AN ANALYSIS OF THE DUTCH HORTICULTURE ENERGY OPERATIONS IN 2030 USING MIXED-INTEGER LINEAR PROGRAMMING

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Executive Summary

Introduction

In the Netherlands, greenhouse horticulture is a vital component of the country's agricultural sector, contributing significantly to the economy, environment, and society. However, greenhouse horticulture heavily relies on natural gas for heat and electricity, leading to high CO2 emissions. To address this issue, the greenhouse horticulture sector and the government are committed to reducing their Annual CO2 equivalent emissions and aim to achieve climate neutrality by 2040, as outlined in the Energy Transition Covenant for Greenhouse Horticulture 2022-2030. To discourage natural gas consumption, particularly in combined heat and power (CHP) systems, policymakers have introduced changes such as restructuring energy taxation and replacing the sector-specific CO2 system with a flat individual CO2 levy. Simultaneously, network charges are expected to increase due to infrastructure expansion costs, and both electricity and gas prices are predicted to decrease in the following decade. Successful transition also requires factors beyond the greenhouse horticulture sector's control, such as advancements in the Dutch sustainable energy system, third-party supply of heat and electricity, and consumer willingness to choose climate-neutral products.

Research goal and questions

This master's thesis is part of the overarching TU Delft research project, DEMOSES, which aims to develop and integrate supporting energy models to enhance long-term decision-making processes in restructuring the Dutch energy system. The main objective of this thesis is to create a unit commitment (UC) model to analyse the evolving energy landscape of the horticultural sector in the Netherlands, and its impact on the energy-related operations of horticulturists until 2030. The model is built in collaboration with AgroEnergy and represents the horticultural sector within the broader energy models of the DEMOSES project. The main research question of this thesis is: *"How will the evolving contextual factors within the Dutch greenhouse horticulture energy landscape until 2030 affect the energy management practices, emissions, and expenses of horticulturists?".*

To provide a structured approach to addressing the main research question, the research aims to answer the following four sub-questions:

1. *"What are the prevailing trends in energy utilisation, generation sources, CO2 emissions, and trading practices within the greenhouse horticulture sector in the Netherlands?"*
2. *"What are the effects of energy system regulations and costs on the emissions and operational energy costs of greenhouse horticulturists?"*
3. *"How will the emissions and financial dynamics of greenhouse operations evolve when sustainable thermal generation increases and electricity trade adapts accordingly?"*
4. *"What is the impact of energy price developments on the energy operations within the horticultural sector of the Netherlands until 2030?"*

Research approach and methods

For this research, various research methods were employed. The horticultural energy system was analysed by conducting desk research to answer the first research question. A modelling approach was used to answer the second to fourth research questions. Specifically, a unit commitment (UC) model leveraging multi-integer linear programming (MILP) was built to analyse the dynamics of electricity, heat, and CO_2 within the Dutch greenhouse industry. This study aimed to comprehensively understand the implications of evolving policies, technologies, and market conditions in the sector, and optimise decision-making processes. The UC model allowed for a precise representation of the real world that encompasses all relevant boundaries and constraints, capturing the system's intricacies and exploring various scenarios. The input for the model included demand, generation asset specifications, and national energy prices. The UC model can simulate energy system regulations and assess their implications. The model was able to show how different components within the greenhouse industry impact the cost-minimisation of energy operations and identify strategies to enhance efficiency and cost-effectiveness under evolving contextual circumstances.

Key findings & conclusions

The updated energy tax system in 2030 produced contrasting results compared to 2023. In 2023, the tax system incentivised using self-generated electricity from CHP systems, whereas in 2030, it discouraged this practice. The financial implications of this revised energy tax, in conjunction with the new sectoral CO_2 tax, are evident in scenarios without RES availability in 2030. Here, horticulturists experience a 39% increase in annual net costs, with only an 11% decrease in CO_2 emissions, falling short of reduction targets. However, with the wide availability of RES for thermal generation—including geothermal energy, waste heat, heat pumps, and electric boilers—the thesis suggests an extreme increase of 416% in annual net costs, alongside a substantial 55% drop in CO_2 equivalent emissions. Even with the removal of electric boiler capacity from the energy mix, there's still a notable increase in annual net costs. The most cost-effective scenario, aligning with emission reduction goals, entails relying on geothermal and waste heat for sustainable thermal generation, supplemented by CHP generation. With a 51% increase in annual net costs, this scenario achieves impressive emission reductions of 49%. These findings are aggregated trends across various horticultural profiles examined with the UC model.

The research underscores the profound influence of contextual factors on horticulturists' energy practices, particularly highlighting the potential overshadowing effect of high network charges on regulatory efforts to promote sustainable thermal generation. Although the introduction of a sectoral CO_2 tax aims to encourage a shift towards sustainable thermal sources, challenges such as excessive DSO costs could undermine its efficacy. Effective capacity management emerges as pivotal, stressing the necessity for precise allocation to avoid unnecessary network charges resulting from exceeding DSO contract capacities when utilising electric thermal generators during periods of negative electricity prices.

Waste heat emerges as a viable alternative to CHP-generated heat, albeit with limitations in availability within the horticultural sector. Geothermal energy is forecasted to become the primary sustainable thermal provision technology by 2030, emerging as a cost-effective sustainable technology. However, achieving this hinges on ambitious capacity targets contingent upon horticulturists' geographical locations. Furthermore, the integration of geothermal energy remains less economically advantageous than relying solely on CHP systems, despite revisions to the gas tax and the introduction of sectoral CO_2 taxation, underscoring the necessity for revised fiscal policies to drive this transition.

Ultimately, horticulturists are anticipated to transition from being electricity suppliers to balanced electricity traders, incorporating both renewable and conventional thermal sources. While enhancing sustainability, this transition entails increased net costs due to reduced revenue from electricity sales, stemming from less frequent CHP operation in scenarios incorporating RES for thermal generation.

Recommendations

Policy intervention is crucial to address escalating DSO network charges and incentivise a shift towards sustainable energy sources. Regulating network tariffs and revising pricing mechanisms, especially for heat pumps, can mitigate costs and encourage adoption. Incorporating the SDE++ subsidy into the model may further reduce the financial barriers to renewable technologies, promoting their uptake over CHP systems in the model output.

Future research should explore diverse scenarios of geothermal and waste heat availability, refining models to optimise their inclusion. Additionally, investigating various tax regimes and accurate energy price scenarios with an increase in negative prices can inform policy decisions and enhance the economic viability of electric generators. Developing methods to determine optimal heat pump capacity while balancing negative electricity prices and DSO contract limitations is essential for effective energy planning.

Horticulturists should prioritise investments in waste heat and potentially geothermal energy, alongside maintaining CHP systems for load-following needs. Avoiding the installation and commitment of electric/gas boilers and managing heat pump capacity within contracted limits can mitigate costs. Maintaining operational flexibility over committable generators is vital for cost-effective energy management.

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List of Abbreviations

ATES - Aquifer thermal energy storage

CHP - Combined heat and power

CO2 - Carbon dioxide

COP - Coefficient of Performance

DEMOSES - Designing and Modelling future Systems of Energy Systems

EB - Electric boiler

EPEX - European power exchange

EU-ETS - European Union emissions trading system

EZK - Ministry of Economic Affairs and Climate Policy (in Dutch: Ministerie van Economische Zaken en Klimaat)

FDC - Frequency duration curve

GB - Gas boiler

GEO - Geothermal energy

HID - High-intensity discharge

HP - Heat pump

ICIS - International commodity information system

KEV - Capacity for Energy Transition (in Dutch: Klimaat- en Energieverkenning)

KPI - Key performance indicator

kWh - Kilowatt hour

LDC - Load duration curve

LED - Light-emitting diode

LHV - Lower heating value

LNV - Ministry of Agriculture, Nature and Food Quality (in Dutch: Ministerie van Landbouw, Natuur en Voedselkwaliteit)

mFRR - manual Frequency restoration reserve

MILP - Mixed-integer linear programming

MOI - MathOptInterfcae

MWh - Megawatt hour

PBL - Netherlands Environmental Assessment Agency (in Dutch: Planbureau voor de Leefomgeving)

RES - Renewable energy sources

RVO - Netherlands Enterprise Agency (in Dutch: Rijksdienst voor Ondernemend Nederland)

SDE++ - Stimulating Sustainable Energy Production Subsidy Scheme (in Dutch: Stimuleringsregeling Duurzame Energieproductie)

TTF - Title transfer facility

UC - Unit Commitment

WH - Waste heat

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Chapter 1: Introduction

1.1 CONTEXT

The greenhouse horticulture sector in the Netherlands is a national and global leader in innovation, sustainability, and productivity. Its impact is not only economic but also environmental and social, making it a crucial component of the Dutch agricultural landscape. Dutch producers have established strong export positions in fresh vegetables and floriculture, contributing to the country's key role in the global horticultural market (Menrad & Gabriel, 2009). The Dutch greenhouse horticulture sector comprises approximately 2600 companies employing 85,000 workers, with a collective gross national production value of 17 billion euros per year according to the Ministry of Economic Affairs and Climate Policy (EZK) (2019). The horticultural sector necessitates substantial heat and a portion of electricity to provide warmth and lighting within the greenhouses where vegetables and flowers are cultivated. Accordingly, the greenhouse horticulture sector heavily relies on natural gas for heat and electricity generation, constituting approximately nine per cent of the country's total natural gas consumption (Smit & Van Der Meer, 2022).

Along with every other sector, the Dutch greenhouse horticulture sector strives to reduce its CO2 emissions in light of the energy transition that is driven by the climate accord of 2015. Yearly total CO2 emissions in recent years have been between 5.9 and 6.5 megatons of CO2 equivalents (Smit, 2023; Smit & Van Der Meer, 2022). The ambition for the horticultural sector is to reduce these emissions to 4.3 Mton of CO2 equivalents by 2030 (Minister voor Klimaat en Energie, 2023). By 2040 the sector aims to be completely climate neutral. In 2022, 94% of the CO2 equivalent emissions from the horticultural sector were associated with the natural gas consumption of Combined Heat and Power (CHP) systems (Smit, 2023). Consequently, the use of CHP systems has to decrease significantly to reach the intended emission goals of 2030 and 2040.

The Energy Transition Covenant for Greenhouse Horticulture 2022-2030 outlines commitments from both the sector and the government to diminish CO2 emissions. Successful transition requires factors beyond the sector's control, such as the advancement of the Dutch sustainable energy system, third-party supply of heat and electricity and consumer willingness to choose climate-neutral products (Glastuinbouw Nederland, 2023). A combination of policies has been devised to discourage the use of natural gas, especially with CHP systems, aiming to reduce CO2 emissions within the sector. Changes in energy taxation are anticipated to include the elimination of reduced gas tariffs for the horticultural sector in 2025 and the imposition of restrictions on CHP input exemption (Glastuinbouw Nederland, 2023). Furthermore, the CO2 sectoral system will be replaced by a flat individual CO2 levy by 2025 (Minister voor Klimaat en Energie, 2023).

Currently, CHP systems play a crucial role in the Dutch greenhouse horticulture sector. Greenhouse horticulturists operate CHP generators to satisfy their energy needs for heating, electricity, CO2 and occasionally cooling. A portion of the electricity generated by CHP engines is used to power equipment, lighting, and climate control systems within the greenhouses. The remaining share of electricity is sold back to the electricity grid, allowing horticulturists to profit from electricity sales through arbitrage[1]. Accordingly, CHP systems in the greenhouse horticulture sector also contribute significantly to the national electricity supply, covering 11% of the total electricity needs in the Netherlands (Van 'T Hoog, 2022). Figure 1-1 accentuates the balance of purchased and sold electricity in the horticultural sector in 2022. According to Smit (2022), the greenhouse horticulture sector sells more electricity than it consumes, particularly during peak electricity demand periods. CHP systems play a crucial role in providing flexibility in the Dutch electricity market by responding swiftly to fluctuations in electricity demand, due to their capability to switch between electricity and heat production and their relatively quick ramp rates (Salman et al., 2021).

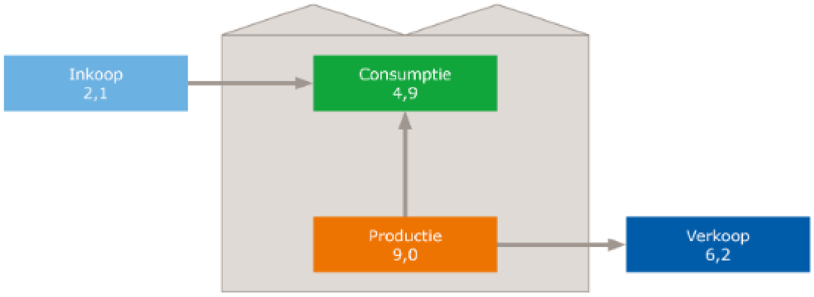


Figure 1-1. Electricity balance of the Dutch horticulture sector in 2022. From (Smit, 2023).

The Dutch energy system relies on CHP systems from the horticultural sector as a demand response tool significantly, during peak electricity demand, greenhouse CHP engines may provide up to 25% of the national electricity (Klaassens, 2023). According to an input note for the Climate Accord 2030 by the Greenhouse Horticulture Steering Group (2018), the road to climate neutrality implies a decrease in the use of CHP systems for both grid supply and self-generation of electricity for lighting. Simultaneously, the demand for electricity increases due to the partial electrification of the heating supply to greenhouses with heat pumps (HP), aquifer thermal energy storage (ATES) and electric boilers (EB). The purchase of electricity in the greenhouse horticulture is expected to increase by approximately 3.5 terawatt hour (TWh) in 2030 and 8 TWh in 2040 compared to the current situation (Stuurgroep Glastuinbouw, 2018). Whereas grid supply from CHP generation diminishes from 6.2 TWh to around 1 TWh (Smit, 2023). This causes the necessity for 8.7 TWh of additional electricity generation outside the greenhouse horticulture sector in 2030 to satisfy the increased demand and reduced supply.

The shift from electricity production to electricity consumption impacts the revenue streams of horticulturists in addition to the impact on the electricity grid and sectoral emissions. This indirectly affects the undertakings of aggregators such as AgroEnergy who optimise electricity trade and minimise operational costs on behalf of horticulturists. The government emphasises the balance between pricing and subsidisation. Therefore, it allocates funds towards initiatives focused on energy conservation and the development of sustainable heat infrastructure (Minister voor Klimaat en Energie, 2023). The affordability and availability of CO2-free energy sources are key factors for the success of the energy transition in the horticultural sector. Regarding affordability, the Stimulation of Sustainable Energy Production and Climate Transition. (SDE++) subsidy provides financial support to geothermal energy (GEO) and waste heat (WH) projects. Since 2024, air-water heat pumps have been incorporated into

[1] Arbitrage involves selling electricity to the grid during periods of high demand when prices are high and purchasing electricity from the grid when prices are low to profit from electricity price fluctuations.

the SDE++ subsidy program to encourage the electrification of heat generation (Minister voor Klimaat en Energie, 2023).

Furthermore, to improve the availability of emission-free energy sources the Dutch government is actively facilitating the development of both geothermal energy and waste heat in horticulture to drive sustainable energy generation. To encourage the expansion of geothermal energy sources, efforts are being made to encourage seismological research in greenhouse areas with potential for harnessing geothermal heat (Glastuinbouw Nederland, 2023). Additionally, the government is intensifying its focus on geothermal energy by addressing regulatory hurdles, reducing costs, and promoting standardisation to facilitate its widespread adoption (Ministerie van EZK, 2019). Meanwhile, the supply of waste heat is being scaled up by adding more sustainable waste heat to the mix. Promising sources of sustainable waste heat include electrolysers for hydrogen production and data centres (Glastuinbouw Nederland, 2023). The establishment and expansion of heat networks is crucial to facilitate the efficient distribution of geothermal and waste heat to end-users

Finally, the use of sustainable energy sources and the economics of CHP generation depend sensitively on the trade-off between natural gas- and electricity prices (Newbery et al., 2002). These prices are becoming increasingly uncertain due to commodity prices, unpredictable weather, growing electricity demand due to electrification and the increasing insertion of decentralised renewable energy generation. Ultimately, the most prominent determinants in the energy landscape of the Dutch greenhouse horticulture sector of 2030 are the aforementioned energy system regulations, the increased availability of sustainable energy sources and the unpredictable energy prices.

1.2 RESEARCH PURPOSE

The objective of this thesis is to create a unit commitment model that can reveal how both anticipated and unpredictable developments in the horticultural energy landscape will influence the comprehensive energy management practices of horticulturists in the Netherlands. This includes aspects such as heat and electricity generation, electricity purchase and sale, CO_2 emissions, and associated costs. This research will involve simulating electricity and heat generation, as well as the trading of electricity and CO_2 by greenhouse companies under both current and future conditions. It will investigate energy-related costs, CO_2 emissions, thermal and electric outputs from generation units, and electricity trading patterns to establish the effects of changes in the energy landscape of the horticultural sector.

1.2.1 Main research question

This research aims to analyse the key factors influencing the energy landscape surrounding greenhouses in the Netherlands, aligning to investigate the comprehensive energy management practices of horticulturists. Specifically, it will explore how regulatory, technological and market developments, may alter heat, electricity and CO_2 generation, application or emission among greenhouse horticulturists. The main research question of this thesis is in line with the research objective:

> *"How will the evolving contextual factors in the energy landscape of the Dutch greenhouse horticulture until 2030 influence the energy management practices, emissions and expenses of horticulturists?"*

1.2.2 Sub-questions

The sub-questions have been formulated to guide the research process and provide a structured approach to addressing the main research question. These sub-questions are designed to break down the research problem into manageable components. The sub-questions are designed to investigate the key determinants shaping the future of the horticultural energy system in the Netherlands. By dividing the energy transition within the horticultural sector into these distinct building blocks, we can develop a comprehensive understanding of the evolving landscape and its potential implications.

1. *"What are the prevailing trends in energy utilisation, generation sources, CO_2 emissions, and trading practices within the greenhouse horticulture sector in the Netherlands?"*
2. *"What are the effects of energy system regulations and costs on the emissions and operational energy costs of greenhouse horticulturists?"*
3. *"How will the emissions and financial dynamics of greenhouse operations evolve when sustainable thermal generation increases and electricity trade adapts accordingly?"*
4. *"What is the impact of energy price developments on the energy operations within the horticultural sector of the Netherlands until 2030?"*

1.3 RESEARCH APPROACH

The selected research approach is a modelling approach, specifically employing a unit commitment (UC) model. This modelling approach will be used to analyse the electricity, heat and CO_2 dynamics within the Dutch greenhouse industry. A UC model focuses on determining the optimal commitment and scheduling of generating units over a longer planning horizon. The objective of a UC model is to minimise the total cost of generating heat or electricity over the planning horizon, taking both variable and fixed costs into account. As horticultural companies strive to maximise revenue and minimise costs, they optimise their energy operations accordingly. Therefore, to comprehensively understand the implications of evolving policies, technologies and market conditions in the Dutch horticultural sector, it is essential to assess the cost-minimisation of energy operations under these changing circumstances. Utilising UC to develop an optimisation model provides valuable insight into the generation of heat and electricity by horticulturists, along with associated CO_2 emissions, costs, and revenue from arbitrage.

UC modelling is the preferred approach for accurately simulating energy management practices within the sector, as it offers a comprehensive understanding of the dynamics at play. A UC model allows for a precise representation of the real world that encompasses all relevant boundaries and constraints, including generation limits, storage capacities, startup and operational costs, as well as minimum up and downtime requirements. This approach allows us to capture the intricacies of the system and explore various scenarios to optimise decision-making processes. Ultimately, modelling provides a powerful tool for gaining insights into the complex interactions within the sector and identifying strategies to enhance efficiency and cost-effectiveness under evolving contextual circumstances. The input for the unit commitment model will entail 1) the heat, electricity and CO_2 demand of greenhouses 2) heat and electricity capacities and efficiencies of CHP systems, gas boilers and various renewable energy sources (RES) 3) national energy prices from the European Power Exchange (EPEX) and Title Transfer Facility (TTF).

The Dutch greenhouse industry represents a complex socio-technical system with numerous interconnected elements, as described above. A UC model offers a systematic and holistic approach to capture the interdependencies between these elements and unpredictable dependent variables, such as the energy market conditions and systemic regulations. Given the potential impact of energy system regulations and costs on the generation and demand of heat, electricity and CO2 in greenhouses, the UC model can simulate these distortions and assess their implications. This approach allows for a comprehensive understanding of the market dynamics under different policy scenarios.

The research aims to understand how different components within the greenhouse industry interact. A UC model allows for the simulation of these interactions, enabling a nuanced analysis of the evolving relationships between greenhouse horticulturists and the energy markets. Greenhouse horticulturists need to adapt their operations strategically to navigate the changing energy landscape. The UC model can provide insights into optimising operational decisions to minimise costs of new RES heat generation while energy prices are expected to change. It can assist in identifying the most effective strategies for participating in the day-ahead electricity market while meeting heat, CO2 and electricity demand.

The UC model developed for this thesis closely mirrors the functionalities of BiedOptimaal. BiedOptimaal is a software tool, utilised by AgroEnergy, designed to satisfy the heat and CO2 requirements of horticulturists at the lowest possible costs, with a forward optimisation period of four days. This tool employs computational models that integrate greenhouse energy consumption, energy strategy, weather forecasts and market price developments to generate tailored bidding solutions for greenhouse cultivators. The output of BiedOptimaal is an EPEX bid for the following day. The output on the EPEX is then imported by AgroEnergy and transformed into dispatch data for the automated operation of the horticulturist's installations. By aligning bids on the EPEX with the energy strategy of horticulturists, BiedOptimaal optimises the operation of thermal generators and maximises revenue from electricity sales, thereby minimising overall energy management costs.

1.4 RESEARCH METHODS

The UC model, built using Julia as the programming language, provides a simulation of 2023 and a projection for 2030, offering insights into long-term trends. It uses a time resolution of one hour to capture temporal fluctuations. The inputs of the optimisation model, such as heat, electricity, and CO2 demand, are primarily influenced by weather conditions. It is noteworthy that weather conditions are exogenous in this model as the only incorporated data is from 2023. Similarly, the EPEX and TTF prices used as inputs fluctuate continuously due to various factors. These inputs are unknown for the entire year as perfect information does not exist in reality. In BiedOptimaal, weather and price forecasts of the next four days are utilised to optimise the energy management of horticulturists for a 96-hour timeframe, repeated daily. Therefore, to accurately replicate the BiedOptimaal optimisation model and simulate an entire year without perfect information, a rolling time horizon is applied in the UC model.

A rolling time horizon in UC modelling involves continuously updating the planning horizon as time progresses, allowing for decisions to be made at regular intervals based on the most current information available. This approach is beneficial in dynamic environments where conditions change continuously, such as in the horticultural energy system with unpredictable weather and uncertain fuel prices (Pineda et al., 2019). With a rolling time horizon, the model can incorporate updated data, such as real-time weather and price forecasts, resulting in more realistic and effective UC modelling (Erichsen et al., 2019). Additionally, using a rolling time horizon enables the consideration of intertemporal constraints without substantially increasing the computational burden of the model (Carrion & Arroyo, 2006). Intertemporal constraints in the context of unit commitment modelling refer to conditions or limitations that are imposed on optimisation over a sequence of time periods (Q. Yang et al., 2022). These constraints help optimise the scheduling of generation units effectively, by accounting for up/down time states and energy storage dynamics across different planning horizons.

Thus, although the model built for this thesis has the demand and price data available for the entire year, the model will only optimise for the next 96 hours. After the first optimisation, the first 24 hours of results are stored. The model will then iterate the optimisation process, starting again from hour 25 and continuing to forecast and optimise for the subsequent 96 hours each day. This approach mirrors the real-world optimisation process, ensuring that the model adapts to changing conditions and provides relevant insights for short-term decision-making.

Only the EPEX and TTF markets are integrated into the model, other electricity markets such as the intraday or balancing markets and the EU Emission Trading System (EU-ETS) are not considered. To capture the relationships between the commitment of thermal generators, and the changing contextual factors of the energy landscape in the Dutch horticultural sector, mixed-integer linear programming (MILP) will be used to optimise the model. MILP allows for the incorporation of binary decision variables, enabling the representation of discrete choices, which is essential for capturing the operational characteristics of generators, such as start-up/shut-down decisions (Fisher et al., 2009). MILP has previously been applied to similar UC problems by using it to optimise the scheduling of CHP systems. Yang et al. (2019) used it to determine the optimal capacity and operating strategy for CHP plants to reduce costs and emissions.

Julia is selected as the programming language for the UC model for a number of its unique features. It is designed for high-performance numerical computing with similar performance levels to C and C++. High performance is necessary for computationally heavy tasks such as solving optimisation problems in economic dispatch and UC (Lin & McIntosh-Smith, 2021). Furthermore, it is an open-source language that can be customised to meet specific modelling requirements. This means that it fosters collaboration which is important concerning the overarching Designing and Modelling Future Systems of Energy Systems (DEMOSES) project so other researchers can later improve or expand the model. Additionally, Julia has a dynamic multiple dispatch paradigm that greatly improves flexibility and composability compared to traditional object-oriented paradigms employed in Python (Johnson et al., 2023).

1.4.1 Research process

The Research process is divided into five different stages. For the second to fourth research stages, Julia will be used to build and iterate the discussed UC model. In the last stage, the output of the UC model will be analysed in Python to form a concise answer to sub-questions two to four. The following sections will describe the research methods of the five different stages, the required input data and the outputs. The research methods and tools that are employed to answer the four sub-questions of this research are summarised in Table 1-1.

Stage 1: Desk research

To formulate an answer to the first research question, first, a thorough understanding of the greenhouse horticulture energy system needs to be formulated. To understand the patterns of energy generation, electricity trade, CO_2 emissions and their financial implications, it is important to accurately delineate the regulatory framework surrounding the horticultural energy systems as well as identify the current market conditions. To create an understanding of the dynamics of the horticultural energy system, its interaction with energy markets and the surrounding regulatory framework, the first stage of the research entails system, policy and market analysis. The analysed data in this research phase consists of national policy documents, energy outlook reports, sector-specific energy monitors and academic literature. The academic literature is reviewed to understand the energy needs of horticulturists and the technologies used in the horticultural energy system. The policy and market analysis are conducted to understand the current and future contextual factors of the system. This stage will answer the first research questions and assist in the data augmentation of experiments in later research stages.

Stage 2: Model creation under current conditions

In the second research stage, we establish a UC model that can simulate the current operations of horticulturists in the Netherlands, leveraging available EPEX and TTF data from 2023 for hourly electricity and gas prices as input. Integral to this process is the incorporation of representative load and demand profiles specific to greenhouse horticulturists in the Netherlands. The profiles that are used for this research are derived from real load and demand data of horticulture companies provided by AgroEnergy. The profiles entail technological assets such as CHP systems, gas boilers and thermal storage tanks along with their technological specifications. Simultaneously, greenhouse acreage and the type of grown crops are considered in the profiles as they determine the heat, electricity and CO2 demand of the greenhouses in the profiles. The precise hourly heat demand of the greenhouses per profile for 2023 is provided by AgroEnergy. The estimated hourly electricity demand patterns per day are also provided by AgroEnergy for each month per crop type. The hourly CO2 demand is derived from weather data of 2023 together with the greenhouse acreage of each profile.

After the fundamental optimisation functions are built to minimise costs while satisfying the heat, electricity and CO2 balance, the contextual boundaries of the horticultural system in 2023 are built into the model. A framework that allows for the inclusion of the current tax system and network charges by distribution system operators (DSO), analysed in the previous research stage, is developed in the model. Accordingly, experiments are conducted by running the model with varying parameter inputs to measure the effects of the energy system regulations and costs in 2023. The output of the model runs in this stage is the hourly value data of relevant dependent variables for the research, stored in CSV files that are analysed in a later stage. In stage 2, the benchmark model is created that can be validated and used to compare future model projections with.

Stage 3: Model validation

The third stage involves validating our UC model using AgroEnergy's available real-world data of fuel consumption and electricity trade on the EPEX by the different profiles in 2023. Furthermore, the optimisation algorithm in the UC model will compared with the model functions of BiedOptimaal to ensure that the UC model mirrors BiedOptimaal as well as possible. This crucial validation step ensures the model's reliability and accuracy. By aligning the model with real fuel consumption data and the BiedOptimaal functionalities, we enhance the model's credibility, providing a benchmark for real-world applicability in greenhouse energy optimisation scenarios.

Stage 4: Model refinement for future scenarios

In the fourth phase, the UC model undergoes further refinement to allow the implantation of RES thermal generation technologies into the model for the analysis of the model's response to technological advancements in 2030. Furthermore, the energy and CO2 tax framework in the model are adjusted to represent the anticipated tax system of 2030 as analysed in the first stage of the research. The data input for the model remains similar, but the heat demand of the profiles will be adjusted in correspondence with predicted trends that follow from the desk research in stage one. Similarly, different future energy price trends will be included in the data input and used for separate model runs to generate data on the energy operations under different market conditions in 2030. The output of the model runs manifests as hourly value data of relevant dependent variables in 2030, stored in CSV files that are analysed in the next and final stage of the research process.

Stage 5: Data analysis

In the final stage of the research process, the outputs of the model from stages two and four, representing simulations for 2023 and 2030, are aggregated into an Excel file and imported into a Python environment. Within Python, the Excel files containing output data from the model for various scenarios are compared and analysed. To accurately address research sub-questions two, three, and four, comparative figures are developed using the Python script. The outputs of this stage include load duration curves (LDCs), frequency duration curves (FDCs), chronological load curves, and bar charts displaying annual purchased and sold electricity, electricity costs, fuel costs, net costs, and CO2 equivalent emissions.

The cost bar charts reveal the annual net expenses related to providing greenhouses with the required heat, electricity, and CO2. Additionally, specific cost charts are created to focus on separate cost items, allowing for an analysis of the individual effects of system regulations and costs. The various electricity bar charts assist in revealing consumption and trade patterns under different regulatory and energy price conditions. Furthermore, emission charts illustrate the differences in CO2 equivalent emission levels between different scenarios. This variety of bar charts showing annual behaviour, costs, and emissions will be used to answer sub-questions two and four.

LDCs are employed to establish the extent to which different thermal generation sources are utilized and the number of operational hours for these generators. Chronological load curves analyse peak and low-demand generation, as well as overall thermal generation patterns within the horticultural sector. FDCs highlight the electricity trading patterns of horticulturists by exhibiting the cumulative frequency of electricity balances. The LDCs, chronological thermal and electricity load curves, and FDCs will be particularly analysed to form an answer to research question three.

Table 1-1. Input data, research methods and tools for the sub-questions.

Sub-question	***Data input***	***Research method***	***Research tools***
1	System regulations, market conditions & operational patterns.	Energy system analysis.	Literature review, policy report review & market analysis.
2, 3 & 4	Heat-, electricity- and CO2-demand time-series, thermal generator capacities and energy price scenarios.	Development, validation and analysis of unit commitment model using MILP.	Julia (Gurobi optimiser), Python and Excel.

1.5 SIGNIFICANCE AND SCOPE

This subsection describes both the societal significance and the academic novelty of the proposed model. The UC model and its outcomes offer benefits to a range of stakeholders involved in the horticultural sector, including AgroEnergy, greenhouse horticulturists, policymakers and the overarching DEMOSES project.

1.5.1 DEMOSES

This thesis is part of the overarching project known as DEMOSES, which aims to develop supporting models to enhance decision-making processes in restructuring the Dutch energy system (TU Delft, 2021). The DEMOSES project focuses on coupling heat, electricity, and gas distribution grids, emphasizing their interdependencies and flexibility solutions. To achieve this objective, the project leverages and improves existing energy models from collaborating partners, while also developing software for model coupling to effectively interconnect these models. AgroEnergy, as a collaborating partner of DEMOSES, contributes to the project by providing data and insights on specific modelling practices related to the interaction of the Dutch greenhouse horticulture sector with the heat, electricity, and gas grids. These insights are derived from AgroEnergy's existing optimisation model for horticulturists; BiedOptimaal

BiedOptimaal presents challenges for model coupling with other systems due to disparities in programming syntax and the sensitive nature of its input data. Since the software is predominantly developed by an external party, AgroEnergy lacks the flexibility to modify it sufficiently for coupling purposes. Moreover, BiedOptimaal's commercial utilisation involves handling extensive customer data, precluding the option of making the model open source for coupling.

Consequently, a new optimisation model has been developed for this thesis, aiming to not only address AgroEnergy's needs but also to represent the horticultural sector within the broader energy models of the DEMOSES project. The new UC model mirrors and adapts BiedOptimaal to ensure alignment with the overarching objectives of DEMOSES, thereby contributing to a comprehensive understanding of energy dynamics spanning multiple sectors. The integration of the UC model into the DEMOSES project underscores its broader significance. As an integral part of this interdisciplinary initiative, the UC model not only fulfils the specific requirements of simulating horticultural energy dynamics but also demonstrates its adaptability for integration with other sectoral energy models.

1.5.2 AgroEnergy and policymakers

For AgroEnergy and its customers, the development of the UC model presents a pivotal advancement. Unlike the existing Biedoptimaal platform, which offers limited flexibility for alterations due to its complex structure, the UC model provides a more user-friendly interface. This interface empowers users to experiment with different settings, thereby fostering a deeper understanding of the energy landscape and enabling strategic decision-making tailored to individual requirements. Additionally, while Biedoptimaal primarily focuses on short-term optimisation, the UC model introduces a novel capability to simulate an entire year, allowing for comprehensive analyses of policy impacts and market conditions on an annual basis. This long-term perspective not only facilitates the assessment of sustainability goals but also aids in formulating robust, long-term investment strategies.

The UC model extends its significance to policymakers by providing valuable insights into the effectiveness of existing and proposed policies. The inability to modify energy system regulations and costs such as energy taxes and network charges within Biedoptimaal restricts experimentation with different conditions in the horticultural energy landscape. By simulating various scenarios in the new

UC model and identifying the effects of energy system regulations and costs, policymakers gain a nuanced understanding of the horticultural energy sector, thus enabling informed policy design and adjustment.

1.5.3 Academic contribution

Furthermore, the model's capability to optimise multiple facets—such as heat, electricity, and CO_2 demand balances—represents a significant academic advancement. In contrast to conventional models focused solely on CHP technology, the UC model integrates diverse technologies, offering a comprehensive approach to optimal energy generation while minimising costs. The developed UC model for this thesis considers heat, electricity, and heat demand, optimising generation costs and revenue from sold electricity accordingly. Additionally, thermal storage is included in the model optimisation. Prior research has developed numerous MILP models for optimising CHP scheduling, primarily focusing on the optimisation between thermal demand and the electricity market (Weber et al., 2018), with a few considering some form of an electricity balance (Belkadi et al., 2019; Huang et al., 2018; Liu et al., 2020). However, no previous research has been identified that considers the CO_2 production from CHP systems as anything but emissions. This gap is largely due to the limited academic literature on CHP optimisation or energy optimisation models in the context of greenhouse horticulture. Many existing CHP optimisation models are situated in other domains such as mobility, micro-grids, urban areas, or district heating networks (Alipour et al., 2015; Costa & Fichera, 2014).

Models that do consider thermal generation, not limited to CHP systems but combining research on CHPs with another thermal or electric technology, often only incorporate a couple of technologies or combine CHP generation with electric RES instead of thermal RES (Gbadamosi & Nwulu, 2020). To date, no model in academic literature has been developed to optimise between six different thermal generation technologies, both conventional and sustainable, while also considering thermal storage. Previous models have delved into the sophistication of thermal storage by considering thermal inertia but have focused solely on CHP systems, neglecting alternative technologies (Wang et al., 2022; Weber et al., 2018). Marttila et al. (2021) specifically address the global sustainable potential of greenhouse production using different heating systems, underscoring a research gap in comparing the environmental impacts of various heating systems in optimisation models.

1.5.4 CoSEM affiliation

This thesis project is written in fulfilment of requirement of the degree Complex Systems Engineering and Management (CoSEM). It embodies a meticulous exploration of the intricate challenges presented by the energy transition landscape, particularly within the greenhouse horticulture sector. Rooted in design and engineering principles, this thesis focuses on crafting an innovative tool, tailored to assess the sector's evolving landscape. At its core, the research delves into the technological realm, with a specific emphasis on the implementation of CHP systems and other sustainable energy technologies. Through this lens we dissect, technical issues surrounding energy generation, consumption, and optimisation, offering insightful analyses that inform strategic decision-making.

Furthermore, the thesis transcends mere technical considerations, embracing a holistic approach that integrates process management strategies and system engineering approaches. By meticulously examining the dynamics of energy management within the changing regulatory framework of the horticultural sector, this thesis navigates the complex interplay between technological advancements and societal policy imperatives.

Central to this research is the application of CoSEM methods, tools, and techniques, which serve as the building blocks for the model design processes and impact assessments. Moreover, this thesis deftly navigates the intersection of public and private values, recognising the nuanced interplay between societal aspirations for environmental sustainability and economic implications for the horticultural sector and its stakeholders. By researching concerns regarding greenhouse gas emissions, sectoral competitiveness and electricity network interaction, this thesis aims to encapsulate the essence of a typical systems engineering project—one that transcends disciplinary boundaries to offer comprehensive solutions to contemporary socio-technical challenges.

1.6 THESIS OUTLINE

The thesis comprises eight chapters structured to explore and analyse the intricacies of the Dutch greenhouse horticulture sector and its energy dynamics. Chapter 2 delves into the analysis of greenhouse energy requirements, CHP systems, policy landscapes, and external influences. Subsequently, Chapter 3 outlines the development of the UC model, covering conceptualisation, formulation, implementation, and validation. Chapter 4 delineates the experimental design, detailing setup and scenario planning. The ensuing Chapter 5 presents the findings, dissecting energy system regulations and costs, sustainable thermal generation, and market prices. The discussion (Chapter 6) critically examines these results, addressing sub-questions and methodological considerations. Chapter 7 synthesises conclusions and offers recommendations for policy, future research, and operational improvements. Finally, Chapter 8 provides a reflective account of the research journey, concluding the thesis with personal insights and lessons learned.

Chapter 2: Greenhouse Horticulture System Analysis

This section will explore the energy dynamics and landscape within the horticultural sector by reviewing a wide variety of literature. By reviewing literature and data, the crucial aspects of the energy landscape in this sector can be defined. Firstly, the energy requirements of greenhouse horticulturists and their sources of energy are delineated. Following that, the concept of energy aggregators is clarified, with AgroEnergy identified as one such aggregator operating within the horticultural energy system. We will examine the national energy outlook of the horticultural sector in the Netherlands, focusing on current emissions, the desired trajectory, and the envisioned energy mix. Additionally, we will analyse the existing regulatory framework and future projections to understand the evolving contextual factors, including policies and market conditions.

2.1 GREENHOUSE ENERGY REQUIREMENTS

Horticulturists need energy to grow the crops in their greenhouses. The energy requirements of horticulturists are dependent on several factors such as the size and type of greenhouse they operate (Djevic & Dimitrijevic, 2009), the location and surrounding climate of the greenhouses, the crops grown inside the greenhouses and the level of technology and automation used in the greenhouses. However, generally, the most important operational functions within greenhouses that require energy are (Paris et al., 2022):

- Heating and cooling: to create optimal growing conditions for plants in greenhouses the temperature needs to be controlled inside. In warmer climates, ventilation, shade netting and evaporative cooling are used to prevent the crops from overheating. Whereas, in colder climates, heating systems are used to maintain a suitable temperature during winter (Chen et al., 2015). In cold regions, heating can represent up to 95% of the total energy demand for greenhouse production (Ahamed et al., 2018).
- Lighting: when there is limited natural daylight, artificial lighting may be necessary in greenhouses for the photosynthesis of the crops (Stober et al., 2017). High-intensity discharge (HID), LED and fluorescent lights are often used to provide artificial lighting. The required energy depends on the duration and intensity of artificial light needed.
- Irrigation: greenhouses often use controlled drip irrigation systems that are connected to water basins to provide the growing crops with the right amount of water (Yuan et al., 2001). The pumps and diffusion systems of these irrigation systems require energy for operation.
- Ventilation: air circulation is important to maintain the health of plants and prevent disease (Omer et al., 2021). Furthermore, ventilation systems can be used for cooling. The fans in these ventilation systems require energy. Besides cooling, heat recovery systems in ventilation can achieve energy savings for heating inside greenhouses (Ferraro et al., 2019).
- Humidity control: sophisticated environmental control systems may be employed to monitor and adjust humidity conditions (Hirasawa et al., 2014). These systems may contribute to energy usage throughout the day and night.

- CO2 enrichment: some greenhouse owners need or choose to use CO2 enrichment of their crops to stimulate plant growth (Yasuda et al., 2014). Since CO2 is a low-energy compound, used in photosynthesis, this greenhouse operation is also an energy requirement.

2.1.1 Greenhouse load profile

Lighting, irrigation, ventilation and dehumidification all require energy in the form of electricity. So the main operational requirements of greenhouses are heating, electricity and CO2. The amount of energy required by the greenhouses in the Netherlands depends on the specific load and demand profile[2] of these greenhouses. A load or demand profile is a representation of how the consumption of energy by a certain consumer or system varies over a specific period. The generation and demand in load profiles are usually measured in time series with intervals of 15 minutes, hours, days, months or years. These profiles are essential to effectively manage power distribution and generation because they offer insight into when and how much energy is used and produced by consumers and businesses (Liu et al., 2017).

The demand profile of greenhouses in the Netherlands exhibits numerous characteristics that are related to the local climate and technology adoption in this region. the Netherlands is exposed to a temperate maritime climate with mild to cold winters. Due to the relatively low temperatures, the greenhouses in this area require a significant amount of heat, especially during the winter months when the heat demand is high (Hemming et al., 2012). The need for humidity control to maintain plant health and prevent mould in the greenhouses is high given the maritime climate in the Netherlands. The electricity demand for dehumidification is highest during the winter months to offset reduced ventilation, increased heating and condensation in these months (de Halleux & Gauthier, 1998). Furthermore, the Netherlands is a high-latitude region in the northern hemisphere where natural light can be limited. Thus, high-efficiency LED light is often used to extend the growing season by maintaining an optimal natural daylight schedule during the winter months(Kong et al., 2018). Besides, cooling is becoming increasingly important with rising temperatures in the supposedly mild summers in the Netherlands. Electricity demand for fans and evaporative cooling is therefore significant in the summer months. Lastly, natural ventilation systems are used to control temperature and humidity during periods of mild weather. These systems are energy-efficient so only slightly add to the load profile.

2.1.2 Greenhouse energy consumption

The ratio between the total energy consumption by greenhouses in the Netherlands in 2010 was 90% heat consumption and 10% electricity. In 2021 the ratio was 80% to 20%, this shows that there is a shift from heat- towards electricity consumption (Smit & Van Der Meer, 2022). This trend can be explained by the electrification of heating, automation of processes and the intensification of growing lights. To satisfy the energy demand of the greenhouses in the Netherlands, horticulturists often employ on-site power generation. The most commonly used method for on-site power generation is CHP systems. Through cogeneration, CHP plants simultaneously produce the required heat and electricity for the greenhouses. To satisfy the total heat demand for greenhouses in the Netherlands, only 12% was provided by sustainable sources such as geothermal and biomass in 2021 (Smit & Van Der Meer, 2022). In 2022 the share of sustainable heat generation increased to 15% (Smit, 2023). This means that the remaining 85-88% of the total heat demand of the greenhouses in the Netherlands is produced by on-site CHP installations and boilers that run on natural gas. Of the heat that is generated with natural gas,

[2] Simply referred to as ‘load profile’ or ‘demand profile’.

CHP systems account for 93% and gas boilers for 7% of the natural gas consumption. Besides, between 55-60% of the yearly Dutch greenhouse electricity demand is being met by on-site generation with CHP systems (Smit & Van Der Meer, 2022). The remaining share of required electricity is purchased on electricity markets.

2.1.3 CHP systems

Around 24% of all greenhouses in the Netherlands use artificial lighting to stimulate crop growth (Berenschot & Kalavasta, 2023; Voogd et al., 2021). Greenhouse corporations that use artificial growing lights are likely to coordinate their CHP electricity production with their light use and sell excess electricity back to the grid. Electricity generated by CHP units can be sold to the grid during periods when lighting is not required in greenhouses, provided that the heat generated can either be utilised or stored, and the revenues exceed the production costs (Smit & Van Der Meer, 2022). In 2021 greenhouse companies with CHP systems in the Netherlands produced a total of 10.4 TWh of electricity. Only 36% of this electricity was used by the horticultural sector. Thus, 64% (6.8 TWh) of the electricity produced by greenhouse CHP systems was sold to the electricity grid in 2021. In 2022, electricity sales to the grid decreased to 6.2 TWh, constituting 70% of the total electricity generated by CHP systems in the horticultural sector (Smit, 2023).

The deployment of CHP plants depends on fluctuating electricity and natural gas prices. Greenhouse horticulturists increase CHP generation and sell electricity when electricity prices are higher than natural gas prices, ensuring profitability. Conversely, if electricity revenues do not cover natural gas costs, horticulturists will purchase electricity from the market, if necessary. The difference between the price of electricity generated and the cost of the fuel required to produce that electricity is called the spark spread, serving as a key metric for assessing the profitability of electricity generation (Graves et al., 2008).

2.2 ENERGY AGGREGATORS

Energy aggregators serve as intermediary entities within energy systems, consolidating energy from multiple producers or consumers to optimise distribution and ensure a reliable energy supply. These sources include renewables such as wind and solar energy, traditional fossil fuel-based energy such as coal and CHP plants, and sometimes energy storage. Aggregators continuously monitor the availability of different energy sources. Aggregators actively participate in electricity markets. They buy and sell electricity in response to market prices, demand fluctuations, and the availability of different energy sources. This dynamic involvement allows them to capitalise on favourable conditions. Additionally, aggregators can provide demand response services with their tradable capacity (Tantau et al., 2021). Aggregators often work with large energy consumers and producers. They can temporarily shift their electricity use or generation during peak demand periods to ensure grid stability. By ramping electricity generation up and down in response to sudden changes in supply and demand, aggregators provide flexibility to the electricity grid (Faria et al., 2018). Aggregators can efficiently take part in different electricity markets such as day-ahead, balancing, and ancillary services, contributing to the optimal use of electricity in providing balancing and ancillary in power systems (Heydarian-Forushani et al., 2015).

2.2.1 AgroEnergy

AgroEnergy is a company that started as an energy cooperative and acts as an aggregator and trades energy on behalf of horticulturists in the Netherlands. AgroEnergy specialises in the development of data-driven solutions for greenhouse horticulturists to enhance energy management. They offer a range of energy products for the procurement of electricity, gas, heat, and sustainable energy generation. The automated energy solutions provided by AgroEnergy are designed to assist horticulturists in optimising their resource allocation. By strategically participating in the energy markets, these solutions aim to streamline operations and deliver cost and time savings for horticulturists. In addition to saving costs, AgroEnergy analyses the electricity market, aiming to predict to optimally sell and buy electricity on behalf of horticulturists and maximise their revenue (Bertolini & Morosinotto, 2023). To do so, AgroEnergy monitors the electricity and heat demand of their customers' greenhouses, while aggregating the available capacity of CHP plants, renewables, biomass and alternative heat sources.

2.3 2030 OUTLOOK

This section provides a glimpse into the anticipated developments for the Dutch horticultural sector in the coming decade. It encompasses two key subsections, each addressing critical aspects of the sector's future trajectory. First, we examine recent trends and future projections, exploring the sector's ambition to achieve climate neutrality by 2040 and the strategic initiatives outlined to reduce CO2 emissions by 2030. Then, the focus shifts to the sector's evolving energy mix, discussing the transition towards sustainable energy sources envisioned for 2030, including the role of geothermal and waste heat as alternatives.

2.3.1 Emissions

The total CO2 emissions resulting from natural gas consumption amounted to 4.9 megatons (Mton) in 2022, as reported by the Energy Monitor Greenhouse Horticulture 2023, the most recent available report on the Dutch horticultural sector. In addition, 1 Mton of CO2 equivalent emissions stemmed from the methane slip of the CHP generators. Thus, the cumulative CO2 emissions of the horticultural sector reached 5.9 Mton of CO2 equivalents. Of this total, 94% emanated from the gas consumption of CHP generators, with a mere 6% attributed to gas boiler combustion. Concerning the total greenhouse area in the Netherlands, this equates to 31.5 kg/m2 of CO2 emissions, precisely measured for crop growth after temperature correction (Smit, 2023).

The Dutch horticultural sector aspires to achieve climate neutrality while ensuring economic viability by 2040. In pursuit of this objective, the Ministries of Agriculture, Nature and Food Quality (LNV), EZK, and Finance, along with Horticulture Netherlands, collectively endorsed the Covenant Energy Transition Greenhouse Horticulture 2022–2030 (Stuurgroep Glastuinbouw, 2018). This covenant, a constituent part of the Climate Agreement 2022, delineates an interim target for the sector to reduce its emissions to 4.3–4.8 Mton of CO2 equivalents (Ministerie van EZK, 2019). Despite the apparent proximity of the CO2 emissions in 2022 to this target, it is important to note that the decrease observed in 2022 was unusually large due to exceptionally high energy prices compelling substantial energy savings. Moreover, the year 2022 experienced an abundance of sunshine hours and higher average temperatures compared to preceding years, resulting in reduced natural gas consumption (PBL, 2023). Consequently, for this research, 2023 is adopted as the reference year. However, precise data regarding the total CO2 emissions for the year 2023 is currently unavailable. The trajectory of yearly CO2 emissions until 2022 is depicted in Figure 2-1.

The figure shows that the trend in CO2 emissions from 2014 to 2021 has been growing. In 2021 the total CO2 emissions of the sector amounted to 6.5 Mton and with the methane slip included this would be 7.8 Mton of CO2 equivalents. From the figure, it becomes clear that the drop in CO2 emissions between 2022 and 2021 is not in line with the developments of CO2 emissions in the years prior. If not for the large energy savings, the CO2 emissions would not have decreased as they did, because the application of renewable energy in the sector rose by 8% between 2022 and 2021 (Smit, 2023). The energy savings were forced by high energy prices so are not expected to be maintained under more optimal market conditions. Thus, the expected emission of CO2 equivalents from the greenhouse horticulture sector in 2023 is expected to be between 5.9 and 7.8 Mton. This implies that the CO2 emissions of the sector have to decrease by 27 – 45% by 2030 to reach the climate accords agreements.

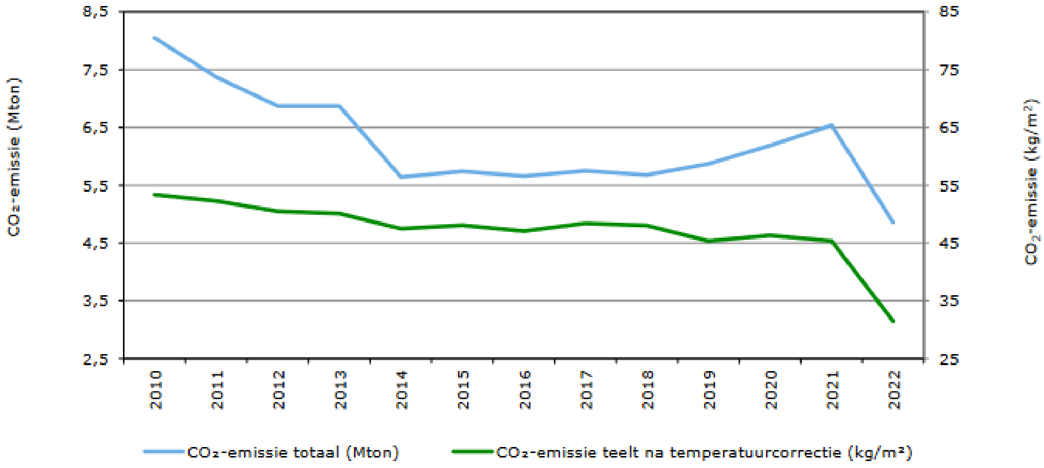


Figure 2-1. Total CO2 emissions and cultivation CO2 emissions after temperature correction. From (Smit, 2023).

2.3.2 Energy mix

Currently, the Dutch horticultural sector relies on CHP energy for 79% of its total heat demand, according to the numbers in section 2.1.2. This has grown in comparison to 2015 when natural gas CHP units met between 50 and 60% of the sector's heat demand. By 2030, this is expected to decrease to a range of 30 to 37% of the required heat supplied by CHP units (Van der Velden et al., 2018). In addition, the majority of electricity that is generated by greenhouse CHP plants gets sold to the grid, meaning a large share of revenue in the horticultural sector is created by CHP energy (Smit & Van Der Meer, 2022). However, the greenhouse sector in the Netherlands aims to be emission-free by 2040, according to national ambitions. To achieve this goal, the sector in the Netherlands strives for a 30% decrease in heat demand by 2040. The remaining required heat should be satisfied by 50% geothermal heat, 33% waste heat and 17% alternative renewable heat sources such as heat pumps, biomass, green gas and hydrogen. To reduce the electricity demand, all greenhouses are to shift towards LED lighting. The remaining electricity demand will be purchased for the biggest part (>90%) from sustainable sources in the electricity market. Only about 10% is predicted to be generated by the horticulturists in the Netherlands with solar and wind generation (Voogd et al., 2021).

In 2030, the heat required by the Dutch greenhouses is expected to be supplied by a mixture of sustainable and conventional technologies. Recent projections estimate that the current 3 PJ supply of geothermal heat to the horticultural sector could grow to 30 PJ by 2030 (Stichting Platform Geothermie et al., 2018). This would satisfy 43% of the predicted required heat. Although this is a substantial surge in geothermal supply, the greenhouse horticulture sector shows potential for short-term expansion by capitalising on its established expertise in subsurface operations. By specifically targeting areas and leveraging prevailing knowledge of subsurface layers, efficiency in costs and implementation can be improved rapidly. Geothermal heat has proven to be the most cost-effective sustainable heat source when waste heat is not available.

Waste heat is considered to be one of the most cost-effective sustainable heat sources in the horticultural sector. The utilisation of waste heat at low temperatures especially has been proven to be a viable option for improving energy efficiency and sustainability in greenhouse facilities (Lee et al., 2015). However, despite the potential of waste heat in the horticultural sector, challenges in harnessing this resource remain. Factors such as the intermittent nature of waste heat sources, the composition of required heat carriers and imperfect information regarding the quality, quantity and origin of waste heat contribute to the cumbersome integration of waste heat recovery systems into horticultural operations (Benedetti et al., 2021; Giordano & Benedetti, 2022; Saha et al., 2021). Currently, there is a supply of 3 PJ waste heat to greenhouse horticulture. The supply of waste heat must be expanded to 10 PJ by 2030, which would cover approximately 15% of the greenhouse heat demand in 2030. The success of utilising waste heat relies on establishing heat transportation networks, accessing more waste heat sources and coordinating the supply and demand of heat in certain areas with urban centres and greenhouse horticulture (Ministerie van EZK, 2019).

The predicted outlook for electricity in 2030 shows a shift from selling electricity to purchasing electricity as opposed to the current trading patterns in the horticultural sector. The electricity demand in 2030 shall be fulfilled by purchasing electricity from the grid for 54% and the remaining 43% should still be generated by on-site CHP plants (Voogd et al., 2021). The sale of electricity from natural gas CHP units is forecasted to decline significantly, dropping from 6.2 TWh in 2022 to a range of 0.6 to 1.1 TWh in 2030 (Smit, 2023; Van der Velden et al., 2018). Meanwhile, the total electricity purchase and on-site renewable electricity production are projected to increase. In 2022, this amounted to 2.1 TWh, but in 2030, it ranges from 2.8 to 5.2 TWh (Smit, 2023; Van der Velden et al., 2018).

Besides acquiring heat and electricity from sustainable energy sources, substantial energy savings will also contribute to the reduction of CO2 emissions by horticulture in the Netherlands. Especially CHP units of companies with lighting systems are anticipated to generate less electricity due to reduced heat demand. The outlook for the projected heat and electricity demand of the sector is discussed in section 2.5.1.

2.4 POLICY AND REGULATORY ANALYSIS

To stimulate the CO2 reductions in the Dutch greenhouse horticulture sector and therewith the energy transition, the Dutch government aims to steer the sector away from using natural gas to generate heat and electricity. Currently, certain tax benefits apply to the gas consumption in the horticultural sector. Starting in 2025, the government will initiate a gradual reduction of these tax benefits to enhance the attractiveness of RES relative to conventional technologies reliant on natural gas consumption. The following subsections highlight the current regulations in place and how the policies in this sector will change over time.

2.4.1 Energy tax

A reduced tax rate is currently applicable to natural gas consumed within the horticultural sector. This reduced rate will undergo a gradual phase-out process spanning from 2025 to 2030. By 2030, the gas tax rates for greenhouse horticulture will align with those imposed on other taxpayers. To provide a numerical perspective, the current normal and reduced gas tax rates are delineated in Table 2-1, with reduced rates applicable solely to the first two consumption brackets. Notably, once gas consumption exceeds one million cubic metres, the reduced rates converge with the normal rates. Additionally, Table 2-2 illustrates the annual incremental adjustments of gas tax rates for the horticultural sector.

Table 2-1. Reduced gas tax rates for the horticultural sector in euros per cubic metre. Adapted from (Belastingdienst, n.d.).

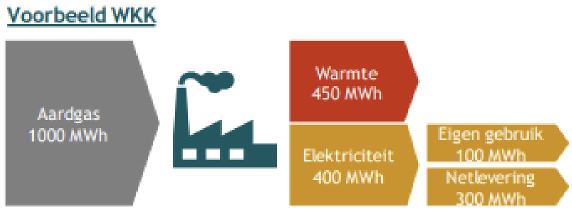
Year	*Rate*	*0 -170.000 m3*	*170.001 - 1 million m3*
2023	Reduced	€ 0,07867	€ 0,03629
	Normal	€ 0,48980	€ 0,09621
2024	Reduced	€ 0,09365	€ 0,08444
	Normal	€ 0,58301	€ 0,22378

Table 2-2. Elimination plan of reduced tax rates for the horticultural sector. Adapted from (Ministerie van Algemene Zaken, 2023).

Year	*Rate greenhouse sector bracket 1*	*Rate greenhouse sector bracket 2*
2025	30% of the normal rate	50% of the normal rate
2026	44% of the normal rate	60% of the normal rate
2027	58% of the normal rate	70% of the normal rate
2028	72% of the normal rate	80% of the normal rate
2029	86% of the normal rate	90% of the normal rate
2030	Normal rate	Normal rate

In addition to the reduced tax rates on natural gas consumption within the greenhouse horticulture sector, an exemption is granted for the gas utilised by CHP generators. The existing tax framework incentivises the utilisation of natural gas-fired heat and electricity over alternative heating methods or grid-purchased electricity. Referred to as the input exemption, this provision will undergo gradual reduction commencing from 2025. By 2030, the input exemption will be diminished to 189.57 normal cubic metres (Nm3) per megawatt-hour (MWh) of electricity, as stipulated by governmental regulations. This quantity corresponds to the volume of gas required to produce one MWh of electricity with a gas-fired power plant boasting an electric efficiency of 60%, which presently represents the highest achievable efficiency for such power plants according to (Moerenhout et al., 2023). Consequently, natural gas utilised for the generation of usable heat and electricity for internal consumption—without being fed back into the grid—will no longer be exempt from gas taxation.

For mid-sized CHP generators with a thermal input capacity of 20 MW and smaller, the electricity consumed from their own CHP will continue to be exempt from electricity tax. Consequently, considering the maximum efficiency of 60%, the tax exemption of natural gas for CHPs is restricted to the quantity of electricity sold to the grid multiplied by 1.67 (Moerenhout et al., 2023). Figure 2-2 illustrates an example of how the taxable amount of fuel can be calculated in 2030 following this new policy for large (Groot) and mid-sized (Middelgroot) CHPs. In this context, 'Aardgas' refers to natural gas, the input; 'Warmte' represents the heat output; 'Elektriciteit' signifies the electricity output; 'Eigen verbruik' denotes the self-consumption from the CHP, and 'Netlevering' indicates the electricity delivered to the grid.



Energiedrager	Belaste energie in het basispad	Belaste energie na maatregel 2	
		Groot	Middelgroot
Input - aardgas	0	1000 - (400*1,67) = 332	1000 - (300*1,67) = 499
Output - warmte	0	0	0
Output - elektriciteit, eigen gebruik	0	100	0
Output - elektriciteit, netlevering	0	0	0

Figure 2-2. Calculation example of the abrogation of the CHP gas tax exemption. From (Moerenhout et al., 2023).

The forthcoming years will witness a reduction in electricity tax, in contrast to the rising tax on natural gas. The reduction of electricity tax by 2030 serves the same objective as the increase in gas tax, namely to incentivise the adoption of sustainable and electric thermal generation within the horticultural sector. It is noteworthy that while the electricity tax decreases relative to 2025 as a reference year, the electricity tax in the final bracket is presently lower than it will be in 2030, specifically 0.12 cents per kilowatt hour (kWh). Figure 2-3 illustrates the annual changes in tax tariffs for both natural gas and electricity consumption. The figure presents tables depicting tax rate changes sourced from Appendix 1b of the 2023 spring memorandum of the Dutch government, with tariffs indicated in cents per energy unit (Ministerie van Algemene Zaken, 2023).

Technisch uitgangspunt tariefaanpassingen energiebelasting						
Aardgas (excl. btw) in cent/m³ (prijspeil 2023)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
0 - 800 m³	48,98	48,98	48,98	48,98	48,98	48,98
800 - 170.000 m³	67,2	68,6	69,6	70,6	73,6	74,3
170.000 - 1.000.000 m³	28,9	41,4	44,9	50,5	57,5	57,8
1.000.000 - 10.000.000 m³	18,7	29,0	32,3	37,8	45,3	45,5
> 10.000.000 m³	4,9	4,8	5,1	5,5	6,1	7,2
Elektriciteit (excl. btw) in cent/kWh (prijspeil 2023)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
0-2900 kWh	9,08	7,90	7,36	6,96	6,49	6,59
2.900- 10.000 kWh	9,08	7,90	7,36	6,96	6,49	6,59
10.000 - 50.000 kWh	6,12	5,69	3,00	3,00	3,00	3,00
50.000 - 10.000.000 kWh	3,47	3,25	3,00	3,00	3,00	3,00
>= 10.000.000 kWh	0,30	0,28	0,27	0,27	0,27	0,27

Figure 2-3. Energy tax tariff changes from 2025 to 2030 in euro cents per cubic metre. From (Ministerie van Algemene Zaken, 2023).

2.4.2 CO2 tax

As a greenhouse grower in the Netherlands, you are obligated to participate in the CO2 regulation for greenhouse horticulture, also known as the CO2 sector system (RVO, n.d.). The CO2 sector system requires greenhouse owners to annually report their natural gas or heat usage, which is then used to calculate their CO2 emissions. These emissions are aggregated to determine the total sector CO2 emissions, which are compared against an agreed-upon emission ceiling for the year. If sector emissions exceed the ceiling, growers may be required to pay a CO2 levy based on the excess emissions. This levy is calculated by multiplying the difference between actual emissions and the emission ceiling by the CO2 emission price per ton. The emission price is determined within the EU-ETS for the year when the sector surpasses the emission ceiling. According to the Netherlands Enterprise Agency (RVO), part of the ministry of EZK, the current CO_2 levy for a greenhouse grower is calculated according to the following formula:

((Et – Er) x P) x (Eb/Et)

Et = total CO_2 emissions of all participants

Er = CO_2 emission ceiling

Et – Er = CO_2 emission balance

P = CO_2 emission price per ton of CO_2

Eb = Greenhouse grower's CO_2 emissions

Between 2018 and 2020, the horticultural sector remained within the emission ceiling, resulting in no CO_2 emission levies being imposed according to the sector system. However, in 2021, the sector exceeded the emission ceiling of 5.9 million tonnes of CO_2 by 253,122 tonnes. Consequently, all horticulturists are required to pay a proportionate share of emission levies for the year 2021. While the RVO has not calculated the total sector emissions for 2022 and 2023 yet, energy monitors within the horticultural sector indicate that the ceiling was not surpassed in 2022, and projections suggest a similar outcome for 2023 (Smit, 2023). As a result, it is assumed that no CO_2 levies will be imposed on emissions from the horticultural sector in 2022 and 2023.

Starting from January 1, 2025, the government will implement an individual CO_2 levy for every greenhouse horticulture company. This levy taxes the CO_2 emissions of each greenhouse horticulture company. This means that the amount of the levy depends on the CO_2 emissions of that company instead of the aggregated emissions of the whole sector (Ministerie van Algemene Zaken, 2023). The sectoral tax on CO_2 for the future is still uncertain as the characteristics of this tax are still to be solidified and can be adjusted in the future when the level of sectoral CO_2 emissions is not decreasing proportionately to set goals. According to Berenschot and Kalavasta (2023), the various versions of the new CO_2 sector system can be described using five key attributes: the portion of emissions subject to the levy, the levy amount, whether it applies solely to CO_2 or other greenhouse gases as well, the implementation timeline from 2025 to 2030 to facilitate sustainability transitions, and the recipient and allocation of levy revenues.

According to experts at AgroEnergy, the anticipated sector system for 2030 is a flat fee that incorporates methane emissions. It is projected that the levy will escalate annually, with the CO_2 tax in 2025 amounting to 20% of the sum in 2030. While the precise levy amount is yet to be determined, the current estimate for 2030 stands at €17.7 per ton of CO_2 equivalents emitted. This flat fee model involves taxing all emissions rather than adopting a marginal taxation system. Furthermore, the revenues generated from the levy are redirected back into the sector through investment subsidies.

2.4.3 Network costs

As more sectors and industries such as transportation, heating and agriculture transition to electric technologies, the overall electricity consumption will rise substantially in the next decade. This causes a surge in electricity demand that puts strain on the existing electricity network infrastructure, leading to challenges such as grid congestion, overloading of transformers and lines, and voltage fluctuations (Poudineh et al., 2017). The strain on the electricity network may result in reliability issues, increased maintenance costs, and the need for grid reinforcements to ensure the grid's stability and performance (Bouloumpasis et al., 2019).

To fix congestion problems in the electricity grid, distribution system operators DSO are forced to make expensive reinforcements such as upgrading the transformer lines or expanding the network (Mukherjee et al., 2021). Such reinforcements and increased maintenance incur extra costs for the DSOs. These costs are passed on to customers through increased network charges that will cover the additional expenses of grid congestion mitigation (Heim et al., 2020). Thus, the network tariffs charged by DSOs are projected to have increased significantly by 2030.

The network charges represent a significant portion of the expenses that horticulturists encounter when purchasing electricity. Particularly, those horticulturists utilising artificial lighting for greenhouse cultivation emerge as high-volume electricity consumers. Upon establishing a new connection to the grid, a one-time connection fee is obligatory. Moreover, an annual fee is levied based on the connection capacity. Additionally, there exists a transport fee comprising a fixed transport-independent tariff and a variable transport-dependent tariff. The variable component of this fee is contingent upon the contracted transport capacity, the actual maximum consumed capacity, and the variable consumption (Stedin, 2023). The contracted transport capacity denotes the maximum anticipated capacity required at any given time throughout the year. Collectively, these charges contribute to the total network charges, which are contingent upon the requisite connection capacity and the corresponding category. Should the maximum connection capacity be surpassed at any instance, the consumer transitions to a higher contract category, leading to proportional increases in the one-time, annual, and transport fees.

The specific network charges are determined by the DSO to which a consumer is linked, based on regional delineations. To exemplify, the network charges levied by Stedin have been outlined in Appendix A. While there may be slight variations in charges among different DSOs, the network charges set by each DSO tend to exhibit similarity. Figure 2-4 provides a map indicating the active DSO in each region of the Netherlands.

Figure 2-4. An overview map of the six Dutch DSOs and their regions. From (Energievergelijk, n.d.).

The predictions regarding future network costs for electricity present distinct trajectories, as delineated by the Netherlands Environmental Assessment Agency (PBL) and the Network Management Netherlands Association (Netbeheer Nederland) (Akkermans, 2023; van Polen, 2021). According to the PBL, the projection towards 2030 is based on recent price trends from the three largest DSOs: Stedin, Liander and Enexis. Each DSO submits an annual proposal for next year’s network tariffs. In the tariff proposals for the years 2018 to 2021, the network charges of these DSOs have increased annually by an average of 4 per cent. Assuming that the tariffs will continue to increase by the same percentage in the future, network charges will have increased by approximately 50% in 2030 compared to 2020. However, NN highlights that the growth in network management costs for electricity from 2023 to 2030, is expected to rise by a factor of 1.95. This projection underscores the significant challenge of managing and expanding the electricity infrastructure to accommodate the increasing demand and production capacity in the upcoming decade. Although the PBL is a reliable source and the discussed report serves as an appendix to the Climate and Energy Outlook (KEV) 2022, the network management association is deemed to have more accurate insights into the future developments of grid management.

The shift from conventional technologies for thermal generation towards electric methods of generation is stimulated by the fiscal measures in sections 2.4.1 and 2.4.2 that will distort to reduce CO2 emissions. However, the developments in network charges until 2030 can have the opposite effect. The increase in electricity costs caused by rising network charges could potentially counteract the intended effect of the fiscal measures aimed at promoting sustainable heat generation methods in the horticultural sector. The increased network charges may discourage the adoption of electric heat generation technologies, thereby creating a challenge in aligning fiscal policies to transition to more sustainable energy practices.

2.5 EXTERNAL FACTORS

In this section, we examine significant external factors impacting the Dutch greenhouse horticulture sector. First, we explore energy demand, focusing on recent trends and future projections regarding heat and electricity requirements. Following that, we delve into the influence of resource prices, particularly natural gas and electricity, on the operational costs and economic viability of greenhouse operations.

2.5.1 Energy demand

The strong decrease in CO2 emissions in 2022 compared to previous years was caused by a big drop in energy use in the horticultural sector. The total energy demand of the sector in 2022 amounted to 85 Petajoules (PJ). This means there was a decrease in energy consumption of 27% compared to 2021 when the total energy demand was 117 PJ (Smit, 2023). The large decrease was caused by extremely high gas and electricity prices in combination with mild temperatures that instigated a reduction in heat and lighting demand in greenhouses. Therefore, 2022 alone is not representative of the current energy demand in the horticultural sector. The energy demand in 2023 is not expected to decrease much in comparison to 2022 as the energy prices were much lower again, so the energy savings were not as necessary and more heat will have been applied to maintain optimal crop growth.

Multiple sources offer insight into the future development of heat and electricity demand in the Dutch greenhouse horticulture sector. Van der Velden et al. (2018) highlight a general trend of decreasing heat demand across three scenarios for 2030, with reductions ranging from 16% to 31% compared to 2018, attributed to varying energy-saving measures and reductions in area size. According to Stichting Platform Geothermie et al. (2018), the total heat demand of the greenhouse horticulture sector in 2030 will be 70 PJ. Glastuinbouw Nederland (2023) indicates a significant reduction in heat demand from 92 PJ in 2017 to 60 PJ by 2040, primarily driven by energy-saving measures. Notably, 90% of the heat is projected to be sustainably generated by 2040, with the remaining 10% supplemented by emerging solutions like hydrogen and further energy efficiency improvements.

Furthermore, individual greenhouse companies are making continuous efforts toward energy conservation, employing practices like "The New Cultivation" and “Greenhouse as Energy Source” principles (Smit, 2023). These principles are projected to contribute to a 35% decrease in heat demand by 2040 compared to 2017 (Glastuinbouw Nederland, 2023). However, it's noted that substantial innovative efforts are necessary to achieve further energy savings, emphasizing the need for area redevelopment and the refinement of energy-saving concepts such as energy screens, dehumidification and efficient lighting. Finally, Rooijers, et al. (2015) offer insights into broader agricultural trends, indicating a projected 20% reduction in total acreage by 2050. This will diminish greenhouse energy demand alongside factors like enhanced energy efficiency, crop changes, and process innovation. This combination of factors is estimated to result in a total energy demand of approximately 60 PJ, comprising 20 PJ of electricity and 40 PJ of heat in 2050. The latter prognosis is shown in Figure 2-5 which shows the predicted energy demand development of the horticultural sector from 2015 until 2050.

Although different sources offer varying numbers for both current heat and electricity demand, as well as future energy demand in the greenhouse horticulture sector, all sources estimate a significant decrease in heat demand. The crucial observation from the data presented is that while heat demand is forecasted to decrease in the coming decades, electricity demand in greenhouses is expected to remain constant, see Figure 2-5. The reason for the consistent electricity demand is attributed to projections indicating a decrease in the greenhouse area, counterbalanced by an increase in the application and intensity of artificial lighting. This decrease in surface area and concurrent increase in lighting offset each other, thereby maintaining the electricity demand unchanged (Van der Velden et al., 2018).

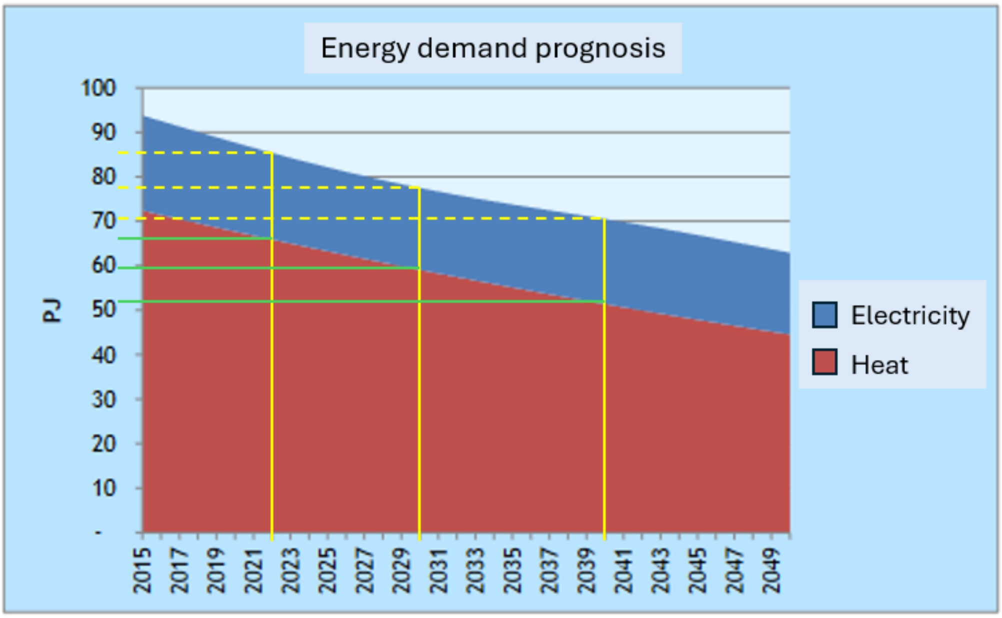


Figure 2-5. Heat and electricity demand projection of the greenhouse horticulture sector from 2015 to 2050 in PJ per year. Adapted from (Rooijers et al., 2015).

2.5.2 Energy prices

Natural gas prices directly impact the operational costs of CHP plants used by horticulturists. Higher gas prices could increase the cost of electricity and heat generation, influencing the economic feasibility of greenhouse operations and potentially affecting their decision to shift from electricity producers to consumers.

Energy prices were highly volatile from 2020 until the start of 2023. In 2020, prices of coal, oil, and natural gas were very low due to reduced demand stemming from the COVID-19 pandemic. However, in 2021, global demand for fossil fuels rebounded, leading to price increases. Then in 2022 natural gas prices surged due to the war resulting from the Russian invasion of Ukraine in February

2022. In 2021, natural gas prices already increased due to Russia reducing gas supply and the low fill level of European gas storage facilities, partly caused by the harsh winter at the beginning of 2021 (PBL, 2022). When Russia decided to completely cut all gas deliveries to Europe, TTF prices peaked in 2022 with an all-time high of 345 €/MWh in March (ICIS, 2024). Figure 2-6 shows that natural gas prices stabilised in 2023 with an annual average TTF price of 37 €/MWh. Future natural gas prices are predicted to decrease slightly, the projected annual average TTF price in 2030 is 34.41 €/MWh, with a low case scenario of 19.53 €/MWh and a high case scenario of 41.85 €/MWh (PBL, 2022). The predicted future price trajectories are showcased in Figure 2-7.

Figure 2-6. Historical price of Dutch TTF from 2020 to 2024. From (Botta et al., 2024).

According to PBL (2022) there was a significant increase in the electricity price in 2021, which was more than three times higher than in 2020, with an average day-ahead price of 103 €/MWh. This price increase was due to the rise in gas and coal prices. After the Russian invasion of Ukraine at the beginning of 2022, the electricity price continued to rise due to further increases in gas and coal prices. The level of the electricity price in the future is mainly determined by the prices of fuels and CO2, the uncertainty of which is reflected in the variable electricity prices in recent years. To represent this uncertainty, three different price scenarios were established in the KEV 2022.

The electricity prices in these scenarios are calculated based on the expected prices for fuels and CO2. In the high-price scenario, it is expected that the electricity price will increase to 93 €/MWh by 2030, while in the low-price scenario, it is expected to decrease to 50 €/MWh. The most likely scenario projects the yearly average EPEX price to be 73 €/MWh. This would be an 18% decrease from the average price in 2023 which was 89 €/MWh. Rand (2018) Predicts that due to low-priced natural gas and the increasing penetration of variable renewable energy sources, average wholesale electricity prices may decrease by approximately 25% by 2030. The trajectories of the future electricity price developments can be seen in the left graph of Figure 2-7.

As renewable energy capacity expands and intermittent sources like wind and solar become increasingly prevalent, the likelihood of negative electricity prices occurring more frequently rises. This trend is driven by the low marginal costs of renewable generation, which can lead to price depression during periods of surplus supply, particularly when demand is low, such as between 900 and 1,800 (Afman et al., 2017). Additionally, the anticipated increase in the volatility of electricity prices, particularly in scenarios with high renewable energy penetration, further supports the expectation of more frequent occurrences of negative prices. While precise predictions remain challenging, these trends suggest that negative electricity prices could become more common, posing both challenges and opportunities for energy markets and grid operators.

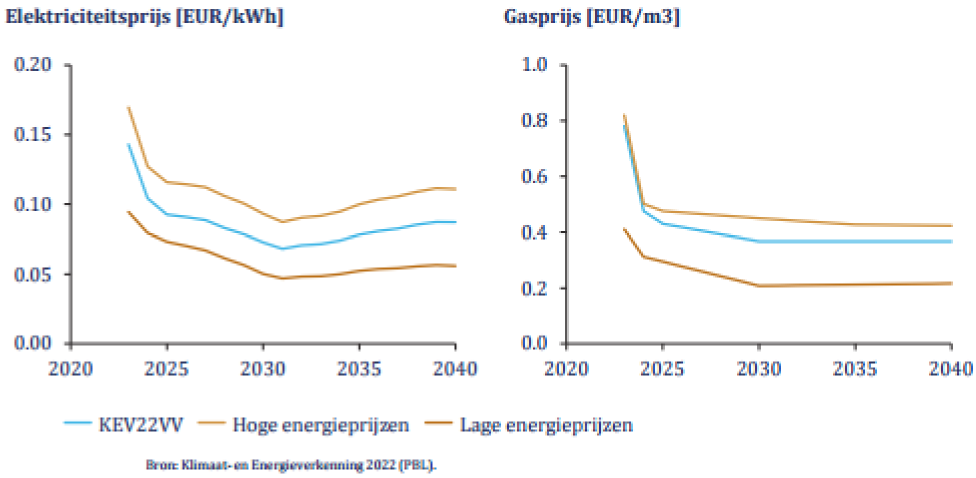


Figure 2-7. Predicted price trajectories of electricity (left) and natural gas (right) until 2040. From (Berenschot & Kalavasta, 2023).

Chapter 3: Greenhouse unit commitment model

This chapter describes the conceptualisation, formulation, implementation, verification and validation of the UC model that was created for the research of this thesis. The model represents a simplified version of the BiedOptimaal model that is used by AgroEnergy to trade energy on the EPEX market on behalf of horticulturists. Creating a new UC model that can be used to optimise energy management and minimise costs of horticultural operations allows specific experiments that BiedOptimaal does not. Furthermore, BiedOptimaal is designed to manage the energy operations of horticulturists in real-time and make predictions up to four days ahead, therefore experiments that simulate future sectoral developments are impossible. The simplified model can generate a future outlook of the horticultural sector in the Netherlands for different scenarios. Based on data from previous years, the horticulturist operations of 2030 can be simulated.

3.1 CONCEPTUALISATION

Horticulturists rely heavily on heat to maintain optimal conditions within their greenhouses for crop cultivation. Currently, the primary heat sources utilised are CHP generators, supplemented by gas boilers when necessary. However, plans entail integrating renewable energy sources into the energy mix to enhance sustainability and maintain economic stability. Additionally, horticulturists typically possess substantial thermal buffers to store and supply heat to their greenhouses. Effective management of energy operations is imperative for horticulturists to minimise operational costs. Strategically committing units, particularly CHP generators, becomes crucial, especially when electricity prices are high relative to natural gas prices. This enables horticulturists to heat their greenhouses or charge their thermal buffers during peak electricity price periods while generating revenue by selling surplus electricity on the EPEX market, thereby offsetting fuel expenses.

The primary objective of the model is to minimise the operational energy costs associated with greenhouse heating by strategically committing available thermal generation units. UC models for thermal generation units, particularly with CHP systems involved, entail sophisticated optimisation algorithms that balance energy production and consumption while maximising revenue in electricity markets.

Technological assets. To delineate the requirements for the UC model, various influencing factors, system scopes, and boundaries need consideration. Firstly, the model incorporates different generation technologies, including CHP, gas boilers, heat pumps, electric boilers, geothermal, and waste heat. Secondly, defining the unique characteristics of thermal generators is pivotal, encompassing factors such as start-up and operational costs, up- and downtime constraints, generation capacities, operational capacity levels, and thermal and electrical generation efficiencies.

Energy balances. Furthermore, three different balances are considered in the UC model. The most important balance is the heat demand of the greenhouses. The required heat of the greenhouses shall at all times be met. The heat is supplied by any of the thermal generators or the available thermal storage capacity. Additionally, there is the required electricity of the greenhouses for lighting mostly. This only applies to specific crops being grown in the greenhouses. The electricity demand can be met by the generated electricity from CHP units or by purchased electricity from the EPEX market. Finally, there is a certain amount of CO2 required to grow the crops in the greenhouses that can be supplied by conventional fuel-based generators such as CHP systems or gas boilers as well as purchased liquefied CO2 from tanks.

Markets and conditions. The model will optimise for the EPEX day-ahead market only. For the purchasing of natural gas, the TTF market is involved in the model. The EU-ETS is not considered in the model. Although the EU-ETS is not considered in the model, sectoral carbon emission levies are considered in the model amongst other important market conditions. Energy taxes on the purchase of both natural gas and electricity are included in the model as well as DSO costs that are involved with purchasing large amounts of electricity.

Geographical scope. The geographical scope of the model is the Netherlands, meaning the model can be used for any horticulturist corporation located in the Netherlands on an individual level. If desired, multiple individual corporations can be used as input for the model and replicated to scale up the output of the model to represent regional or national results.

3.2 FORMULATION

The following subsection will elaborate on the formalisation of the conceptualised model by delineating the mathematical equations of the computational model. The UC optimisation model provides a cost-optimised operating strategy for horticulturists to meet the heat, electricity and CO2 requirements of their greenhouses. The model includes a set of thermal generators in combination with thermal storage. Due to parameters such as electricity and gas prices as well as heat, electricity and CO2 demand, different power states of the generators and storage are optimal at different times. Therefore, there is also a set of timesteps. The sets that are included in the model are defined as follows:

$$g \in G, where\ G = \{CHP, GB, HP, EB, GEO\}$$

$$t \in T, where\ T = \{1, 2, 3, \ldots, 96\}$$

Furthermore, there are several decision variables that the model determines through optimisation to achieve the objective of the model. The decision variables are modified by the model until the best solution is found. They can either be of binary (B) or continuous (C) nature. The decision variables are described in Table 3-1 with their corresponding types, divided into separate categories.

Table 3-1. Decision variables with index t: timestep and index g: thermal generator.

	Decision variables	*Description*	*Type*
Generation	$P_{t,g}^{thermal}$	The thermal output power of a thermal generator in [MWh].	C
	$P_{t,g}^{elec}$	The electrical power output of a CHP generator in [MWh].	C
	$EM_{t,g}^{CO2}$	CO2 output of conventional thermal generators in [kg].	C
	$\delta_{t,g}^{on}$	The operating mode of a thermal generator.	B
	$\delta_{t,g}^{start-up}$	Whether a thermal generator is turned on.	B
	$\delta_{t,g}^{shut-down}$	Whether a thermal generator is shut off.	B
Consumption	$P_{t,g}^{fuel}$	Either consumed natural gas or electricity by a thermal generator in [MWh].	C

	E_t^{used}	Consumed electricity derived from CHP electricity output in [MWh].	C
Inflow	E_t^{pur}	Purchased electricity for consumption from the EPEX in [MWh].	C
	$CO2_t^{liq}$	Purchased liquid CO2 in [kg].	C
Outflow	E_t^{sold}	Electricity sold on the EPEX in [MWh].	C
Thermal storage	TS_t^{state}	State of charge of the thermal buffer in [MWh].	C
	Q_t^{charge}	Charging rate in [MW].	C
	$Q_t^{discharge}$	Discharging rate in [MW].	C
	$Q_t^{destroyed}$	Destroyed heat in [MWh]	C

Besides the decision variables, the constraints of the model need to be parametrised with independent variables. These are the fixed values known before running the model such as prices, capacity limits and efficiencies that characterise the optimisation problem. A list of the used parameters in this model is defined below. Some parameters are different for every timestep. Whereas, other parameters are different for every generator. Few parameters are static and have a constant value.

- Gas price for timestep t in [€/MWh]: c_t^{gas}.
- Electricity price for timestep t in [€/MWh]: c_t^{elec}.
- Liquid CO2 price for timestep t in [€/kg]: c^{CO2}.
- Costs caused by increased machine wear by turning on a thermal generator in [€]: $c_g^{start-up}$.
- Costs required for operating and maintaining a thermal generator in [€]: c_g^{op}.

  Payable tax over taxable consumed natural gas in [€/MWh]: tax^{gas}.
- Payable tax over consumed electricity in [€/MWh]: tax^{elec}.
- Payable tax over emitted CO2 in [€/kg]: tax^{CO2}.
- Fixed hourly network tariffs charged by the network operator in [€]: dso^{fixed}.
- Variable network charges from the network operator in [€/MWh]: dso^{tariff}.
- Minimum and maximum operational capacity of generator g in [MW]: P_g^{min} / P_g^{max}.
- Minimum and maximum state of charge of the thermal storage in [MWh]: TS^{min} / TS^{max}.
- Required thermal energy for the greenhouses for timestep t in [MWh]: Q_t^{demand}.
- Required electrical energy for the greenhouses for timestep t in [MWh]: E_t^{demand}.
- Required CO2 injection for the greenhouses for timestep t in [kg]: $CO2_t^{demand}$.
- Thermal loss per hour of the thermal storage in [MWh]: Q^{loss}.
- Thermal efficiency of generator g in [%]: $\eta_g^{thermal}$.
- Electrical efficiency of generator g = CHP in [%]: η_g^{elec}.

- Efficiency during charging and discharging the thermal storage in [%]: η^{charge} / $\eta^{discharge}$.

Finally, there are dependent variables that can be viewed as the outputs of the model and depend on other variables such as the decision variables and independent variables. In this study, the dependent variables are manifested as the different costs and revenues of the energy operations. Furthermore, the CO2 equivalent emission from conventional generators is an important output of the model. The dependent variables included in the equations of the UC model are described in Table 3-2.

Table 3-2. Dependent variables with index t: timestep and index g: thermal generator.

	Dependent variables	*Description*	*Type*
Costs/Revenue	C_t^{fuel}	Costs associated with the fuel consumption of conventional thermal generators in [€].	C
	C_t^{elec}	Costs associated with the purchased electricity for electric thermal generators and lighting in [€].	C
	C_t^{CO2}	Costs incurred by the emission and purchasing of CO2 in [€].	C
	$C_t^{start-up}$	Costs associated with the deterioration caused by starting up thermal generators in [€].	C
	C_t^{op}	Costs associated with operating thermal generators in [€].	C
	R_t^{elec}	Revenue generated by selling electricity back to the grid in [€].	C
$Outflow$	$CO2_t^{em}$	CO2 that is emitted into the air in [kg].	C
	$CO2_t^{ex}$	Excess produced CO2 in [kg]	C

3.2.1 Objective function

$$\min C = \sum_{t=1}^{T}\left(C_t^{fuel} + C_t^{elec} + C_t^{CO2} + C_t^{start-up} + C_t^{op} - R_t^{elec}\right) + \sum_{t=1}^{T}(50 * Q_t^{destroyed}) \quad (1)$$

The objective function aims to minimise the total costs per timestep t. These costs are a sum of the costs for the required fuel of the conventional generators, the electricity needed for the electric generators and the greenhouse operations, the additional CO2 needs, the start-up costs of the generators and the operational costs of the generators minus the revenue made from the electricity that is sold back to the grid. The objective function will be optimised over 96 hours every time the optimisation function is called upon. This means that the data input for 96 timesteps at a time is used to establish the parameters for each objective optimisation.

3.2.2 Cost functions

$$C_t^{fuel} = \left(P_{t,CHP}^{fuel} + P_{t,GB}^{fuel}\right) * c_t^{gas} + P_{t,GB}^{fuel} * tax^{gas} \quad \forall t \in T \quad (2)$$

$$C_t^{elec} = dso^{fixed} + E_t^{pur} * (c_t^{elec} + tax^{elec} + dso^{tariff}) \quad \forall t \in T \quad (3)$$

$$C_t^{CO2} = CO2_t^{em} * tax^{CO2} + CO2_t^{liq} * c^{CO2} \quad \forall t \in T \tag{4}$$

$$C_t^{start-up} = \sum_{g=1}^{G}\left(\delta_{t,g}^{start-up} * c_g^{start-up}\right) \quad \forall CHP \in G, \quad \forall t \in T \tag{5}$$

$$C_t^{op} = \sum_{g=1}^{G}(\delta_{t,g}^{on} * c_g^{op}) \quad \forall g \in G, \quad \forall t \in T \tag{6}$$

The cost functions are expressions for the objective function that determine the values of the dependent cost variables that represent the different expense items of horticulturist operations. Equation (2) delineates the expression that determines the fuel expenses for running conventional thermal generators. This encompasses the fuel consumption of CHP units and gas boilers, which is multiplied by the gas price of the given timestep. Gas taxes are added to the gas prices for the fuel consumed by gas boilers, whereas no such taxes apply to fuel consumed by CHP plants, as noted in section 2.4.1.

Electricity costs per timestep (equation 3) are dependent upon fixed network charges and the procurement of electricity from the EPEX market. Accordingly, purchased electricity is multiplied by the hourly electricity prices of the EPEX, with electricity taxes and variable network charges added to the EPEX prices. Furthermore, CO2 costs (equation 4) comprise two components. Firstly, costs emerge from CO2 emissions, prompting future tax obligations. Secondly, any additional liquid CO2 required for greenhouse operations must be purchased when the CO2 generation from conventional thermal generators proves insufficient. Finally, start-up and operational costs are addressed in equations 5 and 6. Initiation of a generator incurs associated costs and operational costs are incurred every hour a generator is switched on. These costs aggregate across all thermal generators, although currently applicable solely to CHP generators. The decision variables in these expressions are subject to the constraints described in the following sections.

3.2.3 Operating state

$$P_g^{min} * \delta_{t,g}^{on} \leq P_{t,g}^{fuel} \leq P_g^{max} * \delta_{t,g}^{on} \quad \forall t \in T \tag{7}$$

$$P_{t,g}^{fuel} = P_g^{max} * 0.70 \vee P_g^{max} * \delta_{t,g}^{on} \quad \forall CHP \in G, \quad \forall t \in T \tag{8}$$

Equation (7) maintains the available capacity of any thermal generator within the range of zero or between its minimum and maximum capacities. By combining the binary operating variable with the available fuel capacity, generating units can be committed. The subsequent equation (8) specifically pertains to CHP generators, which operate at fixed capacity levels of 0%, 70%, or 100%, as they cannot be ramped up or down to any continuous capacity.

3.2.4 Start-up/shut-down state

$$\delta_{t,g}^{start-up} \geq \delta_{t,g}^{on} - \delta_{t-1,g}^{on} \quad \forall g \in G, \quad \forall t \in T \tag{9}$$

$$\delta_{t,g}^{start-up} \leq \delta_{t,g}^{on} + \delta_{t+1,g}^{on} + \delta_{t+2,g}^{on} - 2 \quad \forall CHP \in G, \quad \forall t \in T \tag{10}$$

$$\delta_{t,g}^{shut-down} \geq \delta_{t-1,g}^{on} - \delta_{t,g}^{on} \quad \forall g \in G, \quad \forall t \in T \tag{11}$$

$$\delta_{t+1,g}^{on} + \delta_{t+2,g}^{on} + \delta_{t+3,g}^{on} \leq 3 * (1 - \delta_{t,g}^{shut-down}) \quad \forall CHP \in G, \quad \forall t \in T \tag{12}$$

Equations (9 & 11) enforce constraints for generator start-up and shut-down. These constraints dictate that the start-up variable transitions to 1 only if the generator's operating status shifts from 0 in the previous timestep to 1 in the current timestep, and vice versa for the shut-down variable. Equation (10) mandates a minimum uptime for CHP generators, ensuring that once activated, these generators remain operational for at least two subsequent timesteps. Conversely, Equation (12) stipulates a minimum downtime for CHP generators, requiring that once shut down, these generators remain inactive for at least three subsequent timesteps.

3.2.5 Thermal balance

$$\sum_{g=1}^{G}\left(P_{t,g}^{thermal}\right) = Q_t^{demand} + \left(Q_t^{charge} - Q_t^{discharge} * \eta^{discharge}\right) + Q^{loss} + Q_t^{destroyed} \quad \forall\, t \in T \tag{13}$$

$$TS_t^{state} = TS_{t-1}^{state} + Q_{t-1}^{charge} * \eta^{charge} - Q_{t-1}^{discharge} * \eta^{discharge} \quad \forall\, t \in T \tag{14}$$

The thermal balance described in equation (13) is constructed based on a CHP MILP model by (Weber et al., 2018). It ensures that the sum of generated thermal energy from available thermal generators matches the required heat demand precisely. Any surplus heat is stored in the buffer if the generated thermal energy exceeds the demand, while the buffer is discharged to meet demand when the generated heat falls short. Additionally, a small amount of energy is lost in each timestep. In case the thermal storage capacity is at its maximum, heat can be destroyed. The state of charge of the thermal storage in a given timestep (Equation 14) depends on the previous timestep's state of charge, excess heat, and thermal discharge. Relevant charging and discharging efficiencies are accounted for.

Subject to:

$$P_{t,g}^{thermal} = P_{t,g}^{fuel} * \eta_g^{thermal} \quad \forall\, t \in T \tag{15}$$

$$0 \leq P_{t,g}^{thermal} \leq P_g^{max} * \eta_g^{thermal} \quad \forall\, t \in T \tag{16}$$

$$0 \leq Q_t^{charge} \leq \sum_{g=1}^{G}\left(P_{t,g}^{thermal}\right) \quad \forall\, t \in T \tag{17}$$

$$TS^{min} \leq TS_t^{state} \leq TS^{max} \quad \forall\, t \in T \tag{18}$$

$$TS_{t+95}^{state} \geq 0.65 * TS^{max} \quad \forall\, t \in T \tag{19}$$

Constraints in equations (15 – 19) delineate the boundaries of thermal energy within the model. These constraints encompass the thermal efficiency of generators, the allowable range of thermal output of generators, and the limits to the charge rate and state of charge of the thermal storage. Equation 19 specifically ensures that the model optimally maintains the state of charge of the thermal storage at a minimum of 65% of its maximum capacity four days into the future, aligning closely with Biedoptimaal.

3.2.6 Electricity balance

$$\sum_{\{HP,EB\}}^{G} P_{t,g}^{fuel} + E_t^{demand} = E_t^{used} + E_t^{pur} \quad \forall \{HP, EB\} \in G, \quad \forall\, t \in T \tag{20}$$

$$P_{t,g}^{elec} = E_t^{used} + E_t^{sold} \quad \forall t \in T \tag{21}$$

The electricity balance (equation 20) includes the electricity required for greenhouse operations and the sum of electricity needed as fuel for electric thermal generation units. This demand can be met either by electricity generated from CHP units or purchased from the EPEX market. Equation (21) determines the proportion of CHP electricity output that is to be used for greenhouse operations as opposed to the share that is sold on the EPEX.

Subject to:

$$P_{t,g}^{elec} = P_{t,g}^{fuel} * \eta_g^{elec} \quad \forall CHP \in G, \quad \forall t \in T \tag{22}$$

$$0 \leq P_{t,g}^{elec} \leq P_{t,g}^{max} * \eta_g^{elec} \quad \forall CHP \in G, \quad \forall t \in T \tag{23}$$

Constraints in equations (22 & 23) establish the feasible electric output and limits for the CHP generator.

3.2.7 CO2 balance

$$\sum_{\{CHP,GB\}}^{G} EM_{t,g}^{CO2} = CO2_t^{demand} \quad \forall \{CHP, GB\} \in G, \quad \forall t \in T \tag{24}$$

$$CO2_t^{em} = CO2_t^{demand} + CO2_t^{ex} - CO2_t^{liq} \quad \forall \{CHP, GB\} \in G, \quad \forall t \in T \tag{255}$$

Lastly, equation (24) presents the constraint that determines the total emission of CO2 by the conventional generators fuelled by natural gas and (25) the CO2 balance for the greenhouses. Generated CO2 can fulfil greenhouse needs, with excess emissions that are unused if the CO2 emissions exceed the demand. In cases of insufficient CO2 generation or generator shutdown, additional liquid CO2 can be procured.

Subject to:

$$EM_{t,g}^{CO2} = P_{t,g}^{fuel} * 234.22 \quad \forall CHP \in G, \quad \forall t \in T \tag{266}$$

$$EM_{t,g}^{CO2} = P_{t,g}^{fuel} * 201.96 \quad \forall GB \in G, \quad \forall t \in T \tag{277}$$

Expressions in equations (26 & 27) convert CO2 output from MWh to kg and establish limits on this output. The reason a different factor is used for the CHP emissions is to account for the methane slip. It is important to note that these final two equations do not serve as constraints.

3.3 ASSUMPTIONS

When constructing a model, it's crucial to delineate all underlying assumptions as precisely as possible. This serves several purposes, including ensuring transparency and reproducibility for future research. Moreover, describing the foundational assumptions enhances the interpretability of the results (Van Landuyt & Joosen, 2020). The validation of the model is discussed in section 3.5, and the evaluation of its validity and limitations is facilitated by the comprehensiveness of the assumptions (Karnon et al., 2007). This section presents and elaborates upon the assumptions made during the development of the UC model. These assumptions were carefully developed in collaboration with two energy operators and one heat specialist from AgroEnergy, supplemented by relevant literature.

Thermal generation

1. The minimum gas boiler output is assumed to be zero.
2. Both the minimum uptime and downtime for CHP are set at three hours with no maximum uptime specified.
3. Gas boilers, heat pumps and electric boilers do not have a minimum runtime or a minimum downtime.
4. Thermal and electric inertia of committable generators and thermal storage are not considered due to their insignificance in the broader scope of the model.
5. Geothermal- generation and waste heat from heat nets are assumed to remain constant throughout the year, with a contracted capacity in [MW] forming a baseload in [MWh] for each timestep.
6. Horticulturists can either have an individual geothermal source or a shared geothermal source. In this model, geothermal heat can only be contracted so individual generation is not possible.
7. Horticulturists are assumed to have contracts with heat nets or geothermal suppliers lasting up to 12 years. This ensures that the baseload capacity remains consistent throughout different months and seasons. Capacity changes are not possible throughout the contract.
8. All sustainable thermal generation technologies are available to any profile, regardless of the size or geographic location of the profile.
9. In cases where the thermal output of the generators exceeds the thermal demand and the thermal buffer is at its capacity, heat can be destroyed. According to experts at AgroEnergy, this does not occur regularly. Therefore, a penalty of €50 is applied to every MWh of heat that is destroyed. This penalty amount, determined through experimentation, most accurately represents real-world behaviour regarding heat destruction.

Energy consumption

10. It is assumed that there is a general electricity use of 40 kWh per hour for each profile. This electricity is required for everyday operations within and around the greenhouses.
11. Lighting generation is assumed to occur in blocks, with some flexibility limitations compared to reality.
12. Certain crops, such as peppers and red fruit, do not require lighting.
13. The total heat demand of the horticultural sector in 2022 was 85 PJ and total heat demand in 2030 is predicted to be 75 PJ so approximately a 11.8% reduction in heat demand (Smit, 2023; Stichting Platform Geothermie et al., 2018). This is in line with the prognosis by (Rooijers et al., 2015; Van der Velden et al., 2018).

Energetic values

14. For every MWh of natural gas consumed by conventional generators, 201.96 kilograms of CO2 are assumed to be generated, regardless of whether it is used or emitted.
15. The average Lower Heating Value (LHV) of natural gas is 35.17 Megajoules (MJ) per cubic meter. This information is utilized to calculate the equivalence between natural gas

consumption and energy tax. With this LHV value, 102.36 cubic meters of natural gas are equivalent to 1 MWh of natural gas.

16. According to CBS the emission of 1 kg of methane is equal to 25 kg of CO2 equivalents (CBS, n.d.-a). Natural gas weights 0.829 kg per cubic metre (CBS, n.d.-b). Approximately 1.6% of methane is emitted during the combustion of natural gas in CHP generators and methane makes up 95% of the volume of natural gas (Wechselberger et al., 2023). That means that the mass of methane per cubic metre of natural gas is 0.788 kg per cubic metre of natural gas. Thus the methane slip per cubic metre of natural gas is 0.0126 kg in the case of CHP consumption. This equals 1.29 kg per MWh of natural gas. This means 32.26 kg of CO2 equivalents is emitted due to methane slip per MWh of natural gas consumption in CHPs.

Costs

14. In reality the start-up costs of a CHP generator are considered to be dependent on the number of running hours, with more hours resulting in lower costs. However, for the sake of simplification, start-up costs are estimated at €8 per MWh of maximum capacity.
15. The operational costs for CHP are estimated at €8 per hour per MWh of maximum capacity.
16. Operational costs for CHP are assumed to be consistent regardless of operating at 70% or 100% capacity. Consequently, CHP is presumed to mostly operate at full capacity. However, in a simplified model, both states are acknowledged due to perfect price information availability.
17. Start-up costs and operational costs for all thermal generators apart from CHPs, thus gas boilers, heat pumps and electric boilers are assumed to be negligible.
18. A geothermal contract is assumed to cost €325,000 per MW per year.
19. Costs for heat from heat nets are assumed to be €30,000 per MW per year.
20. Although there are many different DSOs in the Netherlands, the network tariffs that are used in this model are assumed to be equal to what Stedin charges.
21. Initial and yearly network connection costs are disregarded in the model.
22. Liquid CO2 is assumed to cost €140 per ton of liquid CO2.

3.4 IMPLEMENTATION

This sub-section elaborates on the temporal settings and functions that were used to implement the formalised model into the Julia programming language. The packages that were used to build the optimisation model and the function of the optimisation function have been elaborated upon in 1)a)Appendix B.

3.4.1 Temporal settings

Time resolution

The time resolution of a model defines the granularity at which time is represented, indicating the smallest time interval the model can simulate. This temporal resolution, or timestep size, balances simulation accuracy with computational efficiency. A higher resolution, with smaller intervals, yields more precise results but demands increased computational resources. Conversely, lower resolution, with larger intervals, sacrifices some accuracy for reduced computational complexity. In this optimisation model, the time resolution is set at one hour, reflecting the minimum feasible interval for the model.

This choice aligns with the hourly trading of electricity on the EPEX day-ahead market. Other time series with varying resolutions, such as greenhouse heat demand (at five-minute intervals) and TTF price data (at daily intervals), are converted to hourly resolution. Expert advice from AgroEnergy confirms that a one-hour resolution is sufficient for generating realistic and accurate results.

Optimisation period

Regarding the optimisation period, the optimisation function defines a timeframe, denoted as T, with start and end indices. It optimises variables for all timesteps within T to achieve the optimal objective value. While the entire input dataset spans 8760 data points, representing each hour of the year, optimising for all 8760 hours would be computationally expensive, given the available computational resources and the lack of perfect information for the entire year. Consequently, the model optimises for a more manageable timeframe of 96 hours, representing four days ahead, based on available price and demand predictions, mirroring BiedOptimaal. Of these 96 hours, only the first 24 hours of results are stored per iteration, reflecting the bidding mechanism of BiedOptimaal, where bids for the next 24 hours are locked in on the EPEX market. Therefore, a new optimisation run is conducted daily.

To implement this modelling structure accurately, the model utilises a rolling time horizon. This is a dynamic approach where the optimisation model iteratively solves over a series of periods, with the time horizon advancing as each period is completed (Marquant et al., 2015). A loop within the optimisation model iterates until results for all 8760 hours are stored. During each iteration, the model optimises for a subset of the timeframe and stores the corresponding results. For instance, the first iteration optimises for hours 1 to 96 and stores results for hours 1 to 24, while the second iteration optimises for hours 25 to 120 and stores results for hours 25 to 48, and so forth. This process ensures efficient computation while capturing the dynamics of the bidding process. This process is visualised in Figure 3-1.

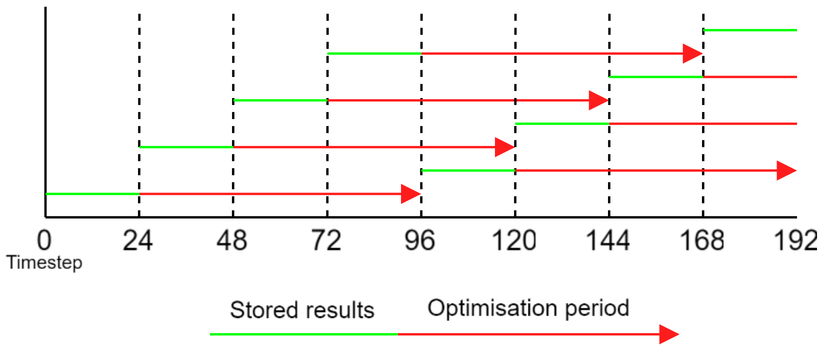


Figure 3-1. Illustration of the rolling time horizon.

3.4.2 Functions

Tax functions

Although the tax values for electricity and gas are fixed parameters, they are updated throughout the total model run. The values of the gas and electricity tax depend on the amount of electricity and taxable gas that is consumed throughout the year. Therefore, two functions are created that return the values of the taxes based on the total consumption. The electricity tax function uses the cumulative amount of purchased electricity as its argument and the gas tax function uses the amount of taxable gas consumption as its argument. After every time the optimisation loop is called on, the amount of purchased electricity gets added to a counter to update the tax bracket. The same happens for the amount of consumed gas that is taxable. This way the model can continuously update the tax values to accurately optimise the objective function every model iteration.

DSO cost function

To calculate the DSO cost for every optimisation run, a similar function to the tax functions is constructed. However, the DSO function uses two arguments to determine the value of the DSO costs for the next model run. One argument is the overall maximum amount of purchased electricity of a single time step and the other is the monthly maximum amount of purchased electricity of a single time step. The first determines what the contracted network capacity with the DSO is and therewith determines both the fixed monthly costs and the variable costs per MWh. The latter argument determines what the maximum amount of drawn electricity is in a month to calculate the DSO max MW costs that are added to the fixed costs in that month. After every model iteration, so inside the temporal loop, the overall and monthly maximum amount of purchased electricity in a single timestep gets updated. Only the monthly maximum gets reset after every month.

3.5 VALIDATION

To establish the efficacy of the developed UC model in accurately simulating energy generation, consumption, and trade within the horticulture sector, the model is validated in this subsection. Model validation encompasses evaluating the degree to which the model accurately represents the real-world system and dynamics it seeks to emulate. During the validation phase, the model is compared with empirical data to gauge its accuracy and reliability. The validation phase is crucial in the modelling process as it adjudges the model's prognostic capabilities and its capacity to generate new data. In validating the Argo UC model, outcomes from the 2023 scenario, incorporating all energy system regulations and costs, serve as a benchmark case. These outcomes undergo assessment against real data from the five profiles for 2023.

3.5.1 Comparison with AgroEnergy data

To assess the model's performance, its settings are configured to mirror the current horticultural systems, creating a reference case. This scenario replicates conditions in the year 2023, utilising EPEX and TTF prices from that year as input data. Additionally, the precise heat demand of the five profiles in 2023, alongside estimated CO_2 and electricity demands for the greenhouses within these profiles, are incorporated as input parameters for the model. To accurately capture the financial dynamics of 2023, prevailing energy system regulations and costs in the Dutch horticultural sector are integrated into the model. This entails the absence of a CO_2 tax, reduced natural gas tax rates applicable to gas consumed by gas boilers and a tax exemption for gas utilised by CHP systems. The natural gas tax, electricity tax and DSO rates are aligned with Table 4-2 and Table 4-4 of subsection 4.1.1. As previously noted in subsection 2.4.3, the network charges assumed in this study align with the rates stipulated by Stedin. Lastly, thermal generators available to horticulturists comprise solely CHP systems and gas boilers, each with specified capacities as detailed in Table 4-1.

Natural gas consumption

AgroEnergy has provided a time series comprising the hourly natural gas consumption of all generators combined, measured in cubic meters, and the hourly electricity position on the EPEX, measured in kilowatt-hours, for the five profiles. The initial phase of model validation involves comparing the actual final natural gas consumption and electricity balance of 2023 with the corresponding gas consumption and electricity balance derived from the model's benchmark results, separately for each profile. To compute the total natural gas consumption from the model results, the gas consumed by the CHP system and gas boiler is aggregated and converted from MWh to cubic meters. To determine the electricity balance for the entire year, the total amount of sold electricity is subtracted from the total amount of purchased electricity and converted from MWh to kWh. Figure 3-2 illustrates the comparison between real-world natural gas consumption in 2023 and the benchmark model results for each profile.

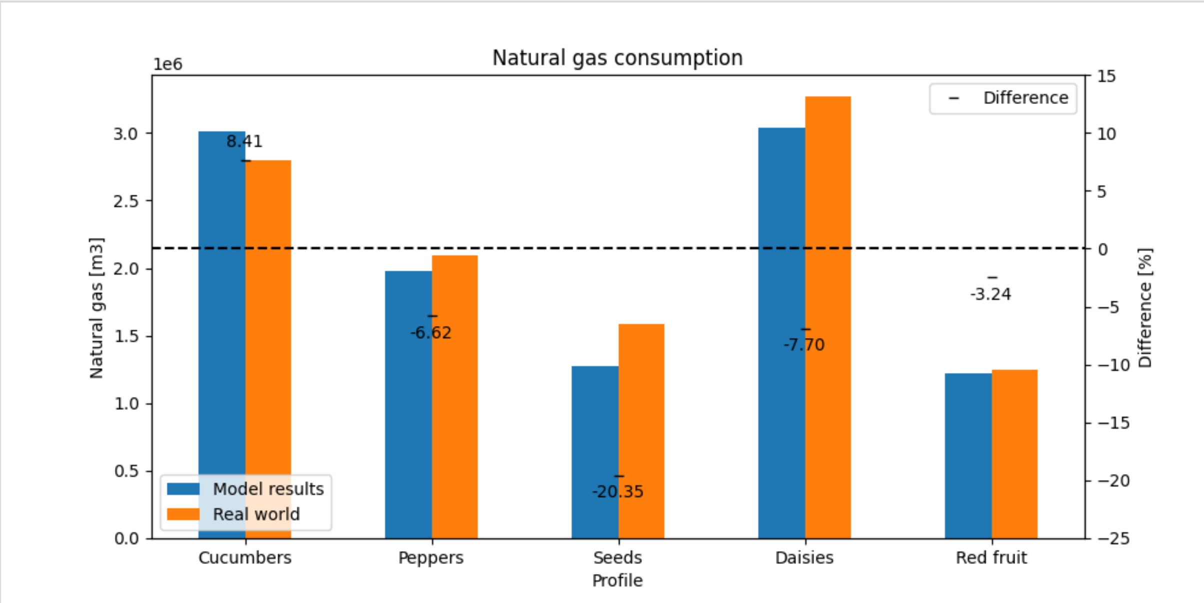


Figure 3-2. Comparison of model validation case output against real data for natural gas consumption.

The evaluation of the model results against real-world data reveals that the model effectively simulates a comparable level of natural gas consumption in 2023. It is evident that, across all profiles except cucumbers, the model predicts a lower natural gas consumption compared to the real consumption. Notably, the simulation of the red fruit profile demonstrates the most precise results concerning natural gas consumption, closely followed by cucumbers and daisies. Conversely, profiles with lower overall gas consumption exhibit less accurate results, with the seeds profile displaying a 20% difference from real-world consumption. While this deviation is not excessively pronounced, achieving a higher percentage of resemblance is desirable to ensure reliable predictiveness.

Electricity balance

The modelled final electricity balance, as per the 2023 benchmark case, is evaluated against the actual annual electricity balance of 2023, as depicted in Figure 3-3. The comparison between real data and model results for the daisies, cucumbers, peppers and red fruit profiles reveals a striking resemblance with only a 3 to 7 per cent difference from real-world behaviour, indicating robust predictive power and reliability. However, the seeds profile demonstrates a notable disparity, with a 25% difference between the real electricity balance and the model results. This significant gap undermines the reliability of the model's predictive power concerning the electricity balance of the seeds profile.

However, a 25% difference is not considered an extreme outlier. The electricity balance of each profile is predominantly influenced by the greenhouse electricity demand. The validation of the electricity balance only considers the amount of purchased and sold electricity, overlooking the consumption of self-generated electricity from CHP systems. To thoroughly evaluate each profile, it would be beneficial to discover the quantity of electricity generated by the CHP systems utilised for greenhouse self-consumption. This could elucidate the discrepancy between the model results and reality for the seeds profile. Moreover, if the actual electricity demand in 2023 deviates from the estimated electricity demand used as input for the model, the electricity balance may not align. A lower demand would result in increased electricity sales, while a higher demand would necessitate more electricity procurement, greater self-consumption of CHP-generated electricity, reduced electricity sales, or a combination of these factors.

The natural gas consumption exhibits a consistent pattern across the five profiles, with modelled consumption slightly lower than actual natural gas usage. A similar trend emerges in the validation of electricity balance. Specifically, all profiles indicate a lower level of electricity sales relative to reality. In contrast, the seeds profile demonstrates comparatively higher electricity sales and lower electricity procurement compared to real-world data.

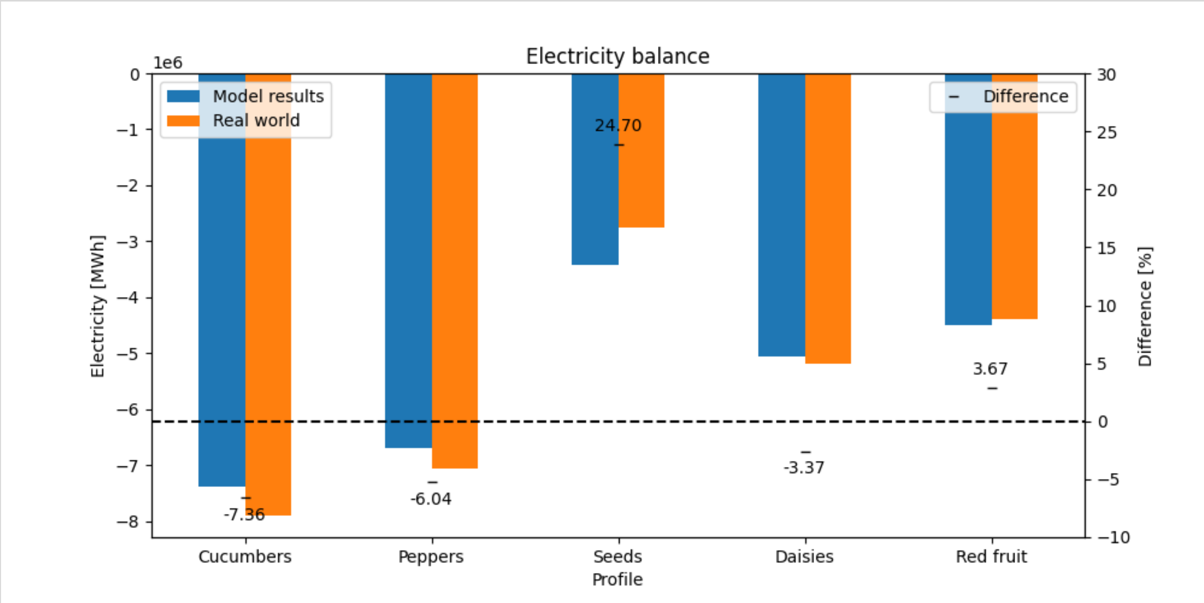


Figure 3-3. Comparison of model validation case output against real data for electricity trade.

Furthermore, the electricity balance patterns of the 2023 scenario were examined at hourly, daily, and monthly intervals, comparing them with real electricity balance time series data. This approach allowed us to assess not only the accuracy of the annual electricity flow in and out of the horticultural companies but also the fidelity of the trading patterns depicted in the model. The analysis focused on the three most accurate months and the three least accurate months, as illustrated in Figure 3-4 and Figure 3-5, respectively. Despite discrepancies, even in the least accurate months, the response to market prices appeared consistent, with fluctuations generally aligning with the real electricity balance. However, there was a slight divergence in the aggregated balance from January to March. Additional details on the remaining six months can be found in Appendix C.

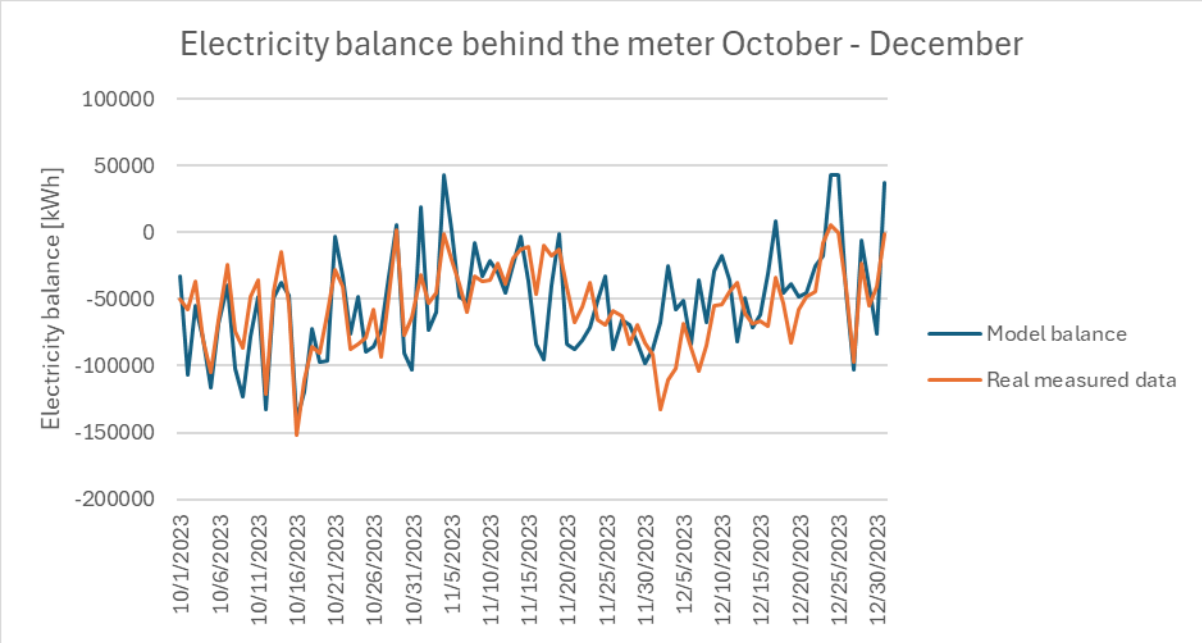


Figure 3-4. Validation of electricity trading pattern from October to December.

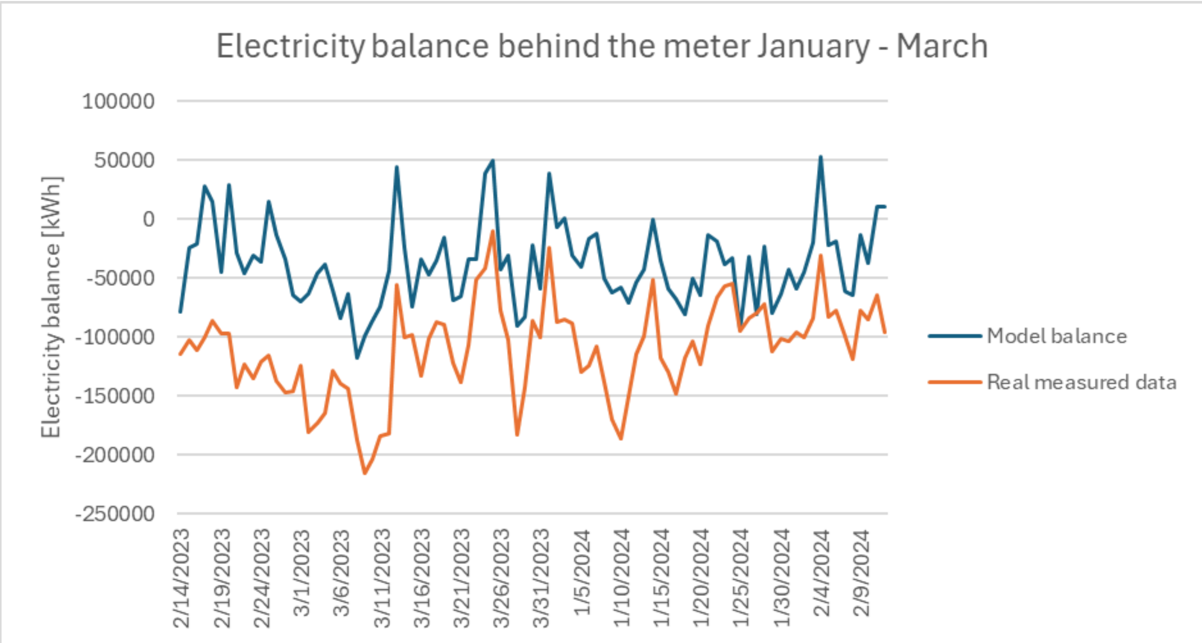


Figure 3-5. Validation of electricity trading pattern from January to March.

Chapter 4: Experiment design

In this section, the experiments that are conducted with the model are discussed. The chapter will elaborate on the data input that is used to run the model, the variables that are modified, the base case scenarios and the experiment scenarios. The input variables of the different scenarios for the experiments are based on the current and projected developments in policy, grid conditions, technology integration and energy prices that were identified in Chapter 2:.

4.1 EXPERIMENT SETUP

In this study, the experiments are conducted by adjusting the input parameters of the UC model to generate a range of scenarios. Initially, we delve into the diverse model inputs that serve as the foundational model input for all scenarios. Subsequently, the independent variables of the experiments are described and their possible values for the experiment scenarios are delineated. Accordingly, the scenarios used for experimentation are created by combining different values of the independent variables. Finally, an overview of the scenarios and their variable values is provided.

4.1.1 Base data input

The data input that is used as the foundational input for all the experiments of this research is outlined in the following subsection. The inputs that need to be defined for every experiment are the energy demand time series, technological specifications of the standard horticultural thermal assets and hourly energy prices.

Demand

Data from 2023 serves as the foundation for understanding the operational energy dynamics within the horticultural sector. This specific reference year facilitates the optimisation of the model under existing conditions. Various parameters, including heat, electricity, and CO2 demands associated with different horticultural profiles, are incorporated as data inputs. Hourly demand data of 2023, obtained from AgroEnergy, forms the primary dataset, accurately portraying the energy consumption patterns of horticultural customers utilising AgroEnergy's optimisation tools.

Factors such as greenhouse insulation, weather conditions, greenhouse size, lighting systems, and the types of crops cultivated within the greenhouses influence the depicted heat demand within the time series. The amount of required heat varies between different crops as well as the demand patterns that vary from daily to seasonal intervals. Similarly, electricity demand profiles are contingent upon the nature of crops being cultivated, with certain varieties requiring additional artificial lighting. Furthermore, CO2 demand is primarily influenced by weather conditions, particularly solar radiation levels.

To accurately simulate real-world scenarios, the model incorporates multiple profiles representing various crops commonly cultivated in greenhouses, such as cucumbers, peppers, seeds, daisies, and red fruits. The heat demand time series are sourced from a dataset containing the heat demand of the aforementioned five profiles, measured in kW with a time resolution of five minutes. The dataset originates from AgroEnergy's database, where they store the historical heat demand data of their clients. To convert this demand to kWh with an hourly time resolution, the power rates per five minutes are aggregated and then divided by twelve to obtain the hourly energy consumption. The aggregated heat demand per month that served as input for the year 2023 is displayed in Figure 4-1. The demand is expressed per acre of greenhouse area to ensure comparability of profiles.

there are no exact time series available, so the time series are constructed based on expected patterns. There is a baseload demand of 40 kWh per hour of electricity for every profile for day-to-day operations. The rest of the electricity demand depends on if additional lighting is required for the crops. In consultation with energy operations experts at AgroEnergy and drawing from data obtained from real clients with comparable greenhouse and crop setups, daily lighting patterns were devised for each crop type. These daily patterns are subject to seasonal variability in both the magnitude and duration of demand. As Figure 4-2 shows, that the seeds profile requires the largest peak of electricity for lighting, and daisies require the longest period of lighting red fruit requires no electricity besides the baseload.

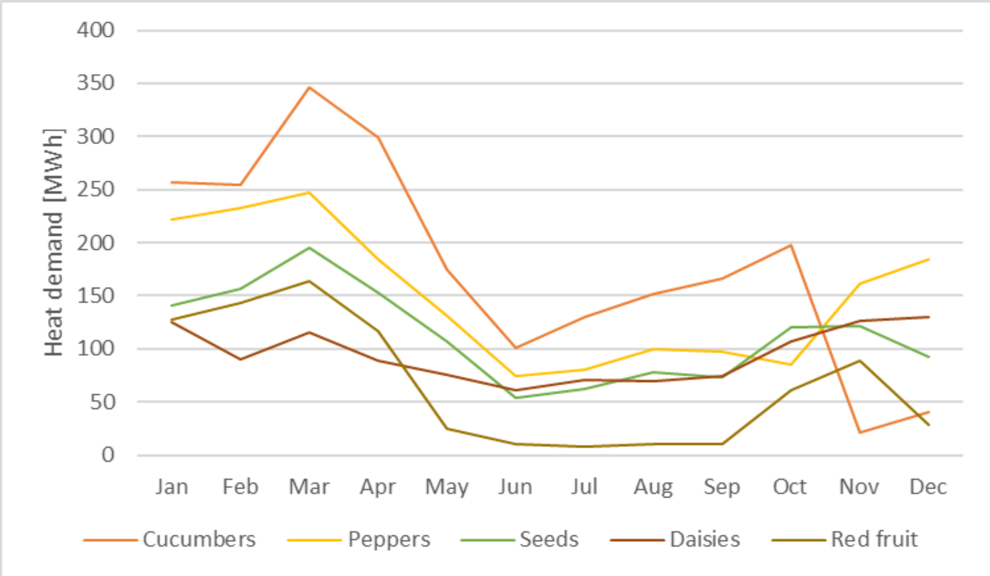


Figure 4-1. Monthly heat demand per hectare of greenhouse acreage of different profiles in 2023.

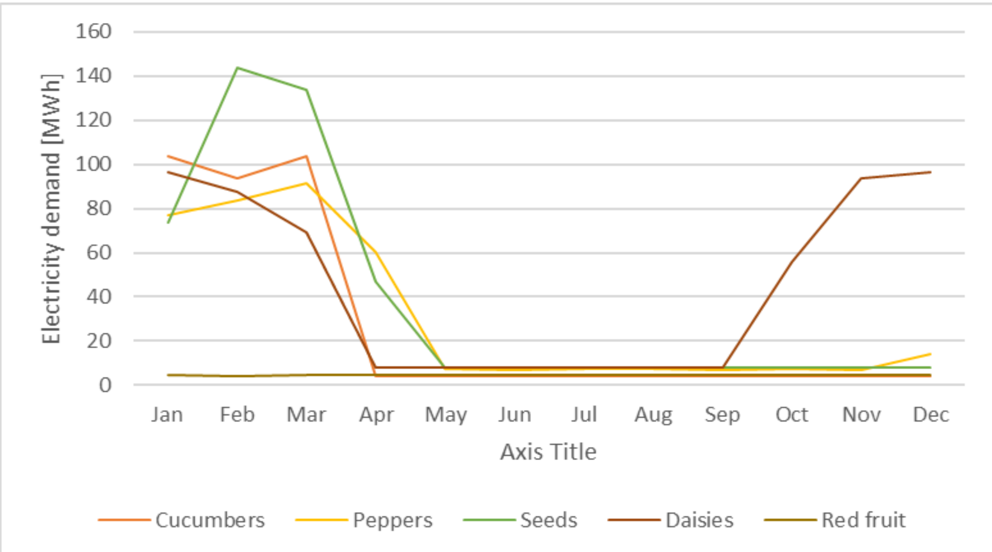


Figure 4-2. Monthly electricity demand per hectare of greenhouse acreage for different profiles in 2023.

Similar to the electricity demand time series, the CO2 demand data is not the exact CO2 demand of the client profiles because this data is not available. Instead, A weather time series with the solar radiation levels of the year 2023 is extracted from the KNMI (Royal Netherlands Meteorological

Institute) database. With the hourly solar radiation levels, the required CO2 in kg/ha can be calculated using the radiation in J/cm2. The demand in kg/ha per hour is multiplied by the areal factors of the different profiles to retrieve the final CO2 demand per hour for every profile. Figure 4-3 illustrates the monthly fluctuation in CO2 demand per acre of greenhouse area, which is utilised in the total calculations for each profile. The daily patterns reveal that additional CO2 demand occurs exclusively during daylight hours.

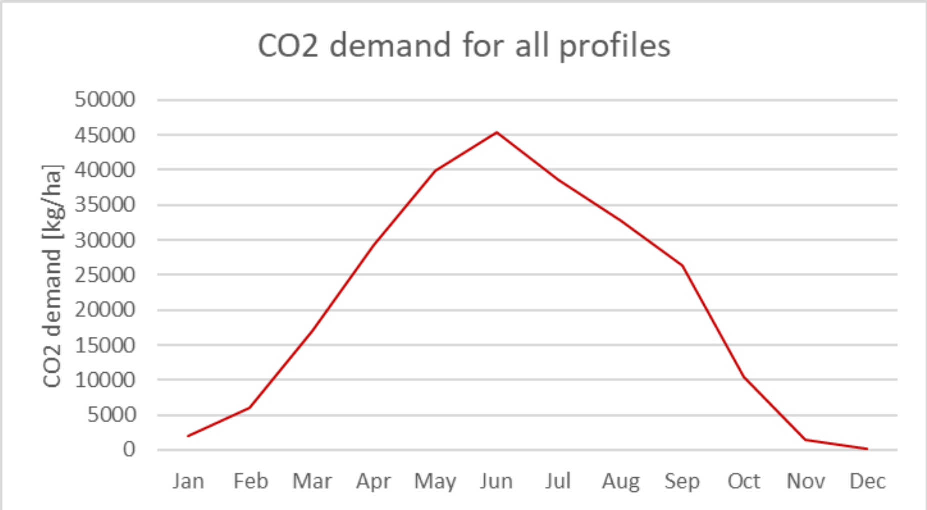


Figure 4-3. Aggregated CO2 demand per hectare of greenhouse acreage for every profile 2023.

Thermal assets

Each demand profile was matched with a corresponding asset profile, reflecting the mix of available technological assets encompassing both thermal generation units and thermal storage tanks. This ensured alignment between the utilised technological asset capacities and the demand profiles. The technological asset values used as input for the model are sourced from the same customer dataset as the demand profiles from AgroEnergy, reflecting real-world capacities alongside their associated efficiencies and characteristics. Table 4-1 shows the asset parameter settings that belong to the separate profiles according to AgroEnergy's database. These settings were used as input for the parameters of the different profiles in the UC model.

Table 4-1. Matching profile asset parameters from the AgroEnergy database.

Asset parameters	*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
Area [ha]	7.20	4.10	3.70	12.5	6.1
CHP max capacity [MW]	5.35	5.63	4.22	7.38	4.84
CHP electric efficiency [%]	41.0%	42.7%	43.8%	40.7%	41.0%
CHP thermal efficiency [%]	51.4%	46.2%	47.4%	48.8%	50.3%
GB max capacity [MW]	9.67	4.48	6.08	4.84	4.40
Thermal buffer max state of charge [MWh]	69.76	20.06	35.58	55.00	55.64
Thermal buffer min state of charge [MWh]	26.16	8.02	8.37	12.79	22.38
Thermal storage loss [%]	1.0%	2.0%	1.0%	0.5%	0.5%

Energy prices

Finally, the model integrates pricing data from the year 2023 for both TTF and EPEX, shedding light on prevailing market conditions. In section 2.5.2, details were provided on the average gas and electricity prices of 2023 alongside projections for future averages. To capture the variability in energy prices, the hourly time series of energy prices from 2023 is incorporated into all model scenarios. AgroEnergy provided both the EPEX and TTF time series for 2023. While the EPEX data was already available in hourly resolution, the TTF prices change every 24 hours and remain constant over weekends. Consequently, the TTF prices, although transformed into an hourly time series, lack hourly fluctuations, with Saturday and Sunday prices assumed to mirror those of Friday. The electricity and gas price patterns of 2023, serving as fundamental inputs for the model, are illustrated in Figure 4-4. EPEX and TTF prices of 2023 in hourly resolution.

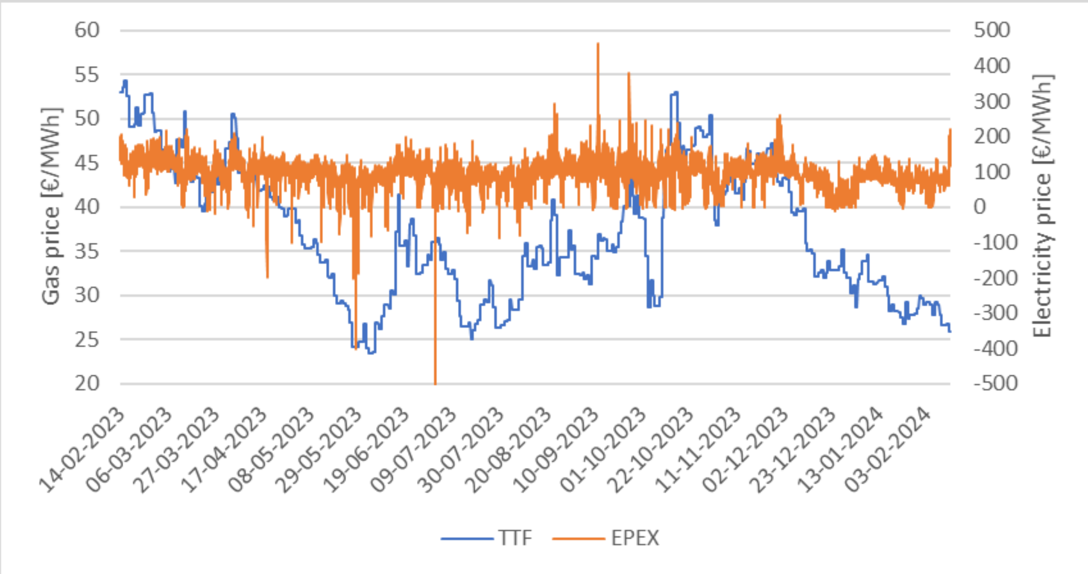


Figure 4-4. EPEX and TTF prices of 2023 in hourly resolution.

4.1.2 Experiment variables

The subsequent subsection outlines potential modifications to the previously described data input and introduces new independent input variables. Here, we delve into the diverse values that all independent variables, subject to experimentation, may assume. These variables, pivotal in assessing various contextual conditions within the horticultural energy landscape, are categorised into three main groups: energy system regulations and costs, RES capacities, and energy prices. The range of values attributed to these variables is derived from the research conducted in Chapter 2:, encompassing current and projected contextual factors within the horticultural sector.

Energy system regulations and costs

The energy system regulations encompass various policy adjustments, tailored with the goal to decrease the overall CO2 emissions of the horticultural sector. In the context of the horticultural energy system, energy system regulations designed by the government aim to disrupt the current pattern of energy production and consumption of energy resources. The policy instruments should steer the energy generation in the horticultural sector away from natural gas consumption. Alongside energy system regulations, there exist additional energy system conditions stemming from costs controlled by market parties. One notable example of such conditions is DSO costs, which influence the market dynamics independently of policy interventions.

Energy tax: Relevant tax tables sourced from the Dutch government tax authorities' website contributed to the comprehensive data input utilised within the model. The gas and electricity tax tariffs that are used for the main 2023 scenario are displayed in Table 4-2. Currently, gas tax is only paid over fuel that is consumed by gas boilers as CHP generators are exempt from energy taxes. Over the gas that is consumed by gas boilers, the reduced gas tax rate is paid.

Table 4-2. 2023 tax rates for scenario data input. Adapted from (Belastingdienst, n.d.).

Gas bracket [m3]	*Reduced rate [€/kWh]*	*Normal rate [€/kWh]*	*Electricity bracket [kWh]*	*Normal rate [€/kWh]*
0 – 170,000	€ 0.07867	€ 0.48980	0 – 10,000	€ 0.12599
170,000 – 1 million	€ 0.03629	€ 0.09621	10,000 – 50,000	€ 0.10046
1 million – 10 million	€ 0.05109	€ 0.05109	50,000 – 10 million	€ 0.03942
Over 10 million	€ 0.03919	€ 0.03919	Over 10 million	€ 0.00115

Changes in the gas tax regulations are implemented to reflect alterations in energy taxation policies and incentives. These modifications involve the removal of CHP exemptions from the gas tax and the gradual elimination of reduced rates by 2030 for gas consumption of gas boilers as well as CHP generators. For the gas consumed by a CHP generator that is taxable, the comparison lies between the fuel consumption of a CHP generator operating at maximum efficiency and the actual fuel consumption of a CHP generator. This comparison specifically targets the portion of fuel utilised solely for generating electricity sold back to the grid, excluding internal use. The inequality of fuel consumption between these scenarios is subject to gas tax. The deductible fuel loss that diminishes this inequality of fuel consumption, decreases annually. These adjustments aim to assess the impact of gas taxation on the competitiveness of CHP generators and gas boilers as thermal sources for the greenhouses. The gas tax rates of 2030 are available in **Error! Reference source not found.**. When the gas tax is implemented in 2030, the equation that calculates the fuel costs (equation 2) in the model is changed to equation (27) which is displayed below.

$$C_t^{fuel} = \left(P_{t,CHP}^{fuel} + P_{t,GB}^{fuel}\right) * c_t^{gas} + \left(P_{t,CHP}^{taxablel} + P_{t,GB}^{fuel}\right) * tax^{gas} \tag{7}$$

In which $P_{t,CHP}^{taxablel}$ represents the taxable share of fuel that is used by the CHP. This taxable share of fuel is also added to the cumulative amount of taxable gas in each optimisation iteration.

Predicted electricity tax rates for 2030 are used for all future scenarios, reflecting anticipated changes in electricity taxation policies. These adjustments, play a role in shaping the economic viability of consuming electricity to generate heat with electric generators such as heat pumps and electric boilers. The rates for 2030 are slightly lower than in 2023 to stimulate using electricity as a resource instead of fossil fuels. Together with the gas tax rates, the electricity tax tariffs of the different brackets in 2030 are visible in Table 4-3. The rates are extracted from Appendix 1b of the spring memorandum of the Dutch government.

Table 4-3. 2030 gas and electricity rates for scenario data input. Adapted from (Ministerie van Algemene Zaken, 2023)

Gas bracket [m3]	*Normal rate [€/kWh]*	*Electricity bracket [kWh]*	*Normal rate [€/kWh]*
0 – 170,000	€ 0.74300	0 – 10,000	€ 0.06590
170,000 – 1 million	€ 0.57800	10,000 – 50,000	€ 0.03000
1 million – 10 million	€ 0.45500	50,000 – 10 million	€ 0.03000
Over 10 million	€ 0.07200	Over 10 million	€ 0.00270

DSO Costs: The operational costs that are associated with maintaining and managing the distribution networks by DSOs are also considered in some scenarios. For simplification purposes, the DSO costs in the optimisation model are assumed to be equal to the costs that Stedin charges for their operating services. Table 4-4 shows the different electricity transportation categories that can be contracted with Stedin including the matching maximum connection capacities. The rates that determine the fixed and variable DSO costs that are to be paid over purchased electricity from the grid are presented for each transportation category.

Table 4-4. Stedin periodic connection costs 2023. Adapted from (Stedin, 2023).

Transportation category	*Connection limit [kW]*	*Transport [€/month]*	*kW contract [€/month/kW]*	*kW max [€/month/kW]*	*kWh Tariff [€/kWh]*
LS	0.05	1.500	1.184	0.000	0.058
Trafo MS/LS	0.15	36.750	3.171	2.426	0.015
MS	1.5	36.750	1.610	2.426	0.015
Trafo HS+TS/MS	8	230.000	3.047	4.065	0.000
TS	Inf	230.000	2.944	4.018	0.000

Variations in DSO costs are incorporated into different scenarios, reflecting changes in infrastructure investment and regulatory frameworks. Adjustments involve scaling DSO costs by factors of 1.95 relative to 2023 levels, representing a scenario of increased operational and maintenance expenses. A prognosis on the financial impact of the energy transition for DSOs states that the network charges are expected to have increased by 95% in 2030 compared to 2023 (Akkermans, 2023). These modifications aim to assess the impact of distribution network costs on overall horticultural energy system costs and profitability.

CO2 Tax: The CO2 tax is subject to adjustments in different scenarios, reflecting changes in emissions regulations. Currently, the horticultural sector is exempt from CO2 emission taxes. However, future scenarios include variations in CO2 tax rates, with flat rates ranging from €14/ton to €17.7/ton in 2030. Both rates are included in the experiments to establish the appropriate tax rate for CO2 under different circumstances. The values of the CO2 emission tax for the horticultural sector are extracted from the "Computational model individual sector system horticulture" strategic advice report from Berenschot & Kalavasta (2023), developed for the government.

By modifying energy system regulations across scenarios, the experiments aim to elucidate the complex interactions between regulatory policies, market incentives, and technological advancements in shaping the future of energy systems. These nuanced adjustments provide valuable insights into the potential challenges and opportunities associated with transitioning towards a more sustainable and resilient energy future.

Renewable thermal assets

Modified parameters relating to asset capacity involve varying the proportions of different energy-generating assets relative to the primary CHP and gas boiler capacities within each profile. These adjustments are crucial in evaluating the feasibility and effectiveness of different energy generation strategies within the experimental framework.

Heat pumps and electric boilers: The capacity of heat pumps across scenarios is set at 100% relative to the CHP capacity of the profile. The heat pumps included in the experiments have a COP (Coefficient of Performance) of 3.0 or an efficiency of 300%, and no minimum capacity. Similarly, the capacity of electric boilers is set relative to the gas boiler capacity of the profile, with scenarios including 100% electric boiler capacity relative to the gas boiler capacity. The thermal efficiency of electric boilers in the model experiments is 100%, and they have no minimum capacity. Neither type of electric thermal generation unit is subject to start-up or operational maintenance costs.

Geothermal energy: The integration of geothermal energy into the energy generation mix is also considered. By 2030, it is projected that geothermal energy will be capable of meeting 5% of the national heat demand in the Netherlands. The objective is to allocate 30PJ of geothermal heat to the horticultural sector, which would fulfil 43% of the sector's heat requirement. As a result, the incorporation of geothermal heat into the model is designed to ensure that the contracted capacity can meet 43% of the heat demand for each profile (Stichting Platform Geothermie et al., 2018).

To determine the appropriate geothermal contract capacity, the annual heat demand for each profile in MWh is retrieved from the respective heat demand time series. Subsequently, the total demand was multiplied by 43% and divided by 8760 hours to ascertain the necessary contract capacity for geothermal supply, assuming a load that provides a baseload across the entire year with a full load equivalent to 8760 hours. The load of geothermal heat remains consistent and immutable throughout the year. Consequently, geothermal supply is excluded from the optimisation function and treated as a constant input, as it does not function as a committable generator. A geothermal contract is associated with a fixed price of €325,000 per MW of contract capacity per year. The contract capacities utilised for the experiments are presented in Table 4-5. To experiment with lower geothermal availability, the scenarios can also entail only 50% of the contracted capacity displayed in the table.

Waste heat: Thermal energy waste heat through heat networks is also incorporated in the future thermal energy mix of horticulturists. The ambition concerning waste heat from industry entails achieving an annual heat supply of 10PJ to the horticultural sector (Ministerie van EZK, 2019). This target represents 20% of the total available waste heat from industry and 15% of the horticultural sector's heat demand. The determination of waste heat contract capacities via heat networks follows the approach that was used to calculate the geothermal contract capacities. Waste heat supplied through a heat network also maintains an unalterable baseload throughout the year, with a full load equivalent of 8760 hours. Similarly, waste heat supply is excluded from the optimisation function and treated as a constant supply. A waste heat contract through a DHN costs €30,000 per MW of capacity per year. The contracted capacities utilised in the experiments to represent 15% of the total heat supply are delineated in Table 4-5. To experiment with lower waste heat availability, the scenarios can also entail only 50% of the contracted capacity displayed in the table.

Table 4-5. Contracted capacities for geothermal and waste heat in 2030 of different profiles.

Asset parameters	*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
Geothermal contract [MW]	0.764	0.366	0.249	0.703	0.241
Waste heat contract [MW]	0.267	0.128	0.087	0.245	0.084

Thermal Storage: While not subject to variation across scenarios, the presence of thermal storage remains a constant consideration. Thermal storage facilities enable the efficient management and utilisation of excess energy, ensuring reliability and stability in energy supply.

By modifying asset capacities across scenarios, the experiments aim to explore the optimal combination of energy-generating assets within each profile, considering factors such as efficiency, sustainability, and economic viability. These adjustments provide valuable insights into the potential benefits and challenges associated with different energy generation strategies in real-world applications.

Energy prices

The uncertain parameters of the future energy landscape in the horticultural sector encompass variations in market conditions, influencing the profitability and competitiveness of energy generation and consumption. Experimenting with these parameters is essential to create an understanding of the effect energy prices have on the energy management practices of horticulturists.

Electricity Prices: Fluctuations in electricity prices are simulated across scenarios, reflecting changes in supply and demand dynamics, as well as market volatility. Scenarios include low prices, mid-range prices, and high prices, each with corresponding average values. These variations enable the assessment of the sensitivity of energy generation technologies to changes in electricity market conditions. The average electricity prices in 2030 are predicted to range from 50 to 93 €/MWh on the EPEX, with the most likely average price being 73 €/MWh following current historic price trends (PBL, 2022). To create the time series of the EPEX prices for 2030, the average price of 2023 is retrieved from the data set for 2023. Accordingly, the price of each hour is multiplied by a mutation factor that corresponds with the difference between the average price of 2023 and the price variations of 2030.

Gas Prices (TTF): Similar to electricity prices, variations in gas prices are introduced to simulate changes in fuel costs and market dynamics. Gas prices are delineated into low, mid, and high categories, each with different average values. These adjustments enable the evaluation of the economic viability of gas-based energy generation technologies such as CHP generators under different market conditions. The average gas prices in 2030 are predicted to be 19.53 €/MWh, 34.41 €/MWh or 41.85 €/MWh in the different price categories respectively (PBL, 2022). The time series of the different scenarios in 2030 were constructed in the same way as the electricity time series in 2030.

By modifying external factors across scenarios, the experiments aim to assess the resilience and adaptability of energy generation and consumption to changing market conditions. These adjustments provide valuable insights into the challenges and opportunities associated with navigating the complex landscape of energy markets and regulatory frameworks.

Demand

Finally, it is important to note that although demand is not used as an independent variable to experiment with. The heat demand in 2030 changes in comparison to 2023. To accurately simulate scenarios in 2030, the overall heat demand decreases by 12% according to the predictions described in section 2.5.1. Thus, for future scenarios, a 0.88 factor is multiplied by the heat demand of every data point from the 2023 time series. The electricity demand remains unchanged for 2030 as predicted in section 2.5.1. Because the weather in 2030 is unpredictable, the same seasonal and daily variation is assumed. The CO2 demand remains unchanged in 2030 as this is weather-dependent and cannot be predicted.

4.2 SCENARIOS

In the subsequent section, values are assigned to the independent variables and merged with the base case inputs to formulate scenarios. These scenarios serve as the final input for various experiments designed to address the research questions of this thesis. Initially, the section outlines the scenario names, abbreviations, details, and research objectives. Following that, Table 4-6 presents a comprehensive summary of the variable configurations for each scenario.

- Scenario 1: Base case 2023 - BC2023

This scenario represents the baseline conditions of the year 2023 as they are described in section 4.1.1. The scenario serves as a reference point to assess deviations from the standard conditions of 2023 without any energy system regulations and costs or renewable thermal energy sources available.

- Scenario 2: RES and no energy system regulations and costs 2023 - RES2023

In this scenario, the renewable assets that are predicted to be included in 2030 will be implemented to establish the effect of the wide availability of renewable assets under current demand and prices. The aim is to evaluate the hypothetical impact of renewable energy integration in the absence of other market interventions in 2023.

- Scenario 3: Only energy tax 2023 - ET2023

This scenario isolates the effect of energy taxes, utilising the current energy tax system with the corresponding rates for the different tax brackets as provided in section 4.1.2. To assess the influence of energy taxation on energy operations and emissions of horticulturists, the energy taxes are included in the base case scenario to separate the effects of energy tax from the effects of DSO costs in 2023.

- Scenario 4: Only network charges 2023 - DSO2023

DSO costs are the sole energy system condition considered in this scenario, maintaining the network charges demanded by Stedin in 2023. This scenario is designed to understand the impact of DSO costs on the energy landscape in the horticultural sector, independent of other factors.

- Scenario 5: All energy system regulations and costs 2023 - ARC2023

This scenario incorporates all energy system regulations and costs present in 2023, including energy taxes and network charges. To examine the cumulative effect of various energy system regulations and costs on the energy operations of horticulturists. This is the scenario that most accurately simulates the energy dynamics within the horticultural sector as they are in the real world.

- Scenario 6: Base case 2030 - BC2030

Similar to BC2023, this scenario reflects the base conditions of the year 2030, accounting for a 12% decrease in heat demand and the inclusion of RES thermal generation availability. The base case in 2030 establishes a baseline for comparison with future scenarios, considering projected changes in heat demand and RES capacity. Renewable assets are assumed to be available in every scenario of 2030 until specified otherwise. Furthermore, the energy prices remain unchanged.

- Scenario 7: Only energy tax 2030 - ET2030

Energy taxes are applied based on 2030 rates in this scenario, while other parameters remain constant. This scenario facilitates the examination of the impact of updated energy taxation policies on horticulture energy operations in 2030. Additionally, it allows for comparison with similar scenarios in 2023 to assess temporal changes and to assess whether the restructuring of the tax system aligns with desired outcomes.

- Scenario 8: Only network charges 2030 - DSO2030

Solely DSO costs are included, but the 2023 rates are increased by 95% in this scenario for 2030, with other variables held constant. This scenario allows for exploration of the implications of heightened network charges on the energy costs and emissions among horticulturists in 2030, this scenario enables comparison with analogous cases in 2023 to understand temporal shifts in market responses.

- Scenario 9: Only CO2 tax 2030 - CO2T2030

This scenario introduces a CO2 tax of €17 per ton emitted in 2030, while other variables remain unchanged. By assessing the impact of carbon pricing mechanisms on Dutch greenhouse horticulture in 2030, this scenario can reveal the impact of the CO2 tax in the future, and whether it is sufficient.

- Scenario 10: All energy system regulations and costs 2030 - ARC2030

All anticipated energy system regulations and costs for 2030, including energy taxes, network charges, and CO2 taxes, are incorporated. This scenario experiment examines the combined effects of multiple market interventions in 2030. Additionally, it enables comparison with the ARC2023 case to understand the temporal developments.

- Scenario 11: No RES 2030 - NORES2030

Renewable energy sources are excluded in this scenario for 2030, while all energy system regulations and costs of 2030 are included in the experiment. This scenario allows for an assessment of the consequences of a lack of renewable energy integration in the horticultural sector in 2030.

- Scenario 12: 50% geothermal and waste heat 2030 - HGW2030

Similar to scenario 11, this is an experiment that aims to explore the outcome of the model simulations under different capacity circumstances in 2030. The capacities of the electric thermal generators remain unchanged, but the contract capacities of geothermal and waste heat are multiplied by 50%.

- Scenario 13: Low energy prices 2030 - LOW2030

Energy prices are set to the low projection for 2030, while all parameters remain as they are in the ARC2030 scenario. This scenario investigates the implications of reduced energy prices on energy in 2030.

- Scenario 14: Medium energy prices 2030 - MID203

Energy prices in 2030 are established at a moderate level while keeping other variables constant. By evaluating the effects of moderate energy prices on energy market dynamics in 2030, this scenario facilitates comparison with the ARC2023 scenario. These price forecasts represent the most probable projections for 2030.

- Scenario 15: High energy prices 2030 - HIGH2030

Energy prices are elevated to a high level for 2030 while keeping other parameters constant. This scenario delves into the repercussions of heightened energy prices on energy market dynamics in 2030, providing valuable insights into the worst-case scenario for horticulturists regarding market conditions.

Table 4-6. Experiment scenario settings.

Scenario	*Heat demand*	*Energy tax*	*DSO costs*	*CO2 tax*	*HP & EB*	*GEO & WH*	*Energy prices*
BC2023	Base	-	-	-	-	-	Base
RES2023	Base	-	-	-	100%	100%	Base
ET2023	Base	2023 rates	-	-	-	-	Base
DSO2023	Base	-	2023 rates	-	-	-	Base
ARC2023	Base	2023 rates	2023 rates	-	-	-	Base
BC2030	-12%	-	-	-	100%	100%	Base
ET2030	-12%	2030 rates	-	-	100%	100%	Base
DSO2030	-12%	-	+95%	-	100%	100%	Base
CO2T2030	-12%	-	-	17 €/ton	100%	100%	Base
ARC2030	-12%	2030 rates	+95%	17 €/ton	100%	100%	Base
NORES2030	-12%	2030 rates	+95%	17 €/ton	-	-	Base
HGW2030	-12%	2030 rates	+95%	17 €/ton	100%	50%	Base
LOW2030	-12%	2030 rates	+95%	17 €/ton	100%	100%	Low
MID2030	-12%	2030 rates	+95%	17 €/ton	100%	100%	Medium
HIGH2030	-12%	2030 rates	+95%	17 €/ton	100%	100%	High

Chapter 5: Results

The results from the model-driven experiments are analysed in the subsequent sections. These experiments encompass 15 distinct scenarios, each reflecting diverse regulatory, market, or capacity conditions. The model was meticulously crafted to address the four research sub-questions outlined in this thesis. The analysis in this section exclusively addresses sub-questions two to four, while insights into sub-question one were gleaned from the desk research in Chapter 2:. Therefore, the experiments conducted with the model are developed in such a way that we can gather data to help us identify:

2. *"What are the effects of energy system regulations and costs on the emissions and operational energy costs of greenhouse horticulturists?"*
3. *"How will the emissions and financial dynamics of greenhouse operations evolve when sustainable thermal generation increases and electricity trade adapts accordingly?"*
4. *"What is the impact of energy price developments on the energy operations within the horticultural sector of the Netherlands until 2030?"*

To address sub-question two, an in-depth analysis will commence by examining the specific impacts of individual energy system regulations and costs in both 2023 and 2030. Subsequently, a comprehensive assessment of the implementation of all energy system regulations and costs for both years will be conducted against base case scenarios. Following this, a comparison between the most accurate scenario for 2023 and the most probable scenario for 2030 will be undertaken. This comparison will involve interpreting findings related to thermal output from generators, electricity trade, and CO2 emissions to gather data essential for addressing sub-question three. Lastly, various energy price scenarios for 2030 will be juxtaposed with prices from 2023 to analyse the implications of market conditions and generate data for sub-question four. Throughout these approaches, comparisons between 2023 scenarios or 2030 scenarios against 2023 scenarios contribute to addressing sub-question one.

When examining the results of individual profiles, the total amounts of energy production, costs or emissions are analysed separately. However, when profiles are grouped to identify overarching patterns, the results are aggregated per hectare of greenhouse area for each profile, ensuring comparability. The sequencing of cases analysed next to each other depends on what is deemed relevant to observe the effects of certain changes in the model's conditions.

5.1 ENERGY SYSTEM REGULATIONS AND COSTS

This section delves into an analysis of energy system regulations and costs affecting energy operations within horticulture, focusing on energy tax, electricity tax, gas tax, DSO costs, and CO2 tax. Through detailed examinations of scenarios spanning 2023 and 2030, the effects of these distortions on energy production costs and CO2 emissions are explored. By dissecting various scenarios and comparing them against base cases, we gain insights into how these distortions shape the operational landscape for horticulturists, highlighting shifts in costs, energy consumption patterns and environmental impacts.

5.1.1 Energy tax

Upon the implementation of energy taxes, which involves the introduction of both electricity tax and gas tax to the experimental scenarios, the effects of the energy taxes on the costs of energy production for horticulturists are examined. This includes analysing the electricity costs and fuel costs for each profile individually to demonstrate the effects of the energy taxes. Subsequently, the focus shifts to examining the effects of the energy taxes on the total CO2 emissions connected to the generation of energy for greenhouses. To illustrate the existing patterns of costs and emissions and how they are affected by the introduction of energy taxes, the profiles have been grouped in several figures. The analysis concentrates on BC2023, ET2023, BC2030 and ET2030, allowing for an exploration of how patterns change due to energy tax in both 2023 and 2030 and how the two years compare to each other. Refer to Table 4-6 for a summary of the conditions associated with these scenarios.

Electricity tax

The bar charts in Figure 5-1 display the total costs of electricity for the described scenarios of all profiles. The total cost of electricity per year contains the costs of electricity purchased from the grid and the electricity tax that is to be paid over the purchased electricity. DSO costs are not present in these four scenarios. The costs are displayed for each profile individually in a cumulative way, so the stacked bars that show the two cost elements make up the total electricity costs.

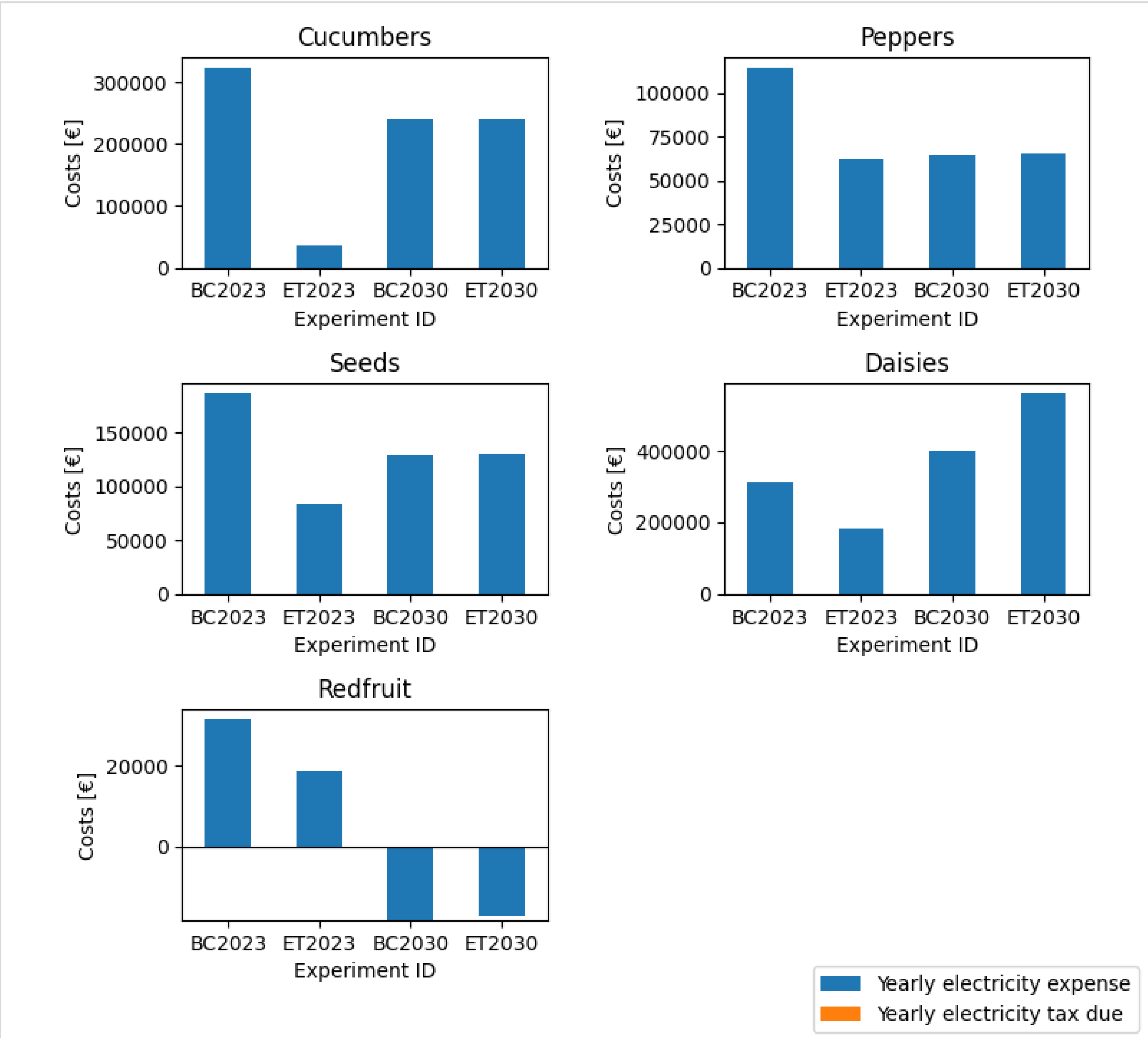


Figure 5-1.Stacked bar charts of the annual electricity costs, divided into electricity expenses and tax expenses.

The profiles show a similar pattern where the introduction of energy tax in 2023 causes a decrease in the yearly electricity costs. In 2030 on the contrary, electricity costs either remain unchanged or increase when an energy tax is implemented. The share of electricity tax is barely visible in Figure 5-1 because the tax expenses for electricity are very small compared to the total costs of electricity. To accentuate the changes in both the costs of electricity and the taxes, Table 5-1 shows the numerical values of the yearly costs for the profiles in the different scenarios. It becomes clear that although the electricity tax rate per kWh decreases from 2023 to 2030, the total paid electricity tax will increase due to a surge in purchased electricity. All profiles exhibit that the total electricity costs decreased after the implementation of the energy tax in 2023 but increased after the implementation of the energy tax in 2030. This phenomenon is discussed further in the Profiles combined sub-section of 5.1.1, as it stems not solely from the introduction of electricity tax but from the alteration of the whole energy tax framework within the horticultural sector.

Table 5-1. Yearly costs of electricity and tax in euros per profile for the relevant scenarios.

Scenario	*Cost item*	*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
BC2023	Electricity	€ 323,850	€ 114,730	€ 185,682	€ 310,543	€ 31,083
	Tax	€ 0	€ 0	€ 0	€ 0	€ 0
ET2023	Electricity	€ 35,339	€ 61,801	€ 83,491	€ 182,632	€ 18,719
	Tax	€ 32	€ 37	€ 47	€ 109	€ 13
BC2030	Electricity	€ 239,632	€ 64,402	€ 129,056	€ 399,872	€ -17,942
	Tax	€ 0	€ 0	€ 0	€ 0	€ 0
ET2030	Electricity	€ 240,741	€ 65,474	€ 130,030	€ 560,140	€ -16,907
	Tax	€ 145	€ 56	€ 72	€ 223	€ 22

Gas tax

Similarly to the electricity tax, the proportion of gas tax concerning total fuel expenditure appears scarcely discernible in Figure 5-2. The introduction of an energy tax leads to only a marginal rise in annual fuel expenses across all profiles. Each profile exhibits a consistent trend, wherein overall fuel expenditures exhibit minimal fluctuation pre-and post-implementation of the energy tax. However, a notable decline in fuel costs is evident between the years 2023 and 2030. This decline is attributable to the integration of RES into the energy mix of horticulturists in 2030.

Although seemingly insignificant in Figure 5-2, the amount of gas taxes due after the implementation of EB taxes in 2030 is higher than in 2023. For example, in the case of the cucumbers profile, in 2023 the gas tax of SC3 only amounts to €163 every year. Whereas in 2030 after the implementation of the gas tax, it is a total of €2,208. This is because in 2023, the natural gas purchased for the consumption of CHP generators is exempt from gas taxes, so only gas taxes are paid over the fuel consumed by the gas boiler. In 2030, this is not the case anymore. The gas tax is then also due over a share of the fuel that is consumed by CHP generators. This explains the difference in gas taxes between the two years. While the difference in gas taxes due increases from 2023 to 2030, the gas tax of the cucumbers profile remains less than 0.5% of the total fuel expenditure. Therefore, as observed in the charts for 2030, the gas taxes do not cause an actual decrease in natural gas consumption. The natural gas and tax annual costs are displayed in Table 5-2 for further reference.

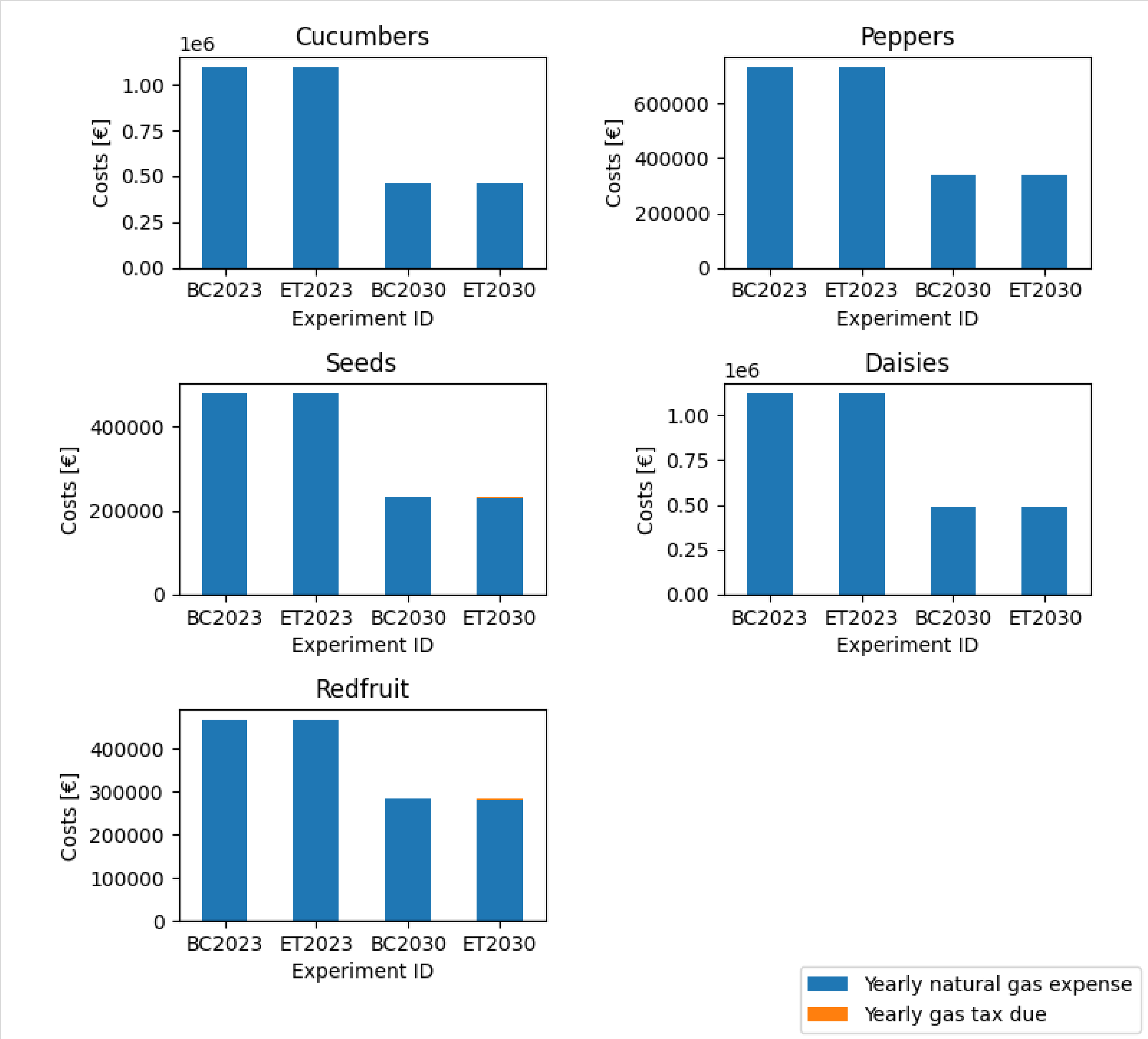


Figure 5-2.Stacked bar charts of the annual fuel costs, divided into gas expenses and tax expenses.

Table 5-2. Yearly costs of natural gas and tax in euros per profile for the relevant scenarios.

Scenario	*Cost item*	*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
BC2023	Natural gas	€ 1,096,005	€ 732,741	€ 479,119	€ 1,120,987	€ 465,766
	Tax	€ 0	€ 0	€ 0	€ 0	€ 0
ET2023	Natural gas	€ 1,096,962	€ 732,997	€ 479,088	€ 1,121,127	€ 465,802
	Tax	€ 163	€ 33	€ 4	€ 48	€ 6
BC2030	Natural gas	€ 463,225	€ 338,153	€ 232,069	€ 488,432	€ 284,467
	Tax	€ 0	€ 0	€ 0	€ 0	€ 0
ET2030	Natural gas	€ 461,399	€ 337,407	€ 230,697	€ 485,050	€ 282,063
	Tax	€ 2208	€ 1581	€ 1063	€ 2376	€ 1440

Profiles combined

In each profile, it is observed that the introduction of energy tax in 2023 significantly decreases electricity costs. In 2023, when the electricity tax is implemented, electricity costs drop significantly because the gas tax is implemented simultaneously. The gas tax in 2023 does not apply to CHP generators, making it more economical to generate electricity with CHP generators instead of buying it from the grid. Figure 5-3 highlights that in 2023, when the energy tax is introduced, the purchased electricity per hectare decreases for each profile because that is electricity that requires an energy tax. Used electricity per hectare, on the other hand, increases for every profile. This is electricity that is used for own consumption from CHP generation, see Figure 5-4.

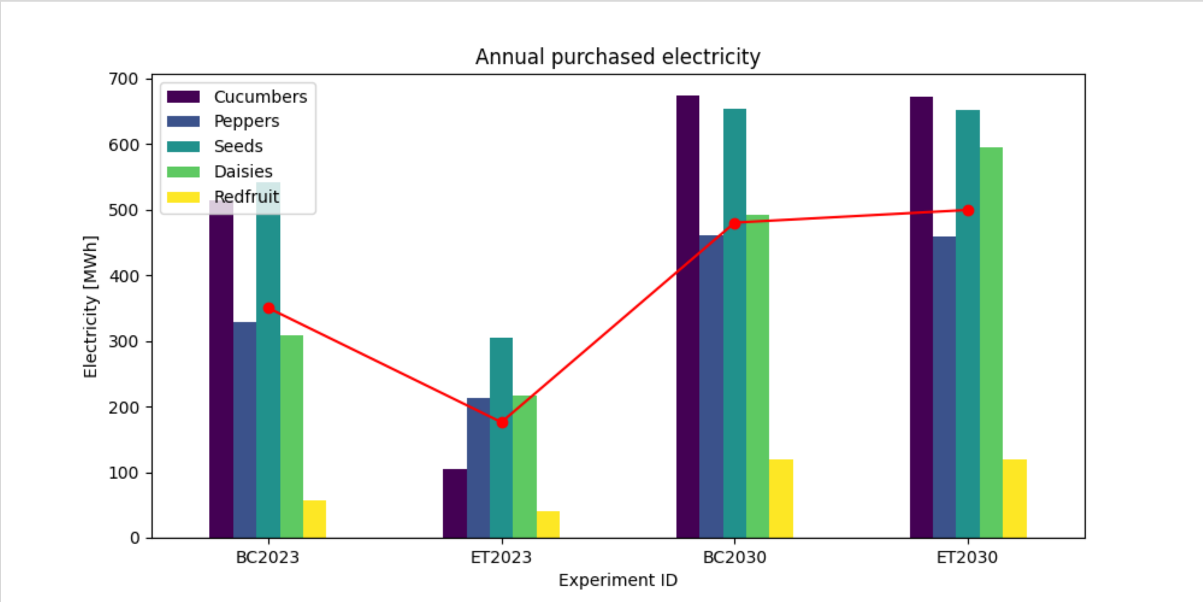


Figure 5-3. Purchased electricity from the EPEX per hectare of greenhouse area.

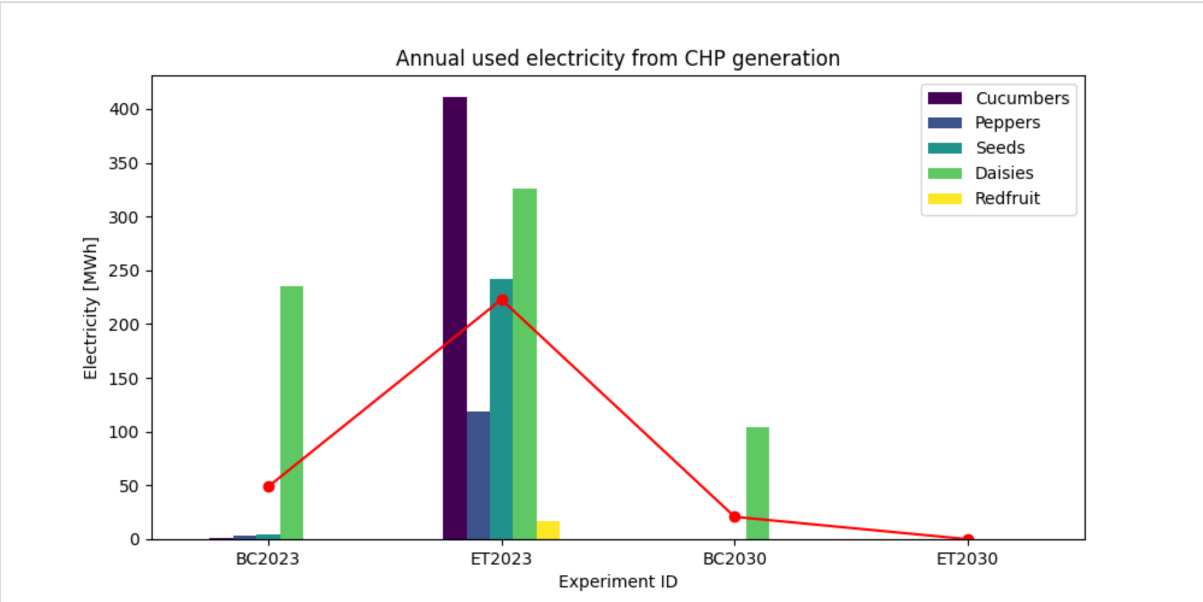


Figure 5-4. CHP generated electricity that is used for own consumption per hectare of greenhouse area.

As noted, observable reversals for the years 2023 and 2030 are demonstrated in Figure 5-3 and Figure 5-4. This is attributable to the removal of the tax exemption for CHPs concerning the gas tax. Initially, in 2023, the imposition of an energy tax prompted horticultural producers to increase their reliance on self-generated electricity, a strategic manoeuvre aimed at circumventing the financial burden imposed by the electricity tax. Conversely, by the year 2030, the energy tax framework induces a different adaptation among horticulturists, who then opt to slightly escalate the sale of self-produced electricity. This strategic pivot is motivated by an imperative to mitigate the financial liabilities associated with the gas tax, which is levied on the fuel consumed by CHP installations in 2030. In 2030, fuel utilised by CHP systems to generate electricity for grid delivery remains exempt from gas tax, whereas in 2023, all fuel consumed by CHP systems enjoyed this exemption. Consequently, in 2030, the proportion of electricity sold to the grid is maximised, leading to a substitution of self-consumed electricity with purchased electricity and an increase in overall electricity expenses.

It is important to note that the reversal in 2030 described above is particularly pronounced for the Daisies profile. The Daisies profile is distinct from the other profiles due to its greenhouses requiring electricity for artificial lighting for almost twice as long as the other profiles, as can be observed in Figure 4-2. Therefore, this energy tax-induced trend is especially relevant for horticulturists growing crops that necessitate artificial lighting for a significant portion of the year.

Figure 5-5 shows the annual costs of each profile per hectare. It can be stated that the implementation of energy taxes does not affect the net costs of greenhouse operations in 2023 or 2030. In 2023, the total costs of natural gas remain similar, and the electricity costs drop, but because more electricity is used for own consumption, less is sold to the grid, and the electricity revenue drops as well, as can be seen in Figure 5-6. In 2030, the total electricity costs increase slightly for the Daisies profile, but the revenue from electricity increases simultaneously, so in both years, the annual net costs are balanced out.

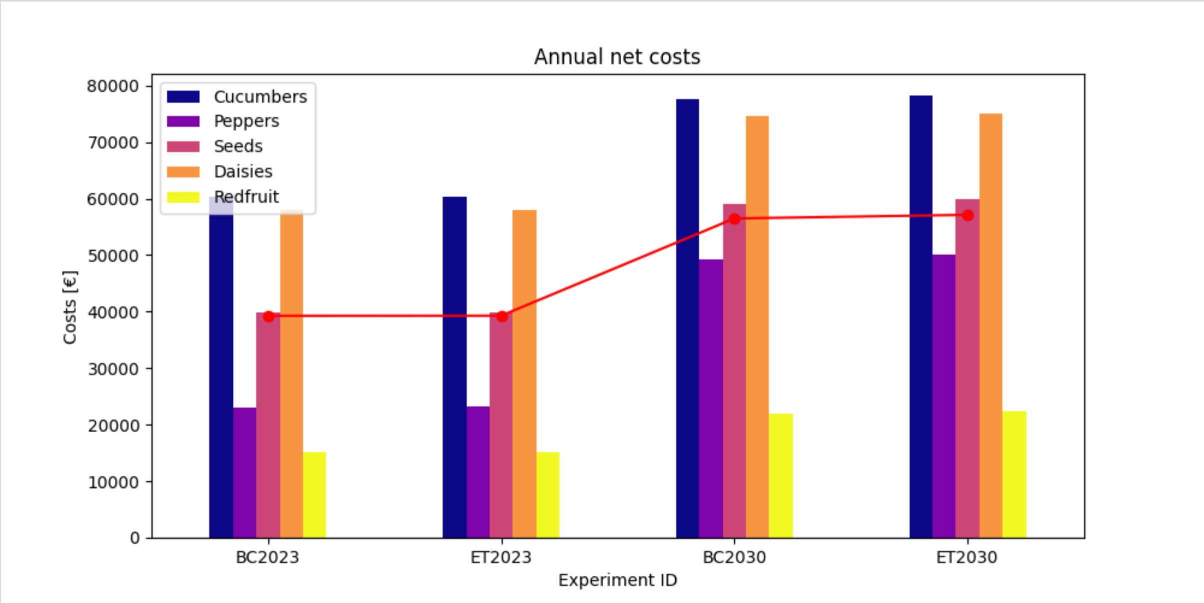


Figure 5-5. Annual net costs per hectare of greenhouse area.

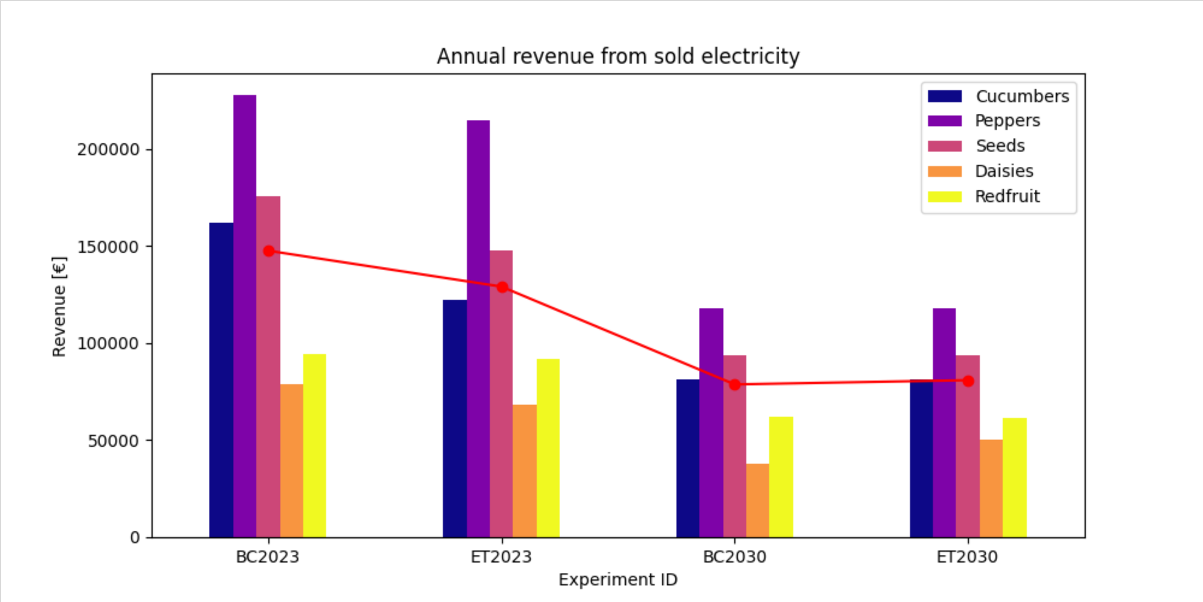


Figure 5-6. Annual revenue from electricity sold on the EPEX per hectare of greenhouse area.

Figure 5-7 shows the effect of the implementation of energy tax in both 2023 and 2030 on the total CO2 emissions. The figure displays the results of the profiles' summed-up CO2 emissions per hectare. In neither 2023 nor 2030 the emitted CO2 emissions change after the energy tax is implemented. There is a significant decrease in CO2 emissions between 2023 and 2030, but this is not attributable to the energy tax as it is caused by the insertion of renewable energy sources into the thermal energy mix of the horticulturists.

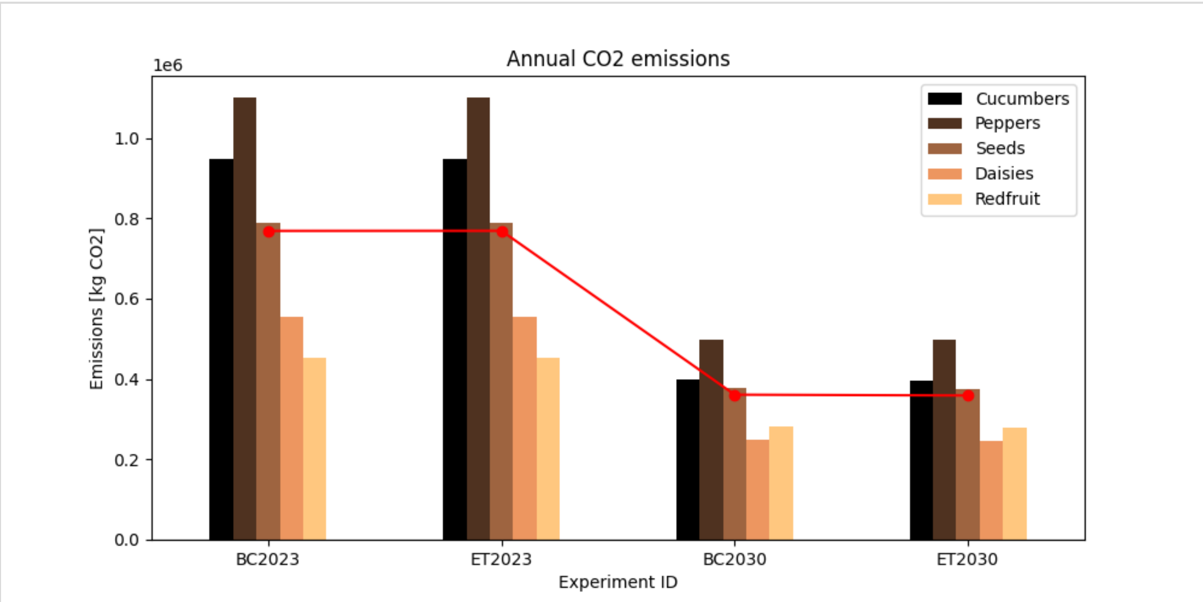


Figure 5-7. Annual CO2 equivalent emissions per hectare of greenhouse area.

5.1.2 DSO costs

The following subsection elaborates on the analysis of BC2023, DSO2023, BC2030 and DSO2030, refer to Table 4-6 for a summary of the scenarios. The comparison of these scenarios will highlight the effects of introducing DSO costs as an energy system cost item to the horticultural energy system.

The bar charts presented in Figure 5-8 depict the total yearly electricity costs for each profile. These costs contain the expenses made by purchasing electricity from the EPEX and the connected network charges that have to be paid to the DSO. The outcomes of the implementation of DSO costs in 2030 partially align with expectations, in that the DSO costs surpass those of 2023, consequently elevating the total electricity expenses. In DSO2030, the network charges are multiplied by a factor of 1.95 compared to 2023, so it is expected that the network charges in 2030 will be significantly higher. However, the extreme surge in DSO costs observed in the bar charts cannot solely be attributed to the rise in network tariffs.

The steep rise in DSO costs among all profiles can be attributed to the structural pricing mechanisms of network charges. Once the stipulated contract capacity is exceeded—even if only momentarily as dictated by the optimisation algorithm—the applicable network charges transition permanently to a higher connection category. This regulatory framework results in a substantial and sustained increase in annual electricity costs, predicated on a single instance of capacity overshoot. This phenomenon underscores the financial ramifications of exceeding contracted network capacities. The operation of this pricing mechanism is illustrated by the plots in Figure 5-9.

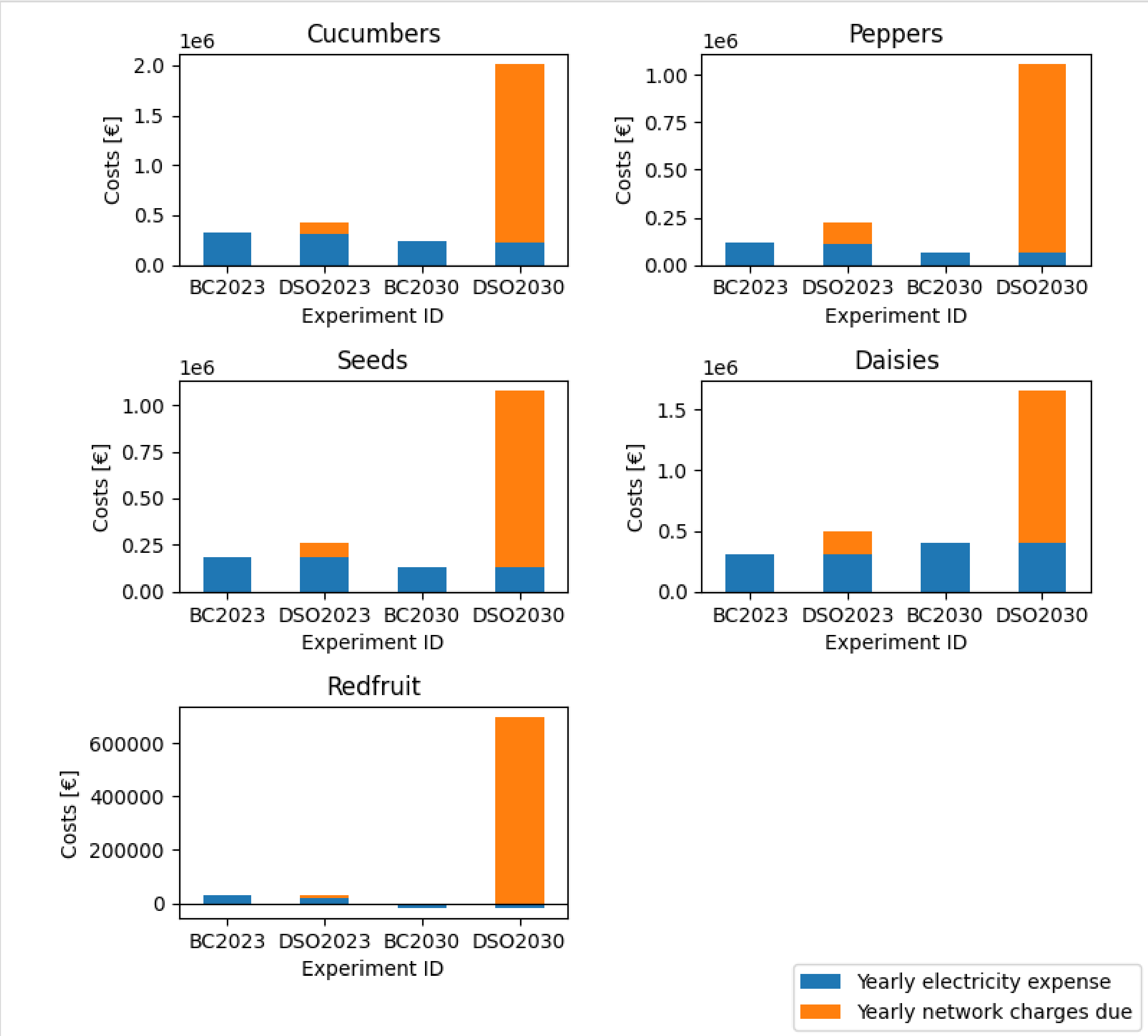


Figure 5-8. Stacked bar charts of the yearly electricity costs, divided into electricity expenses and network charges.

Figure 5-9 illustrates the effects of the DSO cost pricing mechanism when committing thermal generators that run on electricity in 2030. While the Cucumbers profile is used as an example, this phenomenon occurs across all profiles when the DSO costs are implemented in 2030. The DSO contract a horticulturist holds is based on the maximum capacity of electricity purchased from the EPEX and is updated when this capacity is exceeded. The predominant cost items in the DSO contract are (1) the contract capacity in €/kW, paid every month and based on the all-time maximum purchased capacity from the grid, and (2) the monthly maximum purchased capacity in euro/kW, also paid every month and based on the maximum drawn capacity from the grid in the relevant month.

When negative electricity prices occur, the optimisation algorithm uses electric generators to produce heat. Because the capacities of the heat pump and electric boiler are equal to those of the CHP system and gas boiler, respectively, a large amount of electricity can be purchased in a single timestep. For instance, at timestep 662, the electricity price on the EPEX is negative, prompting the electric generators to run at full capacity, resulting in 16.82 MWh being purchased from the grid. Consequently, the cost of purchased electricity for this timestep is €-16.83. However, this significantly exceeds the contracted DSO capacity, increasing the monthly contract costs to €49,518.08 (16.82 MW * 2.944 €/kW * 1000) for the remaining year. Additionally, the monthly maximum purchased capacity costs for the remaining month will be €67,589.49 (16.82 MW * 4.018 €/kW * 1000).

At the beginning of the next month, as shown at timestep 696 in Figure 5-9, the monthly maximum purchased capacity will reset to 0 MWh. However, the monthly contract costs will remain elevated and due to recurring negative electricity prices, the electric capacity for heat generation is frequently utilised, thus increasing the monthly maximum purchased capacity costs again in the subsequent month. Thus, although the increased tariffs in 2030 result in costs that are nearly twice as high as those in 2023, the primary reason for the surge in DSO costs is the available electric capacity for thermal generation in combination with the DSO pricing mechanism.

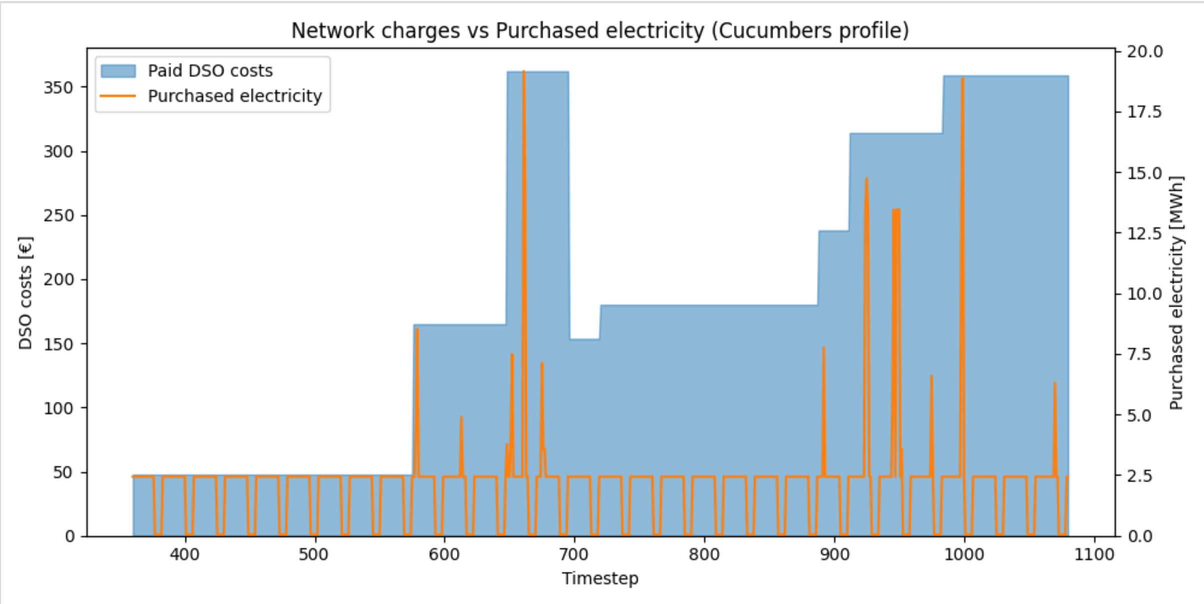


Figure 5-9. Network charges and purchased electricity per timestep for the last two weeks of January and the first two weeks of February in the DSO2030 scenario.

Profiles combined

The inclusion of the DSO costs adds to the net costs of horticulturists significantly. Figure 5-10 illustrates the net yearly costs of the profiles per hectare for different scenarios. In 2023, DSO costs contribute on average €100,635.80 per hectare of greenhouse area to the total costs across all profiles. By contrast, in 2030, the escalation of DSO costs results in an addition of €1,135,918.66 per hectare on average to the overall expenses of horticulturists, constituting nearly 55% of the total expenses of horticulturists. Despite the considerable augmentation in DSO costs impacting electricity expenses significantly, there is no concurrent increase in CO2 emissions as electricity costs rise, see Figure 5-11. This observation suggests that the output of CHP units and gas boilers remains unaffected by fluctuations in electricity expenses.

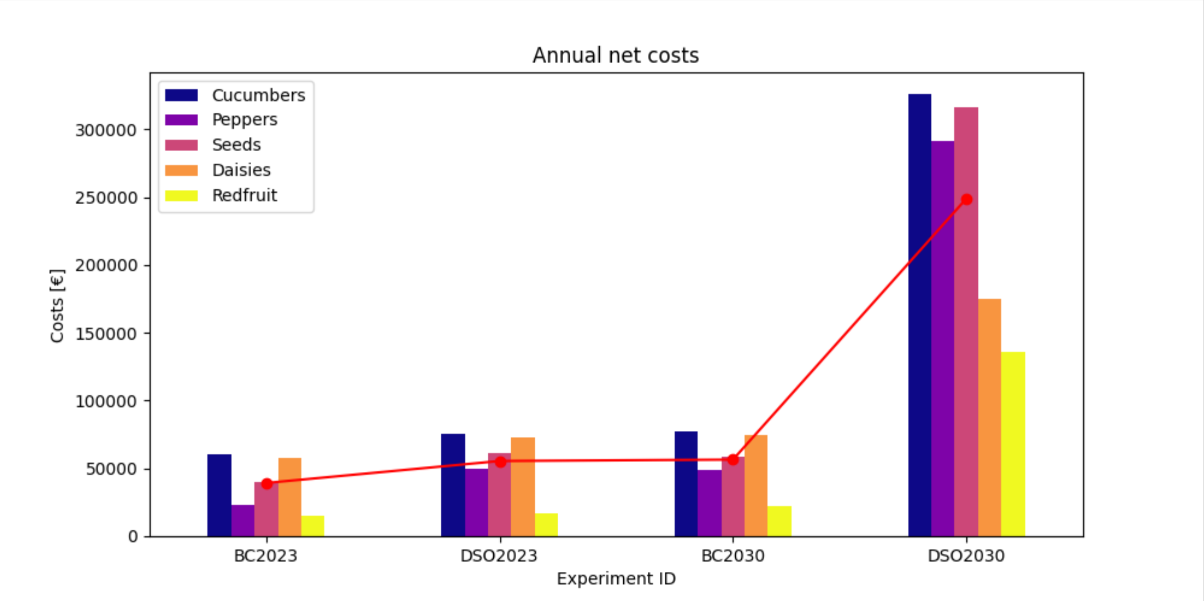


Figure 5-10. Annual costs per hectare of greenhouse area.

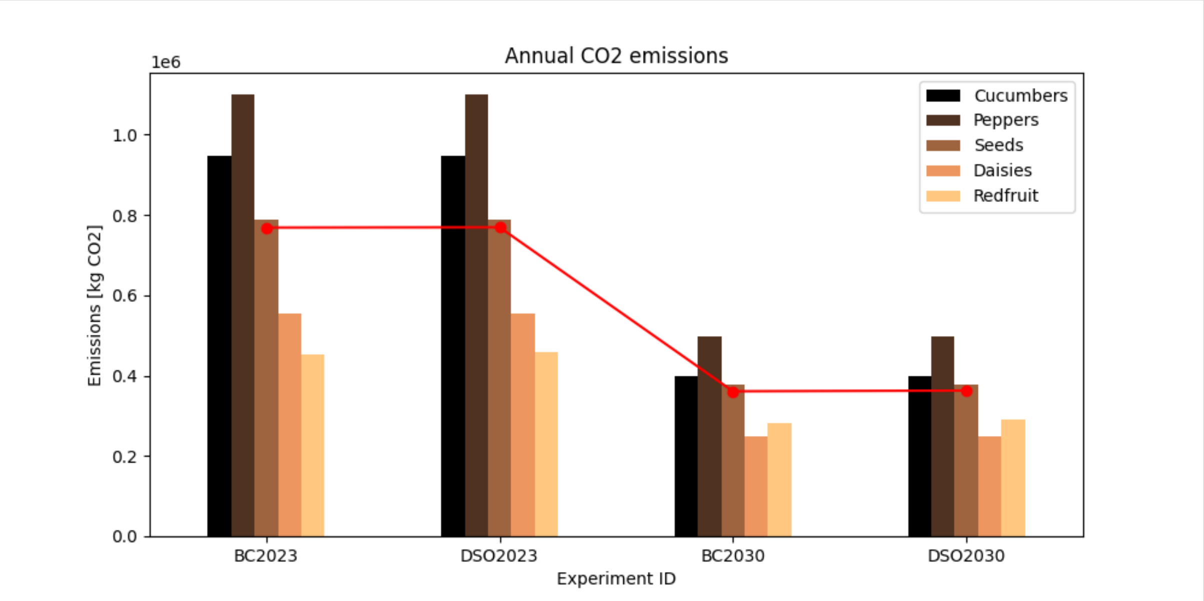


Figure 5-11. Annual CO2 equivalent emissions per hectare of greenhouse area.

5.1.3 CO2 tax

To assess the impact of the introduction of the sectoral CO2 tax on the energy operation costs of horticulturists, comparisons are made between the results of the base case scenarios for 2023 and 2030, alongside CO2T2030, across various graphs and tables. Additionally, it is crucial to examine the effect of the sectoral tax on the emissions of horticulturists cultivating different crops, a matter further elucidated through the aforementioned case analyses.

Profiles combined

When considering all five profiles, the implementation of the sectoral CO2 tax results in a marginal rise in net costs for horticulturists, as depicted in Figure 5-12. Notably, total costs in 2030 show a significant increase compared to 2023. This escalation can be attributed to the introduction of RES for thermal generation and is elaborated upon in section 5.1.4. The upsurge in CO2 costs in 2030 stems primarily from the necessity to procure additional liquid CO2 for injection into greenhouses. However, with the introduction of a sectoral CO2 tax, a further increase in net costs can be observed. Table 5-3 delineates the liquid CO2 costs in 2030 post-CO2 tax implementation, juxtaposed with CO2 tax costs. It reveals that the CO2 tax accounts for 15 to 25% of total CO2 expenses across different profiles, contributing marginally to the annual net expenses per hectare and causing a subtle distortion in emissions.

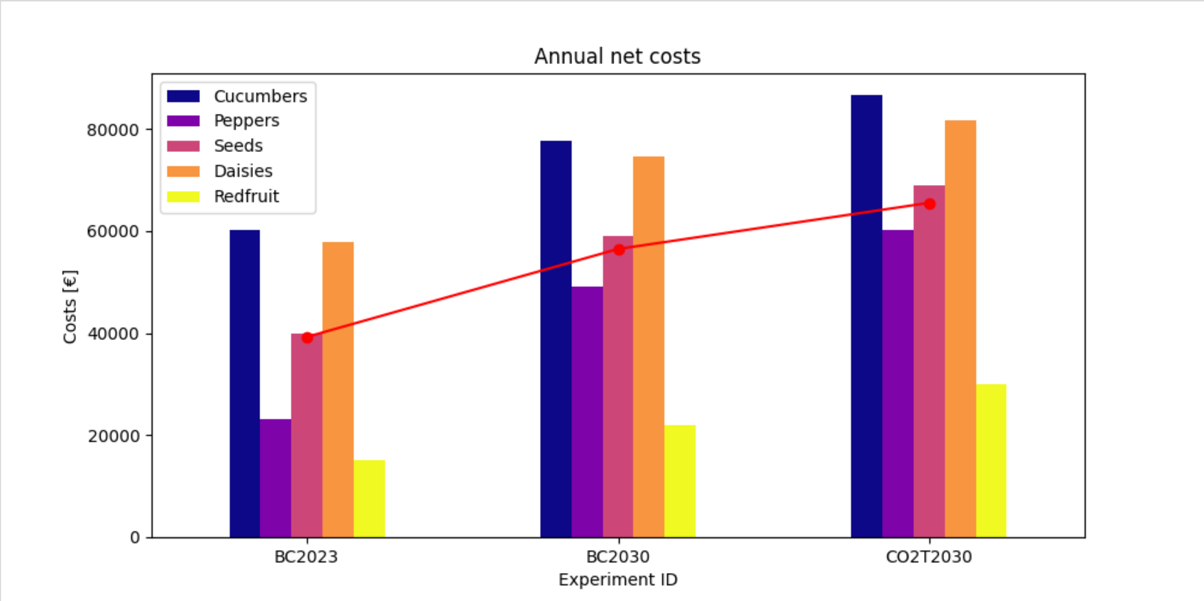


Figure 5-12. Stacked annual costs per hectare of greenhouse area.

From 2023 to 2030, the average expenses for purchased liquid CO2 across all profiles surge from €12,837.70 per hectare of greenhouse area to €19,677.36 per hectare, marking a 53% increase. After the implementation of the CO2 tax, liquid CO2 expenditures show an additional growth of 14%. The imposition of the sectoral CO2 tax significantly inflates total CO2 costs with taxes levied on emissions from conventional generators as well as the additional liquid CO2 expenses. Initially, in the 2023 and 2030 base cases, liquid CO2 costs constitute 100% of total CO2 expenses. Table 5-3 elucidates the altered scenario in 2030 following the implementation of CO2 taxes.

Table 5-3. Annual liquid CO2 costs and CO2 taxes in 2030.

Profile	*Cost item*	*Costs in [€]*	*Share of total CO2 costs*
Cucumbers	Liquid CO2	€134,101.27	75%
	CO2 tax	€45,331.61	25%
Peppers	Liquid CO2	€106,593.40	76%

	CO2 tax	€32,940.71	24%
Seeds	Liquid CO2	€90,333.31	81%
	CO2 tax	€21,243.06	19%
Daisies	Liquid CO2	€252,474.11	85%
	CO2 tax	€45,183.42	15%
Red fruit	Liquid CO2	€140,789.23	85%
	CO2 tax	€25,121.10	15%

Besides its impact on the total costs for horticulturists, the implementation of the CO2 tax in 2030 also results in a small decrease in CO2 emissions, see Figure 5-13. The figure shows the CO2 emissions per ha of greenhouse area of the different profiles. The average annual emissions of all profiles per hectare are 361 tons of CO2 when there is no CO2 tax in 2030. After the implementation of the CO2 tax, this emission dropped to 314 tons of CO2 emitted, meaning a 13% decrease. The reduction in CHP and gas boiler output causes this drop in CO2 emissions. The average amount of fuel consumed by conventional generators across the five profiles drops by 13% as well after the CO2 tax is implemented in 2030 from 1,541 MWh to 1,342 MWh per hectare of greenhouse area.

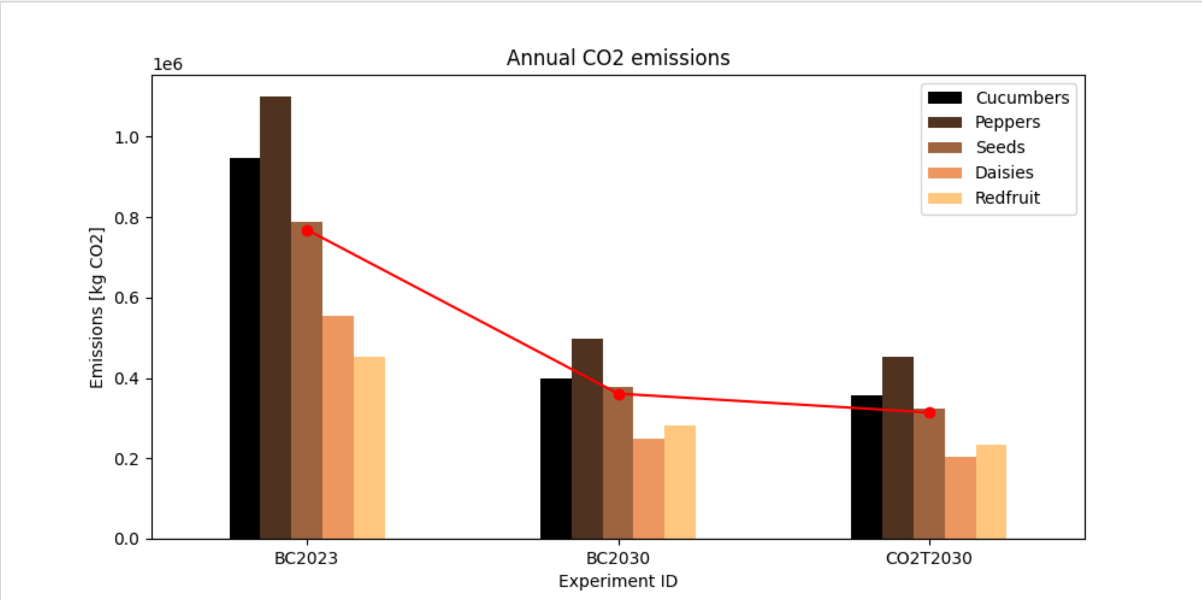


Figure 5-13. Stacked Annual CO2 equivalent emissions per hectare of greenhouse area.

5.1.4 All energy system regulations and costs

In this section, we will compare scenarios BC2023, ARC2023, BC2030, ARC2030 and NORES2030. These cases are analysed to establish the effect of the implementation of all the energy system regulations and costs combined on the total energy costs for horticulturists and the CO2 equivalent emissions caused by them. The summarised details of these scenarios can be found in Table 4-6.

Profiles combined

To illustrate the effects of the energy system regulations and costs, the results are displayed in clustered bar charts. These charts show that there are large differences in the effects of the energy system regulations and costs depending on the profile. These differences can be ascribed to the variation in heat, electricity and CO2 demand per hectare among the profiles. The scenarios have been compared based on the costs or revenue per hectare of all the profiles combined. Based on previous results where the effects of the separate energy system regulations and costs were analysed, it can be stated that the inclusion of DSO costs was the biggest determinant in the overall costs. Therefore, the overall annual costs will be compared to the annual electricity costs and revenue. Figure 5-14 shows the annual net costs per hectare for each profile and scenario. Figure 5-15 below shows the annual electricity costs per hectare without the electricity revenue subtracted from them. The pattern of the average increase in net costs aligns with the average increase in electricity costs. Additionally, when the electricity costs are high in ARC2030, Figure 5-16 shows that the revenue from electricity sales is relatively low, causing a double effect in net costs.

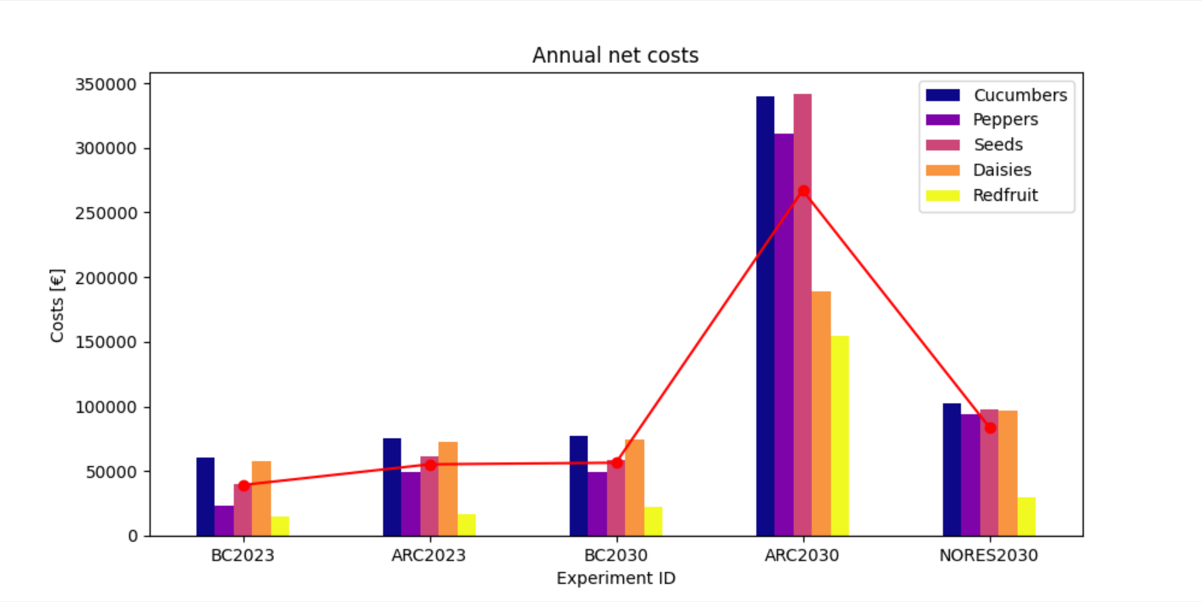


Figure 5-14. Annual net costs per hectare of greenhouse area.

In the absence of any energy system regulations and costs, the minor increase in annual net costs observed in BC2030 relative to BC2023, see Figure 5-14, is attributable to the inclusion of RES thermal generators. When RES generators are added to the energy mix, the costs for geothermal and waste heat contracts are included in the expenses. Additionally, with CHP systems and gas boilers operating less frequently, more liquid CO2 needs to be purchased for the greenhouses. While reduced operation of CHP systems and gas boilers does result in lower fuel costs for natural gas, the primary impact of decreased CHP operation is a significant reduction in the sale of electricity to the grid, causing an increase in net costs throughout the year, despite the reduction in heat demand between 2023 and 2030. The shifts in these cost- and revenue items are visible in Figure D1 of 1)a)Appendix D.

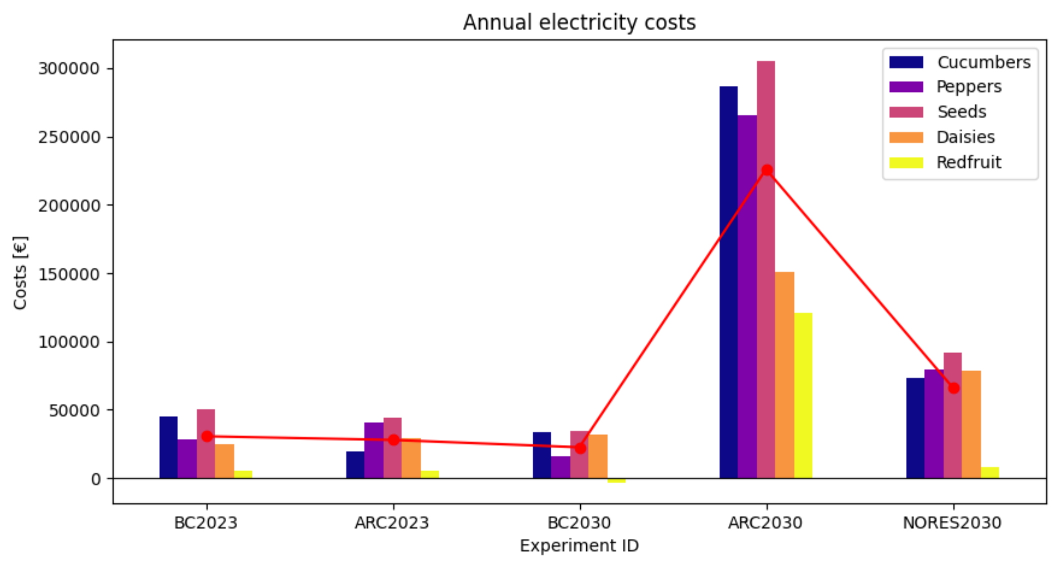


Figure 5-15. Annual electricity costs per hectare of greenhouse area.

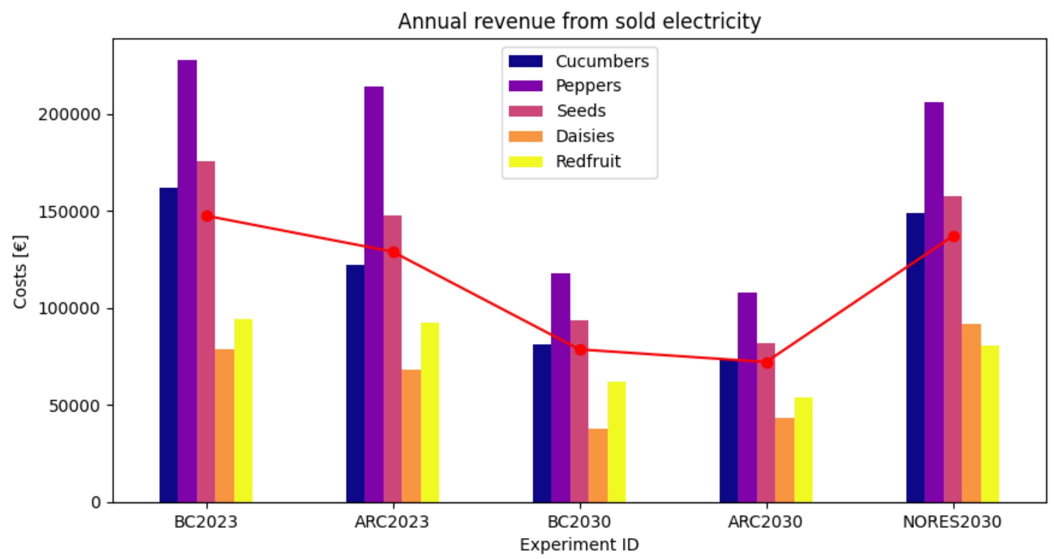


Figure 5-16. Annual electricity revenue from sold electricity on the EPEX per hectare of greenhouse area.

Upon the introduction of all energy system regulations and costs, it becomes apparent that electricity costs, particularly those associated with DSO charges, play a pivotal role in driving the uptrend in overall expenses for 2030. This cost inflation is multifaceted. The integration of RES such as geothermal, waste heat and heat pumps results in diminished CHP operation for heat generation, consequently reducing the electricity output. This decrease in electricity generation curtails the potential for revenue generation through grid sales. Thus, while electricity costs rise due to increased network tariffs and high-capacity DSO contracts, the revenue from CHP-generated electricity diminishes.

To highlight the effect of energy system regulations and costs on net annual costs through increased electricity costs combined with low electricity revenue in 2030, the average net annual costs are compared with the average net annual electricity costs of the five profiles. To determine the net annual electricity costs, the annual electricity revenue is subtracted from the annual electricity costs.

Consequently, the average net electricity costs amount to €-56,097.65 in BC2030, while the overall net costs average €56,486.51. In ARC2030, the average net electricity costs rise to €153,852.86, with overall net costs averaging €267,119.29. Thus, the increase in net electricity costs between BC2030 and ARC2030 is €209,950.50, and the rise in overall net costs is €210,632.78. This indicates that, in 2030, the increase in net electricity costs accounts for 99% of the total net cost augmentation, primarily driven by DSO costs. Additionally, there is an average cost increase of €8,393.90 among the profiles, attributable to the introduction of the sectoral CO2 tax in ARC2030 compared to BC2030. However, this cost uptick is largely offset by a reduction in fuel and operational costs for CHP systems.

Figure 5-14 exhibits that the NORES2030 scenario showcases elevated annual net costs across all profiles compared to scenario ARC2023. However, the net costs are much lower compared to ARC2030. There is a noticeable escalation in both electricity expenses and revenue relative to the 2030 base case. With conventional generators as the sole thermal generation units—absent the costs associated with geothermal or waste heat and the increased electricity demand for heat pumps and electric boilers—the ramifications of gas taxes on CHPs and CO2 taxes on emissions intensify. In this scenario, the strategic optimisation of CHP operations aims to mitigate the heightened costs associated with conventional thermal generation through increased electricity revenue.

Finally, the effects of the energy system regulations and costs in the different scenarios are displayed in terms of CO2 emissions in Figure 5-17. In neither 2023 nor 2030, an observable change in CO2 emissions is caused by the implementation of energy system regulations and costs. This is in line with the previous results that show the effects of the separate energy system regulations and costs. Comparative analysis of ARC2030 and BC2030 reveals an inconsequential variation in emissions, underscoring the predominant strategy to minimise electricity use due to elevated DSO charges, thereby indicating the higher operational costs of electric thermal generators vis-à-vis conventional thermal generators in the context of the future gas and CO2 taxation frameworks.

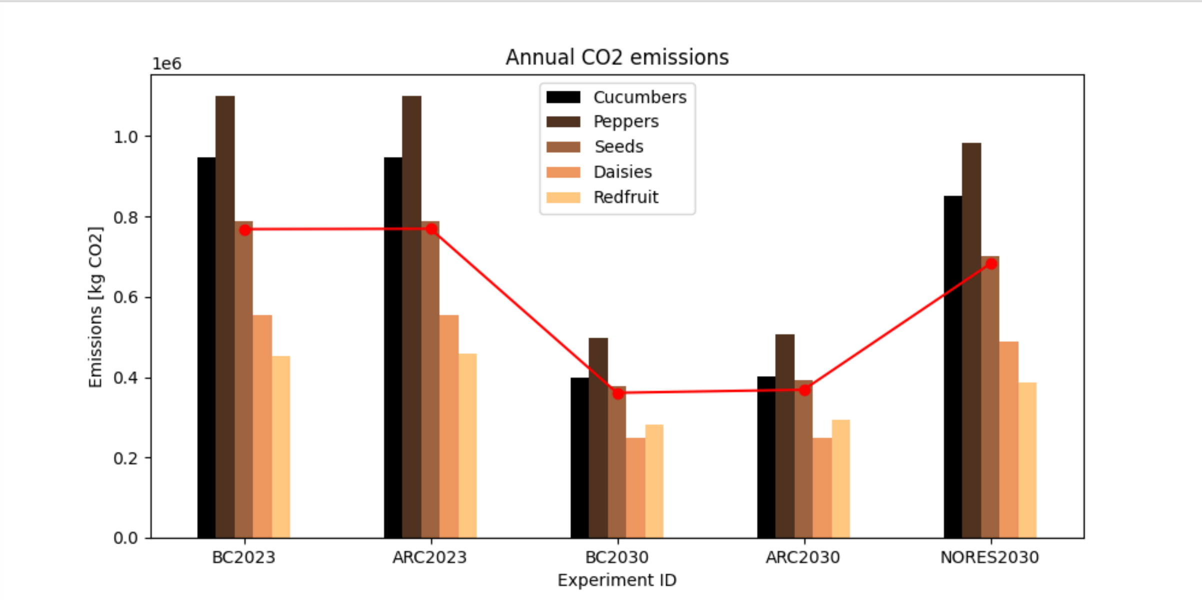


Figure 5-17. Annual CO2 equivalent emissions per hectare of greenhouse area.

The reduction in CO2 emissions observed in 2030 compared to 2023 when energy system regulations and costs are in effect but RES asset availability is non-existent (as displayed in Figure 5-17), is primarily ascribed to the predicted decrease in heat demand over the intervening years.

5.2 SUSTAINABLE THERMAL GENERATION

The figures in this section all show results per hectare of greenhouse area so the results can be aggregated to show the accumulated comparison of the scenarios. To demonstrate the impacts of integrating sustainable thermal energy sources, an analysis and comparison of scenarios ARC2023 and ARC2030 have been conducted. Both scenarios operate under neutral pricing conditions and encompass the implementation of all energy system regulations and costs. The sole disparity between the two lies in the availability of RES assets in 2030, contrasting with their absence in 2023. Furthermore, to explore the financial and emission impact of different energy mixes in 2030, scenarios NORES2030 and HGW2030 are compared with ARC2023 and ARC2030. This will show what happens when no renewable assets are available for thermal generation in 2030 and when the availability of geothermal and waste heat is halved.

5.2.1 Load duration curves

ARC2023

In 2023, the annual thermal output of the CHP systems of the five profiles summed up is 7763 MWh per hectare of greenhouse area and the thermal output of gas boilers amounted to 502 MWh per hectare. The thermal outputs of the CHP and gas boiler of the separate profiles are displayed in MWh per hectare in Table 5-4. The maximum output of all CHPs combined in a single timestep is 2.14 MW per hectare which is the sum of the maximum capacities of the CHPs from all profiles. The maximum combined gas boiler thermal output in a single timestep in 2023 is 2.65 MW per hectare. The number of operational hours of the CHP generators in 2023 ranges from 2681 hours (red fruit) to 5176 hours (cucumbers). Figure 5-18 shows a load duration curve for 2023 to visualise the thermal output in descending order. The CHP generators provide both the baseload and the load following capacity of thermal energy while the gas boilers provide the peak load capacity.

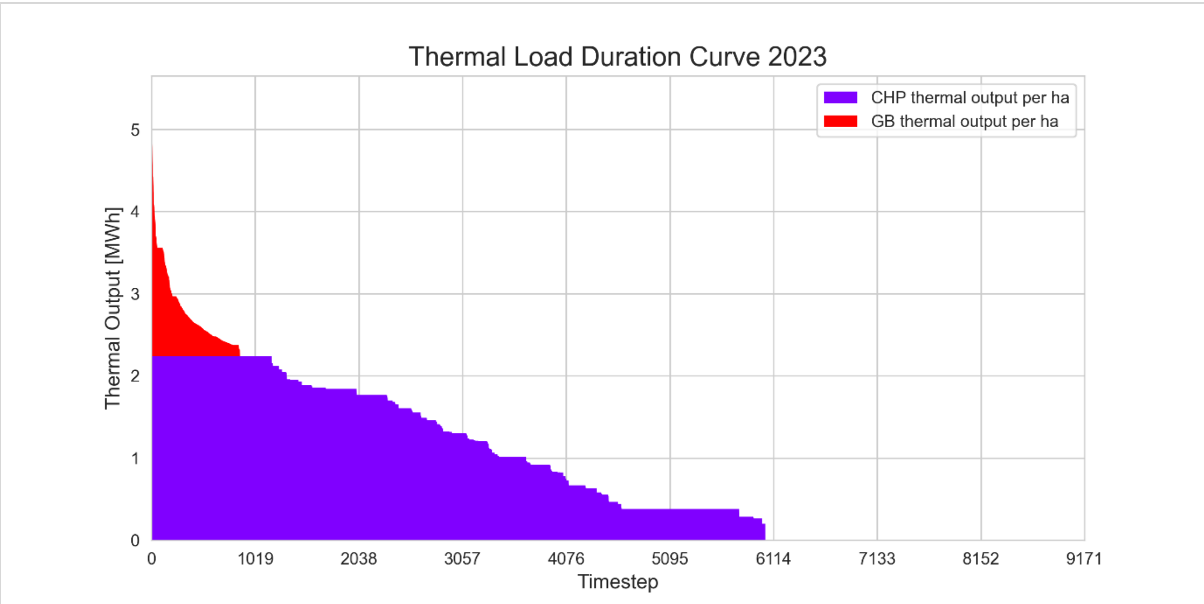


Figure 5-18. Load duration curve of 2023, output per hectare of all profiles accumulated.

Table 5-4. Annual operational hours and thermal output per hectare for each thermal source in 2023.

Method		*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
CHP	Operational [hrs]	5176	3590	3189	4066	2681
	Thermal output [MWh]	**1931.68**	**2128.07**	**1589.84**	**1136.22**	**976.70**
GB	Operational [hrs]	648	225	35	228	28
	Thermal output [MWh]	**328.16**	**99.92**	**13.10**	**48.26**	**12.16**

ARC2030

In 2030, the mix of sources providing thermal energy is more varied. Alongside thermal energy from CHPs and gas boilers, there is now a baseload of geothermal and waste heat. Additionally, heat pumps and electric boilers can be switched on and off, akin to conventional thermal generators, to offer sustainable flexibility in heat supply. Heat pumps, especially, can cater to peak demand due to their high COP. In 2030, the CHP capacity provides the load-following capacity of thermal output instead.

Because the capacities of the CHPs and gas boilers remain unchanged, the maximum output of all CHPs combined remains at 1.57 MW per hectare in 2030. However, the maximum output of the gas boilers decreases to 0.50 MW per hectare. The total and maximum thermal output, along with the duration that a generator was switched on, are displayed per profile in Table 5-5 for each generator in MWh per hectare or hours. The load duration curve visualizing the aggregated cumulative thermal output of the generators in descending order is displayed in Figure 5-19.

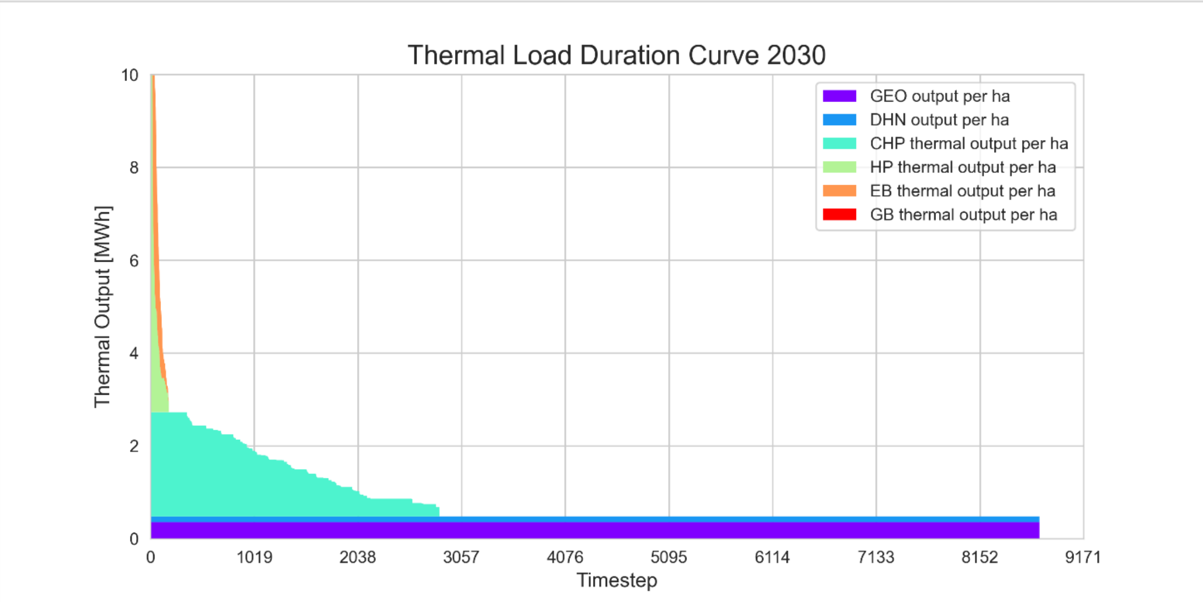


Figure 5-19. Load duration curve of 2030, output per hectare of all profiles accumulated.

In 2030, a cumulated baseload of 3131 MWh thermal energy per hectare is provided by geothermal heat for the profiles together. Additionally, a baseload of 1094 MWh is provided by waste heat. The thermal output from CHPs decreases by 58% to 3255 MWh per hectare, and the output of gas boilers decreases by 98% to 7 MWh per hectare. Furthermore, the heat pumps of the combined profiles generate 481 MWh of heat per hectare in 2030, while electric boilers are responsible for 419 MWh of thermal energy per hectare.

Table 5-5. Annual operational hours and thermal output per hectare for each thermal source in 2030.

Method		*Cucumbers*	*Peppers*	*Seeds*	*Daisies*	*Red fruit*
CHP	Operational [hrs]	2172	1549	1343	1539	1472
	Thermal output [MWh]	**773.25**	**889.64**	**650.49**	**422.44**	**519.50**
GB	Operational [hrs]	8	14	0	2	3
	Thermal output [MWh]	**2.24**	**4.12**	**0.00**	**0.30**	**0.65**
HP	Operational [hrs]	95	95	22	64	38
	Thermal output [MWh]	**142.40**	**138.14**	**61.30**	**73.09**	**65.87**
EB	Operational [hrs]	120	120	78	115	54
	Thermal output [MWh]	**133.64**	**101.21**	**108.39**	**40.28**	**36.21**
GEO	Operational [hrs]	-	-	-	-	-
	Thermal output [MWh]	**926.88**	**779.76**	**587.84**	**491.26**	**345.10**
Waste	Operational [hrs]	-	-	-	-	-
	Thermal output [MWh]	**323.92**	**272.70**	**205.39**	**171.21**	**120.29**

Comparative analysis of Table 5-4 and Table 5-5 demonstrates that with the inclusion of renewable assets, the gas boiler becomes nearly obsolete across all profiles. Only in the Peppers profile, the gas boiler is utilised sporadically throughout the year, whereas in the other four profiles, it is expected to generate (almost) zero MWh per hectare in 2030. Thus, in the realm of demand response at peak load capacity and thermal generation when electricity prices are negative, the gas boiler is replaced by heat pumps and electric boilers in 2030. The superior efficiency of heat pumps over electric boilers becomes evident from Table 5-5 as heat pumps generate more heat in far fewer operational hours.

5.2.2 Chronologic thermal output

For this subsection, area charts have been created to display the summed thermal outputs in MWh per hectare from the available thermal sources of the five profiles per timestep. The output charts provide zoomed-in snapshots of seven days, or 168 hours, to illustrate the daily patterns of thermal load application in comparison to fluctuating electricity prices. For both ARC2023 and ARC2030, the thermal load per timestep is plotted for a cold week (December 1st to December 7th) with standard fluctuations on the EPEX and a warm week (July 1st to July 7th) with reoccurring negative electricity prices.

ARC2023

In 2023, CHP systems provide the majority of the required heat. The CHP systems are optimised to generate heat when the spark spread is high, maximising the revenue from electricity sold on the EPEX. As a result, the commitment of CHP units during the cold week of 2023 closely follows EPEX prices, with blocks of CHP operation aligning with electricity price trends. However, during the warm week of 2023, the blocks of CHP operation are noticeably less dense. This is because heat demand is lower in the summer, reducing the likelihood of CHP operation when no thermal energy is required. Additionally, the EPEX curve in the warm week plot is lower than in the cold week, indicating a less favourable spark spread.

Another interesting observation from Figure 5-20 is that when prices drop to or below zero, gas boilers are committed instead of CHP units. This occurs because generating electricity with CHPs during these hours would require horticulturists to pay to dispose of the excess electricity. Since this warm week occurs in the summer, greenhouses will have no need for electricity for artificial lighting, making it more cost-effective to operate gas boilers and avoid electricity generation.

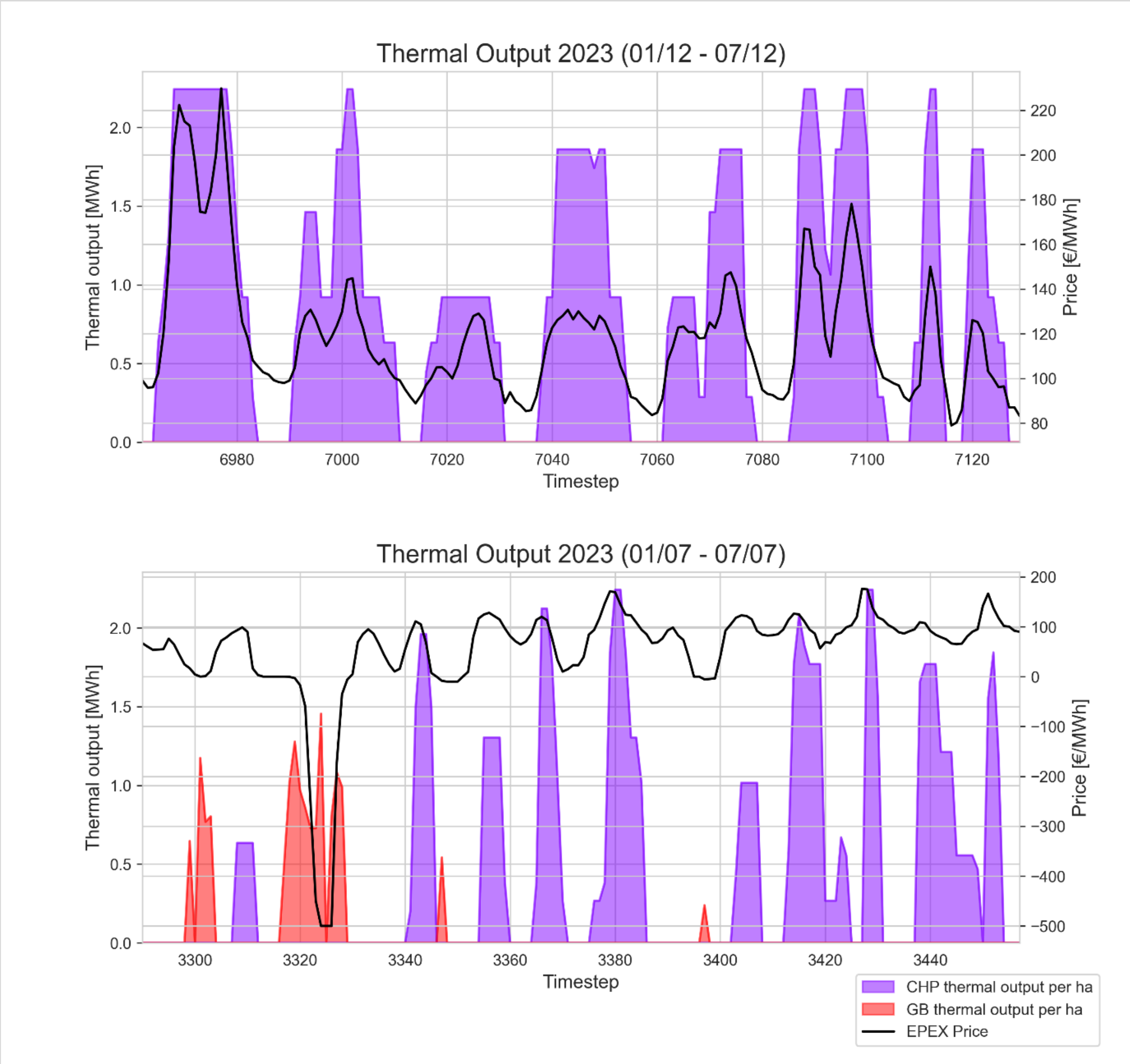


Figure 5-20. Thermal output per hour in the coldest (top) and warmest (bottom) weeks of 2023, output per hectare of all profiles accumulated.

ARC2030

In 2030, the baseload of thermal energy will be provided by geothermal and waste heat sources. This baseload remains constant throughout the year, as these thermal sources are not committable and cannot be turned on and off. During winter, CHP systems provide load-following capacity, similar to their operation in 2023, by responding to EPEX prices. When comparing CHP commitment during the cold weeks of 2023 and 2030, it is evident that the peaks of CHP generation in 2030 are generally lower and do not surpass the EPEX price peaks as frequently as in 2023, as depicted in Figure 5-21. This is because the residual heat demand is smaller after the baseload is provided by geothermal and waste heat sources. Consequently, less heat is required from CHP systems, which are optimised more for electricity generation than heat generation. This optimisation results in the peaks of CHP generation aligning with the EPEX price peaks. Additionally, the commitment blocks of CHP units will be thinner in 2030. CHP generation will be more expensive in 2030 due to CO2 and altered energy taxes, meaning the spark spread must be larger for CHP units to be activated, which explains why the commitment blocks are less dense.

Figure 5-21 shows that during the warm week of 2030, CHP systems are operated much less frequently than in the warm week of 2023. The supply of geothermal and waste heat energy is sufficient for the greenhouses during many periods in summer. Notably, in the warm week of 2030, the heat pump and electric boiler capacities are committed when the EPEX price drops far below zero. Analysing the commitment of the thermal generators that run on electricity reveals that they are used solely when EPEX prices drop to or below zero, capitalising on the opportunity to receive money for generating heat. When prices drop as low as shown in Figure 5-21, the full capacities of heat pumps and electric boilers are committed.

This figure illustrates the accumulated thermal outputs per hectare for the five profiles, considering the generator efficiencies. This explains why the peak of heat pumps is much higher, as they have an efficiency of 300% compared to electric boilers with 100%. Section 4.1.2 explains that the capacities of the heat pumps and electric boilers align with the respective capacities of the CHP systems and gas boilers of the five profiles, as detailed in Table 4-1. Thus, the profiles can respond to negative electricity prices with accumulated electric capacities ranging from 9.24 (Red fruit) to 15.02 MW (Cucumbers).

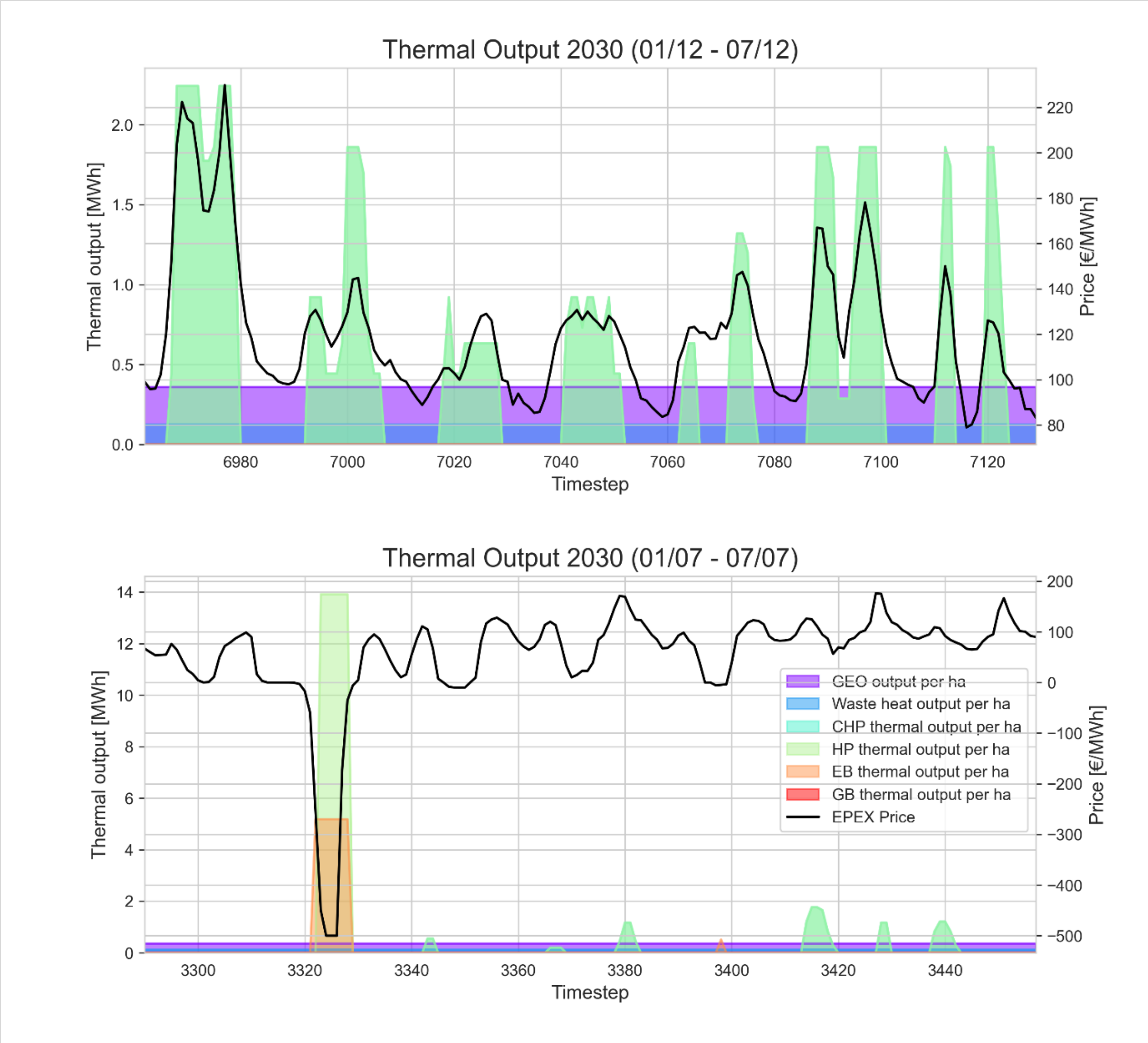


Figure 5-21. Thermal output per hour in the coldest (top) and warmest (bottom) weeks of 2030, output per hectare of all profiles accumulated.

5.2.3 Electricity trading

The following subsection aims to analyse the balance between electricity that is purchased from the grid and sold back to the grid to display the pattern in trading behaviour that horticulturists have in 2023 and 2030. The figures display area charts that show the accumulated electricity sold and purchased of the different profiles in MWh per hectare throughout the same zoomed-in time snaps that were used to show the thermal output per timestep.

ARC2023

In 2023, the total amount of sold electricity per hectare across all profiles amounts to 5,598 MWh, whereas the amount of purchased electricity is only 875 MWh per hectare. The amount of electricity sold throughout the year depends on the spark spread between the EPEX and TTF prices. The graph of the cold week in Figure 5-22 supports this by showing that electricity is only sold during the peaks of the EPEX. When electricity prices are low, no electricity is sold, and more is purchased. During the warmer week, there is less heat required by the greenhouses, leading to less electricity being sold to the grid because the CHPs are operated less. This is illustrated in Figure 5-22 by the decreased density of the sold electricity area during these timesteps. The blocks of sold electricity in 2023 for both the cold and warm weeks align with the blocks of CHP operation shown in Figure 5-20.

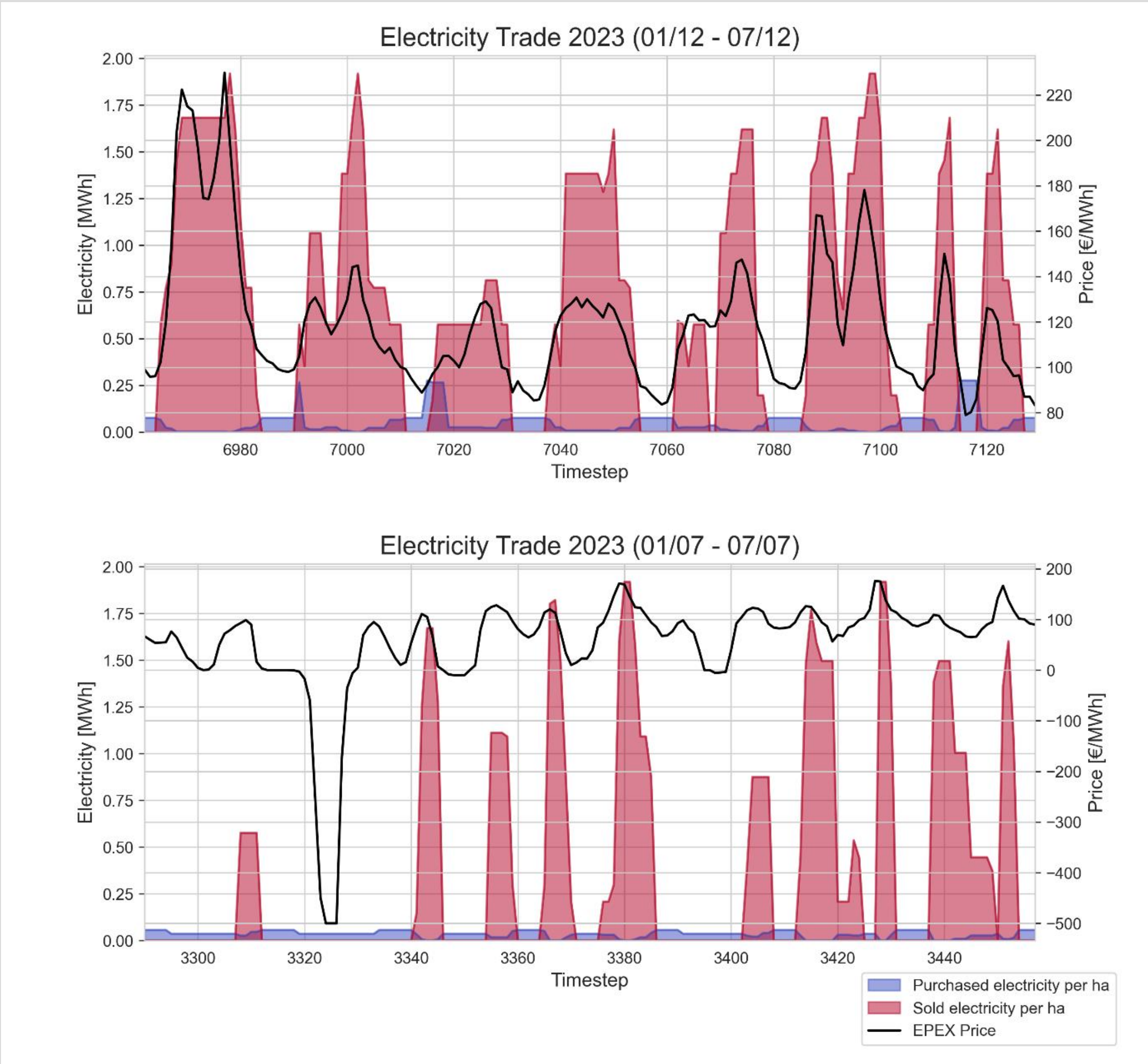


Figure 5-22. Area chart of the sold and purchased electricity per timestep in the coldest (top) and warmest (bottom) weeks of 2023, MWh per hectare for all profiles accumulated.

ARC2030

In 2030, the amount of electricity sold to the grid is 2,802 MWh per hectare for all profiles combined, while the total purchased electricity per hectare is 2,560 MWh. The difference between sold and purchased electricity is more balanced due to the decreased thermal output of the CHPs and the increased electricity demand from electric thermal generators. Figure 5-23 shows that the blocks of sold electricity are thinner and lower in the cold week of 2030, reflecting the reduced electric output from CHP systems. Simultaneously, the blocks of purchased electricity increase due to the new tax regime that imposes a gas tax on electricity generated by CHPs and used for private consumption. The greenhouse electricity demand that was supplied by CHPs in 2023 will be replaced with purchased electricity in 2030. In the warm week of 2030, there are few peaks of electricity being sold to the grid, which coincides with the peaks of thermal output from the CHPs shown in Figure 5-21. As expected, there is a large peak of purchased electricity when the EPEX prices are at their lowest, supplying electricity for the heat pumps and electric boilers.

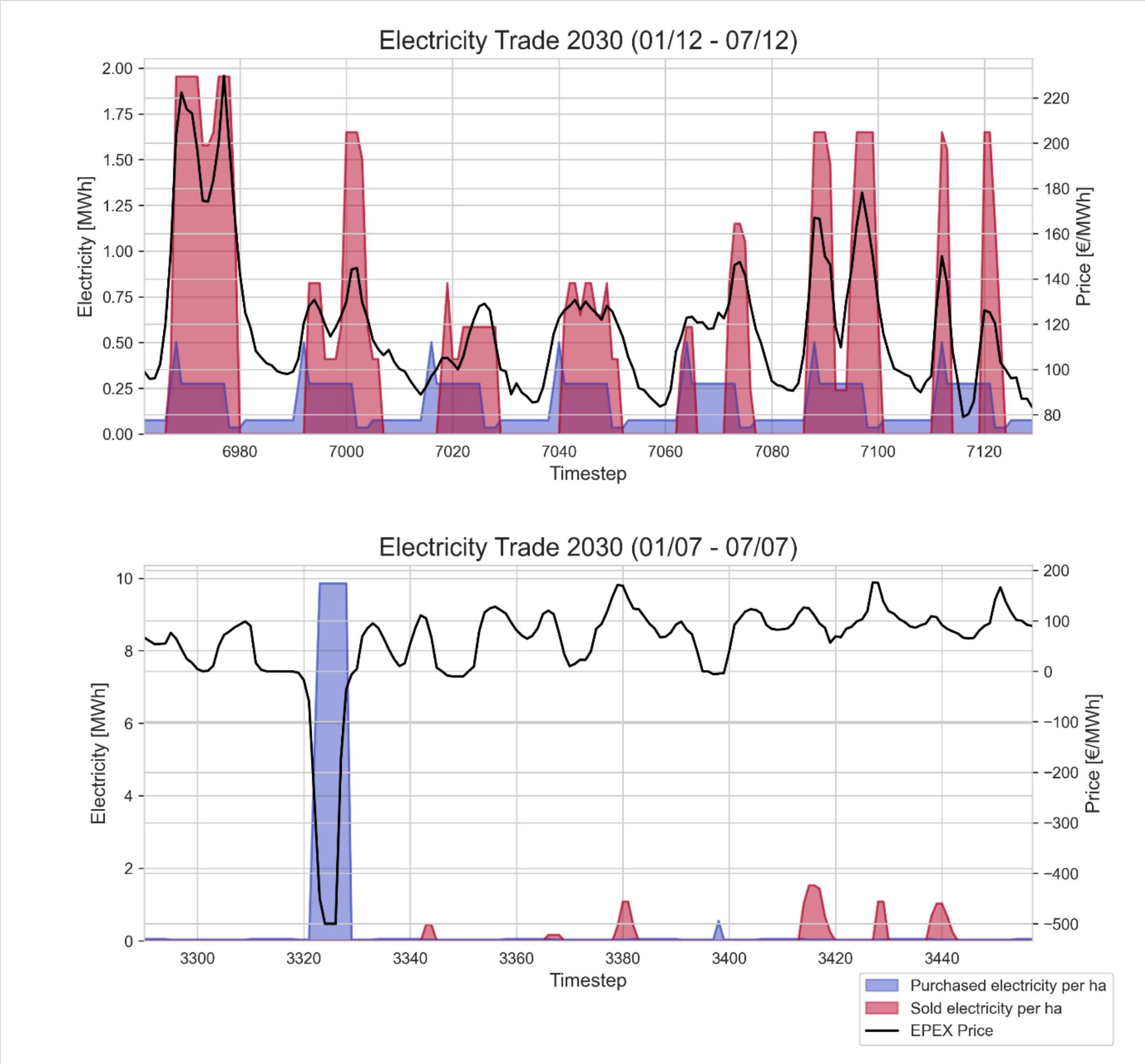


Figure 5-23. Area chart of the sold and purchased electricity per timestep in the coldest (top) and warmest (bottom) weeks of 2030, MWh per hectare for all profiles accumulated.

In 2023, the amount of electricity sold on the EPEX is over six times as great as the amount purchased from it. However, by 2030, this balance shifts closer to a 50/50 ratio. As previously identified, the increase in electricity costs and the decline in revenue from selling electricity contribute to the rising net costs of horticulturists. This trend is mirrored in Figure 5-22 and Figure 5-23. The transition towards RES and reduced utilisation of CHP generators, as becomes apparent in Figure 5-21, resulting in a decreased surplus of electricity available for sale back to the grid. Coupled with the growing adoption of electric thermal energy sources like heat pumps and electric boilers, this necessitates a higher volume of purchased electricity. Consequently, horticulturists transform their role within the energy market, shifting from large-scale electricity suppliers to consumers who procure almost as much electricity as they sell back to the grid.

Frequency duration curve

An FDC is an invaluable tool for understanding the distribution of electricity balance levels over time. When analysing an FDC, the steepness of the curve offers crucial insights into the intricacies of electricity supply and demand dynamics. A steep curve denotes a higher frequency of instances where electricity balance levels are lower, indicating heightened electricity sales periods. Conversely, a flat curve suggests more frequent occurrences of higher electricity balance levels, signifying reduced trading activity. In Figure 5-24, an FDC representing the electricity balance behind the meter of ARC2023 and ARC2030 is depicted. The electricity balance for each timestep is computed by deducting accumulated sold electricity from accumulated purchased electricity for both years, with the values sorted and ranked accordingly. Subsequently, the ranked values are utilised to compute the cumulative frequency of each electricity balance data point.

The illustration reveals that in 2023, approximately 60% of timesteps experienced a negative electricity balance, indicating more electricity sales than purchases during this period. Conversely, in 2030, electricity sales surpass electricity procurement only 30% of the time, showcasing a more balanced buying and selling dynamic. The flattened curve in 2030 corroborates the decline in electricity sales to the grid.

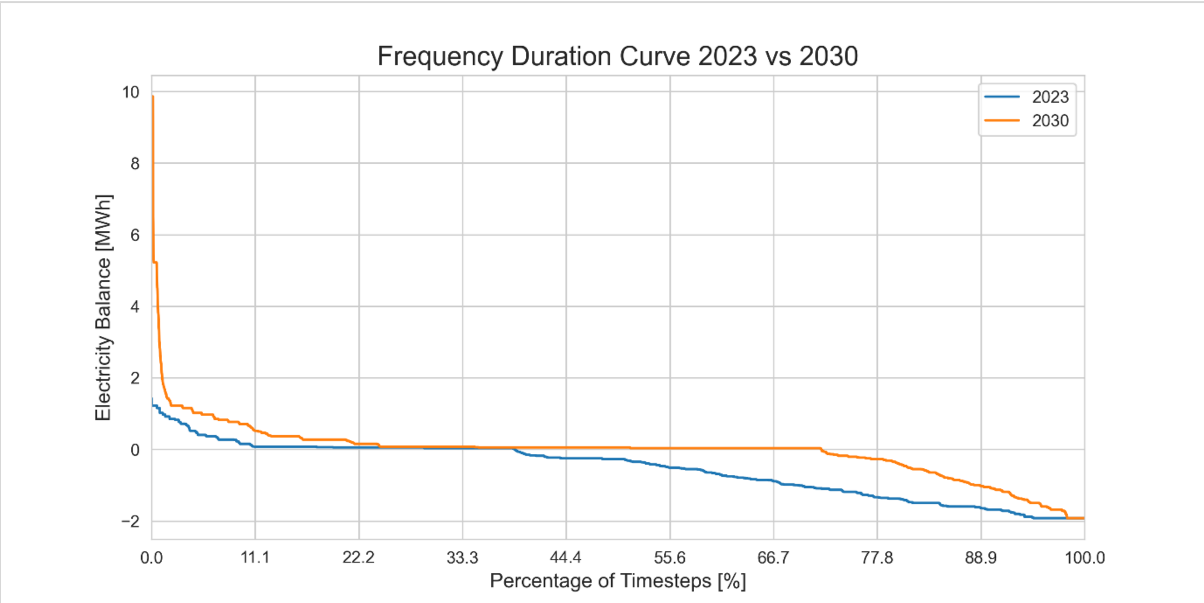


Figure 5-24. Frequency duration curve of the electricity balance behind the meter of ARC2023 and ARC2030.

5.2.4 Energy mix

Figure 5-25 shows that when the energy mix changes according to the current ambitions in ARC2030, over 60% of the generated heat is supplied sustainably. With this surge in sustainable heat generation, the CO2 equivalent emissions of the combined profiles per hectare decreased by 55% according to Figure 5-27. However, this large reduction of emissions comes at an average annual €190,000 per hectare cost increase, see Figure 5-26. This is an average annual net cost increase of 416% per hectare of greenhouse acreage.

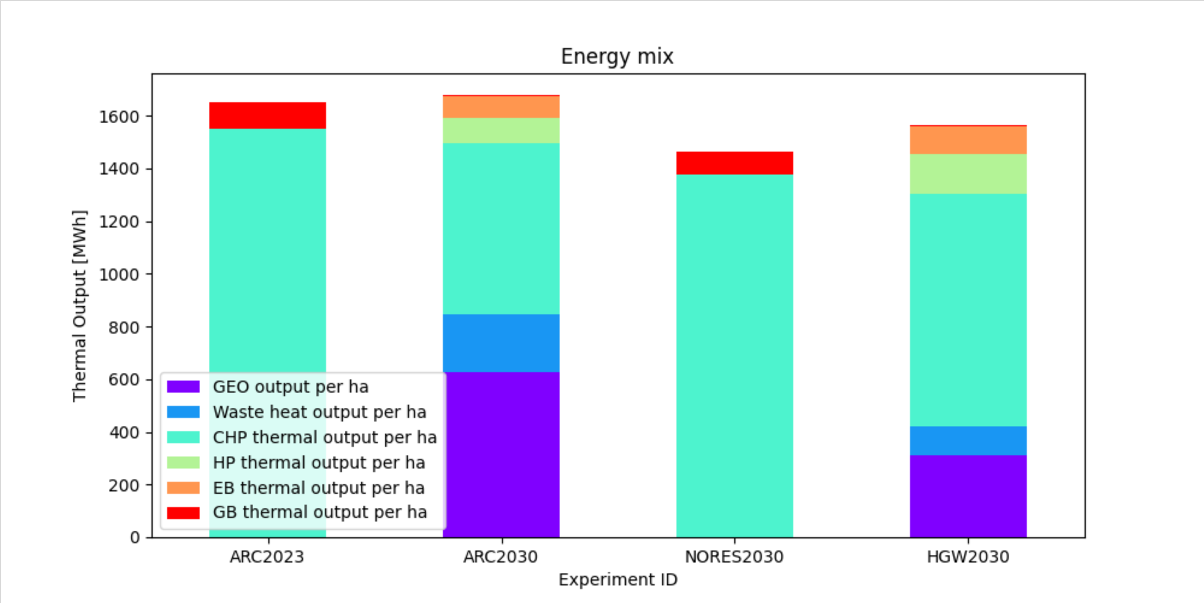


Figure 5-25. Stacked average thermal output per hectare of greenhouse area for each source.

In the NORES2030 scenario, when no renewable assets are available, the net costs only increase by 39% per hectare every year. Though when there is no renewable thermal generation capacity available, the only CO2 emission reductions are attributable to predicted energy savings which results in a decrease of only 11% according to Figure 5-27.

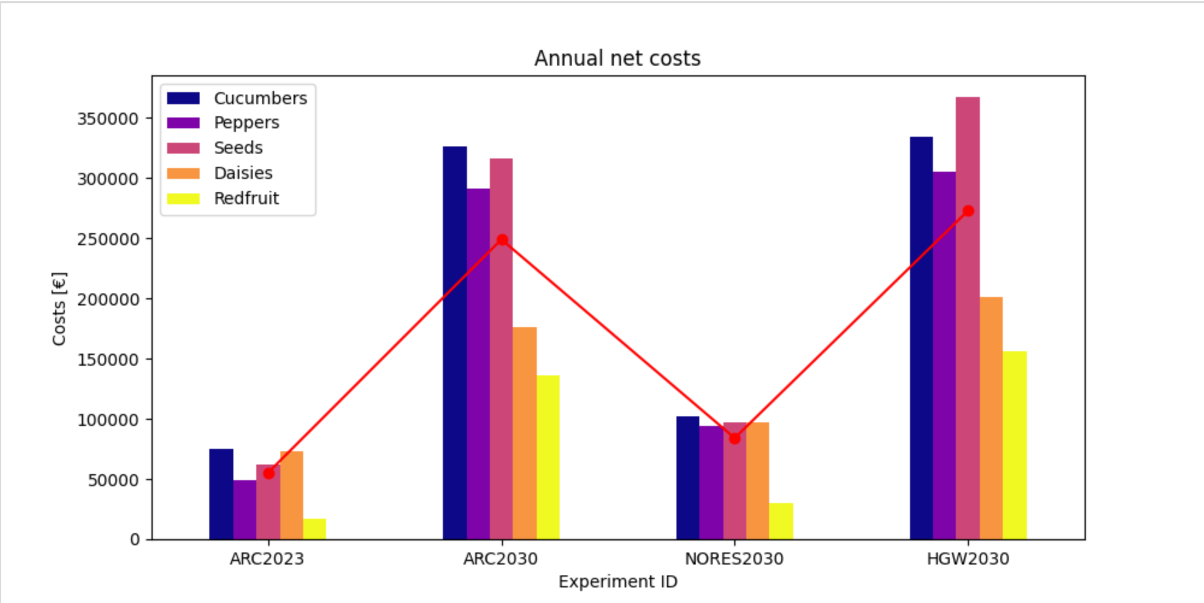


Figure 5-26. Clustered annual costs per hectare of greenhouse area.

The HGW2030 scenario shows a situation where only half of the predicted geothermal and waste heat is available to the horticultural sector. Figure 5-27 exhibits that the total decrease in CO2 emissions compared to 2023 would be 46% in this scenario. However, this is the most expensive scenario with an average upsurge in annual net costs of 430% compared to ARC2023, according to Figure 5-26. Consequently, HGW2030 emerges as the least optimal scenario, characterised by heightened costs without commensurate reductions in CO2 emissions compared to ARC2030, which features greater availability of geothermal and waste heat. This discrepancy arises from the substitution of geothermal and waste heat load with costly electric generation exacerbated by high DSO charges, and increased CHP generation subject to gas and CO2 tax, as can be seen in Figure 5-25.

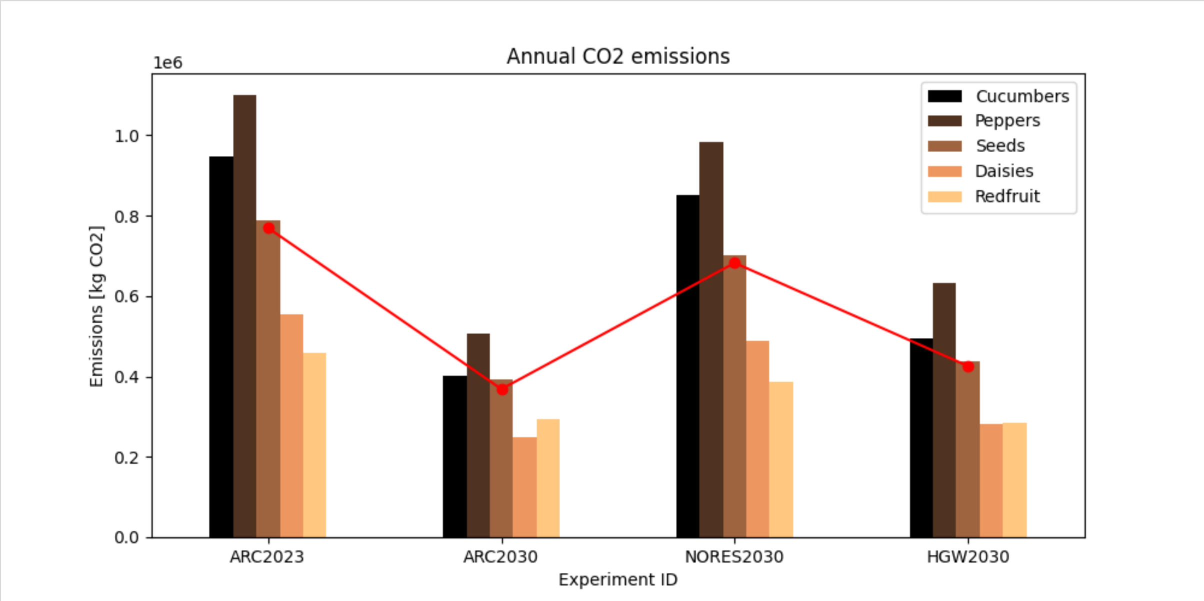


Figure 5-27. Clustered Annual CO2 equivalent emissions per hectare of greenhouse area.

5.2.5 Destroyed heat

On average, across the five profiles, 36 MWh of thermal energy per hectare of greenhouse area was wasted in ARC2023, as depicted in Figure 5-28. However, ARC2030 exhibits a notable increase in the destruction of heat compared to 2023, with 231 MWh per hectare on average when renewable energy sources RES are integrated. This surge is primarily attributed to the persistent availability of geothermal and waste heat sources in the model. Particularly during summer months, when greenhouse heat demand diminishes, an excess of thermal energy from these sources persists as they cannot be turned off. This heat will be destroyed when it is not required by the greenhouses and thermal storage is at capacity. Furthermore, the inclusion of electric generation sources results in elevated thermal generation capacities during periods of negative electricity prices. Consequently, surplus heat, upon reaching storage capacity, is disposed of. To address this, a penalty mechanism is enacted, wherein surplus heat incurs a charge of €50 per MWh, encouraging the preference for purchasing electricity for electric generators over excessive thermal generation. Therefore, when electricity prices fall below -€50 per MWh, it becomes economically advantageous to discard surplus heat when not needed.

In the ARC2023 scenario, the average state of charge per hectare of greenhouse area of the thermal buffers across all profiles and all timesteps of the year is 5.3 MWh. In ARC2030, this average increases to 5.7 MWh. Although this may seem like a minor difference, considering it is across all 8,760 timesteps of the year, it indicates that the thermal storage in 2030 is generally higher. This is because the buffer reaches its maximum capacity for extended periods throughout the year. Figures in 1)a)Appendix E illustrate the patterns of the accumulated storage charge and discharge capacities, as well as the storage state per timestep, for the coldest and warmest weeks of the ARC2023 and ARC2030 scenarios.

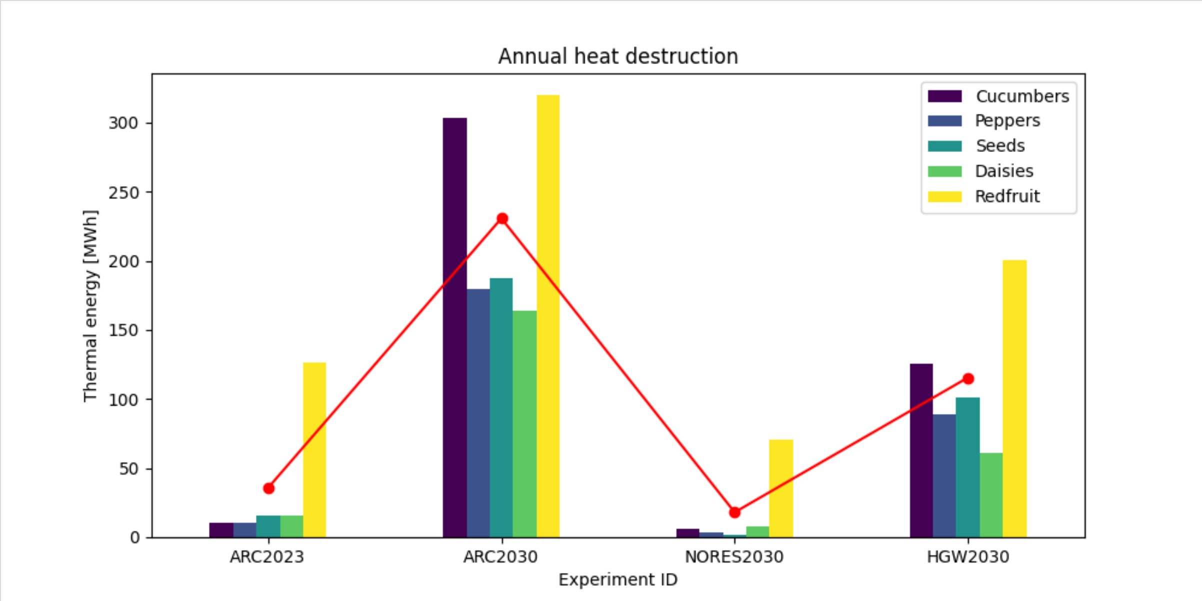


Figure 5-28. Clustered annual destroyed heat in MWh per hectare of greenhouse area.

5.3 MARKET PRICES

To demonstrate the effects of unpredictable future market prices on the energy costs for horticulturists and the total emissions in the sector, scenarios ARC2023 and ARC2030 are compared with LOW2030, MID2030 and HIGH2030. These latter scenarios depict the same conditions but with low, medium, and high projected EPEX and TTF prices in 2030. The results are juxtaposed in clustered bar charts illustrating the costs or emissions of the separate profiles per hectare of greenhouse area. Given the significant variations in costs in 2030 and emissions in 2023, a median line is included to indicate the average costs and emissions per hectare in Figure 5-29 and Figure 5-30.

Figure 5-29 displays the annual costs per hectare for the different profiles. The median line indicates that the annual costs are projected to be the lowest in HIGH2030. The current prices represent the next best scenario cost-wise, with MID2030 being slightly more expensive than ARC2030. Conversely, MID2030 presents the worst-case scenario in terms of costs. The average annual costs per hectare in 2030 range from €160,000 per hectare to €360,000 per hectare.

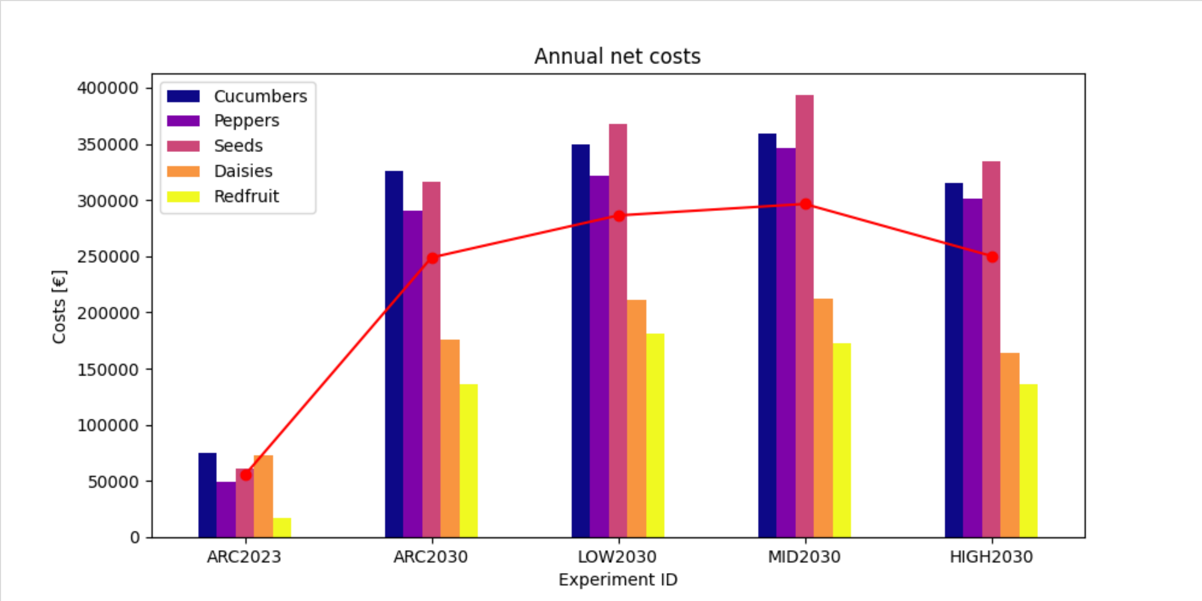


Figure 5-29. Annual net costs per hectare of greenhouse area.

Although the Annual CO2 equivalent emissions per hectare seem to change only slightly in the different price scenarios according to Figure 5-30, there is a correlation between the emissions and the increase in fuel and electricity costs. Table 5-6 shows the average annual prices of ARC2030, LOW2030, MID2030 and HIGH2030. The average annual prices of the low, medium and high scenarios are compared against the primary 2030 scenario to establish how much the prices change. This way the changes in gas and electricity prices can be compared.

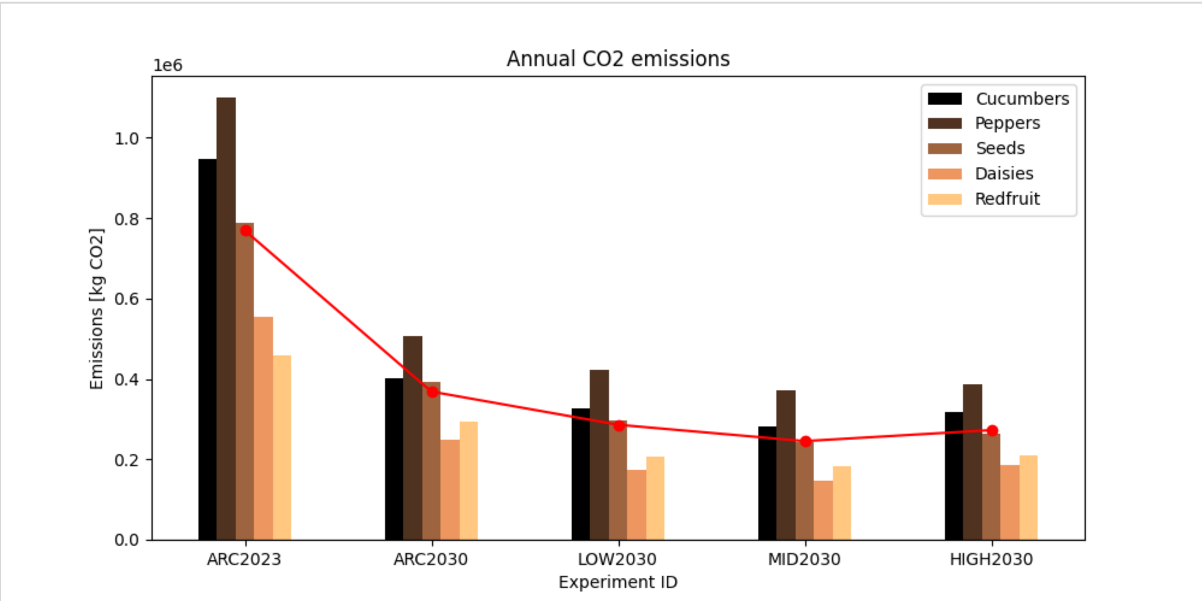


Figure 5-30. Annual CO2 equivalent emissions per hectare of greenhouse area.

When TTF prices decrease more than EPEX prices, the emissions decrease only slightly compared to the main 2030 scenario. Conversely, when EPEX prices decrease more or increase less than TTF prices, the average CO2 emissions per hectare are marginally lower than those in the main 2030 scenario. This phenomenon arises from the inherent dependence of CHP system profitability on the disparity between electricity and gas prices. In the scenario where average electricity prices experience a relatively greater decline or smaller increase compared to average natural gas prices in 2030, there will be fewer instances throughout the year where it becomes advantageous to consume gas instead of electricity to generate heat. With relatively lower electricity prices, the revenue from CHP-generated electricity sales diminishes, making heat pumps associated with high DSO costs more frequently operated as they are triggered by low electricity prices. Consequently, CHP systems will operate less frequently, resulting in a marginal decrease in emissions for the MID2030 scenario compared to ARC2030, accompanied by an increase in costs.

Table 5-6. Percentual change in yearly average prices compared to ARC2030.

	Current	*Low*	*Mid*	*High*
EPEX mean [€]	89	50	73	93
Change		**-44%**	**-18%**	**+4%**
TTF mean [€]	37	20	34	42
Change		**-46%**	**-8%**	**+14%**

5.4 ELECTRIC THERMAL GENERATOR CAPACITY

After conducting the original experiments using the scenarios described in Table 4-6, the results were analysed in the previous subsections. One particularly interesting finding is discussed in Section 5.2, where it is observed that heat pumps and electric boilers are utilised during very few timesteps throughout the year, but at high capacities. Section 5.1.2 identifies this usage pattern as a key reason for the exponentially increased net electricity and overall annual costs for horticulturists when a large capacity of electric generators is available for thermal energy generation, combined with the network charges of 2030. This trend is most evident in the costs associated with scenario ARC2030.

To explore the cost-effectiveness of smaller or no electric capacity for thermal generation, two additional scenarios were designed. These scenarios investigate whether limiting electric capacity can mitigate the high costs identified in ARC2030. The settings for these additional experiments are summarised in Table 5-7. The settings for the two new scenarios are the same as those for ARC2030, with modifications to the electric capacity. In scenario ARCHP2030, all energy system regulations and costs are implemented, but there is no electric boiler capacity available. In scenario ARCOGW2030, all energy system regulations and costs are implemented, but neither heat pumps nor electric boilers are available, relying solely on geothermal and waste heat as renewable energy sources.

Table 5-7. Extra experiment scenario settings.

Scenario	*Heat demand*	*Energy tax*	*DSO costs*	*CO2 tax*	*HP & EB*	*GEO & WH*	*Energy prices*
ARCHP2030	-12%	2030 rates	+95%	17 €/ton	100% HP & 0% EB	100%	Base
ARCOGW2030	-12%	2030 rates	+95%	17 €/ton	0%	100%	Base

Figure 5-31 demonstrates that as more electric capacity for thermal generation is removed from the horticulturists' energy mix, the net annual costs decrease. When less electric capacity is available for heat generation, the electricity loads purchased from the EPEX are more limited. This limitation prevents horticulturists from exceeding their contracted capacities with the DSOs as steeply. When heat pumps are available but electric boilers are not, the annual net costs drop significantly in scenario ARCHP2030. However, because the heat pump capacities match the CHP system capacities, the peaks in purchased electricity can still be high. This means horticulturists are likely to fall into the Trafo HS+TS/MS transportation category (see Table 4-4) with their DSO, which remains costly if the heat pumps are operated at full capacity even once. In line with this observation, the scenario where only geothermal and waste heat are available as RES results in net costs that are closest to the NORES2030 scenario, where no RES are included at all.

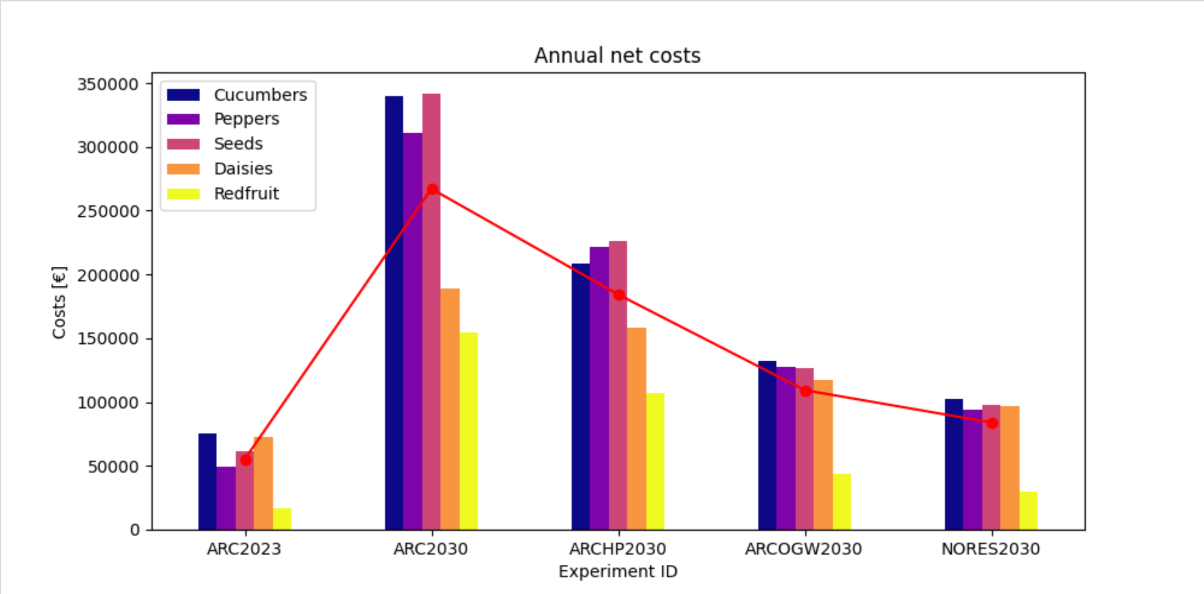


Figure 5-31. Annual net costs per hectare of greenhouse area.

While the net annual costs rise by 51 per cent on average for the five profiles, Figure 5-32 shows that the annual CO2 equivalents diminish by 49 per cent annually in ARCOGW2030 compared to ARC2023.

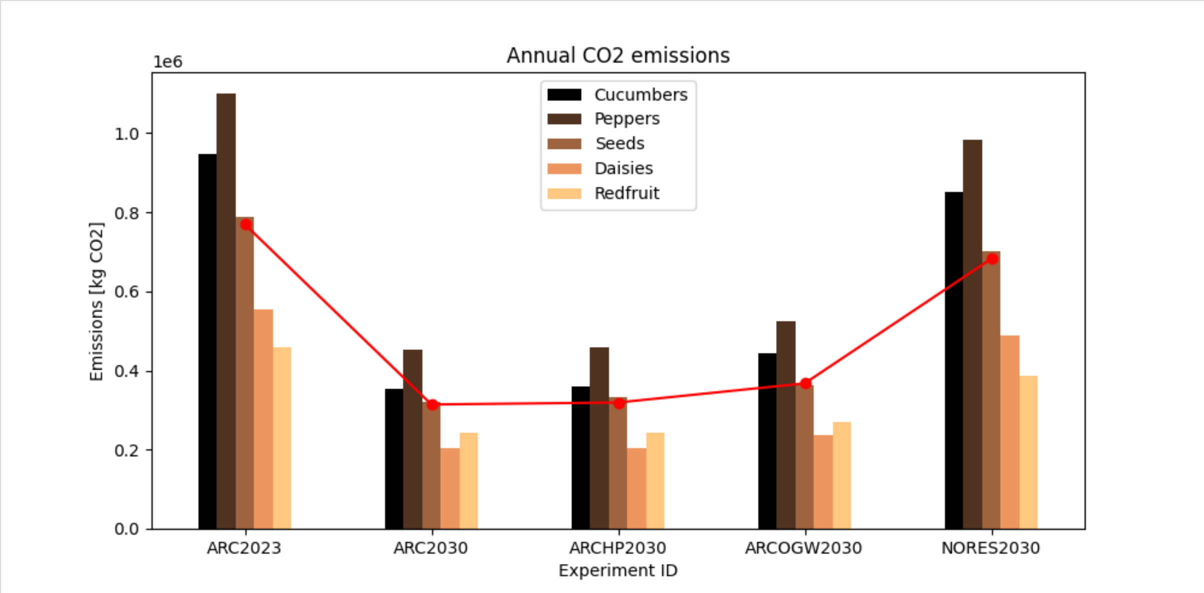


Figure 5-32. Annual CO2 equivalent emissions per hectare of greenhouse area.

Chapter 6: Discussion

In the following chapter, the results from Chapter 5 are discussed. The first sections will elaborate on model behaviour that is displayed by the results in terms of the four sub-questions of this thesis. Thereafter, the model and methodology limitations and implications are discussed.

6.1 RESULTS

6.1.1 Sub-question 1

> *"What are the prevailing trends in energy utilisation, generation sources, CO2 emissions, and trading practices within the greenhouse horticulture sector in the Netherlands?"*

The energy consumption within the horticultural industry is primarily influenced by weather and market conditions, as discussed in section 2.5.1, with the former factor not being considered in this thesis. In 2022, there was a notable decrease in energy consumption compared to 2021, leading to a corresponding decline in CO2 emissions. This reduction can be attributed to the combination of high energy prices and mild weather conditions. The strong causal relationship between energy consumption and CO2 emissions in 2022 stems from the predominant use of conventional thermal generators fuelled by natural gas in the horticultural sector. As delineated in section 2.3.2, approximately 85% of the heat generated for greenhouse cultivation is sourced from a combination of CHP systems and gas boilers. The majority of this heat is generated by CHP systems, with gas boilers providing a minor contribution. The extensive application of CHP systems in the horticultural sector is driven by their financial efficiency, enabled by the cogeneration of heat and electricity. Collaborating with energy aggregators such as AgroEnergy, horticulturists optimise CHP system operation to meet greenhouse heating, electricity, and CO2 demands, while also capitalising on favourable electricity market conditions to minimise overall costs. The current regulatory framework reinforces this behaviour by exempting CHP system gas consumption from taxation and waiving emissions levies for horticulturists.

6.1.2 Sub-question 2

> *"What are the effects of energy system regulations and costs on the emissions and operational energy costs of greenhouse horticulturists?"*

To address the second research question, this subsection begins by examining the independent ramifications of the three identified energy system regulations and costs, both for the years 2023 and 2030. Subsequently, the cumulative effects resulting from the concurrent implementation of all energy system regulations and costs are discussed. This approach facilitates a detailed exploration of each distortion's individual mechanisms before elucidating their collective influence, thereby offering a comprehensive response to the second research question.

Energy tax

The introduction of energy tax has yielded contrasting effects in both 2023 and 2030, as elucidated in section 5.1.1 of the results. In 2023, the implementation of energy tax adheres to the prevailing tax framework within the horticultural sector. Under this system, standard electricity tax rates apply to purchased electricity, while a reduced tax rate is applied to natural gas consumed by gas boilers and no tax is levied on natural gas consumed by CHP systems. As a result, there is a decrease in both the amount of electricity purchased from and sold to the grid, accompanied by a corresponding increase in the utilisation of electricity generated by CHP systems for internal consumption. The reductions in both purchased and sold electricity correspond proportionally with the increased utilisation of electricity generated by CHP systems for internal purposes. The tax structure in 2023 incentivises horticulturists to use self-generated electricity from CHP systems, which is exempt from taxation, over purchased electricity subject to taxation. This shift leads to a decrease in electricity sales and subsequent revenue, offsetting the cost savings derived from reduced electricity expenses. Consequently, while operational electricity costs decrease, overall operational costs remain unchanged following the implementation of energy tax, with emissions from CHP operation remaining constant.

Conversely, the energy tax system in 2030 steers horticulturists away from reliance on electricity generated by their CHP systems. In the future, standard gas tax rates will be applied to the portion of natural gas consumed by CHP systems to generate electricity not sold back to the grid, while electricity tax rates on purchased electricity will be reduced compared to 2023. Consequently, post-implementation of the energy tax in 2030, there is a notable reduction in the consumption of electricity generated by CHP systems, accompanied by a minor increase in purchased electricity from the grid as well as electricity sold to the grid. As a result, while electricity costs rise due to increased grid reliance, electricity revenue expands equally, resulting in no net change in annual costs for horticulturists. Furthermore, emissions from CHP operation remain unaffected by the energy tax implementation, as the CHP output remains constant.

Despite observable shifts in electricity consumption and trading patterns among horticulturists following changes to the energy tax system, the overall impact remains negligible. While the stability of net annual costs is advantageous for horticulturists, the primary objective of altering the sectoral tax system—to discourage CHP system operation and reduce emissions—appears unfulfilled. Notably, the introduction of the revised tax system in 2030 alone, fails to deter horticulturists from CHP operation or reduce emissions across the research profiles. This observation suggests that the revised energy tax as the sole regulatory change in the energy system does not effectively incentivise horticulturists to transition away from CHP operation towards viable electric alternatives.

DSO costs

Upon integrating DSO costs into the model for both 2023 and 2030, an increase in net annual costs is observed, as documented in section 5.1.2. In 2023, this cost escalation is primarily attributed to network charges payable to the DSO for electricity purchased from the grid to meet greenhouse electricity demands, due to the exclusive reliance on thermal generators fuelled by natural gas within the profile configurations for 2023. The cost increase is markedly higher in 2030 compared to 2023 due to two main factors. Firstly, the DSO network charges are 1.95 times higher in 2030. Secondly, there is a heightened demand for electricity in 2030, facilitated by the availability and utilisation of electric generators to provide heat for the greenhouses as needed. Consequently, the surge in electricity costs results in an approximately 416% annual net cost increase for horticulturists when DSO costs are incorporated into the model for 2030.

The DSO pricing mechanism, as illustrated in Figure 5-9 in section 5.1.2, imposes significant financial burdens once the stipulated DSO contract capacity is exceeded, even momentarily. This increase results in a permanent transition to a higher connection category, causing annual electricity costs to rise substantially based on a single instance of capacity overshoot. While the optimisation algorithm effectively reduces direct electricity purchase costs during negative price periods, it inadvertently triggers significant increases in network charges. The reason for this issue is that, although

DSO costs are included in the optimisation algorithm, the capacity limits are not. DSO costs are established based on the monthly and yearly maximum capacities drawn from the grid. When the algorithm ramps up electric generators during periods of low electricity prices in a 96-hour optimisation run, it does not account for how this impacts the contract capacities beyond the optimisation period. Consequently, the overall cost structure becomes heavily burdened by elevated DSO fees, despite decreased expenses for actual electricity. This mechanism underscores the financial risks of exceeding contracted capacities and highlights the importance of precise capacity planning and management.

Despite the substantial rise in electricity costs, the findings indicate no corresponding increase in CO2 emissions with the integration of DSO costs into the model, suggesting a negligible shift from electric sources to conventional sources emitting CO2 between scenarios BC2030 and DSO2030. Specifically, the results reveal only marginal decreases in the thermal output of electric generation units annually, which are deemed insignificant. However, outcomes among the researched profiles underscore a reduction in electricity procurement from the grid following the introduction of DSO costs in both 2023 and 2030. This reduction is compensated by an increase in self-generated electricity consumption from CHP systems to mitigate the financial ramifications of grid electricity purchases. Consequently, although the output of CHP systems remains consistent, the imposition of DSO costs incentivises the utilisation of electricity from CHP systems for select profiles.

Concludingly, the introduction of DSO costs in 2030 appears to have no discernible adverse impact on CO2 emissions in the horticultural sector. However, the inclusion and escalation of DSO costs significantly elevate the financial burden associated with electricity consumption for horticulturists in 2030. This not only poses economic challenges for horticultural companies but also constitutes a market barrier hindering the transition from conventional thermal generators to electric thermal generators.

CO2 tax

Section 5.1.3 of the results delineates the CO2 costs in 2030 post-CO2 tax implementation, revealing that the tax contributes marginally to annual net expenses per hectare and induces a notable distortion in emissions when the tax is implemented on its own. The sectoral CO2 tax inflates total CO2 costs due to taxes levied on emissions from conventional generators. Meanwhile, a 13% decline in CO2 emissions upon the introduction of the CO2 tax is noted in the results. The observed decrease in emissions and increase in costs is indicative of the CO2 tax's efficacy and suggests that the tax rate may be sufficiently punitive to engender an environmental impact when implemented without other energy system regulations. However, the primary driver behind the reduction in CO2 emissions remains to be the incorporation of geothermal and waste heat sources into the energy mix.

Determining the effects of the newly implemented sectoral CO2 tax system presents challenges. Given the absence of a CO2 tax on emissions from the horticultural sector in 2023, no experimentation was undertaken to assess its impacts during that year. The primary objective of the CO2 tax is to incentivise horticulturists to transition away from conventional thermal generation fuelled by natural gas, achieved through levies imposed on CO2 emissions resulting from the combustion of natural gas in CHP systems and gas boilers. Consequently, it can be inferred that in 2023, the introduction of the CO2 tax would have led to increased operational energy costs, while emissions would have remained unchanged, given the lack of sustainable alternatives within the energy mix of the research profiles. A potential minor shift from CHP systems to gas boiler utilisation may have occurred due to the higher emissions associated with CHP systems, attributable to methane slip that causes high CO2 equivalent emissions and is thus subject to taxation.

Assessing the effects of the CO_2 tax on both costs and emissions in 2030 necessitates the availability of sustainable thermal generation sources. The profiles in the CO_2 tax experiments for 2030 incorporate capacities for geothermal, waste heat, heat pumps, and electric boilers, in addition to CHP systems and gas boilers. However, it is crucial to note that geothermal and waste heat capacities are not considered in the model optimisation, as they are determined by fixed contracted capacities and cannot be adjusted through UC. Consequently, the observed effects in the results are linked solely to the trade-off between conventional and electric generators when CO_2 taxes are integrated into the model. To ascertain the impact of the CO_2 tax on the replacement of conventional thermal generation capacity with fixed-contract heat sources, it is necessary to establish optimal contract capacities using a separate model. Alternatively, treating geothermal and waste heat sources as committable units in the current model during CO_2 tax inclusion could provide insights into the desired contract capacities from a financial perspective.

All energy system regulations and costs combined

Upon thorough examination of the comprehensive introduction of energy system regulations and costs, it becomes evident that electricity costs, particularly those attributed to DSO charges, emerge as the primary driver of the upward trajectory in net costs for both 2023 and 2030. Besides the notable escalation in electricity-related expenditures, the financial impact of gas tax on emissions appears non-existent. However, when examining the implementation of all energy system regulations and costs in 2030 when there is no RES available, it becomes apparent that annual net costs increase by 45% compared to the equivalent scenario in 2023. This is visible in Figure 5-14.

Comparative analysis of the implementation of all energy system regulations and costs in 2030 compared to the base case of 2030 reveals minimal variation in emissions, underscoring the prevalent strategy of minimising electricity usage for thermal generation due to elevated DSO charges. This indicates the higher or equal operational costs associated with electric thermal generators compared to conventional thermal generators within the renewed gas and CO_2 taxation frameworks.

With the alteration of the energy tax framework and the introduction of CO_2 tax in the horticultural sector in the Netherlands, policymakers aim to incentivise the utilisation of RES for thermal generation and reduce CO_2 emissions. However, simultaneous significant increases in network charges due to rising network management and infrastructure expansion costs for DSOs counteract the intended effects of energy system regulations. The results highlight that the escalation of DSO costs stimulates the use of self-generated electricity from CHP systems, while the alteration of the tax framework aims to discourage it. Meanwhile, the impact of the CO_2 tax on emissions in 2030 becomes insignificant when considered in combination with the escalated DSO costs. Thus, Dutch horticulturists in 2030 will contend with the burden of both energy system regulations and costs from market parties, which contradict each other.

The results analysis underscores the complexity of achieving emissions reductions through fiscal policy mechanisms. While the CO_2 tax represents a step in the right direction, its current structure and rate may not fully exploit the potential for reducing emissions through the expanded use of environmentally friendly heat sources. Therefore, recalibration of the CO_2 tax, coupled with enhanced mitigation of DSO costs and precise capacity management, may be necessary to realise more substantial and desired environmental gains.

6.1.3 Sub-question 3

"How will the emissions and financial dynamics of greenhouse operations evolve when sustainable thermal generation increases and electricity trade adapts accordingly?"

The experiments conducted reveal a significant shift in thermal output dynamics. In 2023, greenhouse horticulturists rely heavily on heat from CHP systems and gas boilers. However, the introduction of renewable asset capacity results in a remarkable reduction in gas boiler thermal generation, almost to the point of elimination, meaning they will become obsolete. Similarly, the use of CHP systems decreased by 58%, leading to substantial emission reductions that align with the emission goals set for 2030. Geothermal heat and, to a lesser extent, waste heat largely replace traditional thermal generation sources. According to Figure 5-25, in 2030, geothermal and waste heat sources together comprise an average of 50% of the energy mix among horticulturists.

The load duration curves underscore the limited utilisation of electric committable generation units besides the introduction of geothermal and waste heat. When operated, heat pumps and electric boilers operate for a limited number of timesteps, yet exhibit substantial capacities. In the ARC2030 scenario, the continued predominant use of CHP systems over heat pumps and electric boilers, suggests that electric thermal generation remains prohibitively expensive, particularly due to the void revenue from electricity sales. The electric capacity for thermal generation is solely committed when electricity prices drop to or below zero. When only half of the envisioned geothermal and waste heat capacities are implemented, there is a slight uptick in heat pump usage, but CHP usage increases significantly more.

The shifting thermal and electricity generation dynamics, characterised by decreased CHP output, significantly impact the electricity balance of horticulturists. In 2023, horticulturists are net suppliers to the grid, selling six times more electricity than they purchase, by 2030, this balance shifts to near neutrality, with the amount sold matching that purchased. This shift not only creates a gap in electricity supply to the national grid, as anticipated in section 2.3.2, but also carries significant financial burdens for horticulturists. The transition from CHP generation to renewable capacity leads to a substantial increase in energy costs, driven by the higher costs associated with geothermal contracts compared to CHP operations. Additionally, halved electricity sales, coupled with grid electricity procurement in high capacities with increased DSO charges, result in a 416% increase in net costs of the energy operations for horticulturists.

While the inclusion of renewable energy sources leads to significant emission reductions, cost optimisation remains the predominant factor driving greenhouse horticulture operations. The findings indicate that although emission goals may not be met in the NORES2030 scenario where energy system regulations and costs are considered without renewable capacity, total annual costs are lower when horticulturists continue to rely solely on CHPs and gas boilers. This suggests that current market incentives may not be robust enough to drive a substantial shift towards renewable thermal generation. Mitigating factors such as reduced DSO costs or subsidies like the SDE++ could facilitate a smoother transition towards renewable energy utilisation.

Regulatory mitigation of DSO costs, coupled with efficient load management strategies for available electric capacities, is paramount. The sporadic and rare utilisation of full heat pump and electric boiler capacities in 2030 necessitates DSO contracts accommodating these high capacities, resulting in considerable associated costs. Addressing these challenges requires interventions on both regulatory and operational fronts. From a regulatory perspective, revising the pricing mechanism of DSO contracts may prove beneficial. This revision should avoid the permanent shift to a higher contract category solely upon exceeding contracted capacity during instances of negative electricity prices. Negative prices signify an oversupply of electricity to the grid, and drawing large amounts of electricity for congestion mitigation should be encouraged rather than discouraged.

Furthermore, the substantial increase in net costs observed in 2030, as evidenced by the findings of this study, underscores the inefficacy of high electric capacities for thermal generation. Under the current DSO pricing framework, it appears financially prudent for horticulturists to restrain the installation and utilisation of thermal generators requiring electricity. Since horticultural operators have autonomy over generator commitments, they can choose not to exceed their contracted capacities with DSOs, despite recommendations from optimisation models when surplus capacity is available. Moreover, manual constraints on maximum electricity purchases per timestep can be readily implemented in optimisation models to prevent contract overruns and mitigate associated costs.

When considering the installation of limited capacity, it is logical to prioritise heat pump capacity alone. Heat pumps offer the advantage of generating three times as much heat while consuming the same amount of electricity as electric boilers, making them a more efficient and cost-effective choice. Given anticipated conditions in 2030, the combination of both heat pumps and electric boilers may prove unnecessary. This is exhibited in section 5.4 which proves that the same scenario in 2030 with only heat pump capacity is less costly than when both heat pumps and electric boilers are available. Furthermore, the figures in this section suggest that implementing only geothermal and waste heat into the energy mix as RES sources is the cheapest scenario that still achieves the ambitioned CO_2 emission reductions with a reduction of 49% compared to the current situation.

In conclusion, the inclusion of renewable energy sources leads to a significant reduction in emissions but also alters the economic landscape for greenhouse operations. The shift away from CHP operation towards renewable capacity transforms greenhouse growers from electricity suppliers to consumers with a neutral balance. This change places strain on the economic viability of renewable energy, particularly under projected energy system regulation and cost developments. Thus, optimising geothermal- and heat pump capacities for 2030 becomes imperative to determine whether the economically optimal capacities will suffice to achieve the sector's environmental goals.

6.1.4 Sub-question 4

> *"What is the impact of energy price developments on the energy operations within the horticultural sector of the Netherlands until 2030?"*

The findings presented in section 5.3 shed light on the evolving landscape of energy operations within the horticultural sector in response to fluctuating energy prices. The net costs incurred by horticulturists demonstrate an upward trajectory across the low and mid-price scenarios investigated, with an exception for the high-price scenario. However, an interesting observation arises when comparing the net average costs between the medium price scenario of 2030 and the scenario maintaining energy prices from 2023. The total average costs incurred by horticulturists exhibit a marginal increase in the medium price scenario of 2030 compared to the scenario maintaining energy prices from 2023. This discrepancy is particularly noteworthy, considering that the annual mean prices in the medium scenario of 2030 are lower than current energy prices. Consequently, a slight decrease in total costs was anticipated due to the expected reduction in both electricity and gas prices.

Nevertheless, while both electricity and gas prices decrease, the drop in electricity prices outpaces that of gas prices by a considerable margin. Consequently, the optimisation algorithm may favour the purchase of electricity for thermal generation over gas at certain time steps, leading to increased electricity consumption and subsequent network charges for purchased electricity. Concurrently, the relatively lower electricity prices exacerbate the decline in revenue from electricity sales compared to the reduction in natural gas costs. These dynamics elucidate the slight increase in overall costs observed in the medium-price scenario.

On a positive note, the heightened use of electric thermal generation precipitates a modest reduction in CO_2 emissions. Consequently, the medium price scenario emerges with the lowest CO_2

emissions among all energy price scenarios, underscoring the pivotal role of relative electricity and gas prices in shaping emissions outcomes. This augurs well for future emissions reduction efforts, especially considering that the medium price scenario aligns with the most probable scenario according to forecasts outlined in section 2.5.2. It is important to note that while the medium price scenario incorporates the most probable mean energy prices, the predicted increase in the volatility of these prices has not been considered in the 2030 scenarios. This omission could significantly impact the model's results. Future experiments investigating the operational energy costs and emissions in the horticultural sector should account for this increased volatility to provide a more accurate representation of potential outcomes.

In conclusion, the impact of energy market prices on horticulturists' operations unfolds in nuanced ways. While cost reductions typically accompany declines in energy prices, the intricate interplay between electricity and gas prices can lead to unforeseen fluctuations in operational expenses. Moreover, the reliance on thermal generation and consequent emissions hinges predominantly on the relative pricing dynamics between electricity and gas.

6.2 MODELLING PROCESS AND METHODS

6.2.1 Model limitations

Optimisation

The Julia model currently features only one optimisation function, focusing on optimising the energy production, consumption, and distribution of greenhouses, with a primary emphasis on purchasing and selling electricity on the EPEX market. However, in practice, AgroEnergy engages in trading across multiple markets, employing stop-loss orders on platforms like the intraday and balancing markets. Additionally, horticulturists are assumed to possess separate heat pipes for different CHPs, allowing them to utilise generated capacity across various markets. Trading activities on the mFRR (Manual Frequency Restoration Reserve) market are common, involving commitments to either generate or abstain from generating electricity for 24 hours, adjusting output based on demand signals, and receiving compensation for participation. Notably, an additional optimisation function, comparing revenue from the EPEX market with mFRR compensation daily, considering storage limits and ramped-up generation on preceding or subsequent days, is currently absent from the model. Implementing such an optimisation function would enhance the accuracy of the model's results.

Although updated, the model only optimises using current gas and electricity taxes, as well as DSO costs. Because it can only optimise for 96 timesteps ahead, it lacks foresight regarding potential changes in taxes when transitioning to the next bracket based on gas consumption or electricity purchase. Consequently, it does not account for instances where variable DSO costs diminish after a certain threshold of electricity purchases, for instance. Nor does it incorporate the substantial increase in network contract charges when a contract capacity is breached in a single timestep. Incorporating a dimension into the model that optimises over an entire year to assess the optimal timing of taxes and DSO costs relative to other resources would likely yield more favourable outcomes.

Temporal settings

The model operates with a rolling time horizon, where the optimisation function is invoked to optimise for 96 hours, but only the initial 24 hours of optimised results are retained. This iterative process continues until 8760 hours of results are stored. The 96-hour timeframe is chosen to align with the optimisation approach utilised by AgroEnergy's BiedOptimaal for the majority of its clients. However, for larger clients, an extended optimisation period is sometimes employed, with

BiedOptimaal optimising up to seven days ahead, particularly significant for horticulturists equipped with substantial thermal storage buffers. The UC optimisation model, however, utilises exclusively the 96-hour optimisation timeframe to ensure comparability of results. Nevertheless, in practice, for larger clients such as the daisies profile, adopting a longer optimisation period might prove advantageous, a feature that can be adjusted within the model if needed.

DSO cost function

The optimisation model incorporates a function to determine DSO contract costs based on historical and monthly maximum grid capacities. However, this function operates independently of the model's optimisation function. Consequently, the model may allocate capacity solely based on energy prices and DSO costs within the current model run, potentially leading to inefficient outcomes. For instance, if DSO costs remain low during optimisation, significant capacity may be purchased for thermal generation, resulting in increased DSO contract expenses due to higher transportation categories and maximum drawn capacities. The optimisation algorithm cannot anticipate these consequences as it is confined by predefined boundaries. Unlike the model, real-world actors such as EnergyOperators at AgroEnergy and horticulturists exercise discretion over their generation units, minimising the risk of overcapacity. Thus, the model's failure to account for human decision-making processes renders it misaligned with reality, emphasising cost minimisation over realistic operational constraints and strategic decision-making.

Heat destruction

A €50 per MWh penalty is imposed on the destruction of heat in the model, though in reality, destroying heat incurs no direct cost. For this reason, the penalty on heat destruction is included only in the objective function of the optimisation algorithm and not in the constraints that calculate the net costs for the horticulturists. This distinction ensures that the penalty influences the model's behaviour without directly impacting the calculated financial outcomes for the horticulturists, allowing for a more realistic simulation of their operational decisions.

The model focuses solely on cost optimisation, lacking the ability to autonomously avoid generating heat when it is unnecessary. In 2023, this penalty makes sense to some extent because even if the spark spread is high enough to generate heat purely for the sale of electricity, horticulturists might be disinclined to do so due to the unsustainable nature of emitting CO_2 without a practical purpose. Essentially, this would mean generating emissions solely for profit. However, in the future, this rationale does not apply when electric capacity is used to generate and destroy heat when not required by greenhouses. This is because heat pumps and electric boilers do not emit CO_2. Therefore, the penalty may not be relevant for the future model, or it could be applied exclusively to heat destroyed from conventional thermal generation. Implementing this selectively is challenging, as tracing the source of destroyed heat when it comes from storage complicates the process.

Despite the destruction of heat due to electric generation driven by favourable electricity prices, horticulturists might consider increasing thermal storage capacity, especially when a significant amount of geothermal and waste heat is being destroyed. Geothermal heat is particularly costly, so if it cannot be ramped up or down, not being able to store it during warmer months would be wasteful. Therefore, while the penalty serves as a practical measure within the model, its future applicability needs reconsideration, especially concerning heat generated by non-emitting sources. Increasing thermal storage could mitigate wastefulness and better align operations with sustainability goals.

6.2.2 Input limitations

Thermal storage

In reality, the thermal losses of the heat buffer utilised by horticulturists are directly influenced by the state of charge of the thermal storage and would therefore be regarded as a decision variable. However, in this model, the hourly thermal loss is treated as fixed. These thermal losses represent an increment of the maximum thermal storage capacity, with the specific increment varying depending on the profile, as sourced from the AgroEnergy database. Initially, the thermal loss was integrated into the model as a decision variable, but it significantly strained the model's resources relative to the relatively small magnitude of the thermal losses within the scope of this research. This strain is due to the necessity of carrying all storage-related variables, such as state of charge and (dis)charging rate, across the optimisation iterations within the rolling time horizon loop, resulting in slower model performance. Consequently, only the most critical determinants for thermal storage are treated as decision variables in the model.

Weather data

The base case for the model was constructed using only 2023 as the reference year. This choice was influenced by the observation that price trends in 2023 exhibited greater stability compared to previous years such as 2022 and 2021, which were impacted by the COVID-19 pandemic and the conflict in Ukraine, resulting in significant energy disruptions in the Netherlands. However, it is important to note that utilising only one year for weather condition data implies a limitation in capturing the variability of weather conditions. Factors such as temperature, solar radiation, and humidity significantly impact the heat, lighting, and CO_2 requirements in greenhouses. To better understand the interaction between these factors and the variables studied in this thesis, it would be beneficial to incorporate weather data from multiple years to create scenarios for reference years, allowing for a more comprehensive analysis of the weather's impact.

CHP

In the current model, the thermal inertia associated with CHP generators and thermal storage is not accounted for, as a constraint on CHP generation operations. Thermal inertia refers to the characteristic of the system where changes in the rate of heat generation or consumption occur gradually due to the thermal mass of the components involved. Its inclusion in the model could offer valuable insights into the dynamic behaviour of CHP systems.

However, while thermal inertia is indeed a relevant consideration, the focus within the model has been primarily diverted from analysing ramping rates. Ramping rates, which denote the rate at which a generator's output can be adjusted, assume greater importance when examining the thermal and electrical production of CHPs at a micro level. This is particularly pertinent in scenarios such as intraday or balancing markets, where rapid response times are crucial for maintaining grid stability and meeting fluctuating demand.

Conversely, when evaluating CHP operations solely within the context of the EPEX over a yearly timeframe, the significance of ramping rates diminishes. In such cases, the model may be unduly burdened by the inclusion of ramping rates, which may not lead to equal benefits in terms of how accurate or relevant the results are. Therefore, while acknowledging the potential importance of thermal inertia in shaping CHP generation dynamics, the current model neglects them. This strategic emphasis ensures that the model's resources are effectively allocated towards capturing the most salient aspects of CHP operation within specific temporal and market contexts.

Renewable energy

The accessibility of various renewable heat sources is primarily influenced by the geographical locations of horticultural companies. Presently, the availability of resources is presumed to be uniform across different profiles, as the specific locations of companies within these profiles have not been taken into account. However, in reality, these profiles may exhibit varying capacities of geothermal and waste heat resources. In contrast, this research assumes a consistent base load that encompasses the amount of heat equivalent to the proportion assumed to be supplying the entire sector by 2030.

Geothermal heat production inherently generates geothermal gas as a byproduct, which carries several implications, including environmental and operational considerations. However, the current model has omitted this aspect, due to challenges in accurately assessing its effects and a prioritisation of more immediate operational concerns. Additionally, certain geothermal sources possess characteristics that require the inclusion of a heat pump to adjust temperatures. This supplementary component not only improves the system's temperature control capabilities but also enhances its overall capacity to manage thermal dynamics. However, in the current model, the integration of geothermal heat with a heat pump does not allow for flexible capacity adjustments. This limitation stems from simplifications made to streamline the modelling process. Despite these limitations, it could prove useful to comprehend the interaction between geothermal heat, geothermal gas generation, and heat pump dynamics to develop more comprehensive models in the future.

Chapter 7: Conclusions and recommendations

In this chapter, the conclusions of this thesis are provided along with recommendations for future research, policy development and modelling improvements. Additionally, the conclusions of this research lead to recommendations concerning the operations of horticulturists in 2030.

7.1 CONCLUSIONS

The objective of this thesis was to assess the implications of evolving contextual factors within the Dutch greenhouse horticulture sector's energy landscape. Specifically, it aimed to elucidate the ramifications of anticipated energy system regulations and costs, sustainable technologies and future energy pricing on horticulturists' energy operations in 2030, encompassing operational costs, emissions, generation patterns and electricity trade. To achieve this, a collaborative effort with AgroEnergy led to the development of an optimisation model employing MILP techniques to minimise horticulturists' costs under diverse market scenarios. This model, integrated into the DEMOSES project, facilitates the representation and linkage of simulated Dutch horticultural energy system behaviours with other heat, electricity, gas, and distribution models.

The envisioned regulatory transformations in the Dutch horticultural energy landscape aim to substantially reduce CO2 equivalent emissions between 27-45% by 2030 to reach the climate accord agreements. Presently, emissions primarily stem from CHP generators and are supplemented by gas boilers utilising natural gas. A significant aspect of horticulturists' business model revolves around CHP operation, leveraging the sale of CHP-generated electricity on the EPEX during periods of favourable electricity prices and low natural gas prices when the spark spread is high. In a bid to curb CHP usage and diminish sectoral emissions, the Dutch government is revising the sector's tax framework from 2025 onwards. Notably, CHPs will lose their exemption from gas tax, reduced gas tax rates will be abolished, and CO2 taxes will be introduced for the sector, alongside lowered electricity taxes.

In addition to evolving regulations in the horticultural energy system, the costs imposed by market participants and uncertain developments in the availability of RES for thermal generation will shape the operational energy behaviour of horticulturists. This thesis has demonstrated that under specific assumptions, these contextual factors significantly influence each other. Throughout the experiments conducted in this study, the primary factor influencing both the energy operations of horticulturists and the efficacy of energy system regulations is the network charges imposed on horticulturists in 2030. Assuming a large capacity of heat pumps and electric boilers is available in 2030, and considering that the current DSO pricing mechanism remains unchanged with DSO tariffs increasing as predicted, the DSO costs imposed on horticulturists escalate exponentially. Thus, while the described energy system regulations aim to incentivise a shift towards sustainable thermal generation, high network charges in 2030 could potentially outweigh the benefits of these regulations.

When electric generation units with large capacities are used to generate thermal energy for greenhouses, horticulturists need to substantially increase their contracted capacities with their DSO. The electric capacity of heat pumps and electric boilers is primarily utilised to capitalise on negative electricity prices for heat generation. However, the DSO contract capacities are not incorporated into the optimisation algorithm of the model developed for this thesis. Consequently, these capacities are exceeded when the electric generators are available and prices are negative, resulting in an automatic and permanent transition to higher capacity contracts with the DSOs.

These findings underscore the importance of precise capacity management and restraint in a future where the energy mix is diverse. It can be concluded that committing a large combined amount of heat pump and electric boiler capacity for thermal generation during short peaks is superfluous and is expected to negatively impact electricity costs for horticulturists. Therefore, given the superior thermal efficiency of heat pumps, they are the more cost-effective option for capitalising on negative electricity prices.

With the energy and CO2 tax system currently envisioned for 2030, CHP systems are expected to remain more cost-effective than heat pumps throughout the year. When the sectoral CO2 tax is introduced on its own, it appears stringent enough to induce a transition from conventional thermal sources to sustainable ones. However, under conditions with extreme DSO costs, the mitigating effects of the CO2 tax on emissions are outweighed. It becomes more cost-effective for horticulturists to pay the CO2 tax for conventional generators than to incur the DSO costs for electric generators. Notably, this study did not account for the increasing frequency of EPEX prices dropping to zero or below. As this trend is expected to rise significantly in the coming years with the electrification of the Dutch energy system, the economic viability of heat pumps might improve. However, their usage must be controlled to avoid surpassing DSO contract capacities.

Conversely, waste heat already presents a cost-effective alternative to CHP-generated heat; however, its availability to the horticultural sector is forecasted to be limited. Geothermal heat is anticipated to dominate thermal energy provision in 2030, with ambitions to supply between 40% and 50% of the required heat in the horticultural sector. The findings of this thesis suggest that achieving this level of geothermal capacity has the potential to substantially reduce CO2 emissions by 49%, thereby meeting national emissions targets for 2030. This outcome holds regardless of whether electric thermal generators are included in the energy mix. When relying exclusively on geothermal and waste heat for RES thermal generation, the anticipated increase in annual net costs is modest, at only 51%. On the contrary, when an abundance of heat pump and electric boiler capacity is introduced alongside geothermal and waste heat, the estimated annual net costs for horticulturists rise by approximately 416%.

Notably, the geographical location of horticultural companies was not considered in this research, while the availability of geothermal energy largely depends on subsurface conditions in the area where the greenhouses are located. Moreover, the target for widespread geothermal energy availability is ambitious, given that the capacity in 2030 would need to be ten times what is currently available. Additionally, the examination of various scenarios in this thesis indicates that integrating geothermal heat may not be as cost-effective as exclusively relying on CHP systems for providing greenhouse heat in 2030, despite the new energy tax and CO2 system. This conclusion is predicated on the anticipated annual costs of geothermal energy projected by AgroEnergy. This underscores that the envisioned fiscal measures alone may not suffice to prompt a natural transition towards geothermal energy.

Ultimately, in 2030, the trading patterns of horticulturists are poised to evolve, transitioning from the predominant supply of electricity to a balanced electricity trade. This shift accompanies the adoption of a diverse mix of both renewable and conventional thermal energy sources. Consequently, while this transition substantially enhances the sector's sustainability, an inevitable outcome is the escalation of annual net costs, stemming from diminished revenue from electricity sales as CHP systems are operated with reduced frequency and capacity.

7.2 RECOMMENDATIONS

7.2.1 Policy Recommendations

To mitigate the reliance on CHPs and incentivise a transition towards more sustainable energy sources, there is a pressing need for policy intervention to address the escalating network charges imposed by DSOs. Without effective management of these charges, the intended fiscal energy system regulations may prove insufficient in achieving their emissions reduction targets. Mitigation of DSO costs involves regulating tariffs to prevent excessive increases. More importantly, the pricing mechanism should be revised to be more flexible. The current system, where contracts are based on maximum capacities that adjust even when exceeded momentarily, significantly contributes to increased net costs when electric thermal generators are used. To incentivise the use of heat pumps, a pricing mechanism allowing contract capacities to be exceeded during periods of negative prices could be beneficial, provided that the installed grid connections can accommodate the increased load.

Furthermore, the integration of the SDE++ subsidy presents a promising avenue for reducing the costs associated with geothermal energy and heat pumps. It is recommended to incorporate this subsidy into the developed model to evaluate its efficacy in lowering the costs of renewable generation. This could potentially facilitate a shift away from CHP generators, providing financial incentives for horticulturists to adopt more sustainable thermal generation technologies.

7.2.2 Model Development and Future Research

In terms of model refinement and future research, it is imperative to conduct additional experiments considering different scenarios of geothermal and waste heat availability. This would enable a thorough assessment of the optimal inclusion of these sources for horticulturists. Currently, the UC model cannot optimise costs for geothermal and waste heat, necessitating enhancements to incorporate these sources into the optimisation process.

Moreover, the model should be utilised to conduct further experiments exploring various tax regimes. By examining the effects of different gas and CO2 tax levels or alternative implementation strategies, such as differential tax rates, insights can be gained into the conditions necessary to make renewable energy sources economically viable. This research would be instrumental in informing policy decisions aimed at promoting the adoption of sustainable energy technologies within the horticultural sector.

It is recommended that future experiments include more accurate energy price scenarios, which not only factor in general upward or downward trends in mean prices throughout the year but also account for the predicted increase in volatility. Market mechanisms, policy interventions, and technological advancements outside the horticultural sector could influence the occurrence of negative prices. For a more accurate prediction, detailed data and models specifically tailored for forecasting electricity prices in the Netherlands are required. By coupling the UC model of this thesis to a national dispatch model that simulates the prices for 2030 or beyond, the UC model results would be more precise. Specifically, the installation of heat pump capacity could become more lucrative in scenarios with more extended periods of price depression.

Accordingly, similar to the exploration of optimal geothermal capacity for various horticultural profiles, it is imperative to determine the appropriate capacity for heat pump installation. This determination will hinge on the increasing frequency of negative electricity prices and the trade-off between capitalising on these negative prices and the resultant increase in contracted capacity with the DSO. Future research should focus on developing a robust method or model to establish the optimal heat pump capacity, balancing the benefits of low electricity prices against the consequences of high network charges.

Furthermore, the necessity of a €50 per MWh penalty for heat destruction in the 2023 scenarios warrants deeper investigation. While the rationale behind this penalty in 2023 is to simulate autonomous avoidance of wasteful behaviour, the energy operators at AgroEnergy would not expect a penalty this high to be necessary to accurately simulate real heat destruction behaviour. This discrepancy suggests that the model needs further refinement or that it optimises the costs for horticulturists more efficiently due to the perfect information it operates with, which may not fully capture the complexities and uncertainties of real-world operations.

7.2.3 Horticulturist Operations

Future investments in waste heat, and potentially geothermal heat at reduced costs, are recommended in conjunction with maintaining CHP systems as committable generators to fulfil load-following and peak capacity requirements. The findings of this thesis suggest that investment in electric boilers may not be warranted, as committing both heat pumps and electric boilers simultaneously can lead to costly consequences when DSO contract capacities are exceeded. Due to their superior thermal efficiency, it is therefore recommended to invest solely in heat pump capacity if deciding to invest in electric capacity for thermal generation at all. The results indicate that gas boilers, which are currently committed when electricity prices are low or negative, will be replaced by electric thermal generation in 2030 for all scenarios. As a result, gas boilers will become obsolete and can be excluded from the future energy mix.

Furthermore, it is essential to limit the commitment of heat pump capacity to the DSO contracts that horticulturists are willing to pay for. The optimisation algorithm should be constrained to avoid excessively surpassing contracted capacities, as the repercussions of such actions are permanent and costly. Horticulturists should maintain autonomy over the use of their committable generators to manage their operational flexibility and costs effectively.

Chapter 8: Reflection

Embarking on my thesis project marked the culmination of my academic journey, merging theoretical knowledge with practical application in the realm of energy markets. My academic background had primed me for this endeavour, as my interest in gas and electricity markets had been cultivated through modules that delved deep into their intricacies. It was during these modules that I first became enamoured and enthused with unit commitment, economic dispatch, agent-based and network models. Besides the interdisciplinary modules I followed for Complex Systems Engineering I began to take more modules in the electrical engineering department to enhance my technical knowledge. Resultingly, for my thesis, my sights were set on creating a dynamic model that incorporated energy storage and renewable energy integration, while simultaneously incorporating societal developments and regulatory interventions. Fortunately, I stumbled upon the this modelling project under the overarching DEMOSES project that ticked all my boxes. Additionally, it allowed me to gain experience and learn from a company within the sector a was creating my model for and writing my thesis about through my internship at AgroEnergy.

Although I had previously made unit commitment models, this project proved to be unlike anything I had done before, which was an exciting but sometimes frustrating challenge. My supervisor at AgroEnergy, Vincent, underscored the complexity of the model I sought to replicate, highlighting the difficulty in encompassing every aspect within a simplified model in a relatively short amount of time. This complexity, coupled with the intricacies of different energy balances and many sector specific constraints, rendered the modelling process time-consuming and error-prone. Additionally, having only minor experience with programming languages such as NetLogo, MATLAB, and Python's NetworkX, I encountered a steep learning curve when tasked with mastering Julia. Consequently, the excessive time spent on model creation led to neglect in writing my thesis report—an oversight I now recognize could have been mitigated by simultaneous attention to both tasks.

Reflecting on my experience, I acknowledge the value of collaboration and support, yet found it challenging to reach out for assistance when it came to the actual programming of my model. In hindsight, I recognise the potential benefits of seeking advice on the programming aspects of model building, which could have alleviated some of the difficulties encountered. Additionally I experienced myself continuously underestimating the time it would take to finish modelling tasks as well as writing about them.

The invaluable support from my supervisor, Sugandha, proved instrumental in navigating the scope of research and prioritising tasks effectively throughout the iterative process if building my model and writing my thesis. Her insights provided clarity amidst the complexity of the project, facilitating a structured approach to problem-solving and task management. While getting lost in the intricate details of my model, Sugandha’s holistic approach would often help met fix road blocks in my model. I have learned the importance of stepping back from minute problems, temporarily parking them to refocus my attention elsewhere. This approach allows for a fresh perspective upon returning to the issue, facilitating clearer insights and more effective problem-solving.

From Vincent, I gained valuable insights into the horticultural sector, offering a glimpse into its inner workings within the Dutch energy landscape. Specifically, I learned how the trade of electricity significantly bolsters the profitability of horticultural companies. Vincent's expertise extended to the intricacies of electricity trading across different markets and the functioning of bidding systems within these markets. Participating in an internship with AgroEnergy not only provided enjoyment to my thesis project but also afforded me sector-specific knowledge. Surrounded by energy operators and heat specialists, I gained rapid insights for modelling decisions, which in turn proved instrumental in refining the inputs for my model.

Overall, this project served as a lesson in time management, problem-solving, and the importance of maintaining a broad perspective amidst intricate challenges. The structured environment of the internship provided invaluable support, underscoring the significance of practical experience in complementing academic pursuits.

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Appendices

Appendix A – Stedin network charges

Transportcategorie	Grens gecontracteerd transport-vermogen[6]	Transportdiensten					
		Vastrecht	Variabele tarieven[11]				
		Transport in € per maand	kW contract in € per maand per kW	kW max in € per maand per kW[7]	Dubbel tarief normaal in € per kWh[9]	Dubbel tarief laag in € per kWh[10]	Blind verbruik in € per kVARh
LS	t/m 50 kW	1,50	1,1841	-	0,0579	0,0357	0,0135
Trafo MS/LS	51 t/m 150 kW	36,75	3,1714	2,4264	0,0148	0,0148	0,0135
MS	151 t/m 1.500 kW	36,75	1,6104	2,4264	0,0148	0,0148	0,0135
Trafo HS+TS/MS reserve	> 1.500 kW	230,00	1,5236	1,4071[8]	-	-	0,0135
Trafo HS+TS/MS	> 1.500 kW	230,00	3,0473	4,0649	-	-	0,0135
TS reserve	> 1.500 kW	230,00	1,4720	1,3910[8]	-	-	0,0135
TS	> 1.500 kW	230,00	2,9440	4,0184	-	-	0,0135

[6] *Geldt voor aansluitingen aangelegd na 1 januari 2007. Daarnaast geldt dat de transportcategorie (netvlakniveau) niet hoger kan zijn dan de aansluitcategorie (zie tabel 2)*
[7] *De hoogste, in elke verbruiksmaand afzonderlijk opgetreden, belasting uitgedrukt in kilowatt (kW), en bepaald als gemiddelde belasting van een periode van 15 minuten tenzij anders met Stedin is overeengekomen*
[8] *Wordt per week berekend*
[9] *Geldt van maandag t/m vrijdag van 7.00 uur tot 23.00 uur*
[10] *Geldt voor alle overige uren en op feestdagen, te weten: Nieuwjaarsdag, 2e Paasdag, Koningsdag, Hemelvaartsdag, 2e Pinksterdag, 1e en 2e Kerstdag*
[11] *Als waarden niet zijn ingevuld, betekent dit dat de tariefdrager niet van toepassing is voor deze specifieke categorie*

Figure A1. Fixed and variable components of transportation fees imposed on large consumers in 2023. From (Stedin, 2023).

Appendix B – Model formalisation

Packages

There are six packages that were added and used to build the optimisation model: XLSX, DataFrames, PlotlyJS, JuMP, Gurobi and MathOptInterface. The first three packages require little elaboration. XLSX enables the reading and writing of Excel files in Julia. This package has provided a flexible way to import data from a single file per scenario instead of separate CSV files. The DataFrames package is used for creating and handling tabular data structures. The package has similar functionalities to pandas in Python and allows the modification, structuring and filtering of data. Then the PlotlyJS package is a plotting library that offers interactive data visualisation capabilities. This allows for enhanced exploration and interpretation of the model outputs. The latter three packages demand more substantiation so are depicted below.

JuMP is a domain-specific modelling language embedded in Julia, designed for mathematical optimisation. This package enables the structured specification of optimisation problems with algebraic constraints, making it a suitable tool for various optimisation problem classes (Mate et al., 2021). Among these tasks are MILP optimisation tasks. The JuMP package is utilised to formulate and solve optimisation problems within the UC model. It boasts an intuitive syntax and extensive solver support that enhance productivity and ease of use.

Gurobi is a solver package for linear programming and mixed integer programming problems. The JuMP package relies on solvers to solve the optimisation problems formulated with JuMP. The Gurobi solver is a powerful tool for efficiently solving large and complex optimisation problems. Integrated with the JuMP package, the Gurobi optimiser leverages Julia's dynamic and compiled nature, allowing for efficient optimisation with high computational speeds (Dunning et al., 2017). Julia's design, with features like multiple dispatch, enables heavy compiler optimisation, which can significantly benefit from optimisation algorithms like Gurobi (Belyakova et al., 2020).

MathOptInterface or (MOI) is an abstraction layer in Julia used by JuMP to convert the defined optimisation problem in JuMP to any specific structure for each solver. MOI provides a standardised framework for interacting with solvers, enabling continuous integration and interoperability across various solver implementations. Using MOI enhances the flexibility and scalability of the model implementation.

Optimisation function

JuMP builds optimisation problems incrementally in a ‘Model’ object. Subsequently, the model is created by passing the HiGHS optimiser to the ‘Model’ function. The first elements of the model to be defined are the variables. Variables in JuMP can be declared using @variable, including their lower and upper bounds. Binary variables can be specifically created and constrained to the set {0, 1}. The objective of the model can be set using @objective. For this model, a minimisation objective is passed to the objective function. Mathematical constraints are modelled using @constraint to define them. When all elements are defined in the model function, the ‘optimize!’ function is called upon to solve the optimisation problem. The fixed parameters of the model are declared outside of the optimisation function and can be passed as arguments to the function. Thus, all the described elements of section 3.2 can be implemented using the JuMP package.

Appendix C – Monthly electricity balance patterns

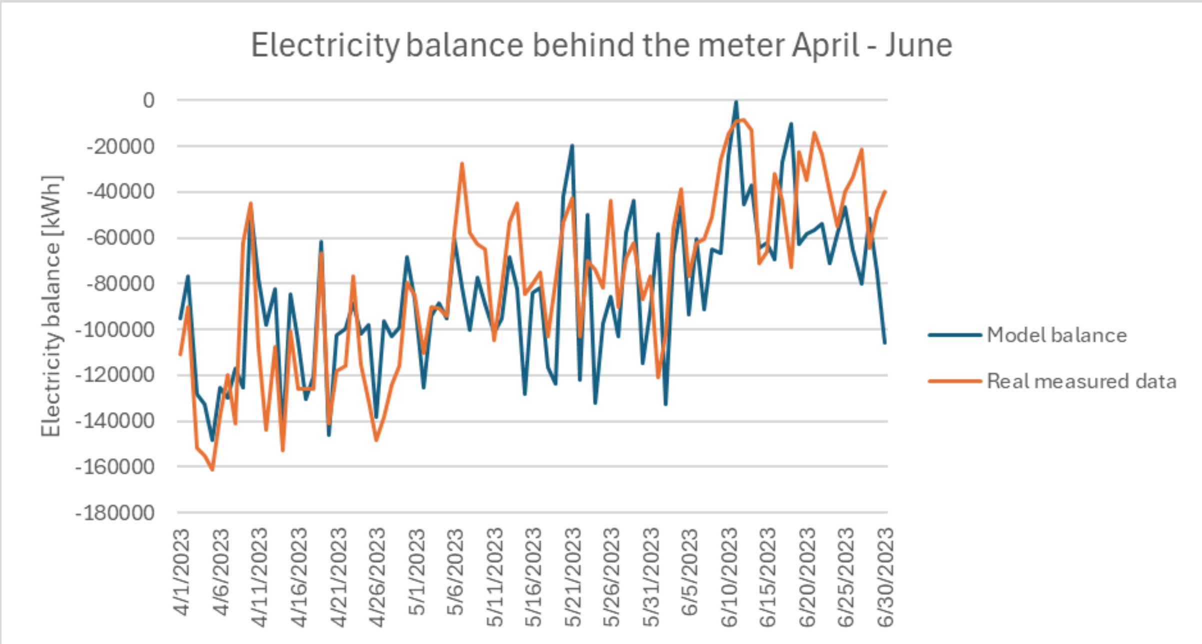

Figure B1. Validation of electricity trading pattern from April to June.

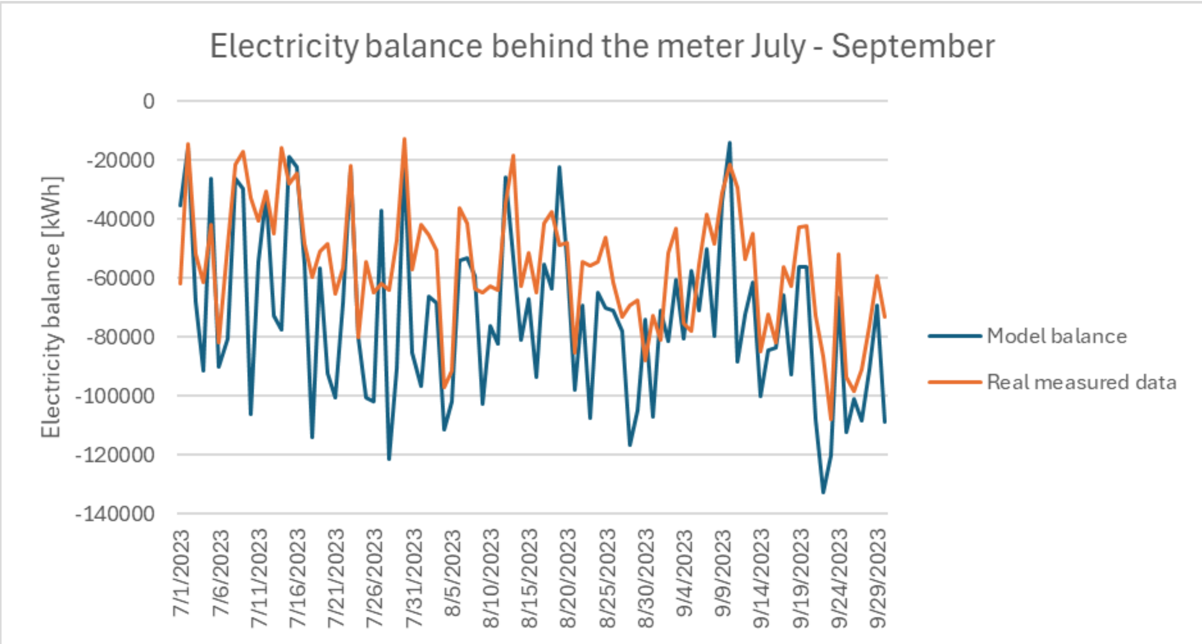

Figure B2. Validation of electricity trading pattern from July to September.

Appendix D – Cost items

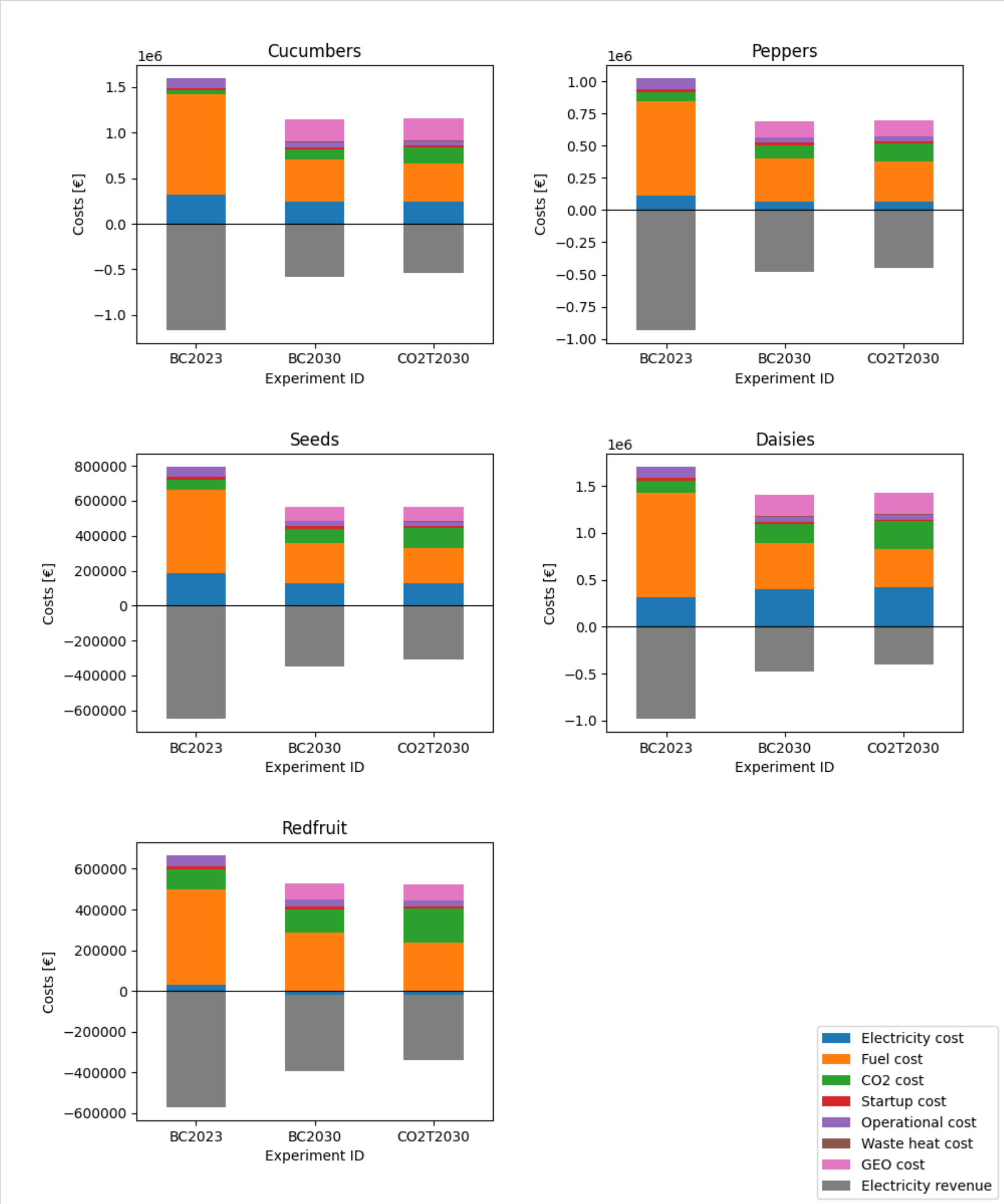

Figure C1. Division of all cost items that make up the annual net costs for CO2 tax analysis.

Appendix E – Thermal storage

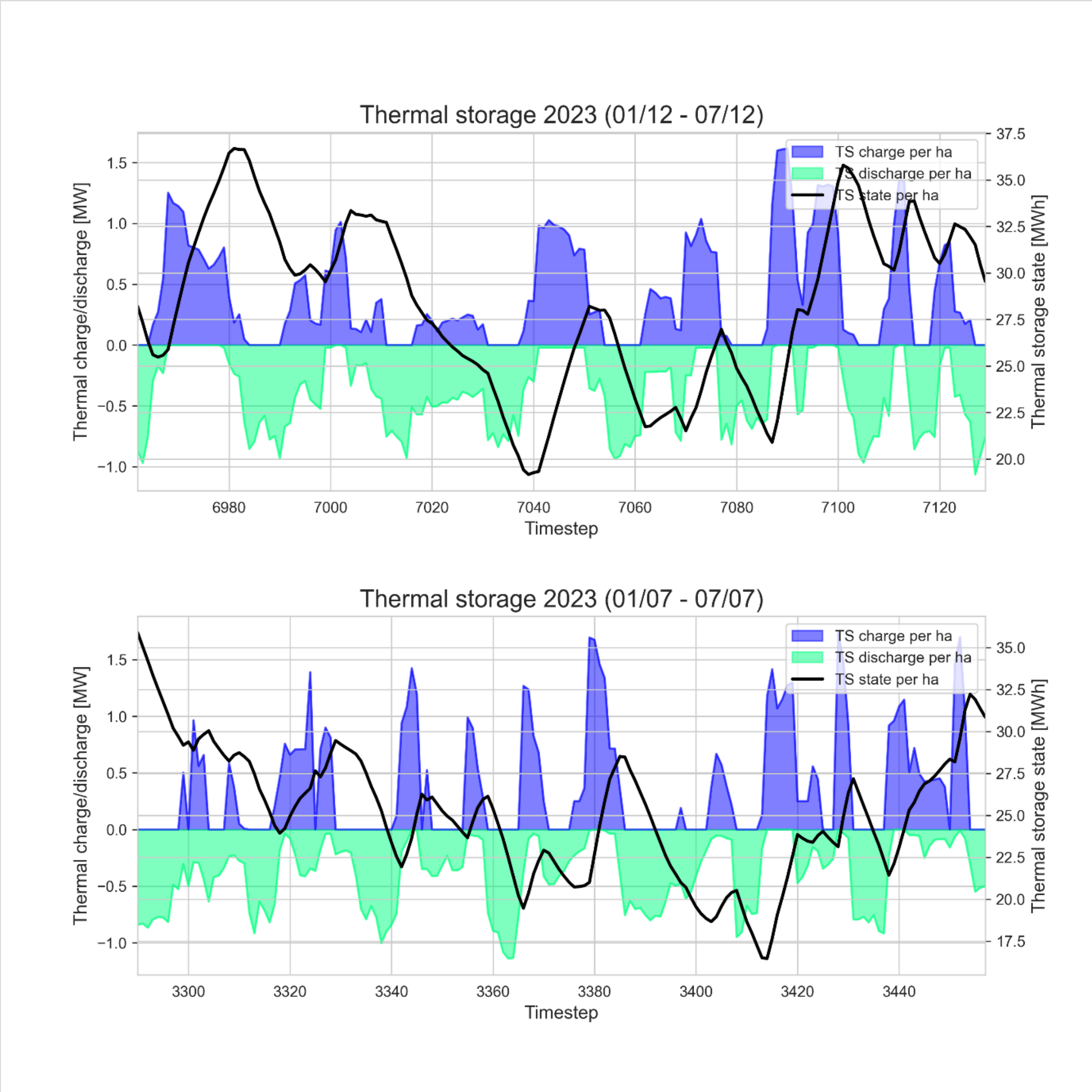

Figure D1. Thermal storage fluctuations in the coldest and warmest week of the year in 2023.

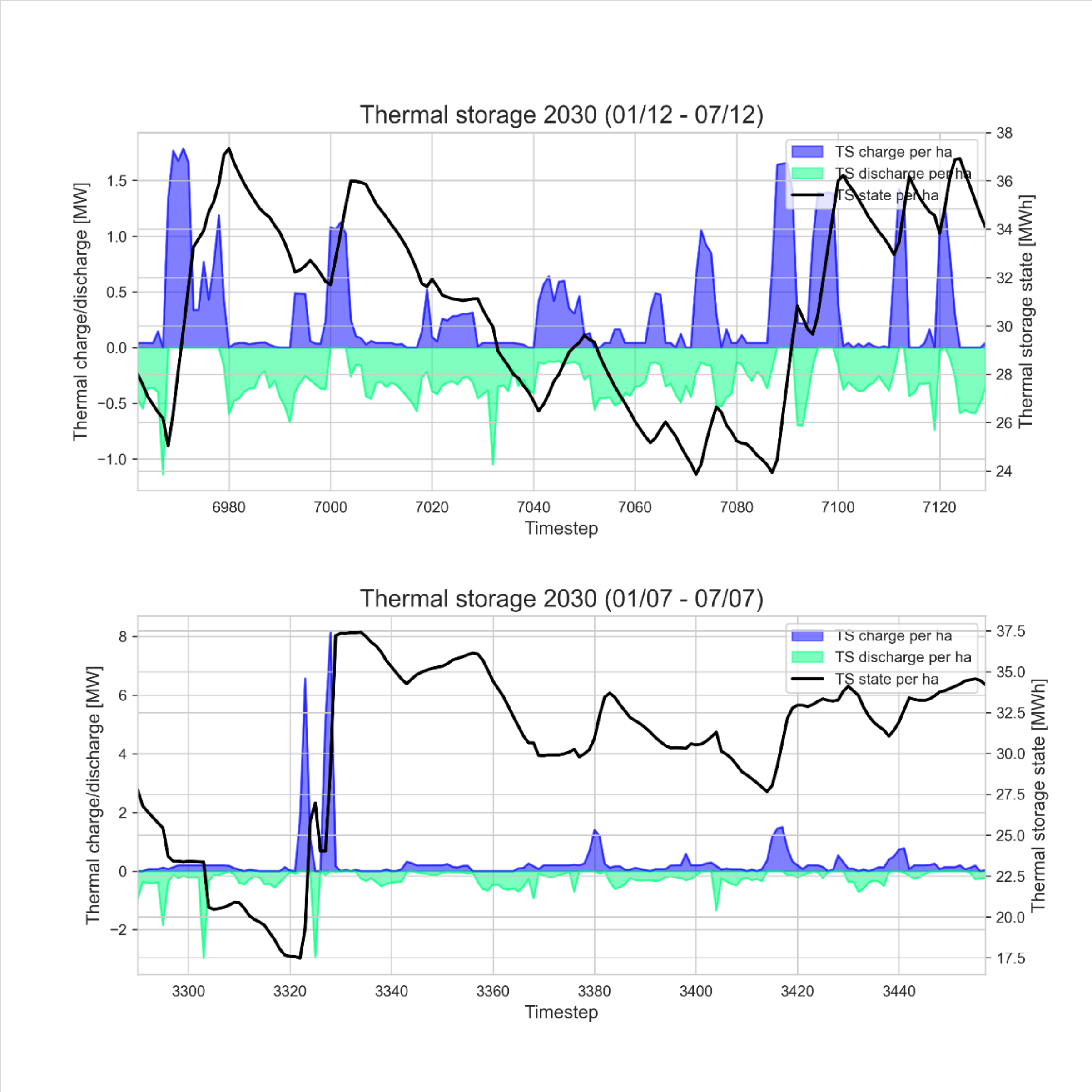

Figure D2. Thermal storage fluctuations in the coldest and warmest week of the year in 2023.