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Faculty of Engineering Science

Short-Term Operational Flexibility in Long-Term Generation Expansion Planning

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Dissertation presented in partial fulfillment of the requirements for the degree of Doctor of Engineering Science (PhD): Electrical Engineering

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Preface

Doing a PhD can be quite the journey, and at the end of all of it what is left as a reminder of someone pouring four years of their professional life into doing academic research is a little booklet like this one. Long after its contents will have become obsolete, this particular specimen will still serve as a reminder for me of the great experience that I had during my time as a PhD researcher. And for that, I have a lot of people to thank.

First and foremost I want to thank my supervisor. Geert, thank you for giving me the opportunity to do research for four years in such a great environment, for your advice during our frequent meetings, and for your belief in my research and the way in which it developed over the past years. It took some time for me to find my rhythm, but you always supported me, even during these meanders; something which I deeply appreciate. I think that we can now look back on a successful endeavor, and I hope that many more may follow.

Thanks to the members of my jury. Thank you prof. Bultheel, for chairing my jury and for leading the proceedings in the right direction. Thank you professors Belmans and D'Haeseleer, Ronnie and William, for your sharp remarks and insights over the full four years as members of my supervisory committee; these helped to steer my thinking in a consistent manner and challenged my ideas, which contributed greatly to the quality of this work. Merci prof. Hadj-Said, Nouredine, pour avoir voulu completer mon jury. Vous étiez là à la fin de ma thèse de master au G2Elab à Grenoble, et ça me rend très heureux que vous étiez aussi là à la fin de ma thèse de doctorat. J'ai beaucoup apprecié vos remarques, qui m'ont aidé à améliorer le texte. Thank you prof. Delarue, Erik, for also being a part of my jury. I really appreciated our in-depth discussions on the modeling work. You helped me position my work, understand its strengths and weaknesses, and outline its contributions more clearly.

Thanks also to the people who worked on the GOA project, of which this PhD was a part. The project had the ambition to study "whether it is possible to supply all end energy as demanded by the overall society, without emitting any greenhouse gas", and I think we have managed to put forward some important contributions which help understand this challenge and realize the transition. Thanks to all the professors who were part of it: professors Helsen, Saelens and Driesen, and once more Geert, Ronnie, William and Erik; and thanks to the other PhD students with whom I had a lot of fun collaborating: Kenneth, Dieter, Christina, Yves and Felix.

Which brings me to my wonderful colleagues. Life as a PhD student would have been very different without these amazing people surrounding me. Thanks to Luc for keeping me mobile. I admire the patience with which you listened to me every time I came walking into your office to tell you about how I broke the Elmoto in yet another way, and the skill with which you fixed it every time. The people of Elmoto could learn a thing or two from you! Thanks also to Johan and Roland, who made time spent in and around the lab all the more fun and interesting. Thanks to the people from the secretariat: Nathalie, Martine, Veerle, Nele and Katleen, especially for all the agenda related magic tricks she performed when trying to get my supervisory committee in one room at the same time. And thanks to Veronica for making all of my IT-problems disappear, with some very hands on comm-fixing during my preliminary defense. Thanks to Kenneth and Andreas for the great collaborations during our times together as ombudspersons (and also to Erik and Emily!), and to Lieve and Kristl and the other members of the POC for the many constructive dialogues.

Thanks to all the PhD students and postdocs at Electa for some amazing times. Be it at the ESAT Christmas party, during an intensive game of Volley- or other types of pong, or at our annual convention around 8:30 at the Capucijnenvoer and the subsequent folklore-enriched tour of Leuven's city center; time spent with you was always entertaining. Thanks to my office mates. I switched locations a couple of times over the years, but always found myself in the company of some great people. My first stop was the coffee break room. It wasn't easy fitting four desks in there, but Kris, Blas, Diyun, myself and later on Yves made it work. I then moved to somewhat spacier accommodation in the electrothermics lab with Felix, where we were joined by Pieter, Jeroen, Kristof, Ratmir and Taha, thanks to whom I actually learned something about power electronics (and Persian literature for that matter). Next, Felix and I moved upstairs to the office of the "power group", which was an electric bunch of people (ha, get it?). I don't know if their is an upper limit to the amount of Gaston & Leo quotes and videos one can bear, but I'm sure I tested theirs ("goat'r nog wa van keume, seg?!"). This was also more or less the time during which the "Market Madness" group was born; an exquisite selection of PhD researchers that under the guidance of Kristof tackled some of the most burning market design questions during champagne- (or maybe just cava-) laden breakfast meetings. I moved one last time, but to two places at once: in part to the notorious basement floor of ESAT with Hanspeter, Kristof and Diyun (looking forward to our next meet-up, like when Kristof buys another house, or has another baby); in part to the brand new offices of EnergyVille in Genk, with our new colleagues from VITO and imec. This PhD was at times quite literally a journey.

A number of colleagues deserve a special mention because of their contributions to my research. First, thank you Kristof. One and a half year into my PhD, I hadn't really figured out how this academic world worked, and you helped me a great deal in getting there; focusing my attention on one problem at a time, taking me through the paper writing process and much more. Thanks to all my thesis students: Jonas (who actually ended up at Electa as well), Dries, Nick, Sander, Wouter and Vincent. Together we explored some interesting research questions, which helped me improve my model, and resulted in some great Master theses. Thanks to Kris, with whom I figured out the nitty-gritty details of the clustered approach and had some great off-topic discussions, both of which required some challenging brain gymnastics. I think we can be proud of the result of our modeling efforts. Thanks to Tom, a.k.a. T Breezy, with whom I explored the depths of the research on energy storage, most often to the tune of some groovy record. And finally, tremendous thanks to Hanspeter. It's hard to explain just how much you taught me about programming, how much more efficiently I worked because of all the tips and tricks I got from you, how much fun we had during the lab sessions of SDS with Sandro or during the P&D project on the Smart Energy Houses, etc. I have a lot of respect for you and I value our friendship greatly. Dat we nog lang mogen mogen!

Heel wat mensen hebben het leven naast het doctoreren ook uiterst aangenaam gemaakt. Het is een beetje raar dat ik na vier jaar werken de kans krijg om die mensen daarvoor te bedanken, maar als de kans zich aanbiedt, dan grijp ik ze met plezier. Een dikke merci aan de Ring boys en in het bijzonder Mighty Mike a.k.a. DJ Magmar voor de schoon tijden, de mensen van het speelplein voor de long-term friendships, mijn band members bij EME voor de muzikale live-avonturen, de Hiphophooradio crew voor een tocht door de muziekgeschiedenis, de Stormvogels van het D-team voor de sportieve feestelijkheden, de Feytons-fixt-dat-wel peoples voor de ski trips en nieuwjaarsweekends, de BD League voor de FPL-competities, de Barboek-familie voor een tweede thuis, Saskia en Sarah om met mij te weten samenwonen (bedankt, hé), Felix (wait but why?), de beste generatie scoutsleiding die de FOS van Kessel-Lo ooit gekend heeft voor de general awesomeness, The Lonely Moose Club voor de menige zelf-relativerende discussies (you're not special, hé Arjun) en levensadvies (mijn tweede mama, die Emma), Marten en Kenneth voor de lees- en schrijfavonturen, en de Burgi boys en hun +1's voor de trips, soirées en algemeen wangedrag.

Tot slot een woord van dank voor mijn familie. Ik prijs me bijzonder gelukkig om deel uit te maken van zo'n warme en hechte familie, langs beide kanten. Bedankt aan mijn fantastische grootouders, en zeker mijn grootmoeder, bomma, die er niet meer is, maar nog steeds een grote inspiratie is voor mij voor hoe ik in het leven wil staan. Bedankt aan al mijn tantes en nonkels, en nichten en neven die ondertussen ook hun eigen bundles of joy op de wereld zijn beginnen zetten, en natuurlijk mijn petekind(je), Carlijn, die de kerstperiode altijd beter maakt met onze sleepovers. Bovenal ben ik dolgelukkig met de plaats die ik mijn thuis mag noemen. Ik kan me waarlijk geen betere plek voorstellen om telkens weer naar terug te keren. Bedankt aan mijn broer Dieter en ons Nina, en mijn ouders. Van pre-practice dinners op woensdag tot zaterdagse quality time; ondanks al mijn bewuste button-pushing, koppigheid en overall "uitdagendheid" in de dagdagelijkse omgang, weet ik dat jullie er altijd onvoorwaardelijk voor mij zullen zijn. Whatever may come next, ik weet dat we het samen het hoofd zullen bieden, en dat is eigenlijk alles wat ik zou kunnen wensen.

Leuven, december 2016
Arne

Abstract

In light of the European climate ambitions, there has been substantial growth in capacity of variable renewable energy sources in many Member States, with significant future growth expected. Such sources impact the operation of the power system by challenging its ability to maintain the short-term balance between supply and demand. Firstly, their output is variable and uncertain, increasing the need for short-term flexibility. Secondly, they displace part of the conventional flexibility providers, i.e. the dispatchable generation technologies, decreasing the supply of short-term flexibility. These sources also impact the planning of the power system by challenging its long-term ability to meet the aggregate demand for electricity. Firstly, only a limited share of their capacity can be called upon at any given time. Secondly, their impact on power system operation also has an impact on power system planning. The first aspect, related to *firm capacity adequacy*, is well understood and is mostly dealt with adequately in planning models. The second aspect, related to *flexibility adequacy*, has only recently emerged as an area of interest in planning.

To study the importance of short-term flexibility adequacy in long-term power system planning, a high level of temporal and operational detail is needed, while managing the required computational effort. For that purpose, an alternative approach is developed for representing power system operation in planning: a clustered formulation of the unit commitment problem. Using this formulation, a planning model is developed which identifies the optimal investment portfolio, taking into account renewable energy objectives, and determines the scheduled production and consumption levels to deliver energy and reserve. The need for short-term flexibility is represented via the modeling of the day-ahead electricity market with an hourly resolution – to include the effects of variability, and operating reserve requirements following the guidelines of the European Network for Transmission System Operators for Electricity – to include the effects of uncertainty. The supply of flexibility is represented via mathematical models of dispatchable and variable generation, long-term demand response, re-electrifying and non re-electrifying storage, and flexibility through interconnection.

First, the developed planning model is applied to a test system to assess the impact of short-term flexibility requirements on the cost and composition of the optimal investment portfolio. The supply of short-term flexibility is limited to the sources most commonly found in European power systems, namely dispatchable generation technologies and pumped hydro energy storage. Results show that renewable uncertainty is the most important driver of the short-term flexibility-related costs. Results further show that the way of handling this uncertainty, i.e. the adopted reserve sizing and allocation strategy, is decisive for the final impact of flexibility adequacy requirements. Based on the findings of this work it can be said that it will most likely no longer be cost-effective to centrally impose a level of reliability in a highly renewable power system. In a liberalized and decentralizing power system context, the value of reliability will also be something to be determined in a liberalized and decentralized way. Finally, it has to be noted that other elements than short-term flexibility requirements may have larger impacts on total system cost, and that it might therefore be more opportune for other planning models to dedicate additional computational resources to these issues, rather than to including the short-term flexibility constraints. This, naturally, depends on the goal of the research.

Second, the planning model is used to assess the value of alternative sources of short-term flexibility, and the importance of the level of operational detail for assessing their impact. The supply of short-term flexibility is expanded to include a number of selected technologies of the three other types of flexibility sources: energy storage, demand response and interconnection. Results show that different technologies generate added value in different ways, but that they are also to a certain extent interchangeable. Results further show that the optimal level of investment depends on how well the technologies are able to compound different sources of added value, and that high operational detail in a power system planning model is therefore indispensable, as it enables the model to capture the total added value of the different technologies. The combined flexibility of the considered conventional and alternative flexibility providers allows to significantly reduce the cost of short-term flexibility requirements. By unlocking their potential through technology-neutral and internationally harmonized market desings, and coupling it to an ambitious operating reserve strategy, the flexibility providers could thus enable the integration of large shares of variable renewable energy sources without significant flexibility adequacy-related costs.

Beknopte samenvatting

Naar aanleiding van de Europese klimaatdoelstellingen, is er in vele lidstaten een aanzienlijke groei geweest in de capaciteit van variabele hernieuwbare energiebronnen, en wordt er in de toekomst nog een sterke groei verwacht. Enerzijds hebben deze bronnen een impact op de uitbating van het elektriciteitssysteem, daar ze het bewaren van de korte-termijn-balans tussen vraag en aanbod bemoeilijken. Vooreerst is hun productie variabel en onzeker, wat de nood aan korte-termijnflexibiliteit verhoogt. Ernaast verdringen ze deels de conventionele flexibiliteitsverschaffers, i.e. de volledig stuurbare productietechnologieën, wat het aanbod aan korte-termijnflexibiliteit verlaagt. Rechtstreeks hiermee verbonden hebben deze bronnen ook een impact op de lange-termijn planning van het elektriciteitssysteem, daar ze het beantwoorden van de vraag naar elektriciteit op lange termijn bemoeilijken. Gelinkt aan hun weersafhankelijkheid is de onzekerheid van de beschikbaarheid van hun capaciteit. Ook hun impact op de uitbating heeft een impact op de planning. Naar het eerste aspect, gelinkt aan zekere-capaciteit-adequaatheid, is reeds veel onderzoek gedaan. Naar het tweede aspect, gelinkt aan korte-termijnflexibiliteit-adequaatheid, is veel minder onderzoek gedaan, waardoor de impact ervan nog niet goed begrepen wordt.

Adequaat de impact van korte-termijnflexibiliteit in lange-termijnplanning bestuderen vereist veel operationeel detail en een hoge tijdsresolutie, gegeven een beperkte rekenkracht. Gegeven deze doelstelling is een nieuwe aanpak uitgewerkt voor het integreren van operationele beperkingen in een planningsmodel: een geclusterde formulering van het "unit commitment" probleem. In dit werk is een planningsmodel uitgewerkt, op basis van deze formulering, dat de optimale investeringsportfolio bepaalt, onder doelstellingen voor het aandeel hernieuwbare energie, alsook de planning van productie en consumptie voor het leveren van energie en reserves. Voor de voorstelling van de nood aan korte-termijnflexibiliteit wordt de uurlijkse elektriciteitsmarkt gemodelleerd – om de effecten van variabiliteit te vatten, en de reservevereisten volgens de voorschriften van het Europese Netwerk van Transmissiesysteembeheerders – om de effecten van onzekerheid te vatten. Elektriciteitsproductie (stuurbaar en

variabel), lange-termijnvraagsturing, opslag, en flexibiliteit via interconnectie worden allen via mathematische modellen beschreven om het aanbod aan korte-termijnflexibiliteit voor te stellen.

In eerste instantie is dit model toegepast op een testsysteem om de impact van korte-termijnflexibiliteitvereisten op planning te evalueren. Jaarlijkse optimalisaties met verschillende niveaus van operationeel detail laten toe om de impact op kost en investeringen te bepalen. Om de huidige situatie weer te geven, is het aanbod van flexibiliteit in deze analyses beperkt tot productietechnologieën en pompopslag. Uit de resultaten blijkt dat de hernieuwbare onzekerheid de belangrijkste drijfveer is van de flexibiliteitskosten. Uit de resultaten blijkt verder dat de manier waarop met deze onzekerheid wordt omgegaan, i.e. de reservestrategie, bepalend is voor de uiteindelijke impact van de onzekerheid. Precies o.w.v. de hoge kosten verbonden aan onzekerheid in zeer hernieuwbare systemen, lijkt het dat het niet langer kost-efficiënt zal zijn om centraal strenge doelstellingen op te leggen voor de betrouwbaarheid van de elektriciteitsvoorziening. In een geliberaliseerd en decentralizerend elektriciteitssysteem zal de waarde van betrouwbaarheid bij voorkeur ook op een geliberaliseerde, decentrale manier tot stand komen. Tot slot dient opgemerkt te worden dat andere elementen een grotere impact kunnen hebben op de planning, en dat het daarom voor bepaalde planners interessanter kan zijn om rekenkracht aan andere zaken dan korte-termijnflexibiliteit-adequaatheid te wijden.

In tweede instantie is het model toegepast om de waarde van alternatieve korte-termijnflexibiliteitsverschaffers te evalueren, alsook het belang van het operationeel detail om die waarde te kunnen inschatten. Het aanbod van flexibiliteit wordt uitgebreid met de drie alternatieve types flexibiliteit: opslag, vraagsturing en interconnectie. Uit de resultaten blijkt dat verschillende technologieën op verschillende wijzen toegevoegde waarde genereren, maar tegelijkertijd dat ze tot op zekere hoogte inwisselbaar zijn. Uit de resultaten blijkt verder dat het optimale investeringsniveau van een technologie afhangt van hoe goed die verschillende bronnen van toegevoegde waarde weet te combineren, en daaruitvolgend dat een hoog niveau operationeel detail nodig is in planningsmodellen om al deze waarde te kunnen vatten. De verzamelde flexibiliteit van de conventionele en alternatieve verschaffers staat toe om de korte-termijnflexibiliteitskosten sterk te verminderen. Door dit potentieel te ontgrendelen via technologie-neutrale en internationale gecoördineerde martkmechanismen, en dit te koppelen aan een ambitieuze reservestrategie, kunnen deze flexibiliteitsverschaffers dus de integratie van grote hoeveelheden hernieuwbare bronnen mogelijk maken zonder dat daarbij grote flexibiliteitskosten veroorzaakt worden.

Acronyms

AC	Alternating Current
ACE	Area Control Error
BES	Battery Energy Storage
BRP	Balance Responsible Party
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenses
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CUC	Clustered Unit Commitment
DG ENER	Directorate-General for Energy
EENS	Expected Energy Not Served
ENTSO-E	European Network for Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
aFRR	automatic Frequency Restoration Reserves
mFRR	manual Frequency Restoration Reserves
GEP	Generation Expansion Planning
GFPP	Gas-Fired Power Plants
GHG	Greenhouse Gas
HP	Heat Pump
HV&AC	Heating, Ventilation & Air Conditioning
HVDC	High Voltage Dirrect Current
LDC	Load Duration Curve
LFC&R	Load Frequency Control and Reserves

LOLE	Loss Of Load Expectation
LTDR	Long-Term Demand Response
NEMS	National Energy Modeling System
NEP	Network Expansion Planning
NREL	National Renewable Energy Laboratory
OPEX	Operational Expenses
P2G	Power-to-Gas storage
pdf	probability density function
PHES	Pumped Hydro Energy Storage
PV	solar Photo-Voltaic power
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources for Electricity
VRES-E	Variable Renewable Energy Sources for Electricity
RLDC	Residual Load Duration Curve
RR	Replacement Reserves
SMES	Superconducting Magnetic Energy Storage
TSO	Transmission System Operator
UC	Unit Commitment
UC&ED	Unit Commitment and Economic Dispatch

Nomenclature

Sets

Symbol	Index	Description
$\mathbb{T}$	t	Time steps
$\mathbb{P}$	p	Periods
$\mathbb{A}$	a	Allocation horizons
$\mathbb{AT}$	a, t	Mapping of allocation horizons to time steps
$\mathbb{Z}$	z	Zones in the model
$\mathbb{Z}_{\mathbb{E}}$	z_e	Zones exporting, copy of $\mathbb{Z}$
$\mathbb{Z}_{\mathbb{I}}$	z_i	Zones importing, copy of $\mathbb{Z}$
$\mathbb{F}$	z, z	Mapping of interconnections
$\mathbb{C}$	c	Countries in the model
$\mathbb{J}$	j	Jointly sizing zones in the model
$\mathbb{CZ}$	c, z	Mapping of zones to countries
$\mathbb{JZ}$	j, z	Mapping of zones to jointly sizing zones
$\mathbb{R}$	r	Reserve categories
$\mathbb{RU}$	–	Upward reserve categories, $\mathbb{RU} \subseteq \mathbb{R}$
$\mathbb{RUA}$	–	Upward aFRR and FCR, $\mathbb{RUA} \subseteq \mathbb{RU}$
$\mathbb{RUF}$	–	Upward FCR, $\mathbb{RUF} \subseteq \mathbb{RUA}$
$\mathbb{RD}$	–	Downward reserve categories, $\mathbb{RD} \subseteq \mathbb{R}$
$\mathbb{RDA}$	–	Downward aFRR and FCR, $\mathbb{RDA} \subseteq \mathbb{RD}$
$\mathbb{RDF}$	–	Downward FCR, $\mathbb{RDF} \subseteq \mathbb{RDA}$
$\mathbb{I}$	i	Injection technologies, $\mathbb{I} = \{\mathbb{G}, \mathbb{S}\}$
$\mathbb{ID}$	–	Dispatchable injection technologies, $\mathbb{ID} = \{\mathbb{GD}, \mathbb{S}\}$
$\mathbb{O}$	o	Off-take technologies, $\mathbb{O} = \{\mathbb{S}, \mathbb{D}\}$
$\mathbb{G}$	g	Generation technologies
$\mathbb{GD}$	–	Dispatchable generation technologies, $\mathbb{GD} \subseteq \mathbb{G}$
$\mathbb{GR}$	–	Renewable generation technologies, $\mathbb{GR} \subseteq \mathbb{G}$

$\mathbb{GG}$	–	Gas-fired generation technologies, $\mathbb{GG} \subseteq \mathbb{GD}$
$\mathbb{S}$	s	Storage technologies
$\mathbb{SE}$	–	Re-electrifying storage technologies, $\mathbb{SE} \subseteq \mathbb{S}$
$\mathbb{SN}$	–	Non-re-electrifying storage technologies, $\mathbb{SN} \subseteq \mathbb{S}$
$\mathbb{D}$	d	Demand response technologies

Variables

Symbol	Unit	Description
$p^{\mathrm{cap,i}}_{z,i}$	MW	Injection, installed power capacity
$p^{\mathrm{i}}_{z,i,t}$	MW	Injection, level of operation
$p^{\mathrm{ru,i}}_{z,i,t}$	MW	Injection, change in level by ramping up
$p^{\mathrm{rd,i}}_{z,i,t}$	MW	Injection, change in level by ramping down
$p^{\mathrm{su,i}}_{z,i,t}$	MW	Injection, change in level by starting up
$p^{\mathrm{sd,i}}_{z,i,t}$	MW	Injection, change in level by shutting down
$p^{\mathrm{cu,i}}_{z,i,t}$	MW	Injection, curtailment level
$r^{\mathrm{i,a}}_{z,r,i,a}$	MW	Injection, reserve provision over allocation horizon
$r^{\mathrm{i,b}}_{z,r,i,t}$	MW	Injection, reserve provision over time step
$r^{\mathrm{i,a,t}}_{z,r,i,a,t}$	MW	Injection, mapping allocation reserves to time steps
$r^{\mathrm{i}}_{z,r,i,t}$	MW	Injection, total reserve provision
$r^{\mathrm{s,i}}_{z,r,i,t}$	MW	Injection, spinning reserve provision
$r^{\mathrm{su,i}}_{z,r,i,t}$	MW	Injection, reserve provision through start ups
$r^{\mathrm{sd,i}}_{z,r,i,t}$	MW	Injection, reserve provision through shut downs
$n^{\mathrm{i}}_{z,i,t}$	-	Injection, number of on-line units
$n^{\mathrm{su,i}}_{z,i,t}$	-	Injection, number of units starting up
$n^{\mathrm{sd,i}}_{z,i,t}$	-	Injection, number of units shutting down
$n^{\mathrm{su,r,i}}_{z,r,i,t}$	-	Injection, number of units allocated to start up
$n^{\mathrm{sd,r,i}}_{z,r,i,t}$	-	Injection, number of units allocated to shut down
$p^{\mathrm{cap,o}}_{z,o}$	MW	Off-take, installed power capacity
$p^{\mathrm{o}}_{z,o,t}$	MW	Off-take, level of operation
$p^{\mathrm{ru,o}}_{z,o,t}$	MW	Off-take, change in level by ramping up
$p^{\mathrm{rd,o}}_{z,o,t}$	MW	Off-take, change in level by ramping down
$p^{\mathrm{su,o}}_{z,o,t}$	MW	Off-take, change in level by starting up
$p^{\mathrm{sd,o}}_{z,o,t}$	MW	Off-take, change in level by shutting down
$r^{\mathrm{o,a}}_{z,r,o,a}$	MW	Off-take, reserve provision over allocation horizon
$r^{\mathrm{o,b}}_{z,r,o,t}$	MW	Off-take, reserve provision over time step
$r^{\mathrm{o,a,t}}_{z,r,o,a,t}$	MW	Off-take, mapping allocation reserves to time steps

$r^{\mathrm{o}}_{z,r,o,t}$	MW	Off-take, total reserve provision
e^{cap}_{s}	MWh	Storage, installed energy capacity
$e_{z,s,t}$	MWh	Storage, energy level
$e^{\mathrm{first}}_{z,s,t}$	MWh	Storage, energy level for representative periods
$e^{\mathrm{last}}_{z,s,t}$	MWh	Storage, energy level for representative periods
$c^{\mathrm{cyc}}_{z,s}$	€	Storage, cycling costs
$e^{\mathrm{lp}}_{c,t}$	MWh	Gas grid line-pack buffer, energy level
$p^{\mathrm{lp,c}}_{c,t}$	MW	Gas grid line-pack buffer, charging
$p^{\mathrm{lp,d}}_{c,t}$	MW	Gas grid line-pack buffer, discharging
$e^{\mathrm{us}}_{c,t}$	MWh	Underground gas storage, energy level
$p^{\mathrm{us,in}}_{c,t}$	MW	Underground gas storage, injection
$p^{\mathrm{us,ex}}_{c,t}$	MW	Underground gas storage, extraction
$p^{\mathrm{imp}}_{c,t}$	MW	Import of natural gas
$p^{\mathrm{syn}}_{z,i,t}$	MW	Use of synthetic gas
$p^{\mathrm{nat}}_{z,i,t}$	MW	Use of natural gas
$d^{\mathrm{cap,up}}_{z,d}$	MW	Demand, upward adjustment capacity
$d^{\mathrm{cap,dn}}_{z,d}$	MW	Demand, downward adjustment capacity
$d^{\mathrm{dn}}_{z,d,t}$	MW	Demand, upward adjustment level
$d^{\mathrm{up}}_{z,d,t}$	MW	Demand, downward adjustment level
$f^{\mathrm{cap}}_{z,z'}$	MW	Interconnection capacity
$f_{z,z,t}$	MW	Flow between zones
$f^{\mathrm{r,a}}_{z,z,r,a}$	MW	Reserve exchange over allocation horizon
$f^{\mathrm{r,b}}_{z,z,r,t}$	MW	Reserve exchange over time step
$f^{\mathrm{r,a,t}}_{z,z,r,a,t}$	MW	Mapping allocation reserves to time steps
$f^{\mathrm{r}}_{z,z,r,t}$	MW	Total reserve exchange
$p^{\mathrm{ls}}_{z,t}$	MW	Load shedding level

Parameters

Symbol	Unit	Description
ΔT^{t}	hours	Duration of a time step
$\Delta T^{\mathrm{r}}_{r}$	hours	Duration of reserve delivery
S^{res}_{c}	%	Renewables target
S^{firm}_{c}	%	Firm capacity target
$D_{z,t}$	MW	Electricity consumption
D^{peak}_{z}	MW	Electricity peak consumption
$R^{\mathrm{ex,a}}_{z,r,a}$	MW	Exogenous reserve need per allocation horizon

$R^{\mathrm{en,a}}_{z,r,i,a}$	%	Endogenous reserve need per allocation horizon
$R^{\mathrm{ex,b}}_{z,r,t}$	MW	Additional exogenous reserve need per time step
$R^{\mathrm{en,b}}_{z,r,i,t}$	%	Additional endogenous reserve need per time step
$R^{\mathrm{j,ex,a}}_{j,r,a}$	MW	$R^{\mathrm{ex,a}}_{z,r,a}$ for joint zones
$R^{\mathrm{j,en,a}}_{j,r,i,a}$	%	$R^{\mathrm{en,a}}_{z,r,i,a}$ for joint zones
$R^{\mathrm{j,ex,b}}_{j,r,t}$	MW	$R^{\mathrm{ex,b}}_{z,r,t}$ for joint zones
$R^{\mathrm{j,en,b}}_{j,r,i,t}$	%	$R^{\mathrm{en,b}}_{z,r,i,t}$ for joint zones
$C^{\mathrm{inv,i}}_{i}$	€/MW	Injection, power investment cost
$C^{\mathrm{fom,i}}_{i}$	€/MW	Injection, fixed operating and maintenance cost
$C^{\mathrm{fuel,i}}_{i}$	€/MWh	Injection, fuel cost
$C^{\mathrm{vom,i}}_{i}$	€/MWh	Injection, variable operating and maintenance cost
$C^{\mathrm{ra,i}}_{i}$	€/MW	Injection, ramping cost
$C^{\mathrm{su,i}}_{i}$	€/MW	Injection, start up cost
$C^{\mathrm{sd,i}}_{i}$	€/MW	Injection, shut down cost
P^{i}_{i}	MW	Injection, unit size
$P^{\mathrm{i,firm}}_{i}$	%	Injection, firm capacity fraction
$P^{\mathrm{min,i}}_{i}$	%	Injection, minimum level of operation
$T^{\mathrm{mut,i}}_{i}$	hours	Injection, minimum up time
$T^{\mathrm{mdt,i}}_{i}$	hours	Injection, minimum down time
$R^{\mathrm{s,i}}_{i}$	%	Injection, ramping rate (spinning) in the market
$R^{\mathrm{su,i}}_{i}$	%	Injection, ramping rate (start up) in the market
$R^{\mathrm{sd,i}}_{i}$	%	Injection, ramping rate (shut down) in the market
$R^{\mathrm{s,r,i}}_{r,i}$	%	Injection, ramping rate (spinning) for reserves
$R^{\mathrm{su,r,i}}_{r,i}$	%	Injection, ramping rate (start up) for reserves
$R^{\mathrm{sd,r,i}}_{r,i}$	%	Injection, ramping rate (shut down) for reserves
η^{i}_{g}	%	Injection, fuel efficiency
$P^{\mathrm{res}}_{i,t}$	%	Variable renewable input profile
$P^{\mathrm{rel}}_{z,i,t}$	%	Reliable share of variable renewable input profile
$C^{\mathrm{inv,o}}_{o}$	€/MW	Off-take, power investment cost
$C^{\mathrm{fom,o}}_{o}$	€/MW	Off-take, fixed operating and maintenance cost
$C^{\mathrm{fuel,o}}_{o}$	€/MWh	Off-take, fuel cost
$C^{\mathrm{vom,o}}_{o}$	€/MWh	Off-take, variable operating and maintenance cost
$C^{\mathrm{ra,o}}_{o}$	€/MW	Off-take, ramping cost
$C^{\mathrm{su,o}}_{o}$	€/MW	Off-take, start up cost
$C^{\mathrm{sd,o}}_{o}$	€/MW	Off-take, shut down cost
$P^{\mathrm{o,firm}}_{o}$	%	Off-take, firm capacity fraction
$C^{\mathrm{inv,e}}_{s}$	€/MWh	Storage, energy investment cost
$C^{\mathrm{cyc,cap}}_{s}$	€/MWh	Storage, cycling cost, capital component
$C^{\mathrm{cyc,op}}_{s}$	€/MWh	Storage, cycling cost, operational component

η_s^{o}	%	Storage, charging efficiency
η_s^{i}	%	Storage, discharging efficiency
E_c^{lp}	MWh	Gas grid, line-pack buffer energy capacity
E_c^{us}	MWh	Underground gas storage, energy capacity
$P_c^{\mathrm{us,in}}$	MW	Underground gas storage, injection capacity
$P_c^{\mathrm{us,ex}}$	MW	Underground gas storage, extraction capacity
$C_d^{\mathrm{inv,d}}$	€/MW	Demand, investment cost
$C_d^{\mathrm{op,d}}$	€/MWh	Demand, operational cost
$P_{z,d,t}^{\mathrm{d,ref}}$	MW	Demand, reference consumption profile
M_d^{min}	MW	Demand, minimum consumption margin
M_d^{max}	MW	Demand, maximum consumption margin
$\Delta P_{d,t}^{\mathrm{up}}$	MW	Demand, maximum upward adjustment
$\Delta P_{d,t}^{\mathrm{dn}}$	MW	Demand, maximum downward adjustment
ΔE_d^{up}	MWh	Demand, maximum upward energy adjustment
ΔE_d^{dn}	MWh	Demand, maximum downward energy adjustment
H_d^{up}	hours	Demand, period with one full upward activation
H_d^{dn}	hours	Demand, period with one full downward activation
A_d^{up}	-	Demand, maximum full upward activations
A_d^{dn}	-	Demand, maximum full downward activations
$C_{z,z'}^{\mathrm{inv,f}}$	€/MW	Interconnection, investment cost
F^{r}	%	Interconnection, fraction of reserve exchange
C^{nat}	€/MWh	Cost of natural gas
C^{ls}	€/MWh	Load-shedding cost
C^{cu}	€/MWh	Curtailment cost

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Chapter 1

Introduction

1.1 Motivation

1.1.1 The growth of variable renewables

In light of the European climate ambitions and related targets, there has been substantial growth in the share of Renewable Energy Sources (RES) in the total gross energy consumption of the Member States. In the power sector, the share of Renewable Energy Sources for Electricity (RES-E) grew at an average of 1.3 percentage points per year over the period 2005-2013, amounting to 25.4% of all consumed electricity coming from RES-E in 2013 (Figure 1.1) [1]. With the 2020 climate & energy package putting forth a 20% target for RES by 2020 [2], the 2030 climate & energy framework introducing a 27% target for RES by 2030 [3], and the *Energy Roadmap 2050* of the Directorate-General for Energy (DG ENER) indicating RES targets of at least 55% and up to 75% by 2050; future growth of RES-E is to be expected.

In many Member States the growth in RES-E is realized by increased development of Variable Renewable Energy Sources for Electricity (VRES-E), so-called because of their dependency on a variable resource [5], because of which their electricity generation output is variable, only limitedly controllable and limitedly predictable. Figure 1.2 shows that, even though hydropower still remained the largest contributor of renewable electricity, producing 45.5% of the total renewable electricity generation in 2013, the growth in renewable electricity generation over the decade 2003-2013 stemmed predominantly from the threefold increase in the use of biomass, the fivefold increase in the use of

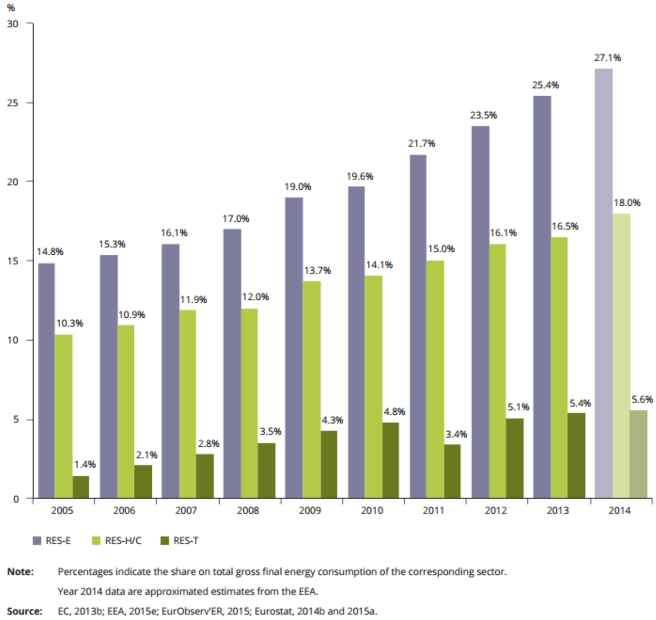

Figure 1.1: Renewable energy shares by sector in the EU – Electricity (E), Heating and Cooling (H/C), and Transport (T) [1]

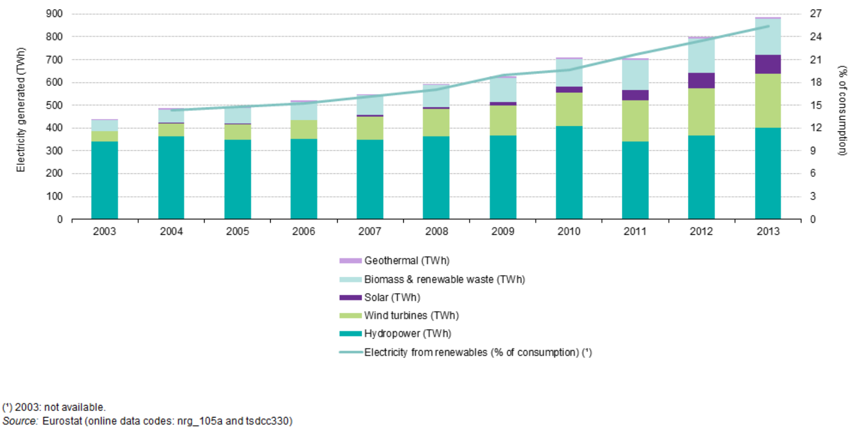

Figure 1.2: Breakdown per type of renewable energy source of the renewable share of electricity consumption in the EU [4]

wind energy, and the even greater increase in the use of solar Photo-Voltaic power (PV) – from 0.1% to 9.6%. In 2013, 38% of the renewable electricity originated from VRES-E [1], with most of this coming from wind energy and PV, and a very limited share coming from tide, wave and ocean power (0.05%) [4]. The introduction of such significant shares of VRES-E into the European power system challenges the security of our electricity supply [6, 7].

1.1.2 Security of electricity supply

Security of electricity supply is defined by Eurelectric (the Union of the Electricity Industry in Europe) as "the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner; relating to the existing standards and contractual agreements at the points of delivery" [8]. Note the part of the definition: "[...] with a specified level of continuity [...]", which already recognizes the economical infeasibility of realizing an electricity supply that is 100% reliable. Even so, realizing a supply that meets the end-users' desired level of security is a complex task relating to several aspects, categorized along the lines of long-term and short-term security of electricity supply (see Figure 1.3).

Long-term security of electricity supply

Long-term security of electricity supply is defined by Eurelectric as "the simultaneous adequacy of access to primary fuels, generation, networks and market" [8]. It consists of three elements: access to primary fuels, market adequacy and system adequacy [9]. Access to primary fuels relates to e.g. the geopolitical challenges connected to fossil fuels or the public acceptance of certain fuel types. Market adequacy relates to regulatory aspects of the power system, i.e. establishing "an efficient link between producers and consumers of electricity" [8] and providing a stable regulatory framework. System adequacy is defined by Eurelectric as "the ability of the electricity system to convert primary fuels into electricity and transmit that electricity to end-users in a sustainable manner" [8]. System adequacy itself is comprised of network adequacy and generation adequacy. This distinction is made because of the fundamentally different economic context in which they operate; the former being realized in the context of regulated monopolies, the latter in the context of the liberalized market. Network adequacy is defined as "the availability of sufficient network infrastructure to meet demand" [8]; encompassing transmission and distribution grids, and cross-border interconnections. Generation adequacy is defined as "the availability of enough generating (and import) capacity to meet demand" [8].

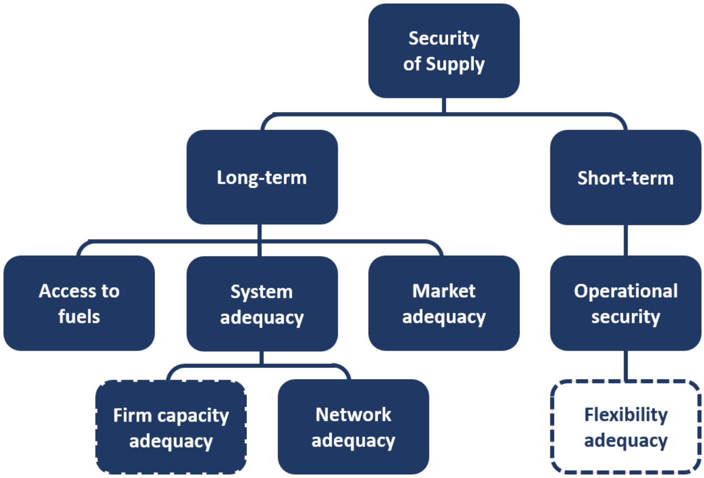

Figure 1.3: Different aspects of security of electricity supply

Both these definitions are somewhat outdated as they neglect the more dispersed installation of VRES-E capacity compared to conventional generation capacity, the increasing mobilization of the demand side, the more prominent role storage technologies are expected to play, etc. Therefore, it is best to update them. Network adequacy can be redefined as the availability of sufficient network infrastructure to accommodate the flows of electricity. Where current networks have been designed to transport electricity from centers of production (typically one or more big power plants) to centers of consumptions (e.g. cities or industrial sites), future networks will have to accommodate more bidirectional flows (with e.g. consumption centers at times becoming net producers of electricity due to decentralized VRES-E capacity) and extend their reach to locations with favorable renewable resources where at present network infrastructure has been less developed (e.g. off-shore wind farms). Generation adequacy, in turn, is best replaced by **firm capacity adequacy**, which is the availability of sufficient firm capacity to maintain the supply-demand balance. Firm capacity is the amount of capacity available for an increase in production or decrease in consumption that is guaranteed to be available at a given time [10], usually expressed as a percentage of the installed capacity. It can be provided not only by conventional generation technologies, but also by e.g. VRES-E and demand side technologies. The share of firm capacity in the installed capacity varies significantly across technologies, with e.g. wind energy technologies exhibiting values around 20-30% [11] whereas for conventional generation technologies this is typically around 90%, depending on the rate of failures and outages.

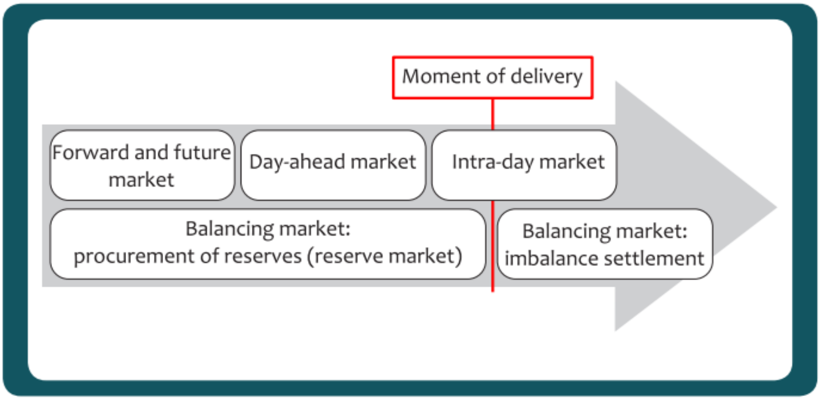

Figure 1.4: Consecutive electricity markets, designed to deal with the real-time character of keeping the balance between supply and demand of electricity [12]

Short-term security of electricity supply

Short-term security of electricity supply or "operational security" is defined by Eurelectric as "the operational reliability of the system as a whole and its assets, including the ability to overcome short-term failures of individual components of the system" [8]. Electricity is a unique commodity in the sense that supply and demand should be in balance in real-time. In Europe, if this is the case, then the system's frequency is at its nominal level, i.e. 50 Hz. If total supply is higher than total demand, frequency rises and vice versa. Deviations in frequency lead to a number of problems; ranging from damage to frequency-sensitive loads, over the tripping of frequency-sensitive protections, to a partial or full black-out of the power system.

European electricity markets have been designed in such a way that they are adapted to deal with this specific characteristic [12]. A number of markets are organized in consecutive order, from years before to beyond the actual moment of delivery (Figure 1.4). Balancing Responsible Parties (BRPs)[1] trade electricity in the **forward and future market** and the **day-ahead market**, and pass on a balanced portfolio to the TSO after market closure of the latter market. In the **intra-day market**, they can trade to adjust their portfolios based on better information on e.g. VRES-E forecasts. In contrast to the day-ahead

[1] A BRP is a private legal entity that has the responsibility to present a balanced electricity production and consumption portfolio to the Transmission System Operator (TSO). A BRP can represent several producers and consumers, and can own its proper production and consumption means, and trade with other BRPs [12].

market, a BRP is not expected to have a balanced portfolio at the end of the intra-day market. Any residual imbalance remaining after the intra-day stage is dealt with in the **balancing market**. Individual BRP imbalances are added to arrive at the power system's total imbalance. A TSO will correct this imbalance by activating operating reserves (see further). The TSO is the only buyer in the balancing markets, even though BRPs can possess their own means for the short-term balancing of their portfolios. The costs of the procurement and activation of these reserves are passed on by the TSO to the BRPs via the **imbalance settlement**, in which a BRP is either charged or remunerated for its imbalance, depending on its imbalance position.

The final responsibility for keeping the balance lies with the TSO. To that end it contracts ancillary services such as operating reserves [13]. Operating reserves are capacity contracted specifically by a TSO to overcome the "short-term failures of individual components of the system" mentioned before, and more generally cope with the different sources of uncertainty in its power system. In the power sytems of the European Network for Transmission System Operators for Electricity (ENTSO-E), operating reserves are categorized into three groups, namely: the Frequency Containment Reserves (FCR), the Frequency Restoration Reserves (FRR) — split into the automatic Frequency Restoration Reserves (aFRR) and manual Frequency Restoration Reserves (mFRR) – and the Replacement Reserves (RR). An overview of their interrelation is shown in Figure 1.5. The Network Code on Load Frequency Control and Reserves (LFC&R) provides the general framework for their use and characteristics [14]. FCR are used to stabilize the frequency after a disturbance or incident in a matter of seconds. They are activated automatically. FRR aim to restore the system frequency by restoring the balance in the control zone of a TSO, thus relieving the system wide activated FCR. FRR capacity is activated either automatically (aFRR) or manually (mFRR). Their activation is triggered by the Area Control Error, which is calculated as the difference between the scheduled and actual power interchange of a control zone. RR can be used to progressively relieve the activated FRR or to support the FRR activation.

To perform all these balancing activities – from coping with the differences in residual electricity demand between consecutive hours in the day-ahead market to the real-time, fast-response delivery of operating reserves – short-term operational flexibility is needed. This flexibility can come from the supply side, the demand side, storage and through interconnection. Flexibility shortages might lead to the inability of the power system to maintain the short-term balance between supply and demand, not because of a shortage in capacity, but because of an inability to adjust supply and/or demand sufficiently quickly in response to e.g. the variability and uncertainty of VRES-E output. Ensuring that sufficient flexibility is available to maintain the supply-demand balance

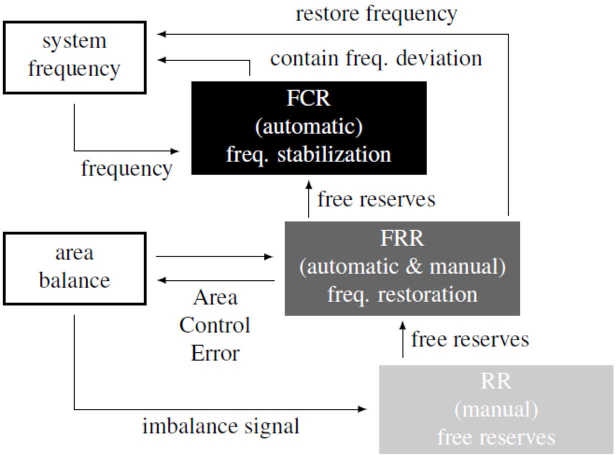

Figure 1.5: Interrelation of operating reserves

therefore is an important part of ensuring operational security, and thus the short-term security of electricity supply. This concept, which omits certain other aspects of operational security such as the need for black start capacity, is labeled in this work as **flexibility adequacy** (see Figure 1.3). It is this aspect of VRES-E integration – its impact on flexibility adequacy – that this work is concerned with.

1.1.3 Short-term flexibility in long-term planning

The impact of variable renewables on flexibility adequacy

Until recently short-term flexibility adequacy was not assumed to be an important issue for ensuring security of supply, especially not in the sense that it would determine any long-term decisions such as investments in generating or network capacity. On the one hand this was due to the relatively low need for short-term flexibility, which was mainly driven by outages on the supply side and the transmission networks, and by the limited and well understood variability and uncertainty of the demand side. On the other hand it was due to the relatively high supply of flexibility, a consequence of a specific characteristic of power system planning that is discussed further down. However, the recent and expected growth in VRES-E challenges this assumption. The impact of VRES-E integration on flexibility adequacy is twofold.

First, **VRES-E integration increases the need for short-term flexibility**. This impact stems from the fact that VRES-E output is variable and uncertain. Due to its dependency on weather conditions, output can fluctuate rapidly following the variations in wind speeds or solar irradiation, requiring additional flexibility. Furthermore, in contrast to conventional power plants – whose output can be fully controlled within the limits of the installed capacity – the only control over the VRES-E output can happen through curtailment, i.e. the deliberate reduction of output to below what is at most possible. This control, then, again depends on the availability of the VRES-E's "fuel", i.e. the variable wind speeds and solar irradiation. Finally, output is forecasted via weather forecasts, and in approaching real-time these forecasts are normally increasingly accurate, but some uncertainty remains and errors do occur. As installed capacity of VRES-E increases, such forecast errors can result in significant additional ramping requirements for the other elements of the power system; requiring among other things the procurement of greater volumes of operating reserves.

Second, **VRES-E integration decreases the conventional supply of short-term flexibility**. Presently, flexibility typically comes from the supply side, namely from the conventional, dispatchable power plants, and from large scale Pumped Hydro Energy Storage (PHES) plants, which are able to ramp up or down their electricity production (and consumption in the case of PHES) more or less rapidly depending on their technical characteristics. While VRES-E may be adept at providing the energy once provided by the conventional plants, it is far less obvious whether they are able to provide the flexibility (or the firm capacity discussed earlier) now provided by the conventional power plants [6]. Alternative sources of flexibility will thus have to be addressed. The demand side also already offers some flexibility, with some large industrial consumers optimizing their use of electricity taking into account electricity price evolutions during the day, and others being contracted by TSOs to provide operating reserves by reducing their consumption when activated. Nevertheless, additional demand side flexibility will become important, such as flexibility in the residential sector (e.g. coordinated charging of electric vehicles). Likewise, other storage technologies than PHES are expected to play a more significant role, such as Battery Energy Storage (BES). Finally, flexibility can also already be found through the interconnection of different power systems, now mostly to (partly) export or import surpluses or shortages of electricity to and from neighboring power systems. Here, e.g. also the exchange of operating reserves can become important.

This twofold impact of the integration of variable renewables challenges flexibility adequacy, and thus operational security. First, this has an impact on the short-term operation of the power system. However, while the required flexibility might still be found in existing portfolios when facing limited shares of VRES-E [13, 15], this might no longer be the case when facing higher shares of VRES-E [16, 17]. Then, VRES-E related flexibility adequacy issues could also challenge power system planning, and investment decisions in supply side, demand side, and storage technologies, and networks should take these issues into account so that flexibility adequacy can be ensured. Nevertheless, at the outset of this PhD power system planning models had not yet evolved to consider this impact.

The impact of flexibility adequacy on long-term planning

Given the complexity of the problem, power system planning has typically been split up into two subproblems along the same lines as system adequacy (see Figure 1.3), leading to two groups of models. The first group, called Network Expansion Planning (NEP) models, focuses on investments in network capacity on the transmission and/or distribution level. The goal of these models is to ensure network adequacy. Therefore, they have a very detailed representation of the network, so that they are able to identify which lines need to be reinforced, or where new transport routes have to be developed, such that the network can accommodate generation, storage and demand; cope with transmission-distribution interactions or interactions between different power systems; etc. The second group, called **Generation Expansion Planning (GEP)** models, focuses on investments in supply side technologies. The goal of these models has been to ensure generation adequacy. They have a less detailed representation of the network, usually limited to import/export between power systems. Much like generation adequacy shifted to firm capacity adequacy, the goal of these models increasingly shifts to firm capacity adequacy, now also focusing on investments in demand side and storage technologies. Given these two groups of models, long-term power system planning becomes a two-step process, with the output of the GEP models serving as an input for the NEP models.

This work focuses on investments in supply side, demand side and storage technologies and network capacity, with only a simple representation of the network; i.e. on GEP models. The scope of GEP models has traditionally been limited to firm capacity adequacy, not considering flexibility adequacy. For this, there are two reasons. The first reason is related to the need for and supply of flexibility. On the one hand, as mentioned before, the need for flexibility was low, something which is changing due to increased VRES-E integration. On the other hand the supply of flexibility in the portfolios coming out of existing GEP models was rather high, even though these models did not explicitly address flexibility adequacy. This was due to a specific characteristic of these models, that can be demonstrated via a simple example based on the screening curve methodology.

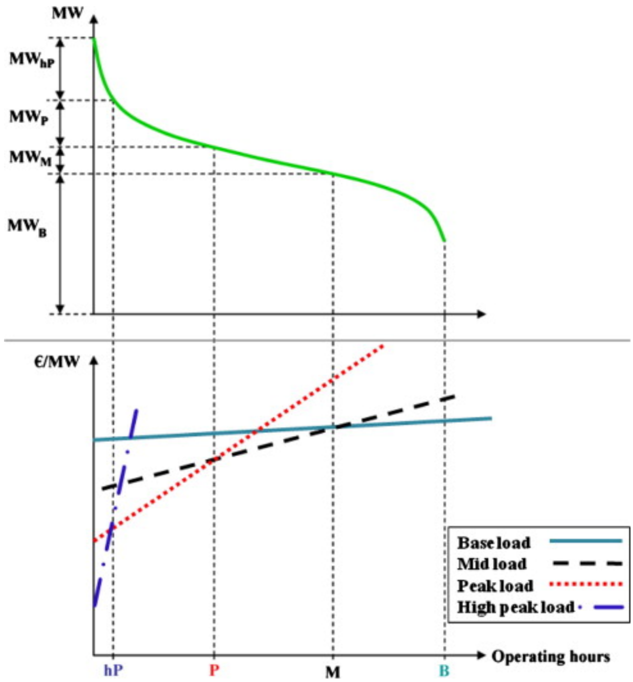

Figure 1.6: Example of a load-duration curve and the optimal operating hours and installed capacity for base (B), mid (M), peak (P), and high peak (hP) technologies resulting from the screening curve methodology [18]

The screening curve methodology is one of the traditional ways for solving the power system planning problem [19, 20, 21]. It uses a simplified representation of production costs via technology cost curves. The intersections of these curves are matched to points on the load-duration curve (a curve sorting the hourly demand levels of the power system at hand for a specific year from high to low). From this the cost-optimal investments portfolio in generation capacity can be derived (Figure 1.6). This methodology has important limitations, of which power system planners are well aware. Nevertheless, the tendency that is of importance here persists. Looking at Figure 1.6, it can be seen that a certain share of the installed capacity only operates for a limited number of hours per year. For this, it is then economically optimal to use technologies with low fixed costs, in this example the *peak* and *high peak* technologies. It so happens that these technologies are also very flexible, able to ramp up and down more rapidly than the high fixed cost *mid* and *base* technologies. So, merely by performing an economic optimization, traditional GEP models proposed very flexible investment portfolios. This effect is reinforced by other often encountered constraints, such as a capacity margin (imposing that total capacity should be 120-150% of peak demand). Given the even lower number of operating hours for such capacity, the optimization opts again for the low fixed cost technologies, introducing even more flexibility. Now, however, due to the downward effect of VRES-E integration on the operating hours of conventional generation capacity, and the liberalized context of the power system which challenges the economic viability of investments in capacity with such a low number of operating hours, the conventional supply of flexibility is decreasing.

The second reason for which planning models did not explicitly addressed flexibility adequacy issues has to do with the additional complexity it introduces. To keep computation efforts within limits, power system planning models typically do not consider the same level of temporal and operational detail as power system operation models. Simplifications are made in the temporal resolution (e.g. not checking the supply-demand balance on an hourly basis), and in the operational constraints on the technology (e.g. ramping ability) and the system level (e.g. the need for operating reserves). As a result, such models cannot be used to appropriately study the impact of short-term flexibility adequacy issues on the optimal investment portfolio.

In summary, it can be said that due to historical and computational reasons GEP models did not consider flexibility adequacy issues; a simplification that was considered acceptable as it was assumed that such issues would have a negligible influence on investments. However, in the face of growing VRES-E shares across European power systems, it is expected that this assumption can no longer hold. Existing simplifications will then lead to an underestimation of VRES-E integration costs, and an underestimation of the value of technologies that can provide the required flexibility. The integration of large shares of VRES-E increases the need for and reduces the conventional supply of short-term flexibility. This is expected to have an impact on the long-term planning of the power system, and adequate requirements will have to be formulated in order to ensure flexibility adequacy. **It is the goal of this PhD thesis to understand how short-term flexibility adequacy impacts long-term planning**. Therefore, a GEP model is developed which considers firm capacity adequacy *and* flexibility adequacy. Using this model, it is studied how flexibility constraints alter the cost and composition of the optimal investment portfolio, which allows to more appropriately identify the costs related to the transition towards a power system with high shares of VRES-E. Finally, the model also considers alternative sources of flexibility, such as storage and demand side technologies, which allows to appropriately estimate the added value of these technologies, often specifically adept at providing the necessary short-term flexibility to accommodate the integration of VRES-E.

1.2 Context: Concerted Research Action

This thesis was developed in the context of a “Concerted Research Action” (cfr. Geconcerteerde Onderzoeksactie, GOA), an internal project funding mechanism of the KU Leuven with a specific focus on research on sustainability. The project, entitled *Fundamental Study of a Greenhouse Gas Emission-free Energy System*, aims to establish a well justified priority list of actions and milestones to cost-effectively arrive at a CO_2 lean energy economy towards 2050. It is postulated that the ideal system is such a CO_2 lean energy provision system. Subsequently, the project’s goal is “to investigate in a fundamental way the question whether it is possible to supply all end energy as demanded by the overall society, without emitting any greenhouse gas”.

The goals and general approach stated by the GOA project inspired a number of the methodology choices made in this PhD:

Back-casting approach Firstly, the project selects a back-casting approach, which means that a desired end goal is formulated, and then intermediate objectives are derived via reasoning backward. This is translated in this work by limiting the focus to finding the optimal investment portfolio for a certain year, given specific exogenously imposed targets, and not considering the pathway towards that year.

Technical feasibility Secondly, the project emphasizes the need to check the technical feasibility of realizing a CO_2 lean energy provision system, more specifically whether security of supply can be guaranteed in such a system. This thesis deals exclusively with the power system, not considering other energy forms than electricity. To decarbonize the electricity provision system, a number of solutions are available, such as electricity production based on nuclear energy, electricity production based on fossil fuels with Carbon Capture and Storage (CCS)[2], or electricity production from (variable) renewable energy sources. From a security of supply point of view, the latter is the most challenging, in that dealing with the associated variability and uncertainty of VRES-E will challenge current practices of power system operation the most. Therefore, given the emphasis on technical feasibility, in this work the decarbonization of the electricity provision system will be pursued only by means of increasing the share of VRES-E in the electricity consumption, assuming that other decarbonization would be comparatively easier to realize, and consequently lead to smaller short-term flexibility related impacts.

[2] “CCS is a technology that can capture up to 90% of the carbon dioxide (CO_2) emissions produced from the use of fossil fuels in electricity generation and industrial processes, preventing the carbon dioxide from entering the atmosphere” [22].

All-electric society Thirdly, the project postulates an all electric society at the end-energy level. This vision is taken into account when a number of the assumptions are made regarding the flexibility of the residential electricity consumption, related e.g. to the penetration of heat pumps and electric vehicles.

Integrating flexibility Finally, the project highlights the importance of the integration of the supply side, demand side, and interconnecting networks in mobilizing the necessary flexibility to deal with the inevitable increase in VRES-E capacity. This is why in this work flexibility from different providers on different levels is studied, from centralized storage and generation technologies, over residential and industrial demand-response, to cooperation between power systems.

1.3 Scope and Contributions

The aim of this thesis is to help understand the importance of short-term flexibility requirements in long-term power system planning. It is crucial for policy-makers to have a profound understanding of all costs related to VRES-E integration. A thorough quantification of the costs associated with the impact of VRES-E integration on short-term flexibility adequacy, and additional insights from a planning perspective into how to deal cost-effectively with their variability and uncertainty, contributes to such an understanding. Furthermore, it is important for policy-makers and market players to understand how short-term flexibility requirements alter investment decisions in a power system planning model, allowing to identify more correctly the added value of flexible technologies and the role they play in the operation of power systems with large shares of VRES-E.

Therefore, the focus in this work is on developing a methodology for evaluating the impact of VRES-E related short-term flexibility challenges on planning and assessing the value of technologies that can help address these challenges. To gain preliminary insights this model will be applied to a conceptual test system for a number of analyses. The share of VRES-E in electricity consumption of the power system will be imposed, ranging between 0% and 50%. The insights of these analyses obviously have a number of limitations. The system is also an "island" system, i.e. a power system that is not connected to neighboring systems (with the exception of the analyses that consider interconnection), which is more challenging for power system operation. The model uses data of a single year, meaning that the results are not evaluated for their robustness to e.g. changes in yearly VRES-E output. Uncertainty related to input data and assumptions can have important implications for outlining robust decarbonization pathways [23, 24]. Some authors have even suggested that it might be better to keep planning tools simple, so that more scenarios can be evaluated more quickly, leading to a better understanding of tackling this uncertainty [25, 26]. Consequently, certain models have been presented that propose investment portfolios that are robust to uncertain future conditions [27, 28]. Such approaches are beyond the scope of this work.

Furthermore, several other important aspects have not been modeled or studied in detail. While the VRES-E integration will also have an impact on reactive power management, the developed model only looks at active power. No detailed firm capacity adequacy analysis has been performed either, even though it also is an important aspect of system adequacy. Such an analysis requires data on fluctuations in yearly output of VRES-E, technical potentials, etc. This is beyond the scope of this work. Market design and other policies will be key in incentivizing the right investments to arrive at a power system portfolio that ensures flexibility adequacy. While this thesis provides insight in the composition of such a portfolio, no work has been done to identify the policies that can bring about such a portfolio in a liberalized power sector.

Finally, the interaction between VRES-E and the transport of electricity, as mentioned before, is not considered. The impact of cooperation between neighboring power systems in dealing with short-term flexibility adequacy has been studied, and an estimation of its impact on the total transmission capacity need between such systems has been formulated; but no detailed transmission or distribution system planning has been performed. It is clear that VRES-E integration will bring important changes to these fields, but that is beyond the scope of this work. For this, readers are referred to the PhD thesis of another KU Leuven PhD researcher, H. Ergun [29]. In this thesis a state-of-the-art NEP model is developed. The GEP model developed in this thesis has been formulated in such a way that its outcomes can serve as inputs to this NEP model.

Consequently, in this work no alternative will be proposed to the roadmaps as those presented by the European Commission, as this requires a great deal of additional input – preferably following from extensive stakeholder consultation, and the modeling of other sectors of the European system to incorporate the interaction of the power sector with the overall system. The insights generated in this work, however, could inform the developers of the models behind such roadmaps, e.g. PRIMES [30] and TIMES [31], as to where an increase in the considered detail on power system operation and short-term flexibility could be useful. Outcomes of such models could also be reevaluated with the tools presented in this work to check if short-term flexibility adequacy can be ensured, and study in more detail how that flexibility would be optimally supplied by the different available flexible technologies.

Given this scope delimitation, there are three main contributions to the state-of-the-art in this thesis:

Modeling short-term flexibility A power system planning model has been developed that includes detailed requirements for short-term flexibility that allow to deal with the variability and uncertainty of VRES-E. This is done via the representation of the short-term scheduling phase and the inclusion of operating reserves requirements based on guidelines of the European Network of Transmission System Operators. Furthermore, it represents the supply of flexibility in detail as well, by including the necessary technical constraints for the short-term operation of different flexible technologies on the supply, transport and demand side.

The impact of short-term flexibility Using the developed model, the impact of short-term flexibility requirements on the integration costs of VRES-E and the optimal investment portfolio is identified. Different strategies for dealing with the uncertainty of VRES-E are studied, which provides a better understanding into how to deal with their integration in a cost-effective manner.

The supply of short-term flexibility The added value and the role of alternative short-term flexibility providers is studied, including storage and demand response technologies; as well as the importance of short-term flexibility requirements to be able to assess this added value appropriately. The impact of cooperation between neighboring power systems is also analyzed, as well as the extent to which these technologies are interchangeable when they compete for providing the same short-term flexibility services.

1.4 Outline

The outline of this thesis is organized as follows:

Chapter 2 describes the way short-term flexibility has been dealt with in long-term power system planning in the state-of-the-art of literature. It discusses both how the variability and uncertainty of VRES-E has been integrated in planning, and how the flexibility offered by the different providers has been modeled and their corresponding role and impact studied. It concludes by outlining the current shortcomings in the literature and indicating which of these will be addressed here.

Chapter 3 presents the planning tool developed in this thesis. First, it describes the methods for analyzing the variability and uncertainty that drive the need for, with a specific focus on VRES-E. Then, it present the mathematical description of the planning model, including the models of the supplyof flexibility.

Chapter 4 studies the impact of the short-term flexibility requirements on the outcome of the power system planning model. It quantifies separately the costs related to variability and to uncertainty, as well as the corresponding impact on the composition of the optimal investment portfolio. It studies the importance of the adopted strategy for dealing with operational uncertainty, and concludes by qualitatively discussing the importance of the flexibility-related costs compared to other cost drivers. The work in this chapter is based on:

- A. van Stiphout, K. De Vos and G. Deconinck, "The Impact of Operating Reserves on the Investment Planning of Renewable Power Systems," *Power Systems, IEEE Transactions on*, Year: 2016, Volume: PP, Issue: 99, Pages: 1 – 12
- A. van Stiphout, K. Poncelet, K. De Vos and G. Deconinck, "The Impact of Operating Reserves in Generation Expansion Planning with High Shares of Renewable Energy Sources," *14th IAEE European Energy Conference*, Rome, Italy, 28-31 October, 2014

Chapter 5 studies the role of alternative flexibility providers, i.e. other than dispatchable generation technologies. It discusses their impact on the costs, the investments decisions, and the operation of a highly renewable power system; and the importance of detailed flexibility requirements to capture the added value of such technologies. The work in this chapter is based on:

- A. van Stiphout, T. Brijs, G. Deconinck and R. Belmans, "Quantifying the importance of power system operation constraints in power system planning models: A case study for electricity storage," *Journal of Energy Storage*, October, 2016, submitted
- T. Brijs, A. van Stiphout and R. Belmans, "Evaluating the role of electricity storage by considering short-term operation in long-term planning," *Sustainable Energy, Grids and Networks*, October, 2016, submitted
- A. van Stiphout and G. Deconinck, "The Impact of Long-Term Demand Response in Investment Planning of Renewable Power Systems," *13th International Conference On The European Energy Market (EEM)*, Porto, Portugal, 6-9 June, 2016
- A. van Stiphout, S. Vaeck and G. Deconinck, "The Role of Long-Term Storage in Investment Planning of Renewable Power Systems," *IEEE International Energy Conference EnergyCon 2016*, Leuven, Belgium, 4-8 April, 2016
- A. van Stiphout, K. De Vos and G. Deconinck, "Operational Flexibility Provided by Storage in Generation Expansion Planning with High Shares of Renewables," *12th International Conference On The European Energy Market (EEM)*, Lisbon, Portugal, 19-22 May, 2015

Chapter 6, finally, summarizes the insights of this work and provides conclusions and indications for future research.

Chapter 2

Power system operation in power system planning

2.1 Introduction

The consideration of the impact of short-term power system operation on long-term power system planning is an emerging field of research. In the past, planning tools were able to yield adequate investment portfolios using only a very coarse representation of power system operation. However, given the historic and expected growth of the share of VRES-E, these simplifications are challenged, and concerns regarding short-term flexibility adequacy have to be dealt with explicitly. Furthermore, as the need for short-term flexibility rises, and the share of conventional generation technologies in the electricity generation mix decreases, alternative sources of short-term flexibility have to be found. To be able to understand their role in the operation of increasingly renewable power systems, and their subsequent impact on planning of such systems, their operation will also needs to be modeled appropriately.

This chapter starts by defining short-term flexibility: where does the need for flexibility originate, and how can it be supplied? Next, it reviews (1) how short-term power system operation has been represented in long-term power system planning models; and (2) how the potential of alternative short-term flexibility providers, such as storage and demand response, has been assessed. Finally, this chapter concludes by indicating the shortcomings in the current literature, and outlines which of these will be addressed over the course of the following chapters.

2.2 General definition

A number of authors have attempted to define *flexibility*. Most authors discuss flexibility purely from a technical point of view. A recent National Renewable Energy Laboratory (NREL) study defines flexibility as “a measure of a system’s ability to change supply or demand as needed to accommodate variability and uncertainty at different time scales” [32]. Similar definitions can be found with other authors [33, 34, 35]. However, a technical definition by itself is insufficient when dealing with concerns on flexibility in power system planning. A more appropriate impetus is given in [36], which states that flexibility “represents the extent to which a power system can adapt electricity generation and consumption as needed to maintain system stability in a cost-effective manner”. It is this link to the economics of power system operation that is of crucial importance.

To address flexibility from a planning perspective, the definition of *flexibility* needs to be accompanied by a definition of *flexibility adequacy* [37]. Recall the definition of *system adequacy*, which points to the long-term technical ability of the power system to provide a secure supply of electricity. As mentioned earlier, the focus here is on generation adequacy and its two sub-aspects: *firm capacity adequacy* and *flexibility adequacy*. The former relates to the ability of the power system to meet peak aggregate demand, and thus essentially to whether or not there is sufficient capacity available at all times (in light of the VRES-E integration, this points mostly to such things as back-up capacity). The latter relates to the ability of the power system to follow changes in aggregate demand, and thus – linked to the definition of flexibility above – to its ability to adjust supply and demand *sufficiently quickly* to deal with the variability and uncertainty present in the system at different time scales. Whether a supply of electricity is secure or not, depends on the pre-specified level of continuity and quality. This can be translated into a value of lost load (e.g. 3000 €/MWh) to be taken into account during the planning phase, and into reliability standards such as the Loss Of Load Expectation (LOLE) and the Expected Energy Not Served (EENS).[1] Thus, flexibility adequacy can be said to be ensured when a power system has sufficient flexibility to meet the desired level of security of supply.

To summarize, *flexibility* is a measure of a system’s ability to deal with variability and uncertainty, whereas *flexibility adequacy* points to whether a system has sufficient flexibility to provide a secure supply of electricity. The next two subsections will discuss where the need for flexibility comes from, and how it can be supplied.

[1] LOLE points to the expected average amount of time per year during which demand exceeds the available supply; EENS points to the expected average energy not served to end-consumers during those periods where demand exceeds the available supply.

2.2.1 The need for short-term flexibility

The integration in the power system of every element that is only limitedly controllable and/or limitedly predictable incurs an additional need for short-term flexibility. The limits to the control can be technical, e.g. a conventional generation plant has a limited rate at which it can ramp up or down its production. The limits can also be economic, e.g. an industrial plant can have processes that require a minimum level of consumption to keep running, and plant operators can be willing to pay more for electricity in order to not have to reduce their consumption below this minimum level. The limits to predictability can manifest themselves in multiple ways. One example is that of elements whose output cannot or only limitedly be controlled, and must thus be forecasted, as is the case for VRES-E. This can lead to forecast errors, i.e. deviations of real-time output from the forecasted output. Another example is that of unexpected outages, where an entire element can stop producing or consuming electricity (or importing or exporting electricity) due to malfunctioning.

These two drivers of the need for short-term flexibility can each be associated with an integration cost and more generally described as follows [38, 39]:

variability – profile costs The variability of the production or consumption profile of an element in the power system can require adjustments in the scheduling of production or consumption of the other elements in the power system that deviate from their most economic scheduling. This incurs additional costs, which are called profile costs.

uncertainty – balancing costs The uncertainty of the production or consumption of an element leads to deviations of real-time output from the scheduled or forecasted output, which can lead to imbalances between supply and demand, requiring additional adjustments in the real-time levels of production or consumption of the other elements in the power system. This also incurs additional costs, which are called balancing costs.

Note that in the literature profile costs are typically split up into two sub-costs when discussing the impact of VRES-E integration: the *utilization costs* and the *flexibility costs*. The former relates to the structural changes in the residual load curve, that exhibits more moments of low or even negative residual load, which lead to important changes in the capacity factors of the dispatchable technologies (typically inducing a shift from the use of base load to mid load generation technologies). The latter relates to the steeper and more frequent ramps in the residual load curve caused by the integration of VRES-E, which lead to increased cycling and the starting up and shutting down of the dispatchable technologies in the power system.

When translated to power system operation, it can be said that *variability* relates to the day-ahead and intra-day stages, when production and consumption of the different power system elements is scheduled and forecasted. It is addressed via the day-ahead and intra-day markets. BRPs can adjust their own production and consumption, and buy and sell electricity on the markets to balance their portfolio. Differences in net aggregate demand between consecutive time steps of the markets can force BRPs to deviate from their economically optimal schedule. These additional costs are passed on by BRPs with sufficient flexibility in their portfolio to those BRPs lacking flexibility.

Uncertainty relates to the moment of delivery, when production and consumption have to be adjusted in real-time to deal with deviations of the scheduling and forecasts. It is addressed via a TSO's operating reserves and a BRP's own balancing resources. A TSO contracts reserve capacity. However, it will typically not contract sufficient reserve capacity to cover all occurring imbalances. It also expects BRPs to procure their own balancing services to balance their own portfolio themselves. These balancing services are not subjected to detailed product requirements, as is the case for operating reserves, but merely serve to adjust a BRPs residual imbalance. For this imbalance it is either charged or remunerated during imbalance settlement. In Belgium, the TSO has designed settlement tariffs such that BRPs are charged more or remunerated less when the total system imbalance exceeds a certain level, thus explicitly incentivizing them to have access to sufficient flexible resources.

The integration of VRES-E introduces additional variability and uncertainty in the power system, thus requiring additional short-term flexibility. The output of VRES-E is variable, because of technical reasons (e.g. weather dependency) and at times also economic reasons (e.g. some existing subsidy schemes keep incentivizing VRES-E to fully inject their available output, even when electricity prices are negative and there clearly is a surplus of electricity in the system). This additional variability leads to bigger differences in net aggregate demand between consecutive time steps of the markets, requiring more flexibility from the BRPs. The output of VRES-E is also uncertain. Output has to be forecasted, and forecast errors can occur in real-time. The extent of the impact of forecast errors obviously depends on the quality of the forecasts; improving such forecasts facilitates VRES-E integration [40]. VRES-E installations can also malfunction, leading to unexpected outages. This additional uncertainty requires TSOs and BRPs to contract more operating reserves and balancing resources.

Quantifying a power system's need for flexibility in detail is hard, because it depends on the variability and uncertainty present in the system at a given time. Furthermore, the ability of a system to adjust supply and demand also varies in time depending on whatever technologies are on-line, or can be brought on-line sufficiently quickly to respond to a change in aggregate demand. This ability also depends on the time horizon over which this change occurs, and the characteristics of the technologies available in the system, which have different ramping abilities over different time horizons. As such, defining a high level need for flexible capacity – as a method to ensure flexibility adequacy – is a challenging task. While it might be very useful for adjusting high level energy system models, the use of metrics makes it hard to capture the difference in adjustment abilities over different time horizons of flexible capacity originating from different technologies. Therefore, no such metric will be defined in this work, as it is the goal of this research to understand in detail the impact of flexibility requirements. A much more appropriate approach for this goal is to expose a power system's portfolio to expected operational conditions, i.e. variability and uncertainty, and evaluate its ability to meet aggregate demand cost-effectively given a certain value of lost load. A full explanation of the adopted approach is given in Chapter 3.[2]

2.2.2 The supply of short-term flexibility

Many different options exist for the supply of short-term flexibility, and for increasing this supply in response to the increase in need for short-term flexibility following VRES-E integration. Broadly speaking, these options can be divided in four categories: supply side flexibility, demand side flexibility, energy storage, and interconnection (see Figure 2.1). The way in which these technologies can offer flexibility is determined by their specific technical and economic characteristics. However, they are to a certain extent interchangeable, as they compete for providing the same flexibility services. The final mix of flexibility providers should thus be the result of an economic optimization, choosing between all providers that can technically supply the required flexibility. In what follows existing and expected flexibility providers of the four categories will be discussed.

[2] The use of simplified metrics could be of interest for "high-level" power system planning models, such as the PRIMES or the TIMES models. Those models currently cannot spare the computation power needed for a full representation of power system operation. However, as this work is interested in accurately determining the impact of short-term flexibility on planning, no simplifications can be made in representing the flexibility challenges. Future work could derive simplified metrics, suitable for integration in more high-level planning tools, based on the outcomes of this work. A valuable impetus is provided in [41], where a power system's flexibility needs are categorized by ramp magnitude, ramp frequency, and response time. Other interesting proposals are provided in [42, 43, 44, 45] which propose still other methods for evaluating power system flexibility, such as the concept of flexibility envelopes.

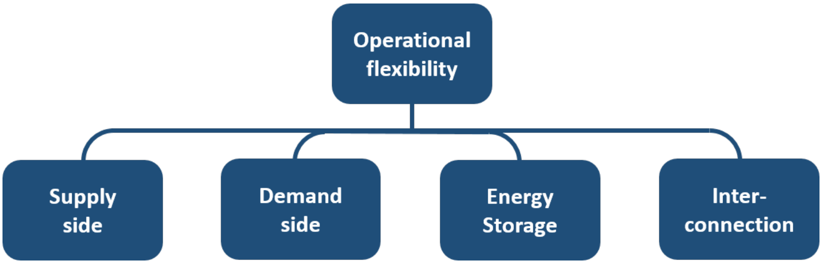

Figure 2.1: Overview of sources of short-term flexibility

Supply side flexibility

The most obvious option of supply side flexibility are the **dispatchable generation** technologies, the traditional option for supplying flexibility. These are both the conventional power plants (e.g. nuclear, fossil fuel) and the dispatchable renewable technologies (e.g. biomass) whose output can be fully controlled within the technical limits of their operation. The most important limits, from a flexibility perspective, are a technology's ramping abilities, its minimum output level, and its minimum up and down times (i.e. how long a plant has to be on-line once it has started up, and how long it has to stay off-line once it has shut down). These characteristics can vary tremendously over different generation technologies. The less flexible technologies or *base-load* technologies, intended to produce almost constantly at their full capacity, have ramp rates of 1-5% of its capacity per minute, a minimum output level of 50%, and minimum up and down times that can exceed 24 hours. This are typically the nuclear, coal and lignite, and certain biomass technologies. The more flexible technologies or *mid-* and *peak-load* technologies, used to follow variations in demand or even exclusively during peak demand hours, have ramp rates that can exceed 10% of their capacity per minute, a minimum output level of down to 10%, and minimum up and down times of a couple of hours at most. These are typically the gas and fuel, and run-of-river hydro technologies [46] (pumped hydro technologies will be discussed in the section on storage). All these technologies are also able to provide reserve capacity, the extent to which depending on their technical abilities. As such, dispatchable generation is able to deal with both variability and uncertainty.

While very adept at providing flexibility, the greenhouse gas emissions related to electricity production of fossil fuel technologies (coal, gas, etc.) might limit the future role of these technologies. The use of CCS technology could solve this problem, once it becomes available, and research shows that this should not impact the flexibility of the generation technologies, depending on the used CCS technologies [47]. Another important remark in the perspective of decarbonization is related to the significant lead times that can be associated with the construction of new power plants. Depending on the technology, the construction period ranges between 2 and 10 years, barring any delays. Furthermore, these technologies also have long technical lifetimes, ranging between 20 and 60 years [48]. Given the rapid evolution of the power system, this incurs significant uncertainty for investors, who might see the business case of their investment alter rapidly under the changing circumstances. It is thus quite unclear what role conventional power plants will play in the future of the power system. In any case, this points to the importance of providing a stable regulatory framework for the transition, to avoid any additional uncertainty.

A less obvious supply side flexibility option is that of **variable generation**. While the VRES-E introduce additional variability and uncertainty, they can also provide flexibility themselves by controlling their output. The way of controlling VRES-E output is through curtailment. This control can be used in several ways. Output can be reduced when there is simply too much VRES-E produced electricity, e.g. because of local network congestion or a lack of electricity demand [49]. It can also be reduced preemptively to e.g. 90% of its possible output to allow to increase output should there be a sudden lack of electricity production from other sources. Output can also be altered through curtailment to smoothen the output profile, reducing flexibility requirements for the other elements of the power system. Additionally, curtailment can be used for providing reserve capacity. In case of a sudden surplus in electricity, e.g. because of the loss of an interconnection that was exporting or simply when more VRES-E output is available in real-time than what was forecasted, VRES-E output can be regulated downward quickly. VRES-E can also provide upward reserve power, by structurally curtailing a part of their output, which can then be ramped up when necessary. The control of VRES-E in such ways has already been proved in practice, with e.g. the Spanish TSO able to remotely control 96% of installed wind capacity for operational reasons [50].

More recently several novel ways of controlling VRES-E output have been studied, that relate to flexibility constraints over very short timescales. For example, the control of the kinetic energy stored in the rotors of the turbines has been proposed as a method for smoothing the output of wind farms [51] or for providing frequency response [52]. Other authors have discussed the use of VRES-E power converters for the provision of virtual inertia [53]. This becomes of importance when VRES-E integration becomes so large that VRES-E provide 80% or more of the electricity during certain moments of the year. Inertia, the most important way for dealing with variability and uncertainty over very short timescales (milliseconds to seconds) to ensure frequency stability, at present comes predominantly from conventional power plants. If as a result of such high instantaneous VRES-E penetrations too little inertia is left in the system to ensure a stable operation, currently TSOs can impose a minimum number of conventional generators to remain on-line [54]; even though this goes against market outcomes and induces additional curtailment. The use of virtual inertia could be an alternative to such measures.

Demand side flexibility

Not only the supply side, but also the demand side has flexibility to offer. There are 3 ways in which demand can be adjusted to deal with flexibility concerns: (1) increasing, (2) decreasing, and (3) shifting demand. Other demand side measures include e.g. reducing reducing demand through energy efficiency measures, but these will not be discussed here. The first option, increasing demand, can be used to deal with excess VRES-E output or any other incident that results in surplus electricity. This comprises demand that would otherwise not have been realized, e.g. additional consumption of an industrial site in response to favorable electricity prices. The second option, decreasing demand, can be used to deal with incidents resulting in a shortage of electricity. This comprises demand that would have been realized, but now definitively will no longer be realized, e.g. the shedding of certain demand. The final option, shifting demand, can be used for various reasons; from smoothing the demand profile to reduce flexibility requirements for the other elements of the system, to better matching of demand with VRES-E output. This comprises demand that would have been realized at a certain time, but is now realized at a different time. Depending on the underlying processes, and whether demand is shifted forward or backward in time, this can be accompanied by efficiency losses, resulting in a higher total demand.

The potential of demand side flexibility, or *demand response*, depends on the available flexible capacity (not necessarily symmetric for up- and downward regulation), and the possible limits to the control of this capacity (in terms of economics, duration of control, etc.). Both these elements depend on the underlying demand process. The different demand processes are discussed according to the three major demand sectors: residential, service & commercial, and industrial.

In the **residential** sector a distinction can be made between flexibility options that depend on user behavior and those that could be piloted automatically. The former refers to conscious changes in the way consumers use electricity, e.g. in response to a time-varying electricity tariff. The latter can be subdivided in 3 main groups: thermal loads (heat pumps, air conditioning, refrigerators, etc.), time-varying storage (electric vehicles), and loads with shiftable cycles (dish washers, washing machines, etc.). In principle, the electricity consumption of all these loads can be scheduled without intervention of the end-consumer, given that the consumer's comfort constraints are respected. This flexibility is mobilized via smart grids, essentially distribution networks equipped with information and communication technology that allow to coordinate the actions of producers, consumers and the so-called "prosumers" [55]. Residential demand response has been studied extensively in the literature, e.g. the flexibility of electric vehicles [56], the heating sector [57] or household appliances [58]. Real-life demonstrators have also shown the feasibility of using demand response flexibility to facilitate VRES-E integration via smart grid infrastructures [59, 60].

Flexibility in the **service & commercial** sector is mostly related to the flexibility in the consumption of office buildings: air conditioning, ventilation, lighting, etc. Costs vary widely, but according to the review in [61] the potential is much lower than that of the residential sector.

Flexibility in the **industrial** sector is the most diverse, given the multitude of electricity consuming activities, ranging from cement producing industry to large cold stores in food processing. The different industrial demands can be grouped into process-independent loads, process-interlocked loads, storage-constraint loads and sequential loads [62]. Each category has its specific technical limits on the mobilization of flexibility, which are typically accompanied by economic concerns (customers' orders, etc.). Some industrial consumers optimize their consumption on a daily basis, based on the electricity prices in the day-ahead and intra-day market. A lot of industrial consumers, however, have long-term contracts with fixed electricity prices to protect against uncertainty in price evolution, which hampers the mobilization of their flexibility. Currently, they normally only alter their consumption for flexibility reasons when asked directly to do so, e.g. when they are contracted by a TSO to provide reserve capacity, as is the case in Belgium [63].

In contrast to the supply side forms of flexibility described above, control of flexible resources on the demand side is often spread over many actors, rendering its control much less straightforward. Therefore, many different schemes have been suggested to pilot demand response (see Figure 2.2). In a **direct control** scheme, e.g. a TSO or a demand response aggregator can directly control the consumption of the loads to which they have access. While this method is very effective in mobilizing flexibility, it also presents a number of challenges related to computational ability to centrally pilot a large number of loads, or to privacy concerns. **Dynamic pricing** refers to all schemes where consumers are subjected to a time-varying electricity price. This gives them an economic incentive to adjust their consumption based on the electricity price, which is linked to the availability of electricity. Besides the clear economic

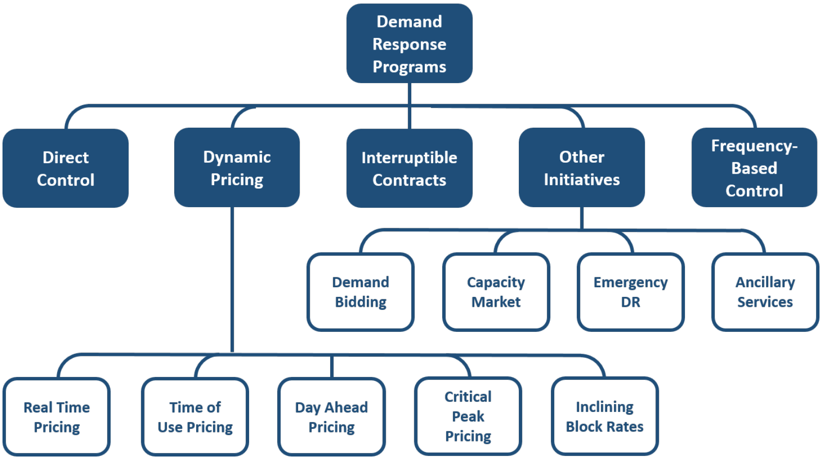

Figure 2.2: Overview of demand side response programs

benefits for the consumer, this also incurs benefits for other players in the power system, through deferring operational costs of peak generation units, deferring investments in generation and network capacity, and increasing the reliability of electricity supply [64, 65]. **Interruptible contracts** were already mentioned when discussing the contracting of reserve capacity with industrial consumers by TSOs. Consumers agree to reduce their consumption by a certain amount for a certain price. Such schemes can also be used for VRES-E curtailment. Other initiatives refer to many other arrangements, such as the bidding of firm capacity from the demand side in a capacity market, or the provision of emergency demand response or other ancillary services, an example being the strategic reserves contracted in Belgium [66]. Finally, demand can also be piloted via **frequency based control**, thus omitting the need for additional communication infrastructure. This is for example the case for certain dishwashers that are triggered to start working upon receiving a frequency signal, or when loads adjust their consumption when the frequency deviates from its nominal level.

Energy storage

Another option for matching supply and demand, rather than adjusting either, is the use of energy storage. Storage installations can be stand-alone, or they can be integrated in the supply side (e.g. in combination with a VRES-E installation [67]) or the demand side (e.g. a household battery or an electric vehicle [68]). Storage technologies can provide flexibility to the power system in three ways that are very similar to those of the demand side: (1) increasing net consumption, (2) increasing net production, and (3) shifting energy. The first option can be realized by increasing the charging or decreasing the discharging of a storage unit. The second option is the reverse. Such actions are useful in the same way as outlined above for demand side flexibility: dealing with (sudden) surpluses or shortages in electricity supply via the provision of operating reserves [69, 70]. The final option points to the ability of storage to charge energy when it is more readily available and discharge it when energy is more scarce. As such, storage can e.g. reduce the need for back-up generation in a highly renewable power system by bridging low VRES-E output moments with previously stored energy [71].

The potential of energy storage to provide flexibility depends on the available capacity (charging power, discharging power, and energy), the technical limits of operation, and the energy conversion process; all of which depend on the storage technology at hand. The available **power and energy** capacity has implications for what kind of flexibility services a storage technology is best at offering. Depending on the technology, installation cost for power and energy can be very different (Figure 2.3), leading to divergent energy-to-power ratios in installations. Certain technologies are characterized by a low energy-to-power ratio. Such technologies provide mostly power-related flexibility serves such as operating reserves and frequency stability support. Examples include flywheel storage [72], and superconducting magnetic energy storage [73]. Technologies characterized by a high energy-to-power ratio mostly provide energy-related flexibility services such as shifting energy over hours or days. Examples of such technologies include compressed air energy storage [74], and PHES [75] with naturally present height differences, which has been developed extensively in Europe [76]. Other technologies with intermediate energy-to-power ratios can provide both power- and energy-related flexibility services, and actual deployment depends on the economics of the specific use-cases. Such technologies typically offer several flexibility services simultaneously to be competitive [77]. Examples include battery energy storage systems (BES) [78], and new PHES installations without naturally present height differences [79].

The **technical limits of operation** have a very obvious impact on a technology's ability to provide flexibility. In general, storage technologies are very flexible, but some differences do exist. E.g. BES can ramp up quasi 100% of power capacity per minute [81], whereas process control might limit such abilities in the case of Power-to-Gas storage (P2G) [82]. A number of storage technologies do not have a minimum level of operation, allowing them to remain connected to the power system at all times, e.g. Superconducting Magnetic Energy Storage (SMES) and again BES. Others do have a minimum

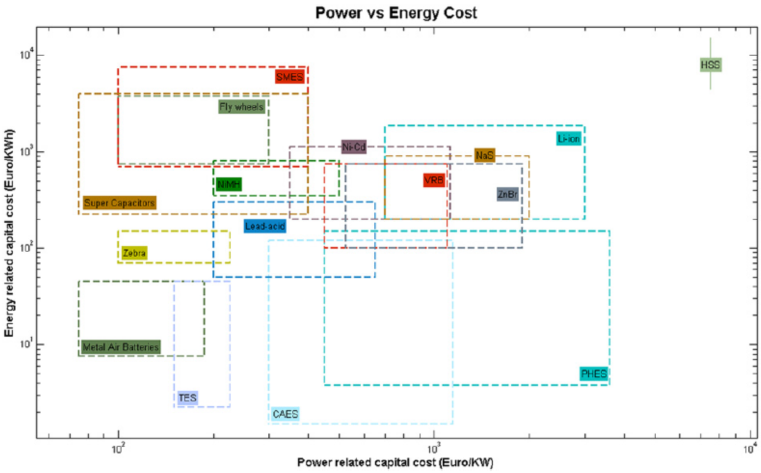

Figure 2.3: Overview of power and energy costs for different energy storage technologies [80]

level, ranging between 10% and 50% of power capacity, e.g. P2G [82] and PHES [75], which means that units need to be started up, limiting the speed of their response.

Finally, also the **energy conversion process** impacts the supply of flexibility. First, it determines the round-trip efficiency, which can range from around 90% for BES down to 25% for P2G [83]. Second, it can also impose limits to the number of cycles a technology can do over its lifetime; e.g. BES typically can perform only 3000 cycles over their lifetime [81]. Lastly, not all storage technologies reconvert their charged energy back to electricity. Examples include hydrogen storage (which can re-electrify if a fuel cell is used) [84], power-to-gas producing synthetic methane [85], and power-to-heat (e.g. electric boilers or heat pumps, usually seen as part of demand side flexibility). This means that there is no discharging operation which can provide flexibility, but energy forms like synthetic methane do facilitate storage over very long periods, e.g. monthly or seasonal storage. Besides these technologies, e.g. also large PHES installations can perform seasonal storage [86]. The coupling to the heat sector, in turn, provides additional flexibility by having a demand that is different in time, and by using thermal buffers as storage [87].

Interconnection

A final option to deal with flexibility is through the interconnection of different power systems. Interconnection has a two-fold impact on short-term flexibility. First, it reduces the need for flexibility; and, second, it increases the supply of flexibility. Interconnection allows to smooth both variability and uncertainty over a larger area, also when it comes to VRES-E output. Already on the level of e.g. a single wind farm such effects are noticeable [88], but more importantly on the power system level such spatial smoothing decreases output variability and forecast errors, both for wind [89] and solar energy resources [90]. Such cross-power system balancing will be very important in facilitating VRES-E integration [91]. However, to benefit from such effects, adequate regulation will be needed to deal with the bottlenecks in the grid on the borders of power systems [92]. Given such regulation, collaboration between power systems can decrease VRES-E integration costs, be it through imbalance netting [93], coordinated activation of reserve capacity [94], or coordinated sizing and allocation of such reserve capacity [95]. To enable such cooperation between power systems, additional interconnection capacity will be needed, especially when moving towards high VRES-E penetrations [96]. Several technology options are available to realize these capacity expansions, from conventional Alternating Current (AC) technology to the development a European High Voltage Dirrect Current (HVDC) supergrid [97].

2.3 Studying the need for short-term flexibility

The first goal of this work is to evaluate the impact of power system operation on power system planning given the integration of large shares of VRES-E. Therefore, this section will provide a review of how VRES-E variability and uncertainty, and the related need for short-term flexibility, has been integrated in power system planning. The scope of this review is limited in a number of ways. First, the goal of this section is not to provide an exhaustive overview of energy system models. For that, readers are referred to a number of review papers [98, 99, 100]. Second, not all planning models limit their scope to the power system, but consider also other parts of the energy system, as is the case e.g. for PRIMES [30] and TIMES [31]. The focus here will be on power system planning, and as mentioned before on generation expansion planning. For an overview of VRES-E impact of transmission expansion planning, readers can check e.g. [101, 102, 103, 104]. It should be noted that planning the use of all the available flexibility in GEP to facilitate VRES-E integration – thus not taking into account its possible benefits for network planning – can lead to missing part of its benefits, as has been shown in e.g. [105]. Finally, not all planning models are optimization models, some are simulation models; not optimizing the investment portfolio, but merely trying to predict its evolution given policy, risk-behavior, and so on [25]. The focus here is on optimization models.

2.3.1 Existing simplifications of power system operation

To evaluate the impact of VRES-E integration on power system planning sufficient detail is needed in three areas: spatial resolution, temporal resolution, and operational detail. To keep computational efforts of power system planning models in check, traditionally in each of these areas simplifications of the representation of the power system were made.

Spatial resolution

Historically, the level of spatial resolution has been low; with planners usually aggregating production and consumption at the level of the power system – or depending on the size a limited number of zones within that power system. This posed no problems, as networks where designed to facilitated the electricity flows between large production and consumption centers. With the introduction of VRES-E, this simplification is challenged in two ways. First, because of the impact of the disperse installation of VRES-E on the electricity networks, which will not be studied here. Second, because of the difference in resource quality of VRES-E in different locations. Wind speeds and solar irradiation can vary significantly over geographical areas, leading to a very different annual electricity production. Representing these different resource qualities as a single, average wind and solar resource can lead to an incorrect estimation of the optimal investments in VRES-E capacity (or an incorrect estimation of the cost of a certain amount of capacity) [106, 107]. Thus, a new balance in the trade-off between computational effort and spatial resolution has to be found. This will not be studied in detail in this work.

Temporal resolution

Temporal resolution can be understood along two dimensions. A first dimension has to do with the overall time period under consideration. Here, a distinction has to be made between static and dynamic planning models. Static planning models consider a single year and optimize investments based on the operational costs of that year and annualized investment costs. The underlying assumption is that the operational costs are representative for the entire lifetime of the investments. It is possible to take into account existing installed capacities, or to ignore them – the so-called “greenfield” approach. Dynamic planning models consider periods of several years, e.g. 20-30 years. In such models the operational costs are calculated for a number of representative years, e.g. once every five years. This allows a better approximation of the operational costs over the lifetime of the different investments. This also allows to take into account effects of capacity legacy – i.e. previously installed capacities, construction times of new capacity, decommissioning of capacity, etc. A dynamic planning model thus allows to construct pathways, but is also computationally more intensive. The adopted approach for this work is a static greenfield approach.

A second dimension has to do with the temporal resolution within the year(s) used to calculate the operational costs. Four distinct outcomes can be identified when it comes to balancing the trade-off between computational effort and this temporal resolution. First, planners can simply ensure the annual energy balance, ignoring when production and consumption take place. This approach poses obvious problems given the limited controllability of VRES-E. Second, they can use Load Duration Curves (LDCs), as is the case in the screening curve method presented in the Introduction. With the integration of VRES-E this approach is adjusted to using Residual Load Duration Curve (RLDC), which already takes the VRES-E production into account. This approach omits the chronology of the production – consumption balance, which does not allow to capture e.g. ramping challenges. Third, planners can opt for a set of representative periods (or time slices). Within these periods, they typically ensure the hourly production – consumption balance. Some authors adopt even smaller time steps, e.g. on a 15 minute basis, to capture the effects of VRES-E integration on power plant cycling, but this approach is typically restricted to operational models [108, 109]. The representative periods are chosen so that their RLDC approaches the yearly RLDC. The issue here is that it is hard to represent all annual fluctuations of VRES-E production, consumption, etc. in a limited set of days or weeks. Finally, the most accurate approach, but also most demanding computationally, is the use of hourly information for the entire year. Such a thing is common practice in operational models, but much less frequently encountered in planning models. The influence of the chosen resolution will also not be studied in this work. However, results of [110] and [111] already show that a coarse temporal resolution leads to an overestimation of RES uptake, an underestimation of operational costs, and sub-optimal investments. Therefore the final approach, hourly data for the entire year, will be adopted.

Operational detail

The level of operational detail is obviously the most important aspect in this work. A high level of detail is needed to appropriately assess the short-term flexibility costs incurred by VRES-E integration, and the added value of technologies that can facilitate power system operation in the presence of large shares of VRES-E. Many different approaches to solve the trade-off between computational effort and operational detail exist, often stylized per model, and very often not benchmarked with an operational model.

On the one hand, a distinction can be made in how planning models deal with the variability of VRES-E (i.e. the *profile costs*) by looking at their representation of the day-ahead production – consumption balance, also referred to as the market. The reference is the representation thereof in Unit Commitment (UC) models[3], i.e. the full representation of technology constraints (ramping ability, minimum up and down times, etc.) and system constraints. Any simplification of this representation will allow to save computational effort, but introduce errors. Traditionally, simplifications were made all the way to the full exclusion of operational constraints. This, however, is no longer acceptable in the presence of large shares of VRES-E, and an increase in operational detail is required [25]. A remark has to be made here on the link between temporal resolution and operational detail. A full year time resolution already implicitly includes part of the profile costs of VRES-E – i.e. the utilization costs, as the fast-response, low-capital cost generation technologies are already installed for purely economic reasons (cfr. Introduction). Then, imposing constraints on the dynamics of technologies only incurs the additional costs related to diverging from the merit order in clearing the market equation – i.e. the flexibility costs.

On the other hand, a distinction can be made in how they deal with VRES-E uncertainty (i.e. the *balancing costs*) by looking at their representation of the need for operating reserves. The reference here is the full representation of all the operating reserve categories, with the associated technical and allocation constraints; the underlying assumption being that BRPs contract their balancing

[3]"The UC problem can be defined as the scheduling of generation of electric power generating units over a daily to weekly time horizon in order to minimize operational system costs. The unit commitment solution must respect the technical and operational limits of the electricity system, such as power plant constraints and reserve requirements. The problem solution gives for each generation unit and each time step the unit commitment (UC) decision, i.e., the on/off-status, and the economic dispatch (ED) decision, i.e., the power output if on-line. The UC decision is typically taken hours to days before the actual delivery, since most power plants cannot start up quickly. The ED decision is typically taken minutes to hours before the actual delivery, as changing the power output of an on-line plant requires less time than bringing a power plant on-line. The UC decision problem translates into a more complex mathematical formulation than the ED decision, due to the binary nature of the on/off decision." [112]

capacity following the same product characteristics as those imposed by TSOs for their operating reserves. A further assumption is that system sufficiency is ensured for reserves (i.e. that sufficient reserve capacity is contracted to meet a certain reliability target), not indicating which share is to be contracted by TSOs or by BRPs. Any simplification w.r.t. this representation will also allow to save computational effort, but introduce additional errors. Again, traditionally, simplifications were made all the way to the full exclusion of operating reserve requirements. But also here, such simplifications are challenged in the presence of large shares of VRES-E, and an increase in operational detail is required [25].

2.3.2 Increasing operational detail in power system planning

The exact level of operational detail in a power system planning model naturally depends on the specific focus of the model at hand, i.e. the research questions that the model developers wish to address. This imposes limits to how much the level of operational detail can be increased. Such an increase requires more computational effort, which can only be solved – barring an increase of the available computational power – by decreasing the complexity of other aspects of the problem. This can be realized by decreasing the spatial and/or temporal resolution, or by reducing the size of the problem at hand, e.g. moving from an energy system scope to the sub-problem of the power system. Commonly in the literature, the models that show most operational detail are static models that focus exclusively on the power system. However, even in those models, when operational detail is increased to approach that of power system operation models, a decrease in temporal resolution is often employed to relax computational requirements.

To increase the operational detail in planning models, two distinctly different options can be identified [111]. The first option is to **soft-link the planning model with a detailed operational model** (i.e. a Unit Commitment and Economic Dispatch (UC&ED) model), e.g. [113, 114, 115, 116]. With the aid of such a model, it is possible to check the operational feasibility of a proposed portfolio and/or get an accurate estimate of the operational costs – potentially using the outcome to update the operational costs used in the planning model. The second option is to **increase the detail on power system operation in power system planning models directly**. This latter option is the one that will be investigated. This subsection will review the level of operational detail present in planning models currently available in the literature.

The lowest level of operational detail can be found in dynamic planning models that study the evolution of the entire energy system. Prime examples include the U.S. government's National Energy Modeling System (NEMS) [117], used by the Energy Information Agency to project the impact of U.S. energy policies on the U.S. economy and environment; the TIMES model used more often by Member States of the E.U. [118]; and others such as the LIMES-EU model of the Potsdam Institute for Climate Impact Research [119, 120]. These models use representative periods and employ stylized operational constraints, limited to some constraints on the ramping and minimum output level of the production technologies. Similar approaches can be found in models that focus on other challenges for the electricity system, such as e.g. [28, 121, 122], which focus respectively on uncertainty regarding energy costs and energy security, the use of Combined Heat and Power (CHP) as a link between the electricity and the heat sector, and on evaluating policies regarding electricity production externalities.

Certain authors attempt to increase the level of operational detail, without an explicit representation of reserve requirements, via the use of reliability indices, e.g. Loss Of Load Probability or Expected Energy Not Served [123, 124, 125]. To calculate such indices, probabilistic models are developed for the uncertainty of e.g. load, outages and intermittent generation [126, 127, 128]. Some authors have incorporated these indices in their objective function and formulate a multi-objective planning model in which there is a trade-off between reliability-driven generation investments and other goals, such as cost of emissions or investment risk [129, 130], or transmission investments [131, 132].

Operational detail can be increased further by explicitly modeling the reserve requirements are modeled more explicitly. An often used modeling approach is that of a capacity reserve margin or planning reserve, defined as the difference between the installed capacity and the peak load, divided by the peak load (typically around 120-150%) [133]. An example can be found in the US-REGEN model of the Electric Power Research Institute (EPRI) [134], that in addition uses stylized ramping constraints, and is coupled to a UC model to check the operational feasibility of the outcomes. A similar approach is found in [135], barring the soft-link to a UC model. More detail in operational constraints in a model that employs a capacity reserve margin can be found in [136, 137], the latter being the Regional Energy Deployment System of NREL. A capacity margin can also be combined with the aforementioned reliability indices, as is the case in [138, 139]. An alternative approach is that of calculating the need for additional peak units for reserve capacity [132, 140]. These approaches still do not touch upon the dynamics of reserve capacity. They do not capture the influence of the reserves on the operation of the system and, thus, do not distinguish between spinning and non-spinning reserves. Therefore, they cannot guarantee that the required reserve capacity is available when needed. The use of a capacity margin relates more to firm capacity adequacy than to flexibility adequacy. The use of a post-processing approach, in turn, impacts the optimality of the previously achieved results; especially when reserve requirements increase.

2.3.3 Dispatch and investment models

The highest level of operational detail is found in those models that subject the generation expansion planning problem to hourly operation constraints with a full UC description, including the operating reserve requirements. Recently, the efforts for developing such models – also referred to as "dispatch and investment models" [141] – have been growing, as it has become one of the preferred methods to investigate flexibility concerns related to VRES-E integration in planning. As the level of operational detail is so high, this approach is almost exclusively applied in static planning models. And even then, with models that are fully dedicated to this research question, modelers have to make certain concessions to manage computational efforts. Some authors have limited the detail of the reserve requirements, considering a single product instead of all; but most commonly authors have reverted back to using representative days or weeks to relax computational requirements (albeit with a higher total resolution than traditional time slices). Consequently, there is also increasing literature on improving the way in which such days/weeks are selected to better reflect the VRES-E related flexibility challenges, e.g. [142, 143, 144].

Some of the first authors to attempt to bring the level of operational detail in a static planning model closer to the level of detail in UC models were De Jonghe et al. [18]. By employing more detailed short-term generation constraints and a single reserve product, endogenously depending on the wind deployment, the authors could propose better investment portfolios with high shares of wind energy. A similar approach can be found in the SWITCH-WECC model [145, 146], developed at the University of California, Berkeley. Others have recently attempted to formulate similar improvements for existing dynamic planning models. In these models the operational costs are calculated via the dispatch of a very small number of time slices. In [147, 148] additional operational constraints are added to OSeMOSYS (which uses 12 days) based on a comparison of the endogenously calculated operational costs with the outcomes with of a TIMES-PLEXOS model. These additional constraints include endogenously sized primary and secondary reserves, and more detailed ramping constraints. In [32] improvements are proposed for NREL's Resource Planning model to better capture value of flexibility. A fully constrained dispatch, subject to three types of operating reserve requirements is performed, albeit only for four representative days. While these improvements are important, and have a significant impact on the results (up to 24% capacity differences in [147, 148]), it is very hard to capture all variability and uncertainty of VRES-E in such a limited number of days.

Very recently static dispatch and investment models have been formulated that consider more or less a full UC description, while considering at least a number of weeks. In [149] such detailed constraints are formulated, only omitting minimum up and down times, with one endogenously sized reserve product, optimizing over three representative weeks. A similar approach can be found in [150] with an optimization over five weeks, but only considering a very small power system. Even more operational detail is taken into account in the POWER model developed at Stanford University [151, 152]. The model includes hourly ramping constraints, three reserve products (planning, contingency and forecast error reserves), network constraints; only omitting the sub-hourly ramping and start-up and shut down constraints for reserve provision; while optimizing the dispatch over 20 to 60 representative days. To conclude, the IMRES model of the Massachusetts Institute of Technology [153, 154] has a similar level of operational detail, optimizing the dispatch for four representative weeks.

Clustered Unit Commitment

A separate group of models among these dispatch and investment models are those that use a technology-clustered formulation of the unit commitment problem – Clustered Unit Commitment (CUC) in short – rather than the traditional binary formulation. In the traditional formulation a binary variable is introduced for each unit tracking the on/off decision for each time step. This formulation gives rise to a vary large number of possible binary combinations, even for small power systems, which results in a computationally demanding model. The clustered formulation drastically reduces the number of possible combinations by grouping units that have similar parameters. Instead of having to keep track of all individual commitment decisions, the model only has to keep track of the total number of units on-line per cluster (an integer variable), as is shown in Figure 2.4. Consider an example power system with 3 clusters of units containing respectively 10, 20, and 40 units. In the binary formulation this would give rise to a possible $(2^{10} \times 2^{20} \times 2^{40}) \approx 1.2 \times 10^{21}$ states per time step. In the clustered formulation this is reduced to $(11 \times 21 \times 41) \approx 9.5 \times 10^{3}$ states. Furthermore, as the clustered formulation reduces the number of continuous variables and constraints, as constraints now only have to be drafted for a small number of clusters, instead of for each individual generator [155]. The clustered formulation is thus less demanding computationally than the traditional formulation, consequently allowing for the use of a higher temporal resolution. In this work, such a clustered formulation was developed and used to represent power system operation in the realized planning model.

The use of a clustered formulation introduces a two-part error. The first part has to do with the inherent difference between a binary and a clustered formulation. This difference causes some commitment situations to be possible in the latter which are not possible in the former. The second part has to do with the

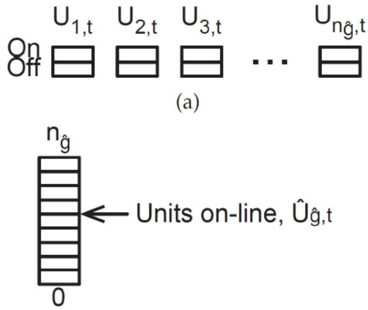

Figure 2.4: Binary vs. clustered unit commitment decisions – ĝ is the set of generators, U is the commitment decision of a single unit, Û is the cumulative commitment decision for the cluster of generators [155].

grouping of units with similar, but not identical parameters. In power system operation models, this second type of error is important, as individual power plants can be very different in their technical characteristics, even if they can be grouped in the same technological category (e.g. coal-fired power plant, open-cycle gas turbine, etc.). These differences depend on many project-specific elements. In power system planning models, this is less of an issue. It is common practice in planning to use a single representative set of technical parameters per technological category, as it is nearly impossible – and perhaps also not very relevant – to predict how future circumstances would inform such detailed, project-specific decisions. Hence, in this regard adopting a CUC approach does not introduce additional errors compared to other planning models.

The use of the CUC approach in a planning model was developed and proposed at a similar moment, but independently by Palmintier [155] and Poncelet & van Stiphout [156]. Given how recently it has been published, the use of CUC in power system planning literature is very limited. Palmintier validated the approach in [157, 158] and used it in [159] to show the impact of unit commitment constraints on GEP, demonstrating that simplifications in operational detail lead to sub-optimal investments, and an underestimation of operational costs and carbon emissions. Palmintier's model formulation was also used in [160], and expanded to include the flexibility of Electric Vehicle (EV)s. The model formulation of Palmintier, however, has limited detail when it comes to the reserve requirements, and considers only the flexibility of thermal generators. These are the elements of the CUC approach that have been further developed in this work, and will be discussed over the next chapters.

2.4 Studying the supply of short-term flexibility

The second goal of this work is to study the role of alternative short-term flexibility providers in facilitating the integration of large shares of VRES-E. This section will provide an overview of how the value of different flexibility providers has been assessed in the literature. Again, the scope of this review will be limited mainly to power system planning, and more specifically to generation expansion planning. The section will discuss consecutively the literature on supply-side flexibility, demand-side flexibility, energy storage and interconnection.

2.4.1 Supply-side flexibility

The overview of the literature on supply side flexibility can be short. First, the default condition is to consider the flexibility of dispatchable generation. Whether or not the supply of such flexibility is modeled appropriately depends on the level of operational detail that is considered; which has already been discussed above. Models that include a UC-like representation of the operational constraints (i.e. minimum output levels, minimum up and down times, and constraints on ramping abilities over the different time horizons of the market balance and the operating reserve products) are said to have adequately modeled dispatchable generation.

Second, the potential of the flexibility of variable generation, i.e. the VRES-E, is rarely investigated. There is some literature on the potential of curtailment as a flexibility provider. Most models include curtailment at a certain cost as an option for helping to maintain the balance between production and consumption, but very few authors consider the potential of VRES-E to provide operating reserve capacity. Exceptions include [35] and [147].

2.4.2 Demand-side flexibility

Given the expected decrease in the share of dispatchable supply side technologies in the power system, triggered by the increase of VRES-E, the body of literature on the potential of demand-side flexibility is growing. In broad terms, two approaches can be identified for the integration of demand side flexibility in power system planning: (1) flexibility aggregation models, and (2) technology- or process-specific models. Flexibility aggregation models take the flexibility of different types of demand side processes and aggregate them to arrive at an overall amount of flexibility, no longer distinguishing based on the origin of the flexibility. Technology- or process-specific models take one specific type of demand side flexibility, and scale that flexibility up to e.g. the level of the power system.

Flexibility aggregation models

Within the category of flexibility aggregation models, a number of approaches exist. One of the first approaches was to integrate the possibility of sheddable load into power system planning models, also referred to as Integrated Resource Planning. This approach has been used for a long time, e.g. by Hobbs et al. already in 1993 in [161], because of the simplicity. Essentially, the possibility is introduced to structurally reduce demand, at a certain cost and limited in power and energy. Such flexibility could come from many different types of consumption processes. More recently, this approach was used in e.g. [122], and in a flexibility-centered report of NREL [32], which provides further insight into the value of this option, by assessing a wide array of shedding costs to more accurately determine the added value. While a valuable approach, it is not sufficient by itself to represent the potential of demand-side flexibility.

Therefore, other authors adopt an approach that allows not only to reduce, but to increase and to shift demand. This approach has been used frequently in high-level energy system models, notable examples being the *Roadmap 2050* of the European Climate Foundation [162] and the Energy Revolution study of Greenpeace [163]. In the models used for these studies the demand profile can be adjusted by shifting consumption within a 24-hour time frame. Such shifting is limited in energy (typically a percentage of daily energy), and in power (a percentage of hourly consumption). The obvious issue with this approach is that it is unclear to what extent it accurately represents the flexibility of the underlying consumption; especially given the lack of a bottom-up validation of the chosen values for the power and energy constraints of such demand shifting.

A final approach that will be discussed here is that of using price elasticities. Price elasticities are an approximation of how total demand responds to a change in electricity price. E.g. if electricity would be cheap because of high VRES-E output, demand would be higher, and vice versa. Typically, the elasticity data used in planning (or operational) models is empirically determined; e.g. in [58, 164] the elasticity of Belgian and Swiss residential electricity demand is presented, and in [165] the elasticity industrial costumers in the Midwest of the U.S. Certain authors implement these elasticities directly into their planning model, and co-optimize the use of this flexibility with investments in VRES-E capacity [166] or in all types of generation capacity [167, 168]. Other authors use a two-step, iterative method [135, 169, 170]. First, the planning model is run. From this model the electricity price for the time period under investigation is extracted. Using this price curve and the price elasticities, the demand profile is updated. This new profile is put back into the planning model, and the investment portfolio re-optimized. This process is repeated until convergence. Price elasticity approaches can provide a more accurate reflection of the potential of demand side flexibility. However, when looking towards 2050, having to use price elasticities measured in today's power system imposes some limits. Flexibility might be low, reflecting today's limited response of the demand side. This does not allow to take into account the flexibility of a number of "new" loads, which are rarely found today, but could be much more deployed in the future (e.g. EVs and Heat Pumps (HPs)).

Technology- or process-specific models

Technology- or process-specific models are either used to aggregate flexible demand technologies which are small in power, but high in number (e.g. EVs and HPs); or to represent in detail the flexibility of large consumers that can offer a large amount of flexibility by themselves (typically industrial demand response). Integration of such models in power system operation models has been extensive, e.g. [58, 171]. However, given the added complexity of such more specific models, integration in power system planning models has been limited. Nevertheless, a lot of flexibility is available. A detailed overview of theoretic process-specific availability of flexibility in Europe for residential, service & commercial, and industrial (with differentiation per type of process) demand side flexibility is given in [172]; indicating among other things that Heating, Ventilation & Air Conditioning (HV&AC) presents a major source of flexibility, and that most potential for demand increase can be found in the residential sector.

A typical use of technology-specific models is in the study of EV flexibility. Through appropriate control, the flexibility of charging large, dispersed fleets of EVs can be used on the power system level [173]. Such flexibility is often quantified using flexibility curves [56]. EV flexibility has been integrated in planning models by several authors, e.g. in [174, 175] which use the Balmorel model [176], and in the earlier cited [160] which uses the CUC model framework of Palmintier. Another often encountered use of technology-specific models can be found when studying HV&AC flexibility. Also here, appropriate control strategies allow to use the flexibility of large clusters of thermostatically controlled loads [177], whose flexibility can also be presented in an aggregated way using flexibility curves, e.g. in [57, 178], which look at the flexibility of buildings, and heat pumps and auxiliary heaters, respectively. The potential of this flexibility in planning has been checked e.g. in [179], which looks at the building stock of Germany, or in [180], which looks at the potential of heat pumps in the Baltic region. Finally, authors have included the flexibility of industrial demand flexibility via process-specific models. E.g. in [181] such a model is proposed for industrial coldstores, while in [118] the flexibility of the electricity demand of the steel sector is modeled explicitly.

2.4.3 Energy storage

There has been a lot of research on assessing the potential of energy storage to facilitate VRES-E integration. Research shows that significant operational cost savings can be realized with energy storage in highly renewable power systems because of their fast-response operation [182, 183, 184] or the ability of certain storage technologies to deal with prolonged low VRES-E output (e.g. via seasonal storage) [85]. However, some authors also point out that the deployment of energy storage could actually increase overall Greenhouse Gas (GHG) emissions by increasing the number of operating hours of slow-response generators [71, 185]. The scope of this part of the literature review will also focus mainly on the integration of energy storage in generation expansion planning. Like for the supply-side flexibility, the quality of the modeling of storage usually depends on the quality of the representation of the need for flexibility, as storage is most often represented as a dispatchable technology (i.e. a charger and a discharger connected by an energy reservoir).

Some authors focus exclusively on the sizing of the storage capacity, given exogenous generation capacity evolutions. They do this by looking at the residual load [186], at the variability of the power system [187], at the uncertainty of the power system [188], or by looking at variability and uncertainty simultaneously [189, 190, 191] through a decomposition of the balancing problem in its periodic components (days, hours, minutes) to determine the maximum energy storage requirements over different time-scales. Most authors, however, co-optimize investment in storage capacity with investments in generation capacity and/or transmission capacity, etc. Examples of simplified methods, from an operational point of view, include [192], which uses a RLDC method, and [102], which co-optimizes investments in storage, generation, and transmission, but does not implement operational constraints.

As the short-term flexibility of energy storage is one of the main added values, most models assessing the potential of energy storage have at least some operational detail; ever more so in recent publications. [67] already considers the hourly clearing of the market balance, subject to operational constraints, but does not consider operating reserves. In [141] a dispatch and investment model is proposed with high operational detail (hourly market balance and operating reserves), but with economic rather than technical ramping limits. [193] – which looks at the value of Compressed Air Energy Storage (CAES), with exogenous investments in RES-E – also models power system operation in detail, but considers only a single reserve product. In [116] the planning model is soft-linked with a UC model, allowing to fully capture the operational value of storage. The time slices, however, only cover a day, which does not allow to capture the added value of the ability to shift energy over longer periods, especially important when looking e.g. at seasonal storage. The same issue is present in NREL's adjusted Resource Planning Model [32] and the model of the Energy Futures Lab of Imperial College London [70, 194]. These authors integrate a very detailed dispatch in their planning model, providing valuable insights in the value of storage in daily operation, but only look at a limited number of representative days. Finally, the very recent [153] includes a lot of operational detail, and considers five representative weeks, but fixes the energy-to-power ratios, making it difficult to assess the added value of energy vs. power flexibility services. Furthermore, the energy-to-power ratios are quite high (2 hours for the BES technology and 10 hours for the PHES technology). Also here it is still hard to capture the full value of seasonal storage.

2.4.4 Interconnection

As mentioned, not a lot of research has been done on evaluating the contribution of interconnection to the supply of flexibility from a planning point of view. It has been shown that the need for flexibility decreases as the geographical size of the system increases [195], which can be achieved through strengthening interconnection between different powers systems. Furthermore, as discussed in the previous section, authors such as Van den Bergh et al. [95] have shown that cooperation between neighboring power systems in the organization of ancillary service markets can further facilitate VRES-E integration by reducing operational costs. However, when it comes to the impact of increased interconnection and cooperation on power system planning, literature is almost non-existent.

Obviously some authors have looked into the need for additional network capacity to accommodate large shares of VRES-E, e.g. [196, 96, 197]. Besides such work, all generation expansion planning models considering interconnection capture part of this value, as connecting different zones allows to smooth out the variability of their respective residual electricity demand. However, to the author's knowledge, none have looked into the possible impact on the investments in (flexible) power system technologies of operating reserve cooperation between neighboring power systems, be it in sizing or allocation.

2.4.5 Discussion

When it comes to modeling and assessing the potential of **supply-side flexibility**, research has been developed extensively. Only the representation of the flexibility of variable generation technologies in planning models needs improvement. Therefore, in this work the possibility for VRES-E to contribute to the operating reserves will be taken into account. A similar conclusion can be drawn for assessing the potential of **interconnection**. The possibilities of reserve cooperation between neighboring power systems and their impact on investments in interconnection and flexible technologies needs to be modeled explicitly, as will be done in this work.

The literature on **demand-side flexibility** is growing and the models are getting more complex. The models used in planning, however, have (1) either focused on a single type of demand-side flexibility, (2) used coarse high-level representations of total demand-side flexibility, or (3) are based on the flexibility currently available in the case of price elasticities. For this work two types of demand-side flexibility will be developed. First, the research discussed above looks exclusively at the short-term flexibility demand response technologies have to offer. This work is also interested in the long-term flexibility of demand response technologies – further referred to as Long-Term Demand Response (LTDR); i.e. demand that is able to shift between days or even weeks (e.g. in the manufacturing industry) – and its subsequent impact on investment planning. Therefore, a model is developed that can capture the long-term shifting ability of demand response. Second, during this PhD in collaboration with three Master students, over the course of two Master Theses, a model has been developed to represent the flexibility of residential electricity demand through price elasticities. A bottom-up model was developed to calculate the values of these elasticities through explicit modeling of the operation of individual loads. This allows to reflect the technical limits of operation in the price elasticities, and to include the effects of the deployments of flexible loads (EVs, HPs, etc.) to investigate possible future circumstances. This work will not be presented here; readers are referred to [198, 199, 200] for a detailed discussion of the achieved results. Moreover, from an operational perspective such demand response can offer flexibility in a similar way as energy storage. Thus, when discussing energy storage, the necessary links will be made to short-term demand response.

Finally, the remarks concerning the literature on **energy storage** are valid for all short-term flexibility suppliers. If the need for and the supply of short-term flexibility are not modeled in sufficient detail in a planning model, then the potential of a flexible technology cannot be assessed appropriately. This is especially true for storage. It is of paramount importance to include both the hourly market balance and the operating reserve requirements, as certain storage technologies can simply not rely solely on their operation in the market balance to recover their investment costs. They need to be able to deliver operating reserves [201]. Additionally, it is important that the time resolution is sufficiently high to be able to capture the value of technologies that can deal with the seasonal variations of VRES-E. The use of a CUC model framework allows this. As such, it is possible to assess the potential of seasonal storage technologies and LTDR technologies. In conclusion, three storage technologies, representative for the dynamics of available storage options, will be modeled in this work: (1) a BES technology, representative for all storage technologies that are always on-line, an important advantage from an operational point of view [109], (2) a PHES technology, representative for all storage technologies that need to be committed for operation, and (3) a P2G technology, representative for all storage technologies that can provide long-term or seasonal storage.

2.5 Conclusion

To study the impact of VRES-E related flexibility challenges on power system planning a high level of operational detail is needed. Consequently, there is an emerging interest in the literature to improve the representation of power system operation in planning models. This has led to the development of so-called dispatch and investment models, models that focus specifically on the impact of operation on planning. However, the high operational and temporal detail of such models is computationally demanding. One way to manage this computational effort has been to use representative days or weeks. Another way has been to use a clustered rather than the traditional binary formulation of the unit commitment problem to model operation constraints. This approach is developed in Chapter 3, and used in Chapter 4 to assess the impact of flexibility adequacy on planning following high renewable integration.

In light of the decreasing share of dispatchable generation, alternative sources of short-term flexibility have to be found. Flexibility can be provided by variable generation, demand-side and energy storage technologies, and through increasing the interconnection with other power systems. Research into the potential of variable generation and flexibility through interconnection has been scarce. More research has been performed on demand-side flexibility and energy storage flexibility. However, this research has often been performed on providers separately and with models that do not have sufficient operational detail to capture all the added value of these technologies. Therefore, models are developed for a number of flexible technologies in Chapter 3, and used in Chapter 5 to study both their impact on planning and the importance of the operational detail to assess their potential.

Chapter 3

Modeling short-term flexibility

3.1 Introduction

In this Chapter the power system planning model that was developed during this work is presented. The proposed dispatch and investment model, developed in the clustered unit commitment framework, identifies the optimal investment portfolio to meet the aggregate electricity demand, taking into account renewable energy objectives, and determines the scheduled and forecasted levels of production and consumption of the different technologies to deliver energy and reserve. The need for short-term flexibility is represented via the modeling of the day-ahead electricity market with an hourly resolution – to include the effects of variability, and operating reserve requirements following the guidelines of the ENTSO-E – to include the effects of uncertainty. The following sections present the operating reserve sizing and allocation methodologies and their integration in the power system planning model, the representation of the supply of short-term flexibility via different mathematical models for the different flexibility providers, and the description and modeling of the other elements of the power system planning model. Finally, the limitations of the developed modeling approach are discussed.

3.2 Day-ahead market

To deal with the variability aspect of the need for flexibility, the day-ahead market is included in the planning model. The representation used in this work does not fully reflect reality. In practice BRPs buy or sell electricity in this market so as to be able to present a balanced portfolio to the TSO after market closure. However, not all produced and consumed electricity passes by this market. First of all, BRPs may own production and consumption means, only trading to meet their aggregate demand. Second, not all of this trade happens through the day-ahead market; e.g. BRPs can also set up bilateral contracts.

In the model developed here, however, all produced and consumed electricity will pass through the day-ahead market, also referred to as the balance equation. The need for flexibility in this market arises from the variability of the VRES-E production profile and the electricity consumption profile of inflexible demand. These profiles are modeled via hourly time series. To ensure variability is dealt with appropriately, the balance equation is evaluated with an hourly time step (as is the case in practice as well), and all contributions to this equation – except for the inflexible profiles – are subjected to detailed technical constraints (see Section 3.4).

3.3 Operating reserve requirements

To deal with the uncertainty aspect of the need for flexibility, operating reserve requirements are integrated in the planning model. Also here, the adopted representation does not fully reflect reality. As mentioned before, operating reserves are capacity contracted by a TSO to be able to cope with the different sources of uncertainty in the power system. However, as was also explained, a TSO typically does not contract sufficient capacity to cover all uncertainty in the system. It will expect BRPs to own or procure their own flexible resources to (partly) keep their portfolios balanced when moving from the day-ahead stage to real-time. These resources are not subjected to detailed product requirements, as is the case for the operating reserves. Consequently, a BRP can combine resources with a wide range of ramping abilities, minimum output levels, reaction times, etc.; whatever enables him to balance his portfolio on the 15 minute basis of the imbalance market.

To represent the many ways in which a BRP could attempt to resolve its imbalance is not only impractical from a modeling perspective, it is also impossible to predict and mimic all of these strategies. Therefore, within this work all uncertainty is pooled, and operating reserve requirements are formulated to deal with total system uncertainty. The underlying assumption here is that whatever capacity would not be contracted by the TSO, would be provided by the BRPs; and that those BRPs contract either flexible resources that follow operating reserve product characteristics, or flexible resources that can provide the same service when combined. As such, abstraction is made from which of the operating reserve capacity is to be procured by the TSO, as an ancillary service to balance their system, or by market parties to balance their portfolio. Rather, system sufficiency is enforced. However, the methodology has been developed in such a way that the difference in contracting strategies between a TSO and BRPs can to a certain extent be reflected in the model. This will be further explained in Section 3.3.5 when discussion reserve allocation.

3.3.1 Sizing of operating reserves

To size the operating reserve requirements, this work follows the guidelines of the European Network for Transmission System Operators for Electricity in its *Network Code on LFC&R* [14], issued in 2013. This work also follows the new nomenclature used in this network code, as it was already introduced in Section 1.1.2. In its network code, ENTSO-E discusses the different imbalance drivers which have to be taken into account when sizing the operating reserves [202] (see also Figure 3.1):

- Disturbance or full outages of power system equipment, i.e. production, consumption or transmission assets
- Continuous, stochastic variations of consumption and renewable production within the resolution of electricity market time steps
- Stochastic forecast errors of consumption and renewable production
- Deterministic imbalances resulting from the deviations between actual consumption and the step-shaped schedules of the market
- Network splitting (beyond the scope of this work)

The expected magnitude and duration of an imbalance caused by one of the above factors, possible mutual dependency of imbalances and imbalance gradients all have to be taken into account when sizing the different types of reserves; namely the Frequency Containment Reserves (previously referred to as the "primary" reserves), the automatic and manual Frequency Restoration Reserves (previously referred to as the "secondary" and "fast tertiary" reserves), and the Replacement Reserves (previously referred to as the "slow tertiary" reserves).

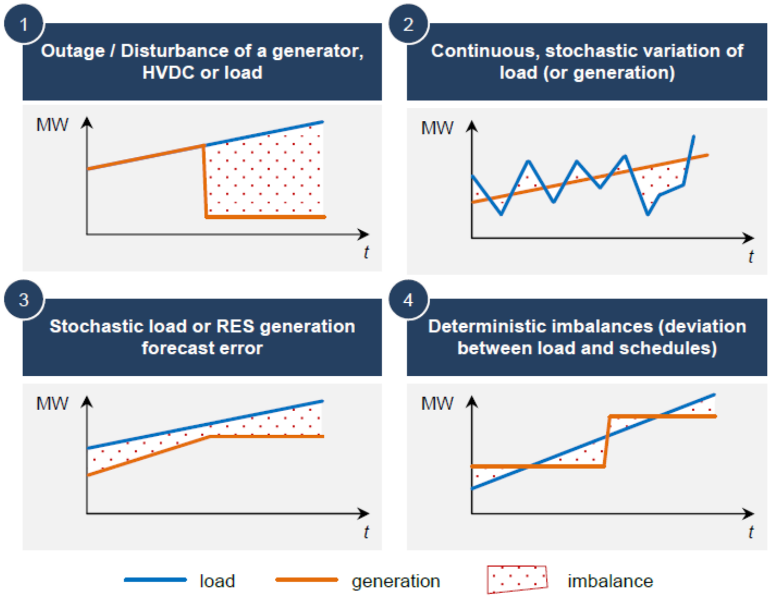

Figure 3.1: Simplified representation of the different imbalance drivers to be taken into account when sizing the operating reserves [202].

Frequency Containment Reserves

Any imbalance between total production and consumption immediately leads to a frequency deviation in the entire synchronous area. This area consists of all power systems that are synchronously connected, i.e. share the same frequency. To keep this deviation from reaching a critical value, the aptly-named Frequency Containment Reserves are activated automatically over the entire synchronous area (see Figure 3.4). E.g. for the Belgian power system, operated by TSO ELIA, this synchronous area is Continental Europe.

As they are activated at this level, the FCR are also sized at the level of the synchronous area. FCR capacity is sized following the so-called N-1 criterion, i.e. such that it allows to deal with the largest active power imbalance that can occur in the synchronous area, also referred to as the Reference incident. For the synchronous area of Continental Europe, however, given the system's great size this deterministic assessment is complemented with a probabilistic assessment (see Figure 3.2). The risk level chosen for this probabilistic assessment was "once in 20 years". Practice showed that the best approach to meet this risk level

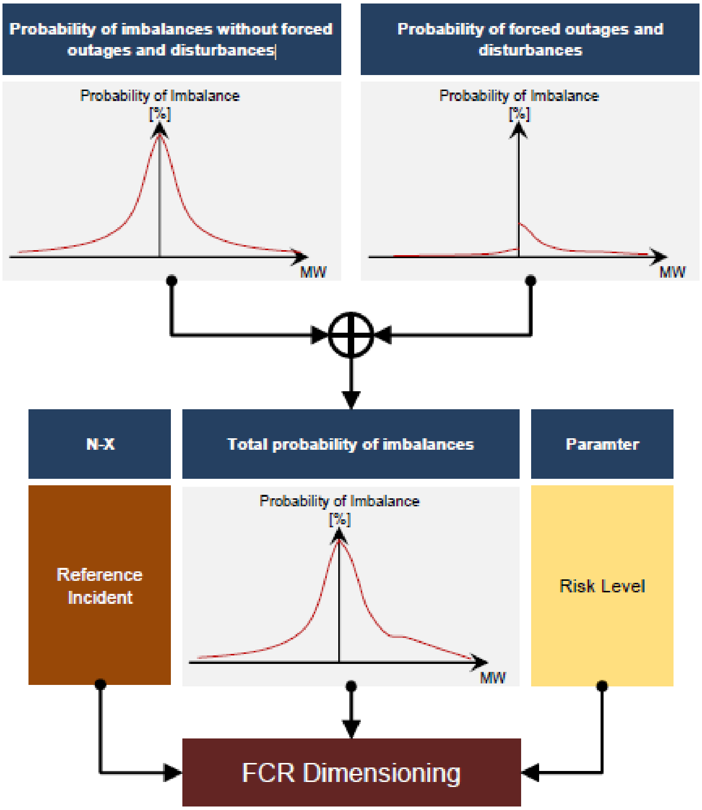

Figure 3.2: Fictional example of combined deterministic and probabilistic sizing of the FCR capacity [202].

was to use an N-2 criterion, i.e. the loss of the two biggest units. This comes down to 3'000 MW of FCR – the loss of the two biggest nuclear power plants of 1'500 MW each, both in the up- and the downward direction, respectively referred to as the positive and negative FCR. This effort is shared over the different control zones according to their weight in the system.

Frequency Restoration Reserves and Replacement Reserves

Once the frequency deviation is contained, the frequency has to be restored to its nominal level through the use of FRR and RR. If insufficient FRR and RR are available, this will prevent the full relief of activated FCR capacity, leading to a persistent usage of this capacity and thus avoiding a return to an N-1 or N-2 secure state.

The dimensioning of FRR and RR thus has a direct impact on the operational security of the entire synchronous area. This is why, while the sizing of FRR and RR capacity is left to the TSOs, ENTSO-E puts forward a set of minimum requirements for the sizing process (see Figure 3.3). First, TSOs need to conduct a deterministic assessment based on the highest positive and negative active power imbalance in their power system, also referred to as the Dimensioning Incident. The contracted FRR capacity has to be able to at least cover the positive and the negative Dimensioning Incident. Second, system operators need to conduct a probabilistic assessment based on historical system imbalance records of at least a full year. The 99% quantile of the observed imbalances sets the minimum value for the sum of the contracted FRR and the RR capacity. TSOs are free to choose how they split the total FRR capacity into automatic FRR and manual FRR, as long as it enables them to meet the frequency quality standards set by ENTSO-E.

The contracting of RR is not obligatory. If the deterministic assessment is binding, then no RR is required at all. If the probabilistic assessment is binding, then TSOs can contract either FRR or RR to cover this additional part of the requirement (see Figure 3.3). Contracting RR is cheaper than contracting FRR, as the latter are subjected to more stringent technical requirements. This can thus be an option to contract reserves in a more economically efficient way when the probabilistic requirement is binding. Some TSOs, e.g. the Belgian and German TSOs, go beyond the 99% quantile, and impose themselves a 99.9% quantile requirement (at times symmetrical, at times only in the upward direction), making it more likely for the binding probabilistic requirement to be binding, especially in the case of large control areas. In practice, however, instead of contracting all of this additional capacity themselves as FRR or RR, they only contract a part of it and incentivize market players to balance their market positions themselves. This strategy is e.g. employed by the Belgian TSO ELIA, which does not contract any RR capacity. In this work at all times sufficient reserve capacity is contracted to meet the imposed quantile requirement, i.e. the “system sufficiency” mentioned earlier. For this only FRR are contracted. Even when the probabilistic requirement is binding, the requirements will be met exclusively with FRR. This is more expensive than when a mixed FRR - RR approach would be applied, and can be seen as the most stringent way for ensuring reliability.

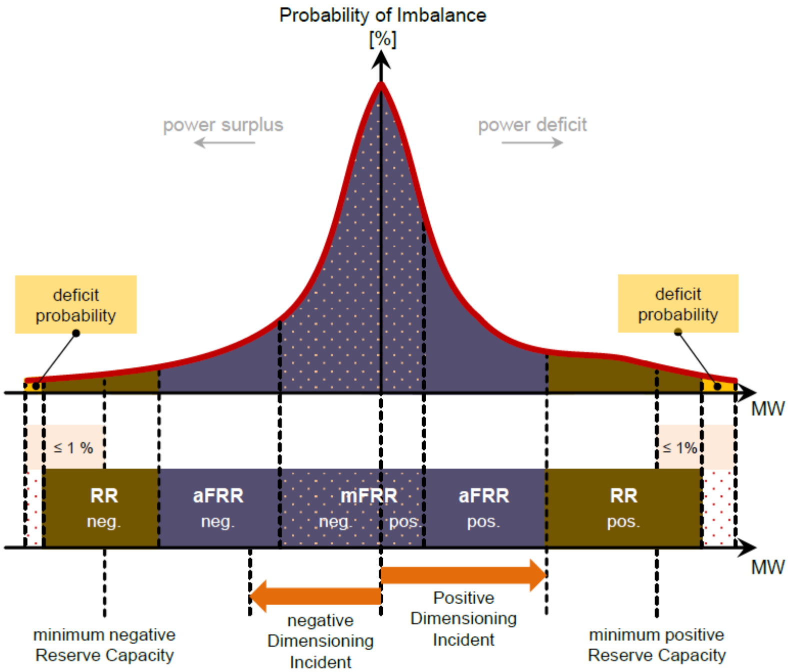

Figure 3.3: Fictional example of combined deterministic and probabilistic sizing of the FRR and RR capacity [202].

3.3.2 Activation of operating reserves

Once sized and contracted, operating reserve capacity is activated in real time when an active power imbalance occurs (see Figure 3.4). FCR activation occurs automatically through governors whenever an FCR provider observes system frequency excursions. The capacity has to be fully available within 30 seconds. Next, in the control area where the imbalance occurred, the FRR are activated to restore the balance in that control area, thus restoring the system frequency and relieving the FCR activated over the entire synchronous are. First, the aFRR capacity is activated automatically, then the mFRR is activated manually. The aFRR typically have to be fully available within a couple of minutes, whereas mFRR usually have around 15 minutes to ramp to full capacity. Their activation is triggered by the Area Control Error (ACE), which is calculated from the deviation between the scheduled and actual power interchange of a control area, corrected for the frequency.

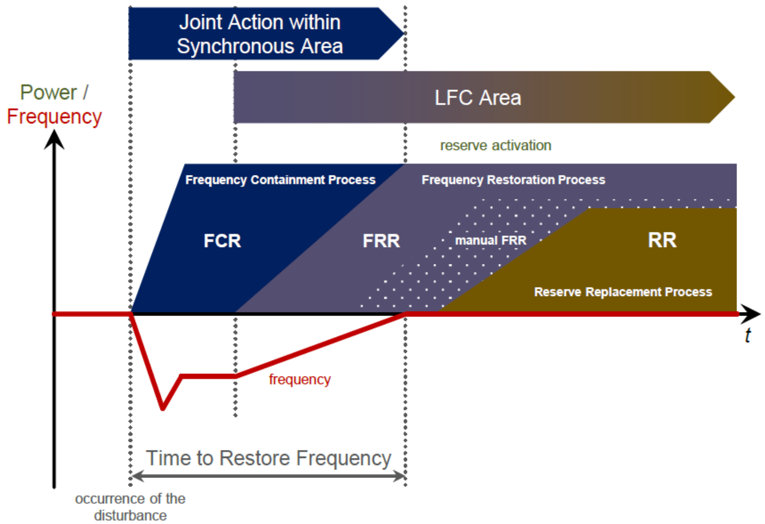

Figure 3.4: Consecutive activation of FCR, FRR and RR to contain and restore the frequency, and relieve activated reserve capacity to be ready for a next incident [202].

Activation of operating reserve capacity is not considered in this work. The scope is limited to the day-ahead stage (electricity market and operating reserve sizing and allocation). Considering the real-time would add significant complexity to the model, increasing the computational requirements for a model that already considers significant operational detail. However, a first mathematical formulation for reserve activation within the model was drafted and implemented, and a number of preliminary analysis were carried out. As these equations were not included for the analyses performed in this work, they are not presented here. Where relevant, a reference will be made to the outcomes of these initial analyses.

3.3.3 Renewable uncertainty and system stability

The emphasis of this work is on the additional variability and uncertainty introduced by VRES-E. VRES-E uncertainty influences the need for operating reserves in two ways. First, there is a direct influence via the errors made when forecasting their output. Forecast errors influence the need for FRR, both the fast component aFRR, and the slower component mFRR [203]. Section 3.3.4

explains how this effect is taken into in the model. Second, there is an indirect influence through their impact on the stability of the power system, which has an impact on the need for FCR.

The increase of the share of VRES-E decreases the share of dispatchable generation means in the power system. This decreases the amount of inertia in the power system. As explained in Section 2.2.2, this inertia is key in keeping the system frequency stable, as it helps smooth out variations over very short time frames. Insufficient inertia leads to a fast rate of change of frequency. This could cause an imbalance to lead to a frequency deviation that becomes too large for the FCR to contain it, growing too quickly for the aFRR to respond when FCR prove to be insufficient. This in turn can lead to critical frequency deviations and consequently to a potential system blackout. There are two ways to address this problem: (1) ensure a certain amount of inertia to be present in the system, or (2) increase the fast-response reserve capacity. The first could be done by either imposing that a number of conventional generators remains on-line to provide the required inertia, or by providing virtual inertia via power converters (connected to VRES-E or storage units). The second could be done by contracting additional FCR or by contracting reserves that respond even more rapidly (in a matter of seconds).

However, this issue and its solutions will not be dealt with in this work, for a number of reasons. First, the issue in itself is part of an emerging field of research. Inertia insufficiency on a power system level due to VRES-E integration has only recently become an issue. Even in those systems that are confronted with the issue the most, e.g. Ireland, the exact need for inertia is not very well understood. The measures it currently employs, such as keeping a number of conventional generators on-line, have been shown to not be a good proxy for the amount of inertia in the system [54]. Given the current knowledge on the subject, it is also difficult to formulate a specific need for inertia within a planning model. To study inertia and power system stability, a high level of spatial resolution and a detailed grid representation are needed. Given the current focus of the proposed planning model, such an approach would require even more computational power. Furthermore, while the alternative to conventional generators, i.e. providing virtual inertia, could be very promising, the current research on this topic is still in its early stages [53], prohibiting an accurate model representation. Finally, while some initial analyses have been carried out into the need for additional FCR capacity [204] or for even faster reserve products [205], linking the deployment of VRES-E capacity to a need for FCR is something that is not yet very well understood. For these reasons, the impact of VRES-E integration on the need for FCR will not be treated in this work.

3.3.4 Integrating operating reserve requirements

The first step in integrating the operating reserve requirements is formulating a methodology for the sizing of the operating reserves. For this sizing the imbalance drivers cited in Section 3.3.1 have to be taken into account. These drivers can be split into two groups: forecast errors, and the other imbalance drivers. The uncertainty of forecast errors is much more variable over time than that of the other imbalance drivers. The possible size of such forecast errors depends on the forecast itself, making it interesting from an economic point of view to update the associated reserve capacity more frequently than for the latter group of imbalance drivers. For the latter, the level of uncertainty can be assumed to be more or less constant over time. As such, when sizing operating reserves to deal with those, sizing on an annual basis can be said to be sufficient. However, when dealing with forecast error uncertainty, it is desirable to update the operating reserve requirement more frequently.

Two approaches can be identified to deal with forecast error uncertainty, depending on whether or not the sizing horizon falls within the forecast horizon. If this is not the case, then the sizing of the operating reserves cannot take into account the expected level of uncertainty, but must be exclusively informed by historical information. E.g. in the case of sizing on annual basis, with currently available climate models it is impossible to predict VRES-E output levels for a day ten months in the future. Consequently only historical VRES-E forecast error information can be used. Such an approach is called a *static* approach. If the sizing horizon falls within the forecast horizon, then the sizing can be informed with a more accurate estimate of the uncertainty expected to be in the system. E.g. in the case of sizing on an hourly basis, the day-ahead forecast of VRES-E output can be used to perform a conditional probabilistic assessment, i.e. looking at historical records to evaluate the expected forecast errors given a certain expected level of output. Such an approach is called a *dynamic* approach. Both methods will be studied in this work and are presented hereafter.

A note must be made on the extent to which these approaches can be compared. In this work the commonly used 3σ requirement is applied (99.7% quantile), respecting the ENTSO-E guidelines ("at least 99%"). However, a static and a dynamic approach using this 3σ requirement cannot be compared directly, as they do not lead to the same level of reliability. In theory, if both approaches are used on the same data set with the same quantile requirement, then the dynamic approach will result in operating reserve capacities that lead to a higher level of reliability. This is because the dynamic approach, as will be explained in more detail hereafter, splits up the data set into smaller groups based on the forecast level. Applying the same quantile requirement to a number of smaller data sets leads to higher reserve requirements, than when that requirement

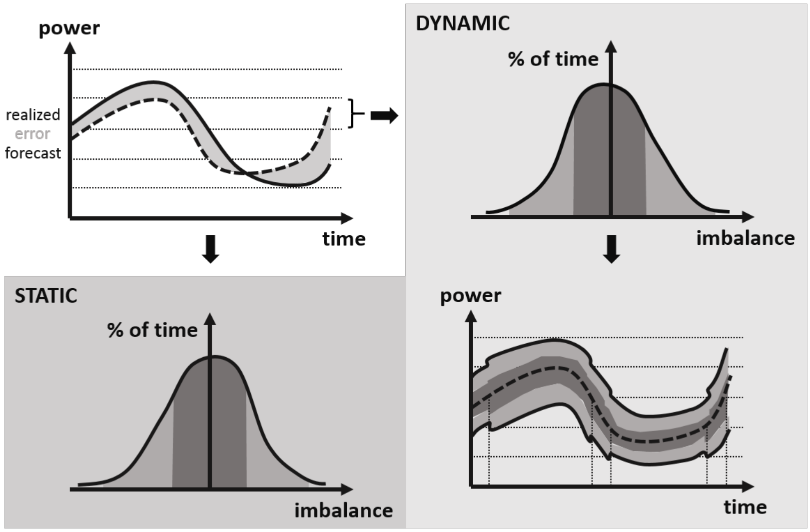

Figure 3.5: Static vs. dynamic reserve sizing

is applied to the whole data set as once. To actually be able to compare the performance of these approaches, the reserve requirements of both approaches need to be adjusted until they result in the same level of reliability (e.g. by having the same LOLE). This, however, is beyond the scope of this work. The essence here is to keep in mind that the dynamic sizing strategy used here leads to at least the same, and possible a higher, level of operational security.

Static vs. dynamic reserve sizing

Figure 3.5 shows a conceptual example of the static and dynamic reserve sizing methods used in this work. In the static method the historical forecast error data is described in a probability density function (pdf) over the sizing horizon. In this work, following ENTSO-E guidelines, historical records of a year are used. The use of data of more than one year would lead to a more informed representation of the uncertainty at hand. However, the focus here is on methodology, not data. Two sizing horizons are considered in this work for the static reserve sizing method: annual and monthly. In the first case a single pdf is drafted with the entire data set. In the second case, the data is split up per month, leading to 12 pdfs. The 99.7% quantile of these pdfs then dictates the yearly, or monthly, total FRR requirement.

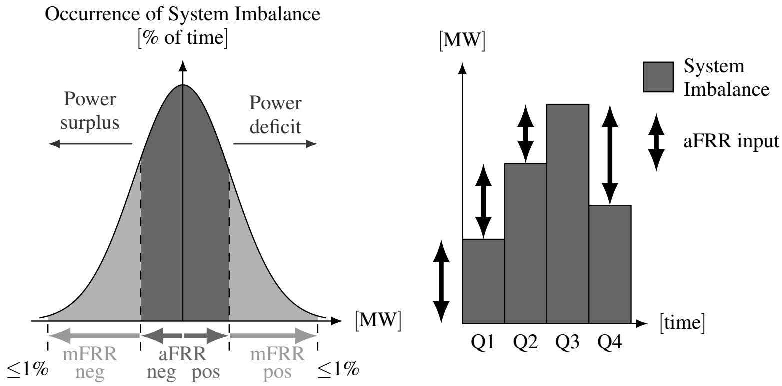

Figure 3.6: Method for translating a total FRR requirement to separate aFRR and mFRR requirements [202].

In the dynamic method the annual forecast error data is grouped into smaller sets based on the forecast level. As an example, an hourly dynamic sizing method is developed. Therefore, in this work, the entire forecast range is described by five equidistant intervals: 0%-20%, 20%-40%, and so on. For each subset a pdf is drafted, and the 99.7% quantile is calculated. With this, it is possible to determine the normalized 99.7% confidence interval around the forecast. The difference between the forecast and the boundaries of the 99.7% confidence interval then describes the need for FRR.

Subsequently, the total FRR requirement resulting from the static and dynamic sizing methods has to be translated to separate requirements for aFRR and mFRR. This is done by following the approach of the Belgian TSO ELIA, which is based on the imbalance volatility, defined as the difference between the imbalances of two consecutive quarters of hours (Figure 3.6) [206]. Within the relevant data subsets, the difference in consecutive imbalances results in a new time series, with a value for every 15 minutes of the year. This data can again be described in a pdf. A certain share of this imbalance volatility is to be covered by the aFRR. This share is not communicated by the TSOs. In this work a 2σ requirement is selected (i.e. the 95% quantile). This is slightly less strict than the requirement for total FRR, which is assumed to be realistic because of the higher cost of aFRR relative to mFRR. Thus, the 95% quantile of the imbalance volatility pdf prescribes the aFRR requirement. By subtracting the aFRR requirement from the total FRR requirement, the mFRR requirement can be determined.

Renewable vs. other uncertainty

In the framework of a planning model, the absolute size of the forecast errors is not known beforehand, as it depends on the installed VRES-E capacity. First, this prevents a simultaneous analysis of all imbalance drivers, which neglects the inclusion of corresponding statistical smoothing effects. To include this effect, distributions of imbalances would have to be convoluted endogenously. This operation, however, is too complex to be included in the model. Therefore, the operating reserves to deal with the other imbalance drivers, such as outages and load variability, have to be sized independently, and added to operating reserve requirements covering variable renewable generation. Second, this requires the sizing of the renewable reserve requirements to be formulated endogenously, meaning that the reserve requirements depend on the VRES-E capacity variables in the model. Finally, this has implications for the joint sizing of operating reserves of different power systems. While the uncertainty of other imbalance drivers can simply be pooled and the corresponding reserves sized exogenously, again the joint treatment of the renewable uncertainty of the different renewable resources is impossible if the installed capacities are unknown. To overcome this issue, the normalized forecast error data is pooled, and a single set of reserve requirements is determined per type of VRES-E for the research in Section 5.4, which studies the role of interconnection.

To integrate renewable reserve requirements, a probabilistic assessment is required. For each type of VRES-E a pdf of the normalized forecast errors is introduced. In the case of the static sizing method (annual or monthly), this results in a required amount of MW of FRR capacity per MW of installed VRES-E capacity. In the case of the hourly dynamic sizing method, this results in a required amount of MW of FRR capacity per MW of forecasted VRES-E output. These total requirements are again split up into separate aFRR and mFRR requirements, following the methodology described above.

It is assumed that VRES-E do not add to the need for downward reserves. In case of unexpected excess generation, the market framework will incentivize VRES-E to adjust their output downward if insufficient alternative providers for downward flexibility can be found. The literature shows the technical feasibility of providing balancing services with wind power plants, and various demonstrations already show how wind power is controlled by the TSO to support network stability [50]. This is less straightforward for distributed VRES-E, such as rooftop PV, but it is expected that at higher renewable penetrations these technologies will participate in providing downward flexibility, by means of enabling control infrastructure. Thus, only upward reserve requirements will be formulated for VRES-E uncertainty.

To integrate the reserve requirements dealing with the other imbalance drivers, a combined probabilistic and deterministic assessment is required. In contrast to the renewable requirements, this assessment is performed exogenously. Following ENTSO-E guidelines, a probabilistic assessment is performed using historical records of system imbalances of a full year. The 99.7% quantile of the pdf of these imbalances prescribes the total FRR requirement. Following again the same method as described above this total requirement is split up into an aFRR and a mFRR requirement. Then, it is ensured that the total FRR capacity can cover the highest active power system imbalance within the considered power system, both in the up- and downward direction. Should this deterministic assessment be binding, then the mFRR capacity calculated in the probabilistic assessment is supplemented until the total FRR capacity meets the requirement from the deterministic assessment. Also here the difference could be made between static and dynamic reserve sizing. However, as the emphasis of this work is on the uncertainty stemming from intermittent RES, only a static reserve sizing method with a yearly sizing horizon is used.

3.3.5 Allocation

The modeling of the technical constraints related to allocation is presented in the following section. Here, two important aspects are discussed. The first aspect is the allocation of operating reserves to VRES-E technologies. The provision of upward reserves is not allowed. If VRES-E provide upward reserve capacity, this capacity should be available with sufficient certainty in real-time, e.g. with a 99.7% probability. This means that the sum of what is sold in the day-ahead market and what is provided as upward reserve power cannot exceed the share of the forecast that is available with 99.7% certainty, which implies an impractical level of curtailment. In real-time operation, during activation, available VRES-E surpluses could be used. However, firstly, the activation phase is not considered. Secondly, to include this possibility in a planning model, a thorough probabilistic analysis should be performed to evaluate to what extent such upward reserve provision is reliable. This has not been studied in detail in this work. The provision of downward reserves is allowed. The share of the forecast that is available with 99.7% certainty (i.e. the lower boundary of the 99.7% confidence interval of the forecast, see the example in Figure 3.5) is assumed to be sufficiently reliable to supply downward FRR. The allocation of downward reserves to VRES-E would lead to curtailment during activation. Thus, less VRES-E electricity would be absorbed to help meet the RES-E objective. This could in part be compensated by surpluses during other moments, e.g. by the activation of upward VRES-Ereserve capacity. However, as the activation phase is not considered, this effect is not captured.

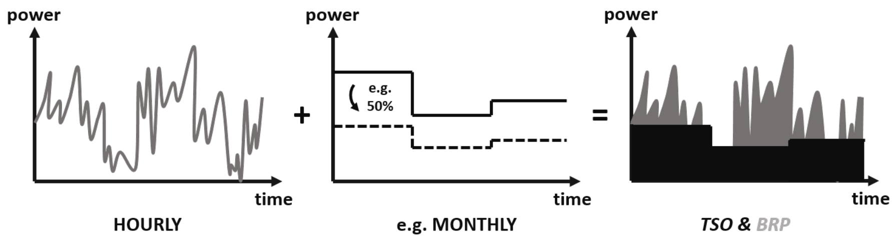

Figure 3.7: Reflecting TSO & BRP reserve procurement

The second aspect relates to the horizon over which the reserve capacity is allocated. When a TSO allocates reserve capacity to an ancillary service provider, it expects this party to provide this service for a certain time. Contracts are made on an annual, monthly, and at times already weekly or daily basis. The allocation horizon is obviously linked to the sizing horizon. The allocation horizon can at most be the sizing horizon; e.g. if the reserve requirements are updated on a monthly basis, then allocation contracts for a specific capacity are also updated at least on a monthly basis. The allocation horizon can be shorter; e.g. updating the allocated capacity on a daily basis with requirements updated only on a monthly basis. It is important to represent these characteristics of allocation of reserves in the model. The most economic way of allocating reserve capacity is to allocate on the time step of the model, hourly in the case of this work. This allows to optimally use the flexibility available in the system at every time step. However, TSOs contract reserves over a longer period as a kind of insurance, so that the flexibility will definitely be available when needed. This incurs additional costs, both in investment and in operation, as it forces to keep certain elements in the power system for the provision of flexibility, even when other sources of flexibility are available. BRPs, in contrast, will try to optimize the use of the available flexibility in their portfolio, before incurring additional costs by introducing other sources of flexibility. This situation is reflected in the model as shown in an example in Figure 3.7. First, reserve capacity is allocated over a chosen set of horizons, reflecting the reserves a TSO would contract, e.g. a share of the monthly sized reserves allocated on a monthly basis. Then, operational security is ensured for every hour as follows: using the hourly dynamic sizing method the required hourly reserve capacity is determined. Subsequently, this is compared hour by hour with the reserve capacity allocated over longer time horizons. If insufficient reserve capacity has been contracted, then the difference is allocated on an hourly basis. This then reflects the flexibility the BRPs would have to procure themselves.

3.4 Model description

This section provides a comprehensive formulation of the developed long-term power system planning model. First, Section 3.4.1 provides the objective function. Then, Section 3.4.2 discusses the included system level constraints. Finally, Sections 3.4.3 to 3.4.7 provide the formulation of the technology level constraints. All technologies are defined as injection and off-take technologies. In the developed model injection encompasses dispatchable and variable generation, and electricity storage discharging, while off-take points to electricity storage charging and flexible consumption. The basic spatial level of the model is that of the zone. At this level all operational constraints are formulated, including the electricity balance equation, the operating reserve requirements, and the exchange of electricity. Consequently, this is also the level at which the installed capacities are determined. Each zone, in turn, belongs to a country. At this level all policy related constraints are formulated, including the target for the share of renewable energy in the electricity consumption.

3.4.1 Objective function

The objective function reads as follows:

$$
\begin{aligned}
\min \quad \sum_{z \in \mathbb{Z}} \Bigg[\sum_{i \in \mathbb{I}} \Big[& (C_i^{\mathrm{inv,i}} + C_i^{\mathrm{fom,i}}) \cdot p_{z,i}^{\mathrm{cap,i}} \\
& + \sum_{t \in \mathbb{T}} \big[(C_i^{\mathrm{fuel,i}} + C_i^{\mathrm{vom,i}}) \cdot p_{z,i,t}^{\mathrm{i}} \cdot \Delta T^{\mathrm{t}} \\
& + C_i^{\mathrm{ra,i}} \cdot (p_{z,i,t}^{\mathrm{ru,i}} + p_{z,i,t}^{\mathrm{rd,i}}) \\
& + C_i^{\mathrm{su,i}} \cdot p_{z,i,t}^{\mathrm{su,i}} + C_i^{\mathrm{sd,i}} \cdot p_{z,i,t}^{\mathrm{sd,i}}) \big] \Big] \\
+ \sum_{o \in \mathbb{O}} \Big[& (C_o^{\mathrm{inv,o}} + C_o^{\mathrm{fom,o}}) \cdot p_{z,o}^{\mathrm{cap,o}} \\
& + \sum_{t \in \mathbb{T}} \big[(C_o^{\mathrm{fuel,o}} + C_o^{\mathrm{vom,o}}) \cdot p_{z,o,t}^{\mathrm{o}} \cdot \Delta T^{\mathrm{t}} \\
& + C_o^{\mathrm{ra,o}} \cdot (p_{z,o,t}^{\mathrm{ru,o}} + p_{z,o,t}^{\mathrm{rd,o}}) \\
& + C_o^{\mathrm{su,o}} \cdot p_{z,o,t}^{\mathrm{su,o}} + C_o^{\mathrm{sd,o}} \cdot p_{z,o,t}^{\mathrm{sd,o}}) \big] \Big]
\end{aligned}
$$

$$
\begin{aligned}
&+\sum_{s\in\mathbb{S}}(C_s^{\text{inv,e}}\cdot e_s^{\text{cap}}+c_{z,s}^{\text{cyc}})\\
&+\sum_{d\in\mathbb{D}}\big[C_d^{\text{inv,d}}\cdot(d_{z,d}^{\text{cap,up}}+d_{z,d}^{\text{cap,dn}})\big]\\
&\qquad+\sum_{t\in\mathbb{T}}\big[C_d^{\text{op,d}}\cdot(d_{z,d,t}^{\text{dn}}+d_{z,d,t}^{\text{up}})\big]\\
&+\sum_{z_e\in\mathbb{Z}_\mathbb{E}}\big[\sum_{z_i\in\mathbb{Z}_\mathbb{I}\$(z_i,z_e)}(C_{z_e,z_i}^{\text{inv,f}}\cdot f_{z_e,z_i}^{\text{cap}})\big]\\
&+\sum_{t\in\mathbb{T}}\Delta T^{\text{t}}\cdot\Big(C^{\text{nat}}\cdot p_{z,i,t}^{\text{nat}}+C^{\text{ls}}\cdot p_{z,t}^{\text{ls}}+\sum_{i\in\mathbb{I}\setminus\{\mathbb{ID}\}}C^{\text{cu}}\cdot p_{z,i,t}^{\text{cu,i}}\Big)\Big].
\end{aligned}
\tag{3.1}
$$

The objective function minimizes the total cost, consisting of the power investment and fixed operating and maintenance costs, the fuel and variable operating and maintenance costs, the ramping, start-up- and shut-down costs, and the operating reserve activation costs for injection and off-take technologies; the energy investment and cycling costs for the storage technologies; the power investment and operational costs of the flexible demand response technologies; the interconnection investment costs; and the natural gas cost, the load shedding cost, and the curtailment cost.[1]

3.4.2 System constraints

The included system constraints are the balance equation, the operating reserve requirements, and a renewable energy and firm capacity requirement (3.2a) - (3.2k). First, the balance equation, mimicking the day-ahead market (on a zonal instead of the country level), ensures that the sum of power injections and off-takes equals the zone's electricity demand, taking into account the effects of flexible consumption, reduced by possible load shedding, and corrected for export and imports flowing to and from the zone (3.2a). The reference consumption of the demand response technologies is subtracted from the demand before the planned consumption is added to it, so that the total consumption remains the

[1]To facilitate notation of the equations a specific operator that is used in GAMS to describe logical conditions will also be used throughout the model description. The term \$(condition) can be read as "such that condition is valid" where *condition* is a logical condition [207]. Furthermore, when summing over interconnections "$\$(z_i, z_e)$" is short for "$\$\big((z_i, z_e) \in \mathbb{F} + (z_e, z_i) \in \mathbb{F}\big)$". Essentially, the set $\mathbb{F}$ contains only one of two possible (z, z) combinations to indicate that there is an interconnection between two zones. This shortened notation will also be used throughout.

same. Second, a set of operating reserve requirements are imposed (3.2b)–(3.2i) following the methodology discussed in Section 3.3.5. The first equation mimics the “TSO requirements”, with a specific allocation horizon (3.2b), reflected in the superscript a. $R^{\mathrm{en,a}}_{z,r,i,t}$ and $R^{\mathrm{ex,a}}_{z,r,a}$ deal with the renewable and other uncertainty, respectively. If, e.g., the sizing horizon is annual, and the allocation horizon is monthly, then these parameters would have the same value for the 12 elements a of the allocation horizon set $\mathbb{A}$. The second equation mimics the additional “BRPs flexibility” required to meet the total hourly need for reserve capacity (3.2c), reflected in the superscript b. Equations (3.2d)–(3.2f) and (3.2g)–(3.2i) link the reserve capacity held over a certain allocation horizon to the corresponding time steps of the market, and sum these with the additional reserve capacity to arrive at a total reserve capacity per technology per time step per reserve category, for injections and off-takes, respectively. Currently, the reserve requirements to deal with the non-renewable uncertainty are calculated at the country level, as this is the level at which this information is available. It is divided between the zones based on their peak demand. Reserve requirements to deal with the renewable uncertainty are calculated at the level of the resource, i.e. if the data is available, this is directly at the zonal level. Finally, a requirement for the share of renewable energy in electricity consumption (3.2j) and for the amount of firm capacity (3.2k) are imposed.

$$\forall\, z \in \mathbb{Z}, t \in \mathbb{T}:$$

$$\sum_{i\in\mathbb{I}} p^{\mathrm{i}}_{z,i,t} - \sum_{o\in\mathbb{O}} p^{\mathrm{o}}_{z,o,t} + \sum_{z_e \in \mathbb{Z}_{\mathbb{E}}\$(z_e,z)} f_{z_e,z,t} =$$

$$D_{z,t} - p^{\mathrm{ls}}_{z,t} + \sum_{d\in\mathbb{D}} (p^{\mathrm{o}}_{z,d,t} - P^{\mathrm{d,ref}}_{z,d,t}) + \sum_{z_i \in \mathbb{Z}_{\mathbb{I}}\$(z_i,z)} f_{z,z_i,t}, \quad (3.2a)$$

$$\forall\, z \in \mathbb{Z}, r \in \mathbb{R}:$$

$$\sum_{i\in\mathbb{I}} r^{\mathrm{i,a}}_{z,r,i,a} + \sum_{o\in\mathbb{O}} r^{\mathrm{o,a}}_{z,r,o,a} + \sum_{z_e \in \mathbb{Z}_{\mathbb{E}}\$(z_e,z)} f^{\mathrm{r,a}}_{z_e,z,r,a} =$$

$$R^{\mathrm{ex,a}}_{z,r,a} + \sum_{i\in\mathbb{I}\setminus\{\mathbb{ID}\}} (R^{\mathrm{en,a}}_{z,r,i,a} \cdot p^{\mathrm{cap,i}}_{z,i}) + \sum_{z_i \in \mathbb{Z}_{\mathbb{I}}\$(z_i,z)} f^{\mathrm{r,a}}_{z,z_i,r,a}, \quad \forall\, a \in \mathbb{A}, \quad (3.2b)$$

$$\sum_{i\in\mathbb{I}} r^{\mathrm{i,b}}_{z,r,i,t} + \sum_{o\in\mathbb{O}} r^{\mathrm{o,b}}_{z,r,o,t} + \sum_{z_e \in \mathbb{Z}_{\mathbb{E}}\$(z_e,z)} f^{\mathrm{r,b}}_{z_e,z,r,t} =$$

$$R^{\mathrm{ex,b}}_{z,r,t} + \sum_{i\in\mathbb{I}\setminus\{\mathbb{ID}\}} (R^{\mathrm{en,b}}_{z,r,i,t} \cdot p^{\mathrm{cap,i}}_{z,i}) + \sum_{z_i \in \mathbb{Z}_{\mathbb{I}}\$(z_i,z)} f^{\mathrm{r,b}}_{z,z_i,r,t}, \quad \forall\, t \in \mathbb{T}, \quad (3.2c)$$

$$r^{\mathrm{i,a,t}}_{z,r,i,a,t} = r^{\mathrm{i,a}}_{z,r,i,a}, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$\mathbb{AT}, \quad (3.2d)$$

$$r^{\mathrm{i,a,t}}_{z,r,i,a,t} = 0, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$(!\mathbb{AT}), \quad (3.2e)$$

$$r^{\mathrm{i}}_{z,r,i,t} = \sum_{a\in\mathbb{A}} r^{\mathrm{i,a,t}}_{z,r,i,a,t} + r^{\mathrm{i,b}}_{z,r,i,t}, \qquad \forall\, t \in \mathbb{T}, \quad (3.2f)$$

$$r^{\mathrm{o,a,t}}_{z,r,o,a,t} = r^{\mathrm{o,a}}_{z,r,o,a}, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$\mathbb{AT}, \quad (3.2g)$$

$$r^{\mathrm{o,a,t}}_{z,r,o,a,t} = 0, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$(!\mathbb{AT}), \quad (3.2h)$$

$$r^{\mathrm{o}}_{z,r,o,t} = \sum_{a\in\mathbb{A}} r^{\mathrm{o,a,t}}_{z,r,o,a,t} + r^{\mathrm{o,b}}_{z,r,o,t}, \qquad \forall\, t \in \mathbb{T}, \quad (3.2i)$$

$$\sum_{t\in\mathbb{T}} \sum_{g\in\mathbb{GR}} \sum_{z\in\mathbb{Z}\$\mathbb{CZ}} p^{\mathrm{i}}_{z,g,t} \geq S^{\mathrm{res}}_{c} \cdot \sum_{t\in\mathbb{T}} \sum_{z\in\mathbb{Z}\$\mathbb{CZ}} D_{z,t}, \qquad \forall\, c \in \mathbb{C}. \quad (3.2j)$$

$$\sum_{z\in\mathbb{Z}\$\mathbb{CZ}} \Big(\sum_{i\in\mathbb{I}} P^{\mathrm{i,firm}}_{i} \cdot p^{\mathrm{cap,i}}_{z,i} + \sum_{o\in\mathbb{O}} P^{\mathrm{o,firm}}_{o} \cdot p^{\mathrm{cap,o}}_{z,o} \Big) \geq$$
$$S^{\mathrm{firm}}_{c} \cdot \sum_{z\in\mathbb{Z}\$\mathbb{CZ}} D^{\mathrm{peak}}_{z}, \quad \forall\, c \in \mathbb{C}. \quad (3.2k)$$

3.4.3 Dispatchable injection and off-takes

Producing electricity with dispatchable generation technologies, charging and discharging electricity with energy storage technologies, and consuming electricity with controllable demand-side technologies are all modeled as dispatchable injections and off-takes. This is done in the Clustered Unit Commitment framework, which was presented in Section 2.3.3. In this framework injections and off-takes are subjected to commitment constraints (including minimum up and down time constraints), minimum output level constraints, ramping constraints over different time horizons, and reserve provision constraints. First, units are grouped per technology, which results in integer commitment variables instead of binary. All operational constraints are then formulated on the technology level. Finally, the model is relaxed, which results in linear commitment variables. This allows the integration of such detailed short-term operational constraints in a long-term planning model while maintaining reasonable computation times.

The modeling of dispatchable injections and off-takes is completely equivalent. The only difference is the operating reserve categories to which they contribute, i.e., a potential increase in the level of injection will contribute to the upward reserves; whereas a potential increase in the level of off-take will contribute to the downward reserves. For brevity, only the equations which describe the short-term operation of an injection are included, indicated by the superscript i, added to all variables and parameters. To obtain the equations of an off-take, one only needs to replace the superscript by o and switch the operating reserve categories (e.g. $\mathbb{RUA}$ becomes $\mathbb{RDA}$, and $\mathbb{RD}$ becomes $\mathbb{RU}$). The short-term operation of dispatchable generation technologies ($i \in \mathbb{GD}$) is fully described by (3.3a) – (3.5l).

Commitment constraints

Commitment constraints are formulated on the technology level. The number of on-line units of a technology can be altered by starting up off-line units or shutting down on-line units (3.3a). It is limited to the maximum number of on-line units, determined by the ratio of the installed capacity and the technology's unit size (3.3b). The number of off-line units that can be started up, or allocated to start up for reserve provision, is limited to those units that have been off-line for at least the technology's minimum down time (3.3c). Similarly, the number of on-line units that can be shut down, or allocated to shut down for reserve provision, is limited to those units that have been on-line for at least the technology's minimum up time (3.3d).

$$\forall\, z \in \mathbb{Z}, i \in \mathbb{ID}, t \in \mathbb{T}:$$

$$n^{\mathrm{i}}_{z,i,t+1} = n^{\mathrm{i}}_{z,i,t} + n^{\mathrm{su,i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t}, \tag{3.3a}$$

$$n^{\mathrm{i}}_{z,i,t} \leq p^{\mathrm{cap,i}}_{z,i} / P^{\mathrm{i}}_{i}, \tag{3.3b}$$

$$n^{\mathrm{su,i}}_{z,i,t} + \sum_{r \in \mathbb{RU}} n^{\mathrm{su,r,i}}_{z,r,i,t} \leq p^{\mathrm{cap,i}}_{z,i} / P^{\mathrm{i}}_{i} - n^{\mathrm{i}}_{z,i,t} - \sum_{w=1}^{T^{\mathrm{mdt,i}}_{i}} n^{\mathrm{sd,i}}_{z,i,t-w}, \tag{3.3c}$$

$$n^{\mathrm{sd,i}}_{z,i,t} + \sum_{r \in \mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t} \leq n^{\mathrm{i}}_{z,i,t} - \sum_{w=1}^{T^{\mathrm{mut,i}}_{i}} n^{\mathrm{su,i}}_{z,i,t-w}. \tag{3.3d}$$

Ramping constraints

A technology's injection level can alter by ramping up or down on-line units, starting up off-line units, or shutting-down on-line units (3.4a). The injection level is limited by the minimum output level $P_i^{\mathrm{min,i}}$ (3.4b) and the installed capacity (3.4c). Units starting up and shutting down have to overcome at least the minimum output level (3.4d), (3.4f) and are limited in their ramping by the technology's ramping ability (3.4e), (3.4g). Ramping up and down of on-line units is also limited by the technology's ramping ability (3.4h), (3.4i), and by the available capacity margin, while ensuring that ramping ability allocated to spinning reserve provision is not doubly booked (3.4j), (3.4k).

$$\forall\, z \in \mathbb{Z}, i \in \mathbb{ID}, t \in \mathbb{T}:$$

$$p^{\mathrm{i}}_{z,i,t+1} = p^{\mathrm{i}}_{z,i,t} + p^{\mathrm{ru,i}}_{z,i,t} - p^{\mathrm{rd,i}}_{z,i,t} + p^{\mathrm{su,i}}_{z,i,t} - p^{\mathrm{sd,i}}_{z,i,t}, \tag{3.4a}$$

$$p^{\mathrm{i}}_{z,i,t} \geq n^{\mathrm{i}}_{z,i,t} \cdot P^{\mathrm{min,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4b}$$

$$p^{\mathrm{i}}_{z,i,t} \leq n^{\mathrm{i}}_{z,i,t} \cdot P^{\mathrm{i}}_i, \tag{3.4c}$$

$$p^{\mathrm{su,i}}_{z,i,t} \geq n^{\mathrm{su,i}}_{z,i,t} \cdot P^{\mathrm{min,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4d}$$

$$p^{\mathrm{su,i}}_{z,i,t} \leq n^{\mathrm{su,i}}_{z,i,t} \cdot R^{\mathrm{su,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4e}$$

$$p^{\mathrm{sd,i}}_{z,i,t} \geq n^{\mathrm{sd,i}}_{z,i,t} \cdot P^{\mathrm{min,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4f}$$

$$p^{\mathrm{sd,i}}_{z,i,t} \leq n^{\mathrm{sd,i}}_{z,i,t} \cdot R^{\mathrm{sd,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4g}$$

$$p^{\mathrm{ru,i}}_{z,i,t} + \sum_{\mathbb{RU}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t}) \cdot R^{\mathrm{s,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4h}$$

$$p^{\mathrm{rd,i}}_{z,i,t} + \sum_{\mathbb{RD}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t} - \sum_{\mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t}) \cdot R^{\mathrm{s,i}}_i \cdot P^{\mathrm{i}}_i, \tag{3.4i}$$

$$p^{\mathrm{ru,i}}_{z,i,t} + \sum_{\mathbb{RU}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{i,t} - n^{\mathrm{sd,i}}_{z,i,t}) \cdot P^{\mathrm{i}}_i - (p^{\mathrm{i}}_{z,i,t} - p^{\mathrm{sd,i}}_{z,i,t}), \tag{3.4j}$$

$$\begin{aligned} p^{\mathrm{rd,i}}_{z,i,t} + \sum_{\mathbb{RD}} r^{\mathrm{s,i}}_{z,r,i,t} \leq {} & (p^{\mathrm{i}}_{z,i,t} - p^{\mathrm{sd,i}}_{z,i,t} - \sum_{\mathbb{RD}} r^{\mathrm{sd,i}}_{z,r,i,t}) \\ & -(n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t} - \sum_{\mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t}) \cdot P^{\mathrm{min,i}}_i \cdot P^{\mathrm{i}}_i\ . \end{aligned} \tag{3.4k}$$

Reserve allocation

The dispatchable injection technologies contribute to upward reserves through spinning (on-line) units and non-spinning (off-line) units that can start up sufficiently quickly (3.5a), and to downward reserves through spinning units that either remain or that can shut down (3.5b). Spinning reserve provision is limited by the ramping ability for the different upward (3.5c)–(3.5e) and downward (3.5f)–(3.5h) reserve categories, while ensuring that no ramping ability is doubly booked. Units providing reserves through starting up or shutting down are also limited by the technology's ramping ability, and have to overcome at least the technology's minimum output level (3.5i)–(3.5l).

$$\forall\, z \in \mathbb{Z}, i \in \mathbb{ID}, t \in \mathbb{T}:$$

$$r^{\mathrm{i}}_{z,r,i,t} = r^{\mathrm{s,i}}_{z,r,i,t} + r^{\mathrm{su,i}}_{z,r,i,t} \qquad \forall\, r \in \mathbb{RU}, \tag{3.5a}$$

$$r^{\mathrm{i}}_{z,r,i,t} = r^{\mathrm{s,i}}_{z,r,i,t} + r^{\mathrm{sd,i}}_{z,r,i,t} \qquad \forall\, r \in \mathbb{RD}, \tag{3.5b}$$

$$\sum_{r \in \mathbb{RUF}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t}) \cdot R^{\mathrm{s,r,i}}_{FCR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5c}$$

$$\sum_{r \in \mathbb{RUA}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t}) \cdot R^{\mathrm{s,r,i}}_{aFRR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5d}$$

$$\sum_{r \in \mathbb{RU}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t}) \cdot R^{\mathrm{s,r,i}}_{mFRR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5e}$$

$$\sum_{r \in \mathbb{RDF}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t} - \sum_{r \in \mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t}) \cdot R^{\mathrm{s,r,i}}_{FCR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5f}$$

$$\sum_{r \in \mathbb{RDA}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t} - \sum_{r \in \mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t}) \cdot R^{\mathrm{s,r,i}}_{aFRR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5g}$$

$$\sum_{r \in \mathbb{RD}} r^{\mathrm{s,i}}_{z,r,i,t} \leq (n^{\mathrm{i}}_{z,i,t} - n^{\mathrm{sd,i}}_{z,i,t} - \sum_{r \in \mathbb{RD}} n^{\mathrm{sd,r,i}}_{z,r,i,t}) \cdot R^{\mathrm{s,r,i}}_{mFRR,i} \cdot P^{\mathrm{i}}_{i}, \tag{3.5h}$$

$$r^{\mathrm{su,i}}_{z,r,i,t} \geq n^{\mathrm{su,r,i}}_{z,r,i,t} \cdot P^{\mathrm{min,i}}_{i} \cdot P^{\mathrm{i}}_{i} \qquad \forall\, r \in \mathbb{RU}, \tag{3.5i}$$

$$r^{\mathrm{su,i}}_{z,r,i,t} \leq n^{\mathrm{su,r,i}}_{z,r,i,t} \cdot R^{\mathrm{su,r,i}}_{r,i} \cdot P^{\mathrm{i}}_{i} \qquad \forall\, r \in \mathbb{RU}, \tag{3.5j}$$

$$r^{\mathrm{sd,i}}_{z,r,i,t} \leq n^{\mathrm{sd,r,i}}_{z,r,i,t} \cdot P^{\mathrm{min,i}}_{i} \cdot P^{\mathrm{i}}_{i} \qquad \forall\, r \in \mathbb{RD}, \tag{3.5k}$$

$$r^{\mathrm{sd,i}}_{z,r,i,t} \leq n^{\mathrm{sd,r,i}}_{z,r,i,t} \cdot R^{\mathrm{sd,r,i}}_{r,i} \cdot P^{\mathrm{i}}_{i} \qquad \forall\, r \in \mathbb{RD}. \tag{3.5l}$$

3.4.4 Variable generation

The short-term operation of the VRES-E technologies follows equations (3.6a)–(3.6d). To calculate the intermittent output a normalized feed-in profile $P^{\text{res}}_{z,i,t}$ is used. It is scaled with the installed capacity. The sum of VRES-E injection and curtailment is limited to this output (3.6a). A part of this forecast (calculated via a probabilistic analysis, see Section 3.3.5), namely $P^{\text{rel}}_{i,t}$, is considered sufficiently reliable to supply downward reserves (3.6b). Such reserve provision is limited to the injection level (3.6c). Upward reserve provision is currently not allowed (as was explained in Section 3.3.5) (3.6d).

$$\forall\, z \in \mathbb{Z}, i \in \mathbb{I}\backslash\{\mathbb{ID}\}, t \in \mathbb{T}:$$

$$p^{\text{i}}_{z,i,t} + p^{\text{cu,i}}_{z,i,t} \leq P^{\text{res}}_{i,t} \cdot p^{\text{cap,i}}_{z,i}, \tag{3.6a}$$

$$\sum_{\mathbb{RD}} r^{\text{i}}_{z,r,i,t} \leq P^{\text{rel}}_{z,i,t} \cdot p^{\text{cap,i}}_{z,i}, \tag{3.6b}$$

$$\sum_{\mathbb{RD}} r^{\text{i}}_{z,r,i,t} \leq p^{\text{i}}_{z,i,t}, \tag{3.6c}$$

$$\sum_{\mathbb{RU}} r^{\text{i}}_{z,r,i,t} = 0. \tag{3.6d}$$

3.4.5 Demand response

The short-term operation of the flexible demand side processes is modeled as a dispatchable off-take. The flexibility of these processes is determined as their deviation from a reference consumption profile $P^{\text{d,ref}}_{z,d,t}$. Any deviation from the reference profile is labeled as an activation flexibility $F = \Delta P \cdot \Delta T$, where ΔP is the adjustment in power and ΔT is the corresponding duration of this activation. These activations are constrained in a number of ways. Firstly, the total annual consumption has to be at least the same as the reference consumption (3.7a) – possibly reduced by a certain margin M^{min}_{d}, and can only exceed it by a limited margin M^{max}_{d} (3.7b). The activation of downward flexibility is constrained following (3.7c)–(3.7f); the activation of upward flexibility following (3.7g)–(3.7j). Any adjustment from the reference consumption is considered activated flexibility $d^{\mathrm{dn}}_{z,d,t}$ (3.7c), $d^{\mathrm{up}}_{z,d,t}$ (3.7g). This activated flexibility is firstly limited in terms of power to the available capacity $d^{\mathrm{cap,dn}}_{z,d}$ (3.7d), and $d^{\mathrm{cap,up}}_{z,d}$ (3.7i); and to the maximum available potential $\Delta P^{\mathrm{dn}}_{d,t}$ (3.7e), and $\Delta P^{\mathrm{up}}_{d,t}$ (3.7j). Secondly, an activation is limited in terms of energy, to $\Delta E^{\mathrm{dn}}_{d}$, and $\Delta E^{\mathrm{up}}_{d}$; the product of the power of the activation and its duration. The full use of this flexible energy can only occur once during a certain period of H^{dn}_{d} hours (3.7f), and H^{dn}_{d} hours (3.7k). Finally, the total amount of activated flexibility is limited on an annual basis to the equivalent of a maximum number of activations of the full flexibility A^{dn}_{d} (3.7f), and A^{up}_{d} (3.7l).

$$\forall\, z \in \mathbb{Z}, d \in \mathbb{D}:$$

$$\sum_{t\in\mathbb{T}} p^{\mathrm{o}}_{z,d,t} \geq M^{\mathrm{min}}_{d} \cdot \sum_{t\in\mathbb{T}} P^{\mathrm{d,ref}}_{z,d,t}, \tag{3.7a}$$

$$\sum_{t\in\mathbb{T}} p^{\mathrm{o}}_{z,d,t} \leq M^{\mathrm{max}}_{d} \cdot \sum_{t\in\mathbb{T}} P^{\mathrm{d,ref}}_{z,d,t}, \tag{3.7b}$$

$$d^{\mathrm{dn}}_{z,d,t} \geq P^{\mathrm{d,ref}}_{z,d,t} - p^{\mathrm{o}}_{z,d,t} \qquad \forall\, t \in \mathbb{T}, \tag{3.7c}$$

$$d^{\mathrm{dn}}_{z,d,t} \leq d^{\mathrm{cap,dn}}_{z,d} \qquad \forall\, t \in \mathbb{T}, \tag{3.7d}$$

$$d^{\mathrm{dn}}_{z,d,t} \leq \Delta P^{\mathrm{dn}}_{d,t} \qquad \forall\, t \in \mathbb{T}, \tag{3.7e}$$

$$\sum_{z=1}^{H^{\mathrm{dn}}_{d}-1} d^{\mathrm{dn}}_{z,d,t} \leq \Delta E^{\mathrm{dn}}_{d} \qquad \forall\, t \in \mathbb{T}, \tag{3.7f}$$

$$\sum_{t\in\mathbb{T}} d^{\mathrm{dn}}_{z,d,t} \leq \Delta E^{\mathrm{dn}}_{d} \cdot A^{\mathrm{dn}}_{d}, \tag{3.7g}$$

$$d^{\mathrm{up}}_{z,d,t} \geq p^{\mathrm{o}}_{z,d,t} - P^{\mathrm{d,ref}}_{z,d,t} \qquad \forall\, t \in \mathbb{T}, \tag{3.7h}$$

$$d^{\mathrm{up}}_{z,d,t} \leq d^{\mathrm{cap,up}}_{z,d} \qquad \forall\, t \in \mathbb{T}, \tag{3.7i}$$

$$d^{\mathrm{up}}_{z,d,t} \leq \Delta P^{\mathrm{up}}_{d,t} \qquad \forall\, t \in \mathbb{T}, \tag{3.7j}$$

$$\sum_{z=1}^{H^{\mathrm{up}}_{d}-1} d^{\mathrm{up}}_{z,d,t} \leq \Delta E^{\mathrm{up}}_{d} \qquad \forall\, t \in \mathbb{T}, \tag{3.7k}$$

$$\sum_{t\in\mathbb{T}} d^{\mathrm{up}}_{z,d,t} \leq \Delta E^{\mathrm{up}}_{d} \cdot A^{\mathrm{up}}_{d}. \tag{3.7l}$$

3.4.6 Energy storage

Certain storage technologies consume electricity when charging, store it under some energy form, and then reconvert it to electricity when discharging. These technologies are referred to as re-electrifying storage technologies. Belloyd, first the energy constraints of such technologies are presented. Other technologies also charge electricity, but do not reconvert it to electricity. Rather, the energy is used directly under the form to which it has been converted. Those energy constraints are presented further below.

Re-electrifying storage energy constraints

The short-term operation of the discharging of a storage technology is modeled as a dispatchable injection, while the short-term operation of the charging is modeled as a dispatchable off-take. These processes are linked through the equations governing the energy level of the storage. The energy level alters through charging and discharging (3.8a). This constraint is cyclical (indicated by the "++"), so that overall energy neutrality of the storage technologies is ensured. The energy level is constrained in both directions by the available capacity and the margins that have been allocated for reserve provision (3.8b), (3.8c). Finally, the cycling costs of the storage technologies are calculated (3.8d).

$$\forall\, z \in \mathbb{Z}, s \in \mathbb{S} :$$

$$e_{z,s,t{+}{+}1} = e_{z,s,t} + \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,t}\right) \cdot \Delta T^{\mathrm{t}} \quad \forall\, t \in \mathbb{T}, \tag{3.8a}$$

$$e_{z,s,t} \geq (1/\eta^{\mathrm{i}}_s) \cdot \sum_{r \in \mathbb{RU}} r^{\mathrm{i}}_{z,r,s,t} \cdot \Delta T^{\mathrm{r}}_r \quad \forall\, t \in \mathbb{T}, \tag{3.8b}$$

$$e_{z,s,t} \leq e^{\mathrm{cap}}_{z,s} - \eta^{\mathrm{o}}_s \cdot \sum_{r \in \mathbb{RD}} r^{\mathrm{o}}_{z,r,s,t} \cdot \Delta T^{\mathrm{r}}_r \quad \forall\, t \in \mathbb{T}, \tag{3.8c}$$

$$c^{\mathrm{cyc}}_{z,s} \geq (C^{\mathrm{cyc,cap}}_s - C^{\mathrm{inv,e}}_{z,s}) \cdot e^{\mathrm{cap}}_{z,s} + \sum_{t \in \mathbb{T}} \Big[C^{\mathrm{cyc,op}}_s \cdot \big[\left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,t} + (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,t}\right) \Big]. \tag{3.8d}$$

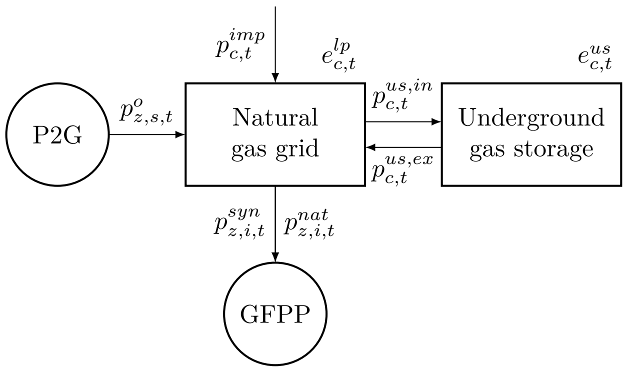

Figure 3.8: Conceptual model of the gas infrastructure

Non-re-electrifying storage energy constraints

P2G, which converts electrical energy to synthetic methane through the electrolysis of water and subsequent methanation of the produced hydrogen gas, is chosen as a representative technology for non-re-electrifying energy storage. Storing energy as gas facilitates long-term storage, relative to e.g. BES. It does require, however, an alternative way to reconvert the energy back into electricity; in this case gas-fired electricity generation technologies.

In the representation developed here, electricity is charged, converted into synthetic methane, and subsequently injected in the existing natural gas grid. The stored synthetic methane is then reconverted to electricity in Gas-Fired Power Plants (GFPP). The planning model is extended with a conceptual model of the gas infrastructure representing an underground seasonal storage and the line-pack, the inherent flexibility of the gas transmission network, as energy buffers. This network and its storages are modeled at the level of the country, not considering any constraints on the flows in the gas grid. The gas flows occurring in the conceptual model are shown in Figure 3.8. Gas can be injected in the grid via the extraction of gas from the underground storage, via P2G, or via the import of natural gas. It can be extracted from the grid via the injection of gas into the underground storage, or via the gas demand of the GFPP (synthetic and natural). The operation of the line-pack buffer is expressed mathematically in (3.9a)–(3.9d); the operation of the underground storage in (3.9e)–(3.9h), with limits on injection and extraction rates. (3.9i) tracks the synthetic and natural gas consumption of the GFPP, while (3.9j) ensures that over the time horizon of the model no more synthetic gas is consumed in the GFPP than is produced by the P2G capacity. Finally, the injection output and reserve variables of the P2G capacity are forced to zero, as there is no injection (3.9k),(3.9l).

$$\forall\, c \in \mathbb{C}, t \in \mathbb{T}:$$

$$e^{\mathrm{lp}}_{c,t{+}{+}1} = e^{\mathrm{lp}}_{c,t} + p^{\mathrm{lp,c}}_{c,t} - p^{\mathrm{lp,d}}_{c,t}, \tag{3.9a}$$

$$e^{\mathrm{lp}}_{c,t} \leq E^{\mathrm{lp}}_{c}, \tag{3.9b}$$

$$p^{\mathrm{lp,c}}_{c,t} = p^{\mathrm{us,ex}}_{c,t} + p^{\mathrm{imp}}_{c,t} + \sum_{z \in \mathbb{Z}\$\mathbb{CZ}} \sum_{s \in \mathbb{SN}} (\eta^{\mathrm{o}}_{s} \cdot p^{\mathrm{o}}_{z,s,t}), \tag{3.9c}$$

$$p^{\mathrm{lp,d}}_{c,t} = p^{\mathrm{us,in}}_{c,t} + \sum_{z \in \mathbb{Z}\$\mathbb{CZ}} \sum_{i \in \mathbb{GG}} (p^{\mathrm{syn}}_{z,i,t} + p^{\mathrm{nat}}_{z,i,t}), \tag{3.9d}$$

$$e^{\mathrm{us}}_{c,t{+}{+}1} = e^{\mathrm{us}}_{c,t} + p^{\mathrm{us,in}}_{c,t} - p^{\mathrm{us,ex}}_{c,t}, \tag{3.9e}$$

$$e^{\mathrm{us}}_{c,t} \leq E^{\mathrm{us}}_{c}, \tag{3.9f}$$

$$p^{\mathrm{us,in}}_{c,t} \leq P^{\mathrm{us,in}}_{c}, \tag{3.9g}$$

$$p^{\mathrm{us,ex}}_{c,t} \leq P^{\mathrm{us,ex}}_{c}, \tag{3.9h}$$

$$\frac{p^{\mathrm{i}}_{z,g,t}}{\eta^{\mathrm{i}}_{g}} = p^{\mathrm{syn}}_{z,g,t} + p^{\mathrm{nat}}_{z,g,t} \qquad \forall\, z \in \mathbb{Z}, g \in \mathbb{GG}, t \in \mathbb{T}, \tag{3.9i}$$

$$\sum_{z \in \mathbb{Z}\$\mathbb{CZ}} \sum_{i \in \eth\mathbb{G}} p^{\mathrm{syn}}_{z,i,t} \leq \sum_{z \in \mathbb{Z}\$\mathbb{CZ}} \sum_{s \in \mathbb{SN}} (\eta^{\mathrm{o}}_{s} \cdot p^{\mathrm{o}}_{c,s,t}) \qquad \forall\, c \in \mathbb{C}. \tag{3.9j}$$

$$\forall\, z \in \mathbb{Z}, s \in \mathbb{SN}, t \in \mathbb{T}:$$

$$p^{\mathrm{i}}_{z,s,t} = 0, \tag{3.9k}$$

$$r^{\mathrm{i}}_{z,r,i,t} = 0 \qquad \forall\, r \in \mathbb{R}, \tag{3.9l}$$

3.4.7 Interconnection

Interconnection impacts both the need for and the supply of flexibility. For the operating reserves, this impact has to be modeled explicitly. Figure 3.9 shows how this works. First, zones can jointly size reserves. (3.10a), (3.10b) organize the reserve requirements for jointly sizing zones. These constraints are complementary to (3.2b), (3.2b): (3.10a), (3.10b) ensure that sufficient reserve capacity is available for the jointly sizing zones; while (3.2b), (3.2c) do so

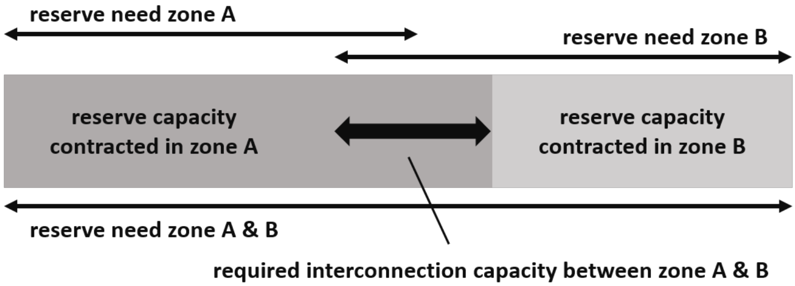

Figure 3.9: Example of two zones jointly sizing and allocating reserve capacity

for each individual zone. Second, zones can jointly allocate reserves. (3.10c)–(3.10e) translate the reserve exchange capacities of (3.2b), (3.2c) to a total capacity per reserve category per time step per interconnection. (3.10f)–(3.10j) ensure that sufficient interconnection capacity is available for both energy and reserve exchange. Depending on which combination of (z, z) is contained by $\mathbb{F}$, only one of the two right hand side capacity terms will be non-zero. (3.10f) constrains electricity exchange to the available capacity, whereas (3.10g), (3.10h) constrain reserve exchange. (3.10i), (3.10j) treat the simultaneous exchange of electricity and reserves. Two situations are decisive: when a zone is exporting electricity and upward reserve power (3.10i), or when a zone is importing electricity and exporting downward reserve power (3.10j). For these simultaneous exchanges, only a fraction F^{r} of the exchanged reserve capacity is counted. This allows to mimic the possibility of temporary overloading the interconnection capacity during reserve activation.

$$\forall\, j \in \mathbb{J}, r \in \mathbb{R} :$$

$$\sum_{z\in\mathbb{Z}\$\mathbb{J}\mathbb{Z}} \big[\sum_{i\in\mathbb{I}} r^{\mathrm{i,a}}_{z,r,i,a} + \sum_{o\in\mathbb{O}} r^{\mathrm{o,a}}_{z,r,o,a}\big] = R^{\mathrm{j,ex,a}}_{j,r,a} + \sum_{z\in\mathbb{Z}\$\mathbb{J}\mathbb{Z}} \sum_{i\in\mathbb{I}\setminus\{\mathbb{ID}\}} (R^{\mathrm{j,en,a}}_{j,r,i,a} \cdot p^{\mathrm{cap,i}}_{z,i}), \quad \forall\, a \in \mathbb{A}, \quad (3.10a)$$

$$\sum_{z\in\mathbb{Z}\$\mathbb{J}\mathbb{Z}} \big[\sum_{i\in\mathbb{I}} r^{\mathrm{i,b}}_{z,r,i,t} + \sum_{o\in\mathbb{O}} r^{\mathrm{o,b}}_{z,r,o,t}\big] = R^{\mathrm{j,ex,b}}_{j,r,t} + \sum_{z\in\mathbb{Z}\$\mathbb{J}\mathbb{Z}} \sum_{i\in\mathbb{I}\setminus\{\mathbb{ID}\}} (R^{\mathrm{j,en,b}}_{j,r,i,t} \cdot p^{\mathrm{cap,i}}_{z,i}), \quad \forall\, t \in \mathbb{T}, \quad (3.10b)$$

$$\forall\, z, z' \in \mathbb{Z}, r \in \mathbb{R}:$$

$$f^{\mathrm{r,a,t}}_{z,z',r,a,t} = f^{\mathrm{r,a}}_{z,z',r,a}, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$\mathbb{AT}, \tag{3.10c}$$

$$f^{\mathrm{r,a,t}}_{z,z',r,a,t} = 0, \qquad (\forall\, a \in \mathbb{A}, \forall\, t \in \mathbb{T})\$(!\mathbb{AT}), \tag{3.10d}$$

$$f^{\mathrm{r}}_{z,z',r,t} = \sum_{a \in \mathbb{A}} f^{\mathrm{r,a,t}}_{z,z',r,a,t} + f^{\mathrm{r,b}}_{z,z',r,t}, \qquad \forall\, t \in \mathbb{T}, \tag{3.10e}$$

$$\forall\, z_e \in \mathbb{Z}_{\mathbb{E}}, z_e \in \mathbb{Z}_{\mathbb{E}}\$(z_e, z_i), t \in \mathbb{T}:$$

$$f_{z_e,z_i,t} \leq f^{\mathrm{cap}}_{z_e,z_i}\$(z_e, z_i) + f^{\mathrm{cap}}_{z_i,z_e}\$(z_i, z_e), \tag{3.10f}$$

$$\sum_{r \in \mathbb{RU}} f^{\mathrm{r}}_{z_e,z_i,r,t} \leq f^{\mathrm{cap}}_{z_e,z_i}\$(z_e, z_i) + f^{\mathrm{cap}}_{z_i,z_e}\$(z_i, z_e), \tag{3.10g}$$

$$\sum_{r \in \mathbb{RD}} f^{\mathrm{r}}_{z_e,z_i,r,t} \leq f^{\mathrm{cap}}_{z_e,z_i}\$(z_e, z_i) + f^{\mathrm{cap}}_{z_i,z_e}\$(z_i, z_e), \tag{3.10h}$$

$$f_{z_e,z_i,t} + \sum_{r \in \mathbb{RU}} F^{\mathrm{r}} \cdot f^{\mathrm{r}}_{z_e,z_i,r,t} \leq f^{\mathrm{cap}}_{z_e,z_i}\$(z_e, z_i) + f^{\mathrm{cap}}_{z_i,z_e}\$(z_i, z_e), \tag{3.10i}$$

$$f_{z_i,z_e,t} + \sum_{r \in \mathbb{RD}} F^{\mathrm{r}} \cdot f^{\mathrm{r}}_{z_e,z_i,r,t} \leq f^{\mathrm{cap}}_{z_e,z_i}\$(z_e, z_i) + f^{\mathrm{cap}}_{z_i,z_e}\$(z_i, z_e), \tag{3.10j}$$

3.4.8 Implementation

Software environment

The mathematical model presented above has been implemented in GAMS. Around this GAMS file, a suite has been set up in Python making it possible to use the model without having knowledge of the implementation. All required input data has to be inputed into a set of Excel files. By running a first Python script, the data in these files is loaded into an SQL database. This database is easily accessible via a plug-in for Firefox, via which the values of input parameters can be altered in a straightforward way, without altering the original data. By running a second Python script, the required data is extracted from the SQL database and converted to the GAMS data format, an instance of GAMS is launched with this data, an optimization is performed with a CPLEX solver, and eventually the outcome is stored in a GAMS database. By running a third Python script, finally, the information in this output database is converted to the Excel data format, and written in a new set of Excel files.

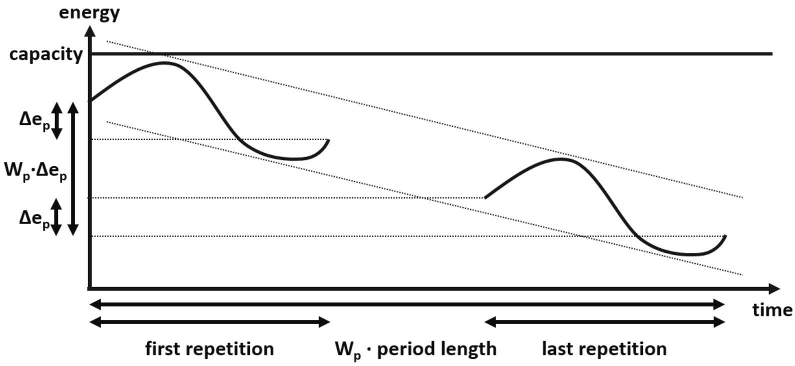

Figure 3.10: Energy level evolution when using representative periods

Representative periods

To increase the potential uses of the model, the original formulation as presented here was implemented in such a way that it includes the possibility of using representative periods. Decreasing the temporal resolution within the year(s) used to calculate the operational costs relaxes computational efforts, which in turn could allow to take more years into account; in short it facilitates the transition from a static to a dynamic planning model. The use of representative periods requires altering certain aspects of the model formulation. Firstly, the index t has to be replaced by p, t, where p is an element of the set of representative periods $\mathbb{P}$. All corresponding operational costs are multiplied by W_p, which indicates the weight of a certain period. In the objective function this comes down to replacing all "$\sum_{t\in\mathbb{T}}$" by "$\sum_{p\in\mathbb{P}}\sum_{t\in\mathbb{T}} W_p\cdot$". Secondly, some additional equations need to be introduced for governing the energy level of the storage technologies. Two options exist. If the temporal resolution is very coarse (e.g. a number of days per year), the introduction of a simple additional equation suffices. This equation ensures that the overall energy injection and extraction is zero over the total model horizon (3.11). The cyclical nature of (3.8a) can then be dropped (i.e. the "++" replaced by a simple "+"). Such an approach is also sometimes found in the literature [32, 116].

$$\sum_{p\in\mathbb{P}}\sum_{t\in\mathbb{T}} W_p \cdot \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,p,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,p,t}\right) = 0 \quad \forall\, z \in \mathbb{Z}, s \in \mathbb{S}. \quad (3.11)$$

If the temporal resolution is more detailed (e.g. a number of weeks per year), then it makes sense to follow the evolution of the energy level of the storage technologies between consecutive representative periods. The approach developed here assumes that the behavior within a period is repeated until the next period (see Figure 3.10). I.e. the net change in energy level is expected to occur W_p times (3.12a). Now, this equation is cyclical, ensuring energy neutrality over the model horizon. Given the linear nature of this approximation, in total this operation will respect the operational and capacity limits if the first and the last repetition of this period respect those limits. Therefore, equations (3.8a)–(3.8c) are dropped and replaced by (3.12b)–(3.12i). A similar replacement is done for (3.9a)–(3.9h) of the gas infrastructure model, but not presented here for brevity.

$$\forall\, z \in \mathbb{Z}, s \in \mathbb{S}, p \in \mathbb{P}:$$

$$e_{z,s,p{+}{+}1} = e_{z,s,p} + \sum_{t \in \mathbb{T}} W_p \cdot \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,t}\right), \tag{3.12a}$$

$$e^{\mathrm{first}}_{z,s,p,1} = e_{z,s,p}, \tag{3.12b}$$

$$e^{\mathrm{last}}_{z,s,p,1} = e_{z,s,p} + \sum_{t \in \mathbb{T}} (W_p - 1) \cdot \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,t}\right), \tag{3.12c}$$

$$\forall\, z \in \mathbb{Z}, s \in \mathbb{S}, p \in \mathbb{P}, t \in \mathbb{T}:$$

$$e^{\mathrm{first}}_{z,s,p,t+1} = e^{\mathrm{first}}_{z,s,p,t} + \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,p,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,p,t}\right) \cdot \Delta T^{\mathrm{t}}, \tag{3.12d}$$

$$e^{\mathrm{first}}_{z,s,p,t} \geq (1/\eta^{\mathrm{i}}_s) \cdot \sum_{r \in \mathbb{RU}} r^{\mathrm{i}}_{z,r,s,p,t} \cdot \Delta T^{\mathrm{r}}_r, \tag{3.12e}$$

$$e^{\mathrm{first}}_{z,s,p,t} \leq e^{\mathrm{cap}}_{z,s} - \eta^{\mathrm{o}}_s \cdot \sum_{r \in \mathbb{RD}} r^{\mathrm{o}}_{z,r,s,p,t} \cdot \Delta T^{\mathrm{r}}_r, \tag{3.12f}$$

$$e^{\mathrm{last}}_{z,s,p,t+1} = e^{\mathrm{last}}_{z,s,p,t} + \left(\eta^{\mathrm{o}}_s \cdot p^{\mathrm{o}}_{z,s,p,t} - (1/\eta^{\mathrm{i}}_s) \cdot p^{\mathrm{i}}_{z,s,p,t}\right) \cdot \Delta T^{\mathrm{t}}, \tag{3.12g}$$

$$e^{\mathrm{last}}_{z,s,p,t} \geq (1/\eta^{\mathrm{i}}_s) \cdot \sum_{r \in \mathbb{RU}} r^{\mathrm{i}}_{z,r,s,p,t} \cdot \Delta T^{\mathrm{r}}_r, \tag{3.12h}$$

$$e^{\mathrm{last}}_{z,s,p,t} \leq e^{\mathrm{cap}}_{z,s} - \eta^{\mathrm{o}}_s \cdot \sum_{r \in \mathbb{RD}} r^{\mathrm{o}}_{z,r,s,p,t} \cdot \Delta T^{\mathrm{r}}_r. \tag{3.12i}$$

3.5 Validation

To validate the developed model, the performance of the adopted approach for the representation of power system operation – i.e. the use of the relaxed version of the clustered formulation of the unit commitment problem – is compared to a benchmark. That benchmark is the mixed integer linear problem formulation of the unit commitment problem. This means that any errors introduced by restricting the order of the problem to first order constraints are not considered. Moving from the benchmark to the adopted approach is a two-step process, where each step allows to reduce the required computational effort, but also introduces an error.

In a first step, units are clustered per technology, thus moving from the binary to the integer-clustered formulation. This step introduces a two-part error: one part due to the clustering of non-identical units and another part due to the inherent difference between the clustered and the binary formulation. The former is less important in a planning context, as discussed before, and is not studied here. The latter was quantified over the course of a Master's thesis via a number of metrics. Firstly, the total cost of the two approaches is compared, i.e. the value of the objective function. Secondly, the energy mix is compared by comparing the mean deviation of the shares of different technologies in the total electricity production. Finally, the calculation time of the approaches is compared to estimate the computational performance. These metrics were calculated using data of the year 2013 for the Central Western European electricity system. The details of the analysis can be found in [208]. The results of this analysis and a similar analysis performed by Palmintier et al. in [158] are presented in Table 3.1. These results show the incredible performance of the clustered approach in terms of the trade-off accuracy vs. computational effort. Depending on the exact case, the problem is solved 20 to 2 000 times faster, with outliers of a factor of 10 000, while errors remain below 1%, also for metrics not shown here (e.g. carbon emissions). This performance has been confirmed in later work of Palmintier [159], and by other authors adopting the approach [160].

In a second step, commitment variables are relaxed, thus moving from the integer-clustered to the relaxed-clustered formulation. The impact hereof on the trade-off accuracy vs. computation time was not verified by the authors themselves. Rather, they relied on the work of Palmintier et al., again in [158, 155], which showed that even in this case average errors remained below 1.5%, while allowing further reductions in computation time. This final "speed-up" allows to incorporate such detailed operational constraints in a planning model, which – as is shown by these validations – accurately reflect power system operation while keeping computation times feasible.

Table 3.1: Table showing the performance metrics of the clustered problem formulation compared to the traditional binary formulation.

	Average error Total cost	Energy mix	Relative computation time
Meus et al. [208]	0.24%	0.04%	3.8%
Palmintier et al. [158]	0.0.5 - 0.4%	0.01 - 0.3%	0.05 - 0.25%

It has to be noted that the relaxation of the clustered formulation means that this representation of power system operation comes close to a technology-based linear problem formulation of power system operation that can be found in many planning models, such as e.g. [18]. However, given the multitude of formulations of this latter kind – which are mostly not benchmarked – it is hard to compare their performance in terms of accuracy vs. computation time to the performance of the relaxed-clustered formulation developed here. A single case can be found, once more in [155], where the performance of the model of [18] is compared to the relaxed-clustered formulation. While readers are referred to that reference for a detailed analysis, in short results show that the relaxed-clustered formulation is better at estimating costs, energy mixes, etc. Nevertheless, it would be valuable to get a better understanding and quantification of the difference between the relaxed-clustered formulation and other variations of a technology-based linear problem formulation. However, this is left for future research.

In general, the main advantage of the clustered formulation over a technology-based formulation is that it can be traced directly to the way in which the benchmark (the binary formulation) is formulated. Mathematically, this means that the difference between the two kinds of formulations mostly comes down to the way in which commitment and its effects are represented. In the clustered formulation commitment is dealt with explicitly, allowing to capture the effects of minimum up- and down-times (and the related start-up and shut-down costs), to model the dynamics of spinning vs. non-spinning reserves (very important to capture e.g. the benefits of reserve provision by battery storage) which among other things allows to study reserve strategies, etc. It has the added benefit that parameters for ramping, minimum output levels, and so on can be taken directly from the benchmark, rather than having to define approach-specific parameters, which have to be estimated and can thus be case-specific.

3.6 Limitations and added value

The model presented here can provide some insights for policy-makers, investors, and regulators into the impact of short-term flexibility challenges on power system planning. However, there are some important limitations to the way in which this model and the results of this work can be interpreted and applied beyond this context. The sections below present the most pertinent limitations and summarize the models added value.

First, this model does not provide pathways for the transition of the power system, as it lacks important information to do so. Policies are not represented in detail, nor the interaction between policy-makers and policy-takers. A system-wide optimization is performed, which is not reflective of how markets operate and market participants behave in reality. The model focuses exclusively on the power system, not considering interactions e.g. other sectors of the economy, the change of land use, the water use, etc. Within the power system only flexibility adequacy and firm capacity adequacy (in a simplified way) are enforced; other adequacy concerns (fuel, regulatory, etc.) are not considered. Lastly, and perhaps most importantly, no stakeholder involvement was organized to help determine the data and assumptions for the model and the initial analyses.

Second, the developed model itself has certain limitations. The model only looks at the optimal solution. Changes in assumptions or values of parameters could lead to different optimal outcomes. Therefore, the focus of the analyses is on evolutions in the outcomes when varying control parameters (i.e. the renewable target), rather than on the absolute values. The model is a static, greenfield planning model; which means that aspects like revenue changing over a technology's lifetime, capacity legacy, construction times, capacity decommissioning, etc. are not considered. The model is linear, which introduces a number of errors as technical behavior is not necessarily linear. The clustering approach also introduces an error, as discussed before. The model is deterministic, with perfect foresight and reserve requirements to cover unforeseen events. Thus, the stochastic nature of power system elements is not modeled explicitly. The initial analyses consider the system as an island power system, neglecting the potential benefits of interconnection. When interconnection is included, grid constraints are modeled as market exchanges between zones. Within zones, sufficient transmission capacity is assumed to be available. Distribution grid constrains are not considered. No sub-hourly cycling of power system elements is considered. Real-time operation is also not modeled, which prohibits including the effects of e.g. reserve activation. Lastly, there are some limitations to the technology models, e.g. such as the use of a simplified representation of the gas infrastructure for the P2G model.

Finally, there are some data-related limitations. There is rather high uncertainty on some of the input data, especially on the technical and economic parameters of relatively new technologies. Moreover, the analyses have been performed using data of a single year. No limits have been imposed on the potential investments in certain power system technologies, which can be especially important when it comes to VRES-E. If that capacity is limited, then curtailment is a less obvious balancing option, impacting the added value of other balancing options. Lastly, the spatial resolution of the model is low, using only one zone to represent an entire power system with a single input profile per VRES-E type, which excludes smoothing effects, robust analysis of expected output over longer periods, etc. Even though their impact could be important, no sensitivity analyses were performed on these data-related limitations as the focus is on methodology.

Keeping in mind these limitations when interpreting its results, the added value of this model is that it allows to study the impact of short-term flexibility adequacy challenges on long-term planning. It allows to study the interactions of firm capacity adequacy and flexibility adequacy targets, the impact of reserve sizing and allocation strategies on the integration costs of renewable sources, the role of flexible technologies in ensuring flexibility adequacy and how that translates into investment, the interaction of different flexibility providers and how that impacts investment in those providers, etc. When using the model to study this kind of research questions, it offers new insights compared to other planning models currently available in literature.

3.7 Conclusions

In this chapter a model framework has been described that allows to study the impact of short-term flexibility on power system planning. An input data processing method has been developed to translate historical uncertainty data into operating reserve requirements following ENTSO-E's Network Code on Load Frequency Control and Reserves. Subsequently, a mathematical model was developed where the need for short-term flexibility is represented via the representation of the day-ahead market and the operating reserve requirements, and the supply of flexibility via models of several sources of flexibility. Models have been presented for the flexibility of dispatchable and variable generation, long-term demand response, re-electrifying and non re-electrifying storage, and flexibility through interconnection. Over the following chapters this model is used to perform several analyses related to the cost of flexibility and the supply of flexibility through alternative sources. For different scenarios the investment portfolio is optimized by minimizing the total system cost under different targets for the share of renewable energy.

Chapter 4

The impact of short-term flexibility

4.1 Introduction

The power system planning model presented in the previous chapter is now applied to a test system. By evaluating scenarios with different levels of operational detail for an increasing renewable target, the profile and balancing costs, and the impact of the short-term flexibility requirements on the optimal investment portfolio of this test system are quantified. It is further investigated how the balancing costs depend on the adopted reserve sizing and allocation strategies. Based on the outcomes of these scenarios, the importance of short-term flexibility constraints for VRES-E integration costs and investment decisions is discussed in a general context.

4.2 Test system

This section presents the data of the test system that is used to perform the analyses in this chapter and the next. First, the input data related to the operating reserve requirements, and the demand and VRES-E output profiles are presented. Next, the technical and economic parameters of the technologies used for the analyses of this chapter are discussed.

The demand profile of the test system is the demand profile of the Belgian power system for 2015. This profile has a peak demand of 13.1 GW and a total annual consumption of 85.2 TWh. The profile actually presents the demand for electricity as seen by the grid, and not the total electricity consumption; the difference being the auto-consumption of e.g. PV production. This auto-consumption is neglected, and the profile is treated as if it were the total electricity consumption. To ensure a correct correlation of VRES-E generation and demand, the VRES-E profiles used are also those of the Belgian power system for the year 2015. Three sources are used, namely an onshore and an offshore wind resource and a solar PV resource. The wind profiles have 3 625 and 2 277 equivalent full load hours, respectively, while the PV profile has 1 033 full load hours. To size the exogenous operating reserves, the system imbalance data of the Belgian power system for the year 2015 is used for the probabilistic assessment, while the loss of a 1 GW HVDC interconnector is considered as the Dimensioning Incident (positive and negative direction) for the deterministic assessment. To size the endogenous operating reserves, forecast error data of the Belgian power system for the year 2015 is used. All the information is collected from the website of the Belgian TSO ELIA [209]. Throughout this work, the operating reserve characteristics of the Belgian TSO will be used. This means that the FCR capacity has to be on-line in 30 seconds ($T^{\mathrm{r}}_{FCR} = 0.5$), automatic FRR capacity in 7.5 minutes ($T^{\mathrm{r}}_{aFRR} = 7.5$), and manual FRR capacity in 15 minutes ($T^{\mathrm{r}}_{mFRR} = 15$); assuming linear ramping to the allocated capacity. With storage technologies energy capacity is reserved such that when called upon they are able to deliver FCR during a quarter of an hour ($\Delta T^{\mathrm{r}}_{FCR} = (0.5/2 + 14.5)/60$), aFRR during an hour ($\Delta T^{\mathrm{r}}_{aFRR} = (7.5/2 + 52.5)/60$), and mFRR during 3 hours ($\Delta T^{\mathrm{r}}_{mFRR} = (15/2 + 165)/60$).

For the analyses in this chapter four dispatchable generation technologies, one storage technology, and three variable generation technologies are selected. The four dispatchable generation technologies – namely a *Base*, *Mid*, *Peak* and *High Peak* technology – are selected so as to be representative in terms of the dynamics of their operational characteristics. The selected storage technology is based on the operational characteristics of a PHES technology. The combination of these five technologies is assumed to be representative of the flexibility found in most European power systems today, and can thus serve as a “flexibility benchmark”. Finally, the three variable renewable generation technologies are a PV and an onshore and an offshore wind technology, with the resources as described above. As no grid constraints in terms of power flows are taken into account, no distinction is made towards the location or voltage level to which they are connected. The technical parameters of the generation and storage technologies are based on the report of the Deutsches Institut fur Wirtschaftforschung on *Current and Prospective Costs of Electricity Generation until 2050* [48]. These parameters are shown in Table 4.1.

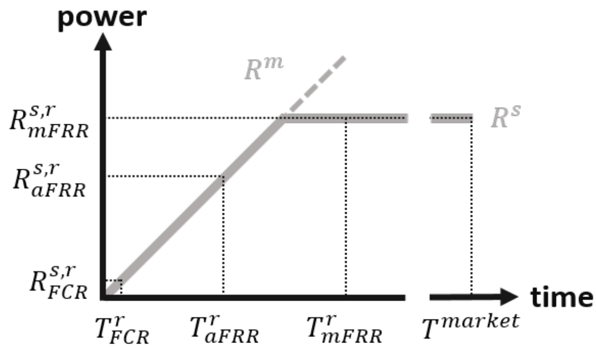

Figure 4.1: Deriving ramping abilities from input parameters

Table 4.1: Table of technical input parameters. Ramping parameters are derived as follows: $R_i^{\text{su,i}} = R_i^{\text{sd,i}} = max(R_i^{\text{s,i}}, P_i^{\text{min,i}})$; $\forall r : R_{r,i}^{\text{s,r,i}} = min(R_i^{\text{m,i}} \cdot T_r^{\text{r}}, R_i^{\text{s,i}})$ (same for off-takes). For storage, off-take and injection parameters are identical.

Set	Name	P_i^{i}	$P_i^{\text{min,i}}$	$R_i^{\text{s,i}}$	$R_i^{\text{m,i}}$	η_s^{i}	$T_i^{\text{mut,i}}$	$T_i^{\text{mut,i}}$	N_s^{cyc}
		MW	$\%$	$\%$	$\%/min$	$\%$	h	h	-
$\mathbb{ID}$	Base	400	50	33	3	-	24	24	-
$\mathbb{ID}$	Mid	300	50	50	4	-	6	4	-
$\mathbb{ID}$	Peak	200	50	80	6	-	4	1	-
$\mathbb{ID}$	High Peak	100	10	100	10	-	1	1	-
$\mathbb{S}$	PHES	100	50	100	50	87	0	0	∞

A note is made on the ramping ability of the different dispatchable technologies. Here, a dual approach is applied as presented in Figure 4.1. For reserve provision the parameter R^{m} is gathered from [48], and used to derive the ramping ability for each reserve category. However, this parameter is high enough to allow almost every generation technology cited in the report to ramp its full capacity on an hourly basis. While deemed appropriate for infrequent use (i.e. reserve provision), such ramping speeds are believed to be too high for continuous operation (i.e. electricity generation), potentially incurring additional maintenance costs. Therefore a second ramping parameter is introduced: R^{s}, which defines the ramping ability per time step of the balance equation (for these analyses $T^{\text{market}} = \Delta T^{\text{t}} = 1$). The value of this parameter is derived from what literature typically employs, such as in [18].

Table 4.2: Table of economic input parameters. Investment costs are annualized with a 5% discount rate. Storage off-take and injection parameters are identical.

Set	Name	Investment cost						Operational cost			
			Total		Annualized						
		N_i^{cal}	$C_i^{\mathrm{inv,i}}$	$C_s^{\mathrm{inv,e}}$	$C_i^{\mathrm{inv,i}}$	$C_s^{\mathrm{inv,e}}$	$C_i^{\mathrm{fom,i}}$	$C_i^{\mathrm{fuel,i}}$	$C_i^{\mathrm{vom,i}}$	$C_i^{\mathrm{ra,i}}$	$C_i^{\mathrm{su,i}}$
		years	€/*kW*	€/*kWh*	€/*kW*	€/*kWh*	€/*kW*	€/*MWh*	€/*MWh*	€/*MW*	€/*MW*
$\mathbb{ID}$	Base	50	5 000	-	274	-	43	10	5	1.3	200
$\mathbb{ID}$	Mid	35	1 700	-	104	-	34	26	10	1.3	50
$\mathbb{ID}$	Peak	25	855	-	61	-	21	43	10	0.7	37
$\mathbb{ID}$	High Peak	15	486	-	47	-	12	66	10	0.3	25
$\mathbb{IR}$	PV	25	895	-	64	-	13	0	0	-	-
$\mathbb{IR}$	Wind on	30	1 270	-	83	-	27	0	0	-	-
$\mathbb{IR}$	Wind off	30	2 600	-	169	-	80	0	0	-	-
$\mathbb{S}$	PHES	50	375	5	21	0.3	0	-	0	0	0

The economic parameters of the different technologies are based on the JRC EU-TIMES model data, and annualized using a discount rate of 5% [210]. The energy cost of the PHES technology is very low (€5/kWh), reflecting the investment cost of a site with natural PHES potential (height difference, basins, etc.). Most of these sites have obviously already been developed. As such sites are limited in their availability, the maximum investment in energy capacity of this technology is also limited; to 6 GWh. Investment in power capacity is not limited. For investment in power capacity, further distinction could be made between charging and discharging capacity (or off-take and injection capacity). Nevertheless, for this work investment will be assumed to be symmetrical, with power investment costs spread evenly over off-take and injection capacity. All economic parameters are shown in Table 4.2. Obviously, the outcome of the investment optimization will depend heavily on the exact values of these parameters. However, it is not the goal of this work to identify the influence of uncertainty of these cost parameters on the model outcome; not in the least because of the uncertainty surrounding (the evolution of) the costs of certain flexible technologies. The focus is on identifying changes in model outcome when the same set of technologies is subjected to different investment optimization constraints.

4.3 Adequacy, Variability and Uncertainty

To identify the different aspects of the impact of short-term flexibility, three scenarios are set up. In the first scenario – named ***Adequacy*** – the hourly balance between supply and demand is ensured, but no operational constraints are considered; not related to the hourly dispatch, nor to the operating reserves.

Investment in technologies in this scenario will follow the logic of the screening curve method, already discussed in Section 1.1.3. The total installed capacity will be driven only by the cost of load shedding: generation and storage capacity will be added until the cost of additional capacity exceeds the cost of load shedding. Investment in technologies will then also depend in part on their contribution to *firm capacity adequacy*. It must be noted, however, that the outcome of this scenario as studied here does not ensure firm capacity adequacy. For this a more detailed analyses would be needed, with detailed information on a technology's firm capacity share, and using data on e.g. VRES-E output of several years rather than a single one. Nevertheless, the outcome can provide an indication of a technology's contribution to firm capacity adequacy, and – more importantly – allows to single out the technology's contribution to flexibility adequacy studied in the next two scenarios.

The outcome of this scenario allows to quantify the cost of increasing the renewable share beyond the economic optimum. This cost – labeled the ***reconfiguration cost*** – is calculated by taking the cost of the model outcome for a certain renewable share (e.g. a 20% target), subtracting from it the cost of the model outcome when no renewable share is imposed (i.e. the 0% target), and dividing this cost surplus by the total generated renewable electricity (in the case of this example 20% of total demand). On the one hand this cost is driven by the increased investment in VRES-E capacity. On the other hand it is driven by the fact that increasing the renewable share, besides lowering the total energy of the RLDC, causes the RLDC to have more low or negative values. Consequently, in the mix of whatever dispatchable capacity is still installed, there is a shift e.g. from base- to mid-load generation technologies, making it more expensive. This latter cost driver shows some parallels to the *utilization cost*, the first part of the profile cost. Recall that this cost relates to how structural changes to the RLDC following VRES-E integration impact the utilization of installed dispatchable capacity. However, the two cannot be compared directly. The utilization cost is linked to studying the impact of VRES-E integration on power system operation; the reconfiguration cost to its impact on power system planning. In an operation model, the impact of VRES-E on the RLDC leads to dispatchable capacity being *underutilized*, i.e. not able to recover its costs on e.g. an annual basis. In a planning model, such underutilized capacity is not installed; rather the dispatchable capacity mix is *reconfigured* until all of the installed capacity is able to recover its costs.

In the second scenario – named ***Variability*** – the hourly balance between supply and demand is ensured, and the operational constraints related to the hourly dispatch are considered, but not those related to the operating reserves. The difference in investment between this and the previous scenario allows to identify the way in which technologies are able to deal with variability (i.e.

the hourly dispatch constraints). The outcome of this scenario further allows to quantify the ***flexibility cost***, the second part of the profile cost, and the first part of the cost of ensuring flexibility adequacy. This cost is calculated by taking the cost of the model outcome of the Variability scenario for a certain renewable share (e.g. a 20% target), subtracting from it the cost of the model outcome of the Adequacy scenario for that same renewable share, and dividing this cost surplus by the total generated renewable electricity (in the case of this example 20% of total demand). Also here it has to be noted that this flexibility cost does not fully correspond with that calculated in operation models. In a planning model, the optimization can opt for the capacity mix that minimizes this additional cost. In an operation model such a reconfiguration is not possible. The flexibility cost as calculated here will thus be on the lower end of the estimates found in operations literature.

In the third scenario – named ***Uncertainty*** – the hourly balance between supply and demand is ensured, and the operational constraints related to both the hourly dispatch and the operating reserves are considered. The difference in investment between this and the first scenario allows to identify the contribution of technologies to dealing with both variability and uncertainty (i.e. the hourly dispatch constraints and the reserve requirements). The outcome of this scenario further allows to quantify the ***flexibility and balancing costs***, i.e. the cost of ensuring flexibility adequacy. This cost is calculated by taking the cost of the model outcome of the Uncertainty scenario for a certain renewable share (e.g. a 20% target), subtracting from it the cost of the model outcome of the Adequacy scenario for that same renewable share, and dividing this cost surplus by the total generated renewable electricity (in the case of this example 20% of total demand). Once more, for the reasons cited before, these costs as calculated here are expected to be on the lower end of estimates in operations literature.

In theory the balancing cost could also be calculated separately. This could be done by comparing the cost of the Uncertainty scenario with that of the Variability scenario. However, such an endeavor would lead to an underestimation of the cost of uncertainty. Part of the flexible capacity installed to deal with hourly dispatch constraints at times has surplus flexibility available, which can then be used to deal with uncertainty. This synergy causes the total flexibility and balancing costs to be lower than the sum of the separate costs. It could also be done by introducing an additional scenario that considers the operational constraints related to the operating reserves, but does not consider those related to the hourly dispatch. However, given that this is not an approach that would be encountered in an actual planning model, it was not deemed useful to perform this additional effort. Therefore, the balancing cost is not quantified separately. Rather, the impact of increasing operational detail is evaluated: first variability, then variability and uncertainty.

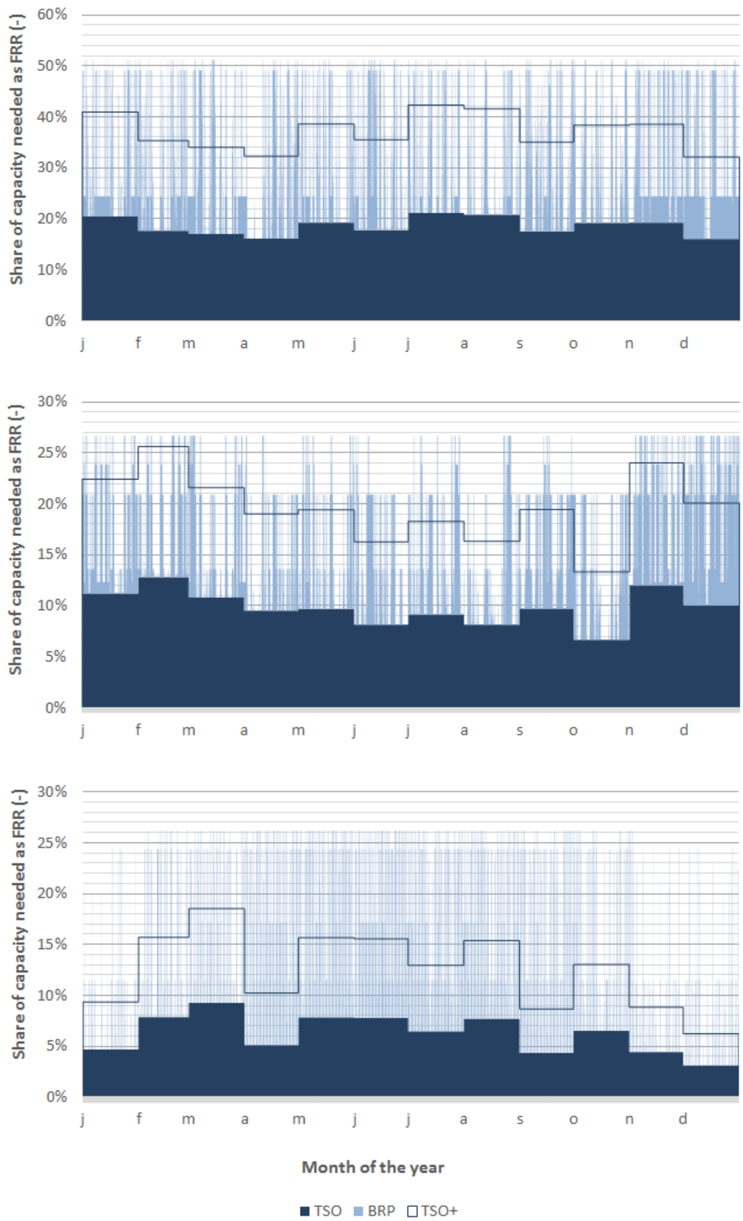

Figure 4.2: FRR requirement for (from top to bottom) offshore wind, onshore wind and PV uncertainty expressed as a percentage of installed capacity.

Table 4.3: Overview of scenarios

	Adequacy	Variability	Uncertainty
Operational detail	Hourly balance	Hourly balance Dispatch constraints	Hourly balance Dispatch constraints Reserve requirements
Captured costs	Reconfiguration cost	Reconfiguration cost Flexibility cost	Reconfiguration cost Flexibility cost Balancing cost

In the final scenario, at all times a set of operating reserve requirements has to be met. The exogenous component is sized on a yearly basis and allocated on a monthly basis. Following from the analysis of the input data mentioned above 100 MW of up- and downward FCR, 249 MW of up- and downward aFRR, and 751 MW of up- and downward mFRR are required. For the endogenous component, the dual approach presented in Section 3.3.5 is used. This approach is visualized in Figure 4.2 for the uncertainty of the offshore and onshore wind, and the PV technology. The line denoted by *TSO+* indicates the capacity that follows from the monthly sizing of the reserves using the methodology presented in Section 3.3.4. 50% of this capacity is actually allocated on a monthly basis, denoted in the figures by *TSO*. On top of that reserve capacity is contracted on an hourly basis, denoted in the figures by *BRP*. This capacity is calculated by comparing the outcome of the hourly sizing of the reserves with the *TSO* capacity: if there is insufficient *TSO* capacity to meet the hourly sized reserves, that capacity is to be allocated on an hourly basis in the model. These figures also already show the impact of making the sizing of reserves more dynamic. Reserve capacity is updated more frequently based on the uncertainty present in the system, at times leading to higher, at other times to lower capacity. The impact hereof will be explored in more detail in Section 4.5. Note as well the difference in magnitude between the offshore wind uncertainty and that of the two other variable resources.

The developed model is now applied to the test system under these three scenarios (see Table 4.3 for an overview) in a greenfield setting, i.e. without assuming any pre-existing installed capacities. The portfolio and operation of the system is optimized for a year with hourly time steps. An objective for the share of RES-E electricity in the final electricity consumption is imposed, ranging from 0% to 50%. The cost of VRES-E curtailment is assumed to be 0 €/MWh, while the cost of involuntary load shedding is set at 3 000 €/MWh. The former is a valid assumption since in the long-term VRES-E support through green certificates or feed-in tariffs is assumed to disappear, while the latter represents the current price cap of the Belgian day-ahead market.

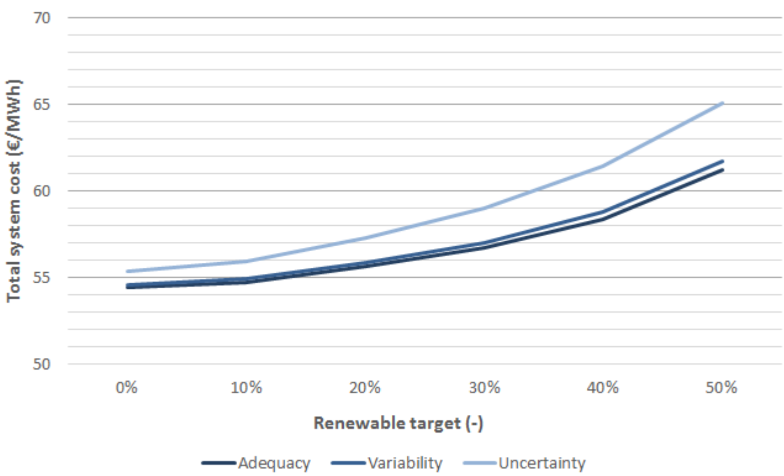

Figure 4.3: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the Adequacy, Variability and Uncertainty scenario.

4.4 The impact of short-term flexibility

4.4.1 The impact on system cost

Figure 4.3 shows the total system cost for all scenarios expressed in €/MWh. Note that this is not an electricity price (i.e. the price in the market); it is merely the total system cost divided by the total electricity demand of the test system (cfr. 85.2 TWh). Note as well that the exact values are not the main focus here. To say anything meaningful about those, a more robust analysis on the input data related to the economic parameters is needed; but as was mentioned in Section 4.2 this will not be done. The main focus is on the difference between scenarios and the evolution of the outcomes over the different renewable targets.

In Figure 4.3 it can be seen that the cost of the *Adequacy* scenario rises from 54.4 €/MWh under a renewable target of 0% (i.e. when no renewable target is imposed) to 61.2 €/MWh under a renewable target of 50%; an increase of 12.5%. The greatest share of these costs are capital expenses, amounting to 64% at 0% RES-E and rising to 68% at 50% RES-E. From these results, the VRES-E-related reconfiguration cost can be calculated using the method explained in Section 4.3. The reconfiguration cost rises from 3 €/MWh$_{\mathrm{RES}}$ at a 10% share to 14 €/MWh$_{\mathrm{RES}}$ at a 50% share.

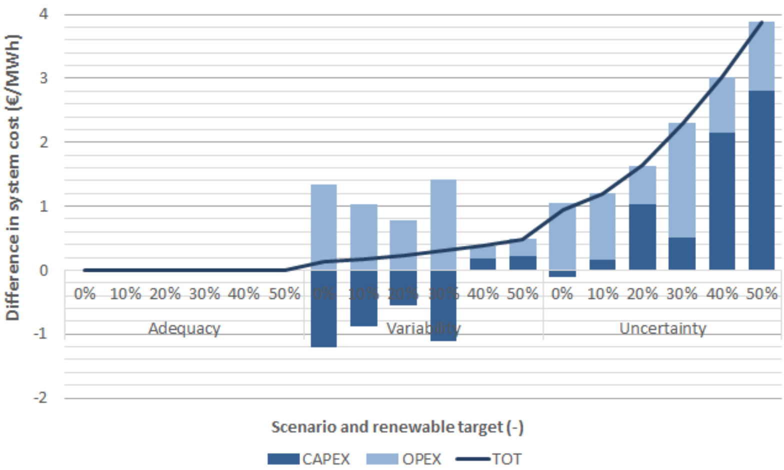

Figure 4.4: Difference in total system cost of the Adequacy, Variability and Uncertainty scenario, compared to the Adequacy scenario.

The cost of the *Variability* scenario rises from 54.6 €/MWh to 61.7 €/MWh; an increase of 13.1%. This is only slightly higher than in the *Adequacy* scenario, with the cost surplus increasing from 0.3% to a 0.8% as the renewable target increases. This results in the VRES-E related flexibility cost rising from 0.2 €/MWh$_{\mathrm{RES}}$ at a 10% share to 0.7 €/MWh$_{\mathrm{RES}}$ at a 50% share, which is in line with estimates found in operations literature, citing values around 0-2 €/MWh$_{\mathrm{RES}}$ [211]. However, the difference between the two scenarios is greater than these costs suggest, as can be seen in Figure 4.4. This figure breaks down the difference in total system cost in the differences in Capital Expenses (CAPEX) and Operational Expenses (OPEX). These range up to 1.2 €/MWh and 1.4 €/MWh in absolute terms, respectively. Especially, at low renewable targets, the difference is quite high. In the *Adequacy* scenario there is more investment in the less flexible, high-CAPEX and low-OPEX generation technologies. This is partly displaced by investment in more flexible, lower-CAPEX and higher-OPEX generation technologies. At high renewable targets, changes in the RLDC already push investments towards more flexible capacity in the *Adequacy* scenario, leading to different changes in system cost.

The total system cost of the *Uncertainty* scenario is significantly higher than that of the *Adequacy* scenario. It rises from 55.4 €/MWh to 65.1 €/MWh; an increase of 17.6%. The cost surplus w.r.t. the *Adequacy* scenario increases from 1.5% to 5.5% as the renewable target increases. This results in the sum of the flexibility and balancing costs rising from 2.6 €/$\mathrm{MWh_{RES}}$ at a 10% share to 5.9 €/$\mathrm{MWh_{RES}}$ at a 50% share, which is again more or less in line with the findings of operations literature, citing values around 0-5 €/$\mathrm{MWh_{RES}}$ [7, 212]. The structure of this cost increase, shown in Figure 4.4, is different from that of the *Variability* scenario. There, the increase in OPEX is partly compensated by a decrease in CAPEX. Here, also the CAPEX increase, leading to a much higher total system cost increase. The underlying reason for this will also be discussed hereafter.

4.4.2 The impact on investments

Figure 4.5 shows the total installed capacities of the test system for the different scenarios and renewable targets. For the storage technology only the power capacity is shown in this figure. Given the low cost, the 6 GWh of available energy capacity is fully developed in all scenarios for all renewable targets. For load shedding, denoted by "LS", the maximum occurring power is shown. In terms of energy, load shedding is negligible (<0.01% of total demand). Figure 4.6 shows the difference in installed capacity with the outcome of the Adequacy scenario serving as the reference.

The total installed capacity of dispatchable technologies remains almost constant over the different renewable targets in the *Adequacy* scenario, with a slight decrease for the higher targets due to the perceived firm capacity of the variable capacity. As the renewable target increases there is a shift from Base to Mid capacity, and an increase in Peak and High Peak capacity. Furthermore, there is an increase in the maximum load shedding power, from 150 MW to 633 MW. These changes are driven by the changes in the residual load curve. Investment in PHES power hovers around 650 MW for lower renewable targets, and increases up to 1 134 MW for the 50% case.

The net difference in investments w.r.t. the *Variability* scenario, shown in Figure 4.6, is of the order of magnitude of 100 MW. The changes in capacity, however, are of the order of magnitude of 1 000 MW. The shift from Base to more flexible capacity as the renewable share increases, is even more outspoken in this scenario due to the ramping constraints. This explains the cost difference discussed above: there are CAPEX savings, as the Base technology is CAPEX intensive; but these are undone by the increase in OPEX, due to the higher operational costs of the more flexible generation technologies. There is increased investment in PHES, due to its high flexibility and ability to capture part of the renewable energy that would otherwise be curtailed due to ramping constraints. Finally, as more flexible capacity is available to deal with the dispatch constraints, load shedding decreases to at most 483 MW.

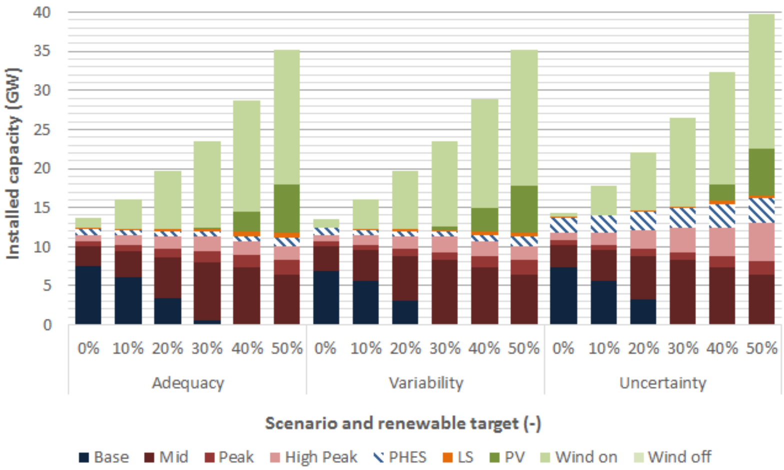

Figure 4.5: Installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

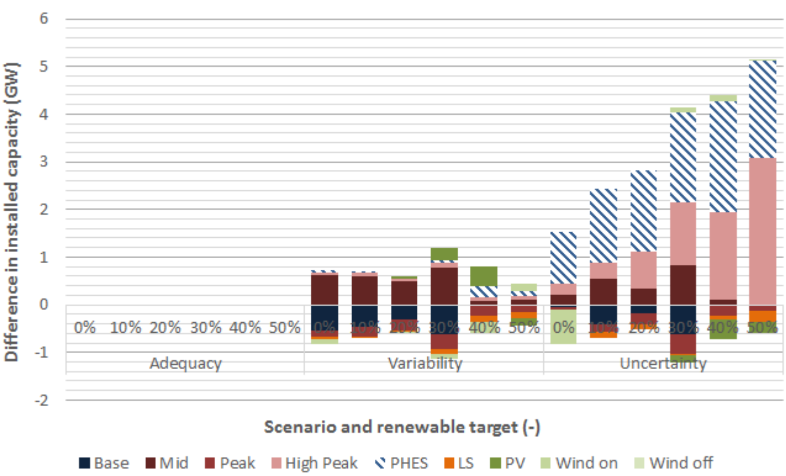

Figure 4.6: Difference in installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario, compared to the Adequacy scenario.

The net difference in investments w.r.t. the *Uncertainty* scenario, also shown in Figure 4.6, is much greater, ranging up to 4.5 GW of additional capacity for the highest renewable target. The tendencies for investment in Base, Mid and Peak capacity are more or less similar to those in the other scenarios, but there is tremendous growth in the High Peak and PHES capacity. Here, the total installed dispatchable capacity is driven by the peak load and the exogenous and endogenous upward reserve requirements; mainly by the reserve requirements that have to be held over the monthly allocation horizons. E.g. for the 30% and 50% targets, the total installed dispatchable capacity is 14.9 GW and 16.1 GW, respectively; which relates closely to the sum of the peak load (13.1 GW), the exogenous reserve requirements (1.1 GW) and the monthly endogenous reserve requirements (approximately 1.1 GW and 2.0 GW, respectively). This capacity increase is mainly realized by installing more of the (very flexible) low-CAPEX High Peak and PHES capacity, which provide the bulk of the upward FRR (see Section 4.4.3).

First, these results show the importance of sufficiently short allocation and sizing horizons. If too much capacity is held as reserves during moments of low VRES-E output, then there is a greater need for generation capacity to be able to actually produce sufficient electricity during these moments, thus increasing the required peak capacity. This will be discussed in more detail in Section 4.5. Second, this shows the importance in determining the desired level of reliability. The crucial element is the *cost-effectiveness* of maintaining reliability. Here, the applied 3σ-rule (ensuring that at least 99.7% of all imbalances can be covered), leads to a total installed dispatchable capacity that is 105-124% of peak demand. Mostly planners have avoided the possibility of having too little capacity by imposing high costs for load shedding, stringent centralized requirements for LOLE or EENS indicators, or capacity reserve margins ranging up to 150% [133, 134, 138, 139]. However, it is also possible to be too stringent, leading to a higher cost of reliability than what consumers are willing to pay. Given better information on such things, this 3σ-rule should be adjusted to more appropriately reflect this actual value.

Finally, investments in variable renewable capacity follow similar tendencies over the different scenarios. It is clear that – given the assumed cost structure and renewable resource – the onshore wind technology is the most cost-effective option for meeting the renewable target. The offshore wind technology is too expensive to warrant investment in any of the scenarios. At higher targets, there is also some investment in the PV technology. This is mostly to achieve a greater diversity of moments in which there is renewable production. Due to the use of a single profile, increasing the installed onshore wind capacity means increasing renewable production during moments in which there already is production. This eventually leads to curtailment. Onshore wind capacity is only increased until the yield of the additional capacity falls below that of the alternative; in this case the PV technology. More detail in the representation of these resources might result in less investment in PV resources, to be substituted by investments in onshore wind resources with a lower yield than the originally modeled onshore wind resource, but still with a higher yield than the PV resources. The emergence of PV capacity is slightly more pronounced in the *Variability* scenario than in the *Adequacy* scenario, due to the additional curtailment following from the introduction of the dispatch constraints. Paradoxically, it is less pronounced in the *Uncertainty* scenario. Here, the operating reserve requirements lead to additional investment in PHES capacity. This additional capacity enables the system to better cope with moments of renewable overproduction, meaning that more of the otherwise curtailed wind output can be recovered, requiring less diversification in renewable capacity.

4.4.3 Energy and reserve provision

Figure 4.7 shows annual electricity generation and curtailment for all scenarios. The operational constraints have a relatively small impact on the observed generation patterns. As the renewable target rises, the generation mix follows the capacity mix: the Base-generated electricity gets replaced by Mid-generated and renewable electricity. There is a small additional shift in Base- to Mid-generated electricity and a slight increase in curtailment when moving from the *Adequacy* to the *Variability* scenario. This increase in curtailment is limited, as it is for the most part countered by the increased reliance on the PV technology. In the *Uncertainty* scenario, these tendencies are less pronounced, as the operating reserve requirements drive additional investments in flexible capacity.

Figure 4.8 shows the average reserve allocation for the upward reserve categories. Part of this capacity is allocated on a monthly basis, part on an hourly basis. The capacities depicted in this figure are the average allocated capacities for the year under evaluation. It is important to keep in mind that some technologies provide significantly more reserve capacity during certain moments than their annual average. E.g. the Mid technology, which provides on average 8 MW of upward FCR in the 20% case, provides 98 MW of upward FCR during the month of June of the evaluated year. Overall, the reliance on the PHES and High Peak technology is striking. Essentially, the PHES technology provides all the "on-line" reserve capacity (the upward FCR and aFRR, and the downward reserves), i.e. capacity that otherwise would have to be provided by *spinning* generation technologies; whereas the High Peak technology provides the mFRR via *non-spinning* capacity, i.e. capacity that can start up sufficiently quickly. The latter owes this role to its low CAPEX and the fact that possible activation costs are not included (as the real time phase is not modeled), making it the

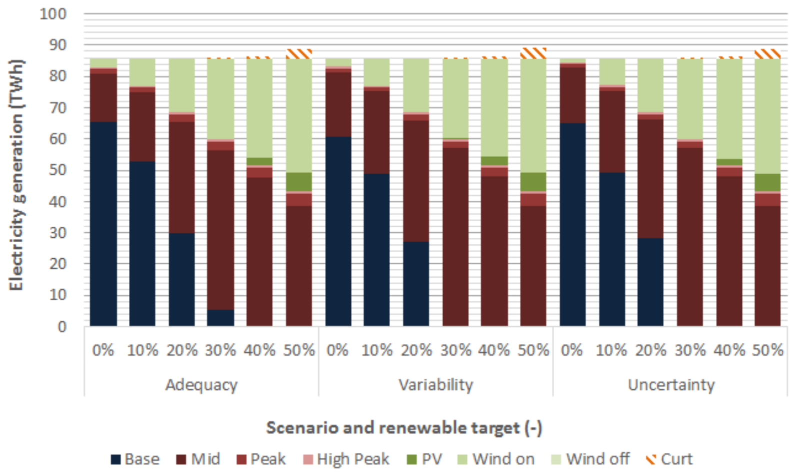

Figure 4.7: Annual electricity generation and curtailment in TWh for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

most cost-effective option to meet this requirement. The former owes its role also to its low CAPEX and to the fact that it enables the low-OPEX generation technologies (Base, Mid) to work closer to there maximum capacity, allowing for cheaper electricity production.

Figure 4.9 shows the average reserve allocation for the downward reserve categories. The tendencies here follow those of the annual electricity generation. Initially, there is little value for downward reserves, as a lot of downward flexibility is available. The Base technology has around 8 700 full load hours, meaning that it is on-line and able to provide downward flexibility almost continuously. At higher renewable targets the downward reserve provision is gradually taken over by the Mid and the PHES technology. The shift towards the Mid technology can be explained by investment shifting from the Base towards the Mid technology. The shift towards PHES, however, is driven by the increasing instantaneous renewable penetrations. As the renewable target reaches and surpasses 30%, the instantaneous renewable penetrations can exceed 80% and even 90%. To enable such high instantaneous penetrations, the operating reserves have to be met by the PHES. Here, the structural advantage of a storage vs. a generation technology comes forth. The PHES technology can provide both up- and downward operating reserve power, while having a net output that is zero or negative. Should a generation technology have to provide the downward reserves and upward spinning reserves, this would mean that a

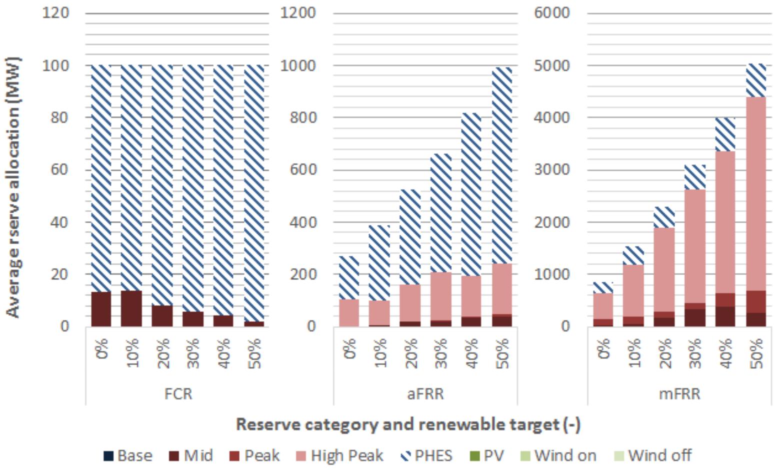

Figure 4.8: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

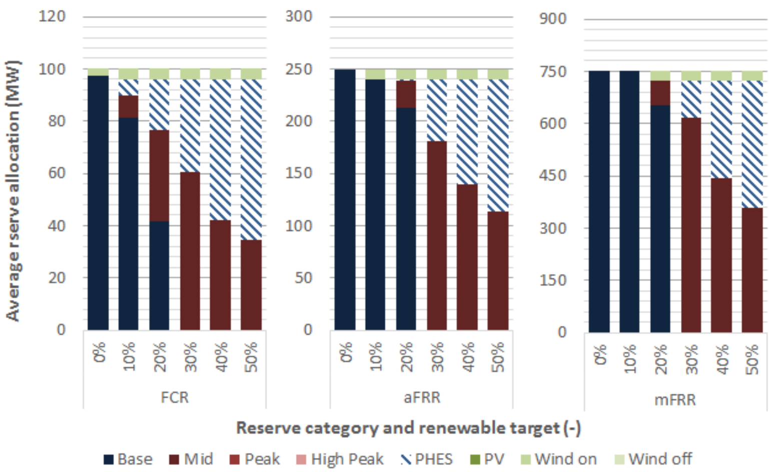

Figure 4.9: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

certain amount of generation would have to be on-line. This would introduce an *incompressible* part of the supply, that would limit the maximum instantaneous renewable penetration, leading to more curtailment. Hence, the shift towards the storage technology and the variable RES-E themselves for the provision of downward reserves.

Nevertheless, these high instantaneous penetrations, enabled by storage and VRES-E flexibility provision, might not always be feasible, due to concerns related to system stability and inertia. TSOs could impose that at all times a certain minimum share of the on-line generation has to come from dispatchable generation technologies, as they already do in certain power systems, e.g. Ireland [213]. The influence of such an approach was checked by reevaluating the *Uncertainty* scenario with an additional constraint which imposed that at all times at least 20% of the on-line generation had to come from conventional technologies. At low renewable targets this has no impact, but from 30% and on this induces significant additional costs, ranging up to 2.2 €/MWh. As such the flexibility and balancing costs increase to 2.6-10.2 €/MWh_{RES}, compared to the original 2.6-5.9 €/MWh_{RES}. While in the future renewables or storage systems could e.g. provide synthetic inertia, currently such additional reliability constraints can thus severely increase the cost of reliability.

4.5 Dealing with uncertainty: reserve sizing

As the uncertainty-related balancing costs prove to be the most significant costs in ensuring flexibility adequacy, the way in which uncertainty is tackled deserves further analysis. Both the adopted strategy for sizing reserves and the adopted strategy for allocating reserves have an important impact on the eventual balancing costs and on the optimal investment portfolio. This section discusses the impact of changing the sizing horizon, while the next section discusses the impact of changing the allocation horizon.

To make the results more traceable, for this section and the next the dual approach (TSO vs. BRP reserve allocation) is dropped. Instead all operating reserve requirements are allocated over the same allocation horizon. The sizing of exogenous reserves is not changed; they remain sized on a yearly basis. The sizing of the endogenous reserves, in contrast, is done again, now using three horizons: yearly, monthly and hourly. Figure 4.10 shows the box-plots of the FRR requirements for the different variable renewable resources for the different sizing horizons next to the box-plot of the reserve requirements as applied in the *Uncertainty* scenario. An important tendency becomes obvious straight away: while the median value decreases as the sizing horizon decreases, the maximum

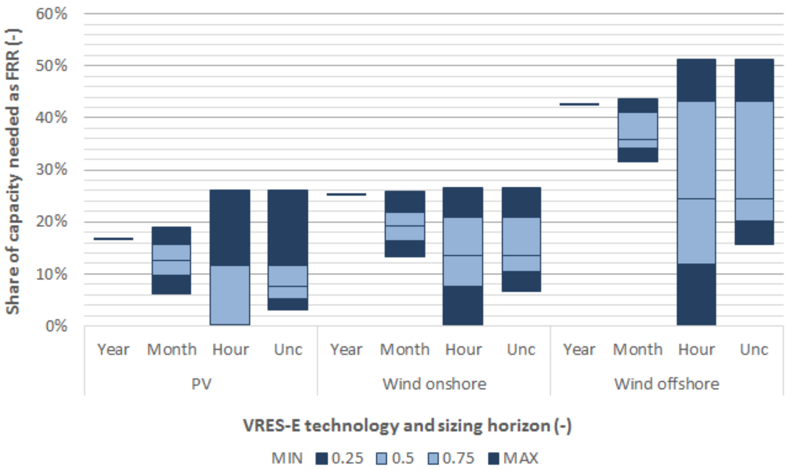

Figure 4.10: Box-plots of the FRR requirements for PV, and onshore and offshore wind uncertainty with yearly, monthly and hourly sizing and for the *Uncertainty* scenario expressed as a percentage of the installed capacity.

value actually increases. As the horizon decreases, the logic of the reserves shifts from one of constant reserve to one of constant reliability. During moments of low uncertainty less reserve capacity is held under a more dynamical sizing strategy; while during moments of high uncertainty more reserve capacity is held. In the former situation the less dynamic strategy is more and possibly too reliable (w.r.t. its cost-effectiveness); in the latter situation it is less reliable. Note again that these different strategies do not result in the same level of reliability. For all strategies the 3σ-rule was applied. This implies that the more dynamic strategy is at least as reliable as the less dynamic strategy, and possibly more reliable (when expressed in indicators such as the LOLE and EENS). Adjusting the FRR levels of the scenarios such that they would yield the same reliability would improve the value of the comparison, most likely leading to more benefits coming from the more dynamic strategies. However, for reasons explained previously in Section 3.3.4 this will not be investigated here. Finally, for these three new scenarios (yearly, monthly and hourly sizing) allocation will be realized on an hourly basis. Allocation horizons cannot be larger than the sizing horizon; there is no point in updating the volume to be contracted more often than the the frequency at which capacity is actually allocated. Hence, the smallest sizing horizon under consideration determines the allocation horizon, i.e. hourly.

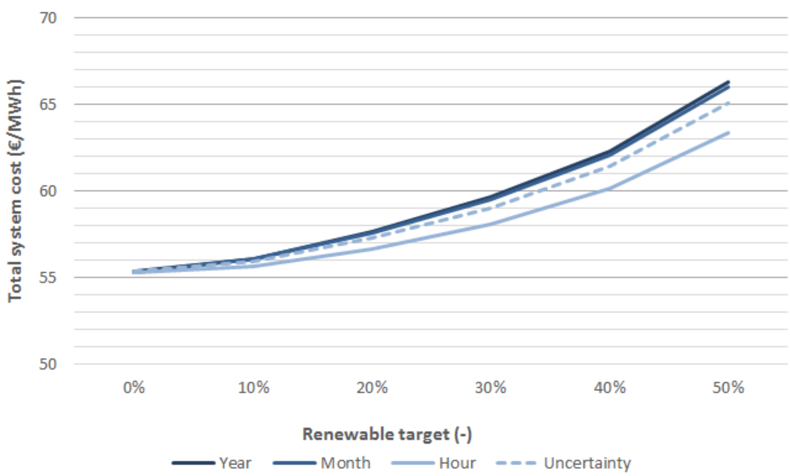

Figure 4.11: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the Year, Month, Hour and Uncertainty scenario.

4.5.1 The impact on system cost

Figure 4.11 shows the total system cost for all scenarios expressed in €/MWh. The cost of the *Year* scenario rises from 55.3 €/MWh to 66.3 €/MWh as the renewable target increases. The cost of the *Month* scenario is very similar, rising from 55.3 €/MWh to 66.0 €/MWh. Both scenarios are more expensive than the *Uncertainty* scenario previously evaluated. The *Hour* scenario, in contrast, undercuts the cost of the *Uncertainty* scenario. The cost of the *Hour* scenario rises from 55.3 €/MWh to only 63.4 €/MWh. As such, the flexibility and balancing costs of these scenarios are 4.5-8.3 €/MWh_{RES}, 4.1-7.8 €/MWh_{RES} and 0.3-2.5 €/MWh_{RES}, for the *Year*, *Month* and *Hour* scenario respectively. For the first two, this means an important markup compared to the original *Uncertainty* scenario, which has a flexibility and balancing cost of 2.6-5.9 €/MWh_{RES}.

The breakdown of the difference in total system cost between the different scenarios already reveals the main impact of changing the sizing horizon (see Figure 4.12). When switching from a yearly to a monthly sizing horizon the cost savings are of another order of magnitude compared to switching from a yearly to an hourly sizing horizon, but in both cases the savings are driven by a decrease in CAPEX. This is the result of the way in which the sizing horizon determines the need for total dispatchable capacity, as will be discussed

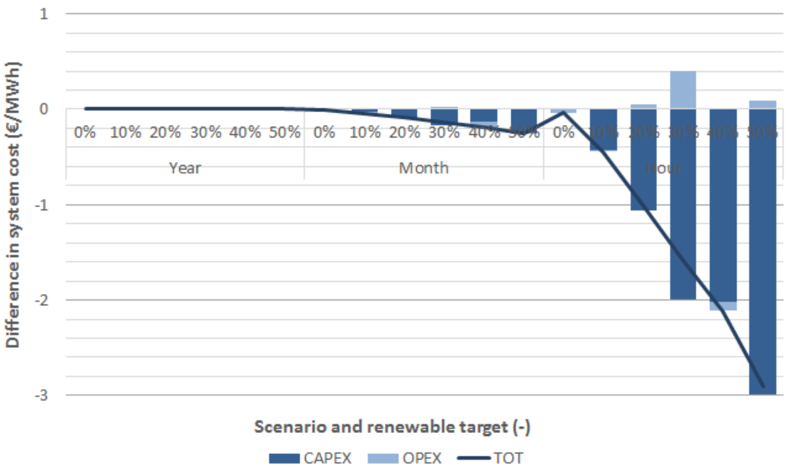

Figure 4.12: Difference in total system cost expressed in €/MWh of total demand for the Year, Month and Hour scenario, compared to the Year scenario.

directly hereafter. In conclusion, it can be said that decreasing the sizing horizon decreases system costs. Actual savings might even be higher than what the results here suggest: recall that as the sizing horizon decreases, the level of reliability is at least the same or higher. Adjusting the reserve requirements to lead to the same level of reliability might then further decrease costs.

4.5.2 The impact on investments

The impact of changing the sizing horizon on the optimal investment portfolio is very straightforward. Figure 4.13 shows the total installed capacities for the different sizing scenarios and renewable targets. Due to the switch to an hourly allocation horizon, the drivers behind the total installed dispatchable capacity are slightly different from those in the *Uncertainty* scenario. Now, every hour all available flexibility can be used to meet the demand and the reserve requirements. Hence, the required total dispatchable capacity is determined in moments of low VRES-E output. After all, when facing a high renewable generation forecast, high upward reserve capacity might be needed, but then also more dispatchable capacity is available for the provision of those upward reserves, as it is not needed for the generation of electricity. In contrast, when facing a low renewable generation forecast, less dispatchable capacity is available for the provision of upward reserves. It is the demand for upward reserve power,

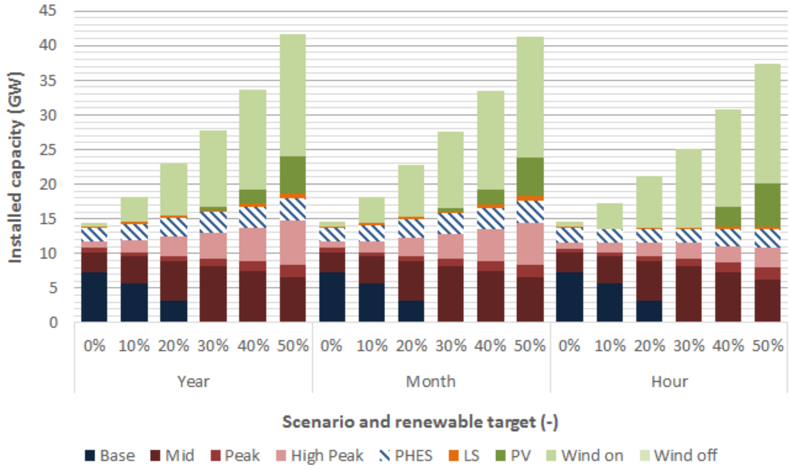

Figure 4.13: Installed power capacity in GW for the Year, Month and Hour scenario for different renewable targets.

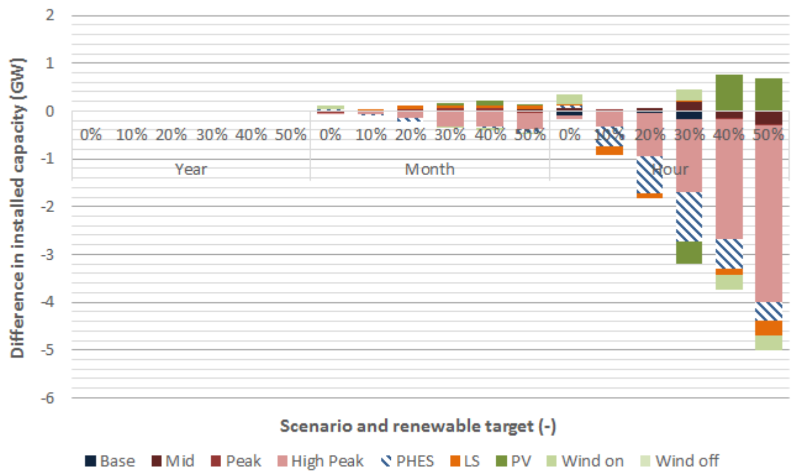

Figure 4.14: Difference in installed power capacity in GW for the Year, Month and Hour scenario, compared to the Year scenario.

and the level of electricity demand, during those moments that determines the required dispatchable capacity. In the *Year* scenario, this demand is the same throughout the year, e.g. for the 50% case: 1.1 GW of exogenous reserves and 5.5 GW of endogenous FRR. This leads to a peak dispatchable capacity of 18.0 GW. In the *Month* scenario this endogenous requirement drops to 4.0 GW, but the peak dispatchable capacity drops only to 17.5 GW. While the average reserve requirement decreases quite strongly compared to the *Year* scenario, apparently during the decisive moment the monthly reserve requirement does not differ strongly from the yearly requirement. The decrease in dispatchable capacity is much more significant in the *Hour* scenario. For the 50% case the average endogenous FRR capacity does not drop much further: from 4.0 GW (monthly) to 3.0 GW (hourly). The dispatchable capacity, however, drops to 13.6 GW. This means that the total dispatchable capacity is essentially only driven by the peak load and the exogenous requirements (13.1 GW and 1.1 GW), and no longer by the endogenous, VRES-E-related requirements.

Figure 4.14 brings forth even more explicitly the tendency discussed above. The difference in capacity between the different scenarios is basically a decrease in PHES and mainly High Peak capacity. Moving from the *Year* to the *Month* scenario, this decrease is a couple of 100 MW. Moving from the *Month* to the *Hour* scenario, it is a couple of 1 000 MW. Some TSOs across Europe have already implemented monthly sizing. The results here, however, suggest that the greatest gains in a highly renewable power system are to be reaped when bringing the sizing horizon even closer to real time; allowing for a better matching of allocated reserve capacity to the uncertainty present in the system.

4.5.3 Energy and reserve provision

The annual electricity generation and curtailment of the three scenarios are almost identical to those of the *Uncertainty* scenario. The same can be said for the provision of downward reserves, as well as for the provision of upward FCR. The upward FRR allocation is obviously different, as it is the sizing of the endogenous component of these reserves that is different over the scenarios. Figure 4.15 shows the average upward aFRR allocation for the three scenarios; Figure 4.16 the average upward mFRR allocation. For both reserve categories, the average reserve capacity decreases as the sizing horizon decreases. While the level of reliability is maintained or increased, the average held reserve capacity decreases. So, besides decreasing the total dispatchable capacity need, more dynamic reserve sizing strategies result in a more efficient reserve allocation. As in the *Uncertainty* scenario, the PHES technology dominates the aFRR provision, whereas the High Peak technology dominates the mFRR provision.

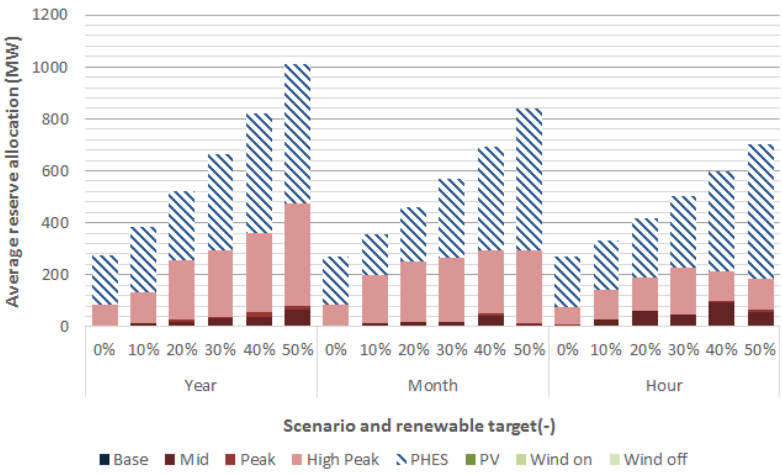

Figure 4.15: Upward aFRR allocation in MW for the Year, Month and Hour scenario for the different renewable targets.

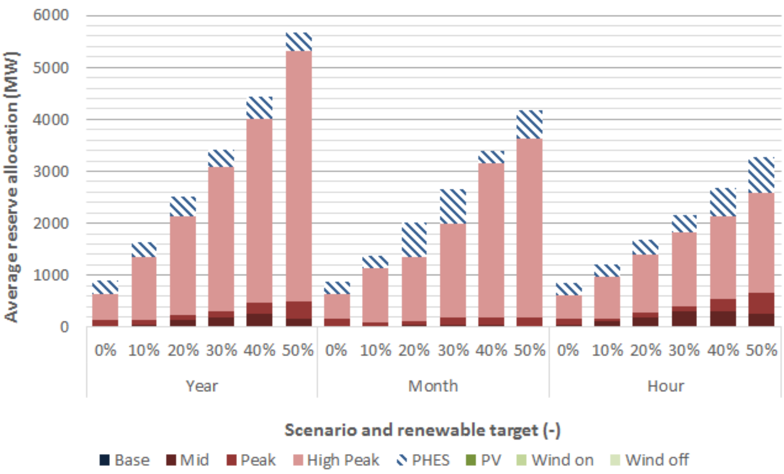

Figure 4.16: Upward mFRR allocation in MW for the Year, Month and Hour scenario for the different renewable targets.

4.6 Dealing with uncertainty: reserve allocation

The previous section showed how the hourly allocation enabled the system to benefit from the improved sizing strategy. This section will look at the impact of changing the allocation horizon. Clearly, an hourly allocation horizon allows the model to consider at every time step the available flexibility and to allocate this flexibility optimally over the ramping and reserve requirements. However, TSOs might not be comfortable with a reserve allocation mix that changes so frequently. Hence, by introducing longer allocation horizons they pay a kind of insurance premium so as to be sure that the reserve capacity is available when called upon. This section attempts to quantify that premium. Three allocation horizons will be considered: yearly, monthly and hourly. Again, the allocation horizon cannot be larger than the sizing horizon. Hence, the largest allocation horizon under consideration determines the sizing horizon for the three scenarios to be evaluated here, i.e. yearly. In the three scenarios both the exogenous and the endogenous component of the reserve requirements are sized on a yearly basis. For the three VRES-E technologies this means a fixed percentage of the installed capacity to be held as FRR, shown in Figure 4.10. Both components are then subjected to yearly, monthly and hourly allocation horizons.

4.6.1 The impact on system cost

Figure 4.17 shows the total system cost for the three allocation scenarios and the *Uncertainty* scenario. All three scenarios are more expensive than the *Uncertainty* scenario due to the adoption of a yearly sizing strategy. Among each other, the scenarios' costs decrease as the allocation horizon decreases; an effect that is ever more pronounced as the renewable target increases. The total system cost of the *Year* scenario rises from 55.4 €/MWh to 67.6 €/MWh; the cost of the *Hour* scenario from 55.3 €/MWh to 65.8 €/MWh; that of the *Month* scenario lying almost perfectly in the middle. As such, the flexibility and balancing costs are 5.5-10.6 €/$\mathrm{MWh_{RES}}$, 5.2-8.7 €/$\mathrm{MWh_{RES}}$ and 4.5-7.5 €/$\mathrm{MWh_{RES}}$, for the *Year*, *Month* and *Hour* scenario respectively. For all three, this means a cost increase compared to the *Uncertainty* scenario (2.6-5.9 €/$\mathrm{MWh_{RES}}$).

Figure 4.18 shows the breakdown of the cost differences between the three allocation scenarios. There is not a straightforward tendency, as was the case for the impact of changing the sizing horizon. While mixed initially, at higher renewable targets there is a decrease in both CAPEX and OPEX. Whereas the sizing horizon mostly impacts the peak need for dispatchable capacity, the

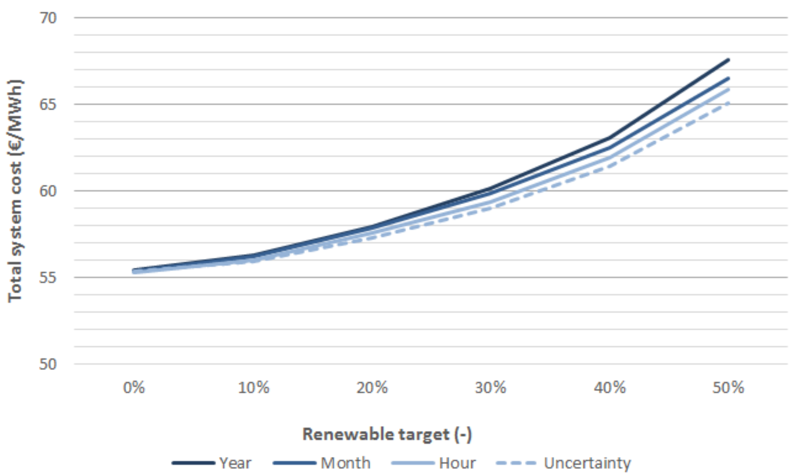

Figure 4.17: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the Year, Month, Hour and Uncertainty scenario.

allocation horizon has its most important impact on the operation of the power system. A more frequent update of the reserve allocation allows for a more efficient use of the available flexibility. This, in turn, allows for a more efficient use of the electricity generation means, leading firstly to OPEX savings, and at times also to a shift in investments (see below). A final aspect worth noting is that – in contrast to what was seen when studying the impact of the sizing horizon – in the case of these three scenarios half of the savings realized by allocating on an hourly basis vs. a yearly basis can already be realized by adopting a monthly allocation horizon.

4.6.2 The impact on investments

Figure 4.19 shows the portfolios of the three allocation scenarios. The difference between the scenarios is less pronounced as it was in the previous section. The portfolios all strongly resemble that of the *Year* scenario of the previous section, showing how the yearly sizing strategy sets the total dispatchable capacity need. Altering the allocation horizon given a sizing horizon results in more subtle differences. These are more clearly visible in Figure 4.20. The main tendency in this figure is the replacement of High Peak capacity by PHES capacity as the allocation horizon becomes shorter. The decrease in High Peak capacity is the result of it being possible to use the capacity more efficiently. E.g., in

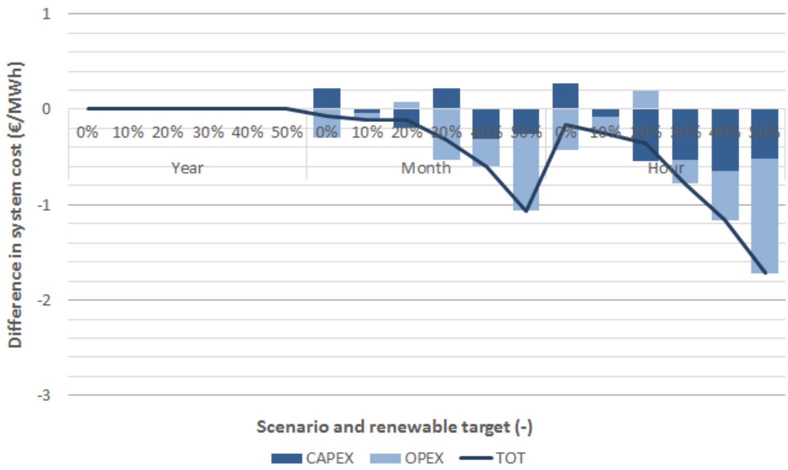

Figure 4.18: Difference in total system cost expressed in €/MWh of total demand for the Year, Month and Hour scenario, compared to the Year scenario.

the 20% case of the *Year* scenario 3.8 GW of the High Peak technology is installed. 2.0 GW hereof is set aside the entire year to provide upward FRR (all mFRR in this case). The remaining 1.7 GW is used to meet peak load, which is again most crucial during moments of low VRES-E output (maximum generation and reserve needed from dispatchable technologies). This results in a rather low 189 full load hours. In the *Month* scenario 3.2 GW of the High Peak technology is installed, which provides on average 2.3 GW of upward FRR, but still manages to increase its full load hours to 208. Thus, shortening the allocation horizon allows for a more efficient use of capacity. This effect is even more pronounced in the *Hour* scenario. Here, only 2.8 GW of the High Peak technology is installed. This capacity supplies on average 2.0 GW of upward FRR and increases its full load hours further to 258 GW. In the previous section, where all three scenarios had hourly allocation, this more efficient use allowed to reduce the total dispatchable capacity need when using monthly and hourly sizing horizons: moments of high VRES-E output mean high reserve needs, but low generation needs; moments of low VRES-E output mean high generation needs, but low reserve needs. In this section, which uses a yearly sizing horizon, moments of low VRES-E output mean high generation needs, *and* high reserve needs. Therefore, whatever High Peak capacity can be omitted, is replaced by the PHES technology, which has slightly lower CAPEX. Clearly, to reap the full benefits of improved reserve strategies, both the sizing and allocation horizon have to be shortened in a coordinated fashion.

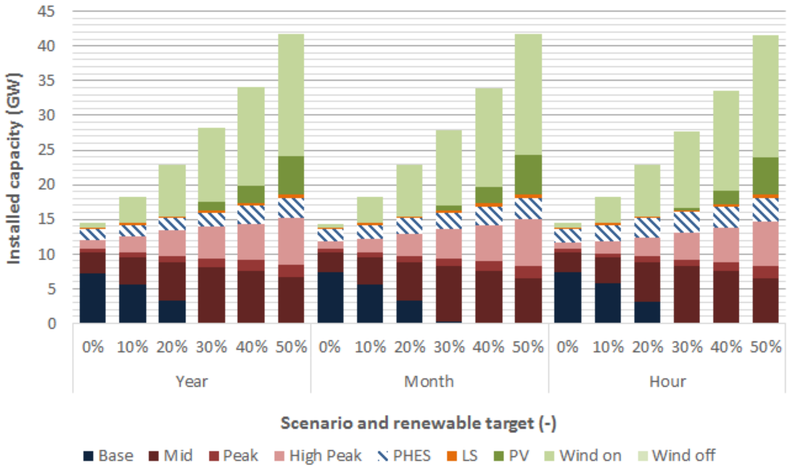

Figure 4.19: Installed power capacity in GW for the Year, Month and Hour scenario for different renewable targets.

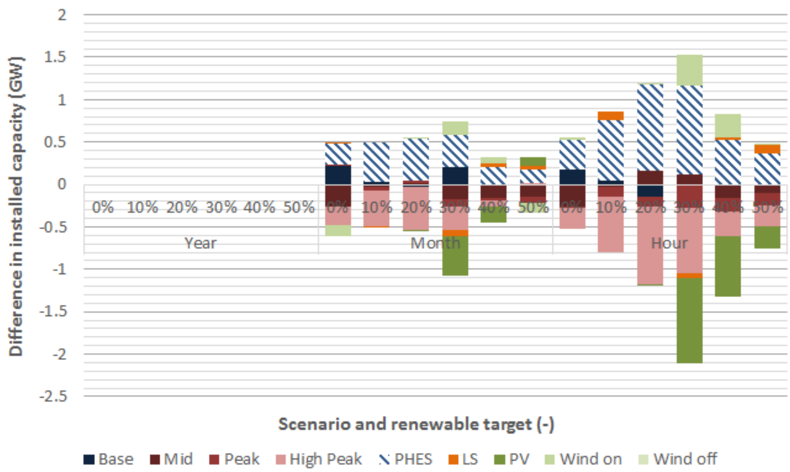

Figure 4.20: Difference in installed power capacity in GW for the Year, Month and Hour scenario, compared to the Year scenario.

An additional benefit of shorter allocation horizons is reduced curtailment. Long allocation horizons mean that certain technologies have to be on-line continuously for the supply of the "on-line" reserves, i.e. upward spinning reserves and downward reserves, which creates an incompressible part of the supply, as mentioned before. This incompressible part limits the maximum instantaneous penetration of VRES-E, inducing more curtailment, and consequently requiring the model to pursue further diversification of its VRES-E capacity, driving it to install more capacity of the less cost-effective PV technology. Shorter allocation horizons allow certain technologies to provide reserves that cannot provide those over long horizons. These include the less flexible dispatchable technologies, but also the VRES-E technologies themselves. This effectively cancels the effect of the incompressible part of the supply. Now, situations can arise where all downward reserves are provided by storage and VRES-E technologies and all upward reserves by storage, because of which the maximum instantaneous VRES-E penetration is only limited by the level of the demand. This drastically reduces curtailment, allowing the model to rely more on the cost-effective onshore wind technology, reducing investment in the PV technology.

4.6.3 Energy and reserve provision

Changing the allocation horizon naturally has an important impact on the average reserve allocation. The impact is similar for all upward reserve categories on the one hand, and for all downward reserve categories on the other hand. For brevity, only the aFRR provision will be discussed in detail as a representative example. Figure 4.21 shows the average upward aFRR allocation for the three allocation scenarios. In the *Year* scenario this is exclusively provided by the PHES technology. A storage technology is simply the most cost-effective solution for the year long provision of a reserve product that would otherwise have to be provided by a generation technology that is on-line. Especially in the presence of VRES-E output, forcing dispatchable generation technologies on-line is costly, due to its impact on curtailment, etc. (cfr. the discussion in the previous section). As the allocation horizon is shortened to a month instead of a year, it already becomes possible to adjust the reserve allocation to the operational circumstances. The 40-80 MW provided by the High Peak technology on average is actually the result of the technology providing 200-400 MW for 3 months of the year. These months are characterized by a lower VRES-E output, meaning that the High Peak technology has to be on-line more frequently for electricity production, enabling it to provide spinning upward reserve power. Shortening the allocation horizon further to an hour reinforces this effect many times over. Now reserves can be allocated based on the flexibility available in that exact hour. Consequently, not only the High Peak technology's contribution increases, but

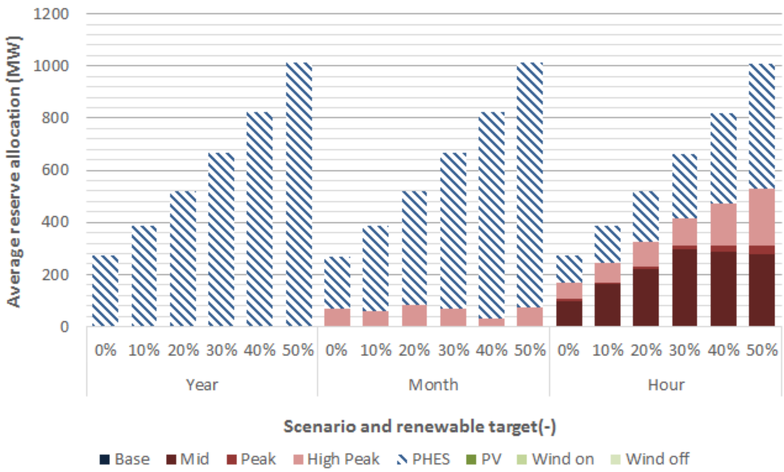

Figure 4.21: Upward aFRR allocation in MW for the Year, Month and Hour scenario for the different renewable targets.

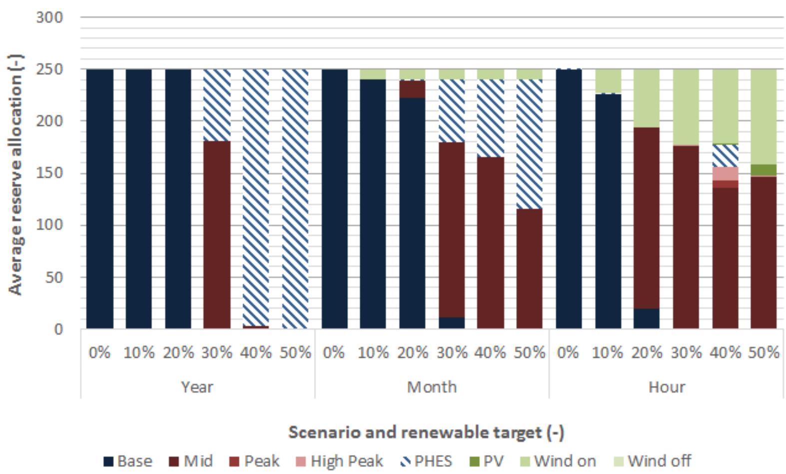

Figure 4.22: Downward aFRR allocation in MW for the Year, Month and Hour scenario for the different renewable targets.

suddenly also the Mid technology starts providing reserves. Similar tendencies occur in the provision of the other upward reserve categories. This allows to operate the portfolio much closer to its economic dispatch.

The tendencies described above can also be found when looking at the provision of the downward aFRR, shown in Figure 4.22. At low renewable targets, it is dominated by the Base technology. As the target increases in the *Year* scenario, it is taken over by technologies that can guarantee being on-line all the time; which essentially comes down to the PHES technology. Moving to a monthly allocation horizon allows the Mid technology to take on a bigger share of the reserve allocation, providing all required aFRR for 5-7 months of the year depending on the renewable target. Moving to an hourly allocation horizon has an even more important implication: suddenly the full potential of the VRES-E technologies to provide downward reserves is unlocked. For the cases with a renewable target of 30% and higher, the onshore wind technology provides all downward aFRR for more than a quarter of the year, a trend that is also present with the other downward reserve categories. It is such reserve provision that cancels the effect of the incompressible part of the supply; reducing curtailment, and as a consequence reducing also operational and capital expenses.

4.7 Discussion

Short-term flexibility constraints have an impact on both the total system cost and the optimal investment portfolio. However, simply increasing the renewable share beyond that of the most economic portfolio, even without considering operational constraints, already increases the total system cost: capital expenses on VRES-E capacity increase and changes in the residual load curve shift investments from base-load to mid- and peak-load generation technologies. The cost of this reconfiguration effect was estimated at 3-14 €/MWh_{RES} for the test system. These costs are normally captured by all power system planning models, also those that do not consider short-term flexibility related constraints.

Of greater interest for this work are the additional costs and effects incurred by short-term flexibility constraints. The flexibility cost, which relates to constraining the hourly dispatch in accordance with the technologies' technical characteristics, only presents a limited additional cost for the test system: in the range of 0-1 €/MWh_{RES}. This cost, which is in line with findings in the literature, is relatively low compared to the total system cost (ranging between €54-68/MWh). The most important part of flexibility adequacy costs, then, is clearly the balancing cost. Depending on the adopted reserve sizing and allocation strategy, total flexibility and balancing costs of the test system range between 6-11 €/MWh_{RES} for the (improbable) worst case (yearly sizing, yearly allocation), and between 0-3 €/MWh_{RES} for the best case (hourly sizing, hourly allocation). The way in which uncertainty is tackled is thus a decisive factor for the integration cost of VRES-E, especially at high renewable penetrations.

4.7.1 Cost-effective reliability?

Given the assumptions made to obtain these results – such as the fact that flexibility could only come from "conventional" providers, or the assumed 3σ-rule for sizing the reserves, or not considering the possible benefits of improved forecasting techniques – it can be concluded that the greatest cost in ensuring short-term flexibility adequacy stems from dealing with operational uncertainty. This raises a crucial question regarding flexibility adequacy: what level of reliability is cost-effective? As the share of VRES-E technologies in the electricity supply will increase, so will the level of uncertainty. Consequently, the cost of ensuring reliability will increase. Results here showed how the cost of flexibility adequacy for the test system increased from a mere 1 €/MWh (2% of total system cost) when no renewable target was imposed to 2-6 €/MWh or 3-11 €/MWh$_{\text{RES}}$ (3-9% of total system cost) under a 50% target, depending on the reserve strategy. Moreover, the reserve requirements were also the main driver for the total installed dispatchable capacity. As such, concerns about flexibility adequacy inevitably become entangled with concerns about firm capacity adequacy, and thus system adequacy in general.

Currently, it is common practice in planning models to impose a level of reliability; be it through constraints on LOLE and/or EENS indicators, capacity reserve margins, or reserve requirements as is done here. The cost of shedding load or reserve is fixed, and typically quite high. While this may have been in line with past practices, how reflective of current market conditions are such constraints? Which entity would impose such constraints on market parties, and how? In some member states, e.g. in Belgium, a TSO is obliged by law to meet certain reliability standards. But what is the meaning of such obligations in a liberalized electricity market? A TSO contracts reserve capacity and coordinates power system operation such that a certain quality of electricity supply can be realized (e.g. evaluated based on LOLE and/or EENS indicator performance). As long as sufficient capacity is available in the system, this is feasible. But if a TSO's control zone is suffering from a structural capacity shortage, should a TSO make up for this shortage by contracting more reserve capacity? Or should it impose greater economic penalties on BRPs that fail to balance their portfolio, incentivizing them to procure more (flexible) capacity? Or should policy-makers impose some sort of capacity obligations on market parties? Are policy-makers willing to accept capacity shortages if the markets do not provide sufficient incentives and stability for market parties to invest in new capacity?

This entire discussion, which also ties in with the discussion on capacity markets and so on, requires more dedicated study than what has been undertaken here. Nevertheless, based on the findings of this work, it can be said that it will most likely no longer be acceptable (or at least not cost-effective) to ensure reliability no matter what in a highly renewable power system. It is the author's intuition that, in a liberalized and decentralizing context, the value of reliability will also be something to be determined in a liberalized and decentralized way. Retailers would get information on their consumers' willingness to pay for an uninterrupted service. Retailers would then make sure that they have both sufficient capacity (firm capacity adequacy) and sufficiently dynamic capacity (flexibility adequacy) to meet their consumers' wishes. To facilitate this information exchange, perhaps new markets will be required, e.g. decentralized capacity markets to cost-effectively realize firm capacity adequacy; complementing existing markets, e.g. balancing markets to cost-effectively realize flexibility adequacy. The main point is that this information exchange occurs. And – more related to the power system planning aspect – that such information is considered in planning models when deciding on the value of lost load, reserve requirements, etc.

4.7.2 Allocating computational power

The results presented in this Chapter show that the greatest cost increase occurs when the reserve requirements are included. However, including these requirements also strongly drives up the time required to solve the model. The *Adequacy* and *Variability* scenarios require computational times in the order of magnitude of minutes; for the *Uncertainty* scenario this is in the order of magnitude of hours. The predominant driver of this increase is the use of allocation horizons, which links multiple time steps. Current planning models cannot spare the computational resources for such an increase in complexity, but the question must be asked: even if they could, should this be the priority for enhancing current power system planning models? The answer, obviously, is that this depends on the goal of the research, but the author's intuition is that in most cases the answer would be "no". Unless the aim of the research is to evaluate the impact of short-term flexibility and/or the value of short-term flexibility providers – as is the case for this research – then computational resources would probably best be spent elsewhere.

If the goal of a power system planning model is to truly generate pathways for the transition of the power system, then other costs and factors will be more decisive than those related to flexibility adequacy. The profile and balancing costs of 50% renewable case of the test system amounted to 6 €/MWh in the worst case, and to less than 3 €/MWh in the best case. This means that if uncertainty is dealt with appropriately, the costs of profile and balancing make up around 5% of the total system cost. Hence, the other factors driving the total system cost can be said to be more important: investment costs, fuel costs, availability of certain technologies, etc. The availability of CCS, for example,

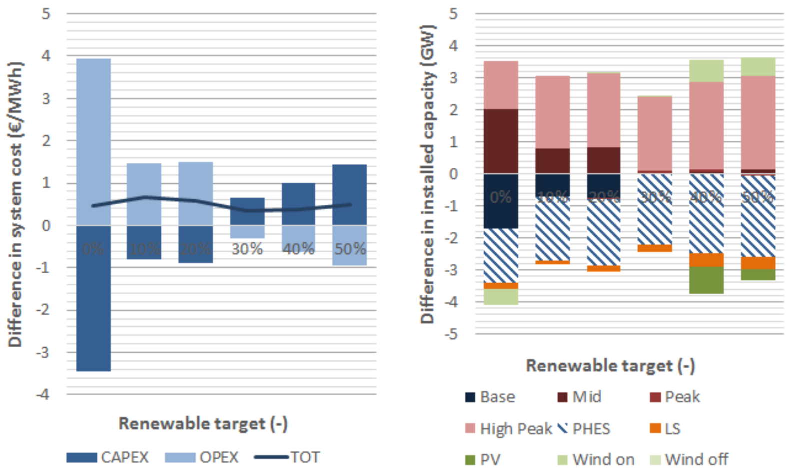

Figure 4.23: Difference in total system cost and installed power capacity for the extended Variability scenario vs. the Uncertainty scenario.

could have a tremendous impact. If emission targets drive the deployment of dispatchable generators with CCS, then flexibility adequacy could be guaranteed without imposing specific constraints [214]. It is this kind of uncertainty (on costs, availability, policy interactions, etc.), rather than operational uncertainty, that is the most interesting issue to devote more computational resources to when drafting transition pathways. Some authors have even suggested that it might be better to keep planning tools simple, so that more scenarios can be evaluated more quickly, leading to a better understanding of the effect of this kind of uncertainty [23, 25, 26].

A possible solution to incorporate the insights from this work in planning models with a broader scope could be to use an adjusted version of the capacity reserve margin. This simplification takes advantage of the inherent preference of planning models for the low-CAPEX, highly flexible High Peak technology. Instead of imposing a fixed margin, the capacity reserve margin would be linked to the deployment of VRES-E capacity. This becomes a three-step process. The first step would be a detailed analysis on the zonal level, considering all short-term flexibility related constraints (including the reserve sizing and allocation strategy within that zone). This would show how the dispatchable capacity need increases as the renewable target increases for that zone. E.g., for the *Uncertainty* scenario the dispatchable capacity need is 13.6 GW when no renewable target is set, requiring approximately 10.2% of additional dispatchable capacity for every installed MW of VRES-E capacity. This analysis would have to be carried out for all zones considered by the planning model. The second step would be to integrate only the operational constraints of the *Variability* scenario in the "high-level" planning model, extended with this additional dispatchable capacity need constraint for each zone. As a test, the extended version of the *Variability* scenario was rerun, and its outcome compared with that of the *Uncertainty* scenario. Figure 4.23 shows that the approximation is good, both in terms of total system cost and total capacity needs. The difference is that the model now chooses almost exclusively for the High Peak technology, here at the expense of the PHES technology. Therefore, the third and final step of this approximation method would be to redo a fully constrained optimization of the portfolio on the zonal level, setting a minimum value for all capacity in accordance with the outcome of the "high-level" planning model, except for the capacity of the High Peak technology. This capacity would then be filled in with the most cost-effective mix of short-term flexibility providers. Obviously, this approximation will induce errors, as it excludes the impacts of flexible capacity on e.g. base-load capacity or VRES-E capacity discussed in this Chapter. Nevertheless, it allows to include to a certain extent the impact of short-term flexibility constraints in "high-level" planning at a feasible computational cost.

4.8 Conclusions

The model proposed in the previous chapter has been applied to a test system with flexibility options reflecting today's availability. The outcome shows that the cost of ensuring flexibility adequacy is in the range of 1-6 €/MWh and 0-11 €/MWh$_{\mathrm{RES}}$, depending on the renewable target and the reserve strategy, increasing as the target increases; compared to a total system cost ranging between 54-68 €/MWh. Results showed that the desired level of reliability and the way of handling uncertainty are decisive for the eventual cost of flexibility adequacy. Furthermore, it is also important to see these costs in perspective: other elements may have larger impacts on total system cost, and therefore it might be more opportune for other planning models to dedicate additional computational resources to these issues, rather than to including the short-term flexibility constraints. This, naturally, depends on the goal of the research. If the goal e.g. is to study the future role and impact of flexible technologies, then high operational detail is a must. This is exactly the goal of the next chapter, which studies several "alternative" sources of short-term operational flexibility, and their impact on costs and investments.

Chapter 5

Alternative sources of short-term flexibility

5.1 Introduction

In the previous chapter, the supply of flexibility was limited to those sources most commonly found in European power systems, namely generation technologies and pumped hydro energy storage. In this chapter, the potential of alternative sources of flexibility is investigated. An increasing need for short-term flexibility and a decreasing share of conventional generation technologies in electricity generation following increased VRES-E integration, means that the added value of such alternative flexibility providers could be important. This chapter quantifies the impact of the use of alternative sources of short-term flexibility on both the total system cost and the optimal investment portfolio by reevaluating the three scenarios of the previous chapter for the same test system – the *Adequacy*, *Variability* and *Uncertainty* scenario. The difference in outcome for each of the scenarios allows to identify a flexibility provider's added value for dealing with adequacy, variability and uncertainty. It will also show how important the associated operational constraints are for capturing the full added value of the flexibility providers. Three types of alternative sources are considered: energy storage, demand response, and interconnection. First, these flexibility types are evaluated separately. Then, they are evaluated jointly, to allow the flexibility providers to compete for the provision of flexibility services.

Table 5.1: Table presenting the technical input parameters of the storage technologies. Off-take and injection parameters are identical.

Set	Name	P_i^{i}	$P_i^{\mathrm{min,i}}$	$R_i^{\mathrm{s,i}}$	R_i^{m}	η_s^{i}	$T_i^{\mathrm{mut,i}}$	$T_i^{\mathrm{mut,i}}$	N_s^{cyc}
		MW	%	%	%/*min*	%	*h*	*h*	-
$\mathbb{S}$	BES	100	0	100	100	95	0	0	3 000
$\mathbb{S}$	PHES+	100	50	100	50	87	0	0	∞
$\mathbb{S}$	P2G	100	20	100	10	56	0	0	∞

5.2 Energy storage

5.2.1 Introduction

The first alternative source of flexibility to be evaluated is energy storage. Three storage technologies are selected, distinctively different in their operational characteristics. Technical and economic parameters of all technologies are based on the report of National Renewable Energy Laboratory on *Cost and Performance Data for Power Generation Technologies* [215]. Technical parameters are presented in Table 5.1, economic parameters in Table 5.2. The first technology is a BES technology, whose characteristics are based on Li-ion storage. The energy cost of this technology – currently around €300/kWh – is expected to decrease over the coming years/decades. As the scenarios pursue high renewable targets, also more reflective of future conditions, an estimate of future energy costs will be used here: €150/kWh. The operation of the BES technology is governed by the same set of equations that describes the operational behavior of the PHES technology used in the previous chapter. Nevertheless, there are two important differences between these technologies from an operational perspective. First, the cycle life of the BES technology is limited. A BES unit is designed with both an economic and a technical lifetime in mind. E.g., for the technology considered here the economic lifetime is 15 years, the technical lifetime is 3 000 cycles. This means that the unit can perform 200 cycles per year. Should the unit perform more cycles, its economic lifetime is shortened, incurring additional costs; an effect that is taken into account in the modeling. Should the unit perform less cycles, then this incurs an opportunity cost; an effect that is inherently considered by the model. Second, the technology is always "on-line". I.e., its minimum output level is zero, as are its minimum up and down times. This means that the BES technology is continuously connected, an important operational asset, e.g. for the provision of operating reserves.

Table 5.2: Table presenting the economic input parameters of the storage technologies. Investment costs are annualized with a 5% discount rate. Off-take and injection parameters are identical.

		Investment cost						Operational cost			
			Total		Annualized						
Set	Name	N_i^{cal}	$C_i^{\text{inv,i}}$	$C_s^{\text{inv,e}}$	$C_i^{\text{inv,i}}$	$C_s^{\text{inv,e}}$	$C_i^{\text{fom,i}}$	$C_i^{\text{fuel,i}}$	$C_i^{\text{vom,i}}$	$C_i^{\text{ra,i}}$	$C_i^{\text{su,i}}$
		years	*€/kW*	*€/kWh*	*€/kW*	*€/kWh*	*€/kW*	*€/MWh*	*€/MWh*	*€/MW*	*€/MW*
$\mathbb{S}$	BES	15	200	150	19	14	0	-	0	0	0
$\mathbb{S}$	PHES+	50	375	50	21	2.7	0	-	0	0	0
$\mathbb{S}$	P2G	30	100	30	65	-	0	-	0	0	0

The second storage technology is another PHES technology, named *PHES+*. While most natural potential in Europe has been developed [76], there are some opportunities to develop additional energy storage sites, albeit at higher costs. This includes e.g. sites where there is a natural height differences, but no basins; or sites where both the height difference and the basins have to be created. As a consequence, the energy cost of such sites is much higher than that of sites with natural potential. This is reflected in the economic parameters of the technology, namely through the energy cost of €50/kWh (compared to the €5/kWh of the "natural" PHES technology used before). This technology's operational behavior is also constrained by the same set of equations governing the behavior of the PHES technology used in the previous chapter.

The third and final storage technology is a P2G technology. This technology, in contrast to the two other storage technologies, does not reconvert the charged energy back into electricity. Rather, electricity is converted into gas, which is injected in (a conceptual model of) the gas grid, to be used as fuel for the gas-fired power plants. This facilitates the long-term storage of energy in e.g. underground gas storages, which can be practical for dealing with seasonal variations in VRES-E output. This also means that only the technology's charging operation can offer flexibility to the system. The technology's charging behavior follows the same set of constraints as the other storage technologies, but its energy constraints are different (see Section 3.4.6).

Before discussing the scenarios' outcomes, two remarks have to be made. First, it is important to note that the added value that will be captured by the storage technologies as they are modeled here, cannot be captured exclusively by those technologies. A number of demand response technologies can offer short-term flexibility that from an operational perspective is very similar to that of storage technologies. For example, electric vehicles can offer flexibility in a way that is very similar to what the BES technology can do. Similarly, coordinated use of heat pumps can adjust the residual load curve much like a PHES technology can. Both types of flexibility can also shift energy over time: demand response technologies through changing the moment of consumption, storage technologies through charging, storing and discharging energy. The point is that when interpreting the results of this section it is important to keep in mind that the benefits realized by the storage technologies considered here could also (in part) be realized by certain demand response technologies.

Second, it has to be noted that for the analyses of this chapter the level of temporal detail is altered. This is due to the high computation times required for solving the *Uncertainty* scenario in Section 5.5, which considers all flexibility providers and two zones. Optimizations were performed on a station with a 64-bit Windows, an Intel(R) Core(TM) i7-3740QM 2.70 GHz processor and 8.00 GB RAM of memory. When solving this scenario on this station for a full year with an hourly resolution, computation times increased up to 200+ hours, mostly due to the increased spatial resolution. To facilitate the analyses, the temporal detail is decreased to 13 representative periods of 168 hours (i.e. 13 weeks). The implications hereof for the model description have already been discussed in Section 3.4.8. Using weeks allows to still capture shifting over periods longer than a day; using one week in four allows to still properly describe e.g. seasonal variations in output, variability, uncertainty, etc. The periods are selected using the algorithm presented in [144], which also discusses the performance of the algorithm. Based on the metrics discussed in [144], it can be said that the use of 13 weeks introduces a very limited error, while allowing for a significant reduction of the computation times. Now, the different cases of the *Uncertainty* scenario of Section 5.5 can be solved with computation times that remain below 72 hours. To facilitate comparison over sections, all analyses in this chapter are performed with this level of temporal detail.

5.2.2 The impact on system cost

Figure 5.1 shows the total system cost of the three storage scenarios, and the three reference scenarios of the previous chapter. The three storage scenarios have a cost that is lower than that of the corresponding reference scenario. The cost of the *Adequacy* scenario rises from 54.4 €/MWh to 61.0 €/MWh. Introducing the hourly dispatch constraints in the *Variability* scenario leads to a minor cost mark-up, with total system cost now rising from 54.6 €/MWh to 61.4 €/MWh. As was the case in the previous chapter, introducing the operating reserve requirements leads to a higher mark-up, with total system cost now rising from 55.2 €/MWh to 63.4 €/MWh. Nevertheless, this still means a significant cost reduction compared to the reference *Uncertainty* scenario, amounting to €1.7/MWh for the 50% case.

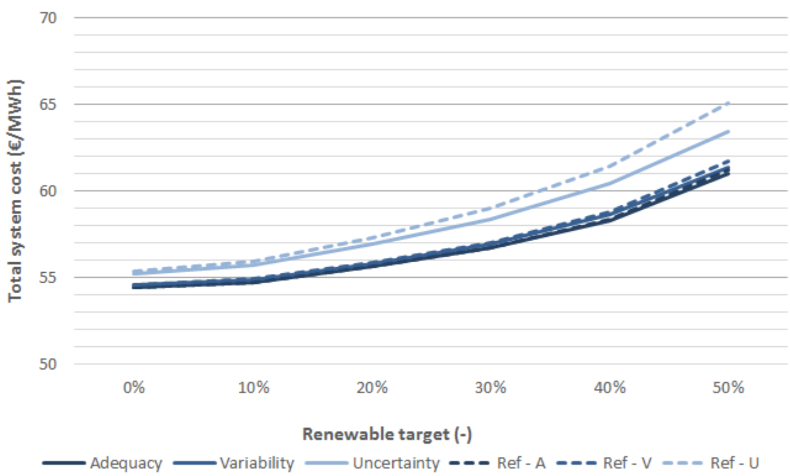

Figure 5.1: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the storage and reference scenarios.

Figure 5.2 shows the breakdown of the cost difference between the storage and reference scenarios. E.g. the Adequacy results show the difference between the *Adequacy* scenario with storage and that of the previous chapter. These results show that the added value of storage technologies for contributing to adequacy is rather limited, with total system cost savings amounting to at most 0.2 €/MWh. This is not to say that storage technologies are not adept at e.g. providing firm capacity; it merely shows that – given the assumed cost structures for all technologies – the selected storage technologies cannot provide that firm capacity much more cost-effectively than the other technologies of this test system. The added value for dealing with variability is not much larger, but the underlying shifts in investments are clearly larger. At intermediate renewable targets, the flexibility of the storage technologies allows for an increased reliance on the less flexible Base technology; as will be discussed in the next subsection. At high renewable targets, when the Base technology has already disappeared from the optimal investment mix, the shifts are more subtle. Nevertheless, they still result in increased cost savings; at most 0.4 €/MWh. Finally, the added value for dealing with uncertainty is of another order of magnitude. The cost differences already suggest how adept storage is at providing reserve capacity, something that will be confirmed in Section 5.2.4. At low and intermediate renewable targets, similar tendencies as for the *Variability* scenario are visible, but more pronounced. At high renewable targets, cost savings brought forth by storage are truly significant, ranging up to 1.7 €/MWh.

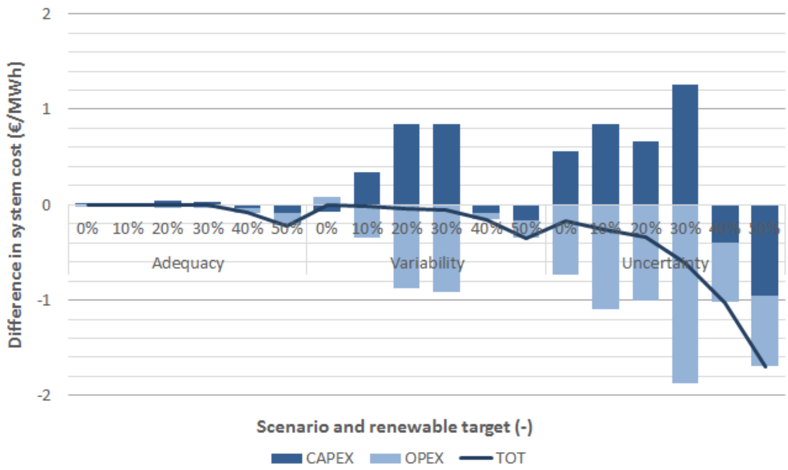

Figure 5.2: Difference in total system cost expressed in €/MWh of total demand for the storage scenarios, compared to the reference scenarios.

5.2.3 The impact on investments

Figure 5.3 shows the installed power capacities of the three storage scenarios. The overall lay-out of these portfolios is similar to that of the three reference scenarios. Installed dispatchable capacity remains more or less constant for the *Adequacy* and *Variability* scenarios, with a slight decrease at high renewable targets. In the *Uncertainty* scenario it increases again, ranging up to 16.5 GW for the 50% case (vs. 16.2 GW in the corresponding reference scenario). Also the total installed capacity is similar, just below 35 GW for the first two scenarios, and 38.4 GW for the third scenario (vs. 39.4 GW in the reference *Uncertainty* scenario). As for the storage technologies themselves, investment in the BES technology is limited to the *Uncertainty* scenario. The BES technology is very adept at providing reserves, and is only a cost-effective investment option when the operating reserve requirements are considered. The PHES+ technology is a cost-effective option in all scenarios, but also sees most investment in the third scenario. Finally, the P2G technology does not warrant investment in any scenario. Given the assumed cost structure, it is only cost-effective at much higher renewable targets (90-100%). In this chapter the focus is kept on the 0-50% renewable target range. For an analysis of the 50-100% range, readers are referred to Appendix A. In this appendix, the role of the P2G technology – and its added value compared to other options for reaching a fully renewable power supply, e.g. biomass – is discussed in detail.

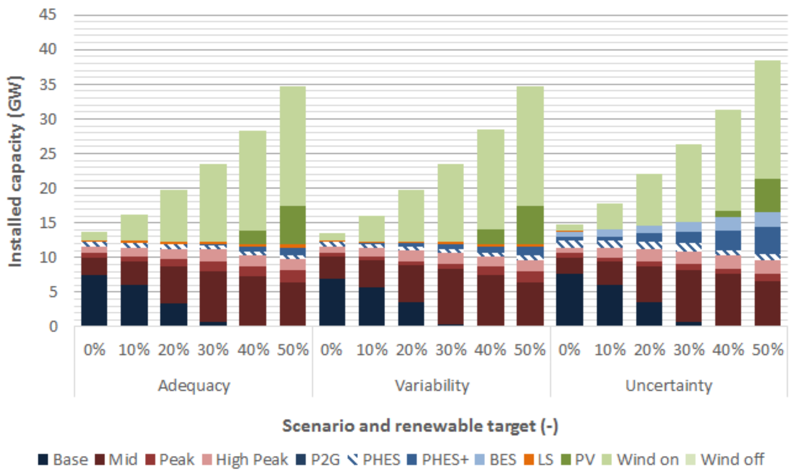

Figure 5.3: Installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

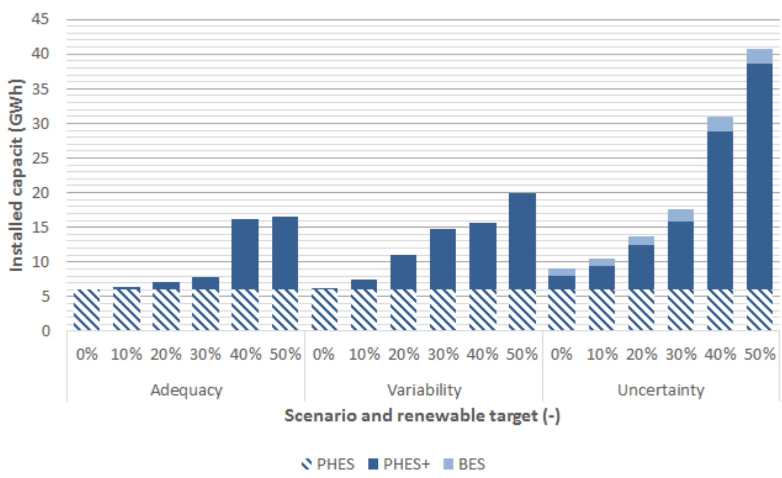

Figure 5.4: Installed energy capacity in GWh for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

Figure 5.4 shows the investment in energy capacity for the re-electrifying storage technologies. As in the three reference scenarios, the available 6 GWh of natural PHES potential is fully developed in all cases of all storage scenarios. In the *Adequacy* scenario, this capacity more or less suffices, until the 40% case. At these higher targets, it becomes cost-effective to develop more of the more expensive PHES+ energy capacity, in order to store otherwise curtailed renewable energy. Energy to power ratios for the two PHES technologies, shown in Figure 5.5, are more or less the same, hovering around 10 hours. At 50% there is a slight decrease, which is the result of increasing power capacity investment and stagnant energy investment; i.e. the storage technology has to deal with larger peaks.

In the *Variability* scenario, additional PHES+ energy capacity is developed, also at lower renewable targets. The hourly dispatch constraints have two relevant impacts here: first, they lead to increased curtailment, and second, they make it harder to operate the less flexible generation technologies close to their most economic operating point. Both issues can be dealt with by the PHES+ technology, resulting in more investment in its energy capacity. This twofold effect also causes the first real difference between the energy to power ratios of the storage and reference scenarios. In the reference scenario the PHES also has to deal with both issues, resulting in more power capacity investment, but cannot expand its energy capacity. In the storage scenario this drives a shift in investment from PHES to PHES+ power capacity (see just below): an energy to power ratio of around 10 hours is the most cost-effective solution for this system. If additional PHES power capacity investment decreases this ratio too much, the storage capacity cannot be operated sufficiently effectively. Then, it is better to shift investment towards the PHES+ technology.

In the *Uncertainty* scenario energy capacity investment is by far the greatest. The operating reserve requirements motivate additional energy capacity development, even at low renewable targets. At high renewable targets no less than 30-40 GWh of energy capacity is developed. For certain power systems this energy storage potential might be available, but for others – such as the Belgian system – it might not be. However, recall here that part of the added value realized by this energy capacity could be provided by demand response technologies. Shifting consumption and providing an energy buffer for (renewable) generation are both services that can also be realized by demand response technologies. What is also striking is the stark decrease in the energy to power ratio in this scenario. At low and intermediate renewable targets this is now around 5 hours for the PHES technologies, and only 1 hour for the BES technology. This latter technology provides “on-line” reserve capacity, i.e. up- and downward FCR and aFRR, and downward mFRR; reserves that otherwise would have to be provided by on-line generation technologies. These reserve categories (except for the downward mFRR) have energy requirements of less than an hour. Given the high energy cost of the technology, only just enough energy capacity is developed to provide these services. The PHES technologies – as was the case in the reference *Uncertainty* scenario – also provide mFRR. This reserve category requires more energy (just less than 3 hours), but still less than what is used for non-reserve related services, resulting in the lower energy to power ratios. At high renewable targets, when these non-reserve related services become relatively more important again, there is an increase in the energy to power ratio, although it still remains below the results of the other two scenarios. Once again, investment shifts from the PHES technology in the reference *Uncertainty* scenario to the PHES+ technology in the storage *Uncertainty* scenario so that the PHES and PHES+ technologies have the most cost-effective energy to power ratios.

Figure 5.6 shows the difference in installed power capacity between the three storage and the three reference scenarios. In the *Adequacy* and *Variability* scenarios, the shift in investments is in the order of magnitude of 1 GW. At intermediate renewable targets the investment in PHES+ capacity allows for a more efficient operation of the Base technology, which shifts part of the investment in the Mid technology back to the Base technology. Essentially, the PHES+ capacity deals with variability, allowing for higher full load hours for the Base technology; the more flexible technology helps the less flexible technology. At high renewable targets the PHES+ technology replaces part of the PHES capacity, following the mechanism related to the energy to power ratios described above. There is also additional PHES+ investment: with more energy capacity available, more of the otherwise curtailed energy can be stored, motivating additional storage investments and reduced PV investment. This stored energy can be dispatched, reducing the need for Mid capacity. Finally, the PHES+ power capacity does provide some firm capacity, replacing a fraction of the High Peak capacity. All these tendencies are more pronounced in the *Variability* scenario than in the *Adequacy* scenario as the dispatch constraints uncover more of the added value of the flexible PHES+ technology. In the *Uncertainty* scenario the shift of investments is of another order of magnitude all together. All the tendencies seen in the first two scenarios are also present here and compounded with the impact of the operating reserve requirements. In the reference scenario significant additional High Peak and PHES capacity was installed to meet these reserve requirements. This capacity is largely replaced by BES and PHES+ capacity, as these technologies now provide the bulk of the reserve power. With more of this storage capacity available, also more curtailment can be avoided, leading to even higher load shedding and VRES-E capacity reductions than in the first two scenarios.

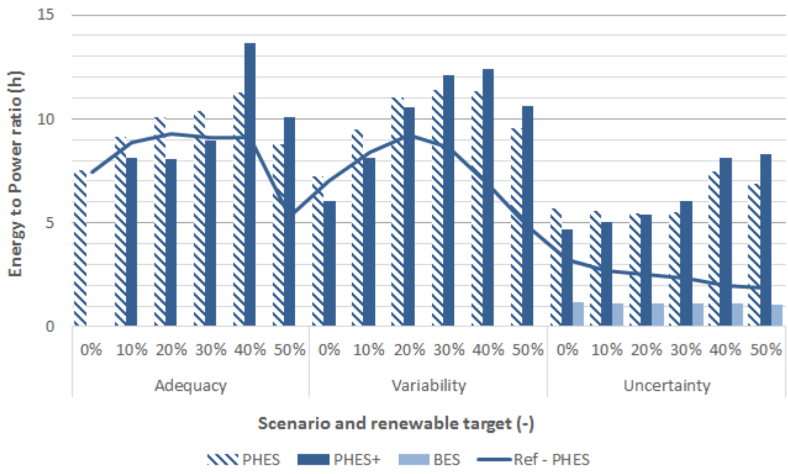

Figure 5.5: Energy to power ratio in hours for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

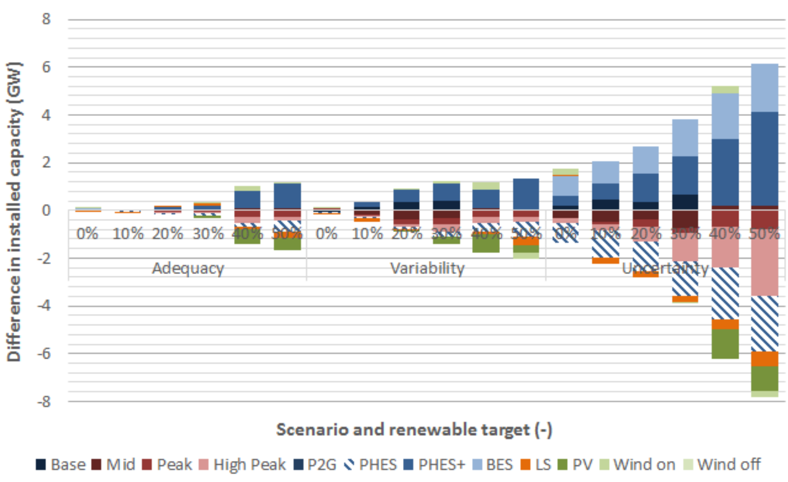

Figure 5.6: Difference in installed power capacity in GW for the storage scenarios, compared to the reference scenarios.

5.2.4 Energy and reserve provision

Energy and curtailment patterns do not change significantly compared to the reference scenarios. The changes that occur follow the changes in installed capacity: a shift of a couple of TWh of Mid to Base generated electricity and a reduction in curtailment. This merely confirms the observed tendency that the introduction of more flexible technologies into the power system increases the amount of time that the less flexible (dispatchable or variable) technologies can operate. It is interesting to note, however, that the full load hours of the High Peak technology in the *Uncertainty* scenario increase strongly. In the reference scenario these were around 200-300 hours for intermediate and high renewable targets. In the storage scenario these rise to 400-500 hours. This is not because the electricity generated by the High peak technology increases, but because its capacity decreases so strongly. Used as the main provider of upward mFRR in the reference scenario, this role is now taken over by the PHES+ technology at high renewable targets. This suggests that the model would have relied more on the PHES technology for upward mFRR provision if sufficient energy capacity would have been available. Now it can, albeit at a higher energy capacity cost. Providing 1 MW of mFRR with the PHES+ technology requires investing in 1 MW of power capacity and 2.9 MWh of energy capacity. The cost hereof is 49.0 k€ per year. This is slightly higher than the 46.8 k€ per year for High Peak power capacity. However, at high renewable targets the energy capacity of the PHES+ technology provides additional added value when it is not needed for reserve provision. As such, it becomes a more cost-effective option, shifting part of the High Peak investment towards PHES+ investment. This observation shows once more that flexibility providers are to a certain extent interchangeable, and that their cost-effectiveness in providing that flexibility and other services (to compound different sources of added value) will be decisive for their future deployment.

An interesting picture is presented by the reserve provision. Figure 5.7 shows the average upward reserve allocation, Figure 5.8 the average downward allocation. What is striking is the important role for the BES technology. It plays a major role in the provision of all on-line reserve categories. It dominates the provision of FCR for all renewable targets, and plays an important role in the provision of the other on-line reserve categories at higher targets. The reliance on the BES technology for FCR provision makes sense: a low power capacity cost and a low energy requirement, because of which the high energy capacity cost is not a deterrent to investment. Moreover, the BES technology does not need to be committed, so it can provide these reserves at any moment. At higher renewable targets it becomes worth it to pay also the higher energy capacity cost so that the BES technology can take over the provision of the other on-line reserve categories from the generation technologies. Reserve provision by

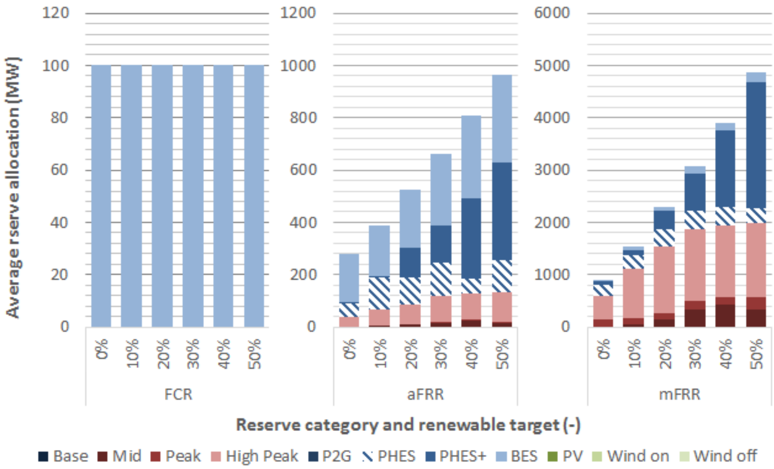

Figure 5.7: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

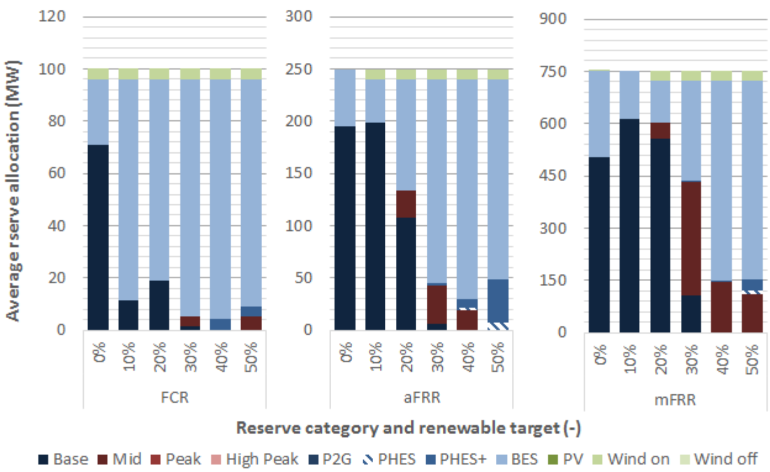

Figure 5.8: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

storage technologies for the on-line reserve categories takes away the limit to the instantaneous VRES-E penetration. This reduces curtailment, thus reducing the need for VRES-E capacity. And given that this is one of the main drivers of the total system cost increase as the renewable target increases, this motivates the additional energy capacity development.

The PHES+ technology's main contribution is in the provision of upward FRR at intermediate and high renewable targets. Its lower energy cost makes it a more cost-effective option than the BES technology for the provision of mFRR, as for this reserve category sufficient energy has to be reserved to be able to deliver the allocated capacity for 3 hours. It also takes over part of the High Peak technology's reserve capacity, following the dynamics explained above. In a similar manner, it starts to provide a more significant share of the aFRR as the renewable target increases. The added value of the PHES+ energy capacity increases, making it more competitive with the BES technology for the provision of also these reserves. This ability of the PHES+ technology to combine multiple sources of added value is what drives its great deployment.

A final remark is made on the fact that the activation of reserves is not considered. After being activated, storage technologies have to restore not only their power level, but also their energy level. So the cost of that electricity relative to the fuel cost of the generation technologies would have an important impact on which technology is the most cost-effective option to provide the reserves, and drive the related investments. Some preliminary research was performed into the influence of activation. While more detailed research is required to provide conclusive answers, some tendencies can be discussed. At low renewable targets, the impact was small. At these targets in the most expensive hours the electricity price is set by the High Peak technology; the storage's competition for providing upward FRR. As the model considers perfect foresight, the storage technologies were able to plan their charging and discharging in such a way that their "fuel cost" (i.e. the electricity cost) was competitive with that of the High Peak technology. At high renewable targets, their was even a shift towards more reliance on storage technologies for the provision of reserves. As the renewable target increases, the average electricity price decreases due to the increased VRES-E penetration, reducing the storage technologies' "fuel cost". So, in conclusion, while the optimal share of reserve power delivered by storage might differ from what is presented above when activation is taken into account, it is interesting to note that – perhaps counter-intuitively – doing so might actually increase that optimal share.

5.2.5 Discussion

This section has looked at a first type of alternative source of flexibility, namely storage. To study its role, it considered three storage technologies distinctively different from an operational perspective: a BES technology, an additional PHES technology (PHES+) and a P2G technology. Given the assumed cost structures and the considered renewable target range (0-50%), the P2G technology was not a cost-effective option. Its role over a higher renewable target range (50-100%) is studied in Appendix A. The other two technologies were cost-effective options, but the level of investment depended strongly on the considered scenario.

In the *Adequacy* scenario investment in storage technologies is very limited: no BES capacity, and limited PHES+ capacity. Consequently, cost savings realized by storage are limited; at most 0.2 €/MWh. The provision of firm capacity can generate some added value for the storage technologies, but they cannot do it much more cost-effectively than the options already available in the reference scenario. Deployment of storage in this scenario is further driven by its ability to smooth the residual load curve, thus reducing curtailment, and thus reducing the need for VRES-E capacity to meet the renewable target.

In the *Variability* scenario there is slightly more deployment of the PHES+ technology; with increased power capacity development at low renewable targets, and increased energy capacity development for all targets. This capacity provides the same added value as in the previous scenario, but now also helps to cope with the ramping constraints related to the variability of the load and VRES-E output. This way the residual load curve is smoothened once more. Essentially, the flexibility of the storage technologies allows the less flexible generation technologies to operate more economically. This provides a larger shift in investments at lower renewable targets, but the total system cost savings increase only slightly; at most 0.4 €/MWh.

In the *Uncertainty* scenario, finally, there is far greater investment in the storage technologies, including BES deployment. This leads to much higher savings, ranging up to 1.7 €/MWh. This shows two things. First, it shows that storage technologies are great at providing reserves, and that they are a very cost-effective option to do so in a system with a high VRES-E penetration. This is primarily because they take away the limits imposed to the maximum instantaneous VRES-E penetration, which persist when the on-line reserve capacity is provided by generation technologies. This way, they allow to reduce curtailment, reducing the need for VRES-E capacity to meet the renewable target. Moreover, the energy capacity developed to provide these reserves can be used to store otherwise curtailed renewable energy when it is not need for reserve provision, further reducing the VRES-E capacity need. Second, it shows how important it is for storage technologies to be able to compound several sources of added value so that they can warrant investment. Therefore, it is crucial to consider the operating reserve requirements in a planning model if the added value of storage is to be assessed accurately. Not doing so means underestimating the added value of storage technologies. Only providing firm capacity and residual load curve smoothing does not generate sufficient added value to generate significant investment. However, compounding this added value with that of reserve provision turns the storage technologies into cost-effective investment options.

Finally, it has to be noted once more that part of the added value generated here by storage technologies could also be generated by demand response technologies. Such technologies could also provide firm capacity, smoothen the residual load curve, and provide reserve capacity; all by shifting consumption appropriately. There is great potential in e.g. the coordinated charging of electric vehicles, the coordinated use of heat pumps, etc. It becomes clear from the results here, however, that the key determining factor for the future development of such potential will be the ability to provide these services cost-effectively. For example, in the results above investments shift from the High Peak technology to the PHES+ technology, as the former loses its role as the main upward mFRR provider. Even though the PHES+ capacity is slightly more expensive for providing this reserve capacity, it is able to use its capacity for other purposes as well, making it the more attractive investment option. Thus, besides striving for competitive power and energy costs, one of the main challenges to realize significant deployment for flexibility providers will be to find a way to compound several sources of added value.

5.3 Demand response

5.3.1 Introduction

The second alternative source of flexibility to be evaluated is demand response. As was discussed in Section 2.4.5, distinction is made between what is called short-term and long-term demand response. The former points to demand response that shifts demand over hours or days, typically in sync with daily cycles of consumption: e.g. residential electricity demand, industrial cooling sites, etc. As mentioned before, during this PhD over the course of two Master Theses a modeling approach was developed to represent one such type of short-term demand response, namely the flexibility of residential electricity demand (which includes the flexibility of EVs, HPs, etc.). Details of this work can be found in [198, 199, 200]. Results from this work showed that, from an operational perspective, such short-term demand response offers similar flexibility as energy storage. In the previous section reference was made to these similarities where appropriate. Therefore, it is deemed more interesting here to focus on a type of demand response that offers flexibility in a different way, namely long-term demand response.

Long-term demand response (LTDR) points to demand response that is able to shift demand over longer periods (i.e. weeks, months). A typical example of the kind of electricity demand that can offer such LTDR is that of the manufacturing industry. This kind of demand can, within the limits of the economic constraints in which it operates, increase its consumption of electricity during moments where (renewable) energy is abundant, e.g. moments of high solar output in summer; and reduce its consumption during moments where (renewable) energy is more scarce, e.g. a cold-spell in winter. As such, these processes are able to store energy in finished goods. Such flexibility can be especially interesting for power systems with high VRES-E penetrations, where the energy availability depends strongly on meteorological conditions. Instead of having to rely on e.g. back-up generation to bridge these cold-spells, demand could in theory be reduced structurally via LTDR.

It is very hard to determine the economic factors of an LTDR technology from an outside perspective. Take, for example, a manufacturing process. The average capacity factor of the process has an important impact on the demand response potential. If the site has been designed to run almost continuously at full capacity, then reducing demand during a certain moment, would mean that demand would need to be increased at other moments (if total output would need to remain constant). The most extreme example would be a site that runs at twice its current full capacity during the summer, and at zero capacity during winter (instead of full capacity throughout the entire year). This would incur additional CAPEX, as additional process capacity would need to be developed. The cost hereof is obviously very process-dependent, and data on such costs is hard to find. Moreover, shifting demand itself could incur costs, e.g. OPEX related to personnel costs or use of other resources. Also such costs are process-dependent and hard to estimate. Therefore, no economic parameters will be assumed for the included LTDR technology. Rather, the technology's flexibility will be available for free (i.e. $C_d^{\mathrm{inv,d}} = 0$), and the cost savings it realizes will be evaluated. This provides insight into what the mobilization of such flexibility can cost at most for it to be cost-effective.

The short-term operation of the LTDR technology is modeled as a dispatchable off-take, i.e. in the same way as the charging of a storage technology. A conservative estimate is used for the dynamics of the process: a minimum off-take level of 50% of the capacity ($P_d^{\mathrm{min,o}} = 50$), an hourly ramping rate of 10% ($R_d^{\mathrm{s,o}} = 10$), a minute ramping rate of 0.5% ($R_d^{\mathrm{m}} = 0.5$), and a minimum

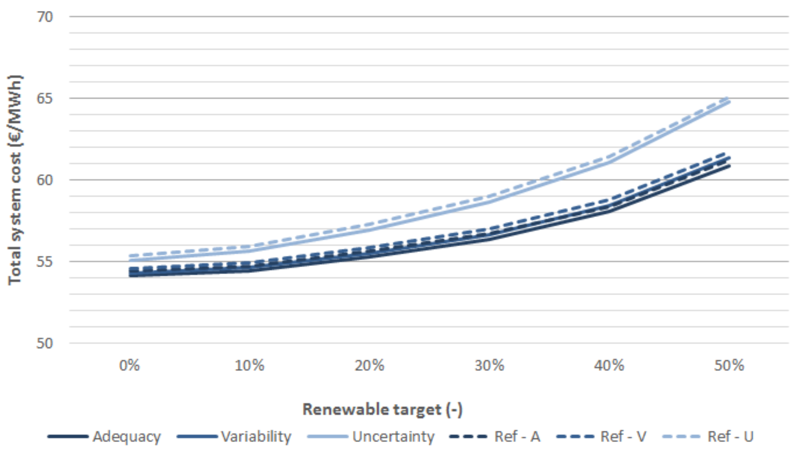

Figure 5.9: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the demand response and the reference scenarios.

up and down time of 12 hours ($T_d^{\mathrm{mut,o}} = T_d^{\mathrm{mdt,o}} = 12$). A total capacity $p_{z,d}^{\mathrm{cap,o}} = 550$ MW is assumed to be available, with a reference consumption $\forall t \in \mathbb{T} : P_{z,d,t}^{\mathrm{d,ref}} = 500$ MW. The operation of the LTDR technology is further constrained by the equations presented in Section 3.4.5. The technology has to at least consume its annual reference consumption ($M_d^{\mathrm{min}} = 1.00$), and can exceed that consumption by at most 5% ($M_d^{\mathrm{max}} = 1.05$). In this analysis, only the activation of downward flexibility is constrained, as this is judged to be the most crucial for dealing with moments of low VRES-E output. The use of the downward flexibility is constrained as such: $\Delta P_{d,t}^{\mathrm{dn}} = 500$ (meaning a full shut down is possible), $\Delta E_d^{\mathrm{dn}} = 12\,000$ (equivalent to a full shut down for 24 hours), and $H_d^{\mathrm{dn}} = 168$ (meaning that at most one full activation is allowed per week). Finally, at most 8 full activations can occur per year ($A_d^{\mathrm{dn}} = 8$), meaning that 96 GWh of flexibility is available in total (0.11% of the total demand). A detailed analysis on the influence of the number of activations in [216] showed that for this technology and this test system around 80% of the maximum cost savings could be realized with 8 activations (compared to an unconstrained use of the LTDR technology's flexibility). This article further includes sensitivity analyses on the values of $\Delta P_{d,t}^{\mathrm{dn}}$, ΔE_d^{dn} and H_d^{dn}, and how they influence the performance of the LTDR technology. These will not be discussed here.

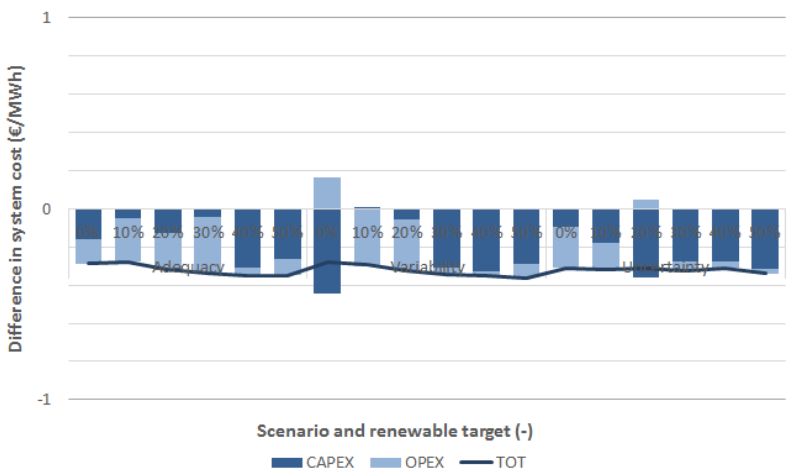

Figure 5.10: Difference in total system cost expressed in €/MWh of total demand for demand response scenarios, compared to the reference scenarios.

5.3.2 The impact on system cost

Similarly as in the previous section, the outcome of the three scenarios with additional flexibility – now from the LTDR technology – is compared to the outcome of the three reference scenarios. Figure 5.9 shows the total system cost for these six scenarios. As in the case of the storage scenarios, the three demand response scenarios have a lower total system cost than the reference scenarios. However, in this case the cost savings are more or less independent of the scenario. This is very different from the storage scenarios, where much more significant savings could be realized in the *Uncertainty* scenario compared to the *Adequacy* and *Variability* scenarios. The cost of the *Adequacy* scenario rises from 54.1 €/MWh to 60.9 €/MWh. In the *Variability* scenario total system cost rises from 54.3 €/MWh to 61.4 €/MWh. Finally, in the *Uncertainty* scenario total system cost rises from 55.1 €/MWh to 64.7 €/MWh.

Figure 5.10 breaks down the total system cost savings into CAPEX and OPEX savings. Savings increase slightly as the renewable target increases, but never surpass 0.4 €/MWh in any of the scenarios. There are no significant differences between scenarios. Almost all of the cost savings of this type of demand response can already be detected in the *Adequacy* scenario. This suggests that main added value is linked to ensuring system adequacy cost-effectively, be it by providing firm capacity or by facilitating a more economic operation of the

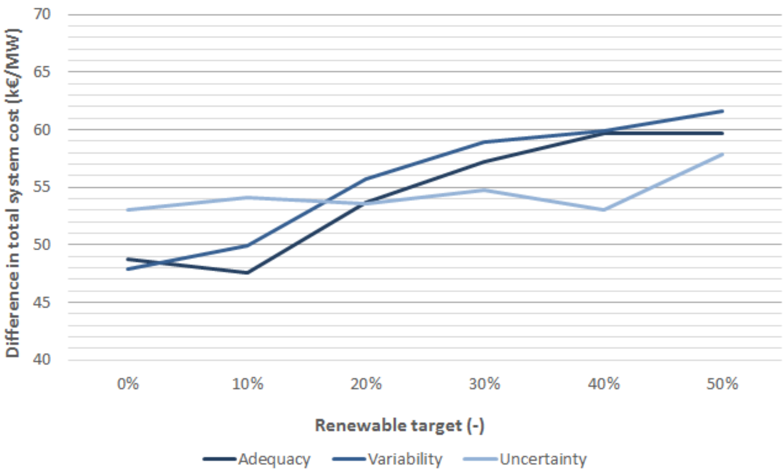

Figure 5.11: Difference in total system cost expressed in €/MW of available demand response capacity between the demand response and reference scenarios.

generation technologies. The make up of the cost savings do not show a very clear pattern when it comes to CAPEX vs. OPEX. On average, they are made up mostly of CAPEX savings. Especially for high renewable targets the savings are predominantly realized through a decrease in CAPEX across all scenarios.

Only evaluating the total system cost savings is not fully correct, as only a limited potential is available. It is more correct to evaluate these cost savings per MW of available demand response capacity; that is to divide the annual total system cost savings by the demand response capacity of 500 MW. This then presents the value of that capacity for the test system. Figure 5.11 shows this form of expressing the cost savings. For all scenarios the savings range between 47.6-61.6 k€/MW. In the *Adequacy* and *Variability* scenarios the value of the LTDR technology increases as the target increases, by 22% for the former and 29% for the latter; in the *Uncertainty* scenario it remains more or less constant. At low targets, the value of firm capacity in this test system is simply linked to the cost of the cheapest options for capacity: the 41.1 k€/MW for PHES power capacity, or the 46.8 k€/MW for High Peak capacity. At these targets the LTDR technology provides firm capacity, but the fact that the savings it realizes are bigger than these costs, shows that it does more than just providing firm capacity. It also adjusts its consumption to smoothen the residual load curve, i.e. it provides some “short-term demand response services”. The analysis following hereafter will discuss this in more detail. At high renewable targets, the value of firm capacity increases. Essentially, the High Peak technology becomes a less attractive option because it requires the generation of non-renewable electricity. The PHES technology would still be cheaper purely in terms of capacity, but given its limited energy capacity – which is strained ever more at higher renewable targets – the value of the LTDR technology is higher. In the first two scenarios, also the value of the short-term demand response services increases, albeit less strongly than the firm capacity value (see Section 5.3.4). In the *Uncertainty* scenario, however, this is not the case. The LTDR technology – given its assumed operational parameters – is not very adept at providing reserves. This means that it does not succeed in deferring investments in the High Peak technology and – more importantly – in the PHES technology. The latter provides the "smoothing" services when it is not providing reserves, reducing the added value of this service for the LTDR technology. Hence, its value remains more or less constant.

5.3.3 The impact on investments

Given the relatively small shifts in investments, it is not very interesting to look at the total installed capacities. Rather, the difference in installed capacity will be discussed straight away. These differences are shown in Figure 5.12. The values shown for the demand response technology (denoted by *DR* in the figure), are the maximum occurring values of downward flexibility activation. For the first two scenarios these are slightly smaller than 500 MW for low targets, but the full 500 MW at higher targets, indicating once more how the capacity value increases. The other values in this figure further confirm the fact that the LTDR technology's main added value comes from providing capacity: it replaces High Peak capacity and reduces load shedding. Averaged over the renewable targets, the 500 MW of LTDR capacity reduces the total dispatchable capacity and load shedding by 385 MW, 354 MW and 466 MW in the *Adequacy*, *Variability* and *Uncertainty* scenario, respectively. The fact that this is slightly lower for the *Variability* scenarios than for the *Adequacy* scenario points to the increased reliance on the short-term demand response services in the former scenario, brought about by the introduction of the hourly dispatch constraints. The figure further shows small shifts of Mid to Base capacity, thanks to such smoothing of the residual load curve, and some more or less capacity neutral shifts in VRES-E capacity. These latter shifts are most likely related to the synergies between the used load and VRES-E profiles and the way in which the LTDR technology is able to shift its consumption in these cases.

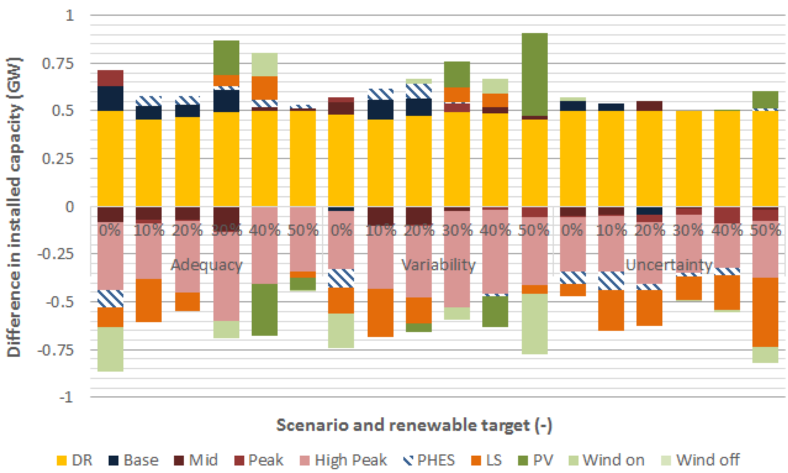

Figure 5.12: Difference in installed power capacity in GW between the demand response and reference scenarios.

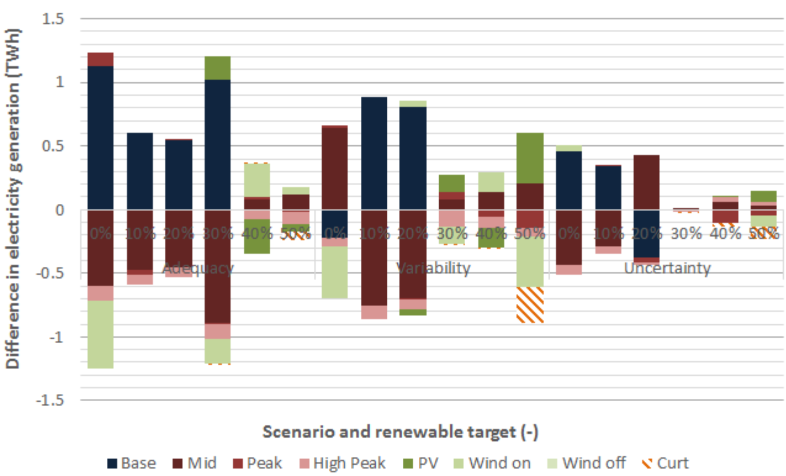

Figure 5.13: Difference in annual electricity generation and curtailment in TWh between the demand response and reference scenarios.

5.3.4 Energy and reserve provision

Again, given the relatively small shifts in electricity generation, it is more interesting to look at the differences in annual electricity generation, rather than at the total generation. Therefore, Figure 5.13 shows these differences. Firstly, this figure confirms a tendency already discussed in the section on storage: the introduction of more flexible technologies facilitates the operation of the less flexible technologies. Secondly, it shows that the LTDR technology effectively reaps this benefit of smoothing the residual load curve, what can be said to be a typical "short-term demand response service". As the activation of downward flexibility (i.e. reducing consumption) is constrained, this happens mostly by carefully planning the moments of overconsumption. Finally, the figure also reveals how the added value of such smoothing becomes less important relative to the added value of providing capacity as the renewable target increases via the decreasing shift in electricity generation. In the *Uncertainty* scenario the electricity generation shifts are also smaller to begin with, as the need for capacity is higher in this scenario, even at low targets.

It is not very interesting to present the figures of the up- and downward reserve provision, as they barely change from those of the reference *Uncertainty* scenario. Reserve provision by the LTDR is very limited and more or less constant over the different renewable targets. On average it provides 1 MW, 3 MW and 15 MW of upward FCR, aFRR and mFRR, and 0 MW, 0 MW and 3 MW of downward FCR, aFRR and mFRR, respectively. Given that this might even be an overestimation (as this capacity is not counted towards the maximum number of activations), it is clear that this is not a great source of value. Admittedly, this is definitely influenced by the conservative assumptions in terms of the dynamics of the consumption process; but in general it makes sense that the optimal use of a relatively large amount of capacity that can only be activated sporadically lies in strategically reducing electricity demand during moments of severe supply shortages.

5.3.5 Discussion

This section has looked at an example technology of a second type of alternative source of flexibility, namely demand response. The technology under consideration, a representation of a manufacturing process, was labeled a long-term demand response technology, because of its theoretical ability to shift demand over long periods of time (i.e. over the entire year). As such, it can structurally reduce its demand for a prolonged period, which helps the power system overcome moments of low electricity availability, e.g. during a cold spell (i.e. moments of low VRES-E output). This suggests that this kind of flexibility's main asset is the provision of firm capacity, the value of which would only increase as the VRES-E penetration increases and such cold spells become more important. These expectations were confirmed by the results. Essentially all of the technology's benefits could be captured in the *Adequacy* scenarios, telling us two things. First, it tells us that for this technology it is less important to consider all short-term flexibility constraints to be able to assess its value. Nevertheless, introducing these constraints did alter the added value of the technology in the *Uncertainty* scenario. While limited in this case, the impact hereof could be more important in some cases. Second, it tells us that indeed the technology's main added value comes from its ability to provide firm capacity. The introduction of the LTDR technology mainly allowed to reduce investment in other firm capacity options, here notably the High Peak technology, and to reduce load shedding.

Nevertheless, the added value of this technology – whose flexibility was available for free – was higher than the capacity cost of its alternatives. This is because, especially at low renewable penetrations, it was able to generate additional added value. Restricted in its number of downward activations (i.e. decreased consumption), part of these activations were indeed used to overcome cold spells, but the remaining downward activations and the upward activations (i.e. increased consumption) were used to provide typical "short-term demand response services": smoothing of the residual load curve. Once more, this shows the importance for flexibility providers to compound multiple sources of added value. Eventually, the available 500 MW of the LTDR technology managed to generate total system cost savings of up to 0.4 €/MWh, independent of the scenario. In absolute values, this is rather modest. However, evaluated per MW of available LTDR capacity, this comes down to 48-62 k€/MW of total system cost savings per year. Consumption processes that can provide this kind of flexibility at a cost lower than these savings, would be a cost-effective flexibility option for this test system.

As the underlying consumption process was assumed to not be very dynamic, the contribution of the LTDR technology to operating reserves was very limited. This means that additional value could be generated by a process or technology that is able to adjust its level of demand more dynamically in function of system conditions. However, considering the fact that this kind of flexibility would mostly be found in the industrial sector, it is not unlikely that process operators would prefer a limited number of activations (i.e. deviations from their planned operating schedule). Then it is sensible to expect that the optimal use of such capacity, restricted in its number of activations, is probably the strategic reduction of net electricity demand during moments of low supply availability.

Table 5.3: Table presenting the cost outcomes of Zone A and B for the reference scenarios over the 0-50% renewable target range. Scenario costs are in €/MWh of total demand; profile and balancing costs are in €/MWh of RES output.

	Adequacy	Variability	Uncertainty	Reconfig.	Flexibility	Flexibility & Balancing
Zone A	54.4 - 61.2	54.6 - 61.7	55.4 - 65.1	3.2 - 13.6	0.2 - 0.7	2.6 - 5.9
Zone B	55.8 - 61.7	56.0 - 62.4	56.7 - 69.5	4.4 - 11.9	0.3 - 1.0	5.7 - 13.8
Joint	55.2 - 61.5	55.4 - 62.1	56.1 - 67.6	3.9 - 12.6	0.3 - 0.8	4.4 - 10.4

5.4 Interconnection

5.4.1 Introduction

The third and final alternative source of flexibility to be studied is interconnection. Therefore, a second zone is introduced. So far, all analyses have been performed for a single zone whose characteristics are based on the Belgian power system – hereafter referred to as Zone A – with input data gathered from the Belgian TSO ELIA. Now, a second zone – hereafter referred to as Zone B – is included in the optimization, with characteristics based on the Dutch power system (i.e. the time series of demand, VRES-E output and forecast errors, etc.) and input data gathered from the Dutch TSO TenneT. For this zone, also the reference situation has to be known, i.e. the outcome of the *Adequacy*, *Variability* and *Uncertainty* scenarios with only the flexibility of generation technologies and a PHES technology (also with 6 GWh of energy capacity available at 5 €/kWh). Appendix B presents these results for Zone B in detail. The cost-related results for the two zones, separately and joint, are summarized in Table 5.3. These results show that, while comparable on other aspects, the renewable uncertainty in Zone B is significantly larger than in Zone A. Whether this is because the uncertainty is actually larger (because of meteorological conditions or forecasting techniques), or because there is an issue with input data (different reporting techniques, etc.) is unclear. In any case, these data will be used as they are for the remaining analyses. For these analyses, the portfolios of both zones are optimized jointly under a joint renewable target (i.e. the zones do not need to meet the target separately, only jointly).

Interconnection has a two-fold impact on short-term flexibility. Firstly, it reduces the need for flexibility by smoothing both variability and uncertainty over a larger area. Capturing the influence on variability is straightforward: adding exchange variables in the balance equations allows the two zones to couple their residual load curve to the extent allowed by the interconnection capacity

Table 5.4: Table presenting the exogenous reserve component in MW for Zone A and B and joint sizing.

	Upward			Downward		
	FCR	aFRR	mFRR	FCR	aFRR	mFRR
Zone A	100	249	751	100	249	751
Zone B	120	287	713	120	287	713
Joint	220	389	234	220	389	257

(determined endogenously). Capturing the influence on uncertainty is less straightforward. This means reevaluating the sizing of the reserves. Normally, the imbalance data of the two zones would be convoluted. In this context, this is not possible as the absolute size of the imbalances is not known beforehand, more specifically imbalances driven by VRES-E forecast errors. Therefore, to be able to formulate a set of joint reserve requirements – as described by equations in Section 3.4.7 – again a distinction is made between renewable and other uncertainty (or endogenously and exogenously sized reserves). For the exogenous component, the FRR are sized by convoluting absolute imbalance data and subjecting the outcome to a probabilistic assessment. The deterministic assessment is only performed on the zonal level. FCR are kept constant. The resulting reserve requirements are presented in Table 5.4. Recall that these reserves are sized on annual basis, but allocated on a monthly basis. Recall also that the equations of Section 3.4.7 ensure that each zone contracts enough reserve capacity to meet the reserve requirements following sizing on the zonal level, be it by contracting capacity within the zone itself or by importing it. So, e.g. while the joint downward mFRR requirement is only 257 MW, Zone A needs to contract at least 751 MW, and Zone B 713 MW of downward mFRR.

For the renewable uncertainty, a convolution of forecast errors is not possible, as this depends on the installed VRES-E capacity. Nevertheless, an approach is proposed which should be able to capture some of the benefits of joint sizing. The normalized forecast error data of both zones is convoluted per VRES-E type to arrive at what can be seen as a description of the uncertainty of the joint renewable resource. On the supra-zonal level, this is then the uncertainty that has to be dealt with. A probabilistic assessment is performed, resulting in the FRR requirements depicted in Figure 5.14. Recall the dual sizing approach: the "TSO" component, allocated on a monthly basis, and the "BRP" component, allocated on an hourly basis. This figure immediately shows the shortcomings of this method. For example, the FRR requirements for onshore wind are greater in Zone B than in Zone A; the joint FRR requirement lies somewhere in between. Now, when a MW of onshore wind capacity is installed in Zone A more reserve

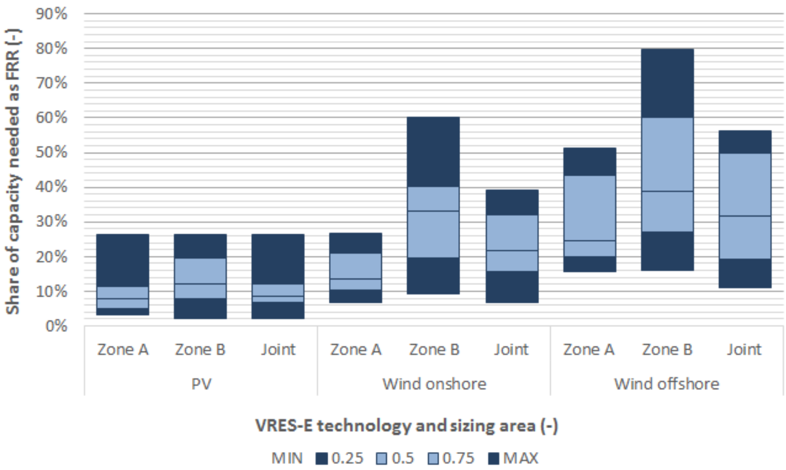

Figure 5.14: Box-plots of the FRR need for PV, and on- and offshore wind uncertainty for Zone A and B, and joint sizing as a percentage of capacity.

capacity has to be contracted (to meet the joint requirement) than when Zone A is considered separately. Essentially, when considering both zones jointly instead of separately onshore wind capacity in Zone A will become relatively more expensive, and in Zone B less expensive. Nevertheless, VRES-E capacity growth is expected in both zones, which will partly relieve this impact.

The second impact of interconnection is that it increases the supply of flexibility. To enable such cooperation between power systems, interconnection capacity is needed. The cost of interconnection capacity between the two zones is set at 25 k€/MW/year. This cost is calculated using the formulas of [217]. It is representative for the costs of a 1 000 MVA connection, realized either as a two circuit 400 kV AC underground cable connection of 150 km, or as a one circuit 320 kV DC underground cable connection of 300 km. In both cases installation costs and any converter costs are included, and a life time of 50 years and discount rate of 5% are assumed. In the *Adequacy* and *Variability* scenario, such capacity facilitates exchanges in the balance equation. In the *Uncertainty* scenario, reserves can also be exchanged following the equations of Section 3.4.7. For this reserve exchange, the parameter F^{r} is determined, which sets the fraction of the exchanged reserve capacity for which nominal interconnection capacity has to be reserved – thus taking into account possible temporary overloading during reserve activation. For the analysis performed here, $F^{\mathrm{r}} = 25\%$, meaning that 25% of reserve capacity has to be counted.

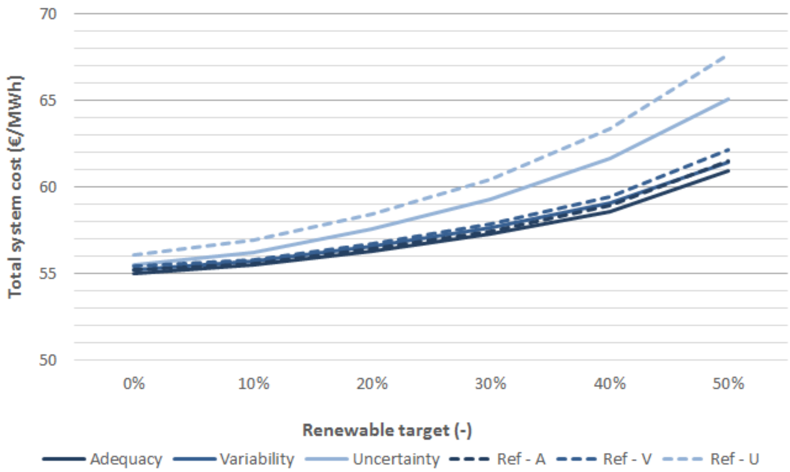

Figure 5.15: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for interconnection scenarios and the reference scenarios.

5.4.2 The impact on system cost

Figure 5.15 presents the total system cost of the interconnection and reference scenarios (the latter are the sum of the reference scenarios of Zone A and B). Developing interconnection capacity clearly reduces the total system cost: all interconnection scenarios have a lower cost than their corresponding reference scenario. The cost of the *Adequacy* scenario rises from 55.0 €/MWh to 60.9 €/MWh as the renewable target increases. Introducing hourly dispatch constraints means that cost in the *Variability* scenario rises from 55.2 €/MWh to 61.4 €/MWh. Finally, introducing operating reserve requirements in the *Uncertainty* scenario means that cost now increases from 55.5 €/MWh to 65.1 €/MWh. The cost savings in this final case are visibly larger than in the other two cases, ranging up to 2.5 €/MWh for the 50% target.

Figure 5.16 shows the breakdown of the cost savings driven by interconnection. In the three scenarios, the tendency at low renewable targets is similar: an increase in CAPEX, which is compensated by a decrease in OPEX. The increase in CAPEX comes from investment in interconnection capacity and a shift in investments from Mid to Base capacity, as will be discussed further below. This shift in investments is also the main driver of the decrease in OPEX. At high renewable targets the total CAPEX remain constant or decrease: the investment in interconnection capacity is compensated by decreased investments in other

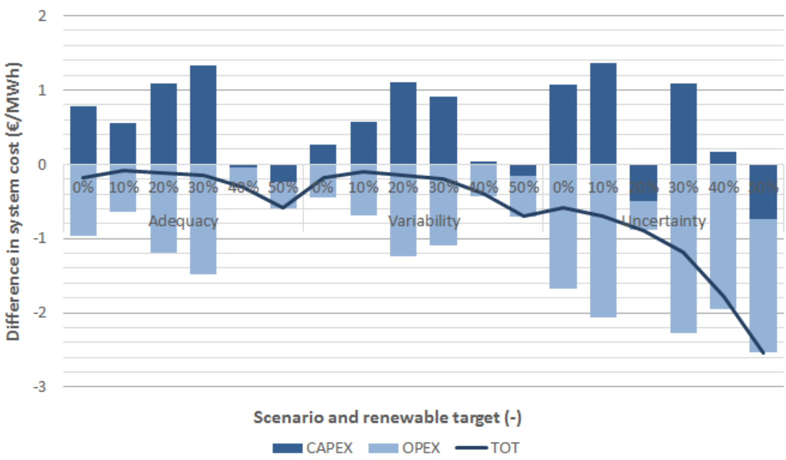

Figure 5.16: Difference in total system cost expressed in €/MWh of total demand for the interconnection scenarios, compared to the reference scenarios.

technologies, as will also be discussed below. The decrease in OPEX then leads to even higher total system cost savings. In the *Adequacy* scenario at low renewable targets these dynamics lead to modest cost savings; no more than 0.2 €/MWh. At high renewable targets, the effect is slightly more pronounced, with cost savings ranging up to 0.6 €/MWh for the 50% case. Firstly, interconnection has a modest contribution to firm capacity adequacy, as will be shown when discussing investments. Secondly, it allows the two zones to combine their residual load curves, creating a more smooth total residual load curve; an impact that is more pronounced at higher renewable targets. The absolute values of the cost savings obviously depend on the adopted economic parameters. In the *Variability* scenario, cost savings are very similar, ranging up to at most 0.7 €/MWh. This indicates that the flexibility costs do not motivate significant additional interconnection capacity investment. Cost savings in the *Uncertainty* scenario are much more important, ranging between 0.6-2.5 €/MWh. This indicates that there is great value for interconnection capacity to help deal with balancing costs, something that is also clearly reflected in the investments.

5.4.3 The impact on investments

Figure 5.17 shows the investment portfolios for the three scenarios summed over the two zones. In the first two scenarios, total dispatchable capacity is around 30 GW, with a slight decrease as the renewable target increases. This is on average 300-400 MW less than in the reference *Adequacy* and *Variability* scenarios. Total renewable capacity increases from 0.5 GW to about 52 GW for the 50% case; which is at most about 1.2 GW less than in the corresponding reference scenarios. Investment in interconnection capacity in these two scenarios ranges up to 2.2 GW and 2.3 GW, respectively, denoted by "Int" in Figure 5.17. In the *Uncertainty* scenario, there is significantly more investment in interconnection capacity; ranging up to 4.1 GW. This additional investment is driven by the capacity reductions that it can enable. Total installed dispatchable capacity increases from 31 GW to 39 GW; and while that is an important increase, it is 1.8 GW up to 6.0 GW less than in the reference *Uncertainty* scenario. Moreover, total renewable capacity, which rises from 0 GW to 53 GW, is also up to 2.5 GW lower.

Figure 5.18 shows the difference in investments. Tendencies in the *Adequacy* and *Variability* are very similar, confirming that including the hourly dispatch constraints does not generate much added value for interconnection. At low renewable targets, there is a shift from Mid to Base capacity. At intermediate targets this is accompanied by some additional High Peak capacity, which helps meet peak demand and reduces PHES capacity and load shedding. For these targets there is also a small shift from onshore wind to PV capacity. Apparently, now that the output can be spread over a larger system, the PV technology becomes more cost-effective. Investment in interconnection capacity is around 0.5 GW for lower targets, more than doubling towards the 50% case.

The *Uncertainty* scenario shares most of these tendencies, but additionally shows a major reduction in PHES and mostly High Peak capacity. At low renewable targets, investments shift from Mid to Base capacity, and there is 2 GW less PHES and High Peak capacity, and load shedding. This reduction becomes even greater at high renewable targets, ranging up to 5.5 GW. Additionally, there is less VRES-E capacity. For the 0% case, this is because that capacity is now relatively more expensive (due to joint sizing, see discussion above). At high targets, this is because the interconnection capacity reduces curtailment. Investment in interconnection capacity is also more important, starting around 0.8 GW and increasing up to 4.1 GW. The ability to share reserve power is clearly an important driver of investments in interconnection capacity. This raises the question as to how dependent these outcomes are on the parameter F^{r} (set here at 25%). Therefore, the 50% case was reevaluated with $F^{\mathrm{r}} = 100\%$. This caused system cost to increase by less than 0.1 €/MWh and investment in interconnection capacity to actually increase to 4.5 GW. Clearly, the possible reductions in capacity motivate paying the cost of the interconnection capacity. Even when that cost doubles, system cost increases by no more than 0.5 €/MWh and investment in interconnection capacity is still 3.2 GW.

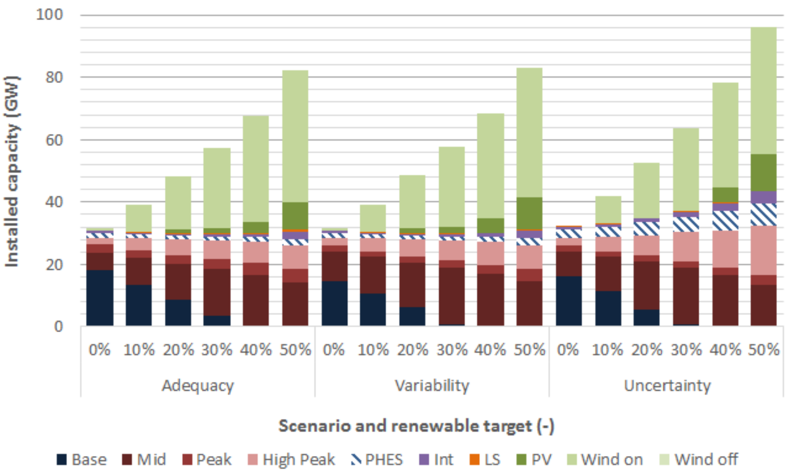

Figure 5.17: Installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario for the different renewable targets.

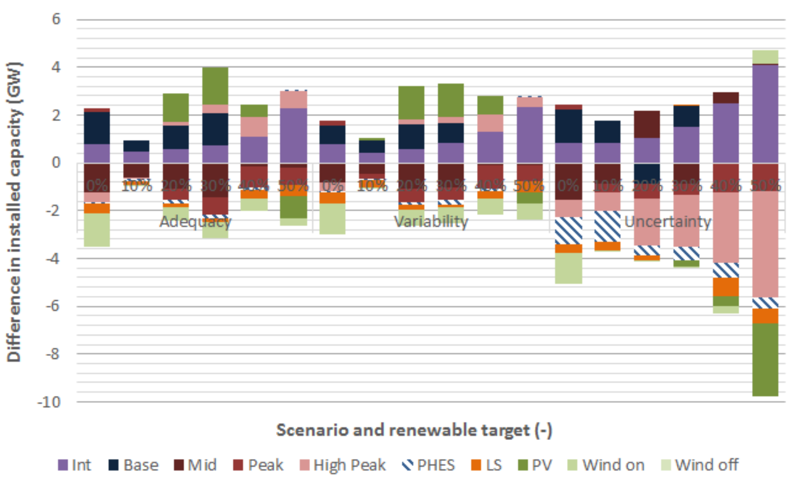

Figure 5.18: Difference in installed power capacity in GW for the interconnection scenarios, compared to the reference scenarios.

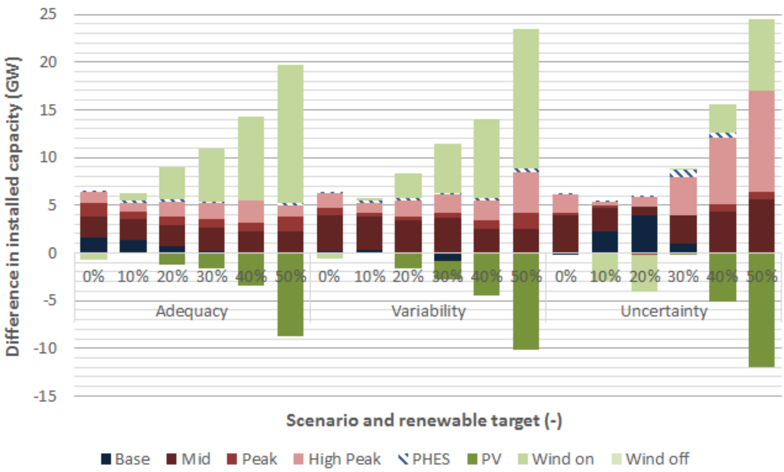

Figure 5.19: Difference in installed power capacity in GW between Zone A and B for the interconnection scenarios. Positive values mean additional capacity in Zone B, and vice versa.

Finally, it is interesting to look at how capacity is spread over the two zones. Figure 5.19 shows the difference in installed capacity between the two zones, with positive values indicating capacity of which there is more in Zone B than in Zone A, and vice versa. There is about 5 GW of dispatchable capacity more in Zone B than in Zone A, which is about the difference in peak demand. In the *Uncertainty* scenario this is more, driven mostly by an increase in High Peak capacity. This is linked to the higher uncertainty that characterizes the onshore wind resource of Zone B. This uncertainty also drives a shift in VRES-E capacity investment. In the first two scenarios installed VRES-E capacities are more or less the same compared to a situation where the renewable target would be imposed per zone rather than for the two zones jointly. In Zone A, the target is met by a mix of onshore wind and PV capacity; in Zone B exclusively by onshore wind capacity. That is why the onshore wind capacity increases faster in Zone B than in Zone A. This trend, however, is almost fully reversed in the *Uncertainty* scenario. The annual yield of the onshore wind resource in Zone A may be lower than in Zone B, but so is its uncertainty. That is why in this scenario, much more capacity of this resource is developed. A resource's uncertainty thus also becomes an important factor in its overall cost-effectiveness.

5.4.4 Energy and reserve provision

The tendencies in energy and curtailment patterns are similar to those discussed in the previous sections. Compared to the reference scenarios, when introducing interconnection there is a shift of 5-10 TWh of Mid to Base generated electricity and a reduction in curtailment at higher renewable targets. This increased Base operation and uptake of VRES-E output is made possible by the interconnection capacity, which smooths the joint residual load curve by linking the separate residual load curves.

A more interesting picture is painted by Figure 5.20, which presents the average upward reserve allocation. The full lines in this figure indicate the total allocated reserve capacity. The dashed lines indicate the limits within which it must stay. The lower limit is set by the joint requirements; the upper limit by the sum of the separate requirements (for the upward FCR these lines coincide). The FCR provision is more or less the same as in the reference scenario, albeit with a slightly more important role for the Mid technology: the interconnection capacity allows it to increase its full load hours, thus making it available more often to provide reserve power. The same can be said for the provision of the aFRR. Here, the limits are close; the joint sizing does not lead to much lower requirements. It does do so for the mFRR. The reserve sharing is not pushed to the lower limit, but e.g. for the 50% case on average 1.8 GW less reserve capacity is held. It is, however, not this average that is most important. For that same case at most 4.1 GW of upward FRR is exchanged, which is exactly the amount of interconnection capacity available; and thus clearly the driving factor for the investment in that capacity.

Figure 5.21 presents the average downward reserve allocation. Again, the mix of reserve providers does not change much. What does change – in the case of the downward FRR – is the total capacity held on average. For the aFRR at high renewable targets this is the lower limit, set by the joint requirements. At low targets, it is slightly higher, showing that there is too much downward reserve power available to motivate further investments in interconnection capacity to bridge this gap. That same tendency is present in the provision of downward mFRR. However, here the lower limit is not set by the joint reserve requirement, but by the separate requirement of Zone A, which imposes that at least 751 MW of downward mFRR has to be available. Clearly, also in the case of downward reserve provision, the interconnection capacity provides clear added value by allowing significantly less reserve capacity to be held.

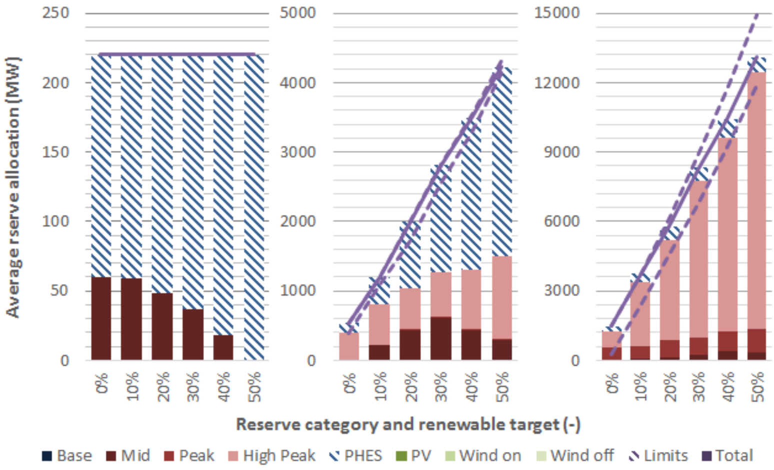

Figure 5.20: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

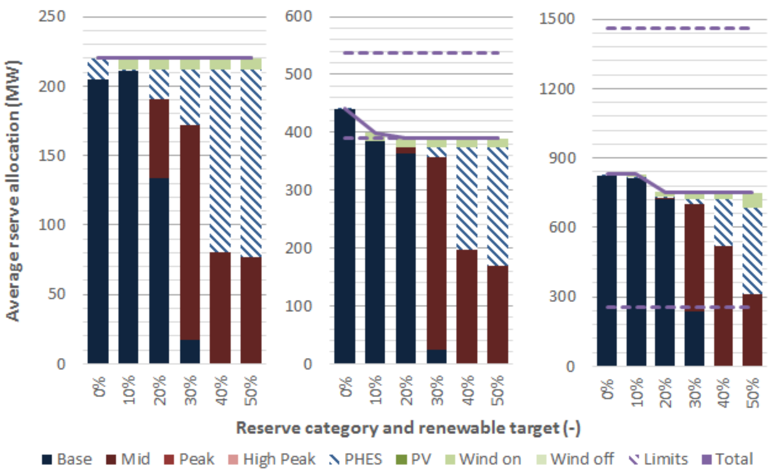

Figure 5.21: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

5.4.5 Discussion

This section has looked at a third and final type of alternative source of flexibility, namely interconnection. By connecting different control zones, interconnection capacity can increase the supply of flexibility and reduce the need for flexibility within a zone. The results of the *Adequacy* scenario showed the reference against which these flexibility exchanges can be evaluated. In this scenario, the interconnection capacity allows for an exchange of firm capacity, mostly through a reduction in load shedding, and in part also through a minor reduction in peak capacity. Essentially, when capacity is scarce in one zone, there might be some capacity available in another zone. Interconnection capacity allows to export this surplus capacity to a zone with a capacity shortage. The most pronounced effect of interconnection capacity, however, was that of smoothing out variability. The combined residual load curve is smoother than the separate residual load curves. This allows to increase the full load hours of the (high CAPEX) low OPEX generation technologies, leading to an overall cheaper electricity production. These added values are well-known and captured by most power system planning models that consider interconnection.

Against this reference, the hourly dispatch constraints were included in the *Variability* scenario. This led to only slightly more investment in interconnection capacity, and only slightly higher savings. Admittedly, this is obviously linked to the fact that the flexibility costs – which make up the difference between the outcome of the *Uncertainty* and the *Variability* scenario – are not very high to begin with, so there is not a lot of potential to realize cost savings. Nevertheless, the hourly dispatch constraints do generate some additional added value for interconnection capacity. The flexible means are not always needed at the same time in the different zones, creating some potential for an exchange of their flexibility.

A more important increase in added value was seen when introducing the operating reserve requirements in the *Uncertainty* scenario. Firstly, cooperation between control zones in reserve allocation allows to reduce the total dispatchable capacity. The decisive moment for the need for capacity occurs at a different moment in the different zones – linked to moments of low VRES-E output. This means that when full upward capacity is needed in one zone (for both generation and upward reserve provision), there might be some surplus capacity in another zone. As in the *Adequacy* scenario, interconnection capacity then allows to share this surplus capacity, reducing the overall capacity need. Essentially, if several zones need a significant amount of upward reserve capacity to be activated only infrequently, it makes sense to share such capacity between zones. The amount of interconnection capacity installed to enable this exchange will then obviously depend strongly on the amount of upward reserve capacity –

or more generally back-up capacity – to be held; which in turn ties in with the discussion on the desired level of reliability held at the end of the previous chapter. Interconnection capacity, however, does not only allow to share upward reserve capacity, but also downward reserve capacity. As such, it can increase the maximum instantaneous VRES-E penetration. For example, if in one zone VRES-E output is low, then dispatchable generation capacity will be on-line and downward reserve capacity will be available. If at the same time in another zone VRES-E output is high – and consequently less conventional downward reserve power is available (i.e. non-variable), then downward reserve capacity can be imported over the interconnection capacity from the first zone, instead of forcing other downward reserve providers in the system, thus avoiding possible additional curtailment. The added value hereof for interconnection capacity will obviously depend on the extent to which downward reserve provision of VRES-E technologies is possible (related to the allocation horizon adopted within a control zone). Finally, if zones cooperate the allocation of their reserves, then they can also opt to jointly size their reserve requirements. This will result in less reserve capacity to be held in total, which might actually reduce the needed interconnection capacity compared to a situation where control zones perform their reserve sizing independently. Nevertheless, it does lead to additional total system cost savings.

5.5 Competing flexibility options

5.5.1 Introduction

To conclude the analyses of this chapter, the three alternative sources of flexibility are introduced jointly in the two-zone system. From the previous sections it has become clear that these alternative sources at times generate added value from the same services. Therefore, it is interesting to study what happens to the investment in these sources, and in the other components of the investment portfolio, when they are allowed to compete for the provision of the same services. The three storage technologies and the interconnection technology of Sections 5.2 and 5.4 are used as they are presented in these sections. For the demand response technology used in Section 5.3 a capacity cost is introduced (no energy cost is considered). Based on the added value of this technology as depicted in Figure 5.11 this cost is set at 55 k€/MW per year. 500 MW of the technology is available for investment in both zones. The same three scenarios discussed in all other sections will be evaluated here and compared with the three reference scenarios. They will be referred to further as the “flexibility” scenarios.

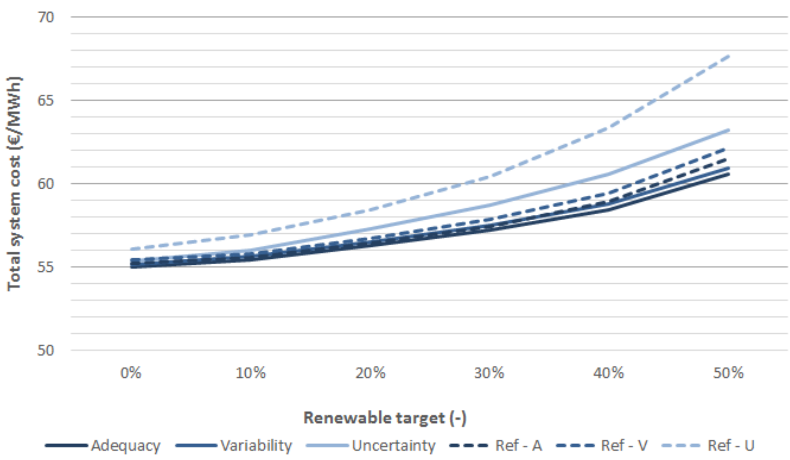

Figure 5.22: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the flexibility and reference scenarios.

5.5.2 The impact on system cost

Figure 5.22 presents the total system cost of the flexibility and reference scenarios. It is clear that the introduction of the technologies of the three types of alternative flexibility sources produces significant cost savings. The cost of the three flexibility scenarios is far below that of the corresponding reference scenario (see also Table 5.5). In the *Adequacy* scenario total system cost increases from 55.0 €/MWh to 60.6 €/MWh. This means that the reconfiguration cost is now 4.7-11.2 €/MWh$_{\text{RES}}$. As can be seen in Table 5.5, this is a reduction for high renewable targets. The fact that the lower boundary of the cost is a little higher has to do with the cost savings that are already present in the case with no renewable target (i.e. the 0% case). Thanks to the different flexibility options, this case can be realized at a lower cost than in the reference *Adequacy* scenario, due to an increased reliance on low-OPEX generation technologies. As a consequence, relatively more additional costs are incurred by the introduction of VRES-E capacity in the 10% case, which reduces the cost-effectiveness for the low-OPEX generation technologies.

The cost of the *Variability* scenario increases from 55.2 €/MWh to 60.9 €/MWh. This means that the flexibility cost is now -0.2-0.3 €/MWh$_{\text{RES}}$. The negative lower boundary is again due to the outcome of the 0% case. The flexibility options allowed to realize a very cost-effective investment portfolio for the 0% case of the *Adequacy* scenario through its reliance on the low OPEX generation

Table 5.5: Table presenting the cost outcomes of Zone A and B for the reference and flexibility scenarios over the 0-50% range. Scenario costs are in €/MWh of total demand; profile and balancing costs in €/MWh of RES output.

	Adequacy	Variability	Uncertainty	Reconfig.	Flexibility	Flexibility & Balancing
Reference	55.2 - 61.5	55.4 - 62.1	56.1 - 67.6	3.9 - 12.6	0.3 - 0.8	4.4 - 10.4
Flexibility	55.0 - 60.6	55.2 - 60.9	55.4 - 63.3	4.7 - 11.2	-0.2 - 0.3	3.2 - 5.5

technologies. Introducing the hourly dispatch constraints leads to a relatively higher cost increase for this case than for the 10% case, which already relied less on those technologies. Hence, the negative flexibility cost for the 10% case. Also for higher targets, the flexibility cost are reduced. Finally, in the *Uncertainty* scenario the total system cost increases from 55.4 €/MWh to 63.3 €/MWh. This means that the flexibility and balancing costs are now 3.2-5.5 €/MWh$_{\mathrm{RES}}$, which is again a significant cost reduction compared to the reference scenario.

Figure 5.23 shows the breakdown of the cost savings for the three flexibility scenarios. This breakdown predominantly follows the tendencies already present in the sections on storage and interconnection. At low renewable targets there is an increase in CAPEX, which is offset by a decrease in OPEX. As in those sections, this is mostly due to a shift in investment from Mid to Base capacity. This is made possible by the flexibility of the different alternative providers, which smooth the residual load curve so that more capacity of the less flexible Base technology can be installed. Once more the more flexible technologies facilitate the operation of the less flexible technologies. At high renewable targets the cost savings are realized by a decrease in CAPEX and a modest decrease in OPEX. Here, the flexibility providers' main impact is the reduction in investments in peak and VRES-E capacity, and the reduction of load shedding.

In the *Adequacy* scenario these dynamics lead to cost savings ranging between 0.1-0.9 €/MWh (a decrease of 0.3-1.5%). Investment costs of alternative sources of flexibility in this scenario (i.e. PHES+, BES, LTDR and interconnection capacity; there were no investments in P2G capacity) range between 0.3-0.7 €/MWh (0.5-1.2% of total system cost). At low and intermediate renewable targets shifts in CAPEX and OPEX are much larger than the final savings. The alternative flexibility providers can thus contribute to the two defining aspects of this scenario: firm capacity adequacy and residual load curve smoothing. They can, however, not do it much more cost-effectively than the options available in the reference scenario. At high renewable targets, when the value of firm capacity and the importance of reducing curtailment become greater, they have a bigger impact.

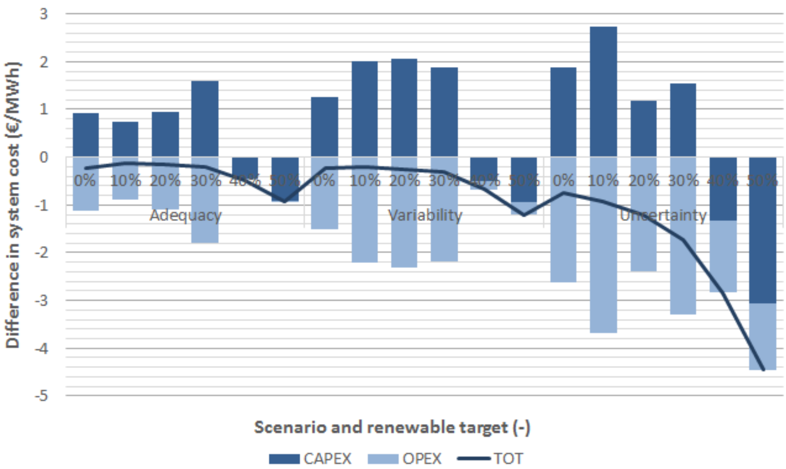

Figure 5.23: Difference in total system cost expressed in €/MWh of total demand between the flexibility and reference scenarios.

In the *Variability* scenario cost savings increase to between 0.2-1.2 €/MWh (0.4-2.0%). Alternative flexibility sources investment costs between 0.3-0.8 €/MWh (0.5-1.3%). At low and intermediate renewable targets shifts in CAPEX and OPEX are even greater than in the first scenario, but the final savings increase only marginally. This is obviously related to the fact that the flexibility costs are very low for these targets, meaning there aren't many additional savings to be realized. At higher targets flexibility costs are slightly larger, resulting also in higher savings.

Finally, in the *Uncertainty* scenario cost savings range between 0.7-4.4 €/MWh (1.4-6.9%), with alternative flexibility sources investment costing between 0.4-1.5 €/MWh (0.7-2.3%). At low and intermediate renewable targets final savings are now also important, mostly through greater OPEX savings. The alternative flexibility providers take over most of the reserve provision from the generation technologies, allowing the latter to operate more economically. At high renewable targets, they also drastically reduce investment in peak capacity following the dynamics discussed in the previous section. The difference in outcome between this scenario and the first two shows once more their strength in providing reserves and the importance for the alternative flexibility providers to be able to compound different sources of added value. Now – given the assumed cost structures – investment in an alternative source of flexibility can generate system cost savings of almost three times its investment cost.

5.5.3 The impact on investments

Figure 5.24 shows the total installed capacity for the three flexibility scenarios. What stands out immediately is that there is investment in all three types of alternative sources of flexibility in all three scenarios, with investment levels differing depending on the scenario. This shows that there is no "winner-takes-it-all" dynamic: while the providers compete for the same services, they offer a specific combination of sources of added value that cannot simply be replaced by providers of another type. However, the figure also shows that the exact level of investment depends strongly on the extent to which the providers are able to compound these different sources of added value. For example, the considered demand response technology is very adept at providing firm capacity, but less so at providing reserve capacity. As a consequence, investment in this technology is smaller in the *Uncertainty* scenario than in the *Adequacy* scenario.

Before looking at the difference in installed capacities between the flexibility and reference scenarios, it is interesting to zoom in on the installed flexible capacity, as presented in Figure 5.25. "Flexible" capacity refers to High Peak, PHES, PHES+, BES, LTDR and interconnection capacity, and the maximum occurring load shedding. The dashed grey line indicates the total flexible capacity in the reference scenarios, which is made up of High Peak (50-70%) and PHES (20-30%) capacity, and load shedding (2-10%). It is interesting to see that – again given the assumed cost structures – the total flexible capacity is more or less the same in the flexibility and the reference scenarios; even if the availability of interconnection does reduce the capacity need in the *Uncertainty* scenario. This shows once more how flexibility adequacy and firm capacity adequacy are closely linked, especially when considering operating reserve requirements. It also shows that the simplified approach for incorporating the impact of short-term flexibility constraints in power system planning models presented at the end of the previous chapter could be a valid approximation. Recall that this method omits the operating reserve requirements and simply imposes a total dispatchable capacity requirement, that would lead mostly to investment in High Peak capacity. That capacity would then be reevaluated in a dispatch and investment model with several flexibility options such as the one used in this work, while fixing all other generation capacities. Although obviously some of the added value of the different flexibility providers would be missed (e.g. residual load curve smoothing), this figure suggests that this High Peak capacity would indeed be a good estimate for the total flexible capacity need.

The difference in installed power capacity is shown in Figure 5.26. In the *Adequacy* scenario, the shift from Mid to Base capacity can be seen for low and intermediate targets. There is also less investment in High Peak capacity and a reduction in load shedding, mostly thanks to investment in LTDR capacity.

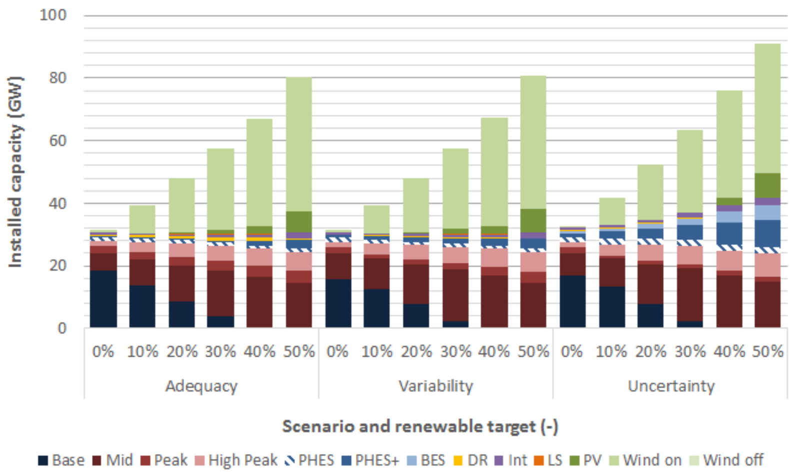

Figure 5.24: Installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

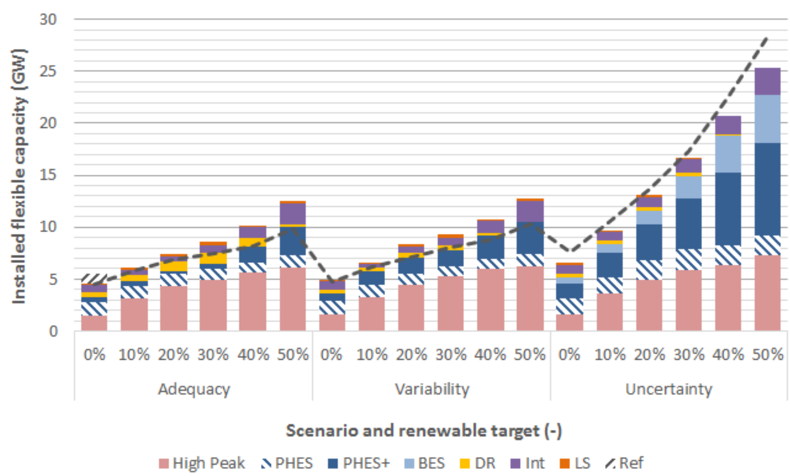

Figure 5.25: Installed flexible power capacity in GW for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

At high renewable targets increased investment in PHES+ and interconnection capacity allows to reduce load shedding and investment in High Peak capacity and in VRES-E capacity, thanks to a reduction in curtailment. As firm capacity is already more available, investment in LTDR capacity is smaller for these cases. The hourly dispatch constraints of the *Variability* scenario drive up investment in storage capacity. There is a slightly larger shift from Mid to Base capacity, and less investment in LTDR capacity – again because of the greater availability of firm capacity following the increased PHES+ investment. Finally, in the *Uncertainty* scenario, much like in Section 5.2, the investment in storage technologies is of another order of magnitude than in the first two scenarios. They replace High Peak capacity and PHES capacity (also driven by the effects of the energy to power ratios) as they take over reserve provision. The possibility to exchange reserves over the interconnection capacity and jointly size them further reduces the need for peak capacity. Investment in LTDR capacity is almost gone in this scenario, although not entirely. At high renewable targets, investment in VRES-E capacity can also reduced significantly. In total, installed capacity can be reduced by up to 10 GW.

To better understand the competition between the different flexibility providers, the difference in investment in alternative sources of flexibility is examined in Figure 5.27. For storage, investments are compared with those of Section 5.2. This section only includes results for Zone A. To be able to make the comparison for both zones, the three scenarios of that section were also evaluated for Zone B. The results hereof will not be presented separately, but merely used to compose Figure 5.27. For demand response, it is hard to compare investments as the technology was made available for free in Section 5.3. Therefore, the developed capacity will be compared with the 500 MW available in each zone. For interconnection, investments are simply compared with those of Section 5.4. Finally, the difference in energy capacity will not be treated separately. Energy to power ratios are similar to those presented in Section 5.2, so the main tendencies in energy capacity investment follow those in power capacity investment.

The results in Figure 5.27 show that there is decrease in investment for all alternative flexibility providers. The total decrease in flexible capacity investment is the largest in absolute terms in the final scenario; mostly because flexible capacity investments were the largest to begin with in this scenario. In relative terms, the decrease is more comparable over the different scenarios. Nevertheless, it still increases as the amount of short-term operational detail increases: 23% less flexible capacity in the *Adequacy* scenario, 29% less in the *Variability* scenario, and 35% less in the *Uncertainty* scenario. Of all alternative providers, the LTDR technology is clearly affected the most by the availability of competing providers. In the last two scenarios (almost) none of the available capacity is developed for high renewable targets. In these

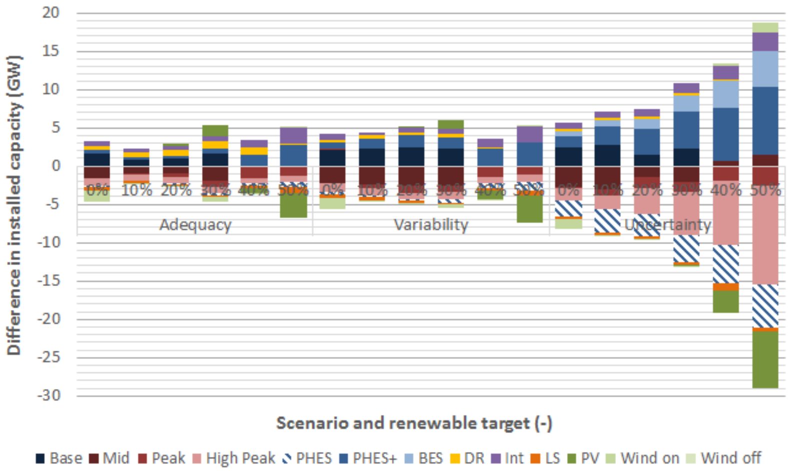

Figure 5.26: Difference in installed power capacity in GW between the flexibility scenarios and the reference scenarios.

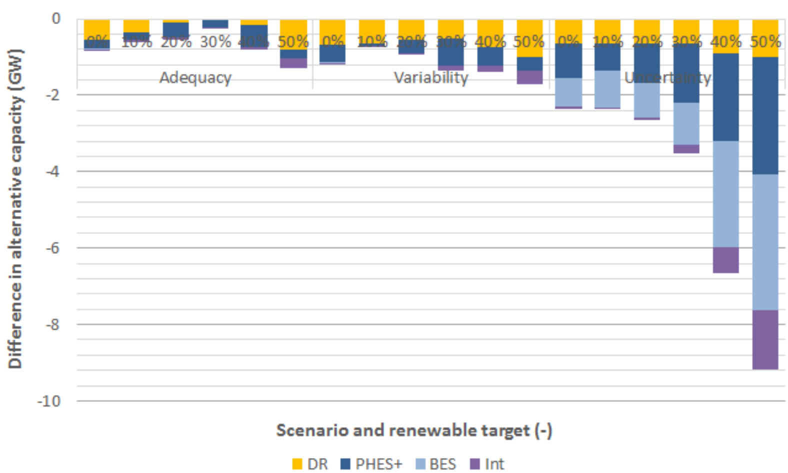

Figure 5.27: Difference in installed flexible capacity in GW between the flexibility scenarios and the reference scenarios.

cases a significant amount of peak and storage capacity is developed to deal with VRES-E variability and uncertainty. Given the assumed low dynamics of the underlying process, the LTDR technology cannot contribute a lot to dealing with this increased need for flexibility. Consequently, it does not succeed in compounding sufficient added value to remain competitive with the other providers. The impact on interconnection capacity investment is smaller; around 10% on average over all scenarios with outliers of 30-40% for the high renewable targets in the *Uncertainty* scenario. Apparently, the interconnection technology generates sufficient added value, through its residual load curve smoothing, reserve exchanges, etc., to more or less maintain investment levels. For storage, the impact is different for the two technologies. Investment in PHES+ capacity decreases by around 25% on average over all scenarios. The coupling of the two zones – which smears out (VRES-E) variability and uncertainty – reduces storage needs. In the first two scenarios, it is the reduced need for smoothing services that drives down PHES+ power and energy capacity investment; in the third scenario, it is also the reduced need for reserve power. This reduced need for reserve power leads to a more significant reduction in BES investment, a technology that is more reliant on reserve provision to be competitive. BES capacity decreases by around 45% on average in the *Uncertainty* scenario.

5.5.4 Energy and reserve provision

Figure 5.28 shows the difference in annual electricity generation between the three flexibility scenarios and the three reference scenarios. At low and intermediate renewable targets, the shift from Mid to Base generated electricity is present in all scenarios. This shift is greater in the *Variability* scenario than in the *Adequacy* scenario. In the reference scenarios, the introduction of the hourly dispatch constraints causes a shift from Base to Mid generated electricity. In the flexibility scenarios this shift is not only stopped, it is reversed. This shows the extent to which the more flexible technologies are able to facilitate the operation of the less flexible technologies. Results of the *Uncertainty* scenario are more or less the same as for the *Variability* scenario for these targets. At high renewable targets, the Base technology can no longer achieve sufficient full load hours to warrant investment, not even with all the alternative flexibility providers available. Now, there are shifts from Peak to Mid and from PV to onshore wind generated electricity. The former tendency is the result of the same process that enabled the shift from Mid to Base electricity at lower targets. The latter tendency is the result of the flexible technology reducing curtailment, boosting the yearly output of the final installed onshore wind capacity. In the *Uncertainty* scenario, this effect is even more pronounced because the alternative flexibility providers take over part of the reserve provision. Firstly, this allows

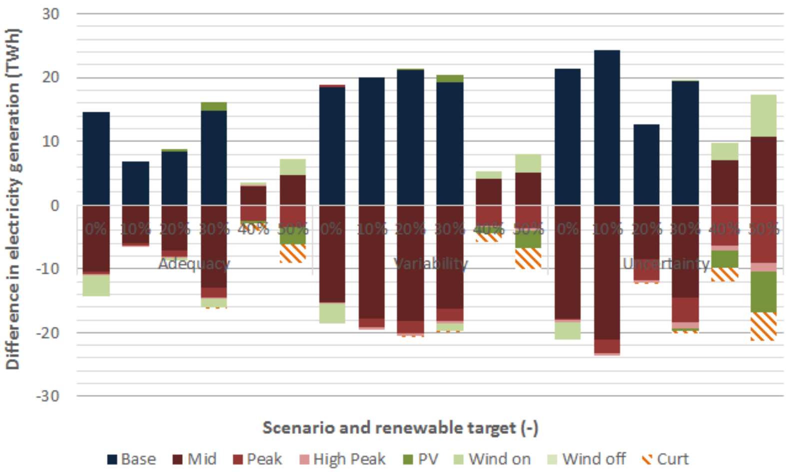

Figure 5.28: Difference in annual electricity generation and curtailment in TWh between the flexibility scenarios and the reference scenarios.

the less flexible Mid technology to operate more economically. Secondly, this allows to reduce the impact of the incompressible part of the supply, which reduces curtailment.

Figure 5.29 present the average upward reserve allocation. This figure is very similar to that presented in Section 5.2.4, as the storage technologies take over most of the reserve provision. The BES technology again plays its most important role in the provision of on-line reserves, the PHES+ technology in the provision of the more energy-intensive upward reserves. The difference between the storage and the flexibility *Uncertainty* scenario is that now the interconnection capacity allows to pool reserves and reduces the reserve need. For the 50% case on average around 2.1 GW of upward reserve capacity is exported from Zone A to Zone B, and 0.4 GW from Zone B to Zone A. These averages are more or less the same as in the interconnection scenario. However, the maximum reserve exchange is different. In the interconnection scenario this was 4.1 GW; in the flexibility scenario this is only 2.5 GW, which again sets the interconnection capacity. In the flexibility scenario reserve capacity is cheaper than in the reference scenario, meaning that the value of interconnection capacity for exchanging reserves is lower in the flexibility scenario, resulting in less investment. The contribution of the LTDR technology is once again limited, but non-zero: less than a MW of FCR, 11 MW of aFRR and 45 MW of mFRR on average over the renewable targets.

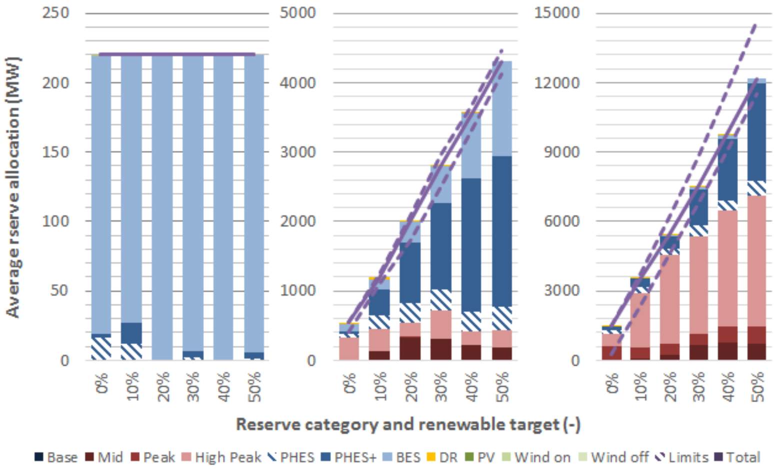

Figure 5.29: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

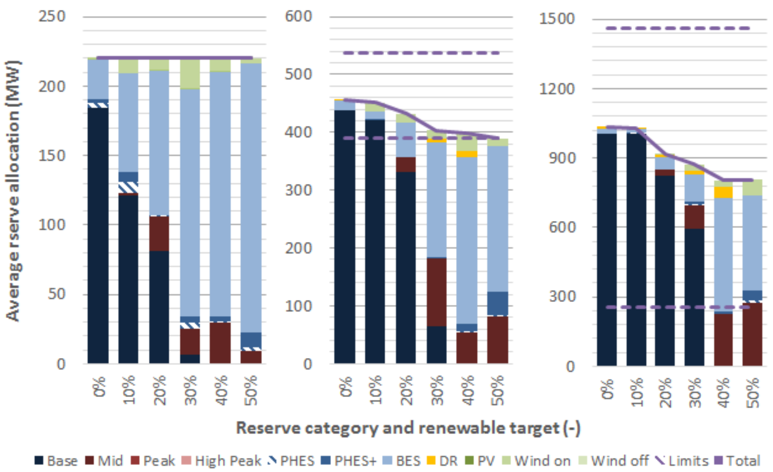

Figure 5.30: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

Finally, Figure 5.30 presents the average downward reserve allocation. Also here, the allocation is very similar to that of Section 5.2.4: the BES technology takes over the supply of these on-line reserves from the Base technology as the renewable target increases. The interconnection capacity once more facilitates the reserve provision. Nevertheless, since downward reserve power is more readily available at low renewable targets, the reserve exchange only becomes important at higher renewable targets, resulting in lower average reserve allocation. Again, the LTDR technology plays a limited role in the reserve provision, but still has a non-zero contribution: less than a MW of FCR, 3 MW of aFRR and 17 MW of mFRR on average over the renewable targets.

5.5.5 Discussion

This section has looked at the impact of competition on the investment in different flexibility providers. The technologies studied in the previous sections as examples of different types of alternative sources of flexibility were introduced simultaneously in the two-zone test system. Thus, they had to compete for the provision of the different services. The resulting investments in the alternative flexibility providers show that these providers are to a certain extent interchangeable, but also that there is no single technology that takes the place of all others. Investment in all alternative flexibility providers decreases compared to when they are considered separately. The extent to which they are able to maintain investment depends strongly on how well they were able to compound different sources of added value. For example, the LTDR technology, which is mostly adept at providing firm capacity, is not able to generate sufficient additional added value (e.g. from reserve provision) to warrant much investment. At high renewable targets, when peak and storage investments driven by the operating reserve requirements make firm capacity more readily available, it even disappears from the investment portfolio. The two storage technologies are more resistant to the competition. The PHES+ technology – which generates added value from firm capacity provision, residual load curve smoothing, managing the impact of hourly dispatch constraints and reserve capacity provision – only loses around 25% of the investment it warrants when considered separately. The BES technology – which is more reliant on reserve capacity provision for its added value – loses more; around 45%. The interconnection capacity investment is even less influenced by competition. The fact that it not only helps to increase the supply of flexibility – be it through power, energy or reserve exchange, but also to decrease the need for flexibility is of great value for the test system. Consequently, it only loses around 10% of the investment it warrants when considered separately.

With all these alternative flexibility providers included, the test system might also be seen as more representative of the future circumstances in which these high renewable targets may become reality. Therefore, it is interesting to reconsider the different costs induced by the short-term flexibility requirements as they were calculated in the previous chapter. In the reference scenarios for Zone A the reconfiguration cost ranges between 3-14 €/MWh_{RES}, the flexibility cost between 0-1 €/MWh_{RES} and the flexibility and balancing costs between 3-6 €/MWh_{RES}. Considered jointly with Zone B the reconfiguration cost ranges between 4-13 €/MWh_{RES}, the flexibility cost between 0-1 €/MWh_{RES} and the flexibility and balancing costs between 4-10 €/MWh_{RES}. After the introduction of the different alternative flexibility providers the reconfiguration cost ranges between 5-11 €/MWh_{RES}, the flexibility cost around 0 €/MWh_{RES} and the flexibility and balancing costs between 3-6 €/MWh_{RES}. Especially for the flexibility and balancing costs this is an important cost reduction, ranging between 28%-47%. This suggests that a future power system, combining the availability of alternative flexibility providers with an operating reserve strategy with short sizing and allocation horizons, could facilitate high renewable penetrations without incurring significant flexibility and balancing costs. While also reduced, the reconfiguration cost as calculated here is still important, resulting still in a significant VRES-E integration cost. Nevertheless, a decrease in investment costs for VRES-E and flexible technologies would further reduce the impact of also this part of the VRES-E integration costs. As mentioned before, such cost evolutions are not studied in this work.

5.6 Discussion

5.6.1 Different, but interchangeable

Alternative sources of short-term flexibility can facilitate the integration of VRES-E into the power system. Different technologies do so in a different way. The three alternative types of flexibility (i.e. non-supply-side flexibility) were evaluated separately and jointly.

First, flexibility from energy storage was evaluated. The three selected technologies; BES, PHES+ and P2G; were deployed in different ways. The P2G technology is only cost-effective at very high renewable shares (80+%). In combination with GFPP capacity, it is able to offer firm capacity and to convert the variable VRES-E output into a dispatchable electricity source, while its contribution to the operating reserves is limited. Thanks to its relatively low energy cost and competitive power cost, the PHES+ technology saw investment across all scenarios, increasing as the renewable target and the amount of operational detail increased. The technology provides firm capacity, smooths the residual load curve, manages the impact of the hourly dispatch constraints and provides reserve capacity. The BES technology has the technical ability to provide the same services, but due to its high energy cost only becomes a cost-effective investment option when the operating reserves are considered. It is clear then that technical ability in itself is not sufficient to warrant investment. As flexibility services can be provided by different (types of) technologies, being able to provide these services in a cost-effective way is crucial.

Second, flexibility from demand response was evaluated. The potential of short-term demand response (residential flexibility, industrial cooling sites, etc.) is very similar to flexibility from storage from an operational point of view. This was not studied separately. Eventual investments will depend on the cost-effectiveness of such technologies in providing flexibility and other services. The potential of long-term demand response, which is able to structurally reduce demand for longer periods of time, was studied via an example process. The technology had similar value across all scenarios and became only limitedly more valuable as the renewable target increased. Due to its (assumed) low dynamics, the technology's main added value is the provision of firm capacity, with smaller contributions from residual load curve smoothing and operating reserve provision.

Third, flexibility from interconnection was evaluated. Therefore, a second zone was introduced. Investment in the interconnection capacity between the two zones increased as the renewable target and the amount of operational detail increased. Interconnection capacity allows to pool firm capacity and reserve capacity. As dispatchable capacity shortages in different zones do not coincide perfectly in time, capacity from one zone can to a certain extent be used in another zone when needed. Furthermore, the interconnection capacity reduces the need for flexibility by smearing out variability (thus smoothing the residual load curve) and uncertainty (thus reducing the operating reserve requirements) over a larger geographical area.

Finally, the selected technologies of the three different alternative types of flexibility were allowed to compete for the provision of flexibility. This competition caused investment to decrease for all alternative flexibility providers. The final level of investment depended strongly on how well the technologies were able to compound different sources of added value, a key factor in determining their cost-effectiveness. This proved problematic for the long-term demand response technology, but less so for the storage and interconnection technologies.

5.6.2 Sources of added value

From the analyses performed above, it becomes clear that the ability to compound added value is crucial in determining the final level of investment in the different alternative flexibility providers. This is not only true for the technologies themselves, but also for the models used to study them. Researchers interested in studying the role of short-term flexibility providers need to include sufficient operational detail in their power system planning models. Not doing so can lead to both an under- and overestimation of the value of certain technologies. For example, the added value for the power system of the selected demand response technology was actually lower when all operational constraints were included than when they were not. In contrast, investments in storage technologies were of another order of magnitude when including full operational detail compared to not including it or only partly. To such an extent even that the battery energy storage technology did not warrant any investment unless when the operating reserve requirements were considered.

Given the clear dependence of the final level of investment in these flexible technologies on specifically the operating reserve requirements, the optimal investment level will inescapably be linked strongly to the chosen level of power system reliability. The flexible technologies are very adept at providing upward capacity, be it as firm capacity or as reserve capacity. It is a main source of added value for them, one that they are able to combine with other sources, making them a more cost-effective solution than peak generation capacity, which is essentially set aside for dealing with severe shortages, not participating in power system operation but for a very limited number of hours. Determining the total need for upward capacity, as a result of reliability considerations, will thus be decisive for determining the need for alternative flexibility providers.

When it comes to the value of providing downward flexibility, the story is somewhat different. The considered alternative flexibility providers have the inherent advantage that they do not impose any limits to the maximum instantaneous VRES-E penetration: demand response technologies operate on the demand side, storage technologies can operate with a net electricity production of zero, and interconnection capacity can import downward flexibility from another zone where VRES-E output is relatively lower and more dispatchable means are thus on-line at that moment. The way that this allows to reduce curtailment is an important source of added value for the alternative flexibility providers, especially at high renewable penetrations. However, in the results presented above, part of the reserve capacity had to be allocated on a monthly basis, excluding most of the VRES-E potential. The value of providing downward flexibility will decrease if the allocation horizon shortens sufficiently to unlock the full potential of VRES-E technologies to provide downward reserves. Moreover, should TSOs decide to impose a minimum level of dispatchable generation to be on-line at all times (although this might increase the value of storage, which could deal with the subsequently increased curtailment), this would decrease the added value of downward flexibility for the alternative flexibility providers.

Finally, there are several additional sources of added value that are not captured by the model used here – e.g. the provision of voltage regulation services, black-start capacity, etc. and other non-operational services – that would increase the optimal level of investment for the different alternative flexibility providers.

5.6.3 Remunerating flexibility

To unlock the potential of alternative flexibility providers in the way that was studied here, future market designs related to flexibility will have to meet two criteria. First, any market design should be formulated in a technology-neutral way. The results above showed how flexibility providers are to a certain extent interchangeable. Consequently, any market design related to flexibility should allow for such interchangeability. For example, many existing reserve products have been described in a way that is tailored to dispatchable generation technologies. Such product descriptions should be revised so that they simply reflect the balancing service a TSO wishes to procure, only excluding from participation those providers that cannot meet these requirements. Second, it is important to move forward on these market designs in an international context; something that is already being pushed on the European level, e.g. in ENTSO-E's Network Code on Electricity Balancing [218]. The results above showed how the joint sizing and allocation of reserves allowed for important cost savings. Such collaboration – and realizing the corresponding benefits – is only possible when product descriptions, contracting procedures, activation procedures, etc. are compatible across control zones.

If these criteria are met, then the flexibility of alternative flexibility providers can greatly reduce the VRES-E integration costs, as was shown in this chapter. For the two-zone test system reconfiguration costs decreased from 4-13 €/$\mathrm{MWh_{RES}}$ to 5-11 €/$\mathrm{MWh_{RES}}$, and flexibility and balancing costs decreased from 4-10 €/$\mathrm{MWh_{RES}}$ to only 3-6 €/$\mathrm{MWh_{RES}}$, a reduction of 28%-47%. Investment in alternative flexibility providers – which is modest in comparison to the total system cost: 0-2 €/MWh vs. 55-63 €/MWh (1-2%) – generates total system costs savings for the test system of two to three times the investment cost.

The value of these alternative flexibility providers is thus obvious. What is less obvious is how they will be remunerated for this value. As was discussed in detail above, besides the more easily traceable provision of firm capacity and reserve capacity, the alternative flexibility providers also help other technologies: they help increase VRES-E uptake (e.g. like discussed by increasing the maximum instantaneous VRES-E penetration) and help increase the amount of time that less flexible technologies can operate. At present there are no obvious market mechanisms – at least not in the Belgian power system – through which market players can remunerate each other for such services. Nevertheless, several interesting proposals have been made. For example, the Belgian regulator CREG recently launched a proposal for a market model to mobilize the flexibility of the demand-side [219]. This proposal includes the definition of a new actor, the Flexibility Service Provider, which would coordinate the activation of flexibility between those who offer the flexibility, those who need it, the associated BRPs, the TSO, etc. Such concepts and models provide the necessary structure for information, money, power and energy flows, but do not entirely solve the problem.

The questions that remains to be answered is how to value flexibility. In theory, the energy-only market which is in place today could provide the necessary price signals. During moments of capacity scarcity – driven by either firm capacity scarcity or flexibility scarcity – electricity prices would increase to very high levels, such that firm capacity and flexibility providers can recover their investment and operating costs. These scarcity prices should then reflect the value of firm capacity and/or flexibility, linked to the value of lost load. However, in practice there are several issues with this theory [220]. Firstly, policy makers are not keen on such high price spikes, whether or not they should be. Secondly, it is unclear how market participants should change their bids to take scarcity into account (or how a regulator would distinguish between scarcity pricing and market power abuse). And thirdly, it is difficult to accurately predict the revenue of such rare but high price spikes, which in turn makes it difficult for investors in new capacity (generation or otherwise) to develop solid business plans. It is obviously an option to accept this uncertainty, leaving it up to the investors to figure out a way to deal with it. However, choosing this option also means accepting the structural capacity shortages that would result from a lack of investment should investors shy away from such uncertainty. Given the political difficulty of such an approach, alternatives are being investigated in which rare, uncertain and very high price spikes would be replaced with more frequent and lower price spikes. The idea is to remunerate flexible capacity more, redistributing profit in their favor, and attempting to leave bidding behavior in the energy market unchanged. While initial results show a lot of promise, this approach is obviously not the only possibility. Many approaches are possible to realize this, and many are being investigated, e.g. real time reserve markets, markets for ramping ability, etc. It is a general recommendation based on the results of this work to focus future research on working out these designs.

5.7 Conclusions

In the previous chapter, the provision of flexibility was restricted almost exclusively to supply-side flexibility (i.e. generation technologies). In this chapter, the provision of flexibility was expanded to also include the three other types of flexibility sources: energy storage, demand response and interconnection. The potential of these alternative sources of short-term flexibility was studied by looking at the impact on power system planning of a number of selected technologies. Different technologies generate added value in different ways; and to be able to capture their total added value in a power system planning model high operational detail was shown to be indispensable. As the technologies proved to be interchangeable to a certain degree, the extent to which they are able to compound different sources of added value is crucial for the final level of investment in a technology. In the end, the combined flexibility of conventional and alternative flexibility providers allows to significantly reduce the cost of short-term flexibility requirements. For the two-zone test system studied in detail here, flexibility and balancing costs decreased from 4-10 €/$\mathrm{MWh_{RES}}$ (with only conventional flexibility providers) to 3-6 €/$\mathrm{MWh_{RES}}$, a reduction of 28%-47%. By unlocking this potential through technology-neutral and internationally harmonized market desings, and coupling it to an ambitious operating reserve strategy, alternative flexibility providers should thus be able to facilitate the integration of large shares of VRES-E without incurring significant flexibility adequacy-related integration costs.

Chapter 6

Conclusions

6.1 Overview and conclusions

At the outset of this PhD thesis, three main contributions were postulated:

Modeling short-term flexibility Developing a power system planning model that includes detailed short-term flexibility requirements and an accurate representation of the short-term flexibility supply of different technologies.

The impact of short-term flexibility Quantifying the impact of short-term flexibility requirements on cost and investments, as well as testing different strategies for dealing with VRES-E uncertainty.

The supply of short-term flexibility Studying the added value and role of alternative short-term flexibility providers (storage, demand response, interconnection), separately and in competition.

After motivating the relevance of these contributions through an extensive literature review in Chapter 2, the contributions themselves were presented in Chapters 3-5. The most important insights of these chapters are reiterated here. Put together, they allow to arrive at a clear understanding of the importance of short-term flexibility in power system planning.

Modeling short-term flexibility

First, a tool was developed which allows to study the impact of flexibility adequacy issues on power system planning. A generation expansion planning model was presented in which the short-term operation of the power system is modeled using the relaxed version of a technology-clustered formulation of the unit commitment problem. The need for short-term flexibility is represented through the modeling of the day-ahead electricity balance with an hourly resolution (to include the effects of variability), and operating reserve requirements following ENTSO-E's Network Code on Load Frequency Control and Reserves (to include the effects of uncertainty). The supply of short-term flexibility is represented through the modeling of different flexibility providers of the four types of flexibility: supply-side (dispatchable and variable generation), demand-side (long-term demand response), energy storage (battery, pumped hydro and power-to-gas), and interconnection.

The impact of short-term flexibility

Second, this tool was applied to a test system to understand and quantify the impact of short-term flexibility requirements on the cost and composition of the optimal investment portfolio in light of an increasing share of variable renewables. In what can be described as a "business as usual" setting – i.e. a reserve strategy that mimics current practice, and a conventional supply of flexibility (dispatchable generation and pumped hydro energy storage) – the impact of ensuring flexibility adequacy increased drastically as the renewable share increased. At a 50% share, compared to a 10% share, the cost of ensuring flexibility adequacy more than tripled in absolute terms, increasing from 2% to 6% of total system cost. Investments shifted away from base load to more flexible generation technologies in the dispatchable capacity mix, and investments in peak capacity (both generation and storage) increased strongly. The exact numbers of these results obviously depend on the characteristics of the zone under analysis (e.g. on the quality of VRES-E forecasting or VRES-E output variability). Nevertheless, the results for a second zone of the test system – where the cost of ensuring flexibility adequacy more than quintupled over the same renewable share range, increasing from less than 3% to more than 11% of total system cost, and changes in investments showed the same patterns – confirmed the observed link between the impact of ensuring flexibility adequacy and the share of variable renewables. In conclusion, where until recently it was assumed that short-term operational flexibility adequacy issues would not have a significant impact on long-term planning, this work has shown that in the face of growing shares of variable renewables and under current practices this assumption can no longer hold. Ensuring flexibility adequacy then leads to a strong increase in the total system cost and to significant changes in the optimal investment portfolio when moving from low to high shares of variable renewables. Under these conditions, future power system planning will have to consider these issues to come up with operationally reliable investment portfolios.

The results of this work also point to two of the main options for addressing the increasing impact of ensuring flexibility adequacy. On the one hand, as the reserve requirements were by far the most important driver of this impact, it is clear that an improved reserve strategy can facilitate the integration of such large shares of variable renewables. At a 50% share, a reserve strategy with yearly sizing and allocation leads to flexibility adequacy costs for the first zone amounting to more than 9% of the total system cost. For that same share, a reserve strategy with hourly sizing and allocation reduces these costs to less than 4% of the total system cost. Bringing the sizing horizon closer to real time allows to better match reserve capacities to the uncertainty present in the system, reducing the peak capacity need. Bringing the allocation horizon closer to real time allows to more efficiently use the flexibility available in the system, easing the flexibility requirements for the dispatchable portfolio. Put together, these reserve strategy improvements allow to almost halve the cost of ensuring flexibility adequacy compared to the business as usual setting. Reserve strategies will thus have to evolve as the share of variable renewables grows.

On the other hand, addressing alternative sources of flexibility can also facilitate renewable integration. Different technologies of the three alternative types of flexibility were studied: energy storage, demand-side flexibility, and interconnection. Without yet delving into their separate roles, it is clear that – given a technology-neutral (such that all types of flexibility providers can compete) and internationally harmonized (such that efforts can be shared across power systems) market design – the combined flexibility of these alternative providers can significantly reduce the cost of ensuring flexibility adequacy in the face of a growing renewable penetration. In the "business as usual" setting, at a 50% variable renewables share, the flexibility adequacy costs of the two-zone test system decreased from 9% to only 4% of the total system cost after the introduction of all alternative flexibility providers. Their flexibility facilitated the operation of the less flexible generation technologies, allowing investments to partly shift back to those technologies. Investments in peak generation capacity decreased strongly as the provision of reserves was taken over by storage technologies and the need for reserve capacity decreased through reserve exchange over the interconnection capacity. As such, these alternative flexibility providers allowed to more than halve the cost of ensuring flexibility adequacy compared to the business as usual setting. The supply of flexibility will thus have to diversify as the share of variable renewables grows.

The supply of short-term flexibility

Third, the separate roles of the alternative short-term flexibility providers, and how these evolve as the renewable share increases, were studied. Of the three alternative types of flexibility a number of representative technologies were studied. For energy storage, the battery, pumped hydro and power-to-gas technologies were studied. The power-to-gas technology did not warrant any investment in the investigated renewable share range. Under the assumptions made here, it only played a role at extremely high renewable shares (80+%). The battery and pumped hydro technology, in contrast, played a very important role, notably in ensuring flexibility adequacy, ever more so as the renewable share grew. A significant share of their added value is generated by the provision of reserve capacity (particularly the "on-line" reserve capacity, i.e. reserve capacity that would otherwise have to be provided by "spinning" generation capacity). They also helped ease the cycling requirements for conventional generation capacity. This results in significant investment; even more for the pumped hydro than for the battery technology, as it also presents a cost-effective option for storing surplus renewable production thanks to its relatively low energy cost.

For demand-side flexibility, a long-term demand response technology was studied, mimicking the flexibility of a kind of industrial electricity demand that can be reduced or cut a limited number of times per year. As the underlying consumption process was assumed to not be very dynamic, the technology mostly presented a source of firm capacity. It is also sensible to expect that this kind of flexibility would be used in this way, as industrial operators would likely prefer a limited number of activations. Interestingly, the added value of this technology was higher at lower shares of renewables when competing with other alternative flexibility providers, as firm capacity was already more readily available at higher renewable shares due to the reserve requirements. While not specifically studied in this work, it is worth noting that the added value of short-term demand response technologies can be expected to be in line with that of the battery and pumped hydro technologies, as they can provide flexibility in a very similar fashion.

For interconnection, the exchange of energy and capacity between power systems was studied, i.e. at a highly aggregated level. Besides the possibility to exchange firm capacity and energy, the possibility to exchange reserves was also studied. This allows neighboring power systems to jointly size their and pool reserves, reducing the need for reserve capacity. While the greatest added value of interconnection still lay in exchanging firm capacity and energy, the exchange of reserve capacity proved to be a great source of added value, ever more so as the renewable share increased.

While they do so in different ways, these technologies can all offer the same four services studied in this work: providing firm capacity, smoothing the residual load curve, dealing with dispatch constraints, and providing reserve capacity. Therefore, they can compete, if the market design allows for it; which it should given the apparent benefits discussed above. The specific equilibrium in investments among these technologies then naturally depends on their cost structures. For a number of these technologies, notably certain storage and demand response technologies, there is quite some uncertainty on the evolution of these costs in the future. The influence of changes in these cost structures was not studied. What can be said, however, is (1) that the added value of those technologies adept at offering short-term flexibility will increase as the renewable share increases; and (2) that their total added value will depend strongly on the way in which they are able to combine the provision of different services, such as those modeled here and others currently not captured by the model (voltage support services, etc.). And that is why, power system planning models wishing to study the role of these alternative flexibility providers need to include sufficient operational detail to appropriately reflect a system's short-term flexibility need and supply. Not doing so can lead to both over- and underestimations of the added value of certain technologies.

6.2 Recommendations for further research

To conclude this thesis, the most pertinent recommendations for further research related to short-term flexibility in long-term planning are formulated. First, even when adopting a reserve strategy with hourly sizing and allocation, the cost of ensuring flexibility adequacy approximately doubles when going from a 10% to a 50% share. With the cost of ensuring reliability increasing thusly, the way in which strict, centralized reliability targets are used for planning purposes, or at times imposed on TSOs for operation purposes, is challenged. Moreover, this renewable integration also impacts other aspects of operational security that have not been included in the model and could drive up the cost of ensuring reliability even further, such as the need for black-start capacity, the impact on inertia, etc. While industrial consumers can reflect their willingness to pay for reliability directly in the contracts they conclude, a large part of the society is represented for this by their government. The question then becomes whether these governments can hold on to their strict targets – which are often politically motivated – with the cost thereof increasing, and simply assume that the consumers they represent are willing to pay for these increasing costs. In a liberalized, decentralized power system with an increasing cost of ensuring reliability, it might be more interesting to explore a liberalized, decentralized way of valuing reliability, e.g. via decentralized capacity markets.

Nevertheless, the extent to which all of this will be crucial to deal with, depends very much on the extent to which the transition towards a low-carbon power system will be based on variable renewables. The analyses in this work are based on increasing the share of variable renewables, as this approach was considered to be the most challenging way to achieve the climate goals from a power system operation perspective, and thus the most instructive case to study. However, the transition of the power system can also be realized in other ways, which are much less demanding from an operational perspective, e.g. by developing generation capacity equipped with Carbon Capture and Storage. Then ensuring flexibility adequacy, and the corresponding cost, will have a much of less important impact for long-term planning, making it less necessary to formulate appropriate constraints.

This leads to a second recommendation, related to allocating computational resources. On the one hand, the inclusion in planning models of constraints for ensuring short-term flexibility adequacy comes at a high computational cost (particularly because of the reserve allocation constraints). On the other hand, the cost of ensuring flexibility adequacy will most likely remain limited to a couple of percent of the total system cost, even at high renewable penetrations; because of the fact that the power system transition needs not to be based entirely on variable renewables, that more appropriate reserve strategies will most likely be adopted and alternative sources of flexibility will most likely be addressed, that renewable forecasting techniques can be expected to improve, etc. Uncertainty over fuel prices, availability of technologies, demand growth, etc. will carry more weight in planning than operational uncertainty. Consequently, if the specific focus of the planning exercise is not on flexibility adequacy, then computational resources are best dedicated elsewhere, e.g. to studying more scenarios, so as to realize more robust planning outcomes. Nevertheless, if the focus is on flexibility adequacy related challenges, e.g. to study inertia aspects or flexible technologies not studied here, then detailed constraints are a must to avoid over- and underestimations of costs and added values.

Finally, a more general recommendation is given for the planning process. The focus of this work has been exclusively on the operational challenges of the power system transition. However, there are many non-technical challenges related to such a transition which have an important impact on society in a broad sense. On the one hand, these challenges are related to such aspects as land use and land use change, water use, life cycle greenhouse gas emissions, renewable potentials, etc. On the other hand, these are related to public acceptance issues surrounding the construction of new infrastructure, which technologies can be a part of the future electricity generation mix, the way in which new market designs influence consumers' everyday activities, privacy aspects related to the use of demand-side flexibility, etc. In general, it can be said that these and other aspects which influence a lot of the assumptions made at the outset of a planning exercise, as well as the interpretation of the outcomes of the planning exercise itself, need to be the subject of an extensive debate with broad stakeholder participation. The framework within which policy makers or other planners perform a planning exercise needs to be the result of a collaborative effort and presented transparently, such that it can be understood and accepted by all stakeholders.

Once this framework is known, and thus decisions on key-issues made, there needs to be a thorough analysis of all uncertain elements within the framework: the availability of certain technologies such as CCS, evolutions in investment and fuel prices, the interaction between policy makers and policy takers, etc. Therefore, it is relevant that future research is dedicated to developing planning tools that are able to analyze a large number of scenarios, and present not necessarily exact transition pathways to be followed, but rather an acceptable, robust "solution space" for the power system transition.

Finally, once the "solution space" is known, a major challenge will be to realize it. Given the liberalized context in Europe, the Member States' governments and/or public enterprises are no longer the actors that realize the investments. If policy makers want to realize a certain change in the power system, they need to design appropriate policy measures and market mechanisms which bring this change about. This is an area that deserves a lot of attention from researchers, be it the market designs themselves, or the way private investors and consumers react to those designs or other policy measures. Specifically related to short-term flexibility, there are important challenges related to designing markets that appropriately remunerate flexibility providers for the services they provide, and key decisions to be made on how to value flexibility, and more generally speaking reliability.

Appendix A

Power-to-Gas

A.1 Introduction

When evaluating the role of storage as an alternative source of flexibility in Section 5.2, the P2G technology did not warrant any investment for the 0-50% renewable target range. In this appendix, the 50-100% renewable target range is examined to study the role of P2G and its added value compared to other options for reaching a fully renewable power supply, e.g. biomass. Note that this appendix will not deal with the technical or economic requirements of getting the carbon dioxide on site (to be combined with the produced hydrogen to form the synthetic methane). To be able to evaluate the value of the P2G technology, the three reference scenarios (i.e. without the three additional storage technologies) have also been evaluated for the 50-100% range. The outcome hereof will not be presented when appropriate.

The technologies available for investment are the same as in Section 5.2. Recall that the Peak and High Peak technologies are Gas-Fired Power Plants, and can thus be used to reconvert the synthetic gas produced by the P2G technology into electricity. One additional constraint is added for the PHES+ technology: the maximum installed energy capacity is set at 60 GWh. This number is not intended to be an estimate of the available potential. It is merely introduced to check whether it has an impact on the deployment of the P2G technology. Furthermore, a biomass technology is introduced. The technology's technical parameters are the same as those of the Mid technology. Its economic parameters, presented in Table A.1, are based on the JRC EU-TIMES model data [210]. The annual electricity generation of the biomass technology is limited to 20 TWh.

Table A.1: Economic input parameters of the biomass technology. The investment cost is annualized with a 5% discount rate.

		Investment cost						Operational cost			
			Total		Annualized						
Set	Name	N_i^{cal}	$C_i^{\mathrm{inv,i}}$	$C_s^{\mathrm{inv,e}}$	$C_i^{\mathrm{inv,i}}$	$C_s^{\mathrm{inv,e}}$	$C_i^{\mathrm{fom,i}}$	$C_i^{\mathrm{fuel,i}}$	$C_i^{\mathrm{vom,i}}$	$C_i^{\mathrm{ra,i}}$	$C_i^{\mathrm{su,i}}$
		years	€/*kW*	€/*kWh*	€/*kW*	€/*kWh*	€/*kW*	€/*MWh*	€/*MWh*	€/*MW*	€/*MW*
$\mathbb{ID}, \mathbb{IR}$	Biomass	35	2595	-	158	-	95	57	15	1.3	50

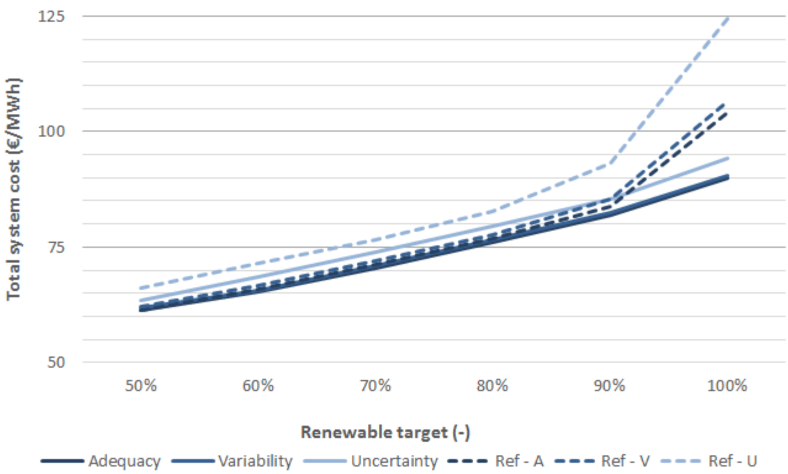

Figure A.1: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the storage scenarios and the reference scenarios.

A.2 The impact on system cost

Figure A.1 shows the total system cost of storage and reference scenarios for the 50-100% renewable target range. The cost of all six scenarios increases more or less linearly until the 90-100% target range. Here, the reference scenarios – and especially the Uncertainty scenario – show a steep increase, landing the total system cost at a level that is approximately twice that of the 0% case (cfr. 55 €/MWh). These values, however, cannot be used for any reasonable interpretation. A situation where renewable penetration would approach 100% without the use of storage is not realistic, but merely a theoretical exercise used here to evaluate the role of storage. What this figure suggests is that realizing a fully renewable supply without storage is practically infeasible.

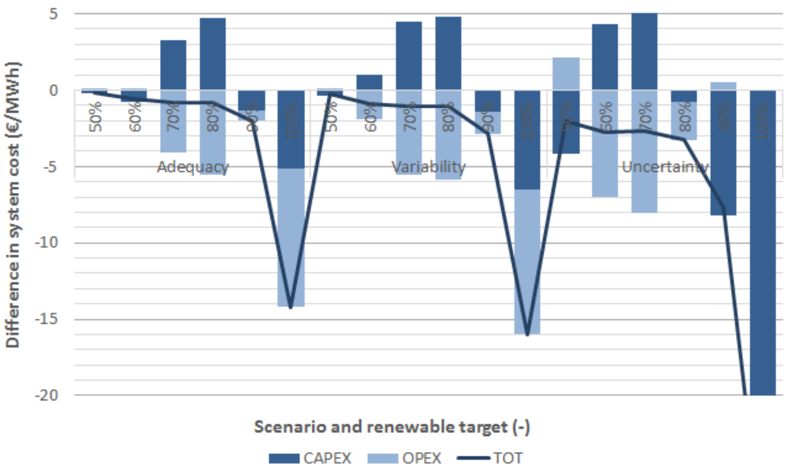

Figure A.2: Difference in total system cost expressed in €/MWh of total demand between the storage scenarios and the reference scenarios.

The three storage scenarios have a cost that is lower than that of the corresponding reference scenario. The cost of the Adequacy scenario rises from 61.0 €/MWh to 90.1 €/MWh. Introducing the hourly dispatch constraints in the Variability scenario leads to a cost mark-up of 0.5 €/MWh that is more or less independent of the renewable target. Introducing the operating reserve requirements in the Uncertainty scenario leads to a higher mark-up, with total system cost now rising from 63.4 €/MWh to 94.3 €/MWh. Thus, in this scenario a fully renewable power supply can be realized at only 170% the cost of the lowest cost investment portfolio of the power system (i.e. the 0% case).

Figure A.2 shows the breakdown of the cost difference between the storage and reference scenarios. From this, the added value of the storage technologies can be derived. As this appendix focuses on the role of the P2G technology, it is important to note already here that P2G capacity is only developed for the 90% and 100% cases. This makes it hard to identify the value of the technology via the cost savings, as the outcome of the reference scenarios are not realistic for these targets. For the other targets the analysis of Section 5.2.2 is confirmed: (1) the storage technologies can provide firm capacity and residual curve smoothing, but not much more cost-effectively than the other available technologies; (2) they help deal with the hourly dispatch constraints; and (3) they are very adept at providing reserve capacity. Excluding the results of the 100% case, cost savings in the Adequacy scenario range between 0.2-2.0 €/MWh, in the

Variability scenario between 0.4-2.9 €/MWh, and in the Uncertainty scenario between 1.7-7.7 €/MWh. The increase in CAPEX for the 50-80% range stems from investment in storage and in additional VRES-E capacity, whose output can now be used more efficiently, avoiding investment in the very expensive Biomass technology, leading to large OPEX savings. For the 90% case, also the CAPEX decrease, as investment in VRES-E capacity can be reduced.

A.3 The impact on investments

The difference in investment between the reference and the storage scenarios is vast. To appreciate just how different they are, the investment portfolio of the reference scenarios is shown in Figure A.3. What immediately stands out is that the approximately linear growth in total capacity seen for the 0-50% renewable target range is no longer present here. This is due to the development of Biomass capacity. This technology, while expensive both in CAPEX and OPEX, is the best alternative for the increasingly inefficient VRES-E capacity (due to increased curtailment) and the need for firm capacity. Results for the Adequacy and Variability are very similar, with slightly more investment in Biomass in the latter due the increased curtailment following the introduction of the hourly dispatch constraints. In the Uncertainty scenario, Biomass investment is even higher and High Peak capacity increases to unrealistic levels. In the 100% case, which has a total installed capacity of 87.3 GW (out of the scope of this figure), 17.1 GW of High Peak capacity is installed. Besides being practically infeasible, these results show two shortcomings of the model. First, in a fully renewable system reserve provision by such a technology would not be possible, as reserve activation would lead to non-renewable electricity generation. As the real-time phase is not considered, this effect is not captured by the model. Second, the amount of firm or back up capacity should not be that much higher than the peak demand. An upper limit for this capacity is currently not included in the model. Finally, load shedding also increases to unrealistic levels. In the 100% case this increases up to 2 GW, with 3-4% of total demand being shed.

Figure A.4 shows the installed power capacities of the three storage scenarios. There are several distinct differences. First, conventional generation capacity does not completely disappear: 3-4 GW of GFPP capacity remains in the 100% case to reconvert the synthetic methane. Second, installed biomass capacity and load shedding are significantly lower. Now, the combination of the P2G technology and the GFPP on the one hand, and the non-P2G capacity on the other hand provide the required firm and dispatchable capacity. Thirdly, the tremendous increase in High Peak capacity in the Uncertainty scenario is gone, only partly replaced by growth in storage capacity. Finally, it can already be

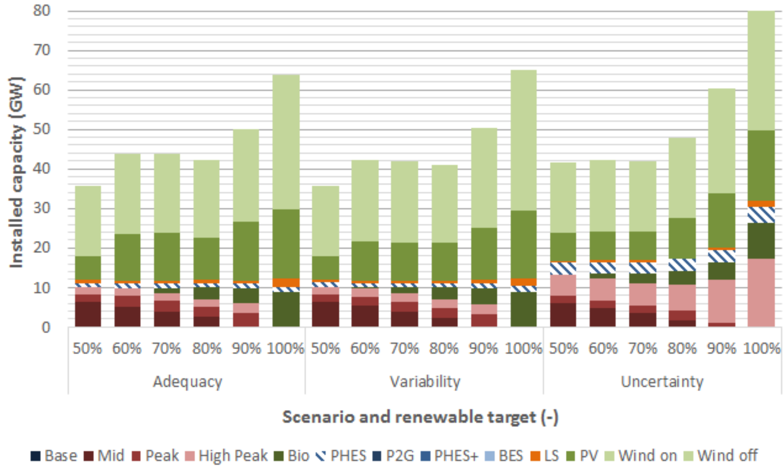

Figure A.3: Installed power capacity in GW for the Adequacy, Variability and Uncertainty reference scenarios for different renewable targets.

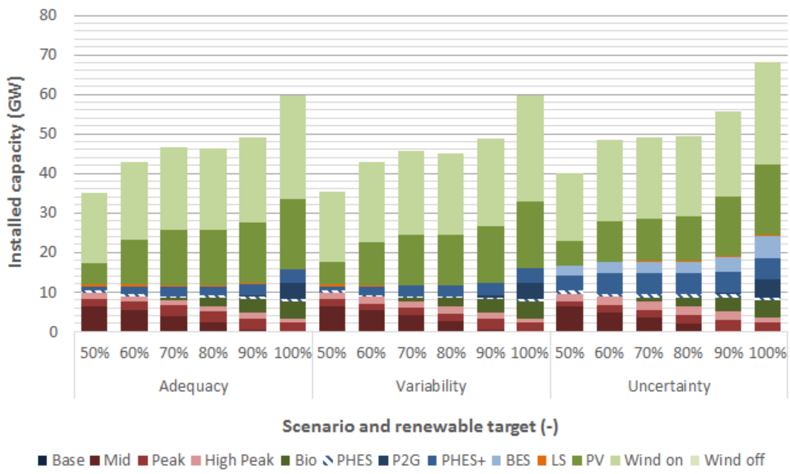

Figure A.4: Installed power capacity in GW for the Adequacy, Variability and Uncertainty storage scenarios for different renewable targets.

noticed that investment in P2G capacity is only really significant for the 100% case. There is some minor P2G capacity development at 90% (460-530 MW), but only the fully renewable target garners investment that is comparable to investment in other storage options – given the assumed cost structure. In the Adequacy scenario 4.1 GW is developed for the 100% case. In the Variability scenario this becomes 4.3 GW. In the Uncertainty scenario 4.7 GW of P2G capacity is developed. This is only a small increase, as it is only driven by the reserves the P2G technology can provide. If the real time phase would be considered, then more synthetic gas would be needed for activating the reserves of the GFPP, potentially further driving up P2G investment.

Figure A.5 shows the investment in energy capacity. Again, the available 6 GWh of natural PHES is always fully developed. The energy capacity limit for the PHES+ technology (cfr. 60 GWh) is only reached in the 100% case for the first two scenarios. At lower targets, energy capacity development levels off with VRES-E capacity development. In the Uncertainty scenario, the 60 GWh limit is already reached at 70%. Then the power capacity investment of the PHES+ technology also stabilizes. This does not, however, lead to increased P2G investment, but to increased Biomass investment. In fact, it is only when this technology reaches its generation limit (cfr. 20 TWh/year) in the 90% case, that investment in P2G capacity takes off.

Figure A.6 shows the difference in installed power capacity. This figure focuses on the -10 GW to +20 GW range. In the 100% cases, the shifts in investments are even larger; for these cases the investment portfolio is simply fundamentally different. At lower targets in the Adequacy scenario additional PHES+ capacity is developed, initially to replace High Peak and PHES capacity as reserve provider, then also to defer investment in Biomass capacity by facilitating VRES-E capacity integration. At 90%, P2G capacity development starts, which also reduces curtailment. Tendencies in the Variability scenario are more or less the same, with a little additional PHES+ capacity development. Finally, in the Uncertainty scenario there is additional storage investment (PHES+ and BES) as the storage technologies take over the reserve provision.

A.4 Energy and reserve provision

The generation and curtailment patterns of the reference scenarios are presented in Figure A.7. This figure shows the huge amounts of curtailed VRES-E output. As this curtailment (partly the result of using a single profile per VRES-E technology) decreases the cost-effectiveness of VRES-E technologies, the Biomass technology starts taking over. When it reaches its generation limit,

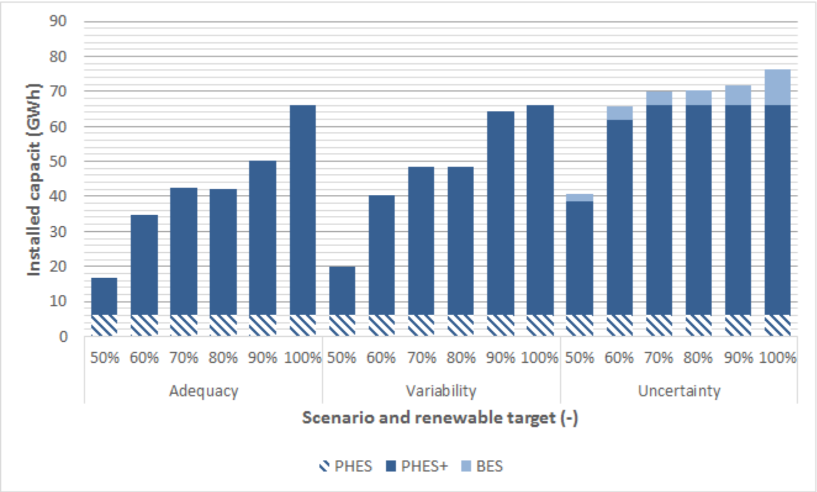

Figure A.5: Installed energy capacity in GWh for the Adequacy, Variability and Uncertainty storage scenarios for different renewable targets.

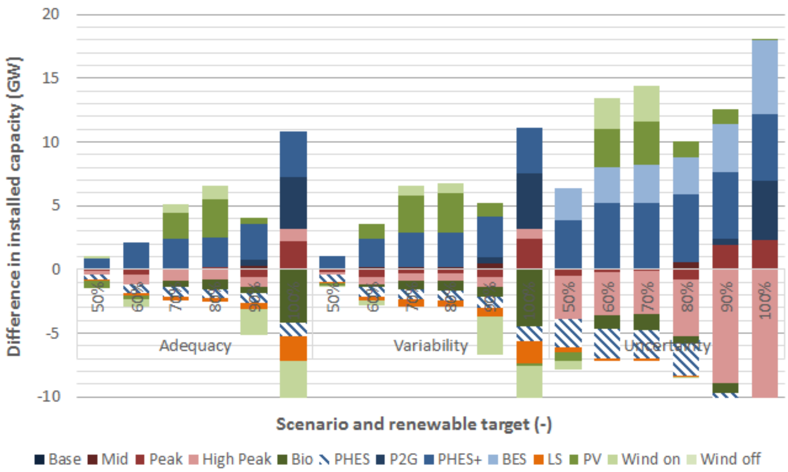

Figure A.6: Difference in installed power capacity in GW between the storage scenarios and the reference scenarios.

the model has no choice but to further develop the already unfavorable VRES-E capacity, leading to the high amounts of curtailment. More operational detail means earlier development of Biomass capacity, and thus somewhat paradoxically to less curtailment for the 50-70% range of the Uncertainty scenario.

Figure A.8 shows the difference in annual generation and curtailment. This figure zooms in on the -15 TWh to +15 TWh range. In the 100% cases, between 25 TWh and 33 TWh of curtailment can be avoided, depending on the scenario. This figure reflects the shifts in investment. On the one hand, the storage technologies facilitate the operation of the less flexible Mid technology at the expense of the Peak technology. On the other hand, they facilitate the uptake of VRES-E output, thus requiring less Biomass-generated electricity for the 60-80% range. In the 100% case there is some GFPP electricity; this comes from synthetic gas, making up around 3-4% of the electricity production.

Figure A.9 and A.10 show the average up- and downward reserve allocation. Once more, the BES technology plays the most important role in the provision of the on-line reserve categories. The PHES and PHES+ technology contribute mostly to the upward FRR. The contribution of the P2G technology is limited, but non-zero. In the 100% case it provides around 800 MW of upward FRR. The contribution of the Biomass technology is also limited. Its dynamics are those of the Mid technology, which is not a very flexible technology.

A.5 Discussion

This appendix has studied the 50-100% renewable target range to evaluate the role of a P2G technology. In combination with GFPP capacity, the P2G technology is able to offer firm capacity and to convert the variable VRES-E output into a dispatchable electricity source. Its contribution to operating reserves is limited. Given the assumed cost structure, the technology is only a cost-effective option at extremely high renewable targets (90-100%). Even with a limit to the energy capacity of the other storage technologies, it is cheaper to develop Biomass capacity instead. Only when the Biomass technology reaches its generation limit, does the P2G technology start to warrant investment. Some factors that were not considered here could improve the case for P2G: limits to the VRES-E capacity potential, acceptability issues for the use of biomass, cost reductions and/or technical improvements of P2G technology, etc. Still, other factors could worsen the case for P2G, such as the costs and challenges of gathering the required carbon dioxide emissions on site. In conclusion, the results here suggests that – given the current status of the technology – P2G will only play a role of importance in highly renewable power systems.

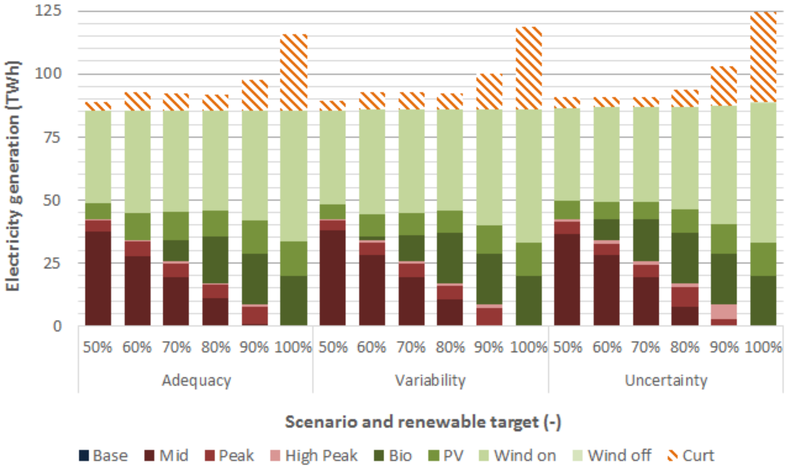

Figure A.7: Annual electricity generation and curtailment in TWh for the Adequacy, Variability and Uncertainty reference scenarios.

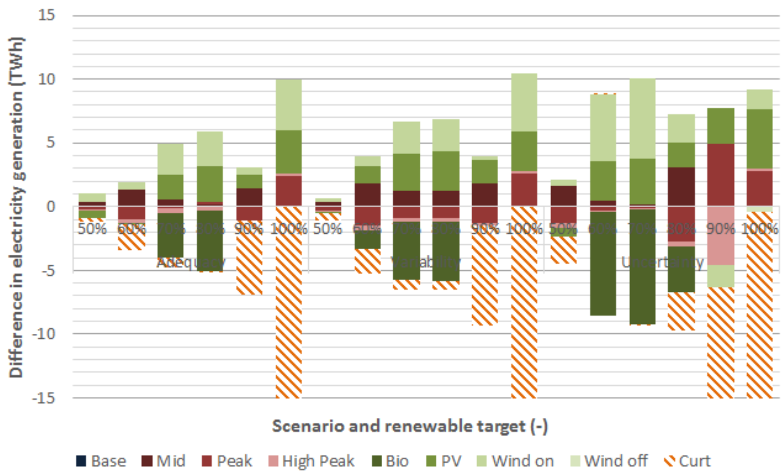

Figure A.8: Difference in annual electricity generation and curtailment in TWh between the storage and reference scenarios.

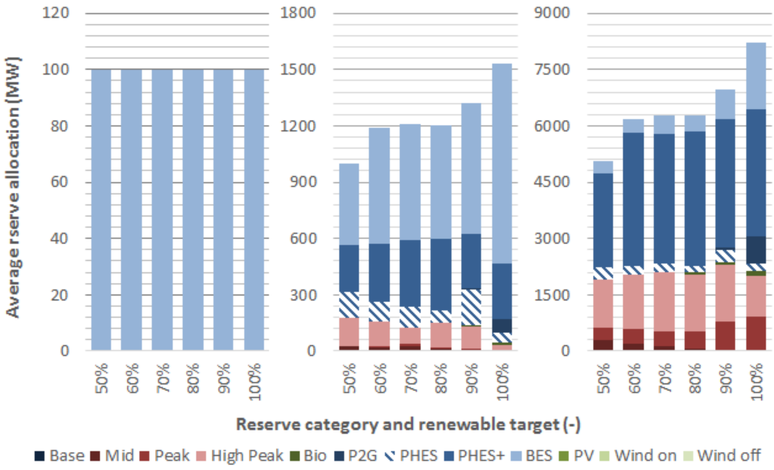

Figure A.9: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

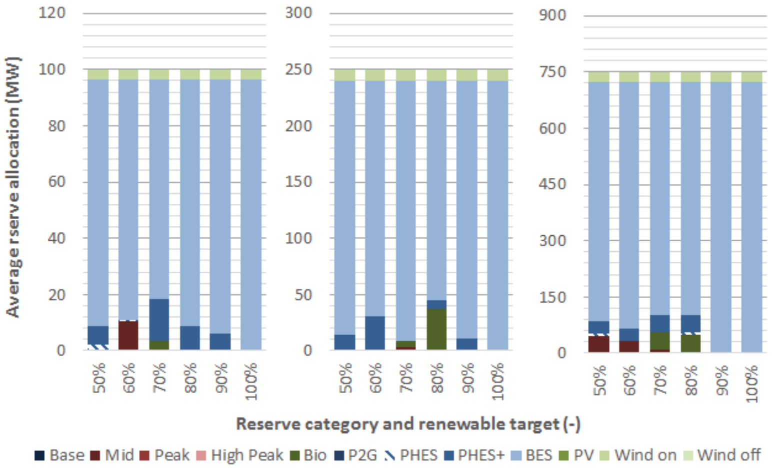

Figure A.10: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

Appendix B

Short-term flexibility analysis of Zone B

B.1 Introduction

To examine the role of interconnection a second zone has to be introduced. In Section 5.4 the outcome of the interconnection scenarios is compared to the outcome of the reference scenarios: the Adequacy, Variability and Uncertainty scenario. For the first zone – Zone A – these scenarios have been evaluated in Chapter 4. For the second zone – Zone B – these scenarios are presented in this Appendix.

The same technologies are available for Zone B as for Zone A, with the energy capacity of the PHES technology also limited to 6 GWh. The demand profile is that of the Dutch power system for 2015, which has a peak demand of 19.1 GW and an annual energy of 114.1 TWh. To ensure a correct correlation, the VRES-E profiles are also those of 2015 for the Dutch power system. Again, an on- and an offshore wind resource, and a solar PV resource are used. To size the exogenous operating reserves, the system imbalance data of 2015 for the Dutch power system are used for the probabilistic assessment, while the Dimensioning Incident (positive and negative direction) for the deterministic assessment is the loss of a 1 GW HVDC interconnector. To size the endogenous operating reserve, forecast error data of 2015 for the Dutch power system are used. All the information is collected from the website of the Dutch TSO TeNNeT [221]. The operating reserve characteristics are still those of the Belgian TSO.

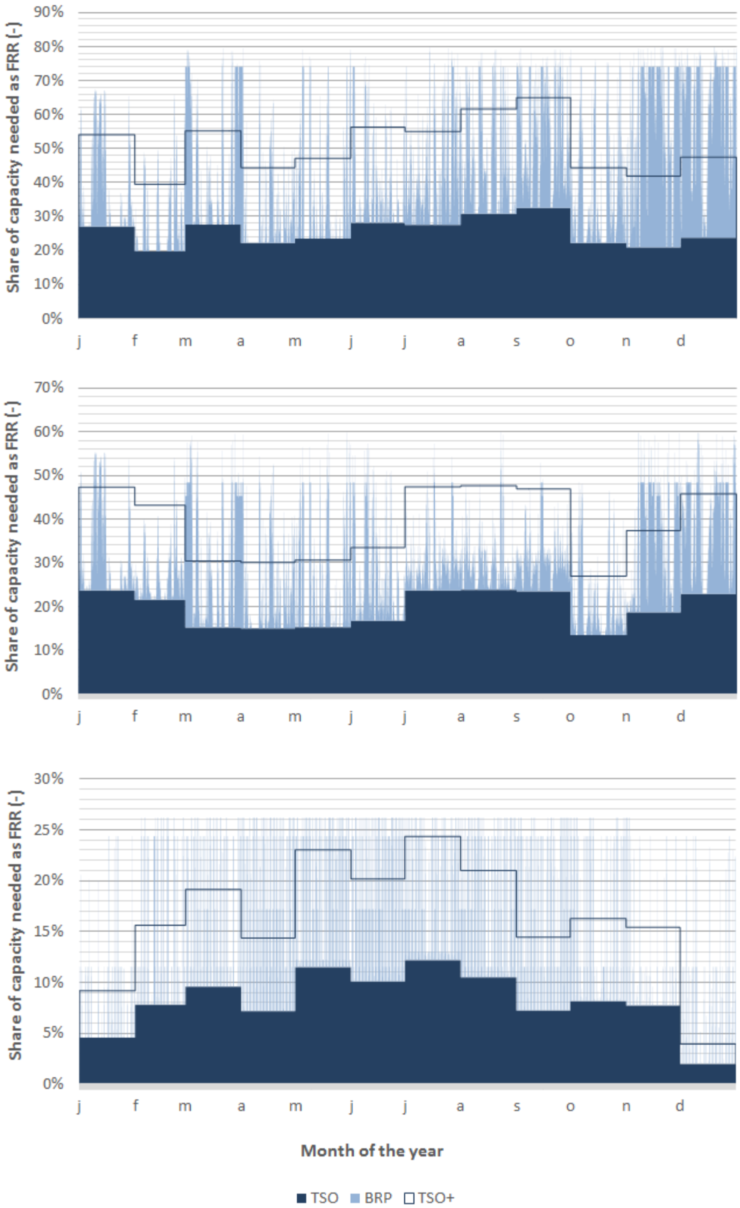

Figure B.1: FRR need for off- and onshore wind and PV uncertainty expressed as a percentage of installed capacity for Zone B.

The exogenous components of the reserve requirements, once more sized on a yearly basis and allocated on a monthly basis, are 120 MW of up- and downward FCR, 287 MW of up- and downward aFRR, and 713 MW of up- and downward mFRR. For the endogenous component, again the dual approach of Section 3.3.5 is used. The outcome of this approach is presented in Figure B.1 for the off- and onshore wind technologies, and the PV technology. Recall that the line denoted by *TSO+* indicates the outcome of the monthly sizing of the methodology of Section 3.3.4; half of this capacity is actually allocated on a monthly basis (*TSO*). On top of that reserve capacity is contracted on an hourly basis (*BRP*), to meet the reserve capacity need of the hourly sizing methodology. These figures already show the high level of uncertainty of VRES-E output in Zone B, especially for the wind resources. Whether this is because the uncertainty is actually larger (because of meteorological conditions or forecasting techniques), or because there is an issue with input data (different reporting techniques, etc.) is unclear. In any case, the data will be used as it is.

The model is now applied to Zone B for the three reference scenarios in a greenfield setting. The portfolio and operation of the system is optimized for a year with hourly time steps. An objective for the share of RES-E electricity in the final electricity consumption is imposed, ranging between 0% and 50%. The cost of VRES-E curtailment is assumed to be €0/MWh, while the cost of involuntary load shedding is set at €3'000/MWh.

B.2 The impact on system cost

Figure B.2 shows the total system cost for all scenarios expressed in €/MWh. The cost of the Adequacy scenario rises from 55.8 €/MWh when no renewable target is imposed to 61.7 €/MWh for a 50% target. This means that the reconfiguration cost for Zone B ranges between 4.4-11.9 €/MWh$_{\mathrm{RES}}$. Introducing the hourly dispatch constraints in the Variability scenario drives up the system costto 56.0-62.4 €/MWh. This means that the flexibility cost for Zone B ranges between 0.3-1.0 €/MWh$_{\mathrm{RES}}$. Finally, introducing the operating reserve requirements in the Uncertainty scenario further drives up the system cost to 56.0-62.4 €/MWh. Then, the flexibility and balancing costs for Zone B range between 5.7-13.8 €/MWh$_{\mathrm{RES}}$. While the reconfiguration and flexibility costs of Zone B are more or less comparable with Zone A, the flexibility adequacy cost is 120-135% higher due to the significantly higher VRES-E uncertainty.

Figure B.3 shows the difference in total system cost in CAPEX and OPEX. The shifts in cost when transitioning from the Adequacy to the Variability scenario are much larger for Zone B than for Zone A: around 4 €/MWh vs. around

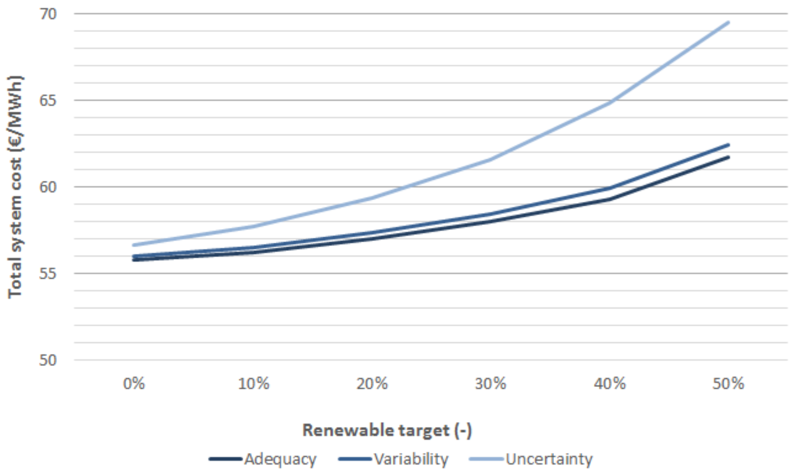

Figure B.2: Total system cost expressed in €/MWh of total demand for an increasing RES-E share for the Adequacy, Variability and Uncertainty scenario.

1 €/MWh. The net cost increase, however, is only slightly higher. Essentially, the demand and VRES-E profiles are more variable for Zone B than for Zone A, causing a larger shift from Base to Mid capacity; but the impact hereof on the total system cost is still limited. Again, at high renewable targets the residual load curve already pushes investments towards the more flexible, low CAPEX technologies in the Adequacy scenario. Consequently, the difference between the two scenarios is smaller in terms of shifts in investments. The total system cost increase when transitioning from the Adequacy to the Uncertainty scenario is much higher. At low renewable targets the cost shift is also the result of the Base to Mid shift. When further increasing the renewable target, the CAPEX increase relatively quicker, driven by massive investment in Peak capacity; as will be shown hereafter. As a result, at high renewable targets there is an significant increase in both CAPEX and OPEX.

B.3 The impact on investments

Figure B.4 shows the total installed capacities of Zone B. Again, the 6 GWh of available energy capacity is always fully developed. Load shedding is negligible (<0.01% of demand). The lay-out of the capacity mix is similar to that of Zone A. Total installed dispatchable capacity remains more or less constant

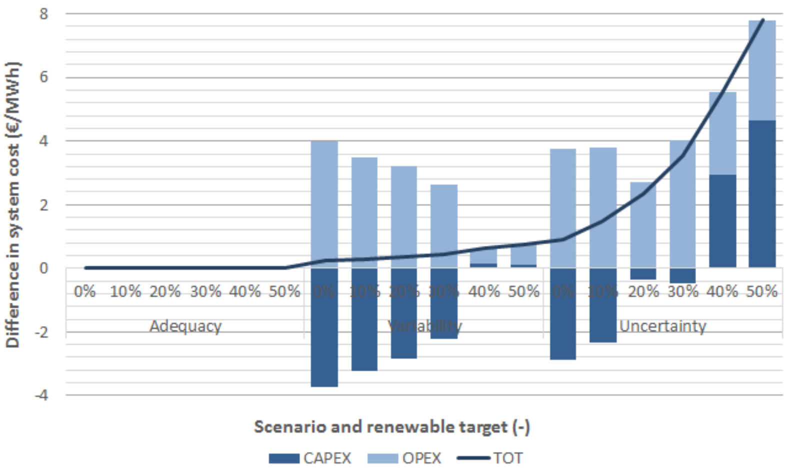

Figure B.3: Difference in total system cost expressed in €/MWh of total demand for the Adequacy, Variability and Uncertainty scenario, compared to the Adequacy scenario.

over the different renewable targets for the first two scenarios, and increases in the last scenario. The increase is relatively larger for Zone B than for Zone A, due to the high VRES-E uncertainty. Investments in VRES-E capacity are similar across scenarios. Once more, the onshore wind resource is the most cost-effective option. Only at higher targets, investment is differentiated for reasons explained in Section 4.4.2, and PV capacity is developed.

Figure B.5 shows the difference in installed capacity compared to the Adequacy scenario. For the Variability scenario the difference is small (at most 550 MW), with larger capacity shifts (up to 3 000 MW). Again, the same two tendencies can be seen. At low targets, there is a shift from Base to Mid capacity. At high targets, there is an increase in High Peak and PHES capacity, a decrease in Peak capacity, and an increased differentiation in VRES-E capacity. These tendencies are also present in the Uncertainty scenario; with much more VRES-E capacity differentiation. Additionally, there is the massive growth in peak capacity to be able to meet the upward reserve requirements. Total installed capacity increases by up to 14.5 GW, with no less than 13.8 GW of this increase coming from additional High Peak and PHES investment.

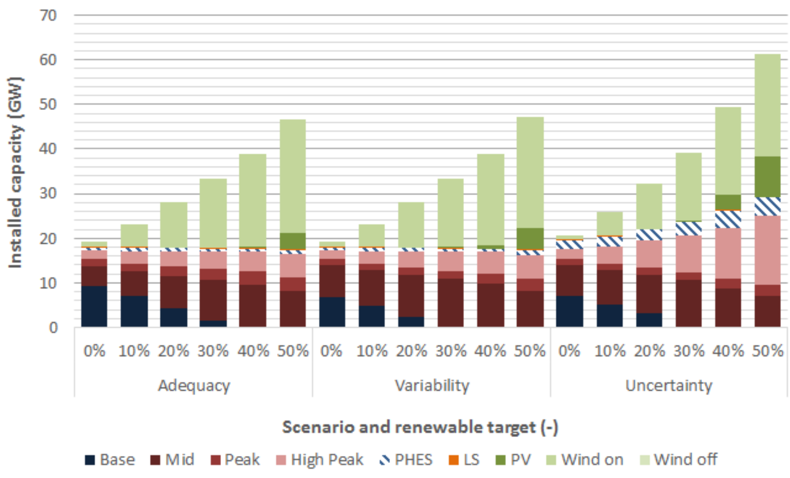

Figure B.4: Installed power capacity in GW for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

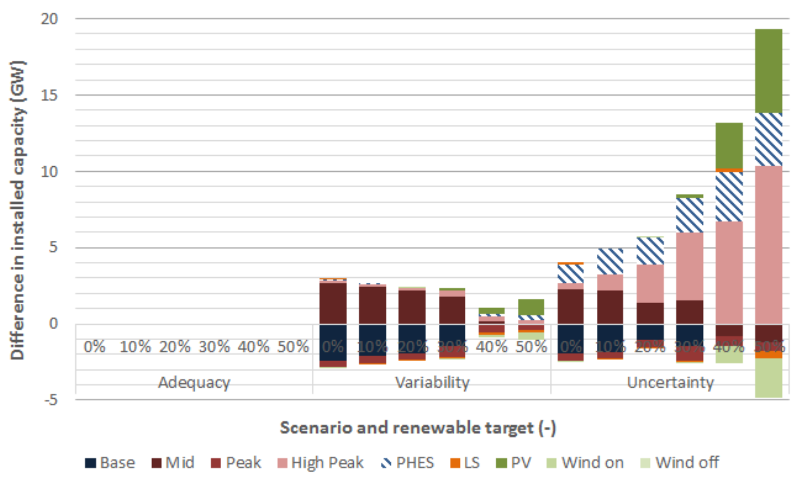

Figure B.5: Difference in installed power capacity in GW for the Adequacy, Variability and Uncertainty scenarios, compared to the Adequacy scenario.

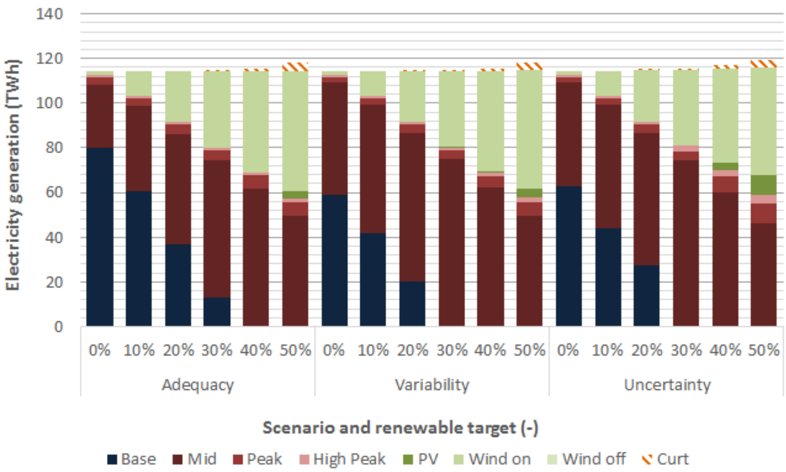

Figure B.6: Annual electricity generation and curtailment in TWh for the Adequacy, Variability and Uncertainty scenario for different renewable targets.

B.4 Energy and reserve provision

Figure B.6 shows the annual electricity generation and curtailment. For Zone B, the operational constraints have a more visible impact on the observed generation patterns. The shift from Base- to Mid-generated electricity is more obvious. PV generation is also clearly higher in the Uncertainty scenario. Otherwise, generation and curtailment are more or less similar across scenarios.

Figure B.7 shows the average upward reserve allocation. The lay-out hereof is similar to that of Zone A. The Mid technology has a slightly larger share of the FCR provision, as they are relatively smaller compared to the system size. The main difference, however, is the tremendous increase in the FRR requirements. The average aFRR and mFRR capacities are three and two times higher, respectively, than in Zone A. This drives the massive High Peak and PHES investments in the Uncertainty scenario.

Figure B.8 shows the average downward reserve allocation. Again, the lay-out hereof is similar to that of Zone A. The allocation follows the annual electricity generation mix. As the renewable target increases, the value for downward reserves increases and the storage technologies assumes a larger share of the provision. A notable difference is the absence of downward reserve provision by variable renewables. In Zone A, on average around 40 MW of downward

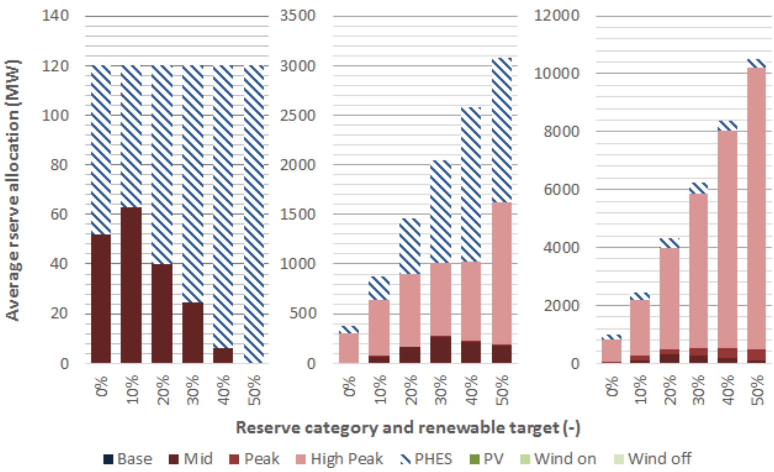

Figure B.7: Upward reserve allocation in MW for the Uncertainty scenario for the different upward reserve categories for different renewable targets.

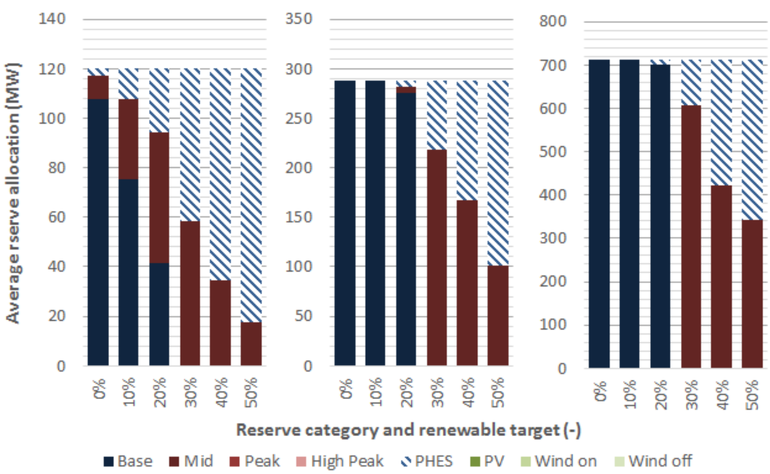

Figure B.8: Downward reserve allocation in MW for the Uncertainty scenario for the different downward reserve categories for different renewable targets.

reserve capacity came from the onshore wind capacity. While modest, the fact that this is not the case in Zone B points once more to the high uncertainty of the variable output.

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Alles is in mij, dacht hij, de hele wereld, al het licht, alle lucht, alle gedachten van iedereen, be–halve ik.

Toon Tellegen, “Het vertrek van de mier”

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