Dissertation

Model-based Analysis and Design of an improved European Electricity Market with high shares of Renewable Generation Technologies

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Kurzfassung

In den meisten Ländern der Welt sind konventionelle Kraftwerke seit Jahrzehnten die vorherrschende Technologie zur Stromerzeugung. Daher existieren mehrere Herausforderungen, um einen hohen Anteil variabler erneuerbarer Erzeugungstechnologien in Stromsystemen effizient zu implementieren.

In dieser Arbeit werden drei verschiedene Arten von Herausforderungen analysiert, welche bei der Integration von erneuerbaren Energiequellen in Stromsystemen beobachtet werden können: das Übertragungsnetz, die Gestaltung des Elektrizitätsmarktes und flexible (steuerbare) Erzeugungstechnologien. Um zukünftige Änderungen in Stromsystemen quantitativ bewerten zu können, wurde das Strommarktmodell EDisOn+Balancing entwickelt.

Der erste Teil der Analyse trägt zur Bewertung der Erweiterungspläne des Übertragungsnetzes in Österreich bei. Zum einen werden die Nachbarländer als jeweils einzelne Knoten pro Land respektiert, zum anderen wird das detaillierte Stromübertragungsnetz der mitteleuropäischen Länder berücksichtigt. Neben der Analyse von hohen Anteilen variabler erneuerbarer Energiequellen in Zentraleuropa werden auch widersprüchliche Tendenzen hinsichtlich erneuerbarer Anteile in Österreich und den übrigen Ländern analysiert. Die Ergebnisse zeigen, dass unter der Annahme, dass die geplanten Übertragungsnetzerweiterungen bis 2030 umgesetzt werden, das österreichische Übertragungsnetz für einen Anteil von fast 100% Strom aus erneuerbarer Energie ausreichend gerüstet ist.

Zweitens werden mögliche zukünftige Regelenergiemarktmechanismen in diversen Regelzonen Europas analysiert, wobei auch die unterschiedlichen Regelenergieprodukte und der Stromgroßhandelsmarkt berücksichtigt werden. In Europa gibt es meist sequenzielle Energie- und Reservemärkte mit separaten Bieter- und Marktclearing-Mechanismen, die von verschiedenen Marktakteuren betrieben werden, d.h. den Strombörsen und dem Übertragungsnetzbetreiber.

Es wurde beschlossen, bei der Modellierung den aktuellen Trend in den US-amerikanischen Märkten zu verfolgen, wo Co-Optimierung von Energie und Reserven angewendet wird. Daher ist das Modell EDisOn+Balancing als Multi-Objective-Strommarktmodell konzipiert, d.h. die Vorhaltung von Regelenergie und der Kraftwerkseinsatz am Großhandelsstrommarkt wird gleichzeitig gelöst. Die Analyse zeigt, dass die Kombination kürzerer Regelenergieprodukte, das Ermöglichen von regelzonenüberschreitender Beschaffung von Regelenergie und die Einbeziehung von anderen Speichern, wie Batterien und Elektrofahrzeuge, eines der gewünschten Regelenergiemarktdesigns sein kann. Die Verkürzung der Produkte unterstützt im Wesentlichen die Integration von erneuerbaren Energien in der Regelenergievorhaltung. Die symmetrische Beschaffung von positiven und negativen Regelenergieprodukten ist aufgrund erhöhter Kosten und Ineffizienzen zu vermeiden.

Der dritte Teil befasst sich mit der Analyse des sozioökonomischen Nutzens von Pumpspeichererweiterungen in Österreich und deren Auswirkungen auf das mitteleuropäische Stromsystem für drei verschiedene Szenarien bis 2030. Die Ergebnisse zeigen, dass die Stromerzeugung und die Kosten der Regelenergiebereitstellung durch den Ausbau der Pumpspeicherkapazitäten in Österreich reduziert werden. Die Notwendigkeit herkömmlicher Reservekraftwerkskapazitäten, die meist als Spitzenlast-Einheit definiert wird, sinkt bei gleichzeitig hoher Versorgungssicherheit. Durch die Verlagerung von konventionellen Kraftwerken auf erneuerbare Energieerzeugungstechnologien können in Mitteleuropa bei der Umsetzung der geplanten Pumpspeicherkapazitäten in Österreich in den kommenden Jahren Umweltschäden von bis zu 1300 MEuro/a vermieden werden.

Wenn mehrere Herausforderungen überwunden werden, kann die Integration variabler erneuerbarer Energiequellen effizient sein und die Schaffung eines nachhaltigen Stromerzeugungssystems in Mitteleuropa ist möglich.

Abstract

For decades conventional power plants have been the predominant electricity generation technology in most countries worldwide. Therefore, there are several challenges for implementing high shares of variable renewable generation technologies in electricity systems in an efficient manner.

In this work three different types of challenges of renewable generation dominated electricity markets are studied: the transmission system, the electricity market designs and flexible (dispatchable) generation technologies. To evaluate future changes in electricity systems quantitatively, the electricity market model EDisOn+Balancing has been developed.

The first part of analysis contributes to the evaluation of transmission expansion planning in Austria. On the one hand, the neighbouring countries are respected as a single node per country and, on the other hand, the detailed electricity transmission grid of Central European countries is respected. In addition to analysing high shares of variable renewable generation sources in Central Europe, also conflicting tendencies in terms of renewable shares in Austria and the remaining countries are analysed. The results show that assuming the planned transmission line expansions are implemented until 2030, the Austrian transmission system is well equipped for a nearly 100% share of renewable electricity generation.

Secondly, possible future balancing market mechanisms in several control areas in Central Europe are addressed, while also respecting the different balancing products and the wholesale electricity market. In Europe there exist mostly sequential energy and reserve markets with separate bidding and market clearing mechanisms, which are run by different entities, i.e. the power exchanges and the transmission system operator. It has been decided to follow in the modelling exercise the current trend in U.S. markets, where co-optimisation of energy and reserves is applied. Therefore, the model EDisOn+Balancing is

designed as a multi-objective market model, i.e. balancing procurement and dispatch on wholesale electricity markets are solved simultaneously. The analysis shows that the combination of shorter balancing products, allowing common procurement of balancing capacity, and enabling other storages, like batteries and electrical vehicles, to provide balancing capacity can be one of the desired market designs. The shortening of balancing product timings supports the integration of renewable electricity generation essentially. Whereas, symmetric procurement of up- and downward products for automatic and manual frequency restoration reserves shall be avoided, due to increased costs and inefficiencies.

The third part is about socio-economic benefit analysis of pumped hydro storage expansions in Austria and their implications on the Central European electricity system for three different 2030 scenarios. The results show that electricity generation and balancing procurement costs are reduced by the expansion of pumped hydro storage capacities in Austria. The necessity of conventional reserve power plant capacity, mostly defined as peaking unit, decreases while maintaining a high security of supply level. Due to a shift from conventional power plants to renewable generation technologies, environmental damage costs of up to 1,300 MEuro/a can be avoided in Central Europe when implementing the planned pumped hydro storage capacity in Austria in the upcoming years.

If several challenges are overcome, the integration of variable renewable energy sources can be efficient and the achievement of a sustainable electricity generation system in Central Europe is possible.

Abbreviations

ACER Agency for the Cooperation of Energy Regulators
aFRR automatic Frequency Restoration Reserve
APG Austrian Power Grid
CACM Capacity Allocation & Congestion Management
CAES Compressed Air Energy Storage
CBA Cost/Benefit Analysis
CCR Capacity Calculation Region
CHP Combined Heat and Power
DC direct current
DCDF Direct Current Distribution Factor
DER Distributed Energy Resources
DLR Dynamic Line Rating
DSM Demand-Side Management
EDisOn+Balancing Electricity Dispatch Optimization & Balancing
ENS Energy Not Served
ENTSO-E European Network of Transmission System Operators for Electricity
EVs Electrical Vehicles
FACTS flexible AC transmission systems
FCA Forward Capacity Allocation
FCR Frequency Containment Reserves
GtoV Grid-to-Vehicle
HVDC High-Voltage Direct Current
IEA International Energy Agency
IEM Internal Energy Market
IGCC International Grid Control Cooperation
INC Imbalance Netting Cooperation
ISO Independent System Operator
LCOE Levelised Cost of Electricity
LMP Locational Marginal Pricing

LOLE Loss of Load Expectation
MAF Mid-term Adequacy Forecast
MARI Manually Activated Reserves Initiative
mFRR manual Frequency Restoration Reserve
NC EB Network Code on Electricity Balancing
NSE Not Supplied Energy
NTC Net Transfer Capacity
PCIs Projects of Common Interest
PHS Pumped Hydro Storage
PICASSO Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PSDF Power Shift Distribution Factor
PTDF Power Transfer Distribution Factor
PtoH Power-to-Heat
PV Photovoltaic
PX Power Exchange
RES-E Renewable Energy Sources for Electricity
RoR Run-of-River
RR Replacement Reserves
RTO Regional Transmission Organisation
SOAF Scenario Outlook & Adequacy Forecast
SRMC Short Run Marginal Costs
TERRE Trans European Replacement Reserves Exchange
TPL Transmission Power Line
TEP Transmission Expansion Planning
TSO Transmission System Operator
TYNDP Ten-Year Network Development Plan
U.S. United States
VtoG Vehicle-to-Grid
VoLL Value of Lost Load

Nomenclature

The sets with corresponding indices, parameters and decision variables of the EDisOn+Balancing model are listed below.

Sets and indices

H, Q (index h)	set of time steps (H=hours, Q=quarter-hours)
I_{ca} (index i)	set of balancing groups in control area ca
CA (index ca)	set of control areas (e.g. APG, TransnetBW, etc.)
$L \subset L_{AC} \dot{\cup} L_{DC}$ (index l, l_{AC}, l_{DC})	set of transmission power lines
TH_i (index th)	set of thermal units in balancing group i
PS_i (index ps)	set of pumped hydro storage units in balancing group i
ST_i (index st)	set of other storage units in balancing group i
$j \in \{a, m\}$	automatically and manually activated FRR

Parameters (italic)

Wholesale market:

$C_{th}^{O\&M}$	operations and maintenance costs	EUR/MWh
C_{th}^{fuel}	primary energy costs	EUR/MWh
C^{CO_2}	CO_2 certificate price	EUR/tCO_2
$SRMC_{h,th}$	short run marginal costs of thermal power plant th	EUR/MWh
$C_{h,th}^{Start}$	start costs of thermal power plants	EUR/MWh
C^{Wi}, C^{PV}	generation costs of wind and PV systems	EUR/MWh
C^{Hy}	generation costs of Run-of-River (RoR)	EUR/MWh
$VoLL$	value of lost load	EUR/MWh
$Demand_{h,i}$	demand in step h and balancing group i	MWh/h
$L_i^{up(down)}$	percentage of demand increase (decrease) in i	%

DT	time frame of demand shift	h
$Demand_{h,i}^{heat}$	heat demand in step h and balancing group i	MWh/h
$ramp_{th}$	ramping limit of thermal power th	%
$Cap_{th}^{max(min)}$	max (min) capacity of thermal power plant th	MW
Em_{th}	CO_2 emissions of thermal power plant th	tCO_2/MWh
η_{th}	efficiency of thermal power plant th	%
η_{th}^{heat}	thermal efficiency of thermal power plant th	%
Cap_i^{Hy}	max capacity of RoR	MW
$Inflow_{h,i}^{hy}$	natural inflow RoR	MWh/h
$Cap_{ps}^{Tu(Pu)}$	max turbine (pump) capacity of unit ps	MW
$\eta_{ps}^{Tu}, \eta_{ps}^{Pu}$	efficiency of turbine and pump	%
$En_{ps}^{min(max)}$	min (max) storage level of pumped hydro storage unit ps	MWh
$Infl_{h,ps}$	natural inflow of unit ps	MWh/h
$CapOut_{st}$	max charging capacity of storage unit st	MW
$CapIn_{st}$	max discharging capacity of storage unit st	MW
$\eta_{st}^{stOut}, \eta_{st}^{stIn}$	efficiency of generation and consumption of other storages	%
$En_{st}^{min(max)}$	min (max) storage level of other storage unit st	MWh
$Wind_{h,i}$	generation of wind turbines	MWh/h
$PV_{h,i}$	generation of PV systems	MWh/h
$CapL_l^{A\rightarrow B(B\rightarrow A)}$	capacity limit of transmission power line l from A to B (B to A)	MW
$A_{l,i}$	incidence matrix	$\{-1, 0, 1\}$
α^{max}	maximum of phase shifter angle	30°
$PTDF_{l_{AC},i}$	power transfer distribution factors of the grid	$\mathbb{R}$
$PSDF_{l_{AC},l_{pst}}$	phase shift distribution factors of the grid	$\mathbb{R}$
$DCDF_{l_{AC},l_{DC}}$	DC lines distribution factors of the grid	$\mathbb{R}$

Balancing market:

$\overline{TC}_{h,th}^{j}, \underline{TC}_{h,th}^{j}$	total costs of up-/downward balancing capacity	EUR/MW
$p_{h,i}^{DA}$	expected wholesale price level	EUR/MWh
$V_{h,ps}^{H2O}$	water value of hydro storage unit ps	EUR/MWh
$V_{h,st}^{Stor}$	storage value of other storage unit st	EUR/MWh
$Peak_h$	Peak=1, Off-Peak=0 or Weekend=-1	$[1, 0, -1]$
$\overline{FRR}_{ca}^{j}, \underline{FRR}_{ca}^{j}$	necessary up-/downward FRR of control area ca	MW/h
z_l	capacity share of line l for balancing purposes	$[0, 1]$

Decision variables

Wholesale market:

$\mathrm{D}_{h,i}^{up(down)}$	increase (decrease) of demand in hour h in node i	MWh/h
$\mathrm{D}_{h',h,i}$	shifting demand from h' to h in i	MWh/h
$\mathrm{thP}_{h,th}$	generation of thermal power plant th	MWh/h
$\mathrm{X}_{h,th}^{X}, \mathrm{X}_{h,th}^{Y}, \mathrm{X}_{h,th}^{Z}$	linearisation of thermal generation	$[0,1]$
$\mathrm{Str}_{h,th}$	thermal power plant th starts or not	$[0,1]$
$\mathrm{PtoH}_{h,i}$	Power-to-Heat device in balancing group i	MWh/h
$\mathrm{tuP}_{h,ps}, \mathrm{puP}_{h,ps}$	generation and pump consumption of PHS unit ps	MWh/h
$\mathrm{storL}_{h,ps}$	storage level of PHS	MWh/h
$\mathrm{stPOut}_{h,st}, \mathrm{stPIn}_{h,st}$	generation and consumption of other storage unit st	MWh/h
$\mathrm{storL}_{h,st}$	storage level of other storages	MWh/h
$\mathrm{DCharge}_{h,st}$	stand-by losses	MWh/h
$\mathrm{hyP}_{h,i}$	generation of RoR plants	MWh/h
$\mathrm{Spill}_{h,i}^{Hy}$	RoR spillage (RES-E curtailment)	MWh/h
$\mathrm{Spill}_{h,i}^{Wind}$	wind generation spillage (RES-E curtailment)	MWh/h
$\mathrm{Spill}_{h,i}^{PV}$	PV generation spillage (RES-E curtailment)	MWh/h
$\mathrm{Spill}_{h,ps}^{PHS}$	spillage of natural inflow of PHS	MWh/h
$\mathrm{NSE}_{h,i}$	not supplied energy	MWh/h
$\mathrm{Flow}_{l,h}$	power flow on transmission line l	MWh/h
$\mathrm{Exch}_{i,h}$	power injection in node/balancing group i	MWh/h
$\alpha_{i,h}$	phase angle of phase shifter in node i	$^\circ$

Balancing market:

$\overline{\mathrm{thFRR}}_{h,th}^{j}, \underline{\mathrm{thFRR}}_{h,th}^{j}$	reserved capacity for up-/downward $j \in \{a,m\}$ FRR of thermal unit th	MW/h
$\overline{\mathrm{psFRR}}_{h,ps}^{j}, \underline{\mathrm{psFRR}}_{h,ps}^{j}$	reserved capacity for up-/downward j FRR of pumped hydro storage unit ps	MW/h
$\overline{\mathrm{stFRR}}_{h,st}^{j}, \underline{\mathrm{stFRR}}_{h,st}^{j}$	reserved capacity for up-/downward j FRR of other storage unit st	MW/h
$\overline{\mathrm{Exch}}_{h,i}^{j}, \underline{\mathrm{Exch}}_{h,i}^{j}$	exchanged reserve capacity for up-/downward j FRR	MW/h
$\overline{\mathrm{RCap}}_{l,h}^{j}, \underline{\mathrm{RCap}}_{l,h}^{j}$	reserved transmission capacity for j FRR on line l	MW/h
$\mathrm{storL}_{h,ps}^{RV+}, \mathrm{storL}_{h,ps}^{RV-}$	reserved storage level of PHS unit ps for up-/downward balancing	MWh/h
$\mathrm{storL}_{h,st}^{RV+}, \mathrm{storL}_{h,st}^{RV-}$	reserved storage level of other storage unit st for up-/downward balancing	MWh/h

Contents

1. Introduction

In the last decades energy systems are facing a huge transition globally. There are several dimensions. One big step forward was the implementation of liberalised electricity markets in Europe instead of regulated, centralised dispatch markets. Another one is the transition from a conventional power generation oriented system to a renewable and sustainable energy generation. This goes hand in hand with the change of the electricity generation from a suppliers point-of-view to a more consumer perspective, or more precisely to the so called "prosumer" perspective. "Prosumers" are producers and consumers, like solar Photovoltaic (PV) owners. Furthermore, the huge research developments concerning information and communication technologies allow shorter timings of markets, exchanges with regional markets and more flexibility on the demand side, because smart home devices, like smart meters, washing machines, refrigerators, etc. need a fast and reliable communication platform. Also coupling of sectors plays and will play in the future an important role, either coupling the electricity with the heating sector, which is already applied to a certain degree, e.g. by heat-pumps or by Combined Heat and Power (CHP) plants. Another way of coupling is transportation and electricity, e.g. with Electrical Vehicles (EVs). The third one is coupling electricity and gas markets, which allows another way of storing energy and eases congestions in the electricity transmission grid.

All this current and future changes are facing several limitations. The majority of the European transmission grid is more than 30 years old and was designed when mostly conventional technologies fed into the electricity transmission grid. These power plants were constructed, if possible, close to high load centres. On the contrary, the renewable technologies are constructed on places with the highest profitability, which is not always close to load centres, therefore, the generated electricity has to be transferred over the grid, e.g. the generation of huge amounts of onshore and offshore wind power in the North of Germany is transferred to the big load centres located in the South. In these hours the German transmission grid strikes their limitations. Additional transmission capacity can relieve these congestions within Germany. This is only one example, but there are several more. The European Network of Transmission System Operators for Electricity (ENTSO-E)[1] assesses every second year the cost and benefit analysis of transmission projects called Ten-Year Network Development Plan (TYNDP), based on national development plans.

Another limitation is the design of electricity markets. For the "new" technologies, like onshore and offshore wind, the introduction of shorter timings of markets is necessary to equalise to a certain extent their prediction errors, but also the forecast algorithms have been improved in the last years. Due to the fact that electricity is not storable in its origin, two types are important in terms of markets: energy which is needed to fulfil the dispatching schedules on a day-ahead or intraday basis and reserves which are needed to equalise supply and demand in real time. In U.S. electricity markets a trend is to implement co-optimisation of energy and reserves, i.e. joint energy and reserve market clearing as part of the centralised unit commitment and economic dispatch done by the Independent System Operator (ISO). On the contrary, in Europe mostly sequential energy and reserve markets exist with separate bidding and market clearing mechanisms. In Europe the Agency for the Cooperation of Energy Regulators (ACER) and ENTSO-E play a key role in achieving the so-called 'European Internal Energy Market'. The task of ACER has been to propose so-called 'Framework Guidelines', providing the basis for the 'Network Codes' - developed by ENTSO-E - for a European cross-border electricity market and the corresponding integration of large-scale Renewable Energy Sources for Electricity (RES-E) in Europe. High shares of RES-E generation require also robust balancing measures and procedures of the electricity system.

With increased use of supply-dependent generation technologies on the one hand and a decline in conventional power plants on the other hand, potential technical impacts in the electricity generation sector (influence on reliability of generation and control concepts) and the distribution sector (influence on grid load and reliability, voltage quality and grid losses) have to be discussed. One solution can be a combination of central and distributed storages, i.e. central storages can be pumped hydro storages and the distributed ones are more likely

[1] ENTSO-E represents 43 TSOs from 36 countries across Europe.

district batteries or EVs. Whereas pumped hydro storages with big storage volumes are able to store excess generation of RES-E over long time periods, the distributed storages are able to shift generation within hours or days, depending on storage capacity. Both concepts increase security of supply. In the Alps, for example the Austrian pumped hydro storages (2018: 3.4 GW) and hydro water reservoirs (2018: 3 GW) with their huge storage capacities of around 1730 GWh play an important role. To describe it in a different way: the hydro storages and reservoirs are able to supply more than the half of Austrian peak-load for 270 hours (=11 days). In addition, the interconnection with neighbouring countries is higher than the European average (Commission Expert Group on electricity interconnection targets, 2017). So the Austrian hydro storages support the integration of renewables in several Central European markets.

To understand and analyse several above-mentioned limitations and chances, the electricity dispatch model EDisOn and its extension including electricity balancing mechanisms called Electricity Dispatch Optimization & Balancing (EDisOn+Balancing) has been developed. The focus of analysis is structured into three parts:

- The first part of this work contributes to the evaluation of transmission expansion planning in Austria in two different ways, notably for 2020, 2030 and 2050. On the one hand, the neighbouring countries are respected as simple nodes and on the other hand, the detailed grid of Central European countries, high shares of renewables and conflicting tendencies for Austria and the remaining countries are analysed by using the model EDisOn.
- The second part addresses possible future balancing market mechanisms in several control areas (operated by the corresponding Transmission System Operator (TSO)s[2]) in Central Europe[3], while also respecting the different balancing products (automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR)) and the wholesale electricity market[4] assuming a certain Distributed Energy Resources (DER) level, notably for the target year 2030. Moreover, the different

[2]Equivalent to the ISO in the US.

[3]Balancing is respected in the control areas of TransnetBW, TenneT, 50Hertz and Amprion in Germany, TenneT in the Netherlands, ELIA in Belgium and Austrian Power Grid (APG) in Austria.

[4]The electricity wholesale market is respected in France, Germany, The Netherlands, Belgium, Switzerland, Italy, Austria, Slovenia, Hungary, Slovakia, Czech Republic and Poland.

design options are depicted with the model EDisOn+Balancing. In Europe there exist mostly sequential energy and reserve markets with separate bidding and market clearing mechanisms, which are run by different entities, i.e. the Power Exchanges and the TSO. It has been decided to follow the current trend in U.S. markets, where co-optimisation of energy and reserves is applied. Therefore, the model is designed as a multi-objective market model, i.e., the balancing procurement and the dispatch on wholesale electricity markets are solved simultaneously.

- The last part is about socio-economic benefit analysis of pumped hydro storage expansions in Austria and their implications on the Central European electricity system. Notably for 2030 the defined scenarios of (ENTSO-E, 2017b) are analysed with three different capacity expansion paths to get a variety of sensitivities. In addition to socio-economic welfare and CO_2 emission reductions, also environmental damage costs and implications on balancing capacity procurement are discussed. Furthermore, reductions in terms of necessary reserve capacity and investments in peak units while maintaining a high security of supply level are analysed.

The remainder of the work is structured as follows. In the next chapter the current status of short term electricity markets in the U.S. is shown, which is compared with the current status-quo of European Electricity Markets and furthermore, the progress in terms of latest developments of European Network Codes are shown. Passing over to literature review in terms of renewable integration, transmission line expansions, new market designs, storages and demand side management. Notably, a selection of works in this sense is mentioned in 2.2. Followed by an assortment of available electricity market models and the additional value provided by the EDisOn+Balancing model. In chapter 3 the methodology of the model EDisOn+Balancing and the mathematical formulation and functionalities are shown. Section 3.3 includes the model validation with data of 2013 and the balancing market mechanisms in Austria and Germany. This section is followed by five quantitative studies, structured into three parts, which are evaluated by using the model EDisOn+Balancing. Firstly, the focus is on grid expansions in Austria and Europe. On the one hand, there is an aggregated electricity grid for the neighbouring countries of Austria respected and on the other hand, a detailed analysis for Central Europe is done. Secondly, the quantitative results of the analysed balancing market designs for 2015 and a future electricity generation scenario for Central Europe to evaluate the challenges of high shares of RES-E are shown. Thirdly, the focus is on pumped hydro storage projects in Austria and how these technologies are able support the integration of RES-E in Central Europe. Finally, the last section provides conclusions based on the quantitative assessments and an outlook on further possible studies in this field. In Appendix A the assumptions of the electricity market model, the used data of each study and additional figures of the study outcomes are included. Relevant publications of the author are listed in Appendix B.

2. State of the Art

Relevant electricity markets for the mentioned developments and analyses are in the United States and in Europe. Therefore, the status of short-term electricity markets in the United States (e.g. PJM) is explained, including links to European electricity markets. The section is followed by an insight in current developments in Europe, especially, in terms of Network Codes, harmonisation processes and integration of RES-E. In the literature review selected works concerning renewable integration, transmission line expansions, new market designs, storages and demand side management are presented. Further, a selection of electricity market models is analysed, e.g. which market features can be simulated by the different mathematical models. It is explained to which category EDisOn+Balancing can be allocated to and what is the additional value of the model. The section is closed by the research question and how it can be answered and quantified.

2.1. Short-term Electricity Markets: United States vs. Europe

Generally, there are many similarities in terms of short-term electricity market design in Europe and the United States (U.S.), e.g. day ahead and real-time markets are operated in both places with similar time lines. However, when looking into the details there are some important differences. A selection of them are explained in the following paragraphs. For a comprehensive comparison of several structural and organisational aspects of U.S. and European electricity markets it is referred to (Auer and Botterud, 2016) and (Botterud and Auer, 2018).

Electricity markets in the U.S. are more closely linked to the physics of transmission systems than it is the case in Europe. A reason for this is, that when ISOs and electricity markets were introduced, they were typically built on existing entities, who were in charge of operating the transmission grid (e.g. PJM). The opposite applies for Europe: new Power Exchange (PX)s were introduced as separate entities apart from existing TSOs, emphasising wholesale electricity market trades and economics. In the European model, the physical anatomy of the electricity system and its operation, which is still conducted by the TSO, has therefore been more decoupled from market operations.

In the U.S. system, price signals are calculated for each node of the transmission system (i.e. Locational Marginal Pricing (LMP)) and the real-time markets are run with high time resolution, i.e. prices are typically calculated every 5 minutes. In Europe zonal pricing is implemented where one price zone usually covers an entire country, see also comparison in Table 2.1, and European balancing markets are operated with lower time resolution, i.e. typically 15 to 30 minutes.

Electricity market operators in the U.S. usually apply a centralised unit commitment model for power plant scheduling, where market participants provide bids including start-up costs and operational constraints. On the contrary, European market operation typically relies on bids without accounting for detailed unit commitment constraints. These are left for the individual generation companies to resolve them internally.

In U.S. electricity markets, a reliability unit commitment typically is performed between day-ahead and real-time operation, where the ISO can commit additional units for reliability purposes based on updated forecasts for load and RES-E. In contrast, European electricity markets rely on intraday markets organised by PXs, which enable market-based re-dispatch.

The trend in U.S. markets is to implement co-optimisation of energy and reserves, i.e. joint energy and reserve market clearing as part of the centralised unit commitment and economic dispatch done by the ISO. In Europe energy and reserve markets are typically operated sequentially with separate bidding and market clearing mechanisms, and the markets are also run by different entities (PXs vs. TSOs).

2.1.1. The short-term electricity markets of PJM

PJM Interconnection is a Regional Transmission Organisation (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The geographical scope of PJM Interconnection is shown in Figure 2.1.

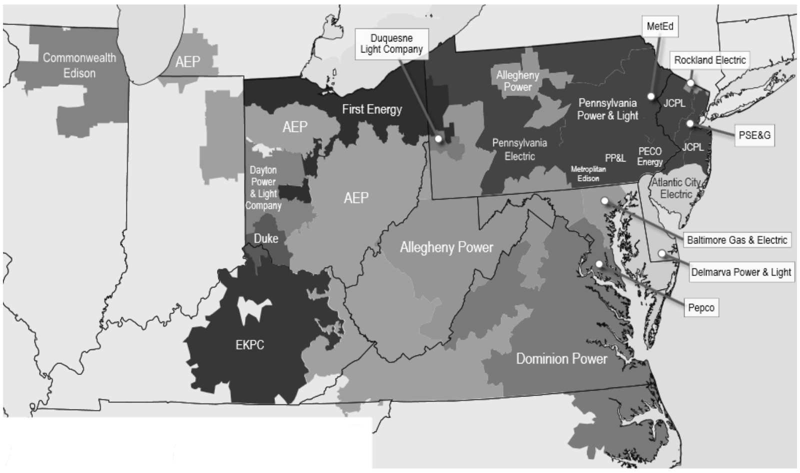


Figure 2.1.: PJM Interconnection coordinates the movement of electricity in all or parts of 13 states and the District of Columbia, source: www.pjm.com.

Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 65 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis.

For 2016 several key statistic measures of PJM, ENTSO-E and Germany are shown in Table 2.1. By comparing the three measures, people served (PJM serves 9% of people living in ENTSO-E region), scope of territory (PJM's territory comprises 6% of Europe) and length of transmission lines (PJM's transmission lines are 27% of ENTSO-E's transmission system), it can be concluded, that

PJM area is more interconnected than European electricity markets. In 2016 the RES-E generation share[1] was 4.7% (mostly from hydro power) in PJM and around 30% (mostly from hydro, wind and solar PV power) in Europe and Germany. So there are different challenges in Europe compared to U.S. electricity markets. PJM Interconnection applies LMP with more than 10,000 bidding nodes allocated to around 20 zones. In Europe mostly national borders are determinative for bidding zone configurations, except in some European countries there are more than one, e.g. in Norway there are 5, in Sweden 4, Denmark is split into two and in Italy there are 6 geographically defined zones. Whereas the contrary is still valid for the Austrian and German electricity day-ahead spot market. Although recently a mechanism was implemented to suspend cross-border trade, if necessary, during critical load flow situations in the electricity system.

Table 2.1.: Key statistics of PJM, ENTSO-E and Germany. Sources: (Bowring, 2017), www.pjm.com, (ENTSO-E, 2017a), (ENTSO-E, 2018), www.netzentwicklungsplan.de, (Bundesnetzagentur and Bundeskartellamt, 2017).

Indicators 2016	**PJM**	P/E	**ENTSO-E**	**Germany**
people served	65 Millions	(9%)	741 Millions	83 millions
transmission lines	131,966 km	(27%)	490,181 km	34,880 km
generation capacity	176,569 MW	(16%)	1,136,795 MW	212,000 MW
electricity generation	812 TWh/a	(22%)	3,633 TWh/a	600 TWh/a
RES-E share	4.7%		33%	29.7%
area served	13 states + D.C.		35 countries	1 country
territory	630,447 km^2	(6%)	10,180,000 km^2	357,376 km^2
bidding zones/nodes	20/10,000+		48+	1

The PJM energy market procures electricity to meet consumers' demands both in real-time and in the near-term. It includes the sale or purchase of energy in PJM's real-time (five minutes forward) and day-ahead market (one day forward).

Ancillary services help balance the transmission system as it moves electricity from generating sources to retail consumers. Balancing the system means matching supply and demand while maintaining a system frequency of 60 Hertz (50 Hertz in Central Europe). Several factors can impact supply/demand balance and the system frequency. Throughout the day, PJM operates markets to procure

[1]RES-E share is measured based on total net electricity generation.

two important ancillary services: regulation and reserves, which work together to maintain this balance, but have different roles:

Regulation is used to control small mismatches between load and generation. It is a reliability product that corrects short-term changes in electricity use that might affect the stability of the system. Regulation signals differ between: (i) D regulation, which is a fast, dynamic signal that requires resources to respond almost instantaneously; and (ii) A regulation, which is a slower signal that is meant to recover larger, longer fluctuations in system conditions.

Reserves help to recover system balance if there is loss of a large generator, resulting in a large deviation of the frequency. This operating reserve is divided into: (i) Primary, Synchronised or Quick Start Reserve where the amount of electricity can be received within 10 minutes; and (ii) Supplemental Reserve, which can be received within 10 to 30 minutes.

2.1.2. European Network Codes and their implementation projects

The Network Codes are a set of rules drafted by ENTSO-E, with guidance from ACER, to facilitate the harmonisation, integration and efficiency of the European electricity market. They are an integral part towards completion of the Internal Energy Market (IEM), and achieving the European Union's energy objectives (Commission, 2014) of: (i) at least 40% cut in greenhouse gas emissions compared to 1990 levels; (ii) at least a 27% share of renewable energy consumption; and (iii) at least 27% energy savings compared with the business-as-usual scenario.

The Network Codes are diversified in Connection, Operations and Market. For this work the most important code family is Market, especially the Network Code on Electricity Balancing (NC EB) and Capacity Allocation & Congestion Management (CACM), but there is further Forward Capacity Allocation (FCA). All of them have already entered into force. The Network Code on FCA deals with rules for long term markets, the forward markets. They have an important role in allowing market participants to secure capacity on cross border lines a long time in advance and therefore have a sort of trade insurance. The Guideline on CACM sets out the methods for calculating how much capacity can market participants use on cross border lines without endangering system security.

It also harmonises how cross border markets operate in Europe to increase competitiveness but RES-E integration. CACM is the cornerstone of a European single market for electricity. The EB Guideline is about creating a market where countries can share the resources used by their TSOs to equalise imbalances. It is also about allowing new players such as demand response and renewables to take part in this market. All in all, the Balancing Guideline should help increase security of supply, limit emissions and diminish costs to customers. Much further tasks are still open for EB compared to CACM, see Figure 2.2.

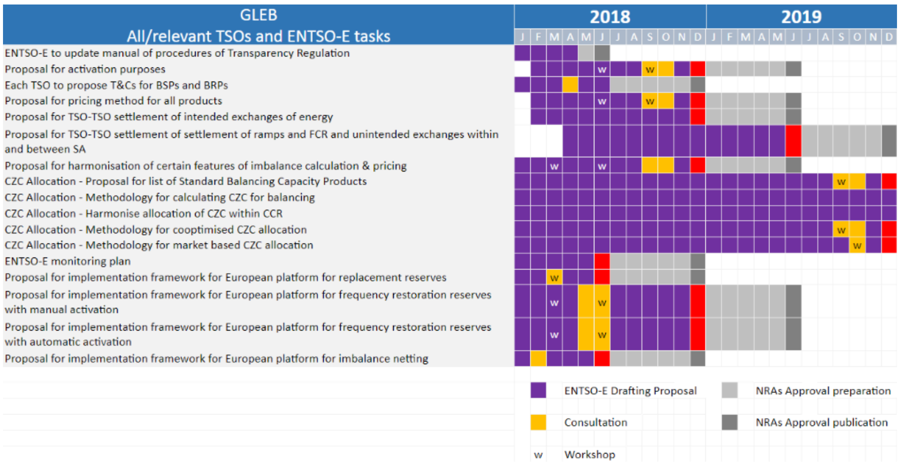


Figure 2.2.: The timeline of the relevant tasks of TSOs and ENTSO-E up to the end of 2019, source: https://electricity.network-codes.eu.

There are several implementation projects to make the CACM and EB codes a reality, some of them are outlined below:

As already mentioned in the previous section, in Europe zonal pricing is applied in electricity markets. Therefore, bidding zones are a core element of European market design. To accommodate and foster the transition towards fully integrated and sustainable electricity markets, transmission infrastructure development is to be paired with regular assessment of the bidding zone configuration, see (ENTSO-E, 2018).

In the Core Capacity Calculation Region (CCR) projectthe TSOs have confirmed their commitment to continue the development of a common day-ahead flow-based capacity calculation methodology. These methods will allow optimising transmission capacities by maintaining a high security of supply level. In addition, the Core CCR will develop a common methodology for coordinated re-dispatching and countertrading to effectively relieve congestions within the interconnected transmission grid.

The common market for procurement and exchange of Frequency Containment Reserves (FCR) (FCR Cooperation[2]) aims at the integration of balancing markets in order to foster effective competition, non-discrimination, transparency, new entrants and increase liquidity while preventing undue distortions. These objectives must be met in consideration of secure grid operation and security of supply. The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) originated as a regional project[3] evaluates the design, implementation and operation of a platform for aFRR. Equivalently, there is the project called Manually Activated Reserves Initiative (MARI), which aims for the creation of the European mFRR platform[4]and Trans European Replacement Reserves Exchange (TERRE) is about the Replacement Reserves (RR)platform and setting up the European RR balancing energy market in order to create a harmonised playing field for the market participants.

TSOs have already started Imbalance Netting cooperation with focus on the pilot projects International Grid Control Cooperation (IGCC)[5] and the Imbalance Netting Cooperation (INC). In order to start the implementation of this European process, TSOs have agreed to use the IGCC as a reference project and thereby as starting point.

[2]This regional project currently involves the TSOs from Austria (APG), Belgium (Elia), Switzerland (Swissgrid), Germany (50Hertz, Amprion, TenneT DE, TransnetBW), Western Denmark (Energinet), France (RTE) and the Netherlands (TenneT NL).

[3]The involved parties are APG, Elia, TenneT NL, RTE and the German TSOs – 50Hertz, Amprion, TenneT, TransnetBW. Since inception, the project has grown to include the following TSOs: ČEPS, Energinet, Fingrid, MAVIR, Statnett, ELES, Red Eléctrica de España and Svenska kraftnät.

[4]19 European TSOs decided to work on the design of an mFRR platform.

[5]It is a regional project operating the imbalance netting process which currently involves TSOs from AT, BE, CH, CZ, DE, DK, FR, NL.

2.2. Review of Literature

In the literature many studies about renewable integration, transmission grid expansions, new market designs, demand side management and storages are published. Notably, a selection of works shall be mentioned in this sense:

Comprehensive literature surveys for the general problem of transmission system expansion and corresponding modelling issues are provided in (Groschke et al., 2009), (Wu, Zheng, and Wen, 2006) and (Hemmati, Hooshmand, and Khodabakhshian, 2013). In (Lumbreras and Ramos, 2016) a critical review on Transmission Expansion Planning (TEP) is performed focusing on recent developments such as renewable integration or regional planning. A multi-objective TEP considering minimising curtailed wind energy is presented in (Ugranlı and Karatepe, 2015). There are several optimisation methods which are applied for TEP, such as mixed-integer linear programming (Alguacil, Motto, and A. J Conejo, 2003), (Torre, A. Conejo, and Contreras, 2008), Benders decomposition (Binato, Pereira, and Granville, 2001) or heuristic methods (Oliveira et al., 2005). Latest works are dealing with the combined problem of generation and transmission expansion planning (Antonio J. Conejo et al., 2016), (Bagheri, Vahidinasab, and Mehran, 2017), (Hemmati, Hooshmand, and Khodabakhshian, 2016) and (Rouhani, Hosseini, and Raoofat, 2014).

Concerning new market designs the focus of (H. Farahmand and G. L. Doorman, 2012), (Hossein Farahmand, 2012), (Y. Gebrekiros, G. Doorman, Jaehnert, et al., 2013), (Y. Gebrekiros and G. Doorman, 2014), (Y. Gebrekiros, G. Doorman, Jaehnert, et al., 2015a), (Y. T. Gebrekiros, 2015) and (Y. Gebrekiros, G. Doorman, Jaehnert, et al., 2015b) is on modelling and analysing electricity balancing markets in Northern Europe. Starting with the optimal reserve activation in the Nordic system, moving on to a cross-border reserve procurement algorithm, continued by a comparison of different designs. The work in (Lorenz, 2017) is about analysing balancing reserves within a de-carbonised European electricity system in 2050. The developments of generation portfolios are transformed into quantitative scenario definitions and applied to dynELMOD (dynamic Electricity Model). The results show that balancing reserve costs can be kept at current levels for a renewable electricity system until 2050, when using a dynamic reserve sizing horizon. Apart from the sizing horizon, storage capacity withholding duration and additional balancing demand from RES-E are the main driver of balancing costs. There is no distinction between different balancing products in the above-mentioned works. However, it is important that future work differentiate between aFRR and mFRR and their interactions.

The responsiveness of demands in electricity markets is analysed in the context of day-ahead planning in (Kristin Dietrich, 2014). It is concluded that in a system with high wind energy production, flexible demands, can be useful to partially level out variations in wind production. In (Eid et al., 2016) and (Borne et al., 2018) the challenges and opportunities of DER, like controllable loads, EVs, distributed generation units, at the distribution and high-voltage level are discussed.

There are contributions categorising and comparing several energy storage technologies. E.g., among others (Zach, Auer, and Lettner, 2012) provides an overview of the state-of-the-art and the expected future development of key technology and economic parameters (like typical rated power, charge/discharge time and frequency, capital and operation cost, etc.) of the two main bulk energy storage technologies Pumped Hydro Storage (PHS) and Compressed Air Energy Storage (CAES). When addressing PHS technology specifically, contributions like (IEA, 2012), (Deane, O Gallachoir, and Mckeogh, 2010), (Ekman and Jensen, 2010) or (Barbour et al., 2016) provide a techno-economic review of existing and proposed PHS plants and discuss improvements in terms of utilisation. The study in (Kougias and Szabó, 2017) analyses in a European context, if PHS utilisation increases at a similar rate as RES-E capacity in the ongoing energy transition. Datasets from 1991 to 2016 are analysed, revealing an uneven utilisation among European countries. While some countries increased the utilisation rates of PHS by a factor of three to four, PHS in others are heavily underutilised. An assessment of further European PHS potential is conducted in (Gimeno-Gutiérrez and Lacal-Arántegui, 2015) by linking two existing reservoirs to form a PHS system. The reservoirs are expected to have adequate difference in elevation and close enough to be reasonably linked. The results show that the theoretical energy storage potential is significant (comparing to existing PHS storage capacity reported for 14 countries by the factor of 3.5). The realisable potential still can be denoted twice the existing capacity.

The European Alps are well positioned to significantly contribute with their PHS capacities to renewable energy transition on national and European scale. Thus a significant amount of references exist focusing on PHS in the European

Alps. E.g. the paper (Gurung et al., 2016) provides a system view of hydropower production and energy storage in the Swiss and Austrian Alps. It discusses advantages and drawbacks of various assessment tools of PHS expansion and concludes that instruments evaluating the impacts and sustainability of PHS projects need to be improved and some of them newly developed. In (Weiss, Zach, and Schulz, 2014) the joint Austrian and German electricity system is investigated with a focus of PHS energy storage contribution and needs to support significantly RES-E integration. The analysis and conclusion of this contribution provide evidence that the still unexploited Austrian PHS potentials together with the already existing capacities can significantly support the German electricity system with its fast growing wind and solar capacities.

There is an enormous need to further implement new energy storage capacities and increase of utilisation of existing ones in electricity systems with high shares of RES-E. This is also concluded in a recent publication by the International Energy Agency (IEA), (IEA, 2012), focusing on (pumped) hydro storage.

Against this background, the European Commission also expects from the different energy infrastructure associations (and their members) that, on the one hand, the potentials and costs and, on the other hand, the system benefits of energy infrastructure investments are assessed. In this context, mainly transmission grid and large/scale (pumped-) hydro storage expansion is subject to ongoing investigations. ENTSO-E has taken a leading role in this process and develops a Cost/Benefit Analysis (CBA), not only for European transmission projects, but also storage projects and additional European infrastructure projects denoted to be so-called Projects of Common Interest (PCIs)[6].

2.3. Electricity Market Models

For evaluating different developments in electricity markets there are several models available. The three main categories of model types are dispatching/unit

[6]The European Commission establishes and updates biannually the list of PCIs. They are denoted to be key infrastructure projects (with a significant amount of energy storage, notably PHS, projects) helping the EU achieve its energy policy and climate objectives of "Affordable, secure and sustainable energy for all citizens, and the long-term decarbonisation of the economy in accordance with the Paris Agreement", (EC, 2013a), (EC, 2016).

commitment models, projects' profitability assessment models and long-term mix models, see Figure 2.3 for a selection of models and their categorisation. In the following section insights in selected models are provided.

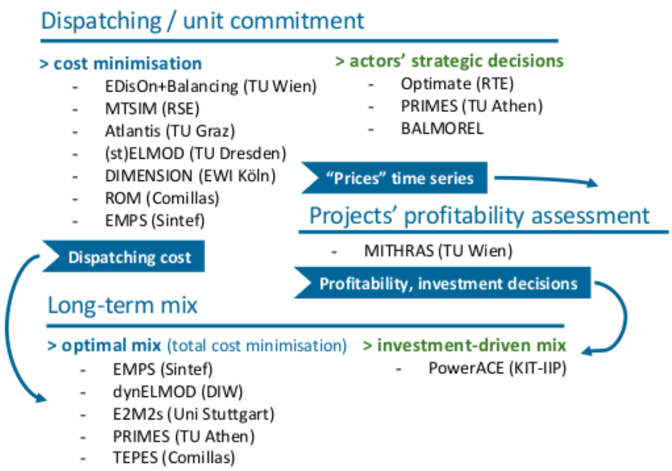


Figure 2.3.: Selection of available models.

2.3.1. Dispatching/Unit commitment tools

Dispatching/Unit commitment tools typically model the operation of generation units based on either an optimisation at the global scale or on the decision of market players (essentially the producers) given market conditions and their respective market strategies. Such tools often work with an hourly time resolution, but, depending on their features, they may have a higher granularity.

The first sub-class within this type usually involves solving an optimisation problem, either deterministic (climatic uncertainty can be represented by using several or numerous scenarios) or stochastic. Demand is typically regarded as inelastic and a very high cost is attributed to unserved load. Generating units that are not constrained by an energy stock are essentially described by variable costs, proportional to their output. The programme, then, either maximises social surplus or minimises total cost, as a proxy to the former, and serving the load is considered a constraint for each hour of the simulation period. This kind of problems simulates the centralised optimal production decisions of a monopoly or, in an equivalent manner, the dispatching that should result from market players' bids under the assumption of pure and perfect competition.

The second sub-class aims at describing an altered situation where some of the postulates of pure and perfect competition are not fulfilled – for instance the market players are not purely rational or have market power – therefore, it essentially falls under the game theory type of tools.

The Medium Term SIMulator (MTSIM) (Zani, Grassi, and Migliavacca, 2011) is a zonal electricity market optimisation tool able to simulate the behaviour of the European electricity system by solving an hourly least cost dispatch problem subject to certain constraints. The models ATLANTIS (Stigler et al., 2016), ELMOD (Leuthold, Weigt, and Hirschhausen, 2012), DIMENSION (Richter, 2011) and ROM (Ramos Galán, n.d.[a]) are also dispatching or unit commitment models, which are either solved by minimising the generation costs or maximising the social surplus. The modelling basics are quite similar, while every model got their specifics, considers different scientific issues and the degree of modelling details varies. ELMOD models the European electricity market including both generation and the physical transmission network by applying the DC load flow approach. The extension stochastic electricity market model (stELMOD) (Abrell and Kunz, 2015) uses stochastic programming techniques to analyse the impact of uncertain wind generation on different electricity markets as well as network congestion management. Besides conventional power plants, combined heat and power plants and power storages, the model DIMENSION considers technologies, e.g. DSM, EVs, that support the future high feed in of renewable energies. The model ROM follows a combined modelling approach that replicates the sequence of planning and real-time operation process in the electricity systems from the system operator's point of view. The day-ahead market is represented by daily optimisation problems, which are solved to compute the unit commitment. It is followed by a simulation stage where the adaption of the day-ahead schedule to correct power imbalances caused by stochastic events is computed, which represents the real-time operation.

The OPTIMATE platform (Weber et al., 2012) intends to replicate in a detailed manner how the sequence of electricity markets (day-ahead and intraday markets, balancing arrangement and imbalance settlements) works and how different players (thermal and renewable generators, consumers, portfolio managers, TSOs, etc.) interact with each other with uncertainty on availability and level of generation and load. The PRIMES model (Capros et al., 1998) is a modelling system that simulates a market equilibrium solution for energy supply and demand. The equilibrium is static (within each time period) but repeated in a time-forward path, under dynamic relationships. The model is organised in sub-models, each one representing the behaviour of a specific agent, a demander and/or a supplier of energy. The BALMOREL (Ravn et al., 2001) energy model is a partial equilibrium model, which supports modelling and analysis of the energy sector with emphasis on the electricity and the combined heat and power sectors.

2.3.2. Projects' profitability assessment tools

Tools of this class are used to assess the potential profitability of building up a new power plant. This typically requires making hypotheses about future market conditions (e.g. market prices can be computed in many ways, for instance through an approach based on the supply of projected demand by projected generation, or through time-series analysis of the historic prices, on the basis of market forward products, etc.) and, on their basis, compute a number of financial indicators reflecting the amount of money that will be generated by selling the energy produced by this new facility. The indicators are used to decide whether or not the project can be started (depending on the risk policy) and also, very often, its financing structure, the debt-to-capital ratio being determined by the risk inherent to the project.

The profitability model MITHRAS (Lettner, 2014) can be used to determine the "PV Parity", an economic cost comparison of a market participant with and without a PV system over the lifetime is made. As a basis for this economic cost comparison the Levelised Cost of Electricity (LCOE) is considered. For systems that primarily generate electricity to be consumed elsewhere, the LCOE is compared to electricity generation costs for several different generation technologies. For a consumer, e.g. a household, the LCOE is comparable to the retail electricity price. For the calculation of future LCOE of PV technologies, a variety of different boundary conditions and assumptions for the future development of several important parameters (e.g. specific cost, efficiency, etc.) is required.

2.3.3. Tools for long-term studies

Two types of approaches are possible, the first one being based on the "centralised" optimisation of the system expansion and operation, and the second one relying on the simulation of market players' decisions (players being investors in this case).

The aim is to find out the structure of the generation mix which provides the least expensive solution to cope with a given demand, ensuring a specified security of supply level. The result of this is, therefore, a static vision of a target ideal mix. However, tools of this class do not give any information on how to reach this target from a previous state, neither do they indicate whether market players' decisions would lead to reaching such a target or not. Such tools usually require solving huge optimisation problems in an approximate manner, based on heuristics. On the other hand, in tools of the second type, the final generation mix (if a stable state can be reached) results from the cumulative investment decisions made by simulated market players on the basis of projects' profitability assessment tools and hypotheses on their risk aversion and strategy. This kind of tools rely on a description of how market design items influence the revenues from running a generating unit or a storage facility to determine how market features alter investors' decisions and, thus, change the prevalence of each technology in the resulting mix. Tools of this class are also very resource-greedy, since running them usually requires the repeated appraisal of several projects against many future scenarios over many years.

Selected long-term operation and investment models are for example EMPS (SINTEF Energy Research, n.d.), dynELMOD (Gerbaulet and Lorenz, 2017), E2M2s (Hundt et al., 2010), TEPES (Ramos Galán, n.d.[b]) and PowerACE (Bublitz, Genoese, and Fichtner, 2014). EMPS has been specifically developed for hydro-thermal power systems. It calculates the optimal dispatch of hydro and thermal power plants, taking into account the uncertainty of climate variables and determining the optimal strategy for handling hydro reservoirs. The investment module uses the results of the operation optimisation to identify the profitability of various assets in order to compute the optimal generation and transmission capacities in the power system. The model dynELMOD endogenously determines investments into conventional and renewable power plants, different storage technologies including demand side management measures, and the electricity grid in five-year steps in Europe until 2050. The electricity and heating market model E2M2s is a fundamental model that determines the optimal use of power plants and optimal investment decisions with the aim of minimising system costs. TEPES is a long-term transmission expansion planning model that determines the investment plans of new facilities (lines and other network equipment) for supplying the forecasted demand at minimum cost. Whereas the model PowerACE is an agent-based, bottom-up simulation model for wholesale electricity markets. With respect to the agents, major generation companies are represented by individual agents and others are modelled to bid electricity demand, generation from renewable energy sources, exchange, and to operate markets. Furthermore, the model contains an investment planning module executed by each generation agent on an annual basis. For that purpose, different investment options are compared according to certain criteria, e.g. the net present value.

2.4. Research question and own contribution beyond the state of the art

In order to be able to analyse and understand different functionalities and designs in terms of electricity markets, the model EDisOn and the extension for respecting electricity balancing mechanisms, called EDisOn+Balancing has been developed.

By using this model different questions can be answered, one of them are price predictions for future scenarios, reducing CO_2 emissions by a predefined level or reaching a certain CO_2 emission target. However, these analyses go often hand in hand through answering much complex questions, like what transmission line expansions are necessary for different assumed renewable expansion paths to guarantee a certain level of security of supply by having enough dispatchable generation capacity. The results of two studies concerning transmission line expansions and the application of other flexible transmission technologies applied in Austria are included in section 4.1.

Another important question in terms of security of supply addresses improvements of electricity market designs, while continuously more renewable technologies enter the markets and a decline in conventional power plants can be observed. It is important to define and evaluate possible future balancing market mechanisms, while also respecting different balancing products (aFRR and mFRR) and the interaction on wholesale electricity markets. To finally, find out the most efficient design for balancing markets. In Europe there exist mostly sequential energy and reserve markets with separate bidding and market clearing mechanisms, which are run by different entities, i.e. the Power Exchanges and the TSOs. When developing the model extension it has been decided to follow the current trend in U.S. markets, where co-optimisation of energy and reserves is applied. Therefore, the EDisOn+Balancing model is designed as a multi-objective market model, i.e. balancing capacity procurements and power plant dispatches on wholesale electricity markets are solved simultaneously. The study outcomes are explained in section 4.2.

Furthermore, the impacts on both markets the wholesale and the balancing market of future storage projects, like pumped hydro storages and batteries, can be analysed. So far, there has not been existing a quantitative socio-economic benefit analysis of energy storage technologies according to the benefit indicators expected by the European Commission in the policy process of the so-called PCIs. The expectation to be listed as a PCI project (being also supported by the European Commission and treated with highest priority) is that the project significantly contributes to the increase of flexibility of the European electricity system. The socio-economic analysis of further hydro storage expansions in Austria and the impacts on Central European electricity markets are shown in section 4.3.

3. Mathematical Formulation of the EDisOn+Balancing model

EDisOn (**E**lectricity **Dis**patch **O**ptimizatio**n**) is a fundamental market model and has been developed in MATLAB® (using the toolbox yalmip (Lofberg, 2-4 Sept. 2004)). A study using the basic functionality of EDisOn can be found in (Burgholzer and Auer, 2016). The model computes the optimal (cost minimal) dispatch of thermal power plants in the electricity system and considers RES-E generation from wind, solar and hydro. Regarding hydro, three different types are considered: pumped hydro storage, hydro storage and run-of-river power plants. It is designed as a linear programming problem (binary on-/off-conditions are linearised, (H. Farahmand and G. L. Doorman, 2012)) and it is deterministic in nature. The model assumes a perfectly competitive market with perfect foresight, and uses an hourly resolution of a full year. The rolling horizon can be split into several resolutions, from one hour up to a whole year. The transmission system can be respected in two ways: either by applying Net Transfer Capacity (NTC) or the direct current (DC) load flow approach. Three new applications have also been added lately. Co-generation of thermal power plants and Power-to-Heat (PtoH) devices can be activated for fulfilling a certain exogenous heat demand, other kinds of storages reflecting DER, like batteries or EVs, are implemented and Demand-Side Management (DSM), i.e. demand shifts, from a central planner point-of-view can be enabled to a certain extend and time frame.

In order to enable the consideration of balancing energy markets, a model extension has been necessary. In additional simulation steps several balancing market mechanisms for electricity are considered in the model EDisOn+Balancing. Firstly, the procurement of balancing capacity and the wholesale market clearing based on an hourly resolution is simulated. Despite the fact that in Europe mostly sequential energy and reserve markets with separate bidding and market clearing mechanisms exist (run by different entities Power Exchanges vs. TSOs), we decided to follow the trend in U.S. markets. The co-optimisation of energy and reserves is implemented, i.e. joint energy and reserve market clearing as part of the centralised unit commitment and economic dispatch, and it is done by the ISO. Subsequently, the activation of balancing energy is simulated for balancing the imbalances of control areas on a quarter hourly resolution. Figure 3.1 provides an overview of the different simulation steps and the corresponding inputs and outputs.

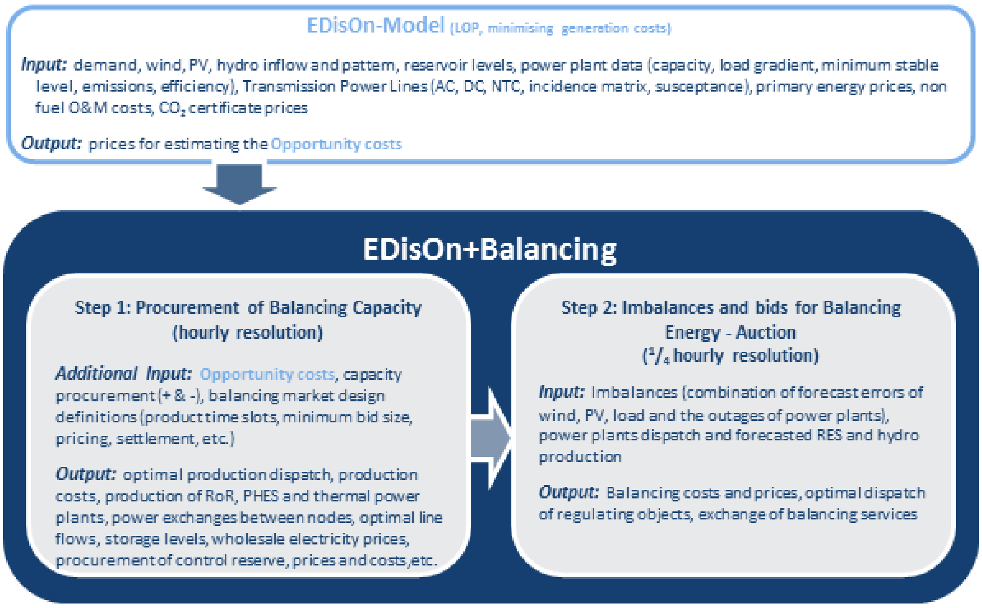


Figure 3.1.: Flowchart of the EDisOn+Balancing model.

3.1. Wholesale market

Generation capacities are given exogenously, therefore, it is no tool to analyse investment decisions. PHS levels and the natural inflow of both PHS and Run-of-River (RoR) are following an annual pattern. Electricity generation of wind and PV are considered based on historical data, but it is also possible to implement time series based on stochastic processes. EDisOn covers the transmission system of Central Europe (partly from 110, 220 up to 380 kV-level).

There are two different aggregation levels, which can be considered for the electricity transmission system. In the aggregated version, for example Austria is divided into 17 load and generation nodes, correlating with the main substations within Austria based on (APG, 2013). In addition the grid data of the control area APG has been checked with employees from the grid operation. Fourteen nodes represent the neighbouring countries or control areas, e.g. Germany comprises four nodes, one node per control area. In this way the generation mix of locational circumstances can be considered to a certain degree, wind turbines in the north of Germany, mostly in 50Hertz and TenneT. PV systems are concentrated in the southern part of Germany, TransnetBW control area. If the connection point of power plants is known, they are allocated accordingly, the remaining generation units are allocated to the closest node. Load allocation is based on population figures and large industrial sites. All parallel Transmission Power Line (TPL) between the nodes are merged to one representative TPL, which leads to a total of 59 TPLs, see Figure 3.2. To be able to consider also DC load flow in the aggregated version, a grid reduction algorithm has been used for the the interconnections to the neighbouring countries, (Kruijer, 2015).

The detailed version has been created by several students based on the ENTSO-E 2013 map[1] and recently, the planned projects of TYNDP 2014 (ENTSO-E, 2014c) and 2016 (ENTSO-E, 2015b) have been added. Austria for example, comprises nearly 78 nodes or transformers, 88 lines. For Central Europe, there are 2269 nodes and 3050 lines considered, see Figure 3.3.

3.1.1. Objective function

The minimisation of total electricity generation costs is the objective function of the market model. Not only thermal generation is considered with its Short Run Marginal Costs (SRMC), but also minor operating costs of RoR, PV and wind generation are taken into account. The last term $\mathrm{NSE}_{h,i}$ in (3.1) is for demand, which cannot be covered by supply. In literature, e.g. (Hogan, 2005), the average Value of Lost Load (VoLL) is assumed to be between 10,000 and

[1] The 2013 ENTSO-E Interconnected Network Grid Map can be ordered at: www.entsoe.eu.

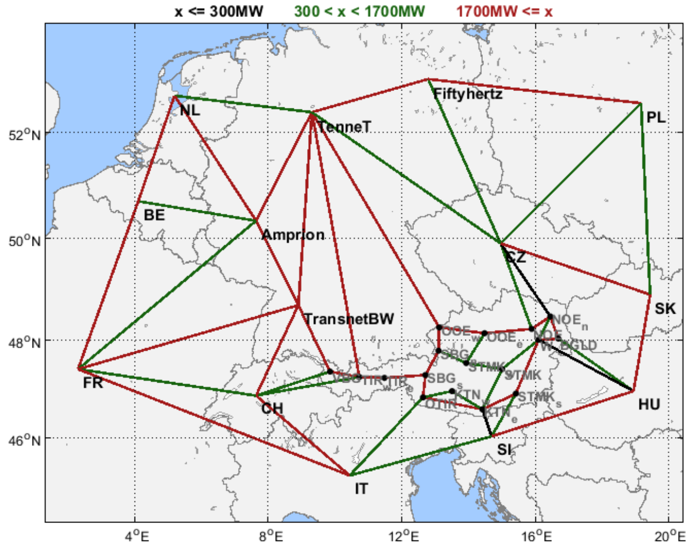


Figure 3.2.: Aggregated transmission grid supposed for the year 2030, based on (APG, 2013).

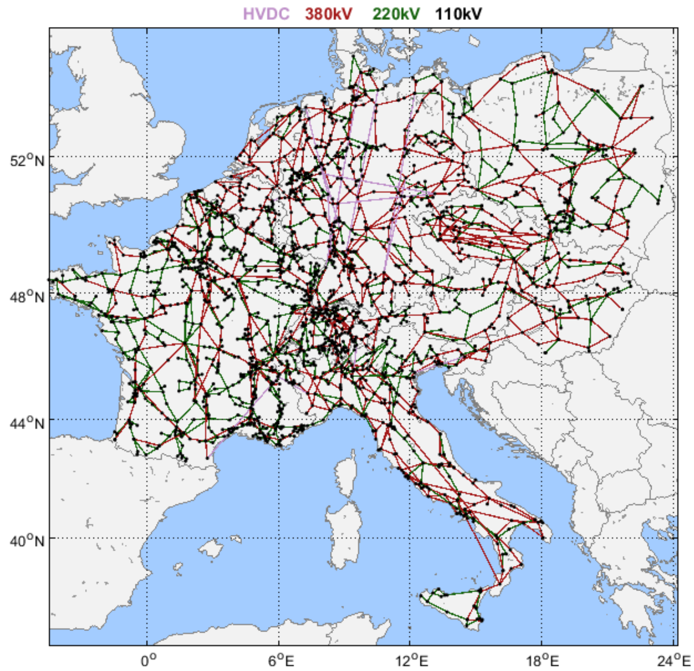


Figure 3.3.: Detailed transmission grid supposed for the year 2030, based on 2013 ENTSO-E Interconnected Network Grid Map and planned projects of TYNDP 2014 and 2016, (ENTSO-E, 2014c) and (ENTSO-E, 2015b).

20,000 USD/MWh. In this analysis a VoLL of 3,000 EUR/MWh is assumed, this is the current peak-price on day-ahead auctions with delivery on the German/Austrian TSO zones at EPEX SPOT[2].

$$\begin{aligned}\min OF^{Wholesale} = \min \sum_{\substack{h \in H,\\ ca \in CA, i \in I_{ca}}} \sum_{th \in TH_i} & (\mathrm{thP}_{h,th} \cdot SRMC_{h,th} + \mathrm{Str}_{h,th} \cdot C^{Start}_{h,th}) \\ & + (\mathrm{hyP}_{h,i} - \mathrm{Spill}^{Hy}_{h,i}) \cdot C^{Hy} + (Wind_{h,i} - \mathrm{Spill}^{Wind}_{h,i}) \cdot C^{Wi} \\ & + (PV_{h,i} - \mathrm{Spill}^{PV}_{h,i}) \cdot C^{PV} + \mathrm{NSE}_{h,i} \cdot VoLL \qquad (3.1)\end{aligned}$$

with $SRMC_{h,th} = C^{O\&M}_{th} + C^{fuel}_{th}/\eta_{th} + C^{CO_2} \cdot Em_{th}/\eta_{th}$, where h describes time (hour) and $th \in TH_i$ thermal unit in node $i \in I_{ca}$, corresponding to control area $ca \in CA$.

3.1.2. Constraint for Demand and Supply

The demand in every node has to be covered by supply in every simulated hour. $p^{DA}_{h,i}$ denotes the shadow price, which is used as the expected hourly price of the wholesale market in the balancing market application in section 3.2.

$$\begin{aligned}Demand_{h,i} = & \sum_{th} \mathrm{thP}_{h,th} + \sum_{ps} (\mathrm{tuP}_{h,ps} - \mathrm{puP}_{h,ps}) + \sum_{st} (\mathrm{stPOut}_{h,st} - \mathrm{stPIn}_{h,st}) \\ & + \mathrm{hyP}_{h,i} - \mathrm{Spill}^{Hy}_{h,i} + Wind_{h,i} - \mathrm{Spill}^{Wind}_{h,i} + PV_{h,i} - \mathrm{Spill}^{PV}_{h,i} \\ & - \mathrm{Exch}_{h,i} + \mathrm{NSE}_{h,i} \qquad : p^{DA}_{h,i} \qquad \forall h \in H, \forall i \in I_{ca} \qquad (3.2)\end{aligned}$$

3.1.3. Technical restrictions for thermal power plants

For thermal power plants, there are some technical constraints, which have to be considered in market models. Thermal units are able to produce less than the maximum capacity and some are able to produce more than a minimum stable capacity only, which is defined in equation (3.3). The following inequalities show how the linearisation of binary on/off conditions for thermal power plants is implemented, based on (H. Farahmand and G. L. Doorman, 2012). The

[2] www.epexspot.com

variables $\mathrm{X}^X, \mathrm{X}^Y$ and X^Z are necessary for the linearisation. X^X says if the thermal power plant is off or between zero and the minimum stable level. In addition, it determines whether there are start costs $\mathrm{Str}_{h,th}$ from hour $h-1$ to h or not. The decision variable X^Y reflects the electricity generation between minimum stable level and the maximum for the wholesale market and in (3.52) it is used for providing downward balancing capacity. Thermal power plants can only bid downward capacity if they are running above the minimum stable level. X^Z describes the reserved upward capacity for balancing the system, see equation (3.51).

$$\mathrm{thP}_{h,th} = \mathrm{X}^X_{h,th} \cdot Cap^{min}_{th} + \mathrm{X}^Y_{h,th} \cdot (Cap^{max}_{th} - Cap^{min}_{th}) \quad \forall h \in H, th \in TH_i \tag{3.3}$$

$$\mathrm{X}^X_{h,th} - \mathrm{X}^X_{h-1,th} \leq \mathrm{Str}_{h,th} \leq 1 \qquad \forall h > 1, th \tag{3.4}$$

$$\mathrm{X}^Y + \mathrm{X}^Z \leq \mathrm{X}^X \leq 1 \tag{3.5}$$

$$\mathrm{X}^X \geq 0, \mathrm{X}^Y \geq 0, \mathrm{X}^Z \geq 0, \mathrm{Str} \geq 0 \tag{3.6}$$

In addition, the changes in generation, i.e. up and down, are also limited by ramp rates (see inequalities (3.7) and (3.8)).

$$\mathrm{thP}_{h,th} - \mathrm{thP}_{h-1,th} \leq ramp_{th} \cdot Cap^{max}_{th} \qquad \forall h \geq 2, \forall th \tag{3.7}$$

$$-\mathrm{thP}_{h,th} + \mathrm{thP}_{h-1,th} \leq ramp_{th} \cdot Cap^{max}_{th} \qquad \forall h \geq 2, \forall th \tag{3.8}$$

3.1.4. Respecting heat demand, CHP and power-to-heat

In every node a heat profile can be respected. The application of CHP of certain thermal power plants and PtoH devices provide the necessary heat demand.

$$\sum_{th \in TH_i} \mathrm{thP}_{h,th} \cdot \eta^{heat}_{th} + \mathrm{PtoH}_{h,i} \geq Demand^{heat}_{h,i} \qquad \forall h \in H, \forall i \in I_{ca} \tag{3.9}$$

3.1.5. Run-of-River power plants

The RoR plants can generate less than the maximum capacity only and should be equal to the natural inflow, which is calculated by using an hourly profile and the annual production. In this context the variable $\mathrm{Spill}_{h,i}^{Hy}$ expresses the lock of a RoR plant is open, i.e. a certain amount of hydro energy is not used for electricity generation.

$$0 \leq \mathrm{hyP}_{h,i} \leq Cap_{i}^{Hy} \qquad \forall h \in H, i \in I_{ca} \tag{3.10}$$

$$0 \leq \mathrm{Spill}_{h,i}^{Hy} \leq Inflow_{h,i}^{hy} \qquad \forall h, i \tag{3.11}$$

$$\mathrm{hyP}_{h,i} + \mathrm{Spill}_{h,i}^{Hy} = Inflow_{h,i}^{hy} \qquad \forall h, i \tag{3.12}$$

3.1.6. Pumped hydro, hydro and Other storages

The pumps and turbines of PHS plants are limited to their technical maximum.

$$0 \leq \mathrm{puP}_{h,ps} \leq Cap_{ps}^{Pu} \qquad \forall h \in H, ps \in PS_{i} \tag{3.13}$$

$$0 \leq \mathrm{tuP}_{h,ps} \leq Cap_{ps}^{Tu} \qquad \forall h, ps \tag{3.14}$$

In the Alps, the reservoir content of PHS plants follows a certain annual pattern, based on data by E-Control[3] (Austrian Regulator) from 1997 to 2011 for Austria or now available on the transparency website of ENTSO-E[4] also for Switzerland, France and Italy. In general, it is limited to its maximum and minimum storage level. Therefore, the equations describing the storage level balance are of high importance (see equation (3.15), (3.16) and (3.17)). $V_{h,ps}^{H2O}$ denotes the water value of storage unit ps, it is needed for calculating the opportunity costs of pumped hydro storage units, which are used in the balancing market application in section 3.2.

[3] Only available in German on www.e-control.at under the header "Marktstatistik/Wasser- und wärmewirtschaftliche Kennzahlen".

[4] Available under "Generation/Water Reservoirs and Hydro Storage Plants" on transparency.entsoe.eu.

$$\begin{aligned} \mathrm{storL}_{1,ps} =& PHSstor_1 \cdot En^{max}_{ps} - \frac{\mathrm{tuP}_{1,ps}}{\eta^{Tu}} + \mathrm{puP}_{1,ps} \cdot \eta^{Pu} + Infl_{1,ps} \\ & - \mathrm{Spill}^{PHS}_{1,ps} \qquad : V^{H2O}_{1,ps} \end{aligned} \tag{3.15}$$

for $h \geq 2$ and $\forall ps \in PS_i$:

$$\begin{aligned} \mathrm{storL}_{h,ps} =& \mathrm{storL}_{h-1,ps} - \frac{\mathrm{tuP}_{h,ps}}{\eta^{Tu}} + \mathrm{puP}_{h,ps} \cdot \eta^{Pu} + Infl_{h,ps} \\ & - \mathrm{Spill}^{PHS}_{h,ps} \qquad : V^{H2O}_{h,ps} \end{aligned} \tag{3.16}$$

$$0 \leq \mathrm{Spill}^{PHS}_{h,ps} \leq Infl_{h,ps} \qquad \forall h, ps \tag{3.17}$$

$$En^{min}_{ps} \leq \mathrm{storL}_{h,ps} \leq En^{max}_{ps} \qquad \forall h, ps \tag{3.18}$$

The consumption and generation of other storages are also limited by their technical maximum.

$$0 \leq \mathrm{stPIn}_{h,st} \leq Cap^{In}_{st} \qquad \forall h, st \tag{3.19}$$

$$0 \leq \mathrm{stPOut}_{h,st} \leq Cap^{Out}_{st} \qquad \forall h, st \tag{3.20}$$

The storage level is limited by its maximum and minimum storage capacity. The equations describing the storage level balance are (3.21) to (3.24). An essential difference compared to PHS is, that instead of natural inflows $Infl_{h,ps}$ a certain discharge $\mathrm{DCharge}_{h,st}$ in every hour is respected. This allows also the consideration of EVs, both Grid-to-Vehicle (GtoV) and Vehicle-to-Grid (VtoG) or GtoV only, with a certain pattern or function defined as $\mathrm{DCharge}_{h,st}$. Concerning start and end storage values, two different approaches exist: either the start and end values are equal $a = 1$ or there is a certain ratio $a \in \mathbb{R}^+$ (see equation (3.22)). $V^{Stor}_{h,st}$ denotes the value of storage unit st. It is used to calculate the opportunity costs for other storages, which are needed in the balancing market application in section 3.2. for $h \geq 2$ and $\forall st \in ST_i$:

$$\mathrm{storL}_{h,st} = \mathrm{storL}_{h-1,st} - \frac{\mathrm{stPOut}_{h,st}}{\eta^{stOut}} + \mathrm{stPIn}_{h,st} \cdot \eta^{stIn} \quad - \mathrm{DCharge}_{h,st} \qquad : V^{Stor}_{h,st} \tag{3.21}$$

$$\mathrm{storL}_{1,st} = a \cdot \mathrm{storL}_{end,st} \qquad \forall st \tag{3.22}$$

$$0 \leq \mathrm{DCharge}_{h,st} \leq \mathrm{stoL}_{h,st} \qquad \forall h, st \tag{3.23}$$

$$En_{st}^{min} \leq \mathrm{storL}_{h,st} \leq En_{st}^{max} \qquad \forall h, st \tag{3.24}$$

3.1.7. Power flows, injections and exchanges

The exchanges - or more precisely the injections - must equal the sum of the flows, which are going out and coming in of each node. Therefore, negative injection in a node means that demand is higher than supply and vice versa. The power flow on each transmission power line has to be between capacity limits of each power line and the same applies for the phase angles of the phase shifters and their maximum value, variables $\alpha_{l_{pst},h}$ and α^{max} (see equations and inequalities (3.25)-(3.27)). The power flows also have to satisfy equation (3.28), where the matrices Power Transfer Distribution Factor (PTDF), Power Shift Distribution Factor (PSDF) and Direct Current Distribution Factor (DCDF) are respected.

$$\mathrm{Exch}_{i,h} = \sum_{l \in L} A_{l,i} \cdot \mathrm{Flow}_{l,h} \qquad \forall h \in H, \forall i \in I_{ca} \tag{3.25}$$

$\forall l \in L \subset L_{AC} \mathbin{\dot{\cup}} L_{DC}, \forall h \in H :$

$$-CapL_l^{B \to A} \cdot DLR_h \leq \mathrm{Flow}_{l,h} \leq CapL_l^{A \to B} \cdot DLR_h \tag{3.26}$$

$$-\alpha^{max} \leq \alpha_{l_{pst},h} \leq \alpha^{max} \qquad \forall l_{pst} \in L_{pst} \subset L_{AC}, \forall h \in H \tag{3.27}$$

$\forall l_{AC} \in L_{AC}, \forall h \in H :$

$$\begin{aligned} \mathrm{Flow}_{l_{AC},h} = & \sum_{i \in I} PTDF_{l_{AC},i} \cdot \mathrm{Exch}_{i,h} + \sum_{l_{pst} \in L_{pst} \subset L_{AC}} PSDF_{l_{AC},l_{pst}} \cdot \alpha_{l_{pst},h} \\ & + \sum_{l_{DC} \in L_{DC}} DCDF_{l_{AC},l_{DC}} \cdot \mathrm{Flow}_{l_{DC},h} \end{aligned} \tag{3.28}$$

3.1.8. Demand-Side Management

To consider DSM, the left-hand side of equation (3.2) is extended with two further decision variables $\mathrm{D}_{h,i}^{up}$ and $\mathrm{D}_{h,i}^{down}$, describing the increase and decrease of demand for every hour h and in each node i, (Kristin Dietrich, 2014). The demand can be shifted within a given time frame DT, i.e. reduced in hour h and increased within $[h, h+DT]$ or vice versa (see (3.30) and (3.31)), and by a certain percentage L_i^{up} and L_i^{down} of the demand in hour h.

$$Demand_{h,i} + \mathrm{D}_{h,i}^{up} - \mathrm{D}_{h,i}^{down} \tag{3.29}$$

$$\mathrm{D}_{h,i}^{up} = \sum_{h'=h}^{h+DT} \mathrm{D}_{h',h,i} \tag{3.30}$$

$$\mathrm{D}_{h,i}^{down} = \sum_{h'=h}^{h+DT} \mathrm{D}_{h,h',i} \tag{3.31}$$

$$\sum_{h'=h}^{h+DT} \mathrm{D}_{h,h',i} = \sum_{h'=h}^{h+DT} \mathrm{D}_{h',h,i} \tag{3.32}$$

$$0 \leq \mathrm{D}_{h,i}^{up} \leq L_i^{up} \cdot Demand_{h,i} \tag{3.33}$$

$$0 \leq \mathrm{D}_{h,i}^{down} \leq L_i^{down} \cdot Demand_{h,i} \tag{3.34}$$

3.1.9. RES-E Curtailment and Not supplied Energy

The remaining constraints consider RES-E curtailment of wind and PV, and limit the occurrence of Not Supplied Energy (NSE).

$\forall h \in H, \forall i \in I :$

$$0 \leq \mathrm{Spill}_{h,i}^{Wind} \leq Wind_{h,i} \tag{3.35}$$

$$0 \leq \mathrm{Spill}_{h,i}^{PV} \leq PV_{h,i} \tag{3.36}$$

$$0 \leq \mathrm{NSE}_{h,i} \leq Demand_{h,i} \tag{3.37}$$

3.1.10. Calculation of PTDF, PSDF and DCDF matrices

When applying the PTDF matrix approach, three assumptions are made (Van den Bergh, K, Delarue, and D'Haeseleer, 2014):

1. Line resistances are negligible compared to line reactances ($R_L << X_L$ lines). This implies that grid losses are neglected and line parameters are simplified.

$$G_L = \frac{R_L}{R_L^2 + X_L^2} \approx 0 \qquad B_L = \frac{-X_L}{R_L^2 + X_L^2} \approx -\frac{1}{X_L}$$

$$\underline{Z_L} \approx j \cdot X_L \qquad \underline{Y_L} \approx j \cdot B_L$$

2. The voltage amplitude is equal for all nodes (in per unit values).

$$|V_N| \approx 1p.u.$$

3. Voltage angle differences between neighbouring nodes are small. This results in a linearisation of the sine and cosine terms in the AC power flow equations.

$$sin(\delta_N - \delta_Q) \approx \delta_N - \delta_Q \qquad \cos(\delta_N - \delta_Q) \approx 1.$$

The matrix B_d is a symmetric L_{AC}-dimensional matrix with the susceptances of transmission power lines in the diagonal entries. The remaining entries are zero. The matrix A comprises the incidence matrix; it describes, which nodes are connected with each other. The PTDF, PSDF and DCDF matrices are calculated as follows (for details see (Van den Bergh, K, Delarue, and D'Haeseleer, 2014)):

$$PTDF^{L_{AC} \times I} = (B_d \cdot A) \cdot (A^T \cdot B_d \cdot A)^{-1} \tag{3.38}$$

$$PSDF^{L_{AC} \times L_{pst}} = B_d - (B_d \cdot A) \cdot (A^T \cdot B_d \cdot A)^{-1} \cdot (B_d \cdot A)^T \tag{3.39}$$

$$DCDF^{L_{AC} \times L_{DC}} = -PTDF \cdot A_{DC}^T \tag{3.40}$$

3.2. Procurement of Balancing Capacity

The capacity procurement is divided into aFRR and mFRR, which are equivalent to secondary and tertiary control reserve in Austria, Germany, Belgium and the Netherlands (ENTSO-E, 2015c). We assume, that the necessary upward (positive) and downward (negative) capacity per control area can be provided by thermal power plants, pumped hydro, hydro and other storages.

3.2.1. Objective function

In comparison to the power plant dispatch optimisation, the objective function additionally considers the costs for reserving capacity to balance possible occurring imbalances of generation and demand in control areas, which can occur in real-time. This implies, that not only the costs of electricity dispatch are minimised, but also the costs for procuring balancing capacity. In the objective function (3.41) weight factors $\omega_1 \in [0,1]$ and $\omega_2 \in [0,1]$ can be chosen, to determine, whether the costs of both markets are considered equally ($\omega_1 = \omega_2$) or the focus is on minimising the costs on one market only.

$$\min \omega_1 \cdot OF^{Wholesale} + \omega_2 \cdot OF^{Balancing} \tag{3.41}$$

with

$$\begin{aligned} OF^{Balancing} = & \sum_{\substack{h\in H,\\ ca\in CA, i\in I_{ca}}} \sum_{th\in TH_i} \sum_{j\in a,m} \overline{\text{thFRR}}^j_{h,th} \cdot \overline{TC}^j_{h,th} + \underline{\text{thFRR}}^j_{h,th} \cdot \underline{TC}^j_{h,th} \\ & + \sum_{ps} \overline{\text{psFRR}}^j_{h,ps} \cdot \max(p^{DA}_{h,i} - V^{H2O}_{h,ps}, C^{PS}) \\ & + \sum_{st} \overline{\text{stFRR}}^j_{h,st} \cdot \max(p^{DA}_{h,i} - V^{Stor}_{h,st}, C^{Stor}) \end{aligned} \tag{3.42}$$

for $j = \{a, m\}$ automatically and manually activated FRR, $h \in H = \{1, ..., 8760\}$ hour, $th \in TH_i$ thermal unit, $ps \in PS_i$ pumped hydro storage unit, $st \in ST_i$ other storage unit, $i \in I_{ca} = \{BG_1, ..., BG_n\}$ balancing group of control area $ca \in CA = \{APG, TenneT, ...\}$.

The total costs of procuring upward balancing capacity is considered as the sum of capacity costs and expected costs of possible delivery, divided into two cases: on the one hand, extramarginal power plants are characterized by short-run marginal costs that are greater than the (expected) wholesale market price, which means these power plants would not operate on the wholesale market when not taking into account the balancing market. However, for providing balancing power it must be running on minimal stable level during the bidding period. On the other hand, inframarginal, where the margin $p^{DA} - SRMC$ determines the opportunity costs of shifting capacity from the wholesale to the balancing market (see (Müsgens, Ockenfels, and Peek, 2014), (Hirth and Ziegenhagen, 2015)).

$$\overline{TC}^j = \begin{cases} (SRMC - p^{DA}) \cdot \frac{Cap_{th}^{min}}{CAP^R} + h \cdot SRMC & \text{, if } SRMC > p^{DA} \\ p^{DA} - SRMC + h \cdot SRMC & \text{, else.} \end{cases} \tag{3.43}$$

with $CAP^R = \min\{\Delta Cap \cdot t^*; Cap_{th}^{max} - Cap_{th}^{min}\}$ describing the possible balancing power capacity, which is either determined by the product of load gradient and activation time or by the difference between minimal and maximal technical load, and $h \in [0, 1]$ the ex-ante probability that a power plant's accepted capacities are called.

The considered costs of downward balancing capacity are as follows:

$$\underline{TC}^j = \begin{cases} (SRMC - p^{DA}) \cdot \frac{Cap_{th}^{min} - CAP^R}{CAP^R} & \text{, if } SRMC > p^{DA} \\ 0 & \text{, else.} \end{cases} \tag{3.44}$$

The resulting cost curves for up- and downward balancing capacity are shown in Figure 3.4 for the technologies gas, coal and oil, and three different efficiencies each, which reflect the age structure of thermal power plants.

3.2.2. Constraints for required balancing capacity products

The required balancing capacity for aFRR and mFRR has to be procured for every hour and the decision variables have to be positive.

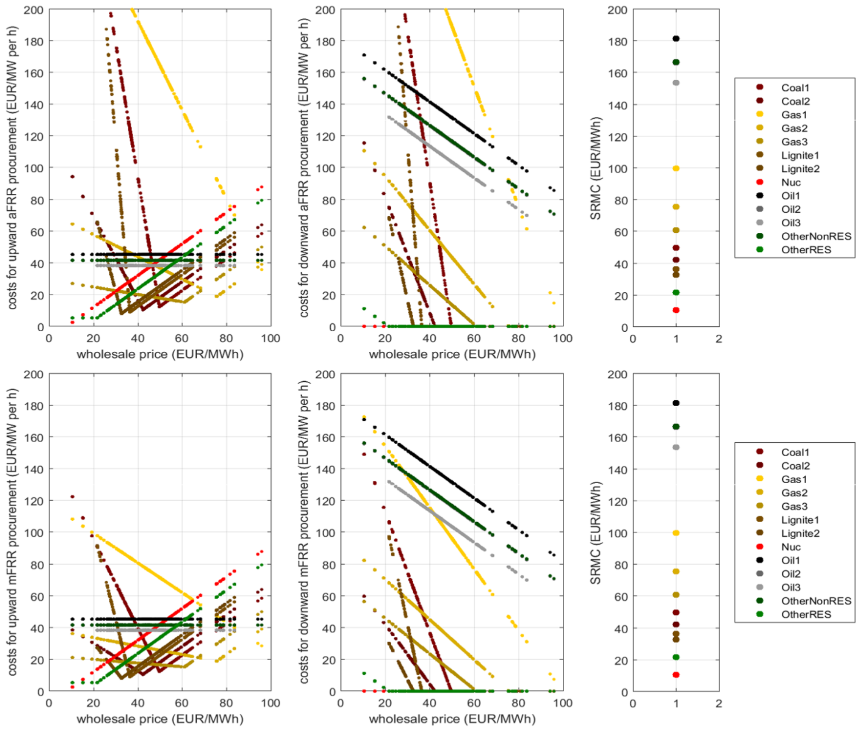


Figure 3.4.: Procurement costs of different technologies for up- and downward balancing capacity.

$\forall j \in \{a, m\}, \forall ca \in CA$ and $\forall h \in H$:

$$\sum_{\substack{th \in TH_i, ps \in PS_i, st \in ST_i \\ i \in I_{ca}}} \overline{\text{thFRR}}^j_{h,th} + \overline{\text{psFRR}}^j_{h,ps} + \overline{\text{stFRR}}^j_{h,st} \geq \overline{FRR}^j_{ca} \tag{3.45}$$

$$\sum_{\substack{th \in TH_i, ps \in PS_i, st \in ST_i \\ i \in I_{ca}}} \underline{\text{thFRR}}^j_{h,th} + \underline{\text{psFRR}}^j_{h,ps} + \underline{\text{stFRR}}^j_{h,st} \geq \underline{FRR}^j_{ca} \tag{3.46}$$

$$\overline{\text{thFRR}}^j_{h,th}, \underline{\text{thFRR}}^j_{h,th}, \overline{\text{psFRR}}^j_{h,ps}, \underline{\text{psFRR}}^j_{h,ps}, \overline{\text{stFRR}}^j_{h,st}, \underline{\text{stFRR}}^j_{h,st} \geq 0 \tag{3.47}$$

3.2.3. Consideration of Peak, Off-Peak and Weekend product time slots and weekly or daily procurement

In general, there are two different time categories known as Peak and Off-Peak. The Peak time is from Monday to Friday starting at 8am until 8pm. The remaining hours of the week are Off-Peak. Except in Austria, there was a third category called Weekend and it defined Saturday and Sunday until mid of 2017. The time series $Peak_h$ includes the information which hour belongs to which category, e.g. for Austria: 1 is Peak, 0 defines Off-Peak and -1 stands for Weekend. In Germany, Off-Peak includes also -1. Furthermore, the procurement can be organised weekly ($wd = 168$) or daily ($wd = 24$). Therefore, the following equations are applied in H/wd loops ($loop = [1, ..., H/wd]$) with $h_P \cdot \mathbb{I}_{\{Peak_h=1\}}, h_{OP} \cdot \mathbb{I}_{\{Peak_h=0\}}, h_{WE} \cdot \mathbb{I}_{\{Peak_h=-1\}} \in WD_{loop} = [(loop-1) \cdot wd + 1, ..., loop \cdot wd]$.

$$\overline{\text{thFRR}}^a_{h_P,th} = \overline{\text{thFRR}}^a_{h,th} \qquad \forall h \cdot \mathbb{I}_{\{Peak_h=1\}} \subset WD_{loop} \tag{3.48}$$

$$\overline{\text{thFRR}}^a_{h_{OP},th} = \overline{\text{thFRR}}^a_{h,th} \qquad \forall h \cdot \mathbb{I}_{\{Peak_h=0\}} \subset WD_{loop} \tag{3.49}$$

$$\overline{\text{thFRR}}^a_{h_{WE},th} = \overline{\text{thFRR}}^a_{h,th} \qquad \forall h \cdot \mathbb{I}_{\{Peak_h=-1\}} \subset WD_{loop} \tag{3.50}$$

Analogously it is applied for all units which provide aFRR, like $\overline{\text{psFRR}}^a_{h,ps}$ and $\overline{\text{stFRR}}^a_{h,st}$, as well as for downward.

3.2.4. Consideration of ramping limits of thermal power plants

Capacity offered for aFRR has to be available within five minutes, for mFRR within 15 minutes. The respective constraints for up- and downward aFRR are stated in equalities (3.51) and (3.52), based on the approach of (Müsgens, Ockenfels, and Peek, 2014).

$$\overline{\text{thFRR}}^a_{h,th} \leq \text{X}^Z_{h,th} \cdot \min\left\{Cap^{max}_{th}, \frac{ramp_{th}}{60} \cdot 5\right\} \tag{3.51}$$

$$\underline{\text{thFRR}}^a_{h,th} \leq \text{X}^Y_{h,th} \cdot \min\left\{Cap^{max}_{th} - Cap^{min}_{th}, \frac{ramp_{th}}{60} \cdot 5\right\} \tag{3.52}$$

3.2.5. Consideration of pumped hydro, hydro and other storages

PHS can provide up- and downward balancing capacity. The turbine and pumping capacities are significant values, but also the storage level variables cannot be neglected. In addition to the storage level equation (3.53), further equations are necessary (see also (Wulff, 2006) and (Y. Gebrekiros, G. Doorman, Jaehnert, et al., 2013)) to reflect the storage level changes of reserving a certain amount of turbine or pumping capacity for balancing (see equation (3.54)-(3.57)). The possible procurement of capacity for balancing purposes is limited by inequalities (3.58) and (3.59).

$$\mathrm{storL}_{h,ps} = \mathrm{storL}_{h-1,ps} - \frac{\mathrm{tuP}_{h,ps}}{\eta^{tu}} + \mathrm{puP}_{h,ps} \cdot \eta^{pu} + Infl_{h,ps} - \mathrm{Spill}^{PHS}_{h,ps} \tag{3.53}$$

$$\mathrm{storL}^{RV+}_{h,ps} = \mathrm{storL}^{RV+}_{h-1,ps} - \sum_j (\overline{\mathrm{psFRR}}^j_{h,ps})/\eta^{tu} \tag{3.54}$$

$$\mathrm{storL}^{RV-}_{h,ps} = \mathrm{storL}^{RV-}_{h-1,ps} + \sum_j (\underline{\mathrm{psFRR}}^j_{h,ps}) \cdot \eta^{pu} \tag{3.55}$$

$$En^{min}_{ps} \leq \mathrm{storL}_{h,ps} + \mathrm{storL}^{RV+}_{h,ps} \tag{3.56}$$

$$\mathrm{storL}_{h,ps} + \mathrm{storL}^{RV-}_{h,ps} \leq En^{max}_{ps} \tag{3.57}$$

$$\mathrm{tuP}_{h,ps} + \sum_j \overline{\mathrm{psFRR}}^j_{h,ps} \leq Cap^{Tu}_{ps} \tag{3.58}$$

$$\mathrm{puP}_{h,ps} + \sum_j \underline{\mathrm{psFRR}}^j_{h,ps} \leq Cap^{Pu}_{ps} \tag{3.59}$$

The formulations for other storages are equivalent, except for one detail: instead of natural inflows there are continuous discharges $\mathrm{DCharge}_{h,st}$ considered for other storages. These discharges can also be understood as a function or pattern of electricity demand of EVs. There are two possibilities to consider: either GtoV and VtoG or GtoV only ($\mathrm{stPOut}_{h,st} = 0 \quad \forall h \in H$).

$$\mathrm{storL}_{h,st} = \mathrm{storL}_{h-1,st} - \frac{\mathrm{stPOut}_{h,st}}{\eta^{stOut}} + \mathrm{stPIn}_{h,st} \cdot \eta^{stIn} - \mathrm{DCharge}_{h,st} \tag{3.60}$$

$$\mathrm{storL}^{RV+}_{h,st} = \mathrm{storL}^{RV+}_{h-1,st} - \sum_j (\overline{\mathrm{stFRR}}^j_{h,st})/\eta^{stOut} \tag{3.61}$$

$$\mathrm{storL}^{RV-}_{h,st} = \mathrm{storL}^{RV-}_{h-1,st} + \sum_j (\underline{\mathrm{psFRR}}^j_{h,st}) \cdot \eta^{stIn} \tag{3.62}$$

$$En^{min}_{st} \leq \mathrm{storL}_{h,st} + \mathrm{storL}^{RV+}_{h,st} \tag{3.63}$$

$$\mathrm{storL}_{h,st} + \mathrm{storL}^{RV-}_{h,st} \leq En^{max}_{st} \tag{3.64}$$

$$\mathrm{stPOut}_{h,st} + \sum_j \overline{\mathrm{stFRR}}^j_{h,st} \leq Cap^{Out}_{st} \tag{3.65}$$

$$\mathrm{stPIn}_{h,st} + \sum_j \underline{\mathrm{stFRR}}^j_{h,st} \leq Cap^{In}_{st} \tag{3.66}$$

3.2.6. Implicit allocation of transmission capacity for balancing

Originally, the common procuring of aFRR by several TSOs has been possible in the model only. The extension of implicit allocation for upward mFRR is shown in the following equations (inspired by (Hossein Farahmand, 2012)). The variable $\overline{\mathrm{Exch}}^j_{i,h}$ for $j = \{a, m\}$ describes the net amount of exchanged balancing capacity for upward aFRR and mFRR. It is defined by the sum over all transmission power lines, where a certain amount, described by $\overline{\mathrm{RCap}}^j_{l,h}$, is reserved for upward balancing between TSOs. The matrix $A_{l,i}$ describes which nodes are connected with each other. Inequality (3.68) sets the minimum required balancing capacity $\overline{FRR}^j_{ca}$ of the types aFRR and mFRR for each control area ca. These required balancing capacities can be either provided by thermal power plants $\overline{\mathrm{thFRR}}^j_{h,th}$, by pumped hydro storages $\overline{\mathrm{psFRR}}^j_{h,ps}$ or by other storages $\overline{\mathrm{stFRR}}^j_{h,st}$ within the same control area, or by units of another control area, if it is enabled $\overline{\mathrm{Exch}}^j_{h,i}$.

$$\overline{\text{Exch}}^{j}_{i,h} = \sum_{l} A_{l,i} \cdot \overline{\text{RCap}}^{j}_{l,h} = \begin{cases} + & \text{export upward FRR} \\ - & \text{import upward FRR} \end{cases} \tag{3.67}$$

$$\sum_{th,ps,st,i} \overline{\text{thFRR}}^{j}_{h,th} + \overline{\text{psFRR}}^{j}_{h,ps} + \overline{\text{stFRR}}^{j}_{h,st} - \overline{\text{Exch}}^{j}_{h,i} \geq \overline{FRR}^{j}_{ca} \tag{3.68}$$

Inequalities (3.69) and (3.70) describe the transmission lines' limitations. The transmission capacity can be either used for wholesale electricity market clearings or can be reserved for balancing purposes. The variable $\overline{\text{RCap}}^{a}_{l,h}$ is the reserved transmission capacity for upward aFRR and $\overline{\text{RCap}}^{m}_{l,h}$ represents mFRR. In addition, $z_l \in [0,1]$ indicates on which line transmission capacity can be reserved or how much of total transmission capacity can be used for balancing purposes.

$$-(\overline{\text{RCap}}^{a}_{l,h} + \overline{\text{RCap}}^{m}_{l,h}) \leq CapL^{B\to A}_{l} + \text{Flow}_{l,h} \tag{3.69}$$

$$-CapL^{B\to A}_{l} \cdot z_l \leq \overline{\text{RCap}}^{a}_{l,h} + \overline{\text{RCap}}^{m}_{l,h} \leq CapL^{A\to B}_{l} \cdot z_l \tag{3.70}$$

Analogously, it is applied to downward aFRR and mFRR. One important distinction compared to upward FRR is, that the meaning of the algebraic signs switches due to the need of reserving transmission capacity in a reversed manner. For downward FRR, positive values of the variable $\underline{\text{Exch}}^{j}_{i,h}$ mean downward capacity is imported and negative equals export. Thus the algebraic sign changes in inequality (3.72) as well.

$$\underline{\text{Exch}}^{j}_{i,h} = \sum_{l} A_{l,i} \cdot \underline{\text{RCap}}^{j}_{l,h} = \begin{cases} + & \text{import downward aFRR} \\ - & \text{export downward aFRR} \end{cases} \tag{3.71}$$

$$\sum_{th,ps,st,i} \underline{\text{thFRR}}^{j}_{h,th} + \underline{\text{psFRR}}^{j}_{h,ps} + \overline{\text{stFRR}}^{j}_{h,st} + \underline{\text{Exch}}^{j}_{h,i} \geq \underline{FRR}^{j}_{ca} \tag{3.72}$$

$$\underline{\text{RCap}}^{a}_{l,h} + \underline{\text{RCap}}^{m}_{l,h} \leq CapL^{A\to B}_{l} - \text{Flow}_{l,h} \tag{3.73}$$

$$-CapL^{B\to A}_{l} \cdot z_l \leq \underline{\text{RCap}}^{a}_{l,h} + \underline{\text{RCap}}^{m}_{l,h} \leq CapL^{A\to B}_{l} \cdot z_l \tag{3.74}$$

3.3. Validation of the EDisOn+Balancing model

The model is validated with empirical data derived from the 'Yearly Statistics & Adequacy Retrospect (YS&AR)' from 2013 published by ENTSO-E, (ENTSO-E, 2014a), and the current balancing market design of the countries mentioned below, see (ENTSO-E, 2015c). The geographical scope comprises Central Europe, i.e., the control areas of Austria (APG), Germany[5] (TenneT, TransnetBW, Amprion and 50Hertz), Belgium (ELIA) and the Netherlands (TenneT NL). For these countries the balancing market mechanisms are applied. The remaining neighbouring countries like Poland, Czech Republic, Slovakia (no direct interconnection to Austria), Hungary, Slovenia, Italy, Switzerland and France are considered for wholesale market clearings only. The respective areas are shown in Figure 3.5. In order to keep computational efforts in an acceptable range, the aggregated electricity grid, with transmission capacities of 2013, as shown in Figure 3.2 is used for simulating the balancing market mechanisms. The detailed transmission system is more suitable for evaluating transmission line expansions.

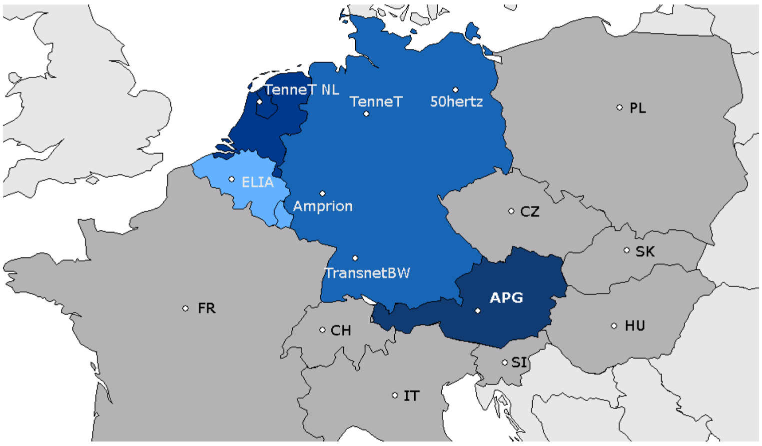


Figure 3.5.: Geographical scope of simulations; blue: balancing and wholesale market, dark grey area: wholesale market consideration only.

The electricity generation resulting from the EDisOn model is compared with the generation structure published in the YS&AR 2013. The graphical comparison

[5]Germany is the only European country with four control areas and corresponding TSOs.

is shown in Figure 3.6. The actual electricity production of hydro, RES-E and thermal power plants for the year 2013 is represented by the electricity dispatch model.

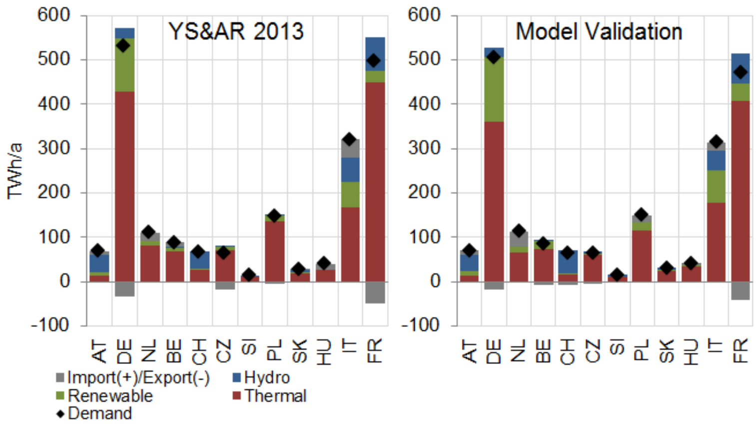


Figure 3.6.: Comparison of simulated electricity generation and YS&AR 2013 data.

The comparison of the resulting balancing capacity prices for the Austrian control area APG (data source: (Austrian Power Grid, n.d.)) with the actual values of 2012 to 2014 show, that the annual average prices for procuring upward aFRR and mFRR are represented adequately by the model. In 2015 daily auctions were introduced, therefore the prices decreased significantly. The costs for downward aFRR and mFRR in Austria are underestimated[6] by the model, see Table 3.7 for upward aFRR and mFRR[7] for Austria and Table 3.8 for the German balancing areas.

The comparison of the German balancing products show that the simulated average annual up- and downward aFRR and downward mFRR prices are in the range of the actual annual values of 2014 to 2016. Whereas the upward mFRR products are overestimated[8] by the model.

[6]The reason could be the underestimation of opportunity costs of pumped hydro storages.

[7]aFRR: OP = Off-Peak Mo-Fr 0:00-8:00 and 20:00-24:00, P = Peak Mo-Fr 8:00-20:00, WE = Weekend Sa-Su; mFRR: six 4-hour products

[8]The upward prices are strongly influenced by the assumed ex-ante probability in definition (3.43) that a power plant's accepted capacities are called. For the analysis, an identical probability of being called is assumed for all accepted bidders. A possibility to get closer to the actual values would be to assume a smaller probability for power plants within the German

Annual average aFRR capacity prices (EUR/MW.h)

APG	OffPeak +	OffPeak -	Peak +	Peak -	Weekend +	Weekend -	
Model Results	17,22	1,10	21,78	0,01	12,46	1,90	weekly
2013	16,73	23,17	14,85	9,00	15,83	29,14	weekly
2014	10,79	17,69	7,58	7,72	8,36	21,58	weekly
2015	3,99	5,62	2,65	3,48	3,15	5,43	weekly & daily

Annual average mFRR capacity prices (EUR/MW.h)

APG	00-04 +	04-08 +	08-12 +	12-16 +	16-20 +	20-24 +	00-04 -	04-08 -	08-12 -	12-16 -	16-20 -	20-24 -
Model Results	1,18	3,06	4,84	4,38	5,51	4,67	1,64	0,60	0,21	0,37	0,10	0,30
2013	1,68	3,51	6,50	4,47	6,65	4,11	17,15	17,78	8,11	9,31	8,49	7,52
2014	0,97	1,70	3,23	1,60	4,32	1,89	14,35	14,00	6,46	7,20	5,22	5,88
2015	0,40	0,91	2,86	1,71	4,49	0,77	11,19	10,74	3,91	4,52	2,46	5,69

Figure 3.7.: Annual average balancing capacity prices (EUR/MW.h) of up- (+: positive) and downward (-: negative) aFRR and mFRR products for the Austrian control area.

Annual average aFRR capacity prices (in EUR/MW.h)

DE	OffPeak +	OffPeak -	Peak +	Peak -
Model Results	8,81	4,48	15,04	3,15
2014	7,40	4,68	7,72	5,09
2015	5,58	2,59	5,93	1,78

Annual average mFRR capacity prices (in EUR/MW.h)

DE	00-04 +	04-08 +	08-12 +	12-16 +	16-20 +	20-24 +	00-04 -	04-08 -	08-12 -	12-16 -	16-20 -	20-24 -
Model Results	5,19	5,49	6,20	6,15	6,47	5,85	2,65	3,54	2,98	2,80	2,69	2,63
2014	0,04	0,26	0,81	0,54	0,94	0,60	5,80	5,47	2,96	3,74	2,78	2,41
2015	0,03	0,27	0,79	0,28	1,36	0,38	3,24	3,05	1,50	1,70	1,28	1,37

Figure 3.8.: Annual average balancing capacity prices (EUR/MW.h) of up- (+: positive) and downward (-: negative) aFRR and mFRR products for the German control areas.

balancing area.

4. Results and Sensitivities

4.1. Power Plant Dispatch and the Transmission Grid

4.1.1. Aggregated grid for Austria's neighbouring electricity system

This study elaborates on the costs and benefits of expanding the Austrian transmission system and the implementation of innovative grid-impacting technologies (e.g. flexible AC transmission systems (FACTS), Dynamic Line Rating (DLR)) to support further integration of RES-E. Therefore, the fundamental market model EDisOn has been developed - respecting DC load flows - and applied for analysing different future scenarios, notably for the time horizon 2020, 2030 and 2050. Up to 2020 and 2030, special focus is put on the finalisation of the so-called "380 kV-level transmission ring" in Austria to enable enhanced RES-E integration. The results confirm that transmission power line expansion in the states of Salzburg and Carinthia is important to connect imports from Germany with pumped hydro storage capacities, on the one hand, and the wind farms in the east with the pumped hydro storages in the western part of Austria, on the other hand. For 2050, the results indicate that the implementation of FACTS and DLR can reduce RES-E curtailment significantly.

The hourly simulation results of the different scenarios provide the basis for calculating the electricity system benefits (welfare, congestion rent, fossil fuel consumption, CO_2 emissions and others). For the evaluation of the benefits key performance indicators are defined and used as shown in Table 4.1, see also (L'Abbate, 2014).

In this section selected results are presented. The corresponding assumptions, information on input data and additional simulation results of 2030 can be found in (Burgholzer, Lettner, and Auer, 2015).

Table 4.1.: Key performance indicators.

Benefit/Aspect	Explanation of the key indicators	Parameters
social welfare increase	ability of a power system to reduce congestion as a basis for an efficient market	welfare, producer and consumer surplus, congestion rents
system reliability	adequate and secure supply of electricity	NSE, load factors of power lines and generation capacity margins
CO_2 emissions reduction	CO_2 emissions in the power system	CO_2 emissions
RES-E spillage reduction	reduce RES-E curtailed energy	$\text{Spill}^{\text{Hy}}, \text{Spill}^{\text{WindPV}}$
controllability & flexibility	possibility to control power flows and different possible future development paths	type of grid technology
socio-environmental impact	public acceptance and environmental impact	type of expanded TPL

Selected scenarios for the time horizon 2020

For the time horizon 2020 in Austria it is important to extend the interconnection to Germany, mainly due to high import expectations of RES-E generation from Germany. Therefore, the expansion of the transmission power line in Salzburg (see power line between node "SBG_n" and "SBG_s" in Figure 4.1) is necessary to connect the imports with the high PHS capacities in the Alps. Furthermore, the extension in Salzburg is of high interest for closing the 380 kV circle in Austria, which is necessary for guaranteeing sufficient security and reliability of supply. In addition, the interconnection to Italy will also be extended. In Table 4.2 the selected scenarios for 2020 are defined.

Table 4.2.: Defined scenarios for the year 2020.

Scenario	2020
(2020 A)	Reference scenario
(2020 B)	with 380 kV expansion in Salzburg

Simulation results show that due to the power line expansion in Salzburg electricity generation of renewables can be slightly increased, especially the utilisation of PHS plants is enhanced. Also thermal generation increases and in this case a fraction of electricity generation from gas-fired power plants is replaced by the much more polluting coal technology. This can be explained for two

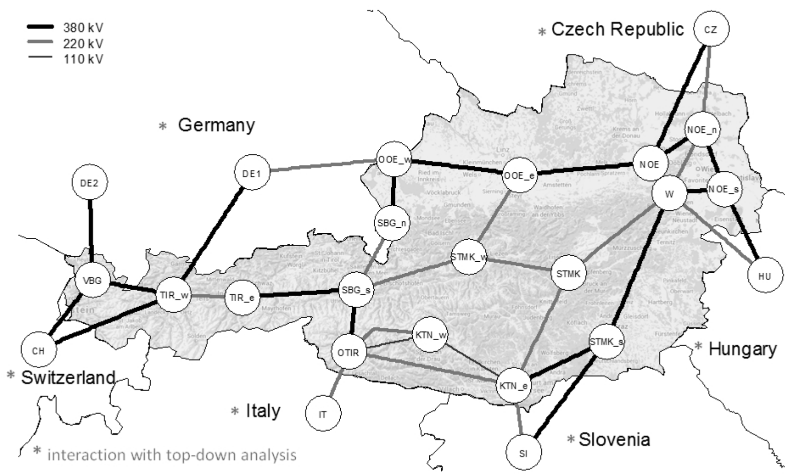


Figure 4.1.: Austrian transmission grid model for the year 2020.

reasons: firstly, the CO_2 certificate price is low; therefore, electricity generation of coal-fired power plants is cheaper than gas-fired power plants. Secondly, the transition to a more flexible grid allows transferring excess generation of coal power plants to the load centres, see Figure 4.2.

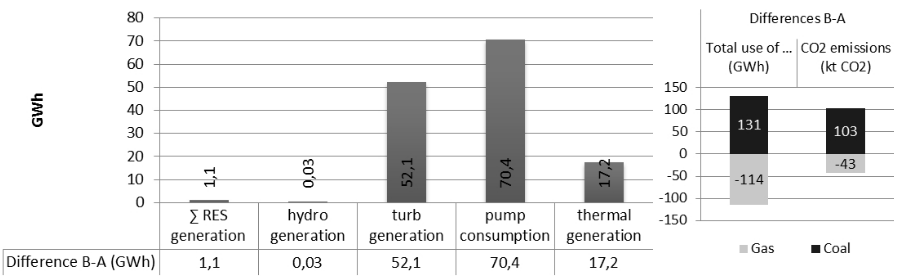


Figure 4.2.: Differences in the generation structure for the (2020 B) case compared to (2020 A).

The cumulative number of hours of transmission power lines with load factors higher than 70% is reduced in the (2020B) scenario compared to scenario (2020A), see Figure 4.3. In particular, for the expanded power line in Salzburg no load factor exceeds 70% in scenario (2020B). The average number of hours for the 23 power lines within Austria can be reduced by around 15%, from 976 to 832 hours per line.

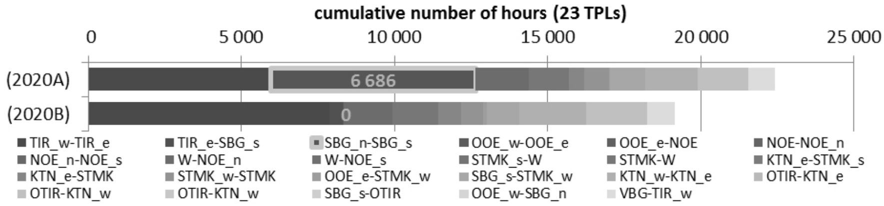


Figure 4.3.: Cumulative number of hours of transmission power lines with load factors higher than 70% for the 2020 cases.

Other important parameters determining security and reliability of supply are Not Supplied Energy (NSE). For the time horizon 2020 for both scenarios there exists no hour where NSE occurs. The electricity generation of RES-E is curtailed in a few hours. Spillages of RoR emerge in scenario A and B in 8 hours; wind is curtailed in scenario A in 4 hours and in B 6 hours. However, RES-E curtailment can be reduced by 41 MWh/a due to the power line expansion.

The implication of all above mentioned facts is that the total generation costs for electricity in Austria are reduced by 0.64 % compared to the base case, which is in absolute numbers 2.1 MEuro/a. In addition, the wholesale electricity prices are slightly lower in scenario (2020B).

An additional important variable in terms of transmission power line expansion is the achievable annual congestion rent, which is calculated for two markets A and B as follows:

$$CR = |p_A - p_B| \cdot Flow_{A-B}$$

The variables p_A, p_B are the price vectors of the two markets and $Flow_{A-B}$ is the vector of the power flows on the considered power line between these two markets.

Assuming a nodal pricing system in Austria an annual congestion rent of around 235 kEuro/a amounts on the transmission power line in Salzburg for scenario (2020A). In this case the annual average price levels of the two considered nodes are slightly different only; the mean price in node "SBG_n" is 0.28 Euro/MWh higher than in "SBG_s". After the power line expansion the prices in the nodes converge and reach the same level on average. Due to the converging prices the congestion rent is reduced in scenario (2020B). Only around 11.8 kEuro/a are earned, which are just 5% of the (2020A) scenario.

An implication of the above mentioned changes is that a nodal pricing approach within a control area would not provide enough incentives to invest in extending the transmission power line in Salzburg. Therefore, regulated grid tariffs are still necessary to guarantee sustainable transmission grid investments in the future.

Table 4.3 provides an overview of the key performance indicators for the two cases of the time horizon 2020, summarising the results of the previous paragraphs. It becomes clear, that the expansion of the 220 kV-level transmission power line in Salzburg and the extension of the German interconnection via Bavaria have positive effects on the Austrian transmission grid, except the socio-environmental impact (reflecting public acceptance) is negative. The increase of CO_2 emissions is around 1%. Therefore, the evaluation is zero. In addition, the upgrade to a 380 kV-level power line in Salzburg is necessary to achieve a closed 380 kV circuit in Austria in the near future guaranteeing sufficient security of supply.

Table 4.3.: Key performance indicators for 2020 cases.

Benefit/Aspect	social welfare increase	system reliability	CO_2 emissions reduction	RES-E spillage reduction	controllability & flexibility	socio-environmental impact
(2020 A) Base	0	0	0	0	0	0
(2020 B) Expansion	+	+	0	+	+	-

Selected scenarios for the time horizon 2050

In 2050 a RES-E share of 64% is assumed for Austria, especially the increase of wind and PV capacity is significant. In order to provide more flexibility in the transmission system one focus is on the analysis of impacts resulting from the application of DLR and FACTS. The second emphasis is put on the extension of PHS capacities (turbine as well as pumping capacity), which provides more flexible generation and additional storage potentials to neighbouring countries, e.g. Germany. Furthermore, the impact of high/low annual production of RoR is analysed. Finally, the focus of analysis is put on the first possible interconnection to Slovakia, a 2 GW High-Voltage Direct Current (HVDC) line. An overview of the selected scenarios is provided in Table 4.4.

Table 4.4.: Defined scenarios for the year 2050.

Scenario	2050
(2050 A)	Reference scenario
(2050 D)	with FACTS & DLR
(2050 F)	high PHS, FACTS & DLR
(2050 r)	-33.3% RoR
(2050 SK)	HVDC SK-AT

For the first scenarios the differences in electricity generation show that the transition to a flexible transmission grid leads to an increase of RES-E generation (see Figure 4.5). In contrast, electricity generation of thermal power plants is reduced (see Figure 4.4). Additionally, the utilisation of PHS plants diminishes except for scenario (2050r), due to less annual electricity generation of RoR plants. For the other scenarios the need for PHS is slightly reduced, which is a result of the more flexible transmission system or because of additional imports from Slovakia as it is for the case (2050 SK). The differences in generation structure of RES-E, RoR and PHS generation for the year 2050 are shown in Figure 4.5.

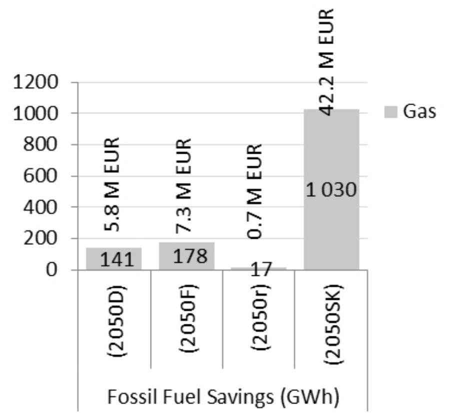


Figure 4.4.: Fossil fuel savings (in GWh) for the 2050 cases and the resulting monetary values.

As mentioned above, electricity generation of thermal power plants is reduced in all 2050 scenarios compared to the base case. The fossil fuel savings are shown in Figure 4.4 both in GWh as well as their monetary values. As a result of additional imports from Slovakia thermal generation diminishes by 12% in scenario (2050 SK).

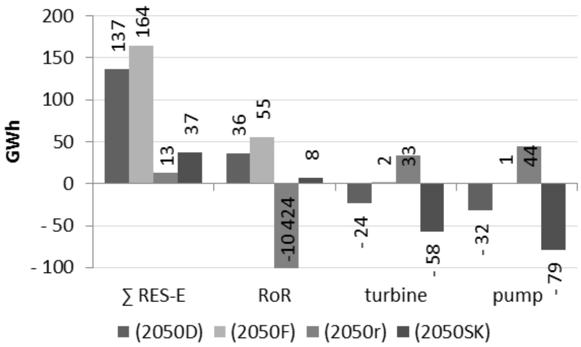


Figure 4.5.: Differences in the generation structure for the 2050 cases compared to (2050 A).

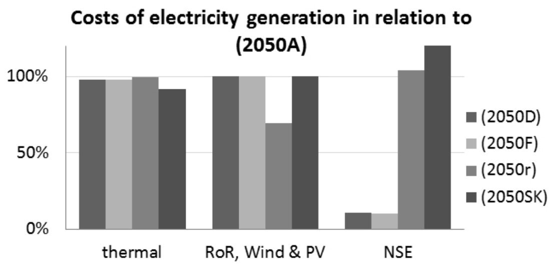


Figure 4.6.: Electricity generation costs in relation to scenario (2050 A).

The annual electricity generation costs of the analytical objective function (see (3.1)) can be split into costs of thermal generation (1282 MEuro/a), RoR, wind and PV generation costs (34 MEuro/a) and costs for NSE (717 MEuro/a). These values are shown in Figure 4.6 in relation to the base case. The costs of NSE for the cases (2050 r) and (2050 SK) are higher than for the reference scenario. From this result it can be concluded that for 2050 it is necessary to achieve a more flexible transmission grid in Austria to guarantee electricity transmission without congestion and to avoid re-dispatch measures and NSE.

An annual congestion rent of 86 MEuro/a could be earned on the new 2 GW SK-AT HVDC interconnection with the assumptions made. In Figure 4.7 the hourly congestion rent, nodal prices of Austria and Slovakia and the hourly load factors of the transmission power lines are shown for the week, where the maximum of the congestion rent occurs.

The major results for the 2050 analysis are summarised (as for the 2020 analysis in Table 4.3) in Table 4.5.

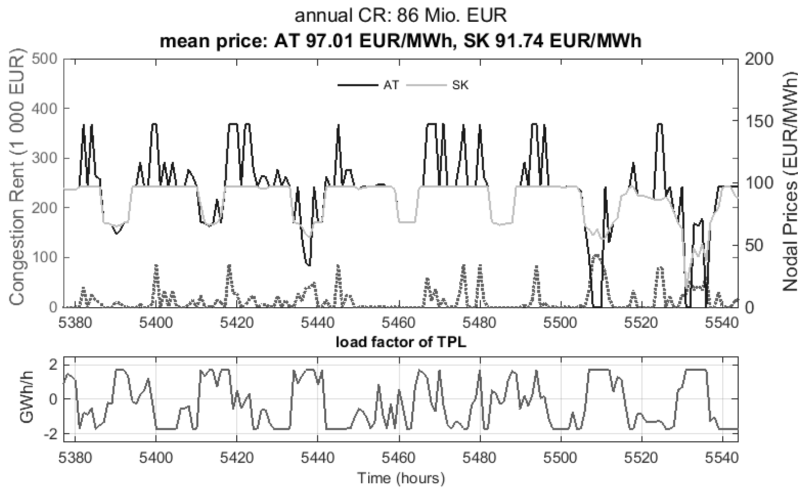


Figure 4.7.: Selected week indicating the congestion rent of the 2 GW HVDC connection to Slovakia.

Particularly the application of DLR is very encouraging and cost effective. In the analysed cases there is, on the one hand, a strong positive correlation between large amounts of wind generation and cooling of the overhead lines by wind (therefore, curtailment of wind can be significantly reduced). But, on the other hand, it must be kept in mind that in case large amounts of power (non-wind related RES-E or conventional generation) have to be transported during periods with low wind speeds, DLR is less effective and the upgrade of lines will be the preferable solution to increase grid transfer capacity.

Conclusions

The major conclusions of the Austrian case study analyses for the time horizons 2020 and 2030 (see (Burgholzer, Lettner, and Auer, 2015) for more details) are that transmission power line expansions (from 220 kV to 380 kV-level) in Salzburg and Carinthia are quite important for closing the Austrian 380 kV circle and, therefore, to guarantee transmission adequacy in Austria up to 2030. The future Austrian 380 kV circuit also provides a significant contribution for enhanced national and European RES-E integration; especially for Austria it is

Table 4.5.: Key performance indicators for 2050 cases.

Benefit/Aspect	social welfare increase	system reliability	CO_2 emissions reduction	RES-E spillage reduction	controllability & flexibility	socio-environmental impact
(2050 A) Base	0	0	0	0	0	0
(2050 D) FACTS & DLR	++	+	+	++	++	0
(2050 F) High PHS, FACTS & DLR	++	+	+	++	++	-
(2050 r) -33.3 % RoR	0	0	0	0	0	0
(2050 SK) HVDC SK-AT	0	0	++	+	+	-

important to foster the connection of wind farms in the eastern part and PHS in the west.

For the time horizon 2050 the analyses of the different scenarios indicate that the implementation of innovative transmission technologies like FACTS and DLR can reduce RES-E curtailment significantly. Thus, more flexibility in the transmission grid will be necessary to support the optimal integration of all electricity produced by renewable technologies. The major implication from the Cost/Benefit Analysis in terms of congestion rent is that the revenues earned mainly contribute to cover the cost of expansions of cross-border interconnections, due to the prevailing differences in zonal prices in Europe. As a consequence, regulated grid tariffs are still necessary in the future to finance transmission expansion, especially within control zones.

Last but not least, the regional analyses of Austria confirm the time line of the Austrian Masterplan 2030 (APG, 2013), having been published by the Austrian transmission system operator Austrian Power Grid. In addition, the implementation of DLR and/or FACTS could achieve further supplementary flexibility in the Austrian transmission grid.

4.1.2. Detailed grid for Central Europe

In this study a sensitivity analysis on varying RES-E penetration in Central Europe and Austria is conducted for 2030. Bottlenecks in the Austrian transmission grid are identified and categorised, whether they are resulting from developments in Austria or neighbouring Central European[1] countries. The annual and hourly average transmission line utilisations for critical line elements are analysed in detail and line segments with high relevance to security of supply are emphasised. Finally, the need of firm capacity and coverage of annual peak (residual) load in the year 2030 are assessed.

As a starting point for the year 2030, the projects of the APG Master Plan 2030 (APG, 2013) and the national Network Development Plan (APG, 2016) are assumed to be implemented, (see illustration A.2 in the appendix). In addition, the projects of the TYNDP 2016 (ENTSO-E, 2015b) are considered in the European context. Phase shifters are not taken into account in grid modelling.

The four defined scenarios are summarised in Table 4.6. In addition, to the two main scenarios, which on the one hand adopt a conservative (2030-REF) and, on the other hand, an optimistic development path for renewable energy (2030-RES), two more sensitivities are analysed. They are used to investigate opposing developments in Austria compared to the remaining Central European countries considered. The development paths of renewable energy for the neighbouring countries are based on Vision 1 and Vision 3-2030 from TYNDP 2016, see (ENTSO-E, 2015e).

Table 4.6.: Analysed scenarios and assumed installed capacities in Austria and in the neighbouring Central European countries.

Scenario	Austria	Neighbouring countries
2030–REF	reference	Vision 1 - 2030
2030–RES	high RES-E	Vision 3 – 2030
2030–SensREF	reference	Vision 3 – 2030
2030–SensRES	high RES-E	Vision 1 - 2030

The following figure shows the annual generation structure of the Central European countries considered in detail. A distinction is made between import/export (positive/negative), generation of hydro power (pumped storage, storage and

[1]The respected countries are: FR, BE, NL, DE, PL, CZ, SK, HU, SI, IT and CH.

run-of-river power stations), generation from thermal power plants (gas, hard coal, lignite, oil, other non-renewable and nuclear) and renewable energy (PV, wind and biomass etc.). In addition, the annual electricity demand per country is shown.

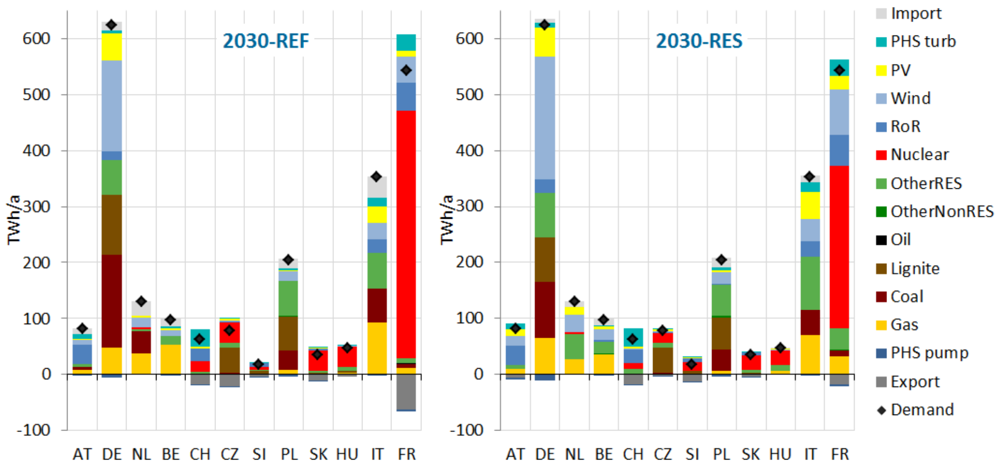


Figure 4.8.: Generation structure for scenario 2030-REF and 2030-RES.

The decline in power generation from thermal power plants in scenario 2030-RES compared to scenario 2030-REF, especially nuclear, hard coal and lignite on the one hand, and the increase in renewable electricity generation in Central European countries, can be clearly recognised on the other hand. Figure 4.9 shows an example of hourly electricity generation for Austria, Germany and the Czech Republic. These three countries have got with significant differences: in Austria, hydro power is the prevailing technology; in Germany, wind power and in the Czech Republic mainly lignite and nuclear power plants.

For Austria, electricity generation from renewable energy sources for all four scenarios is shown in Figure 4.10. The most significant changes occur for the feed-in of biomass, PV and wind energy due to the assumed capacity expansions. In scenario 2030-RES, the annual electricity load in Austria can be covered to almost 100% from renewable energy sources, whereas in scenario 2030-REF only 73% can be covered. The power plant fleet of neighbouring countries has only limited influence on the generation of renewable energy sources in Austria, cf. scenario 2030-REF with 2030-SensREF and 2030-RES with 2030-SensRES. The

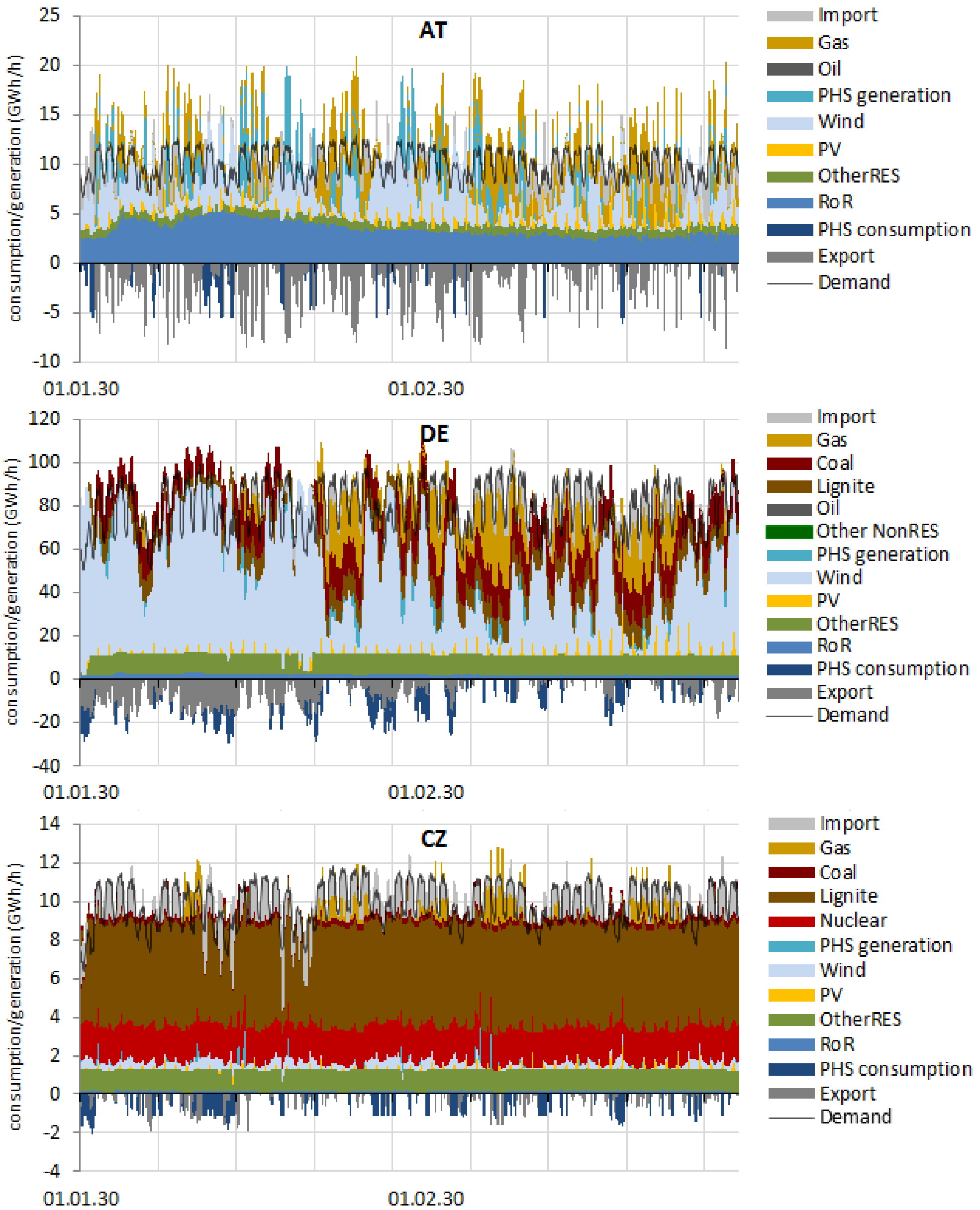


Figure 4.9.: Exemplary electricity generation in Austria, Germany and the Czech Republic for January and February for scenario 2030-RES.

influence mainly affects the pumped hydro storage power plants, with regard to SensREF the storage consumption increases by 150%, which is due to a high renewable share in the neighbouring countries on the one hand. On the other hand, storage use in the SensRES scenario is reduced by 50% (lower proportion of renewable generation in the surrounding Central European countries).

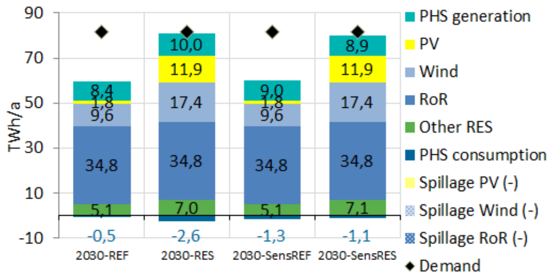


Figure 4.10.: Annual electricity generation of renewable energy sources in detail for Austria.

Evaluating Austria's residual load curves regarding supply-dependent power generation, it can be stated that the curve shifts downwards due to the significant increase in renewable energy sources, resulting in a negative residual load for more than 2000 hours in 2030-RES. This corresponds to about 23% of the year, i.e. renewable energy sources can fully meet Austrian electricity demand during these hours and the surplus can be exported to neighbouring countries. The significant changes in residual load of the considered neighbouring countries also have an influence on the electricity flows within Central Europe, thus Austria is a net importer of electricity in the REF scenarios and a net exporter in the RES scenarios, see Figure 4.11. In addition, the historical physical electricity flows for 2013, 2014 and 2015 are presented, (ENTSO-E, 2014a), (ENTSO-E, 2015a) and (ENTSO-E, 2016b). Especially for the electricity flows to Germany there are deviations from the historical values. This is an effect of the enormous reduction of thermal power generation by about 40% compared to the scenario 2030-RES in Germany (SFS 2015: 86.8 TWh/a nuclear and 319.5 TWh/a from fossil production) or the considerable changes of the electricity generation structures in the remaining Central European countries.

Identified bottlenecks in the Austrian transmission grid

In order to answer the question whether the implementation of the assumed generation structure leads to significant bottlenecks in the Austrian transmission

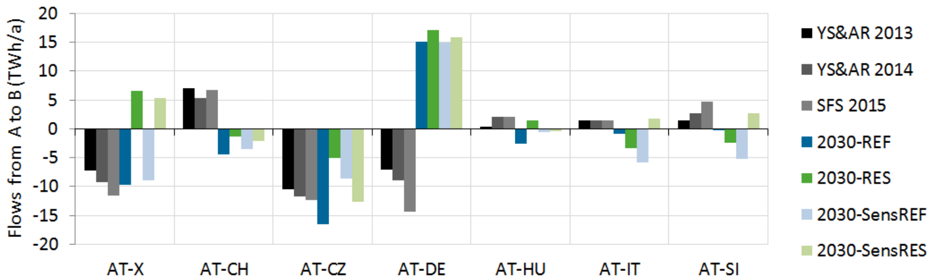


Figure 4.11.: Electricity flows to and from Austria (in TWh/a), positive: Austria exports, negative: Austria imports.

grid, in addition to the planned expansion according to (APG, 2013) and (APG, 2016), the following modelling results are considered:

- the number of hours when transmission lines are more than 80% utilised,
- the hourly and average line utilisation of simulated scenarios are analysed
- and by which generation structure the high utilisation is conditional.

It should be mentioned once again that the simulations are an electricity market modelling with a linearisation of optimal power flow. The underlying transmission grid includes lines with a voltage from 110 kV to 380 kV and the HVDC transmission lines. The principle of (n-1) security in electricity grid planning means that in a grid with predicted maximum transmission and supply tasks, network security remains ensured even if a component, such as a transformer or a circuit, fails or is shut down. Compliance with this principle is ensured by means of the 80% hurdle. This hurdle corresponds to an optimistic estimate of the (n-1) criterion.

In Table 4.7, the average number of hours in which a transmission line is utilised more than 80% is listed separately for the whole region and for Austria. It can be seen that every transmission line in Austria is on average overloaded in 5% of the year (438 hours). This result does not allow a definitive statement about possible or exact bottlenecks in the Austrian transmission system. However, given the increased values for Austria in the 2030-RES and 2030-SensRES scenarios, it can be seen that the increased expansion of PV and wind has significant effects on the electricity grid. The same applies to the Central European electricity system, where an ambitious expansion of renewable energies is assumed for the scenarios 2030-RES and 2030-SensREF.

Table 4.7.: Exceeding 80% of thermal limit (Average number of hours per transmission line).

Scenario	**Central European System** ($x > 80\%$)	**Austria** ($x > 80\%$)
2030–REF	523	441
2030–RES	645	503
2030–SensREF	645	368
2030–SensRES	520	535

For a more detailed overview, see Figure 4.12, where the 88 Austrian transmission power lines are listed individually showing the number of hours where the 80% of thermal limit is exceeded for the four scenarios. In addition, the limit of 5% is marked, e.g. for scenario 2030-REF. Thus, the following statement can be made: 13 of the 88 lines are utilised above average and the remaining are under 5% of the year overloaded. In contrast, scenario 2030-RES shows an average value of 5.7% with 20 lines that are above average. For the entire Central European electricity system, 6% (526 hours) with 463 out of 3050 transmission lines are operating above this value and for scenario 2030-RES 7.4% with 584 transmission line segments.

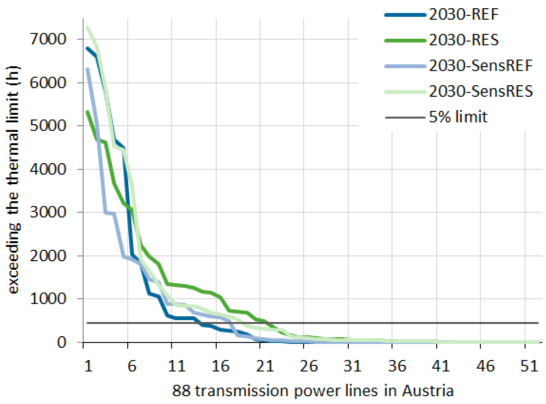


Figure 4.12.: Exceeding 80% of thermal limit for the 88 Austrian transmission power lines.

Figure 4.13 shows graphically the annual average utilisation of Austria's electricity system for the individual scenarios. At first glance, no increased workloads or overloads can be identified. However, various statements can be made regarding the impact of developments abroad (Category I) or in Austria (Category II) based on the utilisation of transmission lines in Austria.

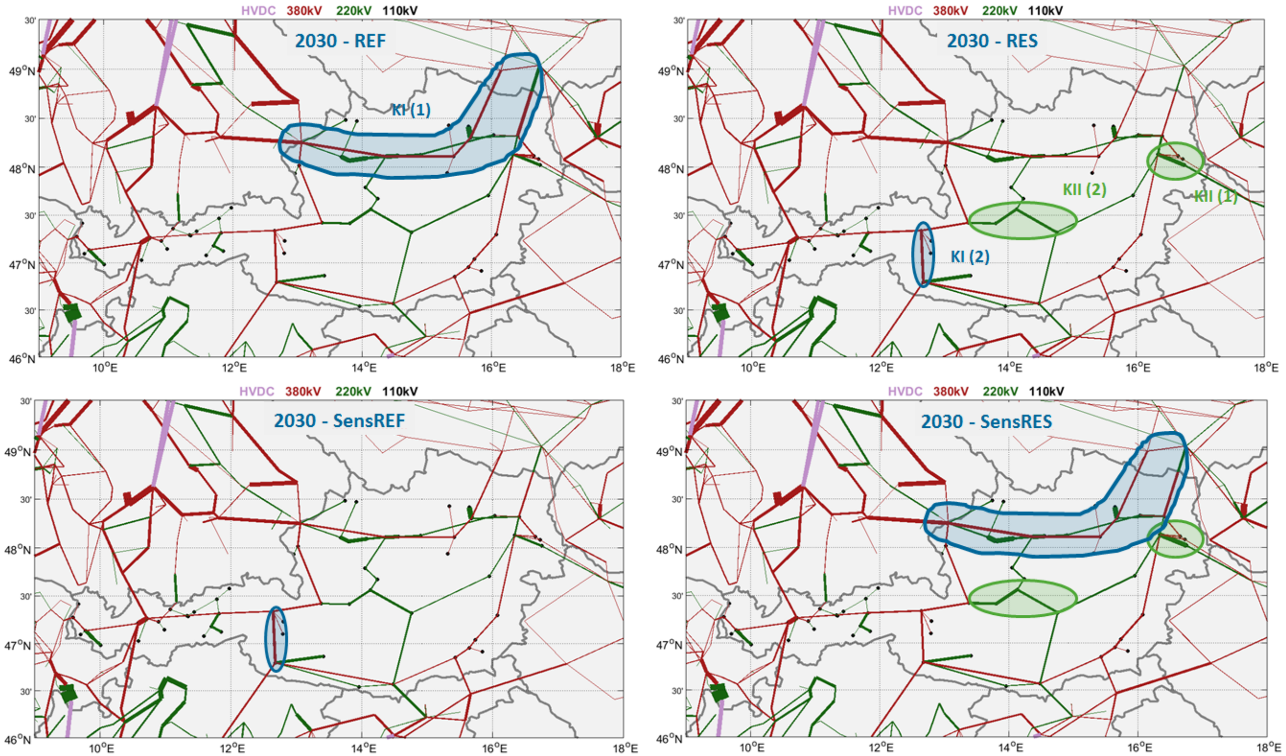


Figure 4.13.: Average annual capacity utilisation of Austria's electricity transmission system, the wider the bars, the higher the utilisation or use of the transmission line.

Category I:

(1) The 380 kV Danube transmission system (West-East link) and the 380 kV circuit in the scenarios 2030-REF and 2030-SensRES (in both cases a conservative expansion of renewable energy sources is assumed in neighbouring countries) have the desired effect and are only about 46% utilised.
(2) The Lienz-Tauern transmission segment is utilised on average by 52% in scenarios 2030-RES and 2030-SensREF (optimistic expansion of renewable energy sources in neighbouring countries) and only 38% in the other scenarios. This confirms that the network projects already implemented allows a strong interaction of pumped hydro storages with RES-E via the transmission grid. Some power plant connection lines are sometimes heavily used.

Category II:

(1) The transmission lines in Lower Austria/Burgenland are more heavily loaded in 2030-RES and 2030-SensRES than in the remaining scenarios. The increased capacity utilisation is due to wind power expansion assumptions, especially in Burgenland and Lower Austria.
(2) The inner-Austrian 220 kV lines are somewhat more utilised in 2030-RES and 2030-SensRES, which can be attributed to increased east-west electricity flows due to high renewable electricity generation in the east and intermediate storage in pumped storage facilities in the west and subsequent returns to the Vienna sink.

Whether these first identified transmission line sections are also overloaded is analysed in the next step on the basis of the 80% exceedance of thermal limits. The values of the individual transmission lines are shown graphically in Figure 4.14 for all scenarios. Percentages refer to the number of hours per year that the 80% thermal limit is exceeded, i.e. a value of 10% means exceedances in 876 hours of the year. Reviewing the above-mentioned transmission lines for overloads gives the following:

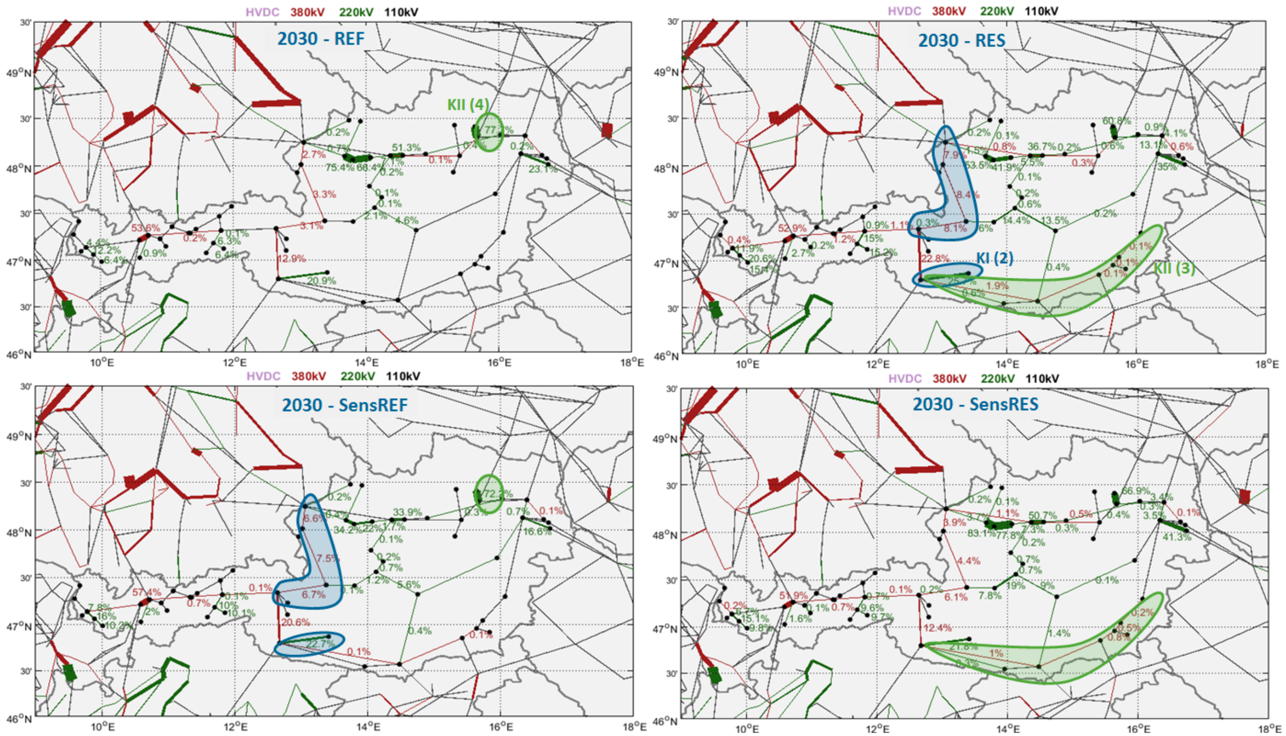


Figure 4.14.: 80% thermal limit exceeded, i.e. line utilization > 80%(expressed as a percentage, for example 10% = 876 hours).

Category I: The 380 kV Danube transmission system (West-East) and 380 kV Weinviertel KI (1) show the desired effect in scenarios 2030-REF and 2030-SensRES (conservative expansion RES in neighbouring countries) and prevent excessive overloading (no 80% excess of thermal limits). In addition to the projects that have already been realised, no further grid expansion is necessary until 2030. Some 220 kV line sections of the Danube transmission line are overloaded by the feed-in of the large run-of-river power plants along the Danube, as they serve as feeders for the 380 kV Danube transmission line segments. Since the overloads for scenario 2030-REF and 2030-SensRES are higher, they can be added to point KI (1), see also Table 4.15. These are manageable exceedances, i.e. they move within a framework in which they can be managed with the help of "Thermal Rating" application or also known as "Dynamic Line Rating".

The overload of the Lienz-Tauern connection KI (2) increases from 12% of the hours to over 20%. The Salzburg line can also be added to KI (2) with regard to the interaction of the pumped hydro storages with RES in 2030-RES and 2030-SensREF. Here, despite the grid expansion considered, exceedances of the 80% criterion in 7 to 8% of the hours occur, in these hours thermal rating can be used as a solution. The 220 kV connection line to the pumped storage region of Malta can also be attributed to point KI (2), which shows an increase of the 80% criterion to 26% and 23% due to the increase in installed capacity. With an assumed installed pumped hydro storage capacity of 2.5 GW, this line section is not sufficient, therefore, reinforcements should be considered.

Category II: The utilisation of KII (1), despite the inclusion of high wind capacity in the 380 kV transmission grid, exceeded the 220 kV transmission lines the 80% criterion (35% of the hours of the year). If high wind power capacities are to be connected away from the 380 kV wind substations, it may be advisable to strengthen the affected line or to build a new line, as otherwise the generated wind power can not be transferred. The application of thermal rating is not sufficient in this case.

Overloading of the inner-Austrian 220 kV lines KII (2) increases to about 10-19% with increased power generation from renewable energy sources. The grid concept of the 380 kV ring and the upgrading of the inland 220 kV transmission lines enables a strong interaction between RES-E (East) and hydro storage (West). However, grid reinforcement beyond the measures described in the master plan is not considered necessary as all overruns can be resolved using thermal rating.

The section Styria-Carinthia-East Tyrol forms one of the main connections of the eastern wind power plants with the pumped storage regions in the west. The result is a slight overload, in the sense that the 80% criterion is exceeded in a maximum of 1.9% of the hours of the year, of this transmission line segment in the 2030-RES and 2030-SensRES scenarios, i.e. these overloads are due to domestic developments and therefore count as a new entry as KII (3).

Due to the fact that it is an important connection for the inner-Austrian East-West electricity flows as well as the RES-E in North and South (DE and IT), the subarea around the West Tyrol node is over 50% overloaded in all scenarios and therefore, no unique category assignment can be made, this section can be considered as a candidate for eventual transmission line amplification.

Transmission grid utilisation of critical line elements in detail

Table 4.15 provides an overview of all transmission line segments which are overloaded in over 10% of the time in at least one of the scenarios (in the sense of exceeding 80% of thermal limit), cf. graphical representation in Figure 4.14. Furthermore, those line sections where a reinforcement or expansion is considered to be necessary are marked with an "X".

Those sections that are already identified in the previous steps can also be found in the table. In addition, other elements are listed that can not be clearly assigned to one of the two categories, such as West Tirol-Imst is equally utilised in all scenarios, or those that are influenced to a varying degree by developments in Austria and neighbouring countries.

The assignments already considered and explained in detail will not be repeated. Added to the already defined categories is KII (4) Dürnrohr-Altenwörth. Here, the increase in congestion does not occur due to the addition of renewable energy sources, but in the conservative scenario, in which more thermal power plants are still operating in Austria.

The remainder belong to the mixed category I+II, with the tendency that the increase in congestion of transmission lines is primarily due to increased RES-E

Figure 4.15.: Transmission line utilisation in detail from west to east (expressed as a percentage, e.g. 10% = 876 hours, green: 10-25%, yellow: 25-50%, red: >50%).

Cat.	Transmission line	2015	2030 – REF	2030 – RES	2030 – SensREF	2030 – SensRES	Expansion necessary
KI+II (1)	UW Bürs	0,2%	4,4 %	11,9 %	7,8 %	6,7 %	
KI+II (1)	Bürs - Rodund	16,7%	12,2 %	20,6 %	16,0 %	15,1 %	X
KI+II (1)	Rodund - Kops	7,2%	6,4 %	15,4 %	10,2 %	9,8 %	X
-	Westtirol - Imst	1,1%	53,6 %	52,9 %	57,4 %	51,9 %	X
KI+II (2)	Zell am Ziller - Mayrhofen	6,4%	6,3 %	15,0 %	10,0 %	9,6 %	X
KI+II (2)	Mayrhofen - Häusling	6,6%	6,4 %	15,2 %	10,1 %	9,7 %	X
KI (2)	Tauern - Lienz	0,0%	12,9 %	22,8 %	20,6 %	12,4 %	
KI (2)	Lienz - Malta	28,1%	20,9 %	25,7 %	22,7 %	21,8 %	X
KII (2)	Hessenberg - Weißenbach	0,0%	4,6 %	13,5 %	5,6 %	9,0 %	
KII (2)	Weißenbach - Sölk	7,1%	2,1 %	14,4 %	1,2 %	19,0 %	
KI (1)	Sattledt - Hausruck1	2,3%	66,4 %	41,9 %	22,0 %	77,8 %	
KI (1)	Hausruck1 - Hausruck2	2,9%	75,4 %	53,5 %	34,2 %	83,1 %	
KI (1)	Ernsthofen - Wallsee	16,1%	51,3 %	36,7 %	33,9 %	50,7 %	
KII (4)	Dürnrohr - Altenwörth	70,2%	77,7 %	60,8 %	72,2 %	66,9 %	
KII (1)	Bisamberg - Wien SO	8,2%	0,2 %	13,1 %	0,7 %	3,5 %	
KII (1)	Neusiedl - Wien SO	29,5%	23,1 %	35,0 %	16,6 %	41,3 %	X
-	Zell am Ziller – Westtirol	10,3%	0,2%	1,2%	0,7%	0,7%	
-	Tauern – Salzburg-Elixhausen	32,2%	3,2%	8,3%	7,1%	5,3%	

in Austria, but also the increased expansion of PV and wind power plants in the neighbouring countries influences the power lines in addition. This conclusion can be drawn from the fact that the values are lowest in 2030-REF and highest for 2030-RES. This is followed by scenario 2030-SensREF, where in Austria a conservative and, in the neighbouring countries, an optimistic expansion of RES-E is assumed, followed by the last scenario, where the assumption is reversed.

The transmission line segments identified here are supply lines to the large pumped storage regions of Austria, for example in Vorarlberg the connection to the Rodund and Kopswerke KI+II+(1) with an installed turbine and pumping capacity of more than 1 GW. KI+II (2) comprises the entire pumped storage and storage power plant group in eastern Tyrol around Roßhag, Häusling, Mayrhofen and Gerlos. For both sections, amplification is recommended, as the overloads that occur will not be manageable, like e.g. by applying thermal rating or re-dispatch measures.

Need of firm capacity and coverage of annual peak (residual) load in 2030

Since 2011, the Association of European Transmission System Operators for Electricity (ENTSO-E) has published annually the Scenario Outlook & Adequacy Forecast (SOAF) based on deterministic analyses for the European electricity system for each country separately, for individual regions and the overall European electricity system. In 2016, for the first time, a new method for calculating the need of firm capacity was implemented, published in the so-called Mid-term Adequacy Forecast (MAF) 2016 (ENTSO-E, 2016a). For the first time, a market-based probabilistic modelling approach is used to determine the medium-term need for assured capacity and flexibility.

Two key metrics in determining the need for assured performance are:

- Energy Not Served (ENS) or „Unserved Energy“, measured in MWh/a.
- Loss of Load Expectation (LOLE), determined by the number of hours per year in which electricity demand can not be fully covered by generation and imports.

The analyses of the last two SOAF (ENTSO-E, 2014b), (ENTSO-E, 2015d) and the most recent MAF 2016 (ENTSO-E, 2016a) show that Austria still has no problems with regard to adequately secured capacities for 2025 or 2030 in the power generation sector. The comprehensive analyses are constantly being further developed.

The report (ENTSO-E, 2015a), which essentially builds on national estimates, considers installed wind and PV capacity as 100% unavailable. Part of the hydro power plant is also considered unavailable due to environmental constraints. Biomass and biogas, on the other hand, are considered practically available at all times. However, special emphasis is placed on the development of transmission lines as a prerequisite for the integration of renewable energy sources and for the maintenance of a high standard of security of supply. The envisaged installed capacities for 2030-REF and 2030-RES are shown in Figure 4.16. In addition, the annual electricity peak load is shown, which in both cases can be covered by applying the above-mentioned assumptions and without taking into account imports.

In addition to considering installed capacities, the 44 hours with highest residual load (= load-PV-wind-RoR) of scenario 2030-RES are analysed. That is 0.5% of the year in which security of supply could be critical. Only hours of November and December are shown in Figure 4.17, with little to no generation from PV, wind and RoR. However, the resulting residual load can be covered in all hours with the existing gas, biomass, biogas and storage power plants, but imports are also used to cover demand. In order to be able to take into account the contribution of supply-dependent infeed, Figure 4.18 shows those 44 hours with maximum demand for electricity, the corresponding percentage values are shown in Table 4.8. It shows that wind generation can make a significant contribution to covering the electricity load peaks, if generation correlates with demand.

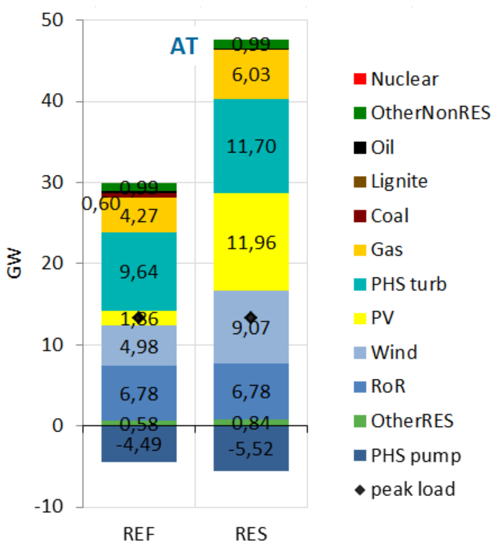


Figure 4.16.: Installed capacities and annual peak load of Austria for scenario 2030-REF and 2030-RES.

Table 4.8.: Contribution of individual technologies to cover electricity demand (including exports), on the one hand, based on the sorting according to maximum residual load and, on the other hand, according to maximum load.

Sorting	load/residual load (GWh)	Export (GWh)	RoR	Bio	Wind	PV	PHS	Gas	Import
max residual load	544 / 421	28	18%	6%	2%	1%	27 %	38%	7%
max load	563 /313	70	19%	6%	19%	2%	21%	30%	4%

Following the approach in (ENTSO-E, 2016a), in which ENS and LOLE values

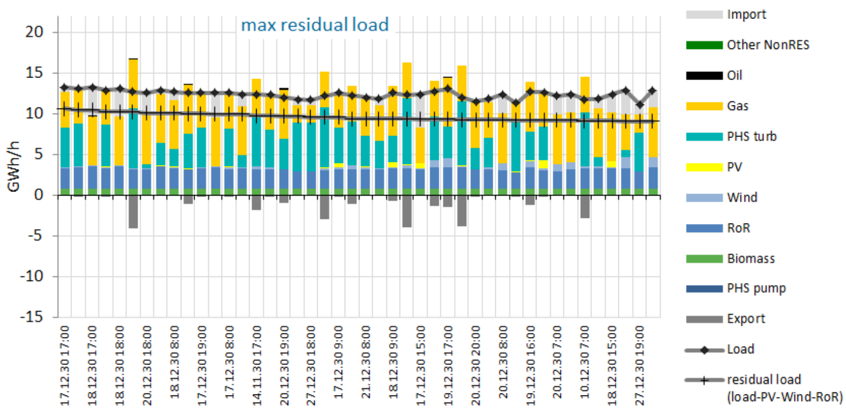


Figure 4.17.: Generation structure of the 44 hours with highest residual load of the year for scenario 2030-RES in Austria.

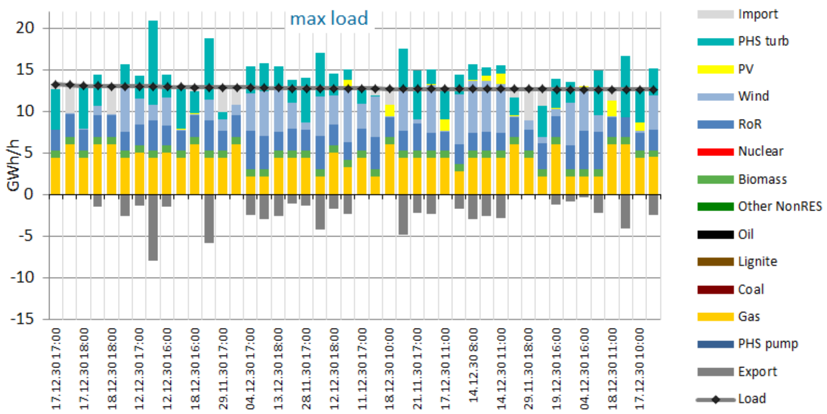


Figure 4.18.: Generation structure of the 44 hours with highest electricity demand of the year for scenario 2030-RES in Austria.

are used for the assessment of security of supply, there is no impact on security of supply for Austria. For all four scenarios, there is a value of zero for unmet demand coverage, i.e. ENS = 0 MWh/a, which in turn implies that LOLE = 0 h/a.

For comparison, Figure 4.19 shows those 44 hours of the year with the lowest residual load (= load-PV-wind-RoR). During these hours, the residual load is negative, i.e. generation of renewable energy sources is higher than demand. On the one hand, it can be shown that electricity generation from wind, PV and RoR is stored by pumped hydro storage facilities and, on the other hand, is exported to neighbouring countries.

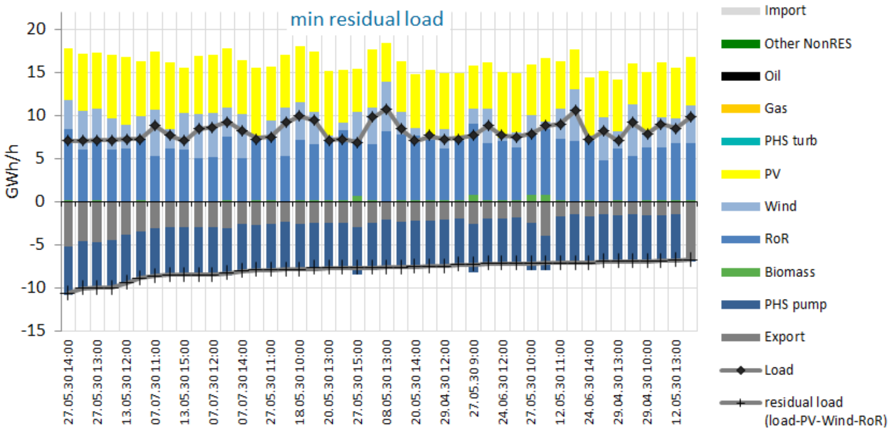


Figure 4.19.: Electricity generation structure of the 44 hours with lowest residual load of the year for scenario 2030-RES in Austria.

The exogenously specified physical interconnection capacity to Austria is 25.3 GW. In terms of congestion management, this physical value is reduced to about one third, i.e. 8.4 GW if the Austrian and German electricity markets are separated, otherwise a capacity of 15.6 GW can be assumed.

Transmission line segments with high relevance to security of supply

According to (APG, 2016), APG is investing several hundred million euros over the next few years in the expansion and modernisation of its grid infrastructure in order to provide optimal conditions for Austria and the local economy. If all transmission power line extensions currently planned and published in (APG, 2016) and (ENTSO-E, 2015b) are implemented, security of supply in Austria achieve 100% based on the simulation results. However, in France and Belgium there are unmet electricity demand of 40 GWh/a and 66 GWh/a, which each equates to a security of supply of 99.9%. Of course, it can not be guaranteed that these values will be achieved even in the distribution level, since evaluating security of supply in the distribution grid was not subject of the analysis.

If the adopted transmission grid extensions are not implemented, the unfulfilled demand for electricity increases to 69 GWh/a in Belgium and 583 GWh/a in France, leading to a deterioration in security of supply. In Germany too, the delay in transmission line expansion is having an impact: there is an unfulfilled electricity demand of approx. 1 GWh/a. However, this represents only a fraction in the face of annual total electricity demand of 624 TWh/a. By means of the simulation results important transmission segments can be assigned to ensure a high security of supply level in Austria, which are:

- the connections of pumped-hydro storage regions, in southern and western Austria,
- the necessary 380 kV integration of wind turbines to the transmission grid situated in Burgenland, Brucker basin and Weinviertel,
- the Danube transmission system as part of the east-west connection for Austria,
- and the already strengthened Salzburg line represents an important north-south connection and connecting pumped storage sites in western and southern Austria.

In the end, this means that the planned complete closure of the 380 kV ring is a necessary prerequisite for Austria's future security of supply. At the same time, if all assumed framework conditions, such as the currently planned and published electricity grid expansions in Austria and Europe, are implemented in time (APG, 2016) and (ENTSO-E, 2015b), supply reliability is 100% in Austria, since electricity demand can be covered at 100% every hour.

4.2. Power Plant Dispatch and Balancing

4.2.1. Status Quo for Balancing in 2015

For modelling the current electricity system and balancing market design, different data sources have been used, but the input is mostly based on data of the 'Statistical Factsheet 2015' published by ENTSO-E, (ENTSO-E, 2016b). The geographical scope comprises Central Europe, meaning that the control areas of Austria (APG), Germany (TenneT, TransnetBW, Amprion and 50hertz), Belgium and the Netherlands are considered in detail. For these countries the balancing market mechanisms are analysed in addition to the wholesale electricity market clearing. The remaining neighbouring countries like Poland, Czech Republic, Slovakia (currently no direct interconnection to Austria), Hungary, Slovenia, Italy, Switzerland and France are considered for wholesale electricity market clearings only. The simulated areas are shown in Figure 4.20.

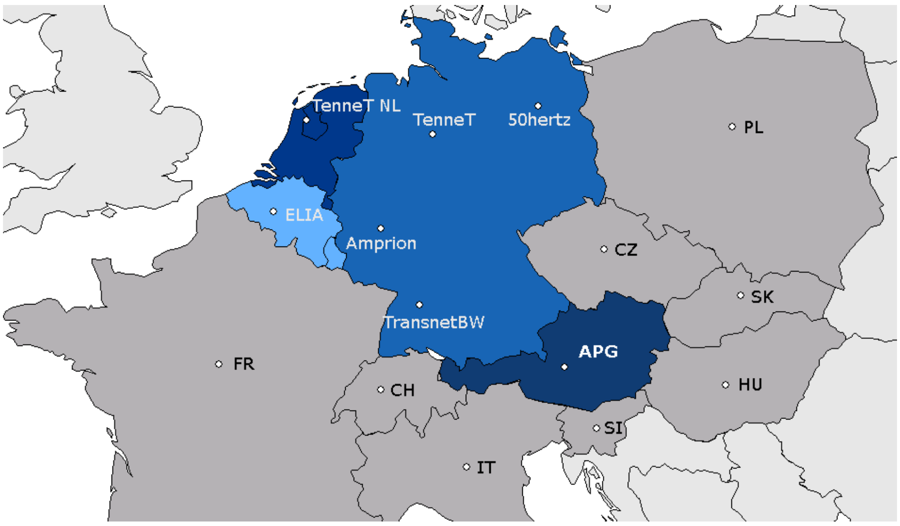


Figure 4.20.: Geographical scope of the simulations; blue: balancing and wholesale electricity market, darkgrey area: wholesale electricity market consideration only.

To figure out which impacts different changes in the product design of aFRR and mFRR have, four scenarios are defined:

Ref Current Design: Peak, Off-Peak and Weekend weekly products for aFRR in the control area APG, Peak and Off-Peak weekly products for aFRR in the remaining. Four-hour daily products for mFRR in all control areas.
A Sensitivity 1: daily 4-hour products for aFRR in all control areas.
B Sensitivity 2: based on scenario A aFRR is exchanged between all TSOs.
C Sensitivity 3: based on scenario B mFRR is exchanged between all TSOs.

In the next sections the outcomes of above-mentioned scenarios are analysed in detail, starting with the impacts on cost structure, divided into impacts on wholesale electricity generation costs and procurement costs for both balancing products aFRR and mFRR. Afterwards, the changes in terms of procured capacity and the corresponding reserved transmission capacities for providing balancing products are analysed. In the last subsection the environmental impacts are summarised, more can be found in (Burgholzer, 2017).

Impacts on the cost structure

The wholesale generation costs are mostly influenced by balancing market design changes in the countries/control areas where the balancing market mechanisms are applied and analysed (TSOs balancing), like in Germany, Austria, Belgium and The Netherlands. In other simulated countries (TSOs wholesale), there can be assessed that the costs are reduced as well, but not in the extent as for the others. In case C the generation costs can be reduced by 0.34% in total, see Figure 4.21, which are around 90 MEuro/a.

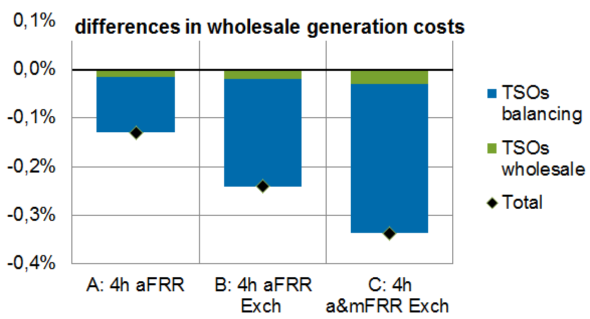


Figure 4.21.: Differences in wholesale generation costs compared to the reference case separately for the wholesale electricity market only TSOs and balancing TSOs.

In Figure 4.22 the differences in terms of wholesale generation costs and procurement costs for FRR compared to the reference case for control areas, where balancing is respected, are shown. In all cases the costs are reduced. The highest avoided costs are examined in case C, where the procurement costs for aFRR and mFRR are reduced by 31% and 27% (73 and 60 MEuro/a). Comparing the avoided costs of case A with B, it can be concluded, that introducing common procurement of aFRR by several TSOs has got higher impacts on costs, than changing the product design only. In addition, common procurement of mFRR (case C) reduces not only the costs for mFRR, but also for aFRR. Thus, positive effects can be observed by further harmonising the procurement of FRR.

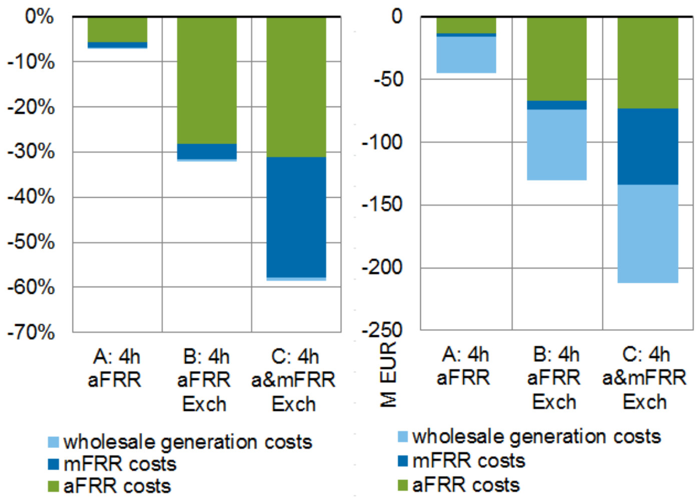


Figure 4.22.: Differences in wholesale generation costs and balancing procurement costs compared to the reference case for control areas, where balancing market is respected (AT, DE, BE, NL).

Interdependencies on procured capacities and exchanges

The average electricity flows resulting from the wholesale electricity market clearing and the reserved capacity for upward capacity of FRR for case C are shown in Figure 4.23. Regarding transmission capacity, it is mostly used for wholesale electricity market flows, except on the interconnection APG to

TenneT the available capacity is more often reserved for upward capacity of aFRR on average. This result can also be seen in Figure 4.24a in case C, where APG provides a lot of excess capacity for upward aFRR to the other control areas.

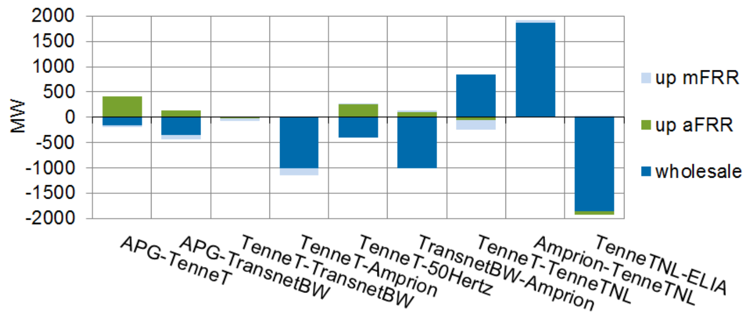
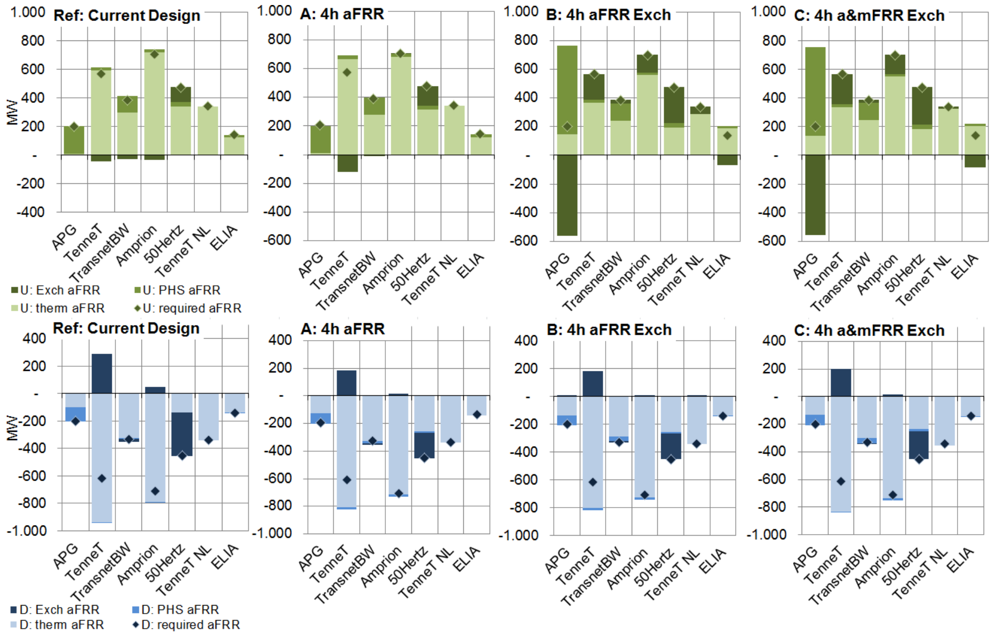
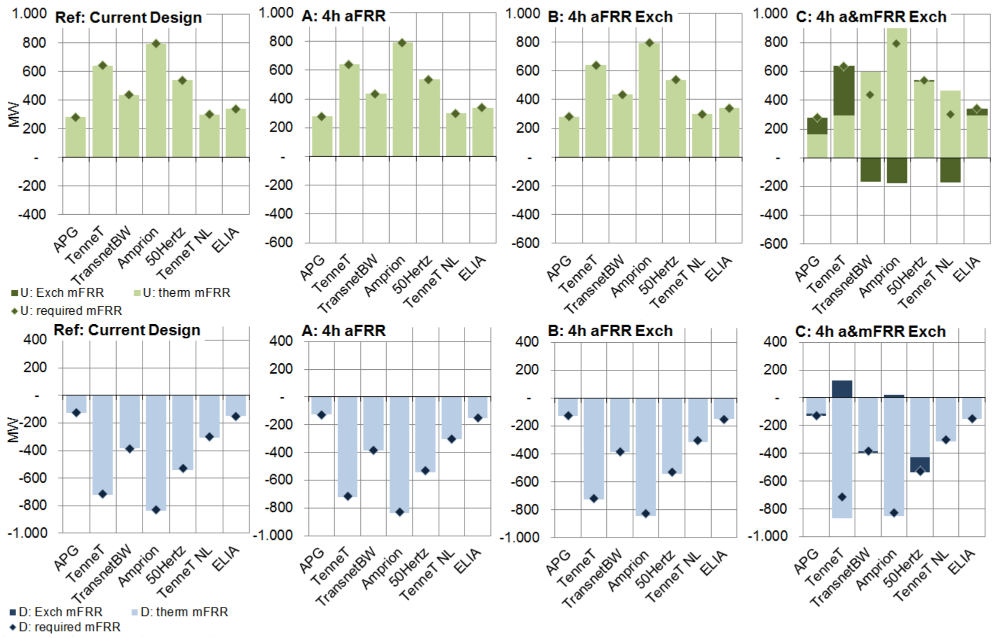


Figure 4.23.: Average electricity flows resulting from wholesale electricity market clearing and reserved capacity for upward capacity of FRR for case C. For the transmission line APG-TenneT positive values mean, that APG provides upward FRR or exports energy to TenneT, negative vice versa.

Figure 4.24 shows how the required capacities of automatically and manually activated balancing capacity are procured on average. It is assumed, that thermal power plants can procure both aFRR and mFRR (U/D: therm a/mFRR), pumped hydro storage (U/D: PHS a/mFRR) is allowed to provide aFRR only (will be further extended in the section refsubsec:balancing2030). In addition, the exchanged procurement of FRR (U/D: Exch a/mFRR) and the required capacity per product and control area (U/D: required a/mFRR) are shown in the figures. Exchanging mFRR between TSOs is only allowed in case C. In this case the control areas of TransnetBW, Amprion and TenneT NL can procure more than they require on average for upward mFRR, as the diamonds in the figures indicate the required balancing capacity per control area. Therefore, they can procure the excess capacity for APG and TenneT. Concerning downward mFRR, TenneT and Amprion provide the TSOs 50Hertz, APG and TransnetBW with excess capacity.



(a) Up- and downward aFRR



(b) Up- and downward mFRR

Figure 4.24.: Average procured capacity for up- and downward FRR for all four scenarios.

Environmental Impacts

In Table 4.9 the reductions in terms of CO_2 emissions are summarised for all scenarios. In addition, the absolute value for the reference case is shown.

Table 4.9.: Differences in CO_2 emissions compared to the reference case for control areas where balancing market is respected.

	APG	Total
Ref:	9.3 Mt CO_2	567.5 Mt CO_2
A: 4h aFRR	-0.5%	-0.3%
B: 4h aFRR Exch	-0.8%	-1.5%
C: 4h a&mFRR Exch	-1.8%	-1.4%

Due to the shortening of aFRR product length and allowing common procurement of aFRR and mFRR (case C), flexibility is gained and, therefore, spillages of renewable electricity generation can be bisected. As a result the renewable share of electricity generation is increased from 28.5% to 29.1% in the simulated area.

Conclusions for 2015

From the above-mentioned analysis several conclusions can be defined: The implementation of shorter balancing products and allowing common procurement of aFRR and mFRR by all TSOs reduces costs for procurement significantly. CO_2 emissions can be reduced by around 1.7% in Austria and by 1.4% for the respected area in total. The spillage of renewable generation can be bisected in Austria and the whole region and therefore, the renewable share of electricity generation is increased to 29.1% in relation to annual electricity demand for Central Europe.

4.2.2. Impact of harmonised common balancing capacity procurement in 2030

For 2030, the assumptions of ENTSO-E's Vision 3 of TYNDP 2016 are used, (ENTSO-E, 2015e), and the aggregated transmission grid as shown in Figure 3.2. Different variations of balancing market designs are analysed, e.g. asymmetric or symmetric (separate or joint) procurement of up- and downward balancing capacity. In terms of timing, weekly or daily procurement of Peak and Off-Peak aFRR products are investigated, leading to the target design of daily 4-hour aFRR products. Another variation concerns the cooperation between TSOs and control areas. The last one is about which power plants are allowed to procure the balancing capacity. In Table 4.10, the defined scenarios are described, which are quantitatively assessed in this section, see also (Dallinger, Auer, and Lettner, 2018).

Table 4.10.: Defined scenarios, the description of cases A to G includes the deviations from the reference case only.

Case	Description
Reference	**asymmetric/separate** procurement of up- and downward balancing capacity **weekly** procurement of Peak (P), Off-Peak (OP) and Weekend (W) aFRR products in AT, Peak and Off-Peak aFRR products in DE, BE & NL **daily** procurement of 4-hour products for mFRR **cooperation** between German TSOs/control areas only **thermal, pumped hydro storage and hydro storage power plants** can procure balancing capacity
A	**daily** P, OP & W aFRR products in AT, P & OP in DE, BE & NL
B	**symmetric/joint** procurement of up- and downward FRR products
C	**symmetric/joint** procurement of up- and downward FRR products **daily** P, OP & W aFRR products in AT, P & OP in DE, BE & NL
D	**daily** procurement of 4-hour aFRR products
E	**daily** procurement of 4-hour aFRR products **cooperation** between all TSOs/control areas for aFRR
F	**daily** procurement of 4-hour aFRR products **cooperation** between all TSOs/control areas for aFRR & mFRR
G	**daily** procurement of 4-hour aFRR products **cooperation** between all TSOs/control areas for aFRR & mFRR **other storages** can also procure aFRR & mFRR

Figure 4.25 shows the average procured balancing capacity for upward (positive) and downward (negative) aFRR per balancing area for selected scenarios presented in Table 4.10 (mFRR is shown in Figure A.3). Balancing capacity can be provided by thermal power plants (therm.), pumped hydro and hydro

storages (PHS) and other storages, like batteries or EVs (OthStor) in case G. The German TSOs can exchange balancing capacity (Exch) in all scenarios, for the remaining control areas this is possible in cases E to G only. Most aFRR capacity is procured by thermal units, except in the Austrian balancing area the majority is supplied by pumped hydro and hydro storages. This includes downward as well as upward balancing capacity.

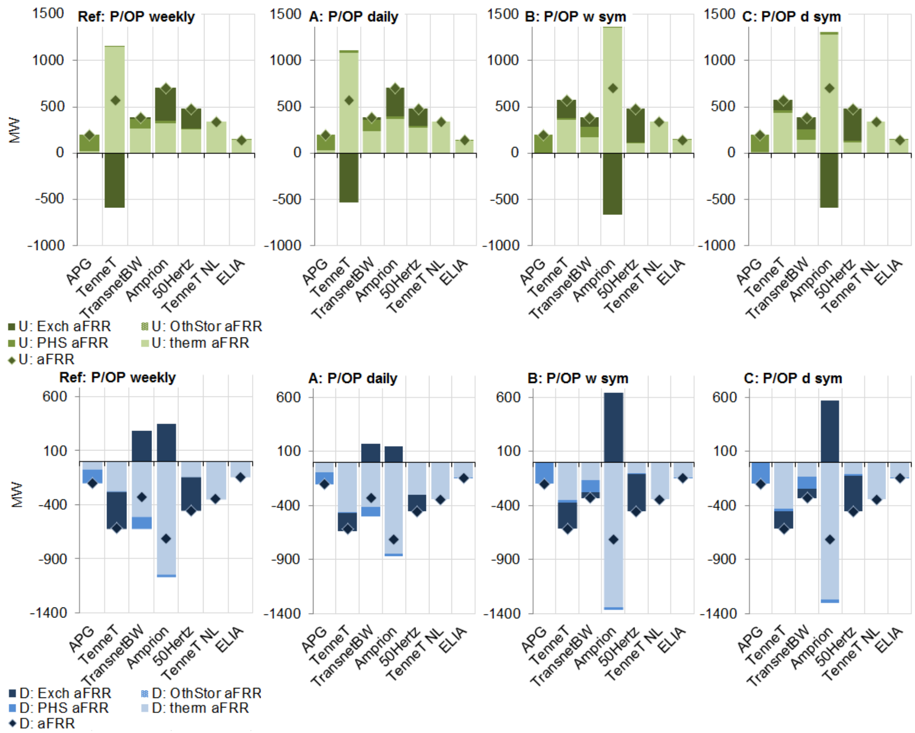


Figure 4.25.: Average procured up- and downward aFRR balancing capacity per control area for the reference case and case A to C (U: upward (positive) in green, D: downward (negative) in blue, aFRR: required capacity/h, in MW).

Weekly versus daily aFRR products

Comparing the cases where weekly auctions (reference case and case B) are replaced by daily ones (case A and C), it is investigated that the average exchanges of balancing capacity between the German balancing areas are reduced significantly. In the latter, for example, the procurement of upward capacity of TenneT for the remaining German balancing areas decreases by around 9% in case A (compared to the reference case). The impacts on downward capacity are even higher, TenneT provides the other German TSOs with around 51% less balancing capacity. Similar outcomes are observed in case B and C, where up- and downward balancing capacity is procured symmetrically. Including not only upward balancing capacity, but also downward; both up- and downward decrease by 11%. These reductions result from the flexibility achieved in time. This means that TSOs are able to manage the installed capacities and the pre-qualified capacities for aFRR and mFRR of their own control area more efficiently. Therefore, the need of procuring additional balancing capacity from other TSOs is reduced. Furthermore, having in mind demand side management and renewable electricity generation (like wind), the shorter the product length and the shorter the timing of the auction ahead, the better it is for these sources/technologies to bid into balancing markets. For example, for wind generation week-ahead forecasts and corresponding binding balancing capacity bids are neither possible nor profitable.

The exchanges for up- and downward mFRR products between German TSOs stay in a similar range in the asymmetric cases (below 1% in case A compared to the reference case). When procuring both FRR products symmetrically, the exchanges by German TSOs for up- and downward mFRR products however increase by 8% and 10% respectively (cf Figure A.3).

Asymmetric versus symmetric procurement of up- and downward FRR products

The comparison of asymmetric and symmetric cases (case A and C) shows, that more balancing capacity is exchanged between German TSOs in the latter. The exchanged upward aFRR is increased by 13% (11%) for weekly (daily) case, whereas downward aFRR balancing capacity is increased by 82% in the daily case. Also the exchanges for downward mFRR rise by 78% (95%) for the weekly (daily) case. The opposite can be observed for the common procurement of upward mFRR in the German control areas: it is decreased by around 37% (31%) for the weekly (daily) case.

The main reason for these increases in terms of exchanged balancing capacity is, that both up- and downward balancing capacity has to be procured to the same extent by all providers. Again, for RES-E sources like wind generation it is not beneficial to bid up- and downward capacity/energy simultaneously, because the provision of upward balancing capacity hampers the exploitation of the full potential of wind generation.

Allocation of cross-border transmission capacities for balancing

When allowing exchanges of balancing capacity between all control areas, the common procurement increases as expected. Particularly in Belgium and Austria the procurement of upward balancing capacity rises significantly, see case E to G in Figure 4.26.

The average common procurement for upward balancing capacity per hour is shown for case D to F in Figure 4.27. Especially in case E and F, significant average procurements of upward balancing capacity from Belgium (E: 109 MW aFRR, F: 153 MW aFRR + 30 MW mFRR) and Austria (E: 413 MW aFRR, F: 176 MW aFRR + 91 MW mFRR) to Germany are shown. The average exchanges within German TSOs are approximately the same in E and F, but in case D most of the directions are reversed, except the exchanges between TenneT and 50Hertz. TenneT provides aFRR and mFRR balancing capacity to 50Hertz to a reduced extent (D: 201 MW aFRR + 18 MW mFRR).

Figure 4.28 shows that the implicit allocation of transmission capacity (meaning reserving a certain transmission capacity for balancing purposes) between balancing areas increases. In case D exchanges between German TSOs is allowed only, therefore, only four duration curves are shown in the figure. In case E and F for almost all hours and transmission lines, a certain transmission capacity is reserved for balancing purposes.

If there is a certain transmission capacity reserved for balancing, the remaining cross-border transmission capacity of two electricity markets can be used for day-ahead and intraday trades. In (ENTSO-E, 2011) the theoretical aspects in terms of optimal determination allocating transmission capacity between day-ahead trading and balancing capacity trading are outlined briefly. It mainly concludes, that cross-border transmission capacity has a positive and declining

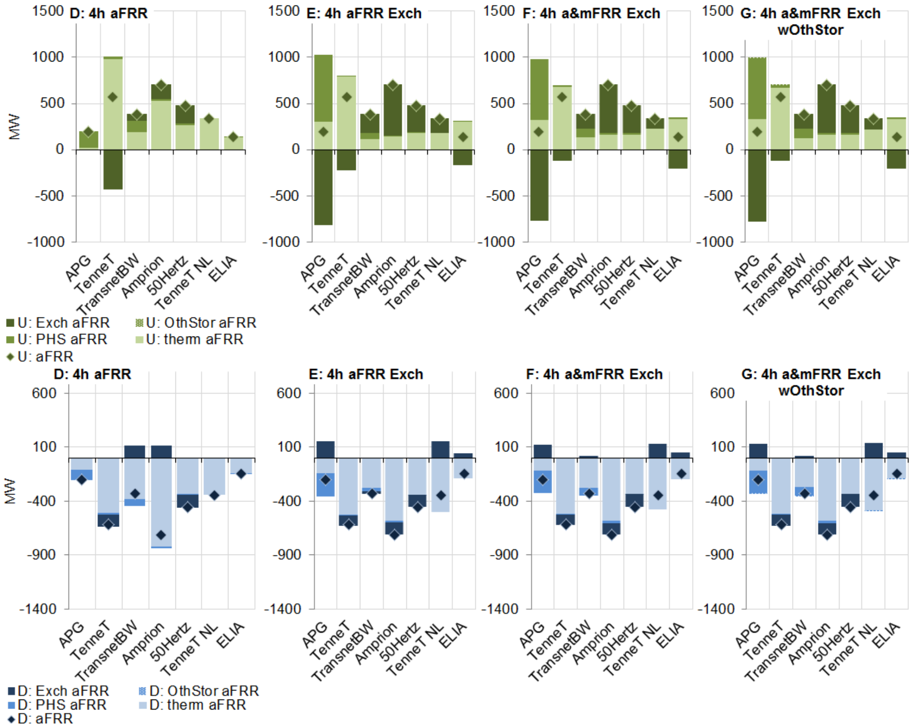


Figure 4.26.: Average procured up- and downward balancing capacity aFRR per balancing area for case D to G (U: upward (positive) in green, D: downward (negative) in blue, aFRR: required capacity/h, in MW).

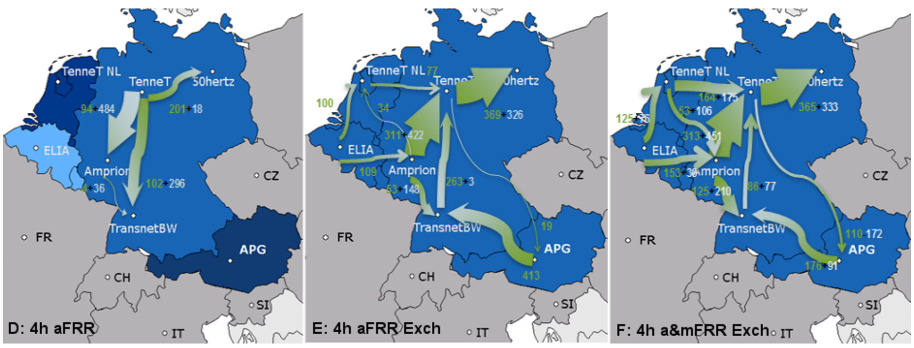


Figure 4.27.: Average common procurement of upward aFRR and mFRR balancing capacity for case D to F (numbers in green: aFRR, numbers in lightblue: mFRR, in MW).

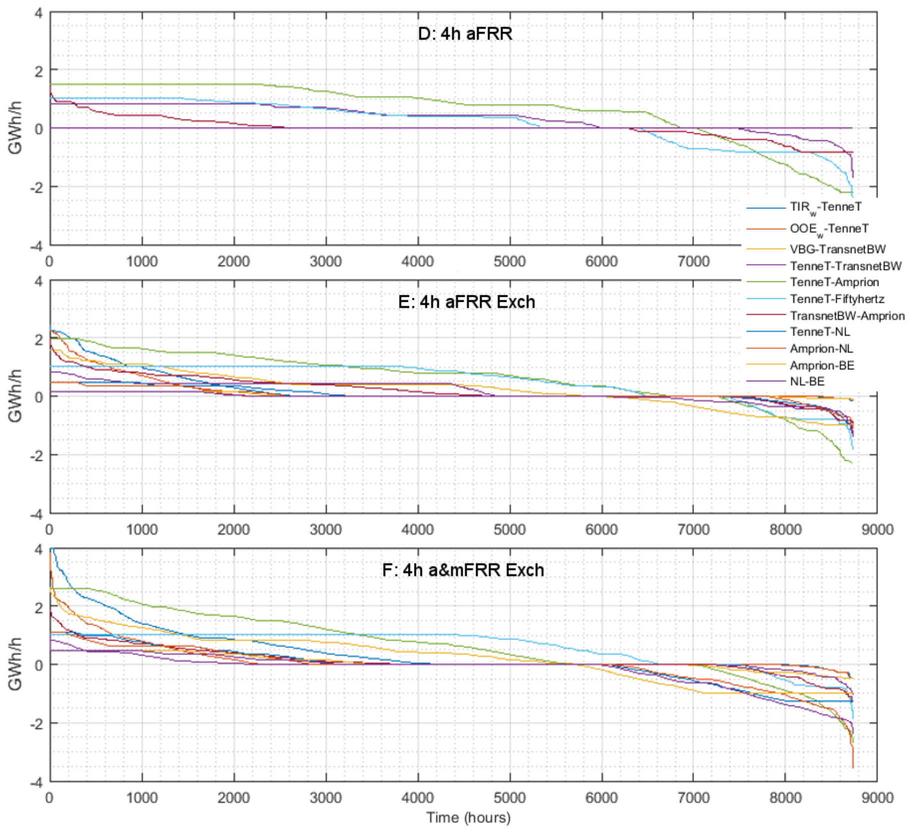


Figure 4.28.: Duration curves of implicit allocation of transmission capacity between several TSOs for upward aFRR and mFRR balancing capacity for case D to F (A-B positive values mean A to B and negative vice versa).

marginal value in all markets. Assuming only two market segments (in this example day-ahead and balancing market) and a given level of cross-border transmission capacity, the optimal allocation of transmission capacity can be illustrated as indicated in Figure 4.29. The optimal allocation of cross-border transmission capacity is illustrated by the intersection of the two curves.

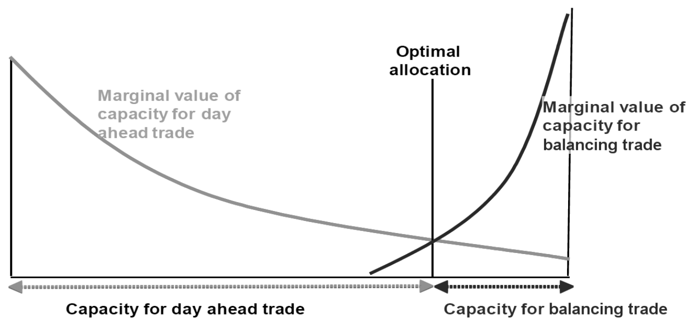


Figure 4.29.: Optimal allocation of transfer capacity between two markets (ENTSO-E, 2011).

Impacts on the cost structure and interdependencies between aFRR and mFRR

Different designs of aFRR products do not only affect procurement costs, they also influence procurement costs of mFRR and total electricity generation costs of wholesale markets. These impacts compared to the reference case are shown in Figure 4.30 in relative and absolute values for TSOs/countries (Austria, Germany, Belgium and The Netherlands).

Notably, the symmetric (joint) procurement of up- and downward FRR products (case B and C) influences the costs for FRR and wholesale generation costs significantly. Whereas the shortening of aFRR product lengths, from daily Peak/Off-Peak products (case A) to 4-hour products (case D), wholesale generation costs and procurement costs for aFRR and mFRR decrease by 97 and 167 MEuro/a. On the one hand, common procurement of aFRR capacities by all TSOs (case E) increases mFRR costs by 12% (51 MEuro/a) compared to the reference case, but on the other hand, significant reductions can be achieved in wholesale generation costs (0.5%, 82 MEuro/a) and the procurement costs for aFRR (37%, 179 MEuro/a). This results in a total reduction of 210 MEuro/a.

Allowing common procurement of mFRR by all TSOs (case F) yields in cost reductions of 243 MEuro/a. The integration of other storages, like batteries or EVs, in balancing markets (case G) results in additional cost reductions of 3 MEuro/a. It has been assumed that 100 MW of other storages are implemented in the control areas (CAs), where balancing is applied.

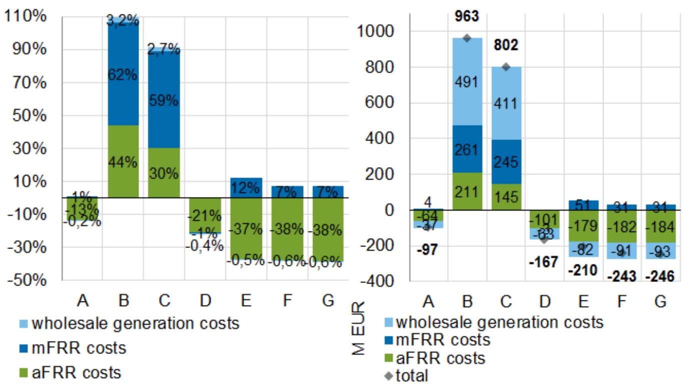


Figure 4.30.: Differences in aFRR and mFRR procurement costs and wholesale generation costs compared to reference case in relative and absolute values for TSOs/countries (AT, DE, BE, NL), where balancing market mechanisms are applied.

The differences in wholesale electricity generation costs compared to the reference case are shown in Figure 4.31. In the plot, changes on generation costs for CAs, where balancing market mechanisms are considered (CAs balancing: AT, DE, BE, NL) and where wholesale market modelling is applied only (CAs wholesale: remaining countries), are presented.

Most changes occur in countries, where balancing markets are simulated, but there are also some changes in the neighbouring countries. The highest impacts occur in cases B and C, due to the application of joint procurement of up- and downward balancing capacity. The influences on wholesale generation costs of applying common procurement in all balancing areas are noteworthy. The costs are reduced in some areas, e.g. in Austria, Belgium and the Netherlands, whereas in some other countries the costs increase.

In general, the electricity generation costs can be lowered by shortening the lengths of balancing products. Applying common procurement promotes this development further (see Figure 4.31).

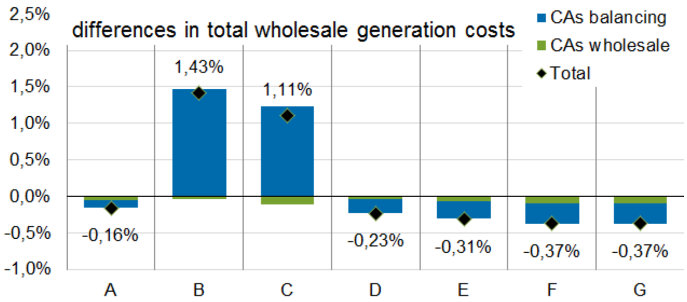


Figure 4.31.: Differences in total wholesale generation costs compared to the reference case for all countries (CAs balancing: AT, DE, BE, NL; CAs wholesale: remaining countries).

Environmental Impacts

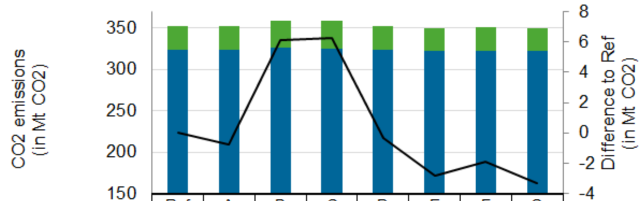
In Table 4.11 the reductions in terms of CO_2 emissions compared to the reference case are summarised for all scenarios. In addition, the absolute value for the reference case is shown.

Table 4.11.: Differences in CO_2 emissions (sum of wholesale and balancing market) compared to the reference case for (CAs balancing: AT, DE, BE, NL), (CAs wholesale: remaining countries) and the total system.

Scenario	CAs balancing	CAs wholesale	Total
Ref: P/OP asym (w)	194.4 $MtCO_2/a$	158.2 $MtCO_2/a$	352.6 $MtCO_2/a$
A: P/OP asym (d)	-0.39%	-0.02%	-0.22%
B: P/OP sym (w)	2.96%	0.22%	1.73%
C: P/OP sym (d)	3.21%	-0.01%	1.77%
D: 4h aFRR	-0.19%	0.02%	-0.10%
E: 4h aFRR Exch	-1.34%	-0.14%	-0.80%
F: 4h a&mFRR Exch	-0.86%	-0.13%	-0.53%
G: 4h a&mFRR Exch wOthStor	-1.61%	-0.13%	-0.95%

In terms of environmental impacts, similar effects as for the wholesale generation costs (cf. Figure 4.31) can be assessed. The different balancing market designs influence mostly countries where electricity balancing is respected (AT, DE, BE, NL), but there are also impacts on the remaining countries. The highest reductions of CO_2 emissions (0.95%, 3.3 $MtCO_2/a$) are achieved by allowing other storages procuring balancing capacity (case G).

The CO_2 emissions separated in wholesale and balancing market for the whole electricity system are shown in Figure 4.32. As mentioned before, the highest reductions can be observed in case G, where 2.8 $MtCO_2/a$ can be saved in the balancing market and 0.5 $MtCO_2/a$ in the wholesale market.



	Ref	A	B	C	D	E	F	G
balancing market	29,3	28,3	33,0	33,6	28,9	27,1	28,0	26,5
wholesale market	323,2	323,4	325,7	325,2	323,3	322,6	322,7	322,7
Difference to Ref (in Mt CO2)	0	-0,8	6,1	6,2	-0,3	-2,8	-1,9	-3,3

Figure 4.32.: Differences in CO_2 emissions compared to the reference case for the whole system separated in wholesale and balancing market.

Due to the shortening of aFRR product length and allowing common procurement of aFRR and mFRR (case F), flexibility is achieved and, therefore, spillages of RES-E are reduced. As a result the share of RES-E increases from 58.34% to 58.44% in the simulated area. The opposite is investigated by applying symmetrically procured up- and downward balancing capacity: RES-E spillage increases by 1774 GWh/a (1429 GWh/a), when comparing case B with Ref (case C with A). The RES-E spillage and the RES-E share for the Central European electricity system are shown in Figure 4.33, separated into the different renewable technologies.

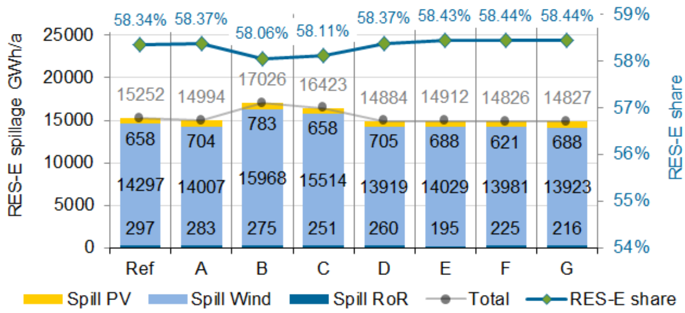


Figure 4.33.: RES-E spillage and RES-E share for the Central European electricity system for all scenarios.

Key Performance Indicators (KPIs) and Conclusions

In Table 4.12 the outcomes of the analysis are summarised based on several key performance indicators (KPIs), like costs, CO_2 emissions, RES-E spillage and RES-E share.

Table 4.12.: Key Performance Indicators (KPIs) for all scenarios for the Central European electricity system.

KPIs for Total System	Ref: P/OP weekly	A: P/OP daily	B: P/OP w sym	C: P/OP d sym	D: 4h aFRR	E: 4h aFRR Exch	F: 4h a&mFRR Exch	G: 4h a&mFRR Exch wOthStor
wholesale generation costs (Meuro/a)	33492	-0,2%	1,4%	1,1%	-0,2%	-0,3%	-0,4%	-0,4%
FRR procurement costs (Meuro/a)	850	-6,5%	34,5%	27,7%	-10,7%	-7,7%	-9,7%	-9,9%
total costs (Meuro/a)	34342	-0,3%	2,2%	1,8%	-0,5%	-0,5%	-0,6%	-0,6%
wholesale CO_2 emissions ($MtCO_2$/a)	323	0,1%	0,8%	0,6%	0,0%	-0,2%	-0,2%	-0,2%
FRR CO_2 emissions ($MtCO_2$/a)	29	-3,4%	12,5%	14,6%	-1,5%	-7,6%	-4,5%	-9,5%
total CO_2 emissions ($MtCO_2$/a)	353	-0,2%	1,7%	1,8%	-0,1%	-0,8%	-0,5%	-0,9%
RES-E spillage (GWh/a)	15252	-1,7%	11,6%	7,7%	-2,4%	-2,2%	-2,8%	-2,8%
RES-E share (%)	58,3%	0,0%	-0,5%	-0,4%	0,1%	0,2%	0,2%	0,2%

In the short term it will not be possible to implement the co-optimisation approach in Europe as it is currently the trend in U.S. electricity markets. Nonetheless, due to harmonisations and by implementing new market designs, several savings in terms of cost reductions, CO_2 emission avoidance and RES-E spillage decreases can be achieved, as it has been shown in the preceding analysis. Therefore, the following conclusions can be drawn:

Shortening the timing and length of aFRR products (from weekly Peak/Off-Peak to daily 4-hour products) reduces the need of transmission capacity between balancing areas, because the available electricity generation capacities within the control areas can be used in a more efficient way due to gained flexibility. As a result the costs of wholesale electricity generation and balancing capacity procurement are reduced. In addition, it is an appropriate design to integrate RES-E and DER in balancing markets, because the shorter the product length, the more RES-E and DER are able to participate in the balancing market.

Symmetric procurement of up- and downward balancing capacity for aFRR and mFRR increases wholesale generation costs and total procurement costs significantly, because balancing providers have to reserve both up- and downward capacity, whether it is economical or not. Procurement exchanges between German TSOs (in case B and C German TSOs are allowed to exchange aFRR and mFRR only) are stimulated to operate generation units in the most efficient way. This design causes increased RES-E spillages and implicates reduced RES-E shares. Therefore, it is a poor design for RES-E integration, due to the fact that e.g. wind farms cannot use their full electricity generation since they must provide upward balancing capacity in addition.

The combination of shorter balancing products, allowing common procurement of aFRR and mFRR, and other storages, like batteries and EVs, providing balancing capacity, enables the highest cost savings for balancing capacity procurement and for the wholesale generation dispatch in Central Europe. Three millions can be saved in addition by allowing other storages to bid on the balancing market.

The highest CO_2 emission reductions are given for cross-border procurement, and if other storages (DER in addition to hydro storages) can procure balancing capacity.

The spillage of RES-E is reduced by 2.8% and renewable share of electricity generation is increased to 58.44% (+0.1%) by allowing other storages procuring balancing capacity and by procuring FRR commonly by all TSOs.

In terms of practical implementation of (at least parts of) the analysed cases, a first progress has currently been achieved, two countries, Austria and Germany, implemented successfully the common activation of aFRR and introduced daily 4-hour products for aFRR. Further steps could be (i) the implementation of common balancing capacity procurement; (ii) enlarging the area of common aFRR activation, for example to Belgium; and (iii) implementing common activation of mFRR.

There are still options and ways to improve European balancing markets, but EU, ACER and ENTSO-E already achieved some progress in doing so, e.g. by approving the Network Code on Electricity Balancing and lately the Guideline on Electricity Balancing entered into force. The implementation of all tasks will take several years.

4.3. Socio-economic Benefit Analysis of PHS expansion in Austria

The Austrian (pumped-) hydro storages with up to 6.4 GW installed turbine and 3.4 GW pumping capacity and their huge storage capacities of around 1730 GWh play an important role for the Central European electricity system. In addition, the interconnection with neighbouring countries is higher than the European average (Commission Expert Group on electricity interconnection targets, 2017). Therefore, Austrian hydro storages significantly support the integration of RES-E in several regional markets. In order to provide a sensitivity on future hydro storage plant penetration in Austria, three different scenarios are assumed for 2030, based on ENTSO-E TYNDP 2018, (ENTSO-E, 2017b). They are called:

- Sustainable Transition (2030-ST) which seeks a fast and economically sustainable CO_2 reduction by replacing coal and lignite by gas in the European electricity sector,
- Distributed Generation (2030-DG) which places prosumers at the centre,
- and the external scenario (2030-EC) which is a core policy scenario produced by the European Commission.

For each of these three scenarios different expansion paths of pumped hydro storages in Austria are analysed:

A. No further pumped hydro storage and hydro storage power plants (PHS & HS) are built in Austria after 2018.
B. PHS expansion cannot be realised as planned[2], around one third of turbine (1 GW) and pumping (400 MW) capacity is not realised.
C. PHS expansion is proceeding as planned (see footnote 2).

The assumed Austrian power plant park is shown in Figure 4.34 (left) and the installed capacities of the respected Central European area are shown on the right based on the ENTSO-E TYNDP 2018 scenarios (ENTSO-E, 2017b).

For additional analyses see (Dallinger, Schwabeneder, et al., 2018).

[2]Source: ENTSO-E, TYNDP 2018. In Austria, it is planned to build around 3.5 GW pumped hydro storage (PHS) and hydro storage (HS) power plants by 2030.

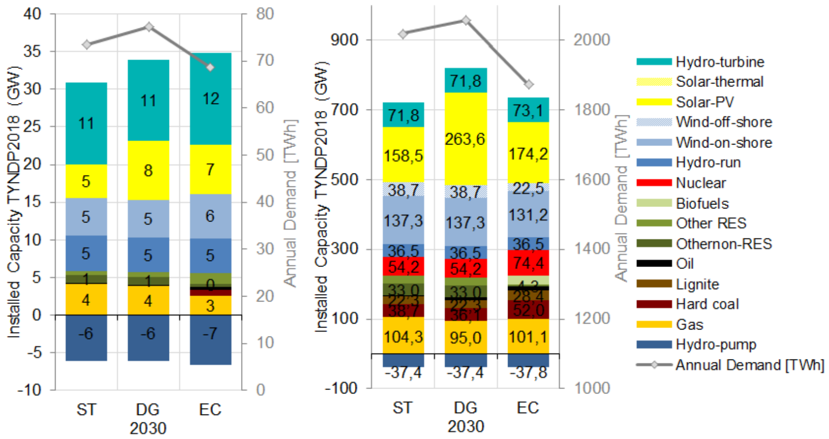


Figure 4.34.: Installed capacities in Austria (left) and for all respected Central European countries (right: AT, BE, CH, CZ, DE, FR, HU, IT, NL, PL, SI and SK), based on (ENTSO-E, 2017b).

4.3.1. Impacts on the electricity generation mix and procured balancing capacities

Figure 4.35 shows the results by applying the EDisOn+Balancing model in terms of generation mix results and the resulting share of renewable electricity generation in relation to annual electricity consumption. It presents the optimisation results per ENTSO-E TYNDP 2018 scenario for both the Austrian and the Central European electricity system. In addition, the changes in generation due to varying installed PHS capacity are shown on the right hand side of Figure 4.35. The RES-E shares are calculated as follows:

$$RES^{share} := \frac{PV + Wind + RoR + Biomass + PHS^{turb} - PHS^{pump} \cdot \eta}{Demand} \qquad \text{(in \%)}$$

In Austria, the RES-E generation share for 2030 is between 69.6% (ST) and 87.5% (EC) for Option A and the planned storage expansion allows additional RES-E share increases of 2.4% (A→C) in 2030-ST and 2030-DG and 2.8% for scenario 2030-EC. The respected Central European area reaches RES-E shares of 47% (ST) and 51.1% (DG). Although the same installed capacities of pumped

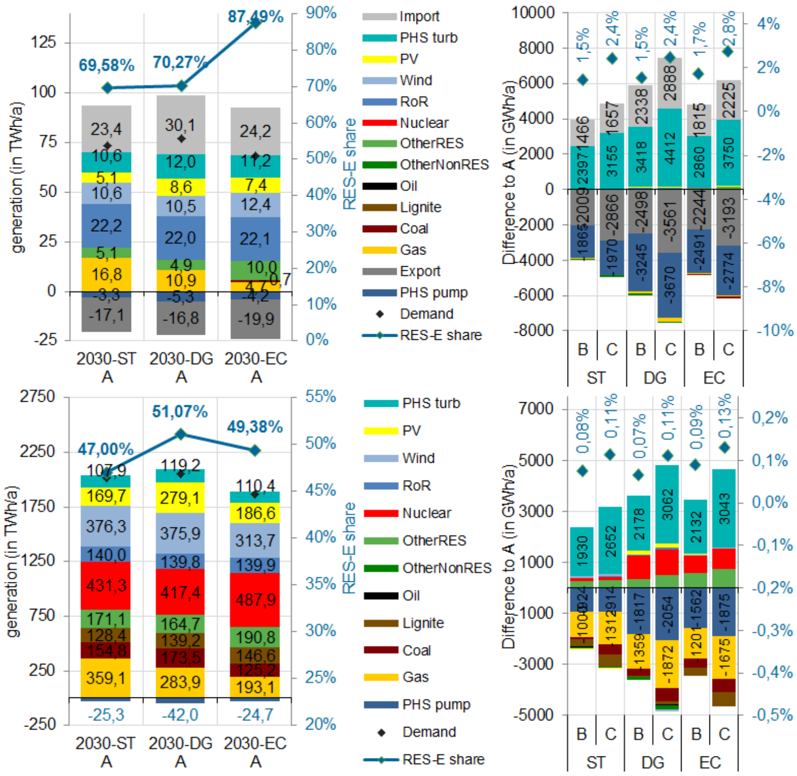


Figure 4.35.: Generation structure and RES-E share in relation to electricity demand in Austria (top) and in the Central European system (bottom) for scenario ST, DG and EC if no PHS expansion in AT after 2018 is assumed. On the right: changes occurring due to PHS expansion (Option B&C).

hydro storages are assumed in Option A, due to higher penetrations of solar PV and wind in scenario DG the consumption and generation of Austrian PHS in scenario DG is higher than in ST (14%) and EC (7%). This is also true for the Central European electricity system (ST: 10%, EC: 8%). The pumped hydro storages largely compensate the occurrence of timing differences of generation and demand peaks and valleys, respectively. The additional PHS capacities in Option B and C change mostly electricity imports to and exports from Austria. In general, Austria is a net importer in all scenarios, but by adding more installed PHS capacity the import dependency decreases, cf. Figure 4.35 (upper right) electricity export increases more than imports (negative values for "PHS pump" and "Export" represent increases).

The PHS expansion in Austria also affects power plant dispatches in neighbouring countries. On the one hand, in all scenarios wholesale electricity generation of lignite, coal and gas power plants are replaced by PHS, PV, wind, nuclear and other RES-E. On the other hand, the balancing procurement of other RES-E like biomass is replaced by gas, lignite and coal power plants, except for scenario 2030-ST. There can be observed a shift, but to a varying extent, e.g. in 2030-DG B wholesale generation of gas power plants is reduced by 1359 GWh/a (see Figure 4.35), whereas balancing procurement of aFRR and mFRR[3] increases by 280 GWh/a in 2030-DG B, see Figure 4.36 (right).

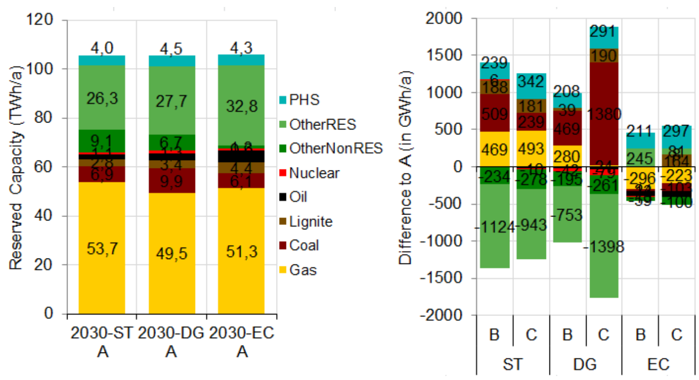


Figure 4.36.: Reserved capacities for aFRR and mFRR in AT, DE, BE and NL for Option A (left) and the changes due to PHS expansion options (right).

It is not possible to completely avoid curtailment of RES-E, but the Austrian PHS expansion supports the more efficient use of renewable electricity integration, not only in Austria but also in neighbouring countries. In the Central European electricity system, RES-E curtailment is reduced by 1.6% in ST, 4.8% in DG and 4.2% in EC (A→C).

[3]For all TSOs of Austria, Germany, Belgium and The Netherlands it is assumed that aFRR is procured daily differentiated by off-peak and peak products and mFRR is procured daily in 4-hour products. Cross-border balancing is not applied.

4.3.2. CO_2 emission reductions and environmental damage costs

The additional pumped storage capacities enable CO_2 emission reductions of 2-9.1% in Austria and 0.1-0.5% in the Central European system per year. With assumed CO_2 certificate prices of 84.3 Euro/t in ST, 50 Euro/t in DG and 27 Euro/t in EC the emission reductions amount in monetary savings of 100 MEuro/a (ST), 24 MEuro/a (DG) and 48 MEuro/a (EC) (A→C).

Based on specific emission factors for SO_2, NO_x, non methane volatile organic compounds (NMVOC) and particulate matter (PM_{10}) (see Table A.3 based on (EEA, 2008)), the resulting emission reductions are calculated. They are assessed based on published environmental damage cost coefficients[4], see (EEA, 2014). The differences in damage costs across the countries are remarkable, but reasonable. The highest damage costs are related to emissions released in the centre of Europe, i.e. France, Belgium, Germany and Austria. These emissions are mainly transported to densely populated areas, and consequently bring about high damage to human health. Moreover, the lowest damage costs are related to emissions in the Nordic countries, Greece and Ireland, which are located in the outskirts of Europe and not upwind of other countries (such as the UK). In Figure 4.37 the environmental damage cost reductions resulting from implementing hydro storage projects in Austria are shown based on national values in Table A.4 for value of a life year (VOLY[5]). Concerning the assessment of climate damage induced by CO_2 a value of 145 Euro/t is assumed, based on (UBA, 2014).

The changes are split into wholesale (left) and up- and downward balancing (right: bal+, bal-). In all scenarios environmental damage costs of electricity wholesale generation are reduced. In contrast to the wholesale market, the emissions of balancing procurement are emitted upon activation only. Therefore, these emissions can be interpreted as an upper limit. The environmental damage costs for upward balancing (bal+) are in all scenarios negative, which is due; because the capacity is procured by lower-emission power plants if the pumped

[4]The damage cost coefficients are adjusted to 2018-Euro/t by using the European consumer price index (CPI), e.g. 2005 = 84.802, 2018 = 103.48, source: eurostat.

[5]The value of a life year (VOLY) is an estimate of damage costs based upon the loss of life expectancy. This measure takes into account the age at which deaths occur by giving greater weight to deaths at younger age and lower weight to deaths at older age, see (EEA, 2014).

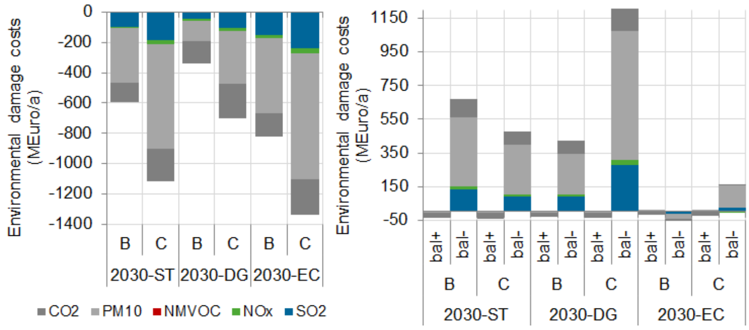


Figure 4.37.: Environmental damage costs of emissions differentiated between wholesale market (left) and procured balancing capacity (right).

hydro storages are added in Austria. In terms of downward balancing (bal-) an increase represents that even more emissions can be avoided if activated.

4.3.3. Residual load curve and relevant parameters for PHS

The higher the penetration level of RES-E is, the more residual load curves (=load-(PV+wind+RoR+biomass)) shift downwards. In all scenarios residual load is to a certain extent negative, i.e. generation from RES-E is higher than demand, see Figure 4.38. The remaining positive area below the curve has to be covered by thermal plants, by PHS and by electricity exchanges with neighbouring countries. For the 2030 scenarios and the expansion Options A to C PHS generation and consumption in Austria and the exchanges to neighbouring countries are shown.

As mentioned previously, Austrian pumped-hydro storage plants are the highest utilised in scenario 2030-DG, where solar PV and wind capacities are the highest followed by 2030-EC and 2030-ST, see also Table 4.13.

Another variables, which are shown in Figure 4.38, are electricity imports to Austria and exports from Austria to neighbouring countries (X→AT), where positive values mean electricity flows to Austria, i.e. imports, and negative values represent exports. The hourly imports and exports increase in all three scenarios, whereas, the number of hours when Austria is a net-importer decreases from

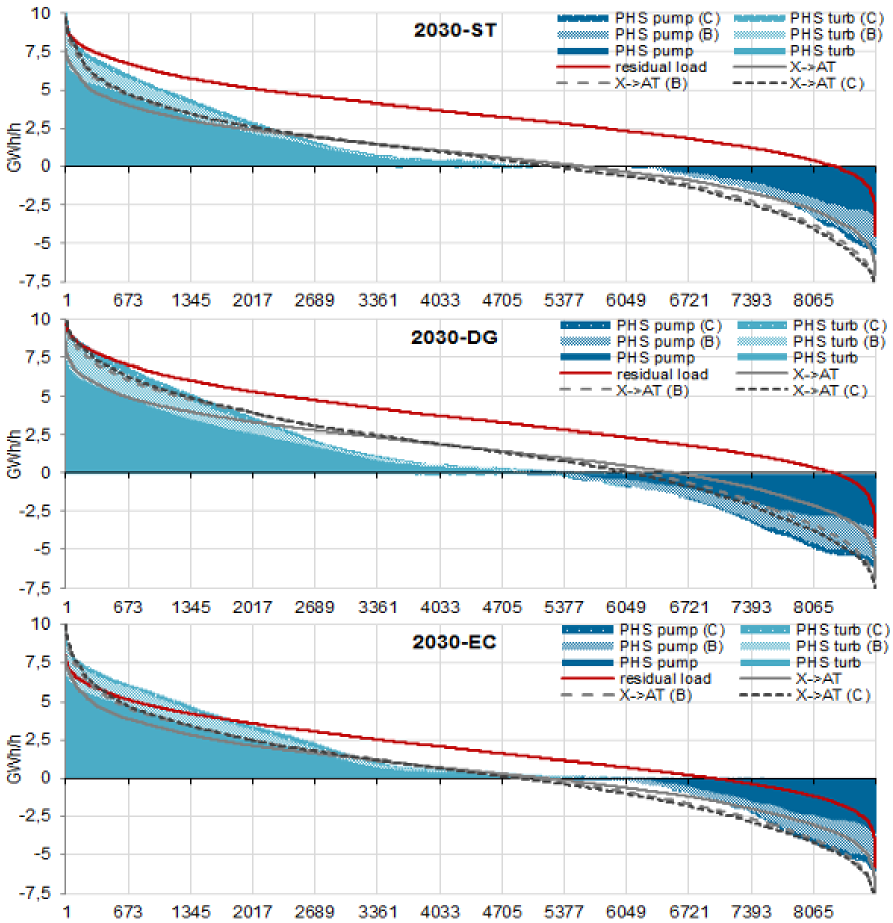


Figure 4.38.: Residual load curve (=load-(PV+wind+RoR+biomass)), PHS generation and consumption in Austria and the exchanges to neighbouring countries (X→AT:positive values represent electricity imports to Austria and negative ones exports).

5579 (2030-ST A), 6544 (2030-DG A) and 5208 hours (2030-EC A) by around 328 (ST), 473 (DG) and 321 hours (EC).

Relevant parameters for determining revenues and costs of hydro power are generation and consumption quantities, the associated profits (assessed on the basis of shadow prices of the demand equation = wholesale price), the operating hours and the annual average price spreads. In Table 4.13, some of these values are listed separately for hydro storages (HS) and pumped hydro storages (PHS) for all three scenarios and each PHS expansion path.

Table 4.13.: Relevant parameters of hydro power plants in Austria for the wholesale generation market.

	2030-ST			2030-DG			2030-EC		
Quantity (GWh/a)	A	B	C	A	B	C	A	B	C
HS turb	3508	3847	3841	3495	3839	3834	3504	3845	3835
PHS turb	7049	9107	9871	8507	11581	12581	7689	10208	11108
PHS pump	-3305	-5170	-5275	-5258	-8504	-8928	-4165	-6657	-6940
Profits (MEuro/a)	1,025	1,124	1,187	923	1,022	1,075	538	605	640
HS turb	414	434	428	349	360	353	212	226	223
PHS turb	832	1,041	1,112	831	1,081	1,158	465	601	647
PHS pump	-221	-351	-353	-257	-419	-435	-139	-222	-230
Operational hours (h/a)									
HS turb	5194	5237	5230	5347	5348	5364	5184	5215	5280
PHS turb	4465	4525	4559	5148	5340	5298	5145	5371	5375
PHS pump	2641	2613	2582	3767	3719	3637	3278	3179	3160
∅ PHS Spread (Euro/MWh)	28.23	25.84	25.19	26.04	22.26	22.14	17.03	15.87	15.61

Significant changes in the quantities result for PHS, since the installed capacity increases from Option A to C. In terms of sales, it should be mentioned that not only the quantity influences sales, but also the endogenous spot prices are decisive for the amount. The average, annual spot price level for Option A in 2030-ST is 88.04 Euro/MWh, in 2030-DG 69.34 Euro/MWh and 45.36 Euro/MWh in 2030-EC. In this regard, a decline in the price spread can be observed and a decline of price spreads due to increased PHS capacity (∅ PHS spread for Option A to C in all scenarios), which confirms the theory of economic self-cannibalism of storages (Ehlers, 2011).

4.3.4. Electricity generation costs, procurement costs and peak-price shaving of additional PHS in Austria

Figure 4.39 shows the reductions in terms of electricity generation and those of balancing capacity procurement. The reference is Option A for the corresponding scenarios, i.e. the assumed primary energy prices and the CO_2 certificate prices are identical for all options within the scenarios (see Table A.2 for details). Furthermore, the procurement costs of aFRR and mFRR are split. In Figure 4.39 left, the percentage monetary savings for system operators[6] are shown and on the right the corresponding absolute values in million euro per anno.

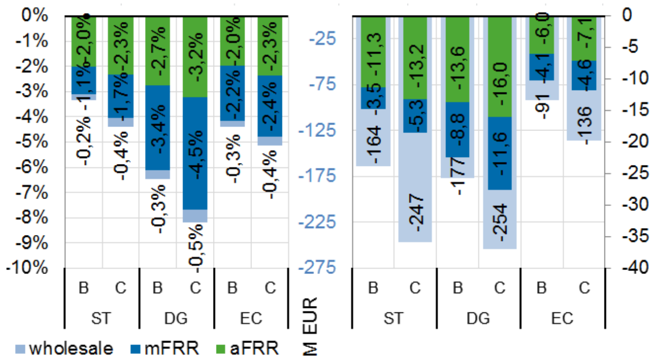


Figure 4.39.: Comparison of electricity wholesale generation cost and procurement costs for automatic and manual Frequency Restoration Reserve (aFRR & mFRR) for each respected scenario (using Option A as a reference).

The realisation of 2/3 of planned PHS expansions (Option B compared with A) amounts in cost savings between 100 MEuro/a (wholesale and FRR for scenario 2030-EC) and up to 200 MEuro/a (2030-DG). In terms of cost reductions per installed turbine capacity in Austria, values between 9300 Euro/MW and 18200 Euro/MW can be achieved. If all planned PHS in Austria are realised (Option C), savings between 148 MEuro/a (2030-EC) and 281 MEuro/a (2030-DG) are observed, which means savings of 12400 Euro/MW (2030-EC) and 23600 Euro/MW (2030-DG) respectively.

Reducing load during peak periods is called peak shaving or peak clipping. Peak shaving can realise a range of benefits when it coincides with peak demand,

[6] In general, all costs are passed on to consumers.

especially in terms of peak prices in the wholesale market, see Table 4.14.

Table 4.14.: Peak-price shaving results for Austria (AT) and the Central European (CE) electricity system (in MEuro/a). The term level means the annual sum of hourly electricity load evaluated with the wholesale prices.

	2030-ST			**2030-DG**			**2030-EC**		
MEuro/a	A	B	C	A	B	C	A	B	C
AT: level	7298			6072			3442		
AT: reductions		52	68		66	84		10	18
CE: level	181746			146595			86055		
CE: reductions		626	722		444	549		94	126

Peak shaving can be achieved by shedding load, by shifting load into off-peak periods or by using onsite generation facilities during peak periods. Due to higher electricity demand during daytime, the electricity prices are higher in peak hours than in off-peak hours. Therefore, for PHS the most economical way of operating usually has been pumping during the night – while prices are low – and generating electricity during the day, when there can be earned enough money to compensate in addition efficiency losses. In recent years, however, a shift can be noticed. During the day several price drops are observed at power exchanges, e.g. on sunny summer days in Germany the electricity prices during midday are dropping, because of high priority in-feeds of solar PV generation or in case of significant additional wind generation prices can even get negative. As a consequence, for storage units a lot of new business cases are possible when responding to price fluctuations accordingly.

Reduction of necessary reserve power plant capacity

The evaluation starts by marking the hours where residual load (=load - (PV+wind+RoR+biomass)) is high (e.g. the highest 10% of the year = 876 hours). Figure 4.40 shows for scenario 2030-ST Option C that the hours occur mainly during autumn and winter.

To get an indication how much capacity of thermal power plants (gas, coal, lignite and oil) can be substituted by pumped hydro storages, the hourly differences of thermal generation in these highest 876 hours of residual load in Central Europe are calculated. Furthermore, several statistical measures like mean, median, quantiles are computed; see column “residualL” in Table 4.15.

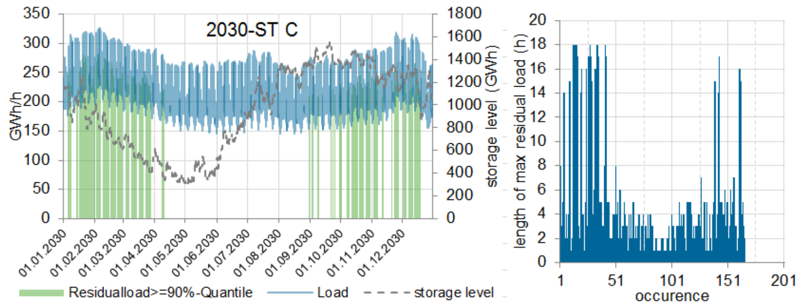


Figure 4.40.: Hours when residual load (=load-(PV+wind+RoR+biomass)) in the total Central European electricity system is higher than the 90%-quantile (green), the available storage level in Austria (grey) and the duration of maximum residual load (right: blue).

The duration of such peaks may not be neglected, because there has to be sufficient storage capacity available. An alternative approach is to compare the differences of the e.g. 876 hours with maximum thermal generation (column "thermP"), which can result in comparing different hours with each other, whereas in the "residualL" approach the same hours of the year are compared and, therefore, results in higher max/lower min values.

Table 4.15.: Statistical measures for indicating reduction of necessary reserve power plants, Option C compared with A for all three scenarios.

(in GW)	**2030-ST**		**2030-DG**		**2030-EC**	
	residualL	thermP	residualL	thermP	residualL	thermP
maximum	6.143	-0.211	6.738	-0.159	7.702	0.028
75%-quantile	-0.079	-0.508	-0.153	-0.478	-0.040	-0.357
median	-0.592	-0.651	-0.715	-0.725	-0.599	-0.478
mean	-0.754	-0.692	-1.006	-0.840	-0.562	-0.508
25%-quantile	-1.316	-0.829	-1.703	-0.887	-1.271	-0.651
minimum	-12.529	-1.358	-8.764	-4.142	-9.713	-1.155

The median and mean values vary between -478 MW (2030-EC: thermP) and -1006 MW (2030-DG: residualL), so comparing these values with the additional installed turbine capacity around one quarter of thermal power plant capacity can be substituted on average in Central Europe. The detailed results of the second approach "thermP" are shown in Figure 4.41. For all three scenarios the values centre around -500 to -750 MW.

Other important events for having sufficient reserve capacities are so-called

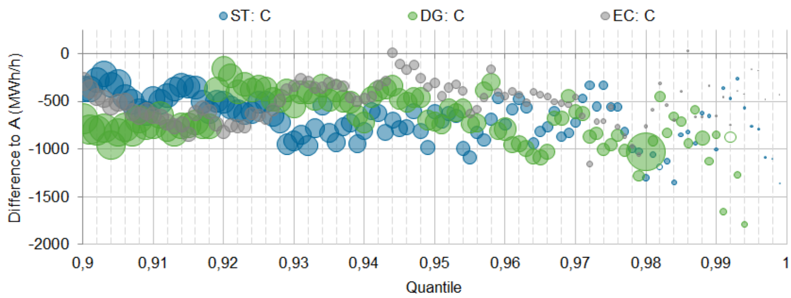


Figure 4.41.: Reduction of necessary reserve power plant capacity by comparing the differences of maximum thermal power generation (Option C compared with A) for all three scenarios.

"Dunkelflauten"[7] (i.e. hourly electricity generation of solar PV and wind is smaller than a certain percentage of installed solar PV and wind capacities). Storage devices with respective storage levels are appropriate generation technologies in relieving this kind of critical situation, but also the interconnections to neighbouring control areas support the electricity system in terms of security of supply.

4.3.5. Summary and comparison of the outcomes for Central Europe

In Table 4.16 the outcomes of the socio-economic analysis for the Central European electricity system are summarised based on several benefit indicators, like costs, CO_2 and additional emissions, peak-price shaving, RES-E spillage and RES-E share. The absolute changes are supplemented by percentages in relation to Option A of the corresponding scenarios.

The highest system cost reductions, in an absolute and relative sense, are achievable in scenario 2030-DG, despite the fact that RES-E capacities with their almost zero marginal costs are the highest. Therefore, the highest RES-E spillage reduction and RES-E share increase in relation to demand are observed for scenario 2030-DG. The annual cost savings translated into savings per additional installed MW of turbine capacity amounts in 23600 Euro/MW in

[7]The term has prevailed in German-speaking countries in recent years.

Table 4.16.: Benefit indicators for all three scenarios and for the PHS expansion options of the analysed Central European electricity system.

KPIs for Total System	2030-ST A	2030-ST B	2030-ST C	2030-DG A	2030-DG B	2030-DG C	2030-EC A	2030-EC B	2030-EC C
wholesale generation costs (MEuro/a)	69189	-164 -0,2%	-247 -0,4%	51872	-177 -0,3%	-254 -0,5%	36106	-91 -0,3%	-136 -0,4%
FRR procurement costs (MEuro/a)	879	-15 -1,7%	-19 -2,1%	755	-22 -3,0%	-28 -3,7%	493	-10 -2,1%	-12 -2,4%
costs (MEuro/a)	70069	-179 -0,3%	-265 -0,4%	52627	-199 -0,4%	-281 -0,5%	36599	-102 -0,3%	-148 -0,4%
CO_2 emissions (wholesale) ($MtCO_2$/a)	388,66	-1 -0,2%	-1 -0,4%	389,27	-1 -0,3%	-2 -0,4%	316,62	-1 -0,3%	-2 -0,5%
CO_2 emissions (FRR) ($MtCO_2$/a)	37,76	1 1,5%	0 0,8%	37,02	0 1,0%	1 3,0%	33,25	0 -0,7%	0 -0,5%
CO_2 emissions ($MtCO_2$/a)	426,42	0 -0,1%	-1 -0,3%	426,30	-1 -0,1%	0 -0,1%	349,86	-1 -0,4%	-2 -0,5%
CO_2 emissions (MEuro/a)	35947,36	-28	-100	21314,79	-31	-24	9446,33	-35	-48
Env. damage costs (wholesale) (MEuro/a)	311532,12	-596 -0,2%	-1116 -0,4%	338458,66	-337 -0,1%	-699 -0,2%	311835,52	-823 -0,3%	-1333 -0,4%
Peak-Price Shaving (MEuro/a)	181745,99	-626 -0,3%	-722 -0,4%	146594,53	-444 -0,3%	-549 -0,4%	86054,83	-94 -0,1%	-126 -0,1%
RES-E spillage (GWh/a)	2232	-37 -1,6%	-35 -1,6%	4010	-171 -4,3%	-191 -4,8%	1726	-63 -3,6%	-73 -4,2%
RES-E (RoR, Biomass, PV, Wind) (GWh/a)	857137	304 0,0%	335 0,0%	959457	524 0,1%	683 0,1%	830983	662 0,1%	812 0,1%
RES-E share (%)	47,00%	0,08%	0,11%	51,07%	0,07%	0,11%	49,38%	0,09%	0,13%

2030-DG. In terms of emissions, it has to be differentiated between wholesale and FRR procurement. On the one hand, they can be seen as already emitted and, on the other hand, the emissions are only emitted when balancing capacity is called. Therefore, the damage costs of these emissions have to be interpreted as an upper limit.The highest peak-price shaving (demand valued with the wholesale prices) is performed for scenario 2030-ST due to the fact that the annual average price level with 88.04 Euro/MWh is the highest (CO_2 certificate price is assumed to be 84.30 Euro/t) compared to 2030-DG and 2030-EC. So the maximum decrease of producer surplus, which is calculated as the difference of revenues and costs, occurs in 2030-ST. In addition to these benefits the hydro storages replace peaking units with regard to reducing necessary reserve capacities, while maintaining a high security of supply level in the Central European electricity system.

5. Synthesis of Results and Conclusions

Several improvements in terms of transmission lines, short-term electricity market designs and flexible technologies (especially storages) are necessary to meet the challenges of future energy systems with high shares of variable renewable electricity generation.

Transmission expansion planning

Concerning transmission expansion planning in Austria, the Austrian TSO APG is investing, according to (APG, 2016), several hundred million Euro over the next few years in the expansion and modernisation of its electricity grid infrastructure in order to provide optimal conditions for Austria and the local economy. If all transmission line extensions currently planned and published in (APG, 2016) and (ENTSO-E, 2015b) are implemented, security of supply in Austria achieves 100% based on the simulation results. The following important transmission line segments can be assigned to ensure a high security of supply level in Austria:

- the connections in the pumped-hydro storage regions, in southern and western part of Austria,
- the necessary 380 kV integration of wind turbines to the transmission grid located in Burgenland, Brucker basin and Weinviertel,
- the Danube transmission system as part of the east-west connection for Austria,
- and the assumed upgraded Salzburg line (220 kV to 380 kV)represents an important north-south connection and also connects pumped storage sites in the western and southern part of Austria.

In the end, this means that the planned complete closure of the 380 kV ring is a necessary prerequisite for Austria's future security of supply.

Future balancing market designs

For the time being, it will not be possible to implement the co-optimisation approach in Europe as it is currently the trend in U.S. electricity markets. Nonetheless, due to harmonisations and by implementing new market designs, several savings in terms of electricity system cost reductions, CO_2 emission avoidance and RES-E spillage decreases can be achieved, as it has been shown in the analysis of future balancing market designs. Therefore, the following conclusions can be drawn:

Shortening the timing and length of aFRR products (from weekly Peak/Off-Peak to daily 4-hour products) reduces the need of transmission capacity between balancing areas, because the available generation capacities within the areas can use their capacity in a more efficient way due to gained flexibility. As a result the costs of total wholesale electricity generation and balancing capacity procurement are reduced. In addition, it is an appropriate design to integrate RES-E and DER in balancing markets, because the shorter the product length, the more RES-E and DER are able to participate in the market.

Symmetric procurement of up- and downward balancing capacity for aFRR and mFRR increases total wholesale generation costs and total procurement costs significantly, because balancing providers always have to reserve both up- and downward capacity, whether it is economical or not. This design causes increased RES-E spillages and implicates reduced RES-E shares. Therefore, it is a poor design for RES-E integration, due to the fact that e.g. wind farms cannot use their full electricity generation since they must provide upward balancing capacity in addition.

The combination of shorter balancing products, allowing common procurement of aFRR and mFRR, and other storages, like batteries and EVs, providing balancing capacity enables the highest cost savings for balancing capacity procurement and for the wholesale generation dispatch.

The highest CO_2 emission reductions are assessed for cross-border procurement, and if other storages (DER in addition to hydro storages) can procure balancing capacity.

In terms of practical implementation of (at least parts of) the analysed cases, a first progress has currently been achieved in two countries, Austria and Germany. Both implemented successfully the common activation of aFRR and introduced daily 4-hour products for aFRR. Further steps could be (i) the implementation of common balancing capacity procurement; (ii) enlarging the area of common aFRR activation, for example to Belgium; and (iii) implementing common activation of mFRR. There are still options and ways to improve European balancing markets, but European Commission, ACER and ENTSO-E already achieved some progress in doing so, e.g. lately the Guideline on Electricity Balancing entered into force and the Network Code on Electricity Balancing has been approved. The implementation of all tasks will take several years.

Flexibility due to additional PHS capacities in Austria

The socio-economic analysis of additional PHS capacities in Austria shows that electricity generation and balancing procurement costs are reduced. The necessity of conventional reserve power plant capacity, mostly defined as peaking unit, is lowered while maintaining a high security of supply level. Due to a shift from conventional power plants to renewable generation technologies, environmental damage costs of up to 1,300 MEuro/a can be avoided in Central Europe when implementing the planned pumped hydro storage capacity in Austria in the upcoming years.

In general, the methodology of the analysis can be applied in any country with similar assumptions. It is not restricted to PHS expansion in Austria only. The cost reductions and revenues are also presented in Euro per installed turbine capacity, hence, the study provides scalability and transferability for other storage projects as well.

Flexible technologies, especially storages, and interconnections are necessary to comply with the challenges of future electricity systems with high shares of variable RES-E generation. To speed up pending projects and attract also private investors in addition, the European Commission assesses PCIs based on their individual contributions for the European electricity system. In case of positive system benefits, these PCIs have access to funding. The methodology presented in this work has been contributing to the ongoing European CBA 2018 assessment of PCI hydro storage projects.

Outlook

Future work shall develop a comprehensive analysis of transnational re-dispatch measures and consider a higher granularity, e.g. time resolution. The higher time resolution is also necessary for the simulation of activating balancing services in real-time and intraday market clearing, which shall be further improved in the model EDisOn+Balancing. Another focus is on implementing uncertainty, e.g. wind and load forecast errors, and respecting additional climatic years. Enlarging the geographical scope by respecting the Nordic countries, the Iberian Peninsula, the South-East European countries, United Kingdom and Ireland is also on the list of further investigations.

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Appendix

Appendix A.

Assumptions, data and additional figures

The assumed primary energy prices and non-fuel O&M costs for the different time horizons used in section 4.1.1 are shown in Table A.1. The merit order curves for Austria in 2020 and 2050 are shown in Figure A.1.

Table A.1.: Assumed primary energy prices and CO_2 certificate prices for 2020, 2030 and 2050, based on (EC, 2013b), (ENTSO-E, 2013), (ENTSO-E, 2014c), and (Korpås et al., 2007).

	unit	primary energy price 2020	primary energy price 2050	non fuel O&M cost 2020-2050
Nuclear	Euro/MWh	1.36	2.02	6.00
Lignite	Euro/MWh	1.58	3.04	3.30
Hard coal	Euro/MWh	10.08	15.27	3.30
Gas	Euro/MWh	28.76	41.01	1.50
Oil	Euro/MWh	60.23	84.18	5.00

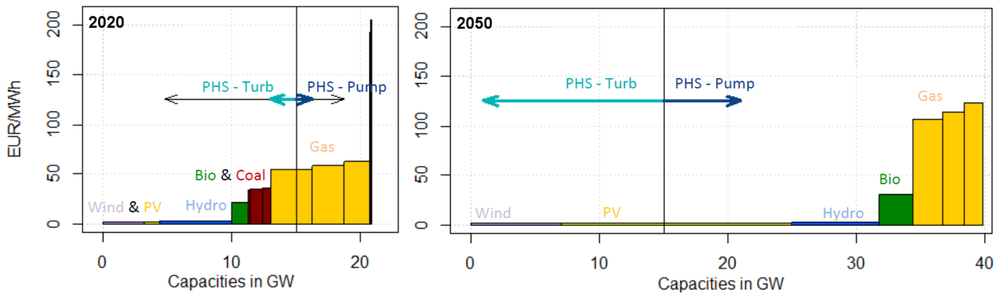

Figure A.1.: Austrian merit order curves used in section 4.1.1 for 2020 and 2050.

After completion of the detailed grid study, presented in section 4.1.2, recent updates indicate that deviations exist in the model under consideration to the current planning state, such as "Reschenpass" will be carried out in 220 kV line construction and will not be considered as in the grid analysis with a voltage of 380 kV. Another point is the changeover of the interconnector operation to 380 kV in Switzerland, which will start after 2030 only. The last point is concerning the expansion of the "Kärnten" transmission line, which has been considered in the analysis as a redundant line to the 220 kV transmission line. However, the existing 220 kV section is boosted to 380 kV. In Figure A.2 the TOP-10-Projects of the APG Masterplan are shown, (APG, 2013).

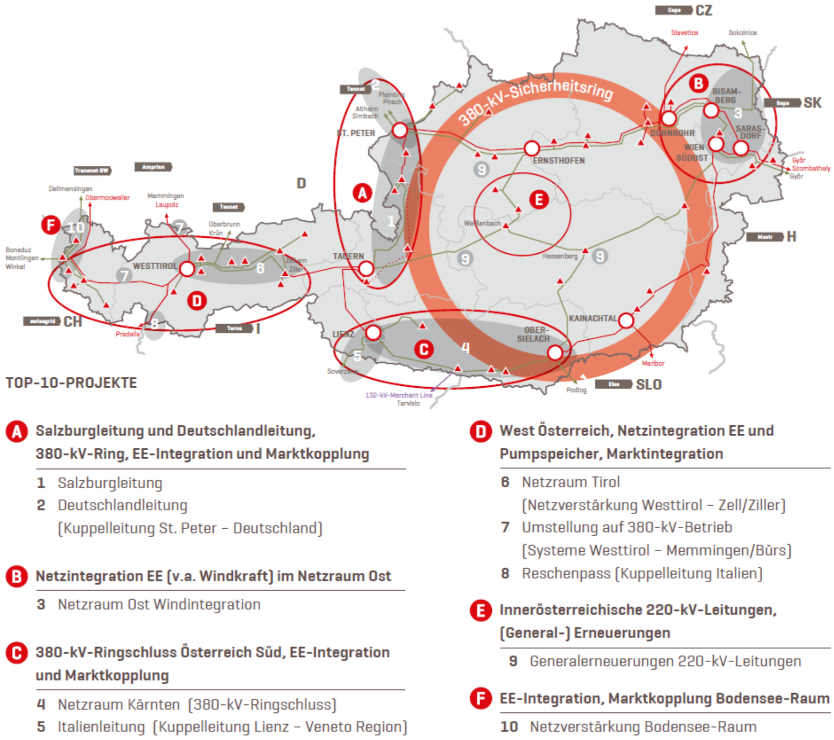

Figure A.2.: The TOP-10-Projects of the APG Masterplan 2030, (APG, 2013).

In Figure A.3 the average procured mFRR balancing capacities for 2030 are shown, which have been assessed in section 4.2.2.

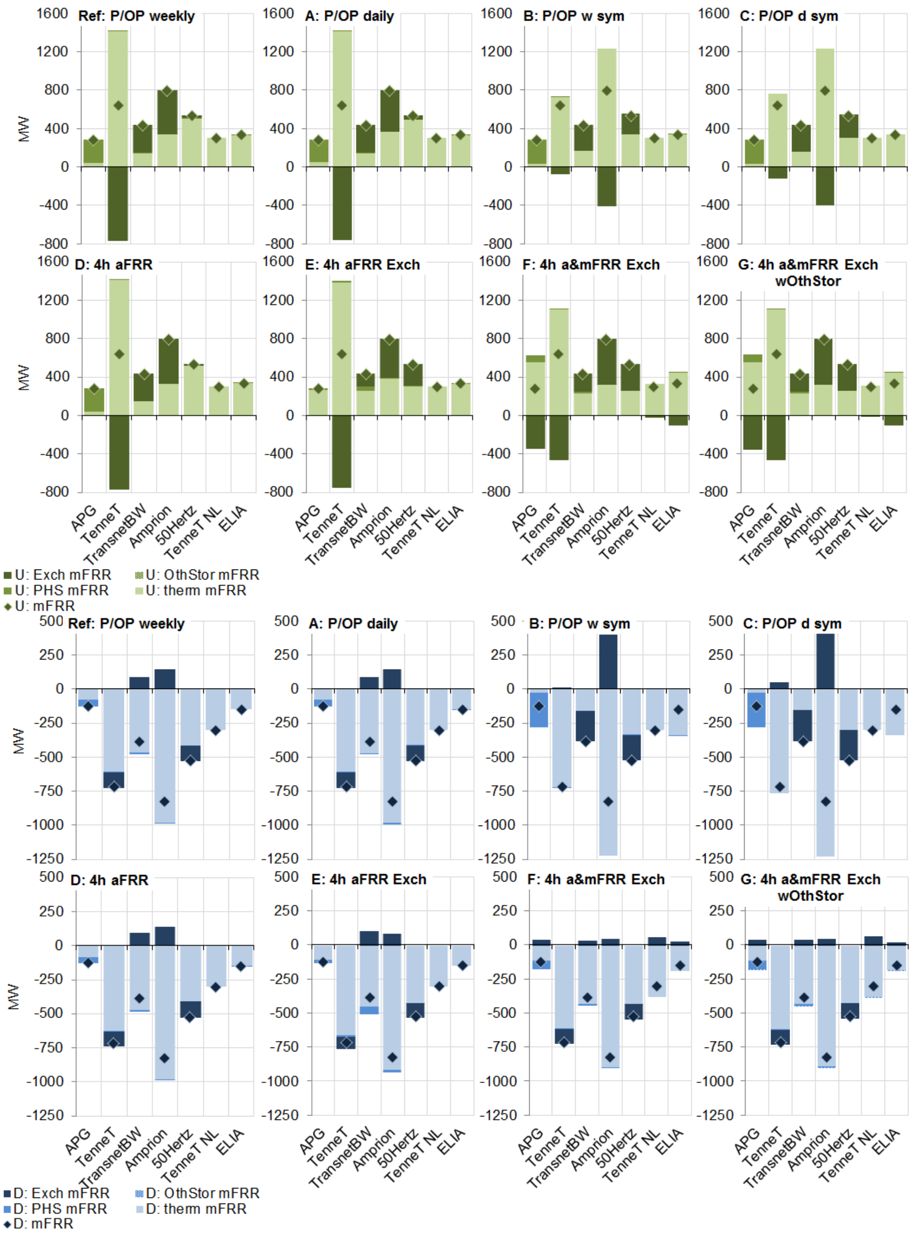

Figure A.3.: Average procured mFRR balancing capacity per control area for 2030 cases (U: upward, D: downward, mFRR: required capacity/h, in MW).

Table A.2 includes the assumed primary energy prices and CO_2 certificate prices of the socio-economic benefit analysis of further PHS capacity expansion in Austria (section 4.3) for the three different scenarios in 2030. The assumed emission factors for each respected primary energy source are included in Table A.3. The national damage costs of emissions are shown in Table A.4.

Table A.2.: Assumed primary energy prices and CO_2 certificate prices for 2030, based on (ENTSO-E, 2017b).

	unit	2030-ST	2030-DG	2030-EC
Nuclear	Euro/MWh	1.69	1.69	1.69
Lignite	Euro/MWh	3.96	3.96	8.28
Hard coal	Euro/MWh	9.72	9.72	15.48
Gas	Euro/MWh	31.68	31.68	24.84
Ligth oil	Euro/MWh	78.48	78.48	73.80
Heavy oil	Euro/MWh	64.44	64.44	52.56
CO_2 prices	Euro/t	84.30	50.00	27.00

Table A.3.: Assumed emission factors per primary energy source, based on (EEA, 2008).

unit	CO_2 (t/MWh)	SO_2 (g/MWh)	NO_x (g/MWh)	NMVOC (g/MWh)	PM_{10} (g/MWh)
gas	0.202	2.448	335.880	5.688	0.360
coal	0.341	2753.998	1051.199	17.712	4330.797
lignite	0.364	4899.596	658.799	28.008	11714.391
fuel oil	0.279	4859.996	701.999	13.320	57.600
other oil	0.267	820.799	464.400	11.664	6.876

Table A.4.: Assumed national damage costs of emissions for value of a life year (VOLY) and a (higher) value of statistical life (VSL), based on (EEA, 2014).

	SO_2		NO_x		NMVOC		PM_{10}	
2005-Euro/t	VOLY	VSL	VOLY	VSL	VOLY	VSL	VOLY	VSL
AT	19651	58494	8681	24442	2248	6184	24870	73794
DE	18956	57524	6817	19059	1891	4772	30721	95814
NL	25269	74414	4854	14770	2364	5722	35413	100156
BE	22591	66516	4152	12227	2368	5750	37226	110845
CH	30800	90337	11997	33635	2946	7855	35991	104042
CZ	12483	36491	6420	17663	2075	5518	25897	74770
SI	15774	47749	9127	25992	2809	7882	21971	66122
PL	11802	33613	5131	13840	1610	4194	27372	76198
SK	10411	30093	6729	17936	1442	3838	21106	59934
HU	11821	35479	7502	20354	1751	4830	24956	76841
IT	14729	46150	7798	23029	3179	8968	31356	100187
FR	15875	45909	5463	13951	1616	4087	21917	62933

Appendix B.

Publications

Proceedings

Burgholzer, B.: “Einfluss der Übertragungsnetzerweiterung im Mittelmeerraum und von solaren Importen aus Nordafrika auf den Kontinentaleuropäischen Kraftwerkseinsatz”, 13. Symposium Energieinnovation, Graz, Austria, 12-14 Feb. 2014.

Burgholzer, B.: “Cost/Benefit Analysis of further expansion of the Austrian transmission gird to enable further RES-E integration”, 14th European IAEE Conference 2014, Rome, Italy, 28-31 Nov. 2014.

Burgholzer, B.: “Zukunft des europäischen Stromnetzes – Ausbau von Stromleitungen bis 2050”, Konferenz “Erdkabel“, Wien, Austria, 2-3 Dec. 2015.

Burgholzer, B.: “Modellierung der Vorhaltung und des Abrufs von Regelenergie mit dem EDisOn+Balancing Modell”, 14. Symposium Energieinnovation, Graz, Austria, 10-12 Feb. 2016.

Burgholzer, B.: “Evaluation of different Balancing Market Designs with the EDisOn+Balancing model”, 13th European Energy Market Conference, EEM 2016, Porto, Portugal, 6-9 June 2016, DOI: 10.1109/EEM.2016.7521271.

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