University of Freiburg

Faculty of Environment and Natural Resources
in cooperation with
Faculty of Engineering

Bidding Strategies and Impacts of Flexible Variable Renewable Energy Sources in a Simulated German Electricity Market

Master thesis submitted in partial fulfilment of the requirements
for the Degree of Master of Science
in Renewable Energy Engineering and Management

BY

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INATECH
INSTITUT FÜR NACHHALTIGE
TECHNISCHE SYSTEME

REM
M.Sc. Renewable
Energy Engineering
and Management

Bidding Strategies and Impacts of
Flexible Variable Renewable Energy Sources
in a Simulated German Electricity Market

Gebotsstrategien und Auswirkungen
flexibeler fluktuierender Erneuerbare Energien
in einem simulierten deutschen Strommarkt

彈性變動型再生能源在一模擬德國電力市場的
競標策略與影響

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Submission Place:	FREIBURG IM BREISGAU
Submission Time:	OCTOBER 2019

Background picture on the chapter title pages: lignite power plant Lippendorf and its surroundings, including the endangered village Pödelwitz, August 2018. Taken and designed by the author of this report.

You know
I believe the Taiwan I love
is not the eight million of the population
who voted to denounce human rights
and bowed under the red swastika

Nor is it the void nationalist call
to build an islandwide wall
turning us into a police state
in exchange of denying another sneaking in

For five million years
typhoons, earthquakes, and floods
for four hundred years
bullets, bombed cities, and martial laws

But still, but still!
Tears dried and the people carried on
the earth mourned but continued to feed
this is the Formosa I truly belong!

Through old Taiwanese practice
of hospitality and forgiveness
have we come all this way along
now standing at the crossroad
must we choose the right path

Through the steady breeze from the sea
and the warm sunshine from the sky
our yet unborn green island
will be defined by the unbound;
it is the universal cause
I was born to defend

∼*The Farewell Letter to a German Friend*, October 2019
Inspired by the Poem "*To Alexey Surkov*" of *Konstantin Simonov*
(quoted in the HBO mini-series *Chernobyl*)

I, *Dung-Bai Yen*, herewith declare that this thesis was written on my own, that I have not used any other sources and materials than those indicated, that I properly cited the materials I have relied upon, and that this thesis has not been submitted elsewhere.

Place, Date

Name

Contents

Appendix

Abstract

The control reserve capacity is an important ancillary service that ensures the reliability of a power system. As more variable renewable energy sources are installed onto the grid, it might be preferable for them to start providing the control reserve capacity whenever possible for the economic and environmental benefits it could bring about, but the question remains whether this “flexible” mode of operation would affect the reliability of the power system significantly, and what specific system, economic, and environmental impacts it would lead to. We therefore modeled how the flexible mode of operating variable renewable energy sources could be carried out, and how it would affect different agents and the entire system in a simulated German electricity market in the near future, using the agent-based electricity market simulation program *flexABLE*.

The results of our simulations suggested that allowing variable renewable energy sources to participate in the control reserve market could reduce the fossil fuel consumption, the total variable system cost, and the total fuel-related carbon emission of the power system, while it could also increase the producer surplus of the variable renewable energy power plant operators, without compromising the reliability of the power system. Factors that would affect the results, e.g. the competition within the renewable energy sector, the fuel switching effect within the conventional energy sector, the feed-in premium level, the reliability criteria of the control reserve services, the carbon price, and the market design were discussed, all of which could provide insights for further research and policy discussions on related topics.

Keywords: variable renewable energy sources, flexible variable renewable energy sources, VRE integration, power system flexibility, control reserve, ancillary services, energy economics, electricity market, economic dispatch

備轉容量乃一確保電力系統可靠度之重要輔助服務。隨著更多變動型再生能源併網，讓這些再生能源提供備轉容量可能可以帶來經濟上和環保上的效益，然而此種彈性調度模式是否會顯著影響電力系統之可靠度，以及其對系統、經濟、環境的具體影響，尚待深研。本研究因而利用甫研發之個體為本電力市場模擬軟體*flexABLE*，模擬變動型再生能源如何彈性調度，並分析此一調度模式將如何影響一模擬德國電力市場的其他個體和系統整體。

模擬結果顯示允許變動型再生能源參與備轉容量市場能在不影響供電可靠度的條件下，降低電力系統的總化石燃料消耗、總變動成本、以及總燃料碳排，並增加變動型再生能源業者的生產者剩餘。再生能源部門內部的競爭、傳統能源部門的燃料轉換、躉購溢價的量值、對備轉容量服務提供者的可靠度要求、碳定價、市場設計等會影響模擬結果的因素在研究中亦有充分討論，以期能對相關後續研究和政策討論提供參照。

關鍵字：變動型再生能源、彈性變動型再生能源、再生能源併網、電力系統彈性、備轉容量、輔助服務、能源經濟學、電力市場、經濟調度

List of Tables

List of Figures

List of Important Abbreviations and Definitions

Chapter 1

Renewable energy sources: Resources that could produce electricity 1) without fuel consumption or 2) with primary energy carriers that could be naturally replenished on a human timescale.

VRE: Variable renewable energy sources, whose power output were weather dependent, such as wind power plants or photovoltaic power plants.

DRE: Dispatchable renewable energy sources, whose power output were rather weather independent compared with VRE, such as bioenergy power plants, hydroelectric power plants, waste power plants, or geothermal power plants.

Conventional power plants: Power plants using fossil fuel or nuclear fuel as the primary energy carrier to produce electricity.

Control reserve: A type of ancillary service for the frequency control of the power system.

Chapter 2

EOM: Energy only market, the market where bulk electricity was sold.

CRM: Control reserve market, the market where positive / negative balancing capacity and energy was sold.

Flexible DRE (VRE): DRE (VRE) power plants that participated in the CRM. In contrast, inflexible DRE (VRE) were renewable energy power plants that did not participate in the CRM.

System must run: The capacity in a power system that was needed for different types of flexibility services, which in this study was identical to the negative control reserve capacity.

TSO: Transmission system operators.

Operation plan: The scheduled plan of the power plants and energy storage units in the power system due to the market results in the EOM.

Redispatch: The change in the scheduled operation plan from the market results in the EOM by the TSO to avoid the risk of transmission line congestion.

Curtailment: The reduction of the power output from a VRE power plant compared with its maximum available power output due to the constraints caused by system must run.

Chapter 3

Residual load: The demand load minus the VRE power output. Depending on the context given, the VRE output might refer to the potential value, the scheduled value, or the actual value.

Chapter 4

t: A 15-minute-long time step representing the duration of the each product in the EOM.

τ: A 4-hour-long time step representing the duration of the each product in the CRM.

EOF: Empirical orthonormal functions.

$ECDF$: Empirical cumulative distribution functions.

Minimum power output: The minimum amount of power a power plant had to deliver to stay operational due to technical reasons.

Must run capacity: The minimum amount of power a power plant had to deliver in the EOM due to its minimum power output and its participation in the CRM, if applicable.

$MUOT$: Minimum unconstrained-operation timespan; the sum of minimum timespans that a energy storage unit could operate without reaching the minimum / maximum state of charge limits when it was discharged / charged continuously.

Firm capacity factor (of VRE): A number between 0 and 1 for a certain type of VRE technology under a given reliability criteria; the firm capacity factor was defined as the value such that in a set of data, the probability of the ratio between actual and predicted VRE power output being less than the value was smaller than the reliability criteria. This definition could be used the other way around to define the reliability criteria when the firm capacity factor was given.

Chapter 5

Direct producer revenue: The revenue which a market participant collected through the market clearing prices (in the EOM) or pay-as-bid prices (in the CRM).

Indirect producer revenue: The revenue which a renewable energy power plant operator collected through the price differences between the feed-in premiums and market clearing prices in the EOM.

Variable system costs: The system costs that were subject to change from different operation results of the same power system. In our study, this included the fuel costs, start up costs, and carbon emission costs of the conventional power plants and the bioenergy power plants, and the operational costs of the energy storage units.

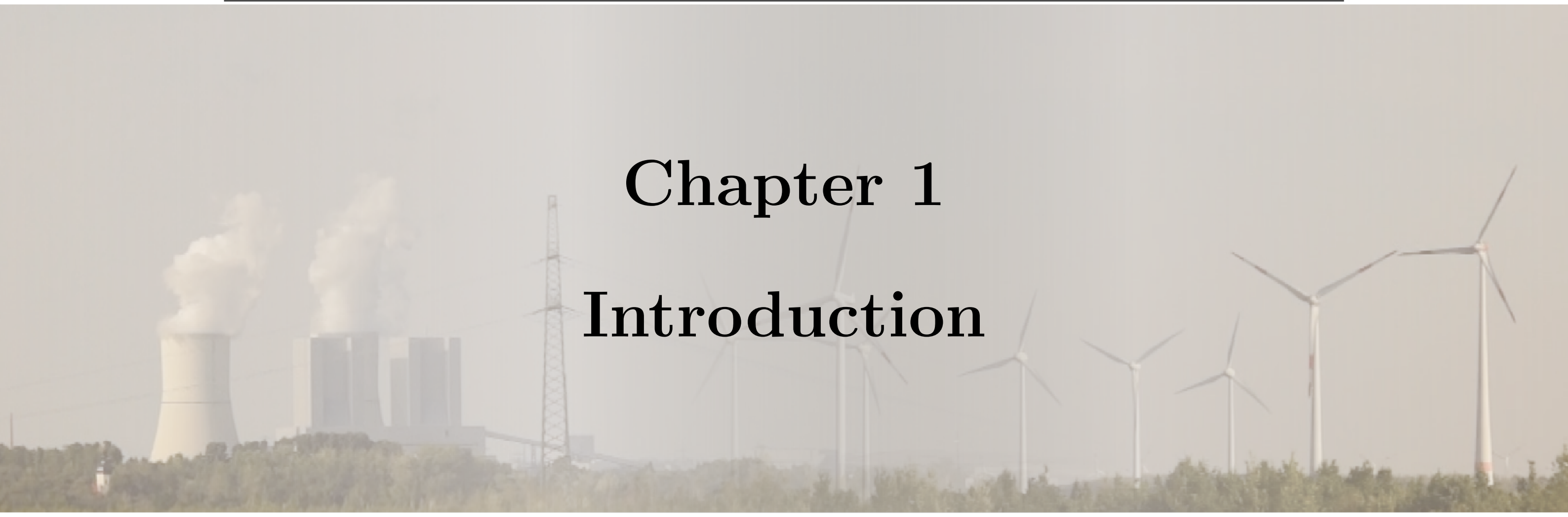
Chapter 6

Operation effect: The change in the total variable system cost or the total fuel-related carbon emission due to variations of operational patterns of the conventional power plants.

Fuel switching effect: The change in the total variable system cost or the total fuel-related carbon emission due to variations of the portfolio of different types of technologies in electricity generation.

Direct merit order effect (of flexible DRE or VRE): The impact flexible DRE or VRE had on the portfolio and prices in the CRM.

Indirect merit order effect (of flexible DRE or VRE): The impact flexible DRE or VRE had on the portfolio and prices in the EOM.



Chapter 1

Introduction

1.1 General Motivation

The world has been ongoing a full scale energy transition. Renewable energy sources, especially variable renewable energy sources (VRE) such as wind power plants or photovoltaic power plants, have grown from a niche in the power system to the main driver of this transition. A recent report from the International Renewable Energy Agency (IRENA) suggested pathways to achieve 66% share of renewable energy sources in total final energy consumption (and 86% in electricity) by 2050 [1], while many more ambitious goals, such as 100% or near 100% renewable energy scenarios, have become more popular not only in public discussions but also in the academic circle: as of September 2019, 8 nations around the world have had near 100% share of renewable energy in their electricity generation portfolio, and 61 nations around the world have passed laws requiring a target of 100% renewable electricity [2]; in the last decade around 180 scientific articles on the technical feasibility and economic viability of power / energy systems running completely on 100% renewable energy sources have been published, around 80 of which in just the last two years [3].

To realize the ultimate goal of deep decarbonization and total transition to renewable energy sources, it is not sufficient to only study the optimized portfolios of the energy system in the future, but also we would need to know what kinds of regulations, policies, or market designs would be required to allow more renewable energy sources onto the grid, for the main driver of the energy transition, the VRE technologies, would fundamentally change the paradigms of how energy systems should be operated. In the recent reports of the International Energy Agency (IEA), it has been stressed more often than not that power system flexibility will be the key to getting more VRE power plants onto the grid [4]. Furthermore, IEA, along with IRENA and other institutes, categorized the transition towards more VRE penetration in the power system into 6 continuous phases, each having different main concerns and cost-effective solutions to the increasing demand of power system flexibility [4, 5].

According to the 6 phase categorization, one of the main challenges in the intermediate phases of the energy transition would be allowing the power system to accommodate 100% of electricity from renewable energy sources, with VRE being the majority, at any given time. Currently there are still some barriers ahead before system operators can achieve this goal; in particular, some of the flexibility services the power system requires are still provided by conventional power plants that have to run at a minimum power output. So long as these flexibility services are only provided by conventional power plants, they will always constitute to a certain level of "system must run", at which renewable energy sources can not penetrate further during times of abundance.

On the timescales of economic dispatch, the control reserve capacity that balances sudden fluctuations and forecast errors is the main flexibility service that results in this system must run. Thus, it was interesting for us to investigate a futuristic scenario where VRE power plants could, if technically feasible, provide such control reserve services and thereby make 100% renewable penetration possible; in particular, we chose Germany, which is currently in the intermediate phases of the energy transition, for the setup of our study.

1.2 Defining Flexible VRE

As mentioned in the previous section, our study focused on the control reserve services which the VRE power plants had the potential to contribute to. Therefore, in the remaining of this report, when we mention the term "flexible" VRE or "flexible" dispatchable renewables (DRE, such as bioenergy power plants or hydroelectric power plants), we would be referring to VRE or DRE power plants that are able to provide control reserve services and participate in the relevant electricity markets, unless otherwise specified. In contrast, "inflexible" VRE or DRE would refer to renewable energy sources that are not allowed to provide control reserve services.

We did notice that the flexibility requirements of a power system came in different timescales, and VRE and DRE power plants might be able to provide flexibility services of other timescales, as further elaborated in section 3.4. Readers should thus be aware of the ambiguity of the term "flexible" or "flexibility" that might arise when comparing our report with other pieces of literature.

There were several reasons why flexible VRE were of particular interest for investigation. Firstly, this operation mode would likely be necessary in the near future to achieve a cost-effective transition of the power system, before the large scale deployment of new energy storage technologies becomes possible: in [6, p.303], such mode was listed as the cost-effective measure to take during phase 3 of the 6 phases of integration of VRE power plants; by contrast, new storage solutions were listed as cost-effective only after phase 4. Secondly, as policy support mechanisms such as feed-in premiums (FiP) would gradually give way to more market-based policies, operators of VRE power plants would in theory have more incentives to participate in services beyond selling bulk electricity, which would require them to operate their VRE power plants flexibly.

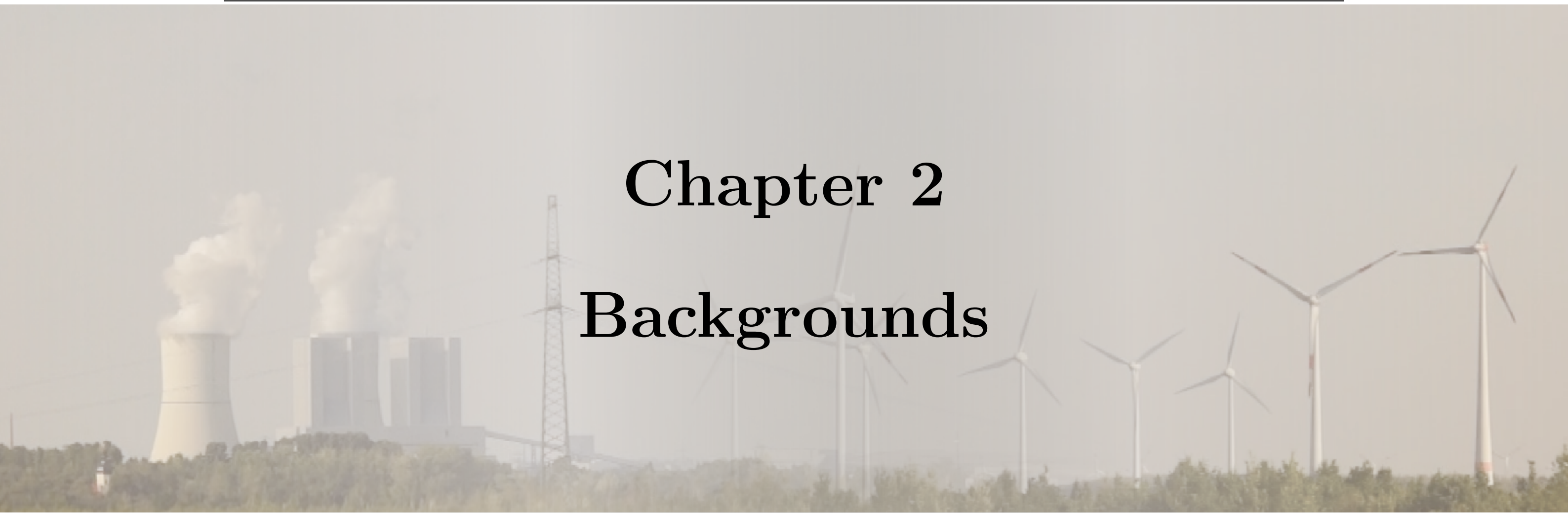
1.3 Problem Statement

Based on the discussions above, we state the research questions of this study as the following:

> *We would first like to know how VRE would behave in the electricity market, if they are allowed to provide control reserve services in the future.*
>
> *We would then like to know, at the intermediate phases of the energy transition in Germany, whether it will be possible for flexible VRE to enter the CRM in a scale relevant to the power system, without compromising its reliability.*
>
> *Finally, if such operation is possible, we would like to know in detail the system, environmental, and economic impacts flexible VRE will result in.*

1.4 Structure of the Report

The remaining of this report is structured as the following. In chapter 2 we will discuss the backgrounds of the electricity market and energy policies in Germany. In chapter 3 we will review existing pieces of literature relevant to our study. In chapter 4 we will describe the methods we used to simulate the electricity market in Germany in futuristic scenarios. In chapter 5 we will show the results from our simulations. In chapter 6 we will further discuss and analyze the results of chapter 5. In chapter 7 we will draw conclusions out of the study.



Chapter 2

Backgrounds

2.1 Backgrounds on the German Electricity Market

The German electricity market is part of the European Network of Transmission System Operators for Electricity (ENTSO-E); in which, two types of sub-markets were considered in the scope of our study: the energy only market (EOM), where participants trade bulk electricity with each other, and the control reserve market (CRM), where participants compete with each other to provide the balancing capacity and energy required by the transmission system operators (TSOs) for frequency control. In the framework of the ENTSO-E, the EOM includes day-ahead and intraday wholesale tradings, and the CRM includes the following types of control reserve services:

1. Primary Control: Primary control aims to stabilize the system frequency at a stationary value within a synchronous area after an incident in the time-frame of seconds [7, P1-4]. Under the current market design, primary control contains only 1 type of product and it is traded two days ahead (see table 2.1). In other pieces of literature, this type of service might be called frequency containment reserve or primary frequency response.

2. Secondary Control: Secondary control maintains power balance within each control area by modifying the active power set points or adjustments of generation sets / controllable load in the time-frame of seconds to 15 minutes after an incident [7, P1-12]. Under the current market design, secondary control contains 12 types of products and they are traded day ahead (see table 2.1). In other pieces of literature, this type of service might be called automatic frequency restoration reserve or frequency regulation reserve.

3. Tertiary Control: Tertiary control uses tertiary reserve that is usually activated manually by the TSOs in case of an observed or expected sustained activation of secondary control [7, P1-25]. Under the current market design, tertiary control contains 12 types of products and they are traded day ahead (see table 2.1). In other pieces of literature, this type of service might be called manual frequency restoration reserve or minute reserve.

After the results in the CRM and the day-ahead EOM are concluded, the TSOs might alter the scheduled operation plan in the EOM to avert transmission line congestion risks. This process is called redispatch [10]. Throughout the day when electricity is actually traded, the intraday EOM continues to take place, allowing the participants in the market to exchange deviations of electricity supply / demand from the scheduled day-ahead operation plan due to prediction errors. After the intraday EOM closes, the balancing responsibility shifts to the TSOs as they use the control reserve resources procured earlier to deal with the imbalances in the power system real time.

For renewable energy power plants, since currently they are not participating in the CRM, there might be an additional reason they would be asked by the system operators to dispatch downwards, besides transmission line congestion risks: the total renewable energy power output can not penetrate to such a level that the services provided in the CRM are threatened. Throughout this study, this level of power output reserved for system security reasons would be called the system

	Primary Control	Secondary Control	Tertiary Control
Auction Period	two-day-ahead	day-ahead	day-head
# of Products	1 (base)	12 (pos/neg; blocks of four hours)	12 (pos/neg; blocks of four hours)
Contract Duration	daily	four hours	four hours
Capacity Payment	yes	yes	yes
Energy Payment	no	yes	yes
Minimum Bid	1 MW	5MW	5MW
Response Time	30 secs, direct	$\leq$ 15 mins, direct	15 mins, direct or scheduled

Table 2.1: Different types of control in the German CRM. Adapted from [8], with auction periods and contract durations for primary and secondary control updated from [9].

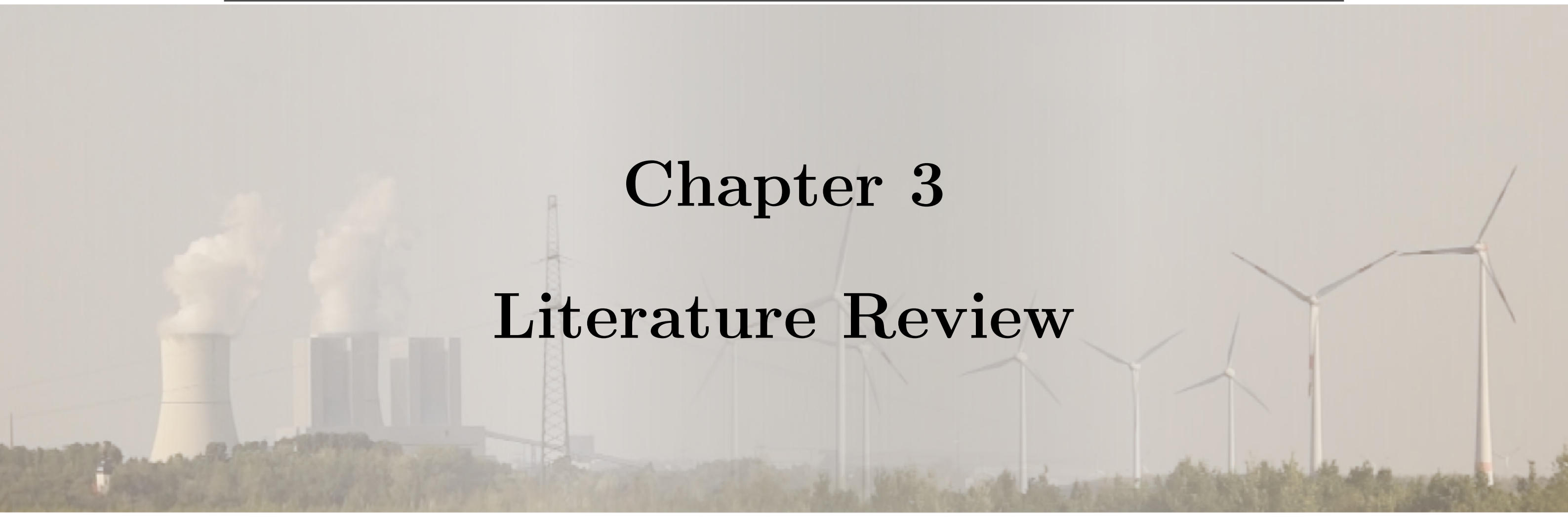
must run level, and the reduction of renewable energy power output due to this reason, voluntarily or not, would be defined as curtailment. The differentiation between downward dispatch due to transmission line constraints and system wide reasons for renewable energy power plants was discussed in depth in [11].

2.2 Backgrounds on the German Energy Transition

Our study required us to make futuristic assumptions of the conventional and renewable power plant fleet in Germany. To achieve so, we would rely on literature that set the power plant fleet of Germany in the future accordingly to existing energy policies. This meant that we were looking for futuristic scenarios with the following constraints:

1. All nuclear power plants would be shut down by 2022 [12].
2. At least 1/3 of the coal capacity would be shut down before 2022, another 1/3 before 2030, and the rest before 2038 [13].
3. The electricity share of renewable energy would reach 65% by 2030 [14] and 80% by 2050 [15].

Of course, since we were only interested in scenarios in the near future (where assuming no large scale installation of new energy storage technologies would be plausible), the constraints in the near to mid-term future above were more important for us throughout the study.



Chapter 3

Literature Review

3.1 Status of the EOM and CRM to Date

The role of the CRM has long been overlooked when modeling electricity markets, for obvious reasons: compared with the EOM, balancing markets have had a relative small market value; it represented 0.77 Euro/MWh, or only about 0.25% of the household electricity prices in Germany in 2014 [8], whereas the EOM corresponded to 39 Euro/MWh that same year. Meanwhile in the US, the value of EOM was 29.46 USD/MWh inside the markets of the Midcontinent Independent System Operator (MISO) and 30.99 USD/MWh inside the Mid-Atlantic region power pool (PJM) in 2017, while that of the ancillary services was 0.10 USD/MWh and 0.78 USD/MWh for the same year respectively [16, p.12].

For the purpose of this research, it was however necessary to include the CRM into our model in detail. Therefore, we chose to use a newly developed electricity market simulation model, *flexABLE*, in our research. A recent paper described in detail the modeling of market dynamics of the EOM and CRM in *flexABLE*, explaining how the opportunity costs of different conventional power plants would affect the bidding strategies of their operators in these two markets [17]. In particular, negative market clearing prices in the EOM and opportunity costs for participating in the CRM were elaborated in the paper. The co-optimization strategies of capacity and energy bids in the CRM was also an important topic we took note of from another paper [18] when we developed the extension features in *flexABLE* described in subsection 4.3.2.4.

It should be noted here that *flexABLE* is an agent-based simulation model. Therefore, our study could focus more on how different agents would behave in different scenarios, and how these changes of behaviors would impact the system and markets collectively, which were the core questions we would want to answer in our study.

A key aspect in the literature was how the markets have evolved empirically after more VRE had been integrated onto the grid. It was clear that due to the merit order effect in the EOM, the growth of VRE had decreased the wholesale prices in the EOM. On the other hand, since higher VRE penetration could lead to higher variability and uncertainty of the residual load profile, it might be tempting to think that TSOs had been increasing their control reserve demand dramatically in recent years due to more VRE power plants getting onto the grid. However, many counter examples have emerged in the past years:

1. In Germany, some researchers used the term "the German paradox" to describe the phenomena that prices and demand dropped in the German CRM, while share of VRE on the grid continued to grow. The term was first coined in [8], where the authors suggested among other factors, improvement of VRE power output and load forecast, reduced frequency of plant outages, and the cooperation of TSOs to be potential candidates to this phenomena. [19] suggested that the introduction of the 15-minute intraday EOM reduced the balanc-

ing demand, while grid control cooperation on the national and international level avoided uneconomical calls. Whatever the reason it has been, the reliability of the German power system has been improving in terms of system average interruption duration (and remained roughly the same in terms of system average interruption frequency) despite the growth of VRE [20].

2. In other parts of Europe, Energinet.dk reported that the total capacity of 4,800 MW of wind power plants and 600 MW of photovoltaic power plants by 2013 had not yet influenced the planned reserve used in their system then [21, p.56]. Ireland, though facing problems with system inertia due to it being an island grid, also experienced no additional reserve requirement during periods of high wind variability [21, p.59]. A 2011 conference paper also reported that no changes of reserve requirement had occurred in Ireland, Denmark, and Portugal, where wind penetration had already reached 11%, 21%, and 17% of the nations' electricity demand respectively at that time [22].

3. In the United States, almost no impact on the control reserve demand was observed after the MISO added 12 GW of wind capacity onto the system with a peak load of 100 GW [23]. In the power system of the Electric Reliability Council of Texas (ERCOT), only about 50 MW of fast-acting stand-by reserve was needed on average after 10,000 MW of wind was integrated onto the grid, after a ramp event forecasting tool was introduced and requirements for certain reserves were adjusted [24]. Other measures system operators in the US have taken included better forecasting tools and development of new flexibility products [25].

3.2 Control Reserve Demand Modeling to Date

Since we were studying futuristic scenarios, it was necessary for us to develop a method to model the control reserve demand of the power system under the demand load and VRE power output conditions we assumed for our simulations.

One method to model the demand of control reserve is to identify different types of imbalances by the timescale and frequency of occurrence. A technical report from the National Renewable Energy Laboratory (NREL) identified three common types of operating reserve a power system would need: regulating reserve, following reserve, and contingency reserve [27, p.8]. Regulating reserve covers the random fluctuations of generation and load on a seconds to minutes timescale, a direct result of the stochastic nature of VRE generation and power consumption [27, p.12-17]. Following reserve covers the variability and uncertainty that occur during normal conditions on a minutes to hours timescale; the variability results from the forecast load and VRE generation profile, while the uncertainty results from the forecast errors [27, p.18-20]. Contingency reserve covers rare events of sudden large loss of supply because of an unplanned outrage of a plant or a transmission line [27, p.20].

In the NREL technical report, it was mentioned that different regional TSO had different rules to determine the control reserve requirement. For example, in PJM, the regulating reserve was determined based on the highest 1% of the peak load during peaking load hours and the lowest 1% of the valley peak during off-peak hours, while in ERCOT it was based on the 98.8th percentile of regulating reserve utilized in previous 30 days and same month of previous year [27, p.40].

Another way to model the demand of control reserve for a power system is to identify different sources of imbalance. Sources of imbalances were categorized by the nature of the imbalance (stochastic / deterministic) and the agents that induced them in [8], as shown in table 3.1. This method of categorization enables one to calculate the positive and negative control reserve requirements at a desired level of power system reliability (ex. a loss of load expectation that is less than 0.1% per year), should the probably distribution of all sources of imbalance be known.

One simple way to determine the control reserve demand, then, is to calculate the required control reserve for different sources of imbalances independently, neglecting the correlations of different

	Stochastic	Deterministic
Conventional Generation	noise, unplanned plant outages	schedule leaps
VRE Generation	noise, forecast errors	
Interconnectors	unplanned line outages	
Load	noise, forecast errors	

Table 3.1: Different sources of power system imbalances. Adapted from [8]

stochastic sources. A recent report that dived into the potentials of flexible photovoltaic power plants used this method when calculating the forecast errors of photovoltaic power output and demand load by analyzing historical forecast error statistics [28, Appendix A]. It then calculated the deterministic control reserve (termed as regulation reserve in the report) demand separately, and used a rule of thumb to determine the contingency reserve demand. A more sophisticated method would be the Graf/Haubrich approach, where the convolution of different stochastic sources is calculated [8].

Unfortunately for our research, we were unable to model the control reserve demand as in [28, Appendix A] or in [8], since we only had the day-ahead forecast errors of the VRE power output and the demand load. These errors would be too large for estimating the control reserve demand; most of them would be balanced out in the intraday EOM. We therefore developed our own probabilistic approach to model the control reserve demand, as described in section 4.2. Of the methods we mentioned in this section, our method resembled the one used in ERCOT the most.

3.3 Control Reserve Demand in the Future

Since our futuristic scenarios involved a significant growth of the VRE capacity in the power system, it was necessary for us to determine whether this growth would affect the control reserve demand significantly enough[1] that we had to take it into account accordingly in our control reserve demand model.

Without considering other factors, a higher penetration rate of VRE will increase the variability and uncertainty of the residual load profile. A recent study thus suggested significantly higher price shares and more frequent high-priced hours of the ancillary services in high VRE scenarios when compared with a reference low VRE scenario [29, p.30]. Older studies and research works gathered by NREL also drew to the summary that an increased amount of VRE would require more regulating or following reserve to achieve the same power system reliability [27, p.85]. Another review paper in 2014 reported that an addition of about 7% of installed wind capacity would be needed for secondary and tertiary reserve at a 20% penetration of wind power, and this requirement would increase 0.2% for every additional penetration rate up to 50% share of wind power in the system [30], as shown in table 3.2. In regions where renewable penetration has just begun to increase, the increase of the variability and uncertainty of the residual load profile also raises many concern as operators there have not yet learnt to deal with these types of challenges yet [31, Section 4.2].

However, just as the intuitive connection between VRE and control reserve demand was proven to be wrong empirically in the "German paradox" [8, 19] and other cases as described in section 3.1, some simulations of futuristic scenarios were also implying that a higher penetration level of VRE would not necessary lead to a same level of control reserve demand growth.

For one thing, the capacity value of VRE remained relatively high enough to reduce the contingency reserve in those simulations, while flexibility issues remained comparatively insignificant. For instance, at a penetration level of 12.2% in 2016, onshore wind power in MISO still accounted

[1]To be more precise, it was the impact on the extreme value statistics that mattered to us the most when modeling the demand of control reserve capacity.

Types of Impact	Value at 20% Wind	Function/observations
Primary Reserve	0.6% of installed wind capacity	$y = 0.015x + 0.002$
Secondary and Tertiary Reserve	7% of installed wind capacity	$y = 0.20x + 0.03$

Table 3.2: Summarized impacts of wind power penetration on the control reserve demand in the literature, valid up to 50% penetration level. Adapted from [30]. Here y is the respective additional control reserve demand (in percentage of installed wind power plant capacity), x is the share in total electricity generation of wind power plants.

for an average equivalent load carrying capability (ELCC) of 15.5% [32]. [33, p.29] revealed that the ELCC of onshore wind power in PJM would remain at 14%-17% even at a VRE penetration level of 30%, which was roughly the same compared with a VRE penetration level of 14% or 20%. Therefore, though a higher share of VRE increases the LOLE due to shortage of flexible sources to meet the regulation and following reserve requirements, it might lower the risk of LOLE due to unplanned outage more and thus improves power system reliability in the end, which was the case in [34]. A study on PJM also suggested that no extra operating reserve would be needed with a 30% penetration of VRE, since a lack of flexibility only occurred at very extreme cases in the simulation and did not exceed the reliability standards of the grid [35]. In summary, the frequency of the activated control reserve capacity might increase as VRE capacity expands, but its extreme values will not increase as significantly.

An important factor that might contain the growth of control reserve demand will be VRE forecast improvement. This will reduce the forecast errors along with the needed conventional generation to provide regulating and following reserve. [36] studied the generation cost savings when forecast errors were improved, and found that systems with a less flexible conventional power fleet and scenarios with higher VRE penetration levels would benefit the most from the improvement, with a maximum saving potential up to 5.84% in a scenario of wind penetration level at 51.64% in the power system of the California Independent System Operator (CAISO). [37] reported that marginal total generation cost savings for improvement of VRE forecasts would be 0.41% per percentage point reduction in maximum absolute forecast error when using a stochastic scheduling model.

Other sources suggested a new market design of the balancing market to utilize existing flexibility resources more efficiently. Wind Solar Alliance called for more flexible products and allowing contingency reserve to accommodate abrupt drops in VRE output [16, p.25]. Wind Europe urged the system must run level to be kept at a minimum and redispatching actions due to system balancing issues should be fully disclosed to inform the public about the cost of inflexibility of the system [38]. Restructuring the conventional power fleet and making it more flexible could also lower the balancing costs of the power system in the future [39, p.16-17].

3.4 Flexible VRE

The final task during our literature review process was to confirm the technical feasibility of flexible VRE. Are VRE power plants actually capable of operating flexibly to deliver ancillary services? If so, how much value could flexible VRE bring to the system or the power plant operators?

Ancillary services can be divided into three groups: frequency control, voltage control, and system restoration [40]. Wind farms, if operated flexibly, can in theory provide all the frequency and voltage control services with no or little technical issues [40]. On the other hand, only large scale solar farms will be able to provide frequency and voltage control without major technical barriers, while small scale photovoltaic systems need to be pooled in a portfolio [40]. [41] reported that wind and photovoltaic power plants had “good” to “very good” capabilities of providing frequency sta-

Reliability Service	Wind	Photovoltaic
Voltage control	O	O
Disturbance ridethrough	O	Δ
Frequency stabilization	Δ	Δ
Frequency regulation	Δ	Δ
Ramping	Δ	Δ

Table 3.3: Summary of the reliability services flexible VRE can provide. O: Technically feasible and market conditions sufficient for large scale deployment. Δ: Technically feasible but market conditions insufficient for large scale deployment. Adapted from [42]

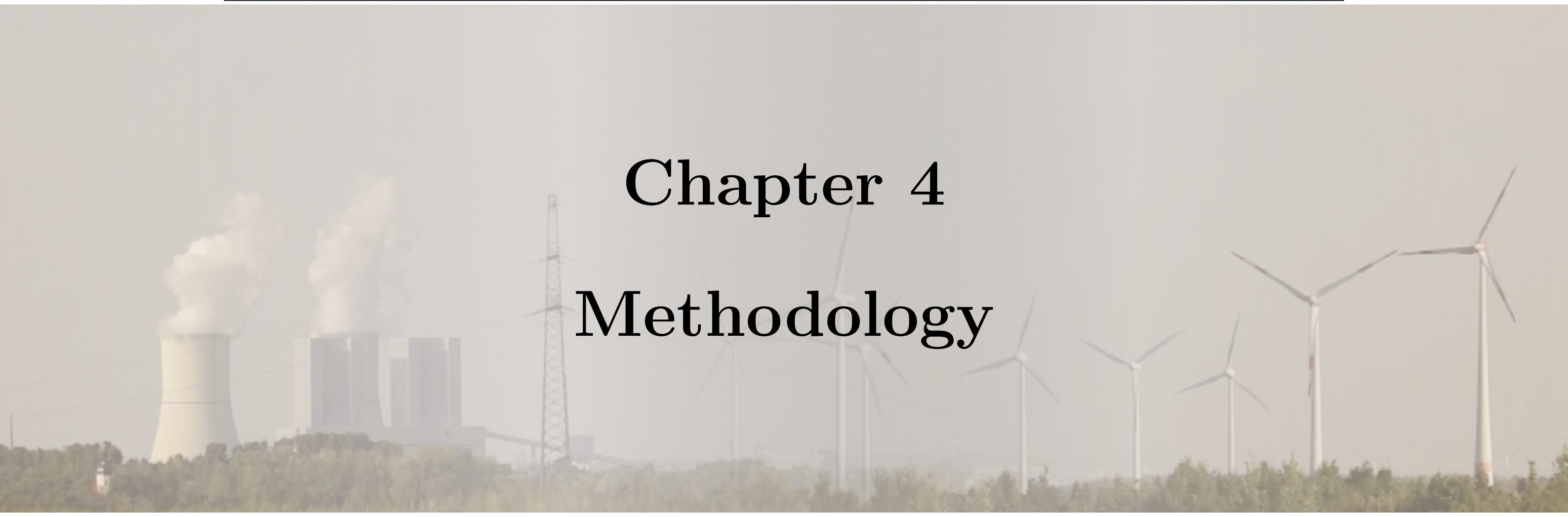
bilization, restoration, and regulation services. [42] summarized that wind and photovoltaic power plants had the technical capability to provide all major frequency and voltage services, though they might face regulatory challenges.

The technical feasibility of providing these services has also been proven on site for both wind and photovoltaic power plants. A study in 2014 demonstrated how a wind turbine can perform automatic generation control with a torque-speed tracking controller [43, p.109-111]. Recent study of a 300 MW solar farm in California has demonstrated that it is indeed possible to operate solar farms in a flexible manner such that they can provide many important frequency and voltage control services, even performing better than conventional sources in some cases [44].

Other pieces of literature investigated the economic value of flexible VRE, and how they will affect the power system. [8] gave arguments for VRE power plants participating in the CRM based on opportunity cost evaluations from a micro-economic perspective. Since they have no minimum power output constraints and almost no marginal costs, VRE power plants would always be a cost-effective measure to provide negative control reserve. On the other hand, it would also be cost-effective for VRE power plants to provide positive control reserve during low wholesale price events in the EOM, especially if they are not given guaranteed levels of feed-in premiums.

From a system cost perspective, [45] calculated the total system cost savings in different regions once VRE were allowed in the ancillary services. It suggested that the introducing of flexible VRE would have significant system cost savings beyond 20% penetration of VRE in Ireland, but the savings would be less in Iberia or Europe [45, p.28]. Another research work suggested that if all the wind power plants in Germany were pooled as one single virtual power plant, it could in theory reduce the cost of providing secondary reserve by 24% and by 21% for tertiary reserve at a security level of 99.99% [46]. A recent study on flexible photovoltaic showed that under the fully flexible mode, photovoltaic power plants would have 50% more energy value on average when compared with the curtailment only mode [28, p.39]. Note that in [46] what was calculated as the economic value was the direct cost savings in the CRM due to a more competitive market, while in [45] and [28] indirect system impacts such as the reduction of fossil fuel consumption and less curtailment of VRE power output were also taken into account to determine the real value of flexible VRE. Based on the results of [28], [47] recently suggested the consumers would save 0.30$ to 1.81$ USD per MWh of electrcity in PJM and MISO, if renewable energy power plants and energy storage units were allowed to provide reliability services in related markets.

Although the feasibility of flexible VRE has been proven technically possible and their potential value calculated, the market design of current power systems provides inadequate, if any, incentives for VRE power plant operators to dispatch their power plants flexibly. Both the academic field and the renewable energy industry thus called for a reform of market design to encourage VRE into participating in the CRM. In particular, [8] and [48] noted that the duration of balancing products should be shortened so that VRE would be able to provide firm reserve. From the viewpoint of the renewable energy industry, other suggestions such as shortening the lead time of the market and allowing hybrid products into the CRM were also key amendments for building an electricity market friendly to flexible VRE [16, 48].



Chapter 4

Methodology

4.1 Input Data

In this study, we gathered the following input data for the simulation:

1. *Predicted and Actual VRE Power Output.* The VRE power output data was gathered from the website SMARD [49]. The data included the total power output of onshore wind power plants, offshore wind power plants, and photovoltaic power plants in Germany in the year 2018, with a time resolution of 15 minutes. Time series of day-ahead prediction[1] and actual output were both included. The original data was in units of energy (MWh), and was converted into units of power (MW) when fed into *flexABLE.*

2. *Predicted and Actual Load.* The demand load data in Geramny in the year 2018 was gathered from the website SMARD [49]. The data had a time resolution of 15 minutes. Time series of day-ahead prediction[2] and actual output were both included. The original data was in units of energy (MWh), and was converted into units of power (MW) when fed into *flexABLE.* Although it was possible to integrate heat demand in *flexABLE*, we did not do so. This meant the synergistic benefits of co-generation from fossil fuel power plants and bioenergy power plants, along with the broader use of P2H, were not considered in our study.

3. *Accepted and Activated Secondary and Tertiary Control Reserve.* The CRM data in Germany from the year 2015 to 2018 was gathered from the website SMARD [49]. The data had a time resolution of 15 minutes. Time series of both positive and negative control reserve were included. Primary control reserve was not included mainly because it was not available on the website, but also because its time scale and activation mechanisms did not correspond to the power system flexibility relevant to our study. The original accepted control reserve data was in units of power (MW), while the activated control reserve data was in units of energy (MWh) and was converted into units of power (MW) when fed into *flexABLE.*

4. *VRE and DRE Capacity.* The installed capacity of VRE power plants (including offshore wind power plants, onshore wind power plants, and photovoltaic power plants) and DRE power plants (including geothermal power plants, waste power plants, hydroelectric power plants, and bioenergy power plants) in Germany in the year 2018 was obtained from the website Energy Charts [51] and Open Power System Data [52]. For VRE capacity in futuristic scenarios, we referred to the year 2025 in the "Energiewende-Referenz" (energy transition reference) scenario as described in [53]. For DRE we assumed no change in capacity in futuristic scenarios. The resulting VRE and DRE capacity of Germany in the year 2018 and our futuristic scenarios is shown in table 4.1. During the simulation, we divided the capacity of each VRE and DRE technology into ten identical pools and assumed that each

[1] According to the website of ENTSO-E [50], the day-ahead prediction should be published no later than 18:00 the day before the operation in the EOM takes place.

[2] According to the website of ENTSO-E [50], the day-ahead prediction of the demand load should be published no later than 2 hours before the day-ahead market closes, which would be 10:00 the day before the operation in the EOM takes place for Germany.

Year	2018	2025
Offshore Wind	6.410 GW	18.000 GW
Onshore Wind	53.010 GW	64.000 GW
Photovoltaic	45.930 GW	72.000 GW
Geothermal	0.042 GW	0.042 GW
Waste	0.255 GW	0.255 GW
Hydroelectric	3.000 GW	3.000 GW
Bioenergy	7.730 GW	7.730 GW
Total	116.377 GW	165.027 GW

Table 4.1: VRE and DRE Capacity of Germany in Different Years of Simulation

Year	2018	2025
Nuclear	10.013 GW	0.000 GW
Lignite	20.875 GW	8.862 GW
Hard Coal	27.716 GW	8.284 GW
CCGT	16.517 GW	16.517 GW
OCGT	5.470 GW	30.140 GW
Oil	3.115 GW	5.839 GW
Pump Storage	6.087 GW	6.087 GW
Total	89.793 GW	75.729 GW

Table 4.2: Conventional Power Plant Fleet of Germany in Different Years of Simulation

pool was operated independently so that the entering / exiting of any single pool in the EOM would not cause an abrupt change of results between two consecutive time steps during the simulation.

5. *Technical and Economical Parameters of Conventional Power Plants and Energy Storage Units.* The database in the existing *flexABLE* program contained information of the maximum capacity, minimum power output, efficiency, ramp up and ramp down rate, variable and start up costs, ..., and all the relevant technical and economical parameters of the existing conventional power plants and energy storage units in Germany as of 2018. For futuristic scenarios, we referred to the year 2025 in the "Energiewende-Referenz" scenario as described in [53] for the total power capacity of nuclear, lignite, and hard coal power plants, which would be in line with the existing nuclear and coal phase out policies described in section 2.2. We assumed that the lignite and hard coal power plants were retired in an orderly fashion, starting from the oldest ones. Meanwhile, we assumed that all the CCGT, OCGT, and oil power plants were kept. In addition, some lignite and hard coal power plants were assumed to be turned into OCGT and oil power plants, while no additional energy storage unit was added. The resulting conventional power plant fleet of Germany in the year 2018 and our futuristic scenarios is shown in table 4.2.

   The technical and start up parameters of different conventional technologies are given in table 4.3 and table 4.4. It should be noted that the flexibility parameters of the conventional power plants inside the database (table 4.3) were estimations of their technical limits, which might not be reached in practice. For example, in this study we assumed that nuclear power plants had a minimum power output 40% of their maximum capacity, while historically they rarely reduced their power output to 70% of their maximum capacity in Germany [54]. Deutsches Institut für Wirtschaftsforschung (DIW) also reported much lower values of ramping rates for the conventional power plants in reality [55]; for example, although new lignite power plants had the technical potential to ramp 2 to 4% of the nominal capacity per minute, in reality it would only ramp 0.58% of the nomimnal capacity in the Nordic market. However, there had been an increase in both the frequency and the scale of flexible operations from lignite power plants observed in the German EOM in the recent years [56, p.54] [57, p.24]; throughout the year 2019, such flexible operations from the entire German lignite power plant fleet have become more common due to further VRE penetration levels and higher carbon prices [58].

   The fuel prices, carbon prices, and carbon emission factors used in the simulations are given in table 4.5. The fuel prices already existed in the original database of the program *flexABLE*, and we assumed them to be the same by 2025. The carbon emission factors were based on reported values in [59, 60][3]. Furthermore, we assumed a carbon price of 50 EUR/tonne

[3] We assumed the fuel of bioenergy to be carbon neutral, and neglected the emissions due to deposit and management of used uranium, thus the emissions of both bioenergy and nuclear might be underestimated, though the values would still certainly be way below the range of those from burning fossil fuel.

Units	Min. Power % P_{max}	Max. Ramp Rate % P_{max} / 15 min	Operation Time Min. hr	Down Time Min. hr
Nuclear	40	60	72	10
Lignite	40	45	10	7
Hard Coal	40	67.5	7	6
CCGT	40	75	5	3
OCGT	20	100	0	0
Oil	20	100	0	0

Table 4.3: Technical Parameters of Conventional Power Plants

Time after Last Shut Down		Hot Start 0-8 hr	Warm Start 8-48 hr	Cold Start >48 hr
Nuclear	Cost (EUR/MW)	140	140	140
	Fuel (MWh_{th}/MW)	16.7	16.7	16.7
Coal $> 300MW$	Cost (EUR/MW)	29.6	46.3	67.5
	Fuel (MWh_{th}/MW)	3.56	5.7	11.28
Coal $\leq 300MW$	Cost (EUR/MW)	44	72.1	71.3
	Fuel (MWh_{th}/MW)	3.56	5.7	11.28
CCGT	Cost (EUR/MW)	23.5	33.4	45.5
	Fuel (MWh_{th}/MW)	1.5	1.5	4.5
OCGT $\geq 50MW$	Cost (EUR/MW)	16.7	21.2	28.8
	Fuel (MWh_{th}/MW)	0.02	0.02	0.06
OCGT $< 50MW$	Cost (EUR/MW)	9.1	9.1	9.1
	Fuel (MWh_{th}/MW)	0.02	0.02	0.06
Oil	Cost (EUR/MW)	19.7	34.9	44
	Fuel (MWh_{th}/MW)	0	0	0

Table 4.4: Start up parameters of conventional power plants. The start up costs were given in the existing database of *flexABLE*. The start up fuel consumption requirements were obtained from [55]. When calculating the carbon emissions in the latter chapters, we assumed all the conventional power plants used oil as fuel for starting up.

Units	Price 2018 EUR/MWh_{th}	Price 2025 EUR/MWh_{th}	Carbon Emission t $CO_{2\,eq}/MWh_{th}$
Bioenergy	20.7	20.7	0.000
Uranium	0.9	0.9	0.005
Lignite	1.44	1.44	0.340
Hard Coal	9.52	9.52	0.325
Gas	24.9	24.9	0.200
Oil	33.39	33.39	0.267
Carbon	20	50	NA

Table 4.5: Fuel prices, carbon prices, and fuel-related carbon emission factors of different technologies. For carbon prices, the unit is EUR/$CO_{2\,eq}$.

$CO_{2\,eq}$ by 2025, taking into account the rapid rise of prices on the European Union Emissions Trading System lately.

4.2 Control Reserve Model

The input data gathered as mentioned in section 4.1 was used to model the required positive and negative control reserve for each 15-minute-long time step t. Note that for the time resolution of our modeling, we only took into account the data of secondary and tertiary control reserve. The control reserve was modeled assuming that:

1. The growth of VRE did not significantly change the extreme value statistics of the required positive and negative control reserve (as argued in some of the literature in section 3.3).
2. The required positive and negative control reserve was a function of predicted load and VRE power output.
3. Events where predicted load and VRE output were similar tended to also have similar probability density functions for activated positive and negative control reserve.

Under these assumptions, we chose the following procedure to reconstruct the probability density functions for activated positive and negative control reserve at each time step t:

1. We constructed empirical orthonormal functions (EOF) from the normalized predicted load and VRE power output data and calculated the scores of each time step t. This was done by performing an eigenvector decomposition first and then finding the dot product of the sample points and the EOF. For more details of the method, please refer to appendix A.1.
2. We built a kernel function that maps pairs of the normalized scores onto a distance metric. The control reserve of a particular time step t was modeled by constructing empirical cumulative distribution functions (ECDF) of the activated positive and negative control reserve. The ECDF for each time step t was constructed using the distances between the score of the time step t and the scores of the historical data as the weights. For more details of the method, please refer to appendix A.2.
3. For a given reliability criteria α (which we took, based on historical data, as 1%) it was then possible to determine the positive and negative control reserve that was required such that the probability of activating positive or negative balancing energy of an amount greater than the accepted control reserve would be smaller than α. Except for a reference scenario based on the power system in 2018 (where the actual data was available), the activated positive and negative control reserve was then modeled from random sampling the ECDF constructed.

Note that through this method we preserved the extreme values from the original data in our model, while taking into account the change of ECDF due to the change of the variables; thus our assumptions were honored.

4.3 Electricity Market Model

Sophisticated schemes to model the bidding strategies of conventional power plants and the sequence of actions in the EOM and CRM had already being developed in the previous versions of the program *flexABLE*, as described in [17]; figure 4.1 is a summarized schematic chart of how the program modeled the electricity market: input time series such as the demand load, the control reserve demand, the actual balancing energy, and VRE power output were fed into the program, in which the CRM and EOM would be modeled accordingly, time step by time step. The market conditions in the EOM would be updated for every 15-minute-long time step t and those in the CRM for every 4-hour-long time step τ; activated balancing energy demand would alter the power output of the corresponding power plants for every time step t, and they would also bid accordingly in future time steps.

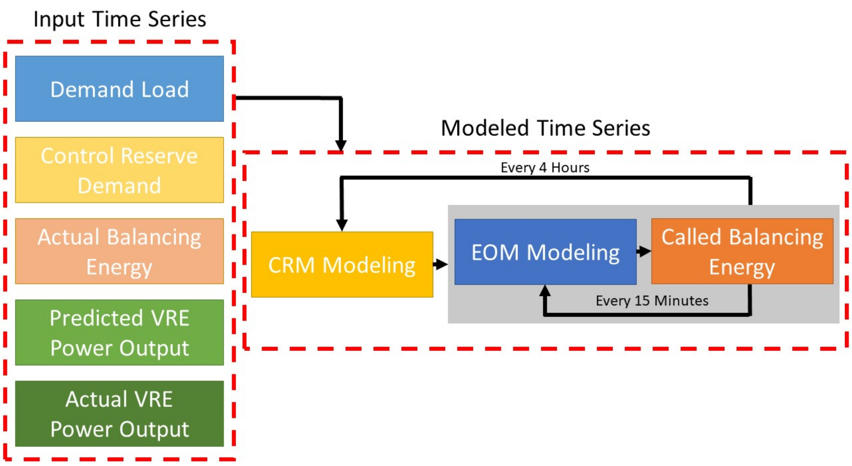


Figure 4.1: Summarized Schematic Chart of the Program *flexABLE*

Based on the existing schemes, we had extended some features of *flexABLE* for the purposes of our study. These extensions are listed below.

4.3.1 Extension of Features in the EOM

4.3.1.1 VRE and DRE Power Plants

Since the program *flexABLE* performed dynamic simulations where agents would make decision at each time step t according to previous market results, we assumed that VRE power plant operators had perfect knowledge of the actual maximum available power output of their power plants and thereby bid accordingly in the EOM.

VRE power plant operators would bid the marginal costs of power production (which was considered to be 0 in our study) in the EOM if no feed-in premium was given to them for selling green energy. If they did receive feed-in premiums that made their revenue independent of the fluctuation of market prices, they would then bid the lowest possible price allowed.

Although the lowest possible bidding price in the EOM would be -3000 EUR/MWh, we set the bidding prices of VRE with feed-in premiums to be -200 EUR/MWh in the EOM, acknowledging the fact that system operators would find curtailment of VRE power output more cost-effective when the bidding prices of conventional power plants was lower than the compensation of downward dispatch for VRE power plant operators[4].

DRE power plant operators would bid similarly to VRE power plant operators in the EOM, but their power plants were assumed to always have 100% of their nominal capacity as their actual maximum available power output[5]. For bioenergy power plants there were also fuel costs associated during operation.

[4]200 EUR/MWh was a parameter we chose arbitrarily. The average compensation for the feed-in management of renewable energy power plants was 94.11 EUR/MWh between 2009 and 2017 [61, p.136 and p.141], but the figure had been growing steadily so we assumed a higher value for it by 2025

[5]Hydroelectric power plants are fully dispatchable in the timescales of daily operations, but they face other operation constraints due to seasonal hydrology variations and the multi-purpose use of the reservoirs. Therefore, in our study we added an operation constraint such that the power output of hydroelectric power plants could not exceed the corresponding historical value at any given time step t.

4.3.1.2 Conventional Power Plants

The operators of the conventional power plants were able to determine the expected on-line / off-line time of their power plants after the default merit order simulation and an additional trial simulation were carried out. Together with the expected price forward curve in the EOM, it would help the power plant operators make commitment decisions.

For conventional power plants that were off-line, participating in the EOM required start up costs additional to the marginal production costs. To determine the bidding prices in the EOM, the operators would first consider the expected profit of running the conventional power plant i at time step t, $EP_{t,i}^{CPP,on}$, within the expected on-line time $ET_{t,i}^{CPP,on}$, which was defined as the following:

$$EP_{t,i}^{CPP,on} = \sum_{j=t}^{t+ET_{t,i}^{CPP,on}-1} (M_{EOM,j}^{PFC} - mc(\eta)_{j,i}^{CPP}) \cdot P_i^{CPP,max} - c_{t,i}^{CPP,su} \tag{4.1}$$

Here $M_{EOM,t}^{PFC}$ is the expected price in the EOM at time step t, $mc(\eta)_{t,i}^{CPP}$ the efficient-dependent marginal cost of the conventional power plant i at time step t, $P_i^{CPP,max}$ the maximum capacity, and $c_{t,i}^{CPP,su}$ the start up cost.

If $EP_{t,i}^{CPP,on}$ was positive for the conventional power plants, then the operators of the plants would not need to raise their bids to cover the start up costs and they would bid the marginal cost $mc(\eta)_{t,i}^{CPP}$ for both the must run and flexible part of the capacity in the EOM. However, if $EP_{t,i}^{CPP,on}$ turned out to be negative, then the bidding prices for these power plants would be determined by the following formula:

$$B_{EOM,t,i}^{CPP} = -\frac{EP_{t,i}^{CPP,on}}{P_i^{CPP,max}} + mc(\eta)_{t,i}^{CPP} \tag{4.2}$$

Here $B_{EOM,t,i}^{CPP}$ is the bidding price in the EOM of the conventional power plant i at time step t. Note that the operators would bid the same price for the must run part and the flexible part of the capacity, since if their power plants could participate in the EOM at the time step t, it would be more preferable to run them at maximum capacity.

Meanwhile, shutting down conventional power plants that were on-line would require additional start up costs in the future. The bidding prices of the must run part of the capacity for these power plants might therefore be reduced, given the fact that staying on line would avoid the start up costs. The expected additional loss of getting off line for the conventional power plant i at time step t, $EL_{t,i}^{CPP,off}$, within the expected off-line time $ET_{t,i}^{CPP,off}$, was given as:

$$EL_{t,i}^{CPP,off} = \sum_{j=t}^{t+ET_{t,i}^{CPP,off}-1} (M_{EOM,j}^{PFC} - mc(\eta)_{j,i}^{CPP}) \cdot P_i^{CPP,min} + c_{t,i}^{CPP,su} \tag{4.3}$$

Here $P_i^{CPP,min}$ is the minimum power output of the conventional power plant i. If $EL_{t,i}^{CPP,off}$ was negative for the conventional power plants, staying on line would lead to a net loss of profit within $ET_{t,i}^{CPP,off}$, and the power plant operators would bid the marginal cost $mc(\eta)_{t,i}^{CPP}$ in the EOM for both the must run and flexible part of the capacity. However, if $EL_{t,i}^{CPP,off}$ turned out to be positive, the power plant operators would consider lowering their bidding prices in the EOM for the must run part in order to avoid a greater loss due to shutting down the power plant and restarting it later. The resulting bidding price would be:

$$B_{EOM,t,i}^{CPP,mr} = -\frac{EL_{t,i}^{CPP,off}}{ET_{t,i}^{CPP,off} P_i^{CPP,min}} + mc(\eta)_{t,i}^{CPP} \tag{4.4}$$

In our simulations, equation 4.4 was the origin of the negative market clearing prices between -200 and 0 EUR/MWh in the EOM. The mr notation in $B^{CPP,mr}_{EOM,t,i}$ indicates that this is the must run part of the capacity.

Comparing equation 4.2 and 4.4 one can see that there is an additional $ET^{CPP,off}_{t,i}$ term in the denominator for the negative bidding prices of on-line conventional power plants. We added this term because we observed that extreme low price events in the EOM tended to have longer durations of time than the extreme price peak events (which were usually abrupt and volatile), thus it was more reasonable for conventional power plant operators to assume that the prices would continue to stay at a similar low level for a long period of time when extreme low prices occurred than to assume the same would hold true when extreme high prices occurred. Of course, this bidding strategy should be further scrutinized in the future versions of *flexABLE*.

4.3.1.3 Energy Storage Units

We updated the bidding scheme of energy storage unit operators in the EOM. The operators would now examine the minimum unconstrained-operation timespan (MUOT) of their energy storage units. MUOT was defined as the sum of minimum timespans that a energy storage unit could operate without reaching the minimum / maximum state of charge limits when it was discharged / charged continuously. It was defined by the following formula:

$$MUOT^{ESU}_{EOM,t,i} = \underset{(1)}{\frac{(SOC^{ESU}_{t,i} - SOC^{ESU}_{min,i}) \cdot \eta_{dc,i}}{P^{ESU,dc}_{max,i}}} + \underset{(2)}{\frac{SOC^{ESU}_{max,i} - SOC^{ESU}_{t,i}}{P^{ESU,ch}_{max,i} \cdot \eta_{ch,i}}} \tag{4.5}$$

Here $MUOT^{ESU}_{EOM,t,i}$ is the MUOT of the energy storage unit i at time step t, $SOC^{ESU}_{t,i}$ the state of charge, $SOC^{ESU}_{min,i}$ the minimum state of charge, $\eta_{dc,i}$ the discharge efficiency, $P^{ESU,dc}_{max,i}$ the maiximum discharge power, $SOC^{ESU}_{max,i}$ the maximum state of charge, $P^{ESU,ch}_{max,i}$ the maximum charge power, and $\eta_{ch,i}$ the charge efficiency. (1) in equation 4.5 is the timespan for the discharge process, and (2) the timespan for the charge process.

After knowing the MUOT of the energy storage units, it would then be possible to compare the expected prices in the EOM within this timespan. For the operators of the energy storage units, the optimal bidding strategy within this timespan was to charge at times when prices were the lowest and discharge at times when prices were the highest; the operators would gain revenue by the spread between the two.

The task for the operators of energy storage units, then, was to determine the bidding prices for charge / discharge at time step t. To achieve so, operators would sort the expected prices in the EOM within the MUOT from both increasing and decreasing directions and transform these prices by the following formulas:

$$\begin{aligned} (1) \quad AMC^{ESU,ch}_{EOM,t,i}(E^{ESU,ch}_{EOM,t,i}) &= \frac{MC^{PFC}_{EOM}(\frac{E^{ESU,ch}_{EOM,t,i}}{\eta_{ch,i}})}{\eta_{ch,i}} + var_{ch,i} \\ (2) \quad AMR^{ESU,dc}_{EOM,t,i}(E^{ESU,dc}_{EOM,t,i}) &= MR^{PFC}_{EOM}(E^{ESU,dc}_{EOM,t,i} \cdot \eta_{dc,i}) \cdot \eta_{dc,i} - var_{dc,i} \end{aligned} \tag{4.6}$$

Where $AMC^{ESU,ch}_{EOM,t,i}$ and $AMR^{ESU,dc}_{EOM,t,i}$ are the adjusted marginal cost / revenue of charge / discharge for the energy storage unit i at time step t, while MC^{PFC}_{EOM} and MR^{PFC}_{EOM} are the default marginal cost / revenue of charge / discharge derived from the expected price forward curve; $var_{ch,i}$ and $var_{dc,i}$ are the variable cost of charge / discharge.

In equation 4.6, the (adjusted) marginal cost / revenue are functions constructed by taking the cumulative charge / discharge energy $E^{ESU,ch}_{EOM,t,i}$ and $E^{ESU,dc}_{EOM,t,i}$ as the argument and the corresponding prices in the EOM as the value. Marginal costs were sorted increasingly while marginal revenues decreasingly by the corresponding prices in the EOM; if the argument of the functions exceeded the charge / discharge limits within the MUOT, the functions returned the maximum / minimum (adjusted) marginal cost / revenue.

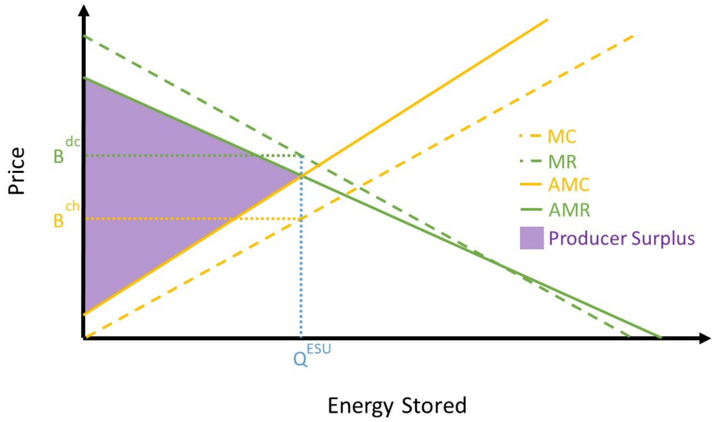


Figure 4.2: A schematic graph of how energy storage units in our model bid in the EOM. All abbreviations in the graph are similar to what we have used in this section. Q^{ESU} represents the optimal amount of energy storage the ESU should charge / discharge within its MUOT. The filled purple area represents the expected producer surplus of the ESU within its MUOT.

The bidding prices of the operators of the energy storage units were then determined by the following formulas:

$$\begin{aligned} (1) \quad B^{ESU,ch}_{EOM,t,i} &= max\{MC^{PFC}_{EOM}(\frac{\cdot}{\eta_{ch,i}})|AMC^{ESU,ch}_{EOM,t,i}(\cdot) \leq AMR^{ESU,dc}_{EOM,t,i}(\cdot)\} \\ (2) \quad B^{ESU,dc}_{EOM,t,i} &= min\{MR^{PFC}_{EOM}(\cdot\, \eta_{dc,i})|AMC^{ESU,ch}_{EOM,t,i}(\cdot) \leq AMR^{ESU,dc}_{EOM,t,i}(\cdot)\} \end{aligned} \tag{4.7}$$

Here $B^{ESU,ch}_{EOM,t,i}$ is the bidding price for charge of energy storage unit i at time step t and $B^{ESU,dc}_{EOM,t,i}$ the bidding price for discharge. If the market clearing price in EOM turned out to be lower than $B^{ESU,ch}_{EOM,t,i}$, the energy storage unit would charge; if it was higher than $B^{ESU,dc}_{EOM,t,i}$ the unit would discharge; if it was in between the bidding prices the unit would stay at rest.

From the operation plans of our simulation results (see figure 6.35 to figure 6.43), one can easily see that the bidding scheme of energy storage unit operators was still far from perfect. Since all the pump storage units had similar technical parameters in our model, they would tend to charge / discharge simultaneously, which would deviate the market clearing prices significantly compared with what energy storage unit operators had expected and relied on for planning their bids.

We might solve this problem in future versions of *flexABLE* by having the energy storage unit operators plan their bids with a price forward curve that takes into account potential charge / discharge behavior of the entire energy storage fleet in the power system. However, if future applications of the program involve energy storage units that have fundamentally different technical parameters, such as battery units or P2G storage units, a new bidding scheme for the energy storage units might have to be adopted.

4.3.1.4 Market Clearing Process

The market clearing process in our study was similar to that in previous versions of the program *flexABLE*. Yet in previous versions of *flexABLE*, there was no guarantee that agents participanted in the CRM would also be in the EOM for sure. This proved to be problematic when we conducted simulations in scenarios that had high share of electricity generation from inflexible VRE.

In order to cope with this problem, we added a system security examination scheme after the default market clearing process was carried out. This scheme would examine whether there existed agents participated in the CRM that were left out of the EOM. If there were, the units of these agents would be put into the EOM, replacing the marginal flexible units in the EOM. In order to prevent strategic arbitrage of the participants in the CRM, the market clearing price in the EOM would not be altered in the process.

The interpretation of this system security examination scheme in the real world can be either an additional market mechanism that agents agreed to enter in advance or a regulation imposed by the system operator. For the simplicity of our study, we assumed it to be regulatory. The curtailment of the available power output of VRE power plants would occur in this process.

4.3.2 Extension of Features in the CRM

4.3.2.1 VRE and DRE Power Plants

In the extended schemes the operators of the VRE and DRE power plants were able to participate in the CRM, since this was the main idea of our study. The main difference between the bidding strategies of VRE power plant operators in the CRM from those of conventional power plant operators was that only a portion of the predicted VRE power output would be considered "firm capacity", reliable enough to participate in the CRM. The total bidding quantity for VRE in the CRM would be the minimum predicted VRE power output within the time interval of a 4-hour-long time step τ in the CRM, multiplied by the firm capacity factor (a predetermined value between 0 and 1), as described in equation 4.8.

$$Q_{CRM,\tau,i}^{VRE,total} = min\{r_i^{VRE} \cdot P_{t,i}^{VRE,forc} | t \; in \; \tau\} \tag{4.8}$$

Here $Q_{CRM,\tau,i}^{VRE,total}$ is the total bidding quantity in the CRM for VRE power plant i at time step τ, r_i^{VRE} the predetermined firm capacity factor, and $P_{t,i}^{VRE,forc}$ the elements of the time series of predicted power output within the time step τ.

In our current scheme, bidding quantities in the positive and negative CRM were assumed to be the same for VRE power plant operators, as shown in equation 4.9. Note that how much predicted power output should be allocated in the positive or negative CRM is itself an optimization problem worthy of scrutiny in the future.

$$Q_{CRM,\tau,i}^{VRE,pos} = Q_{CRM,\tau,i}^{VRE,neg} = \frac{1}{2} Q_{CRM,\tau,i}^{VRE,total} \tag{4.9}$$

For DRE power plant operators, the total bidding quantity in the CRM was always the maximum capacity of the DRE power plants, while bidding quantities in the positive and negative CRM of DRE power plant operators followed the same formula as in equation 4.9.

The method to derive the opportunity costs of participating in the CRM for VRE power plant operators was similar to that described in [17]. However, because VRE power plants were assumed to be capable of ramping up and down instantaneously within their available power output range, and that in some cases VRE power plant operators received feed-in premiums, the formula for determining their capacity prices in the CRM would be slightly different from that for conventional power plants, as shown in equation 4.10.

$$\begin{array}{lll} (1) & cp_{CRM,\tau,i}^{VRE,pos} & = & \sum_{t \; in \; \tau} max(max(FiP_{t,i}, M_{EOM,t}^{PFC}) - mc_i^{VRE}, 0) \\ (2) & cp_{CRM,\tau,i}^{VRE,neg} & = & -\sum_{t \; in \; \tau} min(max(FiP_{t,i}, M_{EOM,t}^{PFC}) - mc_i^{VRE}, 0) \end{array} \tag{4.10}$$

Here $cp_{CRM,\tau,i}^{VRE,pos}$ is the capacity price in the positive CRM for VRE power plant i at time step τ, $FiP_{t,i}$ the feed-in premium promised to that power plant at time step t, $M_{EOM,t}^{PFC}$ the expected price in the EOM, mc_i^{VRE} the marginal cost, and $cp_{CRM,\tau,i}^{VRE,neg}$ the capacity price in the negative CRM. The feed-in premium was given as a time-dependent variable because in practice VRE power plant operators might not receive financial support during some negative market clearing price events in the EOM, though in our study they did not take into account this possibility when making their bids in the CRM.

DRE power plant operators would bid capacity prices in the CRM with the same strategy as described in equation 4.10. The energy prices in the CRM for VRE and DRE power plant operators followed identical formulas as described in [17].

4.3.2.2 Conventional Power Plants

Previous versions of the program *flexABLE* would run into trouble when simulating scenarios with high share of inflexible VRE. One main problem was that during events when high penetration of VRE occurred, conventional power plants would be left out of the EOM to an extent such that no agents participating in the negative CRM could stay in the EOM. Since the conventional power plants that were shut down could not participate in the CRM, this meant a lack of agents to participate in the negative CRM in the following time steps.

To cope with this problem, we allowed OCGT and oil power plants to participate in the CRM even if they were just starting up, since they were assumed to be able to ramp from 0% to 100% of their nominal output within one time step Δt and they had no constraints on their minimum operation time or minimum down time.

4.3.2.3 Energy Storage Units

For operators of energy storage units, the opportunity costs for participating in the CRM would be the contribution margin lost (defined as in [17]) due to additional operational limits resulting from their accepted bids in the CRM. Therefore, the operators compared the differences of the profit gained in the EOM with or without the additional operational limits, and set the capacity prices in the positive / negative CRM accordingly.

The opportunity costs for energy storage units to provide positive balancing energy would be the charge energy required for the additional energy, which would be the lowest price in MC_{EOM}^{PFC} (as described in equations 4.6 and 4.7) which was higher than $B_{EOM,t,i}^{ESU,ch}$ (as described in equation 4.7). With the same reasoning, the opportunity costs for energy storage units to provide negative balancing energy would be the negative value of the avoided charge energy due to less discharge (or more charge), which would be $B_{EOM,t,i}^{ESU,ch}$ (as described in equation 4.7).

Note that although we updated this feature in our version of *flexABLE*, energy storage units were not allowed in the CRM in our simulations.

4.3.2.4 Probabilistic Co-optimization of Capacity and Energy Price

The capacity and energy prices in the CRM discussed above were all derived from the opportunity costs of participating in the CRM for different agents. This bidding strategy was termed "opportunity cost driven bid creation" in [26]. A more realistic bidding strategy for the agents, the "profit maximizing bid creation" as described in [26], was to seek out bidding prices that could maximize their expected profit. This bidding strategy would involve a two stage co-optimization of the bidding capacity price and the energy price in the CRM.

At the first stage of the optimization, the agents determined the optimal energy prices in the CRM. An optimal energy price in the positive / negative CRM would be one that maximized the expected profit gained by providing the balancing positive / negative energy when being called (equation 4.11).

$$ep^* = \arg\max_{ep}\{\sum_{t\ in\ \tau}(ep - mc) \cdot F_t(E_t(ep))\} \tag{4.11}$$

Here ep is the energy price in the CRM (with a star when indicating the optimal value), mc is the marginal cost of providing the balancing energy, $F_t(\cdot)$ the cumulative distribution function for which a certain amount of balancing energy would be called at time step t, and $E_t(\cdot)$ the balancing energy on the merit order curve (as a function of the energy price). Most of the indexes are omitted in the equation due to its generality.

An analytical solution for equation 4.11 occurs when the derivative of the right-hand-side of the equation is 0. In our study, however, we found a sub-optimal solution to the problem by finding the largest of the solutions in a discrete set with fixed values of $F(\cdot)$.

At the second stage of the optimization, the agents determined the highest possible capacity price they could offer without being left out of the CRM. Since the demand for positive and negative control reserve was a predetermined time series, this optimal capacity price would be obtained if the merit order curve of the "opportunity cost driven" bids from all the agents in the market was known: it would be the marginal capacity price of the curve, minus the expected profit gained by providing the balancing positive / negative energy of the corresponding marginal agent.

$$cp^* = cp_{margin} - \pi^*_{margin} \tag{4.12}$$

Here cp^* is the optimal capacity price (which would be identical for all agents), cp_{margin} the "opportunity cost driven" capacity price of the marginal agent in the CRM, and π^*_{margin} the maximized expected profit of that marginal agent by providing balancing energy as described in equation 4.11.

If the "opportunity cost driven" bid of an agent was lower than the optimal capacity price, the agent would bid the optimal capacity price in the CRM as its capacity price; this meant every agent that had a lower opportunity cost than the marginal agent would bid the same capacity price as the marginal agent would. Otherwise, it still bid the capacity price obtained from the "opportunity cost driven bid creation".

4.4 Scenarios Setting

4.4.1 Reference Scenarios

The essence of this study was to examine whether allowing VRE power plants into the CRM would result in significant impacts, and if yes, to quantitatively analyze these impacts. Therefore, we conducted three simulations as reference scenarios to compare the results with. They included:

1. Scenario 0-A: The "Inflexible Renewables 2018" case. This served as a control group simulation where neither VRE nor DRE power plants were allowed in the CRM as in the previous versions of *flexABLE*. The VRE and conventional power plant capacity data of the year 2018 as in table 4.1 and table 4.2 was used.

2. Scenario 0-B: The "Inflexible Renewables 2025" case. In this scenario the VRE and DRE power plants were also not in the CRM, but the VRE and conventional power plant capacity data of the year 2025 was used instead.

3. Scenario 0-C: The "Flexible DRE" case. This scenario was similar to scenario 0-B, but DRE power plants were able to provide control reserve in the CRM.

In all of these scenarios, the renewable energy power plant operators would receive a medium level of feed-in premiums as described in table 4.6. Since VRE power plants did not participate in the CRM, it did not matter which level of the firm capacity factor was used in the program when running the reference scenarios.

Note that currently some of the DRE power plant operators are already participating in the CRM, with Next Kraftwerke GmbH perhaps the most famous among them. So a business-as-usual practice in 2025 would be somewhere in between Scenario 0-B and Scenario 0-C.

4.4.2 Experiment Scenarios

We then determined different types of factors that would constitute the futuristic scenarios we sought to analysis (where both flexible DRE and flexible VRE were allowed in the CRM), which we referred to as the experiment scenarios. We chose two dimensions of factors: the level of feed-in premiums VRE and DRE power plant operators received, and the level of the firm capacity factor r_i^{VRE} (as described in equation 4.8) VRE power plants could provide in the CRM. The levels of feed-in premiums received by different types of VRE power plant operators and the firm capacity factor can be summarized as in table 4.6 and table 4.7. With the two dimensions of factors, we set up 12 experiment scenarios for our study, as shown in table 4.8.

In these futuristic scenarios, we assumed that the predicted and actual maximum available capacity factor of the VRE power plant fleet of Germany would be identical to the historical data of the year 2018. This meant that we simply multiply the predicted and actual power output of the VRE power plant fleet of in Germany with constants that took into account the capacity expansion.This was not a rigorous way to estimate the predicted and actual maximum available power output in the future, since 1) the data we used was a lower bound to the maximum available power output for 2018 and 2) the maximum available power output of the entire fleet would depend strongly on where and what type of VRE power plants were installed. We used this rough estimation of the maximum available capacity factor of the VRE power plant fleet just for the sake of simplicity of this study.

Also, it should be noted that the firm capacity factors for different VRE technologies were likely to be underestimated. The predicted VRE power output data we took was the day-ahead forecast, while in our simulated CRM the VRE power plant operators should be able to bid according to forecasts as late as 4 hours ahead of the trade, since in *flexABLE* the EOM and CRM were assumed to be nearly real time (markets closed and cleared just before the actual trade took place); this should mean a higher firm capacity factor for all the VRE technologies.

Finally, in additional to the capacity factor of VRE power plant fleet, we also assumed that the demand profile was identical to the historical data of 2018 in these futuristic scenarios.

Units	**No FiP** EUR/MWh	**Low FiP** EUR/MWh	**Mid FiP** EUR/MWh	**High FiP** EUR/MWh
Offshore Wind	None	40	80	120
Onshore Wind	None	20	40	60
Photovoltaic	None	60	120	180
All DRE	200	200	200	200

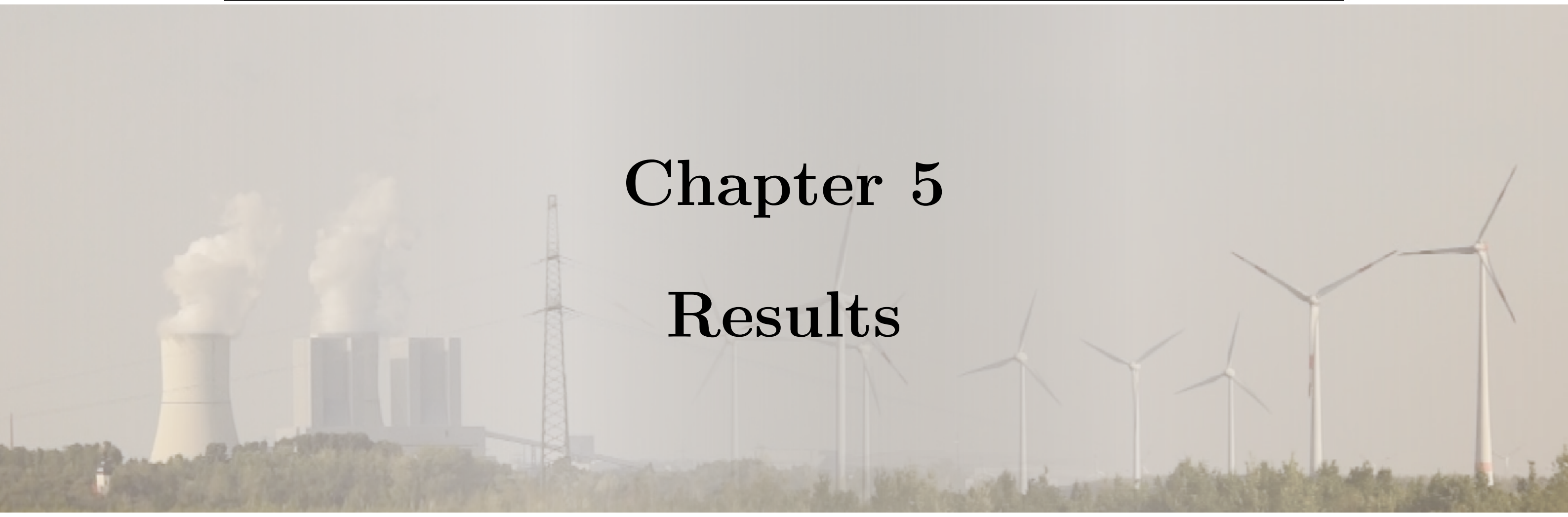
Table 4.6: Levels of feed-in premiums for different VRE and DRE power plant operators.

Reliability Criteria	**Low Firm** 0	**Mid Firm** 0.001	**High Firm** 0.01
Offshore Wind	0.09	0.21	0.35
Onshore Wind	0.39	0.50	0.65
Photovoltaic	0.29	0.32	0.68

Table 4.7: Levels of the firm capacity factor for different VRE technologies. The reliability criteria was defined as the probability that the ratio between actual and predicted VRE power output happened to be below the firm capacity factor in the historical data.

	No FiP	**Low FiP**	**Mid FiP**	**High FiP**
Low Firm	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Mid Firm	Scenario 5	Scenario 6	Scenario 7	Scenario 8
High Firm	Scenario 9	Scenario 10	Scenario 11	Scenario 12

Table 4.8: Setup of Futuristic Simulation Scenarios



Chapter 5

Results

In this chapter (and also in most of chapter 6), we will focus on the results from scenarios 0-B, 0-C, and 7, for they represented the default settings for our two factors: a medium feed-in premium level with a medium level of the firm capacity factor. The only difference between these scenarios was whether or not flexible DRE or flexible VRE were deployed in the CRM, thus the results from these scenarios would give us direct insights of the impacts of flexible renewable energy sources. For a detailed discussion of other experiment scenarios, the reader should refer to section 6.3.

In addition, we would only include bioenergy and hydroelectric power plants in our discussions of the DRE power plants in this chapter and chapter 6, since other types of DRE technologies, namely the geothermal and waste power plants, had capacity values too small to make a difference to the results of the simulation.

5.1 Portfolio

The actual electricity generation portfolios of different technologies in the EOM of the reference and experiment scenarios were plotted in figure 5.1; this figure took into account the activated balancing energy from each type of technology in real time, though the differences between scheduled and actual operation in the EOM were small in general. The portfolios of control reserve capacity in the CRM of the reference and experiment scenarios were plotted in figure 5.2.

From figure 5.1 we can see that the electricity generation from renewable energy sources would grow from 229.03 TWh to 281.33 TWh between reference scenarios 0-A and 0-B. Introducing flexible DRE into the CRM would increase the electricity generation from renewable energy sources to 295.67 TWh (+5.10% compared with scenario 0-B) in scenario 0-C, while introducing flexible VRE into the CRM slightly increased the electricity generation from renewable energy sources to 296.96 TWh (+5.56% compared with scenario 0-B) in scenario 7.

Meanwhile, the electricity generation from conventional energy sources dropped from 264.65 TWh to 210.95 TWh between reference scenarios 0-A and 0-B. Introducing flexible DRE into the CRM would further reduce electricity generation from conventional energy sources to 194.99 TWh in scenario 0-C; in particular, electricity generation from OCGT power plants decreased drastically from 56.76 TWh to 43.34 TWh, while the use of lignite in electricity generation would increase from 54.45 TWh to 56.73 TWh. Introducing flexible VRE into the CRM would further reduce electricity generation from OCGT power plants to 40.81 TWh, but the reduction would be offset by an increase of the use of lignite to 58.46 TWh, and the total electricity generation from conventional power plants only slightly decreased to 193.84 TWh.

From figure 5.2 we can see that the dual phase out of both nuclear and coal power plants between reference scenarios 0-A and 0-B meant that these two technologies would fade out almost entirely

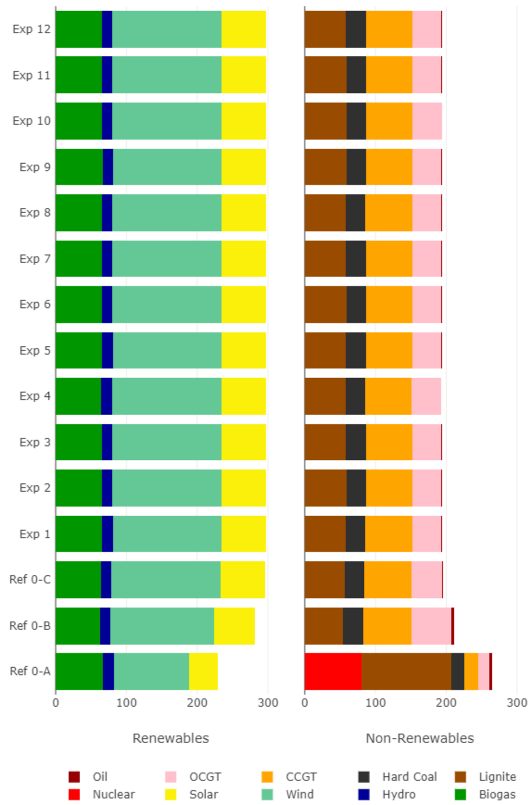


Figure 5.1: Annual electricity generation portfolios (in TWh) in the reference and experiment scenarios.

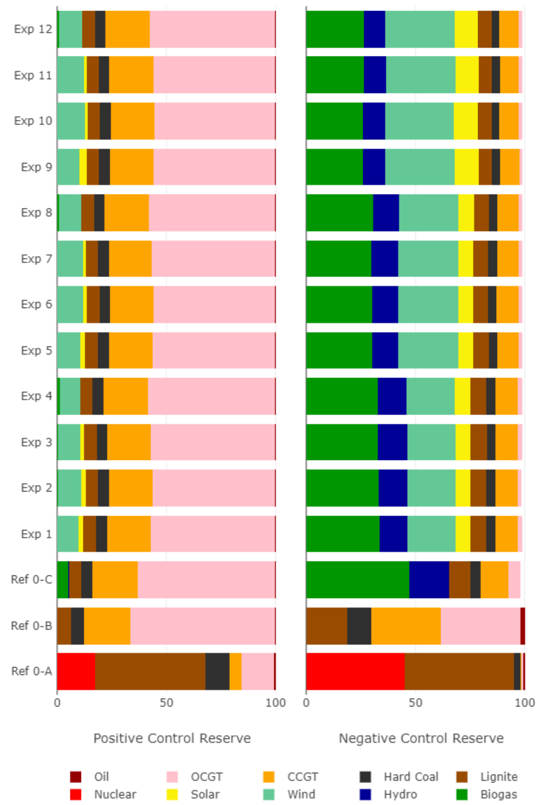


Figure 5.2: Annual portfolios of the control reserve capacity (in percentage) in the reference and experiment scenarios.

in the CRM by 2025. Without renewable energy sources participating in the CRM it would be the OCGT and CCGT power plants that would replace them in the CRM. Introducing flexible DRE would not have a significant impact in the positive CRM, but DRE power plants would provide most of the control reserve capacity in the negative CRM. Flexible VRE, after introduced in the CRM, would compete mainly with flexible DRE for both the positive and negative control reserve capacity, but the share of renewable energy in providing the control reserve capacity would still increase in both the positive and negative CRM.

5.2 Reliability of Control Reserve Services

There was no direct negative impact on the reliability of control reserve services modeled in all the experiment scenarios. That is to say, there existed no events where flexible VRE failed to provide balancing energy when it was needed in those simulations. Such event could only occur when the predicted VRE power output was extremely overestimated and an extreme high amount of balancing energy demand coincided at the same time, and this turned out to be highly unlikely.

As discussed in section 3.1, the control reserve demand of Germany has dropped in the recent years. Since we used the data between 2015 to 2018 as our training set for the model, the control reserve demand was higher in our futuristic scenarios when compared with reference scenario 0-A, in which we used the historical data of the year 2018 only for the accepted and activated control reserve demand: in 2018 the positive control reserve demand was 3221 MW and the negative control reserve demand was 3549 MW on average, while in our futuristic scenarios the positive control reserve demand was 5493 MW and the negative control reserve demand was 4536 MW on average.

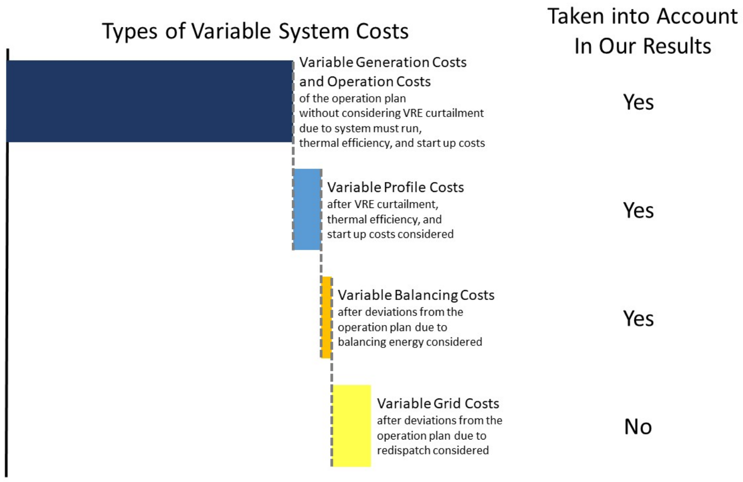


Figure 5.3: A schematic chart of how the variable system costs would be categorized following the definitions of [62] and [63]. Variable grid costs would require a grid model to be properly calculated, therefore they were omitted in our results.

Had we adopted a lower estimation of the control reserve demand, the reliability of flexible VRE in the CRM might be better than what we modeled, but the economical and system impacts might not be as significant as discussed in the chapter 6.

5.3 System Cost

The system cost was defined as the cost an imaginary monopoly would ideally have to bear to provide the same services in the simulations, should she own the entire power system. Because all the futuristic scenarios had the same renewable energy and conventional power plant fleet, the fixed system costs would be the same in all of them. Therefore, only the variable system costs: the fuel costs, start up costs, and carbon emission costs[1] of the conventional power plants and the bioenergy power plants, and the operational costs of the energy storage units, would be different among these scenarios. Only in the reference scenario 0-A with a renewable energy and conventional power plant fleet based on the historical data of 2018 would we have a different total fixed system cost from all other scenarios, but we did not take it into consideration since it was not of interest in our study. We also did not include self-consumption generation sources and decentralized energy storage units, so our resulting total variable system cost would be lower than that of the entire electricity sector in Germany.

We noted that in some pieces of literature, the total system cost was categorized into at least 4 parts: generation costs, profile costs, balancing costs, and grid costs. The precise definition of these costs can be found in [62] and [63]. Figure 5.3 shows how these 4 types of system costs would relate to the results in our study. Note that the variable profile costs and balancing costs were included in our definition of variable system costs; on the other hand, the effects flexible DRE and VRE would have on the reliability, stability, or other metrics of the power system (as will be discussed in section 6.1.1) might actually incur additional variable grid costs (which we did not include in our results) through more redispatch, though those costs were suggested to be one or two magnitude smaller than the sum of the variable system costs we focused in this study [63, 64].

The variable system costs of different technologies were plotted in figure 5.4. In summary, the total variable system cost grew from 10.99 billion Euros in scenario 0-A to 18.52 billion Euros in

[1] We assumed that the social costs the imaginary monopoly must pay due to the carbon emissions of the system was the carbon price, though this required an ideal carbon pricing and it also neglected other social costs associated with the operation of the power system, for example air pollution and radioactive waste disposal.

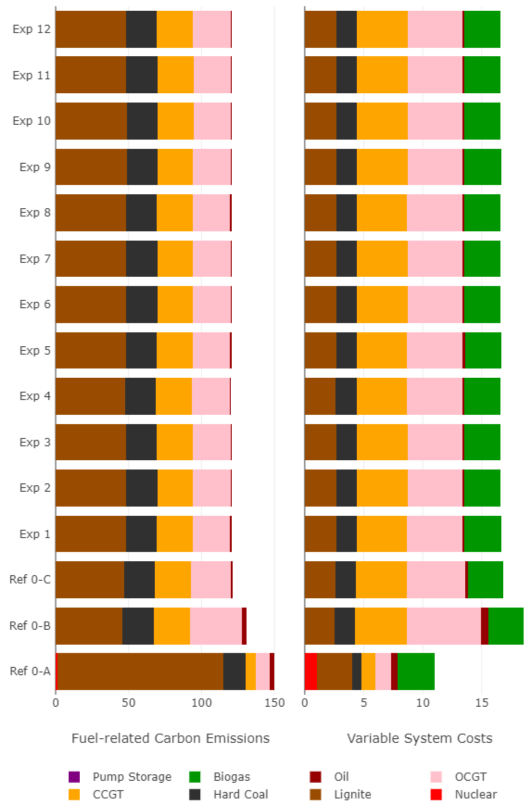


Figure 5.4: Fuel-related carbon emissions (in million tonnes $CO_{2\,eq}$) and variable system costs (in billion Euros) in the reference and experiment scenarios.

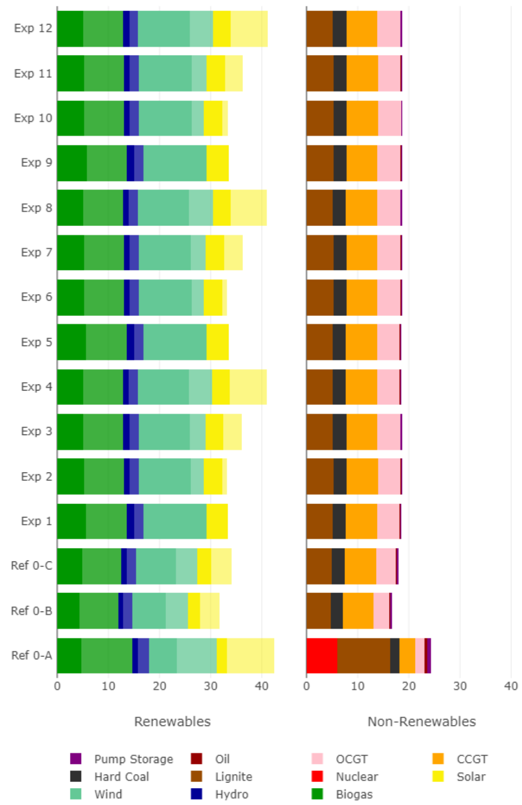


Figure 5.5: Annual producer revenues of different technology types in the EOM (in billion Euros) in the reference and experiment scenarios. The lighter areas for renewable technologies represent the indirectly collected revenue.

scenario 0-B, reflecting the change of the portfolio of the conventional power plant fleet to more power plants with higher variable costs, and also a higher carbon price. Introducing flexible DRE would reduce the total variable system cost to 16.81 billion Euros (-9.23% compared with scenario 0-B) in scenario 0-C, and introducing flexible VRE would further reduce the total variable system cost to 16.60 billion Euros (-10.37% compared with scenario 0-B) in scenario 7.

5.4 Carbon Emission

The fuel-related carbon emissions of different technologies were plotted in figure 5.4. Because all the futuristic scenarios had the same renewable energy and conventional power plant fleet, the carbon emissions that would vary among the futuristic scenarios would be the emissions resulting from the use of fuel during the operation and starting up of conventional power plants. Scenario 0-A of course had a different portfolio of power plant fleet, and carbon emissions would have occurred during the construction phase of the new power plants and infrastructure, but we did not take those into consideration since it was not of interest in our study. We also did not include self-consumption generation sources, so our resulting total fuel-related carbon emission would be lower than that of the entire electricity sector in Germany.

In addition, we noted the fact that since we did not model cross border import / export and the conventional power plants were modeled to be more flexible in our simulations, the total fuel-related carbon emission we obtained in scenario 0-A (149.75 million tonnes $CO_{2\,eq}$) was 37.21%

lower than the approximated value (238.48 million tonnes $CO_{2\ eq}$) obtained from [51][2]; net cross border export in Germany in 2018 accounted for nearly one-tenth of the electricity generation in the electricity markets, while assuming conventional power plants to be more flexible than they would have been in reality resulted in more electricity generation from nuclear power plants.

In summary, introducing VRE capacity expansion and the phase out of major conventional energy sources resulted in a drop of the total fuel-related carbon emission to 130.86 million tonnes $CO_{2\ eq}$ (-12.61% compared with scenario 0-A) in scenario 0-B. Introducing flexible DRE into the CRM would reduce the total fuel-related carbon emission to 121.47 million tonnes $CO_{2\ eq}$ (-7.18% compared with scenario 0-B) in scenario 0-C, while introducing flexible VRE into the CRM would reduce the total fuel-related carbon emission to 120.68 million tonnes $CO_{2\ eq}$ (-7.78% compared with scenario 0-B) in scenario 7.

5.5 Producer Revenue

The producer revenues of different technologies from the EOM were plotted in figure 5.5, that from the accepted balancing capacity in the CRM in figure 5.6, and that from the activated balancing energy in the CRM in figure 5.7. The producer revenue reflects the revenue participants in the electricity markets collected from the consumers. In the CRM this would be the revenue from the accepted balancing capacity bids and the activated balancing energy bids participants received from the system operator, since the system operator would pass this cost onto the consumers in the retailer electricity prices. For power plant operators in the EOM, this would be the sum of wholesale electricity prices multiply by their sold quantities. For energy storage units in the EOM, it would be the revenue gained by the price spread during periods of charge / discharge.

The revenues VRE and DRE power plant operators collected via the price differences between the wholesale electricity prices and the feed-in premium level were also considered part of their producer revenues, since the renewable energy surcharge would ultimately be passed onto the customers in the retailer electricity prices. For clarification, in the remaining parts of this report we would sometimes differentiate between the producer revenue collected directly in the electricity markets (via market clearing prices or pay-as-bid prices) and that collected indirectly via the feed-in premium mechanism. Since the feed-in premium mechanism can be viewed as a special form of power purchase agreement (PPA) between the customers and the renewable energy power plant operators, justified by the social benefits renewable energy could bring to the public, other forms of PPA could also be seen as indirect producer revenues by the definition of this study, though they were not considered in our simulations.

In the EOM, we can see that the feed-in premium level was the major factor that determined the revenue renewable energy power plant operators collected. That said, on the same feed-in premium level, introducing flexible DRE into the CRM did increase the producer revenues of the renewable technologies between reference scenarios 0-B and 0-C: those of the bioenergy power plants increased from 11.95 billion Euros to 12.46 billion Euros (+4.27%), the hydroelectric power plants from 2.68 billion Euros to 2.89 billion Euros (+7.84%), the wind power plants from 10.91 billion Euros to 11.97 billion Euros (+9.72%), and the photovoltaic power plants from 6.12 billion Euros to 6.73 billion Euros (+9.97%). After introducing flexible VRE into the CRM, the producer revenue of the bioenergy power plants increased to 12.99 billion Euros in scenario 7 (+8.70% compared with scenario 0-B), the hydroelectric power plants increased to 2.96 billion Euros (+10.45% compared with scenario 0-B), the wind power plants increased to 13.15 billion Euros (+20.53% compared with scenario 0-B), and the photovoltaic power plants increased to 7.19 billion Euros (+17.48% compared with scenario 0-B).

Meanwhile, the producer revenues of the conventional power plants (pump storage units included)

[2] Here we assumed constant fuel-related carbon emission factors per MWh electricity for different technologies: for lignite power plants it was 1.152 t $CO_{2\ eq}$ / MWh, for hard coal power plants 0.894 t $CO_{2\ eq}$ / MWh, for gas power plants 0.469 t $CO_{2\ eq}$ / MWh, and for oil power plants 0.776 t $CO_{2\ eq}$ / MWh.

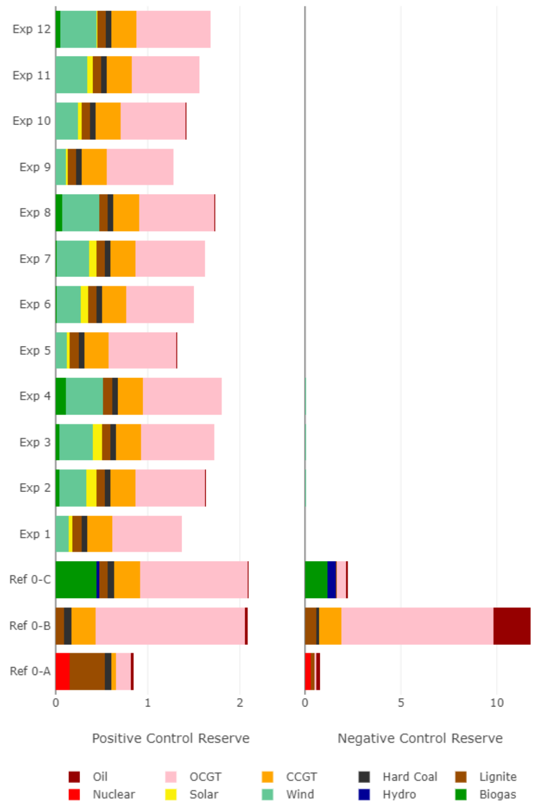


Figure 5.6: Annual producer revenues of accepted balancing capacity of different technology types in the CRM (in billion Euros) in the reference and experiment scenarios.

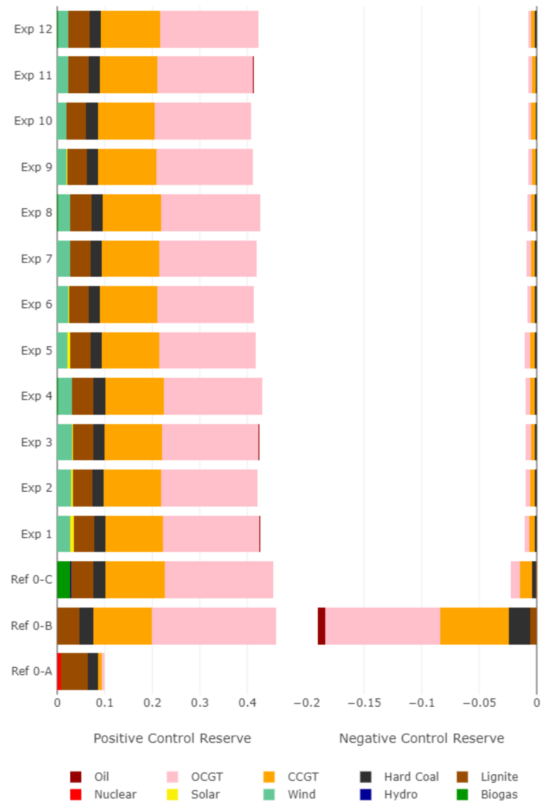


Figure 5.7: Annual producer revenues of activated balancing energy of different technology types in the CRM (in billion Euros) in the reference and experiment scenarios.

in the EOM increased from 16.74 billion Euros to 18.01 billion Euros between reference scenarios 0-B and 0-C, while introducing flexible VRE into CRM would increase the producer revenues of the conventional power plants to 18.70 billion Euros in scenarios 7.

Another perspective is to see the change of producer revenues collected directly from the market and indirectly from the feed-in premium mechanism in the EOM. In the reference scenario 0-B, renewable energy power plants collected 14.17 billion Euros of revenue directly from the market and 17.49 billion Euros of revenue indirectly from the feed-in premium mechanism. In the reference scenario 0-C, the revenue renewable energy power plants collected directly grew to 16.45 billion Euros and the revenue collected indirectly to 17.59 billion Euros. After introducing flexible VRE into the CRM, the revenue renewable energy power plants collected directly increased to 20.19 billion Euros in scenario 7, while the revenue collected indirectly decreased to 16.10 billion Euros. This meant that the introduction of flexible VRE allowed the renewable energy power plant operators to collect more revenue directly from the market and less indirectly from the feed-in premium mechanism.

In the CRM, we can see that the total producer revenue from accepted positive balancing capacity did not change significantly between reference scenarios 0-B and 0-C (around 2.10 billion Euros), but the DRE power plants took away 22.43% of it (0.47 billion Euros) after they were allowed in the CRM. In the experiment scenarios, the feed-in premium level was a key factor in determining the total producer revenue from accepted positive balancing capacity in the CRM, but on the same feed-in premium level, allowing flexible VRE into the CRM would decrease the total market value to 1.62 billion Euros in scenario 7. In that scenario, the renewable energy power plants took away 27.16% (0.44 billion Euros) of the total producer revenue. The producer revenues of the conventional power plants decreased to 1.63 billion Euros in scenario 0-C, and it further decreased to 1.18 billion Euros in scenario 7.

Meanwhile, we can see that after introducing flexible DRE into the CRM, the total producer revenue from accepted negative capacity in the CRM plummeted from 11.76 billion Euros to 2.25 billion Euros. Allowing flexible VRE into the CRM would nearly extinguish the total producer revenue in all experiment scenarios, in particular to 0.01 billion Euros in scenario 7. In scenario 0-C and all the experiment scenarios, the renewable energy power plants dominated the remaining of the total producer revenue from accepted negative capacity.

Introducing flexible DRE did not have a significant effect on the total producer revenue from activated positive energy in the CRM when comparing reference scenarios 0-B with 0-C, where DRE only represented 6.38% (0.03 billion Euros) of the total producer revenue. Introducing flexible VRE into the CRM in scenario 7 would allow the VRE power plants to take away the producer revenues the DRE power plants initial had (in scenario 0-C). The producer revenues of the conventional power plants would drop from 0.46 billion Euros to 0.43 billion Euros between reference scenarios 0-B and 0-C, and they would further drop to 0.39 billion Euros in scenario 7.

For activated negative energy in the CRM, introducing flexible DRE into CRM would increase the total producer revenue from -0.19 billion Euros to -0.02 billion Euros in scenario 0-C, and introducing flexible VRE would further increase the total producer revenue to -0.01 billion Euros in the scenario 7. In all scenarios, the conventional power plants bore nearly all of the negative producer revenues.

Interestingly, the total producer revenue from the accepted balancing capacity and activated balancing energy in the CRM grew significantly when comparing reference scenarios 0-A with 0-B, with OCGT power plants taking away most of the growth. This might result from the fact that in scenario 0-B, OCGT power plants were needed more during high VRE penetration level events when the market clearing prices in the EOM were low, thus their operators would bid higher prices in the CRM as a compensation. Also, our conservative modeling led to a higher control reserve demand on average in the futuristic scenarios, as discussed in section 5.2.

5.6 Producer Surplus

The producer surplus of different power plants in the reference and experiment scenarios were plotted in figure 5.8. The producer surplus of operating a power plant was defined as the producer revenue of participating in the electricity markets minus the variable cost of operation, which in our study only included fuel costs for conventional power plants and bioenergy power plants. In real world practice, to be able to remain profitable, the producer surplus of a power plant must exceed its fixed cost of operation.

For renewable energy power plants, a decrease of the producer surplus was obviously observed between reference scenarios 0-A and 0-B, most significantly for offshore wind power plants due to the greatest drop of the feed-in premium level. Introducing flexible DRE would increase the producer surplus of all the renewable energy power plants when comparing reference scenarios 0-B and 0-C; the median value of the producer surplus of offshore wind power plants grew from 231.12 thousand EUR/MW to 249.23 thousand EUR/MW, onshore wind power plants from 105.43 to 116.95 thousand EUR/MW, photovoltaic power plants from 85.11 thousand EUR/MW to 93.42 thousand EUR/MW, and bioenergy power plants from 1159.43 thousand EUR/MW to 1435.50 thousand EUR/MW.

In the experiment scenarios, the producer surplus of VRE power plants depended much on the feed-in premium level they received. That said, on the same feed-in premium level, the median value of the producer surplus of offshore wind power plants grew to 272.02 thousand EUR/MW in scenarios 7, onshore wind power plants to 134.75 thousand EUR/MW, and photovoltaic power plants to 101.05 thousand EUR/MW. In the meantime, the median value of the producer surplus of bioenergy power plants dropped to 1285.16 thousand EUR/MW.

For conventional power plants, we can see that the producer surplus of lignite shrunk, while the producer surplus of CCGT, OCGT, and oil power plants grew significantly in general when comparing reference scenarios 0-A with 0-B. The median value of the producer surplus of lignite power plants dropped significantly from 383.45 thousand EUR/MW to 318.18 thousand EUR/MW, while that of CCGT power plants increased from 78.23 thousand EUR/MW to 112.29 thousand EUR/MW, OCGT power plants from 160.42 thousand EUR/MW to 235.62 thousand EUR/MW, and oil power plants from 99.62 thousand EUR/MW to 272.72 thousand EUR/MW. Although the median value of the producer surplus of hard coal power plants increased from scenario 0-A to scenario 0-B, their total producer surplus actually shrunk, as will be discussed in section 6.1.3.

Introducing flexible DRE into the CRM would reduce the producer surplus of all types of conventional technologies; in particular, it would extinguish most of the producer surplus of OCGT and oil power plants to a median value of 21.79 thousand EUR/MW and 3.84 thousand EUR/MW respectively. Introducing flexible VRE into the CRM would increase the producer surplus of lignite, hard coal, and CCGT power plants in the experiment scenarios; the median value of the producer surplus of lignite power plants would grow from 285.08 thousand EUR/MW in scenario 0-C to 290.40 thousand EUR/MW in the scenario 7, hard coal power plants from 105.89 thousand EUR/MW to 107.54 thousand EUR/MW, CCGT power plants from 101.38 thousand EUR/MW to 102.46 thousand EUR/MW. On the other hand, the median value of the producer surplus of OCGT power plants dropped to 18.39 thousand EUR/MW, and that of oil power plants would turn negative in all the experiment scenarios.

5.7 Full Load Hours

The full load hours of different power plants in the reference and experiment scenarios were plotted in figure 5.9.

For renewable energy power plants, the expansion of the capacity of VRE power plants reduced their median values of full load hours. That of bioenergy power plants dropped from 8668 hours in scenario 0-A to 8214 hours in scenario 0-B, offshore wind power plants from 2916 hours to 2726 hours, onshore wind power plants from 1649 hours to 1516 hours, and photovoltaic power plants from 890 hours to 798 hours. Introducing flexible DRE into the CRM would increase all of those statistic figures: that of bioenergy power plants would increase to 8226 hours in scenario 0-C, offshore wind power plants to 2875 hours, onshore wind power plants to 1620 hours, and photovoltaic power plants to 861 hours.

After flexible VRE were introduced into the CRM, the median value of full load hours of bioenergy power plants increased to 8448 hours in scenario 7, offshore wind power plants to 2904 hours, and photovoltaic power plants to 873 hours, while that of onshore wind power plants decreased to 1587 hours.

For conventional power plants, increasing the capacity of the VRE power plants and phasing out the older lignite and hard coal power plants would increase the median values of the full load hours of lignite, hard coal, and CCGT power plants while decreasing those of OCGT and oil power plants; the median value of the full load hours of lignite power plants increased from 5872 hours in scenario 0-A to 6153 hours in scenario 0-B, hard coal power plants from 278 hours to 3496 hours, and CCGT power plants from 980 hours to 3553 hours; the median value of the full load hours of OCGT power plants decreased from 2953 hours to 2139 hours, and oil power plants from 1091 hours to 662 hours.

Introducing flexible DRE into the CRM would slightly increase the median value of full load hours of lignite power plants, while reducing those of OCGT and oil power plants, and slightly

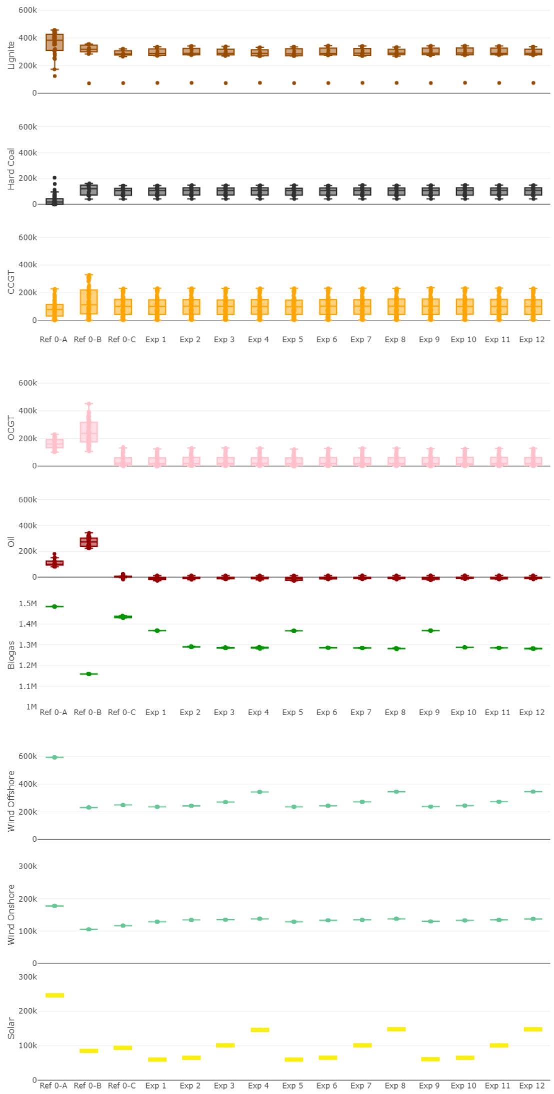


Figure 5.8: Producer surplus of different types of power plants (in EUR/MW) in the reference and experiment scenarios. The lines in the results for photovoltaic power plants were enhanced to yield greater legibility.

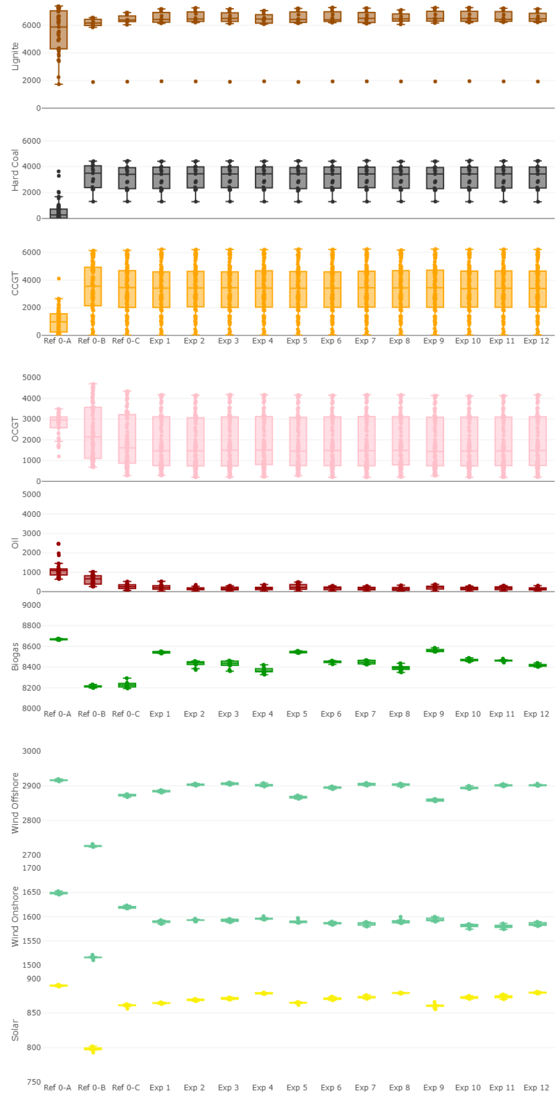
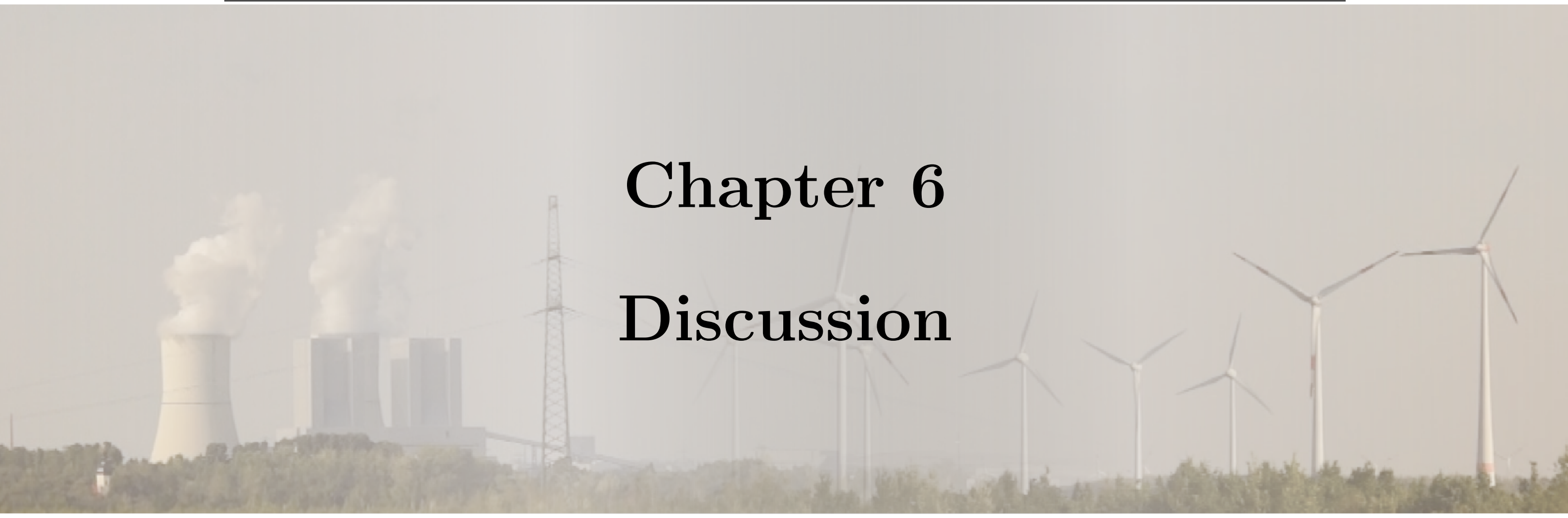


Figure 5.9: Full load hours of different types of power plants (in hours) in the reference and experiment scenarios.

reducing those of hard coal and CCGT power plants in scenario 0-C. The median value of the full load hours of lignite power plants increased to 6370 hours in scenario 0-C, while that of hard coal power plants reduced to 3409 hours, CCGT power plants to 3460 hours, OCGT power plants to 1616 hours, and oil power plants to 252 hours. Introducing flexible VRE into the CRM would have similar effects on conventional power plants as introducing flexible DRE into the CRM except for hard coal power plants, whose full load hours increased to 3445 hours in scenario 7.



Chapter 6

Discussion

6.1 Impacts of Flexible VRE

6.1.1 System Perspective

6.1.1.1 Reliability and Stability Issues

As discussed in section 3.1 and section 3.3, the participation of VRE in the EOM did not affect the control reserve demand significantly and might also not do so in the near to mid-term future; even with our quite conservative modeling of the control reserve demand, the results in section 5.2 also suggested that flexible VRE would not have direct impacts on the reliability of the power system. There might be, however, indirect effects arising after flexible VRE were introduced. Below we discuss two of them.

The first would be the effect flexible VRE had on the duration curve of the largest single conventional power plant unit on-line; this might affect the positive control reserve required for backing up contingency events under the N-1 / N-2 criteria. In figure 6.1 we can see that on the right hand side of this duration curve, there would be a sharp drop of the largest single unit capacity after introducing flexible VRE into the CRM in scenario 7; yet throughout the entire year, the value would be greater on average than those in reference scenarios 0-B and 0-C. If the probability of a power plant failure was constant throughout the simulation time, this would mean a greater positive control reserve would be required for the same reliability criteria in scenario 7.

For long term system planning purposes, it might also be important to know how the annual extreme values on this duration curve would be affected by flexible VRE. We could see in figure 6.1 that introducing flexible DRE would increase the 99.6 percentile of the statistic by about 50 MW, while flexible VRE would not increase the value further.

Consider that allowing flexible renewable energy sources into the CRM would increase 3.87 GW of available positive control reserve capacity from the bioenergy power plants in the model, the indirect effects flexible DRE and VRE would have on the control reserve requirements seem trivial. Nevertheless, quantifying these effects could help further improve the modeling of the control reserve demand in future studies, which would in return change the market conditions agents abided by in the first place.

The second indirect effect flexible VRE might have on power system reliability was due to their spatial correlation of power output. Conventional power plants also showed spatial correlation in their power output to some extent (ex. power plants where a typhoon / hurricane directly hit had to reduce power output simultaneously), but the power output of weather dependent VRE would show higher spatial correlation. This meant that in our scenarios, there would very likely be more occasions that the control reserve capacity were concentrated in some regions while absent in other regions. This would lead to lower resilience against transmission line failure and thereby weakening

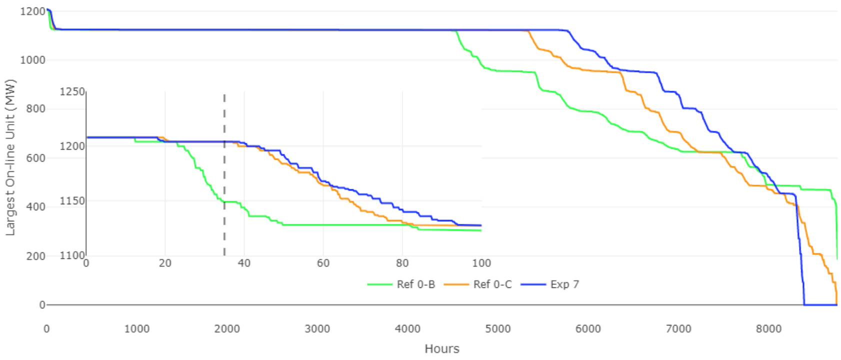


Figure 6.1: Duration curves of the largest single conventional unit on-line in the selected scenarios.

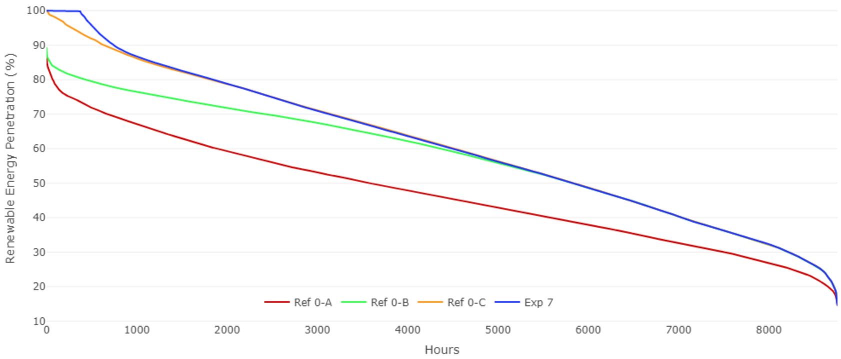


Figure 6.2: Duration curves of the renewable energy penetration in the selected scenarios.

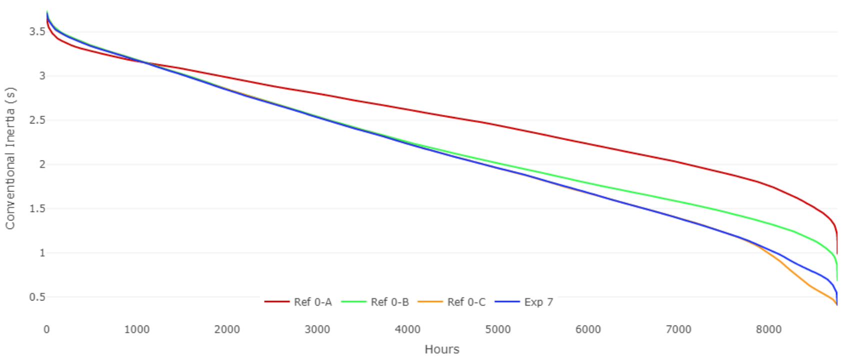


Figure 6.3: Duration curves of the conventional inertia in the selected scenarios.

the reliability of the power system.

The higher spatial correlation of VRE power output would also give rise to the risks of power overflow in transmission lines and other stability issues in the power system. Allowing flexible VRE into the CRM would increase the share of VRE in electricity generation, and therefore it would very likely result in more redispatch to avert these stability issue risks.

Furthermore, although when flexible VRE were introduced, the power system would have lower total must run capacity from the conventional power plants in the EOM, the total downward dispatchable capacity beyond the CRM would actually slightly decrease (as will be discussed in subsection 6.1.1.2), and this capacity would not be located equally on the grid; those regions with a higher concentration of control reserve capacity would have less flexible capacity available for re-dispatch, and vice versa. It might then be necessary to also redispatch the control reserve capacity before redispatching the results from the EOM.

For instance, imagine a case where power output from wind power plants was so strong in north Germany such that they covered all the accepted bids in the CRM and the EOM. However, providing positive control reserve from these power plants to the south would be problematic because the transmission line would already be nearly saturated by southbound power flow. Instead of telling some wind power plants in the north to reduce their power output, reallocating some of the positive control reserve to market participants in the South might be a more efficient solution. Of course, to further quantify this concept, we will have to integrate *flexABLE* with a grid model and also a spatial VRE power output availability model in the future.

Finally, let us examine what impacts flexible VRE would have on the system inertia contributed from conventional sources. Because the rotational mass of the turbines in conventional power plants would store some kinetic energy, they would slow down the rate of change of frequency of the power system when small imbalance between supply and demand occurred. With higher penetration of VRE, this conventional inertia would decrease in general.

Figure 6.2 shows the duration curve of renewable energy penetration in the power system, and figure 6.3 shows the duration curve of the conventional inertia on the grid[1]. We can see that the penetration of renewable energy was higher in scenario 0-B than in scenario 0-A, resulting in a decrease in conventional inertia. Introducing flexible DRE in scenario 0-C would further increase the renewable energy penetration especially on the left hand side of figure 6.2 when the power output from VRE power plants was abundant, which would also correspond to a decrease of the conventional inertia on the right hand side of figure 6.3. Interestingly, although introducing flexible VRE in scenario 7 increased the renewable energy penetration especially on the left hand side of figure 6.2, the conventional inertia on the right hand side of figure 6.3 also increased compared with that in scenario 0-C. By replacing flexible DRE in the positive CRM and voluntarily curtailing some of their available power output, flexible VRE helped enhanced the power system stability.

Of course, the values of the conventional inertia in all futuristic scenarios were still much lower than that in scenario 0-A, and although Germany enjoys the convenience of being within a continental synchronous grid, it might still be preferable to introduce synthetic inertia, turn decommissioned conventional power plants into synchronous condensers, and design new markets that encourages the development of fast frequency response in the future, as suggested in [64, section 3.5].

6.1.1.2 Flexibility (beyond EOM and CRM)

Unlike other parts of this report, in this subsection we consider the power system flexibility beyond our modeled CRM, i.e. the capability of the power system to adjust to deviations from the scheduled operation in the EOM that the control reserve in the CRM could not provide within the length of a single time step Δt. The deviations might be a result of redispatch, or an extreme contingency event such that the control reserve capacity in the CRM would not be enough to cover.

Interestingly, the introduction of flexible DRE and VRE into the CRM actually decreased the total flexible capacity additional to that in the CRM. In scenario 0-B, the total additional upward dispatchable energy was 72.72 TWh, in scenario 0-C it was 49.08 TWh, and 41.32 TWh in scenario 7. The total additional downward dispatchable energy in scenario 0-B was 309.20 TWh, in

[1]We took the average rotational constants of different conventional technology types, including bioenergy and hydroelectricity power plants, from [65]. We assumed all the oil power plants in Germany used combustion turbine to generate electricity.

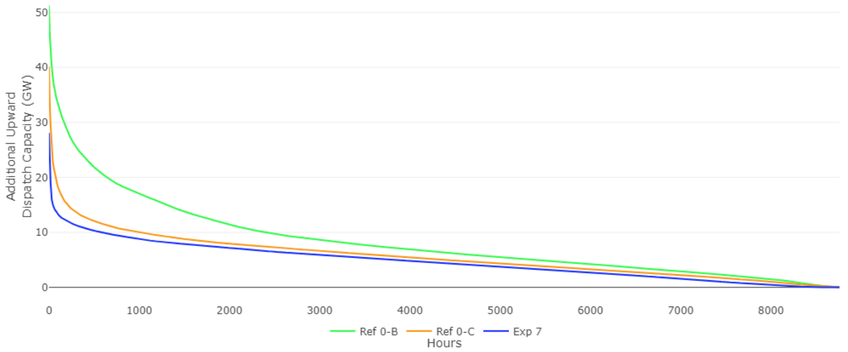


Figure 6.4: Duration curves of the additional upward dispatchable capacity in the selected scenarios.

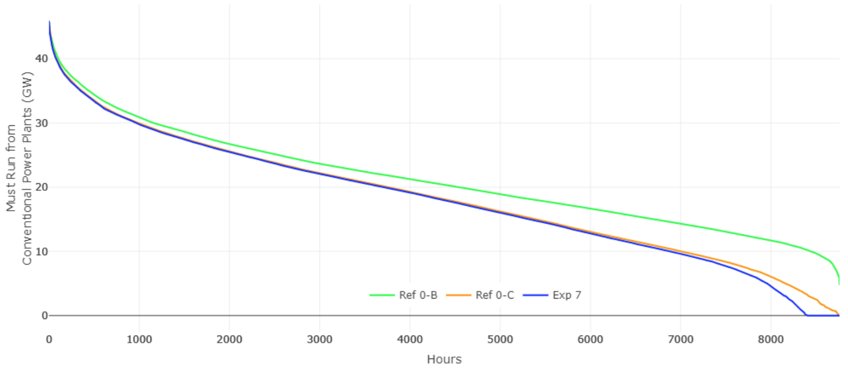


Figure 6.5: Duration curves of the must run capacity from conventional power plants in the selected scenarios.

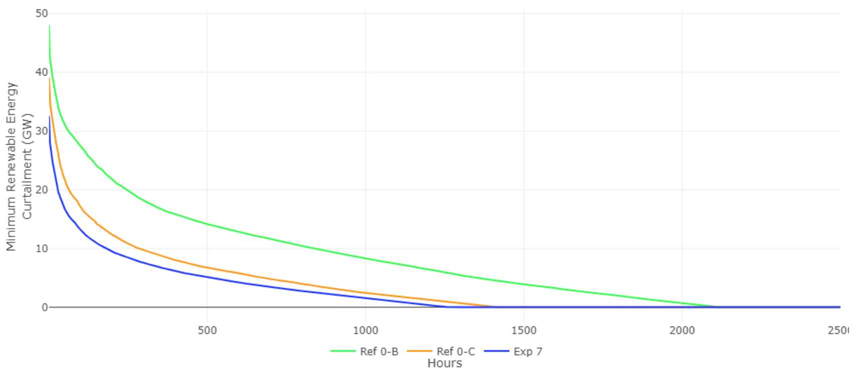


Figure 6.6: Duration curves of the minimum required curtailment of renewable energy power output due to the must run capacity from conventional power plants in the selected scenarios.

scenario 0-C it was 306.60 TWh, and 305.95 TWh in scenario 7.[2] The decrease in the downward dispatchable capacity would be less concerning due to its smaller magnitude, so let us focus on how the additional upward capacity changed after flexible DRE and VRE were introduced into the CRM.

[2]The results shown here did not consider the additional flexible capacity from energy storage units.

From figure 6.4 it is easy to see that not only did flexible DRE and VRE decrease the additional upward dispatchable capacity on average, but also most of the decrease occurred on the left hand side of the duration curve. Since the left hand side of the duration curve represents events with abundant VRE power output availability, we suspected that the decrease of additional upward dispatchable capacity in scenario 0-C and scenario 7 was due to 1) the decrease of the curtailment of VRE power output and 2) the decrease of the total must run capacity of conventional power plants during high VRE penetration events. Less curtailment of VRE meant that less of the available VRE power output would be left outside both EOM and CRM to be counted as the additional upward dispatchable capacity, while fewer number of conventional power plants (thereby reducing the sum of their must run capacity) would result in less upward dispatchable capacity from these power plants.

We can see from figure 6.5 that the total must run capacity of the conventional power plants did indeed decrease when flexible DRE or VRE were introduced into the CRM, especially on the right hand side of the duration curve; the minimum value of the total must run capacity of the conventional power plants was 4.76 GW in scenario 0-B, while in both scenario 0-C and 7 it was 0 GW. This resulted in a decrease from the minimum required renewable energy curtailment due to the total must run capacity of the conventional power plants when it exceeded the residual load, as shown in figure 6.6. In scenario 0-B, there would be 20.57 TWh of available electricity generation from renewable energy sources that needed to be curtailed due to the must run capacity constraint from conventional power plants; in scenario 0-C this figure dropped to 9.21 TWh; in scenario 7 it further dropped to 6.79 TWh.

This result supported the concepts that 1) we should differentiate between the must run capacity of the conventional power plants from the system must run, where the latter would be the total negative control reserve demand of the system and it would be significantly lower than the former, as analyzed in [66][3], and that 2) if we allow all technologies to provide the system must run, the must run capacity of the conventional power plants would not be necessary on the grid and it would in fact be extinguished in events when the available power output from VRE power plants was abundant, reducing the need for renewable energy curtailment.

Meanwhile, the right hand of the duration curve in figure 6.4 was not affected as much as the left hand side after flexible DRE and flexible VRE were introduced into the CRM; this implied that the annual maximum upward dispatchable flexibility requirements additional to the CRM would not be directly affected by flexible DRE or flexible VRE.

In short, the flexibility of the power system beyond the CRM we had modeled would decrease after the available resources were used more efficiently in the EOM and CRM. As discussed in subsection 6.1.1.1, reliability and stability issues might also arise indirectly from an increase in the largest single unit capacity and the uneven distribution of control reserve provided by VRE power plants; whether or not the reduction of flexibility beyond the CRM would further incubate these issues will require further study in the future.

6.1.1.3 Cost

As mentioned in section 5.3, we only considered the variable system costs of different scenarios in our study. To further analyze the results, consider the following equation that decomposes the total variable system cost:

$$VC_{\{T\}} = \underbrace{\sum_{g_i} c_{g_i}^{\{T\}} \zeta_{g_i}^{\{T\}} E_{\{T\}}}_{(1)} + \underbrace{\sum_{s_i} \frac{var_{dc,s_i} E_{dc,s_i}^{\{T\}}}{\eta_{dc,s_i}} + var_{ch,s_i} E_{ch,s_i}^{\{T\}} \eta_{ch,s_i}}_{(2)} \tag{6.1}$$

[3]The term “Mindesterzeugung” in that report had the closest definition to what we called the system must run level here, and the term “preisunelastischen konventionellen Erzeugungsleistung” would correspond to the total must run capacity of the conventional power plants in our study.

Here $VC_{\{T\}}$ is the total variable system cost over a time span $\{T\}$, $c_{g_i}^{\{T\}}$ the average variable costs of operating the generation source g_i within $\{T\}$, $\zeta_{g_i}^{\{T\}}$ the average proportion of g_i in electricity generation within $\{T\}$, $E_{dc,s_i}^{\{T\}}$ the total discharge energy of energy storage unit s_i to the system within $\{T\}$, and $E_{ch,s_i}^{\{T\}}$ the total charge energy of energy storage unit s_i from the system within $\{T\}$. (1) in equation 6.1 is the variable system costs related to generation, and (2) is the variable system costs related to the energy storage operation.

Taking a first order variation of $VC_{\{T\}}$ we would have the following:

$$\begin{aligned}\delta[VC_{\{T\}}] \quad = \quad & (\textstyle\sum_{g_i}\delta[c_{g_i}^{\{T\}}]\zeta_{g_i}^{\{T\}} \quad + \quad \sum_{g_i} c_{g_i}^{\{T\}}\delta[\zeta_{g_i}^{\{T\}}])E_{\{T\}} \quad + \quad \sum_{g_i} c_{g_i}^{\{T\}}\zeta_{g_i}^{\{T\}}\delta[E_{\{T\}}] \\ & + \quad \textstyle\sum_{s_i}\frac{var_{dc,s_i}}{\eta_{dc,s_i}}\delta[E_{dc,s_i}^{\{T\}}] \quad + \quad \sum_{s_i} var_{ch,s_i}\eta_{ch,s_i}\delta[E_{ch,s_i}^{\{T\}}]\end{aligned} \tag{6.2}$$

Here $\delta[\cdot]$ is the first order variation operator described in appendix B.1. However, in our simulations the variation of the total electricity generation could only result from different charge / discharge patterns of the energy storage units. Thus from the conservation of energy we should also have

$$\delta[E_{\{T\}}] = \sum_{s_i}\delta[E_{ch,s_i}^{\{T\}}] - \delta[E_{dc,s_i}^{\{T\}}] \tag{6.3}$$

So we can rewrite equation 6.2 as

$$\begin{aligned}\delta[VC_{\{T\}}] \quad = \quad & (\textstyle\sum_{g_i}\delta[c_{g_i}^{\{T\}}]\zeta_{g_i}^{\{T\}} \quad + \quad \sum_{g_i} c_{g_i}^{\{T\}}\delta[\zeta_{g_i}^{\{T\}}])E_{\{T\}} \quad + \\ & \textstyle\sum_{s_i}(\frac{var_{dc,s_i}}{\eta_{dc,s_i}} \quad - \quad \sum_{g_i} c_{g_i}^{\{T\}}\zeta_{g_i}^{\{T\}})\delta[E_{dc,s_i}^{\{T\}}] \quad + \\ & \textstyle\sum_{s_i}(var_{ch,s_i}\eta_{ch,s_i} \quad + \quad \sum_{g_i} c_{g_i}^{\{T\}}\zeta_{g_i}^{\{T\}})\delta[E_{ch,s_i}^{\{T\}}] \\ = \quad & \underset{(1)}{(\textstyle\sum_{g_i}\delta[c_{g_i}^{\{T\}}]\zeta_{g_i}^{\{T\}}} \quad + \quad \underset{(2)}{\textstyle\sum_{g_i} c_{g_i}^{\{T\}}\delta[\zeta_{g_i}^{\{T\}}])E_{\{T\}}} \quad + \\ & \underset{(3)}{\textstyle\sum_{s_i}\big((var_{ch,s_i}+var_{dc,s_i})} \quad + \quad \underset{(4)}{\textstyle\sum_{g_i}(\frac{1}{\eta_{ch,s_i}}-\eta_{dc,s_i})c_{g_i}^{\{T\}}\zeta_{g_i}^{\{T\}}\big)\delta[E_{ESU,s_i}^{\{T\}}]}\end{aligned} \tag{6.4}$$

Here $E_{ESU,s_i}^{\{T\}}$ is the total amount of energy stored inside the energy storage unit s_i within $\{T\}$. If $\{T\}$ is long enough that the difference between the initial and final state of charge of the energy storage unit becomes irrelevant in the calculation of total charge / discharge energy, then $\frac{E_{dc,s_i}^{\{T\}}}{\eta_{dc,s_i}} \to E_{ch,s_i}^{\{T\}}\eta_{ch,s_i}$, and we could determine the value of $E_{ESU,s_i}^{\{T\}}$ accurately enough for equation 6.4 to be meaningful.

Equation 6.4 has 4 terms in its final form. (1) is the variation of the average variable costs of operating the generation sources, which we will call the operation effect since it mainly results from the change of thermal efficiency and the start up cost due to different operation patterns. (2) is the variation of the portfolio of the electricity generation, which is also known as the fuel switching effect. (3) is the variable costs for operating the energy storage units, and (4) arises from the net energy losses during a charge / discharge cycle of the energy storage units. Since we already know that (3) and (4) were negligible in our simulations (the variations of both the variable system costs due to energy storage units and the total electricity generation were small in all of the scenarios), in the rest of this section we shall focus our discussion on the operation effect and the fuel switching effect on the total variable system cost.

To determine the operation effect and the fuel switching effect flexible DRE and VRE had on the total variable system cost, we performed the decomposition analysis described in appendix B.2.

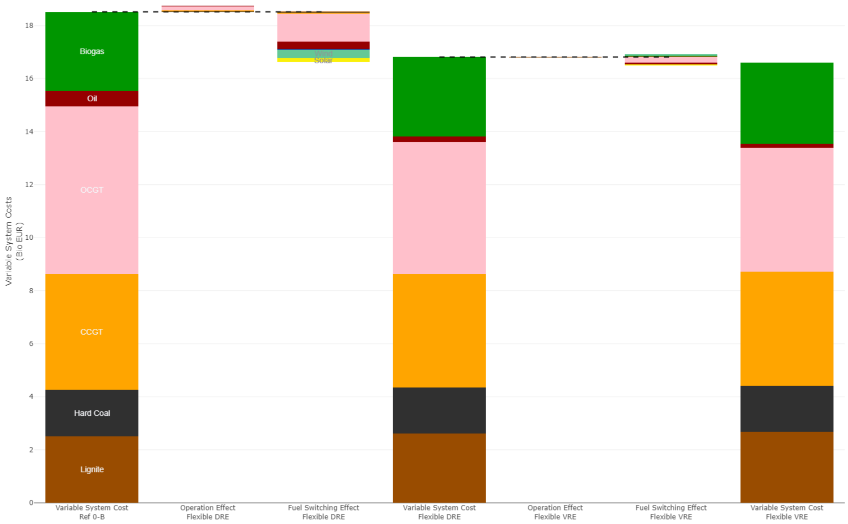


Figure 6.7: Decomposition analysis of the impact flexible DRE and flexible VRE had on on the total variable system cost.

Scenarios	**Ref 0-B**	**Ref 0-C**	**Exp 7**
Units		(EUR/MWh)	
Lignite	46.10	46.01	45.84
Hard Coal	61.91	62.36	62.21
CCGT	64.74	65.38	65.30
OCGT	111.35	114.44	114.68
Oil	149.61	156.03	157.30

Table 6.1: Summary of the average variable costs of different generation technologies in the selected scenarios. Bioenergy power plants were assumed to have constant thermal efficiency and no start up costs, therefore they had a constant average variable cost of 47.05 EUR/MWh in all scenarios.

The result can be seen in figure 6.7 and table 6.1.

We can see from figure 6.7 that introducing flexible DRE into the CRM would allow more VRE to get onto the grid in scenario 0-C. Since these additional electricity generation mostly replaced that from OCGT and oil power plants, it resulted in a strong fuel switching effect on cost reduction between reference scenarios 0-B and 0-C. However, part of the fuel-switching effect was offset by the operation effect of operating OCGT and oil power plants more flexibly. Introducing flexible VRE into the CRM would result in a further reduction of electricity generation from OCGT and oil power plants in scenario 7, though some of this fuel switching effect on cost reduction was offset by less electricity generation from wind power plants. Meanwhile, the operation effect of flexible VRE on the total variable system cost was less significant in scenario 7.

Let us investigate the reason behind the increase of the average variable costs of most conventional technologies between reference scenarios 0-B and 0-C, as seen in table 6.1. Part of it might be because of the drop of full load hours for hard coal, CCGT, OCGT and oil power plants as discussed in section 5.7: a drop of full load hours would deviate a power plant from its optimal operation point, thereby reducing the thermal efficiency of the power plant, causing more fuel consumption for every MWh of electricity produced. A more accurate indicator for this reduction of the thermal efficiency would be the average capacity factors when the power plants were available, which was depicted in figure 6.8. In the figure we can see that the increase of the average capacity

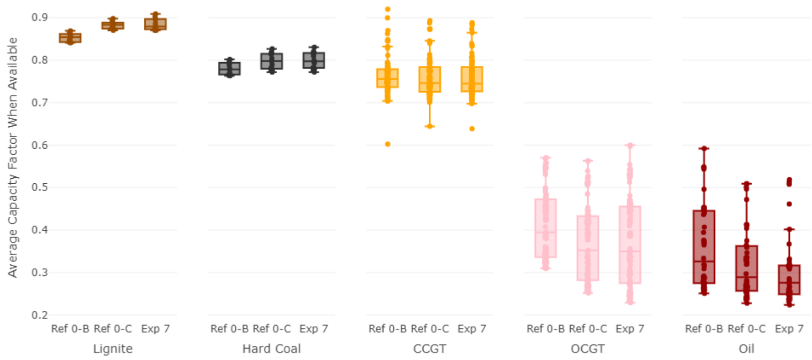


Figure 6.8: Average capacity factor when available for different conventional technologies in the selected scenarios.

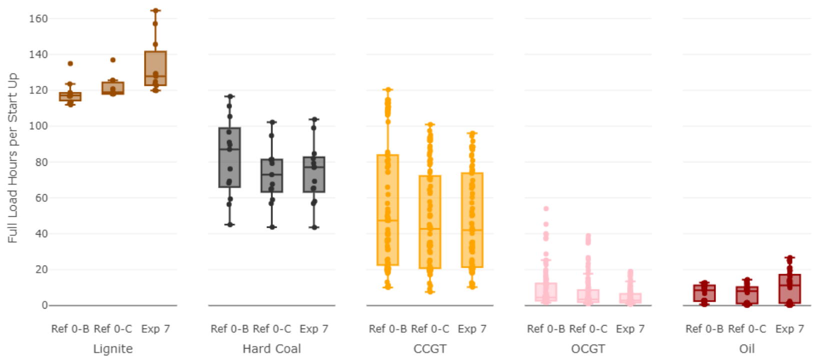


Figure 6.9: Average electricity generated per nameplate capacity between each start up for different conventional technologies in the selected scenarios.

factors when available for the lignite power plants also coincided with a decrease of their average variable costs; the vice versa happened for OCGT and oil power plants, while the connection was not obvious for hard coal and CCGT power plants.

Another factor that we should consider is the start up cost. If a power plant switched off and on more frequently for the same amount of electricity generation, the start up cost would be higher per electricity generated. Figure 6.9 depicts how the average electricity generated per nameplate capacity between each start up changed among the reference scenarios 0-B, 0-C, and experiment scenario 7: from scenario 0-B to scenario 0-C, the median values of the average electricity generated per nameplate capacity between each start up decreased for all the conventional technologies except lignite power plants. After flexible VRE were introduced into the CRM in scenario 7, the median values of the average electricity generated per nameplate capacity of lignite and hard coal power plants increased, contributing to a decrease in the average variable costs of these technologies; meanwhile, although the median value of the average electricity generated per nameplate capacity of oil power plants also increased, the capacity weighted average of that value (the one that really matters when calculating the average variable costs) actually decreased and resulted in an increase of the average variable costs for oil power plants.

6.1.2 Environmental Perspective

As mentioned earlier in section 5.4, we only considered the fuel-related carbon emissions of different scenarios in our study. We performed the same decomposition analysis done in section 6.1.1,

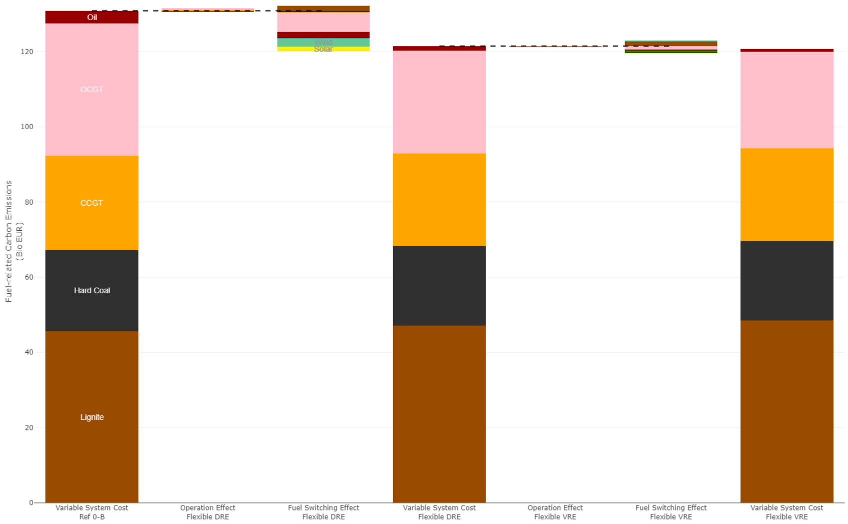


Figure 6.10: Decomposition analysis of the impact flexible DRE and flexible VRE had on the total fuel-related carbon emission.

Scenarios	**Ref 0-B**	**Ref 0-C**	**Exp 7**
Units		(t $CO_{2\,eq}$/MWh)	
Lignite	0.839	0.832	0.829
Hard Coal	0.758	0.758	0.758
CCGT	0.371	0.374	0.374
OCGT	0.622	0.632	0.630
Oil	0.864	0.879	0.876

Table 6.2: Summary of the average carbon emission intensity of different generation technologies in the selected scenarios.

this time replacing the average variable costs with the average carbon emission intensity of different generation technologies; other than that we used basically the same formula as described in equation 6.4 and the methodology as described in appendix B.2. The results of the decomposition analysis can be seen in figure 6.10 and table 6.2.

As seen in figure 6.10, introducing flexible DRE into the CRM allowed more electricity generation from VRE power plants in scenario 0-C, which largely replaced the electricity generation from OCGT and oil power plants; yet operating these conventional power plants more flexibly (as discussed in subsection 6.1.1.3) would result in an operation effect that offset some of the carbon emission reduction due to the fuel switching effect. Introducing flexible VRE would lead to not only a decrease in the consumption of oil and gas, but also an increase in the consumption of lignite, and their impacts on the total fuel-related carbon emission canceled out one another.

Observing table 6.2 we can see that in our simulations the average carbon emission intensity values of conventional generation sources were lower than some pieces of the previous literature would have suggested. For example, in [59] flexible operations of a hard coal power plant with a 40% nominal thermal efficiency was modeled to have a carbon intensity between 0.861 to 1.054 tonnes $CO_{2\,eq}$ / MWh, and that of a CCGT power plant between 416 to 617 tonnes $CO_{2\,eq}$ / MWh. However, we should note that the average nominal efficiency of the conventional power plants in the future will tend to increase (since older, less efficient power plants will be decommissioned first); in [67], the carbon emission intensity of hard coal power plants in the future was projected

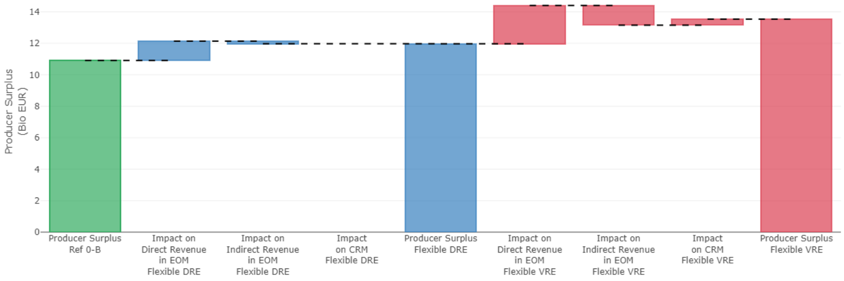


Figure 6.11: Impacts of flexible DRE and flexible VRE on the direct producer revenue, the indirect producer revenue, and the producer surplus of wind power plants.

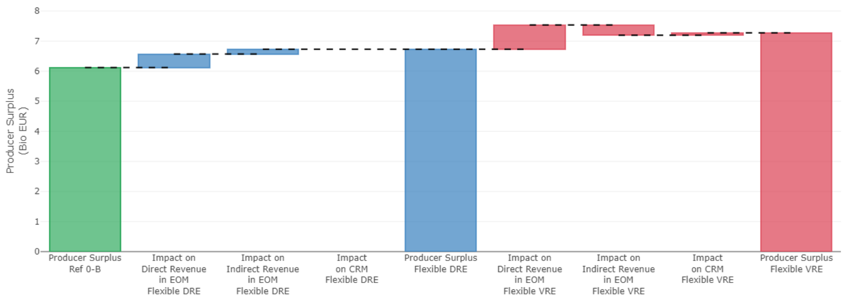


Figure 6.12: Impacts of flexible DRE and flexible VRE on the direct producer revenue, the indirect producer revenue, and the producer surplus of photovoltaic power plants.

to be 0.670 tonnes $CO_{2\ eq}$ / MWh, that of CCGT power plants to be 0.303 tonnes $CO_{2\ eq}$ / MWh, and that of OCGT power plants to be 0.442 tonnes $CO_{2\ eq}$ / MWh under full load operations.

For the record, we note here that total carbon emission is not the only perspective when discussing the environmental impact of the power system. It is clear that in our futuristic scenarios there would no longer be additional radioactive waste produced nor operation-related nuclear safety risks from the electricity sector in Germany, but the impacts of flexible DRE and VRE on other environment indicators might not be equally obvious. For example, using gas as a fuel would produce significantly less SOx and PM 2.5 compared with using lignite or hard coal for the same amount of electricity generated in the future [67, 68], so the fuel switching effect we observed previously might lead to more air pollution in the flexible VRE case. Of course, we would have to investigate further into the emission intensity factors of different air pollutants to quantify these impacts in potential future studies.

6.1.3 Microeconomic Perspectives

6.1.3.1 VRE Operators

For wind power plants, the producer revenue collected in the EOM shrunk from 13.25 billion Euros in scenario 0-A to 10.91 billion Euros in scenario 0-B. Such drop in the producer surplus was a result of both a decrease of the average market clearing price in the EOM and the feed-in premium level.

Introducing flexible DRE into the CRM would increase the producer revenue wind power plants collected in the EOM to 11.97 billion Euros in scenario 0-C. Introducing flexible VRE into the CRM would increase the producer revenue wind power plants collected in the EOM to 13.15 billion Euros in scenario 7 and increase the producer revenue in the CRM to 0.38 billion Euros, resulting in an

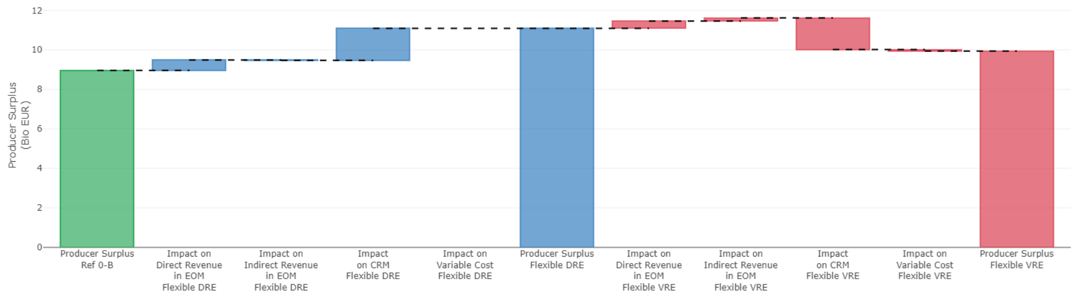


Figure 6.13: Impacts of flexible DRE and flexible VRE on the direct producer revenue, the indirect producer revenue, the variable cost, and the producer surplus of bioenergy power plants.

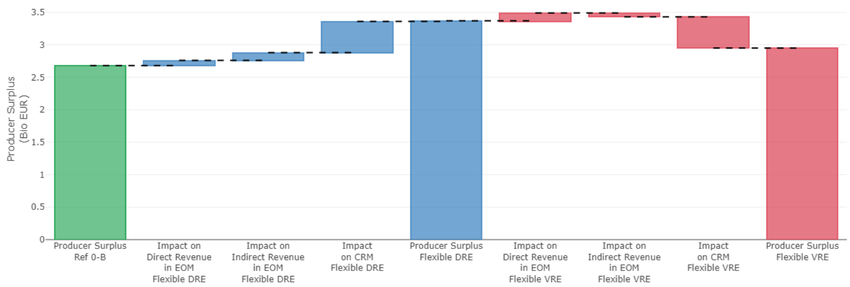


Figure 6.14: Impacts of flexible DRE and flexible VRE on the direct producer revenue, the indirect producer revenue, and the producer surplus of hydroelectric power plants.

increase of the producer surplus to 13.53 billion Euros. Both flexible DRE and VRE would increase the revenue wind power plants collected in the EOM, while allowing VRE into the CRM would result in an additional revenue from that market.

For photovoltaic power plants, the producer revenue collected in the EOM shrunk from 11.32 billion Euros in scenario 0-A to 6.12 billion Euros in scenario 0-B. Similar to the change of the producer surplus for wind power plants, such drop was a result of both a decrease of the average market clearing price in the EOM and the feed-in premium level.

Introducing flexible DRE into the CRM would increase the producer revenue photovoltaic power plants collected in the EOM to 6.73 billion Euros in scenario 0-C. Introducing flexible VRE into the CRM would increase the producer revenue photovoltaic power plants collected in the EOM to 7.19 billion Euros in scenario 7 and increase the producer revenue in the CRM to 0.08 billion Euros, resulting in an increase of the producer surplus to 7.27 billion Euros. Thus the introduction of flexible DRE and VRE into the CRM had similar effects on the profitability of photovoltaic power plants to the effects on the wind power plants, although the additional revenue was smaller.

6.1.3.2 DRE Operators

For bioenergy power plants, the producer revenue collected in the EOM shrunk from 14.63 billion Euros in scenario 0-A to 11.95 billion Euros in scenario 0-B, while the variable cost decreased from 3.15 billion Euros to 2.99 billion Euros, resulting a decrease of the producer surplus from 11.48 billion Euros to 8.96 billion Euros.

Introducing flexible DRE into the CRM would increase the producer revenue bioenergy power plants collected in the EOM to 12.46 billion Euros in scenario 0-C and increase the producer rev-

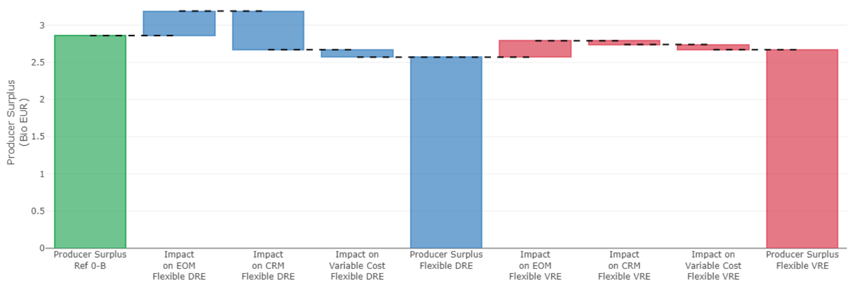


Figure 6.15: Impacts of flexible DRE and flexible VRE on the producer revenue, the variable cost, and the producer surplus of lignite power plants.

enue in CRM to 1.62 billion Euros, while the variable cost remained the same, resulting in an increase of the producer surplus to 11.09 billion Euros. Introducing flexible VRE into the CRM would increase the producer revenue bioenergy power plants collected in the EOM to 12.99 billion Euros in scenario 7, decrease the producer revenue in CRM to 0.02 billion Euros, and increase the variable cost to 3.07 billion Euros, resulting in a decrease of the producer surplus to 9.94 billion Euros. In general, both flexible DRE and VRE would increase the revenue of bioenergy power plants in the EOM, but flexible VRE competed with flexible DRE in the CRM and thus they eroded the revenue of bioenergy power plants in that market.

For hydroelectric power plants, the producer revenue collected in the EOM shrunk from 3.29 billion Euros in scenario 0-A to 2.68 billion Euros in scenario 0-B. Introducing flexible DRE into the CRM increased the producer revenue hydroelectric power plants collected in the EOM to 2.89 billion Euros in scenario 0-C and the producer revenue in the CRM to 0.48 billion Euros, resulting in an increase of the producer surplus to 3.37 billion Euros. Introducing flexible VRE into the CRM would increase the producer revenue hydroelectric power plants collected in the EOM to 2.96 billion Euros in scenario 7 while extinguishing the producer revenue in the CRM, resulting in a decrease of producer surplus. In general, flexible DRE and VRE had similar impacts on hydroelectric power plants compared with those on bioenergy power plants.

6.1.3.3 Conventional Power Plant Operators

For lignite power plants, the producer revenue collected in the EOM shrunk from 10.51 billion Euros in scenario 0-A to 4.67 billion Euros in scenario 0-B, the producer revenue collected in the CRM increased from 0.60 billion Euros to 0.70 billion Euros, and the variable cost decreased from 2.96 billion Euros to 2.51 billion Euros. This resulted to a change of the producer surplus from 8.15 billion Euros to 2.86 billion Euros, which was not surprising due to a rapid coal phase out in the model.

Introducing flexible DRE into the CRM increased the producer revenue lignite power plants collected in the EOM to 5.00 billion Euros in scenario 0-C, decreased the producer revenue in the CRM to 0.18 billion Euros, and increased the variable cost to 2.61 billion Euros, resulting in a decrease in producer surplus to 2.57 billion Euros. Introducing flexible VRE into the CRM increased the producer revenue lignite power plants collected in the EOM to 5.22 billion Euros in scenario 7, decreased the producer revenue in the CRM to 0.13 billion Euros, and increased the variable cost to 2.68 billion Euros, resulting in an increase in the producer surplus to 2.67 billion Euros.

For hard coal power plants, the producer revenue collected in the EOM rose from 1.78 billion Euros in scenario 0-A to 2.52 billion Euros in scenario 0-B, the producer revenue collected in the CRM increased from 0.10 billion Euros to 0.23 billion Euros, and the variable cost increased from 0.78 billion Euros to 1.76 billion Euros. This resulted in a change of the producer surplus from

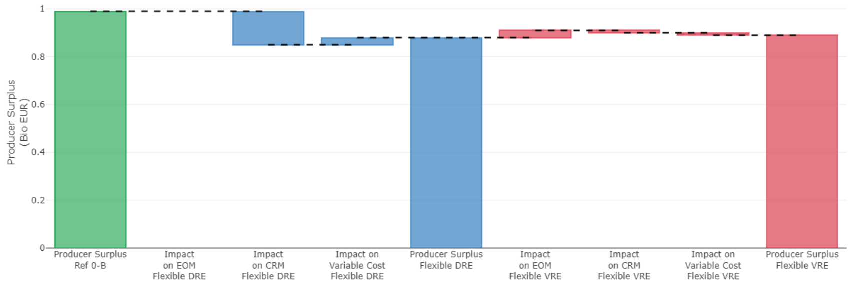


Figure 6.16: Impacts of flexible DRE and flexible VRE on the producer revenue, the variable cost, and the producer surplus of hard coal power plants.

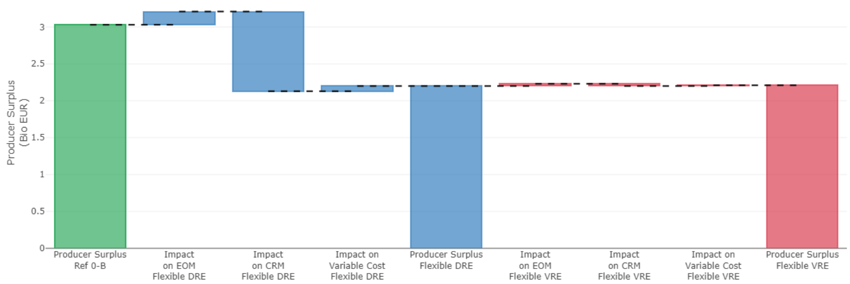


Figure 6.17: Impacts of flexible DRE and flexible VRE on the producer revenue, the variable cost, and the producer surplus of CCGT power plants.

1.10 billion Euros to 0.99 billion Euros. Electricity generation from hard coal power plants actually increased between reference scenarios 0-A amd 0-B, but the market clearing prices in the EOM decreased and some of the most profitable hard coal power plants in scenario 0-A could no longer gain such a high producer surplus, as shown in figure 5.8.

Introducing flexible DRE into the CRM did not alter the producer revenue hard coal power plants collected in the EOM significantly in scenario 0-C, while it decreased the producer revenue in the CRM to 0.09 billion Euros and decreased the variable cost to 1.73 billion Euros, resulting a decrease of the producer surplus to 0.88 billion Euros. Introducing flexible VRE into the CRM increased the producer revenue hard coal power plants collected in the EOM to 2.55 billion Euros and decreased the producer revenue in the CRM to 0.08 billion Euros in scenario 7, while the variable cost increased to 1.74 billion Euros, resulting in a slight increase of the producer surplus to 0.89 billion Euros.

For CCGT power plants, the producer revenue collected in the EOM rose from 2.96 billion Euros in scenario 0-A to 5.90 billion Euros in scenario 0-B, the producer revenue collected in the CRM increased from 0.05 billion Euros to 1.50 billion Euros, and the variable cost from 1.20 billion Euros to 4.37 billion Euros. This resulted in a change of the producer surplus from 1.81 billion Euros to 3.03 billion Euros, reflecting the fact that the electricity generation from CCGT power plants, as well as their contribution to the control reserve capacity, grew significantly between reference scenarios 0-A and 0-B.

Introducing flexible DRE into the CRM would increase the producer revenue CCGT power plants collected in the EOM to 6.08 billion Euros in scenario 0-C, decrease the producer revenue in the CRM to 0.42 billion Euros, and decrease the variable cost to 4.30 billion Euros, resulting in a decrease in the producer surplus to 2.20 billion Euros. Introducing flexible VRE into the CRM would

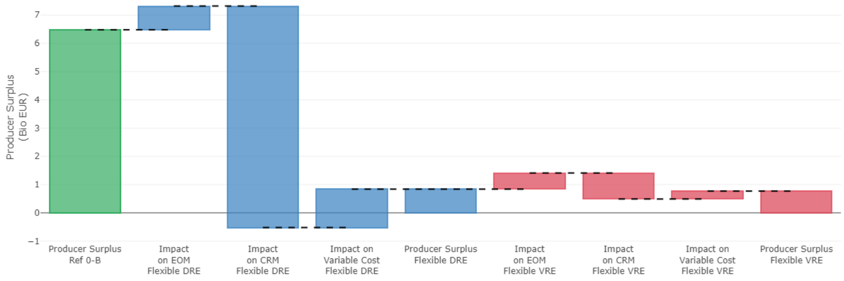


Figure 6.18: Impacts of flexible DRE and flexible VRE on the producer revenue, the variable cost, and the producer surplus of OCGT power plants.

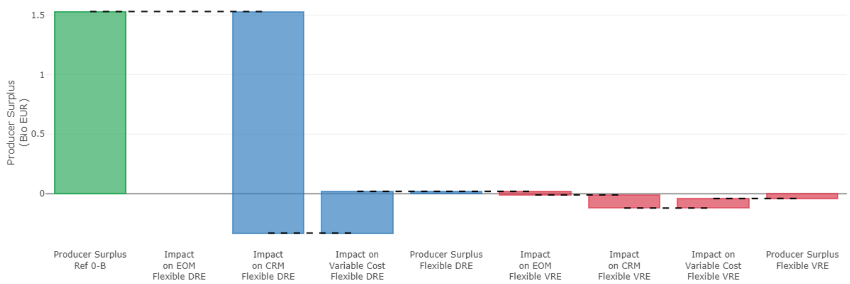


Figure 6.19: Impacts of flexible DRE and flexible VRE on the producer revenue, variable cost, and the producer surplus of oil power plants.

increase the producer revenue CCGT power plants collected in the EOM to 6.11 billion Euros in scenario 7, decrease the producer revenue in the CRM to 0.39 billion Euros, while the variable cost slightly decreased to 4.29 billion Euros. This resulted in a slight increase in the producer surplus to 2.21 billion Euros.

For OCGT power plants, the producer revenue collected in the EOM rose from 1.84 billion Euros in scenario 0-A to 3.08 billion Euros in scenario 0-B, the producer revenue collected in the CRM increased from 0.31 billion Euros to 9.72 billion Euros, and the variable cost from 1.30 billion Euros to 6.32 billion Euros. This resulted in a significant change of the producer surplus from 0.85 billion Euros to 6.48 billion Euros, reflecting the fact that the electricity generation from OCGT power plants, as well as their contribution to the control reserve capacity, grew significantly between reference scenarios 0-A and 0-B.

Introducing flexible DRE into the CRM would increase the producer revenue OCGT power plants collected in the EOM to 3.92 billion Euros in scenario 0-C, decrease the producer revenue in the CRM to 1.88 billion Euros, and decrease the variable cost to 4.96 billion Euros, resulting in a significant decrease in the producer surplus to 0.84 billion Euros. Introducing flexible VRE into the CRM would increase the producer revenue OCGT power plants collected in the EOM to 4.49 billion Euros in scenario 7, decrease the producer revenue in the CRM to 0.96 billion Euros, and decrease the variable cost to 4.68 billion Euros, resulting in a decrease in the producer surplus to 0.77 billion Euros.

For oil power plants, the producer revenue collected in the EOM shrunk from 0.65 billion Euros in scenario 0-A to 0.13 billion Euros in scenario 0-B, the producer revenue collected in the CRM increased from 0.19 billion Euros to 1.97 billion Euros, and the variable cost increased from 0.53 billion Euros to 0.57 billion Euros. This resulted in a significant change of the producer surplus from 0.31 billion Euros to 1.53 billion Euros. While the electricity generation from oil power plants decreased in scenario 0-B, their greater contribution in the negative control reserve capacity gained them more revenue.

Introducing flexible DRE into the CRM would not change the producer revenue oil power plants collected in the EOM in scenario 0-C, while the producer revenue collected in the CRM decreased to 0.11 billion Euros, and the variable cost decreased to 0.22 billion Euros, resulting in a sharp decrease of producer surplus to 0.02 billion Euros. Introducing flexible VRE into the CRM would decrease the producer revenue oil power plants collected in the EOM to 0.10 billion Euros in scenario 7, extinguish their producer revenue in the CRM, and decrease the variable cost to 0.14 billion Euros, resulting a further decrease of producer surplus to -0.04 billion Euros; oil power plants were the only type of convention technology that had negative producer surplus in the experiment scenarios.

Table 6.3 is a summary of the results of this subsection. In general, flexible DRE and VRE

		Lignite	**Hard Coal**	**CCGT**	**OCGT**	**Oil**
VRE Expansion (Ref 0-B)	EOM	−	+	+	+	−
	CRM	+	+	+	+	+
	Variable Cost	−	+	+	+	+
	Producer Surplus	−	−	+	+	+
Flexible DRE (Ref 0-C)	EOM	+	×	+	+	×
	CRM	−	−	−	−	−
	Variable Cost	+	−	−	−	−
	Producer Surplus	−	−	−	−	−
Flexible VRE (Exp 7)	EOM	+	+	+	+	−
	CRM	−	−	−	−	−
	Variable Cost	+	+	−	−	−
	Producer Surplus	+	+	+	−	−

Table 6.3: Summary of the microeconomic impacts different scenarios had on the conventional power plants. A plus sign means an increase of the revenue / cost / producer surplus compared with the previous scenario (for scenario 0-B we compared it with scenario 0-A), a minus sign means a decrease, and a cross sign means no change occurred.

increased the producer revenues of conventional power plants in the EOM while decreasing those in the CRM.

6.1.3.4 Energy Storage Units

Compared with the renewable energy and conventional power plants, energy storage units held a significantly smaller share of the producer revenue in our simulation results. They only gained 0.58 billion Euros and 0.44 billion Euros in the EOM in reference scenarios 0-A and 0-B respectively, with variable costs negligible in both cases; in fact, in all scenarios the variable costs of operating the energy storage units were negligible.

Introducing flexible DRE into the CRM would decrease the producer revenue energy storage units collected in the EOM to 0.36 billion Euros in scenario 0-C, while introducing flexible VRE into the CRM would further decrease that figure to 0.23 billion Euros in scenario 7.

Observing the duration curve of the market clearing prices in figure 6.20 might give us a clue why the producer revenue of energy storage units decreased as flexible DRE and VRE were introduced into the CRM. Energy storage units relied on arbitraging the differences between the peaks and the valleys of the market clearing prices to gain revenue. Although introducing flexible DRE and VRE would increase the values on the left hand side of the duration curve (representing the peaks of the market clearing prices), it would also reduce the occurrence of negative market clearing price events on the right hand side of the duration curve (representing the valleys of the market clearing prices) to a greater extent, eroding the price differences energy storage units arbitraged in reference scenarios 0-A and 0-B.

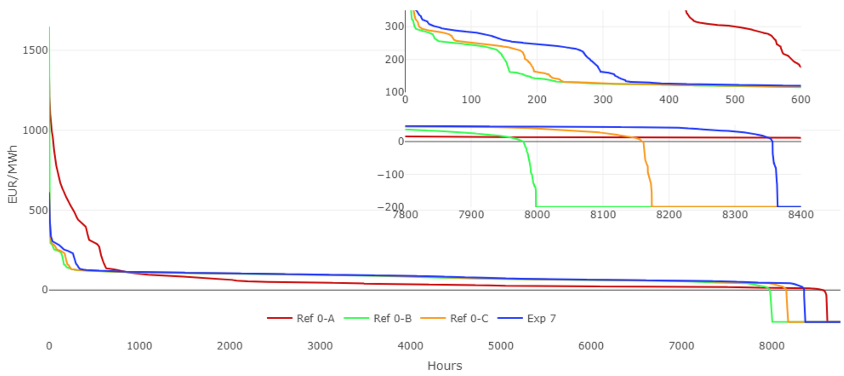


Figure 6.20: Duration curves of market clearing prices in the EOM for selected scenarios.

6.1.3.5 Electricity Consumers

Though we did not model the utility gains of the electricity consumers in our simulations, if we assumed it to be identical throughout all the scenarios, we can still discuss the relative change of the consumer surplus in the scenarios by comparing the total producer revenue (which the consumers would have to pay ultimately) in the scenarios.

In scenario 0-A, the electricity consumers would have to pay 37.53 billion Euros directly for the wholesale prices in the EOM, 29.20 billion Euros indirectly for the renewable surcharge, and 1.71 billion Euros for the control reserve services in the CRM. This resulted in a total expenditure of 68.44 billion Euros for the electricity consumers.

In scenario 0-B, the electricity consumers would have to pay 30.91 billion Euros directly for the wholesale prices in the EOM, 17.50 billion Euros indirectly for the renewable surcharge, and 14.12

billion Euros for the control reserve services in the CRM. This resulted in a decrease of the total expenditure to 62.53 billion Euros for the electricity consumers.

In scenario 0-C, the electricity consumers would have to pay 34.46 billion Euros directly for the wholesale prices in the EOM, 17.59 billion Euros indirectly for the renewable surcharge, and 4.78 billion Euros for the control reserve services in the CRM. This resulted in a decrease of the total expenditure to 56.83 billion Euros for the electricity consumers.

In scenario 7, the electricity consumers would have to pay 38.89 billion Euros directly for the wholesale prices in the EOM, 16.10 billion Euros indirectly for the renewable surcharge, and 2.04 billion Euros for the control reserve services in the CRM. This resulted in an increase of the total expenditure to 57.03 billion Euros for the electricity consumers.

In general, introducing flexible DRE and VRE into the CRM reduced the expenditure electricity consumers would have to pay for the control reserve services in the CRM while increased the expenditure directly for wholesale prices in the EOM. Flexible DRE would slightly increase the indirect expenditure for the renewable surcharge while flexible VRE would reduce it. In both scenario 0-C and scenario 7 the electricity consumers would pay less for the same services in the markets compared with scenario 0-B, thereby their consumer surplus was increased. It is impor-

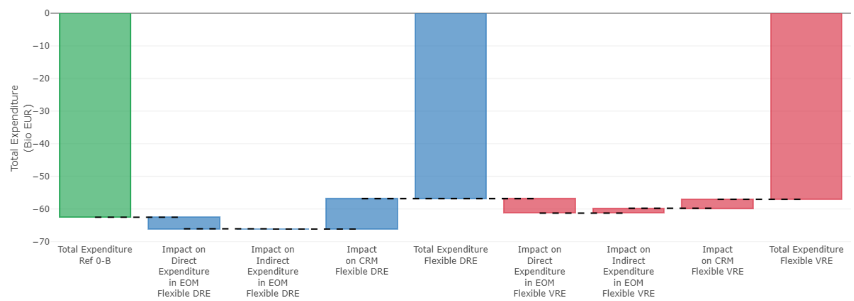


Figure 6.21: Impacts of flexible DRE and flexible VRE on the direct and indirect expenditure of electricity consumers.

tant to know, however, that the total expenditure calculated was not comprehensive. For example, redispatching VRE power output to avoid transmission line congestion would require compensations for the operators of the VRE power plants; such compensations would ultimately be paid by electricity consumers as part of the grid fees. The impacts of flexible DRE and flexible VRE on the grid fees could only be studied if we integrate *flexABLE* with a grid model, a spatial VRE power output availability model, and a reasonable assumption of the redispatch compensation in the future.

Futhrtmore, although assuming the utility gain of the electricity consumers did not change in the scenarios was reasonable, one could still argue simply the fact that more renewable energy was in the power system could have increased the willingness to pay from the consumers; according to [69], the mean of this additional utility gain would be 16.09 EUR per MWh increase of renewable energy in the power system[4], which in our study would translate to an increase of 0.23 billion Euros in the total utility gain from scenario 0-B to scenario 0-C, and 0.02 Billion Euros from scenario 0-C to scenario 7.

6.1.3.6 Overview of the Market

In scenario 0-A, the CRM represented only 4.36% of the direct producer revenue; in scenario 0-B, this figure surged to 31.36%, while in scenario 0-C it decreased to 12.18% and in scenario 7 to

[4]Here the inflation rate of USD between 2006 and 2018 [70] was taken into account, and the exchange rate from EUR to USD was set to be 1.1679, the median value in 2018.

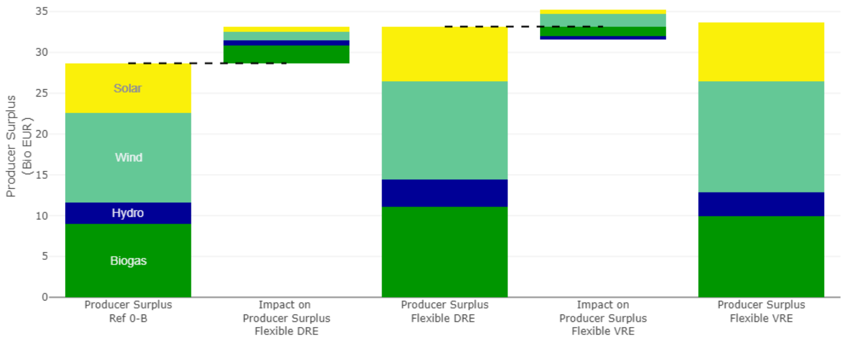


Figure 6.22: Overall impacts of flexible DRE and flexible VRE on the renewable energy sector.

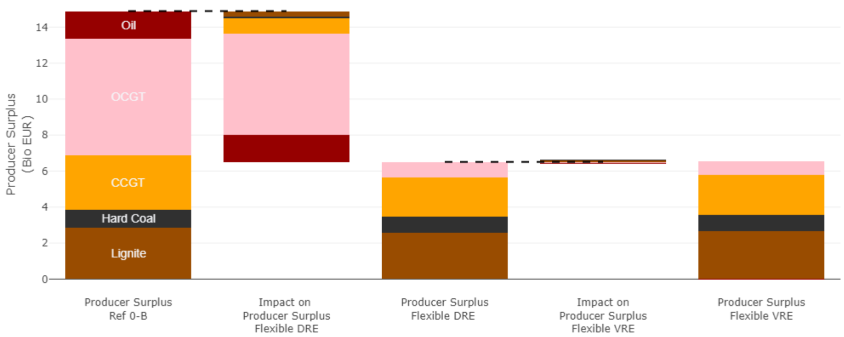


Figure 6.23: Overall impacts of flexible DRE and flexible VRE on the conventional energy sector.

4.98%. The reduction of the total producer revenue in the CRM after flexible DRE and flexible VRE were introduced was a result of more competition in the CRM, in particular in the bidding process of the negative control reserve capacity. This impact of more competition in the electricity market is more famous to be known as the merit order effect; for clarification, we shall call this the direct merit order effect of flexible DRE / VRE in the remaining of this report.

On the other hand, the increase of the direct producer revenue in the EOM after flexible DRE and flexible VRE entered the CRM was a result of the voluntarily curtailment of renewable energy power plants for the positive control reserve; by doing so, conventional power plants that had higher marginal costs would be able to enter the EOM, raising the market clearing prices in that market. For clarification, we shall call this the indirect merit order effect of flexible DRE / VRE in the remaining of this report. We will discuss deeper how the bidding strategies of flexible DRE and VRE caused the direct and indirect merit order effects in the electricity markets in section 6.2.

The impact of flexible DRE and VRE on the surplus of different sectors in the market is also a key insight to the overview of the market. In scenario 0-A, the producer surplus for VRE power plants was 24.57 billion Euros, the producer surplus for DRE power plants 14.77 billion Euros, the producer surplus for conventional power plants (excluding nuclear power plants) 12.22 billion Euros, and the total expenditure of electricity consumers 68.44 billion Euros. In scenario 0-B, the producer surplus for VRE power plants decreased to 17.03 billion Euros, the producer surplus for DRE power plants decreased to 11.64 billion Euros, the producer surplus for conventional power plants increased to 14.89 billion Euros, and the total expenditure of electricity consumers decreased to 62.53 billion Euros. Thus VRE expansion and lowering the feed-in premium level resulted in a net loss for the renewable energy sector, a net gain for the conventional energy sector (excluding

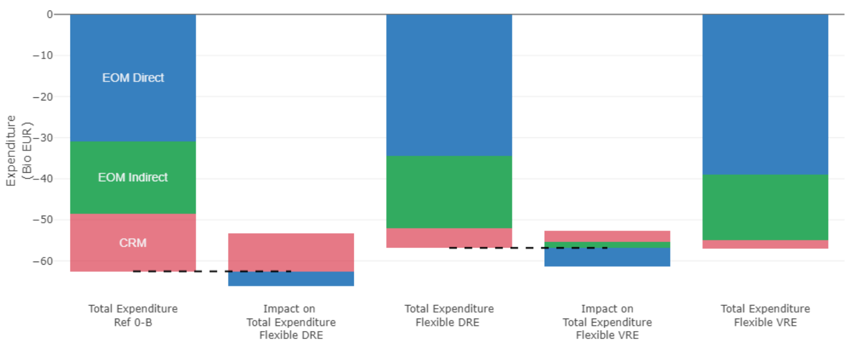


Figure 6.24: Overall impacts of flexible DRE and flexible VRE on electricity consumers.

	VRE Power Plants	**DRE Power Plants**	**Conventional Energy**	**Electricity Consumers**
VRE Expansion (Ref 0-B)	−	−	+	+
Flexible DRE (Ref 0-C)	+	+	−	+
Flexible VRE (Exp 7)	+	−	−	−

Table 6.4: Summary of the microeconomic impacts different scenarios had on different sectors. A plus sign means an increase in the producer / consumer surplus compared with the previous scenario (for scenario 0-B we compared it with scenario 0-A) and a minus sign means a decrease. The results of the convention energy sector did not include nuclear power plants.

nuclear power plants), and a net gain for electricity consumers.

In scenario 0-C, the producer surplus for VRE power plants increased to 18.70 billion Euros, the producer surplus for DRE power plants increased to 14.46 billion Euros, the producer surplus for conventional power plants decreased to 6.51 billion Euros, and the total expenditure of electricity consumers decreased to 56.83 billion Euros. In scenario 7, the producer surplus for VRE power plants increased to 20.80 billion Euros, the producer surplus for DRE power plants decreased to 12.90 billion Euros, the producer surplus for conventional power plants decreased to 6.50 billion Euros, and the total expenditure of electricity consumers increased to 57.03 billion Euros. Thus introducing flexible DRE into the CRM would result in a net gain for the renewable energy sector, a net loss for the conventional energy sector, and a net gain for electricity consumers, while introducing flexible VRE into the CRM would result in a net gain for the VRE sector, a net loss for the DRE sector, a net loss for the conventional energy sector, and a net loss for electricity consumers. A summary of the overall impacts of flexible DRE and VRE on these sectors can be found in figure 6.22, figure 6.23, figure 6.24, and table 6.4.

Finally, let us examine the impact flexible DRE and VRE had on the total surplus in the electricity markets: introducing flexible DRE into the CRM would lead to an increase of the total surplus by 1.71 billion Euros in scenario 0-C compared with scenario 0-B, and introducing flexible VRE into

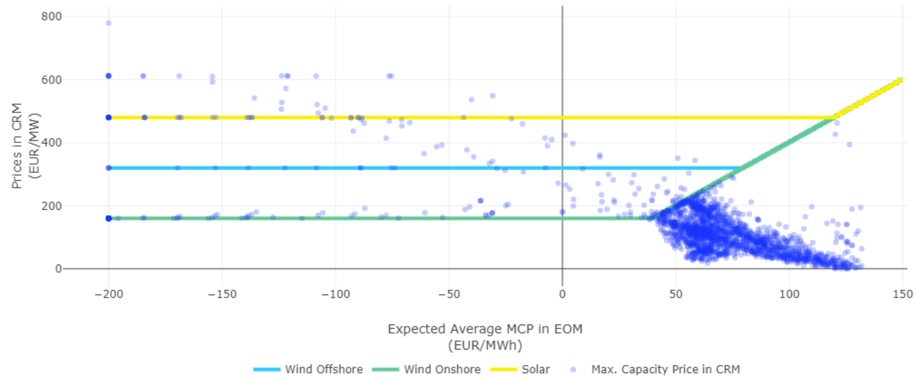


Figure 6.25: Opportunity costs for different VRE technologies and maximum accepted balancing capacity prices in the positive CRM, as a function of the expected market clearing prices in the EOM in a time step τ.

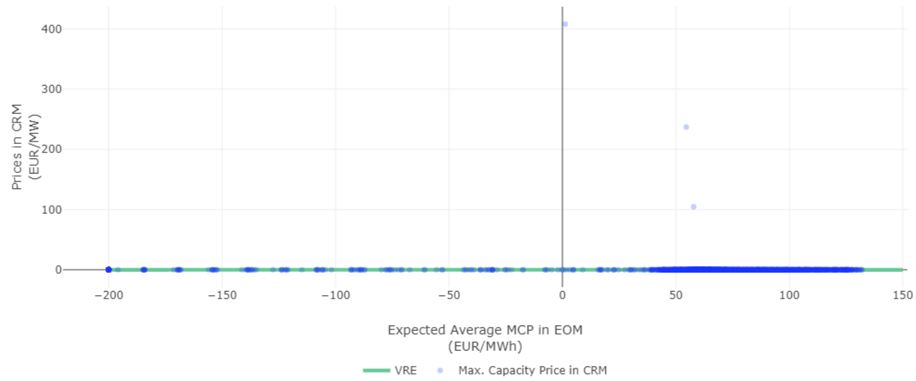


Figure 6.26: Opportunity costs for different VRE technologies and maximum accepted balancing capacity prices in the negative CRM, as a function of the expected market clearing prices in the EOM in a time step τ.

the CRM would lead to a further increase of the total surplus by 0.21 billion Euros in scenario 7 compared with scenario 0-C. This change of the total surplus in the market originated from the change of the total variable system cost; if we consider the potential utility gain due to more renewable energy sources in the electricity generation portfolio (as discussed in subsection 6.1.3.5), then the increase of the total surplus by introducing flexible DRE into the CRM would be 1.94 billion Euros and the increase by flexible VRE would be 0.23 billion Euros.

6.2 Mechanisms of the Impacts

6.2.1 Causes of Direct Merit Order Effects in the CRM

As seen in figure 5.2, the introduction of flexible DRE and VRE had affected the negative CRM more significantly than they did in the positive CRM. This can be explained by comparing the maximum accepted balancing capacity prices and the opportunity costs of providing the control reserve capacity for the renewable energy sources, as depicted in figure 6.25 and figure 6.26. We can see that during most of the time in scenario 7, the maximum accepted balancing capacity price for positive CRM was lower than the opportunity costs of VRE power plants, while VRE power plants had nearly 0 opportunity costs to participate in the negative CRM.

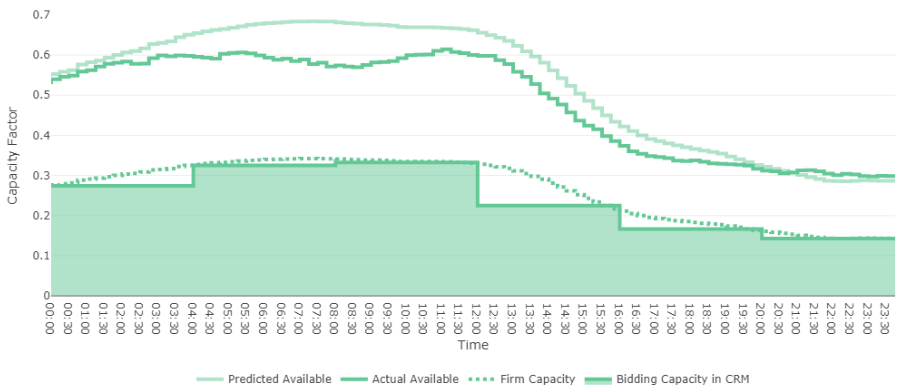


Figure 6.27: The available capacity for onshore wind power plants to participate in the CRM on 1 January of the input data.

Furthermore, we can see that wind power plants contributed significantly higher than the photovoltaic power plants in both the positive and negative CRM. Part of this was due to a higher available power output and a lower opportunity cost of participating in the CRM from wind power plants, but the power output profile of the two technologies also affected their capability of participating in the CRM. This can be seen in figure 6.27 and figure 6.28.

As seen in figure 6.27, since the variation in the wind power output profile tended to be on a larger timescale than the duration of a control reserve product, the wind power plants were able to bid a relative high portion of their predicted power output into the CRM. Meanwhile, in figure 6.28 we see that the daily peak of the photovoltaic power output profile happened to coincide with the end of a control reserve product (and the beginning of the next one), therefore the photovoltaic power plants could only bid a relatively low portion of their predicted power output into the CRM. As a result, even with similar maximum capacity factors in a day, the duration and magnitude of the control reserve capacity wind and photovoltaic power plants could provide varied significantly.

The participation of flexible DRE and VRE caused more competition and lowered the maximum bidding capacity and energy prices via their direct merit order effect in the CRM. Figure 6.35 to figure 6.43 show the operation plans of the EOM and the CRM in select weeks in scenarios 0-B, 0-C and 7. As seen from the figures, in all the selected weeks there were abundant VRE resources, and the DRE and VRE power plants dominated the negative CRM in scenario 7. In some occasions, wind power plants could also dominate the positive CRM for a certain amount of time (figure 6.37 and figure 6.40), while the participation of photovoltaic power plants in the positive CRM remained limited even in summer (figure 6.43).

We plotted the diurnal profile of the portfolio and maximum capacity prices in the CRM in January and July in the selected scenarios (figure 6.29 to figure 6.32) for a better understanding of the direct merit order effects flexible VRE would cause by participating in the CRM. As seen in figure 6.29, flexible VRE (mostly the wind power plants here) had a more profound effect on both the prices and portfolio in the positive CRM in late evening and midnight in January. Part of this was because the market clearing prices in the EOM were lowest in this period of day in January (figure 6.33), making the opportunity costs of participating in the positive CRM for the conventional power plants higher than that for the wind power plants. We can also see that the bioenergy and hydroelectric power plants were casted out of the positive CRM by the wind power plants due to the higher feed-in premium level we assumed for DRE power plants.

In the negative CRM, the wind power plants would compete with DRE power plants for the portfolio and extinguish the capacity prices to near 0 after flexible VRE were introduced (figure 6.30). This is due to the fact that all the renewable energy power plants have 0 opportunity

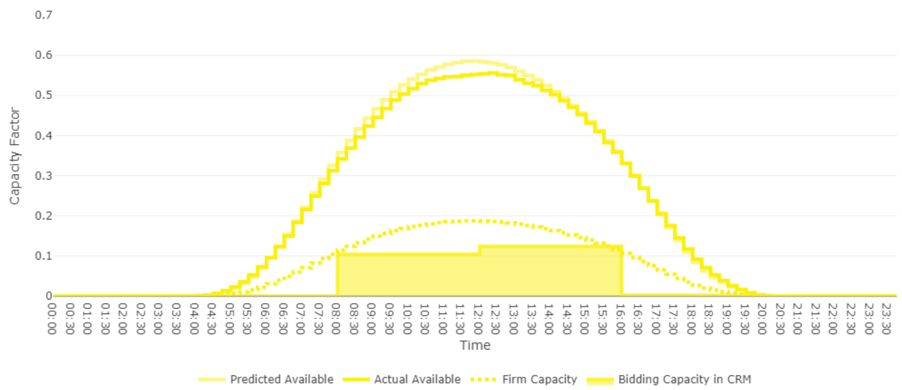


Figure 6.28: The available capacity for photovoltaic power plants to participate in the CRM on 19 July of the input data.

costs of participating in the negative CRM, even at times when market clearing prices in the EOM were negative (if they received feed-in premiums), thus they would all be in the leading rankings of the merit order. As a result, the contribution of conventional power plants in the negative COM dropped significantly after flexible DRE and flexible VRE were introduced.

In July, we see from figure 6.34 that the lowest market clearing price in the EOM in a day would be at noon, when the power output from the photovoltaic power plants (the dominating VRE power plants in summer) was abundant. Yet as discussed previously, photovoltaic power plants were less capable of participating in the CRM due to both their power output profile and the market design we assumed. Therefore even at noon, the contribution of flexible VRE would still be small in the positive CRM, and their effect on the capacity prices of that market was also small (figure 6.31).

In the negative CRM, the photovoltaic power plants would take a larger share in the portfolio at noon due to their 0 opportunity costs when participating in that market (figure 6.32). Yet compared with the market portfolio in January, the share of flexible VRE was small in July, and the DRE power plants still dominated the negative CRM, especially at night when there was no available power output from the photovoltaic power plants.

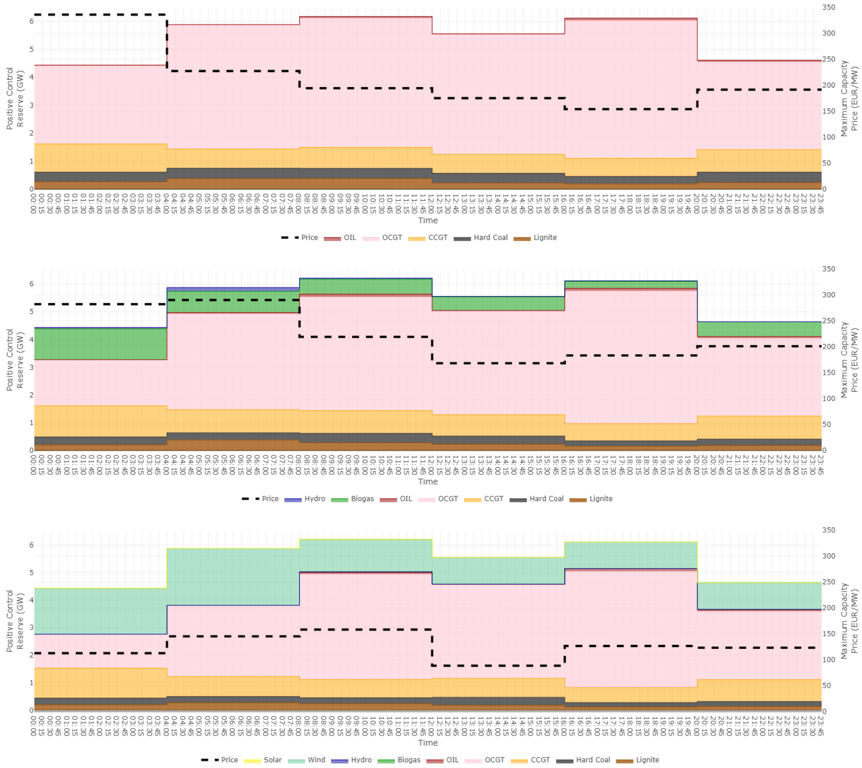


Figure 6.29: Diurnal profile of the portfolio and maximum capacity prices in Jan. in the positive CRM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

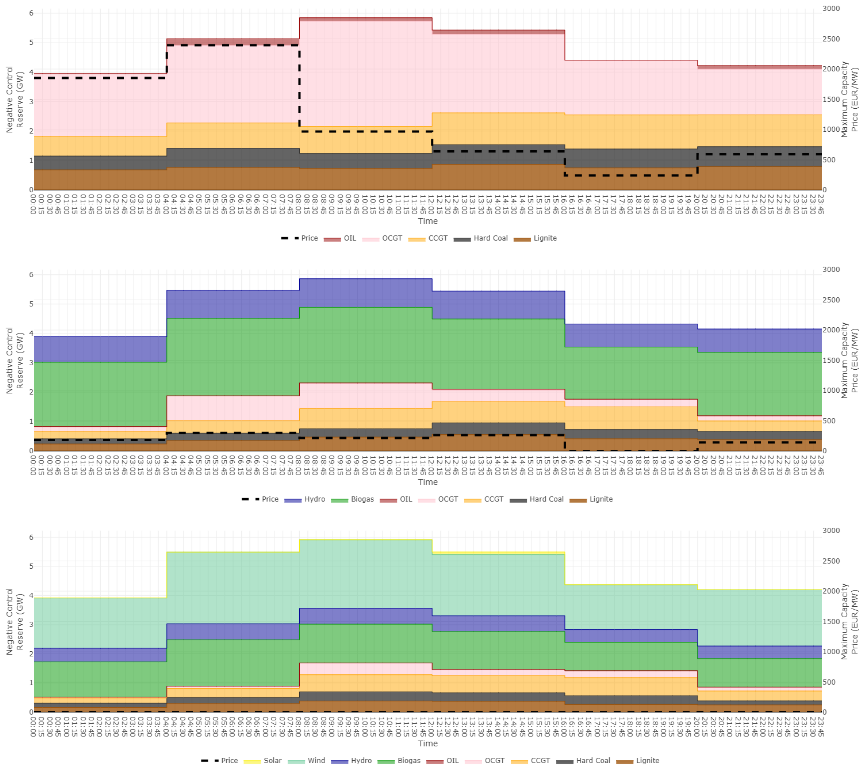


Figure 6.30: Diurnal profile of the portfolio and maximum capacity prices in January in the negative CRM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

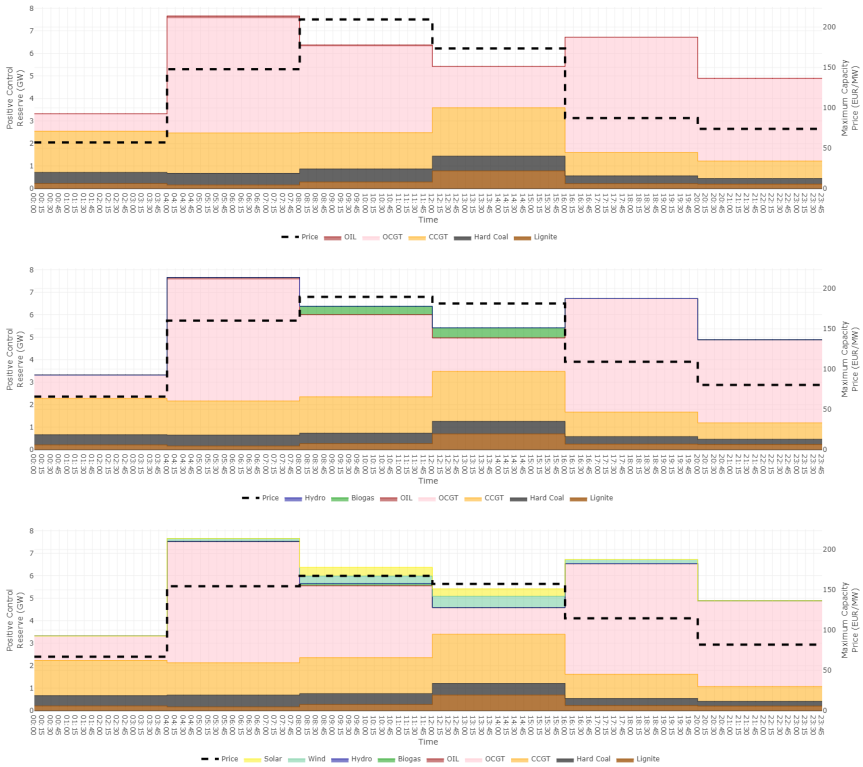


Figure 6.31: Diurnal profile of the portfolio and maximum capacity prices in July in the positive CRM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

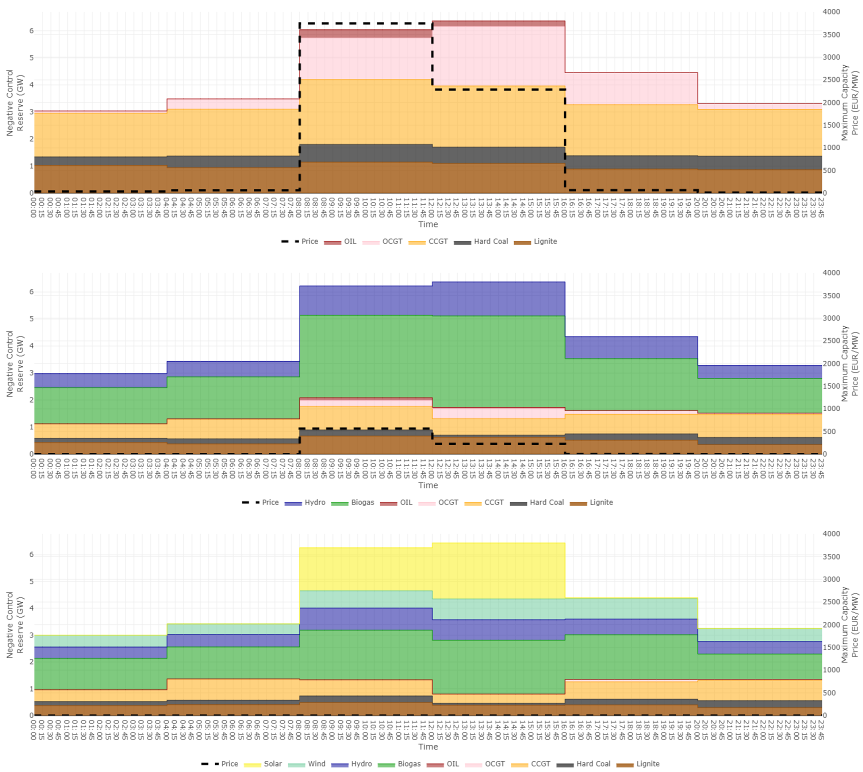


Figure 6.32: Diurnal profile of the portfolio and maximum capacity prices in July in the negative CRM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

6.2.2 Causes of Indirect Merit Order Effects in the EOM

As seen in figure 5.1, the introduction of flexible DRE into the CRM would increase the electricity generation from the renewable energy sources, while reducing the electricity generation from the conventional energy sources, mostly from the OCGT power plants. Introducing VRE into the CRM would only slightly increase the total electricity generation from the renewable energy sources while slightly reducing that from conventional energy sources, but there would be a fuel switching from gas to coal.

Such fuel switching can be best seen in the time intervals when the power output from wind power plants was abundant; in those periods of time (for example, from 15 March to 17 March in figure 6.38 to figure 6.40), lignite power plants would have higher electricity generation in scenario 7 than in scenario 0-B and 0-C. On the other hand, such effect was less observable when the photovoltaic power plants were the dominating type of VRE at noon in summertime (figure 6.41 to figure 6.43), but it was to a less extent still true. In short, at periods of time with high VRE availability, the total use of fossil fuel could be reduced by introducing flexible DRE and flexible VRE into the CRM, but an undesired fuel switching effect from gas to coal would also occur to undermine the carbon emission reduction benefits of flexible renewable energy power plants.

The origin of this indirect merit order effect of flexible VRE had in the EOM was a result of both the OCGT power plants being casted out of the CRM, and the participation of VRE power plants (especially wind power plants) in the positive CRM. Recall in subsection 4.3.1.4 we had examined the system security after the default market clearing process of the EOM and rearranged the results to ensure all the agents which had accepted bids in the CRM would not be left out in the EOM. It was through this process that in scenario 0-B the conventional power plants which participated in the CRM could still be in the EOM during periods of time when the available power output from VRE power plants penetrated into the system must run level, and the OCGT power plants benefited the most out of it.

After flexible DRE and flexible VRE were introduced into the CRM, OCGT power plants were casted out of the CRM. Therefore, they were no longer guaranteed to stay in the EOM and were placed in the merit order of the EOM as usual, which would mean that they would probably also be casted out of the EOM due to their higher marginal costs.

In the meantime, if VRE power plants provided some of the positive control reserve, this would mean that they had to voluntarily curtail some of their available power output in advance, leaving more residual load for the conventional power plants to enter the EOM. Since these were extreme events when VRE power output was abundant and the level of residual load was very low, only the conventional power plants with the lowest marginal costs, in our case the lignite power plants, could have taken the space left by VRE power plants.

The impact this indirect merit order effect of flexible VRE had on the market clearing prices and the portfolio in the EOM can be seen clearer in figure 6.33 and figure 6.34, in which the diurnal profile of these statistics were plotted. We could see the reduction of fossil fuel use and the fuel switching from gas to coal clearly after flexible DRE and VRE were introduced, especially at times of a day when the residual load was low. Also, the market clearing prices in the EOM increased after flexible DRE and flexible VRE were introduced, reflecting the fact that more conventional power plants received accepted bids in the EOM during the default market clearing process described in subsection 4.3.1.4.

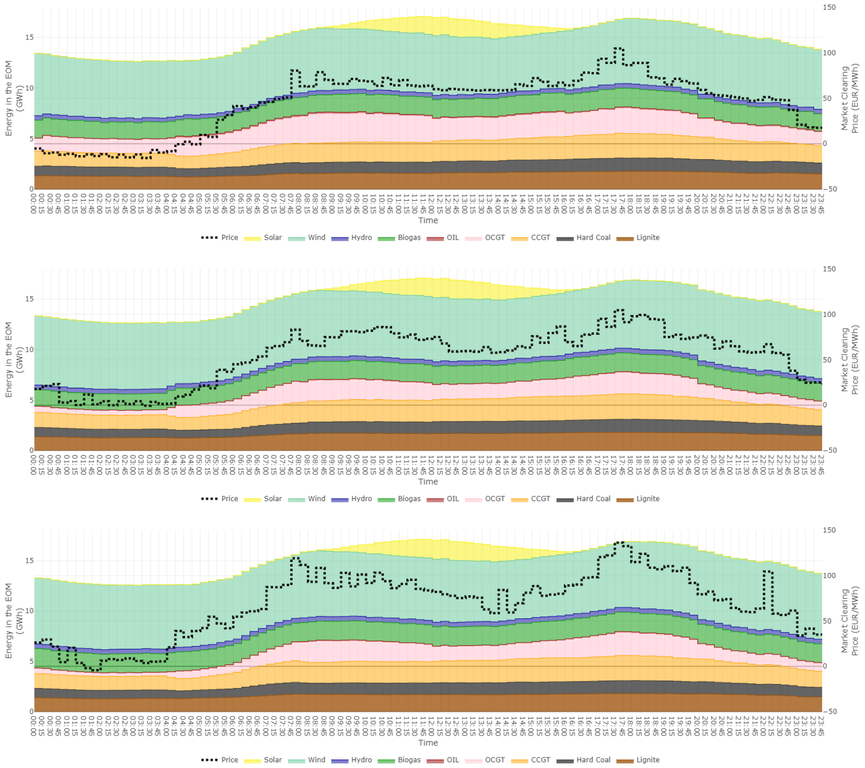


Figure 6.33: Diurnal profile of the portfolio and market clearing prices in January in the EOM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

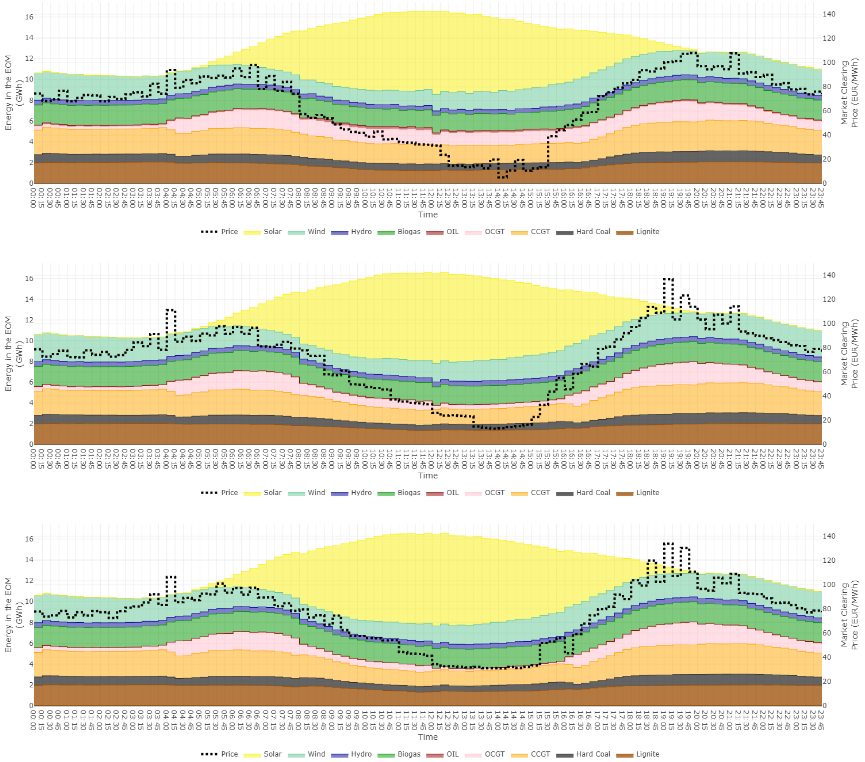


Figure 6.34: Diurnal profile of the portfolio and market clearing prices in July in the EOM for selected scenarios. Top: scenario 0-B. Middle: scenario 0-C. Bottom: scenario 7.

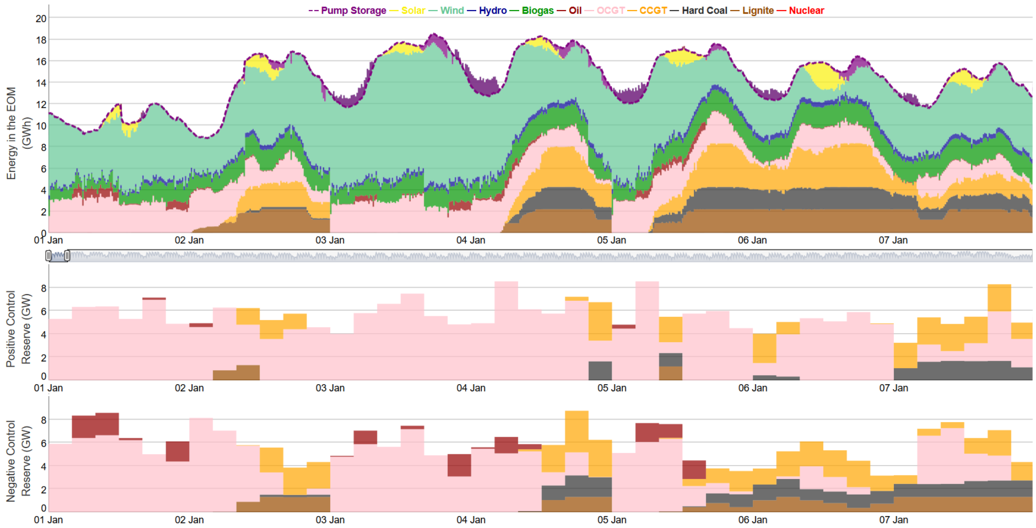


Figure 6.35: The operation plans in EOM and CRM in scenario 0-B in a week in January.

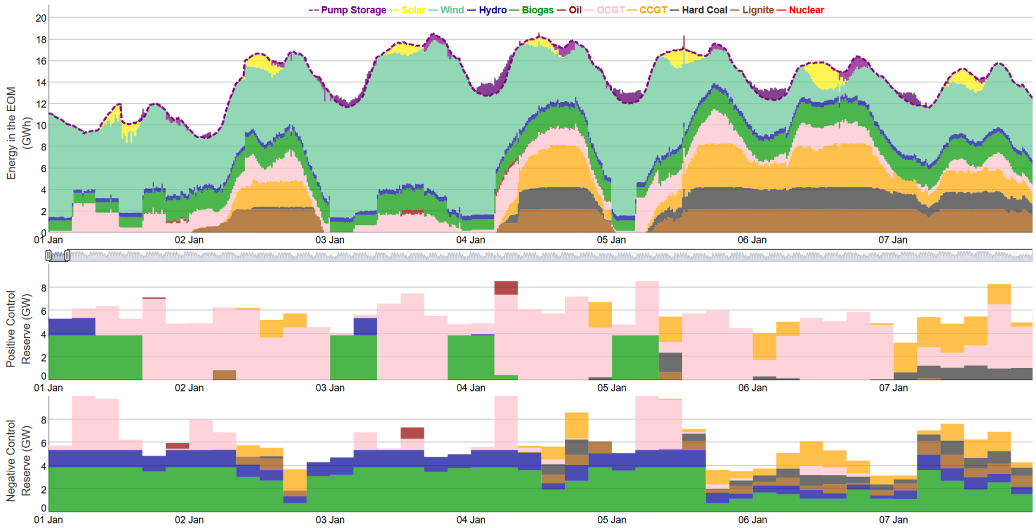


Figure 6.36: The operation plans in EOM and CRM in scenario 0-C in a week in January.

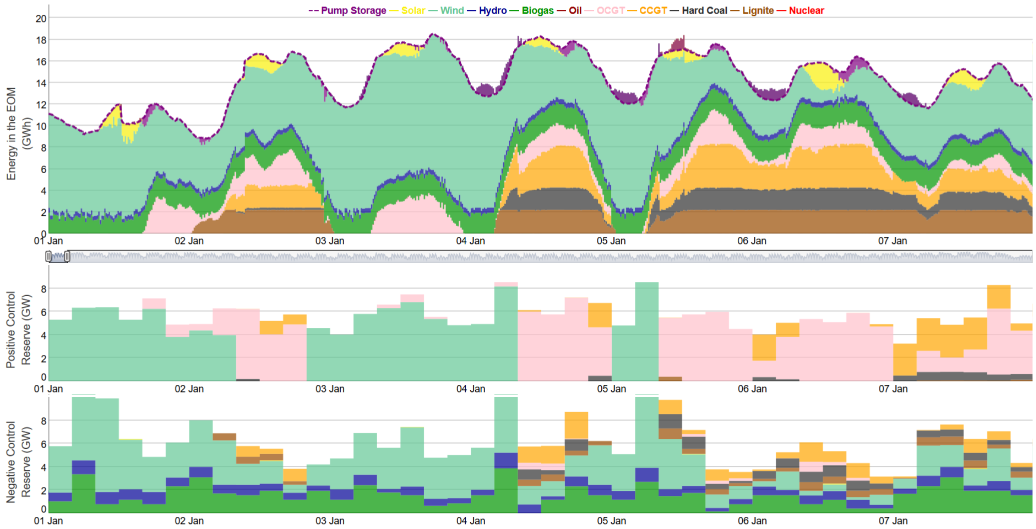


Figure 6.37: The operation plans in EOM and CRM in scenario 7 in a week in January.

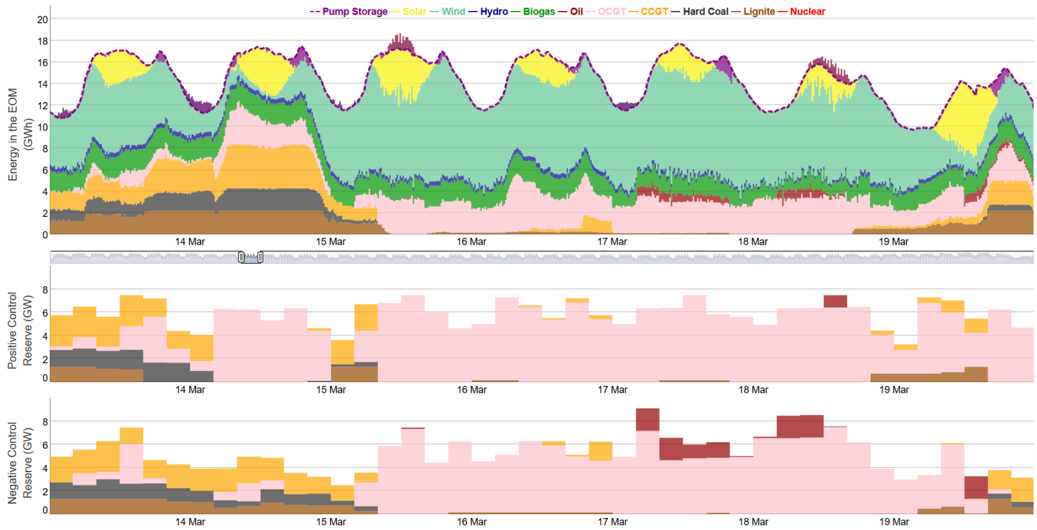


Figure 6.38: The operation plans in EOM and CRM in scenario 0-B in a week in March.

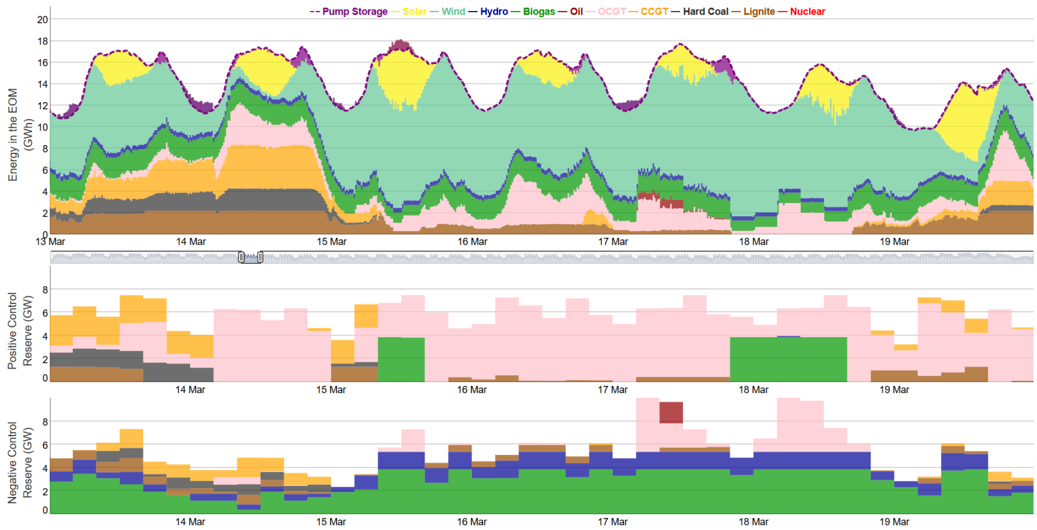


Figure 6.39: The operation plans in EOM and CRM in scenario 0-C in a week in March.

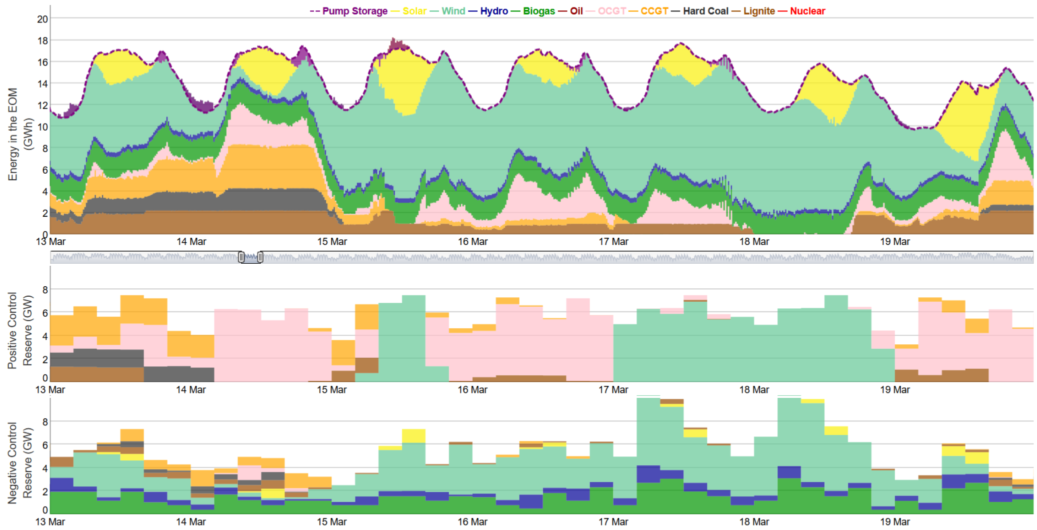


Figure 6.40: The operation plans in EOM and CRM in scenario 7 in a week in March.

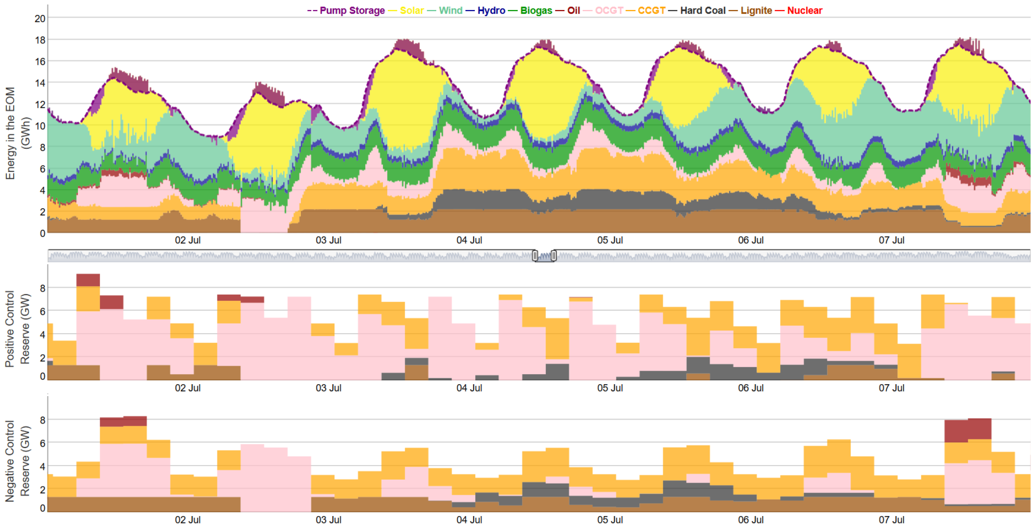


Figure 6.41: The operation plans in EOM and CRM in scenario 0-B in a week in July.

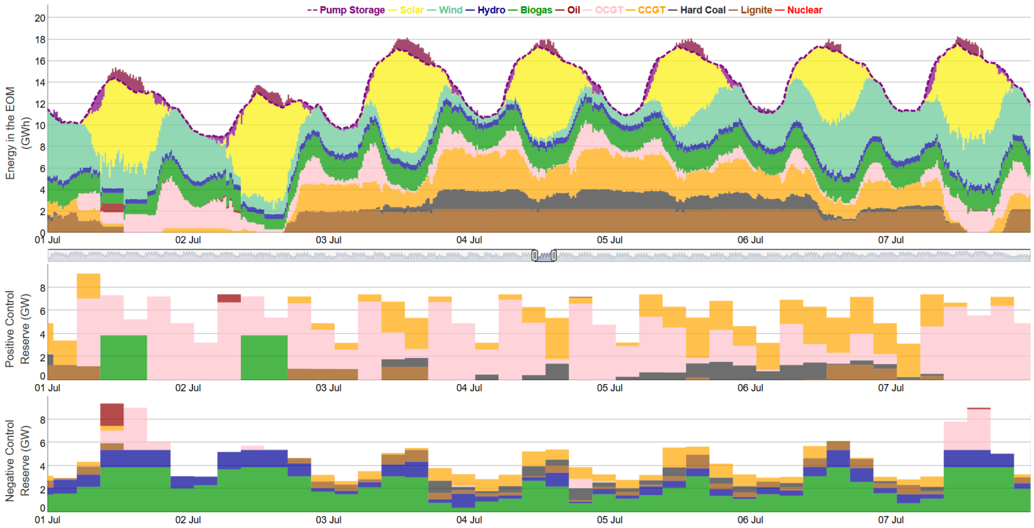


Figure 6.42: The operation plans in EOM and CRM in scenario 0-C in a week in July.

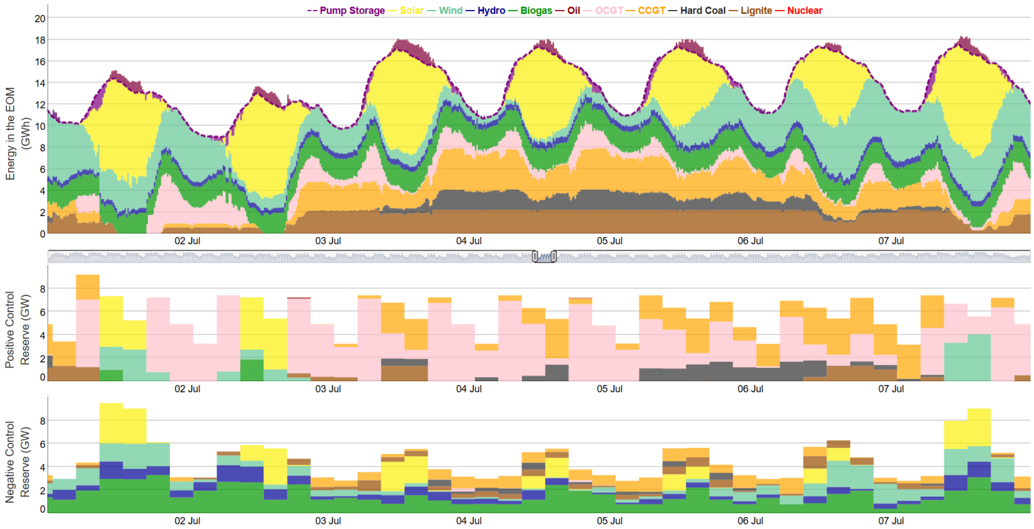


Figure 6.43: The operation plans in EOM and CRM in scenario 7 in a week in July.

6.3 Sensitivity Analysis of Different Simulation Factors

In general, most of the results did not vary significantly among the experiment scenarios. Nevertheless, the feed-in premium level was an important factor in determining the producer revenue of renewable energy power plants in both the EOM and the accepted positive balancing capacity in the CRM (figure 5.5 and figure 5.6); the higher the feed-in premium level, the more incentives renewable energy power plant operators would have to produce as much electricity as possible in the EOM and not curtail it voluntarily, making the capacity prices in the positive CRM higher when VRE power plants dominated the markets. Thus, although the portfolios of VRE power plants in the positive CRM actually decreased as the feed-in premium level increased (figure 5.2), their producer revenue still increased (figure 5.6). We could also see that the feed-in premium level had some effects on the producer surplus and full load hours of the VRE power plants (figure 5.8 and figure 5.9).

Interestingly, photovoltaic power plants seemed to be more able to participate in the positive CRM when there was no feed-in premium mechanism for the VRE power plant operators, and bioenergy power plants could only compete with flexible VRE in the positive CRM when VRE power plant operators received the highest level of feed-in premium assumed in our scenarios. These might be the result of the higher feed-in premium levels both technologies were assumed to receive compared with wind power plants.

Meanwhile, the level of the firm capacity factor was important when determining the portfolios in the negative CRM (figure 5.2). Since the renewable energy power plants would always have 0 opportunity costs when participating in the negative CRM, neither the market conditions in the EOM nor the CRM would affect how much their accepted bids in negative CRM would be; rather, it would be their bidding quantity in the first place that would determine the total amount of negative control reserve capacity VRE power plants could contribute to, which was governed by the firm capacity factor level.

More trivially, the total electricity generation from conventional power plants was slightly reduced at higher feed-in premium levels and lower firm capacity factor levels (table 6.5). For the total fuel-related carbon emission, there was a slight decrease when the feed-in premium level was higher and a slight increase when the firm capacity factor level was higher (table 6.6). For the total variable system cost, experiment scenarios with no feed-in premium mechanism for VRE power plants had the highest values, while scenarios with lower firm capacity factor levels tended to have lower values (table 6.7). Yet these variations were rather insignificant compared with the average values among the experiment scenarios (figure 5.1 and figure 5.4).

The two dimensions of factors we considered in our experiment scenarios were not the only ones that might have altered our results. As stated earlier in section 5.2, we adopted a rather conservative model for the control reserve demand, meaning that we might have overestimated the market size and total value of the CRM. Also, as discussed in the previous section, the current market design of the CRM would be problematic for photovoltaic power plants to fully contribute to the control reserve capacity; changing the duration of a time step in the CRM $\Delta\tau$ from 4 hours to 1 hour would increase the portfolio of photovoltaic power plants in the negative control reserve capacity from 6.88% in scenario 7 to 10.45%, while their portfolio in the positive control reserve capacity would slightly decrease from 1.26% to 1.10%.

In addition, even with a high carbon price of 50 EUR/tonne $CO_{2\,eq}$, the average variable costs of lignite and hard coal power plants were still lower than those of CCGT and OCGT power plants (table 6.1). If the carbon price was set higher, CCGT power plants might become the cheapest source of conventional power plants and the fuel switching phenomenon from gas to coal might not exist, at least not to the extent we had observed.

Indeed, if we increased the carbon price to 100 EUR/tonne $CO_{2\,eq}$, then the electricity generation from lignite power plants would only slightly increase from 33.71 TWh in scenario 0-C to 33.77

	No FiP	Low FiP	Mid FiP	High FiP
Low Firm	-0.15	-0.02	-0.22	-0.52
Mid Firm	0.02	0.23	0.00	-0.35
High Firm	0.12	0.35	0.17	-0.24

Table 6.5: Sensitivity analysis of the total electricity generation from conventional power plants (in TWh), compared with the value in scenario 7 (193.84 TWh).

	No FiP	Low FiP	Mid FiP	High FiP
Low Firm	0.00	-0.03	-0.13	-0.42
Mid Firm	0.20	0.19	0.00	-0.29
High Firm	0.19	0.15	0.10	-0.11

Table 6.6: Sensitivity analysis of the total fuel-related carbon emission (in million tonnes $CO_{2\ eq}$), compared with the value in scenario 7 (120.68 million tonnes $CO_{2\ eq}$)).

	No FiP	Low FiP	Mid FiP	High FiP
Low Firm	0.07	-0.03	-0.02	-0.02
Mid Firm	0.09	0.02	0.00	-0.02
High Firm	0.07	0.01	0.01	-0.02

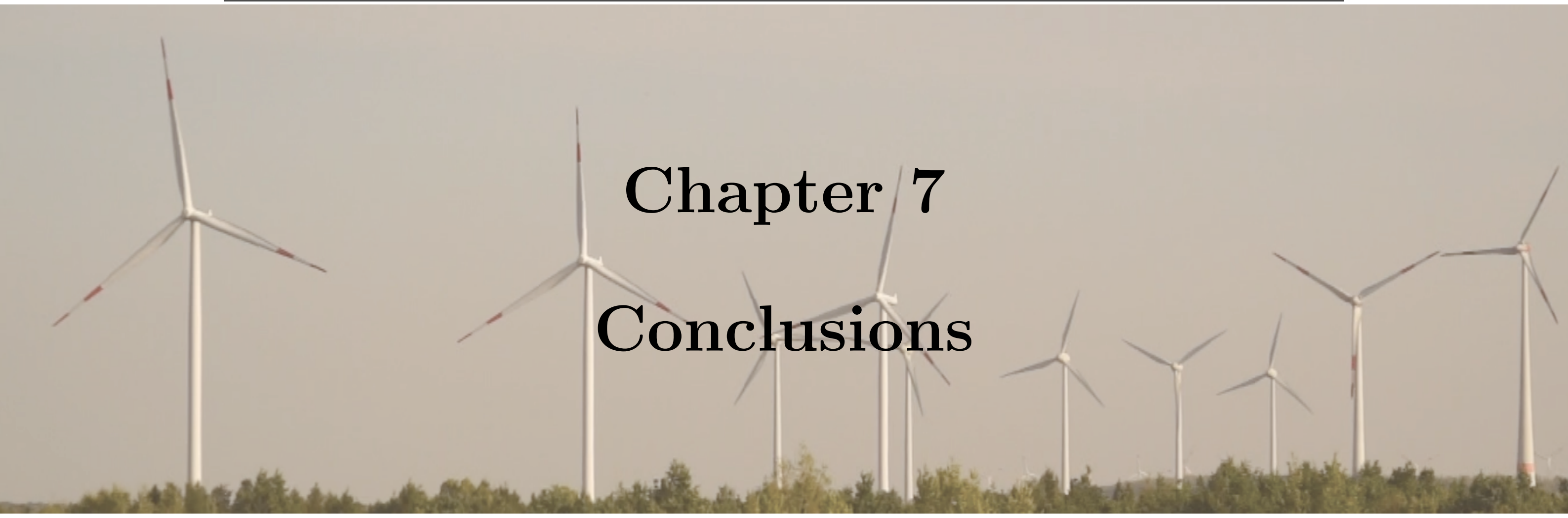
Table 6.7: Sensitivity analysis of the total variable system cost (in billion Euros), compared with the value in scenario 7 (16.60 billion Euros).

TWh in scenario 7, while electricity generation from hard coal power plants would slightly decrease from 14.97 TWh to 14.91 TWh; in the meantime, the electricity generation from CCGT power plants would slightly increase from 92.51 TWh in scenario 0-C to 92.52 TWh in scenario 7, the electricity generation from OCGT power plants would decrease from 51.79 TWh to 50.01 TWh, and the electricity generation from oil power plants would decrease from 1.66 TWh to 1.55 TWh. At such a high carbon price, introducing flexible VRE would lead to more reduction of the total fossil fuel consumption and the total fuel-related carbon emission, owing to the fuel switching effect from gas to coal being avoided.

The pooling size of the VRE capacity would also be crucial for two reasons: firstly, a larger pooling size of the VRE capacity could smooth out the fluctuations of individual power plants, increasing the reliability of the control reserve services flexible VRE could provide; secondly, if the spatial heterogeneity of VRE power output is to be considered in the future, an appropriate choice of pooling size might better reflect this heterogeneity due to the temporal and spatial scales of meteorological patterns. On one hand, by neglecting the spatial heterogeneity and higher relative prediction errors of the smaller pooling size, we might have overestimated the capability of the VRE power plants to provide services in the CRM; on the other hand, just as we had discussed in section 4.4.2, if the prediction data closer to real time was used, the VRE power plants might be able to participate more in the CRM due to less prediction errors. Which of these two factors actually weighted more would be an interesting topic for follow up studies.

Furthermore, many other options that could have provided power system flexibility were not considered in our study. The deployment of new energy technologies was neglected deliberately, but other options, such as demand side management, sector coupling, or cross border transmission, were omitted simply for the convenience of the study. Some of these measures might be more cost-effective for delivering the same services agents in our simulations had provided in the EOM and the CRM, and they might therefore have altered the results of the simulations, had we modeled them.

Finally, the most important factor we did not discuss deeply in our model might be the VRE capacity in the near future. If the VRE capacity was not large enough, operating VRE power plants flexibly might not be as beneficial as our study had demonstrated, from the viewpoints of both the system operator and the power plant operators. The argument for flexible VRE was built on the assumption that there would be a window of opportunity in the near future when VRE capacity would become large enough, while new energy storage technologies would still not be available on a comparable scale. Deviations from this setting might result in a completely different set of bidding strategies for the VRE power plant operators, for example strategies that would combine energy storage units and flexible operations of VRE together in both the EOM and CRM.



Chapter 7

Conclusions

In our study, we had demonstrated how flexible VRE could work in a simulated German electricity market, and quantified their system, economic, and environmental impacts. We achieved this by modeling the control reserve demand of the power system in the future, and extending the electricity market simulation model *flexABLE* to allow renewable energy power plants to participate in the CRM, and to have all the participants bid with an optimized strategy in the CRM.

By participating in the CRM, renewable energy power plants could reduce the need of conventional power plants for providing the same services, reducing the system must run conventional power plants would otherwise have to contribute to and thereby reducing the total fossil fuel consumption, the total variable system cost, and the total fuel-related carbon emission of the power system as a result. In additional to DRE power plants, allowing VRE power plants into the CRM would further reduce these figures, albeit the marginal benefits would be a magnitude smaller than allowing flexible DRE into the market in the first place.

From the microeconomic perspectives, introducing flexible VRE into the CRM would increase the producer surplus of VRE, lignite, hard coal, and CCGT power plants, decrease the producer surplus of DRE, OCGT and oil power plants, and increase the total expenditure from the electricity consumers, compared with the scenario where flexible DRE were already allowed. In total, introducing flexible VRE into the CRM would result in the increase of the total surplus in the market compared with reference scenarios without them, albeit the marginal benefits would be a magnitude smaller than allowing flexible DRE into the market in the first place.

However, there were some undesired side effects occurred after flexible VRE were introduced into the CRM, the most important of which was the fuel switching within the conventional technologies. In order to effectively phase out lignite and hard coal consumption in the electricity sector, these potential side effects in the market must be dealt with, e.g. the introduction of a higher carbon price.

The sensitivity of the two dimensions of factors determining the settings of the experiment scenarios was analyzed. We found out that the feed-in premium levels mainly affected the producer revenues in the EOM and the positive control reserve capacity in the CRM, while the firm capacity factor levels mainly affected the portfolio of the negative control reserve capacity in the CRM.

In addition, we also acknowledged the fact that there were many other important variables that might have altered the result of our study, including the level of control reserve demand, the market design of the CRM, the pooling size of flexible VRE, and other available flexibility options; they should be taken into account thoroughly in follow up studies.

Finally, our study did not consider the grid constraints and the spatial heterogeneity of the VRE power output availability, thus redispatch was not modeled in our simulations. We acknowledged that this might affect the robustness of our result, since risks of transmission line congestion or

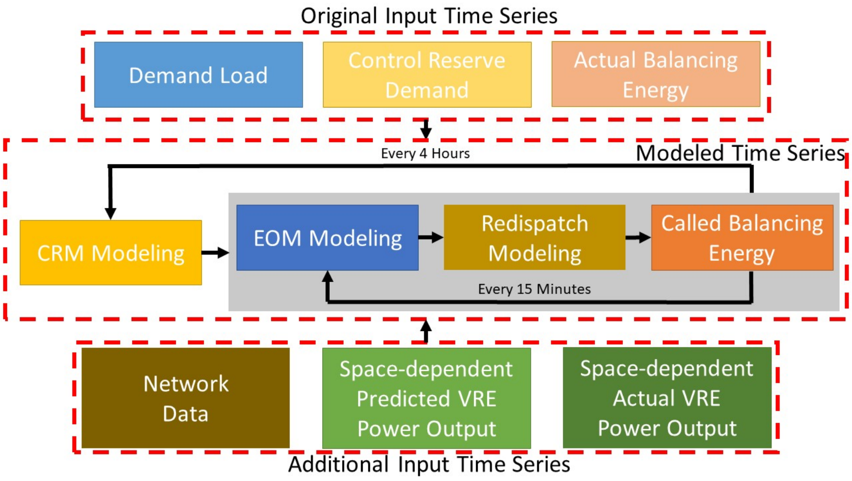


Figure 7.1: A proposed schematic chart of the program *flexABLE* for future studies that would include redispatch in the modeling process. Additional data, namely the network data of the transmission line system and the space-dependent VRE power output data, would be needed for this purpose.

failure might prevent the VRE power plants from providing the control reserve capacity when needed. To better quantify these additional constraints for flexible VRE and the grid costs related to them, it might be beneficial to integrate our electricity market model with a grid model in the future, as proposed in figure 7.1.

Appendix A

Methods Used in the Control Reserve Model

A.1 Finding the Scores of a Data with Eigenvector Decomposition

In the first step of this process, we normalized the predicted load and VRE power output data. This resulted in a $4 \times T$ matrix $[X]$, where the rows represented different types of time series data (the normalized predicted load and capacity factors of offshore wind power plants, onshore wind power plants, and photovoltaic power plants), and the columns represented the total length of the timespan. Since we chose to construct the ECDF for each time step in a day, and we used the data from 2015 to 2018, this meant that T was 1461 in our model, representing the sample points at the same time of each day.

We could then obtain the 4×4 unbiased sample covariance matrix $[\hat{\Sigma}]$ from the following formula:

$$[\hat{\Sigma}] = \frac{1}{T-1}([X]([I] - \frac{1}{T}[U]))([X]([I] - \frac{1}{T}[U]))^H \tag{A.1}$$

Here $[I]$ is the $T \times T$ identity matrix, $[U]$ is the $T \times T$ unit matrix (all the indexes of the matrix are 1), and the H sign indicates a Hermitian transpose of the matrix. We then performed an eigenvector decomposition of $[\hat{\Sigma}]$ and wrote it as in the following form:

$$[\hat{\Sigma}] = [E][D][E]^{-1} \tag{A.2}$$

Here $[E]$ is the 4×4 orthonormal matrix that consists the eigenvectors of the original matrix $[\hat{\Sigma}]$, and $[D]$ the 4×4 diagonal matrix with the corresponding eigenvalues of $[E]$ at its diagonal indexes. We then constructed the $4 \times T$ sample score matrix $[\hat{S}]$ from the following formula:

$$[\hat{S}] = [E][X] \tag{A.3}$$

A.2 Using Kernel Functions as Weights in ECDF

The type of kernel functions we used to obtain the weights was a Gaussian function, and the normalized weights of the historical data at a particular time step t were obtained by the following formula based on a distance metric between the scores of the historical data and that of the time step t:

$$w_j = \frac{\prod_{i=1}^{4} exp(-\frac{(\hat{S}_{ij}-s_{t,i})^2}{2D_{ii}})}{\sum_{k=1}^{T}\prod_{i=1}^{4} exp(-\frac{(\hat{S}_{ik}-s_{t,i})^2}{2D_{ii}})} \tag{A.4}$$

Here w_j is the j-th term of the normalized weights, $\hat{S}_{ij}$ and $\hat{S}_{ik}$ the corresponding indexes of the matrix $[\hat{S}]$ described in equation A.3, D_{ii} the corresponding diagonal index of the matrix $[D]$ described in equation A.2, and $s_{t,i}$ the i-th term of the scores of the time step t. The ECDF of the historical data would then be:

$$\hat{F}(x) = \sum_{j=1,\, x_j \leq x}^{T} x_j w_j \tag{A.5}$$

Here $\hat{F}(x)$ is the ECDF (taking x as the argument) and x_j the value of the argument at each sample point. Note that this method of constructing the ECDF resulted in a step-wise function, but when we used the function wtd.quantile() in the statistic program R to find the quantile, linear interpolation was involved.

Appendix B

Methods Used for Data Analysis

B.1 First Order Variation Operator

The first order variation operator $\delta[\cdot]$ acting on a multivariate function $f(\vec{x})$, by the definition of the Gateaux derivative, is

$$\delta[f(\vec{x})](\vec{h}) = \lim_{\varepsilon \to 0} \frac{f(\vec{x} + \varepsilon \vec{h}) - f(\vec{x})}{\varepsilon} = \nabla f \cdot \vec{h} \tag{B.1}$$

Provided all partial derivatives exist. Here $\hat{e}_i$ are the orthonormal basis vectors forming the vector space where $\vec{x}$ and $\vec{h}$ exist, and x_i and h_i the indexes of the corresponding vectors. Note that each entry of $\vec{h}$ in equation B.1 can be viewed as $\delta[\cdot]$ acting on each corresponding entry in $\vec{x}$, and the equation can therefore be rewritten into

$$\delta[f(\vec{x})] = \sum_i \frac{\partial f}{\partial x_i} \delta[x_i] \tag{B.2}$$

B.2 Additive Form of Refined Laspeyres Decomposition

Suppose we have a multivariate function c and we can decompose it into $c = \vec{a} \cdot \vec{b}$. Suppose now we add some change to $\vec{a}$ and $\vec{b}$, forming $\vec{a} + \Delta\vec{a}$ and $\vec{b} + \Delta\vec{b}$ and resulting in a new data set $c + \Delta c = (\vec{a} + \Delta\vec{a}) \cdot (\vec{b} + \Delta\vec{b})$. Comparing the terms would yield

$$\Delta c = \vec{a} \cdot \Delta\vec{b} + \Delta\vec{a} \cdot \vec{b} + \Delta\vec{a} \cdot \Delta\vec{b} = (\vec{a} + \frac{1}{2}\Delta\vec{a}) \cdot \Delta\vec{b} + (\vec{b} + \frac{1}{2}\Delta\vec{b}) \cdot \Delta\vec{a} \tag{B.3}$$

Note that $\vec{a} + \frac{1}{2}\Delta\vec{a}$ and $\vec{b} + \frac{1}{2}\Delta\vec{b}$ are just the average of the original and the new vectors of $\vec{a}$ and $\vec{b}$ respectively. Thus equation B.3 can be rewritten to

$$\Delta c = \underset{(1)}{\vec{b}_{avg} \cdot \Delta\vec{a}} + \underset{(2)}{\vec{a}_{avg} \cdot \Delta\vec{b}} \tag{B.4}$$

(1) in equation B.4 is the effect on c due to the change of $\vec{a}$, and (2) the effect on c due to the change of $\vec{b}$. Note that if a vector, say $\vec{b}$, has the property $\vec{b} \cdot \vec{u} = constant$, where $\vec{u}$ is a vector with 1 in all entries, we would have $\Delta\vec{b} \cdot \vec{u} = 0$. In such case, it is possible to rewrite equation B.4 as the following:

$$\Delta c = \vec{b}_{avg} \cdot \Delta\vec{a} + \left(\vec{a}_{avg} - \frac{1}{N}[U](\vec{a}_{avg} \circ \vec{b}_{avg})\right) \cdot \Delta\vec{b} \tag{B.5}$$

Here N is the dimension of the vector space where the vectors exist, and $\circ$ the symbol for an entrywise product operation. Equation B.5 can be viewed as a shift of components in $\vec{a}_{avg}$, so that the dot product of those components with $\vec{b}_{avg}$ would be 0, making it easier to interpret the results as relative changes from the weighted average rather than absolute values. Note that $[U]$ (as discussed in appendix A.1) is equal to $\vec{u} \otimes \vec{u}$.

Acknowledgment

This thesis would not have been finished without the help of many other people. In additional to the two examiners, the author would like to thank the following people for their various ways of support during his work:

Scientific Advisory

Ramiz Qussous (Institut für Nachhaltige Technische Systeme, Germany)

Dr. Mikro Schäfer (Institut für Nachhaltige Technische Systeme, Germany)

Cheng-Ta Chu (Industrial Technology Research Institute, Taiwan)

Dr. Chia-Wei Chao (Risk Society and Policy Research Center, Taiwan)

Advisory on Thesis Structure

Yen-Ruei Chen (Msc. Environmental Governance, University of Freiburg, Germany)

林宗毅 (Msc. Bioenvironmental Systems Engineering, National Taiwan University, Taiwan)

Advisory on Layout and Design

尤鈺昕 (Student at National Taiwan University, Taiwan)

羅玉卉 (Student at Soochow University, Taiwan)

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