reflect biomass fleets as well as CCGTs and OCGTs variable costs and their storage echoes.

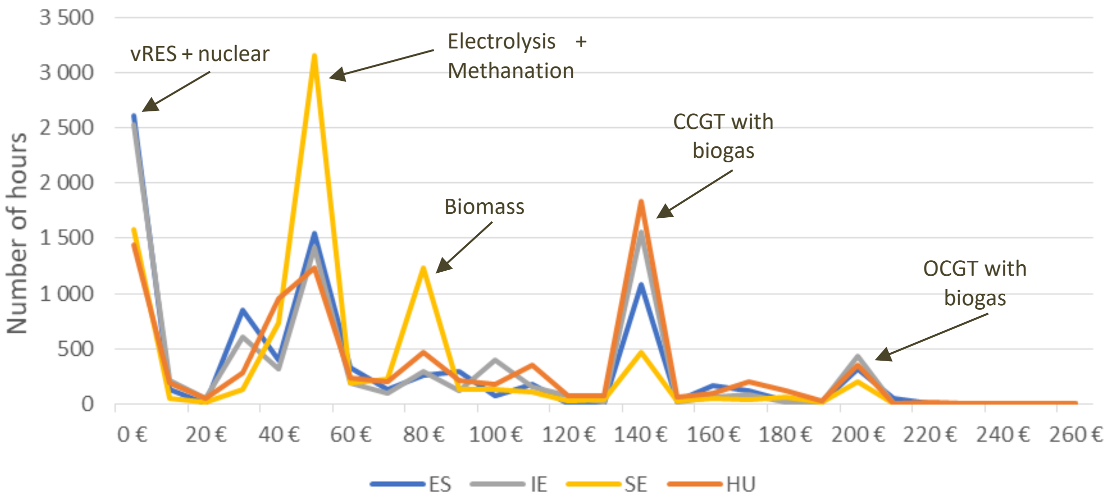


Figure 11 – Wholesale price distributions

5.2.3 Relation between RES generation and power prices

It has been described, so far, which price levels occur on power markets and how often. Now we try to understand how price variations are linked to vRES fluctuations. As described in Section 4.2.1, wholesale prices and power generation levels are dependent through the merit order mechanism. In order to assess this relation, the *residual load* is computed as the difference between system load and vRES generation. For each of the four reference countries, *Figure 12* displays mean daily profiles of the system load (blue lines), the residual load (grey lines) and the wholesale price (orange lines).

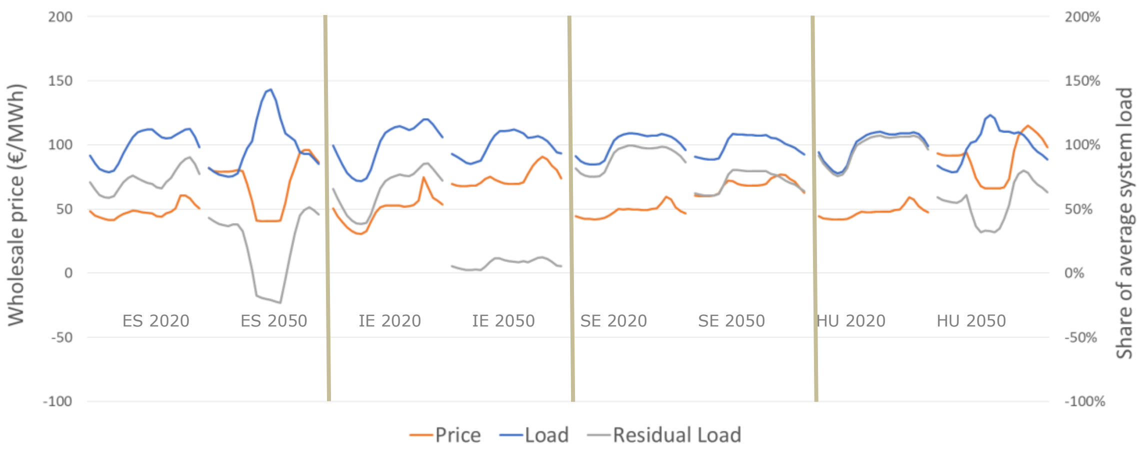


Figure 12 – Mean daily price, load and residual load profiles

In each of the four reference countries, daily load profiles change to varying degrees between 2020 and 2050. In particular in Spain and Hungary, the deployment of demand-side flexibility mechanisms implies load shifting to times when power is cheaper, creating a new load peak in the 2050 load profile at midday, when solar generation is highest.

However, these increases in demand (up to 40% in Spain compared to the 2020 profile) do not represent any additional tension on the market. Indeed, in both Spain and Hungary, midday demand peaks are actually a consequence of system smoothing mechanisms. At these periods, high solar generation leads to a market price reduction which flexibility mechanisms try to exploit by shifting demand (cf. the residual line in Figure 12, grey lines). In certain cases, like Spain, system flexibility is even insufficient to fully compensate vRES generation (i.e. to smooth the residual load), and the residual load turns negative, leaving room for low-cost power export.

As described earlier, price profiles (Figure 12, orange lines) reflect residual load variations through the merit order mechanism. This effect is even neater in 2050 Spain and Hungary where high solar penetration exacerbates daily residual load fluctuations. In Ireland, wind fleets do not have significant daily patterns, thus contributing to a smoother residual load profile. In 2050 Sweden, hydro power capacities facilitate the balancing of residual load fluctuations (resulting from both vRES generation and demand variations). This allows the country's mean price profile to be more stable than its residual load actually is.

Seasonal behaviours of wholesale prices encapsulate valuable information for the understanding of vRES generation and demand fluctuations across the year (cf. Figure 13). In Spain and Hungary, where solar installed capacities are sufficient to drive market prices, midday variations are deeper in July, when solar irradiance is at its peak, than in April and October and virtually inexistent in January. Especially in Hungary, lower demand during week-ends decreases residual load and therefore leads average midday prices to approach zero even closer than on working days. In Ireland and Sweden, where wind power represents a high share in the generation mix, prices fluctuate less. Indeed, as Figure 8 shows, wind generation is more evenly distributed throughout the year and the day. As a consequence, price variations are more limited. Overall, January wholesale prices display higher average levels, reflecting demand's sensitivity to outside temperatures.

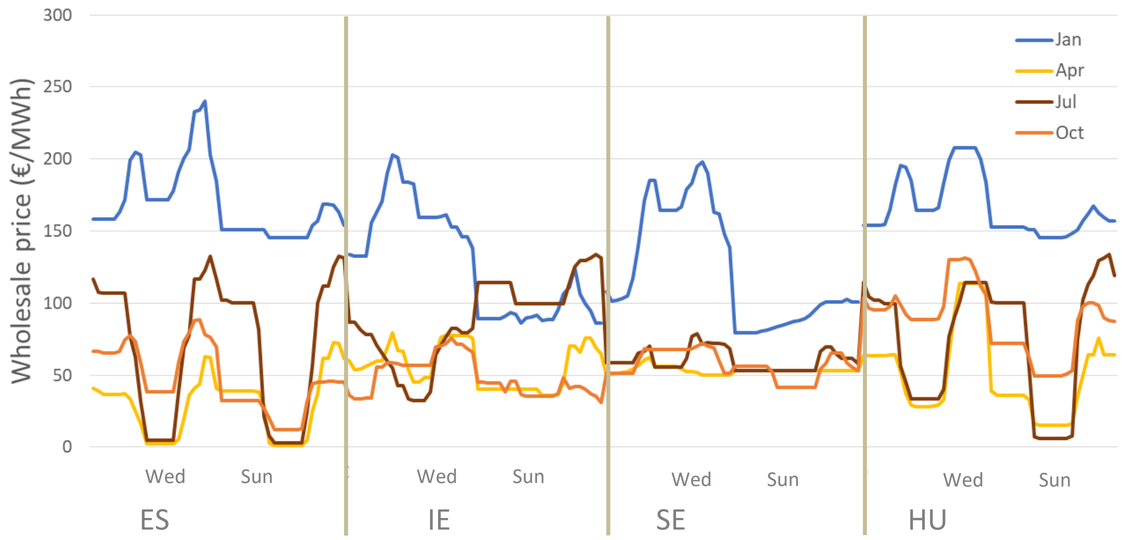


Figure 13 – Seasonal and intra-week mean daily price profiles variations

5.2.4 PRICE DIVERGENCE BETWEEN COUNTRIES

Price variations described earlier reflect discrepancies in terms of merit order structure and demand profiles between countries, resulting in differences in price profiles. Now, the focus is set on price divergences between adjacent countries, which have a significant impact on imports and exports flows. To do so, we compute the average of hourly price differences (in absolute terms) over the year (cf. Figure 14). The study reveals a series of major spreads.

	AT	BA	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GB	GR	HR	HU	IE	IT	LT	LU	LV	ME	MK	MT	NL	NO	PL	PT	RO	RS	SE	SI	SK
AT					3		4	11									13		19														12	
BA																10							1								1			
BE													11	22							6					5								
BG															3									12						9	17			
CH								11					14						19															
CY																																		
CZ								10																				29						3
DE									15				13								2					7	30	30				28		
DK																										14	16					14		
EE												7										0												
ES													14																1					
FI																											5					2		
FR														26					26															
GB																		11								20	37							
GR																			21					14										
HR																	0		10												10		1	
HU																														13	11		2	12
IE																																		
IT																							17		58								8	
LT																						1						28				9		
LU																																		
LV																																		
ME																															2			
MK																															5			
MT																																		
NL																											29							
NO																																3		
PL																																35		30
PT																																		
RO																															14			
RS																																		
SE																																		
SI																																		
SK																																		

Figure 14 - Mean price divergence between neighbouring countries

Italy presents significant price differences with most its neighbours: France, Greece, Austria, Switzerland and Malta (to which it is the only linked country). In the METIS-S1-2050 scenario optimisation, according to Figure 15[15], all available projects for interconnector reinforcement with Italy's neighbouring countries (based on the most favourable grid expansion scenario from TYNDP 2018 (ENTSO-E, 2018)[16]) were fully exploited. Hence, the country's ability to leverage interconnections in order to absorb generation and demand variations is limited, resulting in important spreads with neighbours.

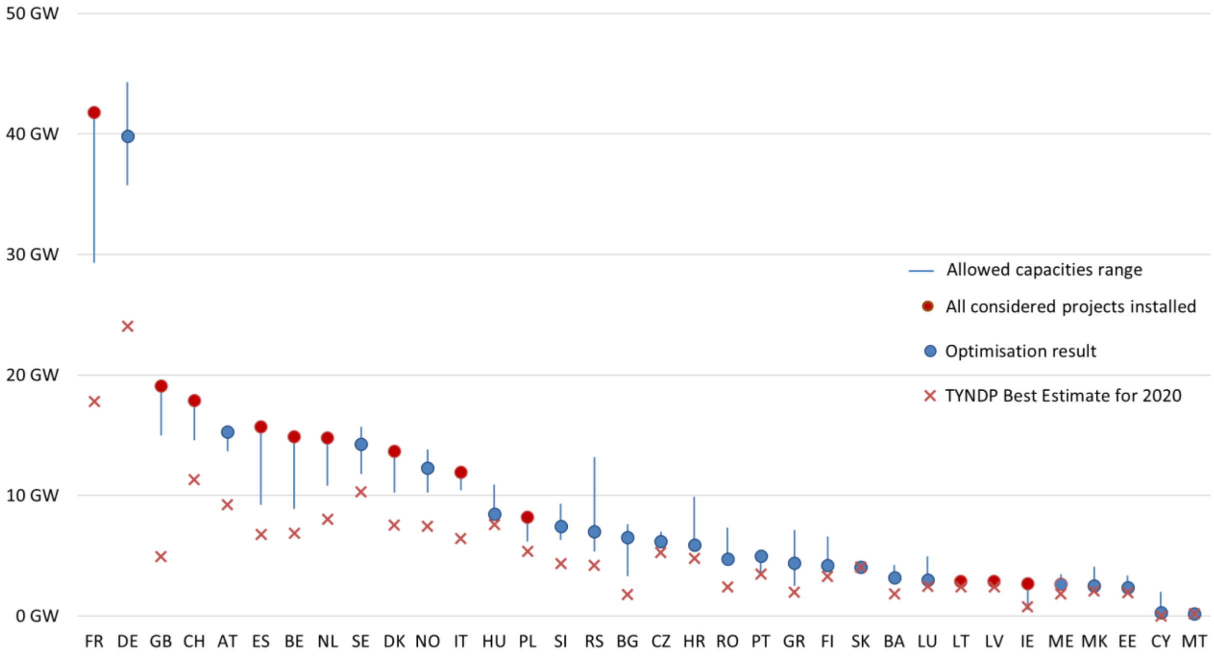


Figure 15 - Optimised export capacities (available range, optimised value, orange when upper bound reached)

In the same vein, power prices in Poland are remarkably different from those in neighbouring countries (Czech Republic, Germany and Lithuania). The country suffers likewise from limited interconnection capacity, and its geographical position (cf. Figure 6) between PV-intensive countries (Sunny cluster, among which Germany) and more balanced northern power systems (Nordic cluster) exacerbates price spreads.
These different merit order structures result in uncorrelated price variations between Germany and its neighbours Norway and Sweden as well, although interconnection facilities are dimensioned without any saturation. This fact illustrates that installing larger transmission capacities would have been uneconomic, although power prices would have been smoothed (see Section 4.2.2).

The red crosses in Figure 15 indicate the interconnection levels from TYNDP's Best Estimate scenario for the year 2020 as a proxy for the current situation. It becomes apparent that interconnector capacities in some countries more than double compared to today's levels.

[15] Further analysis of the interconnector investments in comparison to national RES generation and the European Commission's interconnection targets are outlined in METIS study S1 (Artelys, 2018).

[16] As the TYNDP 2018 does not contain CAPEX data, this information for the individual lines is based on TYNDP data (ENTSO-E, 2016).

6 Evaluation of asset revenues and weather-related revenue variability

As vRES generation is highly dependent on weather, we described above that, in a high vRES penetration environment, wholesale prices may fluctuate widely along the year, across different timescales (seasonal, monthly, daily, hourly variations…). Hence, since climate varies from a year to another, the extent to which producers' profitability and ability to recover their fixed costs each year is expected to fluctuate.

6.1 Assessment framework

We conduct here, for a selection of technologies, an assessment of their revenues' weather-sensitivity. To do so, ten weather test cases are run and compared, on the same power system. These test cases differ by their vRES generation[17] and demand, both in terms of profiles and yearly levels (cf. Figure 16), as some of the consumption posts are highly weather-sensitive as well (e.g. residential heating).
The Test Case 5 is selected as the Capacity Optimisation environment and we optimise all assessed technologies except vRES. Then, without modifying installed capacities, a dispatch optimisation is run on the nine other test cases. As a result of the optimisation, in the Test Case 5, optimised technologies' surplus strictly covers fixed costs.

The selected technologies to be assessed are the following:

- OCGT and CCGT peak generation capacities,
- Pumped hydro storage and lithium-ion batteries,
- Electrolysis facilities,
- Solar and wind power fleets.

Test Case 5 in comparison to all other weather years

The Test Case 5 is selected for being a particularly challenging weather year from a power system point of view. As shown on Figure 16, it features low vRES generation and high power demand. Hence, stress on supply-side flexibility assets such as gas peakers, storage and electrolysis facilities is set to increase. By choosing this test case for capacity optimisation, we avoid an excessive occurrence of loss of load that would distort the analysis. This translates into a more conservative estimation of revenue expectations as the installed plants are slightly over-dimensioned.

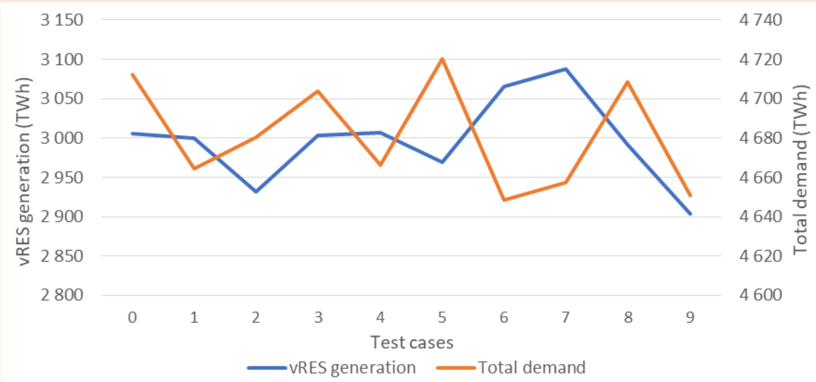


Figure 16 - vRES generation and demand comparison over test cases

[17] Hydro inflow is the same across all test cases.

6.2 Weather-related price variations

As Figure 17 (right hand-side) shows, in all four reference countries, Test Case 5 features one of the highest mean power prices. Comparative price duration curves (left hand-side) reveal that these average variations essentially lie in the length of the near-zero variable cost plateau. Weather variations entail vRES generation fluctuations. In less favourable years, times when vRES generation is sufficient to meet demand become less frequent and the near-zero plateau shortens to the benefit of the mid-merit plateau (see Section 4.2.2). As a consequence, considering others plateaus keep roughly the same length, mean power prices rise.
Swedish mean power prices are very low compared to the Test Case 5. When weather conditions are favourable, the access to flexible hydro capacities allows to benefit from low variable cost units (renewables and nuclear units) most of the year. On the other side, when renewable generation is particularly low, prices increase significantly (as shown by the results in Test Case 2).

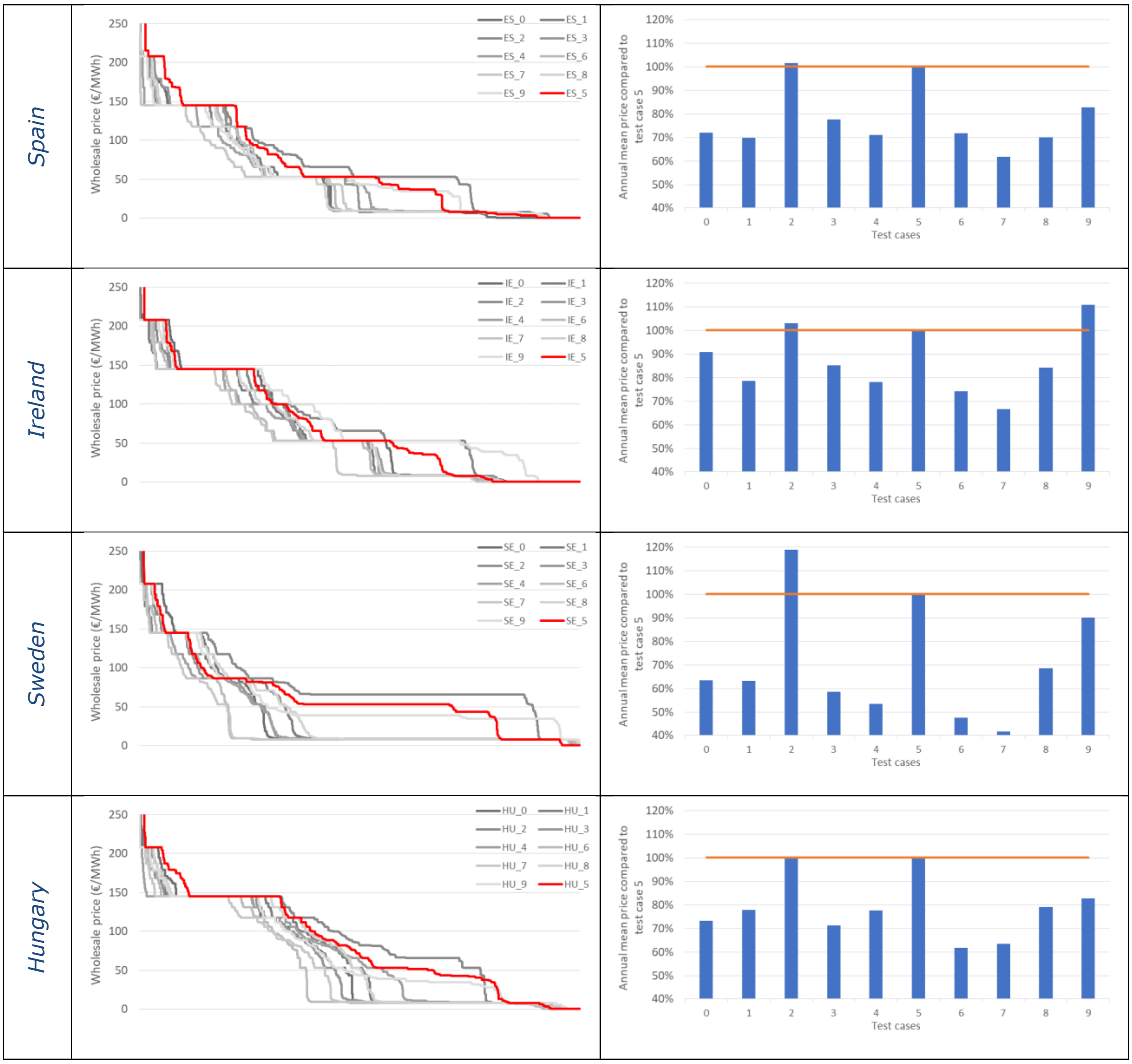


Figure 17 - Price variations over test cases

6.3 Weather-related revenue risks

As weather variations lead to wholesale price fluctuations, we assess the variance of selected technologies' ability to recover their fixed costs. As described in Section 6.1, the capacity of selected technologies was optimised under Test Case 5 before simulating the dispatch of all assets across all ten test cases. As such, in the Test Case 5, their surplus strictly equals their fixed costs (cf. Figure 19).

In the following, we assess surplus variations within clusters and, for every technology, we focus on a specific country's situation, disentangling unit margin (mean infra-marginal rent per MWh produced) and production volume, whose product results in surplus.

6.3.1 Impact on vRES generators

Although Spanish solar generation varies only marginally across the different test cases (cf. Figure 19), solar unit margins are subject to important changes. This can primarily be explained by the fact that solar PV generation is much more concentrated to a limited number of hours. Figure 18 shows the generation-weighted distribution of capacity factors. A (x,y) point on this graph means that y% of the annual production is generated at hours with a capacity factor x. It turns out that wind generation is relatively equally spread across the occurrence of the different capacity factors, while bulk PV generation is concentrated to the hours when PV generation is highest (with 37% of the generation taking place within 800 hours). As these hours also represent periods with low residual demand, adding new generation makes the prices drop during this time slot, and the PV surplus is strongly impacted. Overall, PV surplus can decrease by up to 40% (cf. upper left graph of Figure 19). Wind fleets, whose production is more evenly distributed over time, can capture higher prices during mid-merit hours. Although production varies up to 20%, more stable unit margins compensate and, overall, surplus variations are less pronounced than for solar panels.

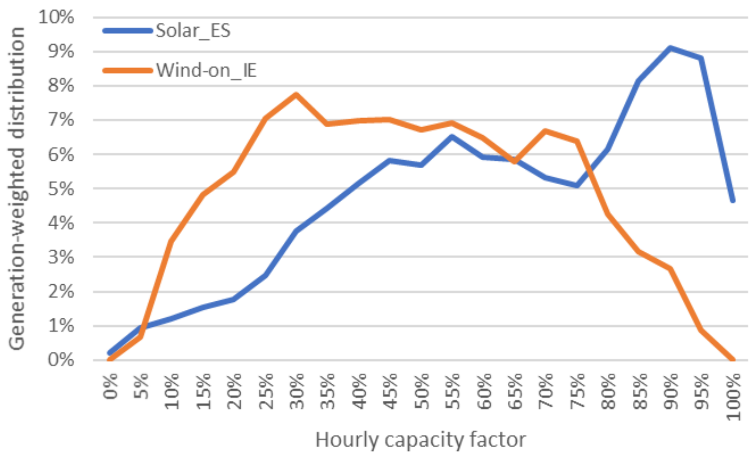


Figure 18 – Distribution of hourly capacity factors under Test Case 5, and related distribution of power generation

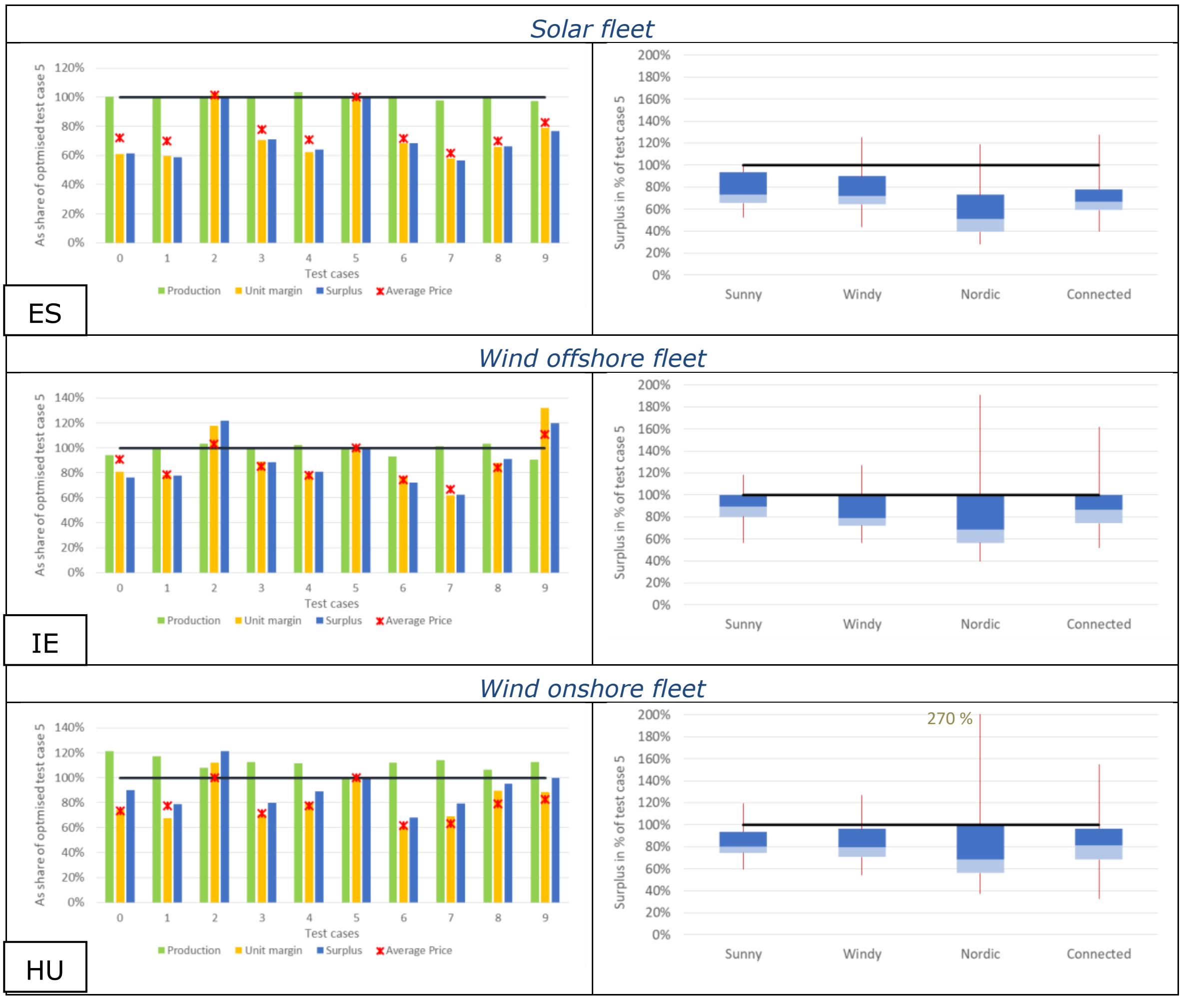


Figure 19 - Surplus variations over the 10 test cases - vRES generators

6.3.2 IMPACT ON FLEXIBILITY PROVIDERS

As expected, OCGT and CCGT revenues are very sensitive to weather variations. Whatever the cluster (cf. Figure 20[18]), levels of profitability fluctuate substantially (up to 50%). Detailed charts for the Irish case show that, in most test cases, prices decrease (materializing through red markers). These surplus variations are the results of both reduced levels of productions (green bars) and diminished unit margins (yellow bars). As detailed earlier, higher levels of vRES generation in favourable years help push gas peakers out of the merit order more often (with equivalent full load hours varying from 50 to 250 hours for OCGTs, 600 to 1 400 hours for CCGTs) and reduce times when even costlier technologies are needed to meet demand (cf. Figure 17). Hence, times when gas peakers produce without setting the clearing price, which are times when gas peakers pocket positive unit margins, decrease. As a result, average unit margins are reduced.

Storage technologies face more limited weather-related revenue risks. Although distributions of pumped hydro storage surplus across clusters display non-negligible variance, the Austrian example, that was selected because the dimensioned capacity did not reach any bound during the optimisation process, features much lower variations. This illustrates that boxplots variances are mainly due to differences between countries instead of weather-sensitivity. For both Austrian pumped hydro storage and Spanish batteries,

[18] No data for some clusters implies that no capacities of the respective technology category were added in the capacity optimisation.

surplus variations rarely exceed 20% (cf. Figure 20, left hand-side). Hence, storage business models rely more on price spreads than average price levels.

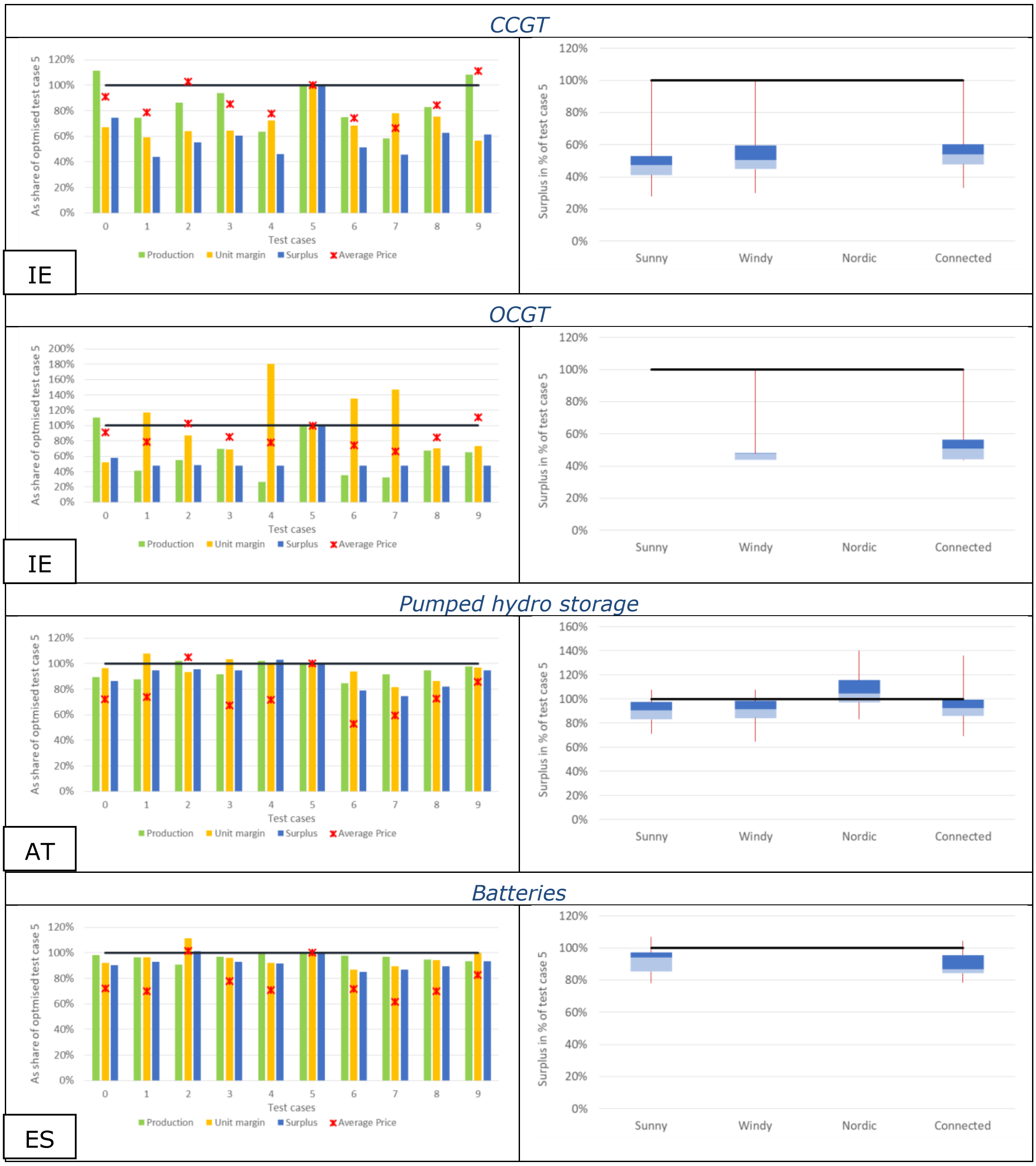


Figure 20 - Surplus variations over test cases - Flexibility providers

6.3.3 Impact on flexible consumers

Electrolysis' revenues are highly uncertain, since production levels depend on the ability to capture very low power prices. Indeed, as H_2 is sold at an independent price on a specific market, annual production and unit margins essentially rely on supply power prices. Figure 21 shows that lower power prices boost H_2 production while higher prices lead to its decrease (cf. test case 2). Hence, production and unit margin increase or decrease at the same time, which exacerbates surplus variations.

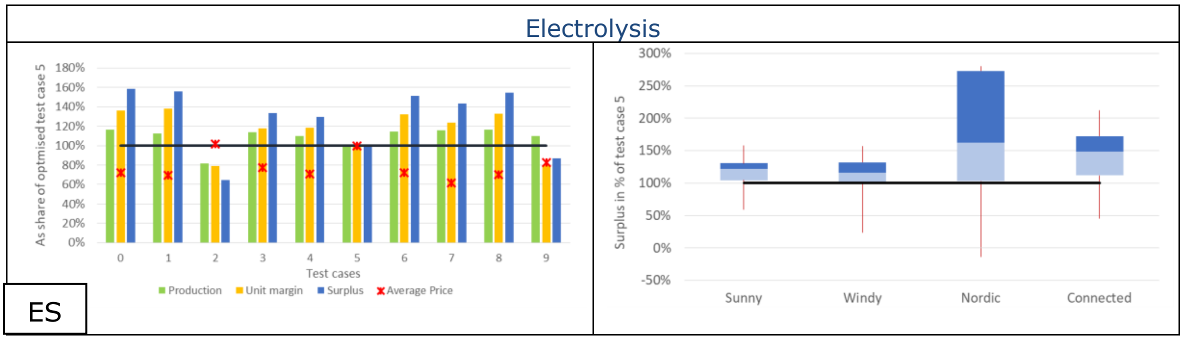


Figure 21 - Surplus variations over test cases - Flexible consumers

7 EVALUATION OF RISK EXPOSURE FOR NEW INVESTMENTS

Before financing their project, investors run a series of stress cases to assess the viability of the project for different evolutions of the power system. While relying by default on the national energy plan, variants on power mix and fuel prices are typically studied to ensure that the impact on prices and revenues remains limited.

In this section, we run similar stress cases: starting from the reference scenario, we modify the power mix, generate associated market prices and study the impact on revenues for different technologies.

7.1 ASSESSMENT FRAMEWORK

In addition to the quantification of weather-related revenue risks, five sensitivity analyses are realised to assess the impact of changes in the power system on the revenues.

Table 4 summarizes the different sensitivities:

1) Increased availability of system flexibility through more batteries

   Enhanced system flexibility smoothes the price volatility but at the same time tends to cut revenues of conventional flexibility providers. Significant deployment of low-cost storage capacities beyond today's expectations may occur for instance through the reutilisation of second-life batteries from electric vehicles, investments into decentralised storage linked to optimised self-consumption or batteries from electric vehicles (EV) becoming available to the market via vehicle-to-grid (V2G) concepts. We analyse a sensitivity with three times as much batteries as in the Base Case, adding some 33 GW of battery capacity with a storage capacity of 4 hours at full load. The additional capacities are allocated to the countries according to the installed PV capacities.

2) Drop in the price of biogas

   In the given scenario, biogas functions as benchmark fuel for synthetic gas (produced via power-based electrolysis and methanation) and serves as back-up fuel for peak-power generation. A change in the biogas price directly affects the competitiveness of synthetic gas, hence the utilisation and profitability of electrolysers and system flexibility. It also impacts the variable cost of gas units and consequently peak prices. The sensitivity analyses the impact of a 20% drop in the biogas price, down from 90 to 72 €/MWh.

3) Uncertain expansion of interconnector capacities

   Interconnectors facilitate the exchange between countries and may hence provide power generators access to additional markets, but also face additional competition with foreign generators. However, new interconnector lines require substantial investments and raise acceptability concerns. We assess the impact of a delayed interconnector reinforcement, with 20% less interconnector capacity than in the Base Case, that is a reduction of about 30 GW in bidirectional exchange capacity.[19]

4) RES deployment above expectation

   Due to their simultaneity in production, higher RES capacities tend to increase the occurrence of RES oversupply and low market prices during the hours of RES generation, thus lowering the market value of existing RES generators, also known as the so-called cannibalisation effect. In two separate sensitivities, the cannibalisation effect of solar PV and wind is analysed, by adding 10% of additional capacity, which equals 65 and 88 GW, respectively.

[19] Assuming a linear decrease across all lines.

Table 4 - Overview of the sensitivities to test risk exposure of new investments

Sensitivity	Short name	Low	Base	High
Base (default settings)	Base Case		X	
Batteries	Batt. +33GW		X	+200% (+33 GW)
Biogas price	Biogas -20%	-20% (-18 €/MWh)	X	
Interconnections	NTCs -20%	-20% (-30 GW)	X	
PV penetration	PV +10%		X	+10% (+65 GW)
Wind penetration	Wind +10%		X	+10% (+88 GW)

All sensitivities are calculated starting from the reference capacity mix and exclusively for the original weather year, i.e. Test Case 5.

7.2 PRICE VARIATION UNDER THE SENSITIVITIES

The assessment of wholesale prices reveals that all sensitivities imply a decrease in mean wholesale prices, except for the sensitivity with reduced interconnector capacities (cf. Figure 22): as expected, the addition of new generation or flexibility capacities tends to decrease prices. Yet, the extent to which the price changes compared to the base case, strongly depends on the individual country, the change in the sensitivities and the national power mix. The amplitude of price change is more pronounced in the case of increased RES capacities, and less intense in the cases of higher battery or reduced interconnector capacity.

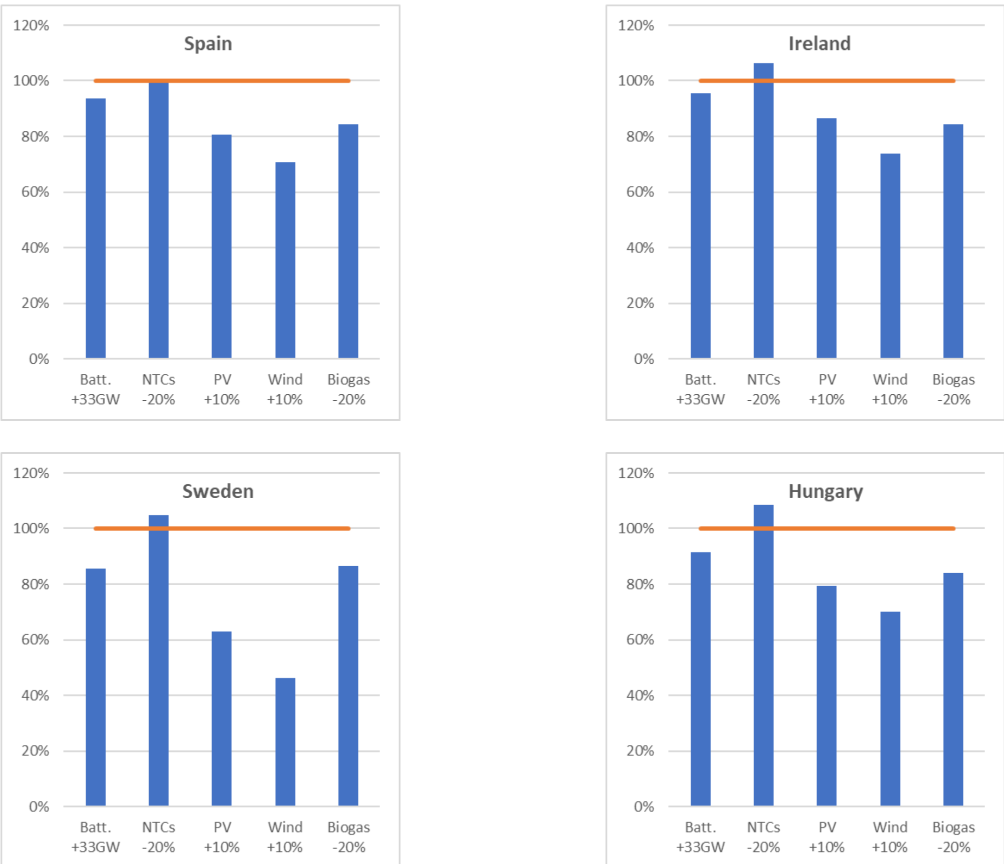


Figure 22 - Evolution of mean wholesale prices across the sensitivities

In order to better understand the effects in the different sensitivities, it is worth assessing the hourly price duration curve, shown in Figure 23 as an example for Ireland. The red line indicates the Base Case. Enhanced PV and wind capacities make more power generation with near-zero marginal generation costs available (meeting constant demand), shifting the entire curve to the left. A similar effect may be observed in the case of a lower biogas price on the mid-merit prices above 40 €/MWh, illustrating the switch from synthetic gas towards biogas for power generation and reduced electricity demand for electrolysis. More batteries imply an increased occurrence of low wholesale prices (see the black line most of the time below the red line at the right of the graph[20]). Reduced interconnector capacities (depicted by the grey line) exhibits fewer hours with prices around 50 €/MWh, as, with lower exchanges between countries, electrolysis capacity more rarely sets the clearing price. In the mid-merit and high price range, this sensitivity clearly exhibits higher prices as domestic generation is required to meet higher demand levels instead of making use from imports, driving up the average wholesale price level.

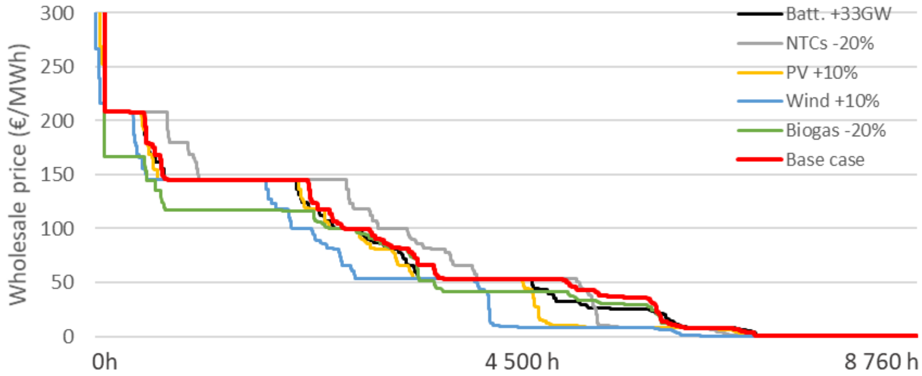


Figure 23 - Price duration curve from Ireland across the sensitivities

7.3 Risk exposure for new investments

The analysis of risk exposure to stress cases on the power system follows the methodology applied to weather-related revenue risks. Potential changes in surplus are split between the price and the volume components, with the first referring to the potential margin of one unit of power output (driven by the market price, depicted by the green bar) and the latter referring to the overall sales volume (driven by the overall dispatch, depicted by the yellow bar).[21] The surplus in the different sensitivities is compared to the original level in the Base Case.[22] In each of the subsequent plots, the change in the average wholesale price is illustrated by a red star in comparison to the price level in the Base Case.

7.3.1 Impact on vRES generators

A first look at the impact of enhanced RES capacities on the profitability of RES generators reveals that the surplus drops more significantly than the average market price (cf. Figure

[20] Typically, storage devices imply a decrease of peak prices and an increase in low price ranges. In the case of Ireland, the increase of demand due to batteries is relatively limited compared to RES surplus and thus does imply only a marginal change in the wholesale price. In total, the decrease of daily peak prices has more impact and the mean wholesale price decreases.

[21] Of course, the price and the volume component are not decoupled but a result from the overall dispatch optimisation. They are merely disentangled for the purpose of understanding.

[22] As stated before, for all assets subject to capacity optimisation the surplus matches exactly the annualised fixed costs (if no bounds are met). As RES capacities were no subject to optimisation in the underlying scenario, the change in surplus is expressed in relation to the original value under the Base Case.

24 and Figure 25). This holds in particular true for solar PV when increasing solar PV capacities. In the case of Spain (or Italy, as another country with high PV penetration), the mean market value (i.e. the production weighted average market price) diminishes by more than 30%, whereas the market price only falls by about 20% (cf. the gap between the yellow bar of the unit margin and the red star of the mean price level). This observation illustrates the cannibalisation effect of PV due to the high correlation of solar PV generation, even across larger geographic areas (e.g. at the country level).
It should be noted that the cannibalisation effect is less pronounced in countries featuring lower penetration rates of the respective technology (see for instance solar PV in Ireland) and for wind power in general (see for instance the impact of 10% more wind capacities on the wind surplus in Ireland), due to higher stochasticity in wind patterns across the entire country.

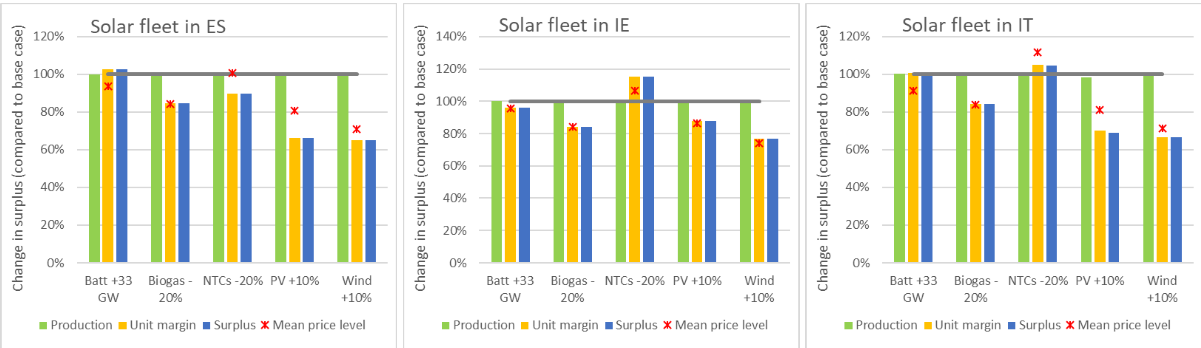


Figure 24 - Change in solar PV surplus across sensitivities

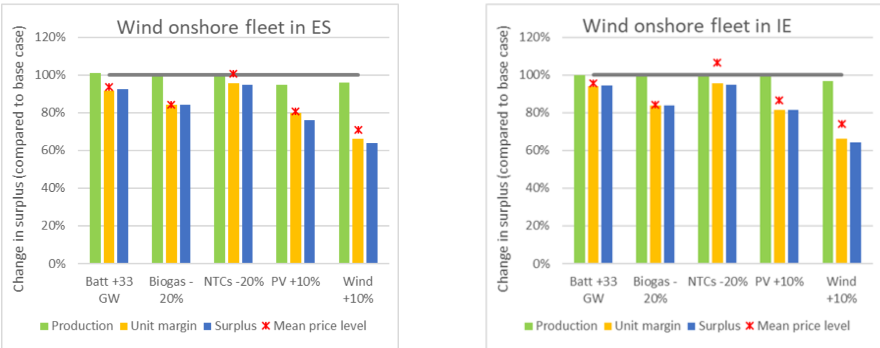


Figure 25 - Change in wind-onshore surplus across sensitivities

It is commonly assumed that the increased availability of battery storage in the power system may help to increase RES revenues, in particular for solar PV generators. However, as indicated by Figure 24, the drop in the average market price compensates the better valorisation during midday hours. As a result, the total revenues of PV units are not enhanced by the additional storage capacity. This effect is illustrated in Figure 26 for solar PV generation in Italy. The shift of generation from midday to morning and evening hours by means of additional batteries may slightly increase the market price level and thus RES market value at midday hours - which raises overall revenues during these hours. However, the reduction in power prices during morning and evening hours diminishes the market value much more substantially, leading (despite lower production levels) to an over-proportionate decrease in revenues, which cancels the benefits.

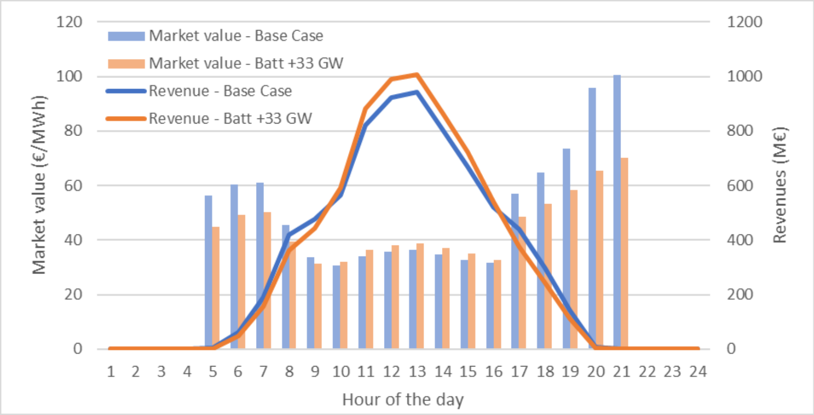


Figure 26 - Revenues vs market value of solar PV in Italy under the Base Case and the Battery sensitivity

The impact of a reduction in the biogas price affects solar PV and wind power to a similar extent. The drop in the wholesale price directly translates into a drop in the unit margin and thus the profitability.

The picture is more heterogeneous with respect to the reduced interconnector capacities. If the wholesale price in the neighbouring countries exceeds the domestic price during hours of RES generation, reduced NTCs imply a reduction in RES surplus (see for instance the case of Spanish solar production that cannot benefit from higher French power prices, as shown in Figure 27). In contrast, if power prices in neighbouring countries are lower, RES generators are protected from competing imports and the surplus is raised (e.g. solar fleet in Ireland).

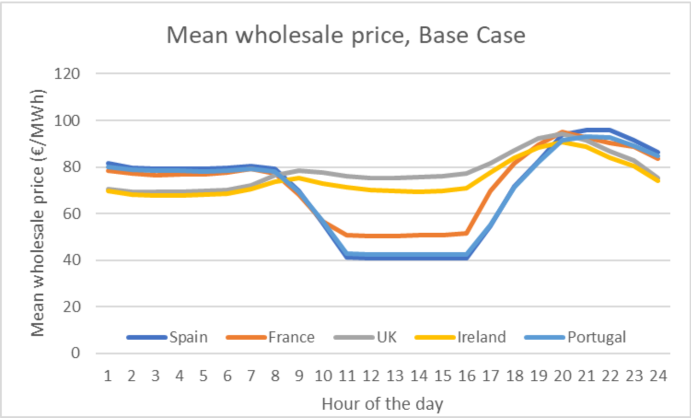


Figure 27 - Mean hourly wholesale price in selected countries in the Base Case

7.3.2 Impact on flexibility providers

The surplus from flexible power producers, such as OCGTs and CCGTs, suffers particularly from higher RES capacities (cf. Figure 28), as the availability of additional power generation at near-zero marginal costs push gas-based power generation out of the market and the lower prices reduce the revenue for each unit of generated electricity. Hence, in the given sensitivities, the revenues drop by more than 40%.

With respect to a reduction in the biogas price, the effect differs between the two technologies. OCGTs experience a slight surplus increase from lower gas purchase costs, as lower electricity generation costs (compared to other peak generation technologies) allows to slightly increase their production and their unit margin. In contrast, when OCGTs set the price, as the price level drops, CCGTs exhibit a reduction in the unit margin[23] and thus in overall surplus.

[23] CCGTs also benefit from lower gas purchase costs. However, as OCGTs feature a lower conversion efficiency than CCGTs and thus provoke an over-proportionate reduction in the power price compared to the reduction in the CCGT electricity generation costs.

In the sensitivities with altered capacities of competing flexibility solutions, namely batteries and NTCs, the conclusion is relatively straightforward: higher flexibility (through more batteries) decreases price spreads and thus reduces the production and the surplus of OCGT and CCGT units; lower flexibility (i.e. less NTCs) prevent electricity imports in peak hours and thus drive up the generation and the surplus. However, if less NTCs reduce the coupling with a market featuring higher mean electricity prices, this results in revenue losses and thus a reduced unit margin (for instance between Ireland and the UK, cf. Figure 27).

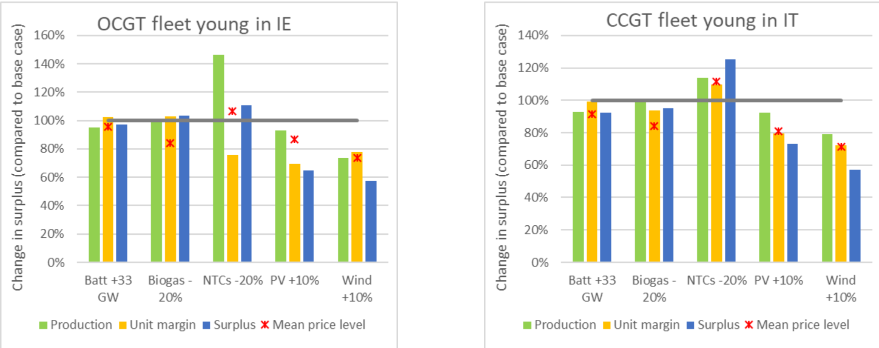


Figure 28 - Change in OCGT/CCGT surplus across sensitivities

The impact on revenues for storage technologies, i.e. pumped storage units and batteries, is similar to the one of flexible generators but not identical. High RES capacities than expected lower purchase as well as selling prices, but tends to lower the price spread (cf. the yellow bars depicting the unit margin in Figure 29). At the same the rise in RES capacities may increase the utilisation of storage units (especially in the PV sensitivity), which may partially offset the reduced unit margin.
In contrast to OCGTs, storage units suffer from a reduced biogas price which lowers selling prices (in peak hours when the price is set by OCGTs or CCGTs) and impacts less purchase prices in off-peak hours.
Higher battery capacity than expected deteriorates the surplus of storage units. This holds in particular true for batteries, where a cannibalisation effect may be observed that is comparable to the one of PV generators, lowering the surplus by more than 30%, while the market price is reduced only by 10%.
In turn, lower NTCs reduce flexibility and thus raise the surplus of storage units.

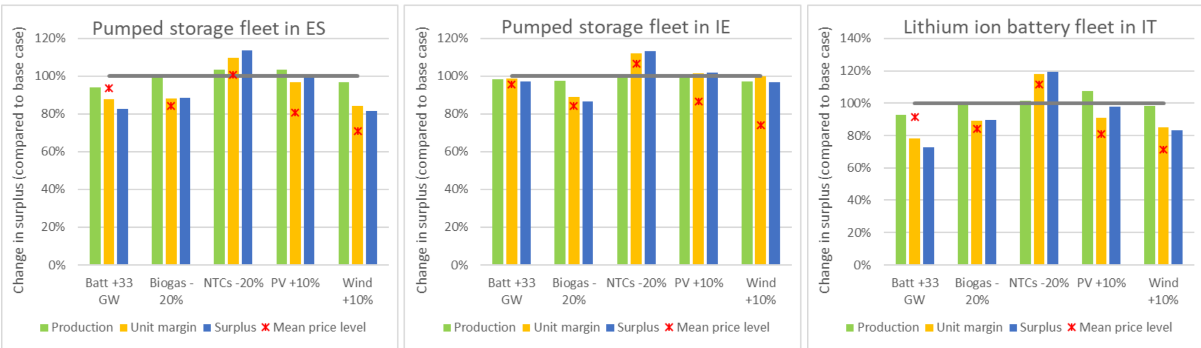
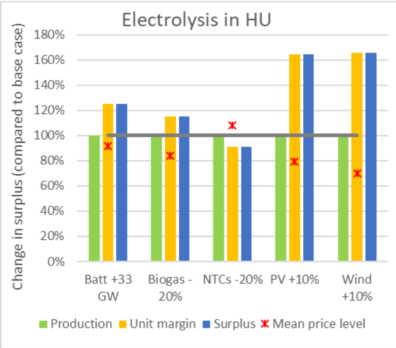


Figure 29 - Change in storage surplus across sensitivities

7.3.3 Impact on flexible consumers

The impact of the stress cases on the surplus of flexible electricity consumers is illustrated on the example of electrolysis. Two cases are presented: first, countries where electrolysis only produces hydrogen for the purpose of the industry and transport sector (meeting a fixed hydrogen demand volume, e.g. in Hungary) and second, countries where the electrolysers' hydrogen production may also be used in a subsequent methanation process to generate methane for power generation and as back-up for heat pumps (e.g. in Spain).

In the second case, the hydrogen demand is subject to the actual methane production and may vary accordingly.
Analysing the electrolysis surplus across the sensitivities in the first case, the outcome is quite intuitive (cf. Figure 30): the lower the mean electricity price, the higher the unit margin and thus the surplus (the production volume remains constant) and vice versa.
In the second case, the production volume may also vary, which amplifies the total impact. The result is yet highly dependent on the country power mix and its interconnection capacity. In the case of reduced interconnector capacities, electrolysis may benefit from enhanced availability of domestic RES generation (which is not exported abroad, cf. lower power prices compared to the Base Case at the right end of the price duration curve in Figure 23) and thus from a higher unit margin, even though mean market prices tend to increase.



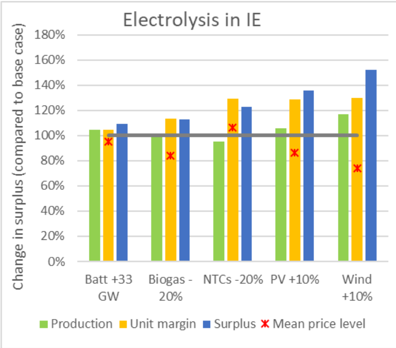


Figure 30 - Change in electrolysis surplus across sensitivities

7.4 Evaluation of risk hedging strategies

After identifying revenue risks via stress cases and sensitivity analyses on the power system, investors traditionally look for risk hedging strategies to cover these risks (cf. Section 4.3). In the following, selected hedging strategies are evaluated for the solar PV asset in Spain (as an example) under the different sensitivities.

The blue bars in Figure 31 recall the initial variation in surplus under the sensitivities if no risk hedging strategy is applied (see also Figure 24).
A **power purchase agreement (PPA)**, today's most common option for risk hedging, equals a take-or-pay agreement between the RES generator and an electricity customer. The PPA stipulates a fixed price for the generator allowing him to recover his capital expenditures while transferring the revenue risk to the counterparty. The customer in turn may sell surplus electricity and purchase lacking electricity supply on the market.
The PPA is modelled by assuming that a RES generator enters a PPA with a customer that features an annual power demand identical to the overall PV generation of the RES generator and that the electricity customer's demand follows the profile of the national electricity demand. From the perspective of the customer, the Base Case serves as benchmark of profitability where he may generate revenues by selling the PV generation at the given market value and pays for purchasing electricity at the market to meet his consumption. For the different sensitivities, it is calculated how the change in market prices affects PV revenues and purchase costs. The net increase/decrease illustrates the extent to which economies in power purchase costs may compensate for reduced PV revenues (and vice versa). The relative change is depicted by the percentage values in Figure 31.
In the case of dropping electricity prices (due to a lower biogas price or higher wind capacities), the customer may benefit from lower purchase costs[24] and the related savings (compared to the Base Case) make up for the potential losses the PV producer would have met. That is, this mechanism may cover risks related to a decrease in the mean market price but it works less effectively in situations of cannibalisation (i.e. the PV sensitivity), as

[24] In the present case it is assumed that the consumer features a load profile that equals the overall system load curve and that the consumer demand is fully met by solar generation (on an annual basis).

selling the PV surplus is restricted to hours with lowered market prices, implying relevant losses which exceed the savings related to reduced power purchase costs. This is also the reason, why a PPA has only a marginal impact on the surplus in the NTC sensitivity where market prices increase. The reduced interconnector capacity implies less exports during PV generation hours, making drop the prices in these hours, while the overall price level rises in particular due to an increase in hours where no PV generation takes places. As a relevant part of the consumption takes place during these hours, power purchase costs partially rise and thus limiting the hedging opportunities. Linking RES generation with a consumer featuring a flexible demand profile (or being equipped with storage) allow to shift demand into hours with low prices or when RES generation is highest (cf. next paragraph).

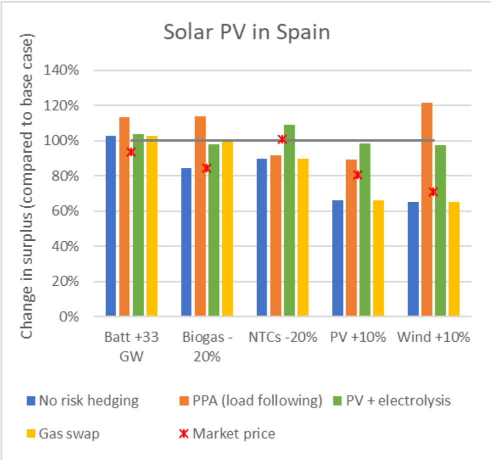


Figure 31 - Impact of risk hedging strategies across sensitivities

Another strategy is to **link RES generation to a power supply contract** of a distinct power end use. The previous assessment of revenue risks revealed that RES generators in general suffer from a drop in prices whereas consumers (such as electrolysis) benefit, and vice versa. Thus, settling a contractual agreement between both parties may hedge the risk for both. In the example shown in Figure 31, solar PV generation is linked to electrolysis by a 1:1 capacity ratio. In terms of modelling, the change in PV revenues and electricity purchase costs are analysed (similar to the PPA). However, in this case the customer's load profile equals the demand curve of the electrolysis and it is subject to optimisation. That is the electrolysis load responds to market price signals. Consequently, in case of declining market prices the energy purchase costs may be reduced over-proportionally by shifting demand into the hours with most important price reduction. As shown in Figure 31, potential revenue losses and gains are nearly perfectly offsetting in the different sensitivities, leading to a total surplus that is comparable to the Base Case. Indeed, the actual outcome of this strategy depends highly on the ratio between generation and consumption, as well as their individual profiles. In the present case, the match works particularly well as the power consumption profile of electrolysis is highly flexible. Consumption may thus be shifted into hours of low electricity prices or high generation from the contracted RES counterparty. That is, broadly speaking the combination of a generator with a consumer featuring demand side flexibility (or being equipped with a storage device) enhance the effectiveness of the risk hedging strategy.

Given the short-term availability of power electricity swaps, **gas swaps** represent an interesting alternative to hedge long-term price risks. In the present analysis, merely the biogas price sensitivity reflects a change in the gas price. The change in the overall surplus is calculated as change in the PV surplus, corrected for the potential losses/gains related to a change in the gas price compared to the Base Case. Thus, as illustrated in Figure 31, reduced PV power market revenues driven by the lower gas price (which drives market prices down) are counterbalanced by savings on gas purchase costs. The extent to which risks are hedged depends in particular on the ratio between power generation and gas purchase. In all other sensitivities, the revenue risks remain unchanged as there is no variation in the gas price.

The **portfolio diversification** through the combination of RES generation capacities **with storage** units proves useful only to a limited extent as batteries suffer from similar revenue risks than the RES generators (cf. Section 7.3.2).

8 CONCLUSIONS AND OUTLOOK

For a 2050 scenario with high renewables share and flexible demand, the study assesses the wholesale market prices and the related revenues for different assets (RES, flexible generation, pumped hydro and battery storage, electrolysis). Based on the quantification of revenue risks related to weather variation and to a series of investment stress cases, simulated as changes in the power mix or fuel prices, different risk hedging strategies are tested and evaluated.

This study shows that a high RES share translates into an important number of hours with near-zero market prices as well as an increased price variation throughout the day (triggered by bulk PV generation) and a larger price range. In the given scenario, prices are increasingly often set by price-elastic consumers (e.g. electrolysers) that may shift the timing or even alter the volume of their demand. Reasonably elevated price levels allow market participants to realise market revenues that may cover their investment costs.

Asset revenues are determined for different weather years, reflecting a change in RES generation (except hydro inflow) and demand volume and profile. Weather-related revenue variation affects in particular peak generation units (up to 50% surplus variation) and RES (in particular solar PV), due to significant variations in prices between years with or without favourable RES resources. Investment risks related to power system stress cases reveal a particular risk amplitude for RES generators and storage providers. In the case of rising capacities of competing projects, revenues of individual projects diminish over-proportionally compared to the market price due to a concentration of production in hours mostly affected by competition-driven price reduction (cannibalisation effect). This is particularly true for solar PV and batteries.

Classical risk hedging strategies include power purchase agreements (PPA) or gas swaps. Their evaluation shows that the first does not cover the risk of cannibalisation, while the latter is inappropriate in case of overcapacities in the power market. Combining a renewable generator with a consumer featuring a flexible demand profile (or being equipped with a storage asset) proofs the most effective strategy to hedge the risks related to changes in the power market.

As part of the uncertainty in power market evolution is triggered by government decisions (e.g. with respect to technology phase-out decisions, introduction of a carbon price, or set-up of renewables targets), the investors should not be left alone with these risks. Public risk hedging strategies could represent effective measures for risk control. This may include PPAs with public services as counterparty, electricity price swaps emitted by public authorities, the introduction of a CO_2 floor price or enhanced system flexibility via the promotion of DSR and storage.

This study represents a first of its kind assessment of 2050 market prices and revenues. Consequently, the analyses might be further developed.

- The present analysis was limited to an assessment with exogenous RES capacities. A holistic capacity optimisation might allow a more robust assessment of investments in generation, storage, transmission and flexible demand assets.
- Further analyses could integrate the weather-driven variability in water inflow of hydro power plants as these may affect market prices in countries with high hydro power shares.
- The assumptions on the electrification of the transport and industry sector were exogenously chosen for the purpose of illustration. Assessing different degrees of electrification could reveal additional information about price setting and revenues in 2050 and reveal further information of the cost of decarbonising the European economy by means of electrification.
- Public risk hedging strategies are potentially subject to various juridical constraints and legal frameworks (such as EU state aid guidelines). A thorough assessment of the potential conceptual design of public risk hedging strategies taking into account the EU legal framework may shed additional light on the feasibility and implementation of the suggested strategies.

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