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Security of supply in decarbonized electricity systems: Optimizing capacity mechanisms under policy interventions for Austria

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Energy Economics Group

Supervisors:
Associate Prof. Dipl.-Ing. Dr.techn. Hans Auer (TU Wien)
Univ.Ass. Dipl.-Ing. Dr.techn. Sebastian Zwickl-Bernhard (TU Wien)
Dipl.-Ing. Stefan Strömer (AIT)

by

Diana Maria Krainer
11779458

Vienna, May 2025

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During the writing process of this thesis, AI-based tools were utilized for spelling, grammar checking, and stylistic improvements. All intellectual contributions, analysis, and interpretations presented herein are the sole work of the author.

Abstract

This thesis investigates which combination of policy measures - consisting of a capacity mechanism and/or renewable energy support - is required to achieve a cost-efficient and decarbonized electricity system that ensures security of supply in Austria by 2040. To capture varying policy frameworks, two reference scenarios are developed: one assuming a pure energy-only market (*optimistic investor*), and another assuming an energy-only market with an implemented tax and anticipated price caps (*pessimistic investor*). In the context of the pessimistic investor scenario, the analysis examines whether a security of supply issue emerges and whether this can be addressed through increased battery deployment (*battery wave*), the introduction of a capacity market (*CM*) or a combination of a capacity market and renewable energy support in the form of a feed-in tariff (*RES+CM*). To address these questions, a market model with multiple optimization problems (agents) - each representing specific stakeholders in the electricity system - was developed and coupled using an Alternating Direction Method of Multipliers (ADMM) algorithm. The model's results reveal that in the case of a pessimistic investor a missing money problem arises. In a market, this problem occurs, when revenues are inadequate to cover investment and operational costs. For a pessimistic investor anticipated price caps limit revenues, leading to insufficient returns to cover the investor's costs. This results in a security of supply problem, which cannot be resolved by increased system flexibility alone, provided by utility-scale batteries. The introduction of a capacity market solves the missing money problem, additionally removing price peaks and lowering the average prices in the energy market. Further, the capacity market without additional measures provides the most cost-efficient solution, when accounting for the economic value of lost load. Results indicate that it should be regarded as the preferred solution due to its lower complexity and reduced susceptibility to implementation errors. An acknowledged drawback of a capacity market with a central buyer is the challenge of accurately determining the amount of capacity to be procured. However, even an inefficient system design, which results in a slight overprocurement of capacity market volume, does not lead to a significant increase in system costs.

Contents

1 Introduction

The climate crisis, driven by human-induced greenhouse gas emissions, demands urgent action to limit global warming to below 2°C and avoid severe environmental and socio-economic impacts [1].

In response, the European Union has launched the European Green Deal—an ambitious policy framework aiming to make Europe the first climate-neutral continent by 2050. The deal outlines a comprehensive set of measures spanning energy, industry, mobility, and agriculture, with the goal of reducing net greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels [2].

Austria has committed to achieving climate neutrality by 2040 - ten years ahead of the EU-wide target - requiring a rapid transformation of its energy sector [3]. The newly elected Austrian government has expressed its commitment to upholding these climate neutrality targets [4]. This is accompanied by a termination of tax reliefs for electric vehicles and photovoltaic modules, while the energy crisis contribution tax (EKB-S) - originally introduced as a temporary measure - has been prolonged for 5 years and intensified [5].

In an electricity system with increasing decentralized and volatile generation the need for additional flexibilities arises. At the same time, ensuring (to a certain extent) predictable revenue streams is essential to attract investment in new capacity and maintain long-term security of supply.

In recent years, electricity markets have experienced heightened price volatility and significant price spikes, mainly driven by the integration of renewables and geopolitical developments as the war in Ukraine [6]. These price peaks lead to market interventions, including the introduction of the energy crisis contribution for electricity by the Austrian government [7]. For investors to commit to capital-intensive investments, they require a sufficient degree of certainty that high price peaks, which are essential for recovering investment costs, will not be prevented by political interventions [8].

At the same time, not only geopolitical disruptions but also shifts in government can result in changing political priorities, which may lead to changing regulatory frameworks and consequently increased market interventions. Such interventions risk suppressing the price peaks that are crucial for some investors to recover their capital and operational expenditures [9]. A good example is the ongoing debate in Germany regarding the use of a strategic reserve under the new government. In order to stabilize market prices the reserve should be activated even before the market fails to clear, creating implicit price caps and effectively dampening or eliminating price peaks that certain investors rely on [10]. In Austria, for example, the coalition agreement of the newly formed government mentions the development of a power plant strategy. However, the specific objectives and measures associated with this initiative have not yet been clearly defined [4].

Finally, the strategic behavior of investors must be taken into account. Since several European countries have already implemented, or are in the process of introducing capacity mechanisms [11], even the political debate surrounding such instruments can lead to withholding of investments. Investors may choose to postpone investments until a mechanism is in place, or they may redirect investments to countries where such frameworks are already operational. Although the direct cross-border participation of capacities in neighboring countries' capacity mechanisms is designed to mitigate such effects, evidence suggests that these negative externalities cannot be fully offset through cross-border participation alone [12].

In light of all these recent political developments and the ongoing transition to a fully decarbonized energy system, the question arises whether the energy-only market provides sufficient incentives to achieve an electricity system that ensures security of supply with a high share of renewable energy generation, or whether additional measures like a capacity mechanism or targeted support for renewable energy sources (RES) are required.

The main research question to be answered in this work is therefore which combination of policy measures (capacity mechanism and/or RES support) enables Austria to achieve a decarbonized electricity system that ensures security of supply by 2040 in the most cost-effective way.

Therefore, a *baseline* scenario was developed, which represents the case of an optimistic investor. In the baseline scenario, there are no policy interventions and there is merely an energy-only market. For comparison a scenario *Tax + price cap* representing a pessimistic investor expecting policy interventions was developed. It is investigated which effects the introduction of taxes and (anticipated) price caps have on the investment decisions and whether a security of supply problem arises. In the context of a pessimistic investor's perspective, three additional scenarios are developed to examine whether

1. the increase of flexibility (*battery wave*),
2. the implementation of a capacity mechanism (*CM*) alone, or
3. a combination of a capacity mechanism and renewable energy support (*CM + RES*)

can resolve possible security of supply issues, and which of those results in the most cost-effective system design.

An agent-based modeling approach was chosen to answer these questions. A market model with multiple optimization problems (agents) - each representing specific stakeholders in the electricity system - was developed and coupled using an Alternating Direction Method of Multipliers (ADMM) algorithm. This allows for a distributed and parallelized optimization of all agents, reducing overall computational time. Policy decisions and regulatory changes can be implemented in a rule-based manner, enabling systematic analysis of their effects. Market prices emerge endogenously within the model, allowing for a detailed examination of the effects of specific policies.

This thesis is organized into the following chapters: In chapters 2 and 3 a short theoretical background on the topics of capacity mechanisms and distributed optimization is given. Chapter 2 outlines the various types of capacity mechanisms and examines their current implementation status within the European Union. Chapter 3 gives a short introduction on decomposition of optimization problems and algorithms used for solving these decomposed problems with a strong focus on ADMM. Chapter 4 specifies the input data used and describes the developed scenarios and modeling approach as well as the optimization problems in more detail. Chapter 5 presents the resulting system and market parameters of the model and discusses the behavior of the agents and security of supply issues. Chapter 7 draws conclusions based on the results provided in chapter 5, answers the questions raised in chapter 1, and summarizes the most important findings.

2 Capacity mechanisms

2.1 Missing Money Problem

Usually the transmission system operator (TSO) is responsible for the short-term balancing of the electricity system through real-time balancing markets. However, ensuring sufficient capacity (capacity adequacy) in the system to meet certain reliability criteria is the task of the regulatory and political entities [13] .

In an energy-only market investors need the confidence that their revenues over all markets (Spot market, balancing markets...) cover the generation and investment costs. A *missing money* problem in a market arises, if the revenues are not adequate and cannot cover these costs [13]. Furthermore [13] introduces the term *missing markets* problem, where revenues are theoretically adequate, but are not perceived as such by investors.

The problem of missing money can arise for various reasons, e.g. due to price caps below the value of lost load (VOLL) or insufficient low energy prices. Several measures are possible to solve this problem of missing revenue, such as increasing price caps or the introduction of capacity mechanisms [14].

The missing markets problem arises if investors cannot adequately allocate their risks through future and forward markets and regulators and policy makers are not willing to provide hedges against market interventions [13].

2.2 Classification

Capacity mechanisms can be categorized in targeted and market-wide mechanisms. Within these groups they can be further subdivided in volume-based and price-based mechanisms. Targeted mechanisms try to identify the additional capacity needed to ensure security of supply, which is not incentivised by the existing energy market. Market-wide mechanisms are called capacity markets and both existing and new capacities can participate. In volume-based mechanisms a central actor sets a certain demand for capacity, which is then procured through a competitive process. In price-based mechanisms the central actor sets a certain price capacity providers receive.

Figure 2.1 shows the taxonomy of capacity mechanisms and the main types in each category [15].

In the following, the different main types of capacity mechanisms are shortly described based on [15]. Mechanisms that are currently implemented in the member states (shown in Figure 2.2) or discussed publicly, are explained in more detail with regard to their advantages and disadvantages and their potential impact on the electricity market.

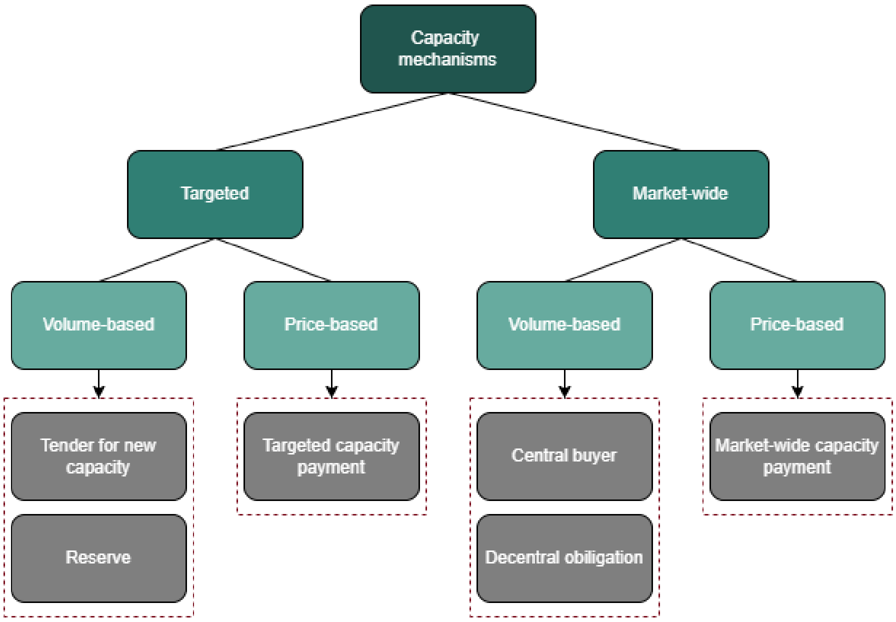


Figure 2.1: Classification of capacity mechanisms and main types based on [15].

2.2.1 Targeted

Strategic reserve

Strategic reserves are typically a volume-based capacity mechanism consisting of capacities that are no longer economically viable and would otherwise have already shut down. Usually, strategic reserves are not allowed to participate in the energy market and are only activated when the energy market fails to clear or certain price caps are reached, indicating times of scarcity.

Strategic reserves are said to have the least disruptive effect on the efficiency of the energy market, since their capacities are held outside the market. However, strategic reserves have to be designed carefully in order for the energy market to still provide sufficient scarcity price signals for investments in new capacities. The activation price of the strategic reserve must be sufficiently high, e.g. equal to the price cap of the energy market or the value of the lost load, so that scarcity prices can still arise on the energy market. If the strategic reserve is activated too frequently the missing money problem is increased, as the occurrence of high market prices is reduced. In addition investors must have a certain amount of confidence in the regulatory framework and future policies, which guarantees only a limited activation of the strategic reserve and allows these scarcity price signals. This point is particularly important when following the newly elected German government's discussions on its strategic reserve [16].

Another effect of a strategic reserve that must be taken into account is, that if the missing money problem of the energy market is not solved, more power plants can threaten to close unless they become part of the strategic reserve, as they are otherwise not economically viable. This effect is called the slippery slope effect and leads to an increased amount of capacity needed for a strategic reserve and the number of capacities contracted in the reserve grows with time.

Tender for new capacity

Tenders for new capacities are volume-based mechanisms to increase the total amount of capacities in the market. Through these tenders financial support is provided for the construction of new power plants.

The introduction of tenders for new, subsidized capacities can lead to reduced prices in the energy market and therefore to reduced revenues for existing or planned capacities. This can lead to the premature closure of generation plants and make investment in new capacities unprofitable. This is called the crowding-out effect.

Additionally, these tenders may incentivize strategic behavior among new investors, who might delay their market entry in anticipation of new tenders from authorities, who show willingness to introduce these tenders, rather than responding directly to market price signals [15].

Capacity payments

Capacity payments are a price-based mechanism, where a targeted capacity, which operates in the market, receives payments for its capacity. A central actor sets the price level for the payments and chooses the targeted capacity. The targeted capacities could be a specific technology or capacities that have to meet certain criteria to be eligible for payments.

2.2.2 Market-wide

Market-wide capacity payments

Market-wide capacity payments are a price-based mechanism, where a central actor sets a price all capacity providers receive, independent of their technologies [15].

Central buyer

A central buyer contracts a certain volume of new and existing capacity through a central bidding process, which determines the market prices.

A central capacity market ensures sufficient long term planning security for new investments, but since the procured volume has to be determined by a traditionally rather risk-averse actor, there is a tendency for overcapacity to occur in the system. As both, existing and new capacities, are allowed to take part, market power of one participant can be limited. As long as new, planned capacities can compete with the least efficient capacities already in the market, new investments can be attracted. A central capacity market is able to address a systematic, market-wide missing money problem [15].

Decentral obligation

Decentral obligations are volume-based mechanisms, where energy suppliers or retailers have to purchase capacity certificates from generating companies based on their peak load or their contribution to the total demand in times of scarcity [15][17]. Market prices are determined through the interaction of all participants in the capacity market, but there is no central bidding process.

As the central capacity market, a decentral obligation resolves the structural missing money problem and theoretically leads to zero capacity costs if the resource adequacy problem is solved. The central actor only determines the rate of demand energy suppliers/retailers have to cover through certificates and not a specific capacity volume. However, this does not mean that a capacity obligation can not also lead to over- or undercapacities in the system. Whether there is over- or undercapacity depends heavily on the penalties imposed if the required certificates are not procured.

For decentral obligations to provide sufficient incentives for investments in new capacities, long-term capacity contracts are needed. The willingness of participants to commit to such long-term contracts is strongly influenced by the uncertainty of capacity prices. In addition, this potential barrier for new entrants can lead to market power of existing capacity providers. A purely decentralized design of a capacity market is therefore not suitable for systems in which additional capacity is required and there is a risk of exercising market power [15].

Combined capacity market

The combined capacity market consists of a combination of a central, volume-based procurement of new capacity and a decentral capacity obligation that energy supplier/retailer have to fulfill, by purchasing certificates from generators or using their own available demand flexibility [18].

The concept of a combined capacity market was introduced as part of the discussion about a capacity market in Germany [18]. Proponents of the combined capacity market see the advantages of using central auctions to ensure sufficient security for investments in capital-intensive new capacities, while at the same time utilizing decentralized demand knowledge and optimally integrating decentralized flexibility options.

Opponents see disadvantages in the complex design of a combined capacity market and its unknown impacts on the electricity market, as there is no combined capacity market in operation yet. Also, it is argued that there is no evidence that the decentral component will significantly enhance the integration of flexibilities in the capacity market. Furthermore demand flexibility can be included efficiently through certain design options in a purely central capacity market [19].

2.2.3 Strengths and Challenges

An overview of the strengths and challenges of the capacity mechanisms listed in Figure 2.1 is presented in Table 2.1.

Table 2.1: Strengths and challenges for targeted and market-wide capacity mechanisms as derived from [15].

Capacity Mechanism	Strengths	Challenges
Tenders for new capacity.	• Provides incentives for new investments. • Useful in achieving certain objectives such as supporting renewable energy. • Potential to solve the missing money problem.	• Not technology neutral. • Reduces prices in the energy market and therefore might lead to a "crowding out" effect.
Strategic reserve	• Least market distortion. • Scarcity prices can still occur.	• Does not solve the missing money problem. • More suitable for adressing short-term problems. • No real incentives for investments in new capacites. • "Crowding out" effect if plants are dispatched before the market fails to clear. • Higher expected profitability in the reserve leading to early market exists. "Slippery slope" effect.
Targeted capacity payments	• Provides incentives for new investments. • Useful in achieving certain objectives such as supporting renewable energy. • Potential to solve the missing money problem.	• In general not technology neutral. • Possible "crowding out" effect. • Possible distortion of market signals. • Unlikely to set the right price, since price is not set by the market. • High risk of under- or overprocurement.

Central buyer	• Technology neutral. • Provides long-term planning security for new investments. • Potential to solve the missing money problem.	• Tendency to overestimate demand due to risk-averse behaviour. • Need to define the to be procured capacity. • Risk of rewarding only existing capacites and not attracting new investments.
Decentral obligation	• No need to specifiy the to be procured volume. • Utilization of decentral knowledge of stakeholders. • Potential to solve the missing money problem.	• Not suitable for attraction of new capacities. • Higher complexity for market. participants. • High administrative effort.
Maket-wide capacity payments	• Technology neutral	• Unlikely to set the right price, since price is not set by the market. • High risk of under- or overprocurement. • Cost-effectiveness unlikely.

2.3 European Union (EU) and capacity mechanisms

2.3.1 EU Regulation

As part of the Clean Energy Package in 2019, the European Parliament and the Council of the European Union introduced the Regulation (EU) 2019/943 on the internal market for electricity [20]. The regulation was amended in 2024 by Regulation (EU) 2024/1747 [21]. The amended regulation defines capacity mechanisms as a measure to reach a desired level of resource adequacy through remunerating resources for their availability. Regulation 2019/943 specifies the circumstances under which a country may introduce a capacity mechanism, the steps that must be taken before such a mechanism is introduced and the general design criteria that a capacity mechanism must meet. For a resource adequacy concern to arise, member states need to have a reliability standard defined. The reliability standard describes the desired level of security of supply and can be chosen by all member states individually. In the following two sections the general and design principles for capacity mechanisms as defined by the regulation are briefly summarized. However, only the most important points are summarized in this work, so there is no claim to completeness.

General principles

For countries to introduce a capacity mechanism, there must arise a resource adequacy concern in the European resource adequacy assessment (EERA). If the countries also carry out a national assessment of the adequacy of resources, this concern must also appear there. In a first step all market failures and regulatory distortions as defined by Article 20 (3) have to be removed. If the resource adequacy problem still occurs, a capacity mechanism can be introduced. Prior to the introduction of the mechanism the countries have to perform a study on the potential impact of the capacity mechanism on the neighboring countries. Furthermore, the first choice for a capacity mechanism must be a strategic reserve, and only if a strategic reserve is not sufficient to solve the problem of resource adequacy another type of capacity mechanism can be implemented. Also capacity mechanisms shall not to be approved for longer than 10 years, and a direct cross-border participation shall be enabled.

Design principles

Design principles that apply to all capacity mechanisms are:

- The process of selecting the capacity providers must be transparent, competitive and non-discriminatory.
- Capacity mechanisms should not create market distortions or limit cross-zonal trade.
- Capacity mechanisms should allow participation of all resources fulfilling certain requirements including storages and demand-side management
- Contracted resources should be penalized for not being available at times of scarcity.

All capacity mechanisms not being strategic reserves should:

- automatically create capacity prices of zero if there is no longer any concern about the adequacy of resources.
- be limited to capacity providers who do not exceed a CO_2 emission limit of 550 gCO_2/kWh. This rule applies to all new capacities and existing capacities have to fulfill it starting in July 2025.

For strategic reserve following rules apply:

- Capacities contracted in a strategic reserve are not allowed to take part in the market - at least for the duration of their contraction period.
- They are not allowed to receive revenues from the wholesale electricity market or the balancing market.
- They should only be dispatched if the balancing reserves of the TSO are in danger of not being able to satisfy the demand = supply constraint of the system [20].

2.3.2 Streamlining the approval of capacity mechanisms

Currently there is a discussion about streamlining the approval process of capacity mechanisms and realizing this by developing a simplified State aid procedure [22]. In the draft *Communication from the Commission on the Framework for State aid measures to support the Clean Industrial Deal (Clean Industrial Deal State Aid Framework – CISAF)* a detailed proposal for a simplified approval process is described in ANNEX I [23]. The simplified process applies to strategic reserves and market-wide capacity mechanisms of the central buyer type. The simplified process tries to include the lessons learned from already implemented capacity mechanisms in the member states as analyzed in [22]. Some interesting design principles for streamlining are listed below, with the note that these points are only an excerpt and do not claim to be exhaustive.

- De-rating factors for different technologies, that all member states have to use, will be provided by the European Network of Transmission System Operators

for Electricity (ENTSO-E) and supervised by the Agency for the Cooperation of Energy Regulators (ACER).
- Cost of New Entry (CONE) and Value of Lost Load (VOLL) shall be calculated by ACER.
- The minimal bid size that is allowed to participate in a capacity mechanism must be below 1 MW.
- If member states have a support for flexibility in place and also a capacity mechanism, the capacities shall be procured together.
- Capacities can be supported by more than one measure as long as there is no overcompensation.
- At least 90% of the costs of a capacity mechanism shall be financed by consumers depending on their behavior during the periods with 1-5% of the highest prices within the year.

2.3.3 Capacity mechanisms in Europe

Figure 2.2 shows the status of capacity mechanisms in the EU in 2023.

Finland, Sweden and Germany have strategic reserves. However, Germany is discussing the introduction of a market-wide capacity mechanism [18][24][25] and the strategic reserve in Sweden expired with 15. March 2025, but there are already discussions about a market-wide capacity mechanism [26]. Also the German government is discussing the utilization of the strategic reserve to stabilize prices in the energy market [10][16].

Italy, Ireland Poland, Belgium and Great Britain have a central capacity market. Great Britain is not shown in Figure 2.2, since it is not part of the EU anymore and therefore also the Electricity Regulation [20] does not apply to its capacity mechanism anymore [9]. In addition to the central capacity market, Italy is in the process of introducing a support scheme for battery energy storage systems (BESS). The first auction shall already take place in September 2025 [27]. Spain has started the process of implementing a central capacity market and most recently concluded the public consultation [28]. The first auctions are planned in the Spanish capacity market in 2026 [29].

France is the only member state, that has a capacity mechanism with decentral obligations in place. However, the decentral market was augmented with central elements to create the necessary security for investments in new capacities and to increase the share of demand response resources participating in the capacity market [19].

Figure 2.3 shows the total capacity, which was remunerated in EU capacity mechanisms from 2020-2024. It illustrates that conventional technologies are the main beneficiaries of the capacity mechanisms, while demand response, RES and battery storage only account for a small share. Natural gas power plants receive the most remuneration,

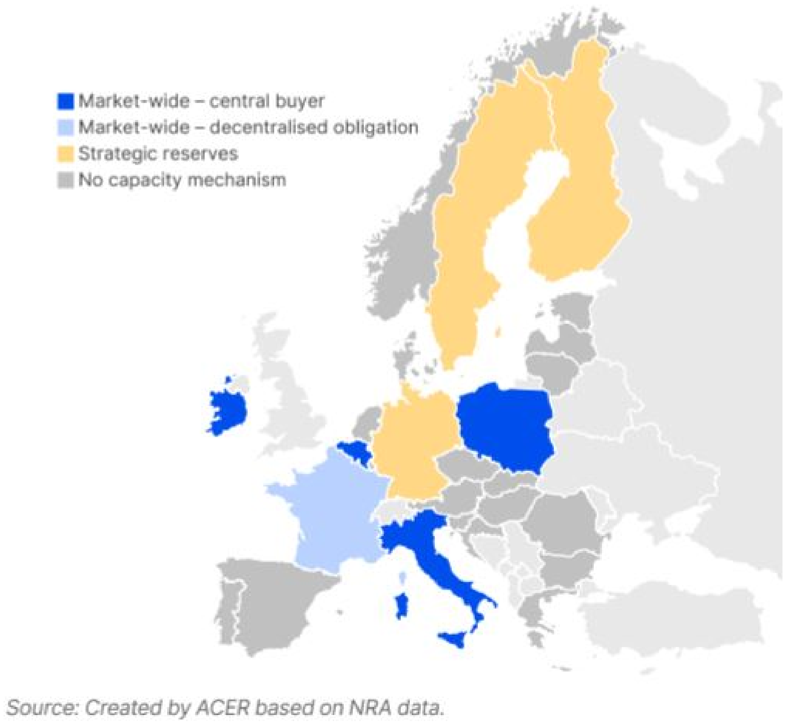


Figure 2.2: Status of capacity mechanisms in the EU - 2023 [11].

followed by nuclear and hydro. Also, there is a significant share of coal, oil and other fossil fuel power plants, that have successfully participated in the auctions.

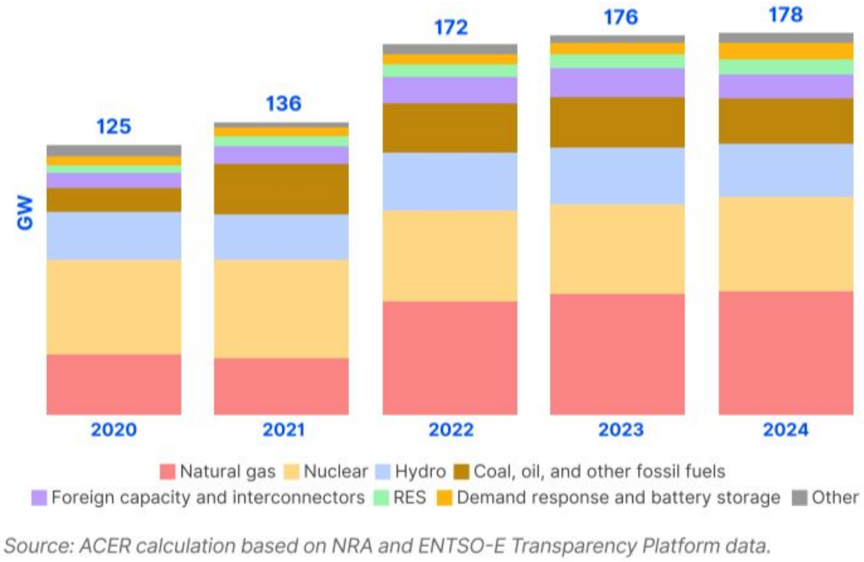


Figure 2.3: Total capacity remunerated in EU capacity mechanisms, per type of technology – 2020–2024 (GW) [11].

3 Distributed Optimization

In order to answer the research question introduced in Chapter 1 an agent-based modeling approach using an algorithm called Alternating Direction Method of Multipliers (ADMM) is proposed. ADMM combines the advantages of Dual Decomposition, which allows to split one large optimization problem in multiple, distributed optimization problems, and the Method of Multipliers, which makes use of the augmented Lagrangian and adds robustness to the algorithm, but does not allow distributed optimization [30].

In the following, a short overview on the theoretical background of Dual Decomposition and the Augmented Lagrangian methods, explicitly the Methods of Multipliers, will be given. In section 3.3 these concepts are combined and the Alternating Method of Multipliers (ADMM), especially the Exchange ADMM, is introduced. The general introduction on the topic of distributed optimization and decomposition methods is mainly based on [30]. Where other sources are used, this is explicitly indicated.

3.1 Dual Decomposition

In order to decompose a problem, it must have a decomposable structure, which means it must have either complicating variables or complicating constraints. In general, decomposition techniques are iterative methods with one master problem, which does not necessarily has to be an optimization problem, and various subproblems. The complicating variables and constraints are considered only indirectly with these techniques [31].

In the following, only decomposition techniques for problems with complicating constraints are considered, since the market balance constraints (supply = demand) are complicating constraints.

A convex problem of the structure

$$\min_{\mathbf{x}} \quad f(\mathbf{x}) \tag{3.1a}$$

$$\text{subject to} \quad A\mathbf{x} = b \quad (\boldsymbol{\lambda}) \tag{3.1b}$$

subject to equality constraints is given. $\mathbf{x}$ is the primal variable $\mathbf{x} \in \mathbb{R}^n$ with $A \in \mathbb{R}^{nxm}$, $\boldsymbol{\lambda}$ is the dual variable of the equality constraints and $f : \mathbb{R}^n \rightarrow \mathbb{R}$ is convex. The Lagrangian of the problem has the form

$$L(\mathbf{x}, \boldsymbol{\lambda}) = f(\mathbf{x}) + \boldsymbol{\lambda} \cdot (A\mathbf{x} - b) \tag{3.2}$$

and the dual problem is then defined as

$$\max_{\boldsymbol{\lambda}} \quad \min_{\mathbf{x}} \quad L(\mathbf{x}, \boldsymbol{\lambda}), \tag{3.3}$$

with

$$g(\boldsymbol{\lambda}) = \min_{\mathbf{x}} \quad L(\mathbf{x}, \boldsymbol{\lambda}) \tag{3.4}$$

as the dual function. The solution of this problem can be found with the dual ascent method, which consists of two iterating update steps. At first, the dual variable is kept constant and $\mathbf{x}$ for the minimal Lagrangian is found. Then the dual variable is updated, based on the optimal $\mathbf{x}$ obtained from the previous minimization step.

$$\mathbf{x}^{k+1} := \operatorname{argmin}_x L(\mathbf{x}, \boldsymbol{\lambda}^k) \tag{3.5a}$$

$$\boldsymbol{\lambda}^{k+1} := \boldsymbol{\lambda}^k + \alpha^k (A\mathbf{x}^{k+1} - b) \tag{3.5b}$$

k is the iteration counter and $\alpha^k \geq 0$ the step size of the dual update step. If the function f is separable

$$f(\mathbf{x}) = \sum_{i=1}^{N} f_i(\mathbf{x_i}) \tag{3.6a}$$

$$\tag{3.6b}$$

the Lagrangian is also separable

$$L(\mathbf{x}, \boldsymbol{\lambda}) = \sum_{i=1}^{N} L_i(\mathbf{x_i}, \boldsymbol{\lambda}), \tag{3.7}$$

where $\mathbf{x_i} \in \mathbb{R}^{n_i}$ are subvectors of $\mathbf{x}$. The problem can be decomposed into subproblems and the solution can be found by the same steps as before, with the addition, that the $\mathbf{x}$-minimization step can be carried out in parallel for all subproblems.

$$\min_{\mathbf{x_i}} \sum_{i=1}^{N} L_i(\mathbf{x_i}, \boldsymbol{\lambda}) = \min_{\mathbf{x_i}} \sum_{i=1}^{N} (f_i(\mathbf{x_i}) + \boldsymbol{\lambda} A_i \mathbf{x_i} - (1/N)\boldsymbol{\lambda} b) \tag{3.8}$$

If the $\mathbf{x}$-minimization step is carried out in parallel, the dual ascent method becomes the dual decomposition. In an economic interpretation of the dual decomposition, the dual variables can be seen as global prices, which are distributed to all the subproblems. The resulting decisions $\mathbf{x_i}$ of the subproblems, obtained by the minimization step, are then gathered and used to calculate the new prices [30].

In addition to convexity, the objective function $f(\mathbf{x})$ of the original problem also has to be smooth, which means a continuous first derivative, and therefore at least a quadratic objective function is necessary to guarantee convergence. Dual decomposition converges under certain assumptions, which are explained in more detail in [30], but these conditions are not met in many applications.

3.2 Method of Multipliers

To generalize dual decomposition for more applications, make it applicable for linear problems and increase its robustness, the idea of the augmented Lagrangian and the method of multipliers was introduced.

Therefore, the Lagrangian is augmented by a quadratic penalty term, which consists of the complicating constraint. The augmented Lagrangian $L_\rho(\mathbf{x}, \boldsymbol{\lambda})$ has the form

$$L_\rho(\mathbf{x}, \boldsymbol{\lambda}) = f(\mathbf{x}) + \boldsymbol{\lambda}(A\mathbf{x} - b) + (\rho/2)||A\mathbf{x} - b||_2^2, \tag{3.9}$$

where $\rho > 0$ is called the penalty parameter. It is obvious that in the optimal point, where the complicating constraint

$$A\mathbf{x} - b = 0 \tag{3.10}$$

is fulfilled, the penalty term disappears and the augmented Lagrangian reduces to the standard Lagrangian. The modified primal problem is

$$\min_{\mathbf{x}} \quad f(\mathbf{x}) + (\rho/2)||A\mathbf{x} - b||_2^2 \tag{3.11a}$$

$$\text{subject to} \quad A\mathbf{x} = b \quad (\boldsymbol{\lambda}), \tag{3.11b}$$

which is equivalent to the original problem 3.1 in the optimality point (x^*, λ^*).

The optimal solution of the modified problem is found through an iterative approach (dual ascent), and is known as Methods of Multiplier. Again the technique consists of an $\mathbf{x}$-minimization step and an update of the dual variable.

$$\mathbf{x}^{k+1} := \text{argmin}_x L_\rho(\mathbf{x}, \boldsymbol{\lambda}^k) \tag{3.12a}$$

$$\boldsymbol{\lambda}^{k+1} := \boldsymbol{\lambda}^k + \rho/2(A\mathbf{x}^{k+1} - b) \tag{3.12b}$$

However, by adding the penalty term to the objective function and creating the augmented Lagrangian, the problem looses its decomposable nature and distributed optimization is no longer possible [30].

3.3 Alternating Direction Method of Multipliers (ADMM)

ADMM is an algorithm, that combines the advantage of distributed optimization of the dual decomposition and the robustness of the method of multipliers. To explain ADMM, the following problem

$$\min_{\mathbf{x}} \quad f(\mathbf{x}) + g(\mathbf{z}) \tag{3.13a}$$

$$\text{subject to} \quad A\mathbf{x} + B\mathbf{z} = c \tag{3.13b}$$

with $A \in \mathbb{R}^{pxn}$, $B \in \mathbb{R}^{pxm}$, the variables $\mathbf{x} \in \mathbb{R}^n$ and $\mathbf{z} \in R^m$ and the convex functions f and g, is considered. This problem is equivalent to the original problem 3.1, with the difference that the variable $\mathbf{x}$ is split into two variables $\mathbf{x}$ and $\mathbf{z}$, which allows a decomposition of the objective function into subproblems. The augmented Lagrangian has the form

$$L_\rho(\mathbf{x}, \mathbf{z}, \boldsymbol{\lambda}) = f(\mathbf{x}) + g(\mathbf{x}) + \boldsymbol{\lambda}(A\mathbf{x} + B\mathbf{z} - c) + (\rho/2)||A\mathbf{x} + B\mathbf{z} - c||_2^2. \tag{3.14}$$

The algorithm (ADMM) to solve this problem consists of three steps:

$$\mathbf{x}^{k+1} := \text{argmin}_x L_\rho(\mathbf{x}, \mathbf{z}^k \boldsymbol{\lambda}^k) \tag{3.15a}$$

$$\mathbf{z}^{k+1} := \text{argmin}_z L_\rho(\mathbf{x}^{\mathbf{k+1}}, \mathbf{z}, \boldsymbol{\lambda}^k) \tag{3.15b}$$

$$\boldsymbol{\lambda}^{k+1} := \boldsymbol{\lambda} + \rho(A\mathbf{x}^{k+1} + B\mathbf{z}^{\mathbf{k+1}} - c) \tag{3.15c}$$

The update steps in order to obtain the values for the iteration k+1 can be explained as follows:

- In the x-minimization step, the variables $\boldsymbol{\lambda}^k$ and $\mathbf{z}^{\mathbf{k}}$ are treated as fixed values, where $\mathbf{z}^{\mathbf{k}}$ is the optimal value from the last iteration.
- In the z-minimization step, the same reason applies only with the difference that $\boldsymbol{\lambda}^k$ and $\mathbf{x}^{\mathbf{k+1}}$ are treated as fixed values.
- In the $\boldsymbol{\lambda}$ update step, $\boldsymbol{\lambda}$ is updated based on the remaining residual of the equality constraint.

The update of $\mathbf{x}$ and $\mathbf{z}$ happens in an *alternating* or sequential manner, which gives the algorithm its name.

3.3.1 Convergence

Under the assumption that the functions f and g

$$f : R^n \to R \cup \{+\infty\} \tag{3.16a}$$

$$g : R^m \to R \cup \{+\infty\} \tag{3.16b}$$

are closed, proper and convex and the unaugmented Lagrangian has a saddle point, it can be shown, that ADMM satisfies

- *Residual convergence.* $r^k \to 0$ with $k \to \infty$. $r^k = Ax^k + B\mathbf{z}^k - c$
- *Objective convergence.* $f(x^k) + g(\mathbf{z}^k) \to p^*$ with $k \to \infty$
- *Dual variable convergence.* $\boldsymbol{\lambda}^k \to \boldsymbol{\lambda}^*$ with $k \to \infty$ [30].

Residual convergence describes the approach towards feasibility (equality constraint is fulfilled), with a growing number of iterations. Objective convergence means that the objective value converges towards an optimal value, as well as the dual variable, which is described by dual variable convergence.

However, it should be noted, that the primal variables $\mathbf{x}$ and $\mathbf{z}$ do not necessarily converge to an optimal solution, even though there is residual, dual and objective convergence. ADMM has shown a very slow convergence to high accuracy in simple cases, but sufficient accuracy for many applications after a couple of dozen iterations. A convergence proof, as well as more detailed explanations of all methods discussed, can be found in [30].

3.3.2 Penalty parameter update

To speed up the convergence, the penalty parameter ρ can be varied, in order to keep the primal residual

$$\mathbf{r}^{k+1} = A\mathbf{x}^{k+1} + B\mathbf{z}^{k+1} - c \tag{3.20}$$

and dual residual

$$\mathbf{s}^{k+1} = \rho A^T B(\mathbf{z}^{k+1} - \mathbf{z}^k) \tag{3.21}$$

in a certain range of each other. The update of ρ, depending on the relation between the primal and dual residual norm, has the following form:

$$\rho^{k+1} := \begin{cases} \tau^{inc}\rho^k & \text{if} \quad ||r^k||_2 > \mu||s^k||_2 \\ \rho/\tau^{dec} & \text{if} \quad ||r^k||_2 > \mu||s^k||_2 \\ \rho^k & \text{otherwise} \end{cases} \tag{3.22a}$$

Typical values are $\mu = 10$ and $\tau^{inc} = \tau^{dec} = 2$ [30].

3.3.3 Exchange ADMM

A special case of the ADMM is the exchange ADMM, which will be used in this work to decompose the problem and iteratively reach a market equilibrium, as required by the market clearing constraints.

The exchange problem is

$$\min_{\mathbf{x}} \quad \sum_{i=1}^{N} f_i(\mathbf{x_i}) \tag{3.23a}$$

$$\text{subject to} \quad \sum_{i=1}^{N} \mathbf{x}_i = 0, \tag{3.23b}$$

where the variables $\mathbf{x_i} \in R^{n_i}$ can be seen as the quantity of commodities exchanged on a market among N subprobems or agents. $f_i(\mathbf{x_i})$ can be interpreted as the cost functions of each agent and $\sum_{i=1}^{N} \mathbf{x}_i = 0$ is the market clearing constraint. All $\mathbf{x_i} > 0$ can be viewed as commodities contributed (supplied) by the agent i to the market and all $\mathbf{x_i} < 0$ as the amount of commodities (demand) agent i receives from the market.

This specific sharing problem, called exchange, can be solved with ADMM in the following steps.

$$\mathbf{x}_i^{k+1} := \text{argmin}_{\mathbf{x}_i} L_{\rho,i}(\mathbf{x}_i^k, \boldsymbol{\lambda}^k) \tag{3.24a}$$

$$:= (f_i(\mathbf{x_i}) + \boldsymbol{\lambda}^k \mathbf{x_i} + (\rho/2)||\mathbf{x}_i - (\mathbf{x_i}^k - \bar{\mathbf{x}}^k)||_2^2 \tag{3.24b}$$

$$\bar{\mathbf{x}}^{k+1} := \frac{1}{N} \sum_{i=1}^{N} \mathbf{x_i} \tag{3.24c}$$

$$\boldsymbol{\lambda}^{k+1} := \boldsymbol{\lambda}^k + \rho \bar{\mathbf{x}}^{k+1} \tag{3.24d}$$

Following [8] variables of agents offering commodities to the exchange (market) are treated as non-negatives and variables of agents receiving goods from the market as negatives. In each iteration, all subproblems are solved and the decisions $\mathbf{x}_i^{k+1}$ of each agent are obtained. These decisions are gathered and used to calculate the remaining market imbalance averaged over all agents $\bar{\mathbf{x}}^{k+1}$ and subsequently the new prices $\boldsymbol{\lambda}^{k+1}$. An increase in prices occurs if there is an excess supply and a decrease if there is an excess demand. The prices $\boldsymbol{\lambda}^{k+1}$ and the averaged market imbalance $\bar{\mathbf{x}}^{k+1}$ are then broadcast to all agents. A central coordinator adjusts the prices until a market equilibrium is reached and the optimal $\boldsymbol{\lambda}^*$ represents the clearing prices. At market clearing, no agent has an incentive to deviate from its decision, and the penalty term reduces to zero. The penalty term regulates the change in the decision variables of all agents from one iteration to the next, prevents an oscillation of the decisions and enables a convergence to the optimal solution [30].

4 Methodology

This chapter includes a detailed description of the modeled scenarios in section 4.1 and a summary of the used input data in section 4.3. A general overview of the distributed, agent-based equilibrium model and the exchange ADMM-based solution technique, is given in section 4.2. In section 4.4 the set of agents, their objective functions and constraints, used for the distributed and independent optimization, are described.

4.1 Scenarios

This work examines which combination of capacity mechanisms and RES support, in the form of a feed-in tariff, is required to lead to a decarbonized electricity system that ensures security of supply in Austria by 2040. Therefore five different scenarios were developed. Table 4.1 summarizes all scenarios and the corresponding market and system parameters.

The *baseline* scenario reflects the perspective of an optimistic investor, assuming an energy-only market without any policy interventions. Price cap and floor for the day-ahead energy market are the Epex Spot market values for Austria [32]. The installed amount of batteries is the TYNDP value as provided by the TSO and there is no capacity market or feed-in tariff.

To capture the uncertainties investors face concerning future policy decisions or regulatory changes, the scenario *Tax + price cap* was developed. This represents the case of a pessimistic investor, who is anticipating a price cap of 400 €/MWh. It reflects the perspective of a pessimistic investor anticipating the introduction of a 400 €/MWh price cap. The price cap represents political reluctance to permit high price peaks, driven by limited public acceptance. Furthermore, the scenario was designed as a worst case scenario in which an additional tax applies on revenues of certain technologies if prices rise above a predefined market price. This tax is in force in Austria and is called *energy-crisis-contribution* [33]. In its' original form, capacity providers get tax breaks on the investment costs of newly installed capacities. These tax reliefs were not considered in this scenario to account for the worst possible case investors might expect.

Table 4.1: All scenarios with the corresponding market- and system parameters.

Scenario	Price cap [€/MWh]	Price floor [€/MWh]	Tax	Installed batteries	CM [GW]	RES [€/MWh]
Baseline	4 000	-500	no	TYNDP	0	0
Tax + price cap	400	-500	yes	TYNDP	0	0
Battery wave	400	-500	yes	10 x TYNDP	0	0
Capacity market (CM)	400	-500	yes	TYNDP	**3.5**	0
Capacity market + RES support (CM + RES)	400	-500	yes	TYNDP	1.5	5

The tax *energy-crisis-contribution* applies to electricity generation from biomass, renewables and waste. Storages, hydropower pumped-storages and gas powered thermal power plants are exempt from this tax. For

- already existing capacities 95% of the revenues above 90 €/MWh
- and for newly built capacities 95% of the revenues above 100 €/MWh

are skimmed by the tax. With the scenario *Tax + price cap* it is examined what effect the introduction of unfavorable new policy decisions and frameworks has on the resulting market and system parameters. It is also questioned whether sufficient investments are still being made to ensure security of supply or if the missing money problem arises.

The scenarios *battery wave*, *capacity market* and *capacity market + RES support* were developed to examine which combination of policy measures ensures security of supply in the most cost-effective way in the case of expected energy not served in the *Tax + price cap* scenario.

Scenario *battery wave* assumes that there is a surge in utility scale battery projects, with installed battery capacity increasing by a factor of 10, approximately aligning with the 2030 projections outlined in [34]. It is questioned if increased flexibility of the system is sufficient to resolve the expected energy not served issue.

In the *capacity market* and *capacity market + RES support* scenarios the capacity demand in the capacity market is varied for a fixed feed-in tariff (0 €/MWh and 5 €/MWh) until the loss of load drops to zero. Again, the resulting system and market parameters are used to determine the most cost-efficient system design that guarantees security of supply.

4.2 High level model overview

In this work an agent-based modeling approach is used. For a set of agents, their unique objective functions and constraints are defined and their optimization problems are solved in an independent and distributed manner. On the one hand, the exchange ADMM algorithm is used to decouple the optimization problems of all agents, on the other hand it is used to achieve a convergence to a market equilibrium. Iteratively, the decisions of all agents are gathered, the resulting market imbalance is calculated and the new prices are broadcast to all agents.

To investigate the main research question, an agent-based modeling framework with the general structure shown in Figure 4.1 was developed. Two markets were introduced, a

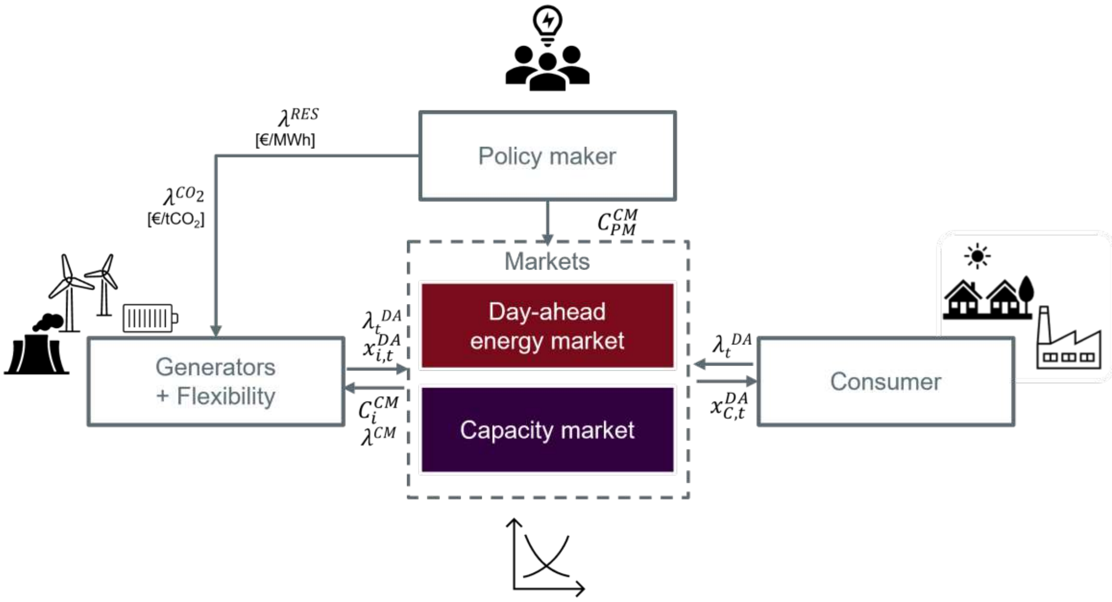


Figure 4.1: High level model overview

central capacity market for newly installed capacity and a day-ahead energy market. The capacity market only allows participation of new capacities, as it is assumed that all existing capacities have already been remunerated by past auctions and the share of already existing capacities compared to the newly installed capacities is relatively low. Therefore it is legitimate to use the term capacity market in this context instead of tenders for new capacity. The day-ahead energy market operates on an hourly basis, while capacity auctions take place once in the whole modeling period. A set of agents consisting of generators, flexibility, and consumers can trade on the day-ahead energy market or offer capacity on the central capacity market. An entity, called policy maker, sets the carbon pricing, the feed-in tariff, and the demand on the capacity market from outside of the modeling framework.

Agents of the three main agent types, namely generators, flexibilities and consumers, can trade their requested or supplied electricity $\mathbf{x}_{i,t}^{DA}$ on the day-ahead energy market. In addition, generators and flexibilities can offer newly installed capacity C_i^{CM} on the capacity market to receive capacity payments for a predefined contraction period. Based on supply and demand on the day-ahead energy market and the capacity market, the remaining market imbalances are calculated and the market prices $(\boldsymbol{\lambda}_t^{DA}, \lambda^{CM})$ are updated. These new prices $\boldsymbol{\lambda_t}^{DA}$ for the day-ahead energy market, and λ^{CM} for the capacity market are distributed to all agents. Based on these prices, all agents optimize themselves and give their decisions about the produced and consumed electricity $\mathbf{x}_{i,t}^{DA}$ and the offered capacity C_i^{CM} back to the markets. This procedure is repeated until the market clearing prices and therefore an equilibrium is reached.

A comprehensive diagram, which illustrates these iterative steps is shown in Figure 4.2. A definition of the primal and dual residuals, as well as the stopping criteria, which

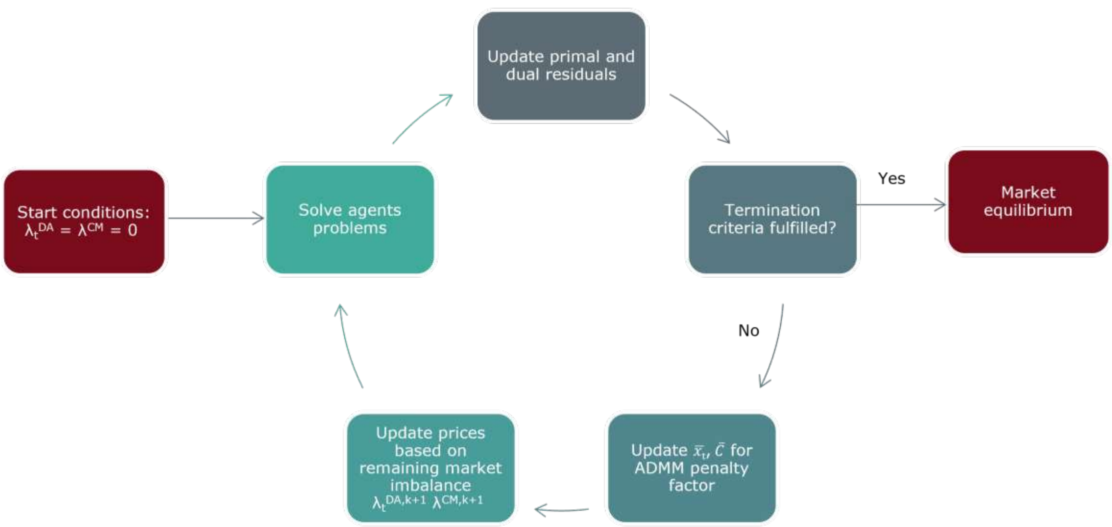


Figure 4.2: ADMM-based workflow for market equilibrium.

leads to the termination of the algorithm, will be given in section 4.4.

Figure 4.2 visualizes how the market equilibrium is found for given values of the feed-in tariff, the CO_2 price and the volume on the capacity market (λ^{CO_2}, λ^{RES}, C^{CM}_{PM}). To optimize the combination of measures in the scenarios *CM* and *CM+RES*, the volume on the capacity market set by the policy maker is varied. The capacity demand is varied for a fixed feed-in tariff (0 €/MWh RES, 5 €/MWh CM+RES) until the expected energy not served (EENS) drops to zero. The capacity demand is varied with a step size of 500 MW, so that the procurement of overcapacity and a resulting not most cost-effective system design are likely. However, this corresponds to the behavior of a risk-averse decision-maker and is therefore a good reflection of reality. The variation of the input parameter can be seen as a Black Box Optimization (BBO), with the Key Performance Indicators (KPIs) of the system and the markets being extracted after convergence to a market equilibrium.

The KPIs for all scenarios are expected energy not served, total system costs, decarbonization, price peaks and volume-weighted average prices in the day-ahead energy market and the price in the capacity market.

In this modeling approach three main types of agents, namely, generators, flexibilities and demand were defined. For each main type several agents were created and their optimization problems were formulated. An overview of the set of agents used in the model is given in Figure 4.3.

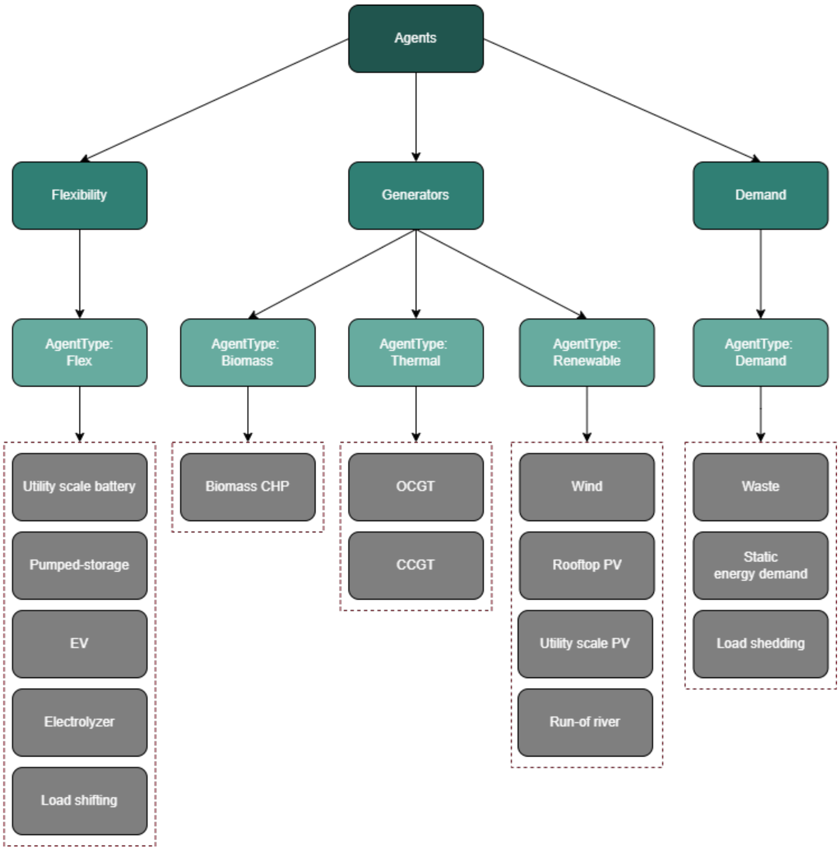


Figure 4.3: Set of agents

4.3 Input data

Climate data for modeling renewable energy generation, as well as the expected energy demand in the electricity sector in Austria by 2040 was taken from the ENTSOs TYNDP 2024 Scenarios [35]. Where it was available, data from the National Transition+ (NT+) scenario was used. In cases where no data was available for the National Transition+ scenario (e.g. availability for EVs), the average of the Global Ambition (GA) and Distributed Energy (DE) scenario was used as input. Following the TYNDP 2024 Scenarios, the climate year 2009 was chosen as the most representative year, and four different weeks were extracted as representative weeks for the optimization. As the starting point for the modeling, the year 2030 was chosen and the corresponding capacities per technology were taken from [35], as provided by the Transmission System Operator (TSO). De-Rating factors for all scenarios were taken from the Belgian TSO

Elia [36]. The optimization was carried out for four representative weeks in the year 2040 and consists of optimal invest and dispatch decisions for all agents. All costs are in 2020 euros.

4.3.1 RES availability

The availability α

$$0 \leq \alpha \leq 1 \tag{4.1}$$

for solar and wind was taken from the Pan European Climatic Database (PECD) 3.1 for the climatic year 2009 and the calendar year 2018. For the availability of run-of-river, the Hydro Inflows for 2040 (climate year 2009) were taken from the Pan European Market Modeling Database (PEMMDB) 2.5 for Austria. These are daily values (GWh/d), which represent the potential energy inflow to run-of-river hydropower plants. These values were reduced to hourly values and the run-of-river availability (capacity factor) was calculated, according to the definition of the PECD [37]. The definition specifies availability as the ratio of the total generation of run-of-river hydropower plants to the total installed capacity.

$$\alpha = \frac{\cdot \text{Inflow}[GWh/d] \cdot 1000}{24 \cdot C^{nom}[MW]} \tag{4.2}$$

4.3.2 EV availability

The availability profile for prosumer and street cars is taken from the TYNDP. The maximum charging and discharging capacities are calculated with the maximal battery charge rate, the availability α_{EV} of the EVs and the share of prosumer and street vehicles.

$$G2V_t = \text{Number of EVs} \cdot \text{Max Battery Charging Rate} \cdot (\sum_{EV} \text{Share}_{EV}[\%] \cdot \alpha_{EV}) \tag{4.3}$$

As the number of EVs and the maximal battery charging rate, the averages from the GA and the DE Scenario for the year 2040, were taken. With a share of 70% prosumer vehicles and 30% street vehicles the grid to vehicle (G2V) potential results in:

$$G2V_t = 4293384 \text{ EV} \cdot \frac{7.3kW}{1000} \cdot (0.7 \cdot \alpha_t^{EV,prosumer} + 0.3 \cdot \alpha_t^{EV,street}) \tag{4.4}$$

Similarly, the vehicle to grid ($G2V_t$) potential was derived with the additional parameter of the share of prosumer and street vehicles that are willing to participate in supplying energy to the grid. For the share of EVs that provide grid services again the average of the GA and DE scenarios were used.

$$\text{Share}_{V2G,prosumer} = 30\% \tag{4.5}$$

$$\text{Share}_{V2G,street} = 7.5\% \tag{4.6}$$

$$V2G_t = \text{Number of EVs} \cdot \text{Max Battery Charging Rate} \cdot (\sum_{EV} \text{Share}_{EV}[\%] \cdot \text{Share}_{V2G}[\%] \cdot \alpha_{EV}) \tag{4.7}$$

$$V2G_t = 4293384 \text{ EVs} \cdot \frac{7.3 \text{ kW}}{1000} \cdot (0.7 \cdot \alpha_t^{EV,prosumer} + 0.3 \cdot \alpha_t^{EV,street}) \tag{4.8}$$

The availability α_{EV} refers to the charging availability, when the EVs are parked and ready to charge or discharge. The hourly EV energy demand for the year 2040 was therefore:

$$D_t^{EV} = (1 - \alpha_t^{EV,pro+street}) \cdot \frac{D^{EV,yearly}}{\sum_t (1 - \alpha_t^{EV,pro+street})} \tag{4.9}$$

The total energy demand for the EVs was again calculated as the average energy demand from the DE and GA scenario of the TYNDP.

$$E_{EV,total} = 8.489911795 \cdot 1e6 \quad MWh \tag{4.10}$$

The maximal energy stored in the batteries of the EVs is:

$$E_{EV} = \text{Number of EVs} \cdot \text{Unitary Capacity} \cdot \ \text{Share}_{EV}[\%] \tag{4.11}$$

$$E_{EV} = 4293384 \text{ EV} \cdot \frac{77.5 \text{ kWh}}{1000} = 332\,737 \text{ MWh} \tag{4.12}$$

Load shifting demand As already discussed, the time series for the electricity demand in Austria in 2040 was taken from the TYNDP 2024 Scenarios. It was assumed that 50% of the total demand is industry demand. Of the industry demand 25% provide load shifting.

$$D_t^{flex} = D_t^{total,DA} \cdot 0.5 \cdot 0.25 \tag{4.13}$$

4.3.3 Domestic hydrogen production

For the estimation of the domestic hydrogen production in 2040, the value

$$D^{H2} = 5511 \frac{GWh}{a} \tag{4.14}$$

was taken from the TYNDP. The yearly production was split in a quarterly production, using weights, and then reduced to hourly values. This timeseries was then used as domestic demand, which the electrolyzers have to cover by local production. However, the hourly H_2 demand is only a guideline and only the overall H_2 demand over the total optimization period has to be covered by the electrolyzers as described in 4.4.2.

4.3.4 Fuel costs and emission factors

This work follows the TYNDP Nation Trends+ assumptions, that in 2040 there will be a natural gas blend instead of pure natural gas in the grids. The chemical composition of this gas blend is summarized in Table 4.2. Due to the chemical composition of the gas

Table 4.2: Share of different gases in the natural gas blend in 2040.

Share	Energy carrier
76 %	Methane
20 %	Biomethane
4 %	E-Methane

blend, the emission factor is

$$F^{CO_2}_{gas,blend} = 0.1549 \quad tCO_2/MWh, \tag{4.15}$$

as obtained from the TYNDP. The H_2 price in the TYNDP 2024 scenarios is rather low with 1-3 €/kgH_2, which seems quite unrealistic considering recent studies [38][39]. Therefore a H_2 price of

$$p_{H_2} = 5\ €/kg_{H_2} \tag{4.16}$$

was assumed and the price of e-methane and subsequently the price of the gas blend was calculated. For the estimation of the e-methane price, the Sabatier reaction was used. The Sabatier reaction describes a catalytic process, where hydrogen (H_2) and carbon-dioxide (CO_2) react highly exothermic (Q) to methane (CH_4) and water (H_2O) [40] [41].

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O + Q \tag{4.17}$$

2.74 kg $CO2$ and 0.504 kg H_2 are required for the production of 1 kg CH_4. The process requires approximately 5.05 times the amount of CO_2 as H_2. With the energy densities of 33.33 kWh/kg for hydrogen [42] and 13.9 kWh/kg for natural gas [43], the required input for 1 MWh synthetic natural gas is:

$$\frac{0.269 \text{ MWh } H_2 + 0.044\text{t CO}_2}{0.223} \rightarrow 1 \text{ MWh } CH_4 \tag{4.18}$$

Based on [44], a price of 150€/tCO_2 for the commodity CO_2 is used, with the assumption that there will only be minor learning effects and the price is also realistic for 2040. E-methane costs are therefore 211 €/MWh, which is in line with the price range for e-methane given by the work of [41]. Costs for the natural gas blend (NG_{blend}) are therefore:

$$NG_{blend} = 0.76 \cdot p_{Naturalgas} + 0.2 \cdot p_{Biomethane} + 0.04 \cdot p_{e-methane} \tag{4.19}$$

Table 4.3: Fuel costs for 2040.

Fuel	Cost [€/MWh]
Hydrogen	150
Natural gas blend	43
Natural gas[1]	20
Biomethane[2]	100
E-methane	211
Wood chips[3]	27

4.3.5 Techno-economic parameters of the agents

In the following, the techno-economic input parameters for all agents are presented in the Tables 4.4-4.7. The main source for the investment and operational costs was the technology data catalog for electricity generation and district heating of the Danish Energy Agency (DEA) [48]. For storage technologies, the technology data for energy storage [49] provided by the DEA was the main reference. Where costs were taken from another source, it is clearly indicated. The values for 2040 were chosen for all prices, and where they were not available, the average of the prices for 2030 and 2050 was used as the best estimate for the price level in 2040. All prices are in 2020 euros.

[1]Natural gas price based on historic data from [45], assuming costs for natural gas will be at least at pre-crisis levels, if not lower due tor reduced demand by 2040.

[2]Biomethane costs are based on [46], assuming no major price changes until 2040.

[3]Wood chip prices are based on [47]. The average of high wood chip prices of 2030 and 2050 was taken and converted to 2020 euros.

Thermal & biomass agents

Table 4.4: Techno-economic specifications of an open-cycle gasturbine, a combined-cycle gasturbine and a biomass power plant. Costs are in 2020 euros.

	Agents	OCGT	CCGT	Biomass
Costs conventional capacity	CAPEX [€/MW]	574 221	866 649	1 042 105
	OPEX fix [€/MW/a]	19 460	28 604	28 392
	OPEX var [€/MWh]	4.36	4.36	1.18
Costs new H_2 capacity	CAPEX [€/MW]	660 354	996 646	-
	OPEX fix [€/MW/a]	22 379	32 895	-
	OPEX var [€/MWh]	5.014	5.014	-
General	Efficiency η [%]	42	59	40
	Lifetime [a]	25	25	25
	De-Rating Factor [%]	92	94	94
	Installed capacity [MW]	562	2 811	658
	Generation limit [TWh/a]	-	-	6

Renewable agents

Table 4.5: Techno-economic specifications of the renewable agents.

	Agents	Solar PV utility scale	Solar PV rooftop	Wind onshore	Run-of-river[4]	Waste
Costs	CAPEX [€/MW]	320 000	669 123	1 109 690	1 254 480	8 070 999
	OPEX fix [€/MW/a]	9 500	9 600	15 965	25 090	187 685
	OPEX var [€/MWh]	0	0	1.89	0	27.7
General	Curtailment [%]	25 %	0%	100 %	0 %	0 %
	Lifetime [a]	25	15	30	50	30
	De-Rating Factor [%]	1	-	7	48	-
	Installed capacity [MW]	6 000	6 000	9 000	5 229	103
	Investment limit [MW]	19 141	20 859	23 939	0	0

Flexibility agents

Table 4.6: Techno-economic specifications of a utility scale battery, hydro pumped-storage, and electric vehicles.

	Agents	Battery utility scale	Hydro pumped-storage	EV
Costs	CAPEX [€/MW]	837 959	4 253 600	-
	OPEX fix [€/MW/a]	5 742	8 507	-
	OPEX var [€/MWh]	1.81	0	-
General	Lifetime [a]	15	50	-
	Charge capacity [MW]	67.8	5 052 · 0.8	C_t^{G2V}
	Discharge capacity [MW]	67.8	6 058 · 0.8	C_t^{V2G}
	Charging efficiency [%]	98.5	87	94
	Discharging efficiency [%]	97.5	87	94
	Energy [MWh]	101.6	1 750 253	E_t^{EV}
	Ratio [MW/MWh]	0.5	-	-
	Initial state of charge (SOC) [%]	55	55	60
	Minimal state of charge (SOC) [%]	10	10	20
	De-Rating Factor [%]	38	-	-
	Investment limit [MW]	-	0	-
	Demand [MW]	-	-	D_t^{EV}
	Energy cycle period [h]	168	168	T

[4] Cost data for run-of-river power plants was taken from [50]. Based on [50] fixed operation- & maintenance costs are assumed to be 3% of CAPEX.

Table 4.7: Techno-economic specifications of electrolyzer and load shifting.

	Agents	Electrolyzer	Load shifting
Costs	CAPEX [€/MW]	1 254 480	-
	OPEX fix [€/MW/a]	25 090	-
	OPEX var [€/MWh]	0	0
General	Lifetime [a]	25	-
	Charge capacity [MW]	1000	1.1x max(peak load)
	Discharge capacity [MW]	-	-
	Efficiency [%]	61.6	100
	Investment limit [MW]	6 000	-
	Demand [MW]	$D_t^{H_2}$	D_t^{flex}
	Load shifting period [h]	T	4

4.4 Modeling

In this section the common shape of the optimization problem for all agents is formulated and other terms like the primal and dual residuals and the termination criteria are defined. Then the formulation of the specific problems for all agents is provided in separate sections 4.4.1 - 4.4.3.

The common shape of the augmented Lagrangian, which has to be minimized to obtain the decision variables for the next iteration for the agents i ∈ {1, N}, has the form:

$$(x_{i,t}^{k+1}, C_i^{inv,k+1}) = \underset{x_{i,t}, C_i^{inv}, C_i^{CM}}{\text{argmin}} \; L_{\rho,i} = \\ f(\mathbf{x}_{i,t}, C_i^{inv}) + \lambda_t^{DA,k} \cdot \mathbf{x}_{i,t} + \rho/2 \cdot ||x_{i,t} - (x_{i,t}^k - \overline{X_t}^k)||_2^2 \\ + \lambda^{CM,k} \cdot C_i^{CM} + \rho/2 \cdot ||F_{dr,i}^{CM} \cdot C_i^{CM} - (F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k)||_2^2 \tag{4.20}$$

$f(x_{i,t}, C_i^{inv})$ is the agent specific cost function, $\lambda_t^{DA,k}$ and $\lambda^{CM,k}$ are the market prices at iteration k, and $\mathbf{x}_{i,t}$ and C_i^{inv} are the decision variables on the hourly dispatch (MWh) and the investment (MW) taken by the agent. C_i^{CM} is the capacity in MW the agent bids on the capacity market and $F_{dr,i}$ is the agent specific de-rating factor with

$$0 \leq F_{dr,i} \leq 1. \tag{4.21}$$

ρ is the penalty parameter, with the initial value $\rho = 10$, and the l_2-norms are the ADMM penalty terms for the market clearing constraints and simultaneously limiting the change in the agents strategy from one iteration to the next. However, it should be noted, that not all agents are allowed an investment decision and therefore not all can trade on the capacity market, which removes all terms related to the capacity market from the augmented Lagrangian.

$\overline{X}_t^k$ and $\overline{C}^k$ are the remaining market imbalances per agent:

$$\overline{X}_t^k = \frac{1}{N} \sum_{i \in N} x_{i,t} \tag{4.22}$$

$$\overline{C}^k = \frac{1}{N} (\sum_{i \in N} F_{dr,i}^{CM} \cdot C_i^{CM} - C_{PM}^{CM}) \tag{4.23}$$

Following the work of [8], [51]–[53] the decision variables of the demand agents have negative values. The coupling constraints, which represent the market clearing of the day-ahead energy market and the capacity market, are incorporated in the objective function as the average market imbalances in the penalty terms. These terms become zero in the case of market clearing. The price update is based on the remaining market imbalance averaged over all agents with the step size ρ :

$$\lambda^{DA,k+1} = \lambda^{DA,k} - \rho \cdot \overline{X}_t^k \tag{4.24a}$$

$$\lambda^{CM,k+1} = \lambda^{CM,k} - \rho \cdot \overline{C}^k \tag{4.24b}$$

The primal and dual residuals, as well as primal and dual stopping criteria are defined following [52] and [54].
Primal residuals of the day-ahead energy (DA) and capacity market (CM):

$$r_t^{DA,k} = \sum_{i \in N} x_{i,t}^k \tag{4.25a}$$

$$r^{CM,k} = \sum_{i \in N^*} (F_{dr,i}^{CM} \cdot C_i^{CM,k} - C_{PM}^{CM}) \tag{4.25b}$$

Dual residual for agent i on the day-ahead energy (DA) and capacity (CM) market:

$$s_{i,t}^{DA,k} = \rho \cdot ((x_{i,t}^k - \overline{X}_t^k) - (x_{i,t}^{k-1} - \overline{X}_t^{k-1})) \qquad \forall i \in N \tag{4.26a}$$

$$s_i^{CM,k} = \rho \cdot ((F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k) - (F_{dr,i}^{CM} \cdot C_i^{CM,k-1} - \overline{C}^{k-1})) \qquad \forall i \in N^* \tag{4.26b}$$

$$s^{DA,k} = \begin{pmatrix} s_{1,t}^{DA,k} \\ . \\ . \\ . \\ s_{N,t}^{DA,k} \end{pmatrix} \tag{4.27a}$$

$$s^{CM,k} = \begin{pmatrix} s_{1}^{CM,k} \\ . \\ . \\ . \\ s_{N^*}^{CM,k} \end{pmatrix} \tag{4.27b}$$

The primal and dual stopping criteria are:

$$\psi^k = ||r_t^{DA,k}||_2 + ||r^{CM,k}||_2 \tag{4.28a}$$

$$\tilde{\psi}^k = ||s^{DA,k}||_2 + ||s^{CM,k}||_2 \tag{4.28b}$$

If both stopping criteria fall below the threshold

$$\epsilon = \zeta \cdot \sqrt{N \cdot T}, \tag{4.29}$$

where ζ is the desired precision, N the number of agents and $t \in T$ the total number of time steps, the algorithm stops. ζ was chosen as $\zeta = 10^{-2}$ and four representative weeks $T = 672$ hours were evaluated.

If the desired level of precision for the stopping criterion is not achieved, the iteration process is terminated once the maximum number of iterations, which was set to $k_{max} = 2000$, is reached.

Also, the variation of the penalty parameter, as described in section 3.3.2 was applied and the chosen values $\mu = 5$ and $\tau^{inc} = \tau^{dec} = 1.1$ were observed to result in the best convergence behavior.

The capital expenditure costs, as well as the operational fix costs were calculated for the time period T in the model.

$$Opex_{fix,T} = \frac{Opex_{fix} \cdot T}{8760} \tag{4.30}$$

The total investment costs were converted to annual costs €/MW/a with the annuity α and were then reduced to the hours of the model T.

$$\alpha = \frac{(1+r)^n \cdot r}{(1+r)^n - 1} \tag{4.31}$$

Here r is the rate of return and n the lifetime of the technology.

$$Capex_T = \alpha \cdot Capex_{total} \tag{4.32}$$

4.4.1 Generators

Renewable

The optimization problem of the renewable agents is as follows:

$$\begin{aligned}\min_{\substack{x_{i,t,res},x_{i,t,cm}\\ C_i^{inv},C_i^{CM}}} &= Capex_T \cdot C_i^{inv} + Opex_{fix,T} \cdot (C_i^{inv} + C_i^{nom}) + Opex_{var} \cdot \sum_t x_{i,t} \\ &-\lambda^{RES} \cdot x_{support} - \sum_t (x_{i,t} \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,t} - (x_{i,t}^k - \overline{X}_t^k)||_2^2 \\ &-\lambda^{CM,k} \cdot (F_{dr,i}^{CM} \cdot C_i^{CM}) + \rho/2 \cdot ||F_{dr,i}^{CM} \cdot C_i^{CM} - (F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k)||_2^2\end{aligned} \tag{4.33}$$

Subject to:
Total generation:

$$x_{i,t} = x_{i,t,res} + x_{i,t,cm} \tag{4.34}$$

Generation limit + support scheme limiting:

$$x_{i,t,res} \leq \alpha \cdot (C_i^{inv} - C_i^{CM} + C_i^{nom}) \tag{4.35}$$

$$x_{i,t,cm} \leq \alpha \cdot C_i^{CM} \tag{4.36}$$

Allowed curtailment:

$$x_{i,t} \geq \alpha \cdot \beta \cdot (C_i^{inv} + C_i^{nom}) \tag{4.37}$$

Bid on capacity market:

$$C_i^{CM} \leq C_i^{inv} \tag{4.38}$$

Investment limit:

$$C_i^{inv} \leq C_i^{inv,max} \tag{4.39}$$

Eligible to the RES support:

$$x_{support} = \begin{cases} \sum_t x_{i,t,res} & \text{if} \quad \text{RES support} = true \\ 0 & \text{if} \quad \text{RES support} = false \end{cases} \tag{4.40a}$$

Variables:

$$x_{i,t,res} \geq 0 \tag{4.41}$$

$$x_{i,t,cm} \geq 0 \tag{4.42}$$

$$x_{support} \geq 0 \tag{4.43}$$

$$C_i^{inv} \geq 0 \tag{4.44}$$

$$C_i^{CM} \geq 0 \tag{4.45}$$

$x_{i,t}$ in MWh is the total generation per time step. In order to limit the renewable agent to taking part in either the capacity mechanism or the renewable support scheme, the variables $x_{i,t,res}$ and $x_{i,t,cm}$ are introduced. This means that energy generated by capacity that is chosen in the capacity market cannot be part of the renewable support scheme. If the agent is eligible for the feed-in tariff, the supported energy $x_{support}$ is the total electricity generation, which is not being part of the capacity mechanism. α is the availability factor of the renewables. Equation 4.37 sets the maximal allowed curtailment for the renewable agent. If the renewable agent must produce (run-of-river), curtailment is not allowed and the parameter β is set to 1. If 100% curtailment is permitted, β is set to zero. Depending on the allowed level of curtailment, β can take any value between 0 and 1. The investment limit takes into account the realistic potential of newly installed capacity in terms of available space that is also economically attractive. $F_{dr,i}^{CM}$ is the agent specific de-rating factor for participating in the capacity market.

Thermal

Objective function of the thermal agents with their constraints:

$$\begin{aligned}
\min_{\substack{x_{i,t,con}, x_{i,t,H_2} \\ C_i^{inv,con}, C_i^{inv,H_2}, C_i^{CM}}} = \; & C_i^{inv,con} \cdot Capex_{T,con} + Opex_{fix,T,con} \cdot (C_i^{inv,con} + C_i^{nom}) + Opex_{var,con} \cdot \sum_t x_{i,t,con} \\
& + C_i^{inv,H_2} \cdot (Capex_{T,H_2} + Opex_{fix,T,H_2}) + Opex_{var,H_2} \cdot \sum_t x_{i,t,H_2} \\
& + \lambda^{CO_2} \cdot \frac{F_{NG_{blend}}^{CO_2}}{\eta_i} \cdot \sum_t x_{i,t,con} + \frac{p_{NG_{blend}}}{\eta_i} \cdot \sum_t x_{i,t,con} + \frac{p_{H_2}}{\eta_i} \cdot \sum_t x_{i,t,H_2} \\
& - \sum_t (x_{i,t} \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,t} - (x_{i,t}^k - \overline{X}_t^k)||_2^2 \\
& - \lambda^{CM,k} \cdot (C_i^{CM} \cdot F_{dr,i}^{CM}) + \rho/2 \cdot ||F_{dr,i}^{CM} \cdot C_i^{CM} - (F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k)||_2^2
\end{aligned} \tag{4.46}$$

Subject to:
Total generation:

$$x_{i,t} = x_{i,t,con} + x_{i,t,H2} \tag{4.47}$$

Total investment:

$$C_i^{inv} = C_i^{inv,con} + C_i^{inv,H_2} \tag{4.48}$$

Generation limits:

$$x_{i,t} \leq (C_i^{nom} + C_i^{inv}) \tag{4.49}$$

$$x_{i,t,con} \leq (C_i^{nom} + C_i^{con}) \tag{4.50}$$

$$x_{i,t,H_2} \leq C_i^{inv,H_2} \tag{4.51}$$

Ramping rates:

$$x_{i,t+1} \leq x_{i,t} + R_i \cdot (C_i^{nom} + C_i^{inv}) \tag{4.52}$$

$$x_{i,t+1} \geq x_{i,t} - R_i \cdot (C_i^{nom} + C_i^{inv}) \tag{4.53}$$

Bid on CM:

$$C_i^{CM} \leq C_i^{inv} \tag{4.54}$$

$$C_{OCGT}^{CM} \leq C_{OCGT}^{inv} - C_{OCGT}^{inv,con} \tag{4.55}$$

CO_2 emissions:

$$e_i = \frac{F_{NG_{blend}}^{CO_2}}{\eta_i} \cdot \sum_t x_{i,t,con} \tag{4.56}$$

Variables:

$$C_i^{inv,con} \geq 0 \tag{4.57}$$

$$C_i^{inv,H_2} \geq 0 \tag{4.58}$$

$$C_i^{CM} \geq 0 \tag{4.59}$$

$$x_{i,t,con} \geq 0 \tag{4.60}$$

$$x_{i,t,H_2} \geq 0 \tag{4.61}$$

The variables $x_{i,t,con}$ and $x_{i,t,H2}$ are the hourly electricity generation of the thermal power plants with either conventional capacity (natural gas blend) or newly constructed H_2 power plants. $p_{NG_{blend}}$ is the price for the gas mix consisting of natural gas (76%), biomethane (30%) and synthetic methane (4%) in €/MWh. p_{H_2} is the future hydrogen price also in €/MWh. $C_i^{inv,con}$ and C_i^{inv,H_2} are the investment decisions in either conventional capacity or new 100% H_2 fired power plants. η is the conversion efficiency in %. For the thermal Open Cycle Gas Turbine (OCGT) agent there is the additional constraint 4.55, as CO_2 emissions are too high for the technology to take part in the capacity market with conventional capacity. e_i is the expression for the CO_2 emissions of the thermal generator and $F_{NG_{blend}}^{CO_2}$ the emission factor in tCO_2/MWh.

Biomass

Objective function and constraints of a biomass agent:

$$\begin{aligned}\min_{\substack{x_{i,t,cm},x_{i,t,res}\\ C_i^{inv},C_i^{CM}}} &= C_i^{inv} \cdot Capex_T + Opex_{fix,T} \cdot (C_i^{inv} + C_i^{nom}) \\ &+ \frac{p_{biomass}}{\eta_i} \cdot \sum_t x_{i,t} \\ -\lambda^{RES} \cdot x_{support} - \sum_t (x_{i,t} \cdot \lambda_t^{DA,k}) &+ \rho/2 \cdot ||x_{i,t} - (x_{i,t}^k - \overline{X}_t^k)||_2^2 \\ -\lambda^{CM,k} \cdot (C_i^{CM} \cdot F_{dr,i}^{CM}) + \rho/2 \cdot ||F_{dr,i}^{CM} \cdot C_i^{CM} &- (F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k)||_2^2\end{aligned} \tag{4.62}$$

Subject to:
Total generation:

$$x_{i,t} = x_{i,t,cm} + x_{i,t,res} \tag{4.63}$$

Yearly limit of total generation:

$$\sum_t x_{i,t} \leq \frac{T}{8760} \cdot X^{max} \tag{4.64}$$

Generation limits + support scheme limiting:

$$x_{i,t,cm} \leq C_i^{CM} \tag{4.65}$$

$$x_{i,t,res} \leq (C_i^{inv} - C_i^{con} + C_i^{nom}) \tag{4.66}$$

Backpressure:

$$x_{i,t} = H_i \cdot c_b \tag{4.67}$$

Bid on capacity market:

$$C_i^{CM} \leq C_i^{inv} \tag{4.68}$$

Eligible to the RES support:

$$x_{support} = \begin{cases} \sum_t x_{i,t,res} & \text{if} \quad \text{RES support} = true \\ 0 & \text{if} \quad \text{RES support} = false \end{cases} \tag{4.69a}$$

Variables:

$$C_i^{inv} \geq 0 \tag{4.70}$$

$$C_i^{CM} \geq 0 \tag{4.71}$$

$$x_{i,t,res} \geq 0 \tag{4.72}$$

$$x_{i,t,cm} \geq 0 \tag{4.73}$$

$$x_{support} \geq 0 \tag{4.74}$$

$p_{biomass}$ in €/MWh is the price of wood chips used in the combustion process. As there is a limit to the theoretical available biomass, due to competing biomass demand in different sectors, the total electricity produced per year is limited. This is expressed by constraint 4.64.

The biomass agent participates in the capacity market and can also be supported by the feed-in tariff. However, generation already remunerated by capacity auctions cannot be supported by the feed-in tariff and therefore the variables $x_{i,t,res}$, $x_{i,t,cm}$ and $x_{support}$ are introduced, as for the renewable agents.

4.4.2 Flexibility

To model flexibility, one agent type was developed and adapted to correctly represent each flexibility option. Figure 4.4 illustrates the general structure of the flexibility agent. For all storage agents, the external load is zero, whereas the storage itself has an

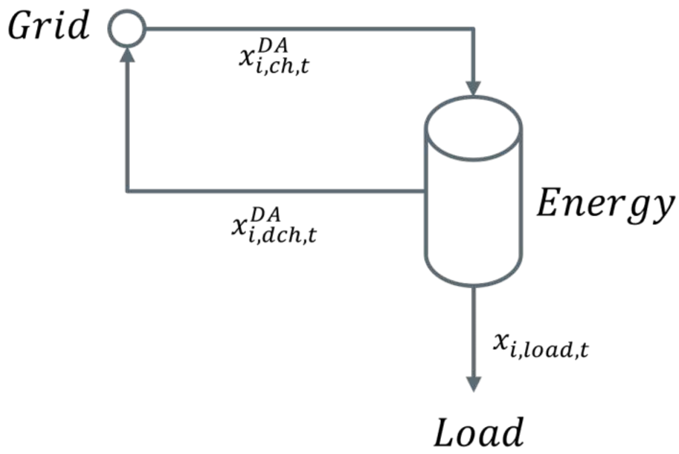


Figure 4.4: General structure of the flexibility agent

energy content which is non-zero. In contrast to this, pure pure flexibilities like load shifting or electrolyzer have an external load but no energy content. In the following the optimization problems, as well as the corresponding constraints are described.

Storage

For the storage the external load is zero, the energy content is non-zero and charging from the grid, as well as discharging to the grid is possible.

Objective function and constraints of a storage:

$$\min_{x_{i,dch,t}, x_{i,ch,t}, C_i^{inv}, C_i^{CM}} = C_i^{inv} \cdot Capex_T + (C_i^{inv} + C_i^{nom}) \cdot Opex_{fix,T} + Opex_{var} \cdot \sum_t (x_{dch,i,t} - x_{ch,i,t})$$
$$- \sum_t ((x_{i,dch,t} + x_{i,ch,t}) \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,dch,t} + x_{i,dch,t} - (x_{i,dch,t}^k + x_{i,ch,t}^k - \overline{X_t}^k)||_2^2$$
$$-\lambda^{CM,k} \cdot (C_i^{CM} \cdot F_{dr,i}^{CM}) + \rho/2 \cdot ||F_{dr,i}^{CM} \cdot C_i^{CM} - (F_{dr,i}^{CM} \cdot C_i^{CM,k} - \overline{C}^k)||_2^2 \tag{4.75}$$

Subject to:
Energy content:

$$E_{i,t} = E_{i,t-1} - \frac{x_{i,dch,t-1}}{\eta_{dch}} - \eta_{ch} \cdot x_{i,ch,t-1} - \frac{x_{i,dch,load,t-1}}{\eta_{dch}} \tag{4.76}$$

Cyclic constraints:

$$E_i[t=1] = E_i[t=T] - \frac{x_{i,dch,T}}{\eta_{dch}} - \eta_{ch} \cdot x_{i,ch,T} - \frac{x_{i,dch,load,T}}{\eta_{dch}} \tag{4.77}$$

$$E_i[t] = E_i[t + T_{cyclic}] \tag{4.78}$$

Total energy content:

$$E_{i,t} \leq (E_i^{inv} + E_i^{nom}) \tag{4.79}$$

Initial energy content:

$$E_i[t=1] = SOC_{inital} \cdot (E_i^{inv} + E_i^{nom}) \tag{4.80}$$

Minimal energy content:

$$E_{i,t} \geq SOC_{t,min} \cdot (E_i^{inv} + E_i^{nom}) \tag{4.81}$$

Energy balance for discharging to load:

$$\sum_{t=T_{bal}} x_{i,dch,load,t} = \sum_{t=T_{bal}} D_t^{flex} \tag{4.82}$$

Charging and discharging limits:

$$x_{dch,i,t} \leq (C_i^{inv} + C_i^{nom}) \tag{4.83}$$

$$-x_{ch,i,t} \leq (C_i^{inv} + C_i^{nom}) \tag{4.84}$$

Constraint for fixed ratio of energy content and charging power for new investments:

$$ratio = \frac{C_i^{inv}}{E_i^{inv}} \tag{4.85}$$

Bid on the capacity market:

$$C_i^{CM} \leq C_i^{inv} \tag{4.86}$$

Variables:

$$C_i^{inv} \geq 0 \tag{4.87}$$

$$C_i^{CM} \geq 0 \tag{4.88}$$

$$E_i^{inv} \geq 0 \tag{4.89}$$

$$E_{i,t} \geq 0 \tag{4.90}$$

$$x_{i,dch,t} \geq 0 \tag{4.91}$$

$$x_{i,dch,load,t} \geq 0 \tag{4.92}$$

$$-x_{i,ch,t} \geq 0 \tag{4.93}$$

The variables $x_{i,ch,t}$ and $x_{i,dch,t}$ in MWh describe the charging and discharging from and to the grid. $x_{i,dch,load,t}$ represents the discharge to satisfy a specific demand D_i^{flex} (e.g. energy demand due to driving an electric vehicle). In the case of a storage D_i^{flex} is zero and therefore also the variable $x_{dch,load,i,t}$ equals zero. Constraint 4.76 describes the energy content in the storage, which must always be the energy content from the last time step plus all charge and discharge processes including their efficiencies. The cyclic constraint 4.77 ensures that the energy content at the beginning of the model horizon equals the energy content at the end of the model horizon. Additionally constraint 4.78 represents the option to set a cyclic constraint for a specific time period, for example the energy content at the beginning of the week must equal the energy content at the end of the week ($T_{cyclic} = 168h$).

These constraints apply to the battery as well as the pumped-storage agent in the model. However, the pumped-storage agent has an additional constraint, which prohibits any investment in new capacities as the pumped-storage potential in Austria is assumed to be already fully utilized.

$$E_i^{inv} = C_i^{inv} = 0 \tag{4.94}$$

Load shifting

Load shifting is assumed to come at no cost for the industry, since some processes (e.g maintenance) are flexible in time. For the load shifting agent, the energy content is zero for every time step

$$E_{i,t} = 0, \tag{4.95}$$

there is only charging from the grid possible,

$$x_{i,dch,t} = 0, \tag{4.96}$$

and there is a flexible demand D_i^{flex}.
The objective function is reduced to:

$$\min_{x_{i,ch,t}} = \sum_t (-x_{i,ch,t} \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,ch,t} - (x_{i,ch,t}^k - \overline{X_t}^k)||_2^2 \tag{4.97a}$$

$$\text{Subject to:} \tag{4.97b}$$

$$\eta_{ch} \cdot x_{i,ch,t-1} = -\frac{x_{i,dch,load,t-1}}{\eta_{dch}} \tag{4.97c}$$

$$\sum_{t=T_{bal}} x_{i,dch,load,t} = \sum_{t=T_{bal}} D_t^{flex} \tag{4.97d}$$

$$-x_{i,ch,t} \leq 1.1 \cdot \text{maximum}(D_i^{flex}) \tag{4.97e}$$

$$-x_{i,ch,t} \geq 0 \tag{4.97f}$$

$$x_{i,dch,load,t} \geq 0 \tag{4.97g}$$

D_t^{flex} is a demand time series and constraint 4.97d specifies, that over the time period T_{bal} the sum of the demand in MWh has to equal the total discharged energy to the load. However, it does not matter how much energy is discharged to the load at every time step. The discharge to the load is only limited by zero (lower bound) and 1.1 times the amount of the peak demand (upper bound). For the load shifting agent the balancing time period $T_{bal} = 4h$ was chosen. The charge and discharge efficiency is $\eta_{dch} = \eta_{ch}$= 100%.

Electrolyzer

The objective function and the constraints of the electrolyzer are very similar to those of the load shifting agent except there are investments possible and operational costs occur. Discharging to the grid is again not possible and the energy content is also zero.

$$\min_{x_{i,ch,t},C_i^{inv}} = C_i^{inv} \cdot Capex_T + (C_i^{inv} + C_i^{nom}) \cdot Opex_{fix,T} + Opex_{var} \cdot \sum_t (-x_{ch,i,t}) - \sum_t (x_{i,ch,t} \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,ch,t} - (x_{i,ch,t}^k - \overline{X_t}^k)||_2^2 \tag{4.98}$$

Subject to:

$$\eta_{ch} \cdot x_{i,ch,t-1} = -\frac{x_{i,dch,load,t-1}}{\eta_{dch}} \tag{4.99a}$$

$$\sum_{t=T_{bal}} x_{i,dch,load,t} = \sum_{t=T_{bal}} D_t^{flex} \tag{4.99b}$$

$$E_i^{inv} = 0 \tag{4.99c}$$

$$-x_{i,ch,t} \leq C_i^{inv} + C_i^{nom} \tag{4.99d}$$

$$-x_{i,ch,t} \geq 0 \tag{4.99e}$$

$$x_{i,dch,load,t} \geq 0 \tag{4.99f}$$

For the electrolyzer, the energy balance time T_{bal} for the demand is the whole modeling time frame. This means, the production of hydrogen can be moved to time periods of high renewable energy generation, like the summer season, without consequences. In this case the charging and discharging efficiencies are electrolyzer specific and given in section 4.3.5.

Electric vehicles (EV)

EV as a flexibility agent is a combination of a storage and load shifting agent. No new investments are allowed

$$E_i^{in} = C_i^{inv} = 0, \tag{4.100}$$

but in this case discharging to the grid (Vehicle-to-Grid) is possible. Furthermore, the EV has an energy storage and therefore the energy content in every timestep is unequal zero.

The objective function and the corresponding constraints are:

$$\min_{x_{i,dch,t},x_{i,ch,t}} = -\sum_t ((x_{i,dch,t} + x_{i,ch,t}) \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,dch,t} + x_{i,dch,t} - (x_{i,dch,t}^k + x_{i,ch,t}^k - \overline{X_t}^k)||_2^2 \tag{4.101}$$

Subject to:

$$E_{i,t} = E_{i,t-1} - \frac{x_{i,dch,t-1}}{\eta_{dch}} - \eta_{ch} \cdot x_{i,ch,t-1} - \frac{x_{i,dch,load,t-1}}{\eta_{dch}} \tag{4.102a}$$

$$E_i[t=1] = E_i[t=T] - \frac{x_{i,dch,T}}{\eta_{dch}} - \eta_{ch} \cdot x_{i,ch,T} - \frac{x_{i,dch,load,T}}{\eta_{dch}} \tag{4.102b}$$

$$\sum_{t=T_{bal}} x_{i,dch,load,t} = \sum_{t=T_{bal}} D_t^{flex} \tag{4.102c}$$

$$E_i^{inv} = 0 \tag{4.102d}$$

$$x_{i,dch,t} \leq C_i^{V2G} \tag{4.102e}$$

$$-x_{i,ch,t} \leq C_i^{G2V} \tag{4.102f}$$

$$x_{i,dch,t} \geq 0 \tag{4.102g}$$

$$-x_{i,ch,t} \geq 0 \tag{4.102h}$$

$$x_{i,dch,load,t} \geq 0 \tag{4.102i}$$

In contrast to the load shifting and the electrolyzer agent, the demand D_t^{flex} cannot be shifted from one hour to another, because the demand symbolizes energy consumption due to driving the vehicles. The energy balance time therefore is $T_{bal} = 1h$.

4.4.3 Demand

Static demand agent

The static demand agent represents the static demand such as households.

$$\min_{\substack{x_{i,t},\\ x_{i,ls,t}, x_{i,cur,t}}} = \sum_t (-x_{i,t} \cdot \lambda_t^{DA,k}) + \rho/2 \cdot ||x_{i,t} - (x_{i,t}^k - \overline{X}_t^k)||_2^2 \tag{4.103}$$

Variable:

$$-x_{i,t} \geq 0 \tag{4.104}$$

The variable $x_{i,t}$ represents the inelastic electricity demand.

5 Results

In order to put the results presented in this section into context, the limitations of the proposed modeling approach must be mentioned. As explained in Section 4.2 there is a hydropower pumped-storage agent, but its seasonality between the modeled representative weeks as well as reservoirs were not considered. Other markets, like intraday or balancing markets as well as resulting potential revenue streams were not considered. Besides the explicit flexible demand agents, the remaining demand is modeled as static time series, assuming no inherent price elasticity. While imports and exports are considered through hourly time series, neighboring bidding zones are not explicitly modeled. As this is a pure market model, grid infrastructure and associated constraints are not represented. From a technological perspective, the model includes only conventional thermal power plants and newly built thermal power plants fully fueled by hydrogen, excluding hydrogen retrofitting and carbon capture and storage (CCS).

Regardless of these limitations significant conclusions about the system- and market behavior can be derived from the results of this work. On the following pages, the results of the various scenarios are presented and the research questions are answered. Conclusions are drawn on the basis of the most important results.

5.1 System- and market results

In Table 5.1 system and market KPIs are presented for all scenarios.

5.1.1 System results

In the *baseline* scenario, there is no expected energy not served and it shows the lowest total system costs with 5650 mio. €/a. The scenario *tax + price cap*, which represents the pessimistic investor, causes EENS of 48 GWh/a and results in the highest system costs of all scenarios with 6165 mio. €/a. For the calculation of the total system costs the upper value of lost load for Austria of 13000€/MWh, as calculated by the E-Control

Table 5.1: Resulting system- and market parameters for all scenarios.

	Scenario	Baseline	Tax + price cap	Battery wave	Capacity market	Capacity market + RES
System KPIs	EENS [GWh/a]	0	48	44	0	0
	Total system costs [million €/a]	5 650	6 165	6 090	5 711	5 900
	Decarbonization [%]	98.9	96.5	96.8	98.8	98.8
Market KPIs	Price peaks [€/MWh]	1 921	400	400	362	362
	Volume-weighted λ_{avg}[€/MWh]	90	83	83	87	87
	Capacity market price [€/MW/a]	-	-	-	85 918	85 919

[55], is used to quantify the EENS. The Austrian value of lost load is therefore in the lower range in an EU-wide comparison [56].

The introduction of the *tax + price cap* leads to a positive EENS, resulting in a 9% increase in total system costs compared to the *baseline* scenario. The installation of ten times the amount of batteries (*battery wave*) leads to a reduction of EENS by roughly 8% compared to *tax + price cap* and the total system costs are reduced to an increase of 8% compared to the baseline level. This observation indicates that increased flexibility alone, in the form of utility scale batteries, does not solve the security of supply problem in the case of a pessimistic investor.

In the scenario *capacity market* the capacity demand was varied in 500 MW steps until the EENS dropped to zero, which was achieved at a total demand of 3.5 GW. The resulting system costs of 5711 mio. €/a are 1% above the baseline costs, but 8% below the scenario *tax + price cap* without additional measures. The combination of a central capacity market and a feed-in tariff of 5 €/MWh leads to system costs roughly 4% above the baseline level, but still 5% below the pessimistic investor scenario with no additional measures. This indicates a potential inefficiency, and therefore over-subsidization, compared to the sole introduction of a capacity market.

It follows from the investigated scenarios, that the most cost-effective combination of measures in the case of the pessimistic investor is therefore scenario *capacity market*.

The decarbonization of the electricity system ranges from 96.5% (*tax + price cap)* to almost 99% in the *baseline* scenario. In all scenarios a CO_2 price of 150 €/tCO_2 in 2040 was assumed. In order to achieve a fully decarbonized electricity system, additional measures - like a sharp increase of the CO_2-price, or restricting the participation in the capacity market to emission-free technologies (as stated by the Regulation 2024/1747 [21]) - would be necessary.

5.1.2 Market results

In the *baseline* scenario a price peak of 1921 €/MWh occurs in the day-ahead energy market, which enables the necessary investment in new capacities. For both scenarios, *tax + price cap* and *battery wave*, the price peaks are limited by the anticipation of price caps, which results in a lack of investment and thus indicates the existence of the missing money problem. In both scenarios with additional measures (*CM, CM+RES)* price peaks of 362 €/MWh occur, which represent the marginal costs of the H_2-fired OCGT thermal agent.

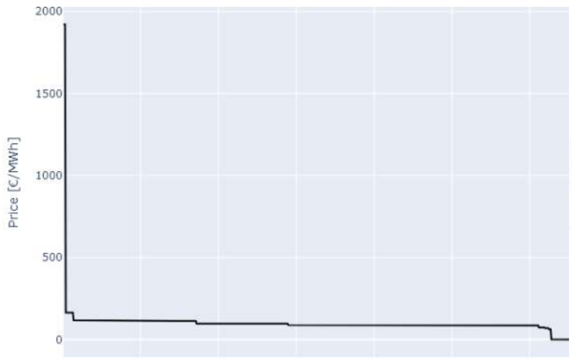
The volume-weighted average price (VWAP) is the lowest in the scenarios *tax+price cap* and *battery wave* with 83 €/MWh. However, it is important to note that both scenarios involve a non-zero EENS. In the scenarios with the capacity market the VWAP stabilizes at 87 €/MWh, which represents a reduction of 3 €/MWh compared to the baseline scenario. The introduction of a capacity market therefore effectively lowers the average market prices in the energy market and removes price peaks above the marginal costs of the most expensive generator.

Table 5.2: Frequency of prices below 50 €/MWh and above 100, 200, 300, 400 and 1000 €/MWh for all scenarios.

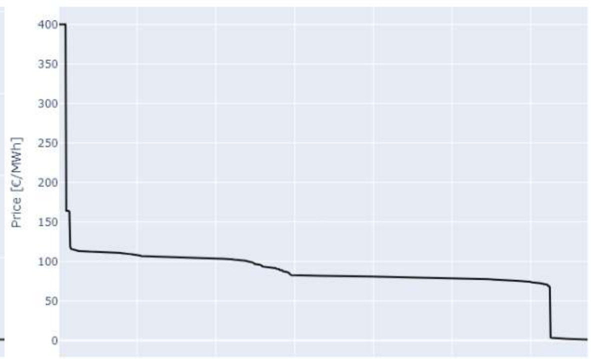
Scenario	Baseline	Tax + price cap	Battery wave	Capacity market	Capacity market + RES
$\leq$ 50 €/MWh	586 h/a	626 h/a	600 h/a	587 h/a	600 h/a
$\geq$ 100 €/MWh	2 229 h/a	3 129 h/a	2 050 h/a	2 229 h/a	2 229 h/a
$\geq$ 200 €/ MWh	39 h/a	117 h/a	117 h/a	78 h/a	78 h/a
$\geq$300 €/MWh	39 h/a	117 h/a	117 h/a	78 h/a	78 h/a
$\geq$ 400 €/MWh	39 h/a	117 h/a	117 h/a	-	-
$\geq$ 1000 €/MWh	39 h/a	-	-	-	-

In Table 5.2 the frequency of prices above certain levels are summarized for all scenarios and Figure 5.6 shows the price duration curves for all scenarios. In the *baseline* scenario 39 h/a occur with prices above 1000 €/MWh. For the *tax + price cap* and *battery wave* scenarios, the price cap is limiting the price peaks to 400 €/MWh in 117 h/a. With the introduction of the capacity market the frequency of price peaks above 200 €/MWh reduces to 78 h/a and in these hours the hydrogen fired OCGT power plant is price setting.

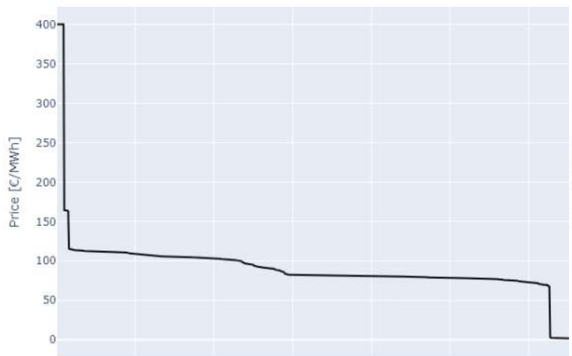
In both scenarios with a capacity market, the price of the capacity market settles at 85918 €/MW/a. In the case of only a capacity market 3.5 GW are procured and with an additional feed-in tariff the capacity necessary to achieve an EENS of zero reduces to 1.5 GW. The chosen capacities were found by varying the capacity demand in the market by 500 MW steps and keeping all other parameters constant. This approach is likely to result in the procurement of overcapacity, which may not lead to the most cost-efficient system design. However, it effectively reflects the behavior of a risk-averse decision-maker who might prioritize ensuring security of supply over the most cost-effective system.



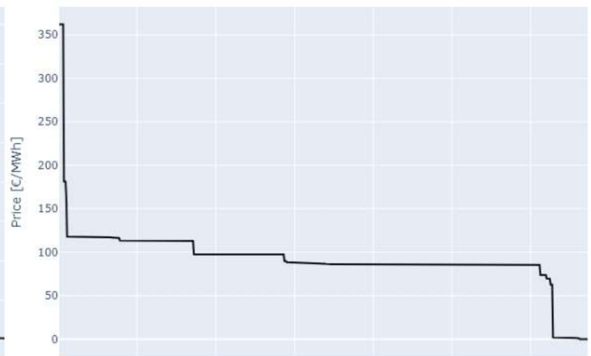
Baseline



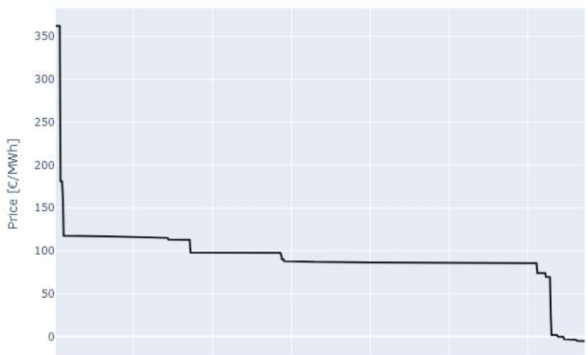
Tax + price cap



Battery wave



CM



CM + RES

Figure 5.6: Price duration curve for 8760h for all scenarios.

5.1.3 Investments

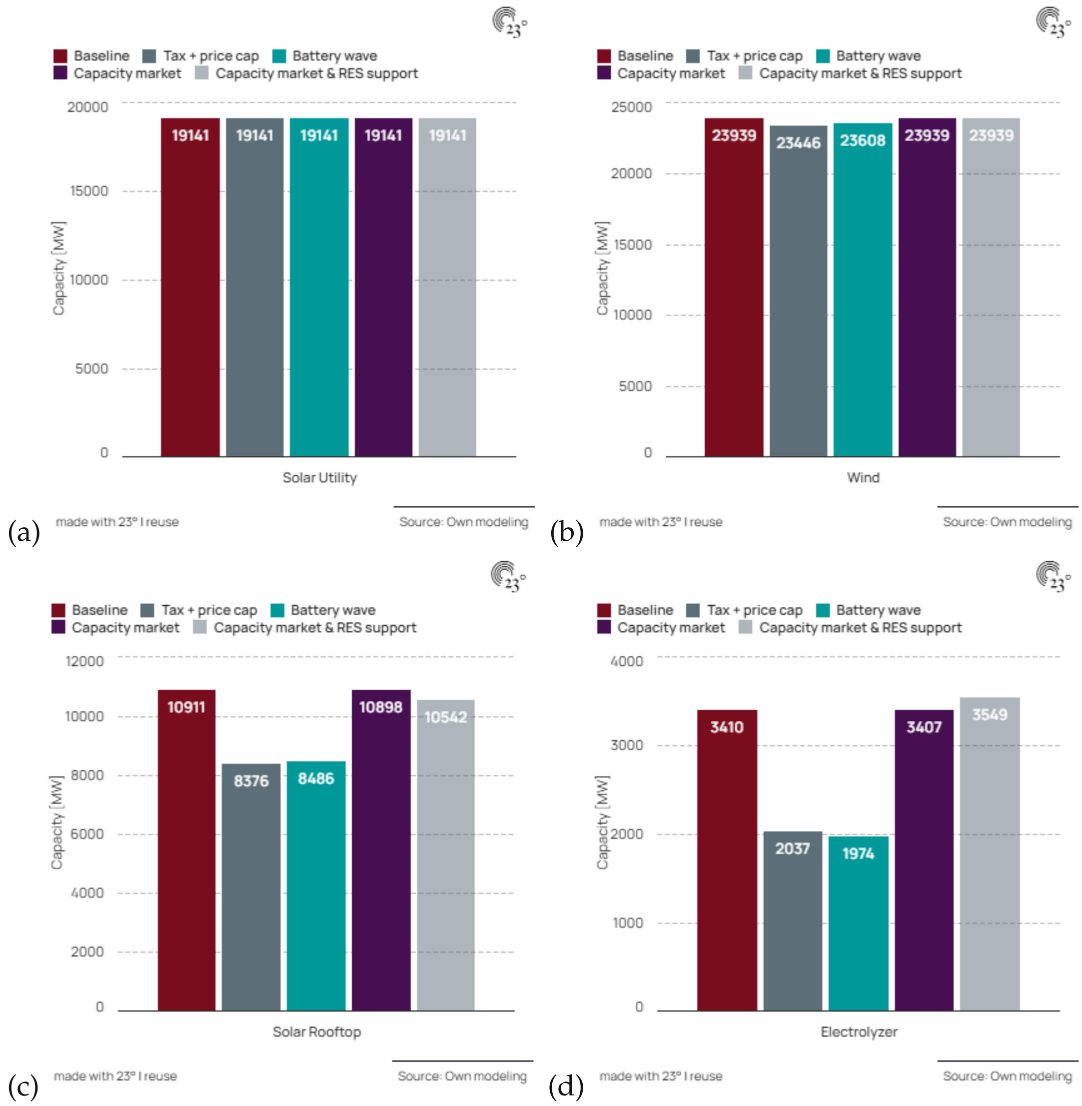


Figure 5.7: Investment decisions of the agents (a) solar utility (b) wind (c) solar rooftop and (d) electrolyzer for all scenarios.

Over all scenarios utility scale PV is expanded up to the upper investment limit as defined by the TYNDP, which is due to the cheap investment costs of utility scale PV. In all scenarios there are no investments in new battery capacities. This could be due to the fact that only 2h-batteries with high investment costs were considered and no additional revenue streams from the intraday or balancing markets make investments profitable. The potential for storing energy and shifting it to periods of high demand is primarily utilized by the hydropower pumped-storage unit. As a result, the battery agent does not generate sufficient revenue for investments in additional capacity.

The introduction of the tax and the price cap results in a decline in investments in wind and rooftop PV. Notably, the simultaneous reduction in rooftop PV investments is interesting, given that these systems are assumed to be residential and thus not subject to the tax. This can be explained by the reduced average prices on the day-ahead market, the only revenue stream for the rooftop PV agent. As a consequence of the reduced investment in renewable energy sources, investment in electrolyzers also declines. Without sufficient low-cost renewable generation, the need for additional peak capacity diminishes, making further investment in electrolyzers not economically viable.

The installation of 10 times the amount of batteries leads to an increase in wind and rooftop PV investment, since there is more flexibility in the system to shift energy to times of higher demand and therefore also increases the price for times with higher renewable generation. This additional flexibility reduces the potential of electrolyzers to utilize the low-cost renewable energy and therefore a slight reduction in installed capacities is observable in the *battery wave* scenario.

The implementation of additional measures (*CM, CM + RES*) results in the full deployment of wind power and increases installed capacities of rooftop PV and electrolyzers to levels that match or exceed those observed in the *baseline* scenario. The increase in the volume-weighted average price might be attributed to the significant expansion of electrolyzer capacity.

In the *baseline* scenario exactly enough new OCGT capacity (1389 MW) is installed to meet peak demand. Biomass is utilized up to its deployment limit, defined by an annual generation cap of 6 TWh, reflecting the restricted and competitive availability of biomass resources. With the introduction of the tax and the price cap, the newly installed OCGT capacity is reduced to 719 MW, resulting in a non-zero EENS. Additionally, there are not enough incentives, due to the missing price peaks, for the biomass agent to fully expand to the set limit. Increasing the battery amount by 10 times leads to a further reduction of newly installed OCGT capacity to 480 MW. The dispatch frequency of the OCGT agent remains approximately the same across the *tax + price* and *battery wave* scenarios. However, the total volume of electricity offered to the market by the OCGT agent decreases, as the battery agent significantly increases its offered volume, during times, where the price cap is reached, from 268 MWh to 2676 MWh. For both scenarios, *tax + price cap* and *battery wave*, a missing money problem arises.

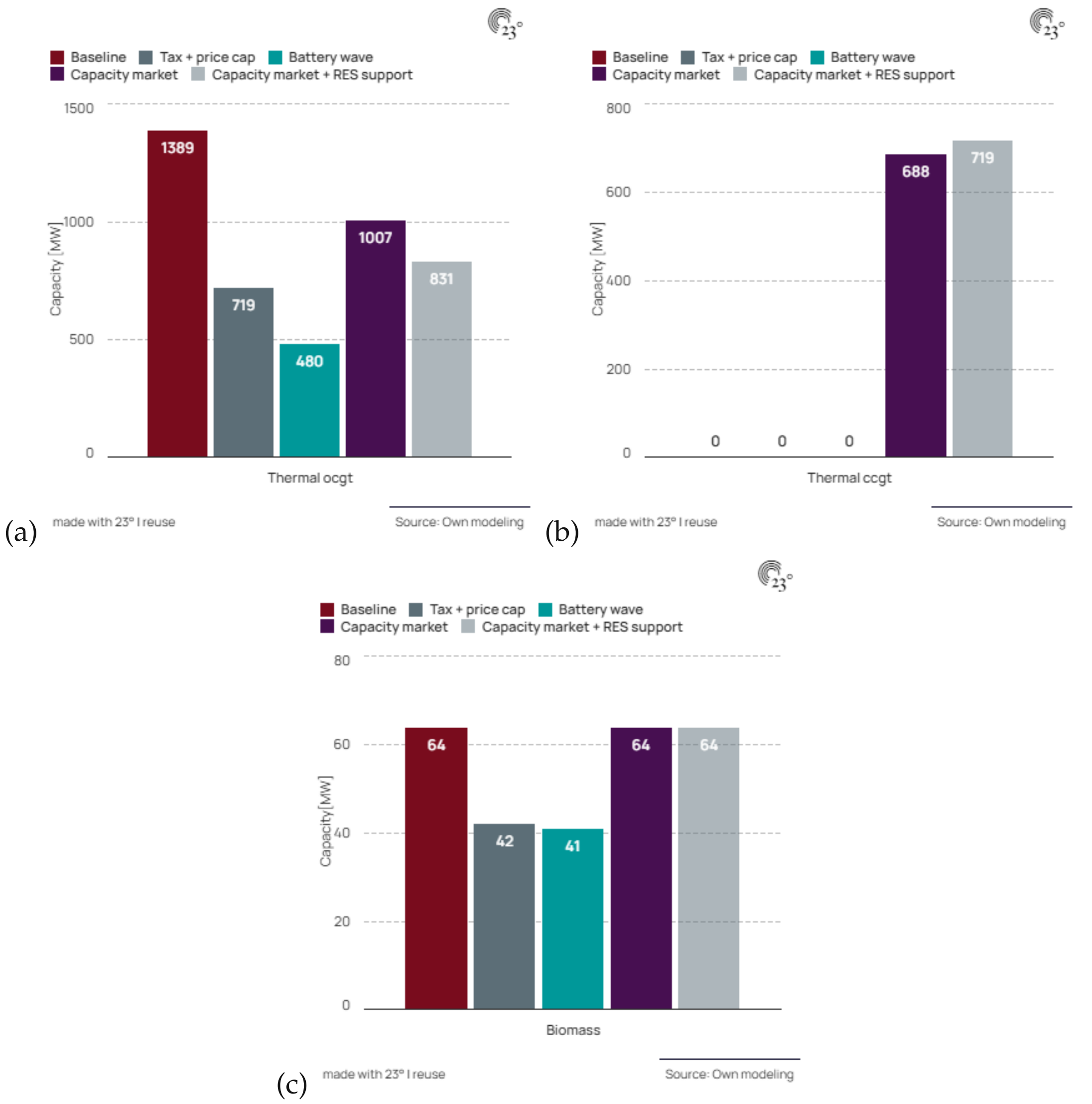


Figure 5.8: Investment decisions of the agents (a) thermal ocgt (b) thermal ccgt and (c) biomass for all scenarios.

New investments in thermal CCGT plants do not occur prior to the introduction of the capacity market. Once the capacity market is implemented, biomass is deployed to its full extent, and - in addition to the emerging CCGT - increased OCGT investments can be observed, although not to the same extent as in the *baseline* scenario. It is important to note that, due to emission limits, methane-fired OCGT power plants are not allowed to participate in the capacity market. The OCGT investments shown represent newly built hydrogen-fired power plants, as illustrated in Figure 5.9. Due to the high investment costs and substantial operating expenses associated with hydrogen-fired power plants, primarily driven by the high cost of hydrogen, investments in conventional CCGT power plants become economically attractive within the framework of a capacity market. Figure 5.9 shows that conventional CCGT power plants are merely constructed in the *CM* and *CM + RES* scenarios.

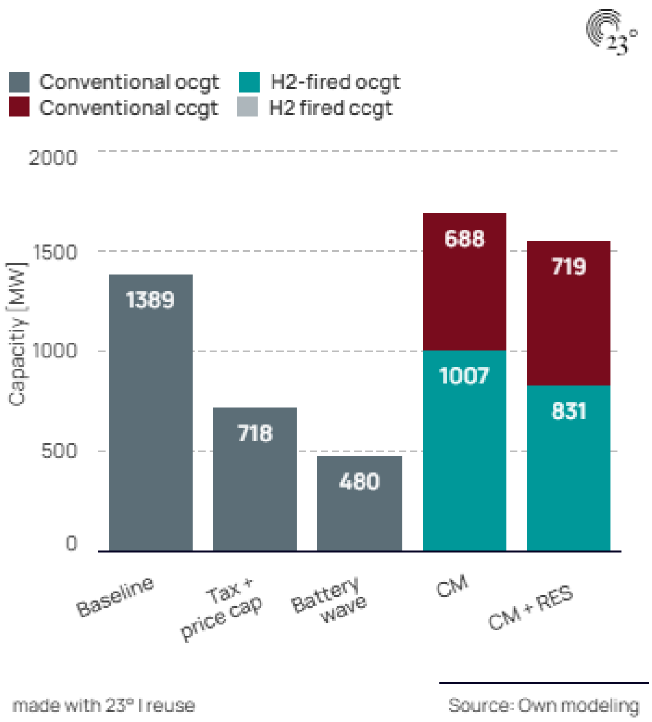


Figure 5.9: Investments of thermal agents per technology for all scenarios.

The share of OCGT and CCGT procurement varies between the *CM* and *CM + RES* scenarios, which can most likely be attributed to the different total volumes procured on the capacity market, varying dispatch decisions and as a consequence different equilibrium points, since a solution does not have to be unique.

In the *CM* scenario, a total thermal capacity of 1695 MW is procured, while in the *CM + RES* scenario, 1550 MW are secured. Compared to the *baseline* scenario, where only a total thermal capacity of 1389 MW is procured to precisely meet peak demand, it becomes evident that in both scenarios with a capacity market an overprocurement of capacity takes place. In the *CM* scenario, approximately 306 MW of thermal capacity is overprocured, while in the *CM + RES* scenario the overprocurement amounts to around 161 MW. Across both scenarios, investments in generation technologies are nearly identical, with only minor differences in rooftop PV deployment. However, given the minimal solar availability during peak price periods in the *baseline* scenario, these differences are unlikely to significantly affect the total thermal capacity required to ensure adequacy during times of scarcity.

The procurement of a slight overcapacity does not significantly compromise the cost-effectiveness of the system design, particularly when the objective is to ensure security of supply. In fact, it remains more economical than the *tax + price* cap scenario, with high economic costs caused by a significant EENS, valued at 13000 €/MWh. Moreover, such additional safety margins may be justified, as the capacity market demand is determined based on modeled weather years and scenario assumptions, which inherently involve uncertainty.

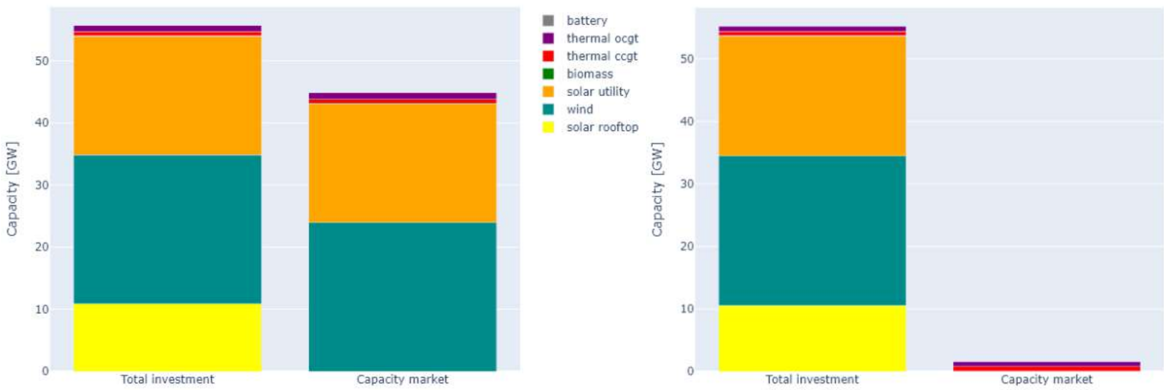


Figure 5.10: Total investments and investments financed by the capacity market for the *CM* scenario (left) and the *CM+RES* scenario (right) . Shown capacities in the capacity market are not de-rated.

Figure 5.10 shows the total investments in the *CM* and *CM + RES* scenarios, along with the corresponding capacities offered in the capacity market. In the scenario with only a capacity market in place, all agents, except for the rooftop solar agent, offer their entire installed capacities to the capacity market. The rooftop solar agent does not participate, as these installations are assumed to be non-aggregated capacities at a residential level, which cannot guarantee existence or availability in future years and are therefore not able to participate in a (long-term) capacity market.

The combination of a capacity market and the feed-in tariff results in renewable capacities exclusively utilizing the RES support mechanism, while only thermal agents participate in the capacity market.

5.1.4 Costs and revenues per agent type

In Figures 5.11 and 5.12 the costs and revenues for the three main agent types and the policy maker are presented across all scenarios.

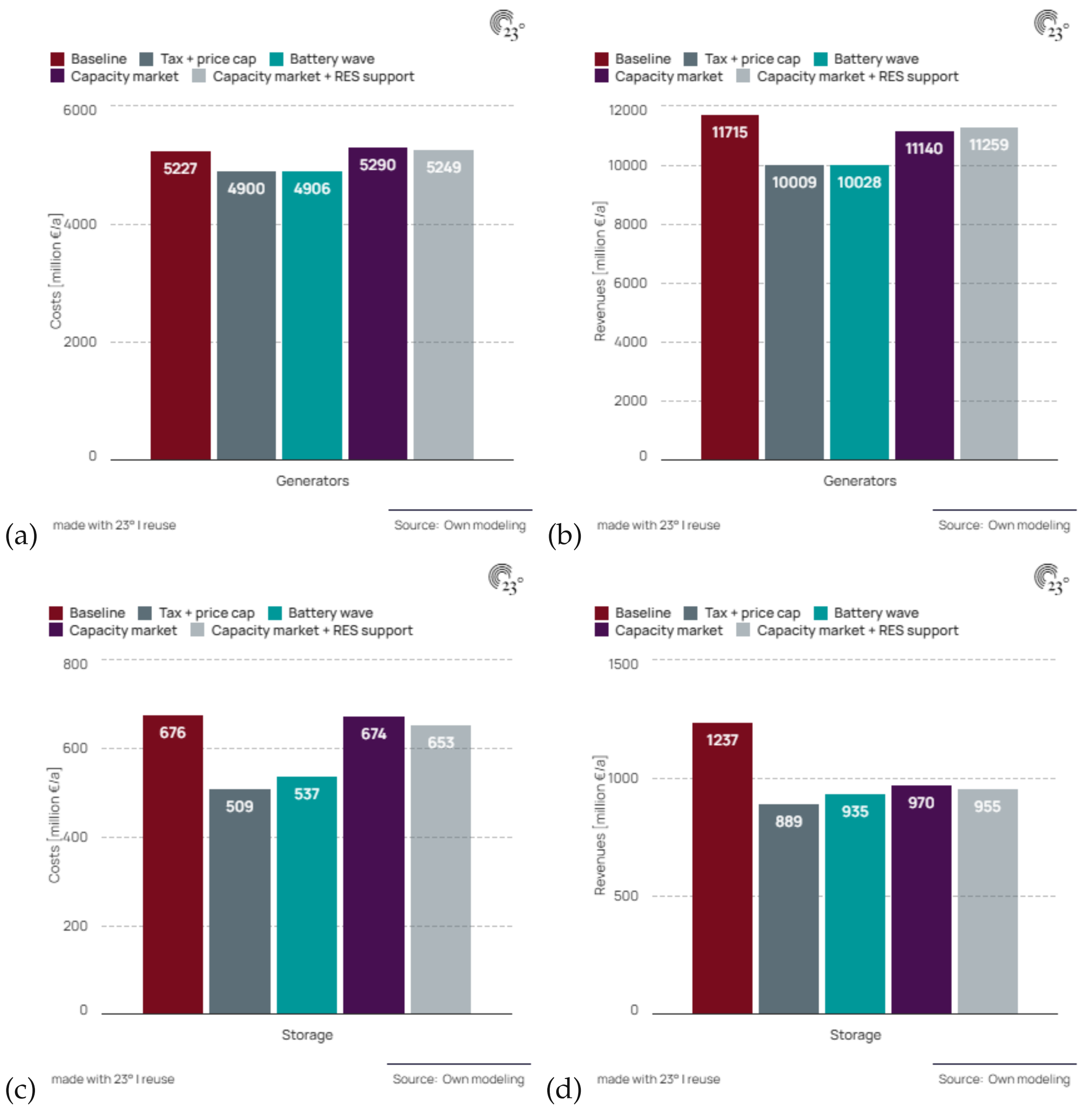


Figure 5.11: Costs (a, c) and revenues (b, d) for the agent types generator and storage across all scenarios.

Compared to the *baseline* scenario, costs and revenues decline for both, generators and storages, in the *tax + price cap* and *battery wave* scenarios. The cost reduction can be attributed to lower investment expenditures, while the decrease in revenue stems from the reduced total installed generation capacity.

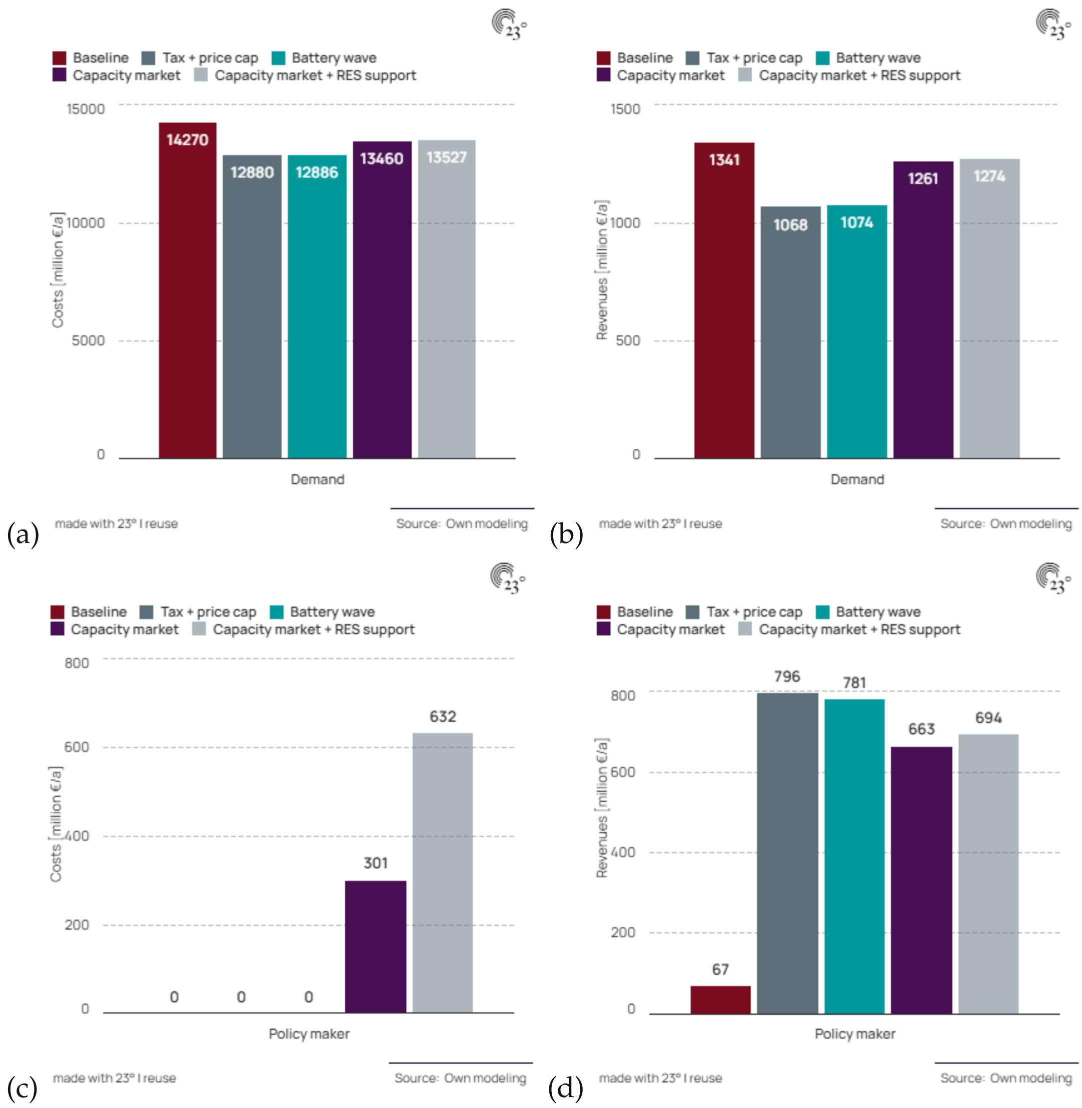


Figure 5.12: Costs (a, c) and revenues (b, d) for the demand agent and the policy maker across all scenarios.

Figure 5.12 shows the costs and revenues for the demand agent and the external policy maker. The decrease in costs compared to the *baseline* scenario for the demand agent is

Table 5.3: Total generation by natural gas blend and hydrogen, as well as tax revenues and share of tax revenues in total policy revenues for all scenarios.

Scenario	Baseline	Tax + price cap	Battery wave	Capacity market	Capacity market + RES
Generation with natural gas blend [GWh/a]	1 613	4 996	4 626	1 589	1 779
Generation with hydrogen [GWh/a]	0	0	0	35	33
Tax revenues [mio. €/a]	-	596	596	600	623
Share of tax revenues in total policy revenues [%]	-	75	76	90	90

primarily driven by the decreased deployment of electrolyzers. Furthermore, the decline in revenues for the demand agents stems from the reduced vehicle-to-grid potential, which is a consequence of lower investment levels in renewable energy sources.

The yearly amount of electricity produced with thermal power plants by natural gas blend and hydrogen combustion, as well as the total revenues from the tax and its share on total policy revenues are summarized in Table 5.3.

A more detailed examination of the policy maker's costs and revenues reveals that in the scenarios involving the tax and no capacity market, approximately 75% of the revenues are generated from the tax, while the remaining 25% originate from the CO_2 price. The slight increase in the share of tax revenues within total policy revenues in the *battery wave* scenario is attributed to the reduced dispatch of fossil power plants, leading to a corresponding decline in revenues from the CO_2 price.

In both scenarios, *CM* and *CM + RES*, where the capacity market is active, the share of tax revenues within total policy revenues rises to 90%, driven by a significant reduction in the dispatch of carbon-intensive thermal power plants.

Across all scenarios with active tax, tax revenues remain relatively stable at around 600 mio.€/a with only a slight increase in the *CM + RES* scenario. This can be attributed to the direct support of renewables, leading to their increased dispatch even at prices above the threshold where the tax is applied.

Table 5.3 shows that the introduction of the tax and the anticipated price cap results in a 210% increase in the dispatch of conventional thermal power plants. As soon as the capacity market is introduced, investments in renewable energy sources increase again and also hydrogen fired thermal power plants are remunerated through the mechanism. This results in generation levels through natural gas blend combustion that are comparable to those in the *baseline* scenario, causing policy revenues resulting from the CO_2 price to decrease.

Refer to Figure 6 in the Appendix for a detailed overview of the cost and revenue structure for the main agent types generation, storage, and demand.

6 Discussion

6.1 Security of supply and cost-effectiveness

As expected, the *baseline* scenario of the optimistic investor with merely an energy-only market results in the most cost-efficient market design. However, under the assumption of a pessimistic investor or in the presence of significant policy interventions, security of supply cannot be ensured, and essential investments are withheld. The integration of additional flexibility through utility-scale battery storage also fails to fully resolve the security of supply issue.

Across the investigated scenarios, security of supply is only ensured following the introduction of a capacity market. Among the assessed options, a standalone capacity market represents the most cost-effective policy measure, resulting in a 1% (+ 0.4 €/MWh) increase in total system costs compared to the *baseline* scenario, showcasing slight inefficiencies of the system design. The preference towards the standalone capacity market is not only due to the fact that this system design represents the most cost-effective option when accounting for the economic value of lost load, but also because of its lower complexity and reduced susceptibility to implementation errors. Furthermore, combining a capacity market with a feed-in tariff significantly increases policy-related expenditures, which essentially doubles the financial burden, that will ultimately be passed on to end consumers, either through taxes or higher prices in the electricity bill.

6.2 Complexity of market design

An acknowledged drawback of a capacity market with a central buyer is the challenge of accurately determining the amount of capacity to be procured. When combining multiple policy instruments, this complexity increases further, as it not only requires defining the procurement volume within the capacity mechanism but also setting the appropriate level of the feed-in tariff.

In this work, a feed-in tariff of 5 €/MWh was selected. However, it is likely that a lower tariff would have been sufficient to incentivize the same level of investment

in renewable generation, which would have resulted in renewable agents still only participating in the feed-in tariff but leading overall to reduced system costs.
Inefficient system designs should be avoided. The combination with a feed-in tariff lacks targeting precision and results in excessive support for generators, leading to unnecessary costs.
This simple example already illustrates the complexity of setting the appropriate price levels and quantities in two complementary support schemes. Their interaction can reduce competitiveness within one mechanism, as fewer agents may choose to participate and thereby increasing the potential for individual agents to exert market power.

6.3 Flexibilites

An increased amount of batteries alone as additional flexibility is not sufficient, but other flexibility options such as reservoirs or elastic demand incentivized by dynamic tariffs were not included in this work. Especially dynamic tariffs for end-consumers will be an important measure to include demand flexibility and provide additional flexibility to the system through price elasticity of demand.

However, it has to be considered that the presented model might underestimate the available flexibility, offered by a potential increase in demand-side flexibility, different import/export behavior, as well as the potentially higher installed capacity of hydropower plants. Through the combination of all these flexibilities it could therefore be possible to reduce the EENS to zero also in the pessimistic investor scenario without a capacity market.

Nevertheless, effectively unlocking the full potential of these flexibilities requires time, particularly to encourage end-consumers to shift from fixed energy tariffs to more flexible tariffs, which are still less publicly known and accepted. As a result, a capacity mechanism may be necessary as an interim solution, even though the full deployment of flexibilities could eventually make such a mechanism obsolete.
In order to investigate these, or similar, topics and subsequently deepen the understanding of the posed questions, continuous future adaptations and extensions of the current model will be necessary.

6.4 Design of the capacity market

Even though the introduction of a capacity market is the least-cost solution under the assumption of a pessimistic investor, it remains unclear how this potential capacity market should be designed. The EU regulation states that a capacity market should provide incentives for capacity providers to be available in scarcity times and penalties should be applied for not being available.

In the capacity market created in this work no such penalties or incentives exist. One resulting effect of these missing penalties is, that in the *capacity market* scenario the wind and solar agents simply bid their total investments on the capacity market. This behavior is not associated with any risk for the renewable agents.

Their contribution to the security of supply is already accounted for through the de-rating factors taken from the Belgian TSO Elia [36]. These de-rating factors are inherently very low (1% solar and 7% wind), which suggests that this choice could limit certain technologies from participating in the capacity market. Through low de-rating factors and additional penalties for not being available, the participation of renewable energy source is hindered severely. However, this effect is observable in Belgium, where penalties for non-availability and reliability options are in place. In the last four Y-4 auctions only thermal capacities, storages and demand-side response were awarded in the framework of the capacity market [57]–[60].

The participation of renewables could be enhanced by adjusting the rules for renewable energy sources, to achieve the desired technology neutrality and higher competitiveness of the capacity market. Low de-rating factors could be combined with reliability options, where capacity providers are required to pay back the difference between the strike price and the market price if the market price exceeds the strike price. With the introduction of reliability options, there is a certain risk associated with participation in the capacity market, especially for renewabale agents. The reason behind this is that price spikes tend to occur during periods of low renewable energy production, as was observed in this work. This creates a challenge for renewable energy providers, as they may not be able to generate power during these high-price periods and still have to pay back the difference between the market price and the strike price.

Whether the introduction of these additional penalties and incentives would have the desired effect, has to be investigated in a future work and cannot be concluded in the scope of this thesis. However, it may be advisable to postpone further investigation until the European Commission has reached an official decision regarding the methodology for de-rating factors. As outlined in section 2.3.2, there is an ongoing discussion about streamlining the approval process for capacity mechanisms. One key element of this reform is the proposal that, in the future, ENTSO-E will be responsible for calculating standardized de-rating factors, which all member states will be required to adopt. Depending on the outcome of the standardized de-rating factors, certain configurations of additional penalties, such as reliability options alone, a combination of reliability options with penalties for non-availability, or penalties without reliability options, may prove more relevant for further investigation than others.

7 Conclusion

This thesis investigates the effects of expected market interventions, in the form of a tax on revenues and anticipated price caps, on the security of supply for Austria in the year 2040. The central research question addressed in this thesis is which combination of measures, namely enhanced system flexibility (*battery wave*), the introduction of a capacity market (*CM*), or the combined implementation of a capacity market with a feed-in tariff for renewables (*CM + RES*), offers the most cost-efficient approach to ensure security of supply in Austria's decarbonized electricity system by 2040. An agent-based modeling approach utilizing an ADMM algorithm was chosen, which allowed direct access to the market prices and therefore enabled a rule-based implementation of policy interventions and studying their effects on an agent level.

The results of the modeling approach allow for several key insights to be derived and lead to the following seven conclusions:

- In the setting of a pessimistic investor that anticipates market interventions (tax + price cap) by policymakers, a missing money problem arises. In a market with a missing money problem investors withhold required investments due to expected inadequate revenues to cover their costs, which subsequently creates a security of supply problem, where installed capacities are not sufficient to cover the total demand and expected energy not served occurs.

- The increase of system flexibility alone through the installation of ten times the amount of battery capacities does not solve the security of supply problem created by anticipated policy interventions. This is due to the energy constraints of the installed batteries and the limited opportunities to shift energy from high production hours to hours with high demand, especially during a dark doldrum period.

- The missing money problem and the resulting security of supply issue can be effectively addressed through the introduction of a capacity market. The implementation of a capacity market is accompanied by the removal of price peaks and a lowering of the average prices in the energy market.

- Considering the value of lost load of 13000 €/MWh for expected energy not served, all scenarios with a capacity market show lower total system costs, than a system with anticipated market interventions.

- In the setting of the pessimistic investor, the most cost-efficient solution to guarantee security of supply is the introduction of a central capacity market without additional measures.

- One of the drawbacks of a central capacity market is always the determination of the to be procured volume. In this work, a slight overprocurement occurred, which did not lead to the most cost-efficient system design. Nevertheless, the results show that moderate overprocurement is economically preferable to underprocurement, which leads to EENS. The outcomes indicate that, while the volume to be procured should be selected with care, a slight overprocurement does not lead to a significant increase in costs. It can even be beneficial by enhancing safety margins during periods of system stress.

- The findings suggest that a capacity market, implemented without additional price-based instruments such as a feed-in tariff, should be considered the preferred approach due to its relative simplicity and lower risk of implementation errors. The combination with a feed-in tariff lacks targeting precision and results in excessive support for generators, leading to unnecessary costs. This price-based support scheme therefore displays the same shortcomings as price-based capacity mechanisms: when the level of the feed-in tariff is not determined through a competitive process, it leads to inefficient procurement of capacity.

8 Outlook

In the ongoing project at AIT Austrian Institute of Technology GmbH, this modeling approach will be further developed to evaluate various capacity mechanisms - including a central capacity market, tenders for new capacity, and a strategic reserve - with respect to their effectiveness in addressing the missing money problem, ensuring security of supply, and optimizing the total cost-efficiency of the resulting system. Additionally, further design options, such as the introduction of reliability options within the central capacity market, will be incorporated to meet the requirements of the Electricity Regulation 2019/943, which mandates the imposition of penalties for non-availability.

Furthermore, there is an ongoing process to improve the integration of demand-side flexibility into the model. As a first step, a certain price elasticity of demand will be implemented to assess whether the security of supply issue persists. In a second step, both explicit and implicit forms of demand-side response (DSR) participation in the capacity market will be incorporated. In the case of explicit participation, DSR units will submit bids in the capacity market, thereby reducing the total volume of capacity to be procured. For implicit participation, the costs of the capacity mechanism will be allocated to the system's peak load hours, effectively strengthening the incentive for consumers to reduce their demand during these periods.

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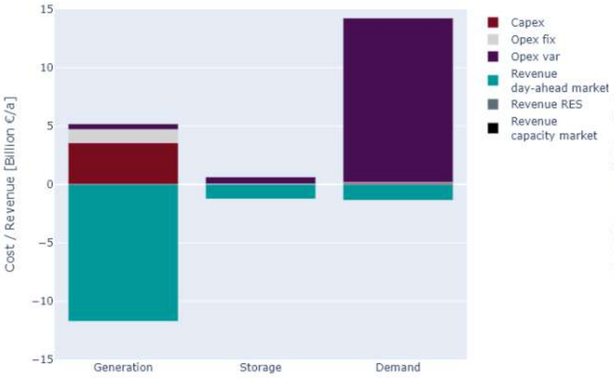
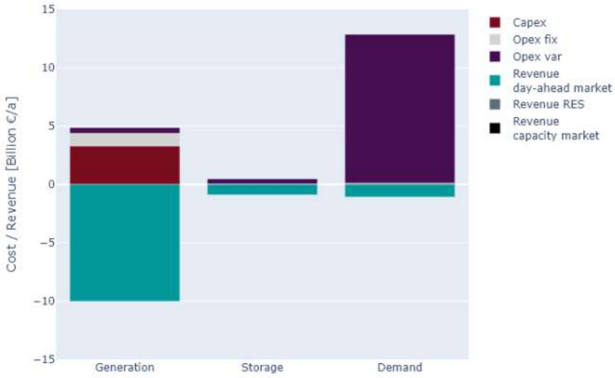
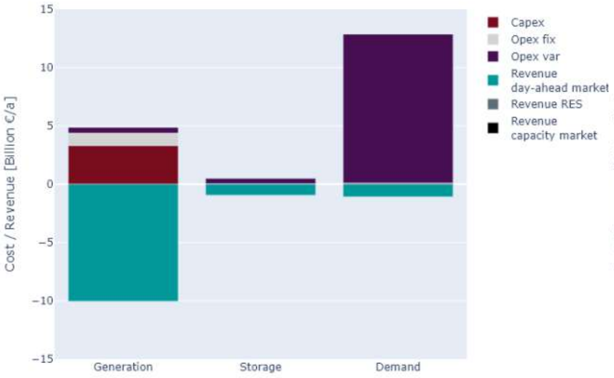
Appendix



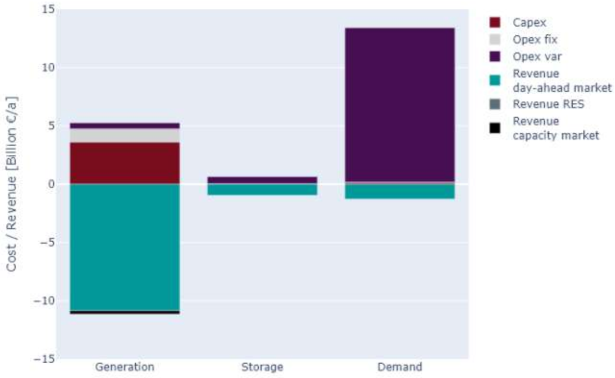
Baseline



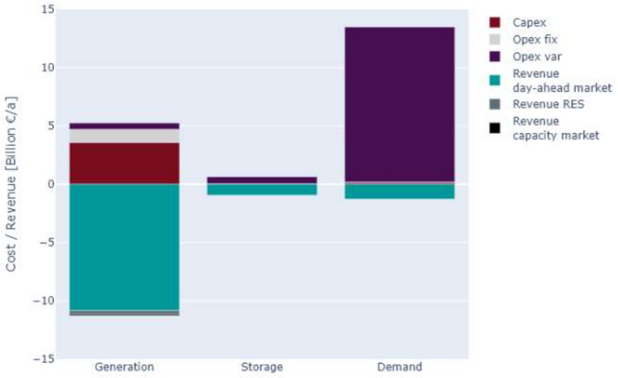
Tax + price cap



Battery wave



CM



CM + RES

Figure 6: Cost and revenues for the main agent types across all scenarios.