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Variable Renewable Energy Investment Conditions and the Role of Power Purchase Agreements in the Green Transition

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Abstract

Variable Renewable Energy Sources (VRES), especially wind power in Finland, play an essential role in achieving climate targets and enabling green growth. However, variable production causes system-wide challenges such as cannibalization, which pushes VRES market values down when their capacity increases. The market value for wind power has been below the required level to recover costs and therefore investing in variable renewables is currently challenging.

This thesis addresses the challenges in VRES market integration and describes Power Purchase Agreements (PPAs). PPAs have emerged as a new hedging instrument to secure investments and fulfill the needs of green electricity procurement. Through a literature review, PPAs are discovered to be a wide group of bilateral agreements, which can help consumers contribute to the green transition and make the projects bankable. So far, the largest renewable energy investors have been large technology companies with ambitious sustainability targets, which highlights the role of these targets driving PPAs. Pay-as-produced PPA structures are used the most, but it is expected that as VRES penetration in the energy system continues, more advanced structures will emerge to support development toward fully renewable portfolios.

To understand the renewable energy investment environment, a system dynamics model is built in this thesis to illustrate the market impacts of VRES in the energy system. With the model, what-if scenarios are tested and overall market trends evaluated. The results show that in the long term, the share of variable renewables does not increase beyond a certain level due to diminishing market value. This is consistent with the observed behavior under the current market conditions. The share of VRES in the energy system can increase if risks are reduced, technologies develop further or consumers are willing to pay a green premium. The experiments show that increasing consumption will expand the total VRES production capacity, but the share of VRES in the energy system increases significantly only if consumption is sufficiently flexible and production value is increased by a green premia or generally higher market prices. The success of the green transition ultimately depends on consumer attitudes and their readiness to pay a higher price for carbon-neutrality compared to the present.

Keywords Market Cannibalization, PPA, System Dynamics, VRES, Wind Energy

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Tiivistelmä

Vaihtelevat uusiutuvat energianlähteet (VRES) ja Suomessa erityisesti tuulivoima, ovat keskeisessä asemassa ilmastotavoitteiden saavuttamisessa ja vihreän kasvun mahdollistamisessa. Vaihteleva tuotanto aiheuttaa kuitenkin järjestelmätason haasteita, kuten kannibalisaatiota, jossa tuotantokapasiteetin kasvaessa markkina-arvo laskee. Nykyisellään tuulivoiman markkina-arvot ovat laskeneet Suomessa alle projektien keskimääräisen kustannustason, mikä vaikeuttaa uusia tuulivoimainvestointeja.

Tämä työ tarkastelee uusiutuvaan energiaan perustuvan energiajärjestelmän haasteita ja selvittää, mitä ovat pitkäaikaiset sähkönostosopimukset (PPA). PPA-sopimukset ovat keskeisiä instrumentteja vaihtelevan tuotannon ja vihreää sähköä hankkivan kulutuksen tarpeiden täyttämisessä. Kirjallisuuskatsauksen perusteella PPA:t ovat laaja joukko kahdenvälisiä sopimuksia, jotka tukevat kuluttajien osallistumisen vihreään siirtymään ja mahdollistavat projektien rahoituskelpoisuuden. Suurimmat uusiutuvan energian ostajat ovat olleet suuria teknologiayrityksiä, joille PPA:lla on tärkeä rooli kunnianhimoisten vastuullisuustavoitteidensa saavuttamisessa. Tuotantoprofiilin mukaan arvotettavat (pay-as-produced) PPA-sopimukset ovat yleisimpiä, mutta on odotettavaa, että jatkossa edistyneemmät sopimusmuodot yleistyvät, koska ne pystyvät paremmin tukemaan täysin uusiutuvan sähkönhankinnan tarpeita.

VRES:n investointiympäristön tarkastelemiseksi työssä on toteutettu systeemidynamiikkamalli havainnollistamaan vaihtelevan tuotannon markkinavaikutuksia. Malli mahdollistaa "entäs jos" -skenaarioiden tarkastelemisen ja yleisten markkinatrendien arvioinnin. Tulokset osoittavat, että pitkällä aikajänteellä VRES:n osuus energiajärjestelmässä ei kasva tietyn tason yli markkina-arvon heikentyessä, mikä on linjassa nykyisissä olosuhteissa havaitun kanssa. VRES:n suhteellinen osuus energiajärjestelmässä voi kasvaa riskien pienentyessä, teknologian kehittyessä ja kuluttajien maksaessa preemioita vihreästä sähköstä. Kokeiden perusteella kulutuksen kasvu saa aikaan VRES-tuotantokapasiteetin lisääntymisen, mutta sen osuus kasvaa kuitenkin merkittävästi vasta, kun kulutuksella on joustokykyä ja sähkön hinta tai viherpreemiot nostavat tuotannon arvoa. Vihreän siirtymän onnistuminen riippuu suuresti kuluttajien asenteista ja heidän valmiudestaan maksaa nykyistä enemmän hiilineutraaliudesta.

Avainsanat Kannibalisaatioilmiö, PPA, Systeemidynamiikka, VRES, Tuulivoima

Use of AI

Large language models (ChatGPT, Microsoft Copilot, and GitHub Copilot) were utilized to assist in the preparation of this thesis. These tools were used to support the formulation of the LaTeX styles and BibTeX entries, to assist in coding for figure creation, and for some rephrasing at text.

Preface

This thesis was conducted at Fingrid Oyj. I would like to thank my advisors for giving me the freedom to independently work on this thesis. In addition, I want to thank my fiancée for her love and support throughout the process.

Helsinki, 31 December 2025

Olli Litmanen

Contents

Abbreviations

CFD	Contracts for Difference
DA	Day-Ahead Market
GO	Guarantees of Origin
LCOE	Levelized Cost of Energy
OTC	Over-the-Counter
PAP	Pay-as-Produced
PPA	Power Purchase Agreement
RES	Renewable Energy Sources
SDAC	Single Day-Ahead Coupling
SIDC	Single Intra-Day Coupling
VRES	Variable Renewable Energy Sources
WACC	Weighted Average Cost of Capital

1 Introduction

The availability of cheap energy has contributed to the economic growth, which has enabled our modern and industrialized society. However, the primary sources of this energy have been fossil fuels, which have caused a global climate crisis threatening long-term well-being on Earth. To maintain and strengthen the standard of living into the future, a fundamental transition is required in the way we produce, consume, and even think about energy. This green transition is seen as a major source of new economic value creation especially in the European Union and in Finland [1, 2].

The success of the green transition depends on investments - particularly in renewable energy infrastructure, but also in broader reindustrialization efforts and new green-era technologies. These include projects focused on the data infrastructure and AI [3], producing green hydrogen [4], e-fuels [5] and in electrification of heavy industries [6], which together will create a modern, low-carbon economy. Technological advancements [7], carbon pricing mechanisms [8], public support schemes [9] and sustainability requirements by investors [10] have boosted the transition. However, despite the ongoing progress, the investment requirements remain huge before all sectors can reach net-zero emission levels [11].

Variable renewable energy sources (VRES), i.e. wind and solar power, act as a backbone of the green electricity system, but they present unique characteristics that make their investment environment challenging. VRES have intermittent and non-dispatchable production profiles and their investment costs occur upfront while the operational costs remain significantly low. The low operational costs lead to phenomena of price cannibalization [12–15], where the market value of renewables decreases as their market share increases. The current situation in Finland, where renewable capacity has expanded rapidly over the past decade, provides a clear example of this effect. Building new VRES production capacity is no longer profitable under the current market conditions [16], even though it is the most cost-effective form of electricity generation [7].

The investment environment for variable renewable energy is largely affected by the electricity market design. The day-ahead wholesale market, which is the main marketplace for physical electricity, operates under a marginal pricing principle, which ensures short-term efficiency, but introduces uncertainty regarding sufficient long-term revenues for capital-intensive variable renewable energy investments [17]. Under marginal pricing, market participants bid on the market based on their short-run marginal costs and the market has a single clearing price, which is based on the most expensive unit required to meet demand [18]. When the share of VRES is high, their low operational costs often set the market price, which creates the cannibalization effect. Overall, price fluctuations in physical electricity markets can be significant, and the market value of variable renewables is influenced by multiple factors, which also affects the risk levels of their investments.

A key enabler for unlocking needed investments in the green transition is bankability. Projects must be financially viable and predictable enough to secure loans and to attract risk-averse private capital [19]. In electricity markets, risks are traditionally managed using cash flow hedging tools based on expected future average prices. However, for capital-intensive renewable energy investments with variable production profiles and cannibalization, these instruments are not de-risking the investments. Addressing investment risks and availability of long-term risk management tools is essential to ensure that both renewable and other large-scale energy projects remain financially viable and can attract the necessary capital [15].

With the VRES penetration, Power Purchase Agreements (PPAs) have emerged as a new financial instrument that helps secure long-term revenue streams for new variable renewable energy investments and meets the demand of consumers seeking green electricity. PPAs are an umbrella term for different bilateral hedging instruments to reduce market risks and to provide revenue stability while taking the technological production profiles into account [20]. As market conditions evolve, both PPA contracts and markets continue to adapt to better respond to the long-term needs of producers and consumers in a system-wide context.

PPAs are increasingly important and prevalent in renewable energy investments and their markets are driven by the industry. While most literature is also based on industry analysis and market reports, the study by Mittler et al. [20] provides the first comprehensive overview of existing PPA structures and characteristics. Still, a deeper understanding of PPAs' influence on market dynamics and investment incentives is highly valuable.

The interaction between renewable energy integration and electricity markets is complex, dynamic, and nonlinear. System dynamics provides a methodology to analyze such systems by capturing their feedback structures and time-dependent behaviors. As Leopold noted in 2016 [21], numerous energy-related system dynamics models have been developed in research, but further research should be focused on renewable energy systems. Since then, the focus on system dynamics based research has expanded to include carbon pricing mechanisms as in [22, 23], but the application of this methodology in the context of variable renewable energy investments with PPA instruments is largely unexplored. Using a system dynamics approach to analyze variable renewable energy market dynamics offers a valuable tool for understanding their complex behavior.

The goal of this thesis is to explore how electricity market participants can hedge their financial exposure in markets increasingly dominated by variable renewable generation, and how new financial arrangements, such as PPAs, shape investment behavior and market development. As a background, the study provides a concise overview of the ongoing electricity transition, its investment needs and risks in Section 2 as well as the basis of the European electricity market system in both physical and financial terms in Section 3.

The methodology of this thesis includes a literature review, expert interviews and a system dynamics model, which are methodologically discussed in Section 4. The literature review, the results of which are presented in Section 5, considers the specific characteristics of variable renewable energy sources, hedging habits and incentives through PPA contracts and the interaction between PPAs and physical electricity markets. Expert interviews complement this available literature and provide practical insights into the dynamics between VRES and PPAs from the industry.

This thesis creates a system dynamics model, which provides an overview of renewable energy interaction with physical electricity markets. The aforementioned expert interviews are used to ensure that the model assumptions and interactions reflect real-world market behavior. The causal model for VRES and the role of PPA contracts is created and presented in Section 6 and the simulation results are presented and discussed in Section 7. The contents of this thesis are concluded in Section 8.

The objectives of this thesis are summarized into the following research questions:

1. How does hedging for VRES energy investments differ from traditional cash-flow hedging in electricity markets, and what is the role of Power Purchase Agreements (PPAs) in enabling these projects?

2. What are the key structures, incentive mechanisms and valuation principles of PPA contracts for producers and purchasers?

3. What are the large-scale dynamics between VRES investments and physical electricity markets and what kind of role do PPAs have in supporting the transition toward a renewable-based energy system?

Research questions 1 and 2 are addressed through a combination of literature review and expert interviews. Due to the lack of transparency and restricted access to detailed PPA contract data, direct empirical analysis of actual contracts is not possible. The literature review aggregates insights from multiple sources and thus provides a broad understanding of the topic. Expert interviews complement this by offering practical perspectives, validating findings from the literature and filling gaps where publicly available information is limited. As no suitable quantitative data exist for examining the large-scale investment dynamics related to the third research question, a simulation-based approach is justified. A system dynamics approach is therefore employed to explore these interactions through structured "what-if" experiments under ceteris paribus ("other things equal") assumptions.

The results of this study provide qualitative and quali-quantitative insights into the role of PPAs and the dynamics of renewable energy investments within electricity markets. They help to clarify key mechanisms, highlight sensitivities to underlying assumptions, and identify potential barriers and enablers for renewable deployment. While the findings do not offer precise forecasts, they can inform decision-making, guide market participants, and support the design of policy interventions toward a fully clean energy system.

2 Background

2.1 Energy transition

Climate change caused by greenhouse gas emissions is one of the greatest, if not the greatest, long-term challenges that societies face today. Continued emission of large amounts of greenhouse gases raises temperatures around the world and leads to a more difficult and costly future if no action is taken. Harms caused by climate change include food insecurity, more common and severe storms, heat waves, rising sea levels and all the associated social consequences. To avoid these outcomes, a transition to a more sustainable world is urgently needed [24, 25].

The economy and energy go hand-in-hand as the more goods and services are produced, the more energy is used. As illustrated in Figure 1, this energy has historically been sourced largely from CO_2-emitting fossil fuels coupling economic growth with environmental harm. Energy needs are likely to remain high and increase in the future despite energy efficiency improvements [26], as illustrated by the rapidly expanding energy-intensive AI sector as a current example [27]. Consequently, a central question for the global economy is whether economic growth and energy consumption can be decoupled from CO_2 emissions and broader environmental degradation.

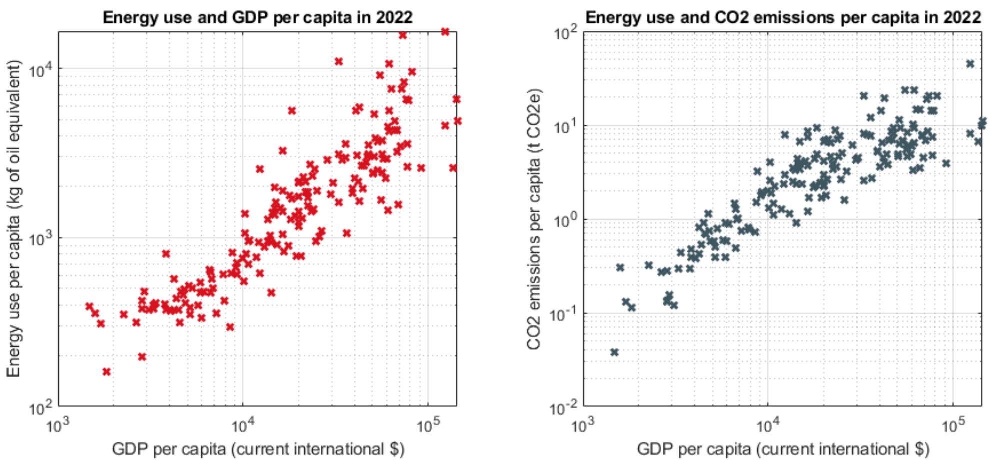


Figure 1: Left: total energy use per capita as a function of GDP per capita. Right: CO_2 emissions per capita as a function of energy use. Each point represents a country. The higher the GDP is, the more energy is used, but also the more CO_2 emissions are caused. However, CO2 emissions are not raising that rapidly that energy use showing that transition to clean energy sources is already progressing. Also energy efficiency improvements have a strong effect on this [26]. Data is from year 2022 and sourced from [28–30].

The transition from fossil fuels to clean energy sources is underway, but substantial investments and policy measures are required to accelerate this transformation [31]. Globally, fossil fuels, i.e. coal, oil and natural gas accounted together for about 80 % of primary energy supply still in 2023 [32]. As a response, the EU has a target to reduce its greenhouse gas emissions by 55% from 1990 levels by 2030, 90% by 2040 and finally to reach net-zero emissions by 2050 [33]. The process leading to these targets is called green transition and it is about replacing carbon emitting processes by new green processes that do not have a significant negative impact on the climate. The transition has been accelerated by the energy crisis, technology advancements and policy implementations but reaching these targets is still a challenging task.

Investments are a key determinant for reaching these climate and sustainability targets. Clean goods production, new energy generation units and energy storage, new clean production facilities and grids between these units do not appear automatically but they need planning and innovation and finally capital commitments to make them happen. European Central Bank (ECB) has estimated that reaching climate neutrality by 2050 would require 1 241 billion euros of annual investments in the green transition, which is about 8.3 % of EU's total GDP in 2023 [11]. The scale of the required investment is exceptional and it requires both public and private resources on a high level [34].

In addition to the climate concerns, Europe has also been concerned about its competitiveness. The Draghi report, commissioned by the European Commission and led by former ECB president Mario Draghi, suggests that the low-carbon transition has an essential lever for Europe's competitiveness in the future [35]. Developing and leading the production of sustainable products and services could provide Europe with a distinct competitive advantage.

2.2 Increasing role of electricity sector

Electricity has a central role in the transition to CO_2 free alternatives, because it can be produced from a wide range of zero-carbon sources such as wind, solar, hydro, and nuclear, and then used flexibly across almost all end-use sectors including transport, heating, and industry. Electricity accounts for about 20 % of final energy consumption globally [32], but in the International Energy Agency's (IEA) Announced Pledges Scenario, this share rises to around 50 % by 2050. Most of the global growth will be from emerging economies [36]. In the EU, it was estimated in 2023 that renewable electricity generation has to be tripled [37] to reach the climate targets. If Europe were to succeed in becoming the leading producer of sustainable goods and services, it would also drive substantial demand for low-carbon electricity.

The prices of variable renewable energy production methods have declined and they have become the cheapest ways to produce electricity. As illustrated in Figure 2, relative competitiveness of renewables compared to fossil fuels makes it the backbone of future energy systems [7]. A competitive technology for providing carbon-free electricity is nuclear fission, which adoption is, however, constrained by high investment costs, long construction times, extended payback periods, and challenges related to public acceptance. In the longer term, nuclear fusion could solve energy supply challenges, but its large-scale deployment is uncertain and very unlikely to occur within the timeframe of the urgent, climate change-driven energy transition [38]. Ultimately, the mix of available technologies and their relative competitiveness will shape the future electricity system, with wind and solar currently representing the most scalable options for large-scale generation.

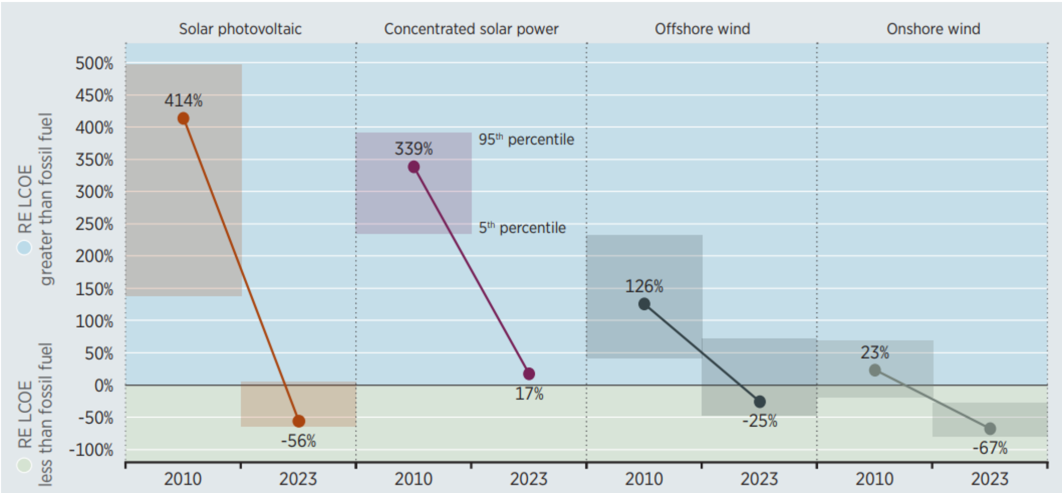


Figure 2: Improvement in levelized cost of energy (LCOE) for renewable energy technologies compared to fossil fuels by [7]. Prices of renewable energy technologies have declined significantly in the last 15 years and have become the cheapest way to produce electricity.

Alternative decarbonization pathways other than electricity exist, but their roles are more limited. Bioenergy has had an important role in global energy mix historically and it has potential for specific industrial and heating applications, but sustainable biomass supply is constrained [32]. Low-carbon hydrogen and synthetic fuels are considered essential for "hard-to-abate" sectors such as aviation, shipping, and steel, which may also benefit from carbon capture [39]. Overall, the large-scale deployment of low-carbon hydrogen and synthetic fuels depends on cheap renewable electricity for electrolysis [40], which again highlights the central role of electricity in the energy transition.

Variable renewable energy has plenty of potential and it is the central among the available technologies, but it also faces system integration challenges. These challenges can be related to land use, grid access, variable output, and financing constraints. The pace and feasibility of the transition to electrified low-carbon energy system is defined by the investment and system integration challenges, which is also the core of this thesis.

2.3 Investments and their risk

According to Fischer and Jordan [41], an investment is defined as a commitment of funds with the aim of receiving a positive rate of return in the future. In their definition, if an investment is properly undertaken, the return will be commensurate with the risk the investor assumes. The funds invested are not necessarily only money, but they can also include time, skills, social capital or other tools or resources for boosting productivity or capability [41].

In this thesis, we focus exclusively on financial investments, specifically private equity investments. Energy investments in the energy transition may include investments in, e.g. skill development, innovation and knowledge but these factors can also often be quantified in monetary terms. There are three key factors which define financial investments and their attractiveness: expected return in terms of money, time horizon and risk. When deciding where to invest, investors compare possible investment projects and value their attractiveness mainly by the combination of these factors, although other aspects such as sustainability, liquidity and portfolio diversification are also considered. The relative attractiveness of an investment is determined by comparing the investment with other comparable investment opportunities [42].

2.3.1 Time value of money

The expected return in terms of money represents the profit the investor is expecting to gain from their investment. Time is an important factor since money has an opportunity cost: gains can be re-invested and investors can enjoy benefits of the compound growth over time. In addition, inflation reduces the purchasing power of the money for the future and thus it should also be taken into account. This is known as time-value of money and it results in the conclusion of money received tomorrow being less worth than the same numerical amount of money received today.

Investment profitability assessment begins typically with the estimation of cash flows. Cash flows represent the actual amounts of money entering or leaving the investor's account over time, in which inflows are typically revenues and outflows consist of costs and investments. The time-value effect is included in these cash-flows using the discounting principle so that the cash flows of different times can be equally compared. Summing the discounted cash flows over the whole timeline results in net present value calculation

$$NPV = \sum_{n=0}^{N} \frac{C}{(1+r)^n}, \tag{1}$$

where r is the discount factor, n is the index of the year, N is the total number of years and C is the future amount of money. The discounting factor r can include inflation. The term inside the sum, $\frac{C}{(1+r)^n}$, is the discounted cash flow at one period of time. Typically, an investment is deemed to be profitable, if the net present value is positive.

In practice, the choice of discount rate is crucial, as compound interest will have a large effect with long periods of time. For example, with a 7 % compound interest rate, invested capital will double in 10 years. For instance, if the discount rate is 7 %, receiving a future cash inflow of roughly 2 million euros after 10 years would have a present value of approximately 1 million euros today. This illustrates that to achieve a target present value, future cash flows must grow sufficiently to compensate for both the time value of money and the chosen discount rate.

The year index n in exponent in Equation (1) illustrates, that usually short-term investments are more profitable than investments in which the same future cash flow is received later. Larger or earlier cash inflows can make an investment profitable even if later inflows are smaller, while delayed or insufficient cash flows may result in a negative net present value despite a seemingly high return rate.

For corporate projects, the discount rate is often based on the weighted average cost of capital (WACC). WACC reflects the average return required by both equity and debt investors and its value is calculated by weighting the debt's interest rate and required rate of return of equity relative to its share of total financing. Using the WACC as a discount rate ensures that the project is expected to at least meet the firm's overall cost of capital [42].

Alternatively, the investments can be evaluated by comparing the project against the risk-free rate, which gives a "safe" benchmark for the project. The risk-free rate represents the return that an investor could earn on a theoretically riskless investments. Truly riskless investments do not exist, but e.g. government bonds are considered as risk-free assets due to their significantly low risk [43]. Thus interest rates of these assets are important to take into account when evaluating the possible values of the discount rate r.

2.3.2 Risk

Generally, a risk is defined as a potential loss or undesired outcome and is usually evaluated by a combination of the probability of undesired event and severity of its consequences [44]. In finance, risk is often quantified as the volatility of the returns, where highly fluctuating returns are generally seen more risky [43]. However, in finance volatility does not necessarily imply negative consequences but it can also lead to positive consequences, such as unexpectedly high returns.

If an investor were perfectly risk-neutral, it would choose the investment based on the highest net present value and profitability of an investment is simply evaluated by the sign of the net present value. In practice, however, investors and organizations are not risk-neutral. Risk affects their relationship to the investments and is thus the third central factor necessary to be considered in investment evaluation.

Investors' attitudes toward risk vary and can be described using risk profiles, which are typically classified as risk-neutral, risk-averse and risk-seeking. Risk-averse investors prefer less uncertain investments, even if it means accepting a lower expected return. Risk-neutral investors invest based on the expected return, and in contrast, risk-seeking investors prefer uncertain investments.

To formalize these preferences, a concept of utility is widely used in finance and in decision analysis. Utility is a numerical representation of the satisfaction or value an investor derives from a given outcome. Utility functions allow different risk attitudes to be compared and incorporated into investment decisions. Figure 3 illustrates different risk profiles using utility.

Investments under risk-averse or risk-seeking risk-attitude cannot be evaluated solely based on the expected monetary value. Instead, expected utility theory is commonly used which considers the total utility as a probability weighted sum of utilities of different outcomes. This can be illustrated using equation

$$EU = \sum_{i=1}^{n} p_i \, U(x_i), \tag{2}$$

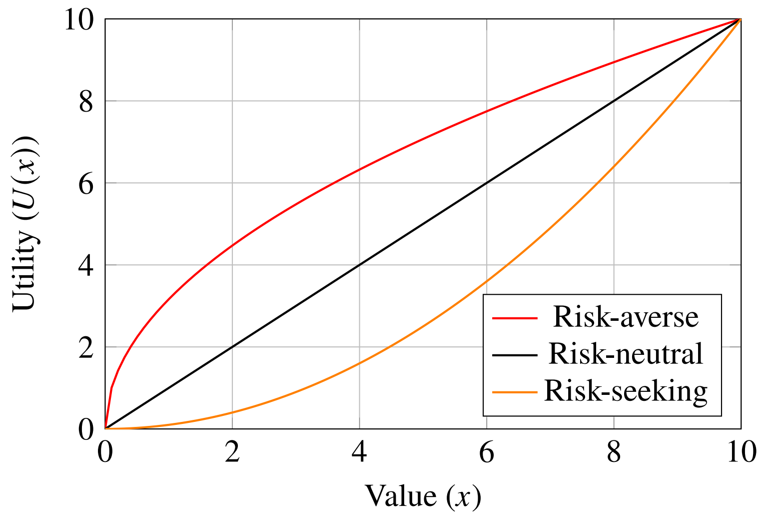


Figure 3: Illustration of different investor risk attitudes using utility functions. The horizontal axis represents the monetary value of outcomes, and the vertical axis represents the corresponding utility. The concave (red) curve shows a risk-averse investor, the linear curve (black) represents a risk-neutral investor, and the convex curve (orange) depicts a risk-seeking investor. A risk-seeking investor prefers a risky asset over a sure outcome of the same expected monetary value because the convex utility function assigns greater utility to uncertain outcomes with potential higher gains. Respectfully, a risk averse decision maker prefers lower expected value in risky asset because of the concave utility function.

where x_i are possible outcomes, p_i are their probabilities, and $U(x_i)$ is the utility of outcome x_i. If the outcomes are measured on a continuous scale, then the sum in Equation (2) is replaced by an integral over this scale. Under expected utility theory, the investor chooses an investment based on the highest expected utility.

Even though expected utility theory is a powerful tool, one has to define a utility function, which can be difficult and time-intensive. Therefore, there are also more straightforward approaches to evaluate investments under risk. One widely used approach is Conditional Value at Risk (CVaR), which focuses on the expected losses in the worst-case scenarios and is particularly relevant for risk-averse decision-making [45]. Other risk measures, such as variance or standard deviation of returns, are commonly used to capture volatility [43] and are often sufficient for portfolio diversification.

Investors can adapt different strategies to decide between investments under risk. These can involve fixing a target level of risk and maximizing expected return, choosing a target return while minimizing risk, or simply minimizing risk for a required return. Generally, risk also has a price, often referred to as the risk premium. The risk premium represents the additional expected return that an investor requires to accept a higher level of uncertainty. In financial markets, assets with higher perceived risk typically offer higher expected returns to compensate investors for bearing that risk. Conversely, low-risk assets tend to offer lower expected returns.

2.4 Private investors and public sector

Investors, defined as stakeholders who make investment decisions, play a key role by defining what gets built, how fast, in which places and using what technologies. Investors are a nonhomogenous group of actors having different preferences on return, risk, time and maybe other values. The investment environment is shaped by laws, policies, technological developments and market conditions and public sector has a strong role shaping this environment. When considering the energy transition in the EU, knowing what kinds of investors are performing the investments, and in what kind of investment environment do they operate.

Climate change is a classic example of negative externalities, where individual countries, firms or consumers do not directly bear the full social cost of their emissions, which leads to overuse of the global commons. This is referred as the "tragedy of the commons", where the atmosphere serves as the core shared resource [46]. Although the scale and consequences of greenhouse-gas emissions were increasingly understood, no single country has been willing to take strong unilateral action. Any emission reductions it made would largely benefit all countries, but the competitive costs both in economically, industrially and political way would be carried locally [47]. Similarly, private companies are unlikely to undertake high-cost, high-risk investments in low-carbon technologies without supportive frameworks, since the competitive market does not reward early movers adequately. To support action and to avoid free-riding, achieving climate neutrality require significant policy intervention from the public sector and international coordination.

Nation-wide cooperation has suffered from low participation and weak enforcement, but a significant step forward was the Paris Agreement in 2015. Nations agreed to limit emissions to 1.5 degree Celcius level, and defined nationally determined contributions (NDCs) to commonly account and monitor proceedings. In Europe, the European Union has taken a forerunner role by implementing binding emission reduction targets, adjusted the investment environment with support schemes for new technologies and created the Emissions Trading System (ETS) [49]. Afterwards, EU programs and

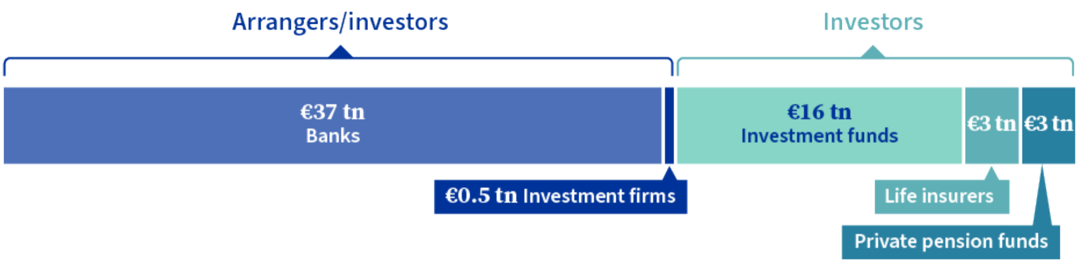


Figure 4: Capital markets in the EU [48]. According to EU's Capital markets union introduction, the scale of private capital in Europe is substantial: banks hold around 37 trillion euros, investment firms 0.5 trillion euros, investment funds 16 trillion euros, life insurers 3 trillion euros, and private pension funds 3 trillion euros.

supernational institutions such as the European Investment Bank have provided grants, guarantees and concessional loans and by these means absorbed some financial risks. By these means, these institutions have attracted private capital for projects that are otherwise difficult to finance due to high upfront costs or uncertain revenue streams. Public sector actors must exercise sound judgment, as various penalty and support schemes can cause side-effects significantly influencing the efficiency of electricity markets. With these actions, public sector can steer the markets in concepts, where unregulated markets fail.

While public sector defines the frames for the investment environment, private capital has to be utilized to achieve these targets. As Figure 4 illustrates, the availability of capital is not a bottleneck in Europe, but capital could be better capitalized. Institutional investors are already active in financing the green transition [50, 51], but accessing these capitals requires sufficiently predictable cash flows from the projects.

Investors in these large capital pools are generally risk-averse, which may constrain the possibility for early-stage innovation in the energy sector. Namely, venture capital, representing more risky capital by contrast, remains very limited, being only a small fraction of EU's GDP and foreign investors have dominated scale-up funding of new greenfield projects [48]. Investors are appreciating green transition with sustainability targets and ESG requirements [52]. However, reducing project risks of green transition investments is still crucial to utilize this risk-averse capital.

3 European electricity markets

Electricity is a unique commodity, because its production and consumption, i.e. supply and demand, must match exactly at all times. Storing electricity on a large-scale is difficult and in addition, electricity can only be delivered to areas, where there is a grid connection [53]. In Europe, electricity markets are organized to ensure the meeting of supply and demand in a fair and efficient way while also enabling efficient cross-border trade within the interconnected European-wide system.

Electricity trading can be broadly divided into physical markets, which guarantee that production equals consumption within grid limits, and financial markets, which provide hedging and risk management tools. In the following, these two dimensions of trading are examined separately.

3.1 Organized physical electricity markets

Physical electricity markets are formed so that they enable buying and selling of electricity in a transparent and efficient way. For each market participant the key goal is to procure electricity such that procured amount of physical electricity equals the measured production or consumption after delivery [54]. Physical electricity trading is mostly conducted on organized marketplaces, which in Europe consist of day-ahead, intraday and balancing markets. Bilateral agreements (OTC-contracts, Over the Counter) are also possible to handle physical electricity trade, if both market participants are located in the same delivery area.

The day-ahead market (SDAC, Single Day-Ahead Coupling) is a European-wide auction illustrated in Figure 5, where trading takes place day before delivery for every 15-minute period of the following day. If there were no transmission limitations, electricity would be traded across the entire market-coupling area with a single uniform price. However, due to network constraints the market area is divided into bidding zones, which usually follow national borders. As exceptions, Denmark is divided in two bidding zones, Italy in five, Norway in five and Sweden in four [55]. In the day-ahead market 30 transmission system operators (TSOs) and 15 nominated electricity market operators (NEMOs) cooperate to determine the market outcome.

Market participants submit purchase and sales bids, which are aggregated into supply and demand curves for each bidding zone. The bids always contain the volume and may also contain the limit price [56]. The market algorithm, called EUPHEMIA, will perform a welfare maximization problem, which maximizes overall economic welfare at the single-market area while respecting interconnector limits [57]. The market price is determined by the marginal pricing mechanism where the last accepted production offer defines the uniform clearing price. If the supply and demand are not met in the markets, the market is curtailed and a single curtailment ratio is applied for the price-independent bids [58].

Marginal cost pricing is designed to guarantee efficient dispatch of electricity. In the marginal cost system, market participants can submit their bids based on their real short-term marginal costs, which increases the overall efficiency of the market. If the bids become accepted, market participants are compensated with the market price, which is at least equal to their marginal cost. In addition, usually the market price offers a better outcome than their marginal cost. If a generator were to submit a bid higher than its actual marginal cost, it would risk not being dispatched, since competitors offering closer to true costs would be selected to meet demand [37]. Therefore, each market participant gets the best possible outcome with bidding at their marginal cost.

The day-ahead market price is influenced by a combination of factors, including temperature, production availability (e.g., outages or revisions), transfer capacities, wind conditions, demand flexibility, and the availability of water resources. Thus, long-term market price prediction is a challenging task. The price differences between zones create congestion rents (or congestion income), which are the financial revenues arising from the limited transmission capacity. Congestion income is calculated as the product of the electricity flow over the constrained line and the price difference between the connected zones. Transmission system operators typically use this income to fund grid expansion, support financial hedging instruments such as financial transmission rights (FTRs) or to reduce transmission tariffs [59].

Figure 5: Regions participating in the Single Day-Ahead Coupling are illustrated in blue [56].

After the results of the day-ahead auction, there is a possibility to adjust one's positions in the intraday market (SIDC, Single Intra-Day Coupling). As already described, market participants have an incentive to balance own portfolios to avoid possibly high balancing costs. The main reason for intraday trading is to correct forecast errors or to respond to unexpected changes in generation and consumption. Trading in intraday is continuous, based on bilateral matching of buy and sell orders, and limited by the cross-border capacities that remain after the day-ahead results. There are also intraday auctions to provide stronger price signals beyond the day-ahead stage [60].

In addition to these so-called wholesale electricity markets, there are also balancing markets operated by Transmission System Operators (TSOs). Transmission System Operators are ultimately responsible for keeping the production and consumption balanced. When deviations occur due to e.g. forecast errors or sudden disturbances, additional resources must be utilized to restore balance. In balancing markets there is effectively one buyer which is the corresponding TSO, but market participants can participate and benefit from engaging in short-term balancing [61].

The imbalance settlement is performed to ensure that the costs of maintaining system balance are allocated to market participants according to their individual imbalances. The imbalance price reflects the cost of activating balancing energy, and participants whose actual production or consumption deviates from their scheduled positions are settled at this price [62]. In periods of major imbalances or scarcity of balancing resources, imbalance prices can become significantly higher than day-ahead or intraday prices and thus create strong incentives for accurate forecasting and balanced positions.

3.2 Guarantees of origin

Electricity is physically uniform in transmission grids, and its source cannot be traced once it enters the network. Nevertheless, as electricity systems are increasingly decarbonized, the origin of electricity has raised an important concern. For that reason the Guarantee of Origin (GO) system was introduced in Europe to certify the source of electricity production. In theory, this system makes possible to verify that a certain quantity of power has been generated from renewable sources [63].

In the GO system, each megawatt-hour of electricity produced receives one GO certificate, which can then be traded independently from the physical electricity. The issuance of certificates is based on verified grid measurements and thus it is ensured that the recorded generation corresponds to actual electricity fed into the network. Certificates available depend on the national implementation, but in Finland, certificates can be granted for wind, solar, hydro, thermal and nuclear production. When a certificate is used to make an energy claim, it is said to be canceled. Each certificate is valid for 12 months and thus the guarantees of origin system results in coarse annual resolution with energy production and consumption matching [64]. The system is implemented under the EU Renewable Energy Directive (RED II) and coordinated across Europe through the Association of Issuing Bodies (AIB) [65].

The purpose of the GO system is to provide transparency to consumers and to enable companies to make verifiable claims about renewable electricity use. Typically, a company may purchase GOs corresponding to its annual consumption and thereby claim that its operations are powered by renewable energy, though its physical electricity supply comes from the general mix on the grid [63]. This separation of certificates and physical energy should allow for flexibility and market-based allocation of renewable attributes [65]. Guarantees of origin are traded mostly bilaterally but there are some organized trading platforms for them as well [66].

However, the system has received increasing criticism for its limited impact on driving the energy transition. Since GOs can be purchased cheaply and without a direct link to new renewable investments, their role as a true decarbonization tool is questionable. In addition, the annual matching and possibility to trade certificates without physical electricity delivery is not seen plausible. For these reasons, policy discussions have considered reforming the GO system to better reflect temporal and locational matching, which would ensure that renewable certificates correspond more closely to actual renewable generation in time and place. However, as the transformation of EU legislation progresses slowly, many companies and industry actors have developed their own mechanisms to demonstrate additionality and contribution to a renewable-based energy system at the top or instead of guarantees of origin [67–70].

The prices of Guarantees of Origin (GOs) are not publicly available in a transparent manner. Despite the lack of transparency, some open-access sources provide insights into the market conditions and future expectations. According to Veyt [71], GO prices have dropped to approximately 0.5 €/MWh in 2024, which is a decline from previous years. However, projections suggest that growing demand will drive prices upward toward 2030 [70, 72].

3.3 Financial electricity markets

The physical electricity market guarantees the supply and demand equilibrium in the short-term, and the resulting price in this market represents the short-term balance on the market. Price volatility in the day-ahead market can be significant, and therefore leaving an entire electricity portfolio unhedged would correspond to a more risk-seeking utility profile. As real market participants are mostly risk-averse, the availability of financial hedging opportunities is essential for market participants to mitigate the risks in these markets. Both electricity producers and consumers want to have predictable cash flows and hedge against price fluctuations. The availability of different hedging opportunities defines how hedging is actually performed [73].

Trading in financial electricity markets takes place both bilaterally and on organized exchanges. Hedging in electricity markets is a continuous process and typically focuses on the near future. The closer the future, the higher the hedging rates typically are. In practice, achieving a 100 % hedge is difficult and thus there is often some part of the portfolio exposed to the physical volatility [73]. Organized exchanges are operated by platforms such as Nasdaq Commodities and the European Energy Exchange (EEX), which list standardized financial products and mostly futures. In contrast, bilateral trading, also known as over-the-counter (OTC) trading, allows counterparties to negotiate customized contract terms directly, which offers greater flexibility at the cost of reduced transparency and credit risk decentralization.

Data on financial electricity markets is generally not publicly available, which makes market analysis challenging for researchers and stakeholders. Market participants and exchanges are required to report transactions to authorities under REMIT act [74, Section 3], and ACER has published a dataset covering electricity and natural gas markets between 1 January 2025 and 31 March 2025 [75]. Although the data is aggregated at a relatively high level, it provides a valuable overview of market scale and activity and represents the first publicly available dataset for EU financial electricity markets. Based on the data, comparison of bilateral trades and trades on organized marketplaces in Finland is illustrated in Figure 6. The role of bilateral trades is significant especially in Finland with more trades than on organized marketplaces on the whole Nordic and Baltic region. The dataset covers only a short time window and the number of transactions do not necessarily correspond to actual traded volumes, but they still highlight the importance of bilateral trading in current market environments.

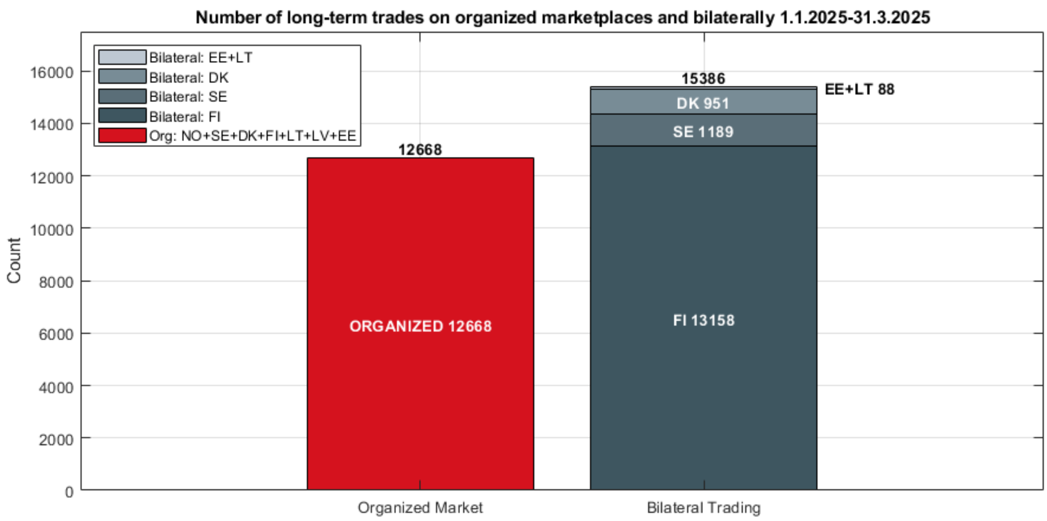


Figure 6: Number of trades on organized marketplaces and bilaterally in Nordic area between 1.1.2025 and 31.3.2025 based on [75]. In the data, trades on organized marketplaces are aggregated for Finland, Sweden, Norway, Denmark, Estonia, Latvia and Lithuania into the same bin. Data of bilateral trades is available from corresponding areas Finland, Sweden, Denmark, Estonia and Lithuania. Bilateral trades of rest of Nordic and Baltic areas (Norway and Latvia) are not separately available on the data due to small number of datapoints and not shown in the Figure.

3.3.1 Hedging on organized marketplaces

On organized exchanges, the most common products are futures linked to day-ahead spot prices in specific bidding zones or larger areas. When participating in such a contract, market participants agree to buy or sell electricity with a predefined price, which is based on the expectation of the day-ahead price. These contracts are typically defined over settlement periods such as a month, quarter, or year, and they are financially settled based on the average spot price during the respective delivery period. The benefit of possible larger areas or "hubs" is the boost in liquidity but their biggest drawback is the need for a separate zonal-to-hub product if the zonal price differs from the hub price.

Products in these organized marketplaces have been generated for the purposes of electricity consumption and can be categorized by their delivery profile. Traditionally those types are baseload and peak-load contracts. Baseload products cover electricity delivery evenly across all hours of the day and thus provides exposure to the average system price over the entire settlement period. There are also peak-load products, which only apply to predefined daytime or high-demand hours and allowing participants to hedge against higher prices during periods of elevated or reduced consumption [76].

In the Nordic market, Nasdaq offers system price product, which references the system price. The system price is a "hub" price calculated across the entire Nordic system (Finland, Sweden, Norway and Denmark) under the assumption that there were no transmission constraints [77]. In addition to this, Nasdaq offers price area differentials (EPADs) in use for this area, where market participants can hedge against price difference between the system price and the zonal price. Nasdaq's Nordic power futures are being migrated to Euronext, where trading and clearing will continue from March 2026 [78].

Currently, in addition to Nasdaq, EEX offers zonal products for the Nordics, but the liquidity of these products has remained generally weak [79]. While competition among exchanges is generally beneficial and can encourage the development of new financial products, in smaller bidding zones this competition can dilute liquidity, as trading volumes are split across multiple platforms. When zonal product liquidity is insufficient or products are unavailable in certain areas, market participants may resort to proxy hedging by using a more liquid area as a reference. The effectiveness of this strategy depends on the physical correlation between the proxy and the actual zonal prices.

Generally, companies participate in financial hedging to align with their underlying portfolios of production or consumption and aim to reduce exposure to price volatility as a risk management tool rather than profit-seeking activity. However, participation in financial markets can also become speculative if positions are taken without a corresponding physical exposure or if the intent shifts toward profiting from anticipated price movements rather than mitigating risk. Such speculative behavior introduces additional uncertainty for the participant, and it can enhance the liquidity of forward markets by increasing trading activity and improving the connection between producers and consumers.

As the number of speculative traders in the markets is currently small, Euronext will introduce a market-making scheme starting in March 2026, simultaneously with the transfer of Nasdaq's Nordic power futures positions to Euronext to enhance liquidity in the Nordic power derivatives market [78]. Market makers are entities that commit to providing continuous buy and sell quotes for specific financial instruments and by these means ensure that other market participants can execute trades without significant delays or excessive price fluctuations. By narrowing bid-ask spreads and maintaining a consistent market presence, market makers facilitate smoother trading and contribute to more efficient price discovery. Euronext's initiative aims to boost liquidity and create a more robust trading environment for Nordic power derivatives [78].

To address the challenges associated with proxy hedging and limited zonal liquidity, additional hedging instruments for cross-border trade are financial or physical transmission rights (FTRs/PTRs) defined in European regulation. FTRs are financial contracts that entitle their holders to receive (or pay) the congestion rent between two bidding zones [80]. For example, a consumer in Estonia seeking to hedge against day-ahead price volatility, can complement its proxy hedging by using an FTR between EE and FI. Transmission rights enable market participants to manage the risks associated with transmission bottlenecks and variable zonal prices without relying only on proxy hedging or illiquid zonal products.

3.3.2 Risks associated with the financial electricity markets

Participating in long-term trade is a risk management tool for the price risk, as these financial contracts allow parties to stabilize profits or losses related to volatile electricity prices. However, electricity procurement is not risk free even if such contracts are formed, because market participants are still exposed, for instance to market risk, liquidity risk, profile risk, and counterparty risk. These risks are present in some extent in both trading on organized marketplaces and bilateral trades, and they have to be taken into account to evaluate overall effectiveness of the hedging strategy.

The market risk arises, as the value of hedging contracts depends on the future development of spot prices. In this context, a contract is said to be in-the-money when its current market value is positive for the holder. Conversely, the contract is out-of-the-money when the market has moved against the holder. When the contract price and the spot price are approximately equal, it is considered to be at-the-money [42]. Market risk can affect a firm's relative competitiveness because if competitors purchase electricity at favorable market prices while the firm is locked into disadvantageous contracts, its cost structure becomes less competitive, which can potentially further affect the firm's market position.

One key issue especially relevant to organized marketplaces is liquidity risk, which stems from the collateral requirements imposed by the exchanges. Collateral requirements are designed to manage counterparty risk, which refers to the possibility that one party defaults on its financial obligations [81]. In practice, market participants must deposit initial margin when entering a futures position, which serves as a financial guarantee that they can procure electricity from markets if they are unable to deliver or procure the contracted electricity. As market prices fluctuate, participants must also maintain a variation margin, which is adjusted daily (or even intraday) to reflect changes in the market value of their open positions [82]. Depending on the size of open positions and market prices, collateral requirements can become high and thus they are one reason, why the liquidity of zonal power derivatives in organized marketplaces has weakened significantly in Nordics area in recent years [83]. In extreme cases, the financial strain caused by margin calls has required external intervention, as seen during the energy crisis when Fortum secured a state-backed bridge financing arrangement with the Finnish government to meet unprecedented collateral needs related to exceptional prices [84].

Another important source of uncertainty is profile risk, which arises when the hedged consumption or production pattern deviates from the standardized delivery profile of the traded product (e.g., baseload versus variable load). The profile risk is handled in physical electricity procurement, but the volume-weighted electricity price may be cheaper or more expensive compared to the baseload electricity price even if the volume matches the contracted volume. The volume risks occurs when the hedged volume does not match the actual physical production or consumption. The resulting difference must be settled in the market, typically at spot or imbalance prices, which could differ from the financial price.

Baseload profiles are central to hedging on organized marketplaces, but the number of producers being able to provide such profiles in evolving and more variable renewable energy based electricity system are limited. When actual production or consumption profile differs from the baseload profile, the associated profile risk becomes high with volatile electricity prices. Risk-seeking speculative traders would be able to participate in such contracts, but many have judged these risks to be too high [85]. Ultimately, high collateral requirements, profile risks, and market risk have driven market participants toward bilateral trading rather than organized marketplaces.

3.3.3 Bilateral long-term trading

Bilateral trading serves as a flexible alternative to organized marketplaces, where market participants can form such contracts that fit their needs. However, analyzing these transactions is difficult, since while some data on trading in organized marketplaces is publicly available, information on bilateral agreements is extremely limited. Bilateral trades are called over-the-counter trades (OTC) [86].

Bilateral trades can be financial and based on the same types of contracts as on exchanges but can also be flexibly negotiated to fulfill any options contract parties have [87]. Counterparty risk is higher in bilateral agreements than in organized marketplaces because there is no central clearing, shared collateral system, or exchange-based risk management rules. Each contract relies on the financial strength of the individual counterparty. Mitigating this risk is essential and can be handled using collateral agreements, but it can also involve different measures such as credit assessments or risk premia in contracts.

A unique bilateral contract structure in Finland is the Mankala model. The Mankala model is a cooperative ownership structure for energy production facilities used by many industrial companies and municipal utilities. In this model, multiple shareholders jointly own a generation company, and each shareholder is entitled to receive electricity in proportion to its ownership share at production cost price rather than at market prices [88]. The electricity is then used by the shareholder or sold onward in the market. Contracts are thus physical OTC trades. The benefit of the model is that it allows investors to secure long-term access to stable electricity in such a way that the risks and capital expenditures are distributed among participants [89]. The Mankala model has played a central role in financing large-scale generation projects in Finland, as in 2018, approximately two-thirds of Finnish nuclear generation operated under the Mankala principle [88].

3.3.4 Interaction between physical and financial markets

In addition to division between trading on organized marketplaces and OTC-markets, financial contracts can be categorized by the nature of the contracts to physical contracts and purely virtual (financial) agreements. Physical contracts involve the actual obligation to produce or consume electricity at a specified time and location, while virtual contracts are only settled financially [90]. Trading on organized marketplaces is virtual, but OTC trades can be either physical or virtual depending on the needs and capabilities of the counterparties. Physical bilateral trades can occur across the grid within the same price area, or within the same site, for example for a factory sourcing power from its own plant or an adjacent power plant. In these cases, the electricity is effectively delivered between the contracting parties, even though it is physically fed into the grid and cannot be individually measured.

Financial contracts, both those performed on organized marketplaces and bilaterally, are typically financially settled against the average spot price over the delivery period. Holding such contracts does not involve physical delivery or receipt of power. Instead, the parties exchange the price difference between the contract price and the realized average price on the day-ahead electricity market. If producers or consumers require actual electricity for physical operations rather than market participation for speculative purposes, they must procure it through the physical electricity markets. Any difference between the contracted position and actual operation is settled through the imbalance settlement system of the physical electricity market. This ensures that deviations between forecasted and realized quantities are properly accounted for. Holding a financial contract does not restrict participation in physical markets in principle, and the decisions in physical procurement are made independently of any underlying financial commitments.

The first step in physical electricity procurement typically takes place in the day-ahead market, where participants submit bids to cover their expected electricity demand or production capacity. After the day-ahead stage, additional opportunities arise in the intraday and balancing markets, where flexibility can have even greater value. These markets allow participants to reduce imbalance costs or, in some cases, to capitalize on others' position difficulties. Participation in balancing markets can be highly profitable for those with the ability to adjust their production or consumption rapidly.

3.4 Investments and lack of them in the energy sector

Wholesale electricity markets have largely functioned well under a merchant structure [91]. In this framework, electricity producers operate without guaranteed payments from a central authority and instead sell their output to unknown buyers through organized markets or bilateral contracts. Revenues are determined by market prices and are typically set according to the marginal cost of the last unit needed to meet demand. Financial instruments are used in cashflow hedging to protect buyers and sellers against volatility.

The profitability of new generation units is traditionally evaluated using the Levelised Cost of Energy (LCOE). It represents the average price per unit of electricity a generator must receive over the project lifetime to cover both operational expenditures (OPEX), capital expenditures (CAPEX) and the required return rate (r) [92]. Operational expenditures consist of fixed and variable operational and maintenance costs (FOM and VOM respectively). FOM represents the costs associated with maintaining the plant regardless of output whereas VOM includes production-specific costs including fuel costs.

The value for LCOE depends largely on the required return rate, also known as the discount rate r, which is typically chosen to reflect the WACC of the project. In addition, the Capacity Factor (CF) describes the ratio between actual energy output over a period of time and the theoretical maximum energy output if the plant operated at its full nominal power capacity throughout that period. The length of the project timeline in years (n) also affects the LCOE.

In general, the LCOE is defined as the ratio of the discounted total costs to the discounted total energy production over the project lifetime, which can be expressed as

$$\text{LCOE} = \frac{PV(C)}{PV(E)}, \tag{3}$$

where $\text{PV}(C)$ and $\text{PV}(E)$ denote the present values of costs and the energy production respectively [16]. In this analysis, discounting is performed on an annual basis, and the annual energy production per unit of installed capacity is defined as $E_t = \text{CF} \times 8760$, where $8760 = 24 \times 365$ denotes the number of hours in a year and CF is the annual capacity factor. The present value of the project costs can then be calculated by

$$\text{PV}(C) = \sum_{t=0}^{n} \frac{\text{CAPEX}_t + \text{OPEX}_t}{(1+r)^t},$$

where $\text{OPEX}_t = \text{FOM}_\text{t} + \text{VOM}_\text{t} \times E_t$. Similarly for energy generation the present value can be calculated as

$$\text{PV}(E) = \sum_{t=0}^{n} \frac{E_t}{(1+r)^t}.$$

If costs are assumed constant over the project timeline, $E_t = \text{CF} \times 8760$ and FOM_t and VOM_t are constants. If all investment costs are assumed to occur upfront at $t = 0$, then

$$\text{CAPEX}_t = \begin{cases} \text{CAPEX}, & \text{if } t = 0 \\ 0, & \text{if } t > 0, \end{cases}$$

and similarly $\text{VOM}_0 = 0$ and $\text{FOM}_0 = 0$. The electricity generation can be denoted as a geometric sum for which $\sum_{k=0}^{n} ar^k = a(\frac{1-r^{n+1}}{1-r})$, and thus

$$\begin{aligned}\mathrm{PV}(C) &= \mathrm{CAPEX} + (\mathrm{FOM}_t + \mathrm{VOM}_t \times E_t) \sum_{t=1}^{n} \frac{1}{(1+r)^t} \\ &= \mathrm{CAPEX} + (\mathrm{FOM}_t + \mathrm{VOM}_t \times E_t) \frac{1-(1+r)^{-n}}{r}.\end{aligned}$$

Similarly, if production is assumed constant over the project timeline, $PV(E) = E\frac{1-(1+r)^{-n}}{r}$. Now substituting this to Equation (3), we get a simplified form

$$\mathrm{LCOE} = \frac{\mathrm{CAPEX} \cdot \frac{r(1+r)^n}{(1+r)^n-1} + \mathrm{FOM}}{\mathrm{CF} \times 8{,}760\,\mathrm{hours/year}} + \mathrm{VOM}. \tag{4}$$

In practice, electricity markets easily recover OPEX through short-run marginal cost (SRMC) pricing, but CAPEX recovery depends on sufficient market prices and is more uncertain [93].

This gives rise to the so-called missing money problem [94]. Because market prices reflect the cost of the last unit dispatched, these last units may not earn enough revenue to cover their fixed costs. This can discourage investment in capital-intensive generation, even though such capacity may be necessary for system reliability. Conversely, the last unit dispatched may temporarily exercise market power if competition is limited, potentially driving prices upward. However, such price manipulation is prohibited under the REMIT regulation [95].

Investment decisions in the electricity sector are based on expectations of future electricity prices. If a project developer believes that the future electricity price is enough to recover the LCOE, an investment is made. After an investment is made, the investment costs become sunk costs, which are irreversible financial commitments that do not influence short-term market operations. Even though the full investment cost cannot be recovered in evolving market conditions, existing capacity does not exit the system if the profits exceed the costs of keeping the production facility in use. It should also be noted that the LCOE is not necessarily a suitable metric for variable renewable energy, as it relies on strong assumptions regarding operating hours. Even when market prices are low, production may be curtailed if the electricity system is unable to accommodate total generation. Therefore, the market environment should be explicitly considered alongside technical properties in LCOE analysis.

The long lead time means that decisions made years ago continue to shape the system for decades, limiting production capacity's ability to adapt quickly to changing market conditions or technological advancements and thus causes system inertia. Although changes in capacity are slow, existing units can adjust their operation almost immediately in response to market signals. In addition, some technologies such as electric boilers for demand-side flexibility and batteries can be built and taken into operation much quicker.

4 Empirical and methodological resources

4.1 Literature review

The amount of academic literature focusing specifically on Power Purchase Agreements (PPAs) is limited, even though the role of PPA contracts has been evolving significantly. The renewable energy markets have been largely driven by industry practices, and the role of industry whitepapers and discussion papers is significant in understanding this topic. The literature review was conducted by combining peer-reviewed academic research and industry sources to understand both theoretical and practical perspectives.

In this thesis, the academic literature was identified primarily through keyword searches on Google Scholar. Additional studies were found by following the references cited by key papers and also the later studies that cite them. This citation chain approach helped to explore the relevant research areas widely.

In addition, industry whitepapers and reports were identified through web searches. Since the nature of the topic is industry-driven, these sources played a significant role in creating an understanding. Information was also gathered from webinars and presentations organized by market participants such as Montel and Pexapark. Webinars provided timely insights into current market practices and developments expressed in the language used by industry actors.

4.2 Expert interviews

To supplement the analysis of academic and industry sources, expert interviews were conducted to provide additional insights to support the development of the system dynamics model and to validate the literature review. The interviews offered practical perspectives and domain knowledge on renewable energy and its interaction with physical electricity markets with a focus on the Nordic electricity system.

In total, nine experts were interviewed. The experts represented different areas of the energy sector, including electricity producers, market consultants, utility traders, and large electricity consumers. The interviews were performed either remotely or in person and typically lasted around one hour, which was a sufficient amount of time to cover the key topics.

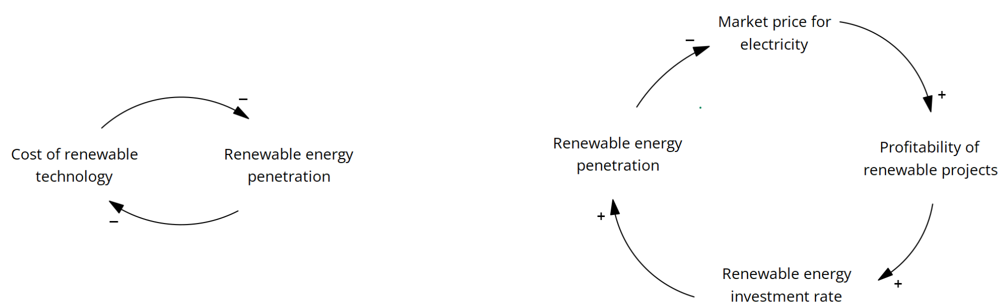
The discussions were held in an informal manner with the help of a set of guiding questions that helped to ensure that all key topics relevant to the model were addressed. The guiding questions used in these interviews are listed in Appendix B. The insights from the interviews were used to identify relevant variables and to validate causal relationships such that the system structure reflects real-world dynamics as accurately as possible.

4.3 System dynamics

System dynamics provides a framework for examining the behavior of complex systems over time by focusing on their interdependencies and feedback mechanisms. This approach simplifies the analysis of such systems, as it typically allows the use of computer simulations, without the need to explicitly define complex differential equations. Thus, the modeler can concentrate on the systems thinking itself. System dynamics method was first developed for industrial production management but it has then evolved into a versatile methodology for example, economics, environmental studies, and energy system analysis as well [96].

System dynamics models are not typically designed to produce highly detailed or precise forecasts, but rather, they aim to represent the underlying causal structures and central feedback loops that affect the system behavior. Because these models depend on their underlying assumptions, they are particularly well suited for exploratory analyses, where the objective is to understand how changes in external conditions or policy interventions may conceptually affect the system. The insights they provide are often qualitative semi-quantitative. Even though the models rely on quantitative formulations, their primary value lies in clarifying mechanisms and illustrating how different elements of the system interact [96].

The system dynamics approach involves causal loop diagrams, which illustrate the cause and effect connections of system variables. These causal loop diagrams are a powerful tool for system thinking itself without even conducting any simulations. Feedback loops can be either reinforcing or balancing. The effects between variables are illustrated with arrows which are marked with a plus (+) or minus (-) symbol to indicate the direction of influence. A loop is formed when following the arrows eventually returns to the original variable. The effect of the loop is reinforcing (positive) effect if the number of negative links is even and otherwise the loop is balancing. An



(a) Example of positive (reinforcing) feedback loop.

(b) Example of negative (balancing) feedback loop.

Figure 7: Illustrative examples of positive and negative feedback loops. In (a), when the installed capacity increases, learning effects reduce technology costs (negative link). Lower costs, in turn, stimulate further capacity additions (negative link), forming a reinforcing loop with two negative arrows. Respectively, in (b), increasing renewable energy penetration lowers the market price of electricity, which in turn reduces profitability and investment rate of renewable energy, which further reduces the renewable energy penetration. Since the loop has one negative link the loop is balancing.

example of a positive feedback loop is illustrated in loop diagram in Figure 7.

In addition to feedback loops, an essential concept in system dynamics is the distinction between stocks and flows. Stocks represent the accumulations or states of the system, which are quantities that build up or deplete over time, such as population, capital, inventory, or knowledge. Flows, on the other hand, represent the rates of change that increase or decrease these stocks. A stock changes only through its inflows and outflows, which introduces delays and system inertia into the model. Graphically, stocks are illustrated as boxes, and flows as double arrows that start or end at the stocks, which thus indicate the direction of accumulation or depletion. An example of stocks and flows is given in Figure 8.

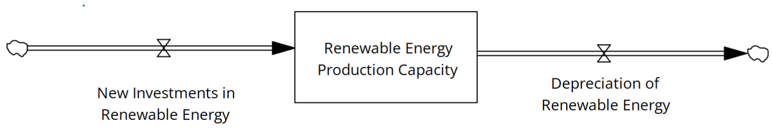


Figure 8: An example of stocks and flows. Renewable energy production capacity is a stock with an inflow of new investments and an outflow of depreciation of renewable energy.

The interaction between stocks and flows can be described mathematically as

$$\frac{dS}{dt} = \text{Inflow(t)} - \text{Outflow(t)},$$

where S is the state of the stock at time t [97]. In other words, flows define the rate of change of a stock variable. As the interest is about the state of the stock variable itself, the state of the stock can be solved as an integral over the time axis of the flow variables as

$$S_T = \int_0^T (\text{Inflow}(t) - \text{Outflow}(t))dt + S_0,$$

where S_0 is the initial state of the stock. In computer simulations, the state of a stock variable S is recorded in every time step and often solved using the simplest Euler method as

$$S_{t+\Delta t} = S_t + (\text{inflow}(t) - \text{outflow}(t))\Delta t. \tag{5}$$

The Euler method assumes that the flows stay constant through the Δt. In simulations, Δt is the time step used in simulations and the result can be made more accurate, if the size of time step is decreased.

Building a system dynamics model starts with defining the problem, which involves identifying the key phenomenon, its boundaries, and the time horizon of interest. Next, the most relevant variables and causal relationships are identified and organized into a causal loop diagram (CLD). This helps visualize the feedback structure and interdependencies within the system.

When the qualitative structure is perceived, the modeler translates the causal relationships into a stock-and-flow diagram, where stocks represent accumulations and flows represent the rates of change between them. Afterwards, each flow is defined mathematically using equations that describe how it depends on other variables and parameters in the system. Delays, nonlinear effects, and external drivers can be added to represent more realistic system behavior.

After the model structure is complete, it is implemented in simulation software to perform numerical simulations. The final stages involve validation and sensitivity analysis, ensuring that the model behaves plausibly and that results are robust with respect to parameter uncertainty. In this thesis, the system dynamics model and simulations are developed using Vensim PLE software.

5 Variable renewable energy characteristics and power purchase agreements

Variable renewable energy technologies, particularly wind and solar, present unique characteristics that distinguish them from conventional power generation units. These differences are most evident in two areas: the variability of their production profiles and the distinct cost structure dominated by capital expenditures (CAPEX) rather than operational expenditures (OPEX). As renewable energy has become central to decarbonization efforts and it is increasingly significant for future electricity systems, these structural features must be considered in both the investment environment and the design of electricity markets [98].

Traditional thermal plants can be dispatched according to electricity demand, but variable renewable units can only generate electricity at the rate at which the underlying wind or solar conditions are available. The actual power output of VRES depends on the availability of the renewable resource and, to some extent, on the operator's ability to curtail or ramp production within technical limits. In principle, in cases of excess generation, operators may down-regulate output, and if they have strategically undersold their expected production in the spot market, limited up-regulation may also be possible. As an example, the variations of wind power over one month in 15-minute resolution with respect to monthly average value are illustrated in Figure 9. The Figure highlights that the variations are substantial and the production differs significantly from the baseload profile creating a profile risk. This is a significant

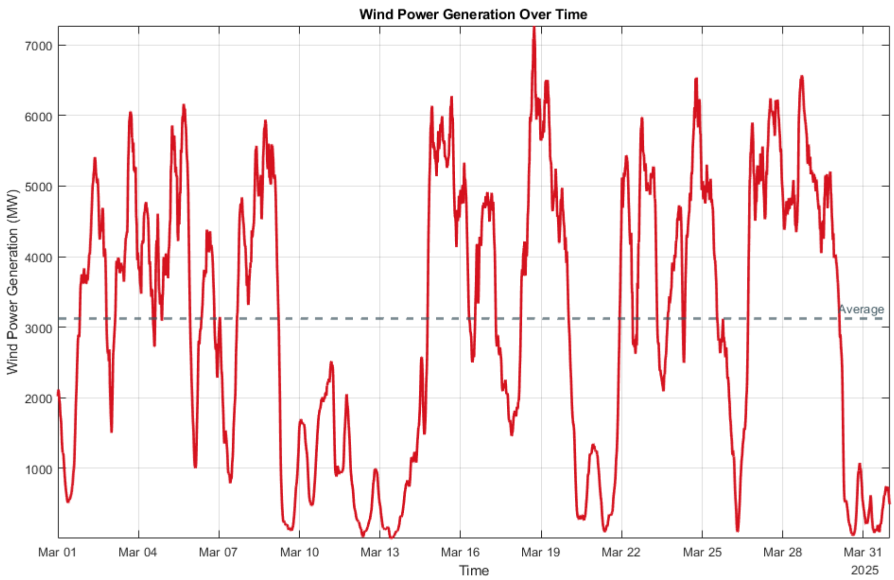


Figure 9: Total Wind Power generation in Finland over March 2025 from [99]. The red curve illustrates the generation of wind power and gray dashed line the average production. Example illustrates that wind power varies a lot over time. While considering a profile risk, any deviation from the dashed line illustrates the risk.

difference in contrast to conventional generation whose output can be scheduled to optimize revenues and to fulfill the baseload profile. Thus, the essential distinction from conventional generation is that variable renewable technologies alone cannot meet demand during periods of low resource availability.

Empirical studies have shown that the Beta distribution provides a good approximation of wind power production profiles [100, 101]. The Beta distribution with shape parameters α and β has the probability density function

$$f(x; \alpha, \beta) = \frac{x^{\alpha-1}(1-x)^{\beta-1}}{B(\alpha, \beta)}, \quad 0 \leq x \leq 1,$$

where $B(\alpha, \beta)$ is the Beta function. In the context of wind power production, x represents the normalized power output, defined as the ratio of the actual power production to the nominal (rated) capacity of the wind power plant. The parameters α and β can be obtained from the empirical mean (μ) and variance (s^2) of the data as

$$\begin{aligned} \alpha &= \mu \left(\frac{\mu(1-\mu)}{s^2} - 1 \right), \\ \beta &= (1-\mu) \left(\frac{\mu(1-\mu)}{s^2} - 1 \right). \end{aligned} \tag{6}$$

The full description of Beta distribution is provided in the Appendix A. Figure 10 illustrates an example of the wind power distribution alongside a beta distribution fit.

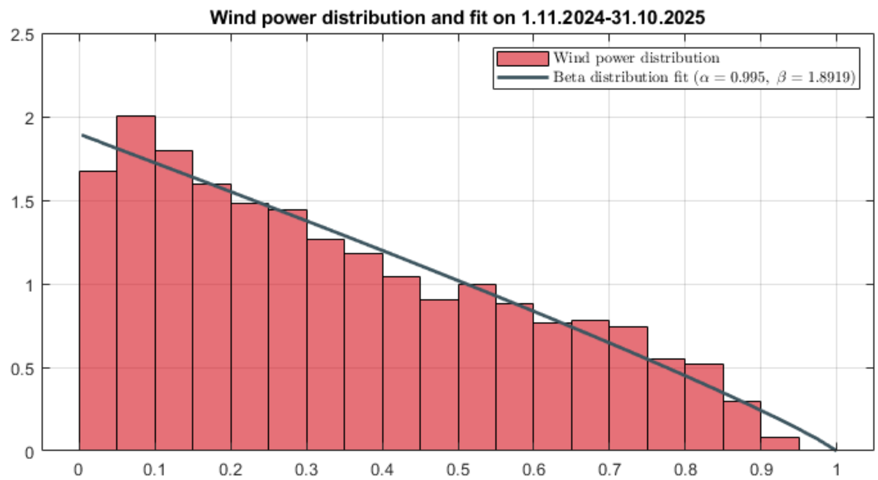


Figure 10: Distribution of wind power production 1.11.2024 - 31.10.2025 and a beta distribution fit. The wind power production is scaled such that a probability density function is formed resulting that the area of bins equals 1. The parameters for the Beta fit are obtained using Equations (6) based on the mean and the variance of the empirical data. Data is available on [99].

A central concept for evaluating VRES in wholesale markets is the so-called capture price. The capture price, also known as renewables' market value, represents the production-weighted average market price received by a generating unit and can be expressed as

$$P_{\text{cap}} = \frac{\sum_t P_t \cdot E_t}{\sum_t E_t}, \tag{7}$$

where P_t is the market price at time t and E_t is the electricity produced at that time [102]. Here, t denotes a discrete market time interval (in Day-Ahead market 15 minutes), and E_t corresponds to the energy generated during that interval, implicitly reflecting the average power output over the period. If electricity production is constant at all times (so-called baseload), then the capture price would equal the average price of the market. The capture price, or capture rate, where capture price is divided by the average price of the market, is a measure of the profile risk in the markets.

From an investment perspective, the CAPEX-heavy nature of renewables means that most costs are incurred upfront, while ongoing operational costs remain relatively low. This cost structure makes the financial viability of projects highly sensitive to revenues that exceed operational costs during operation. An example of relative shares of different LCOE components for different technologies is illustrated in Figure 11.

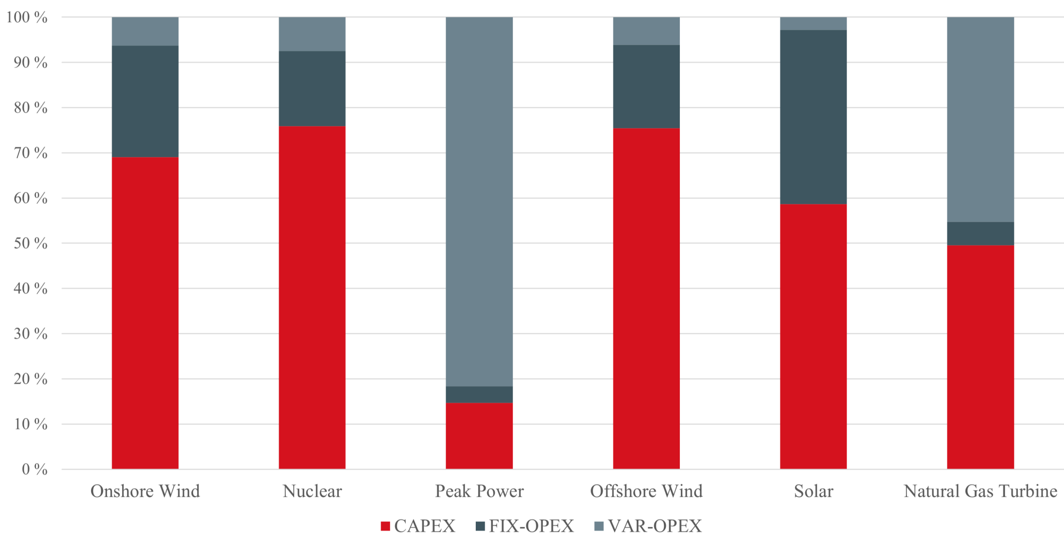


Figure 11: LCOE components of different technologies using technology costs adapted from [103] and [104]. LCOE is calculated componentwise using Equation (4). Corresponding to Eq. (4), FIX-OPEX equals to FOM and VAR-OPEX equals VOM. Peak power is assumed to represent a gas turbine using electric fuel with 40 % efficiency and fuel price of 180 €/MWh. The red part of the column illustrate that the investment costs are dominant in variable renewable energy technologies and in nuclear power. A key difference between variable renewables and nuclear is that nuclear power can offer constant power output.

As seen in the Figure 11, the situation holds for nuclear energy, where the majority of expenses are also upfront capital investments, while operating costs remain comparatively moderate. Thus at this investment perspective Finnish power system makes an interesting combination of renewable energy and nuclear with both sharing similar investment prerequisites. However, nuclear energy is able to provide stable electricity output and its financing is typically guaranteed using the Mankala principle as described in Section 3.3.3.

As noticed, the capture price can differ significantly from the baseload price and is inherently uncertain, which reduces revenue stability. Traditional baseload hedging strategies are not well-suited to variable generation, as the production profile of VRES does not align with the baseload price structure. VRES generators tend to earn lower prices during periods of abundant production and miss the high prices during scarcity, which makes their revenues insufficient to offset losses from high-price hours.

Consequently, relying solely on merchant market revenues, where income is derived from selling electricity at spot prices, is generally no longer considered bankable. Initially, when variable renewable energy first entered electricity markets, more expensive conventional units often set the wholesale price, so the presence of renewables did not significantly affect market revenues. However, as renewable penetration continued, renewable generation began to set the wholesale price more frequently, effectively eating away its own revenues. This phenomenon is known as cannibalization [12].

Figure 12 illustrates capture prices in Finland between 2023 and 2025. Capture prices have been less than average spot prices and over that period, the gap between average prices and capture prices has become greater, which illustrates cannibalization. As the LCOE of wind power is estimated to be somewhere between 40 and 60 €/MWh [103], the current observed capture prices are way too low for economically sustainable wind power industry.

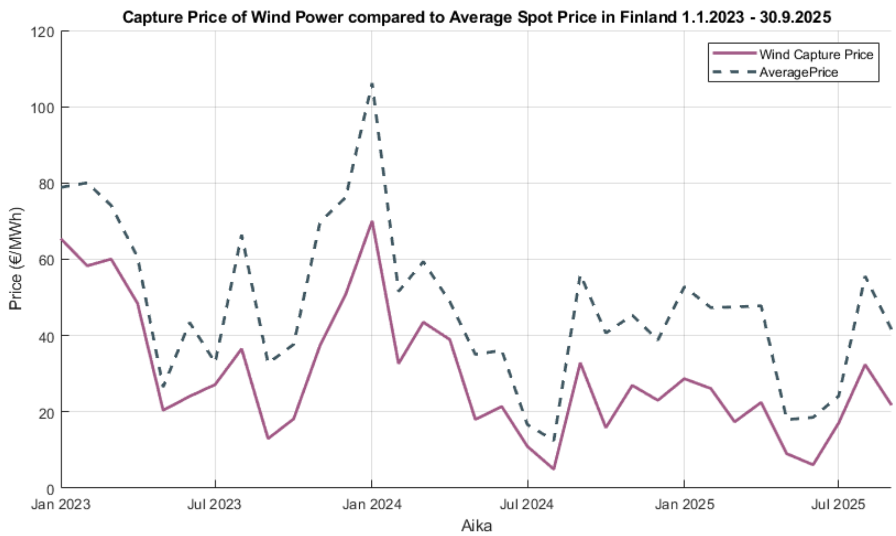


Figure 12: Capture prices of wind power in Finland compared to average spot prices. Data: [99, 105].

Because the merchant model and future capture prices are uncertain, and traditional hedging opportunities were based on average baseload prices, new instruments became necessary to make capital-intensive renewable energy projects bankable [17]. As a result, Power Purchase Agreements (PPAs) have become a central tool in renewable energy financing. PPAs not only provide predictable cash flows that help guarantee the profitability of an investment but also offer additional benefits, such as green premia, guarantees of origin, ESG compliance, and demonstration of additionality. These features can further enhance the environmental and financial impact of renewable projects, which make them more attractive to investors and stakeholders. Thus, the main conclusion for the first research question posed in the Introduction is that hedging in renewable energy markets aligns more closely with investment hedging than with cash-flow hedging.

5.1 PPA types

The term Power Purchase Agreement (PPA) serves as an umbrella for a variety of contractual structures used to facilitate the sale of electricity between a generator and the renewable energy buyer, often called as an off-taker [20]. PPAs are bilateral agreements that can be categorized according to technology type, settlement method, delivery profile, pricing structure, and characteristics of the off-taker. As the energy markets and production methods have evolved, the forms and mechanisms of PPAs have developed, and still continue to develop to address new market conditions of renewable energy.

Due to the bilateral nature of PPAs, there is no public dataset or centralized marketplace where contract information would be available. Instead, most data on PPAs come from reports published by analysis firms, trading houses, and industry associations. As the agreements are negotiated privately between parties, detailed contract terms and prices typically remain confidential. The most common forms of PPAs can be discussed in general terms, but precise contractual details can only be approximated based on available market information [106].

In general, PPAs are agreed for a long duration, typically ranging from 10 to 20 years. The long-term contracts are necessary for renewable energy developers to secure predictable revenue streams, which in turn facilitate project financing by reducing market and price risks and ultimately makes the project bankable [15, 107]. For off-takers, long-term PPAs serve as a hedge against volatile electricity prices and support corporate sustainability targets by guaranteeing access to renewable energy over the contract period [67, 106]. The PPA duration may not always cover the full technical lifetime of the project and thus they do not de-risk the investments completely [14]. Compared to standardized futures and forward contracts on organized marketplaces, which are available for a couple of years, PPAs still offer substantially longer temporal coverage [12].

PPAs are frequently categorized by the type of off-taker and by the pricing and volume settlement mechanism. Typically off-takers are separated into corporate and utilities. Corporates are private companies that procure electricity to power their own operations or to meet sustainability and decarbonization targets. On the other hand, utilities refer to corporations or public entities that provide energy services to businesses and individuals [108]. Utilities often act as intermediaries and purchase power from generators and sell it onward to end-users or aggregating it into broader portfolios.

According to Pexapark's PPA Market Outlook, corporate procurement had accounted for 73 % of the PPA contracted and reported volumes in Europe in 2023, and the remaining 27 % have been signed by utilities [109]. In 2024, role of corporates had increased even more [110]. Wind Europe, interest group of wind power generators has compiled statistics of largest PPA corporate buyers in Europe and the data of them is visualised in Figure 13. As seen in the Figure, large technology companies such as Amazon, Microsoft and Google are consistently among the largest corporate off-takers [111] and thus have driven the PPA markets and variable renewable energy investments in recent years.

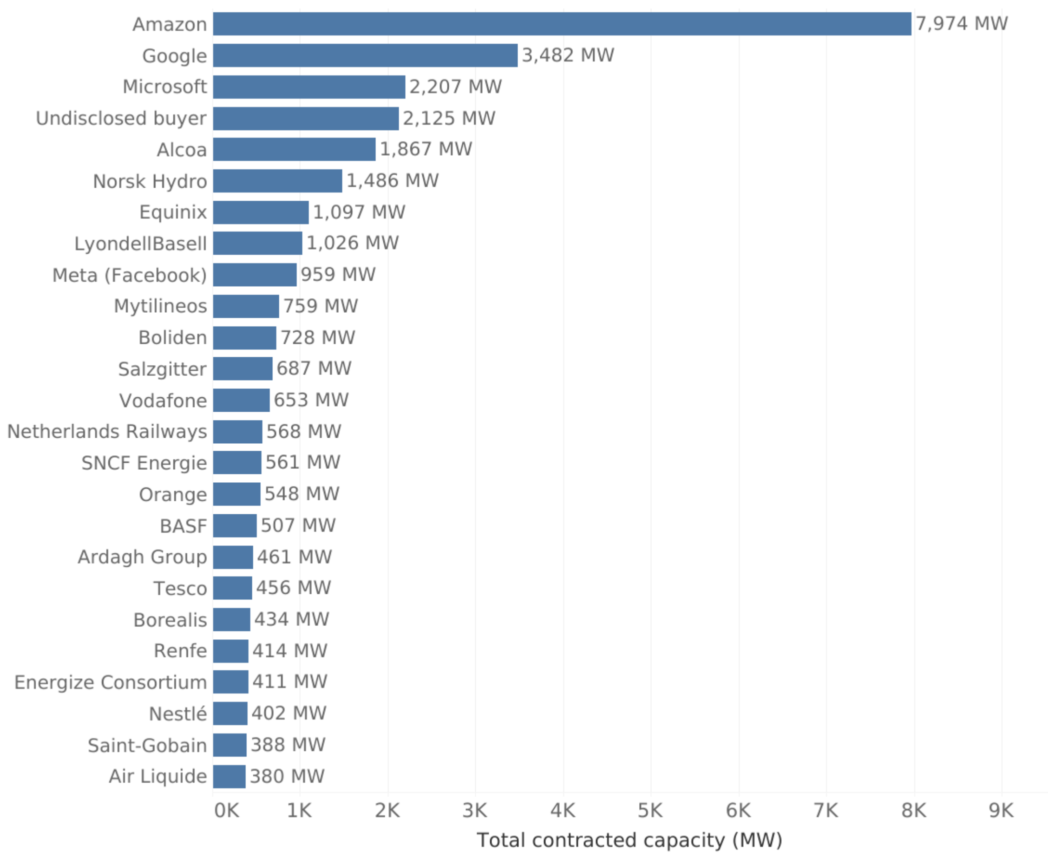


Figure 13: Largest PPA corporate offtakers in Europe [111].

At first, many PPAs mirrored conventional hedging contracts similar to those discussed in Section 3.3: fixed-volume, fixed-price (baseload) agreements that obligate the generator to deliver or to financially settle for a constant volume over the contract period. Even though the production varies, the overall volume could match with the actual production volumes. Under a baseload PPA, the seller must procure the missing electricity from the market when generation is below the contracted volume [108].

In principle, a baseload PPA can work effectively if the market price is independent of the renewable generation and the shortfall in production can be procured on a same price than the excess production is sold on the markets. Even so, the volume risk is present, if the actual production does not match the expected. In practice, however, increased price volatility and renewable cannibalisation have shown that the profile risk is significant [16] and thus baseload PPAs should be evaluated with great caution. The Markbygden wind power project, among Sweden's largest, stands as a warning example of the dangers inherent in baseload PPAs, where the electricity producer has fallen default due to a PPA [112].

To address these issues in the producers perspective, the market has shifted toward more production-linked contracts such as pay-as-produced (PaP) and pay-as-nominated (PaN) PPAs [113]. Namely, a pay-as-produced is a contract, where the offtaker pays based on actual metered generation and thus the both profile and volume risks are faded out from the producer. As off-taker is not willing to carry all this risk, pay-as-nominated (also known as pay-as-forecast) arrangements have developed. In these arrangements, buyer and off-taker settle against a nominated schedule in the day-ahead market.

As expected, there is no single comprehensive statistic available on the relative prominence of different PPA types. However, industry sources and stakeholder interviews consistently indicate that pay-as-produced PPAs have become the most common contract structure in European markets [114–116]. In these analysis, the pay-as-nominated structures may be categorized as pay-as-produced.

Since off-takers are still carrying volume and profile risks in the pay-as-produced and pay-as-nominated contracts, an intermediate contractual models have been presented. These models can be called as volume cap models or a first-MW PPA structures [117, 118]. In this model, an off-taker agrees to purchase the first fixed amount of production, for example, the first 10 MW of each hour's wind or solarpark's generation. The producers sells any generation above this threshold directly to the market. The first-MW structure provides an off-taker with more stable and predictable volume without making producer exposed to baseload obligations. First-MW models are mentioned in more advantageous PPA structures and their role in current PPA agreements is still most likely small [119].

In addition to these structural variations, PPA contracts also differ in their pricing mechanisms. Most simplistically, PPAs are based on a fixed strike price, but a variety of indexation methods have emerged. PPA contracts can be indexed to spot price or some long-term instruments, where strike price is periodically adjusted based on consumer price indices or other agreed benchmarks [120]. In addition, there can be minimum and maximum prices defined, known as cap and floor mechanisms [118]. These indexing mechanisms allow prices to develop in line with broader macroeconomic conditions.

In addition to these, one important aspect concerns balancing responsibilities, which have become a significant part of variable renewable generation. VRES have to make their forecasts day before delivery and even though forecasts have become more accurate, there is still much uncertainty of for example exact timing of a wind front. Balancing responsibilities are typically agreed on PPA contracts. Typically, balancing costs are especially important in those pay-as-produced or pay-as-nominated structures, where producer is typically responsible for the balance between nominated volumes in the day-ahead market and the actual measurable production. However, the same applies to off-taker, which is responsible for its own procurement and the measurable consumption.

Due to bilateral nature of the PPA contracts and different roles, capabilities and interests of different producers and consumers, all aspects discussed here can vary across individual agreements. Various pricing, volume and settlement mechanisms can be combined and thus the range of customized contract structures is wide. Several variants still fall outside the scope of this thesis. Omitted concepts are for example hybrid PPAs of multiple technologies, storage-PPAs or tolling agreements and pay-as-consumed profiles offered possibly by some utility traders.

5.2 Roles and interests of PPA counterparties

PPA contract is in its simplicity a contract between a power generator and an off-taker and furthermore they can be seen as contracts between developers seeking financing and corporations and public institutions seeking to hedge electricity procurement and meet decarbonization targets. For a renewable energy producer the story is somewhat straightforward, as their aim is to ensure the profitability and bankability of their projects. A long-term PPA contract provides predictable cash flows, which significantly reduce merchant price risks. The PPA price for producer is determined by the willingness to accept, which depends mostly on the levelized cost of energy (LCOE) and the financing conditions. In this sense, PPAs function as a cornerstone of project development if no subsidies are available and project developer does not have a clear vision of project's profitability on a merchant basis [121].

For off-takers, the rationale is more complicated as the physical electricity procurement for their actions is not the only aspect of the PPAs. Sustainability is an important driver in PPAs, as corporates are aiming to meet environmental, social, and governance (ESG) objectives and are required to follow Corporate Sustainability Reporting Directive in the EU. PPAs are used to demonstrate concrete progress toward sustainability and decarbonization targets. The Guarantees of Origin (GO) system discussed in Section 3.2 are an important instrument in ESG reporting, but however, due to their challenges they are not sufficient for companies that wish to demonstrate a stronger form of environmental commitment [107]. The GO system allows temporal mismatch between production and consumption, as certificates can be used within twelve months of generation. Therefore, renewable claims may not correspond to real-time or location-based matching of renewable supply and consumption. Thus, initiatives such as RE100 and other voluntary frameworks have emerged to promote more stringent sourcing criteria and "additionality", which is the idea that renewable purchases should lead to new renewable capacity being built rather than merely redistributing existing supply [122].

In this context, PPAs are perceived as the most credible means for corporates to achieve renewable sourcing and demonstrate additionality. A greenfield PPA directly supports the financing of new renewable projects, which is why it is even referred to as "the best hedge against greenwashing" [121]. Nonetheless, recent empirical work shows that the effect of corporate PPAs on additional renewable investment is heterogeneous and some PPAs may not deliver the claimed decarbonisation benefits and therefore risk being used for reputational purposes rather than meaningful energy-transition impact [123]. As shown in Figure 13, large technology and data companies are currently the most active off-takers in European PPA markets. These firms are typically characterized by high electricity consumption, long-term planning horizons, and publicly stated net-zero commitments [124].

When considering the pricing of Pay-as-Produced PPAs, the willingness to pay is linked to the off-taker's wholesale market exposure and expectations of future capture prices [124, 125]. For a Pay-as-Produced PPA, the fair value on the producer's side is determined by accounting for the capture effect and balancing costs, as illustrated in Figure 14. The fair value can be further increased by Guarantees of Origin and the possibility of an additionality or green premium [118]. Additionality allows corporations to actively accelerate the deployment of new renewable capacity beyond what purely market-driven investment would achieve [118]. In the long term, however, the value of this type of premium is likely to diminish, as noted by several interviewees, because coal-based generation is likely to disappear from the electricity mix, and therefore new renewables investments are no longer contributing to displacing CO_2-emitting alternatives [126]. It should be noted, however, that conceptually, differences between PPAs for existing plants and those for new plants will continue to exist, even if they have not been valued differently.

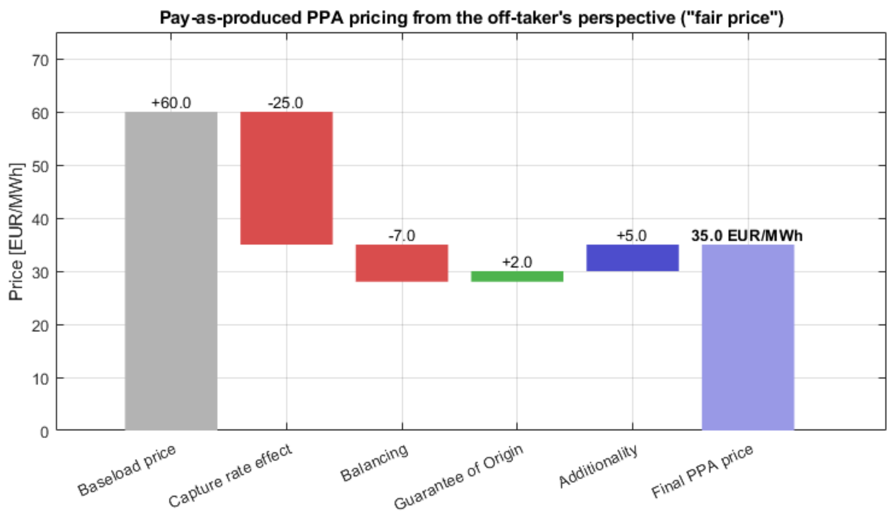


Figure 14: An example of fair value creation of a Pay-as-Produced PPA Contract, adapted from [118]. The values shown in this Figure are arbitrary. Baseload price is the average electricity price. After taking the capture rate effect into account, we get the market value for electricity in PPA contract. The market value is further reduced due to balancing costs. Guarantees of Origin and Additionality possibly increase the total fair value for the PPA contract.

Many pioneering corporates have noticed that prominent Pay-as-Produced PPAs are not sufficient on their own to guarantee temporal matching between renewable generation and electricity consumption. This inspiration has led to the emergence of 24/7 targets and concept of 24/7 renewable PPAs, where each hour of consumption is matched with renewable generation in real time. Compared to annual certificate-based accounting, 24/7 procurement represents a more credible approach to decarbonization by ensuring that renewable energy supply closely follows actual demand [127].

Achieving this temporal alignment requires a diversified combination of generation assets, storage, and demand flexibility to cover periods of low variable renewable output. Pay-as-Produced PPAs may be oversized, but this strategy would lead to high curtailment. A more stable production profile can be achieved by capping variable renewable energy procurement to a defined level. Combining different technologies such as solar and wind power and locations of generation facilities, can increase the number of hours with steady power output. At some point, integrating batteries becomes more feasible than overprocuring renewable generation, and even flexible assets like motor power plants may become practical for covering the last megawatts. However, the simplest solution would be demand-side flexibility, but its practicality is defined by the opportunity costs between stopping the consumption and the 24/7 generation costs [127, 128].

The instruments for such electricity procurement include the aforementioned first-MW PPAs, whose valuation principles differ from conventional Pay-as-Produced PPAs. These contracts are designed to allow the off-taker to procure the entirety of the electricity required for its operations [129]. From the producer's perspective, however, the effective levelized cost of energy (LCOE) is likely to increase significantly, since fewer operating hours are included in contracted portion and valuating the residual production that falls outside the contracted share becomes more complex and is likely small [73, 130]. As these portfolios increasingly resemble baseload generation, the opportunity cost of 24/7 instruments for the off-taker corresponds to the expected future baseload price, potentially with an additionality premium. If this expectation is sufficiently high, First-MW type structures may become economically attractive, as they can effectively reset the LCOE level for the contracted production and make the renewable investments profitable [125, 130].

5.3 PPAs and physical electricity markets

The interaction between Power Purchase Agreements (PPAs) and physical electricity markets depends strongly on the contract type. Similarly with financial contracts described in Section 3.3.4, also financial PPA contracts are typically settled against the day-ahead market price. Both producers and off-takers will have to participate in physical electricity markets for physical electricity procurement. In case of a physical PPA, the electricity flows directly from producer to off-taker and the physical electricity market is not necessarily used for the transaction.

The most common PPA format, Pay-as-Produced (PaP) PPA, is most commonly financially settled based on the producer's actual generation profile. The producer sells its generation on the day-ahead or intraday market and receives (or pays) the difference between the realized market price and the agreed PPA strike price. This structure is often called effectively a contract-for-difference (CfD) [20, 109]. Cash-flows in this kind of agreement are illustrated in Figure 15.

In this kind of agreements, the income for producers is tied to the physical market outcome, and thus producers are incentivized to maximize output whenever generation

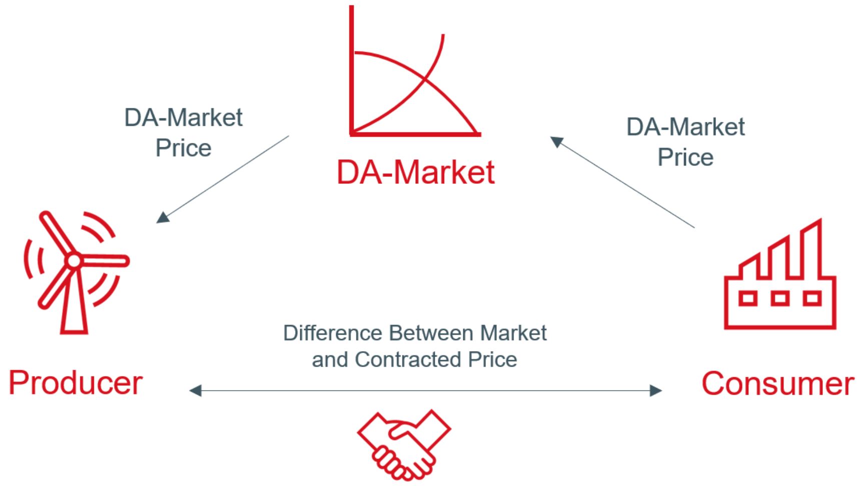


Figure 15: Schematic description of the cash-flows between physical markets, producers and consumers when financial contracts are present. Producers and consumers buy and sell their physical electricity through day-ahead market (DA) and pay or get the market price. If the market price differs from the contracted price, producer or consumer compensate each other such that both parties have effectively the contracted position.

is technically possible. Even when market prices turn negative, continued production will remain rational, as the PPA compensation may offset losses in the spot market. This behavior typically results in bidding at zero or even negative price levels in physical electricity market. To mitigate such effects, some PPAs include floor clauses or negative-price caps, under which hours with extremely low prices are excluded from settlement [131].

Financial electricity markets should not limit participation in flexibility of physical markets, but depending on the PPA structures and technical capabilities, there may exist elements that decrease the incentives for renewables' flexibility. In principle PPAs do not limit participation in balancing markets, as producers can still offer up- or down-regulation capacity as long as the expected balancing revenues exceed the potential reduction in PPA income. Depending on the PPA structure, producing electricity with sub-zero market prices could be better to avoid. However, participation in physical markets for variable renewable energy is also influenced by other technical or external factors rather than contract design. These include e.g. icing risk, physical ability to control power plants, operational safety margins, or eligibility conditions of governmental support schemes. Producers operating under PaP PPAs typically remain balance-responsible parties, and deviations between forecasted and realized generation are settled through the imbalance mechanism. Hence, the imbalance risk is retained by the producer, and its management has a significant influence on total profitability.

On the other hand, physical electricity markets can create substantial arbitrage opportunities for parties operating under PPAs. Arbitrage in this context refers to taking offsetting market positions across different market layers to capture value from price volatility [132]. In practice, this may involve strategically underselling expected wind production in day-ahead market and later buying back any shortfall in intraday or balancing markets when prices move favorably. A well-timed adjustments of physical nominations, combined with flexible participation in balancing services, can therefore generate considerable additional income, especially during periods of large forecast errors or rapid system-wide imbalances. These opportunities become even more important when electricity is coupled with other commodities such as hydrogen or synthetic fuels coupled with 24/7 renewables procurement, which together allow benefiting from the temporal price differences across markets.

5.4 Risks of PPAs

Power Purchase Agreements (PPAs) are fundamentally risk transfer instruments designed to allocate market and operational risks between electricity producers and off-takers. However, despite their hedging nature, PPAs still involve several categories of risk that can affect both contracting parties [108].

- Market price risk arises from the fluctuations in physical market prices. In a fixed-priced Pay-as-Produced PPA structure, the risk is between the contracted price and the price of the underlying electricity. If the price in physical market falls below the contracted price, the off-taker pays an extra relative to the market. Similarly, producer is effectively insulated from the market price risk, but if the price rises, the off-taker will benefit from the hedge. Thus the market risk in a PPA contract shares similar properties with one in those traditional financial hedging instruments discussed in 3.3.2.

- Volume risk arises from the variable and weather-dependent nature of renewable energy generation. Because the producer cannot control the output, the total energy delivery can differ from the forecasted value. Closely related is the profile risk, which refers to the temporal mismatch between the production profile of the renewable generator and the consumption profile of the off-taker. When production occurs during periods of low prices or low demand, the economic value of the delivered energy decreases, even if total annual volumes match expectations. In a Pay-as-Produced PPA the producer is effectively secured against both these risks, and thus the risk is carried by off-taker in these contracts [108].

- Counterparty risk arises from the possibility that one of the contracting parties may default or fail to meet its financial or operational obligations during the PPA term. Since PPAs typically span 10–15 years or more, the long time horizon increases exposure to changes in the counterparty's credit quality. Similarly as in bilateral traditional contracts, the risk can be mitigated using collateral agreements, credit limits or risk premia [133].

- Renegotiation risk: Since PPA contracts do not typically span the entire technical lifetime of a renewable energy project, renegotiation risk and overall future revenue uncertainty are relevant considerations. For example, after a 15-year PPA contract ends, a wind or solar project may still have 10–15 years of operational lifetime remaining [134]. In LCOE calculations, the cost is averaged over the full technical lifetime of the project, which thus assumes that similar revenue levels will be maintained over the whole project timeline and thus after the initial PPA term. At the time of investment decision and signing the initial PPA, post-PPA revenues are uncertain and exposed to market dynamics and policy development.

  Depending on the outlook of the future revenues, project developers may want to exceed the LCOE technology cost levels in initial PPA such that the project is profitable even if the future revenues would be negligible. Thus, as risks in general, the future market risk is making the project more risky and thus more expensive. Options for the post-ppa period are renegotiating with the original off-taker, entering into a new so-called brownfield PPA of an existing unit [135], or selling electricity on the merchant market.

- Imbalance risk is one of the most critical operational challenges of VRES. Imbalance risk arises if the procurements do not match the real production or

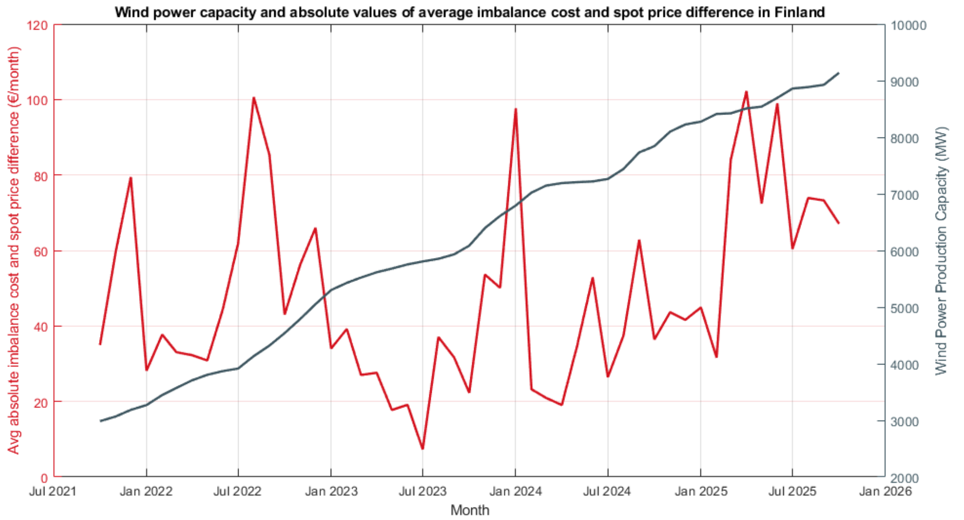


Figure 16: Illustration of monthly average absolute values of difference between imbalance cost and day-ahead market prices between 2021 and 2025 in red. The Figure illustrates that differences between spot price and imbalance prices can be significant. The wind power production capacity illustrated over the same period with gray. Data: [105, 136, 137]

consumption. A transmission system operator has to buy reserves to keep the electricity system balanced, and if the deviation is significant, the imbalance price can be high. Figure 16 illustrates the recent trend of imbalance cost.

In Finland, imbalance risk is particularly significant because much of the renewable generation capacity is geographically concentrated in certain areas. This means that production units are often exposed to the same weather-driven fluctuations simultaneously and, in effect, they themselves are the source of the imbalance risk in the system. Imbalance risk is carried by renewable energy producers, if they have agreed to control the operations based on the day-ahead forecast or nomination. As the market participants are imbalance price-takers, the only way to mitigate the balancing risk is to reduce probability of such events by keeping own electricity balance under control. In some cases, this can be achieved through physical flexibility assets, such as on-site battery storage, which can help balance deviations caused by forecast errors and in some cases, adjusting the electricity market procurements such that positions can be clarified in for example intraday-markets. Diversifying the geographic distribution of renewable energy production, for example by building wind power in Eastern Finland, would also reduce systemic exposure to correlated imbalance events [138].

6 System dynamics model

6.1 Purpose and limitations of the model

The purpose of the system dynamics model is to develop a structured representation of how different interactions and causal mechanisms shape the long-term investment conditions of variable renewable energy. This approach will answer the third research question stated in Introduction and complements the insights obtained from the literature and expert interviews. Visual causal loop diagrams are valuable as such and the simulations help to address common "what-if" scenarios. The model helps to explore how the renewable energy investment environment behaves under different assumptions about control variables while keeping other external factors constant. These assumptions are referred to as *ceteris paribus* assumptions. In this sense, the model's role is to support intuition and reasoning rather than to provide definitive truths or precise forecasts.

The model represents the renewable energy subsystem and is not intended to depict or forecast the full energy system. Although the model is based on numerical inputs and functions, its result should be interpreted primarily in qualitative terms while keeping the limitations and assumptions in mind. Its empirical grounding is based on the Finnish electricity system, which has been one of the most rapidly expanding renewables markets in Europe [104]. Consequently, the constant values and reference capacities are aligned broadly with Finnish conditions to provide a realistic operating context. Numerical values and parameters are discussed in the following sections with description of the model variables, but an overview of the system setup is summarized in Table 1. The complete model is included in Appendix C.

The model includes deliberate simplifications. The model considers only wind power and omits solar power. Solar and wind power do not share same properties and thus they should be considered separately, but since solar energy plays a smaller role compared to wind energy in Finland [104], solar energy is removed from the model for simplicity. Baseload and flexible electricity consumption are treated as an exogenous element in the model and possible feedback from electricity prices and availability are not modeled. They are specified as a constant level in the baseline formulation, and later adjusted as a control variable to explore how changes in consumption influence the system's behavior. Baseload electricity production is assumed constant and flexible generation is not explicitly included in the model. Carbon pricing is excluded from the model, as it is not the focus of this study and its effects on renewable energy

Table 1: Overview of the central level variables of modeled electricity system.

Component	Description of an initial setup
Baseload consumption	8000 MW (constant demand)
Flexible consumption	4000 MW (adjustable demand incl. cross-border flows)
Baseload generation	4000 MW (nuclear capacity)
Variable generation	Wind power

infrastructure are considered external, acting indirectly through the residual price. The price formation mechanism itself is simplified and does not incorporate seasonal variation, intraday structure, or stochastic weather patterns. Because PPA contracts function as intermediating arrangements rather than physical components of the electricity system, they are not modeled as explicit variables.

Given these limitations, the model cannot represent the full structure or give forecasts of the future electricity system. Rather, it isolates and examines the subsystem related to variable renewable energy and the long-term investment dynamics surrounding it. The model aims are supported by the following precise research questions:

- How do renewable-energy investments grow over time, and what mechanisms cause their share in the electricity system to slow down or saturate?
- How do construction delays influence the timing and effectiveness of renewable-capacity expansion?
- How do changes in investment risks and financing conditions shape the development of new renewable capacity?
- How does additionality support influence renewable-energy investments and their long-term integration into the system?
- How can the electricity system accommodate a higher share of renewable energy, and what role do baseload demand, flexibility and price signals play in this?

To answer these research questions, the system dynamics model is built and all simulations are conducted using Vensim PLE software. The model uses a one-year time unit with an integration step of $\frac{1}{16}$ years which corresponds to 23 days. Long integration unit reflects the investment-driven focus of the analysis rather than short-term operational dispatch as the hourly level is intentionally omitted. Models are run for 30 years, but if interesting behavior is captured quicker, only the relevant part of the simulations will be visualised in results.

6.2 Stock and flow variables

The core of the system dynamics model are stock variables representing capacities of different technologies and flow variables changing states of these variables. There are stock variables for each variable included in Table 2. Wind power production capacity (WPPC) illustrates the accumulation of installed production capacity over time. The state of wind power production capacity changes through flow variables wind power go-live (WPPGL) denoting capacity starting production after construction and wind power production decommissioning (WPPD) denoting capacity exits after its technical lifespan. The capacity exit does not depend on the market values, because operational costs of wind power are assumed small and it will be better to keep the plant operational even though the market value is small as it still exceeds operational costs. The value of wind power production capacity at time t can be solved using difference equation

$$\mathrm{WPPC_t} = \mathrm{WPPC_{t-1}} + \mathrm{WPPGL_t} - \mathrm{WPPD_t}.$$

However, since simulation period in this analysis is shorter than the lifespan, the WPPD is omitted in this analysis.

In addition to production capacity, the wind power projects under construction (WPPUC) is modeled as a separate stock. It allows the analysis of investment delays. Projects transition from under construction to operational through the flow wind power commercial operation, which takes construction delay into account. The delay between investment decision and commercial operation is assumed to be constant of 3 years in this model, which describes a typical construction time from investment decision to project going online [104]. Pre-studies and environmental impact assessments occur before the investment decision, and permitting processes often extend the overall project timeline, but these stages are excluded from the model for simplicity. At the top of capacity in production and in construction, a variable of cumulative wind power (CWPPC) capacity is included in the model to represent the total amount of wind power installed throughout history.

Similar stock and flow structures are also used for the other variables such as baseload electricity production capacity, baseload electricity demand and flexible electricity demand. Baseload electricity production is generation that is always dispatched first in this setup, but its capacity is not the point of interest of these considerations and is therefore kept constant. As illustrated in Table 1, baseload generation of 4000 MW reflects the magnitude of Finland's nuclear capacity of five reactors, which are kept running in almost all conditions. Initial value for baseload consumption corresponds to the country's average annual electricity use, as 72.7 TWh of electricity was consumed in 2024 [139], which makes it a bit over 8000 MW per hour. Flexible demand is modeled to be activated at zero price, avoiding wasted renewable production but not increasing the electricity price. The flexible demand of 4000 MW can respond to consumption of storage, other demand-side flexibility and available cross-border transmission.

6.3 Endogenous auxiliary variables

Auxiliary variables are used to support calculations between flow variables. They help express intermediate relationships and clarify how stocks and flows interact in the model. Variables generated by the model's internal structure are considered endogenous. Externalities, i.e., variables that do not have any feedback from the model, are discussed separately.

The wind power production profile is modeled using a Beta distribution. Figure 10 represents the distribution of power over time, i.e., the instantaneous power output, but for modeling, the distribution of the total energy produced over a period is more relevant. The energy produced over time is proportional to the integral of the power, which corresponds to the first moment (expected value) of the power distribution. If the instantaneous power follows a Beta(α, β) distribution, the distribution of energy can be approximated by a Beta$(\alpha + 1, \beta)$ distribution (see Appendix A for detailed motivation). The resulting cumulative distribution function is illustrated in Figure 17.

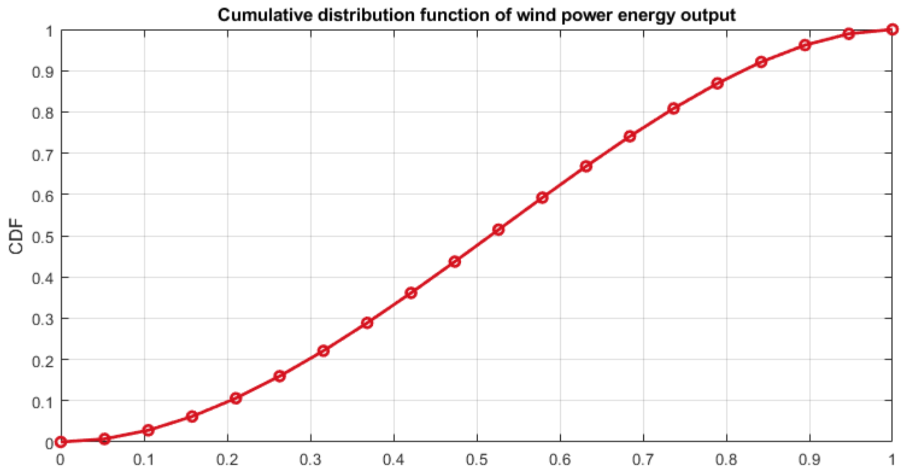


Figure 17: Cumulative distribution function of wind power energy output. The power distribution is calculated using Beta$(\alpha + 1, \beta)$ distribution with parameter values $\alpha = 0.995$ and $\beta = 1.8919$, which are obtained from fit in Figure 10. For simulation purposes, the cumulative distribution is discretized into 20 probability intervals. The lookup function is generated by evaluating the cumulative distribution function at uniformly spaced probability levels (0, 0.05, 0.1, . . . , 1) and applying linear interpolation between these points.

In the model, the market value of wind power depends on whether the market price is determined by wind generation itself or by other, more expensive production technologies during wind power generation. If renewable production is sufficient to meet the remaining demand after baseload generation, the market price is set by their low marginal cost, which is approximated as zero. While renewable generators do incur nonzero operating costs, these costs are small relative to those of conventional marginal technologies and do not materially affect the price-setting mechanism examined in this model.

The threshold fraction of renewable production, θ, represents the share of installed wind power capacity required to meet the demand remaining after reducing the always-running baseload generation. Let WPPC denote the wind power production capacity, TBD the total baseload demand and WPPC the baseload production capacity. Then, the threshold is defined as

$$\theta = \frac{\mathrm{TBD} - \mathrm{BPC}}{\mathrm{WPPC}}. \tag{8}$$

For consistency with Beta-distribution, this fraction is constrained to the interval $[0, 1]$. If there is no wind power, or if the installed wind power capacity is smaller than the difference between total demand and baseload production capacity, the threshold fraction equals 1. As nominal wind power capacity exceeds this difference, the fraction begins to decrease. If wind power generation denoted by random variable X is higher than the threshold, the market price is set by low marginal cost. The share of this production S_R is obtained from the cumulative wind power energy distribution $F_X(\cdot)$ illustrated in Figure 17 as

$$S_R = \Pr(X > \theta) = 1 - F_X(\theta). \tag{9}$$

Thus, S_R captures the share of periods in which wind generation drives prices to the low-cost level.

The capacity factor describes the ratio between the actual average wind-power production and its theoretical maximum output. The capacity factor is derived directly from the fitted Beta distribution that represents normalized wind-power production. The expected value of the Beta distribution is

$$\mathbb{E}[X] = \frac{\alpha}{\alpha + \beta}, \tag{10}$$

which represents the fraction of nominal production capacity generated on average. Using the fitted parameters, the resulting capacity factor η_{tech} is approximately 0.345, which aligns well with observed Finnish onshore wind data [140]. The capacity factor is initially set to the technical value, but feedback from curtailment can reduce delivered energy and lower the actual capacity factor.

Curtailment arises when renewable generation exceeds the demand that remains after baseload production and available flexible demand have been taken into account. In analogy with the probability that renewables set the market price, curtailment is computed using a threshold (θ_C) that compares demand to renewable production capacity. The relevant threshold is

$$\theta_C = \frac{\text{TBD} + \text{FDC} - \text{BPC}}{\text{WPPC}},$$

where, TBD is total baseload demand, FDC the flexible demand capacity, BPC the baseload production capacity, and WPPC the wind power production capacity. The value is constrained again to the interval $[0, 1]$ in the model to align with the Beta-distribution definition. Because flexible demand extends the amount of renewable production the system can absorb before curtailment becomes necessary, this curtailment threshold is always less than or equal compared to the price-setting threshold θ defined using Equation (8). Renewable generation exceeding this threshold relative to installed capacity is considered curtailed in the model.

The random variable describing wind power generation with curtailment is $X_{\text{delivered}} = \min(X, \theta_C)$, where $X \sim \text{Beta}(\alpha, \beta)$. If $X \le \theta_C$, the produced fraction is fully delivered but, if $X > \theta_C$, production exceeds what the system can absorb and the delivered fraction is capped at θ_C. Capacity factor of wind power is thus $\eta_{act} = \mathbb{E}[\min(X, \theta_C)]$. The expectation of delivered wind production, accounting for curtailment, can be expressed as

$$\eta_{\text{act}} = \mathbb{E}[\min(X, \theta_C)] = \int_0^1 \min(x, \theta_C)\, f_X(x)\, dx = \int_0^{\theta_C} x f_X(x)\, dx + \int_{\theta_C}^1 \theta f_X(x)\, dx,$$

where $f_X(x)$ is the probability density function (PDF) of the normalized wind production $X \sim \text{Beta}(\alpha, \beta)$, and θ_C is the curtailment threshold. The integral can be split into two parts containing the part below and above the curtailment threshold. In interval $[0, \theta_C]$ there is no capping, and the integral can be expressed as

$$\int_0^{\theta_C} x f_X(x)\, dx = \eta_{\text{tech}}\, F_{X^+}(\theta_C),$$

where F_{X^+} is the cumulative distribution function of the $\text{Beta}(\alpha + 1, \beta)$ distribution and η_{tech} is the technical capacity factor. For complete derivation, see Appendix A.3. For the second integral,

$$\begin{aligned}\int_{\theta_C}^{1} \theta_C\, f_X(x)\, dx &= \theta_C \int_{\theta_C}^{1} f_X(x)\, dx \\ &= \theta_C\big(1 - F_X(\theta_C)\big),\end{aligned}$$

where θ_C is the curtailment threshold and $F_X(\cdot)$ is the cumulative distribution function of $\text{Beta}(\alpha, \beta)$ distribution. Combining these two equations, the total capacity factor yields $\eta_{\text{act}} = \eta_{\text{tech}}\, F_{X^+}(\theta_C) + \theta_C\, \big(1 - F_X(\theta_C)\big)$, which is used in modeling. Curtailment directly reduces the achievable capacity factor when wind power production capacity increases beyond the system's absorption capability. Total variable electricity generation is then $E_{\text{var}} = \eta_{\text{act}} \times \text{WPPC}$, where WPPC denotes installed wind power production capacity.

Investments in wind power are driven by the willingness to invest in wind power. This willingness is determined by the balance between the Levelized Cost of Energy (LCOE) of variable production and the willingness to pay for variable production. For simplicity, the expectation of future market value for wind power production is equal to the current market value. The willingness to pay for variable generation depends on the market value and possible unevaluated green premia. When the willingness to pay exceeds the LCOE, there is a larger margin for producers to negotiate favorable contract prices. Conversely, if market prices decline, there are less room for negotiations, and new investments become less attractive. The model assumes that there are no external constraints such as component availability limitations or significant grid connection delays beyond the defined investment period.

The LCOE, calculated by Equation 4, depends on technological development, financing costs, the capacity factor of variable production, and the expected operational lifespan of wind energy assets. The technological development is simulated by multiplying the initial capital and variable cost with the factor of technology development. The financing costs (Weighted Average Cost of Capital, WACC) describe the total cost of capital and are used as the discount factor in the LCOE calculation. Financing costs depend on the risk-free rate and uncertainty about future incomes.

Empirically grounding technology cost projections is challenging, and therefore modeling requires assumptions and choices. In this approach, technology costs in LCOE are assumed to decline over time and with increasing cumulative wind power capacity. The cost decrease is simulated using a lookup function illustrated in Figure

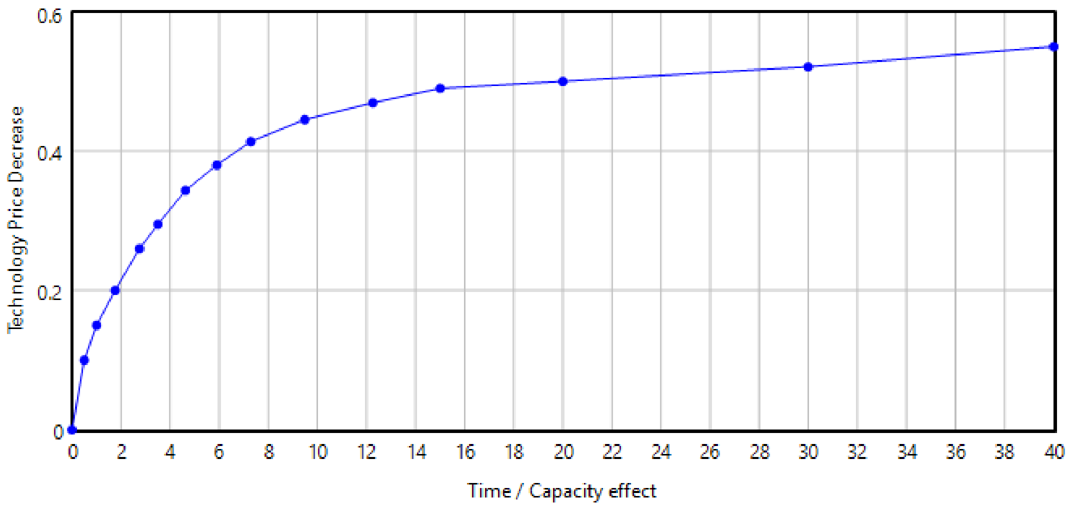


Figure 18: Lookup function describing the relative technology price decrease as a function of time and cumulative installed wind power capacity.

18. Its input variable is defined as

$$x = \frac{\min(\text{Time} - \text{Initial Time}, 30)}{5} + \frac{\text{Total Cumulative Wind Power Capacity}}{1000},$$

where the first term in Equation represents the time-dependent technological progress capped at 30 years and the second term captures the experience-based cost reduction effect based on the total cumulative installed wind power capacity (in MW). The marginal effect of these drivers diminishes over time as early development stages deliver large cost reductions through easiest efficiency improvements, manufacturing optimizations, supply chain learning and scale effects. As cumulative experience grows, remaining improvements tend to require more complex engineering, materials innovations, or fundamental redesigns, and consequently, each additional unit of installed capacity contributes progressively less to reducing overall technology costs [103]. In this modeling choice, if no capacity is added in the model, the costs reduce by approximately 38 % in 30 years. Each 1 GW of added capacity will generate the same effect as 5 years of time-based improvement would do and thus the increase in installed capacity is a significant factor.

6.4 Externalities

The model includes several external factors that influence outcomes but do not depend on the internal feedback loops. These factors are introduced as scenario inputs rather than variables shaped by system behavior.

- **Price when renewables do not set the price**: The model assumes an externally defined constant average electricity price for hours in which variable renewable energy does not determine the marginal price. By default, this value is set at 75 €/MWh and remains unchanged throughout the simulation. In reality, even when renewables do not set the price, they shift the supply curve to the right, which tends to lower prices as more expensive generators are not needed for meeting the demand. However, several mechanisms can counteract this merit-order effect. Due to this effect, the number of operating hours for more expensive generation is limited, and their marginal costs may increase or such units may exit the market entirely due to the missing-money problem. This complex dynamics may lead to increased volatility of the prices, which can also increase renewables' market value. In Nordic electricity system, share of hydropower, which is valuated by its opportunity costs, is significant and its bidding prices may increase due to possibility of higher incomes with higher price. In addition, some flexible consumption such as electric boilers have marginal costs significantly above zero, and can thus introduce price steps that stabilize prices at higher levels. Transmission constraints also strongly influence price formation and can prevent further reductions. Keeping the value constant is therefore a deliberate modeling choice to reduce complex assumptions.

- **Risk-free interest rate**: The risk-free rate is treated as an external macroeconomic condition. It is not determined by electricity-market behavior but strongly affects financing costs and the attractiveness of long-term investments. Changes in the risk-free rate shift the overall cost of capital and provide a way to explore how broader financial conditions propagate into renewable-capacity development. By default, the model uses 6 % discount rate aligned with [104].

- **New flexible and baseload electricity demand**: The entry of new, large-scale electricity demand is represented as an external driver. It is often presented, that there is a chicken-and-egg problem present in the green transition, as new electricity production requires electricity consumption, but electricity consumption requires access to clean electricity production [141]. However, renewable energy capacity has increased rapidly in Finland and the electricity price is very competitive [104], but consumption investments have not proceeded with the same rate [142]. The availability of affordable renewable energy can encourage such investments, but their materialization is largely affected by other external factors. Therefore electricity consumption changes are kept outside the endogenous model structure as a control variable.

- **Technical capacity factor** (η_{tech}): The long-term technical capacity factor for renewable technologies is also included as an external parameter. While it is influenced by weather patterns and turbine properties, these factors are not dynamically simulated in this work and remain constant across scenarios. It is therefore included only to define the relationship between installed capacity and expected energy output, not as a policy lever. The capacity factor used in the modeling is 0.345 obtained from the Beta-distribution fit from empirical data.

6.5 Feedback loops

The model includes multiple feedback loops that describe the dynamic interactions between investment decisions, capacity development, and cost reductions. These dynamic loops together determine the resulting market environment.

6.5.1 Technology development

First key reinforcing feedback loop (R1) is illustrated in Figure 19. The loop can be called technology development effect. In this loop, willingness to invest in wind power drives wind power investment decisions, which increase the stock of wind power under construction. When construction is completed, the capacity transitions into wind power production capacity.

Improved technology development leads to a reduction in the Levelized Cost of Energy (LCOE) of variable production. Lower LCOE, in turn, increases the profitability and attractiveness of new investments, and further reinforces the willingness to invest. This forms a positive (reinforcing) feedback loop, where growth in cumulative capacity supports further growth.

However, in the broader system, this reinforcing process is balanced by other loops. These balancing loops prevent unlimited exponential growth and represent the market and technical constraints that limit expansion. It should also be noted, that speed of technology development is also slowing down because of the

6.5.2 Market cannibalization effect

Another key feedback mechanism in the model is the balancing feedback loop (B1), shown in Figure 20. This loop captures how increasing wind power capacity affects the market value of wind power generation and, consequently, future investment decisions.

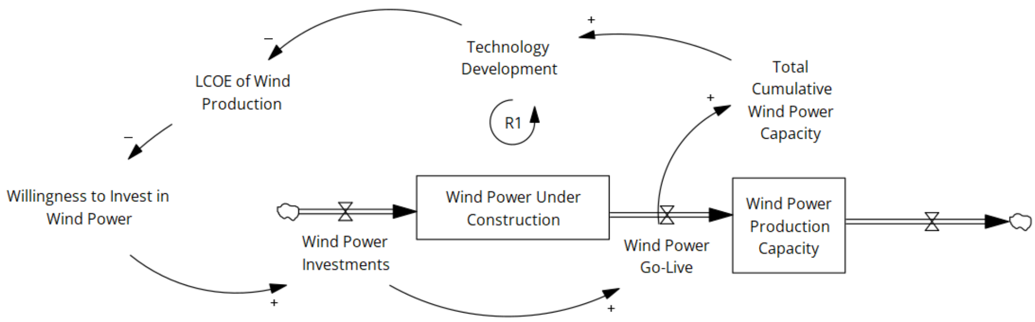


Figure 19: Reinforcing feedback loop (R1) of wind power capacity development. Willingness to invest in wind power leads to new wind power investment decisions and construction, which raise total installed capacity. Higher capacity supports development and learning effects, which reduce the levelized cost of energy (LCOE). In this context, the LCOE represents the expected levelized cost, as it includes strong assumptions about future operating hours. This creates a self-reinforcing growth mechanism for renewable energy expansion.

As wind power under construction transitions into wind power production capacity, the total variable energy producible increases. When the share of hours in which wind power set the market price rises, the market value for variable production tends to decrease due to the cannibalization effect.

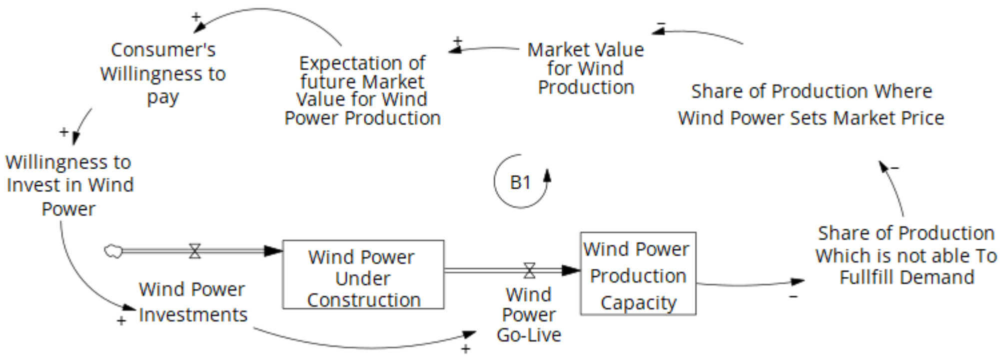


Figure 20: Balancing feedback loop (B1) of market value for wind power production. The model assumes that wind power production share the same properties regarding production timing and profile. The loop can be called cannibalization effect.

A lower market value reduces the expectation of future market value for variable production, which decreases the consumer's willingness to pay for new renewable energy contracts, such as PPAs. Consequently, the willingness to invest in wind power declines, which leads to fewer wind power investment decisions and slowing down further capacity growth.

This creates a balancing feedback loop (B1) that stabilizes the system by counteracting the self-reinforcing growth observed in loop R1. While the reinforcing loop drives technological and investment growth, this balancing loop limits expansion by incorporating market saturation effects, which thus guarantees a realistic long-term market behavior for the model [143].

A key assumption underlying the resulting long-term equilibrium in electricity markets is the so-called no-profit rule. In economic theory, in perfect markets, the average revenues from electricity generation should equal the total costs of electricity generation in equilibrium state. More precisely, the LCOE should equal the market value of electricity produced, i.e. LCOE = MV [144]. This condition guarantees that unprofitable technologies gradually exit the market and technologies being able to recover their costs enter or remain in the markets. In general, the world is not in equilibrium, but such a theoretical background makes the balancing loop B1 behavior justified.

6.5.3 Uncertainty effect and risk mitigation through PPAs

Increasing the Levelized Cost of Electricity (LCOE) of variable production increases uncertainty about future incomes. Higher costs raise the risk of unprofitable market

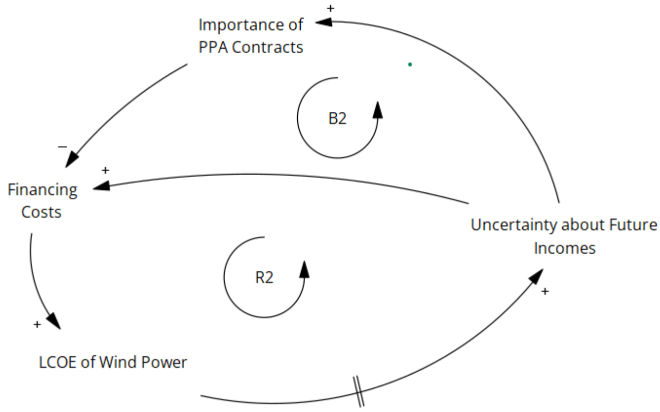


Figure 21: Feedback loops between financing costs, LCOE, uncertainty, and PPAs. Loop R2 represents the reinforcing feedback between uncertainty and financing costs. Loop B2 illustrates the balancing effect of PPAs mitigating uncertainty and financing costs.

outcomes, which in turn increases financing costs, since investors and lenders demand higher returns for perceived risk. Higher financing costs then further increase LCOE, reinforcing the uncertainty effect (loop R2 in Figure 21).

Power Purchase Agreements (PPAs) mitigate this self-reinforcing loop by providing predictable income streams for renewable producers. As the incidence of PPAs increases, uncertainty about future incomes decreases, leading to lower financing costs and thus improved investment conditions. This balancing feedback (loop B2 21) highlights the stabilizing role of PPAs in renewable energy investment dynamics.

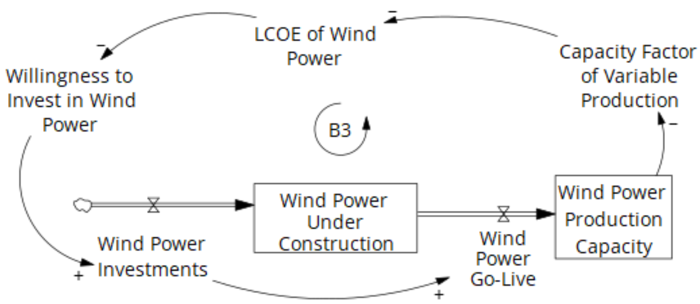


Figure 22: Balancing loop B3 illustrates the decreasing capacity factor due to production capacity increase. Decreasing capacity factor in turn increases LCOE and thus weaken investment conditions, which results in balancing behavior.

The effect of LCOE on uncertainty occurs with a delay illustrated with a delay mark in Figure 21. The cost structures are not instantly reflected but market participants gradually update their expectations of project profitability and risk after observing market trends, policy signals, or financing outcomes from recent projects. However, the modeled delay is short (2 months) and its effect is thus small. Still, the delayed response amplifies the self-reinforcing loop (R2) and undermines the importance of PPAs (loop B2) to provide predictable revenues when market adjustments are made.

6.5.4 Curtailment effect

Curtailment introduces additional balancing effects in the dynamics of renewable energy investments similar to market cannibalization effect. As total variable production capacity increases, periods of generation exceeding grid capacity or demand flexibility become more frequent. Higher curtailment lowers the realized capacity factor of variable generation, which reduces the total market value and also raises LCOE. These effects together limit the amount of new investments, which can be seen as balancing loop B3 in Figure 22.

7 Simulation results and discussion

Computer simulations are performed to answer the research questions of the simulation model stated in Section 6.1. The control variables of the simulation model are adjusted in different simulation runs to study the system behavior under different assumptions. Assumptions of different simulation runs are summarized in Table 2. Run 0 illustrates wind power capacity expansion and saturation in the absence of construction delays. These delays are included in the base scenario, which serves as the reference case for all subsequent runs. Run 1 investigates the effect of varying risk levels and financing costs, while run 2 considers modified external market prices. The impact of green premia is analysed in run 3 by increasing the willingness to pay for renewable energy. Finally, runs 4 and 5 examine the effects of increasing electricity consumption, and run 6 explores the potential for achieving higher shares of renewable generation.

Variable	Run 0	Base	Run 1	Run 2	Run 3	Run 4	Run 5	Run 6
Baseload production (MW)	-	4000	-	-	-	-	-	-
Baseload consumption (MW)	-	8000	-	-	-	12000	10000	10000
Flexible consumption (MW)	-	4000	-	-	-	-	6000	6000
Construction delay (years)	0	3	-	-	-	-	3	3
Residual price (€/MWh)	-	75	-	45-95	-	-	-	100
Interest rate (%)	-	6	2-10	-	-	-	-	-
Green premium (€/MWh)	-	0	-	-	0-25	-	-	25

Table 2: Model parameters for the base scenario and alternative simulation runs. The base scenario defines the reference parameter values, while Runs 1–6 represent targeted modifications to this baseline. Run 0 represents a case without construction delays. Run 1 examines the effect of financing costs, run 2 external market conditions, run 3 the impact of a green premium (additionality), and runs 4 and 5 demand growth through increased baseload consumption and a combination of baseload and flexible consumption, respectively. Run 6 combines demand growth with increased willingness to pay. Cells marked with "–" indicate parameters identical to the base scenario. Numerical entries in other runs override the base scenario values.

7.1 Wind power penetration and saturation

The basic dynamics of wind power penetration into the electricity system are based on the reinforcing and balancing feedback effects from technology development and the market value saturation. The magnitude of these effects determines the rate of development and how the markets saturate. A result of wind power production capacity development without construction delays is illustrated in Figure 23. In the zeroth run, the rate of wind power production capacity increases at an accelerating rate at first. However, after about five years in this simulation, the rate of wind power capacity increase starts to decrease. At the end the capacity increases only slowly, and it finally it approaches level of about 8500 MW.

The causes for the effect of this run are visualized in Figure 24. At first, due to technology development, the cost of renewable energy technologies is decreasing. As

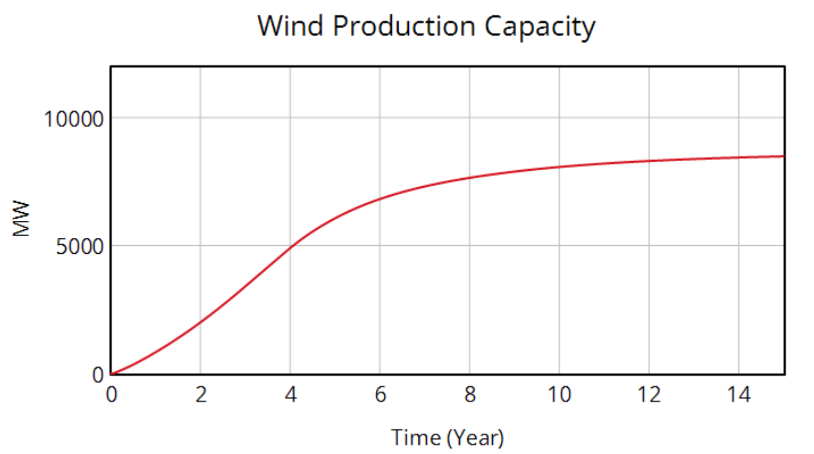


Figure 23: Wind power production capacity development over 20 years in electricity system aligned with assumptions of run 0 in Table 2. There is no capacity decommissioning in the model on this period of time.

the market value is still high and at first there is no cannibalization, the investment margin, i.e., price between the LCOE and the market value of renewable energy technologies, increase. This makes building new wind power attractive and thus makes the wind power production capacity to increase at an accelerating rate. However, when the share of wind power increases, the cannibalization, i.e. the decrease in market value, begins. In this modeling, the cannibalization effect starts when the sum of baseload production (4000 MW) and nominal wind power production capacity

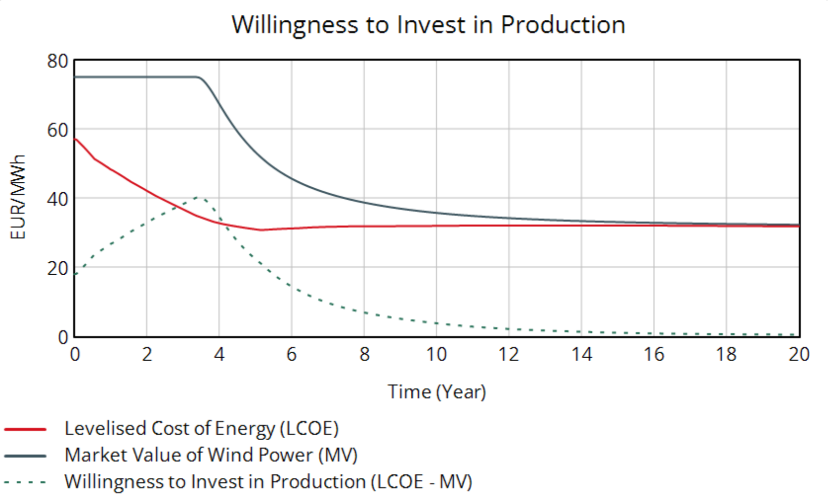


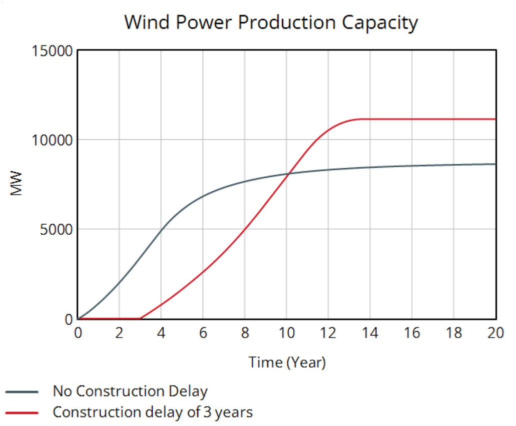
Figure 24: Willingness to invest in new wind power with assumptions of run 0 of Table 2 depends on the wind power market value and cost of technology, whose difference is called an investment margin. If the market value is higher than the technology cost, investments are attractive. The higher the investment margin is, the more renewable energy will be invested.

exceeds the total baseload demand. Due to cannibalization, the wind power market value decreases and the gap between LCOE and market value diminishes. In turn, this makes building new wind power production units not longer profitable, and the market saturates to certain wind power production level.

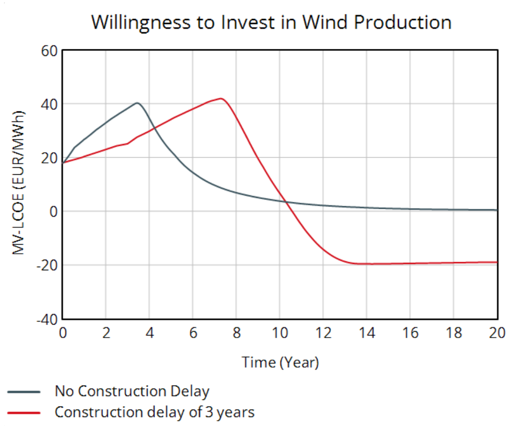
7.2 Construction delays

The model becomes more realistic when a three-year construction delay is included. This delay reflects the time between investment decision and production facility coming online. The delay can be seen as asymmetric information in the markets. The model assumes, that investors base their investment decisions on the current market conditions and the capacity already online, the projects under construction are not considered. As a result, they may commit to investments without knowing the actual market conditions that will prevail when their projects start producing.

The effects of investment delays is illustrated in Figure 25, which contains the evolution of the production capacity and the willingness to invest in wind production. As seen in the Figure, the wind power production begins to increase later when construction delays are included but once the expansion starts, it accelerates more rapidly and reaches a higher level. This is because investment decisions are based on the market environment at the time of the investment. Consequently, investors may invest in projects that would no longer be profitable by the time they become operational due to other similar projects. This leads to an overshooting behavior. This effect concerns all producers, but the risk can be managed through PPA contracts.



(a) Wind power production capacity.



(b) Willingness to Invest

Figure 25: Wind Power Production Capacity and Willingness to invest in wind power production without investment delays (gray) and with a three-year investment delay (red) corresponding to run 0 and the base run in Table 2. With construction delays, total wind power capacity overshoots, causing the profitability of new investments to fall below zero.

The overshooting behavior is something that is now seen in Finland, where renewables capacity has increased even though the market values have declined to a low level. In this analysis, the three year construction delay leads to an over 15 €/MWh difference between LCOE and the market value. By looking at Figure 12, the empirical result in Finland is somewhat similar. The LCOE varies between projects but if it is estimated to be around 40 €/MWh [7] and the market values for last year have been around 15-30 €/MWh, the 15 €/MWh price difference is on the right scale. Shortness of the period and possibility of randomness on empirical data should be noted.

Construction delays could lead to cyclical behavior if production capacity also decreased over time, but behavior after 30 years is very uncertain. Production capacity does not exit the system, because continuing operating will bring more income than decommissioning production facility early, even if the market value is less than the calculated LCOE. Market participants may attempt to increase profits by bidding above their marginal costs, closer to their LCOE. However, any single participant would then have an incentive to lower its bid to increase its operating hours, pushing the bid level back toward marginal cost [17].

Ultimately, only if operational and maintenance costs become higher than the market revenues, the capacity would exit the system. However, finance costs and debt payments can become substantial, and therefore the role of PPA contracts securing the cashflow is particularly important. Off-takers may have strong incentives to renegotiate contract terms, which underscores the need for appropriate counterparty-risk management in PPA contracts. A group of unprofitable investments would depress market revenues for all producers and could burden the system for an extended period. Therefore, many producers may prefer that some capacity exits the market to lift market values back to sustainable levels, but simultaneously hope that they themselves are not the ones forced into default.

7.3 Investment risk and the price environment

The financing costs of the projects have a direct effect on the LCOE and thus the willingness to build new wind power. The scale of the effect is examined by modifying the interest rate between 2 % and 10 %. Again, other factors are kept constant over the simulation. As illustrated in Figure 26, higher investment costs lead to lower levels of VRES penetration. In addition to this exogenous interest rate, the model has an endogenous interest rate effect described in Figures 21. The total financing costs depend on the interest rate, but also the uncertainty about future incomes and role of PPA contracts.

The simulations indicate that lower financing costs translate directly into higher VRES capacity additions. Financing costs are highly influenced by macroeconomic conditions and interest rates. A large share of Finland's wind capacity was invested during the period of exceptionally low interest rates, but rising interest rates have made project financing more challenging. On top of macroeconomic conditions, industry-specific factors also shape the investment environment. In the early greenfield phase, technological risks affect capital costs, but as the industry has scaled, financing conditions have become more sensitive to market risks such as cannibalization. In this context, de-risking PPA contracts emerges as a key tool to enhance investor confidence

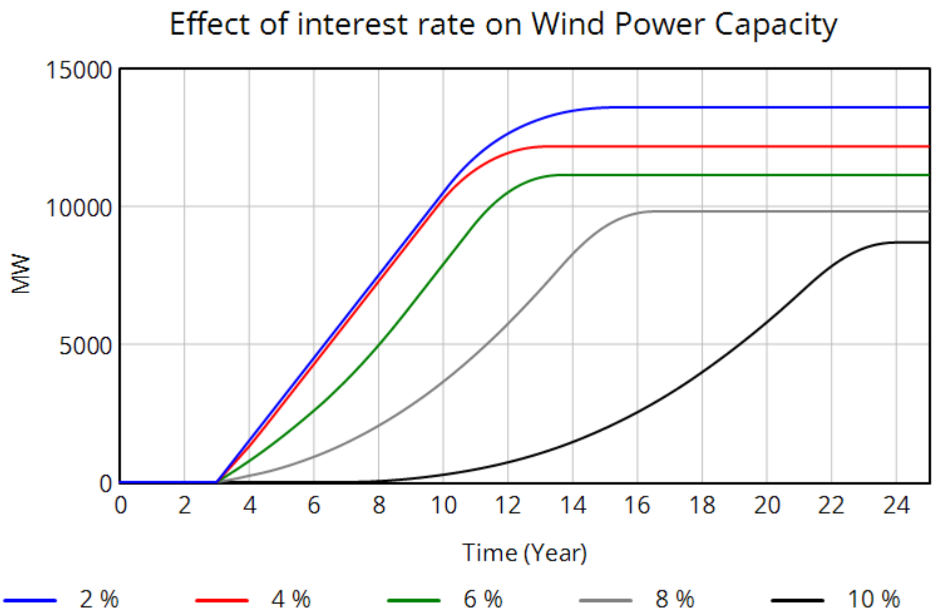
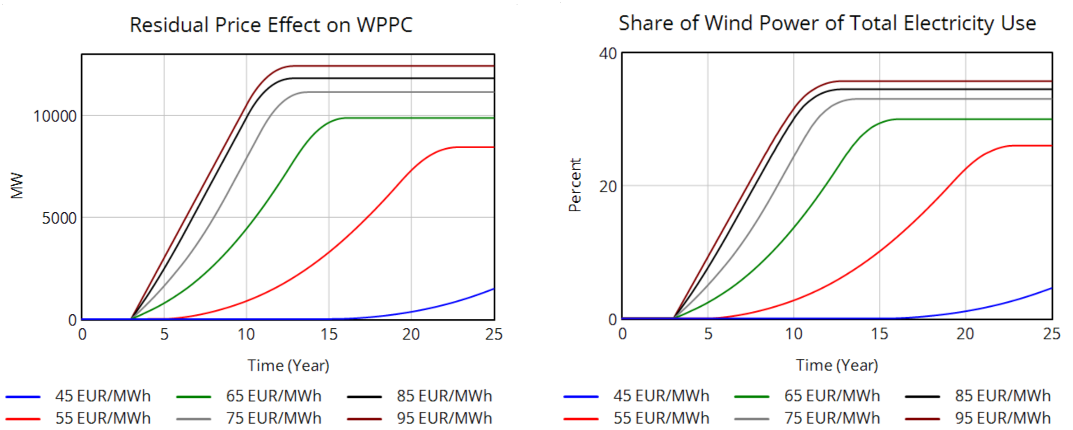


Figure 26: Wind power production capacity in different scenarios of interest (run 1, in Tab. 2). Interest rates represent the WACC and the examined values are 2 % (blue), 4 % (red), 6 % (green), 8 % (gray) and 10 % (black). The higher investment costs lead to lower saturation level of wind power production capacity.

and encourage further renewable capacity expansion. The European electricity market regulation (2024/1747) [145] has defined PPA contracts and provides guidelines for their support and the European Investment Bank has committed to providing guarantees for PPA contracts [146]. It will be seen whether this policy measure will significantly contribute to adding new renewable capacity to the electricity system, or if its impact will be too small compared to other influencing factors.

In previous simulations, the residual average electricity price, i.e. the volume weighted average price of wind power on those hours, when the market price is not set by it, was assumed to be constant of 75 €/MWh. The choice of this value was arbitrary and it is important to study the sensitivity of the residual price on the wind power capacity increase. Higher residual price would increase market value of wind power production and thus lead to higher saturation level of wind power production capacity as illustrated in Figure 27.

Until now, the wind power production capacity was the key research variable, but another way to examine this behavior is to consider the share of wind power in total energy use. The total electricity use is modeled as the sum of baseload and flexible consumption and the share of wind power is the ratio between total wind energy produced and the total consumption. Figure 27b illustrates the effect of the same residual price increases on the total energy use and can be compared to Figure 27a. The share of wind power on total electricity use is increasing with smaller steps than the production capacity itself. This is because of the curtailment, which occurs when wind production capacity is high and there are times when the system cannot



(a) Wind power production capacity. **(b)** Share of wind power

Figure 27: Run 2 of Table 2 considers effect of residual price on wind power production capacity and share of wind power. The higher the price is, the higher is the wind power market value, which in turn, leads to higher wind power production level. Due to curtailment, the share of wind power in total energy use increases less quickly.

use all the electricity that was able to be produced.

7.4 Additionality and its impact

As noted, some investors are prepared to accept higher costs for new renewable energy projects in order to signal their commitment to the green transition. This behavior can be represented as a green premium, which in principle is an increase in the price that consumers are willing to pay for electricity generated from low-carbon sources. A higher willingness to pay effectively increases the revenue potential of new projects and the diminishing market value through cannibalization is compensated with this premium to some extent.

Figure 28 illustrates the implications of green premia ranging from 0 to 25 €/MWh on wind power deployment. As the premium increases, the model yields larger additions of wind capacity and a higher share of wind generation in the overall electricity mix. The premium thus functions as an additional driver for renewable builds by improving project profitability.

In recent years, during the significant renewable capacity increase, only greenfield PPAs are generally available. Conceptually, an additionality premium becomes significant when a project would not have been developed without the PPA, but the increased willingness to pay enables its construction. The existence and value of such premium are difficult to distinguish, as projects might have been profitable even without it. As market values have now declined, additionality premia can play an important role in enabling variable renewable investments in future years. Evidence of this can be seen in large wind power in Finland, even though market values remain low [147]. Additionality may be highly relevant for hydrogen production, because the RFNBO legislation requires it. Additionality premia are likely to gain importance when

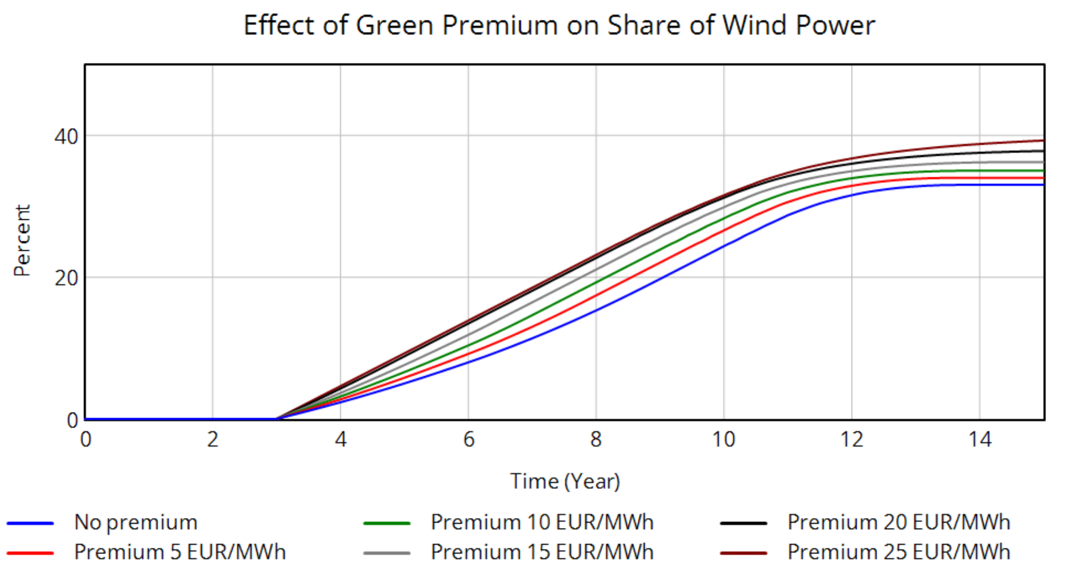


Figure 28: Share of wind power with different sized green premia following assumptions of run 3 of Table 2. Green premium will raise the share of wind power on total electricity use, but its effect is limited on its own because of the increasing renewable energy cannibalization and curtailment.

production facilities exit the system or existing PPA contracts end if the detachment from CO_2 is not complete as there is then a significant difference between new brownfield or greenfield PPAs.

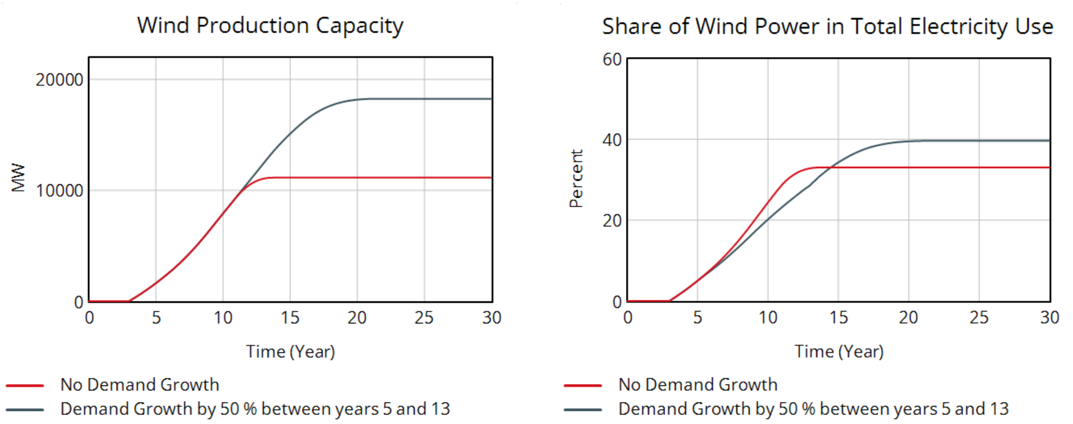
As the large technology corporations shown in Figure 13 account for the largest renewable energy PPA contracts, they are also the most likely to include additionality premia in their operations. This need for additionality is partly driven by competition in AI development, as companies seek to secure sustainable energy sources to support energy-intensive AI training and data center operations. Therefore, it can be concluded that at least some energy remains available despite the growing demands of AI development.

7.5 Pathways to higher renewable shares

Increasing green premia and higher electricity residual prices both raise the share of wind power in total generation. Even under favourable conditions, however, the simulated market saturates at a maximum wind share of roughly 40 %, if electricity consumption is kept constant. When compared to the long-term goals of climate-neutrality, such a share remains insufficient for addressing the structural challenges of the energy transition and making the new green growth possible. The green growth is based on the increasing electricity consumption and therefore the impact of growing consumption is now studied in detail.

At a first simulation, electricity consumption is assumed to raise by 50 % from 8000 MW to 12 000 MW over eight years starting at year 5. Consumption increase thus lasts from year 5 to year 13 and in each year consumption raises by 500 MW. This reflects an example proceedings in electrification. The amount of flexible consumption is still held constant at 4000 MW, and in other words, the consumption growth is all baseload demand in this example run.

Increasing the baseload consumption on its own is increasing renewable energy capacity significantly, because flexible demand increases electricity price in general and thus also market value for wind power increases. However, as the electricity consumption also increases, the resulting equilibrium share of wind power generated energy is somewhat similar and therefore inflexible demand increase does not alone lead to fully renewable based electricity system. Effect of baseload consumption increase is illustrated in Figure 29.



(a) Wind power production capacity.

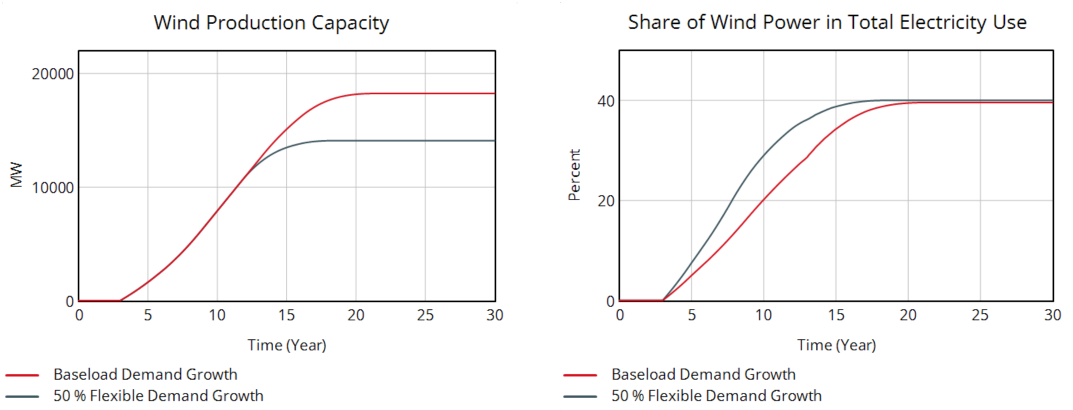
(b) Share of wind power

Figure 29: Illustration of wind power production capacity and the share of wind power of total electricity use with electricity baseload consumption increase and without it, i.e. comparison of base run and run 4 of Table 2. Increasing baseload consumption leads to higher wind power production level, but the share of wind power of total energy use is not raising.

When baseload consumption is increasing, renewable capacity is typically oversized. In the example, the nominal wind power production capacity is now around 18 GW, with baseload electricity consumption resulting in 12 GW and flexible electricity consumption being 4 GW. Thus there are 18 GW - 12 GW - 4 GW = 2 GW extra capacity, which will be curtailed of the topmost production. Curtailment makes the production profile more stable, but at the same time the effective capacity factor is lowered. Consequently, the associated levelized cost of electricity (LCOE) increases. As a result, the economic incentive to further expand wind power diminishes, constraining the ability of renewables to meet the added baseload needs.

The demand can also be flexible. The effect of partly flexible demand is studied by first creating a similar consumption growth as in simulations of Figure 29, but now half of the demand is assumed to be flexible. Flexible demand differs from the baseload demand by its ability to be used only if renewable power is available. The resulting state is illustrated in Figure 30.

Introducing flexible consumption into the system changes the underlying incentives



(a) Wind power production capacity.

(b) Share of wind power

Figure 30: Wind power production capacity and share of wind power of total electricity use in scenario run 4 and 5 of Table 2. In case of baseload demand increase, baseload consumption is increased by 500 MW annually between years 5 and 13. In flexibility scenario, baseload consumption is increased annually by 250 MW and flexible demand is increased annually by 250 MW between years 5 and 13. Having flexible consumption leads to larger share of wind power in total energy use, but the wind power production capacity is smaller.

for variable renewable investment in a different way compared to increasing baseload demand. Flexible demand does not raise electricity prices during periods of scarcity, because it is assumed to operate only when VRES generation is abundant and market prices are close to zero. As a result, flexible consumption does not significantly increase the market value of renewable generation. Instead, its primary effect is to reduce curtailment by absorbing surplus production during high-generation hours. This reduction in curtailment increases the effective capacity factor of wind power, which in turn lowers its levelized cost of electricity (LCOE). A lower LCOE has a feedback making additional renewable investments more attractive.

However, because flexible demand does not contribute to higher electricity prices in tight market conditions, it does not generate the strong price-driven investment signal that baseload demand creates. The renewable capacity therefore grows less aggressively, even though the share of renewables in total electricity use becomes higher. In other words, flexible demand improves the utilization efficiency of existing renewable assets but does not strongly incentivize new capacity additions. This explains why the scenario with flexible consumption results in a higher renewable share but a smaller absolute wind power capacity level. The difference between share of renewables between these runs is still small and the share of renewables is not substantially higher.

Overall, the consumption increases described here are not necessarily feasible as such. Specifically, the feasibility of baseload consumption increase depends critically on the availability of the electricity being able to fill the non-renewable production hours. Transmission to neighboring areas can supplement this development to some extent, but the need for flexible capacity becomes easily high. As simulated, renewable capacity responds to higher demand in the model, but as seen in Fiugre 30b, the share of wind power remains limited and the rest of the electricity should be produced with other production methods. The key question is thus, what are the technologies that can fill these gaps, where VRES are not running.

A concept of opportunity costs becomes important when considering the available technologies. Overscaling renewable generation to achieve 24/7 renewable procurement tends to increase production costs, as curtailment reduces effective operating hours and these hours can no longer be fully assumed in LCOE calculations. However, assessing the feasibility of higher-cost renewable generation also requires a comparative analysis of alternative technologies capable of providing electricity supply. With current technologies, most relevant discussion is between nuclear energy and renewables. Fossil fuels do not seem to be completely out of game yet, because in the United States, the rapid growth of AI data centers has already led to plans for new fossil fuel plants because renewable alternatives cannot be deployed quickly or cheaply enough to cover the additional baseload demand [27]. If carbon price is increased and fossil fuels are being phased out, the costs of alternative technologies raise and renewables become even more cost-effective. Thus it can be concluded that if demand is likely to increase, the electricity prices will have to increase as well to some extent to support the transition to fossil free future.

As discussed with 24/7 renewable portfolios, the renewable electricity procurement is based on combination of multiple technologies, energy storage and demand side

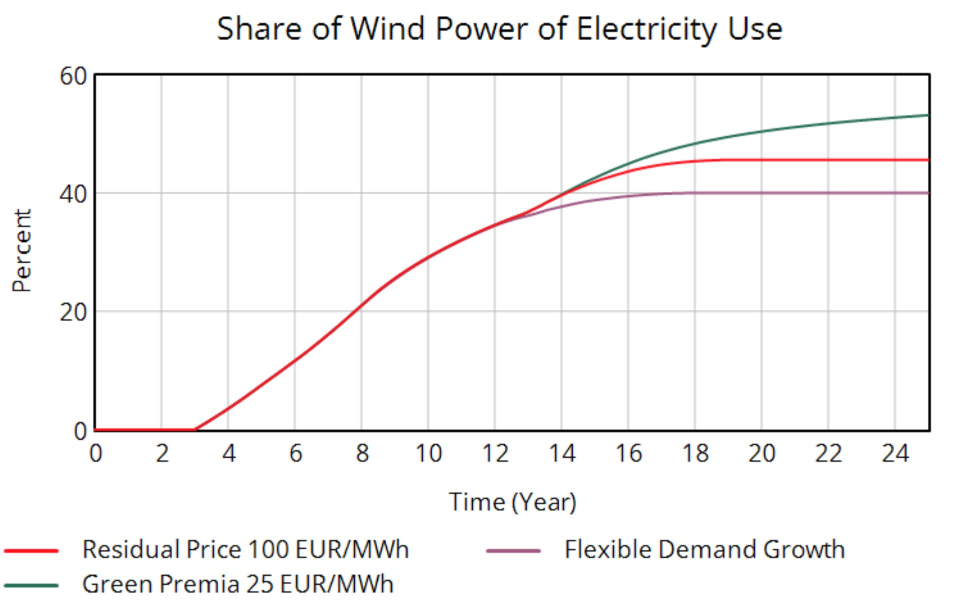


Figure 31: Share of wind power of total electricity use in three scenarios (run 6): higher residual electricity price (100 €/MWh), green premia of 25 €/MWh, and flexible demand growth. Increasing the willingness to pay for renewable electricity or introducing flexible consumption leads to substantially higher renewable shares.

flexibility in a combination determined by the relative costs of different approaches. Being flexible would create arbitrage opportunities in market, while cost of inflexibility will increase. In modeling terms this would include increased willingness to pay for variable renewable energy or higher residual electricity price. The storage and demand flexibility, such as hydrogen production and electric fuels are assumed to behave similarly to flexible consumption and are included as flexible consumption in the model.

A final simulation is performed by introducing a higher residual electricity price, representing a willingness to pay an additional 25 €/MWh for renewable electricity, or alternatively by applying an equivalent additionality premium. The results are shown in Figure 31. In contrast to the earlier scenarios, where the renewable share increased only modestly, the introduction of higher residual prices or green premia raises the share of variable renewable energy sources (VRES) substantially. Both mechanisms improve the market value of wind power, strengthen investment incentives, and allow renewable expansion to continue even after the system would otherwise saturate. Flexible demand alone produces a similar effect by improving utilization and lowering curtailment, but the combination of flexibility and increased willingness to pay for clean electricity enables wind power to reach clearly higher long-run shares.

7.6 Sources of error

The system dynamics model is deliberately simplified and focuses on illustrating structural mechanisms rather than providing precise numerical forecasts. The model is somewhat deterministic and it does not incorporate stochastic behavior as it would make interpretation more complex. Although the internal logic of the model is consistent, some assumptions constrain its quantitative accuracy. A central limitation is the use of a single fixed electricity price of 75 €/MWh, which is relatively high and therefore likely overstates the "default" penetration of wind power. Keeping the residual price fixed ignores how increasing VRES penetration would place lower-cost technologies on the margin, and thus cause the residual price at the top of the supply stack to decline. This omission reduces the realism of the interaction between VRES expansion and market value formation.

Another important simplification is made with treatment of system flexibility. The model assumes effectively unlimited production availability and transmission capacity for balancing the remainder of demand, and it does not consider restrictions on increasing baseload consumption or structural limits in system-level flexibility. This assumption removes potential bottlenecks that, in reality, would influence the ability of the system to accommodate high VRES shares. A further source of inaccuracy arises from the use of the beta distribution to approximate wind power output. While convenient, the beta distribution may not fully capture the temporal variability or geographic diversity of wind conditions in Finland. The model treats all wind power as homogeneous, even though wind patterns for example in Lapland differ notably from those in southern Finland and may not be temporally aligned. Ignoring this spatial heterogeneity reduces the model's ability to reflect real-world balancing challenges.

The representation of flexible demand also adds to the uncertainty. It is modeled using a zero price, which is a strong simplification and may overestimate the responsiveness of demand-side resources in high-renewable systems. Finally, the representation of technological development is not directly based on empirical data, but it is feasible for modeling purposes. While the technological development is defined to mimic real-life behavior, a simpler representation of it could potentially provide clearer insights of the system behavior.

8 Conclusion

This thesis has examined the specialties of VRES from both investment and electricity market perspectives. The main objectives were to understand how hedging for variable renewables differs from traditional hedging approaches, to analyze the PPAs, and to explore how VRES interacts with electricity markets and the dynamics that emerge during VRES integration.

PPAs were examined through a literature review and expert interviews. A key difference between variable renewable energy and traditional baseload hedging is that PPAs are often essential for the feasibility of variable renewable energy investments. This is largely due to VRES' cost structure and production variability. Conventional hedging instruments in the physical electricity markets fail to address the unique production profiles of wind and solar.

PPAs create different incentives for producers and consumers, as producers generally aim to recover the levelized cost of electricity (LCOE), while consumers focus on the market value and demonstrating green values and additionality. The most common PPA type, pay-as-produced, benefits producers but poorly aligns with the hedging needs of consumers' actual consumption profiles. With high cannibalization in the current market environment, it is likely that the trend is now shifting toward more sophisticated structures, such as 24/7 and first-MW contracts, which better match consumption and flexibility requirements.

The system dynamics model developed in this thesis was utilized to explore the overall behavior of the energy system. The model functions as an analytical tool for understanding structural interactions and feedback mechanisms at a system level. As the underlying model assumptions are subject to uncertainty regarding their real-world realization, the results obtained with the model should be interpreted qualitatively to examine how the system behaves under specific assumptions, rather than as a predictive instrument for future outcomes.

Using the model, the study examined how renewable technologies face saturation due to the cannibalization effect, where high production during certain periods lowers market value. Saturation levels are influenced by system structure, electricity prices, financing costs, and also by the willingness to pay for green premia. With the model it is shown that the risk environment has a significant effect on the variable renewable energy penetration, and thus reducing risks is critical for supporting new renewable investments. Risks could be mitigated by decreasing asymmetric information on the markets by increasing transparency and building organized PPA marketplaces. In addition, the role of balancing costs is currently significant for VRES and therefore it is important to mitigate those risks by improving forecastability and technical capability to control power plants in the physical electricity markets.

Consumption behavior and their willingness to pay play a central role in shaping the renewable energy future and the speed at which carbon neutrality can be achieved. Currently, the additionality requirements and green premia can help to reach a larger amount of renewables in the system than without them. As variable renewable energy is specialized with a low marginal cost, the market value of production is based on the most expensive running hours, where price should be high enough to guarantee profitability of an investment. An alternative way is that the renewable cost return would be based on the bilateral agreements, where off-takers would take a cost-based approach rather than evaluating the value based on the market value.

Current marginal-cost-based market structures rely on high price volatility and occasional extreme prices to signal investment, which may not always align with social or economic optimality. Protecting the most vulnerable participants, such as households and small-to-medium enterprises, is possible through baseload price hedging. However, the availability of such hedging instruments strongly depends on the presence of baseload production, storage capacity, or sufficient system flexibility to ensure that these instruments remain viable and attractive for speculative traders. Furthermore, as electricity production becomes more variable, there is a growing need to introduce advanced hedging instruments that can effectively account for and reward system flexibility.

This thesis has highlighted the importance of flexibility and need for storage technologies in wholesale electricity markets. However, with the current wholesale market structure, energy storage also suffer from the cannibalization. As a possible way to solve this, future studies should explore the optimal deployment of storage into markets. Further work on capacity mechanisms and resource adequacy challenges would also provide valuable insights into the "missing money" problem, which affects not only the peaking units but also increasingly variable renewable generators. In addition, the role of different production methods should be explicitly considered in the day-ahead market model, and future studies should examine how the system would benefit from guarantees of origin at an hourly resolution.

While voluntary renewable portfolios and premia for green electricity can support deployment, public policy measures and especially increasing the costs of carbon-intensive technologies are necessary to fully realize the potential of renewables. Individual companies can provide support schemes for renewable energy production through PPAs in the same way government CFDs can do. However, having bulk variable renewables production in the system is not enough, and wider clean flexibility technologies are needed. To support the whole flexibility architecture, opportunity costs of unwanted fossil technologies must be raised high enough, for example, through carbon pricing schemes such that the clean technologies become competitive.

The task of decarbonization is challenging for Europe. The current geopolitical situation adds pressure, and substantial financial resources are being redirected toward security and defense. It is not in Europe's interests to lose competitiveness to countries such as China and the United States, and rather to be a global leader in green technology development. Europe is in a strong position to achieve this objective, as it has advanced variable renewable energy infrastructure and well-established PPA frameworks. Addressing the investment challenges and dynamic effects presented in this thesis, in both policy implementation and investment planning, will bring Europe closer to successfully reaching this goal.

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A Beta distribution

A.1 Properties of beta distribution

Wind power plant power output is naturally bounded between zero and the nominal capacity of the turbine. Empirical studies (e.g. [100, 101]) have found out that beta distribution provides a good approximation of wind power production power. The probability density function of a Beta-distributed random variable x denoting the wind power production power with respect to its nominal power is

$$f(x;\alpha,\beta) = \frac{x^{\alpha-1}(1-x)^{\beta-1}}{B(\alpha,\beta)}, \quad 0 \le x \le 1, \tag{A1}$$

where $B(\alpha,\beta)$ denotes the Beta function. The Beta function is generally defined as

$$B(\alpha,\beta) = \int_0^1 t^{\alpha-1}(1-t)^{\beta-1}\,dt, \quad \alpha,\beta > 0,$$

and can also be expressed in terms of the Gamma function:

$$B(\alpha,\beta) = \frac{\Gamma(\alpha)\,\Gamma(\beta)}{\Gamma(\alpha+\beta)},$$

where the Gamma function is defined by

$$\Gamma(z) = \int_0^\infty t^{z-1}e^{-t}\,dt, \quad z > 0.$$

The expected value of Beta-distributed random variable X is

$$\mathbb{E}[X] = \mu = \int_0^1 x f_X(x;\alpha,\beta)\,dx = \frac{\alpha}{\alpha+\beta}.$$

In case of wind power distribution, expected value describes the average production level compared to its maximum possible output, which is also known as capacity factor. In addition, variance of beta distribution can be calculated as

$$\mathrm{Var}(X) = s^2 = \frac{\alpha\beta}{(\alpha+\beta)^2(\alpha+\beta+1)}.$$

For detailed proofs of mean and variance, see [148]. These mean and variance are easy to calculate from empirical data. Solving parameters yields

$$\alpha = \mu\left(\frac{\mu(1-\mu)}{s^2} - 1\right),$$

$$\beta = (1-\mu)\left(\frac{\mu(1-\mu)}{s^2} - 1\right),$$

which allow the distribution to be fitted directly from historical production data once it is normalized by the nominal capacity. The fitted α and β reflect the average level and variability of production: higher α relative to β indicates a shift toward higher output levels, while larger total shape $(\alpha+\beta)$ corresponds to lower variance and a more peaked distribution.

A.2 Energy distribution

The Beta distribution described above characterizes the instantaneous power output of the wind turbine or wind farm. However, for many analyses, the distribution of energy production over a given period is more relevant. Energy is the total power generated over time, which can be thought of as weighting the power distribution by the power itself. In other words, higher instantaneous power contributes more to total energy, while low power outputs contribute relatively little. This weighting effectively corresponds to the first moment of power distribution.

The distribution of energy (or generated electricity) can be expressed by weighting the original power distribution (Eq. (A1)) $f_X(x)$ with x. The distribution has to be normalized such that it is a probability density function, and thus the new power distribution $f_Y(y)$ is

$$f_Y(y) = \frac{x\, f_X(x)}{\int_0^1 x\, f_X(x)\, dx},$$

where the denominator handles the appropriate normalization. For a Beta-distributed power variable $X \sim \mathrm{Beta}(\alpha, \beta)$, this weighting corresponds to a Beta distribution with a shifted shape parameter

$$f_Y(y; \alpha+1, \beta) = \frac{y^{\alpha}(1-y)^{\beta-1}}{B(\alpha+1, \beta)}, \quad 0 \leq y \leq 1,$$

where y is normalized by the nominal capacity. Thus $Y \sim \mathrm{Beta}(\alpha+1, \beta)$.

A.3 Capacity factor below curtailment

To compute the expected delivered energy below the curtailment threshold θ_C, we start with the integral

$$\int_0^{\theta_C} x f_X(x)\, dx,$$

where $f_X(x)$ is the PDF of a $\mathrm{Beta}(\alpha, \beta)$ distribution. By inserting the PDF and multiplying x by $x^{\alpha-1}$, we get

$$\begin{aligned}\int_0^{\theta_C} x f_X(x)\, dx &= \int_0^{\theta_C} x \frac{x^{\alpha-1}(1-x)^{\beta-1}}{B(\alpha, \beta)}\, dx. \\ &= \frac{1}{B(\alpha, \beta)} \int_0^{\theta_C} x^{\alpha}(1-x)^{\beta-1}\, dx,\end{aligned}$$

where the exponent of x is increased by 1. The remaining integral matches the definition of the incomplete Beta function

$$B_z(p, q) = \int_0^z t^{p-1}(1-t)^{q-1}\, dt,$$

with $z = \theta_C$, $p = \alpha + 1$, and $q = \beta$. Therefore,

$$\int_0^{\theta_C} x f_X(x)\, dx = \frac{1}{B(\alpha, \beta)} B_{\theta_C}(\alpha + 1, \beta).$$

Using the relation between the incomplete Beta function and the CDF of a Beta$(\alpha+1, \beta)$ distribution, we can write

$$\int_0^{\theta_C} x f_X(x)\, dx = \frac{B(\alpha + 1, \beta)}{B(\alpha, \beta)} F_{X^+}(\theta_C),$$

where $F_{X^+}(\theta_C)$ denotes the CDF of Beta$(\alpha + 1, \beta)$. Recognizing that $B(\alpha + 1, \beta)/B(\alpha, \beta)$ equals the technical capacity factor η_{tech}, we obtain

$$\int_0^{\theta_C} x f_X(x)\, dx = \eta_{\text{tech}}\, F_{X^+}(\theta_C).$$

B Guiding questions of expert interviews

- What special characteristics do variable renewable energy sources (wind and solar power) have that affect their investment environment?
- How is the electricity hedging market in general? How does hedging for VRES differ from hedging for traditional units?
- What is the role of PPAs in achieving bankability?
- What are the most typical and more advanced forms of PPA contracts?
- How does obtaining a PPA contract affect participation in physical markets?
- What are the risks of PPA contracts, and how do they compare to risks in the overall electricity hedging market?
- How is revenue cannibalization addressed in PPA contracts?
- Why would consumers participate in PPA contracts if the same electricity could be obtained from the spot market at a low price?
- How do uncertainty and forecasting difficulties affect PPA contracts?
- Does the current marginal price-based market design sufficiently support decarbonization targets?

C Complete system dynamics model

A complete description of the systems dynamics model used in this thesis is illustrated in Figure C1. The complete model with variables and equations are presented in the subsections. The computer simulations are run on discrete time step t_s, which equals 1/16 years. Due to discrete time step, equations are written as difference equations. Simulation time t is discrete, and it is defined in every time step. The implementation of such integration in computer simulations is explained in simulation software documentation [97].

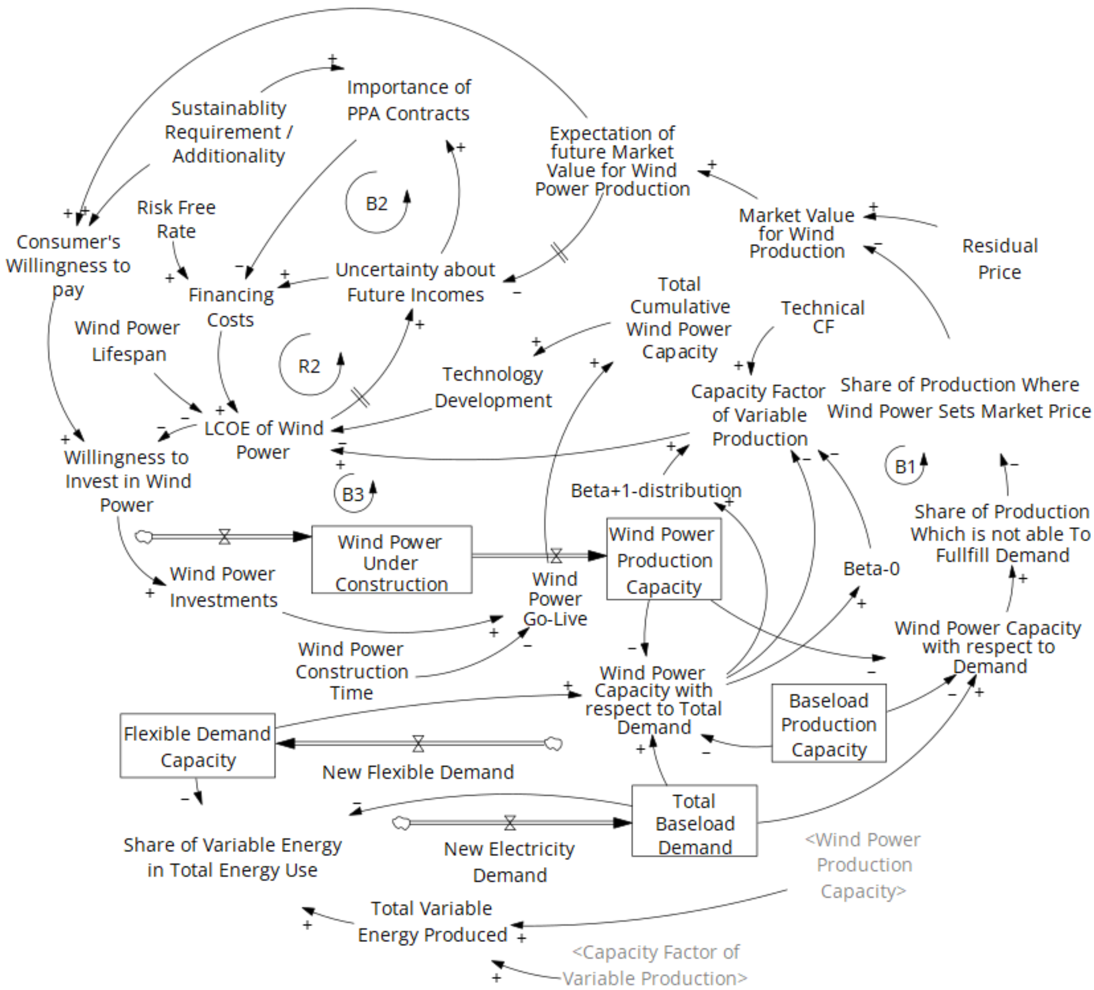

Figure C1: Overview of the system dynamics model used in the simulations. Variables shown in gray indicate shadow variables, i.e., replicated representations of original variables used solely for visualization purposes to enhance diagram readability and minimize overlapping causal links.

Abbreviations
The following abbreviations are used in the model description:

$$
\begin{aligned}
BPC &= \text{Baseload production capacity}\\
CFVP &= \text{Capacity facotr of variable production}\\
CWP &= \text{Consumer's willigness to pay}\\
EFMV &= \text{Expectation of future market value for wind power production}\\
FC &= \text{Financing costs}\\
FDC &= \text{Flexible demand capacity}\\
GP &= \text{Sustainability requirement additionality (green premia)}\\
LCOE_{wind} &= \text{LCOE of wind power}\\
MV &= \text{Market value for wind power production}\\
RP &= \text{Residual price}\\
RFR &= \text{Risk free rate}\\
PPAIMP &= \text{Importance of PPA contracts}\\
SHNSP &= \text{Share of wind power production not able to fulfill demand}\\
SHWSP &= \text{Share of wind production where wind sets the market price}\\
T_{life} &= \text{Wind power lifespan}\\
TBD &= \text{Total baseload demand}\\
TD &= \text{Technology development}\\
TVEP &= \text{Total variable energy produced}\\
UFI &= \text{Uncertainty about future incomes}\\
WIP &= \text{Willingness to invest in wind power production capacity}\\
WPCT &= \text{Wind power construction time}\\
WPI &= \text{Wind power investments}\\
WPPC &= \text{Wind power production capacity}\\
WPPCD_b &= \text{Wind power production capacity wrt. baseload demand}\\
WPPCD_\Sigma &= \text{Wind power production capacity wrt. total demand}\\
WPPGL &= \text{Wind power production go}-\text{live}\\
WPPUC &= \text{Wind power production under construction}\\
\beta^+ &= \text{Beta + 1 distribution}\\
\beta^0 &= \text{Beta} - 0\\
\eta_{tech} &= \text{Technical CF (Capacity factor)}\\
\Sigma_{VRES} &= \text{Total variable energy produced}\\
\Sigma_{WP} &= \text{Total cumulative wind power capacity}
\end{aligned}
$$

Stock (state) equations and delays

$$BPC(t) = 4000$$

$$FDC(t + t_s) = FDC(t) + \text{New Flexible Demand}(t)$$
$$FDC(0) = 4000$$

$$TBD(t + t_s) = TBD(t) + \text{New electricity demand}(t)$$
$$TBD(0) = 8000$$

$$WPPC(t + t_s) = WPPC(t) + WPPGL(t)$$
$$WPPC(0) = 10$$

$$WPPUC(t + t_s) = WPPUC(t) + WPI(t) - WPPGL(t)$$
$$WPPUC(0) = 0$$

$$\Sigma_{WP}(t) = WPPGL(t)$$
$$\Sigma_{WP}(0) = 10$$

$$WPPGL(t) = \begin{cases} 0, & t < WPCT \\ WPI(t - WPCT), & t \geq WPCT \end{cases}$$

Beta distribution

Wind power production is evaluated using beta distribution. The cumulative distribution functions with obtained fitting parameters are modeled using lookup functions, which have value between 0 and 1 on horizontal axis and the corresponding probability in vertical axis of that the value of x is smaller or equal to the value on the horizontal axis. The original cumulative beta distribution function is denoted here as β^0 and the corresponding Beta$(\alpha + 1, \beta)$ distribution is denoted as β^+. The fitting parameters are $\alpha = 0.995$ and $\beta = 1.8919$ and the corresponding cumulative distribution points are for lookups are illustrated in Tables C1 and C2.

Table C1: Beta cumulative distribution function values for the Beta$(\alpha + 1, \beta)$ distribution. The fitting parameters are Beta$(1.995, 1.8919)$.

x	$F_{\beta^+}(x)$	x	$F_{\beta^+}(x)$	x	$F_{\beta^+}(x)$	x	$F_{\beta^+}(x)$
0.00	0.00	0.25	0.15	0.50	0.48	0.75	0.82
0.05	0.01	0.30	0.20	0.55	0.55	0.80	0.88
0.10	0.03	0.35	0.26	0.60	0.62	0.85	0.93
0.15	0.06	0.40	0.33	0.65	0.69	0.90	0.97
0.20	0.10	0.45	0.40	0.70	0.76	0.95	0.99

Table C2: Beta cumulative distribution function values for Beta(α, β). Fitting parameters are Beta$(0.995, 1.8919)$

x	$F_{\beta^0}(x)$	x	$F_{\beta^0}(x)$	x	$F_{\beta^0}(x)$	x	$F_{\beta^0}(x)$
0.00	0.00	0.26	0.43	0.52	0.75	0.78	0.94
0.02	0.04	0.28	0.46	0.54	0.77	0.80	0.95
0.04	0.07	0.30	0.49	0.56	0.79	0.82	0.96
0.06	0.11	0.32	0.52	0.58	0.81	0.84	0.97
0.08	0.15	0.34	0.54	0.60	0.82	0.86	0.98
0.10	0.18	0.36	0.57	0.62	0.84	0.88	0.98
0.12	0.21	0.38	0.60	0.64	0.86	0.90	0.99
0.14	0.25	0.40	0.62	0.66	0.87	0.92	0.99
0.16	0.28	0.42	0.64	0.68	0.88	0.94	1.00
0.18	0.31	0.44	0.67	0.70	0.90	0.96	1.00
0.20	0.34	0.46	0.69	0.72	0.91	0.98	1.00
0.22	0.38	0.48	0.71	0.74	0.92	1.00	1.00
0.24	0.41	0.50	0.73	0.76	0.93		

Auxiliary variables and equations

$$\beta^0 = F_{\beta^0}$$

$$\beta^+ = F_{\beta^+}$$

$$\Sigma_{VRES}(t) = CFVP(t) \cdot WPPC(t)$$

$$CFVP(t) = \eta_{tech} \cdot \beta^+(WPPCD_\Sigma(t)) + \left(1 - \beta^0(WPPCD_\Sigma(t))\right) \cdot WPPCD_\Sigma(t)$$

$$EFMV(t) = MV(t)$$

$$FC(t) = \frac{RFR + PPIMP(t) + UFI(t)}{100}$$

$$LCOE_{wind}(t) = \frac{\mathrm{CAPEX}_0\,(1 - TD(t)) + \mathrm{OPEX}_0\,(1 - TD(t))}{8760 \cdot CFVP(t)}$$

$$MV(t) = (1 - SHWSP(t)) \cdot RP$$

$$PPAIMP(t) = \max\left(0, \min\left(1, \frac{GP(t)}{20} + UFI(t)\right)\right)$$

$$SHNSMP(t) = \beta^+(WPPCD_b(t))$$

$$SHWSP(t) = 1 - SHNSMP(t)$$

$$TD(t) = f\left(\frac{t}{5} + \frac{\Sigma_{WP(t)}}{1000}\right)$$

$$UFI(t) = 1 - \max\left(0, \min\left(1, \frac{EFMV(t-1)}{2 \cdot LCOE_{wind}(t-1)}\right)\right),\ t > 0$$

$$UFI(0) = 0.35$$

$$WIP(t) = CVP(t) - LCOE_{wind}(t)$$

$$WPI(t) = \min(1500, \max(0, 40 \cdot WIP(t)))$$

$$WPPCD_b(t) = \min\left(1, \max\left(0, \frac{TBD(t) - BPC(t)}{WPPC(t)}\right)\right)$$

$$WPPCD_\Sigma(t) = \min\left(1, \max\left(0, \frac{TBD(t) + FDC(t) - BPC(t)}{WPPC(t)}\right)\right)$$

Technology development is modeled using a lookup function f, which is illustrated in Figure 18, with corresponding values provided in Table C3.

Table C3: Lookup table defining $TD(x) = f(x)$

x	$f(x)$	x	$f(x)$	x	$f(x)$
0.00	0.00	3.50	0.30	12.25	0.47
0.50	0.10	4.62	0.34	15.00	0.49
1.00	0.15	5.90	0.38	20.00	0.50
1.75	0.20	7.28	0.41	30.00	0.52
2.75	0.26	9.48	0.45	40.00	0.54
		50.00	0.55	100.00	0.55

Parameters

$$\text{CAPEX}_0 = 2.2 \times 10^6 \text{ (€) [103]}$$

$$\text{OPEX}_0 = 37500 \text{ (€) [103]}$$

$$T_{life} = 30 \text{ (years)}$$

$$\eta_{tech} = 0.345$$

Control variables with base run values

$$GP = 0$$

$$\text{New flexible demand}(t) = 0$$

$$\text{New electricity demand}(t) = 0$$

$$RFR = 6\%$$

$$RP = 75 \text{ (€)}$$

$$WPCT = 3 \text{ (years)}$$