Giving the Green Light to the Green

Facilitating the integration of variable renewable electricity into the power system

Jing Hu

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Groen licht geven aan groen

Faciliteren van de integratie van variabele hernieuwbare elektriciteit in het elektriciteitssysteem

(met een samenvatting in het Nederlands)

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Two roads diverged in a yellow wood,
And sorry I could not travel both
And be one traveler, long I stood
And looked down one as far as I could
To where it bent in the undergrowth;

Then took the other, as just as fair,
And having perhaps the better claim,
Because it was grassy and wanted wear;
Though as for that the passing there
Had worn them really about the same,

And both that morning equally lay
In leaves no step had trodden black.
Oh, I kept the first for another day!
Yet knowing how way leads on to way,
I doubted if I should ever come back.

I shall be telling this with a sigh
Somewhere ages and ages hence:
Two roads diverged in a wood, and I-
I took the one less traveled by,
And that has made all the difference.

The Road Not Taken, by **Robert Frost**

"The fox knows many things, but the hedgehog knows one big thing."
- **Isaiah Berlin**

"I will never die for my beliefs because I might be wrong."
- **Bertrand Russell**

"No one deserves his greater natural capacity nor merits a more favourable starting place in society."
-**John Rawls**

CONTENTS

ABBREVIATIONS

CO_2	Carbon dioxide
CO_{2eq}	Carbon dioxide equivalent
UNFCCC	United Nations Framework Convention on Climate Change
NOAA	National Oceanic and Atmospheric Administration
IPCC	Intergovernmental Panel on Climate Change
IEA	International Energy Agency
VRE	Variable renewable energy
CCS	Carbon capture and storage
IRENA	International Renewable Energy Agency
BNEF	Bloomberg New Energy Finance
LCOE	Levelized costs of electricity
IMF	International Monetary Fund
CAPEX	Capital expenditure
EU	European Union
SRMC	short-run-marginal-costs
EU ETS	European Union Emission Trading Scheme
BRL	Boland–Ridley–Lauret
CF	Capacity factor
IPAC	Integrated Policy Impact Assessment Model
O&M	Operating and maintenance
MPT	Modern Portfolio Theory
NASA	National Aeronautics and Space Administration
MERRA	Modern Era Retrospective-Analysis for Research and Applications
EC	European Commission
WWF	World Wildlife Fund
EVA	Extreme value analysis
GEV	Generalized extreme value
MVP	Mean-variance portfolio
FID	Final investment decision
OECD	Organisation for Economic Co-operation and Development
OPEX	Operating expense
UNEP	United Nations Environment Programme
WACC	Weighted average costs of capital
EIA	Environment impact assessment
DCF	Discounted cash flow
KPI	Key performance indictors
NPV	Net present value

IRR	Internal rate of return
BCR	Benefit-cost ratio
DPBP	Discounted payback period
PI	Profitability index
SCC	Social cost of carbon
CEER	Council of European Energy Regulators
NGCC	Nature gas combined cycle
LRMC	Long-run marginal costs
CSP	Concentrated solar power
NIMBY	Not in my backyard
LCA	Life cycle assessment
VOLL	Value of lost load
LMP	Locational marginal pricing
BRP	Balancing responsible party
TSO	Transmission system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
IEA-RETD	IEA-RETD Renewable Energy Technology Deployment
BMWi	Federal Ministry of Economics and Technology
LRF	Linear reduction factor
MSR	Market stability reserve
GHG	Greenhouse gas
MACC	Marginal abatement cost curve
GDP	Gross domestic product
EEA	European Environment Agency
CRF	Common report format
NER	New entrants reserve
GMBM	Global market-based mechanism
ICAO	International Civil Aviation Organization
RTK	Revenue Tonne Kilometre

1

Introduction

1.1 RELEVANCE OF VRE TO CLIMATE CHANGE MITIGATION

Due to anthropogenic activities, the post-industrial CO_2 emissions have increased unprecedentedly in both magnitude and speed (Weitzman, 2011). By the end of 2018, the atmospheric CO_2 concentration reached 410 ppm (NOAA, 2019). This has far exceeded its pre-industrial level that oscillated within a narrow range between 180-280 ppm over the past 800,000 years (Weitzman, 2011). The increased CO_2 concentration has already caused salient impacts of climate change (e.g. global mean temperature increase, sea level rise, extreme flood and draught, biodiversity losses) at regional and global scale (Hansen and Cramer, 2015; Pautasso, 2011). To avoid the most adverse and irreversible consequences of climate change, the Paris Agreement signed by 175 international parties aims to limit the increase in global mean temperature to 1.5-2 °C by 2100 (UNFCCC, 2015). This can be translated into capping the atmospheric CO_{2eq} concentration to a level between 430-450 ppm (IPCC, 2015 and 2018). It leaves us with a limited remaining carbon budget of 420-1170 GTonne CO_{2eq}, which is equivalent to ~ 10-28 years of current emissions (IPCC, 2015; CarbonBrief, 2018). Accordingly, most available model-based climate mitigation pathways prescribe to reduce global emissions from 2010 levels by 25-45% by 2030 and reach zero emissions between 2050 and 2070 (IPCC, 2018).

The combustion of fossil fuels for energy purposes is the primary cause of global CO_2 emissions. 69%, 24% and 7% of global emissions come from fossil fuel combustion, industrial processes and land use change (IPCC, 2015). Power and heat generation, transport, industry, buildings and other sectors respectively contribute to 41.5%, 24.4%, 18.9%, 8.4% and 6.8% of energy-related CO_2 emissions (IEA, 2019). Effective climate mitigation requires a synergy of emission reduction from all economic sectors. In particular, the power sector needs to be fully decarbonized by 2050 in order to be consistent with least cost climate mitigation pathways (IPCC, 2018). Besides energy efficiency to limit the growth of electricity demand, transitioning the power sector towards zero emissions must rely on the large-scale deployment of low-carbon electricity generation options. They include nuclear, hydro, biomass, carbon capture and storage, and variable renewable electricity (VRE) technologies. Within all low-carbon options, VRE technologies (which convert stochastic weather flows into electricity, such as wind and solar) have the lowest specific embodied energy and life-cycle emissions in terms of each unit of electricity generation (Pehl et al., 2017). In addition, public attitudes towards VRE are generally positive (Poumadere et al., 2011). This is in stark contrast to the post-Fukushima safety concerns about nuclear, concerns of food security about biomass, concerns of land use change about hydro, and concerns regarding seismic activities and leakages about CCS. Thus, it is reasonable to foresee an important role of VRE in future low-carbon electricity generation mix. This is confirmed by a few modelling-based scenario studies (e.g. Pehl et al. (2017); IRENA (2018); BNEF (2019)): the required shares of VRE in total electricity generation in 2050 range between 48 – 62%.

1.2 STATUS AND TREND OF VRE DEVELOPMENT

In the past decade, strong and robust development in VRE has been witnessed globally (see figure 1.1): the total combined installed capacity of wind and solar PV has increased from 137 GW to 1101 GW between 2008 and 2018. This has been driven by two major economies: the European Union (EU) and China. By the end of 2018, the global shares of total installed VRE capacity in the EU and China are respectively 35% and 28%.

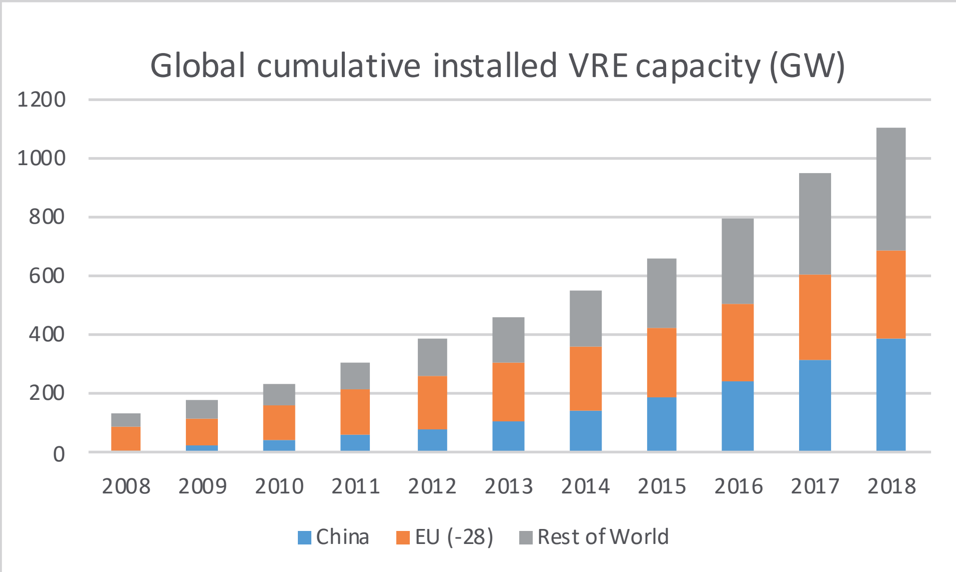

Figure 1.1. Development of global cumulative installed VRE capacity between 2008-2018

Source: Compiled from EU Open Data Portal (2019), World Wind Energy Association (2019), China Energy Portal (2019)

Their leading role in VRE development is likely to continue, as both economies have set ambitious intermediate-term renewable energy targets for 2030. The EU aims for renewable energy to account for at least 32% final energy consumption, which can be translated into 54% renewables share in electricity generation (European Commission, 2019; Banja and Jegard, 2017), while China intends to increase the share of renewables to 35% in electricity generation (Bloomberg, 2018). Besides expressing accountability and leadership in global climate action and energy transition, such targets are also motivated by other co-benefits of renewables. Renewable energy reduces the EU's dependence on energy imports (particularly natural gas from Russia) and improves energy security (Wilson and Dobreva, 2009). As for China, renewables are key to decrease its reliance on coal-fired power plants and mitigate the associated air pollution problems (and resulting social unrest) (Qiu, 2013). Owing to tremendous investments in the EU and China, the large expansion in VRE capacity has led to significant specific cost reductions globally as a combined consequence of technological learning, manufacturing economies of scale, and an increasingly competitive supply chain (IRENA, 2016). The recent developments in terms of levelized costs of electricity (LCOE) for three types of VRE (onshore wind, offshore wind, solar), hydro and nuclear is presented in figure 1.2. The LCOE of VRE decrease over time. In particular, the LCOE of solar and onshore wind decreased by 76% and 34% respectively. In comparison, VRE shows clear advantages over other low-carbon alternatives. The LCOE of onshore wind and solar have already reached a level lower than hydro, and offshore wind has shown higher cost-competitiveness than nuclear.

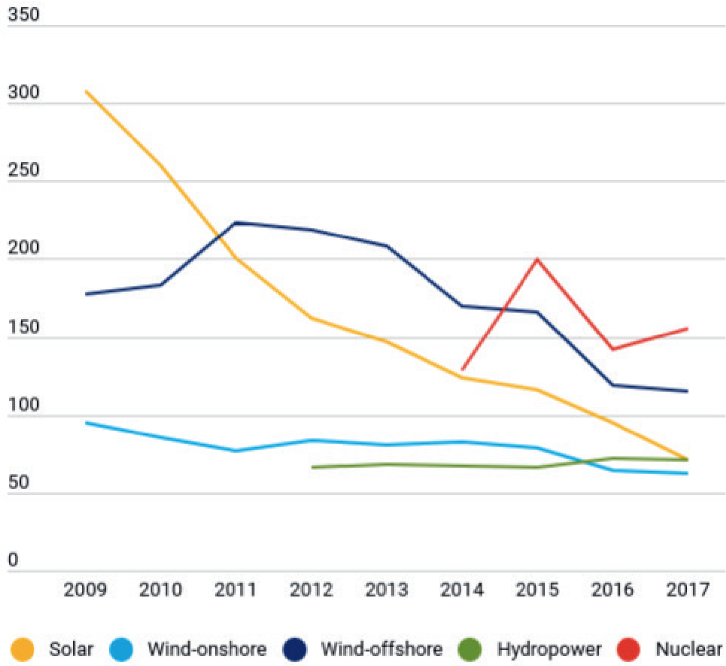

Figure 1.2. Development of LCOE (USD_{2018}/MWh) for VRE, Hydro and Nuclear between 2009-2017

Source: IMF (2019)

1.3 CHALLENGES OF INTEGRATING VRE INTO THE POWER SYSTEM

VRE technologies, depending on stochastic weather flows, are characterized by variable, uncertain and location-dependent outputs (Hirth et al., 2015). The integration of VRE into the power system gives rise to challenges in grid operation. As non-dispatchable technologies with limited controllability, VRE plants have relatively low "firm" capacity. This means that they have limited contribution to securing sufficient generation capacity in the power system at all times (IEA, 2014). Therefore, from the perspective of generation adequacy additional back-up capacity is needed. Secondly, the large ramp-up, ramp-down and forecast errors in VRE outputs can cause sudden disturbance and disruption in power supply. However, the balance between power supply and demand needs to be maintained at all time scales. From the perspective of system reliability, this requires additional reserve capacity to follow output ramps and manage forecast errors (Hermans et al., 2018). VRE plants also cause increased ramping, cycling and part-load operation of fossil-fired thermal generators and spinning reserve, resulting in a lower operational efficiency and higher specific CO_2 emissions (Hirth et al., 2015; de Groot et al., 2017). These challenges can be monetarily measured as "integration costs", which are extra operational and investment costs in the system to accommodate VRE (Ueckerdt et al., 2013). Integration costs become notable when VRE's penetration reaches 10%, which range between 10-25 €/MWh (Sijm, 2014).

The capability to handle grid operation challenges associated with VRE integration varies between power systems, depending on the system's flexibility to respond to changes in VRE outputs (Huber et al., 2014). Flexibility can be limited by either technical inflexibilities or institutional inflexibilities (Kirkegaard, 2019). The former is caused by the absence of sufficient flexibility resources (in terms of fast response dispatchable plants, interconnection, storage and demand response), which is often the case for isolated or islanding power systems (IEA, 2014). The latter refers to the inability to mobilize available flexibility resources due to institutional and regulatory inefficiencies and deficiencies. It is more relevant to emerging economies where institutional reforms on power system restructuring are incomplete (Davidson, 2018). A classic example of an inflexible power system is China. Inflexible coal-fired plants dominate China's generation capacity. Its power system also features institutional inflexibilities, such as hierarchical and fragmented dispatch organizations, inefficient dispatch mechanism, dual-track price system and cross-regional trade barriers (Kahrl and Wang, 2014; Davidson, 2018; Zhang et al., 2018). This leads to deficiencies in its ability to efficiently operate the power system and to cost-effectively integrate VRE. As a result, China has suffered from severe VRE curtailment. The national average curtailment rate in China for wind was ~ 15% between 2011-2016, whereas curtailment rates in United States, Germany and the UK were all below 6% (Zhang et al., 2018; DOE, 2017; Joos and Staffell, 2018).

An effective way to reduce the impacts and costs associated with VRE integration is to utilize the geographical smoothing effect (IEA, 2014). Dispersing the deployment of VRE over a large area with diverse weather patterns can largely reduce the variability and uncertainty in the output of individual VRE generators (Mills and Wiser, 2010; Pinson, 2016). Using modern portfolio theory, previous studies (e.g. Drake and Hubacek, 2007; Degeilh and Sighn, 2011; Tajeda et al., 2017) have developed optimal VRE portfolios for a limited number of regions in the world to explore the geographical smoothing effect. They aim to reduce the volatility of VRE outputs, output ramps, or output forecast errors for each attainable output level. However, a few limitations exist in these studies. Firstly, they tend to focus on only one VRE technology type, build up VRE portfolios based on pre-selected sites, and use low-resolution data to aggregate VRE outputs. Consequently, they cannot fully capture geographical smoothing and minimize the impacts of VRE. Secondly, most of these studies lack a thorough analysis of key portfolio statistics. This hampers the generation of in-depth insights regarding optimal portfolios' properties.

1.4 CHANGING ENVIRONMENT FOR VRE INVESTMENTS

As the cost structure of VRE technologies is predominated by capital expenditures (CAPEX), they are more subject to capital constraints and the cost of capital (Ondraczek et al., 2015). To ensure financial security for the CAPEX recovery of VRE investments, different support schemes (e.g. feed-in tariff, tradable green certificate) have been widely adopted globally. They also can be theoretically justified by the lack of a level playing field due to incomplete internalization of social costs of carbon and (explicit and/or implicit) subsidies for fossil fuels (REN21, 2015). Despite their effectiveness in stimulating VRE investments, these support schemes, in particular the feed-in-tariff, typically create market distortions in regions where a competitive electricity market has been established. They incentivize the site selection and operation practice of VRE generators to only maximize production, disregarding price signals that reflect the needs of the system and the supply-demand dynamics. This can undermine operational efficiency, increase integration costs and exacerbate system stress events, i.e. negative price periods when the minimum must-run generation level exceeds demand (Auer and Burgholzer, 2015).

To avoid subsidy-dependent pathways, better align the development of VRE with price signals, and reduce integration costs, the EU has started the ongoing process of integrating VRE into the electricity market. This means the mandatory participation of VRE in the electricity market, increased exposure and response to price signals, more market-compatible support schemes and digressive support levels (European Commission, 2014). Market integration entails a changing environment for VRE investments. It requires a revision of the electricity market design to guarantee proper market functioning. The electricity price in current "energy-only markets" is settled by the short-run-marginal-costs (SRMC) of the marginal generation capacity. As VRE technologies have a close-to-zero SRMC, they tend to lower the average electricity price through the "merit-order-effect" (Cludius et al., 2014). This decreases revenues for all generators. Insufficient revenues can be detrimental to the business case of VRE investments and investments in peak power plants that are essential to security of supply. This is particularly the concern when prices during scarcity periods (which is key to recover CAPEX for all generators) are capped or eliminated by incoherent out-of-market regulations (Fingrid, 2016; Finon, 2013). The market integration of VRE also requires a reform in the EU emission trading scheme (ETS). A strong and credible carbon price is essential to correct for the market failure of climate change and establish a level playing field. However, the carbon price of the EU ETS had been well-below 10 Euro/Tonne CO_2 during 2012-2017 due to a sizable surplus of emission allowances (Sandbag, 2019). Although the carbon price has returned to a level around 28.7 Euro/Tonne CO_2, it is still far from sufficient to drive VRE investments in the electricity market (Sandbag, 2019).

Unlike the EU that has liberalized its power sector, China is still reforming the power sector. To boost economic efficiency, China aims to establish a competitive electricity market. Elements of completive electricity market (e.g. market-driven dispatch, direct trading of electricity) should increase the flexibility of the power system and alleviate the challenges of VRE in grid operation (Zhang et al., 2018). A national-wide ETS is also under construction to facilitate China's low-carbon transition in a cost-effective manner (Springer et al., 2019). Under this background, the changing investment environment accompanying the market integration of VRE seems inevitable to occur in China as well.

Many studies have discovered and discussed different factors affecting the success and failure of VRE investments. They often limit the scope of discussion from a single and isolated perspective. For instance, from the cognitive and institutional perspective, Masini and Menichetti (2013) show that biased perception and preconceptions can defer VRE investments. Jami and Walsh (2014) discover that the lack of public participation may contribute to the withdraw of VRE investments, based on a case study. Kitzing (2014) compares the effectiveness of different renewable support schemes in stimulating VRE investments from a revenue and risk-return perspective. However, these studies tend to be detached from the actual project life of VRE assets and the accompanying investment decision-making process. An comprehensive overview is yet missing that can establish connections between factors influencing VRE investments, their underlying contributors and the investment decision-making process.

The existing body of literature remains fragmented when pertaining to the market integration of VRE. Previous studies have evaluated the market efficiency of a limited number of market design elements, relevant regulations and policies, but the scope of these studies is often limited to a single segment of the electricity market, e.g. day-ahead market (Oliveira et al., 2015), intraday market (Scharff and Amelin, 2016), and balancing market (Musgens et al.2014; Hirth and Ziegenhagen, 2015). A systematic understanding of the interaction between market design, relevant policies (in particular the EU ETS) and the overall functioning of the electricity market across all market segments is missing. Such a understanding is essential to evaluate the effectiveness of market integration in reducing integration costs and supporting the business cases for VRE investments.

1.5 RESEARCH OBJECTIVES AND RESEARCH QUESTIONS

There are three key knowledge gaps relevant to this thesis: 1) how challenges of VRE in grid operation can be minimized through geographical smoothing; 2) a comprehensive analysis of key factors affecting VRE investment decision-making; and 3) the interaction between electricity market design, ETS and the market integration of VRE.

To address these knowledge gaps, this thesis aims to explore and evaluate different measures (and barriers) that facilitate (and hinder) the integration of VRE into the power system. Our analysis focuses on the power systems of China and the EU, as these two economies have the largest and second largest VRE capacity in the world and both of them face significant challenges of VRE integration. To achieve the research objective, the following research questions are formulated:

- *Q1. How can negative impacts of VRE on grid operation be minimized through geographical smoothing?*
- *Q2. How are investment-decisions made for VRE investments, and what are barriers to VRE investments?*
- *Q3. Which market design options and regulations facilitate or hinder the market integration of VRE?*
- *Q4. How could the carbon price trajectory develop under the EU ETS and what does it mean for VRE investments?*

These research questions are addressed in Chapter 2 through Chapter 6 (see table 1.1). Chapter 2 and Chapter 3 use modern portfolio theory to develop geographically optimal VRE portfolios. They capture geographical smoothing to the largest extent by encompassing all suitable sites for VRE development at high-resolution uniform grid cell level and by explicitly accounting for the complementarity between four different VRE technologies. This helps to minimize the system impacts of VRE on grid operation. Chapter 2 focuses on minimizing the volatility of VRE outputs in China, which is relevant to generation adequacy. Chapter 3 is more relevant to system reliability. It focuses on minimizing the volatility of VRE output ramps using the Taiwan region of China, an islanding power system, as the case study area. It further assesses the additional benefit of optimal portfolios for reducing the magnitude of extreme ramp events by the use of extreme value theory. Chapter 4 develops a comprehensive framework to simulate the investment decision-making process for utility-scale VRE investments. Using such a framework, barriers to VRE investments are identified and evaluated. Based on a comprehensive literature review, Chapter 5 evaluates the pros and cons of different market design options in terms of their impacts on limiting integration costs and the business case of VRE investments. The evaluation also enables the identification of barriers to the market integration of VRE. Chapter 6 provides an ex-ante assessment of the EU ETS' effectiveness in reducing emissions and stimulating low-carbon investments (including VRE technologies) within the EU.

Table 1.1. Overview of the chapters and their corresponding research questions

Chapter	Topic	Research questions			
		Q1	Q2	Q3	Q4
2	Geographical optimization of VRE capacity in China using modern portfolio theory	X			
3	Analysis of extreme ramp events in optimal VRE portfolios using extreme value theory	X			
4	Barrier to investments in utility-scale VRE projects		X		
5	Identifying barriers to large-scale integration of VRE into the electricity market			X	
6	Ex-ante evaluation of EU ETS during 2013-2030				X

1.6 OUTLINE OF THE THESIS

Chapter 2 targets research question 1 by characterizing the return and volatility (i.e. mean and standard deviation of normalized hourly outputs) per VRE asset in China at a high-resolution grid cell level, based on meteorological data. This enables to identify the efficient frontiers of optimal VRE portfolios that capture the geographical smoothing effect for China's future power system to smooth out VRE's output, by the use of modern portfolio theory. The portfolio volatility is minimized for each attainable return. Key statistics of optimal portfolios are further analyzed, including spatial distribution of VRE assets, technology shares, levelized cost of electricity and capacity factor at-risk values. This serves as the basis to understand the properties of optimal portfolios comprehensively and draw recommendations for policy-makers, system operators and VRE investors.

Chapter 3 addresses research question 1 by assessing how the magnitude of VRE output ramps, in particular downward extreme ramps, can be reduced. First, this chapter develops the efficient frontiers of geographically optimal VRE portfolios to minimize the volatility of VRE output ramps for each possible level of total installed VRE capacity that can meet 10%, 20% and 30% of electricity demand, using the Taiwan island of China as a case study area. Next, by the use of extreme value theory, we investigated the hourly downward extreme ramps of optimal portfolios that are expected to occur on average once-every-three-year. This result is compared with the downward extreme ramps of individual VRE assets to demonstrate the benefit of geographical smoothing.

Chapter 4 addresses research question 2 by a comprehensive and up-to-date review-based analysis of barriers to VRE investments, based on the development of an integrated framework that represents different stages (preliminary risk scanning, project development and iterative economic appraisal, capital access) of the investment decision-making process. Barriers in this framework are defined as factors hindering the realization of a positive final investment decision, which can lead to investment withdrawal. Different barriers identified from the existing body of literature and their causal relationships are integrated into such a framework. This analysis also distinguishes symptomatic and fundamental barriers. It serves as the basis to draw policy recommendations for the effective removal of barriers to VRE investments.

Chapter 5 looks into how different market design options and relevant policies affect the market integration of VRE. It addresses research question 3 by performing a comprehensive literature review of barriers to the large-scale market integration of VRE in the EU electricity market design. Market integration barriers are defined as market design elements or relevant policy schemes that lead to either higher integration costs, or endangered business cases for investments in VRE and complementing flexible resources. Based on the set-up of the EU electricity market, integration costs are allocated to each sub-market. Key market design elements are also characterized for each sub-market, focusing on five common dimensions (trading products, price settlement rule, system type, time resolution of trading products, gate closure time). This develops a framework to identify and qualitative assess the most pertinent market integration barriers that increase integration costs or endanger business cases of VRE investments in each submarket. Policy recommendations are also drawn from this assessment to improve the market design to facilitate the market integration of VRE.

Chapter 6 addresses research 4 by providing an ex-ante analysis that quantifies CO_2 emission reduction within the EU resulting from the EU ETS between 2013-2030. Chapter 6 starts from developing a "counter-factual" scenario without the ETS to assess the impact of the ETS, as currently designed. Next, it further analyzes the impact of policy intervention measures (back-loading, alternative emission cap reduction trajectory, market stability reserve) and the inclusion of aviation. Based on the quantified net demand for emission allowances, this analysis also explores a plausible carbon price development trajectory and its implication for low-carbon investments (including VRE technologies) within the EU.

Chapter 7 provides a summary of the main findings of chapters 2-6 to answer the research questions of this thesis, and recommendations for future research are given.

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2

Geographical Optimization of Variable Renewable Energy Capacity in China using Modern Portfolio Theory

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ABSTRACT

The large-scale deployment of wind and solar, which are variable renewable electricity (VRE) technologies, is indispensable to decarbonise China's power sector. However, variability in VRE outputs poses challenges in power system operation in terms of increased demand for backup and reserve capacity. These challenges can be effectively mitigated by "geographical smoothing", because spreading VRE deployment over a large area largely reduces the variability associated with the collective output of VRE. Based on meteorological reanalysis data, this study characterised the return and volatility (i.e. mean and standard deviation of hourly capacity factor) per VRE asset in China at a high-resolution grid cell level. This enabled to identify the efficient frontier of optimal VRE portfolios that capture the geographical smoothing effect for China's future power system, using modern portfolio theory. The portfolio volatility is minimized for each attainable return. We analysed key statistics of optimal portfolios, including technology shares, levelized cost of electricity and capacity factor at-risk values. Our results show complementarity between wind and solar in China, reflected in more optimal return-volatility performance of wind & solar portfolios, as compared to wind-only and solar-only portfolios. In addition, our results show that portfolios with unconstrained technology shares perform much better in return-volatility performance than portfolios with constrained technology shares. This suggests existing scenarios in literature with pre-defined shares of different VRE technologies might be sub-optimal. This study also shows that for optimal wind & solar portfolios a "firm" non-zero minimum portfolio capacity factor (1.4-5.5%) can exist with 100% availability.

NOMENCLATURE

A	wind turbine sweeping area (m^2)
a	capital recovery factor
Alb	surface albedo
A_{PV}	PV panel area (m^2/KW)
AST	apparent solar time (hour)
BRL	Boland–Ridley–Lauret
C	total installed capacity (GW)
CF	hourly capacity factor
CF_0	hourly capacity factor at sea level
$CF_{100\%}$	CF-at-risk at 100% availability of time
$CF_{90\%}$	CF-at-risk at 90% availability of time
CF_h	hourly capacity factor at elevation
$CF_{h,t}$	hourly capacity factor at elevation for specific time t
$\overline{CF_j}$	average capacity factor for technology j
$CF_{k,t}$	hourly capacity factor of VRE asset k for specific time t
$CF_{p,t}$	portfolio hourly capacity factor for specific time t
C_j	total installed capacity of technology j
cov	covariance matrix
$cov_{k,m}$	covariance between asset k and m
C_p	power coefficient of wind turbine
D	wind turbine rotor diameter (m)
N	day number of the year
O&M	annual fixed operating and maintenance costs (USD_{2015}/kW)
$O\&M_j$	annual fixed O&M costs for technology j (USD_{2015}/kW)
P_j	total potentials for technology j (MW)
$P_{j,i}$	potentials for technology j in grid cell i (MW)
P_k	potentials for VRE asset k (MW)
PR	PV performance ratio
P_{rated}	wind turbine rated power output (MW)
PV	photovoltaics
r	discount rate
SF_i	capital costs scaling factor for grid cell i
SL	standard longitude (°)
S_{rPV}	unit spacing area for rooftop PV (km^2/MW)
$t_{sunrise}$	sunrise time (hour)
t_{sunset}	sunset time (hour)
v	wind speed (m/s)
v_0	wind speed at sea level (m/s)
v_h	wind speed at elevation (m/s)
v_{in}	wind turbine cut-in speed (m/s)
v_{off}	wind turbine cut-off speed (m/s)
v^0_{rated}	wind turbine rated wind speed at sea level (m/s)

d	displacement height (m)
df	hourly diffuse fraction
DS	day-light saving time (hour)
ET	equation of time (hour)
h	elevation (km)
h_{hub}	wind turbine hub height (m)
H	hour angle (°)
H_0	hourly extraterrestrial horizontal irradiance (W/m^2)
$H_{0,t}$	hourly extraterrestrial horizontal irradiance for specific time t (W/m^2)
$I_{dif,h}$	diffuse component of hourly global horizontal irradiance (W/m^2)
$I_{dif,p}$	diffuse component of hourly total received irradiance on PV panel (W/m^2)
$I_{dir,p}$	direct component of hourly total received irradiance on PV panel (W/m^2)
$I_{dir,h}$	direct component of hourly global horizontal irradiance (W/m^2)
I_h	hourly global horizontal irradiance (W/m^2)
$I_{h,t}$	hourly global horizontal irradiance for specific time t (W/m^2)
I_j	capital costs for technology j (USD$_{2015}$/kW)
I_p	hourly total received irradiance on PV panel (W/m^2)
IPAC	integrated policy assessment model
$I_{r,p}$	reflection component of hourly total received irradiance on PV panel (W/m^2)
I_{STC}	solar irradiance under standard test conditions (1000 W/m^2)
k_t	hourly clearness index for specific time t
v^h_{rated}	wind turbine rated wind speed at elevation (m/s)
VRE	variable renewable electricity
v_{ref}	wind speed at reference height (m/s)
z	height (m)
z_0	surface roughness length (m)
Z_p	panel azimuth angle (°)
z_{ref}	reference height (m)
Z_s	solar azimuth angle (°)
$Z_{s,ref}$	reference solar azimuth angle (°)
α	solar altitude angle (°)
α_{ref}	reference solar altitude angle (°)
β	panel tilt angle (°)
ϵ	wind turbine power coefficient correction parameter
δ	declination angle (°)
θ	incidence angle (°)
μ	mean of hourly capacity factor
$\mu_{j,i}$	mean capacity factor for technology j in grid cell i
μ_k	mean capacity factor for VRE asset k
μ_p	portfolio return
μ^T	transpose vector of mean capacity factor
ρ	air density (kg/m^3)

K_t	daily clearness index for specific time t
L	local latitude (°)
LCOE	levelized cost of electricity (USD_{2015}/MWh)
$LCOE_{j,i}$	LCOE for technology j in grid cell i (USD_{2015}/MWh)
$LCOE_k$	LCOE for VRE asset k (USD_{2015}/MWh)
$LCOE_p$	portfolio LCOE (USD_{2015}/MWh)
LL	local longitude (°)
LST	local standard time (hour)
m	eastward component of wind speed (m/s)
$maxCF_{100\%}$	portfolio with maximum $CF_{100\%}$
$maxCF_{90\%}$	portfolio with maximum $CF_{90\%}$
maxret	maximum return portfolio
minCV	portfolio with minimum coefficient of variation
minvol	minimum volatility portfolio
MPT	modern portfolio theory
n	northward component of wind speed (m/s)
ρ_0	reference air density at sea level (1.225 kg/m^3)
ρ_h	air density at elevation (kg/m^3)
σ	standard deviation of hourly capacity factor
σ_p	portfolio volatility
φ	persistence index
ω	vector of contributing weight
ω_j	portfolio share of technology j
ω_k	contributing weight of VRE asset k in portfolio
ω^T	transpose vector of contributing weight

2.1 INTRODUCTION

2.1.1 Background

Deep decarbonization of the power sector is essential for reaching the Paris Agreement target to limit the global mean temperature increase to 1.5-2.0 °C (IPCC, 2014; UNFCCC, 2015). Along with other zero- or low-carbon electricity generation technologies (e.g. hydro, biomass, nuclear, carbon capture and storage), the large-scale deployment of variable renewable electricity (VRE) technologies such as wind and solar photovoltaics (PV) is vital in our bid to decarbonize the power sector (IEA, 2015; Crijns-Graus, 2016). The past decade has witnessed fast and robust development in VRE: globally, the total installed capacity of wind and solar PV combined has increased from 102 GW to 941 GW between 2007-2017 (REN21, 2018). Considering the substantial cost reduction resulting from technological learning and economies of scale (Samadi, 2018), post-Fukushima safety concerns about nuclear (Portugal-Pereira and Esteban, 2013) and the lack of commercial track records associated with carbon capture and storage (Banks et al., 2017), it is reasonable to foresee that VRE will play a dominant role in the power system of the future.

Wind and solar PV are considered VRE technologies as their production depends on stochastic fluxes of meteorological resources. Integrating VRE into the power system poses challenges in grid operation and results in "integration costs" (Ueckerdt et al., 2013). Both the variability and uncertainty of VRE outputs necessitates additional backup capacity, reserve capacity and storage to ensure generation adequacy (Luickx et al., 2008), to follow output ramps (Ela et al., 2011) and to balance forecast errors (Gonzalez-Aparicio and Zucker, 2015).

An effective way to mitigate these impacts and reduce integration costs is to disperse the deployment of VRE over a large area with diverse weather patterns (IEA, 2014). Decreased correlation in weather patterns across greater distances creates the ***geographical smoothing effect*** that largely reduces the variability and uncertainty associated with the output of individual VRE generators (Mills and Wiser, 2010; Fertig et al., 2012; Kiviluoma et al., 2016; Girard et al., 2013). This effect can also be strengthened by complementarity between various VRE technology types (Monforti et al., 2014). Consequently, with geographical smoothing, VRE collectively shows higher firm capacity[1] , a smaller spread of output ramps and lower forecast errors (Pinson, 2006; Muzhikyan et al., 2016).

The geographical smoothing effect can be captured by modern portfolio theory (MPT). MPT is a financial theory which helps to guide investment decision-making subject to the

1 Firm capacity can be defined as the fraction of VRE's nameplate capacity that can replace conventional power plants without changing the system reliability.

trade-off between (expected) return and risk (which is usually represented by the volatility of return) in the market (Elton et al., 2013). It is used to obtain the efficient frontier of portfolios of individual financial assets. Because of perfect diversification, any portfolio at the efficient frontier is optimal in the sense that at a given return, risk is minimized, while at a given risk, return is maximized. Figure 2.1 illustrates the efficient frontier of 4 assets (bills, bonds, gold and stocks), where each point on the frontier represents an optimal portfolio.

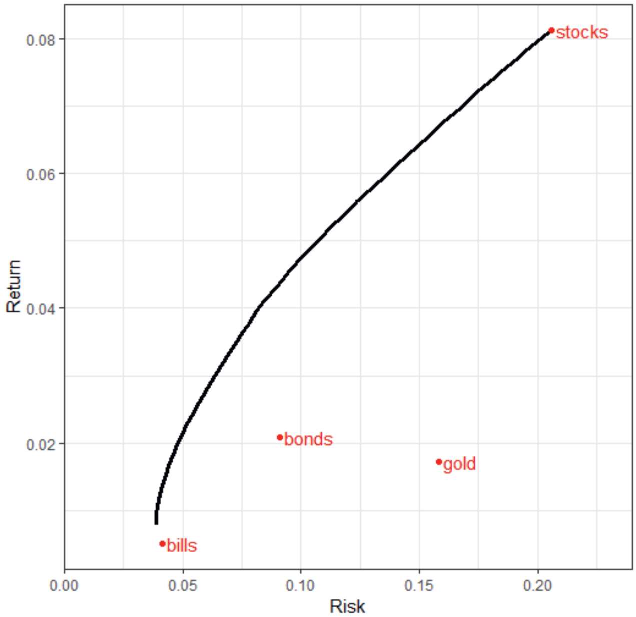


Figure 2.1. Illustration of efficient frontier of 4 assets

Source: Own elaboration

2.1.2 Literature review

Various authors have adopted MPT to identify the geographically optimal portfolios that spread the VRE capacity of one or more technology types across different locations, to capture the geographical smoothing effect. In this context, a certain type of VRE technology at a specific location becomes an individual **VRE asset**. Return is then usually represented as the (physical) power output of VRE whereas risk can either be output volatility (e.g. Drake and Hubacek, 2007; Degeilh and Sighn, 2011; Tejeda et al., 2018; Shahriari and Blumsack, 2018; Koivisto et al., 2018), or output ramp rate volatility (e.g. Roques et al., 2010; Rombauts et al., 2011; Speth, 2013; Novacheck and Johnson, 2017).

When risk is treated as output volatility, i.e. the standard deviation of output across time, optimal portfolios are the minimum volatility portfolio for each possible output level. This is particularly relevant for generation adequacy, which aims to increase VRE's firm capacity and reduce backup capacity. For instance, Shahriari and Blumsack (2018) determine the capacity value (defined as the output available for a pre-specified percentage of time) for optimal wind and solar portfolios, based on the output duration curve. Degeilh and Sighn (2011) also calculate the loss of load probability associated with optimal wind portfolios during peak load time. Both papers demonstrate that MPT helps to increase the firm capacity of VRE. When risk is treated as output ramp rate volatility, i.e. the standard deviation of output ramp rate, it enables us to identify optimal portfolios that can reduce the spread and extreme values of VRE ramp events (Novacheck and Johnson, 2017). Hence, MPT is useful for saving reserve capacity from the perspective of system reliability. Alternatively, Speth (2013) and Lima et al. (2017) also use MPT to increase the predictability of VRE. In their studies, return and risk are respectively framed as average forecast errors and the standard deviation of forecast errors across time.

The representation of VRE assets in MPT literature is either based on pre-selected sites (of existing and planned power plants) or on a uniform grid cell. Many studies adopt the former representation, and they often rely on site-specific output measurement data or pre-developed simulation data from literature. By contrast, Thomaidis et al. (2016); Tejeda et al. (2018); Koivisto et al. (2018) use meteorological data to simulate VRE outputs at uniform grid cell level. This representation is more advantageous, as it enables the portfolio to include VRE assets in all sites, especially in sites without measurement data.

Due to data limitation and modelling complexity, most studies do not explicitly consider transmission constraints through a copperplate assumption. Among few analyses factoring into transmission constraints, the treatment of transmission constraints varies. Roques et al. (2010) formulate cross-border transmission capacity as an additional constraint condition for net imports in the MPT optimization, while Rombauts et al. (2011) add transmission capacity in the optimization objective function by introducing variables of post-transmission power flows. Alternatively, Novacheck and Johnson (2017) use portfolios obtained from MPT optimization as inputs in a power system model to investigate the impact of transmission constraints. They conclude that even if transmission constraints are not represented in the MPT optimization, MPT-based portfolios alleviate transmission congestion due to diversification.

A thorough overview of recent MPT literature is presented in Table 2.1. It assesses different studies according to their return-risk framework, temporal and spatial resolution, geographical scope, inclusion of technology, representation of VRE assets, and treatment of transmission constraints.

Table 2.1. Overview of recent MPT-based studies

Study	Return-risk framework		Resolution		Geographical scope	Inclusion of technology	Representation of VRE assets	Treatment of transmission constraints
	Return	Risk	Temporal	Spatial				
Drake and Hubacek (2007)	Physical output of VRE	Standard deviation of output	Hourly	Site level	UK	Offshore wind	Pre-selected sites	Copperplate
Roques et al. (2010)	Physical output of VRE	Standard deviation of output and output ramp	Hourly	Aggregated to country level	Combined area of Austria, Denmark, France, Germany and Spain	Onshore and offshore wind	Pre-selected sites	Formulated as constraints for net imports
Rombauts et al. (2011)	Physical output of VRE	Standard deviation of output ramp	Hourly	Site level	NA (three fictitious countries)	Onshore wind	Pre-selected sites (sampled from the Netherlands)	Considered in optimization objective by introducing post-transmission power flows
Degeilh and Singh (2011)	Physical output of VRE	Standard deviation of output and output ramp	Hourly	Site level	Two areas considered separately: 7 sites in West Texas; 7 sites in Western United States	Onshore wind	Pre-selected sites	Copperplate
Speth (2013)	Physical output of VRE; average forecast errors	Standard deviation of output and output ramp; standard deviation of forecast errors	Hourly	Site level	Germany	Wind and PV (without detailed technology specifications)	Pre-selected sites	Copperplate
Thomaidis et al. (2016)	Physical output of VRE	Standard deviation of output	Hourly	9km*9km	Southern Iberian Peninsula	Onshore wind and concentration solar power	Uniform grid cell	Copperplate
Santos-Alamillos et al. (2017)	Physical output of VRE	Standard deviation of output	Hourly	Site level but calibrated to 5km*5km grid cell	Spain	Onshore wind	Pre-selected sites	Copperplate

Novacheck and Johnson (2017)	Physical output of VRE	Standard deviation of output ramp	Hourly	Site level	Midwestern United States	Onshore wind	Pre-selected sites	Modelling of power system after optimization
Tejeda et al. (2018)	Physical output of VRE	Standard deviation of output	6-hourly	0.25°*0.25°	European Union	Onshore and offshore wind	Uniform grid cell	Copperplate
Lima et al. (2017)	Average forecast errors	Standard deviation of forecast errors	Hourly	Site level	Northeastern Brazil	Wind and PV (without detailed technology specifications)	Pre-selected sites	Copperplate
Shahriari and Blumsack (2018)	Physical output of VRE	Standard deviation of output	10-min, hourly, daily, weekly and monthly	Site level	Eastern Interconnection of United States	Wind and PV (without detailed technology specifications)	Pre-selected sites	Copperplate
Koivisto et al. (2018)	Physical output of VRE	Standard deviation of output	Hourly	Site level but calibrated to 10km*10km grid cell	Northern Europe	Onshore and offshore wind, PV (without detailed technology specifications)	Pre-selected sites for wind and uniform grid cell for PV	Copperplate

Source: Compiled based on Drake and Hubacek (2007), Roques et al. (2010), Rombauts et al. (2011), Degeilh and Singh (2011), Speth (2013), Thomaidis et al. (2016), Santos-Alamillos et al. (2017), Novacheck and Johnson (2017), Tejeda et al. (2018), Lima et al. (2017), Shahriari and Blumsack (2018), and Koivisto et al. (2018)

2.1.3 Knowledge gap and research objective

While MPT-based studies have been performed for a limited number of regions in the world (e.g. England (Drake and Hubacek, 2007); Southern Iberian Peninsula (Thomaidis et al., 2016); Germany (Speth, 2013); Spain (Santos-Alamillos et al., 2017); Northern Europe (Koivisto et al., 2018); the combined area of Austria, Denmark, France, Germany and Spain (Roques et al., 2010); European Union (Tejeda et al., 2018); Eastern Interconnection of United States (Shahriari and Blumsack, 2018)), to the authors' best knowledge no such study is yet available for China. China has the largest cumulative installed VRE capacity (REN21, 2018). With support from the Chinese government, the momentum of rapid VRE development is likely to continue (Huenteler et al., 2018). However, even today China has already faced severe curtailment problem of VRE generation due to insufficient capability to manage VRE volatility (Liu and Chu, 2018). Therefore, fully exploiting the geographical smoothing effect is essential and pertinent to plan optimal VRE development in China's low-carbon transition. To fill the knowledge gap of the absence of MPT-based study for China, this research aims to explore optimal VRE portfolios that capture the geographical smoothing effect in China's long-term future power system. It also aims to generate in-depth insights of optimal portfolios' properties through analysis of key portfolio statistics (e.g. levelized cost of electricity, value-at-risk of capacity factor), which can be used to support the decision-making in power system investment and operation. The year 2050 is indicatively selected as the target year, since it is often used to set long-term energy/climate targets in many scenario-based studies (e.g. Jiang et al., 2018; European Commission, 2011). In this paper geographical smoothing is defined as the minimum output volatility for each possible output level. The novelty of this study is that we explicitly consider four types of VRE (onshore wind, offshore wind, utility-PV and rooftop PV) and use high-resolution ($0.5° * 0.667°$) meteorological reanalysis data[2] that covers all locations in China to simulate VRE outputs at a uniform grid cell level. This adds to previous studies that 1) tend to focus on only one VRE technology type (Drake and Hubacek, 2007; Santos-Alamillos et al., 2017; Roques et al., 2010; Tejeda et al., 2018; Novacheck and Johnson, 2017), 2) build up portfolios based on pre-selected VRE sites (Drake and Hubacek, 2007; Roques et al., 2010; Novacheck and Johnson, 2017; Shahriari and Blumsack, 2018), and 3) use low-resolution data to aggregate VRE outputs (Tejeda et al., 2018; Roques et al., 2010). The entire China region[3] (including neighboring areas and exclusive economic zone) is divided into 7938 grid cells with a spatial resolution of $0.5° *0.667°$ to match the reanalysis data. Constructing optimal portfolios comprising multiple VRE technology types based on high-resolution meteorological reanalysis data has never been done by previous MPT-based studies for a region at such a large geographical scale and across so many climate zones. Therefore,

2 Reanalysis data is weather data simulated by an atmospheric circulation model, which is used to assimilate historical weather observations for hindcasting purpose (Staffell and Pfenninger, 2016).

3 The Taiwan area is excluded in this study due to the absence of interconnection with mainland China.

this study expands the application of MPT. It also enables a comprehensive understanding of geographical smoothing by encompassing all locations suitable to develop VRE and by accounting for the complementarity between different VRE technologies, which adds value to scientific literature. The contribution of this paper is threefold. Firstly, it informs policy-makers and academic peers about the performance and potentials of each VRE technology type in China at a high-resolution grid cell level. Secondly, optimal portfolios determined in this study can help policy-makers to plan VRE development and grid expansion in a more system-optimized manner and bring about multiple economic benefits. Lastly, the detailed methodology presented in this paper is reproducible, and can be easily applied to other regions with high VRE potentials, such as India and Africa.

In section 2.2 we describe the method used for data processing and post-processing. The results are presented in section 2.3. In section 2.4 we discuss the limitations and uncertainties of this study, while conclusions are drawn in section 2.5.

2.2 METHODS

In this chapter we present the methods applied to carry out the main tasks, five related to the data processing phase (sections 2.2.1-2.2.5) and four related to the post-processing phase (sections 2.2.6-2.2.9). A brief overview of the research design for this paper is presented in Figure 2.2. All tasks were performed using RStudio and ArcGIS.

Section 2.2.1 explains the method for estimating geographical potentials in terms of the maximum capacity (in MW) that can be installed, accounting for different geographical constraints and social acceptance. Section 2.2.2 describes how to characterize the time series of hourly power output per unit rated power for each VRE asset, referred to as the hourly capacity factor (CF). In section 2.2.3 we lay out the method used to determine the average CF weighted by geographical potentials per grid cell in China, per technology. This task combines the results of the previous two tasks. Section 2.2.4 provides the method used to calculate the levelized cost of electricity (LCOE) per VRE asset, built upon the mean of hourly CF introduced in section 2.2.2. Section 2.2.5 describes applying MPT optimization to determine the efficient frontier of optimal portfolios for various 2050 scenarios.

The four post-processing tasks were carried out to analyse key statistics and performance indicators for selected portfolios positioned on the efficient frontier. This enables comparison and explanation. In section 2.2.6 we present the method used to characterize the contributing weights per VRE asset for these portfolios. Sections 2.2.7 and 2.2.8 provide the methods used to calculate the portfolio share per VRE technology and the portfolio

LCOE. Finally, in section 2.2.9, we describe the procedure for how to generate the portfolio CF duration curve and how to determine its Value-at-Risk.

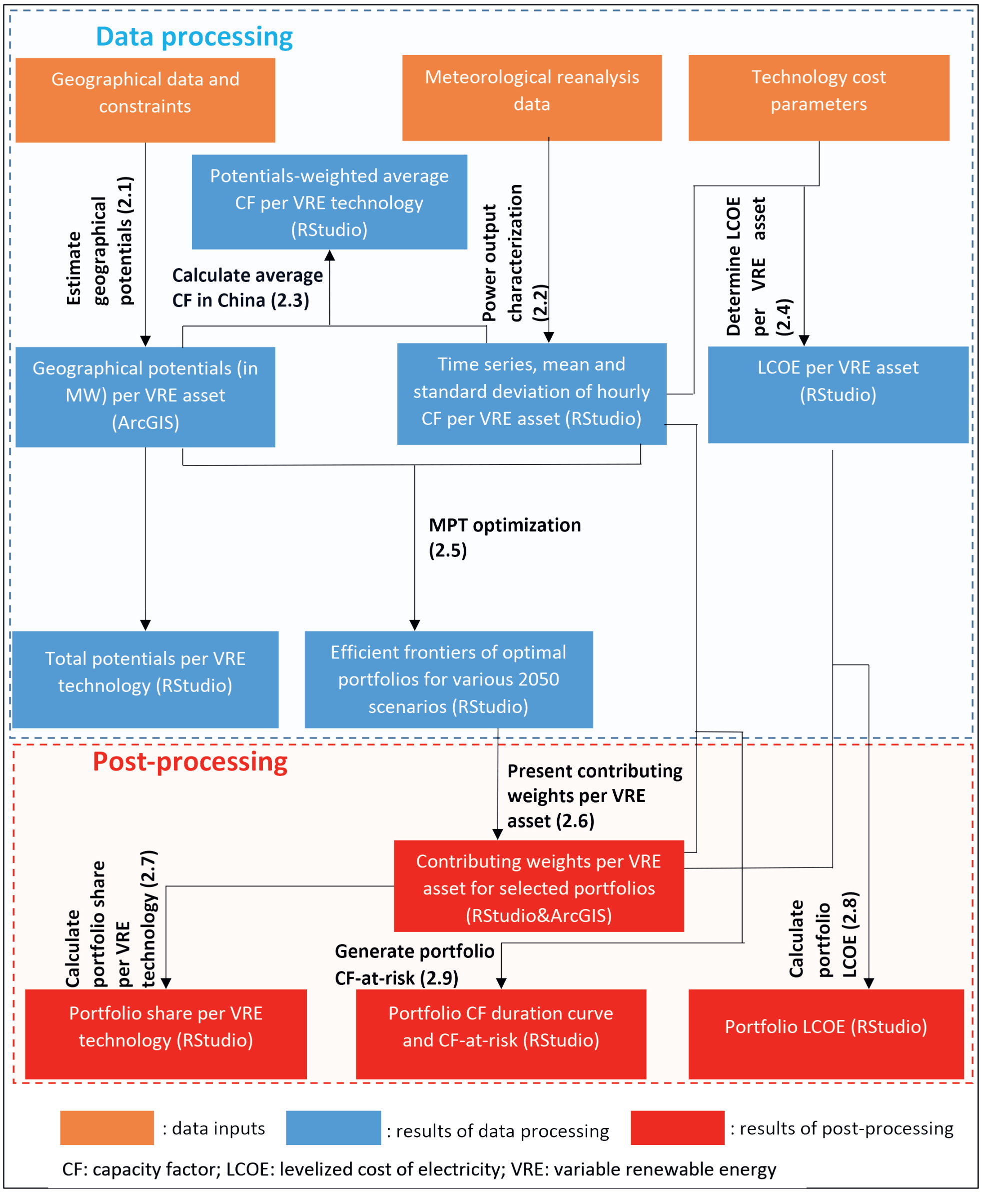


Figure 2.2. Overview of research design

Source: Own elaboration

2.2.1 Data processing task 1: Estimate geographical potentials

The approach we followed to determine the geographical potentials for each VRE asset (defined as a certain VRE technology in a certain grid cell) and the total potentials per VRE technology are described respectively in section 2.2.1.1. and 2.2.1.2.

2.2.1.1 Geographical potentials per VRE asset

Estimating the geographical potentials for each VRE asset was based on a three-step procedure (see Figure 2.3).

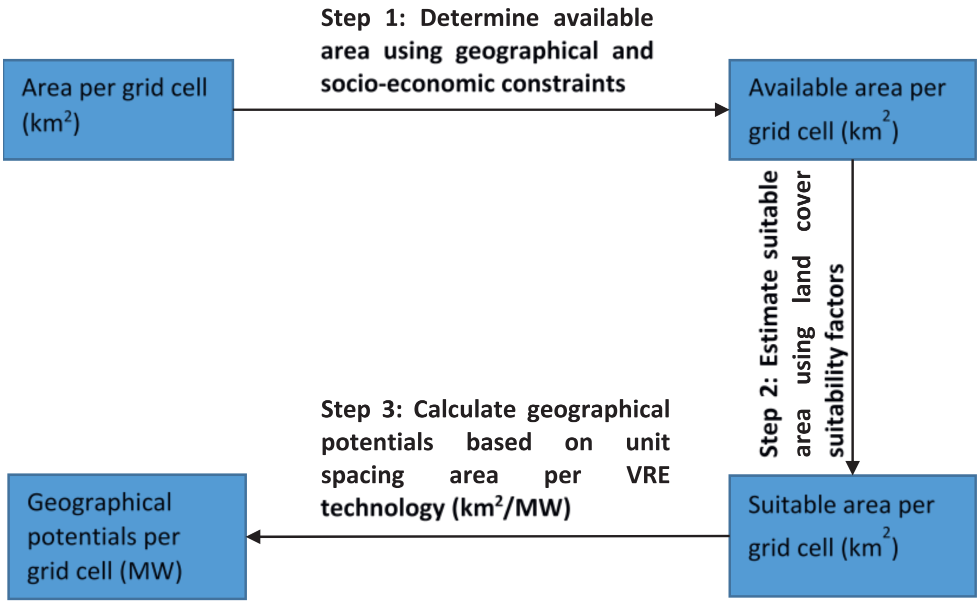


Figure 2.3. Procedure to estimate geographical potentials per VRE asset

Source: Own elaboration

Firstly, based on the territory area of China (which is divided into 7938 grid cells with resolution of 0.5° *0.667°), we calculated the available area (in km²) per grid cell after considering multiple geographical constraints (see Table 2.2). Following Herran et al. (2016), we introduced an additional social acceptance constraint specifically for onshore wind and utility-PV. It is defined as a threshold distance from the dense urban area (urban areas >50%) to restrict visibility impacts that can result in social unacceptance, which we set conservatively at 10 km. Secondly, by using suitability factors for different land cover categories, we further narrowed down the area suitable for deployment of VRE technologies per grid cell (being the multiplication product of the available area and suitability factors). The land cover suitability factors are shown in Table 2.3. Lastly, based on the unit spacing area per VRE technology, we estimated the maximum capacity that can be installed in each grid cell as geographical potentials. Depending on the turbine rotor diameter (D), the unit spacing area for both onshore and offshore wind can be *narrow* (5.25D*5.25D), *intermediate* (7D*7D) and *wide* (10.5D*10.5D) (Volker et al, 2017). We opted to use the intermediate spacing, as it has a relatively low spacing density without incurring large wake losses (Perez-Moreno et al., 2018). The installed turbines were based on three onshore modules (Vestas-112, -117 and -126) with rated capacity of 3.3 MW and one offshore module (Vestas-164) with rated capacity of 8 MW (see Table 2.4 for details).

Both installed utility-PV and rooftop PV were based on the Sanyo HIP-225HDE1 module with a rated capacity of 0.225kW$_p$ for a total area of 1.39 m^2. As rule-of-thumb, the unit spacing area for utility-PV was set at 1 ha/MW (or 0.01 km^2/MW) (de Jonge et al., 2017). For rooftop PV, based on flat roof assumption[4] we calculated the required unit array spacing that avoids self-shading. Following Copper et al. (2016), the hour with the third lowest solar altitude angle on the winter solstice, being the worst-case scenario, was established as the reference condition to calculate the unit spacing area (S_{rPV}) for each grid cell. The calculation was performed with formula 1.

$$S_{rPV} = A_{PV} * \left(\cos(\beta) + \frac{\sin(\beta)}{\tan(\alpha_{ref})} \cos\left(Z_{s,ref} - Z_p\right) \right) \quad (1)$$

where A_{PV} is the PV panel area; β and Z_p are panel tilt angle and azimuth angle; α_{ref} and $Z_{s,ref}$ are solar altitude angle and azimuth angle under the reference condition.

4 Because of the dominance of flat roof residential buildings in China, especially in cities.

Table 2.2. Geographical constraints for determining available area for VRE development

Constraint for each VRE technology	Data sources	Onshore wind	Offshore wind	Utility-PV	Rooftop PV
Territory (km2)	GADM Database of Global Administrative Areas (Global Administrative Area, 2012); Maritime Boundaries Geodatabase (Flanders Marine Institute, 2014)	Administrative terrestrial area	Economical exclusive zone	Administrative terrestrial area	Administrative terrestrial area
Distance to shore (km)	NA	NA	10-90 Note following Eurek et al. (2017), we set the minimum distance to shore at ~10 km to restrict the visibility and environmental impacts of offshore wind. We also considered distance to shore above 90 km too far to develop offshore wind.	NA	NA
Depth (m)	General bathymetric chart of the oceans (GEBCO)_2014 (British Oceanographic Data Centre, 2015)	NA	≤ 60 We only considered offshore wind turbines with bottom fixed foundations (no floating), which usually suit water depth below 60 m (Peyrard, 2015).	NA	NA
Commercial maritime transport (annual number of ship tracks per square km2 in 2013)	Cumulative human impacts: raw stressor data of 2013 commercial shipping activities (Halpern et al., 2015)	NA	≤25	NA	NA
Submarine communications cable	Greg's Cable Map of undersea cable initiatives (Mahlknecht, 2013)	NA	1 km2 buffering from both sides of the cable (Bosch et al., 2018)	NA	NA

Protected areas (km2)	The world database on protected areas (WDPA) and Marine Protected Areas (International Union for the Conservation of Nature and United Nations Environment Programme, 2017)	Terrestrial protected areas	Terrestrial & maritime protected areas	Terrestrial protected areas	Terrestrial protected areas
Permafrost (%)	Global Permafrost Zonation Index Map (Gruber, 2012)	≤0.1	NA	≤0.01	≤0.01
Elevation (m)	Digital Elevation - Global 30 Arc-Second Elevation (GTOPO30) (United States Geological Survey, 2018)	<=2600 Note Eurek et al. (2017) considered elevation above 2500 m too high for onshore wind development due to substantial reduction of wind power density associated air density losses. However, we set the threshold elevation at 2600 m, because wind farms above 2600 m have been accomplished in China.	NA	NA	NA
Slope (degree)	Calculated based on Elevation	<11.31 (or 20%) (Eurek et al., 2017)	NA	<4 (0r 6.99%) (Sun et al., 2013)	NA

Source: Compiled based on Global Administrative Area (2012), Flanders Marine Institute (2014), Eurek et al. (2017), British Oceanographic Data Centre (2015), Peyrard (2015), Halpern et al. (2015), Bosch et al. (2018), Mahlknecht (2013), International Union for the Conservation of Nature and United Nations Environment Programme (2017), Gruber (2012), United States Geological Survey (2018), and Sun et al. (2013)

Table 2.3. Suitability factors for different land cover categories[5]

GlobCover code	GlobCover Category	Suitability factor							
		Onshore wind (High)	Onshore wind (Medium)	Onshore wind (Low)	Utility-PV	Rooftop PV	Offshore wind (High)	Offshore wind (Medium)	Offshore wind (Low)
11	Post-flooding or irrigated croplands	0	0	0.00	0	0	0	0	0
14	Rainfed croplands	0.70	0.60	0.30	0.01	0	0	0	0
20	Mosaic Cropland (50%-70%)/ Vegetation (grassland, shrubland, forest) (20-50%)	0.70	0.60	0.30	0.01	0	0	0	0
30	Mosaic Vegetation (grassland, shrubland, forest) (50-70%) / Cropland (20-50%)	0.70	0.50	0.20	0.01	0	0	0	0
40	Closed to open (>15%) broadleaved evergreen and/or semi-deciduous forest (>5m)	0.10	0	0	0	0	0	0	0
50	Closed (>40%) broadleaved deciduous forest (>5m)	0.10	0	0	0	0	0	0	0
60	Open (15-40%) broadleaved deciduous forest (>5m)	0.10	0	0	0	0	0	0	0

5 The land cover categories and corresponding codes are based on GlobCover 2009 V2.3 Global Land Cover Map (Bontemps et al., 2010). Suitability factors for onshore wind and utility-PV are compiled from Hoogwijk (2004); Herran et al. (2016); Eurek et al. (2017). Following Sun et al. (2013), we limited the deployment of rooftop PV to built-up areas (i.e. artificial surfaces and associated areas under the GlobCover Category). The suitability factor of 0.07 for rooftop PV is the product of the assumed roof area per built-up area (0.15-0.3) and the popularizing ratio of rooftop PV (0.3) (Sun et al., 2013). We also added a land cover category "Sea" with code * specially for offshore wind. The suitability factors for offshore wind from the available sea area here are set at 0.5, 0.4 and 0.3 as high, medium and low values. This is comparable to Deng et al. (2015), where suitability factors of 0.1, 0.3 and 0.4 are assumed for offshore wind.

70	Closed (>40%) needle leaved evergreen forest (>5m)	0.10	0	0	0	0	0	0	0
90	Open (15-40%) needle leaved deciduous or evergreen forest (>5m)	0.10	0	0	0	0	0	0	0
100	Closed to open (>15%) mixed broadleaved and needle leaved forest (>5m)	0.10	0	0	0	0	0	0	0
110	Mosaic Forest/ Shrubland (50-70%) / Grassland (20-50%)	0.50	0.36	0.14	0.01	0	0	0	0
120	Mosaic Grassland (50-70%) / Forest/ Shrubland (20-50%)	0.65	0.46	0.19	0.05	0	0	0	0
130	Closed to open (>15%) shrubland (<5m)	0.50	0.36	0.14	0.01	0	0	0	0
140	Closed to open (>15%) grassland	0.80	0.57	0.23	0.01	0	0	0	0
150	Sparse (>15%) vegetation (woody vegetation, shrubs, grassland)	0.90	0.50	0.10	0.01	0	0	0	0
160	Closed (>40%) broadleaved forest regularly flooded - Fresh water	0	0	0	0	0	0	0	0
170	Closed (>40%) broadleaved semi-deciduous and/or evergreen forest regularly flooded - Saline water	0	0	0	0	0	0	0	0

180	Closed to open (>15%) vegetation (grassland, shrubland, woody vegetation) on regularly flooded or waterlogged soil - Fresh, brackish or saline water	0	0	0	0	0	0	0	0
190	Artificial surfaces and associated areas (urban areas >50%)	0	0	0	0	0.07	0	0	0
200	Bare areas	0.90	0.50	0.10	0.05	0	0	0	0
210	Water bodies	0	0	0	0	0	0	0	0
220	Permanent snow and ice	0	0	0	0	0	0	0	0
*	Sea (10km <=distance to shore<=90km and depth <=60m)	0	0	0	0	0	0.5	0.4	0.3

Source: Complied based on Bontemps et al. (2010), Hoogwijk (2004), Herran et al. (2016), Eurek et al. (2017), Sun et al. (2013), and Deng et al. (2015)

2.2.1.2 Total potentials per VRE technology

We determined the total potentials per VRE technology through summing the maximum capacity that can be installed in each grid cell:

$$P_j = \sum_i^n P_{j,i}, \qquad j = \textit{onshore wind}, \textit{offshore wind}, \textit{utility\_PV}, \textit{rooftop PV} \quad (2)$$

where P_j is the total potentials for technology *j* and $P_{j,i}$ is the geographical potentials for technology *j* in grid cell *i*.

Three cases for onshore wind were explicitly considered to reflect the impact of including/excluding the social acceptance constraint (10 km distance from urban area) and the use of different sets of suitability factors, i.e. 1) High potentials (excluding social acceptance constraint + high suitability factors); 2) Medium potentials (including social acceptance constraint + high suitability factors); 3) Low potentials (including social acceptance constraint + low suitability factors). Similarly, we also considered three cases (high, medium and low potentials) for offshore wind based on high, medium and low suitability factors.

2.2.2 Data processing task 2: Time series, mean and standard deviation per VRE asset

We used historical hourly meteorological reanalysis data during 2000-2015 from NASA's Modern Era Retrospective-Analysis for Research and Applications (MERRA) database (NASA, 2019) to determine the hourly CF time series, including its mean and standard deviation. We extracted hourly wind speed and solar irradiance data for each grid cell from the MERRA database. Section 2.2.2.1 and 2.2.2.2 respectively describes how they were converted into the CF time series for wind and PV.

2.2.2.1 Wind

Following a three-step approach (see Figure 2.4), we determined the CF time series for both onshore wind and offshore wind.

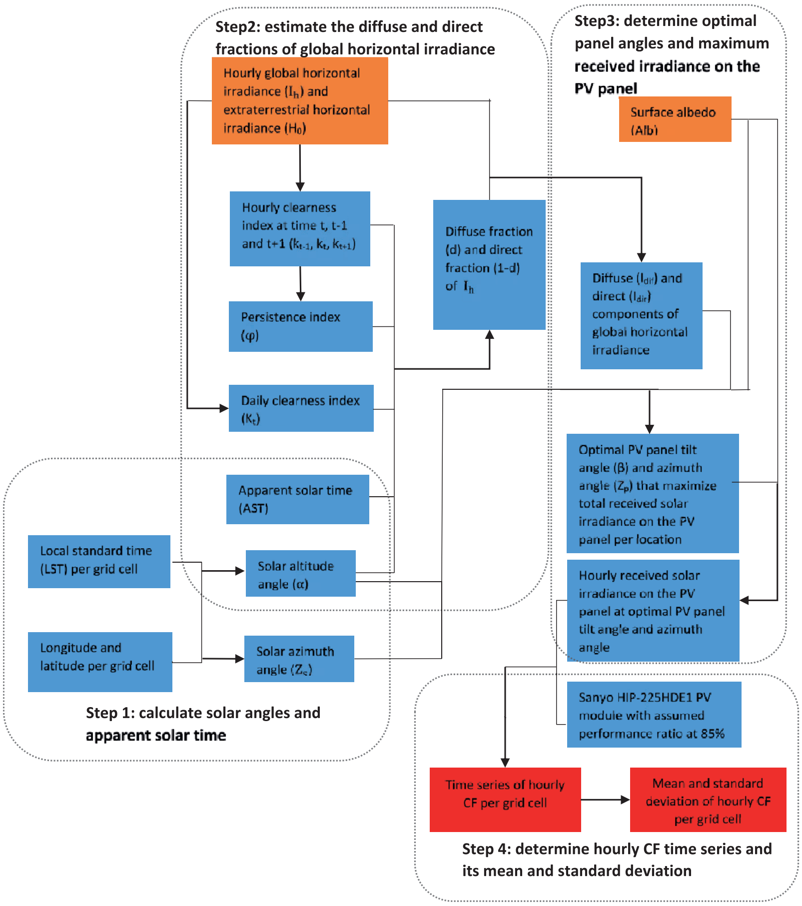


Figure 2.4. Method to determine the hourly CF time series for onshore and offshore wind

Source: Own elaboration

- **Step 1. Determine wind speed at turbine height**

Based on their eastward (m) and northward components (n), we calculated the hourly wind speed (v) at 2m and 10m above displacement height (d) and at 50m above ground:

$$v = \sqrt{m^2 + n^2} \quad (3)$$

Using logarithmic law, wind speed at any height z (v_z) can be extrapolated from the surface roughness length z_0 and a known wind speed at reference height z_{ref} above ground (v_{ref}) (Staffell and Green, 2014).

$$v_z = v_{ref} \frac{\ln\left(\frac{z-d}{z_0}\right)}{\ln\left(\frac{z_{ref}-d}{z_0}\right)} \quad (4)$$

z_0 was determined through a linear regression using the 16-year time series of wind speed at 2m and 10m above displacement height (v_{2+d} and v_{10+d}) for each grid cell:

$$v_{2+d} ln10 - v_{10+d} ln2 = ln z_0 (v_{10+d} - v_{2+d}) \quad (5)$$

We then calculated the 16-year-average wind speed at 100m above displacement height ($\overline{v_{100+d}}$) using formula (4). The International Electrotechnical Commission (IEC)'s 61400-12-1 international standards (IEC, 2005) classify wind turbines based on the local average wind speed at turbine hub height. In absence of manufacturer specifications of hub height, we used $\overline{v_{100+d}}$ as the basis to pre-select the turbine class most suitable to the local wind conditions per grid cell. Following Zappa and Van den Broek (2018), we adopted three representative onshore turbine modules and one offshore turbine module from the Danish manufacturer Vestas. Table 2.4 presents the four Vestas modules in relation to the IEC's classification and their key technical parameters. Note that the hub height (h_{hub}) was estimated based on its empirical relationship with rotor diameter (D) (EWEA, 2009):

$$h_{hub} = 2.7936\, D^{0.7663} \quad (6)$$

Table 2.4. Vestas turbine modules and their key technical parameters

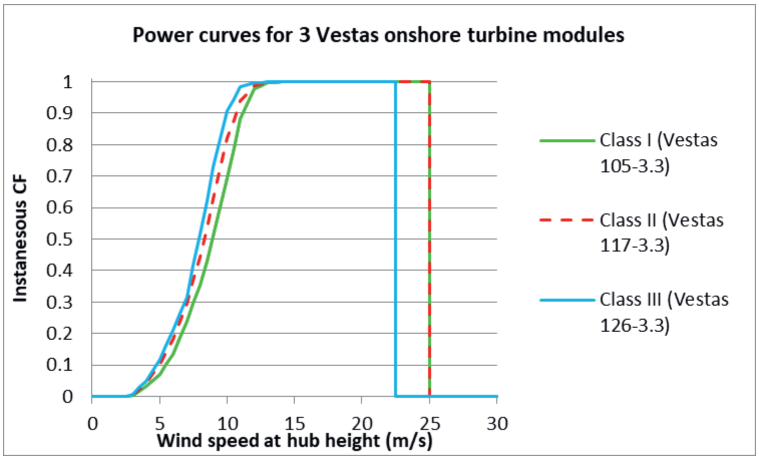
IEC's wind turbine classification according to average wind speed	Usage	Representative commercial turbine module	Rated capacity (MW)	Rotor diameter (m)	Specific power (W/m^2)	Cut-in speed (m/s)	Rated speed (m/s)	Cut-off speed (m/s)	Estimated hub height (m)
Class I: 10 m/s	Onshore	Vestas 105-3.3	3.3	105	381.8	3	13	25	99
Class II: 8.5 m/s	Onshore	Vestas 117-3.3	3.3	117	306.9	3	13	25	107
Class III: 7.5 m/s	Onshore	Vestas 126-3.3	3.3	126	264.7	3	12	22.5	114
Class S: User defined	Offshore	Vestas 164-8.0	8	164	378.7	4	13	25	139

Sources: IEC (2005); Wind-turbine-models.com (2014, 2015a, 2015b and 2015c)

- **Step 2. Determine hourly CF at sea level**

After the selection of most suitable turbine module for each grid cell, the time series of hourly wind speed at hub height were calculated. This enabled us to determine the time series of hourly CF using the power curves of the four individual turbine modules specified by the manufacturer[6]. Figure 2.5 presents these power curves. Because the power curves are tested at sea level with a reference air density ($\rho_0 = 1.225\ kg/m^3$), the determined CF only reflects the hourly power output per unit rated power at sea level (Eurek et al., 2017). They must be corrected for the average elevation of suitable area (*h*) in each grid cell to take reduced air density into account.

6 Note that we do not explicitly consider the "memory effect" of wind speed propagation within a wind farm and the wind farm wake effect. The former can smooth the aggregated power curve of multiple turbines (Norgaard and Holttinen, 2005). The latter causes power losses and thus affects the aggregated power curve as well (Wagner et al., 2009).



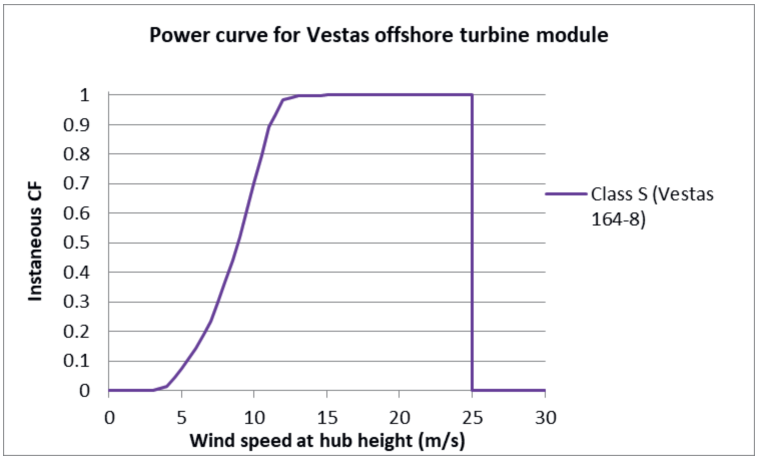


Figure 2.5. Power curves for four Vestas turbine modules

Source: Wind-turbine-models.com (2014, 2015a, 2015b and 2015c)

- **Step 3. Determine hourly CF at elevation level and its mean and standard deviation**

Following Eurek et al. (2017), we developed an approach to obtain the hourly CF time series, adjusted for elevation. For any elevation level *h*, a new power curve of a specific turbine module can be constructed from its original power curve at sea level. This was achieved through dividing the new power curve into five intervals, using the cut-in speed (v_{in}), the rated wind speed at sea level (v^0_{rated}), the rated wind speed at elevation level (v^h_{rated}) and the cut-off speed (v_{off}). v_{in}, v^0_{rated} and v_{off} are all specified in the original power curve, while v^h_{rated} can be estimated from v^0_{rated}.

At a wind speed between v_{in} and v^{0}_{rated}, the instantaneous CF for a turbine with sweeping area (A) and rated power (P_{rated}) at a given air density (ρ) and power coefficient[7] (Cp) is

$$CF = \tfrac{1}{2} C_p \rho A v^3 / P_{rated} \quad (7)$$

In this case, CF is proportionated to ρ, ceteris paribus. Assuming negligible impacts of temperature and pressure, air density at a specific h (ρ_h) can be estimated based on a simple linear relationship (Eurek et al., 2017):

$$\rho_h = 1.225 - 1.194 * 10^{-4} h \quad (8), \text{ or}$$

$$\tfrac{\rho_h}{\rho_0} = 1 - 0.975 * 10^{-4} h \quad (9)$$

According to Eurek et al. (2017), for the same turbine module, the equivalent wind speed (v_h) at elevation h that results in the same CF from a wind speed at sea level (v_0) can be calculated via

$$v_h = \left(\frac{\rho_h}{\rho_0}\right)^{-1/\varepsilon} v_0 \quad (10)$$

Here ε is used to correct for the non-constant [[OMML-EQ-60]] at different wind speeds. If C_p is assumed to be constant, ε is 3. Without the assumption of constant C_p, parameter ε approximates 1.5 in case that the wind speed is above 12 m/s (Svenningsen, 2010; Eurek et al. 2017). As v^{0}_{rated} for all four turbine modules are above 12m/s, we estimated v^{h}_{rated} via the following formula:

$$v^{h}_{\text{rated}} = \left(\frac{\rho_h}{\rho_0}\right)^{-2/3} v^{0}_{\text{rated}} \quad (11)$$

Consequently, we determined CF at elevation h (CF_h) from CF at sea level (CF_0), based on the five intervals divided from the new power curve. If the wind speed (v) is below v_{cut-in}, CF_h is 0; if v is between v_{in} and v^{0}_{rated}, CF_h is the product of CF_h and the ratio $\frac{\rho_h}{\rho_0}$; if v is above v^{h}_{rated} but below v_{off}, CF_h is 1; if v is between v^{0}_{rated} and v^{h}_{rated}, CF_h is linearly interpolated; if v is above v_{off}, CF_h is 0. This creates a stepwise function:

7 The power coefficient is the ratio of the power captured by the turbine rotor divided by the total power available in the wind (Libii, 2013). It is a function of wind speed and capped by the Betz's limit at 0.593 (Svenningsen, 2010; Andrews and Jelley, 2017)

$$
CF_h = \begin{cases} CF_h = 0, & \text{if } v < v_{in} \\ CF_0 \frac{\rho_h}{\rho_0} = CF_0 \;(1 - 0.975 \;\; 10^{-4} h), & \text{if } v_{in} \le v \le v^0_{rated} \\ 1 - 0.975 * 10^{-4} h + * \frac{0.975 * 10^{-4} * h}{v^h_{rated} - v^0_{rated}} (v - v^0_{rated}), & \text{if } v^0_{rated} < v < v^h_{rated} \\ 1, & \text{if } v^h_{rated} \le v < v_{off} \\ 0, & \text{if } v \ge v_{off} \end{cases} \quad (12)
$$

For illustration purpose, the power curves for a class III turbine module at sea level and adjusted to elevation at 2000 m are presented in Figure 2.6.

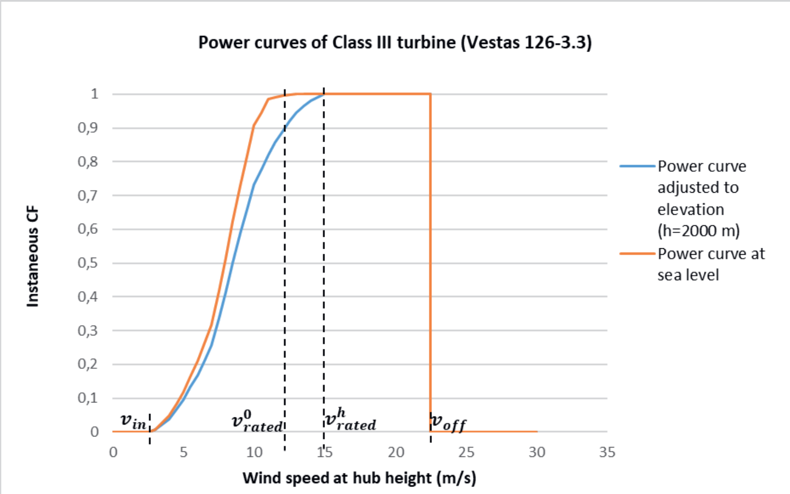


Figure 2.6. Power curves of Class III wind turbine at sea level and corrected for elevation

Source: Own elaboration

The mean (μ) and standard deviation (σ) of the 16-year (140256-hour) time series of hourly CF_h corrected for elevation were determined for each grid cell via:

$$
\mu = \frac{\sum_{t=1}^{140256} CF_{h,t}}{140256} \quad (13)
$$

$$
\sigma = \sqrt{\frac{\sum_{t=1}^{140256} \left(CF_{h,t} - \mu \right)^2}{140256}} \quad (14)
$$

2.2.2.2 Solar PV

Figure 2.7 shows a four-step approach to determine the hour CF time series for both utility-PV and rooftop PV.

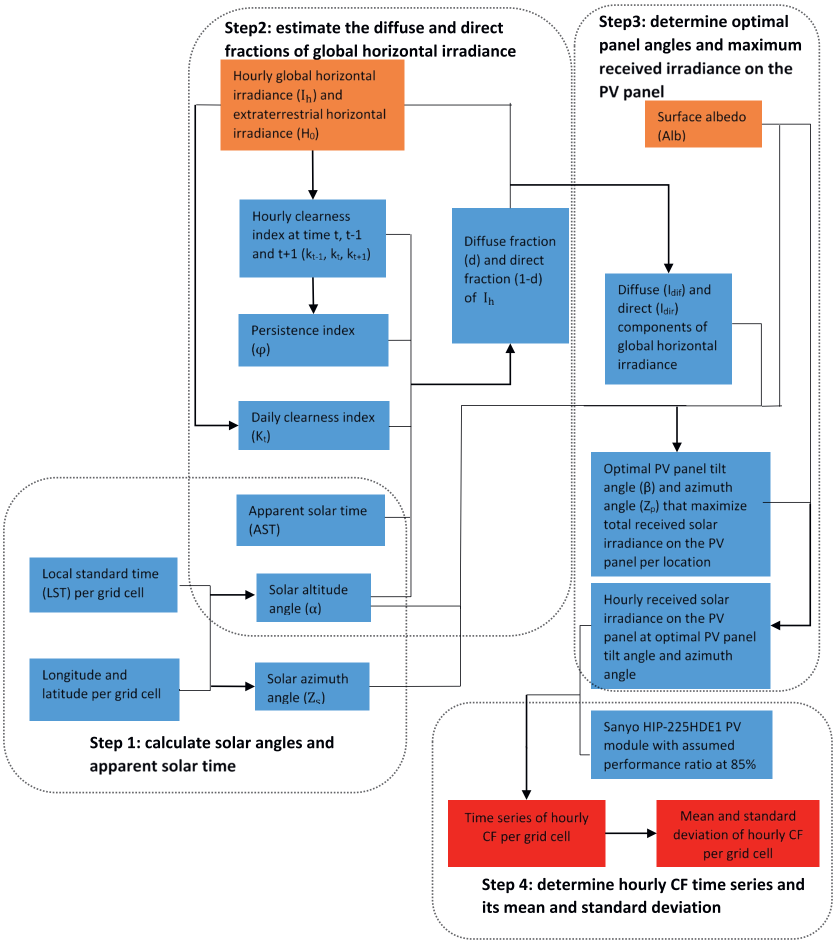


Figure 2.7. Method to determine the hourly CF time series for utility-PV and rooftop PV

Source: Own elaboration

- **Step 1: Calculate apparent solar time (AST) and solar angles**

AST and solar angles depend on local geographical coordinates (longitude and latitude) of each grid cell and the local standard time (LST). The LST is set as the middle point of each hour in the time series. For China, AST was calculated via

$$AST = LST + ET + 4\,(SL - LL) - DS\ [hour]\quad (15)$$

$$ET = 9.87 sin\,(2B) - 7.53 cos\,(B) - 1.5\ sin\,(B) [min]\quad (16)$$

$$B = \frac{(N-81)360}{364} \quad (17)$$

where ET is equation of time; SL is standard longitude; LL is local longitude; DS is day-light saving time (which is zero for China); N is the day number of the year (Kalogirou, 2009).

Although SL is normally the standard meridian (every multiple of 15°) for dividing standard time zones, China only has one official national standard time (China Standard Time) based on SL at 120°.

Solar altitude angle (α) and azimuth angle ([[OMML-EQ-95]]) were calculated through

$$sin\,(\alpha) = sin(L)sin(\delta) + cos(L)cos(\delta)cos(H) \quad (18)$$

$$\alpha = arcsin(\alpha) \quad (19)$$

$$\delta = 23.45 sin\left(\frac{360(284+N)}{365}\right) \quad (20)$$

$$H = (AST - 12)15 \quad (21)$$

$$\cos(Z_s) = \frac{\cos(\delta)(\cos(L)\tan(\delta) - \sin(L)\cos(H))}{\cos(\alpha)} \quad (22)$$

$$Z_s = \begin{cases} \arccos(Z_s), & if\, H < 0 \\ 360 - \arccos(Z_s), & if\, H > 0 \end{cases} \quad (23)$$

where L is local latitude; δ is declination angle; H is hour angle (Muneer et al., 2004; Kalogirou, 2009).

- **Step 2: Estimate the diffuse and direct fractions of global horizontal irradiance**

To determine the diffuse and direct components of hourly global horizontal irradiance, we used Boland–Ridley–Lauret (BRL) model to estimate the hourly diffuse fraction (df). The BRL model is multi-variable logistic model based on hourly global horizontal irradiance (I_h) and extraterrestrial horizontal irradiance (H_0)[8] (Ridley et al., 2010):

2

$$df = \frac{1}{1 + exp\left(-5.38 + 6.63\, k_t + 0.006 AST - 0.007\alpha + 1.75\, K_t + 1.31\, \varphi \right)} \quad (24)$$

$$k_t = \frac{I_{h,t}}{H_{0,t}} \quad (25)$$

$$K_t = \frac{\sum_{t=0}^{23} I_{h,t}}{\sum_{t=0}^{23} H_{0,t}} \quad (26)$$

$$\varphi = \begin{cases} \frac{1}{2}(k_{t-1} + k_{t+1}), & if \; t_{sunrise} < t < t_{sunset} \\ k_{t-1}, & if \; t = t_{sunrise} \\ k_{t+1}, & if \; t = t_{sunset} \end{cases} \quad (27)$$

where k_t, K_t and φ are respectively hourly clearness index, daily clearness index and persistence index.

The hourly diffuse ($I_{dif,h}$) and direct ($I_{dir,h}$) components of I_h are:

$$I_{dif,h} = df\, I_h \quad (28)$$

$$I_{dif,h} = (1 - df)\, I_h \quad (29)$$

8 Global horizontal irradiance and extraterrestrial horizontal irradiance sometimes are also referred to as “terrestrial horizontal irradiance” and “clear-sky horizontal irradiance”, respectively. The former refers to solar irradiance received on a horizontal plane on earth, while the latter refers to solar irradiance received outside the atmosphere.

- **Step 3: Determine optimal panel angles and maximum received irradiance on the PV panel**

The hourly total received irradiance on the PV panel (I_p) consists of direct ($I_{dir,p}$), diffuse ($I_{dif,p}$) and reflection ($I_{r,p}$) components:

$$I_p = I_{dir,p} + I_{dif,p} + I_{r,p} \quad (30)$$

Depending on the panel tilt angle (β) and azimuth angle (Z_p), the three irradiance components can be determined via:

$$I_{dir,p} = \frac{I_{dir,h}\cos(\theta)}{cos(90 - \alpha)} \quad (31)$$

$$cos(\theta) = sin(\alpha)cos(\beta) + cos(\alpha)sin(\beta)cos(Z_p - Z_s) \quad (32)$$

$$I_{dif,p} = \frac{1 + cos\beta}{2} I_{dif,h} \quad (33)$$

$$I_{r,p} = \frac{1 - cos\beta}{2}\left(I_{dir,h} + I_{dif,h}\right)Alb \quad (34)$$

where θ is incidence angle; Alb is surface albedo (Gulin et al., 2013).

Based on $I_{dif,h}$ and $I_{dir,h}$, we determined the optimal panel tilt angle (β) and azimuth angle (Z_p) to maximize the annual total irradiance received on the PV panel. The same optimal angles apply for both utility-PV and rooftop PV, since we assumed utility-PV and rooftop PV are mounted on a surface close to flat (ground with slope below 4° or flat roof). The optimization was performed on an annual basis for each grid cell. In the optimization process we filtered out irradiances associated with α smaller than 0.1 °, because very small α can drastically inflate the total received irradiance. The final angles adopted were calculated from the 16-year average value of the optimized angles, based on which we obtain the time series of hourly irradiance received on the PV panel.

- **Step 4. Determine hourly CF time series and its mean and standard deviation**

The power conversion performance of the selected Sanyo HIP-225HDE1 module is relatively less dependent on temperature (Litjens et al., 2017). Thus, we assumed a uniform performance ratio (PR) at 85% across all grid cells to correct for efficiency losses at non-standard test conditions. This value might seem optimistic, but can be considered realistic even today[9]. The hour CF was determined through

$$CF = \frac{I_p}{I_{STC}} PR \quad (35)$$

Where I_{STC} is solar irradiance under standard test conditions, which is 1000 W/m^2.

Note that within the same grid cell, both utility-PV and rooftop PV have identical 16-year time series profile of hourly CF since the same PV module and optimal panel angles were used. Consequently, we determined the mean (μ) and standard deviation (σ) of hourly CF time series per grid cell using formula (13) and (14).

2.2.3 Data processing task 3: Potentials-weighted average CF per VRE technology

Based on the 16-year mean CF characterized for each VRE technology per grid cell, we calculated the average CF (weighted by potentials per grid cell) for each VRE technology in China:

$$\overline{CF_j} = \sum_i \mu_{j,i} \frac{P_{j,i}}{P_j}, \quad j = onshore\ wind, offshore\ wind, utility\_PV, rooftop\ PV \quad (36)$$

where $\overline{CF_j}$ is the average CF for technology j in China; $\mu_{j,i}$ is the mean CF for technology j in grid cell i; $P_{j,i}$ is potentials for technology j in grid i; P_j is total potentials for technology j in China.

9 Reich et al. (2012) found that the median measured PR for 100 PV installations is ~84% in 2010. They further conclude that an above-90% PR is even realistic back in 2010 and it would be more common in the future.

2.2.4 Data processing task 4: LCOE per VRE asset

The LCOE for each VRE asset was calculated via:

$$\mathrm{LCOE}_k = \mathrm{LCOE}_{j,i} = \frac{a \cdot I_j + O\,\&\,M_j}{8760\,\mu_{j,i}}, \quad (37)$$

$$a = \frac{r}{1-(1+r)^{-L}} \quad (38)$$

where LCOE_k is LCOE for VRE asset *k* of technology *j* in grid cell *i*; I_j is capital costs and $O\,\&\,M_j$ is annual fixed operating and maintenance (O&M) costs for technology *j*; $\mu_{j,i}$ is the mean CF for technology *j* in grid cell *I*; r is the discount rate; *a* is the capital recovery factor.

We set r as the social discount rate at 4%. The unit capital costs and O&M costs for each VRE technology were adopted from the IEA World Energy Outlook's 450 ppm scenario projected for the year 2040 (see Table 2.5). We presumed these costs are constant until 2050[10].

Table 2.5. Unit costs assumptions for each VRE technology in 2050

VRE technology	Capital costs (USD_{2015}/kW)	Fixed O&M costs (USD_{2015}/kW)
Onshore wind	1160	30
Offshore wind	2450	100
Utility-PV	680	12
Rooftop PV	760	12

Source: IEA (2016)

Uniform cost parameters were assumed for onshore wind, utility-PV and rooftop PV across different grid cells. While for offshore wind we used scaling factors to take into account the impact of different average distances to shore and depths on capital costs. Figure 2.8 shows the capital costs scaling factors for offshore wind, where costs in Table 2.5 (2450 USD_{2015}/kW) were used as a reference case (with unity scaling factor).

10 Note this might lead to overestimated costs if the trend of technological learning continues.

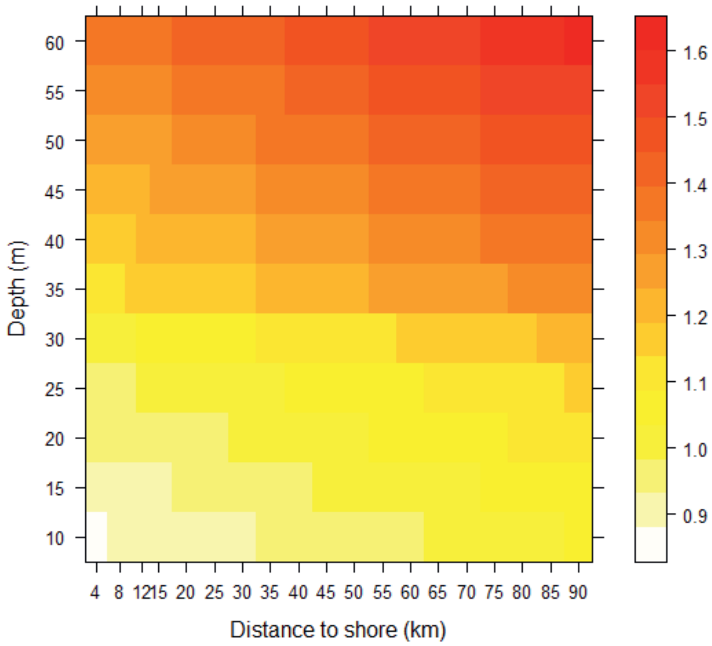


Figure 2.8. Capital costs scaling factors for offshore wind[11]

Source: developed and calibrated based on IEA (2016), Klinge Jacobsen et al. (2016), and Lensink (2016)

Consequently, we scaled up the capital costs for offshore wind in each grid cell:

$$I_{offshore,i} = 2450\, SF_i \quad (39)$$

where $I_{offshore,i}$ is the capital costs scaled up for offshore wind in grid cell *i* and SF_i is the scaling factor for grid cell *i*.

2.2.5 Data processing task 5: MPT optimization

Based on the hourly CF time series obtained for each VRE asset (see section 2.2.2), we calculated the covariance matrix (**cov**) between different VRE assets. VRE assets with zero potentials were excluded to save computation time. To avoid co-linearity issues (due to identical CF time series in the same grid cell), we combined utility-PV and rooftop PV as the same VRE technology, i.e. "solar". This resulted in 3439 VRE assets and a 3439× 3439 **cov**. We then performed the MPT optimization analysis for three 2050 scenarios of

11 Klinge Jacobsen et al. (2016) developed scaling factors for depth and distance to shore up to 35m and 25 km, respectively. We calibrated them to IEA's costs prediction to use the latter as reference case. For depth beyond 35 m, we assumed the scaling factors are mainly driven by costs increase of the jacket, the most cost-effective turbine foundation. Based on ECN's foundation costs model (Lensink, 2016) in relation to depth, we extended the scaling factors to depths up to 60 m. For distance to shore between 25 km and 90 km, we used linear extrapolation to develop the scaling factors.

high renewables in China to obtain the efficient frontier. These are the 1.5 °C Scenario, based on China' official Integrated Policy Assessment Model (IPAC) (Jiang et al., 2018), Greenpeace's Energy Revolution scenario (Greenpeace, Global Wind Energy Council and SolarPower Europe, 2015) and World Wildlife Fund (WWF)'s High Renewables scenario (WWF, 2014; 2015). Key statistics of the three scenarios are presented in Table 2.6.

Table 2.6. Key statistics of three high renewables scenarios for China in 2050

Scenario		IPAC 1.5 °C Scenario[a]	Greenpeace Energy Revolution Scenario[b]	WWF High Renewables Scenario[c]
Renewables penetration in demand (%)		59*	88	88
VRE penetration in demand (%)		38*	55	62
Total installed VRE capacity (GW)		3732	2413	3210
Installed wind (GW)		1486	1181	1710
Of which	Onshore wind (GW)	NA	972	1455
	Offshore wind (GW)	NA	209	255
Installed Solar (GW)		2246	1232	1500
Share of wind in total installed VRE capacity (%)		40	49	53
Of which	Onshore wind (%)	NA	40	45
	Offshore wind (%)	NA	9	8
Share of solar PV in total installed VRE capacity (%)		60	51	47

* In absence of demand data, VRE penetration was calculated based on electricity generation

Source: a) Jiang et al. (2018); b) Greenpeace, Global Wind Energy Council (GWEC) and SolarPower Europe (2015); c) WWF (2014 ;2015)

Then we performed the MPT optimization. We used the total installed VRE capacity prescribed by the three scenarios as sole budget constraints in the optimization to obtain the efficient frontier for wind-only portfolios, solar-only portfolios, and wind & solar portfolios with unconstrained shares of each VRE technology. The resulting portfolios are referred to as **portfolios with unconstrained shares.** After that, the optimization was performed again to obtain the efficient frontier for wind & solar portfolios with constrained shares of each VRE technology, as prescribed by the three scenarios. They are referred to as **portfolios with constrained shares**.

The MPT optimization aims to minimize the portfolio volatility (mimicked by the standard deviation of portfolio CF) for each portfolio return (mimicked by the mean portfolio CF). The portfolio return (μ_p) and volatility (σ_p) can be calculated as follows:

$$\mu_P = \sum_k \omega_k \mu_k = \boldsymbol{\mu}^\mathbf{T} \boldsymbol{\omega} \quad (40)$$

$$\sigma_P^2 = \sum_k \sum_m \omega_k \omega_m \, cov_{k,m} = \boldsymbol{\omega}^\mathbf{T} \mathbf{cov} \boldsymbol{\omega} \quad (41)$$

Where ω_k is contributing weight per VRE asset *k* (share of VRE asset k in total portfolio capacity); μ_k is 16-year mean CF for VRE asset *k* (see section 2.2.2); $cov_{k,m}$ is the CF covariance between assets *k* and *m*; $\boldsymbol{\mu}^\mathbf{T}$ is the transpose vector of mean CF; $\boldsymbol{\omega}^\mathbf{T}$ and $\boldsymbol{\omega}$ are respectively the transpose vector and vector of contributing weight; **cov** is the covariance matrix.

We formulated the MPT optimization as a constrained programming problem, based on the copperplate assumption. Thus, transmission constraints in terms of existing or planned transmission grids were not factored into the optimization. The optimization followed three steps. Firstly, we identified the maximum return portfolio (referred to as **maxret portfolio**) positioned on the efficient frontier through linear programming:

$$\max_{\omega_k} \mu_P$$

$$\text{subject to: } \begin{cases} \sum_k \omega_k = 1 \\ \omega_k \le \frac{P_k}{C} \\ \sum_{k \in j} \omega_k = \frac{C_j}{C} \quad \left(\textit{constrained shares}\right) \end{cases} \quad (42)$$

Where C is total installed VRE capacity.

It is subject to two constraints: the sum of the contributing weights of all VRE assets is equal to one, and the contributing weights of VRE asset *k* must not exceed its potentials' share in total installed VRE capacity ($\frac{P_k}{C}$). Note that the medium potentials for onshore wind and offshore wind assets (see section 2.2.1.2) were used to formulate the constraint. For portfolios with constrained shares, the sum of the contributing weights of assets belonging to technology *j* must equal the required share of technology *j* in total installed capacity ($\frac{C_j}{C}$).

Secondly, we found the minimum volatility portfolio (referred to as **minvol portfolio**) along the efficient frontier based on quadratic programming (using the same constraints as in the linear programming formulated before).

$$\min_{\omega_k} \sigma_P^2$$

$$\text{subject to:} \begin{cases} \sum_k \omega_k = 1 \\ \omega_k \le \frac{P_k}{C} \\ \sum_{k \in j} \omega_k = \frac{C_j}{C} \ (\textit{constrained shares}) \end{cases} \quad (43)$$

Lastly, based on returns associated with the minvol portfolio and maxret portfolio, we divided the return range in between into 50 equal-distanced return points. We then performed the quadratic programming again to minimize the volatility for each of these return points. This naturally depicted the entire efficient frontier.

2.2.6 Post-processing task 1: Spatial distribution of contributing weights for selected portfolios

To enable comparison, we analysed the spatial distribution of contributing weights for the minvol portfolio, the portfolio with minimum coefficient of variation (CV)[12] (referred to as **minCV portfolio**), and the maxret portflio positioned on the efficient frontier. The analysis was performed for both portfolios with unconstrained and constrained technology shares (see section 2.2.5)

2.2.7 Post-Processing task 2: Portfolio share per VRE technology

Based on contributing weights of each VRE asset, we calculated the portfolio share per VRE technology for wind & solar portfolios with unconstrained technology shares (where the total installed VRE capacity serves as the sole budget constraint):

$$\omega_j = \sum_{k \in j} \omega_k \quad (44)$$

We compared the portfolio share per VRE technology between different scenarios. We also assessed the difference between the calculated unconstrained shares and the predefined constrained technology shares.

12 CV is the ratio between portfolio volatility and portfolio return. Therefore, the minimum CV portfolio is the point with the highest slope along the efficient frontier. This is referred to as the maximum Sharpe ratio portfolio in Shahriari and Blumsack (2018).

2.2.8 Post-Processing task 3: Portfolio LCOE

We calculated the portfolio LCOE via

$$\mathrm{LCOE}_{p} = \frac{\sum_{k} LCOE_{k}\, \omega_{k} \mu_{k}}{\mu_{p}} \quad (45)$$

Where LCOE_p is the portfolio LCOE; $LCOE_k$ (see section 2.2.4), ω_k and μ_k are respectively the LCOE, contributing weight and mean CF of VRE asset k; μ_p is the portfolio return.

Since we combined utility-PV and rooftop PV as solar, the LCOE associated with each solar asset was calculated as the average LCOE weighted by the potentials of utility-PV and rooftop PV in the same grid cell.

2.2.9 Post-Processing task 4: Portfolio CF duration curve and CF-at-risk

Based on contributing weights and the CF time series of each VRE asset (see section 2.2.2), we determined the 16-year time series of the portfolio hourly CF:

$$\mathrm{CF}_{p,t} = \sum_{k} \omega_{k}\, CF_{k,t} \quad (46)$$

Following Shahriari and Blumsack (2018), we plotted the long-time duration curve of portfolio CF in relation to its availability (i.e. percentage of time), based on the 16-year time series of hourly portfolio CF. From the portfolio CF duration curve, we obtained the long-time CF-at-risk at 100% and 90% availability of time (denoted respectively as $\mathbf{CF_{100\%}}$ and $\mathbf{CF_{90\%}}$). These values represent the minimum CF that is available 100% and 90% of time[13]. After that, we determined the portfolios with the highest long-time $CF_{100\%}$ and $CF_{90\%}$ (referred to as **maxCF$_{100\%}$ portfolio** and **maxCF$_{90\%}$ portfolio**) positioned on the efficient frontier. To investigate the inter-annual variation of $CF_{100\%}$ and $CF_{90\%}$, we plotted the distribution of annual $CF_{100\%}$ and $CF_{90\%}$ for these portfolios together with the minvol portfolio, minCV portfolio and maxret portfolio. The sample data for the distribution were obtained from the annual CF duration curve of each individual year.

13 90% is assumed to reflect the availability of coal-fired plants, the pre-dominant power generation technology now in China (Miao, 2015). Therefore $CF_{90\%}$ can be interpreted as the minimum CF provided by the VRE portfolios if they are used to replace coal.

2.3 RESULTS

2.3.1 Geographical potentials

2.3.1.1 Geographical potentials per VRE asset

Geographical potentials per VRE asset and their spatial distribution in China are shown in Figure 2.9. Three cases are included (high, medium and low potentials, see section 2.2.1.2) for onshore and offshore wind. As the figure shows, in all three cases, the geographical potentials for onshore wind are concentrated in North (including inner-Mongolia) and Northeast China. This is explained by the geographical constraints applied in the analysis. The exclusion of the 10 km distance from dense urban areas, in the medium case mainly reduces the onshore wind potentials in Northeast China compared to the high case, whereas the potentials in the low case are more evenly reduced over the grid cells by the use of low suitability factors. As for solar, its potentials are spread extensively over China except for Tibet, north Inner-Mongolia and the north of Northeast China due to the exclusion of sloped and permafrost areas. In particular, North and Northwest China have the largest geographical potentials for solar.

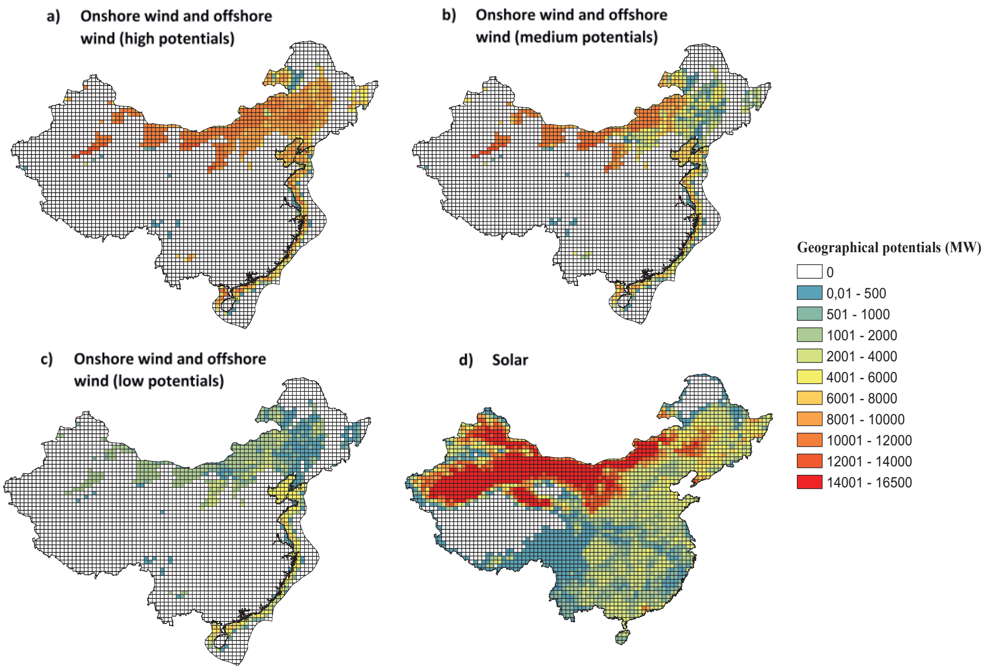


Figure 2.9. Spatial distribution of geographical potentials per VRE asset in China (*zoom in for details*)

Source: Based on own analysis

2.3.1.2 Total potentials per VRE technology

Total potentials for each VRE technology are presented in Table 2.7. China has huge potentials for solar, being 1.6 times larger than the high potentials case of onshore wind. The potential of offshore wind is relatively limited, also in the high potential case. The latter is explained by the relatively small sea area meeting the constraints of depth ≤ 60 m and distance to share ≤ 90 km. We consider the medium case for onshore and offshore wind as a reasonable estimate. If not specified, the results presented in the following sections are based on the medium potential case. For information purposes only, we also show the total potential annual electricity generation (in TWh) for each technology[14] in Table 2.7. The calculation was based on the total potentials and the potential-weighted average CF (see section 2.3.3).

Table 2.7. Total potentials (in GW installed capacity) and potential annual electricity generation (in TWh) per VRE technology in China

Technology	Onshore wind			Offshore wind			Solar			Total		
Geographical potentials (GW)	High	Medium	Low	High	Medium	Low	Total	Utility-PV	Rooftop PV	High	Medium	Low
	4909	3176	575	932	745	559	12936	12576	360	18777	16857	14070
Potential annual electricity generation (TWh)	15094	9654	1783	2776	2219	1665	23570	23025	580	41440	35443	27018

Source: Based on own analysis

2.3.2 Mean CF per VRE asset

Figure 2.10 illustrates the mean CF per VRE asset in China. It shows that the assets with highest CF for onshore and offshore wind are located respectively in east Inner-Mongolia and the Taiwan Strait, where the mean CF can be above 40%. For solar, the best performing areas come from North and Southwest China, whereas South and East China have the lowest mean CF.

14 For comparison, the average electricity consumption of China in 2018 is 6840 TWh (China Electricity Council, 2019).

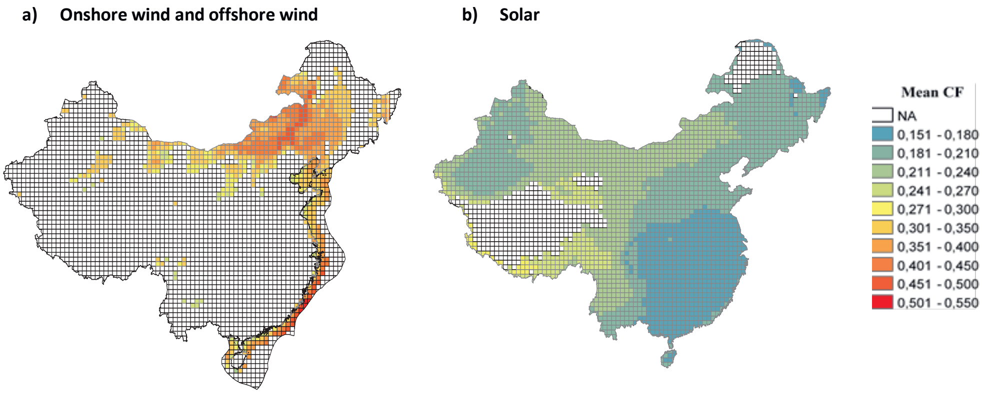


Figure 2.10. Spatial distribution of mean CF per VRE asset in China

Source: Based on own analysis

2.3.3 Potential-weighted average CF per VRE technology

The potential-weighted average CF for each technology is shown in Table 2.8. To enable comparison, we also give the minimum and maximum mean CF of individual asset. The average CF for onshore wind in China is 0.347, which is comparable to the global average CF from operating wind projects in 2017 (BNEF, 2018). Offshore wind has an almost identical average CF to onshore wind. This can be explained by the superior performance and abundant potentials of onshore wind located in Inner-Mongolia. By contrast, the potentials of best-performing offshore wind (around the Taiwan Strait) are relatively small, meaning that the average CF is dominated by less performing offshore wind assets. The average CF for utility-PV is slightly higher (~2 percentage point) than that for rooftop PV.

Table 2.8. Potential-weighted average CF for each technology

Technology		Potential-weighted average CF	Min mean CF of individual asset	Max mean CF of individual asset
Onshore wind	High	0.351	0.241	0.535
	Medium	0.347		
	Low	0.354		
Offshore wind	High	0.340	0.235	0.537
	Medium	0.340		
	Low	0.340		
Solar		0.208	0.158	0.278
Of which	Utility-PV	0.209		
	Rooftop PV	0.184		

Source: Based on own analysis

2.3.4 LCOE per VRE asset

The scatter plot of LCOE for each VRE asset (against its potentials in log scale) is illustrated in Figure 2.11. It shows that the LCOE of onshore wind is slightly lower (between 25-45 USD_{2015}/MWh) than that of solar (between 25-55 USD_{2015}/MWh). By contrast, the LCOE for offshore wind varies widely between assets located in different grid cells, ranging between 63-145 USD_{2015}/MWh. The range in LCOE can be explained by the spatial distribution of LCOE for VRE assets (see Figure 2.12). East Inner-Mongolia (onshore wind) and the Taiwan Strait (offshore wind) show the lowest LCOE, whereas the lowest LCOE for solar is in North and Southwest China. This outcome is consistent with the spatial distribution of the mean CF (see section 2.3.2).

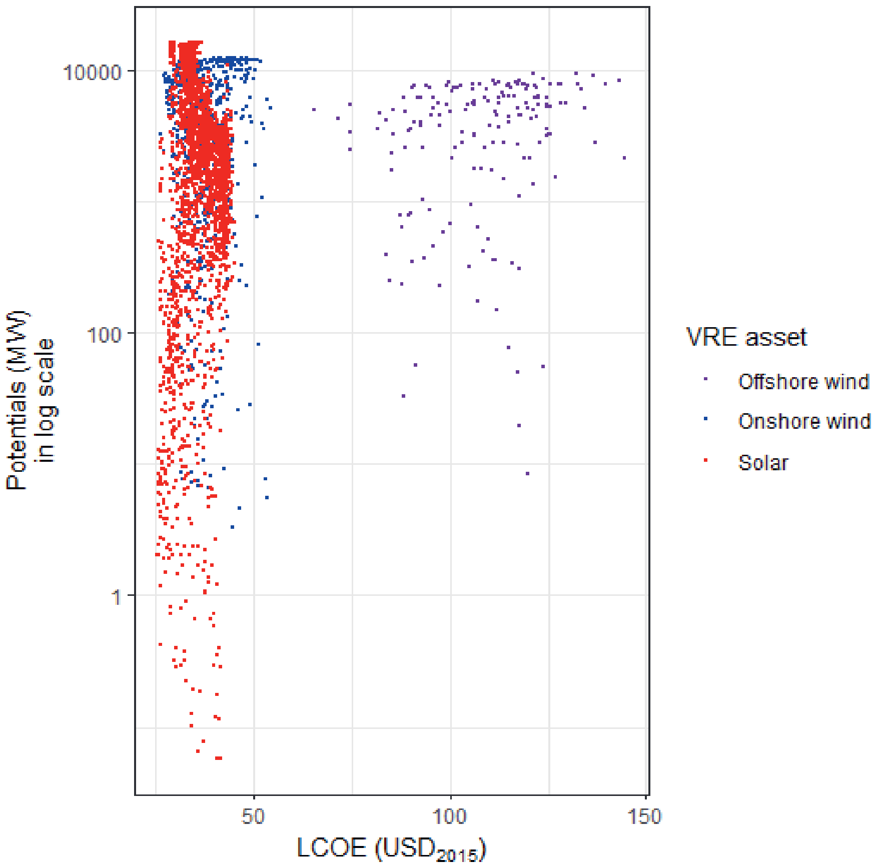


Figure 2.11. Scatter plot of LCOE against potentials (in log scale) for each VRE asset (in medium case)

Source: Based on own analysis

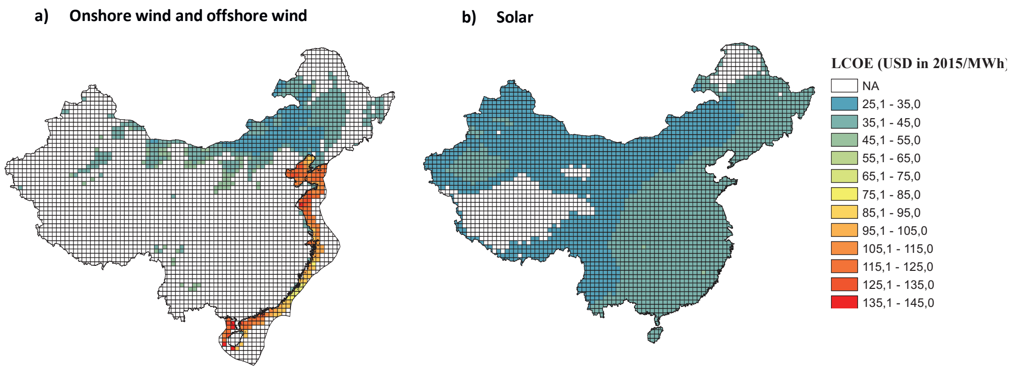


Figure 2.12. Spatial distribution of LCOE per VRE asset in China (in medium case)

Source: Based on own analysis

2.3.5 Efficient frontiers

Efficient frontiers generated from the MPT optimization are presented in Figure 2.13. The three scenarios with different budgets of installed VRE capacity are indicated by different line types, while different colours are used to represent different portfolio types (wind-only, solar-only, wind & solar and wind & solar with constrained technology shares) within these scenarios. For comparison, we also show the return-volatility performance of individual VRE assets[15] (the dots in the figure). Both solar, onshore wind and offshore wind follow a clear tendency ("the higher the return, the higher the volatility"), although heteroscedasticity (unequal scatter) can be observed. The efficient frontiers for wind-only and solar-only portfolios demonstrate better return-volatility performance than individual wind and solar assets. Solar-only portfolios exhibit lower return but higher volatility than wind portfolios, mainly because of the diurnal pattern of solar generation. However, when solar assets mix with wind assets with unconstrained technology shares, their combined portfolios (the red lines) show the best return-volatility performance. Within the same scenario, not only does the wind & solar frontier cover a broader return range, but it shows a smaller volatility level at each attainable return level than the wind-only and solar-only frontiers. This finding is in agreement with Shahriari and Blumsack (2018). However, inferior return-volatility performance is observed for wind & solar portfolios with constrained technology shares (the green, orange and grey lines). For the same portfolio type (e.g. wind & solar), the efficient frontier within scenarios facing a higher capacity budget (e.g. 3732 GW within IPAC versus 2421 GW within Greenpeace) tends to show lower return-volatility performance, because more assets with inferior performance are needed.

15 Note not all VRE assets are included in optimal portfolios positioned on the efficient frontier. The selection of certain VRE assets in optimal portfolios is a result of the optimization. In general, for the same portfolio type, more assets are included in efficient frontiers facing a higher capacity budget.

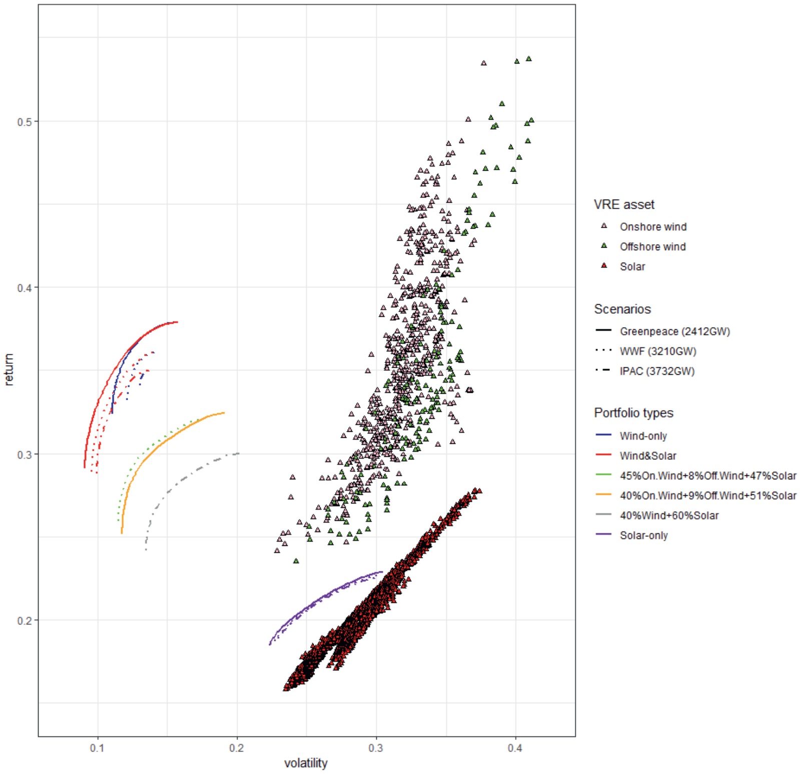


Figure 2.13. Efficient frontier for portfolios with unconstrained and constrained technology shares

Source: Based on own analysis

2.3.6 Spatial distribution of contributing weights

Using the IPAC scenario, for example, we present the spatial distribution of contributing weights for the minvol (the minimum volatility), minCV (the minimum coefficient of variation) and maxret (the maximum return) portfolios positioned on the efficient frontier of wind & solar and wind & solar with constrained technology shares respectively in Figure 2.14 and 2.15. The minvol, minCV and maxret portfolios sit on the bottom-left, steepest and top-right points of the efficient frontier, respectively.

In the minvol wind & solar portfolio with unconstrained technology shares (Figure 2.14), onshore wind is mainly located in east Inner-Mongolia, Northeast, Northwest and North China, while solar is mainly located in Northeast, Northwest and East China. This shows the strong negative correlation between the power outputs of wind and solar assets in these regions. As portfolio return increases, solar assets are gradually replaced by wind assets due to the higher mean CF of the latter. This is true in the case of the minCV wind & solar portfolio, where solar assets in East China (with lowest mean CF) are mainly replaced by increased onshore wind assets in North China. As for the maxret wind & solar portfolio, contributing weights of onshore wind in North China reach the maximum. Solar assets nearly disappear, except for a few grid cells with very limited contributing weights in South Tibet. This is because solar assets in these grid cells have a higher mean CF than unused wind assets to meet the required capacity budget. Across all three portfolios the contribution of offshore wind along the entire coastline of China and onshore wind in east Inner-Mongolia remains nearly constant, meaning these assets may have the best return-volatility performance.

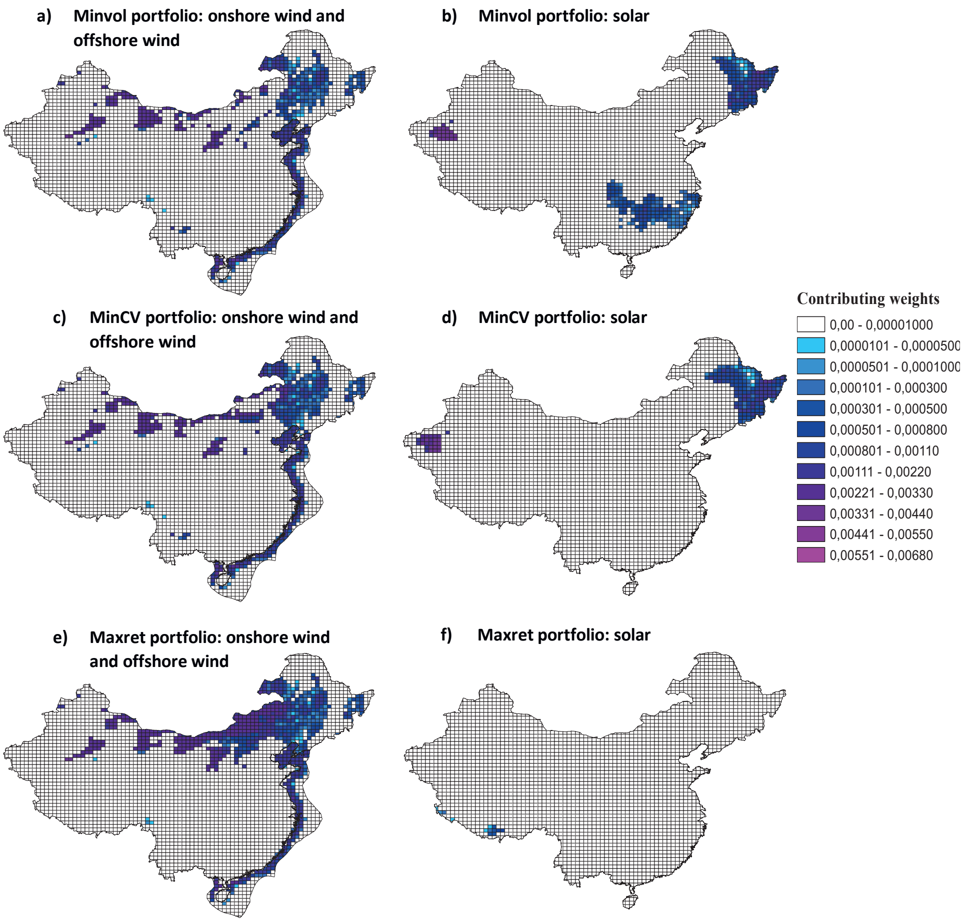


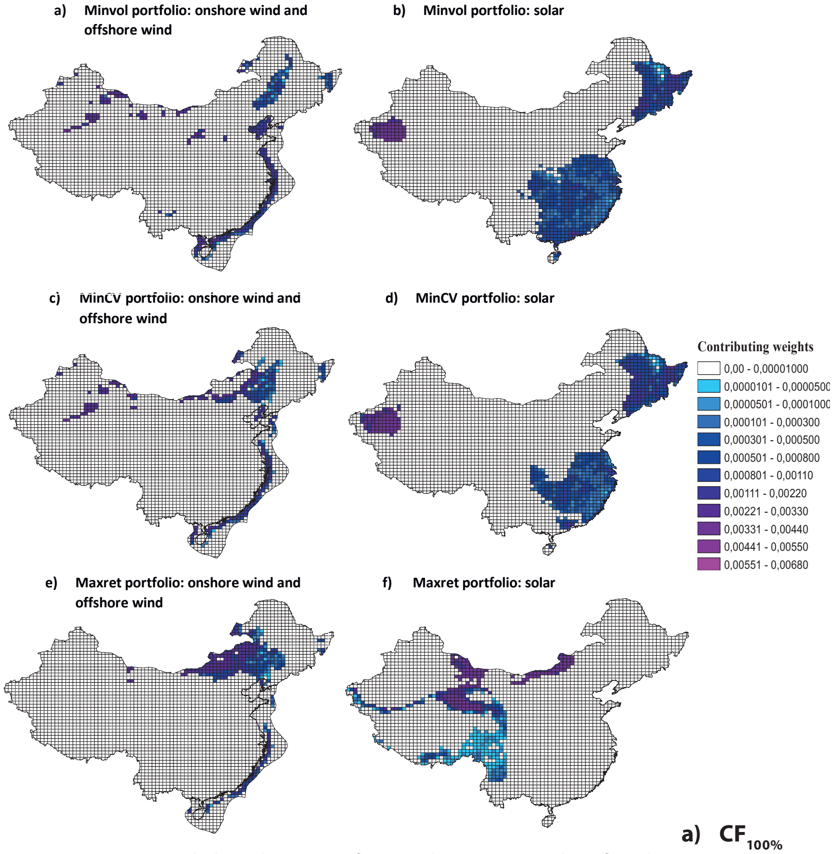
Figure 2.14. Spatial distribution of contributing weights for the minvol, minCV and maxret wind & solar portfolios

Source: Based on own analysis

The case of wind & solar with constrained technology shares (40% wind + 60% solar) clearly shows differing patterns of spatial distribution from wind & solar (see Figure

2.15). Onshore wind assets are initially sporadically dispersed in east Inner-Mongolia, Northeast, Northwest and North China in the minvol portfolio, but they become increasingly concentrated in east Inner-Mongolia as the portfolio return increases (minvol versus minCV and maxret). Meanwhile, the coverage of offshore wind assets reduces gradually on the northern Chinese coastline. This leaves onshore and offshore wind assets with the highest mean CF in the maxret portfolio. As for solar assets, their contributing weights in the Northeast and the west of Northwest China increase from the minvol portfolio to the minCV portfolio, at the expense of decreased contributing weights in Southeast China. However, solar assets in these areas disappear in the maxret portfolio. Instead, they have a fairly large coverage in Inner-Mongolia, Southeast and the east of Northeast China.

The different spatial distributions of VRE assets explain the relatively better return-volatility performance of wind & solar portfolios with unconstrained technology shares compared with wind & solar portfolios with constrained technology shares. The latter has a greater degree of freedom to select the best VRE assets. Therefore, scenarios with predefined technology shares in existing literature might be sub-optimal in terms of return-volatility performance.



a) $CF_{100\%}$

Figure 2.15. Spatial distribution of contributing weights for the minvol, minCV and maxret wind & solar portfolios with constrained technology shares

Source: Based on own analysis

2.3.7 Portfolio share per VRE technology

Figure 2.16 illustrates the share of each VRE technology against the portfolio return for the wind & solar portfolio within the three different scenarios. Two key results are observed. Firstly, within all scenarios, solar is gradually replaced by onshore wind from the minvol portfolio (leftmost point) to the maxret portfolio (rightmost point), as the portfolio return increases[16] (and with it the portfolio volatility). Onshore wind (with a share above 50%) dominates all portfolios, but it faces a ceiling at 82%, even in the maxret scenario. The maximum solar share (23-28 %) is observed in the minvol portfolio, and it decreases to close-to-zero in the maxret portfolio. This again confirms the relatively sub-optimal

16 To avoid misinterpretation, the authors stress that a portfolio with higher return is by no means better than a portfolio with lower return positioned on the same efficient frontier because the higher return portfolio also entails higher volatility. Both portfolios are efficient in terms of the return-volatility trade-off.

return-volatility performance of wind & solar portfolios with constrained technology shares (see Figure 2.13). Secondly, the share of offshore wind is almost constant at 20% (±2%), except for the Greenpeace scenario having the lowest capacity budget. This may suggest a low correlation between the power output of offshore wind and other VRE technologies. The share of offshore wind within the Greenpeace scenario decreases from initially ~25% in the minvol portfolio, to ~20% in the maxret portfolio. Since the low capacity budget of the scenario (2412 GW) is easy to meet, offshore wind is replaced by extra onshore wind assets with better mean CF.

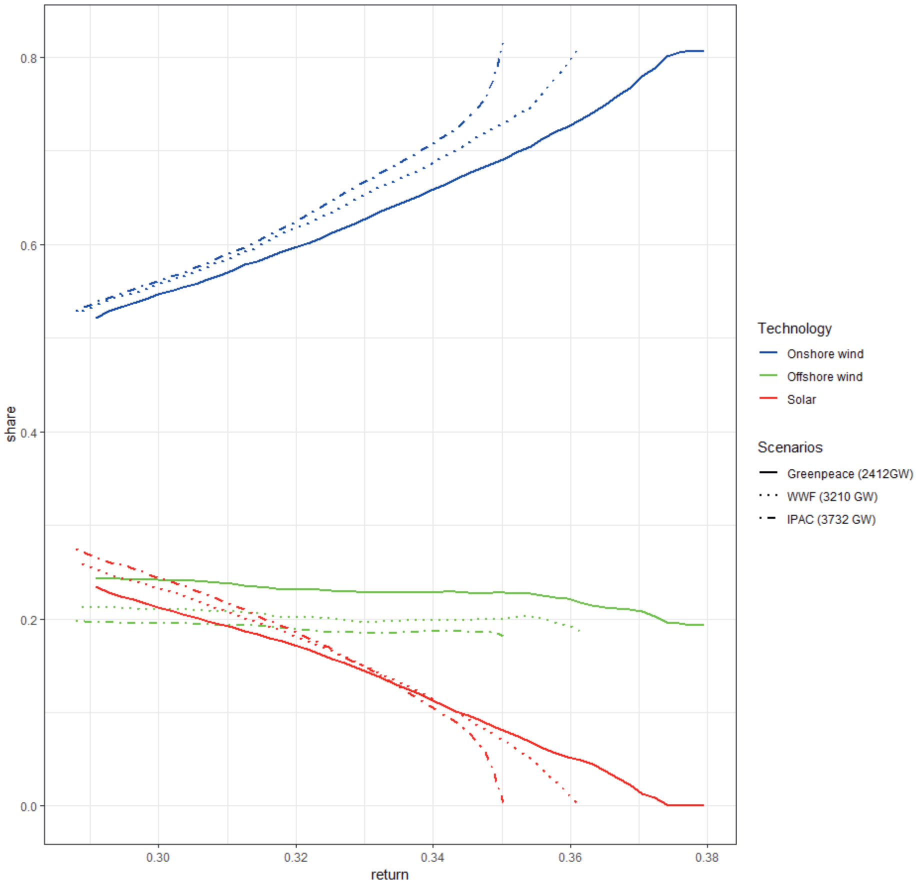


Figure 2.16. Portfolio share per VRE technology for wind & solar portfolios within different scenarios

Source: Based on own analysis

2.3.8 Portfolio LCOE

We present the portfolio LCOE against the portfolio volatility[17] for multiple portfolio types within different scenarios in Figure 2.17. On the one hand, within the same scenario, portfolio types with higher solar share (solar-only, wind &solar with constrained technology shares versus wind & solar, wind-only) tends to show lower portfolio LCOE, because of low LCOE of solar assets. On the other hand, the portfolio LCOE generally decreases with increased portfolio volatility (and thus increased portfolio return) along the efficient frontier. Highest and lowest portfolio LCOE are respectively observed in the minvol (most left point) and maxret (most right point) portfolio. This might seem counter-intuitive, as the portfolio share of solar (with low LCOE) decreases along the efficient frontier. The explanation is that low-CF assets are replaced by high-CF assets at the same time, dominating the overall decreasing trend of LCOE. In addition, it should be stressed that LCOE only covers the *production* costs of VRE, which exclude the integration costs of VRE imposed on the power system (Ueckerdt et al., 2013).

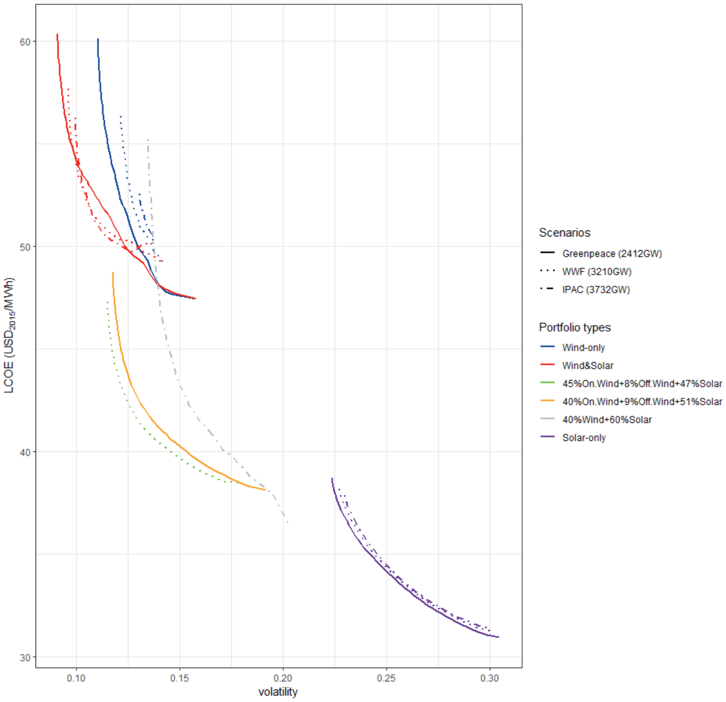


Figure 2.17. Portfolio LCOE for multiple portfolio types within different scenarios

Source: Based on own analysis

17 The reason to plot the portfolio LCOE against the portfolio volatility (instead of portfolio return) is for the best visualization. If we plot the portfolio LCOE against the portfolio return, the curves seem to stack together. The key message of the graph does not depend on choosing volatility or return as the x-axis value, since the same trend is followed.

2.3.9 Portfolio CF duration curve and CF-at-risk

Using the IPAC scenario as an example, figure 2.18 presents the long-time portfolio CF duration curve based on the 16-year CF time series for the minvol, minCV and maxret portfolios positioned on the efficient frontier of wind & solar and wind & solar with constrained technology shares. Note that the portfolio return is represented by the area underneath the duration curve. For either wind & solar or wind & solar with constrained shares, the areas underneath the curve is largest for the maxret portfolio and lowest for the minret portfolio. By contrast, the overall steepness of CF duration curve (in terms of the slope of the linear fit of the curve) is lowest for the minvol portolio, then the minCV portfolio and maxret portfolio. Therefore, the minvol portfolio may be preferable to support power system operation due to its most stable power output. In addition, the CF duration curve of portfolios positioned on the wind & solar frontier with unconstrained technology shares tends to be less steep than the same portfolio positioned on the frontier of wind & solar with constrained technology shares. This implies that scenarios with pre-defined shares of various VRE technologies might be sub-optimal for supporting system operation.

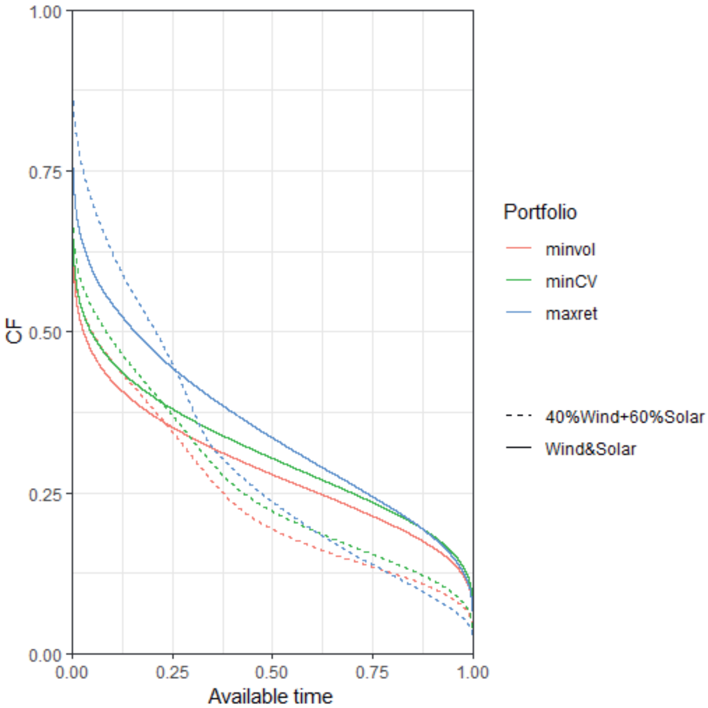


Figure 2.18. Long-time portfolio CF duration curve for Wind & Solar and Wind & Solar with constrained technology shares within the IPAC scenario

Source: Based on own analysis

The long-time CF-at-risk values can be obtained from the CF duration curve. For instance, here the $CF_{100\%}$ (available time 1.00) for the minvol, minCV and maxret wind & solar portfolios are respectively 0.049, 0.052 and 0. 044. This suggests that the portfolios with the highest CF-at-risk values are not necessarily the minvol portfolio, i.e. the tail risk should not be confused with volatility (Taleb, 2010).

To better understand the behaviour of the long-time $CF_{100\%}$ and $CF_{90\%}$ along the efficiency frontier of multiple portfolio types within the three different scenarios, Figure 2.19 was constructed. Note that the solar-only portfolio type is excluded because its $CF_{100\%}$ and $CF_{90\%}$ are zero due to the diurnal pattern of solar power output. It clearly shows that, in case portfolio return increases from the minvol to the maxret portfolio, the $CF_{90\%}$ first increases to a maximum value[18] and then decreases. It seems a similar tendency also exists for the $CF_{100\%}$, but it is less distinguishable due to the presence of noises. A possible explanation for these might be that it is difficult for the $CF_{100\%}$ to exhibit statistical significance as it is the most extreme value of the long-time time series of portfolio CF. We also observe that within the same scenario, both $CF_{90\%}$ and $CF_{100\%}$ are highest for the wind & solar portfolios with unconstrained technology shares, then for wind-only portfolios and lowest for the wind & solar portfolios with constrained technology shares. This reflects the benefit of diversification under the lowest constraints.

18 Note the portfolios associated with the maximum CF100% and CF90% along the efficient frontier are respective the maxCF100% portfolio and maxCF90% portfolio.

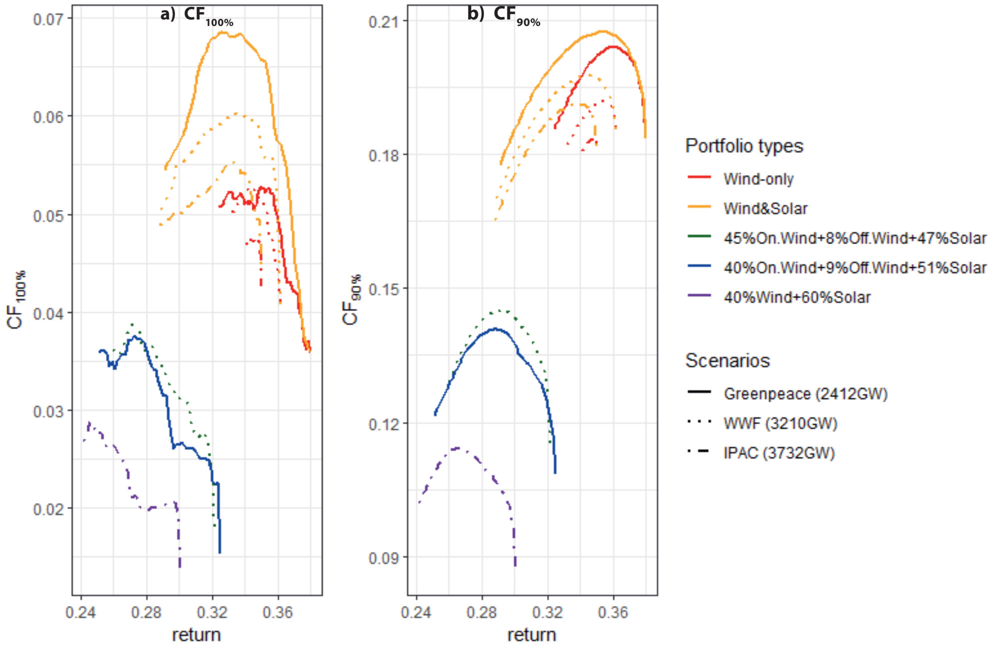


Figure 2.19. $CF_{100\%}$ and $CF_{90\%}$ of multiple portfolio types within different scenarios

Source: Based on own analysis

Next to the long-time $CF_{100\%}$ and $CF_{90\%}$, we also analysed the distribution of annual $CF_{100\%}$ and $CF_{90\%}$ obtained from the annual CF duration curve to investigate the inter-annual variation. Using the portfolio type of wind & solar and wind & solar with constrained technology shares within the IPAC scenario as an example, we present the distribution of annual $CF_{100\%}$ and $CF_{90\%}$ for five selected portfolios (minvol, minCV, maxret, max$CF_{100\%}$ and max$CF_{90\%}$) positioned on the efficient frontier in Figure 2.20. To serve as a benchmark, the long-time values of $CF_{100\%}$ and $CF_{90\%}$ (indicated by the red point) are also shown. The spread and thickness of the distribution curve respectively represent the inter-annual variation and probability density of the sampled annual $CF_{100\%}$ and $CF_{90\%}$. We find that, firstly, the distribution of $CF_{100\%}$ is nearly symmetrical, and the long-time $CF_{100\%}$ is the lowest value of the annual $CF_{100\%}$. By contrast, the $CF_{90\%}$ is negatively skewed (and therefore has more downside tail risks), and the long-time $CF_{90\%}$ nearly coincides with the median $CF_{90\%}$. Secondly, the portfolio $CF_{100\%}$ is rather small and never exceeds 10%, whereas the portfolio $CF_{90\%}$ is 2-3 times the size of $CF_{100\%}$. Since 90% is the availability of coal-fired plants, the $CF_{90\%}$ can be grossly interpreted as the percentage of the capacity of coal that can be replaced by the VRE portfolio. However, the long spread of the sample distribution also suggests that the inter-annual variation of $CF_{100\%}$ and $CF_{90\%}$ can be large, and hence cannot be ignored. Therefore, caution should be given when using the long-time and annual $CF_{100\%}$ and $CF_{90\%}$

to support the operation of a future power system[19]. In addition, we also observe that the distribution spread of $CF_{100\%}$ and $CF_{90\%}$ for wind & solar with unconstrained technology shares is higher than that for wind & solar with constrained technology shares. This might be explained by the smaller inter-annual variation of solar power output (having higher shares in the constrained portfolios) in comparison with wind.

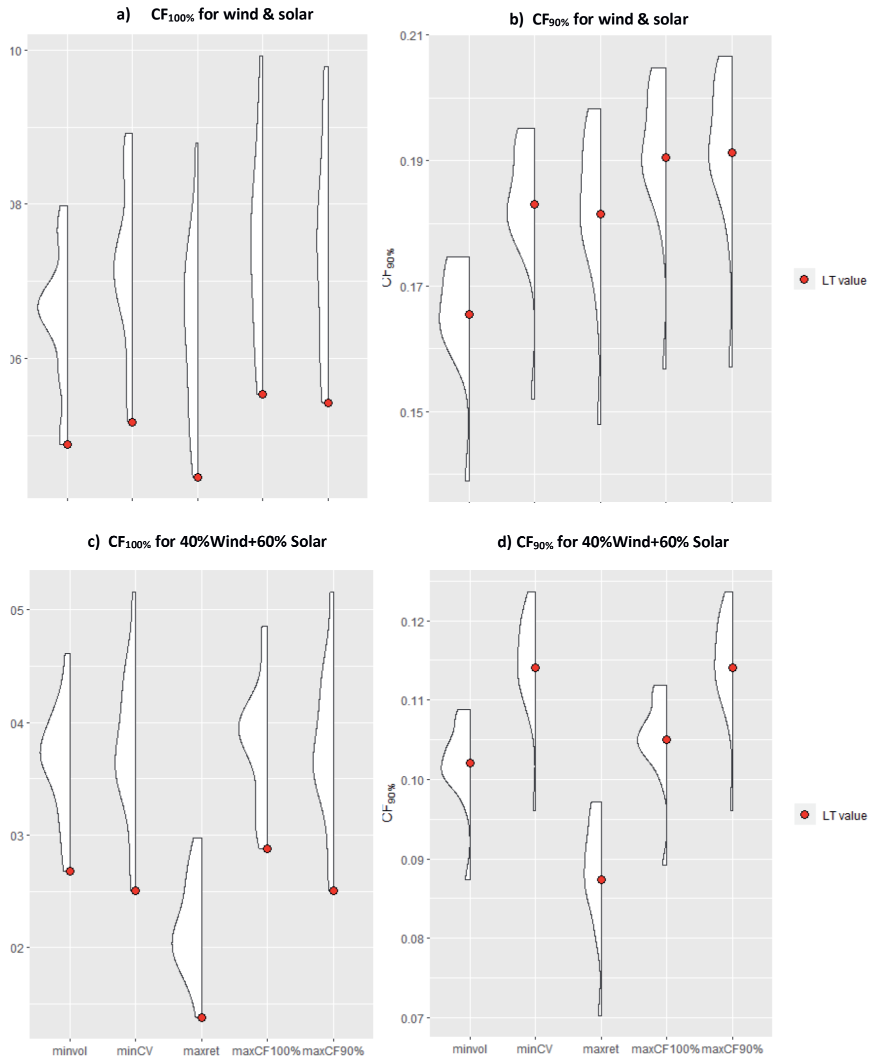


Figure 2.20. Distribution of annual $CF_{100\%}$ and $CF_{90\%}$ for wind & solar and wind & solar with constrained technology shares within the IPAC scenario

Source: Based on own analysis

19 Nevertheless, if the data sample is large enough, the extreme value theory can be used to fit the sample distribution to a generalized extreme value distribution. This can be used to forecast the probability associated with more extreme future CF-at-risk values.

2.4 DISCUSSION

Due to the scope, assumptions and data inputs of this study, a few limitations and uncertainties exist.

- The scope of this paper is limited to the geographical smoothing effect of portfolio volatility for each possible return level. We do not explicitly consider the geographical smoothing of portfolio output ramps and portfolio output forecast errors, which can also be investigated through MPT. This means that the optimum portfolios identified here may be different when these factors are considered, and more specifically the balance between wind and solar assets. However, we expect the difference to be small because of the benefits of diversification.

- Hourly meteorological reanalysis data was used to simulate the hourly VRE power output (in form of CF) and determine the efficient frontier of the return-volatility trade-off. This can mask the sub-hourly volatility of VRE. Shahriari and Blumsack (2018) show that for the same portfolio return, the volatility over a ten-minute scale is larger than that over an hourly scale. In this sense, sub-hourly data captures the output profile of VRE more precisely and closer-to-real-time. This is important for the management of operating reserves, demand response, storage and other flexible resources, but is beyond the scope of this paper.

- This study is based on the assumption of a copperplate, due to the lack of high-resolution data of the transmission grid in China. Therefore, the optimal VRE portfolios obtained in this study may not be achievable considering the current transmission grid in China. However, our results help identify grid bottlenecks and plan grid expansion in China to harvest the benefits associated with geographical smoothing in the most optimal way. Once grid-related data is available, it can be treated as additional constraints in the MPT optimization (Roques et al., 2010) or incorporated into the optimization objective function (Rombauts et al., 2011). Transmission constraints shift the efficient frontier rightwards, resulting in less optimal portfolios than portfolios without transmission constraints (Rombauts et al., 2011). The accuracy of incorporating transmission constraints can be improved by the support of a detailed power flow model based on Kirchhoff's laws (Erdener et al., 2014).

- While the purpose of developing optimal VRE portfolios is to better serve the balance between electricity supply and demand, this paper does not explicitly consider the (hourly) demand profile for China. Besides the lack of reliable data at national and regional levels, the demand profile in the long-term future (e.g. 2050) depends on the highly uncertain trend of electrification and the structural change of the economy. In addition, considering the increasing popularization of smart-grid technology and real-time pricing that encourage demand response, the demand profile can become more flexible and adaptable to VRE outputs. We propose scenario-based studies in future research to explore these areas. Once robust data on the demand profile is available, it can be fed into the MPT optimization. For instance, the sum of regional demand and total export transmission capacity can be set as a ceiling for the regional maximum installed VRE capacity (Roques et al., 2010). Alternatively, the portfolio return and volatility can be formulated as the mean and standard deviation of the residual demand (demand less VRE output) respectively, which helps to increase the match between VRE output and demand (Degeilh and Singh, 2011).

- Regarding the determination of hourly CF time series for wind and solar, a few simple assumptions have been made in the absence of detailed models. For instance, we did not explicitly consider the wake effect (although the selected intermediate spacing implicitly avoids large wake losses) and the smoothing effect resulting from wind speed propagation within a wind farm. This can lead to an overestimation of the mean and volatility of wind's capacity factor. For solar, we assumed a uniform PR at 85% for all solar installations in China. The PR is dependent on the efficiency of the PV system and the module temperature (Dierauf et al., 2013). Although not corrected for the inter-regional differences in weather conditions (solar irradiance, wind speed and ambient temperature) that affect the module temperature, the PR at 85% on average is a realistic assumption for the long-term future (see footnote 7). In addition, we determined optimal angles for both utility-PV and rooftop PV to maximize the total yields per installation, assuming they are both mounted on a surface close to flat. These angles can increase the portfolio return, but are not necessarily preferable to minimize the portfolio volatility. We propose future studies to investigate alternative PV angles and their impact on the efficient frontier.

- We used geographical potentials per VRE asset as constraints (maximum installed capacity per asset) in the MPT optimization. These potentials were estimated based on multiple geographical and social acceptance constraints and land cover suitability factors from literature. Although validating these constraints and suitability factors is beyond the scope of this study, their uncertainties can cause increased or decreased potentials. For instance, the threshold distance to (dense) urban area and shore for onshore and offshore were conservatively set at 10 km. Alternative threshold distances may lead to different potentials and affect the spatial distribution of optimal portfolios.

- To analyse the economics of optimal VRE portfolios, we determined the portfolio LCOE. However, LCOE is an incomplete indicator, as it only covers the unit production cost and does not capture the system-wide costs resulting from adding VRE into the power system. On the one hand, optimal VRE portfolios positioned on the efficient frontier may displace more capacity and production from conventional fossil-fired power plants and minimize the impact of variability on the power system, leading to system cost reduction. On the other hand, additional investment in transmission infrastructure may be required to connect VRE assets with each other and with the electricity consumers. Costs and savings associated with these system-wide impacts are best assessed by more comprehensive indicators such as levelized avoided cost of electricity (EIA, 2019), system LCOE (Ueckerdt et al., 2012) and value-adjusted LCOE (IEA, 2018). This, however, necessitates the development of baseline and reference scenarios based on power system modelling, which can be covered in future research.

- This study identified optimal VRE portfolios in terms of the spatial distribution of different VRE assets based on a greenfield situation, without considering existing VRE capacity in China. This is helpful to explore the theoretically maximum geographical smoothing effect. Nevertheless, such greenfield situation is difficult to meet, given the sunk nature of VRE investments in reality. Alternatively, existing VRE capacity can be framed as constraints in the MPT optimization in future studies. This is expected to reduce the "efficiency" of optimal portfolios in terms of the return-volatility performance. Moreover, optimal portfolios are best achieved through a social planner that makes centralized investment decisions. However, in reality investment decisions for each VRE installation are made by individual investors through project financing or corporate financing. These investors may not be attracted by individual sub-optimal installations, even if they are indispensable to optimize the overall portfolio. Therefore, effective and pragmatic development pathways are essential to achieve optimal portfolios, which require smart policy measures and market designs to steer VRE investments. However, this is beyond the scope of the present work. Roadmap studies are recommended to further analyse this issue.

- We determined the long-time CF100% and CF90% for selected optimal portfolios. They are 100- and 90-percentile values of the 16-year hourly portfolio CF time series, and hence they represent the minimum portfolio CF that is available 100% and 90% of time. As a common practice in MPT literature within the field of economics and finance, the at-risk-value derived from a long-time time series of the underlying variable (e.g. portfolio financial return) is often interpreted as a time-invariant minimum value associated with a given probability (Los, 2003). Based on the ergodicity hypothesis originated from statistic mechanics, over a long-time period (close-to-infinity), the distribution of a stochastic process across time approaches its distribution across ensembles (i.e. all possible stochastic realizations) (Los, 2003). In this sense, it seems plausible to interpret CF100% and CF90% as the minimum CF associated with 100% and 90% probability. While the ergodicity hypothesis (if true) helps to reduce uncertainties associated with unobservable ensemble distribution, it is virtually impossible to prove (Barkley Rosser, 2015). Being a strong assumption, its wide usage in economics and finance also leads to many criticisms (Davidson, 1991; Peters and Gell-Mann, 2016). Therefore, CF100% and CF90% should never be misinterpreted as the minimum CF associated with 100% and 90% probability. Rather, they represent the minimum portfolio CF with 100% and 90% availability.

- Based on key statistics (mean, standard deviation and covariance matrix) derived from historical meteorological reanalysis data, we used MPT to obtain optimal VRE portfolios for China in the (long-term) future. This can give rise to two main limitations. Firstly, despite its general accessibility and global coverage, reanalysis data entails model uncertainties. For instance, they often erroneously predict actual clear-sky conditions as cloudy and lack detailed representation of local terrain conditions (Boilley and Wald, 2015; Staffell and Pfenninger; 2016). This can result in biased estimates of key statistics derived from reanalysis data. This bias, however, can be corrected through validation and calibration with historically observed VRE output data (Staffell and Pfenninger, 2016). Further research on this is recommended, once observed real data for China becomes more accessible. Secondly, drawing conclusive statistics for and between different VRE assets typically requires a long-time period of 15-30 year (Reichenberg et al., 2017). Although we used a 16-year historical period of weather data, its key statistics may not well represent the long-term future (e.g. due to non-stationarity). This is further complicated by the uncertain impact of climate change on future weather, which is not considered in this study. We propose studies based on climate modelling to investigate this issue specifically for China.

2.5 CONCLUSION

In this study, we optimized portfolios of VRE assets using MPT to capture the geographical smoothing effect in China's future power system. The geographical smoothing effect in terms of better return-volatility performance of VRE outputs is expected to bring about multiple benefits to support power system operation. Based on the copperplate assumption, efficient frontiers of optimal VRE portfolios were determined for different scenarios and portfolio types. We also characterized key portfolio statistics (spatial distribution, technology shares, LCOE, CF-at-risk) to understand their behaviour along the efficient frontier.

Main findings of this study are:

- This study shows that China has vast geographical potentials for VRE. The maximum capacity that can be installed is 575-4,909 GW for onshore wind, 559-932 GW for offshore wind and 12,936 GW for solar. The geographical potentials and mean CF determined at each VRE asset level also provide necessary information for policy-makers, academic peers and private investors to evaluate the performance of VRE resources. For instance, they can be used to guide decision-making in project financing of VRE investment. They also support the design of efficient subsidy schemes necessary to reach China's renewable energy targets. The best resources (in terms of both high mean CF and high potentials) are found in Inner-Mongolia (for wind) and North China (for solar).

- Optimal portfolios positioned on the efficient frontier exhibit superior return-volatility performance compared to individual VRE assets in China. The geographical distribution of VRE assets in optimal portfolios provides a rationale for the allocation of national renewable energy targets to different provinces in China. It can help policy-makers to plan and coordinate the development of different VRE assets as well as the transmission grid in a more system-optimized manner. This is expected to bring about significant economic benefits in power system investment and operation. Within the same efficient frontier, portfolios with a higher return also entail a higher volatility. It must be stressed that these portfolios are all efficient, as the portfolio risk is minimized for each attainable return level. Therefore, the selection of portfolios within the efficient frontier is purely a policy decision, depending on the prevailing return-volatility preference.

- The efficient frontier of wind & solar portfolios exhibits better return-risk performance than wind-only and solar-only frontiers. This suggests complementarity between wind and solar in China. Strong negative correlations in power output exist between wind assets in east Inner-Mongolia, Northeast, Northwest and North China and solar assets in Northeast, Northwest and East China. Therefore, it is advisable for policy-makers to coordinate the investment and development of VRE assets in these regions to capture the benefits of diversification. We also demonstrated that for the same total installed capacity, wind & solar portfolios with unconstrained technology shares exhibit better return-volatility performance than portfolios with constrained technology shares. This suggests that existing scenarios in literature with pre-defined shares of different VRE technologies might be sub-optimal to support power system operation. Hence, it is crucial for these scenarios to be thoroughly assessed and reviewed before they are used in policy decision-making.

- With increased portfolio volatility (and portfolio return), the LCOE of wind & solar portfolios decreases along the efficient frontier. Although the portfolio share of solar (with low LCOE) decreases along the efficient frontier, low-CF assets are meanwhile replaced by high-CF assets. The latter factor dominates the overall decreasing trend of LCOE.

- VRE technologies in literature and mass media are often portrayed as "intermittent renewable energy sources". The lexical definition of "intermittency" suggests an on-and-off pattern in VRE outputs. This can lead to a biased impression of VRE technologies, i.e. that they are unreliable. While "intermittency" fairly characterizes the output pattern per VRE installation, the collective VRE output pattern is more important from the perspective of power system operation. We argue that "intermittency" should not be used to characterize the collective output pattern of well-diversified VRE assets spread over a large geographical area. This is supported by the results of this study. The long-time $CF_{100\%}$ for wind & solar portfolios suggests that a non-zero minimum portfolio CF (1.4–5.5%) can exist with 100% availability.

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3

Analysis of Extreme Ramp Events in Optimal Variable Renewable Electricity Portfolios using Extreme Value Theory

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ABSTRACT

Geographically diversified VRE portfolios can be used to smooth out the volatility of VRE output ramps. This study, using Taiwan as case study, developed efficient frontiers of optimal VRE portfolios to minimize the volatility for each possible level of total installed VRE capacity that can meet 10%, 20% and 30% of electricity demand. Our analysis shows that optimal portfolios are also beneficial to reduce the magnitude of extreme downward ramp events, which are sudden losses in VRE power outputs. We specifically investigated hourly extreme ramps that are expected to occur on average once-every-three-year. They are 13-30 % of each unit of installed VRE capacity for optimal VRE portfolios, which are significantly smaller than that (20-64%) for most individual VRE assets. This result helps to manage risks associated with extreme ramp events in power system operation. To capture the benefits associated with optimal portfolios, it is recommended for policy-makers to coordinate the investment and development of VRE assets across multiple locations.

NOMENCLATURE

Abbreviations

EVA	extreme value analysis
GEV	generalized extreme value
MVP	mean-variance portfolio
VRE	variable renewable electricity

Symbols

x_p	total installed VRE capacity needed in the portfolio (MW)
x_i	installed capacity variable of each VRE asset (MW)
$\sigma_{p,ramp}$	portfolio ramp volatility
X	vector of installed capacity variable per VRE asset
cov_{Nramp}	covariance matrix of normalized ramp between different assets
$x_{max,i}$	geographical potentials per VRE asset (MW)
$\mu_{i,N}$	normalized mean output per VRE asset
D	Taiwan's electricity demand in 2030 (290.6 TWh)
L	required VRE penetration in electricity demand
$\sigma_{p,Nramp}$	normalized portfolio ramp volatility
$O_{p,N(t)}$	normalized portfolio output at time step t
$O_{i,N(t)}$	normalized output per VRE asset at time step t
$R_{p,N(t)}$	normalized portfolio ramp at time step t
z	random extreme event z
$G(z)$	cumulative probability density function of a random extreme event z
μ	location parameter
σ	scale parameter
ξ	shape parameter
$T(z)$	return period of a random extreme event z
B	block period (month)

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3.1 INTRODUCTION

To achieve the Paris Agreement target of limiting the global mean temperature increase to 1.5-2 °C, decarbonization of the electric power sector, including large-scale development of variable renewable electricity (VRE) technologies such as wind and solar is key. Due to their variable and uncertain nature VRE technologies pose challenges in power system operation. The sudden ramp-up and ramp-down of VRE outputs (which are increases or decreases in power outputs) necessitate additional back-up capacity, operating reserves and other flexibility resources to ensure generation adequacy and system reliability, resulting in so-called "integration costs" (Hirth et al., 2015).

One effective way to reduce the impact of VRE ramps is to develop geographically diversified VRE portfolios, which smooth out output ramps from individual VRE assets. Previous studies (e.g. Novacheck and Johnson, 2017; Roques et al., 2010) have applied mean-variance portfolio (MVP) analysis to obtain the efficient frontier of optimal VRE portfolios, where the portfolio volatility (i.e. standard deviation) of output ramps is minimized for each attainable (expected) output level. Although optimal VRE portfolios are helpful to reduce the frequency and magnitude of the majority of ramps, their effect on extreme ramps is yet unclear. Due to the non-Gaussian fat-tailed distribution of VRE ramps, low-order statistics (e.g. mean and variance) are insufficient to capture extreme ramps in terms of the distribution's tail behavior (de Marco and Basu, 2018; Taleb, 2010). As rare but high-magnitude events, extreme ramps can cause large disruptions in power supply and threaten generation adequacy, when availability of back-up capacity and operating reserves in the system is low and when VRE's share in the electricity generation mix is high. This is particularly an issue for isolated or islanding power systems which have limited access to flexibility resources (e.g. storage, dispatchable power plants, demand-side response) in absence of interconnection (Ganger et al., 2014). Analysis of extreme ramp events in VRE portfolios is thus of importance to support the planning and operation of power systems, especially when optimal portfolios are considered as a promising solution to facilitate the integration of VRE.

This study aims to investigate extreme hourly ramp events in optimal VRE portfolios[20] through extreme value analysis (EVA). EVA is a statistical branch specialized in assessing the tail behavior of the distribution. In the context of extreme ramps, we focus on downward ramps rather than upward ramps. This is because unlike upward ramps

20 It is important to stress that this study does not aim to minimize extreme ramp events in VRE portfolios, which can be achieved through building up portfolios based on high-order statistics (e.g. skewness and kurtosis). These portfolios are not necessarily optimal in terms of the trade-off between portfolio volatility and expected portfolio output.

that can be solved by curtailment, downward ramps are more relevant for generation adequacy. Although previous EVA-based analyses (e.g. de Marco and Basu, 2018; Ganger et al., 2014) have analyzed extreme ramps for individual wind farms, this study represents the first attempt of applying EVA to VRE portfolios. The Taiwan region of China is selected as the case study area due to its high relevance. Taiwan is the 21st largest economy and 14th largest electricity-consuming region in the world. It has a large islanding power system isolated from mainland China, relying heavily on energy imports. As Taiwan has set ambitious 2030 renewable targets to phase out nuclear power, boost energy security and reduce CO_2 emissions, this year is chosen as target year for the analysis.

3.2 THEORY

3.2.1 Mean-variance portfolio analysis

The MVP analysis originates from financial theory. It is used to select individual financial assets to formulate a series of optimal portfolios subject to the trade-off between (expected) return and risk. The optimal portfolios are positioned on an "efficient frontier", where risk is minimized at a given return, or return is maximized at a given risk. In the context of energy planning, MVP often focuses on minimizing the ramp volatility of VRE portfolios for each attainable (expected) portfolio output, when the total installed VRE capacity is given (Roques et al., 2010). This results in the efficient frontier of optimal VRE portfolios that captures the geographical smoothing effect. Novacheck and Johnson (2017) have formulated an alternative but equivalent framework. It minimizes the portfolio's ramp volatility for a possible range of total installed VRE capacity levels, when VRE's penetration in electricity demand is given. This study follows Novacheck and Johnson (2017)'s framework with some modifications.

3.2.2 Extreme value analysis

EVA determines a stable asymptotical distribution of the tail behavior through sampling many extreme values of a random variable (Gilleland and Katz, 2016). It requires stationarity of the sampled data. Extreme ramps sampled from a time series of portfolio ramps (being the first difference of a time series of portfolio outputs) are assumed to meet this requirement, since differencing increases stationarity (Ganger et al., 2014). The sampling of extreme values can be either based on the block maxima (or minima) method or the peaks over threshold method (Ganger et al., 2014). Due to the practical difficulty in selecting a proper threshold for each optimal portfolio, this study opts to use the former method. The block (B) is a predefined time period, which can be a year, a month or a day. The sampled extreme values (being the maximum value per block) are fit by the generalized extreme value (GEV) distribution. The cumulative probability density function of the GEV distribution for a random extreme event z is

$$G\left(z\right) = \exp\left[-\left\{1+\xi\left(\frac{z-\mu}{\sigma}\right)\right\}\right]_{+}^{-1/\xi}$$

, where G(z) is cumulative probability density function of random variable z; μ ($> -\infty$), σ (> 0), ξ($< \infty$) are respectively the location, scale and shape parameter; $y_+ = \max\{y, 0\}$ (Gilleland and Katz, 2016).

The quantile z of the GEV distribution can be interpreted as a return level associated with a return period T (z) [3]:

$$T(z) = \frac{B}{1 - G(z)}$$

In other words, an extreme value with a magnitude no less than z is expected to occur on average once every return period T (z). Based on the inverse function of G (z), the expected extreme event associated with any return period can be estimated.

3.3 METHOD

The method of the present analysis consists of two main steps, and they were performed through ArcGIS and RStudio. In the first step, we developed the efficient frontiers of optimal VRE portfolios for Taiwan, which consist of three VRE technologies (onshore wind, offshore wind and solar PV). In the second step, we fit extreme downward ramps sampled from the time series of hourly portfolio ramp to the GEV distribution. The fitted GEV distribution enabled us to estimate the expected extreme ramp event that occurs on average once every three years. The method is briefly elaborated below:

3.3.1 Develop optimal VRE portfolios

Firstly, we divided the entire Taiwan region (including exclusive economic zone adjacent to the territorial sea) into 45 equal-sized (0.5° *0.675°) grid cells. As such, each VRE technology type at a specific grid cell becomes an individual VRE asset. Secondly, based on NASA MERRA meteorological reanalysis data of historical hourly wind speed and solar irradiance between 2000 and 2015, we obtained the 16-year time series data of hourly outputs and output ramps for each VRE asset through a power conversion model (Hu et al., 2019). The hourly outputs and output ramps were normalized to the scale of 0-1 (on the basis of each unit of installed capacity) to enable comparison. We further characterized the mean and standard deviation of normalized hourly outputs and output ramps for each VRE asset, and the covariance matrix between different assets. Thirdly, taking into account various geographical constraints and different land cover types, we determined the geographical potentials (maximum capacity that can be installed) for each VRE asset. Fourthly, we performed MVP analysis to obtain the efficient frontier curves of optimal portfolios, based on a copperplate assumption. The objective is to minimize the portfolio volatility for each possible level of total installed VRE capacity, to meet 10%, 20% and 30% penetration levels of VRE in Taiwan's electricity demand in 2030 (290.6 TWh). The mathematical formulation of the optimization is as follows:

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The total installed VRE capacity needed in the portfolio (x_p) is the sum of installed capacity variable of each VRE asset (x_i):

$$x_p = \sum x_i$$

The portfolio ramp volatility ($\sigma_{p,ramp}$) is the product of the vector of installed capacity variable per VRE asset ($\mathbf{X}$), its transpose vector ($\mathbf{X}^\mathbf{T}$), and the covariance matrix of normalized ramp between different assets ($\mathbf{cov}_{\mathbf{Nramp}}$):

$$\sigma^2_{p,ramp} = \mathbf{X}\,\mathbf{cov}_{\mathbf{Nramp}}\,\mathbf{X}^\mathbf{T}$$

X is solved by the minimization of $\sigma^2_{p,ramp}$, which is subject to two constraints.

Firstly, installed capacity per VRE asset must be capped by its geographical potentials:

$$x_i \leq x_{max,i}$$

Secondly, the portfolio output must reach the required VRE penetration level (10%, 20% and 30%) in electricity demand:

$$8760 \sum \mu_{i,N}\, x_i \geq DL$$

,where $\mu_{i,N}$ is the normalized mean output per VRE asset; D is Taiwan's electricity demand in 2030, which is officially forecasted at 290.6 TWh; L is the required VRE penetration level (which is set at 10%, 20% and 30% in this study).

To enable comparison on the basis of per unit installed capacity, the normalized portfolio ramp volatility ($\sigma_{p,Nramp}$) was calculated via:

$$\sigma_{p,Nramp} = \frac{\sqrt{\sigma^2_{p,ramp}}}{x_p}$$

The efficient frontier curves were obtained by plotting the normalized portfolio ramp volatility against the total installed VRE capacity for all optimal portfolios.

3.3.2 Fit generalized extreme value distribution

Firstly, based on the share of each VRE asset in the portfolio, the 16-year time series of normalized hourly portfolio outputs and output ramps were determined for optimal portfolios:

$$O_{p,N(t)} = \frac{1}{x_p}\sum x_i O_{i,N(t)}$$

$$R_{p,N(t)} = O_{p,N(t)} - O_{p,N(t-1)}$$

, where $O_{p,N(t)}$ and $O_{i,N(t)}$ are respectively the normalized portfolio output and output of an individual VRE asset at time step t; $R_{p,N(t)}$ is the normalized portfolio ramp at time step t.

Secondly, we sampled extreme ramps from the time series of normalized hourly portfolio ramps based on the block maxima method using a monthly block size. The sample only includes the largest downward ramp event for each monthly block period. This results in 192 sample points per optimal portfolio. Thirdly, we fit the sampled data to the GEV distribution for each optimal portfolio, using L-moment estimation method. Being the linear combination of order statistics, the L-moment method performs better in parameter estimation for fat-tailed distributions than other conventional methods such as the maximum likelihood estimation method (Šimková, 2017). The fitness of the GEV distribution was assessed descriptively for selected portfolios. Lastly, taking a three-year return period as example[21], we estimated the expected extreme ramp event that occurs on average once every three year (referred to as "once-in-three-year extreme ramp") for each optimal VRE portfolio positioned on the efficient frontiers. Based on the same procedure, we estimated the once-in-three-year extreme ramp for each individual VRE asset to enable comparison.

21 We consider a reliable power system should be able to manage once-in-three-year extreme events. However, the maximum level of extreme ramps that should be managed by the power system and its corresponding return period depend on the reliability standards, the demand profile and the value of lost load. They can only be determined through power system modelling.

3.4 RESULTS

3.4.1 Mean-variance analysis

We present the efficient frontier curves of optimal VRE portfolios that serve 10%, 20% and 30% of electricity demand in Figure 3.1. Each point positioned on the efficient frontiers represents an optimal portfolio. These portfolios are efficient in the sense that for a given total installed capacity (corresponding to meet 10%, 20% and 30% of electricity demand) the normalized ramp volatility is minimized and for a given normalized ramp volatility, the total installed capacity is minimized. A clear trade-off can be observed within the same efficient frontier, i.e. reducing the normalized portfolio ramp volatility must be at the cost of increased total installed capacity to meet the required VRE penetration in demand. To meet 10%, 20% and 30% of electricity demand, the required minimum total installed VRE capacity are 6888-8641, 14344-17316 and 22647-26552 MW, respectively. However, the selection of the installed capacity level depends on the policy preference to the normalized portfolio ramp volatility. For convenience, we refer to the portfolio positioned at the top-left point of the efficient frontier as the min-capacity portfolio and the bottom-right point as the min-volatility portfolio.

The trade-off between the normalized portfolio volatility and the total installed capacity is more obvious for the efficient frontier associated with a higher VRE penetration (30% versus 20% and 10%), reflected in the overall steepness of the curves. This can be explained by the necessary inclusion of more assets with lower mean normalized output in portfolios in order to meet a higher penetration of electricity demand.

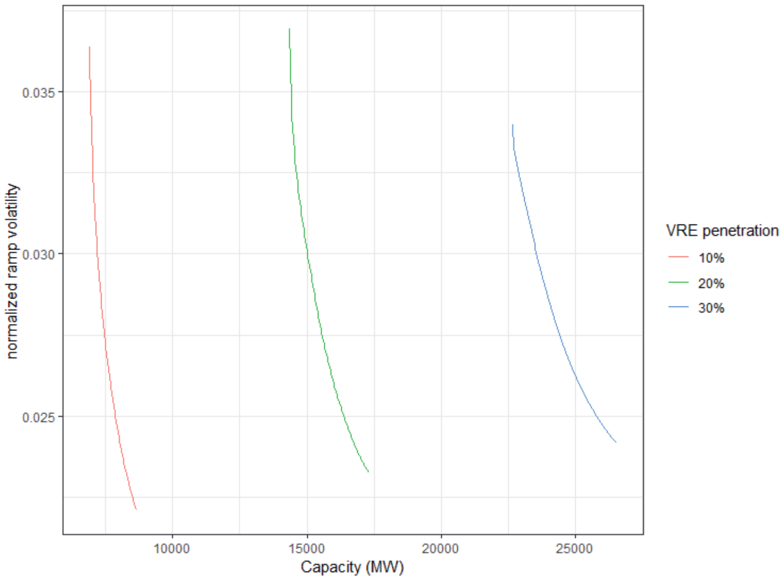

Figure 3.1. Efficient frontiers of optimal VRE portfolios that serve 10%, 20% and 30% of electricity demand

3.4.2 Extreme value analysis

For demonstrative purposes, the return plot for the min-capacity portfolio that serves 10% of electricity demand is presented in Figure 3.2. It is used to descriptively assess the fitness of the GEV distribution to extreme ramps. The return plot shows (both empirical and fitted) relationships between the return period and return level of extreme ramps. The dots, solid and dotted lines respectively represent the sampled extreme ramps, the GEV distribution-fitted extreme ramps and the 95% confidence interval. GEV distribution exhibits overall good fitness to the majority of sampled extreme ramps until the return level reaches ~35% of each unit of installed capacity (corresponding to a return period of 50 months). This suggests that GEV predicts better for the normal occurrence of extremes than "extreme extremes", due to the very limited sample size of the latter. Therefore, the use of EVA to estimate once-in-three-year extreme ramps (which belong

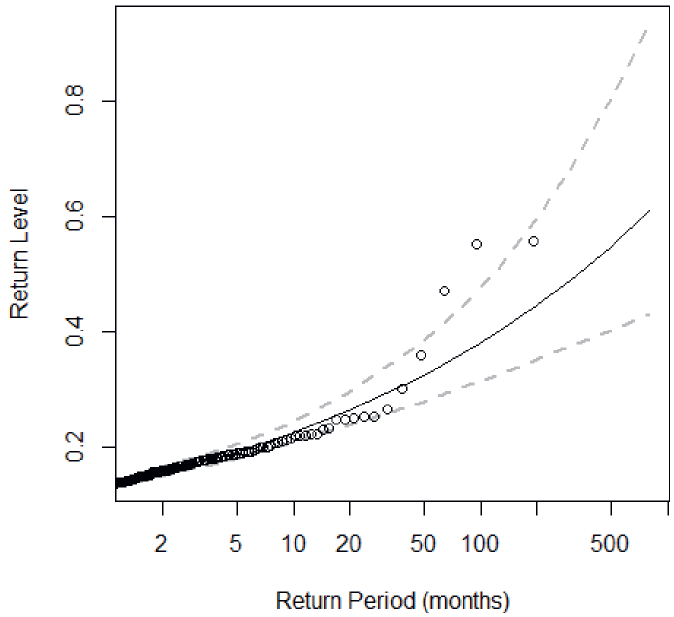

Figure 3.2. Return plot for the min-capacity portfolio that serves 10% of electricity demand

We present the estimated once-in-three-year extreme ramp events for optimal VRE portfolios positioned on the efficient frontiers in Figure 3.3. The magnitude of extreme ramps in terms of a division of each unit of installed VRE capacity decreases with increased total installed capacity along the efficient frontier. This also suggests a clear trade-off between the magnitude of extreme ramps and the total installed capacity for optimal portfolios.

To enable comparison, we also present the estimated extreme ramps and geographical potentials for each individual VRE asset in Figure 3.3. Although a few onshore and offshore wind assets exhibit smaller extreme ramps (based on historic data) than the min-capacity portfolios, they are still much larger than the min-volatility portfolio. The small geographical potentials of these assets also limit their participation in the optimal portfolios. The magnitudes of extreme ramps range between 13-30% of each unit of installed capacity, which are smaller than most VRE assets (20-64 %). This clearly shows additional benefits associated with diversification. Not only do optimal VRE portfolios reduce the volatility of VRE, they are also effective in reducing the magnitude of extreme ramp events.

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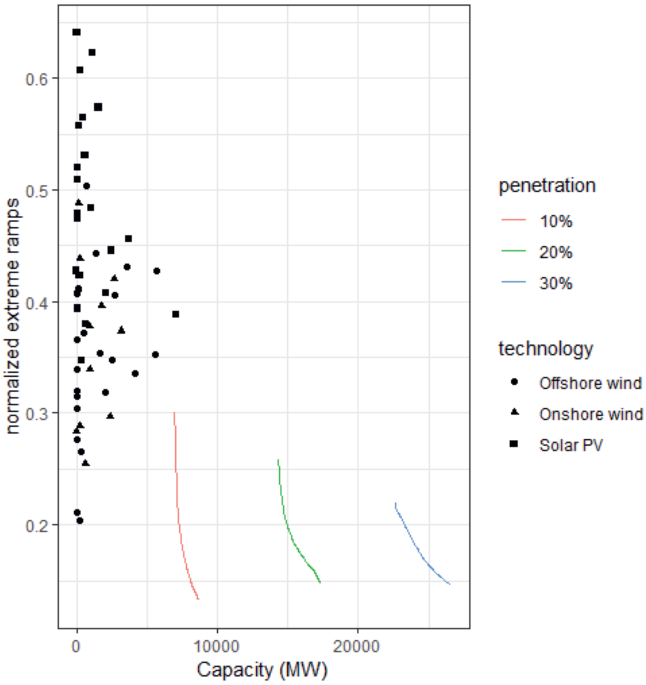

Figure 3.3. Once-in-three-year extreme ramps of optimal VRE portfolios (colored lines) and individual VRE assets (dots)

3.5 CONCLUSION AND DISCUSSION

Geographically diversified VRE portfolios can be used to smooth out the volatility of VRE output ramps. Using Taiwan as a case study area, this study developed the efficient frontiers of optimal VRE portfolios to minimize the (normalized) portfolio ramp volatility, for each possible level of total installed VRE capacity that can meet 10%, 20% and 30% of electricity demand. The analysis of extreme ramp events in optimal VRE portfolios using EVA shows that optimal portfolios are also beneficial to reduce the magnitude of extreme ramp events. The estimated once-in-three-year extreme ramps range between 13-30% (of each unit of installed capacity) for optimal VRE portfolios, which is significantly smaller than the estimated extreme ramps (20-64%) for most VRE assets in Taiwan. This result helps to manage risks associated with extreme ramp events in power system operation. To capture the benefits associated with optimal portfolios, it is recommended for policy-makers to coordinate the investment and development of VRE assets at different locations. Accordingly, the grid infrastructure in Taiwan should be reinforced and extended to enable the realization of optimal VRE portfolios. This is of particular importance, given the past outages in Taiwan due to unreliable grid infrastructure.

The present work of this study is based on two main assumptions, i.e. copperplate representation of transmission grid and stationarity of VRE output ramps. These two assumptions could be relaxed in future research.

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4

Barriers to Investment in Utility-scale Variable Renewable Electricity (VRE) Generation Projects

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ABSTRACT

To effectively mitigate climate change, variable renewable electricity (VRE) is expected to substitute a great share of current fossil-fired electricity generation. However, VRE investments can be obstructed by many barriers, endangering the amount of investments needed in order to be consistent with the Paris 2°C target. To help policy-makers better understand and assess these barriers, an integrated framework was developed. It establishes a clear connection between barriers identified in literature and the investment decision-making process, based on the project life of VRE assets. Barriers in this framework are defined as factors hindering the realization of a positive final investment decision (FID), which can lead to investment withdrawal.

Based on this research, we argue that addressing so-called "symptomatic" barriers alone is hardly effective when the "fundamental" barriers remain untouched. It also demonstrates that monetary and fiscal policies can have side-effects on VRE investments. We suggest that a comprehensive policy framework to support VRE should not be solely limited to the narrow context of climate and energy policy, and the electricity market. It should be incorporated in a broader context including monetary and fiscal policies. When re-designing these macroeconomic policies, their potential negative impacts on VRE investments should be considered.

4.1 INTRODUCTION

To effectively mitigate the worst impacts of climate change, the Paris Agreement agrees to limit the increase in global average temperature to 2 °C above pre-industrial level and seeks to further limit the temperature increase to 1.5 °C (UNFCCC, 2015). This requires a significant contribution of renewables in the global electricity generation portfolio to decarbonize the power sector (OECD, 2016). In particular, variable renewable electricity (VRE), which is electricity converted from stochastic energy flows (e.g. wind and solar), is expected to play an indispensable role in substituting electricity generation from fossil fuels. The 2 °C scenario of the International Energy Agency (IEA) indicates that the combined penetration of wind and solar in global electricity supply has to increase from 4% to 25% between 2013 and 2040 (IEA, 2015). In some regions like the European Union (EU), this figure may be as high as 37% by 2040 (IEA, 2015). Hence, a sustainable and robust growth of investments in VRE is needed for the foreseeable future.

Driven by climate policies (including renewable energy support) and increasing cost reduction associated with technological learning and economies of scale, a strong growth trend for global VRE investments has been witnessed since 2000 (Wustenhagen and Menichetti, 2012; UNEP and BNEF, 2016). During 2004-2015, annual investment in new VRE assets increased from 38.1 billion USD_{2015} to 270.6 billion USD_{2015}[22], resulting in an increase of total installed VRE capacity by a factor of 13 (from 51 GW to 669 GW) (REN21, 2015; UNEP and BNEF, 2016). It is estimated that a cumulative investment in VRE amounting to 4444 billion USD_{2015} between 2016 and 2035 is the minimum level needed to be consistent with the 2°C climate target (IEA, 2014a; UNEP and BNEF, 2016). However, concerns still exist to whether sufficient VRE investments can be realized. Investment in power generation assets, in general, feature sunk capital costs and uncertainty surrounding future returns and costs (Lundmark and Pettersson, 2012). VRE investments, as a result of their specific techno-economic characteristics, can be distinguished from investments in conventional fossil-fired power plants in two main aspects. Firstly, because VRE projects tend to have a higher capital-intensity (measured by capital expenditures (CAPEX)'s share in total operating expenditures (OPEX) and CAPEX) than fossil-fired plants, they are more exposed to capital constraints and the cost of capital (WACC) (de Jager et al., 2011; Waissbein et al., 2013; Henrich, 2014; Donovan, 2015; Ondraczek et al, 2015). Secondly, featuring variable, uncertain and location-dependent outputs, VRE projects are more exposed to downside revenue risks (i.e. actual revenue received below the expected revenue) (Zane et al., 2012; Hirth et al., 2015). Not only facing these two inherent disadvantages, VRE investments can be obstructed by many

22 Original data are given in nominal value. Deflators (http://stats.areppim.com/calc/calc_usdlrxdeflator.php) are used to obtain their constant USD_{2015} value.

other barriers. They either reduce the economic appeal of the investment project, or hinder the process of accomplishing necessary steps before final investment decisions (FID) can be made (OECD, 2016). These barriers have been discussed in a wide range of literature, but in a fragmented manner. They tend to focus on only one type of barrier to VRE investments or limit the scope of their discussion from a single perspective. For instance, Hirth et al. (2015) and Munoz and Bunn (2013) respectively demonstrate that the current EU electricity market design may be detrimental to the business case of VRE investments from the revenue perspective and the risk-return perspective. From the cognitive and institutional perspective, Masini and Menichetti (2013) show that biased perceptions and preconceptions defer the decision-making process for VRE investments, favoring the existing energy production model based on fossil fuels. Drawing from a case study, Jami and Walsh (2014) conclude that the lack of public participation may contribute to the rejection of VRE investments. It seems that based on the current knowledge of literature, a comprehensive overview is missing that connects different barriers and their underlying contributors. This adds difficulty to diagnose and address these barriers. This paper aims to deliver a literature review-based analysis that can provide such overview, through developing an integrated framework to analyze barriers to VRE investments as identified from literature. In such framework, we define barriers to VRE investments as factors hindering reaching a positive FID, which can end up with investment withdrawal. Hence, a clear link can be established between barriers and the decision-making process for VRE investments. This serves as the basis to identify and analyze barriers. The scientific contribution of this paper lies in two main aspects. Firstly, the existing body of both empirical and theoretical literature is limited when pertaining to investment decision-making in power plants and renewable energy, e.g. Wustenhagen and Menichetti (2012); Groot et al. (2013). Often, these literature sources tend to be detached from the project life of VRE asset. Complementing existing literature, this paper bridges the project life and the investment decision-making process. Thus, it offers deep insights for different stakeholders and the scientific community on how VRE investment decisions are made in practice and what factors affect the decision-making process. Secondly, findings of this paper can feed into the discussion of how barriers to VRE investments can be effectively tackled. This helps to safeguard necessary VRE investments consistent with the 2 °C climate target.

This paper is organized as follows: In Section 4.2 an integrated framework is developed to represent the decision-making process for investments in VRE assets from a project developer's perspective, given its essential role in making a FID. This is performed through connecting the investment decision-making process with the project life of VRE assets. Section 4.3 applies the integrated framework to analyze and combine key barriers to VRE investments identified from existing literature, based on the division of the decision-making process into several stages. The survey of relevant literature is based on a few targeted keywords, such as "investment decision-making", "renewable energy" and "barrier". A snowball method is also used to facilitate the literature survey process. This allows the identification of other literature sources from the reference list of a surveyed paper and the identification of new papers citing the surveyed paper. To include literature from different fields that are related to VRE investments, we do not take a specific view to select and assess literature, i.e. an explorative approach is adopted. A total number of 140 literature sources are reviewed (see table 4.1), which consist of peer-reviewed journal papers (60), other academic literature sources (29) and non-academic literature sources (51)[23]. In section 4.4, a synthesis of the review-based analysis is given, including policy implications drawn for policy-makers. We point out the recommendations for further research in section 4.5.

Table 4.1. Summary of reviewed literature sources

Academic literature sources	Peer-reviewed journal papers	63
	Textbooks, professional books, PhD theses, conference/working/discussion papers published by academic organizations	29
Non-academic literature sources	Government documents (e.g. European Commission, OECD) and reports published by organizations affiliated to the government (e.g. IEA, IEA-Renewable Energy Technology Development, World Bank)	23
	Government-funded project reports	10
	Consultancy/think-tank/association reports and column articles (e.g. Bloomberg New Energy Finance)	19
Total		144

4.2 DEVELOPMENT OF THE INTEGRATED FRAMEWORK

The development of the integrated framework for the research was mainly drawn from literature that describes the project life of a VRE asset. The project life of a VRE asset typically consists of several project steps that follow a temporal sequence. They are pre-feasibility study and site prospecting, VRE resource assessment, environmental impact assessment (EIA) and permits acquisition (e.g. land, building, grid connection), off-take arrangement and support scheme application, capital access, engineering and equipment procurement and contracting, construction and commissioning, commercial

23 To better capture first-hand and up-to-date information, a number of non-academic literature sources (51 in total) are also used. Many of them are widely-cited, and they come from official government documents, well-acknowledged organizations and other primary sources (e.g. IEA, World Bank, Bloomberg New Energy Finance). Peer-reviewed reports (e.g. IEA-RETD) are also included among them.

operation and maintenance, and decommissioning[24] (Tetra Tech, 2011; WB and CIF, 2013; ADB, 2014; Deloitte, 2014). Since the step of engineering and equipment procurement and contracting and the step of construction and commissioning involve the commitment of the majority of costs throughout the project life, the implementation of these two project steps marks the actual start of the investment. This implies final investment decision (FID) must be made prior to these two steps (Deloitte, 2014). Investments will only be committed once the FID is made. Therefore, using the FID as a demarcation, the project steps before FID comprise the investment decision-making process. Each project step naturally formulates a decision-making step. Empirically, the decision-making process serves to confirm that the investment case considered is a good investment for the project developer, i.e. with a satisfying economic outcome under a sufficiently high confidence interval (Groot et al., 2013). To streamline the decision-making process, the recognized decision-making steps were further grouped into two sequential principal stages before the decision outcome of the FID: stage prior to capital access (i.e. project development stage) and capital access stage.

VRE investments are subject to many unknown events affecting capital and time expenditures associated with each project step and future cash flows of the investment project. To inform successful decision-making, project developers should be able to evaluate the viability of the project under these unknowns. Based on the measurability of knowledge, Zeckhauser (2014); Diebold et al. (2008); Stirling (1994) distinguish these unknowns into three states: risks/known unknowns (with specified outcomes and probabilities), uncertainties/unknown unknowns (with specified outcomes and unspecified probabilities) and ignorance/unknowable unknowns (with unspecifiable outcomes and probabilities). Although it is uncertainties and ignorance that are mostly encountered in VRE investments, it is common practice to treat uncertainties as risks via assigning a (subjectively) estimated probability distribution function and be wary about ignorance (Wickham, 2006; Kitzing et al., 2014; Zeckhauser, 2014). Hence, in this paper the term "risk" is used to generalize the three states of unknowns, and it is specified to downside risk. In traditional finance theory, the assumption of perfect information and full-rationality implies that investment decision-making should be informed by the statistically measurable risk (Baker and Nofsinger, 2010; Hampl and Wustenhagen, 2013; Pistorius, 2015). However, behavioral and psychological literature points out the subjective perception of risk in reality, reflecting bounded rationality, can strongly affect investment decisions, depending on the developer's judgment and attitude towards

24 Depending on projects and countries, the sequence of project steps may be slightly different. For instance, VRE resource assessment can be performed earlier than site selection and prospecting, and off-take arrangement can be earlier than permits acquisition. Note that some project steps can also be implemented in parallel (Tetra Tech, 2011).

risks (Hampl and Wustenhagen, 2013; Wustenhagen and Menichetti, 2012; Masini and Menichetti, 2013). Furthermore, due to high unknown and unknowable risk level associated with complex VRE investments, their actual risk is *a priori* hardly measurable. Consequently, risk has to be treated with a high degree of subjectivity, which is subject to different psychological, behavioral and institutional attributes (Hampl and Wustenhagen, 2013). To take these into account, we deem it useful to add "preliminary risk scanning" as an additional stage, to the very beginning of the decision-making process. This enables to capture the process of moving the project from investment intention (or formulation of the investment intention) to development action.

Figure 4.1 presents the developed integrated framework for the VRE investment decision-making process, which consists of three main stages. We will elaborate on these three stages below and how they move forward towards reaching the FID.

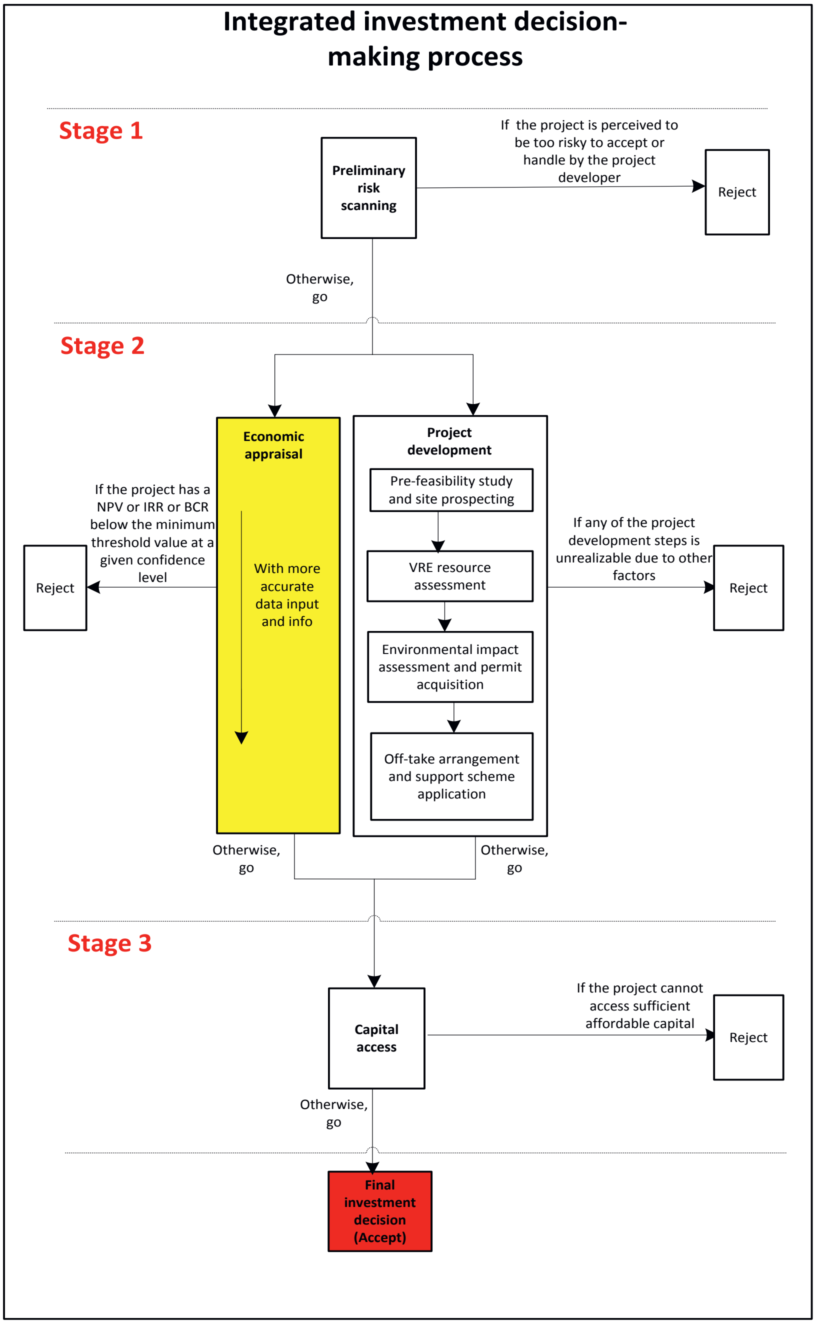

Figure 4.1. Integrated framework for VRE investment decision-making process

- Stage 1: Preliminary risk scanning

Before deciding whether to start the development of a potential VRE project, the project developer is expected to preliminarily scan[25] the risk profile of the project. If risks are perceived too high for the developer to accept or handle, the project will be rejected (Masini and Menichetti, 2013).

- Stage 2: Project development

This stage concerns establishing the layout of the project and thoroughly assessing the economic feasibility of the investment (Deloitte, 2014). It consists of four sequential project steps. Although not comparable to the upfront capital costs required to start the investment, each step of the project development still involves sizable investment and time. Therefore, the project developer must decide whether to move the project forward at the beginning of each step. The decision-making process is assisted by an iterative process of economic appraisal for the investment project in parallel to the project development (Springer, 2013). The investment decision would be rejected if any step of the project development is unrealizable, either due to an undesirable result of the economic appraisal or other factors (e.g. unaffordable costs or complex administrative procedures associated with a step). This minimizes potential losses.

This iterative process also improves the quality of the economic appraisal and reduces its unknown level. This is because as more steps of the project development are proceeded, more accurate data and information inputs regarding the future cash flows of the project will be disclosed (Groot et al., 2013; Springer, 2013). Consequently, the unknown state of project risks tends to switch from unknown unknowns to known unknowns. However, the unknowns of risks do not necessarily decrease. To thoroughly take project risks into account, the iterative economic appraisal can be based on a probabilistic discounted cash flow (DCF) approach. Key performance indicators (KPI) of this approach can be based on either net present value (NPV), internal rate of return (IRR), benefit-cost ratio (BCR) [26], or discounted payback period (DPBP). KPI selection depends on the preference of the project developer, but in principle a minimum required rate of return (i.e. financial hurdle rate) in the form of discount rate should be met (Groot et al., 2013). In the early steps of the financial appraisal, a higher risk-adjusted discount rate can be used to estimate the expected value of these KPI, reflecting the state of high unknown unknowns. In the late steps with more data available, Monte Carlo simulation or statistical mean-variance analysis can be used to give the cumulative probability

25 Note that preliminary suggests that more comprehensive risk assessment need to be conducted to support later stages of investment decision-making. They are incorporated in the iterative process of economic appraisal paralleled to the project development stage in this integrated framework.

26 BCR is the ratio between the present value of the future cash flows and the upfront capital costs. Sometimes it is also referred to as profitability index (PI).

distribution of the KPI (Park, 2015). The resulting at-risk value of KPI (value at a given percentile or minimum value at a given confidence level) can effectively inform the developer whether to proceed with the next project step (Ye and Tiong, 2000). The corresponding minimum criterion[27] is that the NPV-at-risk value should be above 0, the IRR-at-risk value should be above the discount rate, the BCR-at-risk should be above 1, and the DPBP-at-risk value should be below the lifetime of the project. Otherwise, the project would be rejected due to the lack of economic appeal.

- Stage 3: Capital access

After passing through the project development stage and the iterative process of economic appraisal, the decision-making process would enter the capital access stage. Final investment decision would only be accepted if the project developer is able to access sufficient affordable capital to finance the investment. Otherwise, the project would be rejected. Once the final investment decision is accepted, the project developer can start the investment.

4.3 REVIEW-BASED ANALYSIS OF BARRIERS TO VRE INVESTMENTS

The integrated framework provides a basis to identify and analyze barriers to VRE investments from the reviewed literature. It enables to connect barriers with different investment decision-making stages, where barriers increase the likelihood of the investment project being rejected. Barriers for each decision-making stage and their attributes are analyzed in the following sections.

4.3.1 Barriers at preliminary risk scanning stage

Barriers at this stage mainly increase the project developer´s risk perception towards the VRE investment project, which can lead to rejection of the investment. Risk perception is a joint function of both risk judgement and risk attitude (Ricciardi, 2008). The former represents the cognitive/mental process of defining the risk levels of the project, while the latter reflects the affective/emotional attitude towards the judged risk (Weber and Hsee, 1998; Van Winsen et al., 2011). Three types of risk attitude can be distinguished: risk-seeking, risk-neutral and risk-averse. If the project developer is risk-averse, the impact of risk judgment can be amplified and it leads to a higher risk perception (Weber and Hsee, 1998). Therefore, risk perception increases either through increased risk judgement or increased risk averseness.

27 Threshold values for different KPI under the minimum criteria are consistent, which reflect the situation of the required rate of return being just met. Note that it is possible that firms or project developers may set additional cut-off criterion for one or more KPI beyond the minimum criterion, which to some extent reflect their bounded-rationality.

Risk perception can be influenced by actual risk factors for VRE investments, which can occur at different steps of the project life (Hampl and Wustenhagen, 2013). De Jager and Rathmann (2008), Oxera (2011), Hampl and Wustenhagen (2013) and Waissbein et al. (2013) have provided different but similar classifications for these actual risk factors. They include policy risks, public acceptance risk, technology risk, permit risk, construction risk and electricity market risk, to name a few. Most of them will be treated as barriers in later sections of this paper. Here we focus on psychological, behavioral and institutional attributes that can give rise to additional risk perception, which constitute barriers to VRE investments (Gruning and Moslener, 2016). These attributes include ***path dependence, the lack of knowledge and experience, the lack of confidence, the lack of sustainable strategic value, and individualistic worldview and culture.***

4.3.1.1 Path dependence

Path dependence suggests past investments in fossil-fired plants can impact today's decision-making for investment in VRE projects (Wustenhagen and Menichetti, 2012). It has implications for VRE investments at energy system and firm level, both of which can increase the risk perception for potential VRE project developers. At a system level, historical development of fossil-fired plants and complementary infrastructure has displayed multiple comparative disadvantages for VRE technologies (Lehmann et al., 2012). In particular, increasing the uptake of VRE requires large-scale development of flexibility resources, e.g. grid infrastructure, demand response, storage and flexible fossil-fired plants. The lack of flexibility in the current energy system may lead to technological lock-in and increased risk perception for VRE investors. At a firm level, risk perception towards VRE investments of incumbent firms that were heavily involved in fossil fuel investments may be affected by their historical activities (Wustenhagen and Menichettil, 2012). This seems particularly true for large utilities that own large fossil-fired plants and associated infrastructure (Barth and Siebenhuner, 2010). Even when government tightens the environmental standard, these utilities tend to retrofit and upgrade existing plants instead of switching to VRE technologies, to avoid the write-off large sunk costs (Barth and Siebenhuner, 2010).

4.3.1.2 Lack of confidence

The lack of confidence and misinformation about VRE can increase the risk perception towards VRE investment (Huijts et al., 2012). Masini and Menichetti (2013) distinguish two types of confidence related to VRE investments: technology confidence and policy confidence. Technology confidence reflects the project developer's personal belief about the technological performance of VRE. Compared with fossil-fired electricity generation, VRE technologies are less established and often perceived as less mature (Masini and Menichetti, 2013). Skepticism about the reliability and adequacy of VRE technologies increase the risk perception of project developers (Barth and Siebenhuner, 2010). This is often exacerbated by misinformation about VRE technologies created by the fossil fuel lobby (Valentine, 2011; Smink et al., 2015). Policy confidence reflects the developer's personal belief in the effectiveness of policy that aims to stimulate and streamline VRE development (Masini and Menichetti, 2013). The lack of long-term credibility, stability and visibility in policy can reduce such policy confidence.

4.3.1.3 Lack of knowledge and experience

The lack of knowledge regarding VRE technology and its operation can increase the perceived risk towards VRE investment, because the perceived unknown level increases in absence of sufficient knowledge (Masini and Menichetti, 2013; Huijts et al., 2012). Consequently, even risk-seeking investors may feel unable to hedge against VRE technology risk (Masini and Menichetti, 2013). If the knowledge gap fits the developer' personal biases towards VRE technology, it may further reduce the confidence level in VRE investment (Masini and Menichetti, 2013).

Experience enables a better estimate and management of the actual risk level. Through learning by doing, experience in early adoption of VRE technology creates knowledge, which indirectly affects risk perception (Huijts et al., 2012). It also directly reduces the perceived risk due to increased familiarity with the technology. Based on an empirical survey of European investors, Masini and Menichetti (2013) point out that investors with greater experience in the renewable energy sector tend to favor renewable energy technology over fossil-fired technology. This suggests that lack of experience may increase the risk perception towards VRE investment.

4.3.1.4 Lack of sustainable strategic value

Firms with a stronger sustainable strategic value tend to be more accepting and hold a less risk-averse attitude towards VRE investments (Groot et al., 2013; Gamel et al., 2016). A large government ownership often increases the sustainable value and financial robustness of firms, reducing the risk perception (Groot et al., 2013). For instance, in Germany municipal utilities tend to weigh environmental motives higher than commercial utilities in investment decision-making (Barth and Siebenhuner, 2010; Nelson et al., 2016). This suggests that the lack of sustainable strategic value constitutes a barrier to VRE investments.

4.3.1.5 Individualistic worldview and culture

Risk perception for VRE investment can be affected by the worldview and culture of investors. Chassot et al. (2014) prove that investors holding an individualistic worldview favoring a free-market tend to affectively amplify their risk perception towards VRE investments under high regulatory exposure than other investors. Similarly, Weber and Hsee (1998) show that, due to social diversification, investors from a collectivist culture (e.g. China) tends to hold a lower risk perception than their peers from a individualistic culture (e.g. United States, Germany) for the same investment option. Therefore, an individualistic worldview and/or culture can hinder VRE investments.

4.3.2 Barriers in an iterative economic appraisal process

In this paper, the (expected) NPV of the VRE project and its at-risk value using the probabilistic discounted cash flow approach are adopted to perform the economic appraisal process. Therefore, barriers are here defined as attributes that reduce the absolute NPV of VRE investments or its relative value to fossil-fired plants. Attributes increasing the variance of NPV can also be deemed as barriers to VRE investment, which tend to reduce the NPV-at-risk value[28]. Figure 4.2 shows an illustrative example of the probability density function for NPV and the NPV-at-risk value at 5 percentile (or 95% confidence level). The NPV-at-risk value here represents the minimum NPV value with 95% probability. It can be generated through a Monte Carlo simulation, which draws repeated random samples of input parameters for the NPV calculation and statistically analyzes the calculation result. This requires defining the probability distribution for each input parameter and their correlations.

28 Under a higher variance, the probability distribution function for NPV becomes wider. Thus, the NPV-at-risk value at a given percentile tends to decrease. Note that a lower expected NPV also reduces the NPV-at-risk value, because it shifts the entire probability density function leftwards.

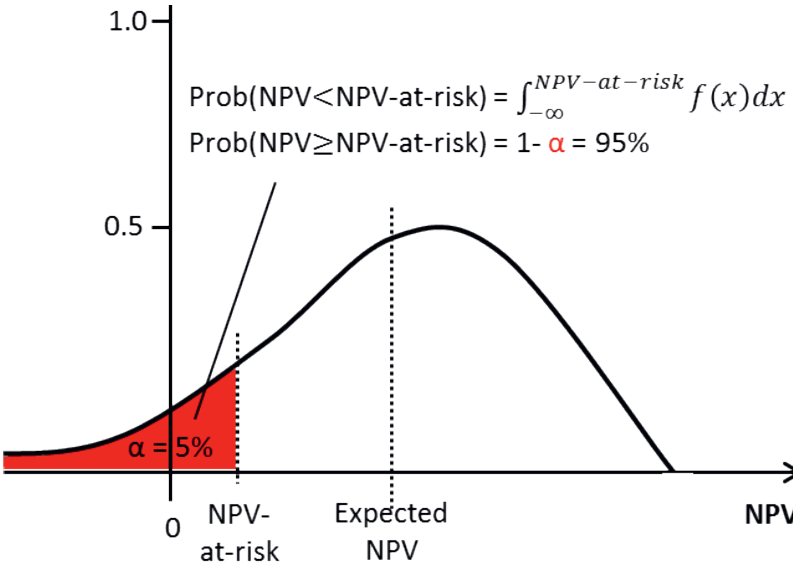

Figure 4.2. Probability density function of NPV and NPV-at-risk at 5 percentile

Source: adapted from Ye and Tiong (2000)

The NPV can be calculated via the following formula:

$$NPV = -I + \sum_{i=1}^{L} \frac{(B_i - C_i)}{(1 + r)^{-L}} \quad (1)$$

Where:
I: Upfront capital costs;
B_i: Annual revenue;
C_i: Annual operating &maintenance costs and tax payments;
r: Discount rate;
L: Project economic lifetime;

Formula (1) shows that barriers can result in a lower NPV or NPV-at-risk value through negatively influencing any of the input parameters of the calculation. In other words, barriers can influence either the expectancy of the economic lifetime, upfront capital costs, discount rate, annual tax payments or annual revenue of the VRE investment.

4.3.2.1 Underestimation of project economic lifetime

Underestimating project economic lifetimes tends to result in underestimated project NPV. Branker et al. (2011) report that although the manufacturers' guaranteed lifetime for solar PV system is usually 20-25 years, working lifetime well beyond 25 years is increasingly shown in practice. Once the guaranteed lifetime has passed, the system would still generate electricity at negligible cost. Therefore, a more credible value on the economic lifetime should be provided by industries that fully considers the trade-off between the actual working lifetime and the system degradation rate (Branker et al., 2011). If the guaranteed lifetime is used to determine the project NPV, it can give rise to misconception.

4.3.2.2 High unit upfront capital costs and capital-intensity

Despite the ongoing effects of technological learning and economies of scale, to date the upfront capital costs per unit of installed capacity for VRE world-wide are generally still higher than that of gas-fired power generation (see figure 4.3). In terms of firm capacity[29], unit upfront capital costs are even more expensive due to the variable nature of VRE. The unit upfront capital costs of onshore wind and PV have experienced significant cost reduction in past years, while a reversed trend has been observed for offshore wind since 2000 (Schwanitz and Wierling, 2016; Sovacool et al., 2017). Half of the increased costs can be explained by increased depth and distance to shore and increased commodity price, while the rest can be largely ascribed to increased offshore turbine price due to limited competition between manufacturers (Voormolen et al., 2016). Quality control for locational-specific mega-turbines, increased construction costs associated with disjointed turbine design and construction, the lack of standardization and fragmented construction industries may also limit the cost reduction for offshore wind (Sovacool et al., 2017).

29 Firm capacity represents the percentage of the nominal capacity of a power plant that can be served as guaranteed power supply with a certain level of system reliability (Sijm, 2014).

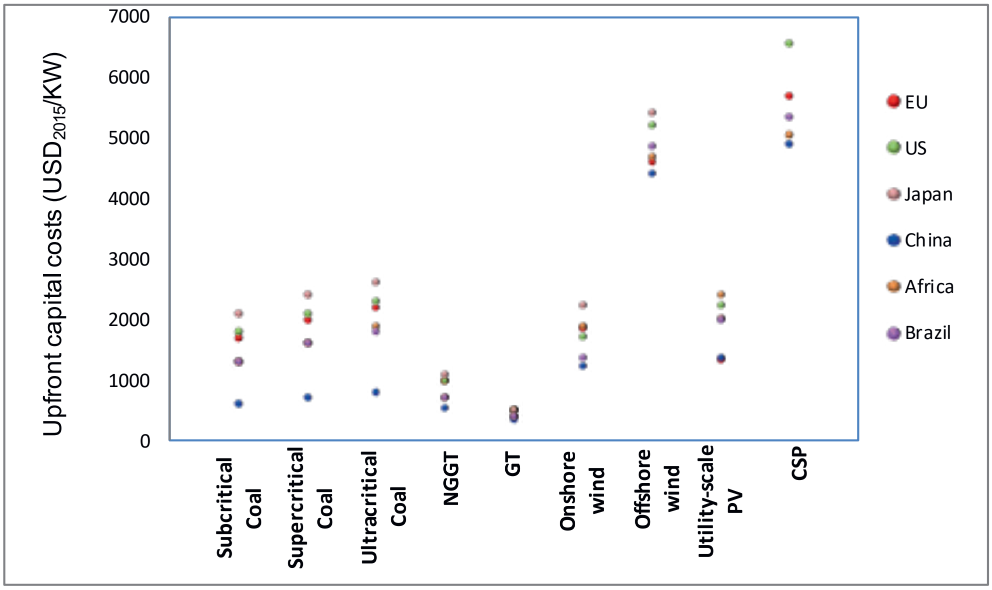

Figure 4.3. Unit upfront capital costs for investments in different fossil-fired electricity and VRE generation technologies

Source: Data derived from IEA (2016)

VRE investments also face higher capital-intensity than fossil-fired electricity generations (Finon, 2013; IPCC, 2011; Hirth and Steckel, 2016). For instance, the capital-intensity for gas-fired generation and coal-fired generation is typically 0.4 and 0.45, while it is 0.8 for onshore wind and even higher for solar (Helms et al., 2015). This tends to negatively impact the NPV of VRE investments, as more costs are paid upfront rather than being discounted in the future.

4.3.2.3 Non-accelerated tax depreciation policies

Tax depreciation policies affect the distribution of annual tax payment of VRE assets. A higher depreciation rate enables the project to claim higher after-tax net revenue in its early operating lifetime, which increases the NPV. This is in the case of accelerated depreciation that prescribes a depreciation time shorter than the project lifetime (Richardson, 2008). On the contrary, non-accelerated depreciation policies (e.g. straight-line depreciation) decrease the economic appeal of VRE.

4.3.2.4 Expected revenue insufficiency

Expectancy of insufficient annual revenue reduces the absolute NPV of VRE investments and its relative value to fossil-fired electricity generation. At worst, the project will be rejected if it fails to break even, i.e. NPV<0. Since the revenue received by VRE is the sum of the market revenue of selling electricity, the revenue of auxiliary products and subsidies from support policy schemes, fundamental causes for revenue insufficiency are related to unfavorable electricity market conditions or unfavorable policies:

- Unfavorable electricity market conditions

The market revenue of VRE is contingent on conditions of the electricity market. In a liberalized electricity sector, the revenue from electricity sales in the spot market usually constitutes the largest source of market revenue, depending on the electricity spot price and sales volume. A ***very low regulatory price-cap*** can decrease the spot price (de Vries and Hakvoort, 2013). Frew et al. (2016) also report that the ***spot price is often depressed by overcapacity*** due to the disconnection between the spot market and administratively-determined higher reliability standards. This gives rise to a market failure (Hogan, 2013; Hogan, 2017). Exacerbated by the large increase in VRE capacity but the limited market exit of surplus baseload capacity and the post-recession low demand, severe overcapacity has been identified in various regions, e.g. Germany and Australia (Auer and Hass, 2016; BMWi, 2015; Jotzo and Mazouz, 2015). This decreases revenue for all generators including VRE. VRE may, however, be more sensitive to a lower spot price compared to other generators. The short-run marginal cost (SRMC)-based price settlement in the spot market seems to not favor VRE characterized by close-to-zero SRMC. Firstly, due to the so-called "***merit-order effect***", there is a tendency of spot price decrease when VRE generation replaces the marginal thermal plant used to set the price (Chaves-Avila et al., 2015). Secondly, with increased VRE penetration, the spot price during periods of VRE generation tends to be further reduced because of the "***decreased temporal correlation effect***" between VRE and demand (Hirth et al., 2015). These two effects have already been demonstrated by many empirical and model-based studies (see Munoz and Bunn, 2011; Wurzburg et al., 2013). ***Decreased electricity sales volume*** of VRE also causes market revenue reduction. It occurs during curtailment resulting from ***limited flexibility*** of the power system to absorb surplus VRE generation (Zane et. al, 2012). System inflexibility can also be amplified by the overcapacity of baseload plants, since it increases the must-run generation level.

Besides providing electricity products, VRE is also able to provide balancing capacity products in the balancing market (Van Hulle, 2015; Hirth and Ziegenhagen, 2015). In particular, the downward balancing services provided by VRE are cost-effective because no opportunity cost is involved (Hirth and Ziegenhagen, 2015). However, ***biased market conditions*** in terms of low time resolution and early gate closure time create an entry barrier for VRE to provide reliable balancing services (Hirth and Ziegenhagen, 2015). This reduces potential revenue streams for VRE. Similarly, an unfavorable imbalance

4

settlement system for allocating system balancing costs can reduce VRE's revenue. For instance, a two-price system penalizes any imbalance of electricity delivery from schedule, even if such imbalance counteracts the system imbalance (Scharff, 2015). This punishes VRE more often due to the difficulty in forecasting (Baker and Gottsterin, 2012). It also discriminates against smaller market participants, which often include VRE, since large market participants are more capable of netting their imbalances (Vandezande et al., 2010).

- Unfavorable policies

Relying on market revenue alone, currently it seems less likely for VRE to recover its high upfront capital costs (Janerio et al., 2016). This can be largely explained by unfavorable Energy & Climate policies that ***fail to create a level playing field*** for VRE to compete with fossil-fired electricity generation in the market. Firstly, due to the ***incomplete internalization of negative externalities*** (e.g. climate change, air pollution, energy dependency) associated with fossil-fired electricity generation, VRE's value in avoiding these externalities is not fully reflected in electricity pricing (Neuhoff, 2005). This represents a fundamental market failure. Emission standards regulation is often criticized for legitimizing pollutant levels below the prescribed emission limits without pricing their external costs (Outka, 2012). Even when there are externality-pricing schemes (e.g. pollution tax or cap-and-trade), the price level is often insufficient to fully internalize all external costs. An often cited-case is the EU emission trading scheme (ETS). Its carbon price (per Tonne CO_2) only oscillated between 6.4-8.6 $Euro_{2015}$[30] in 2015, compared to a social cost of carbon (SCC) at 108 $Euro_{2015}$ estimated by the Stern Review and a minimum carbon price required at 61 $Euro_{2015}$ to make VRE investments break-even (Stern, 2007; Deutsch et al., 2014). Secondly, ***explicit and/or implicit subsidies for fossil fuels***, as market distortions, also reduce the revenue of VRE relative to fossil-fired electricity generation (REN21, 2015). The total global subsidies for fossil fuels amount to 516 billion USD_{2015} in 2014, equivalent to a negative carbon price of 116 USD_{2015}/Tonne CO_2 (IEA, 2015)[31]. This subsidy can be substantially increased, if costs associated with military operations and diplomatic activities to secure overseas fossil resources are included (Outka, 2012). Thirdly, due to historical prioritization of development, fossil fuel industries as incumbents have large ***vested interests*** in maintaining their competitive advantages over VRE in terms of subsidies, existing physical infrastructure and incomplete internalization of externalities (Effendi and Courvisanos, 2012). They also have more political power and lobbying capacity to hinder potential policy efforts that aim to establish a level playing field for VRE (Smink et al., 2015).

30 EEX European emission allowance auction (EUA) market data (https://www.eex.com/en/market-data/emission-allowances/auction-market/european-emission-allowances-auction#!/2016/06/20)

31 Original data are converted into their constant USD_{2015} value.

Support policy schemes for VRE investments can be justified by compensation for the positive externality of technology spillover, a market failure, and the unlevelled playing field (Fischer and Preonas, 2010; Auer and Burgholzer, 2015; Andor and Voss, 2016). These schemes target VRE investments either based on each unit of electricity production or installed capacity. They play an essential role in enabling VRE investments break-even. Hence, ***insufficient support levels*** can lead to revenue insufficiency. Often it is caused by ***constrained government budgets***, especially under austerity measures of fiscal policy (Galgóczi, 2015; Del Rio et al., 2015). For instance, Van der Elst and Bosch (2012) observed that limited budgets under the Dutch SDE+ scheme have led to under-bidding for support application. Many investment decisions will be finally rejected, once the project viability becomes clear (Van der Elst and Bosch, 2012). A similar case is also reported for PV projects in China (SEMI PV Group, 2011).

Negative interactions between the electricity market and policies and between different policies, if not minimized, may also contribute to revenue insufficiency. Two mechanisms are often reported for such interactions. One mechanism is that ***in absence of an ex-post cap adjustment mechanism***, VRE support schemes reduce the demand for emission permits under a cap-and-trade scheme (Richstein et al., 2015). This results in a decreased carbon price and electricity spot price, as observed in the EU ETS (Fischer and Preonas, 2010; Koch et al., 2014). The other mechanism is related to the direct distortion effect of various ***production-based support schemes*** (e.g. feed-in tariff, feed-in premium and tradable green certificates) on the electricity market, which leads to a depressed spot price (Oliveira, 2015). Both interaction mechanisms increase the support level required for VRE investments.

Besides revenue insufficiency, revenue volatility also negatively affects the financial appraisal, since it tends to lower the NPV-at-risk value. Three factors contributing to revenue volatility of VRE investments are often reported in the literature. Firstly, due to the ***merit-order*** and ***decreased temporary correlation effects***, spot price volatility tends to increase with increased VRE penetration in the electricity market. Secondly, price volatility is an inherent characteristic of ***quantity-based policies*** for pricing externalities (e.g. cap-and-trade scheme) or supporting VRE (e.g. tradable green certificate) (Coulon et al., 2015). These are expected to increase the revenue volatility of VRE investments. Large price volatility has been observed in the EU ETS and the Swedish/Norwegian green certificate market (Koch et al., 2014; Fagiani and Hakvoort, 2014). Last but not least, revenue volatility also depends on the ***type and features of support schemes***. Under the same mean value of annual total revenue, feed-in premiums (with fixed premiums on top of the spot price) result in higher volatility than feed-in tariffs (with guaranteed price) (Kitzing, 2014). However, design features such as price floor and cap may limit the higher volatility associated with feed-in premiums (CEER, 2016; Angelopoulos et al., 2016). Tradable green certificates can result in the highest revenue volatility for VRE investments (Fontaine et al., 2016). Although feed-in tariffs provide the most stable revenue, they are increasingly replaced by other support schemes to stimulate improved market integration. For instance, the EU will prohibit the use of feed-in tariffs to support new VRE installations from 2016 onwards (EC, 2014).

4.3.2.5 High discount rate and additional strict cut-off investment criteria

The discount rate is the minimum required rate of return demanded by the project developer, and it represents the present time-value of future cash flows. A high discount rate can be considered a barrier to VRE investments, since it leads to low or even negative NPV. Based on survey and literature data, Oxera (2011) reports the range of (pre-tax) real discount rate used by investors in the United Kingdom for different VRE technologies, against that for Natural Gas Combined Cycle (NGCC) (see figure 4.4). Although only reflecting the situation in the United Kingdom, it shows that VRE investments might face a higher discount rate than fossil-fired electricity generation. As VRE investments are comparatively more capital-intensive, their NPV calculation is more sensitive to high discount rates. Therefore, a higher discount rate further exacerbates the comparative disadvantages

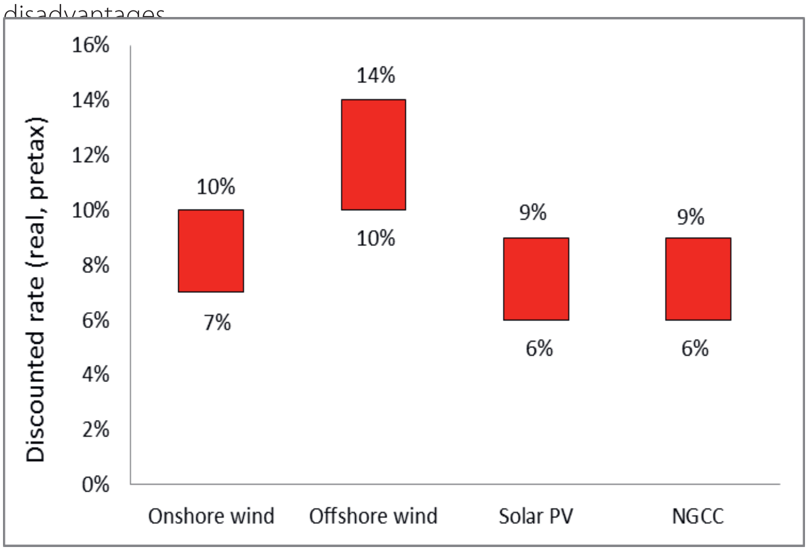

Figure 4.4. Discount rate ranges for investments in different VRE technologies and NGCC

Source: data derived from Oxera (2011)

The discount rate should at a minimum reflect the ***weighted costs of capital (WACC)*** or financing costs of the underlying VRE investment. Therefore, the discount rate increases with the WACC. Companies commonly determine WACC based on the capital asset pricing model (CAPM), which adjusts the risk-free rate based only on systematic risks – risks correlated with overall macroeconomic conditions and business cycles (Oxera, 2011). Due to relatively underdeveloped capital markets, less stable macroeconomic conditions and state of political environments, and higher inflation, VRE investments in developing countries usually face a WACC substantially higher than that in developed countries (Waissbein, 2013; Ondraczek et al., 2015). Angelopoulos et al. (2016) also reports that in the case of onshore wind investments throughout different European countries, the WACC is highest in Greece and Croatia (12%), while lowest in Germany (3.5-4.5%).

The CAPM assumes sector/firm/project -specific unsystematic risks (e.g. revenue volatility associated with input estimates, weather-related resource risks, technology risks) can be fully diversified away without additional costs. In practice this is hardly the case for VRE investments (Fougner, 2011). One explanation is the lack of insurance coverage due to insufficient loss data and high complexity due to the involvement of several project partners, which is particularly the case for offshore wind projects with relatively short track records (Gatzert and Kosub, 2016). Financial theories suggest that unsystematic risks should not be compensated to avoid double counting, since they are already covered through adjusting for the cash flows in the probabilistic DCF approach (Edner and Paulsson, 2013). However, in practice risk premiums adjusted for unsystematic risks are often added on top of the WACC (Jagannathan et al., 2016; Oxera, 2011). Such a practice of "***Fudge factors***" artificially increases the discount rate[32], potentially reducing the NPV of VRE investments and increasing the support level needed. A typical example is the use of a risk-adjusted discount rate to compensate for the revenue volatility (an unsystematic risk) associated with different VRE support schemes, as mentioned by Kitzing (2014). This can result in a higher discount rate for feed-in premium schemes than that for feed-in tariff schemes at the same mean revenue level. Finon (2013) also argues that in the SRMC-based spot market the self-hedging ability to price volatility is very limited for capital-intensive VRE investments, because of the large gap between their SRMC and long-run marginal costs (LRMC). This increases the risk of unrecovered upfront capital costs (downside risk) and, consequently, the discount rate (Finon, 2013).

In presence of many unsystematic risks that are unmeasurable unknown unknowns (e.g. policy uncertainty risks, social acceptance risks, spot price uncertainty risks), fudge factors can be partly, if not fully, justified. Risk premiums that are fed into the discount rate increase with the level of risk perception. In particular, ***policy uncertainty risks due to discontinuity of existing support schemes and the lack of long-term policy visibility***

32 Note that if capital providers also adjust their required rate of return to unsystematic risks, their fudge factors will be fed in to the WACC. It will result in an even higher discount rate.

can have substantial and long-lasting impacts on the risk perception towards VRE investments, which increases the risk-adjusted discount rate (WB and CIF, 2013; De Jager and Rathmann, 2008; Jacobs et al., 2016). For instance, the imposition of retroactive tariff reduction for existing VRE projects almost shut down new VRE investments entirely in Spain in 2013 (UNEP and BNEF, 2014). As demonstrated by Luthi and Prassler (2011), wind project developers in the EU and the US also rank legal security as the most important factor in their investment decision-making (Klessmann et al., 2013). In addition, insurance coverage for policy uncertainty risks barely exists (Gatzert and Kosub, 2016). If project developers are incapable of managing the perceived highly unknown levels associated with VRE investments, they may use a very high discount rate or ***additional strict cut-off investment criteria*** (e.g. high IRR and short PBP) to exclude the investment decision.

4.3.3 Barriers at project development stage

Barriers at this stage hinder the completion of necessary project development steps, and they can be split into two elements: high development costs (section 4.3.3.1) and lack of social acceptance (section 4.3.3.2).

4.3.3.1 High development costs

Before access to external capital, costs associated with different project development steps have to be covered by the developer's own financing resources (WB and CIF, 2013). Therefore, high development costs can be a barrier to VRE investments. ***High development costs may exacerbate revenue insufficiency***, as the project developer tends to demand a higher level of support to compensate for the reduced profit margin (Klessmann et al., 2013). In particular, costs associated with procedures of permits acquisition and grid connection constitute a significant part of project development costs. These costs are usually inflated by complex administrative permitting procedures, excessive power quality demand and unfavorable allocation of grid costs.

- Lengthy administrative permitting procedures

Lengthy administrative permitting procedures can significantly increase the project lead time, required efforts and human resources, resulting in increased development costs (Klessmann et al., 2013). They are reported as the primary concern affecting investment decision-making for European solar PV project developers (Luthi and Wustenhagen, 2011; Klessmann et al., 2013). Lengthy permitting procedures are often prolonged by bureaucracy, non-streamlined procedures, lack of transparency or a clear timeline, the involvement of a large number of authorities and a lack of coordination between involved authorities (Del Rio, 2011; Waissbein, 2013; Henrich, 2014; Verhaegen et al., 2016). This is especially relevant to offshore wind (Gatzert and Kosub, 2016).

- Excessive power quality demand

As non-synchronous generators, VRE generators are connected to the grid via power electronics instead of electro-mechanical links (IEA, 2014b). Unlike fossil-fired synchronous generators, they alone lack capabilities for power quality control, such as system inertia, reactive power and voltage support, transient stability and fault ride-through capability (IEA-RETD, 2015; Van Hulle et al., 2014). To maintain grid stability, the grid code may demand VRE to install additional equipment for power quality control before the issuance of grid connection permits (Basit et al., 2012). If such demand becomes excessive, it may incur high costs for the project.

- Unfavorable allocation of grid costs

Due to relatively remote locations, VRE projects typically incur higher costs associated with grid connection and the reinforcement of the existing grid (Auer, 2011). Thus, unfavorable allocation of grid costs can increase development costs. In general, four prototypical allocation approaches can be distinguished, i.e. deep approach, hybrid approach, shallow approach and super-shallow approach, depending on the extent to which grid costs have to be borne by the developer (Auer, 2011; Swider et al., 2008). In the deep approach, the developer pays for all costs; while only grid connection costs are paid in the shallow approach. In the super-shallow approach, all costs are socialized. Since it is difficult to disentangle the marginal impact of a new VRE project on grid reinforcement requirement, deep and hybrid approaches may unfairly increase the financial burden for the developer (Swider et al., 2008 and Zane et al., 2012). Even if a shallow approach is adopted, grid connection alone can still incur significant costs, especially for offshore wind projects far away from shore (Swider et al., 2008).

4.3.3.2 Lack of social acceptance

The lack of social acceptance ranges from spontaneous protests, professional campaigns and even legal suits (Ecorys, 2008). It often causes delays in project development (especially the permitting step) and the escalation of development costs, which discourages VRE investments (Del Rio, 2011; Enevoldsen and Sovacool, 2016). A high risk perception of social acceptance may also lead to the early rejection of investments at the preliminary risk scanning stage, or a high discount rate in the economic appraisal process (Angelopoulos et al., 2016). Social acceptance towards VRE investments can be distinguished into two dimensions: generic public acceptance at consumer level and local acceptance at community level (Del Rio, 2011).

- Lack of public acceptance

Because of its environmental benefits, social acceptance today for VRE is generally high in major western economies and China (Liu et al., 2013; Knebel et al., 2016; Bertsch et al., 2016). Such acceptance is positively correlated with people's knowledge of VRE, and with education and income levels. This is reflected in the surveyed willingness-to-pay (Liu et al., 2013; Moula et al., 2013). However, ***either too high or substantial increase of support costs*** for VRE can negatively impact public acceptance (Del Rio et al., 2015). This is particularly the case if an additional surcharge in the electricity bill (instead of public budgets or tax-financed funds) is used to finance support costs, e.g. in most European countries (Del Rio et al., 2015). It directly increases the perceived financial burdens of residential end-users and can be socially regressive (Diekmann et al., 2016; Grubb et al., 2016). Due to the ***merit-order effect***, the surcharge level tends to increase with increased VRE penetration. In Germany it increased from 0.011 Euro/kWh to 0.053 Euro/kWh between 2008 and 2012, which has already been declared as too high by more than 51% of Germans (Möhlenhoff, 2014). The high and rapid increase of the surcharge is also explained by the exemption of energy-intensive industry and a large proportion of commercial users (Möhlenhoff, 2014). This form of ***distributive unfairness*** may further endanger public acceptance.

- Lack of local acceptance

Deployment of VRE projects cannot avoid negative local outcomes. Visual impact on landscape, noise and depreciated property value are associated with wind projects, while solar projects can cause heat island effect (mainly in semi-arid lands) and natural habitat losses (Walter and Gutscher, 2010; Barron-Gafford et al., 2016; Carlisle et al., 2016). These impacts tend to increase with project size and often lead to strong opposition by local stakeholders. For instance, local protests forced the withdrawal of the Palen CSP project in California, even though it had been priory approved by state regulators (Roth, 2014). This lack of local acceptance is often cited as "not in my backyard" (NIMBY) syndrome, although this may oversimplify the actual motives of locals (Wustenhagen et al., 2007; Carlisle et al., 2016). Better explanations include ***perceived impacts*** and ***perceived unfairness*** by locals (Wustenhagen et al., 2007; Walter and Gutscher, 2010; Jami and Walsh, 2014; Enevoldsen and Sovacool, 2016). Perceived local impacts of VRE projects can be amplified by ***sub-optimal spatial planning*** and ***misinformation*** (Lantz and Flowers, 2010). Communication with local stakeholders including the provision of credible information and figures corrects misinformation, but its effectiveness can be reduced due to ***mistrust*** of locals towards the (external) project developer (Lantz and Flowers, 2010). Highly complex, non-transparent or inaccurate information, frivolous attitudes towards locals' fears and overlooking long-term relationships with the community all undermine such trust (Walter and Gutscher, 2010). Perceived unfairness includes unfairness associated with the distribution of negative and positive outcomes (i.e. distributive unfairness) and unfairness related to the treatment of relevant stakeholders in the decision-making procedure (i.e. procedural unfairness)

(Wustenhagen et al., 2007). Procedural unfairness, distributive unfairness and mistrust often reinforce each other. Factors contributing to distributive unfairness include the use of universalistic resources (e.g. money) to compensate for losses of particularistic resources (e.g. landscape impact) due to VRE deployment, limited distribution of project profits to stakeholders or distribution to a small number of stakeholders, and the exclusion from financial participation of stakeholders (Walter and Gutscher, 2010). Procedural unfairness is affected by limited participation opportunities (e.g. information, consultation, cooperation) and untimely involvement of locals in project development (Walter and Gutscher, 2010; Jami and Walsh, 2014; Langer et al., 2017).

4.3.4 Barriers at capital access stage

At this stage, the project developer has to access sufficient and affordable capital to finance the investment before the approval of the FID. Financing can be either on-balance sheet corporate financing, or (limited or non-resource) project financing secured against the future project cash flows. Project financing has been increasingly used in the renewable energy sector, and it accounted for 52% of total renewable energy investment in 2015 (OECD, 2016). Due to limited retained earnings reserved for re-investment[33], both corporate financing and project financing require external capitals in the form of debt and equity[34] (IEA, 2014a; De Jager et al., 2011). A high WACC can be caused by ***high risk perception of capital providers*** towards VRE, reducing the project's economic appeal and its affordability to access capital (Campiglio, 2016). Barriers at this stage mainly include the lack of equity and the limited access to bank lending.

4.3.4.1 Lack of equity

The lack of equity for renewable energy investments was previously only a problem in non-OECD countries (WB and CIF, 2013). In OECD countries, the post-recession macro-economic uncertainty has caused conventional equity investors to favor investment in government bonds with high credit ratings (EC, 2013). Investors in VRE projects often include small and medium-sized utilities (e.g. in Germany) (Jacobs, 2012), but their ability to access equity financing is relatively limited (EC, 2013). In Europe, senior executives in the renewable energy sector have expressed concerns over whether sufficient equity is available to finance the offshore wind prescribed by the EU's 2020 national action plans (Freshfields Bruckhaus Deringer, 2013). Due to the lack of equity, VRE projects have to rely on a large amount of debt to leverage investments. Although such leverage

33 Retained earnings account for 2/3 and1/4 of energy sector corporate financing in OECD and non-OECD countries, and they account for only 2.9% total asset financing for renewable energy investment (excluding large hydro) in 2015 (IEA, 2014a; UNEP and BNEF, 2016).

34 A few financial vehicles have emerged in recent years, such as corporate/project green bonds, institutional investors, crowd funding and YieldCos, but they are currently marginal and under-developed, especially in developing countries (IEA, 2014a; UNEP and BNEF, 2014).

reduces the WACC (cost of debt is generally lower than cost of equity), still a minimum equity ratio in total capital is required by debt holders (because of the risk concerns of debt holders and the senior nature of debt), which is typically 15% in OECD countries and 40% in non-OECD countries (De Jager et al., 2011; IRENA, 2012).

4.3.4.2 Limited access to bank lending

Bank lending is the leading external source in financing renewable energy investments. Many national and international development banks have established specific programs targeting renewable energy financing with favorable lending rates. However, loans provided by development banks are limited, because they cannot autonomously create credit (i.e. money) and they have to rely on raising capital from secondary markets (Campiglio, 2016). Commercial banks create credit to provide loans, but they can be biased against VRE investments due to the perception of unattractive risk-return profiles and relatively short track records (Narbel, 2013; Umamaheswaran and Rajiv, 2015; Campiglio, 2016). Moreover, VRE investments, featuring typically smaller nameplate capacity than fossil-fired electricity generation, tend to face disproportionately ***higher due diligence costs*** to obtain loans from commercial banks, due to the significance of economies of scale (WB and CIF, 2013; IPCC, 2011). This may exclude small and medium projects to access bank loans (WB and CIF, 2013; Hamilton, 2010). Last but not least, access to bank lending is affected by ***side-effects of monetary policy***. To date, many central banks (e.g. Eurozone, Japan) have introduced a negative interest rate policies to address excess liquidity and stimulate economic growth (Demiralp et al., 2017; Hannoun, 2015). This seems to increase the incentives for lending and be beneficial for VRE investments. However, empirical evidence shows that it has actually increased the lending rate in economically underperforming countries, especially in vulnerable countries (e.g. Italy, Spain, Portugal) which experienced severe stress during the recession (Demiralp et al., 2015). This is because banks in these countries have a limited ability to pass on profit losses resulting from negative rates to their depositors, and they tend to charge a higher lending rate to compensate for the reduced profits (Demiralp et al., 2015; Stiglitz, 2016). Post-recession macro-prudential regulations, such as Basel III at the global level and Solvency II at EU level, can also tighten the terms and conditions for financing renewable energy, because they focus on banks' short-term liquidity, solvency and stability (Narbel, 2013; IEA, 2014a; Campiglio, 2016). They are expected to significantly reduce both the availability and period of bank lending (Narbel, 2013). Eckhardt (2012) has estimated that the maximum bank lending period in the future is likely to be below seven years (Narbel, 2013). This is especially harmful for capital-intensive VRE investments that require long-term financing (typically 12-15 year) to cost-effectively spread the upfront costs over their operating lifetime (IRENA, 2012).

4.4 SYNTHESIS AND POLICY IMPLICATIONS

This paper develops an integrated framework that analyzes barriers to VRE investments through a literature review-based analysis. The framework covers most barriers to VRE investments identified in the existing body of literature. Figure 4.5 presents an overview of this framework, where each box represents a specific barrier elaborated on previously, and the arrow establishes the causal-relationship between two barriers. This framework connects barriers to different stages of the investment decision-making process which is closely related to the project life of VRE assets. Thus it expands the knowledge base on the key mechanisms through which different barriers hinder the realization of VRE investments and enables relevant stakeholders to better diagnose these barriers. Policy implications can also be drawn from the consultation of such a framework. They can help policy-makers and regulators to design effective instruments to address the barriers and safeguard necessary VRE investments consistent with the 2 °C climate target.

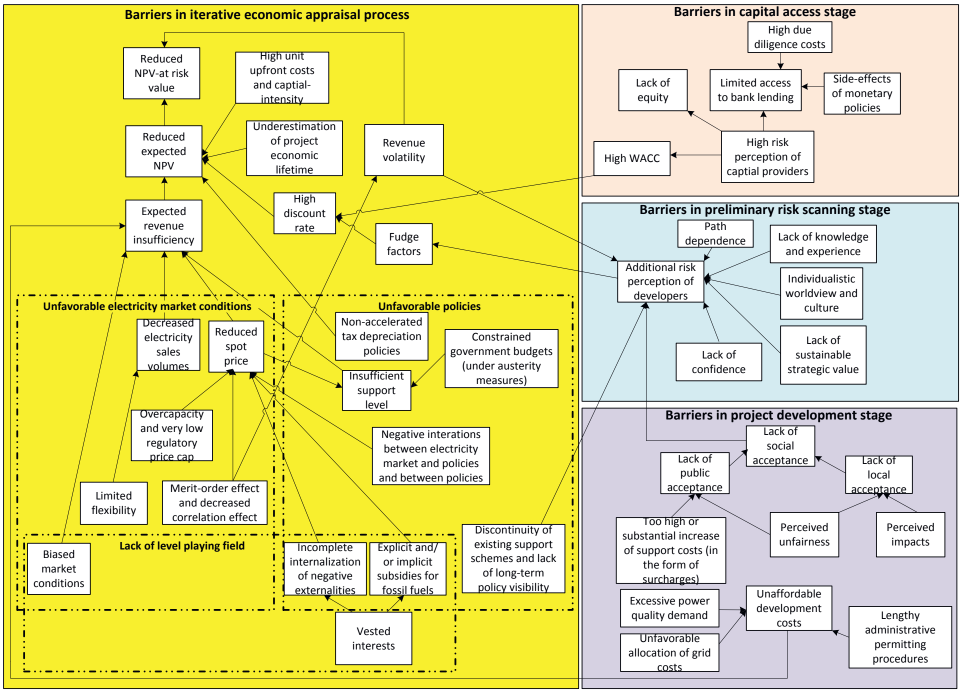

Figure 4.5. Overview of the integrated framework for barriers to VRE investment

The framework confirms the importance of risk reduction for VRE investments, as suggested by a few authors (see e.g. Michelez et al., 2011; Angelopoulos et al., 2016; Angelopoulos et al., 2017). It shows that most barriers can find their impacts, either directly or indirectly, on the economic appeal of VRE investments, which is reflected in the reduced expected NPV or NPV-at-risk value. Barriers in the iterative economic appraisal process chiefly exhibit a negative affect over the sufficiency and/or volatility of the expected revenue, while barriers at other decision-making stages tend to increase the project developer's risk perception and be ultimately fed into the discount rate. To address the impacts of these barriers, policy-makers should design instruments that can improve the risk-return profile of VRE investments. This requires not only the mitigation of actual risks (e.g. social acceptance risks, policy uncertainty risks, revenue volatility risks), but also the addressment of psychological, behavioral and institutional attributors that increase the risk perception. Effective risk reduction necessitates more stable and credible policy instruments that can deliver long-term visibility. They should also be able to target multiple stakeholders involved in VRE investments, including the project developer, capital providers, the general public and locals. Risk reduction can have multiple benefits that contribute to a positive investment decision. In addition to increasing the economic appeal of the project, it increases the chance of progressing the project from investment intention to development action during the preliminary risk scanning stage. Furthermore, It can accelerate the completion of the project development stage and reduce development costs. A reduced risk profile also increases the willingness of capital providers to finance the VRE project at the capital access stage.

Following the integrated framework, two additional main policy implications can be drawn: Firstly, barriers at different decision-making stages can be distinguished into what we call "**symptomatic**" and "**fundamental**" barriers. The former describes a specific symptom or phenomenon that hinders the decision-making process to move forward, while the latter is the root cause behind this symptom. With the help of arrows in figure 4.5, they can be easily identified. Symptomatic barriers can be addressed through policy instruments targeting the symptom itself or fundamental barriers that cause such symptom. We argue that addressing fundamental barriers is more effective and has more long-lasting effects when compared to only addressing the symptomatic barrier. For instance, as a symptomatic barrier, revenue insufficiency can be addressed by subsidies from support policy schemes, which can have rapid effects. This solution alone cannot solve the fundamental causes of the symptom, (e.g. unfavorable electricity market conditions, unfavorable policy and the lack of level playing field). We have shown that if not carefully designed, it may even exacerbate the fundamental barriers (e.g. through price distortion effect of production-based support schemes), increase the subsidy level needed, and cause other side-effects (e.g. increased surcharge levels for consumers). Instead, solving fundamental barriers (through establishing a level playing field, directly targeting market failures and adapting the electricity market to increased VRE generation) can eliminate these concerns.

Secondly, when designing instruments to support VRE investments, policy-makers should not overlook negative interactions with other policy instruments or with the well-functioning of the electricity market. Negative interactions not only undermine the effectiveness of a single policy instrument, but also reduce efficiency of the overall policy mix. This research demonstrates that macroeconomic policies can have negative impacts on VRE investments. For instance, austerity measures in fiscal policy can constrain government budgets, reducing the support level for VRE investments. Side-effects of monetary policy (e.g. negative interest rates, macro-prudential regulations) can increase the lending rate and decrease the availability of bank loans for VRE investments. Therefore, the authors argue that a comprehensive policy framework to support VRE investments should not be only limited to the narrow context of climate and energy policy and the electricity market. It should be incorporated into a broader context that also includes monetary and fiscal policies. When redesigning these macroeconomic policies, their potential negative impacts on other policy objectives (e.g. energy transition and VRE investments) should be considered and corresponding measures should be taken to minimize these impacts.

4.5 RECOMMENDATIONS FOR FURTHER RESEARCH

This paper provides a comprehensive and up-to-date review-based analysis of barriers to VRE investments, based on the development of an integrated framework that represents different stages of the investment decision-making process. Different barriers identified from the existing body of literature and their causal-relationships are well-integrated into such a framework. However, the developed framework can be improved in a few aspects. This also illuminates directions for further research.

First, this framework connects barriers to VRE investments with the investment decision-making process, based on the underlying rationale that barriers increase the likelihood of the investment decision being rejected. It allows the identification and analysis of different types of barriers from existing literature sources, as well as their attributes and relationships, in a straightforward and qualitative manner. However, application of this framework alone is insufficient to disclose the relative size and significance of each identified barrier in terms of the impact on investment decision-making. To complement this research, the authors suggest further studies to quantitatively assess this aspect. These could be conducted through a case study or a survey-based logistic regression analysis. These studies would also be supportive to verify and refine the developed integrated framework that represents the investment decision-making process.

Second, the framework is developed to represent the investment decision-making process for VRE investments, where facing the three states of unknowns (i.e. risks, uncertainties and ignorance) is inevitable. While ignorance is barely conquerable and should be treated warily at best, the framework in this paper assumes (unquantifiable) uncertainties can be reduced to (quantifiable) risks through assigning a (subjectively) estimated probability. Such a reductionist approach allows the application of probabilistic models (e.g. Monte Carlo simulation) to tackle uncertainties in investment decision-making, especially in the economic appraisal process. Despite its convenience, this approach cannot fully tackle uncertainties in the case of events associated with probabilities that cannot be estimated, and the existence of more than one possible probability distribution. A complementary scenario analysis appears to be capable of addressing this issue and it can include unpredictable system-wide structural change events (e.g. changing the infrastructure of the energy system, changing the rules of the electricity market, changing subsidy schemes) into the decision-making process. Under different scenarios, the relevance of each barrier identified in this paper can differ. Low reliability of the input parameters (e.g. for the economic appraisal) also gives rise to uncertainties in the investment decision-making. The combination of a qualitative pedigree analysis and a quantitative sensitivity analysis can better deal with such uncertainties (van der Sluijs et al., 2005). To take all these into account, the authors propose further model-based studies to develop algorithms which can better allow for uncertainties in the investment decision-making process.

Third, because of zero direct emission, VRE investments are considered more environmentally sustainable than fossil-fired electricity generation projects. Hence, the developed framework in this paper mainly focuses on the risk and economic aspects of investment decision-making from the project developer's perspective. However, from a broader view of sustainability, the environmental and social aspects throughout the entire life cycle (including the supply chain) of the underlying VRE investments are as equally important as the economic aspect. Accomplishing certain steps of the project development stage (e.g. EIA and permits acquisition) usually requires a certain level of social and environmental performance of VRE investments, but it is not sufficient to guarantee a high level of sustainability. Although more stringent sustainability criteria are not mandatary for VRE investments (and thus do not constitute barriers), they are expected to be respected. These criteria can include a low embodied energy/emission; a short energy/emission payback period; limited impact on biodiversity; and the use of locally available supply chain, labour and feedstocks etc. To incorporate sustainability criteria into VRE investments, a multi-criteria decision-making process can be established. An accompanying full life cycle assessment (LCA), which includes Environmental LCA, Social LCA and Life-cycle cost analysis, is needed to support such decision-making.

Future studies are recommended to explore this area.

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5

Identifying Barriers to Large-scale Integration of Variable Renewable Electricity into the Electricity Market: a literature review of market design

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ABSTRACT

For reaching the 2 °C climate target, the robust growth of electricity generation from variable renewable energy sources (VRE) in the power sector is expected to continue. Accommodation of the power system to the variable, uncertain and locational-dependent outputs of VRE causes integration costs. Integrating VRE into a well-functioning electricity market can minimize integration costs and drive investments in VRE and complementary flexible resources. However, the electricity market in the European Union (EU), as currently designed, seems incapable to deliver this end. This paper aims to provide a comprehensive literature review of barriers to the large-scale market integration of VRE in the EU electricity market design. Based on the set-up of the EU electricity market, a framework was developed to incorporate the most pertinent market integration barriers and resulting market inefficiencies.

This paper concludes that an overhaul is needed for the current EU electricity market to address all barriers identified. Firstly, a discrete auction intraday market, a marginal pricing balancing market, a two-price imbalance settlement and a nodal pricing locational marginal pricing mechanism seem more promising in limiting integration costs. Secondly, to support business cases of VRE and complementary flexible resources in the electricity market, a level playing field should be established and the price cap should be lifted up to the value of lost load (VOLL). Meanwhile, to fit VRE's market participation, a higher time resolution of trading products and later gate closure time in different submarkets would be required. Lastly, feed-in support schemes currently widely used for VRE investments might be inconsistent with market integration, as they increase integration costs and lock VRE investments in a subsidy-dependent pathway. To avoid such lock-in, further investigation of alternative capacity-based support schemes is recommended.

5.1 INTRODUCTION

The Paris Agreement aims to limit the increase of the global average surface temperature to 1.5-2 °C above pre-industrial level to avoid the worst impacts of climate change (UNFCCC, 2015). Keeping the temperature increase well below 2 °C through cost-effective strategies requires the decarbonization of the power sector, which accounted for 38% of global energy-related CO_2 emissions in 2013 (IPCC, 2014; IEA, 2015a). Variable renewable electricity (VRE), which is electricity generation from stochastic energy flows (e.g. wind and solar), plays an indispensable role in replacing fossil-fired electricity production that, next to climate change, cause other negative externalities including air pollution and energy insecurity (Pearce, 2005; Markandya, 2010; Borenstein, 2012; IRENA, 2016). According to the 2 °C scenario of the International Energy Agency (IEA), the contribution of VRE to global electricity supply has to increase from 4% in 2013 to 25% in 2040 (IEA, 2015b). Similar figures are found for the European Union (EU) that should increase the share of VRE in gross electricity generation from 11% in 2014 (Eurostat, 2016) to at least 36% by 2050 to contribute to its long-term emission reduction target (EC, 2014a). VRE, characterized by variability, uncertainty and locational-dependence, however, interacts with the non-VRE part of the power system (hereafter referred to as the residual system). This results in technological, institutional and managerial challenges associated with grid operation, such as the increased need for flexible resources (e.g. flexible plants, storage, demand response, grid infrastructure) and power quality control, better inter-regional coordination and sophisticated method to size reserve. They often cause extra operational and investment costs in the residual system to accommodate VRE (Henriot and Glachant, 2013; Sijm, 2014; IEA, 2014a; Hirth et al., 2015; Agora Energoewende; 2015; Bunn and Munoz, 2016). These costs are often labelled as integration costs[35], which increase with the rising penetration of VRE. They inevitably become notable when VRE penetration reaches 10%. Various sources (Ueckerdt et al., 2013; Holttinen et al., 2013; IEA, 2014a; Sijm, 2014) indicate that at 10% penetration, integration costs are 9-13 €/MWh for onshore-wind and 26.5-32 €/MWh for solar PV. Integration costs can act as an economic barrier for the continuous growth of VRE (Ueckerdt et al., 2013). Integration costs reduction becomes increasingly prominent in today's energy policy agenda (Roy, 2015). Despite an emphasis on "cost-effectiveness" and "cost-efficiency" in the EU's official *Roadmap for Moving to a Competitive Low Carbon Economy* (EC, 2011) and *Framework Strategy for a Resilient Energy Union with a Forward-looking Climate Change*

35 Integration costs (C_{int}) can be formally defined as additional costs in the residual system for serving the same amount of residual electricity demand (E_{resid}=E_{tot}-E_{VRE}) after VRE introduction, in comparison to a benchmarking conventional system without VRE: C_{int}=C_{resid}-($C_{tot',conv}$/E_{tot})*E_{resid}. The residual system costs equal total system costs minus VRE generation costs: C_{resid}=C_{tot}-$C_{VRE,}$ which include life-cycle (fixed and variable) costs for non-VRE plants, balancing services, grid infrastructure and storage (Ueckerdt et al., 2013). The concept of integration costs and its decomposition will be further discussed in Chapter 5.4.

Policy (EC, 2015a), few efforts have been made yet by policy-makers and regulators for the minimization of integration costs (Narbel, 2014; Roy, 2015).

Many parts of the world (including the EU) have established liberalized electricity markets to facilitate the trade of electricity and boost economic efficiency. A well-functioning competitive electricity market can theoretically limit integration costs associated with a given penetration of VRE. This is the case because a theoretical long-run equilibrium exists to deliver the least-cost residual system, which minimizes integration costs. An electricity market functions well, if its price signals support efficient short-term operation and provide sufficient investment incentives for all generation capacity needed (EC, 2009; Hogan, 2014; EWEA, 2014; Auer and Burgholzer, 2015). This means that it should be able to provide sufficient remunerations to recover capital costs and support business cases for investments in VRE and complementing low-carbon flexible resources, which are indispensable to adapt to the variable and uncertain outputs of VRE. Otherwise, the least-cost residual system will not be reached. However, in absence of a level playing field due to incomplete internalization of social costs of carbon (SCC) and (explicit and/ or implicit) subsidies for fossil fuels, the electricity market cannot effectively promote VRE investments in line with the EU's deep decarbonization goal (EC, 2013). This justifies the adoption of various national support schemes, which has driven the rapid and large-scale capacity expansion of VRE in the EU. These schemes aim to financially secure capital-intensive VRE investments against market revenue risks[36] and thus reduce the cost of capital (Zane et al., 2012; Pahle and Schweizerhof, 2015; Noothout et al., 2016; IEA, 2016a). Their implementation has also contributed to significant costs reduction of VRE technologies, because of economies of scale and technological learning (DeMartino and Le Blank, 2010). Nevertheless, support schemes, in particular the feed-in tariff, typically create market distortions in operational decisions, due to limited exposure and/ or response of VRE generators to market signals (Batlle et al., 2010; EC, 2014a; Eurelectric, 2014; Auer and Burgholzer 2015). Moreover, such schemes often grant priority dispatch[37] and, sometimes, exemption of balancing responsibilities[38]to VRE generators, regardless of price signals that reflect their negative impacts on system operation (Vos et al.,

36 Market revenue risks include price risk due to uncertain electricity price, volume risk due to uncertain sale volume and balancing risk due to penalty for deviations from schedule (Zane et al., 2012).

37 Due to very low marginal costs, VRE is normally dispatched in priority based on the merit order. However, priority dispatch here refers to the situation of VRE being dispatched with no or less respect to its marginal costs and price signals. Priority dispatch can be distinguished into two types: explicit physical priority dispatch (i.e. obligations of system operators to dispatch VRE ahead of any other generators) and implicit financial priority dispatch (i.e. subsidies that enable VRE to bid and accept a price below its marginal costs). Both can undermine operational efficiency and exacerbate system stress events, e.g. negative price periods when minimum must-run generation level is reached (Auer and Burgholzer, 2015).

38 Balancing responsibilities for VRE can be fully exempted (e.g. under feed-in tariff schemes in Germany and Croatia) or largely exempted (e.g. a tolerance marginal for imbalances exists for offshore wind in Belgium) (de Vos et al., 2011).

2011; Ketterer, 2014; Eurelectric, 2014; CEER, 2015; de Jong et al., 2015). These all might contribute to increased residual system costs and thus increased integration costs (Baker et al., 2010; Hiroux and Saguan, 2010; Narbel, 2014; EC, 2014a; Roy, 2015; Oliveira, 2015).

The lack of alignment of VRE development with market price signals have gained increasing concerns, as the penetration of VRE continues to grow (Zane et al., 2012). To reduce integration costs and improve economic efficiency[39], many studies and most EU stakeholders (including the EC) suggest that as an increasingly-mature technology, VRE should be progressively integrated into the electricity market (hereafter referred to as "market integration") (CEER, 2010; Eurelectric, 2014; ENTSO-E, 2014; Hiroux and Saguan, 2010; Abbad, 2010; Zane et al., 2012; Auer and Burgholzer, 2015; EC, 2013, 2014b and 2015c; Roques et al., 2015; Huntington et al., 2017). Despite the lack of a standard definition, two dimensions of market integration, with respect to different time horizons, can be drawn from existing literature:

- Firstly, in the short-run, VRE should be exposed and respond to short-time market price signals as much as possible via more market-compatible support schemes, in order to minimize distortions (Zane et al., 2012; EC, 2013, 2014b and 2016; CCER, 2016).

To fulfill this dimension, the EC's ***Environmental and Energy State Aid Guidelines*** (EC, 2014b) has obliged direct market participation, balancing responsibilities and the removal of subsidies during negative price periods to new VRE installations from 2016 onwards. However, many scholars and stakeholders point out that this also requires the adaption and improvement of electricity market design (Henriot and Glachant, 2013; Purkus et al., 2015; IEA, 2016a; EC, 2016). As the current market design was historically selected for a power system dominated by dispatchable plants, it may not well suit a power system where VRE plays a growing important role (Henriot and Glachant, 2013). Furthermore, due to design flaws, certain elements in the existing market design may be incapable of delivering price signals that reflect real market conditions and associated costs (De Vos et al., 2011; Vandezande et al., 2010; Hiroux and Saguan, 2010; CEER, 2016).

- The second dimension of market integration lies in that support levels should be degressive and eventually be phased out once VRE becomes fully commercially mature (EC, 2014b).

39 "Efficiency" will appear many times in this paper in different terms, such as operational efficiency, allocative efficiency, efficiency of trading behaviors and price efficiency. It should be noted that they all relate to integration costs, because they reflect different aspects of the electricity market's ability in reducing integration costs.

This means that in the long-run, VRE investments should be mainly driven by market price signals to avoid lock-in into a subsidy-dependent pathway (IEA, 2016a; CEER, 2016). Many authors and stakeholders also stress their concern for a level playing field. They argue that the incomplete internalization of externalities and subsidies for fossil fuels place VRE at a competitive disadvantageous position. Even if VRE becomes fully commercially mature, support schemes may still be necessary in order to compensate for the unleveled playing field (Zane et al. 2012; EWEA, 2014; Auer and Burgholzer, 2015; EC, 2015c; IEA, 2016a).

Synthesizing all these views, market integration can be defined as a dynamic transition of letting the investment and production of VRE be increasingly driven by market price signals via a well-functioning electricity market in order to minimize integration costs, which must be safeguarded by increased policy efforts to establish a level playing field, improve the electricity market design and adjust support schemes to minimize distortions. Many barriers to market integration still exist to date. Although they can relate to a broader context that covers multiple dimensions (e.g. technological, institutional, political, and societal) (see e.g. IEA, 2014 and 2016b; IEA-RETD, 2016), barriers related to the market design *per se* are of particular importance. "As the set of arrangements which govern how market actors generate, trade, supply and consume electricity and use the electricity infrastructure" (EC, 2015e), the market design plays a central role in determining market functioning. Market functioning also depends on multiple policy and regulation schemes most relevant to the electrical power sector at EU and MS level, such as carbon pricing under the European Union Emission Trading Scheme (EU ETS) and VRE support schemes. The existence of ill-designed market design elements and policy schemes in the current EU electricity market can give rise to market inefficiencies. They undermine proper market functioning, meaning that they either hinder efficient operation or reduce the feasibility of business cases for investments in VRE and/or complementing flexible resources. Therefore, these design elements and policy schemes directly act as barriers for market integration (hereafter referred to as "market integration barriers"), which also increase integration costs. They are the focus of this paper.

Market integration barriers have been widely reported in literature, but in a fragmented manner. For instance, Scharff and Amelin (2016) analyze the negative impacts of market design elements on efficient trading behaviors in the E_{LBAS}[40] continuous trading intraday market. Both Musgens et al. (2014) and Hirth and Ziegenhagen (2015) report potentially inefficient market designs in the German balancing market, regarding the price settlement rule and the scoring rule. Hiroux and Saguan (2010) assessed a

40 E_{LBAS} is the joint intraday market for Nordic countries, Estonia, Lithuania, Latvia, Netherlands, Belgium and Germany (Scharff and Amelin, 2016)

limited number of market design options affecting integration costs, regarding the gate closure time of the intraday market, system types of the imbalance settlement and the locational marginal pricing mechanism. Oliveira (2015) analytically demonstrated that inefficiencies arising from feed-in VRE support schemes can increase integration costs. To date, however, a framework combining all factors that influence VRE market integration and the general functioning of the electricity market, is still lacking. To fill this gap, this review paper aims to develop a comprehensive framework that incorporates the most pertinent market integration barriers that increase integration costs and resulting inefficiencies. This framework mainly assesses the market integration of large-scale VRE generations, but it is also relevant to small-scale distributed VRE generation. Since distributed VRE generation can participate in the electricity market through smart grid and the role of aggregator, removing market integration barriers is also important to them. The developed framework is supposed to inform policy-makers what market design elements and policy schemes act as market integration barriers. Accordingly, suggestions are given for the redesign of the EU electricity market which aim to improve market functioning and safeguard VRE market integration. This paper provides value-added insights that contribute to facilitate the low-carbon transition of the EU's power sector in a cost-efficient manner. Lessons can also be drawn for countries that plan to decarbonize and liberalize their electric power sector concurrently.

5.2 METHOD

Given that the market integration of VRE by definition is to minimize integration costs via a well-functioning electricity market, the framework can be developed through relating different dimensions of the electricity market design and relevant policy schemes to integration costs. To achieve this end, a literature review was performed. Because our aim was to comprehensively include literature from different fields that are related to the electricity market design and VRE market integration, we did not take a specific view to select and assess literature. This means an explorative research approach was taken.

The detailed approach for developing the framework consists of four steps:

Step 1: Characterizing the EU electricity market design per submarket

In this step, the set-up of the current EU electricity market and the function of each submarket were briefly described. Then key market design elements per submarket were characterized. The characterization focused on five common dimensions, including

- Trading products
- Price settlement rule
- System type
- Time resolution of trading products
- Gate closure time

Step 2: Integration costs and its allocation per submarket

In the second step, the concept of integration costs was reviewed, following Ueckerdt et al. (2013) and Hirth et al. (2015). This laid the theoretical foundation of this paper. Based on their theoretical framework, integration costs were decomposed and allocated to each submarket of the electricity market. Accordingly, a contour of the framework comprising several blocks was sketched, with each block representing a specific submarket.

Step 3: Identifying potential barriers per submarket

Following the contour developed in step 2, potential market integration barriers that increase integration costs for each submarket were identified. This step was conducted on the basis of a comprehensive review of literature. The main focus was key design elements per submarket characterized in step 1. Besides, existing policy and regulations schemes at EU and Member State (MS) level that are important to the functioning of electricity market were also looked into, including:

- Carbon pricing under the EU ETS scheme to internalize the climate externality
- Feed-in support schemes for VRE investments
- Price-cap regulation to prevent market power
- Regulation and/or subsidies to retain baseload capacity for security of supply

Step 4: Synthesis, policy recommendations and further research

In this step the framework was accomplished, highlighting each barrier, their relationship with other barriers, and resulting inefficiencies. Based on the synthesis, recommendations were given regarding how to improve the functioning of the current EU electricity market in order to facilitate successful market integration of VRE. Furthermore, suggestions for further research were also provided for academic researchers.

The outcomes of each method step are presented in Chapter 5.3-5.6.

5.3 CHARACTERIZING THE EU ELECTRICITY MARKET DESIGN PER SUBMARKET

Grid stability requires maintaining balance of active power between supply and demand in real-time (Stoft, 2002; IEA, 2016a). The electricity market should meet this requirement while respecting multiple constraints in generation capacity, flexibility, transmission, storage and demand elasticity (Stoft, 2002; Hiroux and Saguan, 2010; Weber, 2010; Scharff, 2015). This determines the set-up of the electricity market, which involves different submarkets with complementing functions to allocate resources and offer different trading opportunities. In the EU, the electricity market typically consists of a day-ahead (DA) spot market, an intraday (ID) market, a balancing (BA) market and an imbalance settlement (Scharff, 2015). In parallel to these submarkets, a locational marginal pricing (LMP) mechanism exists to represent grid constraints (Hiroux and Saguan, 2010; IEA, 2016a). Figure 5.1 shows an illustrative example of the typical set-up of the EU electricity market. We will now briefly discuss each submarket and their main functions. This serves as the basis for the characterization of market design and later identification of market integration barriers per submarket.

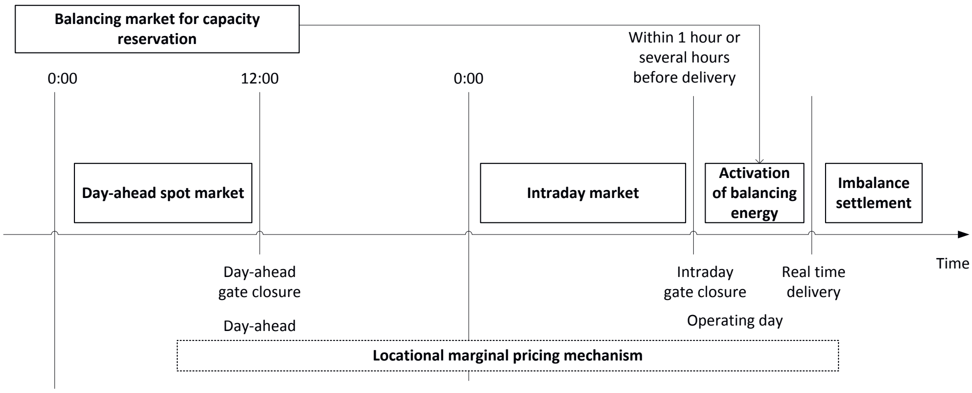

Figure 5.1. Illustrative set-up of the EU electricity market

5.3.1 Day-ahead spot market

The DA spot market is used to trade hourly electricity products in wholesale for the following day. A uniform DA spot price (measured in €/MWh) is set by short-run marginal costs (SRMC)-based bids (i.e. uniform marginal pricing), if the market is able to clear. If the market fails to clear due to insufficient generation capacity to meet demand, the spot price is called scarcity price. Scarcity price in principle should be set at the value of lost load (VOLL), which represents an average consumer's willingness to pay to avoid the involuntary curtailment of electricity consumption (Stoft, 2002; IEA, 2016a). It is also approximately equal to the marginal costs of offering one additional unit of electricity (measured in €/MWh). The gate closure of DA trading is typically 12:00 pm day-ahead (Scharff, 2015). Bid-winning participants need to commit themselves to ex-ante operational scheduling for power generation or consumption on an hourly (e.g. Spain) or half-hourly (e.g. France, Ireland, UK) or quarter-hourly (e.g. Belgium, Netherlands, Germany, Austria, Poland) basis (Just and Weber, 2012; Scharff, 2015; Neuhoff et al., 2015; ENTSO-E, 2016). They also need to assign themselves to one balancing responsible party (BRP), which is financially accountable for the real-time net imbalance from DA commitment of the portfolio of generation and/or consumption it manages (Hirth and Ziegenhagen, 2015).

5.3.2 Intraday market

ID market allows BRPs to obtain a better balanced position based on updated information after the gate closure of DA market (Scharff, 2015). It offers flexibility to reduce the need for more expensive resources with high flexibility for real-time balancing (Weber, 2010; Scharff and Amelin, 2016). ID trading system can be either based on discrete auctions (e.g. Spain, Italy, and Portugal) or continuous trading (e.g. Nordic countries, Netherlands and Belgium). In continuous trading, bids and offers are not matched at the same time but based on "first-come first serve" principle, implying that the price settlement is based on "pay-as-bid" (Scharff, 2015). This also leads to varying prices for the same delivery time (Neuhoff et al., 2016). By contrast, discrete auctions aggregate all bids and offers within each trading period in one single auction (Scharff, 2015). The price settlement for each auction is based on uniform marginal pricing, which is similar to the DA trading (Scharff, 2015). Both continuous trading and discrete auctions typically trade hourly electricity products, while quarter-hourly electricity products are also possible to trade in continuous trading (Neuhoff et al., 2016). The gate closure times for continuous trading and discrete auctions are currently 5-60 min and 135-690 min before delivery (Hagemann and Weber, 2015; Olmos et al., 2016).

5.3.3 Balancing market

Due to remaining uncertainties between ID gate closure and real-time delivery and sub-hourly variability, a BA market is established by the transmission system operator (TSO) for the reservation and activation of balancing capacity from balancing service providers (BSPs). BSPs have to commit themselves at a certain generation level in the DA spot market, so that they can ramp up or down in case of being called to provide balancing energy (Batlle et al., 2013). The TSO determines the size of balancing capacity needed with pre-defined requirements (e.g. contract duration, activation timeframe, ramp rates) and procures them in advance through an auction (Hirth and Ziegenhagen, 2015). The auction consists of a capacity price bid (€/MW•h of capacity product[41]) for capacity reservation and an energy price bid (€/MWh of energy product) for capacity activation (Musgens et al., 2014; Hirth and Ziegenhagen, 2015). Both capacity price and energy price can be determined via pay-as-bid or uniform pricing. Under uniform pricing, the price can be set by either marginal costs or average costs (Scharff, 2015). In the case of the system being short, activated upward reserves receive the energy price being the result of the bid, while in the case of the system being long, activated downward reserves pay the energy price due to saved operating costs (Brijs et al., 2015). The energy price in the BA market can become negative if downward balancing capacity is in scarcity. The time resolution ranges from yearly to hourly for capacity products, and from hourly to quarter-hourly for energy products (ENTSO-E, 2016). As for gate closure time, it ranges from year-ahead to day-ahead before delivery for capacity products, and from hour-ahead to quarter-hour ahead before delivery for energy products (ENTSO-E, 2016).

5.3.4 Imbalance settlement

IB settlement is used to allocate *ex-post* the costs associated with the reservation and activation of balancing capacity in the BA market to imbalanced BRPs that deviate from their DA commitments. In practice, an IB settlement price mainly consists of the energy price for the activation of balancing capacity in the BA market (Chaves-Avila et al., 2014). Therefore, trading product in the IB settlement is the imbalanced energy between a BRP's real-time delivery and its DA commitment. The time resolution (or settlement period) of the IB settlement and its trading products is consistent with that of the BRP's DA commitment, i.e. ranging from hourly to quarter-hourly (ENTSO-E, 2016; Fernandes et al., 2016). Sometimes the settlement price also includes a multiplicative (e.g. Belgium, France) or additive punitive component (e.g. Germany) to strengthen incentives for BRPs to reduce own imbalances (Vandezande et al., 2009; 2010). Using the DA spot price as a reference, the IB settlement price tends to be higher for upward balancing (in the case of the system being short) and lower for downward balancing (in the case of the system being long). The IB settlement can be either based on a one-price system (e.g. Germany, Spain) or a two-price system (e.g. France, Italy) (Ranci and Cervigni, 2013). Table 5.1 (adapted from Scharff, 2015) shows the economic outcome for BRPs with different positions in respect of system imbalance under a one-price system and a two-price system. In both systems, short BRPs pay while long BRPs get paid. The difference is that in the one-price system the same IB price applies to both BRPs counteracting and aggravating system imbalance. By contrast, two respective price signals (i.e. system

41 The capacity product refers to the commitment of reserving a maximum amount of balancing capacity for a specific duration of time. Therefore, it is measured in MW•h. This is different from the energy product measured in MWh. The latter is the total electricity output associated with the actual activation of balancing capacity.

imbalance price and DA price) exist in the two-price system for BRPs aggravating and counteracting system imbalance (Vandezande et al., 2010; Scharff, 2015). Because of the opportunity costs implied in the spread between the IB price signal and the DA spot price, the two-price system discourages BRPs of any deviations from their DA commitments. However, in the one-price system, BRPs with own imbalance to the opposite direction of system imbalance (i.e. passive balancing) are rewarded.

Table 5.1. IB settlement under a one-price system and a two-price system

P_{DA}, P_{up} and P_{down} respectively denote DA spot price, IB price for upward balancing and IB price for downward balancing. E_{short} and E_{long} represent the amount of energies that deviates from DA commitment for BRPs that are short and long, respectively. The green color indicates the IB price is more beneficial for BRPs with respect to the DA spot price, while the red color implies the opposite.

One-price system	System/BRP Position	System short (upward balancing)	System in balance (no balancing)	System long (downward balancing)
	Short BRP	Pay: $P_{up} * E_{short}$	Pay: $P_{DA} * E_{short}$	Pay: $P_{down} * E_{short}$
		Net loss: $(P_{up} - P_{DA}) * E_{short}$	Net: 0	Net gain: $(P_{DA} - P_{down}) * E_{short}$
	Long BRP	Receive: $P_{up} * E_{long}$	Receive: $P_{DA} * E_{long}$	Receive: $P_{down} * E_{long}$
		Net gain: $(P_{up} - P_{DA}) * E_{long}$	Net: 0	Net loss: $(P_{DA} - P_{down}) * E_{long}$
Two-price system	System short (Up-regulation)	System short (upward balancing)	System in balance (no regulation)	System long (downward balancing)
	Short BRP	Pay: $P_{up} * E_{short}$	Pay: $P_{DA} * E_{short}$	Pay: $P_{DA} * E_{short}$
		Net loss: $(P_{up} - P_{DA}) * E_{short}$	Net: 0	Net: 0
	Long BRP	Receive: $P_{DA} * E_{long}$	Receive: $P_{DA} * E_{long}$	Receive: $P_{down} * E_{long}$
		Net: 0	Net: 0	Net loss: $(P_{DA} - P_{down}) * E_{long}$

Source: Adapted from Scharff (2015)

5.3.5 Locational marginal pricing mechanism

The LMP mechanism is used in the electricity market to represent grid constraints at different locations on the electricity network, in order to efficiently use the transmission capacity as a scarce good. Electricity prices at two different locations are the same if there is sufficient transmission capacity (i.e. market coupling). However, locational electricity prices differ if grid congestion occurs between the two locations (i.e. market splitting). Depending on the level of details for grid constraint representation, LMP mechanism can be based on a nodal pricing system (e.g. Pennsylvania-New Jersey-Maryland (PJM) interconnection in US) or a zonal pricing system (e.g. most Member States in EU) (Neuhoff and Boyd, 2011). Nodal pricing represents the grid transmission capacity at each node of the power system. By contrast, zonal pricing only takes into account the capacity of interconnector between two different price zones, without representing the constraints within each zone.

5.3.6 Market design characterization

Based on the above descriptions, it is possible to characterize the electricity market design per submarket according to the five key dimensions. The characterization results are shown in table 5.2.

Table 5.2. Market design characterization for each submarket

<table>
<tr><th>Submarket</th><th>Trading products</th><th colspan="2">Price settlement rule</th><th colspan="2">System type</th><th>Time resolution of trading products</th><th>Gate closure time</th></tr>
<tr><td>DA spot market</td><td>Energy</td><td colspan="2">Uniform marginal pricing</td><td colspan="2">N.A.</td><td>Hourly</td><td>12:00 pm DA</td></tr>
<tr><td>ID market</td><td>Energy</td><td>Uniform marginal pricing</td><td>Pay-as-bid</td><td>Discrete auctions</td><td>Continuous trading</td><td>Hourly for discrete auctions; both hourly and quarter-hourly for continuous trading</td><td>135-690 min before delivery for discrete auctions; 5-60 min before delivery for continuous trading</td></tr>
<tr><td>BA market</td><td>Capacity and energy</td><td>Uniform marginal pricing</td><td>Pay-as-bid</td><td colspan="2">N.A.</td><td>Ranges from yearly, weekly to hour(s) ly for capacity products;
ranges from hourly to quarter-hourly for energy products</td><td>Ranges from year-ahead, week-ahead to hours-ahead delivery for capacity products;
ranges from hourly-ahead to quarter-hourly ahead delivery for energy products</td></tr>
<tr><td rowspan="3">IB settlement</td><td rowspan="3">Energy</td><td>Marginal pricing</td><td>Average pricing</td><td rowspan="3">One-price system</td><td rowspan="3">Two-price system</td><td rowspan="3">Hourly or half-hourly or quarter-hourly</td><td rowspan="3">N.A.</td></tr>
<tr><td colspan="2">Including/excluding capacity price</td></tr>
<tr><td colspan="2">Including/excluding multiplicative or additive punitive component</td></tr>
<tr><td>LMP mechanism</td><td>N.A.</td><td colspan="2">N.A.</td><td>Zonal pricing System</td><td>Nodal pricing system</td><td>N.A.</td><td>N.A.</td></tr>
</table>

5.4 INTEGRATION COSTS AND ITS ALLOCATION PER SUBMARKET

Integration costs are additional costs in the residual system resulting from the interaction between VRE, featuring variable, uncertain and locational-dependent outputs, and the residual system (Hirth et al., 2015). For accounting purpose, integration costs can be attributed to the addition of VRE into power system and measured in terms of specific costs (€/MWh$_{VRE}$) (Sijm, 2014). However, integration costs are often not directly borne by VRE generators, in absence of sufficient market exposure and cost-reflective price signals, e.g. under feed-in tariff scheme. This implies that integration costs will be socialized (e.g. to end-users), if they are incompletely internalized in the electricity market (Savage, 2012; Hirth et al., 2015).

The definition and accounting of integration costs may differ between authors, depending on the system boundary, the techno-economic features of existing power system and the assumptions regarding future scenario (e.g. technology mix and cost, demand elasticity, system adaptation) (Agora Energiewende, 2015). Ueckerdt et al., (2013) and Hirth et al. (2015) establish a wide-cited standard theoretical framework, based on welfare economics, to account and conceptualize integration costs. This paper follows Ueckerdt et al. (2013) and Hirth et al. (2015).

The constraints of storage, plant flexibility and grid make electricity a heterogeneous commodity with varying economic values across time, delivery lead time and location (Hirth et al., 2016). This means that VRE cannot directly serve electricity load due to their mismatch across time, delivery lead time and location. Hence, integration costs can either be interpreted as additional costs of accommodating VRE to enable it to serve load, or equivalently, the marginal value reduction of VRE in comparison to a benchmarking power generator perfectly matching load (Ueckerdt et al., 2013; Hirth et al., 2015). Following the variable, uncertain and locational-dependent nature of VRE, Hirth et al. (2015) decomposes integration costs into three components, namely profile costs, balancing costs and grid costs. Profile costs result from the temporal profile mismatch between VRE output and the load. They can be regarded as diminishing cost saving from the substitution of VRE to electricity generation from thermal plants. This is because the use of VRE to serve load involves necessary adjustments of scheduled operation and utilization of thermal plants in the residual system, i.e. increased ramping, cycling, partial-load operations and reduced utilization hours. These adjustments cause additional costs, which decrease the value (i.e. cost saving) that VRE brings to the power system. Therefore, profile costs can also be interpreted as the increase in opportunity costs from the usage of VRE. Balancing costs represent additional expenses for balancing the deviation of VRE outputs from scheduled operation (i.e. forecast errors) because of uncertain VRE outputs. Grid costs refer to cost associated with grid infrastructure investment and management due to locational-dependent siting of VRE resources (Hirth et al., 2015).

The three components of integration costs (profile costs, balancing costs and grid costs) can be allocated to different submarkets, based on the function per submarket. Profile costs can be reflected in the reduced market value (i.e. market revenue) of VRE from a benchmarking power generator with perfect temporal coincidence to the load, which is the difference between load-weighted spot price and VRE output-weighted spot price across time; balancing costs can be reflected in the increased costs associated with balancing services in the ID market and BA market, as well as the price signals to financially settle these costs in the IB settlement; grid costs can be reflected in the price spread between different locations in the LMP mechanism (Hirth et al., 2015). The three types of system integration costs also give rise to three categories of barriers hampering the progress of market integration: barriers increasing 1) profile costs, 2) balancing costs, and 3) grid costs. These barriers can be respectively traced back to certain market design elements per submarket and relevant policy schemes. They either undermine efficient market operation, or reduce the feasibility of business cases for VRE and/or complementing flexible resources. Accordingly, an empty contour of the framework can be drawn, as shown in figure 5.2.

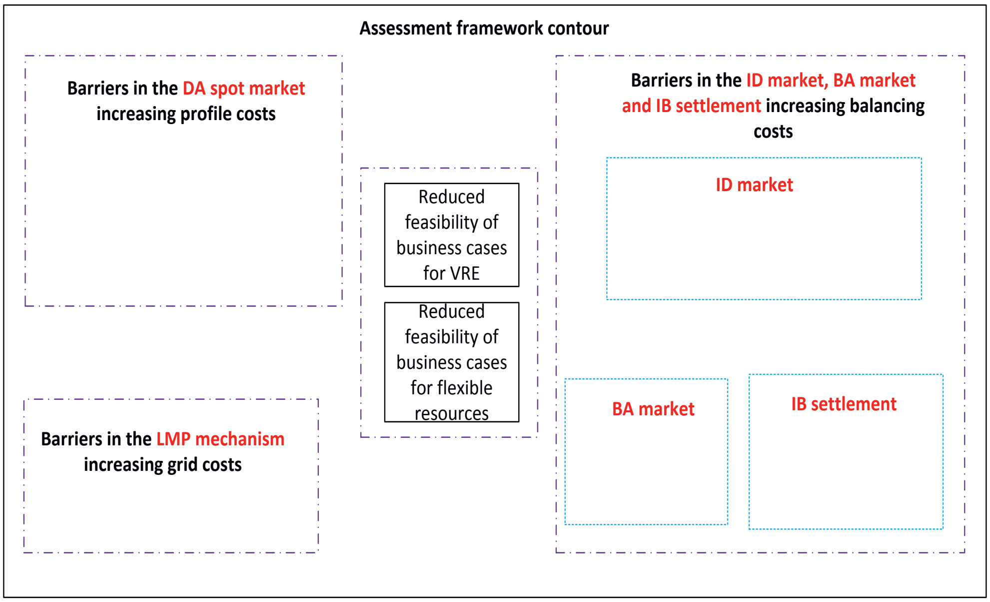

Figure 5.2. Contour of the framework development

5.5 IDENTIFYING POTENTIAL BARRIERS PER SUBMARKET

Via filling the contour set up in chapter 5.4, the following sections respectively present identified potential barriers increasing profile costs in the DA spot market (5.5.1), increasing balancing costs in the ID market, BA market and IB settlement (5.5.2), and increasing grid costs in the LMP mechanism (5.5.3):

5.5.1 Potential barriers increasing profile costs in the DA spot market

Profile costs rise with increased penetration of VRE. They are mirrored in market value (i.e. market revenue) reduction of VRE, being equaled to the VRE output-weighted spot prices over time (€/MWh_{VRE}) (Hirth et al., 2015; IEA, 2014a). This can be explained by two factors. Firstly, rising VRE penetration reduces the temporary profile correlation between VRE and load, implying that it is less likely for VRE at high penetrations to benefit from high spot prices during scarcity periods[42] (Batlle et al., 2013). Secondly, because the price settlement is based on ***uniform marginal pricing***, VRE with close-to-zero SRMC is usually dispatched in priority and replaces electricity generated by the marginal thermal plants that set the spot price. This shifts the supply curve to the right and causes a tendency of lower spot prices when VRE generates (Chaves-Avila et al., 2015). Consequently, both the average spot price and the market value of VRE decrease with the increased penetration of VRE, and the market value of VRE decreases faster, *ceteris paribus*. Clearly, the diminished market value of VRE reduces the feasibility of the business case for VRE investments, when the spot price becomes the sole revenue source (IEA-RETD, 2016). Empirical econometric analyses have indicated a correlation between the increased penetration of VRE and the decreased average spot price in many EU Member States, such as Austria (Wurzburg et al., 2013), Germany (Wurzburg et al., 2013; Cludius et al., 2014), Italy (Clo et al., 2015) and Spain (Saenz de Miera et al., 2008). The reduced average spot price, compounded by the increased levelized costs of electricity generation (LCOE) due to reduced utilization hours, also endangers the business case for flexible gas-fired peak load and mid-merit plants. These plants are considered important back-up plants when VRE does not generate. It is reported that in Europe over 20 GW gas-fired plants were mothballed in 2013 and this figure could increase to 110 GW by 2017 (Tweed, 2014). Although a DA market based on uniform

42 At very low (≤2%) and low (≤5%) penetration of VRE, a positive correlation may exist between the temporal profile of VRE and peak load, varying from different power systems. For instance, in countries with a hot climate, solar outputs may coincide with the summer peak load at noon due to the use of air conditioning for cooling. A similar case is for wind outputs in countries with a cold climate, where the winter peak load occurs in the windy evening after sunset (Agora Energiewende, 2015). These can have an uplifting effect on the market value of VRE. However, as the penetration of VRE further increases, the initial peak load will be inevitably shaved and finally become the valley.

marginal pricing is well-known in promoting short-term operational efficiency, a few studies, e.g. De Castro et al. (2010); EC (2015d); Agora Energiewende (2013), have given concerns over its ability to guarantee long-term market efficiency that foster and remunerate investments in VRE and complementing flexible resources, when VRE with close-to-zero SRMC becomes prevalent and regularly sets the spot price. These concerns seem to be plausible, but often they neglect the fact that the spot price is the result of the supply-demand dynamics and VRE is only one factor that affects such dynamics.

As of today, the current low spot price in Europe is also attributed to a few policy and regulation schemes at EU and MS level:

- The ***persistent weak carbon price under the EU ETS***, which oscillated between 6.4-8.6 €/Tonne CO_2 in 2015 (EEX, 2016), is insufficient to internalize the climate externality and associated SCC (Hu et al., 2015).
- Due to overly-stringent security of supply or grid reliability standards regardless of its costs, ***regulation and retroactive subsidies (e.g. capacity payment) for retaining inflexible baseload capacity result in overcapacity*** (Auer and Hass, 2016; BMWi, 2015). Exacerbated by the large addition of VRE capacity driven by support policy schemes, the post-recession flat/declining electricity demand and the neglect of demand response potentials (Auer and Hass, 2016), overcapacity eliminates the occurrence of scarcity price that are essential to recover capital costs of investments in all types of generation capacity including VRE and flexible resources. For instance, the scarcity price never occurred in Germany in 2014 (de Jong et al., 2015).
- Even if a scarcity situation occurs, price-cap regulation or technical requirement of power exchange can ***limit the scarcity price to a level well-below the VOLL*** (Fingrid, 2016). The price cap currently ranges from 150 to 3000 Euro/MWh in Europe (Finon, 2013). In presence of such a low price cap, the scarcity price is insufficient to remunerate investments in VRE and complementing flexible resources.

These policy and regulation schemes depress the market value of VRE, leading to higher profile costs. In addition, they blur the price formation in the DA spot market, undermining investment incentives included in market price signals.

The reduction of VRE market value (or the increase of profile costs) and the average spot price can be partly, if not fully, mitigated through a few measures that aim to increase the spot price when VRE generates[43]. These measures mainly include flexible resources (i.e. flexible thermal plants, energy storage, demand response), system-

43 Note that some of these measures (e.g. interconnector, demand response) can also lower the spot price when VRE does not generate or generate less. Therefore, their impact on the average spot price might be limited.

friendly VRE technologies and arrangements (i.e. high power density wind turbine, solar panel with unconventional orientation), inter-regional integration of electricity market through market coupling, increasing the carbon price, accelerating the phase-out of the overcapacity of inflexible baseload plants, and increasing the price cap to the VOLL (Hirth and Ueckerdt, 2013; Ketterer, 2014; Nils et al., 2015; IEA, 2014a; EC, 2015d; IEA-RETD, 2016; Hirth and Muller, 2016; Hartner et al., 2015). They in general have an uplifting effect on the spot price when VRE generates, either through 1) shift the supply curve left, or 2) increase residual demand[44], or 3) increase the average height of the supply curve, or 4) smooth the temporal profile of VRE output, or 5) strengthening scarcity price. Therefore, through a synergy of these measures, it seems possible to avoid the situation of spot prices being regularly set by VRE. Even at high penetrations of VRE, spot prices could be restored to a sufficiently high level to stimulate investments in VRE and complementing flexible resources. However, to effectively scale-up the implementation of these measures, many barriers are yet to be overcome. Table 5.3 summarizes different measures limiting the reduction of VRE market value and the increase of profile costs, their mechanisms and potential barriers hindering their implementation. It may take time to fully overcome these barriers. This implies that alongside the progress of implementing these measures, support policy schemes for VRE investments are still needed, at least in the medium term, since the market revenue alone is insufficient to recoup the high capital costs.

44 The residual demand is defined as the demand net the output of VRE, which treats VRE as "must-take" generation

Table 5.3. Measures limiting VRE market value reduction and their barriers

Measures limiting VRE market value reduction and profile costs increase		Mechanism	Potential barriers
Flexible resources	Flexible thermal plants (with low minimum load)	Shift the supply curve leftwards	High capital costs; Unsound business cases due to the lack of scarcity price
	Energy storage	Increase the residual demand	High capital costs; Life degradation and fatigue due to cycling (in the case of battery); Unsound business cases due to the lack of scarcity price
	Interconnector	Increase the residual demand	Lack of coordination between the development of grid and VRE; Lack of investment incentive for TSOs; Fragmentation of individual regional TSOs; Public acceptance of overhead lines
	Demand response	Increase the residual demand	Lack of adequate ICT infrastructure; Lack of real-time pricing; Segmentation of consumer groups with different price elasticities of demand within one household; Behavioral changes needed from consumers
System-friendly VRE technologies and arrangements	High power density wind turbine	Smooth the temporal profile of VRE output	High capital cost
	Solar panel with unconventional orientations	Smooth the temporal profile of VRE output	N.A.
Inter-regional integration of electricity market through market coupling		Smooth the temporal profile of VRE output	Lack of interconnector infrastructure; Fragmentation of individual regional TSOs; Political resistance from national governments due to loss of sovereignty
Increase the carbon price		Increase the overall height of the supply curve	Carbon price sufficiently high to steer VRE investments is likely to face political unacceptance in the short and medium run due to concerns over industrial competitiveness and carbon leakage; Incompatible policy designs that have a depressing impact on the carbon price;
Accelerate the phase-out of the overcapacity of inflexible baseload plants		Shift the supply curve leftwards; strengthening scarcity pricing	Retroactive capacity payments for retaining coal-fired baseload plants (e.g. UK, Spain); (Explicit and implicit) subsidies for fossil fuels; Market-exit restrictions; Overly stringent security of supply standard
Lift up price cap to the VOLL		Strengthening scarcity pricing	Lack of risk hedging products for price spikes; Public and political unacceptance

Source: Buck et al. (2015); de Jong et al. (2015); Papaefthymiou et al. (2014); Zane et al. (2013); Auer (2011); THEMA (2013); Deutsch et al. (2014); Hu et al. (2015); ENTSO-E (2015); He et al. (2013); Hirth and Muller (2016)

Current, ***Feed-in support schemes*** in the form of either tariffs or premiums that remunerate VRE on the basis of per unit of electricity generation are most commonly used in the majority of EU Member States (IHK, 2016). Figure 5.3 shows different types of feed-in schemes, with each type being briefly described.

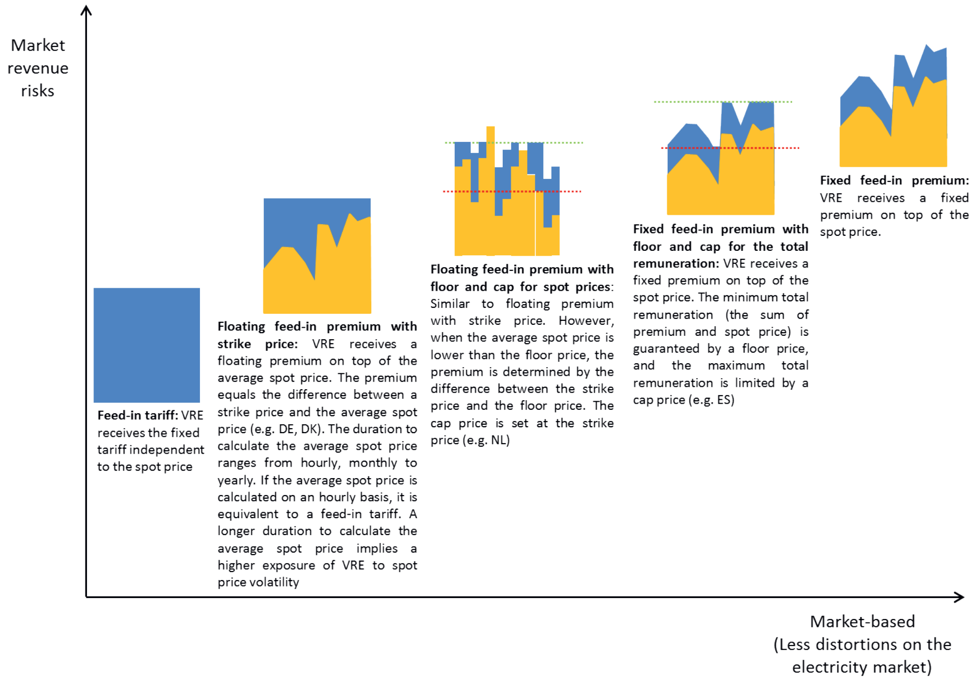

Figure 5.3. Different types of feed-in schemes and their brief descriptions

Source: Compiled based on CEER (2016); Noothoot et al. (2016); Huntington et al. (2017)

In general, these schemes enable VRE generators to largely feed in electricity at very low or negative spot price that is below their close-to-zero SRMC (Auer and Burgholzer, 2015; CEER, 2016; Leuven Energy Institute; 2014). Therefore, they lead to reduced market value of VRE and unnecessarily higher profile costs. The extent to which they are market-based differs, as these feed-in schemes expose VRE to the price signal (and thus the market revenue risks) at different levels in the DA spot market. Depending on their market-based level, feed-in schemes also give rise to different levels of market distortions (Batlle et al., 2012; Eurelectric, 2014; Energy Community, 2015). As the dominant support policy scheme that steers past VRE investments in the EU, feed-in tariff has been introduced in 17 out of the 28 Member States till 2014 (IHK, 2016). However, a feed-in tariff fully shields VRE against market price signals, discouraging developers from adopting more system-friendly technologies and arrangements and selecting generation sites that maximize the market value (i.e. market revenue) of VRE. Consequently, the EC has called for more market-based feed-in premiums to progressively replace feed-in tariffs, stating that feed-in premiums can "put pressure on renewable energy generators to become more active market participants, via incentives to optimise investments, plant design and operation according to market signals" (EC, 2013). It will prohibit the use of feed-in tariffs to support new VRE installations from 2016 onwards, and as of then it is obliged for all Member States to use feed-in premiums (in combination with tenders and the removal of subsidies during negative price periods) for the sake of better market integration (EC, 2014b). Among all feed-in premiums, fixed feed-in premiums are deemed as the most market-based and thus have the least distorting impacts on the DA spot market. However, using an analytical model with empirical data, Oliveria (2015) has demonstrated that even in the case of fixed feed-in schemes, perverse incentives that deviate from the objective of market value maximization always exist for firms that own both VRE generators and thermal generators. As for firms that only own VRE generators, these perverse incentives can still exist if the convexity of the supply curve is high (Oliveria, 2015). As such, it seems reasonable to conclude that all feed-in schemes can disincentivize VRE generators to maximize their market value and act as a barrier that increases profile costs. Figure 5.4 shows that due to the use of feed-in schemes, VRE investments may be locked in a vicious cycle of subsidy-dependent pathway. Feed-in schemes enlarge the gap between the investment costs of VRE and its market value, which in turn increase the subsidy level needed from feed-in schemes to make VRE investments break-even. In other words, feed-in schemes may inefficiently increase their own policy costs. If such policy costs become unaffordable, it can increase the risk of subsidy termination. Therefore, the authors argue that feed-in schemes are inconsistent with the objective of market integration.[45]

45 It should also be stressed that in absence of other more market-compatible support measures and in the context of still existing fossil subsidies and the incomplete internalization of climate externalities, the removal of feed-in schemes is obviously not a good idea.

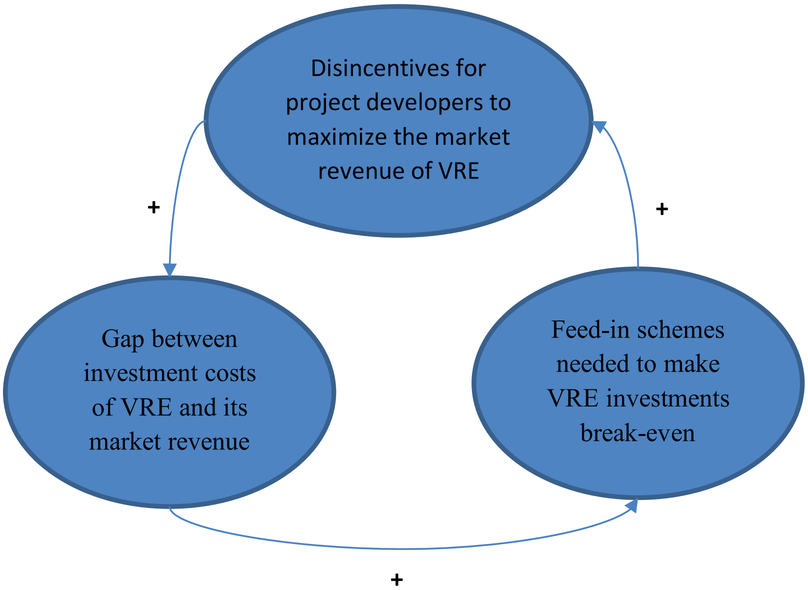

Figure 5.4. Subsidy-dependent pathway for VRE investments

The ***gate closure time*** and the ***time resolution of trading products*** of the DA spot market also affect the market efficiency. Although not directly influencing profile costs, these two design elements have cross-market impact on balancing costs that occur in the ID market, BA market and IB settlement via influencing the demand for system balancing services (Frunt et al., 2010).

The current gate closure time for the EU DA spot market is typically 12:00 pm day-ahead. It is criticized for being too far from the real-time delivery in the following day (BMWi, 2015). In particular, a delivery lead time as long as 36 hours exists for the last hour of the following day. The large forecast errors associated with such long lead time tends to put VRE generators at a more imbalanced position in real time, increasing the overall system demand for balancing resources in the ID market and BA market and the associated balancing costs (Ketterer, 2014). Due to large uncertainties and balancing risks, the early gate closure time also creates an unfavorable condition for VRE generators to submit bids in the DA spot market (Roy, 2015). This can be detrimental to the business case of VRE investments and the process of market integration.

Since hourly electricity products are traded in the DA market, the corresponding DA spot price is also determined on an hourly resolution. However, the spot price with hourly resolution, as an averaged indicator, cannot accurately reflect the physical reality of supply-demand dynamics that is usually scheduled at a sub-hourly resolution (Ketterer, 2014). This is particularly the case for VRE supply, whose sub-hourly variability can be significant (MacDonald et al., 2016). Hence, the correlation can be very low between hourly spot prices and sub-hourly IB prices for the same period, which encourages strategic behavior of BRPs to arbitrage between the price differences through deliberately maintaining an imbalanced position (Just and Weber, 2015; Neuhoff et al., 2015). This results in higher system needs for balancing services and higher balancing costs. Inefficiencies associated with the low time resolution of trading products in the DA spot market will be further discussed in section 5.5.2.3.

5.5.2 Potential barriers increasing balancing costs in the ID market, BA market and IB settlement

5.5.2.1 Potential barriers increasing balancing costs in the ID market

To avoid the use of more expensive real-time balancing capacities, the ID market alongside updated information should be used to the largest extent to reduce imbalances and associated balancing costs (Weber, 2010). However, illiquidity, mirrored by low trading volumes, often characterizes the ID market in Europe, resulting in inefficient performance in terms of resources allocation and limiting balancing costs (Weber, 2010; Chaves-Avila et al., 2013; Chaves-Avila and Fernandes, 2015; Scharff and Amelin, 2016). Multiple factors contribute to an illiquid ID market:

- Due to ***market concentration***, market participants with large generation portfolios tend to net out own imbalances through internal balancing rather than ID trading (Weber, 2010).
- Clear preference of market participants to trade close to gate closure time of the ID market because of more accurate forecasts (Scharff and Amelin, 2016) suggests that a ***gate closure time insufficient close to real-time (>60min before delivery) may undermine liquidity***. This can be relevant for Spain, Italy and Portugal, where ID gate closure times range from 135 to 690 min before delivery.
- ***Limited participation of demand response due to tight access rules*** and difficulty to develop baseline and measure compliance (Auer and Burgholzer, 2015; Borggrefe and Neuhoff, 2011).
- ***Illiquidity can increase the transaction costs*** of market participants because it is likely that their purchases and/or sales move the market price and reduce the benefits from trading. The fear of such transition costs in turn exacerbates illiquidity (Weber, 2010).

5

Liquidity also hinges on whether the system type of the ID is based on discrete auctions or ***continuous trading***. Discrete auctions aggregate all bids and offers within each trading period in one auction, and thus show better liquidity performance (Chaves-Avila and Fernandes, 2015; Scharff and Amelin, 2016). By contrast, the large price variance from trade-to-trade in continuous trading disincentivizes market participants to trade. In addition, unlike uniform marginal pricing used in discrete auctions, the price settlement rule of continuous trading based on "first come first serve" ***pay-as-bid*** is inefficient by nature, because more expensive bids can be accepted if less expensive bids come later (Neuhoff et al., 2016; Scharff, 2015). Scharff and Amelin (2016) also report that transaction costs in terms of ICT system and trading staff costs are often involved in continuous trading because of the need to monitor the market constantly to identify more lucrative prices. Thus, continuous trading can be deemed as an inefficient design element for limiting balancing costs.

In addition, liquidity of the ID market is affected by interactions and interdependencies with the BA market and IB settlement. Weber (2010) argues that since BSPs in the BA market have already earned a capacity price for capacity reservation, they may have incentives to offer energy price bids lower than their true costs for capacity activation. This can lower the energy price for balancing energy, which finally turns into a lower IB price. If the resulting IB price is lower than the ID price, VRE generators and other market participants will have less incentive to reduce their own imbalances through trading in the ID market (Weber, 2010). This, however, is not an issue, if the price settlement rule for both the capacity price bid for capacity reservation and the energy price bid for capacity activation are based on uniform marginal pricing. Musgens et al. (2014) has theoretically demonstrated that, under uniform marginal pricing, rational bidders in competitive markets will disclose their true costs for capacity reservation and capacity activation. To be more specific, the capacity price bid will be equal to the expected opportunity costs from capacity reservation net the expected profits from capacity activation, while the energy price bid will be equal to the SRMC of providing balancing energy (Musgens et al., 2014). Nevertheless, in many EU countries ***pay-as-bid*** (e.g. Germany, Italy) instead of uniform marginal pricing is currently used as price settlement rule for the BA market, which may contribute to the low liquidity of the ID market. Liquidity of the ID market is also dependent on the system type of the IB settlement, i.e. based on a one-price system or a two-price system (Weber, 2010; Scharff and Amelin, 2016). As passive balancing is rewarded in a ***one-price system***, BRPs may strategically maintain an imbalanced position. This can reduce the liquidity of the ID market. Scharff and Amelin (2016) further illustrates that ***compared with a two-price system, ID trading is less reciprocal for both risk-averse sellers and buyers under a one-price system***. Therefore, it can be suggested that the liquidity performance is better when the ID market is combined with the IB settlement based on a two-price system. However, the better liquidity performance will be undermined if an ***inefficient multiplicative punitive component*** is introduced under a two-price system that asymmetrically penalizes short BRPs more than long BRPs, which is, for example, the case in France and Spain (Vandezande et al., 2009; Fernandes et al., 2016). In that case, BRPs including independent VRE generators tend to under-contract or withholding own balancing resources to avoid being short, which may reduce incentives for ID trading.

5.5.2.2 Potential barriers increasing balancing costs in the BA market

The overall efficiency of the BA market depends largely on the price settlement rule used for capacity reservation (via capacity price bid per MW•h) and activation (via energy price bid per MWh). A general consensus is that ***pay-as-bid*** (e.g.Germany, Italy) is inefficient for limiting balancing costs, compared with uniform marginal pricing (Hirth and Ziegenhagen, 2015; Brijs et al., 2015). As pay-as-bid rewards BSPs best at guessing the clearing price, it does not necessarily accept balancing capacities with least costs (Cramton and Stoft, 2007). Musgens et al. (2014) demonstrate that both price settlement rules are equivalent under complete information and perfect competition. However, pay-as-bid shows inferiority under imperfect competition and incomplete information in terms of efficiency, transparency and transaction costs.

The ***low time resolution (e.g. yearly, weekly, daily and four-hourly) and very early gate closure time before delivery (e.g. week-ahead) for capacity products*** of balancing services also reduce the efficiency of the BA market, resulting in unnecessarily higher balancing costs. Balancing service provision involves opportunity costs for thermal plants, because these plants have to commit themselves at a certain generation level in the DA spot market in case of being called. The opportunity costs mainly consist of missed income or imposed losses in the DA market (Hirth and Ziegenhagen, 2015; Musgens et al., 2014). For upward balancing, Just (2011); Musgens et al. (2012) have qualitatively demonstrated that efficient balancing services should be provided by thermal plants with SRMC close to the DA spot price, which leads to lowest opportunity costs and thus lowest system balancing costs. This means that the capacity mix for providing efficient balancing services changes over time, due to varying spot prices. Therefore, a low time resolution of capacity products can give rise to inefficiencies, because it fixes the same balancing capacity mix for a time period with varying hourly spot prices. Similarly, an early gate closure time for capacity products far away from delivery also leads to inefficiencies due to fixing the balancing capacity mix at a specific time when uncertainty of the spot price is high (Just, 2011; Musgens et al., 2012). As for downward balancing services, Hirth and Ziegenhagen (2015) have illustrated that they can be efficiently provided by VRE generators, featuring close-to-zero SRMC, at zero opportunities costs. This also reduces the must-run generation level resulting from the use of thermal plants to provide these services. As shown by a few modelling-based studies and pilot projects (Frauhofer ISE, 2014; Gortz and Baumgart, 2014; Hirth and Ziegenhagen, 2015; Voet, 2015), the technical reliability of balancing services provided by wind farms pooling over a large geographical area is sufficiently high, under hourly time resolution of capacity products and gate closure time one hour-ahead delivery. However, a low time resolution of capacity products and very early gate closure time before delivery create an entry barrier[46] and biased conditions for VRE to participate in the BA market (Hirth and Ziegenhagen, 2015; Van Hulle et al., 2014; Musgens et al., 2012; Fernandes et al., 2016). For instance, in Germany and Belgium, balancing services require a resolution of capacity products ranging from weekly to four-hourly, and the procurement of these services is usually week-ahead or day-ahead (Hirth and Ziegenhagen, 2015; Voet, 2015). Under these conditions, the weather forecasts are too uncertain for VRE to provide reliable balancing services (Hirth and Ziegenhagen, 2015; Fernandes et al., 2016). Consequently, these biased contract conditions reduce potential revenue streams for VRE, which is detrimental to the business case of VRE investments.

In addition, Borggrefe and Neuhoff (2011) point out the ***lack of joint-optimization between BA market and other submarkets*** also increases balancing costs. The current electricity market design in most EU countries requires power generators exclusively commit themselves either in the DA/ID markets trading energy products or BA market trading capacity products. This eliminates the possibility to contract capacity products for the same hour from power plants that have scheduled to decrease electricity outputs in the DA/ID energy submarkets through partial-load operation, even if upward balancing services provided by these partial-load plants can reduce the overall balancing costs (Borggrefe and Neuhoff, 2011).

5.5.2.3 Potential barriers increasing balancing costs in the IB settlement

IB settlement not only allocates balancing costs to imbalanced BRPs, but signals the price of imbalance from DA commitments. Hence, the price settlement rule affects the overall efficiency of the IB settlement for limiting balancing costs. Depending on whether uniform marginal pricing or pay-as-bid is used in the BA market, IB price can be based on marginal costs or average costs associated with the activation of balancing capacity. Compared to marginal pricing, ***average pricing*** (e.g. Germany, France) depresses price signals of the IB settlement. Therefore, it provides less incentives for BRPs to maintain a balanced position and, in particularly, for VRE generators to improve forecast accuracy (Hirth and Ziegenhagen, 2015). Hence, average pricing is inefficient

46 Voet (2015) also points out ***feed-in schemes*** can act as a barrier for VRE to provide balancing services in the BA market, because the loss of subsidies cannot be priced in the energy price bid for capacity activation.

in limiting balancing costs. Moreover, average pricing is also to the disadvantage of the business case for flexible resources. As average pricing reduces the occurrence of negative and/or extreme high IB prices, it masks the system needs for investment in new flexible resources able to provide upward/downward balancing within short lead time (Brijs et al., 2015). Similar to the impact of averaging pricing, the ***exclusion of costs associated with capacity reservation of balancing services*** in the IB price also acts as an inefficient design element limiting balancing costs reduction. Vandezande et al. (2009); Hirth and Ziegenhagen (2015) suggest that capacity reservation costs, instead of being socialized, should be included in the IB price via an additive component to reflect the full costs of imbalance.

The ***low time resolution*** (e.g. hourly) ***of IB settlement*** may also increase balancing costs. According to Fernande et al. (2016) and Vandezande (2011), BRPs that are able to maintain a balanced position over a long period of IB settlement can frequently cause imbalances within the period. As a result, the IB settlement may hamper the cost-reflective allocation of balancing costs (Fernande et al, 2016), inefficiently increasing the system demand for balancing services and associated balancing costs. This is the case for Spain. In other MSs, the time resolution of IB settlement is usually sub-hourly (ENTSO-E, 2016).

In addition, Wawer (2007) considers the system type, i.e. based on a one-price system or a two-price system, as the most important design element affecting the overall efficiency of the IB settlement. However, views regarding the superiority between both systems in limiting balancing costs differ among authors. Vandezande et al. (2009); Moeller and Fabozzi (2011) prefer the one-price system, arguing that passive balancing rewarded under a one-price system could reduce the system needs for holding reserves and the associated balancing costs. However, based on analysis of empirical data in Germany, Just and Weber (2015) have observed that passive balancing under a ***one-price system also creates perverse incentives for strategic behaviors arbitraging between the DA spot price and the IB price***. As explained in Section 5.5.1, the mismatch between hourly spot prices and sub-hourly IB prices for the same time period results in very low correlation between the two price signals. Due to such low correlation, BRPs tend to strategically over-contract and under-contract at high and low DA spot prices, if the system imbalance is expected to be respectively long and short. This strategic behavior could move the system imbalance to the unfavorable direction, resulting in higher demand for balancing capacity and additional balancing costs in an estimated range of € 200-300 million per year (Just and Weber, 2015). The additional balancing costs associated with strategic behavior are very likely to outweigh the expected costs savings from passive balancing under a one-price system. Following the same case in Germany, Chaves-Avila et al. (2014) also reports that a ***one-price system could exacerbate local imbalances in case of grid congestion***, provided that passive balancing gives adverse incentives for local BRPs to intentionally maintain an imbalanced position to the opposite direction of system imbalance. Based on above analyses, a one-price system seems to be less efficient in limiting balancing costs, in comparison to a two-price system designed to prevent BRPs from any imbalance.

5.5.3 Potential barriers increasing grid costs in the LMP mechanism

The efficiency of LMP mechanism mainly depends on its system type, i.e. zonal pricing or nodal pricing. Because of its limited representation for grid constraints, ***zonal pricing*** (especially for large zones) is inefficient in limiting grid costs, in comparison to nodal pricing. As the uniform price across a single price zone cannot represent internal grid constraints, zonal pricing fails to incentivize VRE investments to efficiently use existing grid infrastructure within the same zone. Consequently, suboptimal decisions could be made to invest in VRE at locations lacking grid capacity, resulting in unnecessarily higher grid costs associated with grid extension and expansion (Neuhoff et al., 2013; Batlle et al., 2013). Moreover, exacerbated by increased loop flows associated with the feed-in of VRE into the grid, zonal pricing increases the chance of congestion in meshed networks, because its price signals fail to inform the actual state of power flows (Henriot and Glachant, 2013; THEMA, 2013). Costs associated with grid congestion management are often high due to the need to re-dispatch plants. Recalling that IB settlement based on a one-price system could exacerbate local imbalance in case of grid congestion, zonal pricing that is inefficient in limiting grid costs and a one-price system that is inefficient in limiting balancing costs could further undermine the efficiency of each other.

5.6 SYNTHESIS AND POLICY RECOMMENDATIONS

5.6.1 Synthesis

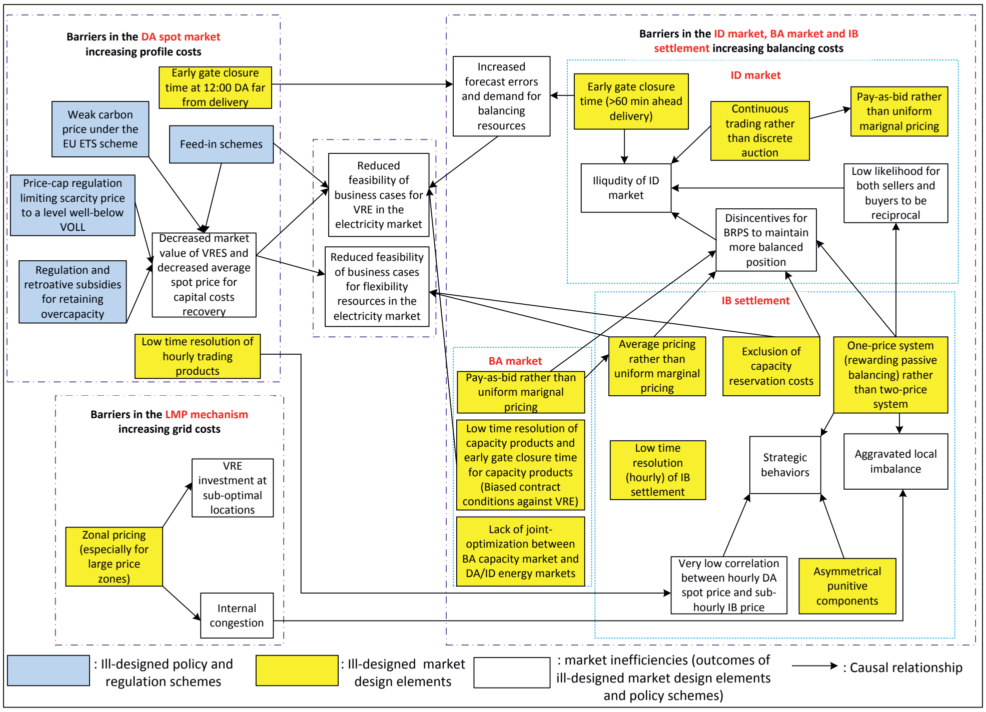

Figure 5.5. Framework for market integration barriers

Figure 5.5 shows that currently many barriers to the market integration of VRE exist in the electricity market in Europe. Many of the barriers lead to the same market inefficiency. Market integration barriers can result in either higher integration costs, or endangered business cases for investments in VRE and complementing flexible resources. Therefore, they should be addressed to facilitate better market integration.

5.6.2 Policy recommendations

Based on this framework, we can draw policy recommendations on how to improve the functioning of the electricity market that serves for VRE market integration from two interrelated aspects. They respectively relate to the reduction of integration costs (section 5.6.2.1) and the business case for VRE and complementing flexible resources (section 5.6.2.2).

5.6.2.1 Reduction of integration costs

Market design elements within a single submarket have intra-market or cross-market impacts on the market efficiency. They can be improved along five dimensions to reduce integration costs:

- The ***price settlement rule*** should help to disclose and reflect the marginal costs of balancing resources in all submarkets where balancing costs occur. In this sense, in the ID and BA market, pay-as-bid is inefficient and should be replaced to uniform marginal pricing. Similarly, average pricing in the IB settlement that corresponds to pay-as-bid in the BA market should be replaced by marginal pricing. It is also suggested that the capacity reservation costs should be included in the IB settlement price and asymmetrical punitive components should be removed.
- The ***system type*** for each submarket should be selected on the basis that it can better and robustly guarantee market efficiency and liquidity. In this sense, continuous trading in the ID market should be replaced by discrete auctions for better liquidity performance, and zonal pricing in the LMP mechanism is recommended to be replaced by nodal pricing for reducing grid costs. In addition, the one-price system in the IB settlement may better be replaced by a two-price system. This is because not only does a one-price system encourage strategic behavior in the IB settlement, but it decreases the liquidity performance of the ID market. It also aggravates local imbalance, if in combination with zonal pricing.
- The low ***time resolution of trading products*** in different submarkets cannot accurately reflect the physical reality of supply-demand dynamics in a power system with increased VRE. Hourly energy products in the DA market and IB settlement can give rise to increased balancing costs in the IB settlement, due to insufficient reflection of the sub-hourly variability and uncertainty associated with VRE. Therefore, it is recommended to increase the time resolution of energy products in the DA market and IB settlement to quarter-hourly. This implies that the current low time resolution of capacity products in the BA market should also be improved to quarter-hourly, to better match the improved time resolution of DA energy products and thus reduce costs associated with balancing capacity products.
- The early ***gate closure time*** insufficiently close to real-time delivery in different submarkets increase forecast errors of VRE and associated balancing costs. In particular, the 12:00 pm DA gate closure time can severely limit the possibility of trading VRE in wholesale without considerable impact on balancing costs. The authors propose to bring the DA gate closure time to 4 hour before delivery. Based on Spanish wind farm data (IEA, 2014b), such gate closure time can guarantee forecast errors well below 10%. It may also make a compromise with the lead time requirement for thermal plants to schedule their generation in a cost-efficient manner (Scharff, 2015). We suggest further studies to investigate such trade-off. As for the ID and BA market,

their gate closure time should be no more than 60 min before delivery to minimize balancing costs.

- The ***lack of joint optimization*** between BA capacity market and DA/ID energy market increases balancing costs. The electricity market design should enable such joint optimization, meaning that commitments to DA/ID energy market and BA capacity market should not be mutually exclusive.

Figure 5.6 illustrates how the set-up of EU electricity market might look like once recommended improvements of design elements are made for each submarket. The red color is used to mark the main improvements.

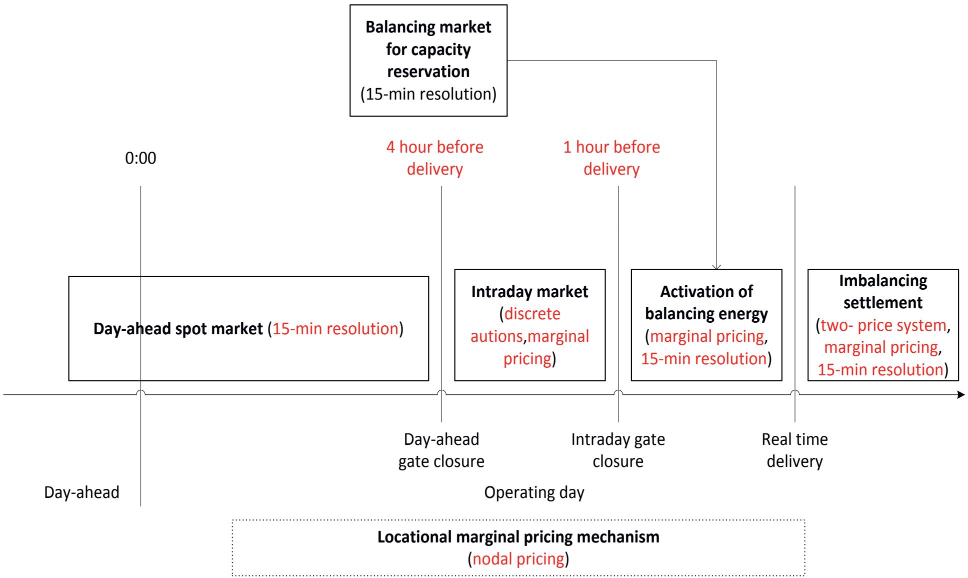

Figure 5.6. Illustration of the recommended EU electricity market set-up

Market inefficiencies may also arise from relevant policy and regulation schemes that distort the electricity market. Their negative impacts mainly concentrate on the DA spot market where profile costs occur. These policy schemes include weak carbon price under the current EU ETS scheme, feed-in schemes, price-cap regulation limiting the scarcity price to a level well-below the VOLL, and regulations and retroactive subsidies for retaining overcapacity. They exacerbate the market value reduction of VRE and thus increase profile costs. Improved policy and regulation schemes can thus lower profile costs and strengthen the business case for VRE and complementing flexible resources because of improved market value. These will be discussed in the next section.

5.6.2.2 Business case for VRE and complementing flexible resources

Market integration requires the electricity market fits the business case for VRE and complementing flexible resources. Market integration barriers, however, can reduce the feasibility of the business case for investments in VRE and flexible resources in the electricity market, and they should be removed:

- ***Feed-in schemes*** provide disincentives for VRE generators to maximize their market value in the electricity market, increasing the required subsidy level and locking VRE investments in a subsidy-dependent pathway. To avoid potential lock-in and support the business case of VRE investment in the electricity market, the authors argue that a direct capacity-based support scheme on top of the market revenue of VRE investments might be a better alternative to the current feed-in schemes. Not only does it minimize direct distortions on the electricity market, but it can incentivize VRE generators to maximize their market value. As the commercial maturity of VRE improves, the capacity-based support scheme can be degressive. Such capacity-based support scheme has been favored by a few authors, e.g. Andor et al. (2012); Eurelectric (2014); Bunn and Munoz (2016); Huntington et al. (2017).
- The weak ***carbon price under the current EU ETS scheme*** is insufficient to internalize the climate externality. It decreases the market value of VRE and creates an unleveled playing field for VRE to compete with fossil-fired generation technologies in the electricity market. Therefore, it reduces the business case for VRE investments. To address this issue, the carbon price should be increased to a level closer to the SCC[47]. It is estimated that a minimum carbon price at 60 $€_{2013}$/Tonne is required to make VRE investments break-even in the electricity market, relying on the market revenue alone (Deutsch et al., 2014). Similarly, explicit and implicit subsidies for fossil fuels also put VRE investments at a competitive disadvantageous position. If these subsidies are not removed, the business cases for VRE investments might remain unsound even in the long run. In that case, the market integration objective seems impossible to achieve.
- The ***scarcity price*** is essential for maintaining the functioning of the electricity market in remunerating investments in VRE and flexible resources. However, the level and frequency of scarcity price are reduced by price-cap regulation and retroactive subsidies for retaining overcapacity. This clearly reduces the feasibility of business cases for VRE and flexible resources, due to insufficient revenue for capital costs recovery. Therefore, the authors suggest policy-makers to lift up the price cap to the VOLL and accelerate the phase-out of excessive inflexible baseload capacity. This can help the electricity market to restore its functioning.

47 Based on the Stern Review (Stern, 2007), the SCC is estimated at 123 $€_{2013}$/Tonne CO_{2eq} for the year 2013. The SCC is also expected to increase at a rate of 2-3% per year (Aldy et al., 2008).

- The electricity market should provide ***a level playing field*** for all market participants. VRE generators capable of providing cost-efficient downward balancing services should be encouraged to participate in the BA market. However, unfavorable market design elements in terms of early gate closure time and low resolution of capacity products limit the possibility for their participation. The exclusion of VRE in the BA market excludes potential revenues from the BA market, which is detrimental to their business case. Hence, to facilitate the business case of VRE, the gate closure of BA market should be moved close to real time (e.g. 1 hour before delivery) and the resolution of capacity products should be increased to at least hourly and ideally quarter-hourly.

5.6.3 Further research

This study has qualitatively assessed barriers to the market integration of VRE through a literature review. To facilitate market integration, recommendations were given regarding how to improve the market design and relevant policy and regulation schemes. The authors propose further researches to quantitatively assess the impact of these improvements. In particular, a cost-benefit analysis is necessary to analyze the pro and cons of the new market set-up (as suggested in figure 6) and to what extent it can reduce integration costs. In addition, it is still unclear at what level the proposed capacity-based support scheme can provide sufficient security for VRE investors to de-risk their investments and limit the cost of capital. Model-based studies are required to further investigate this issue.

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6

Ex-ante Evaluation of EU ETS during 2013-2030: EU-internal abatement

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ABSTRACT

This study investigates CO_2 emission reduction within the EU resulting from the Emissions Trading Scheme (ETS) up to 2030. This is performed by constructing a baseline scenario without the ETS and assessing the impacts of the ETS, as currently designed. The results indicate that the ETS will start to impact emissions primarily after 2025 due to the prevalence of a sizable allowance surplus. The impact of approved (i.e. back-loading and 2.2% linear reduction factor (LRF)) and proposed (i.e. market stability reserve (MSR)) policy interventions and the inclusion of aviation, could accelerate the exhaustion of surplus and increase emission reductions during the investigated period. However, these measures would be insufficient to restore the scarcity of allowances and the corresponding carbon price before the start of ETS Phase IV, and the effectiveness of EU-internal abatement cannot be guaranteed until 2023. The effectiveness could be further reduced in the case of the economic shocks or the exclusion of international aviation.

To restore the scarcity of allowances, other reform options are necessary. This paper extends the reasoning for the early removal of the back-loaded 900 Mtonne allowances by 2020 and broadening the scope of ETS to other sectors with potential high demand for allowances.

Keywords

Policy Evaluation; European Union; Emissions Trading Scheme; EU-internal Abatement; Allowance surplus

6.1. INTRODUCTION

The European Union (EU) has set targets to reduce EU-wide GHG emissions by 20% in 2020 and by 80%-95% by 2050, against the 1990 levels, to mitigate climate change and facilitate its transition towards a competitive low carbon economy. To hit these targets, the EU launched the European Emissions Trading System (EU ETS) in 2005 as a central-pillar climate policy. The EU ETS covers sectors that account for approximately 45% of Europe's total GHG emissions[48], with a stated policy objective to "promote reductions of GHG emissions in a cost-effective and economically efficient manner" (European Parliament and Council, 2003).

The EU ETS is a cap-and-trade system. Its expected overall abatement can be visualized by the gap between the cap and baseline emissions that would have occurred with the absence of the ETS (De Perthuis, 2012). Due to the linkage with the Kyoto flexible mechanisms, overall abatement can be achieved via offsets that reduce emissions outside of Europe (Graus et al., 2009). In accordance with the *supplementarity principle* of the Kyoto Protocol, "[the use of offsets] should be supplemental to domestic action and domestic action will thus constitute a significant element of the effort made" (European Parliament and Council, 2003, page 4). While enhancing the cost-effectiveness of the overall abatement and engaging non-ETS participating countries in climate mitigation actions (Ellsworth et al., 2012), offsets have drawn many criticisms. For instance, the additionality of emissions reduction in many offset projects (e.g. industrial gas offsets) cannot be guaranteed, meaning that offset is *per se* a zero-sum game, at best (Methmann et al., 2013). Furthermore, offsets may discourage and delay domestic activities and risk locking the EU into carbon-intensive infrastructure, rendering its ambitious long-term emissions target too expensive to achieve (Bows et al., 2009). In other words, only with a strong focus on domestic activities can the EU ETS stimulate low-carbon investments in the sectors covered, avoiding the risk of technological lock-in and facilitating decarbonisation in the EU. As emphasized by the European Commissions (EC) (2011a, page 4), "The transition towards a competitive low carbon economy means that the EU should prepare for reductions in its *domestic* emissions by 80% by 2050 compared to 1990. Domestic emission reduction, meaning real internal reductions [within the EU] and not offsetting through the carbon market" (hereafter referred to as "EU-internal abatement"). This raises an interesting question for policy-makers: To what extent will the EU ETS, as currently implemented, drive EU-internal abatement?

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48 A detailed category of activities covered by the EU ETS can be found in DIRECTIVE 2009/29/EC (European Parliament and Council, 2009)

Several ex-post studies (Ellerman et al., 2010, Anderson and Di Maria, 2010, Deutsche Bank, 2010) have quantified the EU ETS's EU-internal abatement for its Phase I&II. Most studies estimated an impact of between 2.5% to 5% (or 150 to 300 Mtonne CO_{2eq}) emissions reduction within Europe against baseline emissions during Phase I (Brown et al., 2012). For Phase II, it was estimated that the EU ETS accounted for at least an EU-wide emissions reduction of 6.3% (or 260 Mtonne CO_{2eq}) during 2008-2009, against baseline emissions (Brown et al., 2012). Egenhofer et al. (2011) calculated that emissions abatement and emissions intensity improvement in Phase II were even larger than the extrapolated trend from Phase I, exhibiting that the EU ETS is accelerating the trend of decoupling economic growth from emissions in Europe (Kettner et al, 2011).

The EU ETS has entered into Phase III since 2013. As a joint result of the economic recession, sizeable influx of offset credits and overlapping energy policies (Taschini et al., 2014), the current performance of the EU ETS is characterized by a large allowance surplus, banked from Phase II and a weak carbon price (EC, 2012a). This surplus "is expected to continue to erode [the EU ETS's] role as a technology neutral, cost-effective and EU-wide driver for low carbon investment" (EC, 2014f, page 8). Some literature and reports have discussed the potential impact of this and different options that may restore the scarcity of allowances (Sandbag, 2012, Grubb, 2012 and EC, 2012a). However, only a few ex-ante studies providing a quantitative analysis on the ETS's EU-internal abatement during the post 2012 period are available. Graus et al. (2009) calculated the volume and structure of the EU ETS's cumulative abatement between 2008-2020, but the result is no longer timely because of the unexpected Phase II allowance surplus. Moreover, the EC (2014a and 2014b) has approved back-loading (i.e. the postponement of auctioning 900 Mtonne allowances until 2019-2020) as a temporary solution, and proposed to establish a market stability reserve (MSR) in 2021 as a sustainable solution to address the sizable allowance surplus. The EC (2014c) also plans to increase the annual linear reduction factor (LRF) of the cap on the EU ETS to 2.2% after 2020 to fall in line with the 2030 emissions reduction target recently approved by the European Council (2014) on October 23rd, 2014. However, the impacts of these policy interventions on EU-internal abatement still need further investigation. In addition, the newly inclusion of the aviation sector into the EU ETS in 2012 could also affect the EU-internal abatement through creating further demand for emissions allowances (Alberola and Solier, 2012). Thus, the aim of this paper is to provide a quantitative assessment of the EU-internal abatement of the EU ETS, during the post-2012 period in an ex-ante manner. With aims to analyses the evolution of allowance surplus over time in terms of volume, structure, duration, and its impact on the EU-internal abatement and emissions trajectory of the ETS sectors. The temporal scope for this analysis is set as the period 2013-2030, which is beyond the current Phase III. As 2030 is the intermediate year of Europe's decarbonisation trajectory, not only can this study deliver insights to improve the performance of EU ETS, but also the produced policy implications may contribute to the on-going discussion of the recent-approved 2030 EU emissions reduction target.

6.2 METHOD

To quantify the ex-ante internal abatement of the EU ETS in the EU-27[49], a baseline scenario without the implementation of the EU ETS during the investigated period is constructed. The baseline emissions represent the level of emissions if a cap and associated carbon price were not to be present. In a prototypical cap-and-trade system without offsetting linkage and allowance surplus from the previous phases, the required abatement effort (i.e. the gap between the cap and baseline emissions) represents the scarcity of allowances. Correspondingly, a carbon price is generated through the market. At individual level, each rational ETS participant will abate along its marginal abatement cost curve (MACC) until the marginal abatement cost equals the carbon price. The overall EU-internal abatement (i.e. the sum of abatement at individual level) in principle should be equal to the required abatement effort of the EU ETS. Although, admittedly, according to economic theory the realized EU-internal abatement may exceed the required abatement effort due to hedging[50] and banking behaviour, this impact is deeply uncertain because of the heterogeneous hedging and banking behaviours and assumed risk premiums of different ETS participants. Thus, for simplification purposes this study only aims to quantify the required abatement effort of the ETS, which could be deemed as a *conservative and minimum* value of EU-internal abatement (see also section 6.4). Given the fact that the large allowance surplus banked from Phase II and the influx of offset credits raise the *de facto* cap of the ETS, they should be taken out from the gap to determine the EU-internal abatement. This formulates a stepwise approach: Firstly, we determine the EU-internal abatement of the EU ETS in stationary sectors during the investigated period without policy interventions (i.e. back-loading, MSR and 2.2% LRF). Secondly, the impacts of the aforementioned policy intervention measures on the EU-internal abatement are further investigated through

49 Croatia, the 28th member state who joined in 2013 is not included in this study. Note that the inclusion of Croatia would have very low impact on results since it accounts only for 0.5% of primary energy use in EU27 in 2011 (IEA, 2013).

50 Hedging refers to the behavior of ETS participants to hold more allowances beyond their annual need for emissions compliance to hedge against uncertain future carbon prices. Therefore, hedging creates an additional market demand for emissions allowances and increases the carbon price, incentivizing ETS participants to abate more so as to bank more allowances if the carbon price is expected to increase in the future. In the case of hedging, theoretically a rational ETS participant would make abatement decisions along its marginal abatement cost curve until the marginal abatement cost equals the market carbon price plus a risk premium for hedging. A detailed discussion on hedging in power sector can be found in Schopp and Neuhoff (2013).

a comparative analysis. Then we determine the impact of the EU ETS on the aviation sector separately, given that the rules applied are different. Finally, the impact on the aviation sector is integrated through an aggregation approach to determine the overall internal abatement of the EU ETS.

6.2.1 Stationary ETS sectors without policy interventions

6.2.1.1 Determine the Cap

According to the revised EU ETS Directive (European Parliament and Council, 2009), to achieve the 20% overall reduction target below 1990 emissions level by 2020[51], the emissions cap for stationary ETS sectors from 2013 onwards should be determined by an annual LRF of 1.74% that started in 2010 on the average cap over Phase II. This implies that the average Phase II emissions cap (2081 Monne CO_{2eq}[52]) has been decreased over time since 2010 to generate the annual emission cap for 2013 and beyond.

6.2.1.2 Develop baseline emissions scenario

The baseline emissions scenario can be constructed based on decomposing emissions of stationary ETS sectors into activity volume (GDP) and emissions intensity (against GDP), assuming GDP is the primary driver for ETS emissions. Through extrapolating the historical trend of emissions intensity improvements into the investigated period, the annual baseline emissions can be calculated. This approach has been applied in Ellerman et al. (2010)'s ex-post study in estimating the abatement impact for the EU-25 throughout Phase I (2005-2007). It is still applicable to this ex-ante study for the EU-27 after appropriate modifications, using the historical trend of emissions intensity improvement immediately before the implementation of the EU ETS (Ellerman et al., 2010), the most up-to-date GDP projection and the latest verified 2012 ETS emissions.

Identify the historical trend of emissions intensity improvement

To obtain a holistic view, a time period of the past two decades (1990-2012) has been investigated, which should be long enough to fully reflect the historical trend of the emissions intensity of stationary ETS sectors before and after the implementation of the EU ETS. To calculate the emission intensity, the annual GDP ($Euro_{2005}$) and verified ETS emissions data are needed. These are provided in Eurostat (2014) and EU ETS data viewer (EEA, 2014), respectively. However, there is no aggregate emissions data available specifically for the ETS sectors before the implementation of EU ETS in 2005.

51 The 20% overall emissions reduction target by 2020 can be translated into 21% and 10% emissions reductions for (stationary) ETS and non-ETS sectors in 2020 (against their 2005 levels), respectively (EC, 2014d). The LRF of 1.74% ensures the 2020 emissions for stationary ETS sectors to be capped at 21% below 2005 level.

52 Data for EU-27, derived from EU ETS data viewer (EEA, 2014)

This problem can be solved through matching ETS sectors with the relevant source categories of the GHG inventory in the UNFCCC common report format (CRF), based on Herold (2007)'s finding of a high consistency between CRF emissions and verified ETS emissions for 2005, through an extensive comparison (Ellerman et al., 2010). Considering the consistency between ETS sectors and relevant CRF sectors, it is possible to generate a data series for the pre-2005 ETS emissions in the EU-27 if the share of ETS emissions relative to relevant CRF emissions is known. Although an average ~85% share of verified ETS emissions out of relevant CRF emissions at aggregate EU level (EU-8, EU-15, EU-23) is given in Herold (2007)'s study, it only holds true for the year 2005. To justify the accuracy of this approach, the share of verified ETS emissions relative to relevant CRF emissions is calculated for the EU-27 from 2005 to 2011[53] in table 6.1.

Table 6.1 Share of verified ETS emissions relative to relevant CRF emissions for EU-27 from 2005 to 2011

Year	$\frac{\text{Verified ETS emissions}}{\text{Relevant CRF emissions}}(\%)$	Verified ETS emissions (MTonne)	Relevant CRF emissions (MTonne)
2005	80.7	2014	2498
2006	80.9	2035	2513
2007	85.9	2165	2520
2008	87.5	2100	2400
2009	87.6	1860	2124
2010	87.3	1919	2197
2011	87.4	1885	2156

Sources: Data compiled from EU ETS data viewer (EEA, 2014) and Greenhouse Gas Inventory Data (UNFCCC, 2014)

The share is steady at ~80.8% during 2005-2006. It then increases to ~85.9% in 2007 and remains constant at ~87.5% during 2008-2011. This can be explained by the fact that the verified emissions did not include Bulgaria and Romania until they joined the EU in 2007, and the scope expansion of the EU ETS in its transition from Phase I (2005-2007) to Phase II (2008-2012) (DECC, 2013). The constant share of verified ETS emissions out of relevant CRF emissions accurately reflects and verifies the consistency between ETS emissions and relevant CRF emissions over time. Thus, a data series of pre-2005 ETS emissions under the scope of Phase II for the EU-27 can be calculated via formula 1:

$$ETS\ emissions_{pre-2005} = 87.5\,\% * Relevant\ CRF\ emissions_{pre-2005} \quad (1)$$

53 Because UNFCCC only provides CRF emissions data up-to 2011, this calculation is only conducted for 2007-2011.

Bearing in mind that verified ETS emissions data for 2005-2007 needs to be adjusted to maintain the consistency of the scope, figure 6.1 shows the trend of ETS emissions in the EU-27 from 1990-2012 (with scope adjustment).

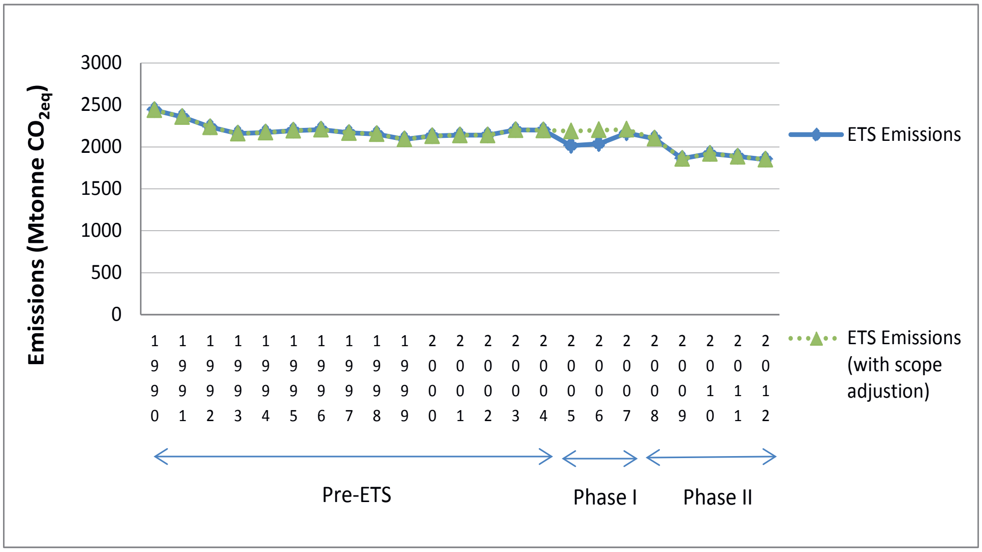

Figure 6.1 (Stationary) ETS emissions for EU-27 (with adjustment to Phase II scope) during 1990-2012

A general decreasing trend of emissions can be observed for the period 1990-2000, followed by a steadily rising trend during 2000-2004. After the implementation of the EU ETS, ETS emissions remain at almost the same level in Phase I (2005-2007), in spite of a relatively robust economic growth of ~2.9%/year (Eurostat, 2014). The downward trend of emissions still continues in Phase II (2008-2012) due to the joint impact of ETS and the economic crisis. Therefore, the period 1990-2012 can be divided into four distinguishable sub-periods. Their corresponding average annual emissions intensity improvement rates are calculated in table 6.2.

Table 6.2 Average annual ETS emissions intensity improvement rate in EU-27 for different time period

Time period		Average annual ETS emission intensity $\left(\frac{ETS\ emissions}{Real\ GDP}\right)$ improvement rate (%)
Pre-ETS implementation	1990-2000	3.48
	2000-2004	1.19
With ETS implementation	2004-2007 (Phase I)	3.12
	2007-2012 (Phase II)	3.17

Strong annual reductions in emissions intensity can be observed respectively for the period 1990-2000, and Phase I&II. To a very large extent the former intensity improvement in 1990s was under the external influence of drastic politico-economic changes in member states in Eastern Europe following the collapse of the Soviet Union. Shut-down of inefficient coal-fired power plants and energy-intensive installations due to economic restructuring in these countries, coupled with the rehabilitation in former East Germany, directly lead to the decrease in emission intensity (Rootzén, 2012 and EEA, 2011). Emissions intensity improvement during this period was also accelerated by the increasing penetration of renewable energy sources in the EU-27 and the significant fuel-switch from coal to gas in the UK. In the EU-27 the penetration of renewable energy in final energy consumption increased by 16% during 1990-1999 (IEA, 2013), while in the UK the shares of coal and gas for electricity generation changed respectively from 65% to 38% and from 1% to 28% (Gummer and Moreland, 2000). As for the emissions intensity improvement during Phase I&II, it should be primarily ascribed to the policy effectiveness of the EU ETS (Laing et al., 2013), whose carbon price spurred substantial abatement actions among both power and industrial installations.

Thereby, neither average annual emissions intensity improvement throughout 1990-2000 nor that during Phase I&II would be suitable for developing a baseline emissions scenario; they are far beyond the level that autonomous emissions intensity improvement could reach under baseline conditions in the absence of external influences or a carbon price. As a result, the moderate average annual emissions intensity improvement rate of 1.19% during 2000-2004 seems to be the most appropriate one to use. It not only corresponds to the historical trend occurring immediately before the implementation of the EU ETS (Ellerman et al., 2010), but it is also hard to find any major external influence other than autonomous improvement that had an impact on emissions intensity, during the period.

Determine the annual GDP of the EU-27 for the period 2013-2030

GDP projections for 2013-2030 can be derived from the AUGUR scenarios, which are the most up-to-date economic scenarios for Europe (Cripps, 2013). They are based on a macro-economic model, officially developed by the EU AUGUR program (EC, 2013). The "multi-speed" scenario is selected in this study because of the moderate GDP growth projection. It assumes that while "the EU continues to play a central role in infrastructure, energy and trade, greater internal flexibility for fiscal and monetary policies are given to each member state to support economic growth at a national level" (adapted from EC, 2013, page 11-12). Figure 6.2 shows the multi-speed Europe scenario together with the other two AUGUR scenarios; "struggling on" and "towards federal Europe". Compared to the multi-speed Europe scenario, they are more extreme cases. The struggling on scenario "maintains the Eurozone intact without addressing long-term problems of government finance, regional depression and unemployment"; while the towards federal Europe scenario "envisages a big-government solution to unequal development in the Eurozone" (EC, 2013, page 26).

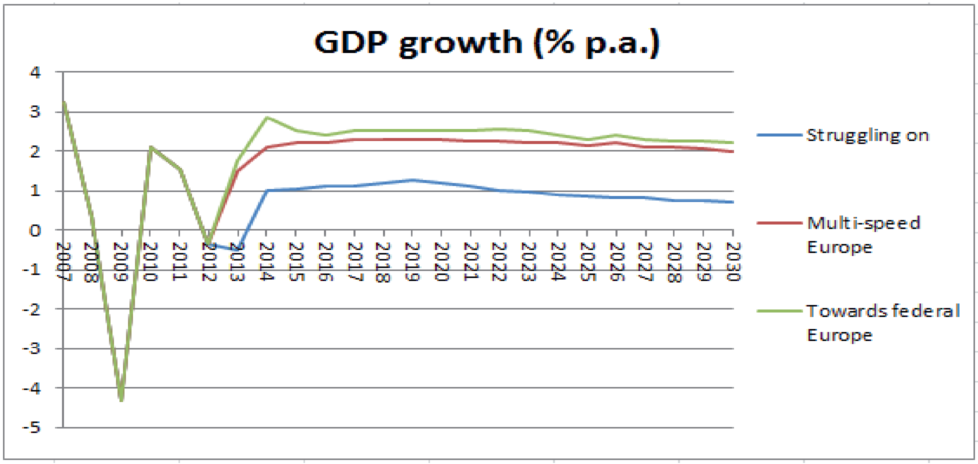

Figure 6.2 AUGUR Macro-model scenarios

Source: Cripps (2013)

Calculating the baseline ETS emissions

The baseline emissions of stationary ETS sectors for year i during the investigated period can be calculated from formula 2:

$$E_{BAU,i(s)} = GDP_i * EI_{2012(s)} * \left(1 - \overline{r_{2000-2004(s)}}\right)^{i-2012}, \; 2013 \leq i \leq 2030 \; (2)$$

$$EI_{2012(s)} = \frac{E_{verified,2012(s)}}{GDP_{2012}}$$

Where;

$E_{BAU,i(s)}$ = *Annual baseline emissions of stationary ETS sectors in year i (Mtonne* CO_{2eq}*)*
GDP_i = *Annual GDP in year i (Billion* $Euro_{2005}$*)*
$EI_{2012(s)}$= *Emissions intensity of stationary ETS sectors in 2012 (0.158 Mtonne* CO_{2eq}*/Billion* $Euro_{2005}$*)*
$E_{verified,2012(s)}$=*Verified emissions of stationary ETS sectors in 2012 (1848 Mtonne*CO_{2eq}[54]*)*
GDP_{2012}= *GDP in 2012 (11720 Billion* $Euro_{2005}$*)*
$\overline{r_{2000-2004(s)}}$= *average annual emissions intensity improvement of stationary ETS sectors during 2000-2004 (1.19%)*

6.2.1.3 Determining allowance surplus and offset credits

The surplus of allowances, in principle, mainly comes from two sources: over-supply of allowances and the usage of offset credits (Carbon market watch, 2012). Over-supply is the phenomenon that the ex-ante determined cap is greater than the ETS emissions (Venmans, 2012). It results either from too low of a cap-setting, or over-estimated baseline emissions in the case of unexpected economic shocks. Offset credits also contribute to the formation of allowance surplus, as the surrender of a number of offset credits for compliance purpose will simply free up the same quantity of allowances in the EU ETS (Ellsworth et al., 2012). Therefore, using data provided in the EU ETS data viewer (EEA, 2014), formula 3 and 4 can be respectively applied to quantify annual and cumulative allowance surplus for a given year i starting from 2008. As inter-phase allowances banking is allowed from 2008 onwards, 2008 is chosen as the starting year for quantifying allowance surplus:

54 Derived from EU ETS data viewer (EEA, 2014)

$$AS_{i(s)} = \left(EC_{i(s)} - E_{i(s)}\right) + OC_{i(s)}, \quad i \geq 2008 \ (3)$$

$$CS_{i(s)} = \sum_{2008}^{i} AS_{i(s)}, \ i \geq 2008 \ (4)$$

Where;
$AS_{i(s)}$= Annual allowance surplus in year i (Mtonne CO_{2eq})
$EC_{i(s)}$=Annual emissions cap in year i (Mtonne CO_{2eq})
$E_{i(s)}$=Annual emissions in year i (Mtonne CO_{2eq})
$OC_{i(s)}$= Annual usage of offset credits in year i (Mtonne CO_{2eq})

$CS_{i(s)}$= Cumulative allowance surplus in year i (Mtonne CO_{2eq})

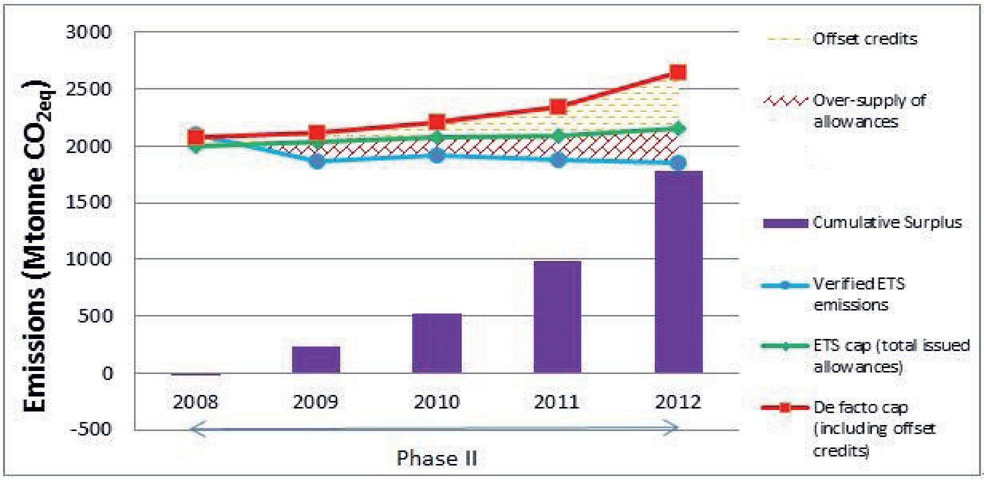

Figure 6.3 Surplus build-up of stationary ETS sectors during Phase II

The cumulative surplus accumulated in Phase II amounted to 1776 Mtonne, of which 41.5% and 58.5% resulted from over-supply and offset credits, respectively. The overall Phase II surplus was even closer to the verified ETS emissions in 2012, and all of it was banked into the post-2012 period.

Surplus build-up during 2013-2030

Besides surplus banked from Phase II, the allowance surplus during the post-2012 period consists of three components: over-supply of allowances, offset credits and the unused Phase II New Entrants Reserve (NER) auctioned in 2013 (EC, 2012b).

Over-supply of allowances

Through comparing the annual emissions cap and projected baseline emissions, the over-supply of allowances during the investigated period can be quantified in an ex-ante manner. Over-supply will emerge only if the pre-determined cap exceeds baseline emissions.

Offset credits

The EC (2014e) estimated that the maximum access of offset credits is limited to ~1600 Mtonne between 2008-2020 for stationary ETS sectors. Since in total 1039 Mtonne offset credits have been surrendered in Phase II (EEA, 2014), the remaining quota for 2013-2020 is only 561 Mtonne. For simplicity this influx of credits is treated as evenly distributed throughout Phase III, resulting in an annual usage of 70.1 Mtonne. For Phase IV (2021-2027) and beyond, it is assumed that the use of offset credits would be banned, given the expiration of the Kyoto Protocol in 2021.

Phase II NER leftover

The Phase II NER is a pool of grandfathered allowances set aside to enable eligible new installations to enter into the EU ETS in Phase II. It is also supposed to recycle allowances from closed installations, preventing excessive allowances entering into the market directly (Gilbert and Phylipsen, 2006). As an impact of the economic crisis, less than 16% of allowances from the NER were issued in Phase II (Pearson and Worthington, 2009). Although France, Ireland and Portugal have committed to cancel their unissued allowances in the Phase II NER, other ETS participant countries would still bring their NER leftover into Phase III (ICIS, 2013 and Ellsworth, 2010). This results in an additional 125 Mtonne allowances auctioned in 2013 (EC, 2012b).

Thus, cumulative surplus for stationary ETS sectors in a given year i during 2013-2030 can be expressed through formula 5:

$$CS_{i(s)} = CS_{phase\ II(s)} + NERL_{Phase\ II(s)} + \sum_{2013}^{i}\left[\left(EC_{i(s)} - E_{BAU,i(s)}\right) + OC_{i(s)}\right],\ 2013 \leq i \leq 2030 \quad (5)$$

$$OC_i = \begin{cases} 70.1\ Mtonne, & if\ i \leq 2020 \\ 0, & if\ 2021 \leq i \leq 2030 \end{cases}$$

Where;
$CS_{i(s)}$ = *Cumulative allowance surplus in year i (Mtonne CO_{2eq})*
$CS_{phase\ II(s)}$ = *Allowance surplus banked from ETS Phase II (1776 Mtonne CO_{2eq})*
$NERL_{Phase\ II(s)}$= *Phase II NER leftover (125 Mtonne CO_{2eq})*
$EC_{i(s)}$= *Annual emissions cap in year i during 2013-2030 (Mtonne CO_{2eq})*
$E_{BAU,i(s)}$= *Annual baseline emissions in year i (Mtonne CO_{2eq})*
$OC_{i(s)}$= *Annual offset credits usage in year i (Mtonne CO_{2eq})*

6.2.1.4 Quantifying internal abatement

In theory, at individual level rational firms will abate along their MACCs until the point equal to the market carbon price plus a risk premium, even if they hold an allowance surplus. However, because of the large surplus at EU-aggregate level and the limited foresight of firms, the carbon price would be depressed and prolonged, thus, insufficient to stimulate investment in most abatement measures (CCAP-Europe, 2012). In addition, the surplus loosens the *de facto* cap of the EU ETS, reducing the required emissions reduction (i.e. the *minimum* value of EU-internal abatement). In others words, internal abatement cannot be guaranteed as long as the cumulative allowance surplus is not fully absorbed as this surplus can be surrendered to avoid abatement. It is therefore assumed that the allowance surplus at an EU-aggregate level is used at a maximum speed, meaning that the impact of hedging/banking is not taken into account in the calculation (see section 6.4). If the year where internal abatement first starts to occur is denoted as x, the cumulative internal abatement for stationary ETS sectors in any given year i, and the total internal abatement for 2013-2030 can be calculated respectively via formula 6 and 7:

$$CIA_{i(S)} = \begin{cases} 0, & \text{if } 2013 \le i \le x-1 \\ \sum_x^i \left(E_{BAU,i(S)} - EC_{i(S)} \right) - CS_{x-1(S)}, & \text{if } x \le i \le 2030 \end{cases} \quad (6)$$

$$IA_{2013-2030(S)} = \sum_x^{2030} \left(E_{BAU,i(S)} - EC_{i(S)} \right) - CS_{x-1(S)} \quad (7)$$

Where;
$CIA_{i(S)}$= *Cumulative internal abatement in year i (Mtonne CO_{2eq})*
$E_{BAU,i(S)}$=*Annual baseline emissions in year i (Mtonne CO_{2eq})*
$EC_{i(S)}$=*Annual emissions cap in year i (Mtonne CO_{2eq})*
$CS_{x-1(S)}$=*Cumulative allowance surplus in the year before internal abatement first occur (Mtonne CO_{2eq})*
$IA_{2013-2030(S)}$=*Total internal abatement during 2013-2030 (Mtonne CO_{2eq})*

6.2.2 Stationary ETS sectors with policy interventions

This section gives the assumptions used to investigate the impact of approved (i.e. back-loading and 2.2% LRF) and proposed (i.e. MSR) policy interventions, on the EU-internal abatement impact of the EU ETS.

6.2.2.1 Back-loading of 900 Mtonne allowances

Back-loading is the postponement of the auction of 900 Mtonne allowances until 2019-2020. The allowances to be auctioned are reduced by 400, 300 and 200 Mtonne during 2014-2016, and increased by 300 and 600 Mtonne in 2019 and 2020 (EC, 2014a). This is modelled by adjusting the cap-setting for stationary ETS sectors.

6.2.2.2 Annual LRF at 2.2% after 2020

The 2030 overall emissions reduction target within the 2030 framework for climate and energy policies proposed by the EC (2014c) has been recently approved by the European Council (2014). It aims to reduce domestic EU emissions by 40% against 1990 levels. For stationary ETS sectors this would deliver an emissions reduction of 43% against 2005 level in 2030, meaning that the current annual LRF of 1.74% for cap-setting has to be increased to 2.2% from 2021 onwards (EC, 2014c).

6.2.2.3 MSR starting in 2021

The EC (2014b) has also proposed to establish a MSR starting in 2021 to address the sizable allowance surplus among stationary ETS sectors and strengthen the system's resilience in case of future demand shocks. The proposed rules for the MSR can be summarized as follows: "In each year i starting in 2021, a quantity of allowances equal to 12% of the cumulative surplus in year i-2 shall be put in the reserve, unless this quantity is less than 100 Mtonne. In any year i, if the cumulative surplus is less than 400 Mtonne, 100 Mtonne allowances shall be released from the reserve; In case less than 100 million allowances are in the reserve, all allowances in the reserve shall be released" (adapted from EC, 2014b, Article 1). Therefore, formula (8) and (9) can be applied respectively to determine the annual number of allowances to be injected in the reserve and the corresponding cumulative surplus excluding allowances in the reserve for a given year i from 2021 onwards[55].

6

55 Note that the our calculation does not take account of the provisions in the MSR proposal (EC, 2014b) that are "aimed at smoothening auctioning supply in the years around transitions between trading phases", as no explicit rules are available for the operation of these provisions.

$$AR_{i(s)} = \begin{cases} 12\% \quad CSER_{i-2(s)}, & \textit{if } CSER_{i-2(s)} \geq 833\ \textit{Mtonne and } CSER_{i-1(s)} \geq 400\ \textit{Mtonne} \\ 0, & \textit{if } CSER_{i-2(s)} < 833\ \textit{Mtonne and } CSER_{i-1(s)} \geq 400\ \textit{Mtonne} \\ * \quad -100\ \textit{Mtonne}, & \textit{if } CSER_{i-1(s)} < 400\ \textit{Mtonne} \\ -\sum_{2021}^{i} AR_{i(s)}, & \textit{if } 0 \ll \sum_{2021}^{i-1} AR_{i(s)} < 100\ \textit{Mtonne} \end{cases} \quad (8)$$

$$CSER_{i(s)} = CS_{2021(s)} - \sum_{2021}^{i} AR_{i(s)} \quad (9)$$

Where;
$AR_{i(S)}$= Annual number of allowances to be injected in the reserve in year i (Mtonne CO_{2eq})
$CSER_{i(S)}$= Cumulative allowance surplus excluding allowances in the reserve in year i (Mtonne CO_{2eq})
$CS_{i(s)}$ = Cumulative allowance surplus in year i (Mtonne CO_{2eq})

6.2.3 Incorporation of aviation sector

The aviation sector has been integrated into the EU ETS since 2012, including both intra-Europe and international flights to or from Europe (European Parliament and Council, 2008). It accounts for 11% of emissions covered by the EU ETS, with most coming from international aviation (Leggett et al., 2012). As the unilateral integration of international aviation has triggered strong dissatisfaction from many other international actors, the EC (2014f) decided to postpone the enforcement of including international flights. It aims to provide negotiation time for reaching a global market-based mechanism (GMBM) through the International Civil Aviation Organization (ICAO) assembly that could deliver aviation emissions reduction at least equivalent to what the EU ETS is going to deliver. Such a GMBM is still pending and uncertain, although ICAO, without a binding commitment, called for appropriate measures to be finalised and voted on in 2016, and implemented in 2020 (Rock et al., 2014). Therefore, it is assumed in this study that the scope of aviation ETS only includes intra-EU flights between 2012-2019, and from 2020 onwards international aviation would be integrated into the EU ETS.

6.2.3.1 Determining the cap

The cap for the aviation sector shall be equivalent to 97% of the historical aviation emissions[56] in 2012, and it shall be reduced to 95% from 2013 onwards (European

56 The historical aviation emissions represent "the mean of the annual emissions in the calendar years 2004, 2005 and 2006" from all flights to and from EU airports, amounting to 219.5 Mtonne CO_{2eq} (EC, 2011b). However, as only intra-EU flights emissions are covered under the EU ETS between 2012-2019, accordingly the aviation cap for this period should also be determined based on average historical intra-EU aviation emissions. According to Preston et al. (2012), intra-EU aviation emissions account for 33.4% of total aviation emissions that would be covered by the EU ETS. As such, historical intra-EU aviation emissions should be equal to 73.3 Mtonne CO_{2eq}.

Parliament and Council, 2008). As such, the annual aviation cap for 2012, 2013-2019 and the post-2019 period can be determined as 71.1, 69.6 and 208.5 Mtonne CO_{2eq}, respectively. The first two including only intra-EU aviation.

6.2.3.2 Constructing the baseline emissions scenario

Alike stationary ETS sectors, baseline emissions of the aviation sector can be projected based on decomposing the annual aviation emissions into air traffic volume and emissions intensity factors, namely *Revenue Tonne Kilometer* (RTK)[57] and Emissions per RTK (EI). Using a combination of top-down and bottom-up approaches, Boeing (2013) provided a projection of the annual air traffic volume growth rate at 4.15%[58] for Europe over the period 2013-2032. Meanwhile, an annual emissions intensity (of air traffic) improvement target of 1.9% for the post-2010 period was stated by IATA (Macintosh and Wallace, 2008 and IATA, 2007). As such, an annual aviation emissions growth rate of 2.17% is assumed. Given the historical aviation emissions (i.e. average annual emissions for 2004-2006), a series of aviation emissions for the EU-27 during the investigated period can be generated, applying formula 8:

$$E_{BAU,\ i(A)} = \overline{E_{2004-2006(A)}} * (1 + 2.17\%)^{i-2006} \quad 2013 \le i \le 2030 \quad (8)$$

Where;

$E_{BAU,\ i(A)}$ = *Annual baseline emissions of aviation sector in year i (Mtonne CO_{2eq})*

$\overline{E_{2004-2006(A)}}$ = *Historical average aviation emissions during 2004-2006 (Mtonne CO_{2eq})*

6.2.3.3 Determining offset credits

In addition to emissions allowances, additional offset credits can be used by the aviation sector. A volume of offset credits up to 15% of the annual aviation emissions can be used in 2012, while for 2013-2020 a usage limit equivalent to 1.5% of the annual emissions has been set (European Parliament and Council, 2008). Just as for stationary sectors, it is assumed that the use of offset credits in the aviation sector would be banned beyond 2020.

57 Revenue Tonne Kilometer (RTK) is the standard activity unit for air transport. One RTK denotes one Tonne of load (passenger or cargo) travelled for one kilometer (ICAO, 2010).

58 This value has been adjusted to the difference of the projected GDP growth rates between Boeing (2013) and Augur multi-speed Europe scenario used in this study. The former assumes an annual GDP growth rate of 1.8% for Europe, while a value of 2.15% is implied in the latter. A projection of air traffic volume growth rate at 3.8% is reported by Boeing under its GDP growth projection, based on the assumption that the growth of air traffic volume is the sum of GDP growth and an independent time-varying function (Boeing, 2013). This leads to an air traffic volume growth rate of 4.15% under the projected GDP growth used in this study.

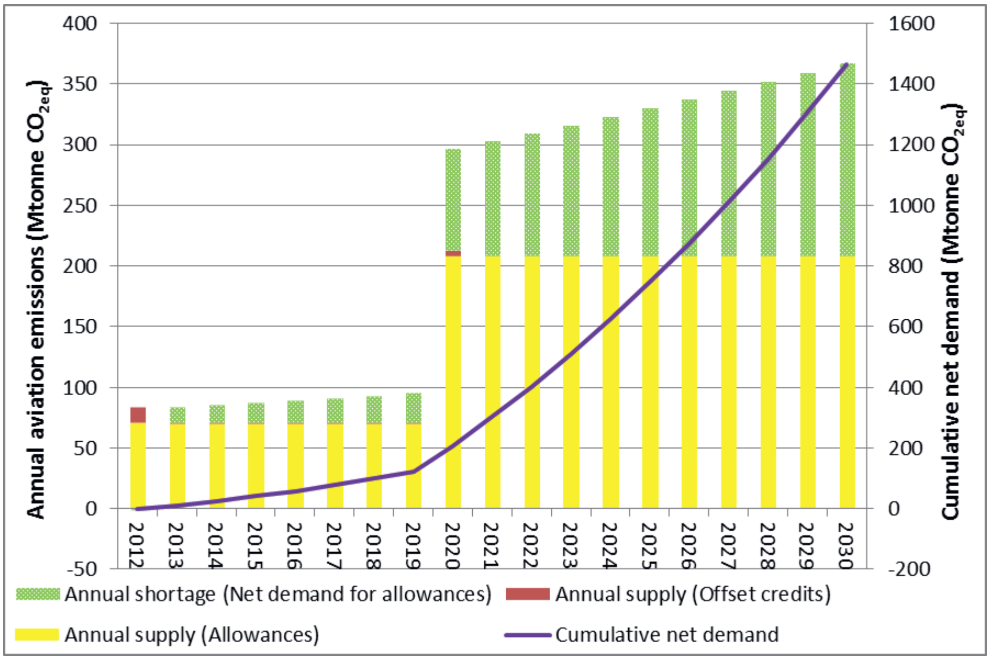

Figure 6.4 Supply/demand balance of allowance for the aviation sector included in the EU ETS

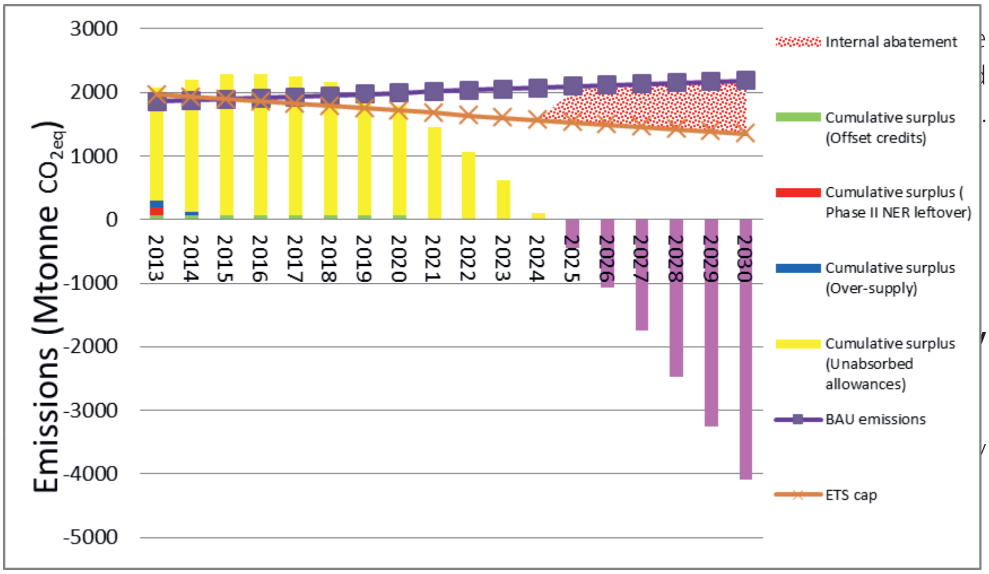

Figure 6.5 EU-internal abatement (excluding aviation) without policy intervention and cumulative surplus build-up of the EU ETS under baseline emissions during 2013-2030

The allowance surplus would continue to build up in an incremental fashion over 2013-2016, due to the combined impact of surplus banked from Phase II, Phase II NER leftover, over-supply of allowance and the usage of offset credits. After reaching its peak in 2016, the allowance surplus would begin to decrease because it is being continuously absorbed by the enlarging gap between baseline emissions and the cap. However, no internal abatement could be guaranteed before the surplus is fully absorbed; the portion of baseline emissions above the cap that should have been abated could still be emitted through surrendering an equal amount of excessive allowances held by ETS participants. This may lead to a deviation from the EU's emissions reduction trajectory and create uncertainty in achieving the 2020 emissions reduction target[59]. It is not until 2025 that the total volume of surplus (2622 Mtonne CO_{2eq}) prevalent throughout most of the investigated period would be fully exhausted, and since then internal abatement would certainly begin to emerge. As demonstrated by the negative bar[60], the cumulative internal abatement would increase from 2025 onwards, reaching 4095 Mtonne by 2030. This value also represents the total EU-internal abatement of the EU ETS during 2013-2030, which can be illustrated by the spotted area. As the EU-internal abatement would only be concentrated over the last six years of the investigated period, the relevance of the EU ETS as an emissions reduction instrument would be limited for many years to come.

6.3.2 EU-internal abatement of the EU ETS (excluding aviation) with policy interventions

Figure 6.6 shows the EU-internal abatement of the EU ETS (excluding aviation) with the incorporation of policy intervention measures (i.e. back-loading, 2.2% LRF and MSR) that aim to restore the scarcity of allowances. Although back-loading would substantially alleviate the build-up of surplus over the initial three years of Phase III, it would also contribute to the rapid surge of surplus in the last two years of the same phase. As a result, in 2020 the cumulative surplus of 1794 Mtonne remains at the same level as the case without back-loading. Compared to the case with unchanged LRF at 1.74%, the LRF of 2.2% starting in 2021 would accelerate the absorption of allowance surplus, but in an incremental manner through increasing the downward slope of the cap. In this way, it would contribute to an additional EU-internal abatement of 524 Mtonne during the investigated period. The establishment of MSR after 2020 would substantially reduce the amount of surplus, with 537 Mtonne allowances being put into the reserve by 2023. However, as the cumulative surplus declines to less than 100 Mtonne in 2023,

59 For ETS sectors, the 2020 emissions reduction target is reflected in the 2020 emissions cap

60 The negative bar (i.e. the negative cumulative allowance surplus) starting from 2025 is equivalent to the cumulative shortage of allowances, whose absolute value per se actually represents the cumulative internal abatement of ETS.

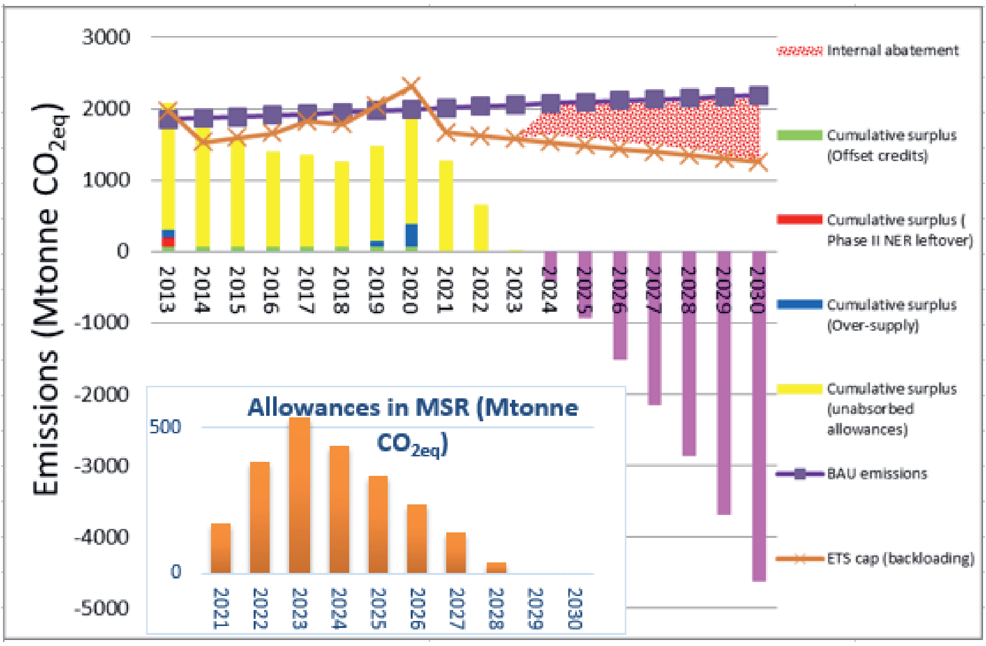

Figure 6.6 EU-internal abatement (excluding aviation) with policy interventions and cumulative surplus build-up of EU ETS under baseline emissions during 2013-2030

As a combined impact of these measures, the allowance surplus would be fully exhausted in 2024, which is only one year ahead of that without policy interventions. The total internal abatement during the investigated period would be increased to 4619 Mtonne, compared with 4095 Mtonne in the case without policy inventions. Despite a duration of 18 years for the investigated period, the occurrence of EU-internal abatement could only be guaranteed in its last seven years because of the sizable total allowance surplus of 2966 Mtonne.

6.3.3 EU-internal abatement of the EU ETS (including aviation) with policy interventions

With the inclusion of the aviation sector (see figure 6.7), the allowance surplus would be fully absorbed in 2023. Hence, the cumulative internal abatement would increase steadily from 2023 onwards, reaching 6084 Mtonne by 2030. However, including the aviation sector would not be sufficient to restore the scarcity of allowance until the last eight years of the investigated period. It would, to some extent, lessen the impact of excessive allowances, by accelerating the process of surplus being absorbed. The full exhaustion of the surplus would be one year ahead of that excluding aviation, and the duration of EU-internal abatement of the EU ETS would increase by one year. This can be explained by the general shortage of allowances and the relatively high abatement cost within the aviation sector (IPCC, 2007). Airline companies have to purchase additional allowances to cover their increasing emissions each year, which would create an additional net demand for allowances from stationary ETS sectors with a significant surplus. Furthermore, the inclusion of the aviation would strengthen the EU-internal abatement during the investigated period. The net shortage of allowances from aviation would increase the total internal abatement by 31.7% (or 1465 Mtonne), compared with the situation excluding aviation.

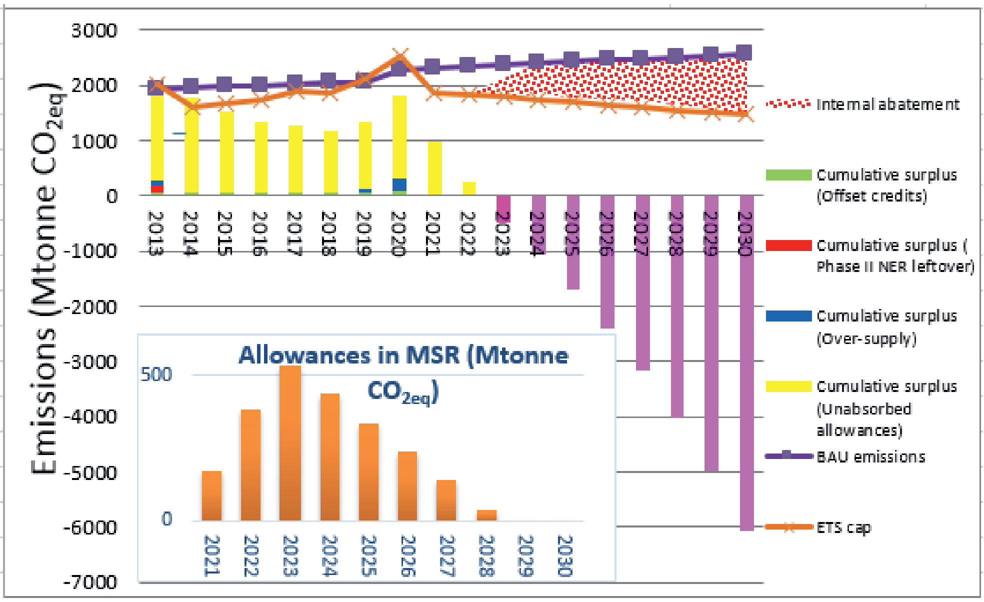

Figure 6.7 EU-internal abatement (including aviation) with policy interventions and cumulative surplus build-up of the EU ETS under the baseline emissions during 2013-2030

6.4 DISCUSSION OF UNCERTAINTIES

The determination of the future EU-internal abatement resulting from the EU ETS involves many data sources and assumptions. This section discusses the main uncertainties that may induce a significant impact on calculated results.

Banking of allowance surplus

In this paper, the ex-ante *minimum* EU-internal abatement (i.e. the required abatement effort) of the EU ETS is quantified, based on the assumption that firms would use allowance surplus at a maximum speed so as to avoid early emissions abatement. This assumption is supported by the time-discounting effect that the perceived abatement cost associated with early reduction actions tends to be higher than those with later actions (Nordhaus, 2008), which, to some extent, reflects the bounded rationality of firms. In addition, the “wait-and-see” strategy aimed at exploiting the reduction of abatement cost due to future technological breakthrough may also favour the postponement of reduction actions (Wigley et al., 1996). However, allowance surplus may also be banked for future usages depending on hedging, arbitrating or speculating purposes (Neuhoff et al., 2012), especially when the abatement investment itself is profitable. In theory, a rational firm will abate emissions along its MACC until its marginal abatement cost equals the market carbon price plus a risk premium. The aggregated risk premium at EU-level would determine the speed at which allowance surplus is used or banked, and correspondingly, how much additional EU-internal abatement would be realized on top of the minimum EU-internal abatement. However, as the heterogeneous hedging strategies, and risk premiums used differs by firm, the realized EU-internal abatement resulting from hedging/banking is intrinsically too uncertain to rely upon.

Emissions intensity improvement and GDP growth rate

In the baseline emissions scenario, a moderate value of the emissions intensity improvement rate (1.19%) and GDP growth rate (2.15%, derived from AUGUR multi-speed Europe scenario) is used. To identify the impact of these assumptions, a sensitivity analysis is conducted, with a high and low value for both intensity improvement rate and GDP growth rate.

Considering the general difference in economic structure, mitigation cost and abatement potential between developed western European countries (EU-15) and transitional eastern European countries (Buchan, 2010), the annual intensity improvement rates during 2000-2004 for EU-15 (0.91%) and Czech Republic (1.98%), were chosen as the low and high value. These respectively represent two typical values for western and eastern European countries. The high and low values (i.e. 0.89% and 2.40%) for the GDP growth rate come from the AUGUR “towards federal Europe” scenario and “struggling on” scenario respectively (see figure 6.2).

The EU-internal abatement for the different GDP growth and intensity improvement rates are presented in figure 6.8. The EU-internal emissions abatement is *ceteris paribus* larger under either higher GDP growth or lower intensity improvement rate, and *vice versa*, because either higher GDP growth or lower intensity improvement increase baseline emissions. The observed largest EU-internal abatement (8299 Mtonne) is under both low intensity improvement and high GDP growth, while the smallest (702 Mtonne) is under the combination of high intensity improvement and low GDP growth. For all scenarios, the contribution of the LRF of 2.2% after 2021 to the EU-internal abatement is fixed at 524 Mtonne, which is insensitive to GDP growth and intensity improvement. However, the impact of the MSR is highly dependent on baseline emissions level. The MSR would not affect the internal abatement under the high baseline emission scenarios (i.e. medium GDP plus low/high intensity improvement, high GDP plus low/high intensity improvement), as the net stock of allowances stored in the reserve is zero by the end of 2030. Interestingly, under the low baseline emissions scenarios (i.e. either low GDP or high intensity improvement), the MSR would increase internal abatement through storing a number of allowances at the end of 2030, ranging from 286 to 1818 Mtonne. The number of allowances stored in the MSR is particularly high (1818 Mtonne) under the lowest baseline emissions (i.e. the combination of low and high intensity improvement), suggesting its ability to strengthen the resilience of the EU ETS in case of uncertain future demand shock. The internal abatement would be otherwise a negative value of -1116 Mtonne without MSR in that case. This represents in essence a sizable volume of unused cumulative allowance surplus by the end of 2030. It would be banked into the post-2030 period of the EU ETS, further depressing the carbon price and undermining the effectiveness of the EU ETS to induce EU-internal abatement.

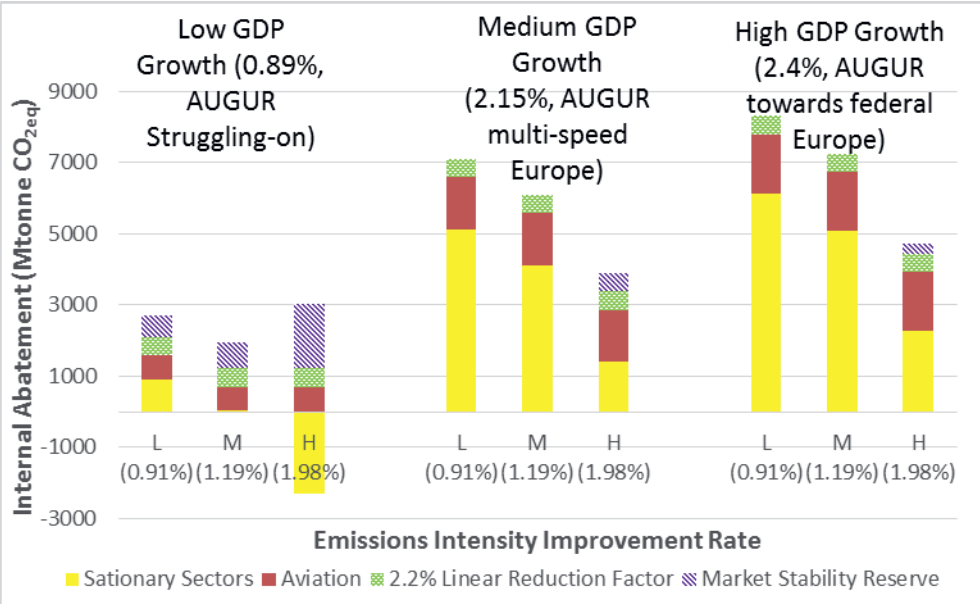

Figure 6.8 Sensitivity analysis of EU-internal abatement of the EU ETS (including aviation) with policy interventions for different annual GDP growth and emissions intensity improvement rates

Linear reduction factor (LRF)

Another parameter that may have a large impact on the EU-internal abatement is the LRF used to determine the ETS cap. This study analyses two cases: the continuation of the current LRF of 1.74% and the increase of LRF to 2.2% starting in 2021. The latter case would deliver a 43% emissions reduction for stationary ETS sectors by 2030 against 2005 emissions level. This is consistent with the 40% EU overall emissions reduction target (against 1990 levels) by 2030 (EC, 2014c) that is recently approved by the European Council (2014). Although this target will ensure the achievement of the lower bound of the EU's long-term 80%-95% overall emissions reduction target by 2050, it is insufficient to fulfil the ambitious higher bound target. To be in line with 95% overall emissions reduction target, the LRF from 2021 onwards should be increased to 2.55%[61]. In that case, it would further increase the EU-internal abatement impact by 399 Mtonne during the investigated period. This also implies that the 2030 emissions reduction target (i.e. the cap) for ETS sectors should have been set at 46% below 2005 level.

Inclusion of international aviation

In this study it is assumed that international aviation is incorporated into the EU ETS from 2020 onwards due to the implementation of a GMBM through the ICAO that is equivalent to the EU inclusion of international aviation under the EU ETS. However, it is still unclear whether such a GMBM could be reached due to the conflicted political interests of different actors. As international aviation roughly accounts for 2/3 of the total aviation emissions under the scope of EU ETS (Preston et al., 2012), the exclusion of international aviation would reduce the EU-internal abatement by 853 Mtonne (under the moderate GDP growth rate of 2.15%) during the investigated period.

6.5 CONCLUSION AND POLICY IMPLICATIONS

This study aimed to investigate the EU-internal emissions abatement resulting from the EU ETS during the period 2013-2030, in a quantitative ex-ante manner. It is identified that the EU ETS (including aviation) would lead to an EU-internal abatement of 5560 Mtonne CO_{2eq} during the investigated period under the most plausible baseline emissions scenario, of which 1465 Mtonne is contributed by the net shortage of allowances in the aviation sector. Under the same baseline emissions, the combined impact of the policy intervention measures approved (i.e. back-loading and 2.2% LRF) or proposed (i.e MSR) by the EC would lead to an additional internal abatement of 524 Mtonne. However, these measures would be insufficient to restore the scarcity of allowances

61 Calculated based on the EU 1990 emissions level of 5583 Mtonne CO_{2eq} (UNFCCC, 2014) and the 45% share of ETS emissions in overall EU emissions

and the corresponding carbon price before the start of ETS Phase IV in 2021. Due to the prevalence of a sizable allowance surplus (2855 Mtonne), the occurrence of EU-internal abatement could not be guaranteed until 2023. The EU-internal abatement impact and policy effectiveness of the EU ETS could be further undermined, in the case of the over-estimation of future baseline emissions or the exclusion of international aviation. Insufficient and deferred EU-internal abatement efforts could reduce the implementation levels of low-carbon technologies. As a result, technological lock-in may occur, rendering the EU's ambitious decarbonisation transition too expensive to realize under much more stringent environmental regulations foreseeable in the future. This is particularly a concern, considering even the annual LRF of 2.2% for the cap-setting after 2020 is insufficient to deliver the higher end of the EU's long-term 80%-95% emissions reduction target by 2050. Not to mention the large allowance surplus that raises the *de facto* cap of the current ETS. A more in depth understanding of where this lock-in would occur and its impact on the transition cost would be a valuable further piece of analysis to understand the scale of this risk.

The large allowance surplus banked from Phase II, due to the overwhelming use of offset credits and the unexpected economic recession, can largely be blamed for the limited EU-internal abatement impact of the EU ETS. However, this can also be traced back to the fundamental design of the EU ETS: the inability of the ETS to adjust its absolute inelastic supply of allowances (the ex-ante determined cap) to the uncertain demand (related to baseline emissions).

The authors here strongly advise policy-makers to allow the EU ETS to respond to unexpected changes in demand through adjustment of the cap in a predictable and transparent manner. The EC (2014b)´s proposal of establishing a MSR seems to be a sensible starting point for this. This paper shows that the MSR is able to significantly reduce the supply of allowances by storing a number of allowances under the low baseline emissions scenarios where there is a demand shock. This may strengthen the resilience of the ETS in the long run. However, further research on the design and operation of the MSR are required to provide more conclusive evidence. The percentage of annual surplus to be put into the reserve could be higher, to better tackle the current persistent surplus and incentivise EU-internal abatement earlier.

As the combined impact of policy interventions that is currently approved or proposed by the EC is insufficient to restore the scarcity of allowances before ETS Phase IV, other reform options are necessary. These options are identified in the EC (2012a)'s Report "*The state of the European carbon market in 2012*", such as retiring a number of allowances in Phase III and extending the scope of the EU ETS. This paper also supports the reasoning

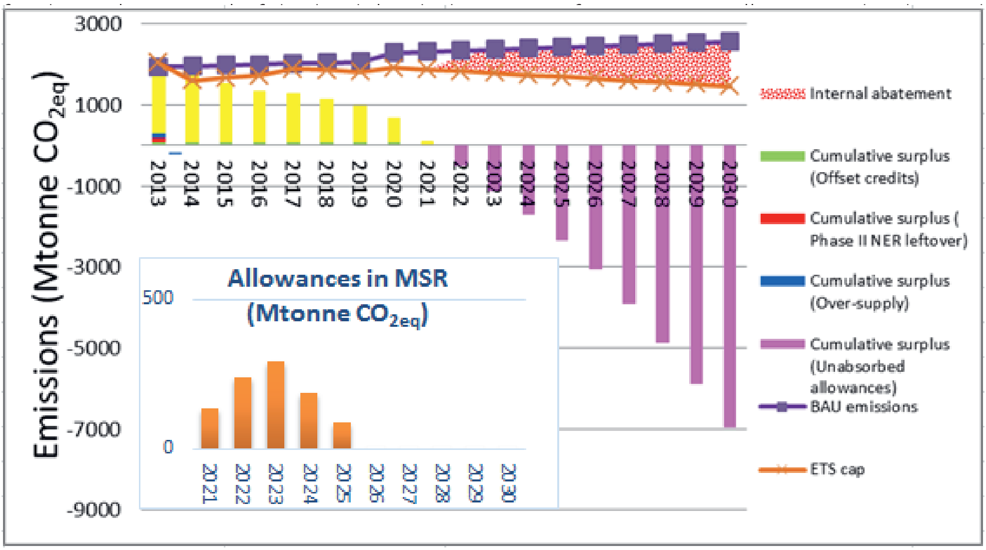

Figure 6.9 EU-internal abatement (including aviation) with early-removal of 900 Mtonne allowance surplus under baseline emissions

Furthermore, based on results regarding the impact of incorporating aviation into the EU ETS, a solution would be to broaden the scope of the ETS to other sectors with potential high demand for emissions rights (e.g. the transport sector). This may create additional demand for allowance surplus under the current scope of the ETS, accelerating the process of allowances surplus being absorbed and increasing the EU-internal abatement.

Last but not least, considering the EU ETS´ central-pillar role in the EU´s transition towards a competitive low-carbon economy, the EU ETS should be able to deliver the EU´s long-term 80%-95% emissions reduction target by 2050 through its cap. Should the EU wants to remain consistent with the higher end of the 2050 target, the LRF would have to be increased to at least 2.55%. This means that the 2030 EU target for emissions reduction should have been set at 53% below 1990 levels, rather than the 40% in the recently approved 2030 framework for energy and climate policies (EC, 2014c and European Council, 2014). A more stringent 2030 target with long-term certainty will in turn bolster ETS participants' confidence in the carbon market, ensuring a stable environment for low-carbon investments essential for the EU's decarbonisation ambition.

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7

Conclusion

7.1 RESEARCH CONTEXT

Post-industrial CO_2 emissions have increased unprecedentedly in both magnitude and speed, as a result of anthropogenic activities (Weitzman, 2011). The increased CO_2 concentration has already caused salient impacts of climate change (e.g. global mean temperature increase, sea level rise, extreme flood and draught, biodiversity losses) at regional and global scale (Hansen and Cramer, 2015; Pautasso, 2011). To avoid the most adverse and irreversible consequences of climate change, a rather limited carbon budget of 420-1170 GTonne CO_{2eq} is remaining (IPCC, 2015). According to most model-based climate mitigation pathways, the power sector needs to be fully decarbonized by 2050 (IPCC, 2018).

Besides energy efficiency measures to limit the growth of electricity demand, transitioning the power sector towards zero emissions must rely on the large-scale deployment of low-carbon electricity generation options. These include nuclear, hydro, biomass, carbon capture and storage, and variable renewable electricity (VRE) technologies. Within all low-carbon options, VRE technologies (which convert stochastic weather flows into electricity, such as wind and solar) have the lowest specific embodied energy and life-cycle emissions in terms of each unit of electricity generation (Pehl et al., 2017). In addition, public attitudes towards VRE are generally positive (Poumadere et al., 2011). Thus, many modelling-based scenarios studies foresee an important role of VRE in future low-carbon electricity generation mix.

In the past decade, strong and robust development in VRE has been witnessed globally, which is mainly driven by the EU and China. Their leading role in VRE development is likely to continue, as they have set ambitious targets to increase the shares of VRE in electricity generation to 35% and 54%, respectively (Banja and Jegard, 2017; Bloomberg, 2018). Owing to tremendous investments in the EU and China, the large expansion in VRE capacity has led to significant cost reductions globally as a combined consequence of technological learning, manufacturing economies of scale and increasingly competitive supply chain (IRENA, 2016). This shows clear advantages over other low-carbon electricity generation technologies.

The integration of VRE into the power system gives rise to challenges in grid operation, because VRE outputs depend on stochastic weather flows. Additional back-up capacity and reserve capacity are needed to ensure generation adequacy, follow output ramps and manage forecast errors. These challenges can be monetarily measured as “integration costs”, which are extra operational and investment costs in the system to accommodate VRE (Ueckerdt et al., 2013). Integration costs become notable when VRE’s penetration exceeds 10%.

The capability to handle grid operation challenges associated with VRE integration depends on the system's flexibility to response to changes in VRE outputs (Huber et al., 2014). Flexibility can be limited by either technical inflexibilities or institutional inflexibilities. The former is often the case for isolated or islanding power systems, due to insufficient flexibility resources in terms of fast response dispatchable plants, interconnection, storage and demand response (IEA, 2014). The latter refers to the inability to mobilize available flexibility resources due to institutional reasons. It is more relevant to emerging economies where institutional reforms on power system restructuring are incomplete (Davidson, 2018). A classical inflexible power system is China, which has suffered from severe problem of VRE curtailment.

Meanwhile, the environment for VRE investments is changing. Despite being effective in stimulating VRE investments, out-of-market support schemes typically creates market distortions in regions where a competitive electricity market has been established. To avoid subsidy-dependent pathway and better align the development of VRE with price signals, the EU has started the ongoing process of integrating VRE into the electricity market. However, this gives rise to new challenges. Market integration requires a revision of the EU electricity market design and a reform of the EU ETS to ensure proper market functioning and a level playing field. As for China, it is still under ongoing power sector reforms. This is expected to increase the flexibility of the power system and alleviate the challenges of VRE in grid operation (Zhang et al., 2018). China aims to establish a competitive electricity market and a national-wide ETS. Therefore, the changing investment environment accompanying the market integration of VRE seems inevitable to occur in China as well.

7. 2 OBJECTIVES AND RESEARCH QUESTIONS

This thesis aims to explore and evaluate different measures (and barriers) that facilitate (and hinder) the integration of VRE into the power system. Our analysis focuses on the power systems of China and the EU, as the two economies have the largest and second largest VRE capacity in the world and both of them face significant challenges of VRE integration. To achieve the research objective, the following research questions have been raised:

Q1. How can negative impacts of VRE on grid operation be minimized through geographical smoothing?

Q2. How are investment-decisions made for VRE investments, and what are barriers to VRE investments?

Q3. Which market design options and regulations facilitate or hinder the market integration of VRE?

Q4. How could the carbon price trajectory develop under the EU ETS and what does it mean for VRE investments?

These research questions were addressed in Chapter 2 through Chapter 6. Table 8.1 presents an overview of research questions and their corresponding chapters.

Table 7.1: Overview of the chapters and their corresponding research questions

Chapter	Topic	Research questions			
		Q1	Q2	Q3	Q4
2	Geographical optimization of VRE capacity in China using modern portfolio theory	X			
3	Analysis of extreme ramp events in optimal VRE portfolios using extreme value theory	X			
4	Barrier to investments in utility-scale VRE projects		X		
5	Identifying barriers to large-scale integration of VRE into the electricity market			X	
6	Ex-ante evaluation of EU ETS during 2013-2030				X

Research question 1 was answered by exploring the geographical smoothing effect that minimizes the volatility of VRE outputs in Chapter 1. Also, Chapter 2 builds up geographically optimal VRE portfolios that minimize the volatility of VRE output ramps, and it further assesses the effectiveness of these portfolios on limiting extreme ramp events. A review-based analysis was performed in Chapter 4 to answer research question 2. It develops a comprehensive framework to represent the investment decision-making process for utility-scale VRE investments, based on which barriers to VRE investments were identified and evaluated. Research question 3 was answered in Chapter 5 by assessing the pros and cons of different market design options in terms of their impacts on limiting integration costs and the business case of VRE investments. The assessment serves to identify of barriers to market integration of VRE. Chapter 6 answered research question 4. It evaluated the EU ETS' effectiveness in reducing emissions and stimulating low-carbon investments (including VRE technologies) within the EU through an ex-ante analysis. The impact of policy intervention measures (back-loading, alternative emission cap reduction trajectory, market stability reserve) and the inclusion of the aviation sector was also assessed.

7. 3 MAIN FINDINGS AND CONCLUSIONS

The answers to the four research questions of this PhD thesis are provided, based on the main findings of the earlier Chapters:

Question 1. How can negative impacts of VRE on grid operation be minimized through geographical smoothing?

Research question 1 is addressed in Chapter 2 and 3 by developing optimal VRE portfolios that utilize the geographical smoothing effect to minimize the impacts of VRE on grid operation. The geographical smoothing effect is captured to the largest extent by encompassing all suitable sites for VRE development at high-resolution uniform grid cell level and by explicitly accounting for four different VRE technologies (i.e. onshore wind, offshore wind, utility-PV and rooftop PV). Key statistics and performance indicators for optimal portfolios are also characterized to improve the understanding of optimal portfolios.

Chapter 2 develops the efficient frontiers for the mainland of China from the perspective of generation adequacy, where the volatility of portfolio outputs is minimized for each attainable output level to facilitate generation adequacy. It shows that optimal portfolios of VRE technologies positioned on the efficient frontier exhibit superior return-volatility performance compared to individual VRE asset (which is a certain technology located in a specific grid cell). Complementarily between wind and solar is also identified, as the efficient frontier of wind & solar portfolios exhibits better return-risk performance than wind-only and solar-only frontiers. This can be explained by the existence of strong negative correlations in power outputs between wind and solar installations across a large geographical area with diverse weather patterns. The result further demonstrates that for the same total installed capacity, wind & solar portfolios with unconstrained technology shares exhibit better return-volatility performance than portfolios with constrained technology shares. This gives caveats that existing scenarios in literature might be sup-optimal to limit the impacts of VRE on grid operation. Lastly, it shows that for optimal wind & solar portfolios a “firm” non-zero minimum portfolio capacity factor (1.4-5.5%) can exist with 100% availability for a large geographical area like China.

Chapter 3 develops the efficient frontiers for the Taiwan island of China from the perspective of system reliability. It quantifies the required installed capacity for optimal VRE portfolios that minimize the volatility of portfolio ramps. To meet 10%, 20% and 30% of electricity demand in Taiwan, the required total installed VRE capacity are 6888-8641, 14344-17316 and 22647-26552 MW, respectively. The analysis of extreme ramp events in optimal VRE portfolios using extreme value theory shows that optimal portfolios are also beneficial to reduce the magnitude of extreme ramp events. The estimated once-in-three-year extreme ramps range between 13-30% of the installed capacity for VRE portfolios, which is significantly smaller than the estimated extreme ramps (20-64%) for most individual VRE assets.

Therefore, geographical smoothing entails multiple benefits to mitigate the negative impacts of VRE on grid operation. It helps the power system to maintain generation adequacy and system reliability, reducing the demand for back-up capacity and reserve capacity and the associated integration costs.

Q2. How are investment-decisions made for VRE investments, and what are barriers to VRE investments?

Chapter 4 addresses research question 2 by developing a comprehensive framework to represent the investment decision-making process in utility-scale VRE projects, based on the project life of a VRE asset. The decision-making process consists of three cascaded stages (preliminary risk scanning, project development and capital access) before the final investment decision is reached. The decision-making process is also assisted by an iterative process of economic appraisal in parallel to the project development stage. The investment decision would be rejected if any stage is unrealizable or the result of the economic appraisal is undesirable.

The integrated framework provides a basis to identify and analyse barriers and their underlying attributors to VRE investments from literature. It enables to connect barriers with different investment decision-making stages, where barriers are defined as factors hindering the realization of a positive final investment decision, which can increase the likelihood of the investment being withdrawal. It shows that most barriers either directly or indirectly reduce the economic appeal of VRE investments, which is reflected in the reduced expected NPV or NPV-at-risk value. Barriers in the iterative economic appraisal process chiefly exhibit a negative effect over the sufficiency and/or volatility of the expected revenue, while barriers at other decision-making stages tend to increase the project developer's risk perception (either due to increased actual risks or psychological, behavioral and institutional attributors that inflate the risk perception) and be ultimately fed into the applied discount rate. Besides reducing the economic appeal of VRE projects, they decrease the chance of progressing the project from investment intention to development action, delay the completion of project development and increase development costs, and reduce the willingness of capital providers to finance the VRE project. This justifies policy measures that aim to improve the risk-return profile of VRE investments.

An important investment barrier identified is negative interactions between different policy measures, which are often overlooked by policy-makers. It demonstrates that macroeconomic policies can have negative impacts on VRE investments. For instance, austerity measures in fiscal policy can constrain government budgets, reducing the support level for VRE investments. Side-effects of monetary policy (e.g. negative interest rates, macro-prudential regulations) can increase the lending rate and decrease the availability of bank loans for VRE investments.

Chapter 4 also distinguishes barriers at different decision-making stages into "symptomatic" and "fundamental" barriers. The former describes a specific symptom or phenomenon that hinders the decision-making process to move forward, while the latter is the root cause behind this symptom. It shows that if not carefully designed, measures only targeting symptomatic barriers may even exacerbate the fundamental barriers. By contrast, addressing fundamental barriers is more effective and has more long-lasting effects.

Q3. Which market design options and regulations facilitate or hinder the integration of VRE into the power system?

Chapter 5 answers research question 3 by providing a comprehensive review-based assessment of barriers to the large-scale market integration of VRE in the EU electricity market design. Based on the set up of the EU electricity market, it first characterizes the electricity market design for each submarket (day-ahead spot market, intraday market, balancing market, imbalance settlement and locational marginal pricing mechanism) from five key dimensions (trading products, price settlement rule, system type, time resolution of trading products and gate closure time). Next, following the Ueckerdt et al. (2013) and Hirth et al. (2015)'s definition and taxonomy of integration costs, the three components of integration costs (profile costs, balancing costs and grid costs) are allocated to different submarkets where they occur. This serves as a framework to assess the impact of different market design options and relevant regulations on integration costs and the business cases for VRE. Market design options and regulations that either increase integration costs or reduce the feasibility of business cases for VRE investments are defined as barriers to market integration.

Chapter 5 concludes that an overhaul is needed for the current EU electricity market to facilitate the market integration of VRE. Firstly, an intraday market with discrete auction, a balancing market with marginal pricing, a two-price imbalance settlement, and a locational marginal pricing mechanism based on nodal pricing seem more promising in limiting integration costs. Secondly, to support business cases of VRE and complementary flexible resources in the electricity market, a level playing field should be established and the price cap should be lifted up to the value of lost load (VOLL). Meanwhile, to enable VRE's market participation, a higher time resolution of trading products and later gate closure time in different submarkets would be required. Lastly, in comparison to alternative capacity-based support schemes, feed-in support schemes, that are currently widely used for VRE investments might be inconsistent with market integration. When VRE penetration in demand becomes non-negligible (e.g. >10%), they can increase integration costs and lock VRE investments in a subsidy-dependent pathway.

Q4. How could the carbon price trajectory develop under the EU ETS and what does it mean for VRE investments?

Chapter 6 addresses research question 4 by performing an ex-ante impact assessment of the EU ETS up to 2030. It quantifies the net demand for emission allowances over time and the resulting emission reduction within the EU. This serves as the basis to qualitatively analyze the carbon price trajectory and the its impact on low-carbon investments (which include VRE technologies).

Chapter 6 starts by constructing a counter-factual scenario without the ETS and assessing the impacts of the ETS, as currently designed. It finds that the ETS will start to impact emissions and low-carbon investments primarily after 2025, due to the prevalence of a sizable allowance surplus equivalent to 2622 Mtonne CO_2. This allowance surplus is a combined result of allowances banked from ETS Phase II, Phase II new entrant reserve leftover, over-supply of allowance and the wide usage of offset credits. It is expected to result in prolonged period of low carbon price incapable to stimulate low-carbon investments.

The impact of policy interventions (back-loading, alternative emission cap reduction trajectory and market stability reserve) and the inclusion of the aviation sector in the EU ETS is further analyzed. It shows that although they can lead to an additional reduction in emissions (1989 Mtonne CO_2) and accelerate the exhaustion of allowance surplus during the investigated period, they are insufficient to restore the scarcity of allowances and the corresponding carbon price before 2020. They still cannot guarantee the policy effectiveness of ETS in reducing emissions and stimulating low-carbon investments until 2023. This is particularly a concern in case of economic shocks or the failure to include international aviation.

7. 4 GENERAL CONCLUSIONS AND POLICY RECOMMENDATIONS

VRE technologies play an indispensable role in decarbonizing the power sector to meet climate mitigation targets. This thesis investigates different measures (and barriers) that facilitate (and hinder) the integration of VRE into the power system, using China and the EU as study regions. It primarily focuses on mitigating the impacts of VRE on the power system, and the changing environment of VRE investments associated with market integration. The conclusions and policy recommendations are drawn from the previous chapters:

Adding VRE technologies into the power system challenges grid operation due to increased demand for back-up capacity and reserve capacity. However, these impacts can be effectively reduced through exploring the geographical smoothing effect. Both decreased correlation in weather patterns across greater distances and the complementarity between various VRE technology types help to capture geographical smoothing. Geographically well-diversified optimal VRE portfolios can be constructed to minimize either the volatility of VRE outputs or VRE output ramps for each attainable output level. The output volatility-minimizing portfolios enable the existence of a "firm" non-zero minimum portfolio capacity factor (1.4-5.5%) with 100% availability. These portfolios can reduce the demand for back-up capacity and contribute to generation adequacy. As for the ramp volatility-minimizing portfolios, next to reducing the spread of majority of ramps, they are also helpful to limit the magnitude of extreme ramp events. Therefore, they can save the system need for balancing and ramp-following capacity, which is beneficial to system reliability. The geographical distribution of VRE assets in optimal portfolios also provides a rationale for the allocation of supranational/national renewable energy targets to national/regional level. It is recommended for policy-makers to plan and coordinate the development of different VRE assets as well as the transmission grid in a more system-optimized manner.

The market integration of VRE is built upon the functioning of the electricity market. A well-functioning electricity market can limit integration costs and support the business case of VRE investments. This must be safeguarded by efficient market design elements, market-compatible regulations and a level playing field. Firstly, to limit integration costs and boost market efficiency, a discrete auction intraday market, a marginal pricing balancing market, a two-price imbalance settlement and a nodal pricing mechanism appear to be more effective. Secondly, a higher time resolution of trading products and later gate closure time would also be required to enable the participation of VRE. Thirdly, to establish a level playing field for VRE to compete with other incumbent technologies, the carbon price under the

ETS should be increased to a level closer to the social costs of carbon. Explicit and implicit subsidies for fossil fuels should also be removed. Finally, the scarcity price (price during scarcity periods) is essential to recover the CAPEX for all generators needed for generation adequacy. It should not be capped or eliminated by the price-cap regulation and retroactive subsidies for retaining overcapacity. The also requires addressing the mismatch between the scarcity price and grid reliability standards and accelerating the phase-out of excessive inflexible baseload capacity.

When designing policy instruments to support VRE investments, negative interactions with other policy instruments or with the functioning of a well-designed electricity market should be minimized. Otherwise, they may contribute to insufficient revenue for VRE in the electricity market and lock VRE investments in a subsidy-dependent pathway. There are two key mechanisms for such interactions: In absence of an ex-post emission cap adjustment mechanism, VRE support schemes reduce the demand for emission allowances under the cap-and-trade scheme. This results in a decreased carbon price and electricity price, as observed in the EU ETS. The market stability reserve to be implemented appear to be helpful to alleviate this problem. The other mechanism results from the direct distortion effect of various production-based support schemes (e.g. feed-in tariff, feed-in premium and tradable green certificate) on the electricity market, which depresses the electricity price. In this regard, more market-compatible support schemes appear to be more suitable for VRE investments.

A comprehensive policy framework to support VRE investments should not be limited to the narrow context of climate and energy policy and the electricity market. Microeconomic policies can have negative impacts on VRE investments. For instance, austerity measures in fiscal policy can constrain government budgets, reducing the support level for VRE investments. Side-effects of monetary policy (e.g. negative interest rates, macro-prudential regulations) can increase the lending rate and decrease the availability of bank loans for VRE investments. When redesigning these macroeconomic policies, potential negative impacts on other policy objectives (e.g. energy transition and VRE investments) should be considered and corresponding measures should be adopted to minimize these impacts.

7.5 RECOMMENDATIONS FOR FURTHER RESEARCH

For point directions for further research, a few recommendations are highlighted:

Optimal portfolios based on low-order statistics and linear dependency (e.g. mean, variance and covariance matrix) are useful to minimize the volatility of VRE outputs and output ramps. Further research incorporating higher-order statistics and non-linear dependency (e.g. skewness, kurtosis, copulas) are needed to develop portfolios that are more robust against extreme tail events, given the fat-tailed nature of the distributions of VRE outputs and output ramps.

Once data becomes available, the demand pattern and demand response should be considered in the development of optimal portfolios. A higher covariance/correlation between the demand and VRE supply saves electricity from other generators to meet the residual demand. Hence, it is relevant to investigate the trade-off between this covariance/correlation, VRE output, and the volatility of VRE output. An "efficient surface" can be developed, which resembles the efficient frontier approach. Similarly, to give a more realistic representation of the power system, further research should look into how to incorporate grid capacity in the development of optimal portfolios. This is useful to identify potential grid constraints.

More market-compatible support schemes can reduce market distortions and the resulting integration costs. However, they can also expose VRE investments more to market risks, which leading to a higher cost of capital. Therefore, these support schemes should be carefully designed to balance the trade-off between integration costs and market exposure. This needs to be further assessed through detailed cost-benefit analyses.

There is growing concern over the ability of the "energy-only" electricity market to ensure generators' profitability and generation adequacy. The "missing money" problem becomes particularly relevant under the context of VRE integration, because VRE with close-to-zero short-run-marginal costs tends to decrease the electricity price. This problem can be addressed either by implementing capacity remuneration mechanisms outside the energy-only market or strengthening the scarcity price (e.g. through pricing the scarcity of operating reserves) within the energy-only market. The pros and cons of either option need to be investigated and compared by modelling-based simulation studies.

The market stability reserve to be implemented seems to be a sensible starting point that enables the ad hoc adjustment of EU ETS' emission cap. This seems promising to increase the EU ETS' resilience to unexpected changes in allowance demand. However, further research on the design and operation of the market stability reserve are required to provide more conclusive evidence on its long-run impact.

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8

Conclusies

8. 1 CONTEXT VAN HET ONDERZOEK

De postindustriële CO_2-uitstoot is ongekend toegenomen, zowel in omvang als in snelheid, als gevolg van antropogene activiteiten (Weitzman, 2011). De toegenomen CO_2-concentratie heeft al belangrijke gevolgen gehad in termen van klimaatverandering (bijv. wereldgemiddelde temperatuurstijging, zeespiegelstijging, overstromingen, verlies van biodiversiteit) op regionaal en mondiaal niveau (Hansen en Cramer, 2015; Pautasso, 2011). Om de meest negatieve en onomkeerbare gevolgen van klimaatverandering te voorkomen, blijft een vrij beperkt budget voor broeikasgasemissies van 420-1170 Gton CO_2eq over (IPCC, 2015). Volgens de meeste modelgebaseerde klimaatmitigatietrajecten moet de energiesector tegen 2050 volledig broeikasgasarm zijn (IPCC, 2018).

Naast energie-efficiëntiemaatregelen om de groei van de vraag naar elektriciteit te beperken, moet de overgang van de elektriciteitssector naar een emissievrije sector afhankelijk zijn van de grootschalige invoering van CO_2-arme opties voor elektriciteitsopwekking. Deze omvatten kernenergie, waterkracht, biomassa, CO_2-afvang en -opslag en variabele hernieuwbare elektriciteit (VRE). Binnen alle CO_2-arme opties hebben VRE-technologieën (die stochastische wind- en zonne-energie omzetten in elektriciteit) de laagste specifieke energie- en levenscyclusemissies per eenheid van elektriciteitsopwekking (Pehl et al., 2017). Bovendien is de houding van het publiek ten opzichte van VRE over het algemeen positief (Poumadere et al., 2011). Veel op modellen gebaseerde scenariostudies voorzien dan ook een belangrijke rol van VRE in de toekomstige broeikasgasarme elektriciteitsproductiemix.

In het afgelopen decennium is wereldwijd een sterke en krachtige ontwikkeling in VRE te zien geweest, die vooral wordt aangedreven door de EU en China. Hun leidende rol in de ontwikkeling van VRE zal waarschijnlijk blijven bestaan, aangezien zij ambitieuze doelstellingen hebben vastgesteld om het aandeel van VRE in de elektriciteitsproductie te verhogen tot respectievelijk 35% en 54% (Banja en Jegard, 2017; Bloomberg, 2018). Dankzij de enorme investeringen in de EU en China heeft de grote uitbreiding van VRE-capaciteit wereldwijd geleid tot aanzienlijke kostenverlagingen als gevolg van technologische kennis, schaalvoordelen bij de productie en een steeds concurrerendere aanbodketen (IRENA, 2016). Dit toont duidelijke voordelen ten opzichte van andere broeikasgasarme technologieën voor elektriciteitsopwekking.

De integratie van VRE in het elektriciteitssysteem brengt uitdagingen met zich mee voor de werking van het net, omdat de VRE-output afhankelijk is van stochastische weersverschijnselen. Extra back-upcapaciteit en reservecapaciteit zijn nodig om de toereikendheid van elektriceitsproductie te garanderen en prognosefouten te beheren.

Deze uitdagingen kunnen in geld worden gemeten als “integratiekosten”. Deze extra operationele en investeringskosten zijn nodig om VRE in het systeem op te nemen (Ueckerdt et al., 2013). De integratiekosten worden aanzienlijk wanneer de penetratie van VRE meer dan 10% bedraagt.

De mogelijkheid om de uitdagingen in verband met de VRE-integratie aan te pakken hangt af van de flexibiliteit van het systeem om te reageren op veranderingen in het VRE-vermogen (Huber et al., 2014). De flexibiliteit kan worden beperkt door technische inflexibiliteit of institutionele inflexibiliteit. Het eerste is vaak het geval voor geïsoleerde of kleine elektriciteitsnetten, vanwege onvoldoende flexibiliteit in termen van snel inzetbare centrales, interconnectie en opslag (IEA, 2014). Het laatste verwijst naar het onvermogen om de beschikbare flexibiliteitsmiddelen te mobiliseren om institutionele redenen. Het is relevanter voor opkomende economieën waar de institutionele hervormingen van de herstructurering van het elektriciteitssysteemelektriciteitssysteem nog niet voltooid zijn (Davidson, 2018). Een klassiek inflexibel elektriciteitssysteem is China, dat te kampen heeft met een problemen bij de integratie van VRE.

Intussen verandert de omgeving voor VRE-investeringen. Hoewel de regelingen voor steun buiten de markt om doeltreffend zijn bij het stimuleren van VRE-investeringen, leiden regelingen voor steun buiten de markt om doorgaans tot marktverstoringen in regio’s waar een concurrerende elektriciteitsmarkt tot stand is gekomen. Om subsidie-afhankelijke trajecten te vermijden en de ontwikkeling van VRE beter af te stemmen op de prijssignalen, is de EU begonnen met het lopende proces van integratie van VRE in de elektriciteitsmarkt. Dit brengt echter nieuwe uitdagingen met zich mee. De marktintegratie vereist een herziening van de opzet van de elektriciteitsmarkt in de EU en een hervorming van het emissiehandsysteem (EU-ETS) om een goede marktwerking en een gelijk speelveld te waarborgen. China is nog steeds bezig met hervormingen van de elektriciteitssector. Verwacht wordt dat dit de flexibiliteit van het elektriciteitssysteem zal vergroten en de uitdagingen van VRE bij de exploitatie van het netwerk zal verlichten (Zhang et al., 2018). China wil een concurrerende elektriciteitsmarkt en een nationaal ETS tot stand brengen. Het veranderende investeringsklimaat dat gepaard gaat met de marktintegratie van VRE lijkt dan ook onvermijdelijk in China te veranderen.

8. 2 DOELSTELLINGEN EN ONDERZOEKSVRAGEN

Dit proefschrift heeft tot doel verschillende maatregelen (en barrières) te onderzoeken en te evalueren die de integratie van VRE in het elektriciteitssysteem vergemakkelijken (en belemmeren). Onze analyse richt zich op de economieën China en de EU, aangezien deze de grootste en op één na grootste VRE-capaciteit ter wereld hebben en beide voor grote uitdagingen staan bij de integratie van VRE. Om de onderzoeksdoelstelling te bereiken, zijn de volgende onderzoeksvragen gesteld:

Q1. Hoe kunnen de negatieve effecten van VRE op de werking van het netwerk tot een minimum worden beperkt door een geografische afvlakking?
Q2. Hoe worden investeringsbeslissingen genomen voor VRE-investeringen en wat zijn de belemmeringen voor VRE-investeringen?
Q3. Welke marktontwerpopties en regelgeving vergemakkelijken of belemmeren de integratie van VRE in het elektriciteitssysteem?
Q4. Hoe kan het CO_2-prijstraject zich in het kader van de EU-ETS ontwikkelen en wat betekent dit voor VRE-investeringen?

Deze onderzoeksvragen werden behandeld in hoofdstuk 2 tot en met hoofdstuk 6. Tabel 8.1 geeft een overzicht van de onderzoeksvragen en de bijbehorende hoofdstukken.

Table 8.1: Overzicht van de hoofdstukken en de bijbehorende onderzoeksvragen

Hoofdstuk	Onderwerp	Onderzoeksvragen			
		Q1	Q2	Q3	Q4
2	Geografische optimalisatie van de VRE-capaciteit in China met behulp van portfoliotheorie	X			
3	Analyse van extreme variaties in optimale VRE-portfolio's met behulp van extreme waardetheorieën	X			
4	Belemmering voor investeringen in VRE-projecten		X		
5	Het in kaart brengen van belemmeringen voor grootschalige integratie van VRE in de elektriciteitsmarkt			X	
6	Ex-ante evaluatie van de impact van EU-ETS in de periode 2013-2030				X

Onderzoeksvraag 1 wordt beantwoord in hoofdstuk door het onderzoeken van het geografische uitmiddelende effect dat de volatiliteit van de VRE-output reduceert. Hoofdstuk 2 stelt geografisch optimale VRE-portfolio's samen die de volatiliteit van VRE-output minimaliseren, en het beoordeelt verder de effectiviteit van deze portfolio's op het beperken van extreme veranderingen in output. In hoofdstuk 4 is een review uitgevoerd om onderzoeksvraag 2 te beantwoorden. Er wordt een uitgebreid kader ontwikkeld om het besluitvormingsproces rondom investeringen in VRE te representeren. Hiermee worden belemmeringen voor VRE-investeringen geïdentificeerd en geëvalueerd. Onderzoeksvraag 3 wordt in hoofdstuk 5 beantwoord door de voor- en nadelen van de verschillende opties voor marktontwerp te beoordelen in termen van hun impact op de beperking van integratiekosten en het verbeteren van de business case voor investeringen in VRE. Hiermee worden belemmeringen voor de marktintegratie van VRE in kaart gebracht. In hoofdstuk 6 wordt een antwoord gegeven op onderzoeksvraag 4. De doeltreffendheid van de EU-ETS bij het verminderen van emissies en het stimuleren van CO_2-arme investeringen (met inbegrip van VRE-technologieën) in de EU werd geëvalueerd aan de hand van een ex-ante-analyse. Ook het effect van beleidsinterventiemaatregelen ("back-loading", een alternatief traject voor de reductie van de emissieplafonds en een marktstabiliteitsreserve) en de opname van de luchtvaartsector werden geëvalueerd.

8. 3 SAMENVATTING VAN DE RESULTATEN

De antwoorden op de vier onderzoeksvragen van dit proefschrift worden gegeven op basis van de belangrijkste bevindingen van de eerdere hoofdstukken:

Q1. Hoe kunnen de negatieve effecten van VRE op de werking van het netwerk tot een minimum worden beperkt door een geografische uitmiddeling?

Onderzoeksvraag 1 wordt behandeld in hoofdstuk 2 en 3 door het ontwikkelen van optimale VRE-portfolio's die gebruik maken van het geografische uitmiddelende effect om de effecten van VRE op het netbeheer te minimaliseren. Dit effect wordt bepaald door alle geschikte locaties voor de ontwikkeling van VRE op een uniform hoge-resolutie rastercelniveau weer te geven en expliciet rekening te houden met vier verschillende VRE-technologieën (d.w.z. windenergie op land, windenergie op zee, grootschlig PV en PV op daken). Belangrijke statistieken en prestatie-indicatoren voor optimale portfolio's worden ook gepresenteerd om het begrip van optimale portfolio's te verbeteren.

In hoofdstuk 2 worden de efficiënte frontiers voor het Chinese vasteland berekend vanuit het oogpunt van toereikendheid van productie, waarbij de volatiliteit van de output van de portefeuille voor elk haalbaar productieniveau tot een minimum wordt beperkt. Het toont aan dat optimale portfolio's van VRE-technologieën die zich op het efficiënte grensvlak bevinden, een superieure opbrengst-volatiliteitsprestatie vertonen in vergelijking met individuele VRE-activa (dat is een bepaalde technologie die zich in een specifieke rastercel bevindt). Als aanvulling wordt vastgesteld, dat de efficiënte frontiers een combinatie bevatten van wind- en zonne-energie en beter presteren dan portfolio's met alleen aan wind of zon. Dit kan worden verklaard door het bestaan van sterke negatieve correlaties in stroomopbrengst tussen wind en zonne-installaties in een groot geografisch gebied met uiteenlopende weerpatronen. Het resultaat toont verder aan dat wind- en zonne-energieportfolio's met aandelen met een ongehinderd technologisch aandeel in hetzelfde totale geïnstalleerde vermogen een betere opbrengst-volatiliteitsprestatie laten zien dan portfolio's met een vooraf bepaald technologisch aandeel. Dit geeft een waarschuwing dat de bestaande scenario's in de literatuur wellicht niet optimaal zijn om de impact van VRE op de werking van het net te beperken. Ten slotte toont het aan dat voor optimale wind- en zonneportfolio's een "vaste" niet-nul minimale portfoliocapaciteitsfactor (1,4-5,5%) kan bestaan met een beschikbaarheid van 100% voor een groot geografisch gebied zoals China.

Hoofdstuk 3 ontwikkelt de efficiënte frontiers voor het Taiwanese eiland China vanuit het oogpunt van systeembetrouwbaarheid. Het kwantificeert de vereiste geïnstalleerde capaciteit voor optimale VRE-portfolio's die de volatiliteit van de outputvariaties minimaliseren. Om aan 10%, 20% en 30% van de elektriciteitsvraag in Taiwan te voldoen, bedraagt de vereiste totale geïnstalleerde VRE-capaciteit respectievelijk 6888-8641, 14344-17316 en 22647-26552 MW. De analyse van extreme outputvariaties in optimale VRE-portfolio's met behulp van de extreme waardetheorie toont aan dat optimale portfolio's ook gunstig zijn om de omvang van deze gebeurtenissen te verminderen. De geschatte één-op-drie-jaar extreme gebeurtenissen variëren tussen de 13-30% van de geïnstalleerde capaciteit voor VRE-portfolio's, wat aanzienlijk kleiner is dan de geschatte extreme hellingen (20-64%) voor de meeste individuele VRE-activa.

Daarom brengt een geografische uitmiddeling tal van voordelen met zich mee om de negatieve effecten van VRE op het elektriciteitsnet te beperken. Het helpt het elektriciteitssysteem om de toereikendheid van de productie en de betrouwbaarheid van het systeem in stand te houden, waardoor de vraag naar back-upcapaciteit en reservecapaciteit en de daarmee samenhangende integratiekosten worden verminderd.

Q2. Hoe worden investeringsbeslissingen genomen voor VRE-investeringen en wat zijn de belemmeringen voor VRE-investeringen?

Hoofdstuk 4 gaat in op onderzoeksvraag 2 door het ontwikkelen van een uitgebreid raamwerk om het besluitvormingsproces rondom investeringen in VRE-projecten in de elektriciteitssector weer te geven, gebaseerd op de evensduur van een VRE-project. Het besluitvormingsproces bestaat uit drie trapsgewijze fases (risicoanalyse, projectontwikkeling en toegang tot kapitaal) voordat de definitieve investeringsbeslissing wordt genomen. Het besluitvormingsproces wordt ook ondersteund door een iteratief proces van economische evaluatie parallel aan de ontwikkelingsfase. De investeringsbeslissing wordt afgewezen indien een fase niet haalbaar is of indien het resultaat van de economische beoordeling negatief is.

Het geïntegreerde raamwerk biedt een basis voor het identificeren en analyseren van barrières en hun onderliggende oorzaken rondom VRE-investeringen in de literatuur. Het maakt het mogelijk om barrières te verbinden met de verschillende fases in het beslissingsproces, waarbij barrières worden gedefinieerd als factoren die een positieve beslissing in de weg staan. Het toont aan dat de meeste belemmeringen direct of indirect de economische aantrekkingskracht van VRE-investeringen verminderen, wat tot uiting komt in de verminderde verwachte netto contante waarde (NCW). Belemmeringen in het iteratieve economische beoordelingsproces vertonen vooral een negatief effect op de toereikendheid en/of onzekerheid van de verwachte inkomsten, terwijl belemmeringen in andere besluitvormingsfasen de neiging hebben om de risicoperceptie van de projectontwikkelaar te verhogen (hetzij door verhoogde werkelijke risico's, hetzij door psychologische, gedrags- en institutionele oorzaken die de risicoperceptie verhogen) en uiteindelijk in de toegepaste discontovoet te worden opgenomen. Naast het verminderen van de economische aantrekkingskracht van VRE-projecten, verminderen ze de kans dat het project van intentie naar ontwikkeling vordert, vertragen ze de voltooiing van het project en verhogen ze de ontwikkelingskosten, en verminderen ze de bereidheid van kapitaalverschaffers om het VRE-project te financieren. Dit rechtvaardigt beleidsmaatregelen die erop gericht zijn het risico-rendementsprofiel van VRE-investeringen te verbeteren.

Een belangrijke investeringsbelemmering is de negatieve wisselwerking tussen de verschillende beleidsmaatregelen, die vaak door de beleidsmakers over het hoofd wordt gezien. Hieruit blijkt dat macro-economisch beleid negatieve gevolgen kan hebben voor investeringen in VRE. Zo kunnen bezuinigingsmaatregelen in het fiscaal beleid bijvoorbeeld de overheidsbegrotingen inperken, waardoor het steunniveau voor investeringen in VRE's kan worden verlaagd. Neveneffecten van monetair beleid (bijvoorbeeld negatieve rentetarieven, macroprudentiële regelgeving) kunnen de rente op leningen verhogen en de beschikbaarheid van bankleningen voor risicokapitaalinvesteringen verminderen.

In hoofdstuk 4 wordt ook een onderscheid gemaakt tussen barrières in de verschillende besluitvormingsfasen in "symptomatische" en "fundamentele" barrières. De eerste beschrijft een specifiek symptoom of fenomeen dat het besluitvormingsproces belemmert om verder te komen, terwijl de tweede de hoofdoorzaak van dit symptoom is. Het toont aan dat, indien niet zorgvuldig ontworpen, maatregelen die alleen gericht zijn op symptomatische barrières, de fundamentele barrières zelfs kunnen verergeren. Het aanpakken van fundamentele barrières is daarentegen effectiever en heeft een langduriger effect.

Q3. Welke marktontwerpopties en regelgeving vergemakkelijken of belemmeren de integratie van VRE in het elektriciteitssysteem?

Hoofdstuk 5 geeft een antwoord op onderzoeksvraag 3 door een alomvattende, op herziening gebaseerde beoordeling te geven van de belemmeringen voor de grootschalige marktintegratie van VRE in het ontwerp van de elektriciteitsmarkt van de EU. Gebaseerd op de opzet van de EU elektriciteitsmarkt, karakteriseert het eerst het ontwerp van de elektriciteitsmarkt voor elke deelmarkt (bijv. spot markten, balanceringsmarkt, imbalance settlement, locatiegebonden marginaal prijsbepalingsmechanisme) vanuit vijf belangrijke dimensies (handel in producten, regel voor prijsafwikkeling, systeemtype, tijdresolutie van handelsproducten en sluitingsduur van de poort). Vervolgens worden, in navolging van de Ueckerdt et al. (2013) en Hirth et al. (2015)'s definitie en taxonomie van de integratiekosten, de drie componenten van integratiekosten (profielkosten, balanceringskosten en netkosten) toegewezen aan de verschillende deelmarkten waar ze voorkomen. Dit dient als kader voor de beoordeling van de impact van verschillende marktontwerpopties en relevante regelgeving op de integratiekosten en de businesscases voor VRE. Marktinrichtingsopties en regelgeving die ofwel de integratiekosten verhogen ofwel de haalbaarheid van business cases voor VRE-investeringen verminderen, worden gedefinieerd als belemmeringen voor marktintegratie.

In hoofdstuk 5 wordt geconcludeerd dat de huidige elektriciteitsmarkt in de EU moet worden herzien om de marktintegratie van VRE te vergemakkelijken. Ten eerste lijken een spot markt met discrete veiling, een balanceringsmarkt met marginale prijsbepaling, een tweeprijsverschilregeling en een locatiegebonden marginaal prijsbepalingsmechanisme op basis van nodale prijsbepaling veelbelovender om de integratiekosten te beperken. Ten tweede moet, ter ondersteuning van bedrijfsmatige gevallen van VRE en aanvullende flexibele middelen op de elektriciteitsmarkt, een gelijk speelveld worden gecreëerd en moet het prijsplafond worden opgeheven tot de "value of lost load" (VOLL). Om de marktparticipatie van VRE mogelijk te maken, zou in de tussentijd een snellere afwikkeltijd en latere sluiting in verschillende deelmarkten nodig zijn. Ten slotte kunnen, in vergelijking met alternatieve, op capaciteit gebaseerde subsidies, terugleververgoedingen, die momenteel op grote schaal worden gebruikt voor VRE-investeringen, onverenigbaar zijn met marktintegratie. Wanneer de toepassing van VRE groter wordt (bv. >10%), kunnen deze subsidies de integratiekosten verhogen en de VRE-investeringen behoefitg houden aan subsidies.

Q4. Hoe kan het CO_2-prijstraject zich in het kader van de EU-ETS ontwikkelen en wat betekent dit voor VRE-investeringen?

Hoofdstuk 6 gaat in op onderzoeksvraag 4 door een voorafgaande effectbeoordeling van de EU-ETS tot 2030 uit te voeren. Het kwantificeert de nettovraag naar emissierechten in de tijd en de daaruit voortvloeiende emissiereductie binnen de EU. Dit dient als basis voor een kwalitatieve analyse van het CO_2-prijstraject en het effect daarvan op broeikasgasarme investeringen (waaronder VRE-technologieën).

Hoofdstuk 6 begint met het opstellen van een contrafeitelijk scenario zonder de ETS en het beoordelen van de effecten van de ETS, zoals deze momenteel is ontworpen. De conclusie is dat de ETS vooral na 2025 van invloed zal zijn op emissies en broeikasgasarme investeringen, omdat er een aanzienlijk overschot aan emissierechten is dat overeenkomt met 2622 Mton CO_2. Dit overschot aan emissierechten is het resultaat van een combinatie van (1) emissierechten die zijn opgespaard in de ETS-fase II, (2) de onaangesproken reserve voor nieuwkomers in de tweede fase, (3) de overalocatie van emissierechten en (4) het ruime gebruik van compensatiecredits. Verwacht wordt dat dit zal resulteren in een langere periode van lage CO_2-prijzen, die investeringen in broeikasgasarme technologieën maar beperkt kunnen stimuleren.

Het effect van beleidsinterventies (“back-loading”, een alternatief traject voor de reductie van de emissieplafonds en een marktstabiliteitsreserve) en de opname van de luchtvaartsector in de EU-ETS wordt verder geanalyseerd. Hieruit blijkt dat, hoewel ze kunnen leiden tot een extra vermindering van emissies (1989 Mton CO_2) en een versnelde uitputting van het overschot aan emissierechten tijdens de onderzochte periode, ze onvoldoende zijn om de schaarste aan emissierechten en de bijbehorende CO_2-prijs voor 2020 te herstellen. Zij kunnen nog steeds niet garanderen dat het ETS tot 2023 de doeltreffendheid van het beleid inzake emissiereductie en het stimuleren van broeikasgasarme investeringen in het kader kan garanderen. Dit is met name een punt van zorg in het geval van economische recessies of het niet opnemen van de internationale luchtvaart.

8. 4 ALGEMENE CONCLUSIES EN BELEIDSAANBEVELINGEN

VRE-technologieën spelen een onmisbare rol bij het CO_2-vrij maken van de energiesector om de klimaatdoelstellingen te halen. Dit proefschrift onderzoekt verschillende maatregelen (en barrières) die de integratie van VRE in het elektriciteitssysteem vergemakkelijken (en belemmeren), waarbij China en de EU als studiegebieden worden gebruikt. Het richt zich in de eerste plaats op het verzachten van de effecten van VRE op het elektriciteitssysteem en de veranderende omgeving van VRE-investeringen in verband met de marktintegratie. De conclusies en beleidsaanbevelingen zijn afkomstig uit de vorige hoofdstukken:

Het toevoegen van VRE-technologieën aan het elektriciteitssysteem stelt het netbeheer op de proef vanwege de toegenomen vraag naar back-upcapaciteit en reservecapaciteit. Deze effecten kunnen echter effectief worden beperkt door het geografische uitmiddelende effect te onderzoeken. Zowel de verminderde correlatie in weerpatronen over grotere afstanden als de complementariteit tussen de verschillende VRE-technologieën helpen bij het vastleggen van de geografische uitmiddeling. Geografisch goed gediversifieerde optimale VRE-portfolio’s kunnen worden geconstrueerd om ofwel de volatiliteit van VRE-output of VRE-variaties te minimaliseren. De output volatiliteit-minimaliserende portfolio’s beschikken over een portfolio met een capaciteitsfactor van 1,4-5,5% en 100% beschikbaarheid. Deze portfolio’s kunnen de vraag naar back-upcapaciteit verminderen en bijdragen aan de toereikendheid van elektriciteitsproductie. Wat betreft de verdeling van de volatiliteit die de volatiliteit minimaliseert, zijn deze portfolio’s, naast het verminderen van de spreiding van de meerderheid van de platformen, ook nuttig om de omvang van extreme outputvariaties te beperken. Daarmee kunnen ze de behoefte aan balancerings capaciteit besparen, wat de betrouwbaarheid van het systeem ten goede komt. De geografische verdeling van VRE-eenheden in optimale portfolio’s biedt ook een reden voor de toewijzing van supranationale/nationale doelstellingen voor hernieuwbare energie op nationaal/regionaal niveau. Het wordt aanbevolen voor beleidsmakers om de ontwikkeling van verschillende VRE-eenheden en het transportnet op een meer systeemgeoptimaliseerde manier te plannen en te coördineren.

De marktintegratie van VRE is afhankelijk van de werking van de elektriciteitsmarkt. Een goed functionerende elektriciteitsmarkt kan de integratiekosten beperken en de business case van VRE-investeringen ondersteunen. Dit moet worden gewaarborgd door efficiënt marktontwerp, marktconforme regelgeving en een gelijk speelveld. Ten eerste, om de integratiekosten te beperken en de marktefficiëntie te verhogen, lijken een intradaymarkt met discrete veiling, een marginale prijsbalanceringsmarkt, een imbalance settlement met twee prijzen en een mechanisme voor nodale prijsbepaling doeltreffender zijn. Ten tweede zou ook een snellere afwikkeling van de elektriciteitshandel en een latere sluitingstijd van de markt nodig zijn om de deelname van VRE mogelijk te maken. Ten derde moet de CO_2-prijs in het kader van ETS worden verhoogd tot een niveau dat dichter bij de maatschappelijke kosten van CO_2-uitstoot ligt, om een gelijk speelveld te creëren voor VRE om te kunnen concurreren met andere gevestigde technologieën. Expliciete en impliciete subsidies voor fossiele brandstoffen moeten ook worden afgeschaft. Ten slotte is de schaarsteprijs van essentieel belang om de CAPEX terug te verdienen voor alle producenten en deze is nodig om de leveringszekerheid van elektriciteitsproductie veilig te stellen. Er mag geen plafond op deze prijs komen en subsidies zijn nodig met terugwerkende kracht voor het behoud van voldoende capaciteit. Het vereist ook dat de discrepantie tussen de schaarsteprijs en betrouwbaarheidsnormen van het net wordt aangepakt en dat de geleidelijke afschaffing van een te starre basislastcapaciteit wordt versneld.

Bij het ontwerpen van beleidsinstrumenten ter ondersteuning van VRE-investeringen moet de negatieve interactie met andere beleidsinstrumenten of met de werking van een goed ontworpen elektriciteitsmarkt tot een minimum worden beperkt. Anders kunnen zij bijdragen aan onvoldoende inkomsten voor VRE op de elektriciteitsmarkt en kunnen zij ertoe leiden dat investeringen in VRE in een subsidieafhankelijk traject worden vastgelegd. Er zijn twee belangrijke mechanismen voor dergelijke interacties: Bij gebrek aan een ex-post-aanpassingsmechanisme voor de emissieplafonds, verminderen VRE-steunregelingen de vraag naar emissierechten in het kader van de “cap-and-trade”-regeling. Dit resulteert in een verlaging van de CO_2-prijs en de elektriciteitsprijs, zoals waargenomen in de EU-ETS. De ten uitvoer te leggen marktstabiliteitsreserve lijkt nuttig te zijn om dit probleem te verlichten. Het andere mechanisme vloeit voort uit het directe verstorende effect van verschillende op productie gebaseerde steunregelingen (bv. feed-in-tarieven, feed-in-premies en verhandelbare groenestroomcertificaten) op de elektriciteitsmarkt, wat de elektriciteitsprijs drukt. In dit verband lijken meer marktconforme steunregelingen geschikter voor VRE-investeringen.

Een alomvattend beleidskader ter ondersteuning van investeringen in VRE mag niet beperkt blijven tot de enge context van het klimaat- en energiebeleid en de elektriciteitsmarkt. Micro-economisch beleid kan negatieve gevolgen hebben voor investeringen in VRE. Zo kunnen bezuinigingsmaatregelen in het fiscaal beleid de overheidsbegrotingen inperken, waardoor het steunniveau voor risicokapitaalinvesteringen kan worden verlaagd. Neveneffecten van monetair beleid (bijvoorbeeld negatieve rentetarieven, macroprudentiële regelgeving) kunnen de rente op leningen verhogen en de beschikbaarheid van bankleningen voor risicokapitaalinvesteringen verminderen. Bij het herontwerpen van dit macro-economisch beleid moet rekening worden gehouden met mogelijke negatieve effecten op andere beleidsdoelstellingen (bv. De energietransitie en VRE-investeringen) en moeten overeenkomstige maatregelen worden genomen om deze effecten te minimaliseren.

8.5 AANBEVELINGEN VOOR VERDER ONDERZOEK

Voor de aanwijzingen voor verder onderzoek worden enkele aanbevelingen gedaan:

Optimale portfolio's op basis van lage orde statistieken en lineaire afhankelijkheid (bv. gemiddelde, variantie en covariantiematrix) zijn nuttig om de volatiliteit van VRE-output en -hellingen te minimaliseren. Verder onderzoek met hogere orde statistieken en niet-lineaire afhankelijkheid (bv. scheefheid, kurtosis, copulas) zijn nodig om portfolio's te ontwikkelen die robuuster zijn tegen extreme staart-verdelingen, gezien de vetstaartverdeling van de verdeling van de VRE-output en -output.

Zodra gegevens beschikbaar zijn, moet bij de ontwikkeling van optimale portfolio's rekening worden gehouden met het vraagpatroon en de vraagrespons. Een hogere covariantie/correlatie tussen de vraag en het VRE-aanbod bespaart elektriciteit van andere producenten om aan de restvraag te voldoen. Daarom is het relevant om de afweging tussen deze covariantie/correlatie, de VRE-output en de volatiliteit van de VRE-output te onderzoeken. Er kan een "efficiënt oppervlak" worden ontwikkeld, dat lijkt op de efficiënte frontiersaanpak. Om een meer realistische weergave van het elektriciteitssysteem te geven, moet verder onderzoek worden gedaan naar de wijze waarop de netcapaciteit kan worden geïntegreerd in de ontwikkeling van optimale portfolio's. Dit is nuttig om mogelijke knelpunten in het net in kaart te brengen.

Meer marktconforme steunregelingen kunnen marktverstoringen en de daaruit voortvloeiende integratiekosten verminderen. Zij kunnen echter ook VRE-investeringen meer blootstellen aan marktrisico's, wat leidt tot hogere kapitaalkosten. Daarom moeten deze steunregelingen zorgvuldig worden opgezet om een evenwicht te vinden met de afweging tussen integratiekosten en marktrisico. Dit moet nader worden beoordeeld aan de hand van gedetailleerde kosten-batenanalyses.

Er is toenemende bezorgdheid over het vermogen van de "energy-only" elektriciteitsmarkt om de winstgevendheid van de elektriciteitsproducenten en leveringszekerheid te waarborgen. Het "missing money"-probleem wordt met name relevant in de context van de integratie van VRE, omdat VRE met bijna-nul marginale kosten op korte termijn de neiging heeft de elektriciteitsprijs te verlagen. Dit probleem kan worden aangepakt door mechanismen voor capaciteitsvergoeding buiten de energy-only-markt in te voeren of door de schaarsteprijs te verhogen op de markt voor uitsluitend energie. De voor- en nadelen van beide opties moeten worden onderzocht en vergeleken aan de hand van op modellen gebaseerde simulatiestudies.

De invoering van de marktstabiliteitsreserve lijkt een verstandig uitgangspunt te zijn voor de ad-hocaanpassing van het emissieplafond van het EU-ETS. Dit lijkt veelbelovend om de veerkracht van het EU-ETS te vergroten, zodat deze beter bestand is tegen onverwachte veranderingen in de vraag naar emissierechten. Verder onderzoek naar de opzet en werking van de marktstabiliteitsreserve is echter nodig om het langetermijneffect van de stabiliteitsreserve van de markt beter aan te tonen.

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CURRICULUM VITAE

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