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Electrical Flexibility in the Chemical Process Industry

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Melsele, December 2020
Jens Baetens

Nederlandse samenvatting –Summary in Dutch–

Met een wereld in volle energietransitie wordt onderzoek over energie verondersteld één van de vereisten te zijn om tot een volledig koolstofvrij energiesysteem te komen. De introductie van elektriciteit als een gemeen goed in de late jaren 1800 heeft een steeds groter wordende wereldwijde vraag naar elektriciteit als gevolg, welke zich tot op vandaag voortzet. Met een overgrote meerderheid van de elektriciteitsproductie die gebaseerd is op fossiele brandstoffen, is ook de wereldwijde uitstoot van CO_2 toegenomen [1]. Dit laatste decennium werd de door fossiele brandstoffen gedomineerde elektriciteitssector echter aangevuld met niet-stuurbare hernieuwbare elektriciteitsproductie, voornamelijk gebaseerd op zon en wind. De introductie van deze niet-stuurbare hernieuwbare elektriciteitsproductie is geografisch niet homogeen verdeeld en kent enkele geconcentreerde zones, zoals Europa met als voorloper Duitsland. Maar ook in België wordt reeds een aanzienlijk deel van de elektriciteit opgewekt met niet-stuurbare hernieuwbare energiebronnen. België bekleedt namelijk een wereldwijde vierde positie voor de productie van hernieuwbare elektriciteit per persoon met windturbines op zee [2]. Het feit dat deze hernieuwbare energiebronnen niet-stuurbaar zijn, is een indirecte aanleiding tot het onderzoek gevoerd en gepresenteerd in dit werk.

Een elektriciteitscentrale wordt als stuurbaar beschouwd wanneer deze kan produceren op vraag en nood hieraan. Elektriciteitsnetwerkoperatoren of de elektriciteitsmarkt geven signalen aan de producenten over wanneer en hoeveel elektriciteit moet worden geproduceerd, om het zo af te stemmen op het verbruik. Deze stuurbare centrales worden daarom als flexibel beschouwd. Dit principe van *productie volgt verbruik* is historisch gegroeid, maar wordt bedreigd door de introductie van niet-stuurbare elektriciteitscentrales. Wegens de lage productiekost zouden de hernieuwbare niet-stuurbare elektriciteitscentrales de conventionele centrales uit de markt kunnen duwen, wat de verplichte balans tussen elektriciteitsproductie- en verbruik dreigt te compromitteren. Om dit risico van de verstoring van de balans te voorkomen, dient er te worden gezocht naar nieuwe bronnen van flexibiliteit. Daarom wordt er, in dit werk, onderzocht of de chemische procesindustrie de mogelijkheid heeft om een deel van deze benodigde flexibiliteit te leveren. De grote energievraag van de chemische sector speelt hierbij een belangrijke rol. De verschuiving van deze flexibiliteit naar de verbruikerszijde wordt ook wel *vraagsturing* genoemd.

Naast de hoofdonderzoeksvraag, namelijk of de chemische procesindustrie technisch geschikt is voor het leveren van deze elektrische flexibiliteit, ook wel systeemflexibiliteit genoemd, worden ook de valorisatie-opties besproken. De energie en ondersteunende dienstenmarkten hebben een gigantische hervorming gekend gedurende de voorbije decennia, met een gelijk speelveld voor alle technologieën tot gevolg. Daarom wordt er in dit werk ook een overzicht gegeven van de mogelijke valorisatie-opties, met daarbij een onderscheid te maken op basis van het impliciete en expliciete karakter. Impliciete flexibiliteit wordt gedefinieerd als de reactie van een marktpartij op prijssignalen [3]. De *SPOT* markten, zijnde de elektriciteitsgroothandelsmarkten waar elektriciteit wordt verhandeld op korte termijn, zijn één van de bronnen voor dergelijke prijssignalen. Maar ook de onbalansprijs, het instrument dat gebruikt wordt in het onbalansverrekeningssysteem om de marktpartijen aan te moedigen om hun balans te behouden of herstellen, is zo een dergelijk prijssignaal. Dit onbalansverrekeningssysteem wordt ook wel de *onbalansmarkt* genoemd en is een systeem dat opgezet is door de transmissienetbeheerder om elektriciteitsverbruikers en -producenten te beboeten of aan te moedigen, gebaseerd op het verschil tussen nominatie en effectieve afname of injectie. Expliciete flexibiliteit wordt gedefinieerd als toegewijde, stuurbare flexibiliteit die wordt verhandeld op speciaal daarvoor voorziene markten. De belangrijkste van deze markten is die van de balanceringsondersteunende diensten, ook wel de reservemarkt genoemd. Volumes van vermogen en energie worden gecontracteerd met een derde partij, meestal de transmissienetbeheerder, die deze dan inzet volgens nood. Deze ondersteunende dienstenmarkt, hoofdzakelijk bestaande uit een frequentiebegrenzingsreserve, frequentieherstellingsreserves en een vervangingsreserve, is de dag van vandaag hoofdzakelijk gebaseerd op landsniveau. In de nabije toekomst zal er een Europese eengemaakte ondersteunende dienstenmarkt gecreëerd worden die de homogenisering van deze producten verreist. Al deze aspecten zoals hier aangehaald, worden bediscussieerd vanuit het standpunt van het valorisatiepotentieel voor de vraaggestuurde flexibiliteit. De ondersteunende dienstenmarkt is ook gekoppeld aan het onbalansverrekeningssysteem, beide worden namelijk uitgebaat door de transmissienetbeheerder. Specifieke marktomstandigheden omtrent het Belgische systeem worden meer in detail besproken, zoals ook de verschillende marktpartijen zoals die gedefinieerd worden door het Europese netwerk van transmissienetbeheerders.

Het *waarom* en *hoe* van het onderzoeken van het potentieel in de chemische procesindustrie tot het leveren van elektrische flexibiliteit is het onderwerp van het tweede hoofdstuk van dit werk. De grootte van het elektriciteitsverbruik van de industrie in het algemeen en de chemische procesindustrie in het bijzonder wordt gezien als de belangrijkste drijfveer van dit onderzoek. De chemische procesindustrie wordt gekenmerkt door een continue 24/7/365 operatie van de processen en een doorgedreven integratie op vlak van energie- en productstromen. Dit voorgaande gecombineerd met veiligheid, wat hoog in het vaandel wordt gedragen, en het onderhevig zijn aan strikte operationele condities maakt dat de flexibele uitbating van deze processen niet voor de hand liggend is. In dit werk wordt een methodologie voorgesteld die de elektrische flexibiliteit van industriële sites analyseert op basis van de vermogens, energiestromen en stuurbaarheid van de processen.

De methodologie wordt toegepast op de Belgische industriële sites van INEOS, wat leidt tot een lijst met concrete voorbeelden van processen en machines die als flexibel kunnen worden beschouwd. Hoewel alle geanalyseerde industriële sites toebehoren tot één bedrijf zijn er onderling toch significante verschillen omwille van de heterogeniteit van de uitgebate processen. Sommige van de processen zijn beschikbaar op de meeste van de productiesites, andere zijn dan weer zeer specifiek en uniek. Gemeenschappelijke ondersteunende processen zijn vaak van thermische aard, met als voorbeelden de verschillende soorten koelprocessen, die een potentieel voor flexibele sturing met zich meedragen. Meer specifieke kernprocessen die gestuurd kunnen worden met een invloed op het elektrisch verbruik zijn elektrolyse en extrusie. Ook de beschikbaarheid van warmtekrachtkoppelingen op de industriële sites wordt bekeken als een bron van flexibiliteit.

Wanneer het niveau van de individuele productiesite wordt overstegen, kan ook het potentieel van clustering beschouwd worden. Twee mogelijke clusterniveaus die beschouwd worden, zijn die op geografisch lokaal niveau en deze op een virtueel landelijk niveau. Een kader wordt voorgesteld die het geaggregeerde elektrische flexibiliteitspotentieel beschouwt, door het opzetten van een INEOS interne balanceringsdienstleverancier. Deze laatste is met andere woorden een virtuele cluster die toelaat de geaggregeerde volumes aan flexibiliteit te verhandelen op de balanceringsondersteunende dienstenmarkt. Dit vertoont gelijkenissen, maar ook verschillen ten opzicht van bestaande commerciële partijen. De transparantie tussen de marktpartijen, zijnde de INEOS industriële sites, en de korte termijn verplichting zijn de meest onderscheidende factoren.

casestudy's worden gebruikt om het voorgaande onderzoek meer gedetailleerd toe te lichten. Zo handelt een eerste casestudy over het ontwikkelen van een model voor een koelsysteem gebaseerd op een geïnduceerde luchtstroom in een koeltoren met verdamping van het koelwater tot gevolg. De elektrisch aangedreven ventilatoren die de luchtstroom in de koeltoren induceren, zijn gedefiniëerd als zijnde flexibel in sturing, rekening houdende met de thermische inertie van een dergelijk systeem. Om de beschikbaarheid en timing van de controle van de ventilatoren te analyseren, wordt het ontwikkelde model gebruikt om de temperatuur van het waterbassin te simuleren. Deze temperatuur is namelijk de limiterende factor in het flexibel bedrijven van de ventilatoren. Er wordt een vergelijking gemaakt tussen een *white box* en een *black box* model, die in dit geval uitdraait in het voordeel van het *white box* model. Dit laatstgenoemde model laat ook toe procesparameters te variëren buiten hun bestaande grenzen. Voorbeelden zijn de vergroting van het koelwatervolume om zo de impact op de thermische inertie te onderzoeken of het simuleren van voorkoeling.

De uitbating van een hybride stoomproductieproces bestaande uit een gasboiler en een elektrodeboiler wordt besproken in de tweede casestudy. Het idee van deze studie is om de elektrodeboiler flexibel in te zetten op basis van prijssignalen van de onbalansmarkt. Een onbalansprijsvoorspellingsalgoritme is daarvoor ontwikkeld om als input te dienen. De bimodale distributie van de onbalansprijs wordt beschouwd als een voordeel voor de operatie van een dergelijk hybride stoomproductieproces.

Een laatste casestudy handelt over de mogelijkheid om de uitbating van een chloor-alkali-elektrolyseproces te optimaliseren. Het wordt aangetoond dat de valorisering van de flexibiliteit op zowel de *day ahead market* als door het leveren van de frequentiebegrenzingsreserve resulteert in een lagere operationele kost ten opzichte van een continue vlakke uitbating van het proces. Om de optimalisatie van het proces op deze markten toe te laten, worden er prijsvoorspellingsalgoritmes ontwikkeld die als input dienen. Aangezien het voorspellen van prijzen onzekerheid met zich meebrengt, wordt dit gecompenseerd door het toepassen van een tweetraps stochastische modelleringstechniek. Er wordt aangetoond dat de stochastische oplossing de winst door het flexibel uitbaten van het proces nog licht kan verhogen.

English summary

With a world in full energy transition, research on the topic of energy is considered as one of the prerequisites to reach the ultimate goal of a fully decarbonised energy system. The introduction of electricity as common good in the late 1800s started a year-over-year increase of the global electricity consumption until today. With the majority of power plants worldwide running on fossil fuels, also the emittance of the greenhouse gas CO_2 has thus been increasing [1]. The last decade, the fossil fuel dominated electricity sector has been supplemented with non-dispatchable renewable electricity generation, based on sun and wind. Being not spread homogeneously across the globe, renewable electricity generation knows some geographically concentrated areas, such as Europe with Germany being the front-runner. But also in Belgium a significant part of the electricity is already being produced by non-dispatchable renewable generation, as it occupies a fourth place world wide in offshore wind production per capita [2]. The fact that these renewable sources are non-dispatchable is the indirect cause of the research as presented in this work.

Dispatching power plants is the concept of instructing them to produce electricity on request, based on the need for electricity. Grid operators or the market give signals to the supply side when en how much electricity to produce, so to attune it with the consumption. This principle of *supply-follows-demand* for electricity has been grown historically, but is being disrupted due to the uprise of non-dispatchable generation. The needed balance of supply and demand of electricity might be compromised as more and more non-dispatchable renewable generators are added into the market, gradually pushing out the conventional fossil fuel power plants. Risking the deterioration of the electricity system operation, new sources of electrical flexibility need to be found. Therefore, in this work, the ability of the chemical process industry to supply this needed flexibility towards the electricity system is being investigated. This shift to revert to the demand side for the sourcing of flexibility is referred to as *demand side response*.

With the main research question dealing with the technical ability of the chemical process industry to supply electrical flexibility, i.e., power system flexibility, also the valorisation options are considered. The energy and ancillary services markets have known a tremendous change over the past decades, fostering a level playing field for all technologies to valorise their flexibility. Therefore, in this work, an overview is given of the options to valorise electrical flexibility, in both implicit and explicit ways. Implicit flexibility is the reaction of a market party to price signals [3]. The SPOT markets, i.e., the electricity wholesale markets where

electricity is traded on short-term basis, are one of the sources for such price signals. But also the imbalance price, the instrument in the imbalance settlement system to incentivise market parties in maintaining or restoring the balance in their portfolio or overall system, is considered. The latter, often being referred to as the *imbalance market*, is a system as setup by the TSO so to penalise or incentivise electricity consumers based on the difference between their nominated and actual electricity consumption and/or production. Explicit flexibility is defined as committed, dispatchable flexibility which is traded onto markets. The main market for trading of this flexibility is the balancing ancillary services market, also termed the *reserves* market. Volumes of power and energy are contracted with a third party, often being the transmission system operator, which then uses is to activate in case of system needs. These ancillary services market, with the frequency containment reserve, the frequency restoration reserves and the replacement reserve, is upon today mostly country based. In the near future, a homogenisation in Europe will allow for a European wide ancillary services market. All these aspects are discussed, always from the viewpoint of valorisation potential for demand side flexibility. These ancillary services market is also coupled to the imbalance settlement system, as both are operated by the transmission system operator. Specific market conditions regarding the Belgian system are discussed as well as the different market actors as currently defined by the European network of transmission system operators.

The *why* and *how* of investigating the potential of the chemical process industry in contributing to supply of electrical flexibility services is the main topic of a second part of this work. The magnitude of electricity consumption of the industry in general, and this sector in detail, is discussed as being the main driver for this research. The chemical process industry is characterised by a continuous 24/7/365 operation and a thorough process integration in terms of energy and materials. Combined with safety being high on the priority list and often tight operational conditions, the flexible operation of processes is not always obvious. Here, a methodology is proposed to assess chemical process industrial sites so to define the electrical flexibility potential. Based on energy, power and controllability of processes, a list is constructed of potentially interesting cases considering electrical flexibility. This list is based on the application of the methodology on all of the Belgian INEOS industrial sites. Being nine heterogeneous and individual sites, despite all being INEOS, comes up with interesting results. While some processes are commonly available on chemical process industrial sites, others are site specific. Commonly found utilities processes are mostly of thermal nature, with different kinds of cooling processes showing a potential for flexible operation. More specific core processes which could be controlled having an influence on the electricity consumption pattern are electrolysis and extrusion processes. With the on-site combined generation of heat and power, also a flexible asset is introduced. The Combined Heat and Power Plant (CHP) allows for a significant flexible control.

Transcending the individual industrial site level, the potential of clustering is considered. Two clustering levels, being a geographical local cluster and a virtual cluster, are defined and applied on the Belgian INEOS sites. Defining the potential considering the electrical flexibility, a framework is proposed to setup an INEOS internal balancing service provider, i.e., a virtual cluster allowing to valorise the aggregated flexibility volumes on the balancing ancillary services market. While similar to existing commercial flexibility service providers, some distinctions are present. The transparency between market parties and the short-term commitment are the most important proposed distinguishing factors.

Case studies present a more detailed research on some of the previously defined potentially interesting flexibility cases. A first case study deals with the development of a model for an induced draft evaporative cooling system. The electricity driven fans to induce an air flow through the cooling tower are defined as being potentially flexible in control, considering the thermal inertia of these systems. To assess the availability and timings to control the fans, the model is used to simulate the water basin temperature, which is the limiting factor in flexible operation. A comparison between a developed black box and white box model is made, in favour of the white box modelling method. The latter allows for the simulation of varying process parameters, such as the enlargement of the thermal inertia by increasing the water volume or using pre-cooling to increase the duration of fan power decrease.

The operation of a hybrid steam production utility, with a natural gas boiler and an electrode boiler, is discussed in a second case study. The idea is to flexibly operate the electrode boiler based on price signals from the imbalance market. An imbalance price prediction is therefore developed to serve as input. The bimodal distribution of the imbalance price is considered as a benefit in the operation of such a hybrid system.

A last case study elaborates on the ability to optimise the operation of a chlor-alkali electrolysis process. Valorising the flexibility on both the day ahead market and by supplying frequency containment reserve is shown to be profitable, especially compared to a flat load operation. To allow for the process to be optimised based on these markets, price prediction algorithms are developed to serve as input. As price predictions bring uncertainty, this is compensated by applying a two-stage stochastic modelling. The stochastic solution proves to slightly further increase the profits to be made by flexible operation.

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List of Acronyms

A

ABS	Acrylonitrile Butadiene Styrene
AC	Alternating Current
ACE	Area Control Error
ACER	Agency for the Cooperation of Energy Regulators
ACF	Auto-Correlation Function
aFRR	automated Frequency Restoration Reserve
AIC	Akaike Information Criterion
AMCA	Air Movement and Control Association
ANFIS	Adaptive Neuro-Fuzzy Interference System
ANN	Artificial Neural Network
AO	Alkoxylate
APSO	Accelerated Particle Swarm Optimisation
ARC	Available Regulation Capacity
ARCH	AutoRegressive Conditional Heteroscedasticity
ARIMA	AutoRegereesive Integrated Moving Average
ARMA	AutoRegressive Moving Average
AS	Ancillary Services

B

BEV	Battery Electric Vehicle
BONMIN	Basic Open-source Nonlinear Mixed Integer programming
BRP	Balance Responsible Party
BSP	Balancing Service Provider
BU	Business Unit

C

CAES	Compressed Air Energy Storage
CAPEX	CApital EXpenditures
CBMP	Cross Border Marginal Price
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
CCTU	Capacity Contracting Time Unit
CDS	Closed Distribution System
CDSO	Closed Distribution System Operator
CHP	Combined Heat and Power
CIM	Continuous Intraday Market
CIPU	Contract for the Injection of Production Units
CMOL	Common Merit Order List
CMSP	Congestion and grid capacity Management Service Provider
CMU	Capacity Market Unit
CREG	Commission for Electricity and Gas Regulation (Belgium)
CRM	Capacity Remuneration Mechanism
CVPP	Commerical Virtual Power Plant

D

DAM	Day-Ahead Market
DC	Direct Current
DCS	Distributed Control System
DER	Distributed Energy Resources
DOL	Direct OnLine
DP	Delivery Point
DRA	Demand Response Audit
DSM	Demand Side Management
DSO	Distribution System Operator
DSR	Demand Side Response

E

EASA	Electrically Active Surface Area
EBGL	Electricity Balancing GuideLine

EBO	Energy Policy Agreement (EnergieBeleidsOvereenkomst)
EBSM	EthyleBenzene Styrene Monomer
EC	European Commission
EDC	Ethylene DiChloride
EEX	European Energy Exchange
EMS	Energy Management System
ENB	Ethylidene Norbornene
ENTSO-E	European Network of Transmission System Operators for Electricity
EO	Ethylene Oxide
EPEX	European Power Exchange
EU	European Union
EV	Expected Value

F

FAT	Full Activation Time
FBMC	Flow Based Market Coupling
FC-HS	Fuel Cell and Hydrogen Storage
FCM	Fuzzy C-Means
FCR	Frequency Containment Reserve
FF	Failure Factor
FFR	Fast Frequency Reserve
FMM	Fifteen Minute Market
FRP	Flexibility Requesting Party
FRR	Frequency Restoration Reserve
FSC	Fuzzy Subtractive Clustering
FSP	Flexibility Service Provider

G

GCT	Gate Closure Time
GOT	Gate Opening Time

H

HDPE	High Density Poly Ethylene
HEX	Heat Exchangers
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High Voltage Direct Current

I

IAE	International Energy Agency
IE	Industrial Ecology
IEM	Internal Energy Market
iFIS	initial Fuzzy Interference System
IGCC	International Grid Control Cooperation
IM	Imbalance Market
IS	Industrial Symbiosis
ISGAN	International Smart Grid Association Network
ISP	Imbalance Settlement Period

L

LAO	Linear Alpha Olefins
LFC	Load Frequency Control
LMN	Local Model Networks
LMP	Local Marginal Price
LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
LT	Long-Term

M

MAPE	Mean Absolute Percentage Error
MARI	Manually Activated Reserves Initiative
MDP	Marginal Decremental Price
MF	Membership Function

mFRR	manual Frequency Restoration Reserve
MIP	Marginal Incremental Price

N

NaCl	Natrium Chloride
NRV	Net Regulation Volume
NTC	Net Transfer Capacity
NTU	Number of Transfer Units
NUL	Nominal Utilisation Level

O

OCGT	Open Cycle Gas Turbine
OPEX	OPerational EXpenditures
ORC	Organic Rankine Cycle
ORDC	Operational Reserve Demand Curve

P

PID	Piping and Instrumentation Diagram
PACF	Partial Auto-Correlation Function
PAO	Poly Alpha Olefins
PCR	Price Coupling of Regions
PFD	Process Flow Diagram
PG	Providing Group
PHS	Pumped Hydro Storage
PICASSO	Platform for the International Coordination of Automated frequency restoration and Stable System Operation
PP	PolyPropylene
PS	PolyStyrene
PSA	Pressure Swing Adsorption
PSF	Power System Flexibility
PV	PhotoVoltaic
PVC	PolyVinyl Chloride
PX	Power eXchange
PySP	Pyomo Stochastic Programming

R

RES	Renewable Energy Sources
RGCE	Regional Group Continental Europe
RHFC	Regenerative Hydrogen Fuel Cell
RMSE	Root Mean Square Error
ROCOF	Rate Of Change Of Frequency
RR	Replacement Reserves

S

SARIMA	Seasonal AutoRegressive Integrated Moving Average
SARIMAX	Seasonal AutoRegressive Integrated Moving Average with eXogenous parameters
SBC	Styrene-Butadiene Copolymers
SC	SuperConductor
SCADA	Supervisory Control And Data Acquisition
SEC	Specific Electricity Consumption
SFP	Specific Fan Power
SI	System Imbalance
SIDC	Single IntraDay Coupling
SIR	Synchronous Inertial Response
SMES	Superconducting Magnetic Energy Storage
SOGL	System Operations GuideLine
SoS	Security of Supply
SPBC	Standard Product for Balancing Capacity
SR	Strategic Reserve
SRD	Strategic Reserve delivered by the Demand side
SRG	Strategic Reserve delivered by Generation units
STAR	Short-Term Auctioning of Reserves platform

T

TBATS	Trigoniometric seasonality, Box-cox transformation, Arma errors, Trend and Seasonality
TCL	Thermostatically Controlled Load
TERRE	Trans European Replacement Reserves Exchange

TGC	Tradeable Green Certificates
ToE	Transfer of Energy
TSO	Transmission System Operator
TTRF	Time To Restore Frequency
TVPP	Technical Virtual Power Plant
TYNDP	Ten Year Network Development Plan

U

UK	United Kingdom
USA	United States of America
USEF	Universal Smart Energy Network

V

VNB	Vinylnorbornene
VOLL	Value Of Lost Load
VPP	Virtual Power Plant
VREG	Flemish Regulator for the Electricity and Gas market
VSD	Variable Speed Drive
VSS	Value of Stochastic Solution

W

WWTP	Waste Water Treatment Plant

1
Introduction

This introduction sketches a global picture of where the research as presented in this work should be placed. This broader context allows to understand the motivation and goal of this research and shows the relevance in today's world. An outline of this work is presented here as well. The research in this work has been carried out at the Electrical Energy Laboratory (EELAB) at Ghent University. The research was conducted in collaboration with all the Belgian INEOS sites, in the form of a VLAIO R&D project named FLEX (HBC.2017.0361).

1.1 Context of the research

The awareness of the existence of an anthropogenic global warming due to the emissions of greenhouse gasses has started a shift in the way we look at our planet. It made clear that the ever increasing deforestation, farming on industrial level and endless usage of fossil fuels will create disrupting conditions for life on earth. Burning of fossil fuels has known a tremendous increase since the generation of electricity in the 1800s. Power plants based on coal, oil and natural gas are upon today the most used method of generating electricity, responsible for over 40% of the global CO_2 emissions. Luckily, a global energy transition path is being walked with the aim of decarbonising the energy sector by the second half of this century. The European Union has set out a long-term strategy to reach a target of 80% renewable electricity generation by 2050 [4]. Affordable and clean energy is also one of the 17 United Nations Sustainable Development Goals, encompassing concrete global actions. But the introduction and scaling up of renewable electricity generation, with sources such as wind and sun, does come with challenges.

Dispatchable fossil fuel power plants adapt their electricity injection into the grid based on the demand for electricity. The required balance between supply and demand is taken care of by the supply side, with the need for electricity being fulfilled at any moment in time. The technical abilities of the dispatchable power plants create a *supply-follows-demand* relationship, not needing any flexibility nor reaction from the demand side. By integrating more non-dispatchable renewable energy into the electrical grid, the *supply-follows-demand* relationship is to be questioned. Wind and solar energy is by nature not continuously available, is prone to uncertainty and is non-dispatchable. More and more renewable electricity generators are added to the grid, thereby pushing some of the conventional power plants out of the market. As a potential solution to the decreasing flexibility in the grid, the concept of Demand Side Response (DSR) gains interest [5]. As demand side, being able to shift electricity consumption in time can contribute to the amount of renewable electricity which can be integrated into the existing electrical grid [6], fostering the long-term goal of a fully decarbonised energy sector.

Next to the ongoing shift in electricity generation, also a drastic change is happening in the European energy sector and accompanying regulation. The past decade, a shift is made from vertically integrated geographically based monopolies to a transparent pan-European energy-only market allowing competitions between parties. Electricity and ancillary services markets are opened up, alleviating technology bans and creating a level playing field for both producers and consumers. Electricity is valued more close to real time and flexibility is sourced via a market structure, with short and flexible contracting possibilities.

All of these aforementioned conditions allow for the demand side to be actively participating in the balancing of the grid, by supplying flexibility in different forms. In this research, the ability of the chemical process industry to contribute to this need for flexibility is investigated. As the chemical process industry is an energy intensive sector with electricity being one of the main energy vectors, the potential presence of flexibility is real. But chemical process industrial sites are complex and prone to safety considering working with hazardous substances. Processes have extensive heat integration, tight operational conditions and cascading effects, possibly hampering the flexible usage.

This work proposes a methodology to analyse the electrical flexibility potential of a chemical process industrial site. An energy, power and controllability based assessment identifies the ability of the industrial site to participate to the flexibility markets. Numerous heterogeneous processes are considered, with the results ranging from being very flexible to not encompassing any flexibility at all. While this methodology is developed based on the chemical process industry, it is deemed expandable to other industrial sectors as well. A look to the future is given, where the electricity energy vector could become even more pronounced considering electrification and where new industrial sites could be designed for flexibility. An overview of the different options in valorising flexible assets shows today's opportunities, with a focus on the European and Belgian markets. The single site level is transcended and the clustering potential is investigated. Processes as identified to be very promising in supplying electrical flexibility are used as case study.

1.2 Outline of this Work

This thesis is organised as follows.

Chapter 2 deals with the concept of power system flexibility and addresses the general needs and means. The grid balancing principle is explained as applied in Europe with a stronger focus on the Belgian system. The wholesale electricity market and the imbalance settlement system is explained in detail as it serves as implicit flexibility valorisation path. Balancing ancillary services, adequacy and security of supply are discussed, with it being linked to explicit flexibility options. Recent changes in energy market roles and regulation impacting flexibility are illustrated, from the viewpoint of industrial consumers. Two main novel contributions are made in this chapter. The first is the simulation of the impact of the imbalance position of a market party, taking into account the imbalance market size. The second is related to the *Transfer of Energy* regulation and deals with the impact on industrial sites regarding their option to valorise flexibility.

Chapter 3 positions the chemical process industry in Europe and Belgium and highlights the energy intensiveness. A first main novelty is the creation of a flexibility assessment methodology for industry. The technology focussed methodology is based on power, energy and controllability, addressing an overall site, process and machine level. As case study, all Belgian INEOS industrial sites are analysed and the results are described and discussed. The second main part of this chapter deals with clustering of flexibility. Two clustering levels are defined, being a geographically confined local cluster and a virtual Belgian cluster. The creation of a framework to set up such a virtual cluster is considered the second main innovative contribution in this chapter. A detailed internal bidding optimisation as well as a remuneration split methodology are described thoroughly.

Chapter 4 goes into more detail on some cases as identified as having a high flexibility potential. As first case study, an industrially sized, induced draft evaporative cooling tower system is modelled with the goal of simulating the encompassed thermal inertia. Two distinct modelling methodologies are described and validated with industrial data. The development of a tractable model of a cooling system with the purpose of simulating fan control for electrical flexibility purposes is considered the main contribution. As second case study, an imbalance price prediction methodology is developed and applied for the control of a hybrid steam production set up. An existing gas boiler accompanied with an electrode boiler is proposed to be operated based on the imbalance price, implicitly contributing to the grids balance. The imbalance price prediction algorithm, based on a combination of the gradient effect and the close-to-real-time data availability of the net regulation volume is presented as novelty. A third and last case study considers the chlor-alkali process and the ability to optimise the operation considering the day ahead market and the provision of frequency containment reserve towards the TSO. Market price prediction models are developed to be used in the optimisation, while the uncertainty they bring is countered by a stochastic modelling. This combined optimisation of a chlor-alkali electrolyser on an electricity market and an ancillary services market is considered to be novel, especially by including the implemented stochastic mitigation strategy.

Chapter 5 concludes this research and gives a view on related future research potential.

2

Power System Flexibility

2.1 Introduction

Power System Flexibility (PSF) is a very broad term encompassing various subtopics and having multiple synonyms such as electrical flexibility, system flexibility or just flexibility in short. Some definitions by major stakeholders and market players are the following. According to the International Energy Agency (IEA), PSF is defined as *the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise* [7]. Eurelectric, the sector association representing the electricity industry in Europe, describes flexibility on an individual level as *the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system* [8]. The International Smart Grid Action Network (ISGAN) defines PSF rather general as *the ability of the power system to manage changes* [9], but at the same time categorises the flexibility into flexibility for power, energy, transfer capacity or voltage. When referred to electricity consumers, often the terms Demand Side Response (DSR) or Demand Side Management (DSM) are used. DSR focusses on the short-term reaction of electricity consumers on (price) signals, while DSM refers to a broader view, including long-term energy efficiency measures as well [10]. The term DSM was first introduced after the 1973 and 1979 oil crises as term for the practice of using less electricity, specifically during peak hours by moving the consumption towards off-peak hours [11]. By shifting the power consumption in time, the operation of more expensive oil based power plants could be avoided, reducing the operational cost of producing electricity and thus the overall electricity cost for consumers. Shifting the electricity consumption in time would nevertheless leave the total consumption to be unchanged, and the CO_2 emissions would even be slightly higher, as during the 1970s the majority of baseload power plants were coal based. The DSM principle thus relied purely on economics. Today, the use of term DSM or DSR is broadened, also including consumers delivering ancillary services towards the Transmission System Operator (TSO) or balancing the variable Renewable Energy Sources (RES) electricity production. Ancillary services, also known as system services, are sourced by the TSO to maintain the grid frequency and voltage at appropriate levels. Since the TSO does not have own flexible assets to do so, it sources this flexibility from grid users, both consumers and producers. While the main incentivisation for DSM is still economics based, e.g., by variable electricity pricing or ancillary service remunerations, an environmental dimension is added as well. Ancillary services provided by loads diminish the need for ancillary services delivered by fossil fuel based power plants, decreasing the CO_2 emissions. Where peak electricity prices were to be avoided in the 1970s due to oil peaking plants burning oil during sky-rocketing oil prices, today consumption of low marginal cost RES electricity is incentivised due to the created price valleys.

In this work the focus is laid on the electrical flexibility of industrial consumers and producers, both power and energy wise. The following definition for flexibility, from an industry viewpoint, is defined. *To be electrically flexible means being able to adapt the power consumption or production profile inter temporally, on a timescale of seconds to hours, based on an external signal which can either be economical or technical in nature.* This broad definition encompasses all types of electrical flexibility which a market player can valorise.

2.2 Need for Flexibility

Electricity is a unique type of energy carrier. Work is done by moving electric charges, i.e. electric current, between two points of different electric potential. Electricity is weightless, odourless, colourless, invisible, etc. in fact, it is quite an abstract form of energy carrier if you compare it to other well known forms of energy such as gas, oil, heat, hydrogen or wood. Electricity is a secondary energy source, which means it cannot be found in nature but must be produced by - or rather converted from - a primary energy source. Due to its nature, this conversion needs to take place at the same moment of the consumption of the electric energy, or, the other way round, the consumption needs to take place at the moment of electricity production. This simultaneousness of production and consumption requires either the producer, consumer or both to be flexible.

2.2.1 History of Electricity Production

In 1871 the Belgian electrical engineer Zénobe Gramme invented the industrially sized DC dynamo, which can be considered the starting point of the industrial production of electricity [12]. In the years after, several power plants were built using Gramme's technology and were either hydro or steam driven. The first coal-fired steam driven power plant was located in Londen, England and supplied a nearby church, criminal court and post office with electricity [13]. Since the DC technology was used, only a small service area was possible. The war of the currents in the following decade was settled in favour of AC technology, which was deemed more efficient and could cover a larger area using higher voltages, thanks to the invention of the transformer. Individual power plants became larger and started to interconnect to improve reliability. Electrical grids emerged, starting on a community level and later on expanding to national and eventually international levels. Today in Europe, a large meshed high voltage AC grid is operational, interconnecting all European countries as well as having connections with other continents. Figure 2.1 gives an impression on the overall size of the grid in Europe and the amount of connections that exist today, overseen by the European Network of Transmission System Operators for Electricity (ENTSO-E).

During the expansion of the electric industry, coal remained the main primary energy source for electricity production but was supplemented with oil as it was easier to transport and handle. Later, also natural gas was added as primary energy source, mainly in countries having it as natural resource. In the 1950s the first nuclear fission power plant started to deliver electricity to the grid, and by 1986 the yearly commissioned nuclear power plants reached a total volume of more than 30 GW. These fossil fuels, nuclear fission and hydro power dominate the electricity producing industry upon today. A common denominator of all the power plants running on these primary energies is that they are *dispatchable*. The electricity is generated on demand, based by the needs of the electricity consumers or the electricity market. Power plants can increase or decrease their outputs by adapting the burning of fossil fuels, the reactivity of the nuclear core or by adapting the flow of water through the dam. This makes the power plants flexible, allowing them to vary the amount of produced electricity and aligning it with the consumption. Quite recently, in the early 2000s, electricity generated from non-dispatchable renewable energies started to get ground. Two major disruptors are wind turbines and photovoltaic panels (PV) which purely rely on the availability of wind and sun to produce electricity. It is not the fact that the electricity is generated from renewable primary energy sources which causes the main disruption - hydroelectric power is also considered renewable and has been around for much longer - but rather the fact that they are non-dispatchable. The required production-consumption balance, which was historically taken care of by the flexibility of the dispatchable power plants, is thereby threatened to be jeopardised.

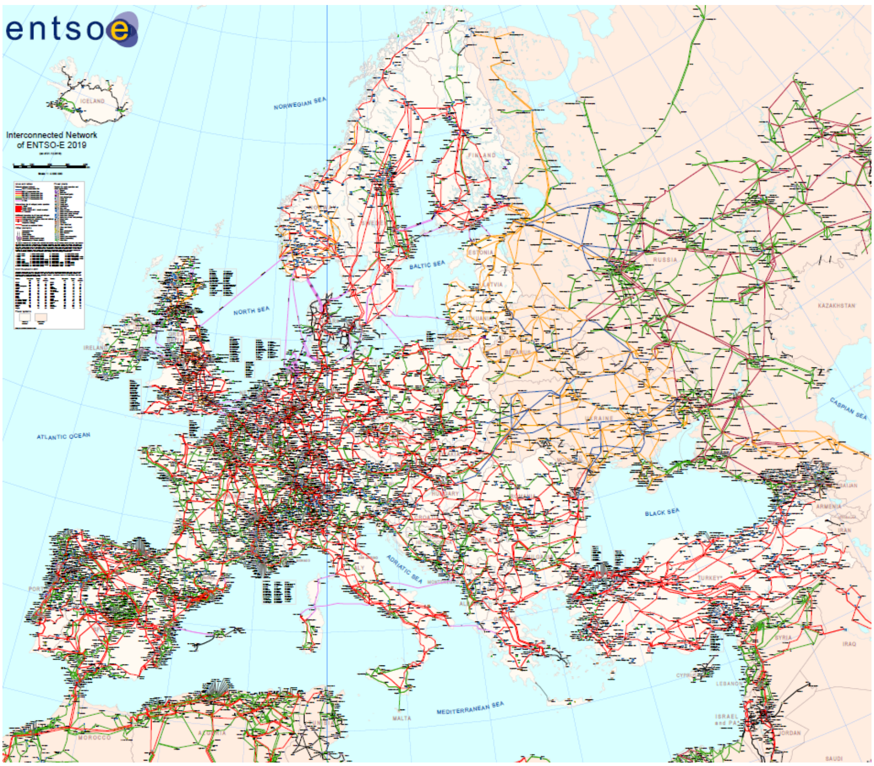

Figure 2.1: Interconnected network of ENTSO-E in 2019 [14].

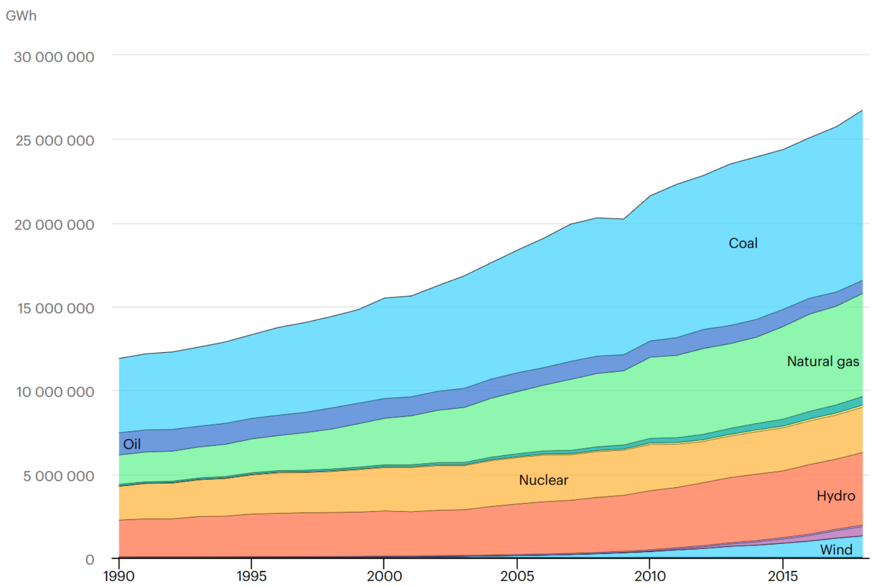

Figure 2.2: Worldwide electricity production by type of fuels [1].

To sketch an idea on the importance of these non-dispatchable RES for the electricity production today, Figure 2.2 shows an overview of the worldwide electricity production by type of fuels for the last three decades [1].

It is clear that upon today coal is the most used primary energy source to produce electricity, covering 38% of the total. A steady growth of the global electricity production is seen as well, where it could be stated that no primary energy type has 'taken over' another, instead they supplement each other to foresee in the growing demand. The non-dispatchable RES generation, i.e., wind (light blue) and PV (pink), have known tremendous year-over-year increases the past decade, yet still only account for a few percentages of the worlds total electricity produced today. But RES electricity generation does not know an equal geographical spread, rather it is clustered in certain countries. Considering the non-dispatchable RES, Germany is one of the frontrunners in Europe with a total of 46% of its electricity generated from RES in 2019 [15]. Those countries already experience the impact of non-dispatchable electricity generation, both on technical and economical level, and therefore can value electrical flexibility.

2.2.2 Storage of Electricity

A solution to the obligation of balancing the generation and consumption for electricity is also made complicated due to the inability to directly store electricity on

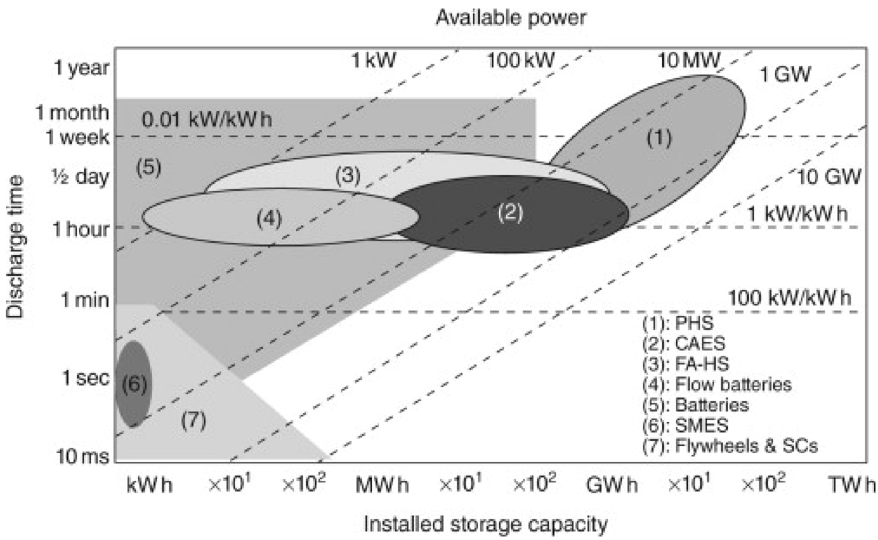

Figure 2.3: Overview of different energy storage technologies, ranked according to discharging time and energy storage volume [16].

a grid scale level. Storing electricity is only possible in an indirect way, by converting it to another type of energy carrier and reconverting it back when needed. Examples are lithium-ion batteries (galvanic potential energy, a type of chemical energy), flywheels (kinetic energy, a form of mechanical energy), pumped hydro storage (gravitational potential energy), hot water (thermal energy) or capacitors (electrostatic charge). Converting energy from one type to another will always go hand in hand with a certain part which is lost, often in the form of low temperature heat. The part of the energy which is converted to the wanted and useful form compared to the original total amount is defined as the efficiency of the energy conversion. Storing electricity is thus only possible by conversion and reconversion, of which the combined efficiencies are defined as the round-trip efficiency. An example is hydrogen. Converting electricity into hydrogen with an electrolysis process will have an efficiency between 60% and 80%, depending on the electrolyser technology. Converting the hydrogen energy back into electricity by the use of a fuel cell can be done with an efficiency of 40% to 60%, again technology dependent. A round trip efficiency of 48% to 24% can thus be reached, i.e., 52% to 76% of the electricity will be lost by storing it. Table 2.1 gives some round trip efficiencies of the most used energy storage technologies. While the round trip efficiency is one of the most important parameters when considering electricity storage, also the energy capacity and charge/discharge times are important.

Figure 2.3 shows an overview of different energy storage technologies and their usage based on the discharging time and the possible energy storage volume [16].

Table 2.1: Round-trip efficiencies of different energy storage technologies [16, 17].

	Pumped Hydro Storage (PHS)	Compressed Air Energy Storage (CAES)	Flywheel	SMES	Regenerative Hydrogen Fuel Cell (RHFC)	Li-ion Battery
Round Trip Efficiency	70% - 85%	60% - 80%	90% - 95%	95% - 98%	30%	90% - 95%

It can be seen that Pumped Hydro Storage (PHS) is the most recommended type for larger energy volumes and longer duration storage, while a flywheel is useful to store electricity for a short period of time and quick discharge. Note that (pumped) hydro storage is the largest type of electricity storage in terms of energy, with a worldwide total estimated capacity of 1.6 TWh [18]. Hypothetically, the energy content of this worldwide PHS would be able to foresee in Belgium's average electricity needs for just over a single week. The actual installed capacity of PHS in Belgium is nevertheless limited to 6000 MWh (see § 2.3.1 for more details). Indeed, the availability of PHS is very dependent on the availability of geographical height (in hills and mountains) and therefore limited in capacity in a country such as Belgium. But also the total global PHS volume is considered to be small. To put this PHS energy content in perspective, Belgium has a single underground natural gas storage facility in Loenhout which has a storage capacity of 725 million m^3 [19]. With the storage of high calorific natural gas, this represents an energy capacity of 8.27 TWh. It becomes clear that the previously made statement of having no grid scale electricity storage available today, is valid. A more recent term with respect to electricity storage is *power-to-X-to-power*. The idea remains to store electricity in an intermediate medium and convert it to electricity again when needed, but the main difference is that this term is mainly used in the context of abundant renewable energy and that the *X* often represents a chemical product, i.e., a molecule. The intermediate medium, noted as *X*, is often hydrogen or a synthesised product based on hydrogen. The ability to store electricity is then limited by the storage potential of *X*. Therefore, often the term *chemical storage* is used as well to refer to storage of electricity by the use of molecules. With the possibility of synthesising hydrogen to methane, i.e., creating synthetic natural gas, the energy storage limits would be defined by the already available natural gas storage facilities. This concept opens the theoretical possibility for large scale storage of electricity, expanding intraday electricity storage to intraweek or even seasonal storage. Next to the given opportunities also some barriers are present, which are discussed in more detail in § 3.3.5.2.

Next to the benefits of enlarging the electricity storage energy wise, also short term and small electricity storage is of interest. These types of electricity storage are visualised in Figure 2.3 on the left hand side, with flywheels and batteries being the two largest technologies. The use of these storage technologies lies in the fast response times and the high power output, which are necessary for certain applications such as real-time balancing of the electricity grid. The grid balancing principle and the need for fast reacting power suppliers is discussed in more detail in 2.3.2. Especially on the Li-ion battery technology, significant progress has been made over the past decade. The applications have widened starting from small batteries for consumer electronics to Battery Electric Vehicles (BEV) and home batteries to even grid scale batteries with power and energy units expressed in MW and MWh such as the Tesla Megapack [20]. In the previous years, such grid scale Li-ion battery packs were installed worldwide with the main goal of balancing the electricity grid [21]. With the ability to provide balancing ancillary services and arbitrage on the intraday and day-ahead electricity markets, business cases for stand-alone batteries prove to be viable [22]. Also in Belgium, large scale Li-ion batteries are present and deliver balancing ancillary services to the grid. They can therefore compete with other types of electrical flexibility providing assets such as conventional power plants or demand side response. Nevertheless, it is not expected that this battery technology will expand in such a way that it will compete with PHS or *power-to-X* on an energy level. In 2017 only 11 GWh of batteries was installed, with a realistic growth path to between 100 GWh and 167 GWh by 2030 [23].

In 2016, a report based on a METIS study conducted in the name of the European Commission (EC) regarding the role and need of flexibility in 2030 with a focus on energy storage was published. Two different scenarios are considered, one more ambitious towards RES integration than the other. The *Green Transition* scenario assumes that 50% of electricity demand in 2030 will be covered by RES, while the *Slow Progress* scenario assumes only a level of 41%. The need for flexibility is calculated over a daily and weekly period and is defined as the amount of energy which has to be shifted in order for the residual demand to become constant over the period. Assessing the drivers for flexibility needs, they found that mainly wind power creates a necessity for weekly flexibility. The impact of PV on the need for flexibility is much lower, and even non-existing as long as the penetration does not increase to 10-12% of the yearly power production [24]. This study concludes that short-term flexibility (few hours) can be provides by batteries, while mid-term flexibility (hours to days) could be provided by PHS and Compressed Air Energy Storage (CAES). An important role can also be played by interconnectors, allowing for the flattening of the variability of the weather conditions [24]. While the main conclusion is considered to be valid, the attention given to *power-to-X*, or *power-to-gas* as it is mentioned in the study, is deemed limited. The date of the study might be of relevance, as the viability of *power-to-X* might have changed over the past years.

It can be concluded that electricity storage is of interest for two major reasons. Grid scale electricity storage, with a focus on energy capacity, is today dominated by PHS but might in the future be surpassed by *power-to-X-to-power* projects. Storage of large volumes of energy, which can be converted back to electricity might be of interest in the light of security of supply issues and seasonal storage. Nevertheless, upon today it cannot be said that large (grid) scale electricity storage is already present. The second main potential for electricity storage is linked to fast response times and high power levels. Technologies such as (Li-ion) batteries and flywheels are of interest and are already available today. Also the economic viability is considered to be good, as several projects are already implemented globally. Also in Belgium grid scale Li-ion batteries are delivering balancing ancillary services to the grid.

Electricity storage is thus one of the major solutions to the increased need for flexibility. Nevertheless, storing electricity goes hand-in-hand with energy losses. The round-trip efficiency will largely define the economic viability of the solution. Producing and consuming the electricity directly avoids these energy losses linked to storage and could thus also have an economic benefit. While the storage of electricity is and will become more important in the future considering the increase of non-dispatchable generation, it is not perceived as being a single overarching solution. Flexibility from other sources, such as the conventional flexibility from dispatchable generation or in the form of demand side management is deemed to be evenly important. In an open electricity market structure as it is known in Europe today, it will be a matter of economics which technologies will provide the necessary flexibility.

2.2.3 Flexibility in Numbers

Defining the future need and availability for power system flexibility is rather difficult as it is based on forecasts and assumptions. Quantitative reports on flexibility needs and availabilities are scarcer than qualitative reports, which only describe the mechanisms and rationale. It is important to make a distinction on the type of flexibility as well, being implicit or explicit, as well as with respect to activation duration and reaction time.

2.2.3.1 Flexibility Needs

The need for flexibility in the grid is defined by the ENTSO-E as the need to cope with residual load ramps. The residual load is a power system indicator, showing the needed capacity which needs to be filled in by conventional, dispatchable, power plants. It is defined as the total system load minus the RES production and, depending on the source of definition, the *must-run* units, i.e., power plants running at lowest capacity which cannot be stopped [25, 26]. An example of a

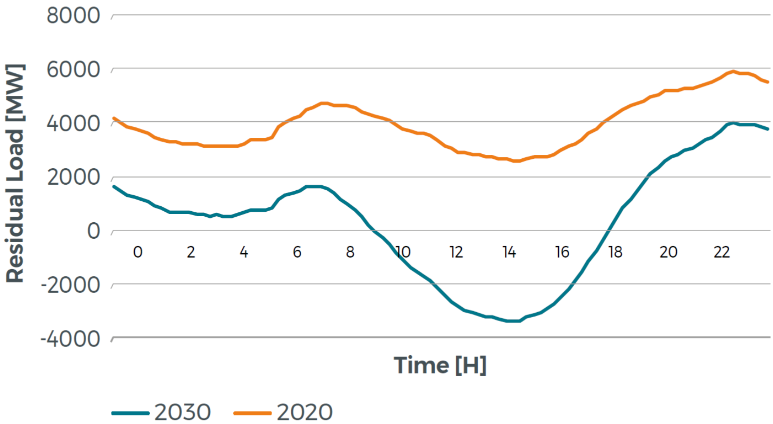

Figure 2.4: Residual load curve prediction for Belgium for 2020 and 2030. The duck curve effect is more pronounced on the 2030 curve [26].

predicted residual load curve for Belgium is given in Figure 2.4. The curve for 2030 is a so called *duck curve*, with low load demand during sunlight hours and a steep increase during sunset hours. It is this residual load ramp which defines the need for flexibility, i.e., the amount of RES integration is the defining parameter. In the Ten Year Network Development Plan (TYNDP), ENTSO-E defines some scenarios based on national trends, global ambitions and distributed energy, where the amount of RES integration varies [27]. In the distributed energy scenario, the resulting hourly ramps of residual loads for the RGCE synchronous area could increase up to 70 GW/h, showing the need for upward flexibility, while also negative values up to 60 GW/h are deemed possible in 2040, creating a need for downward flexibility [27]. Figure 2.4 shows periods with a negative residual load for Belgium by 2030, both in time and magnitude. In other words, there will be moments during which the RES and must-run units will not only cover, but exceed the demand, creating the necessity for downward flexibility. Elia notes that also the loss of an interconnector, e.g., the NEMO link[1], during moments of export, could create the need for fast downward flexibility.

Elia, the Belgian TSO, published a methodology to determine the flexibility needs for Belgium in more detail. Three types of flexibility are defined, being the *Slow Flex* (TF), *Fast Flex* (FF) and *Ramping Flex* (RF), with each their respective characteristics. TF is considered as capacity which can be started or shut down intraday, i.e., several hours beforehand. The FF is considered as capacity which can be controlled close-to-real-time, from a few hours to minutes and RF is capacity which can be controlled in a timeframe of minutes. The methodology

[1] The HVDC interconnector with a capacity of 1 GW between Belgium and UK.

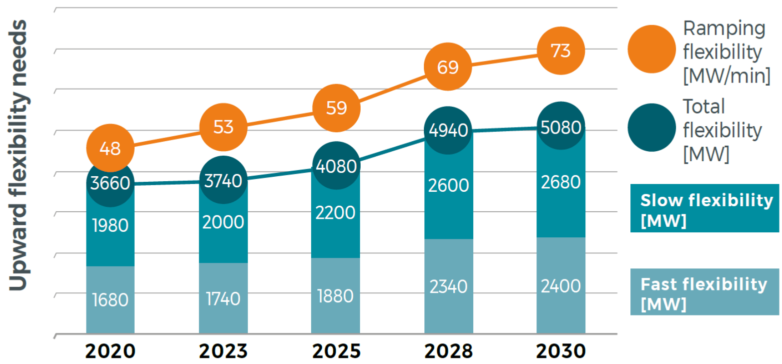

Figure 2.5: Upward flexibility needs for Belgium towards 2030 [26].

is based on monte-carlo simulations and probability distribution functions, considering residual load forecast errors, risks of forced outages, etc. The complete methodology can be found with Elia [26]. Figure 2.5 and Figure 2.6 show the resulting needed flexibility capacity for Belgium towards 2030, for the upwards and downwards type respectively. A general conclusion is that the need for flexibility, both upwards and downwards, for the slow, fast and ramping flex, will increase towards 2030. A total of 5080 MW and 4310 MW of upwards and downwards flexibility will be necessary by 2030 respectively. The main reason to be found for this increase is the integration of RES and the accompanying increasing forecast risks. Focussed on the different RES technologies, it is mainly offshore wind which contributes to the need for flexibility, due to its geographical concentration. It should be noted that these results are based on a *central* scenario of Elia, where the nuclear phase out is confirmed and the nuclear units are replaced by large (600 MW to 800 MW) central generation units. In case of a more distributed generation scenario, the need for flexibility would drop slightly (less than 100 MW). Reason for this reduction is the reduced forced outage risk which is present with large generation units.

2.2.3.2 Flexibility Means

The ability to provide the necessary flexibility defines whether the grid can be safely operated or that measures need to be taken to increase the flexibility with market parties. In its adequacy and flexibility report with horizon towards 2030, Elia defines the assumed installed flexibility in Belgium for 2020 and 2030 [26]. The projection for 2030 is based on a *central* scenario. Figure 2.7 and Figure 2.8 show the assumed installed upward and downward flexibility respectively, with a distinction between the *Slow Flex* (TF), *Fast Flex* (FF) and *Ramping Flex* (RF).

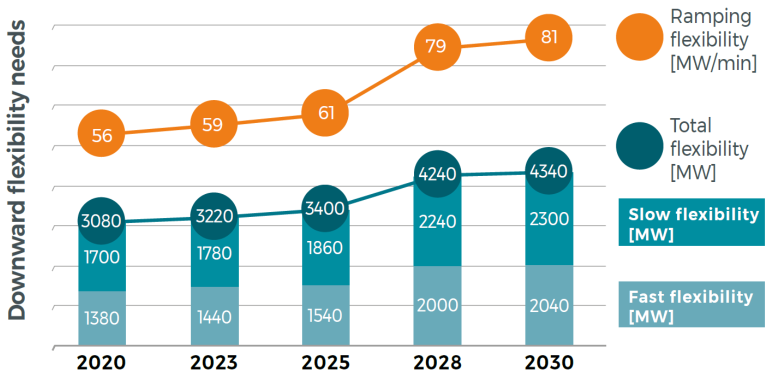

Figure 2.6: Downward flexibility needs for Belgium towards 2030 [26].

It should be noted that the presented available flexibility is based on the technical characteristics of each defined technology and represents the maximum flexibility that could theoretically be activated under ideal conditions [26]. These figures make seem that there will be sufficient flexibility available, with the means exceeding the needs with a factor of three to six. Nevertheless, this does not show the full picture, since the availability of the flexibility can fluctuate in time and does not necessarily align with the need for flexibility. By means of Monte Carlo simulations, Elia checks whether the operational flexibility can cover the needs on a temporal time scale of a single hour.

The results from these Monte Carlo simulations show that by 2030 the available upward flexibility means will not be sufficient to meet the needs, this for both the FF and RF. For the TF the 99.9% will not be covered for the complete time period, yet the potential shortages are minor [26]. For downward flexibility the situation is less precarious, yet also some moments during which the available capacity will not be sufficient do occur. While it is thus expected that enough flexibility capacity will be installed, it is a matter of securing this capacity so that the means can cover the needs during each individual hour of the year.

Looking into the different technologies, the contribution of PHS and existing thermal capacity (CCGT, OCGT, CHP) is considered to stay equal towards 2030. On the other hand, the contribution from DSM and batteries is considered to be growing significantly towards 2030, this for all the types of flexibility. Also new capacity, considered to be built to replace the nuclear power plants, are to be contributing significantly. For DSM and batteries the increase is most significant in the upwards direction, i.e., where load shedding is assumed, while for the downwards direction the largest contribution comes from the wind power, i.e., curtailment. Elia also concludes that non-thermal capacity, i.e., DSM, storage and RES, have the potential to significantly contribute to the ramping and fast flexibility, espe-

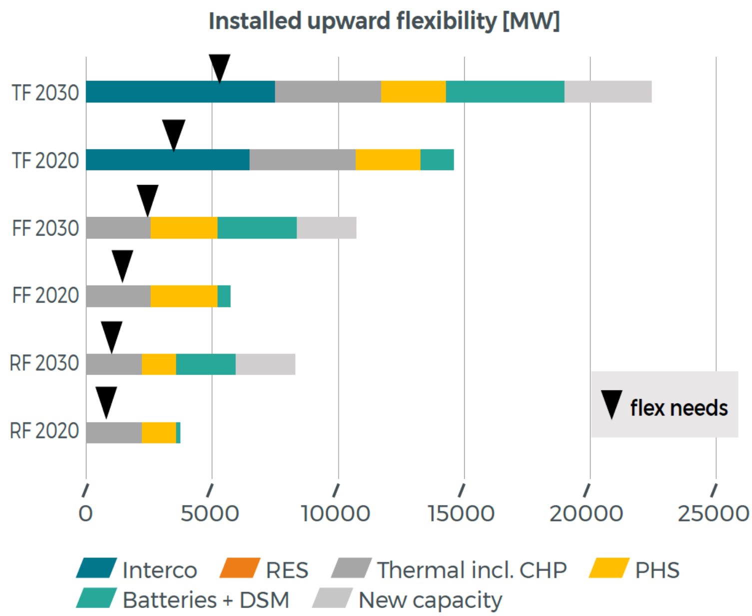

Figure 2.7: Installed available upward flexibility means according to Elia, for 2020 and 2030 [26].

cially towards 2030. Main reasons are the increasing amount of battery storage and the increasing amount of DSM providers [26]. Fast ramping and not requiring must run conditions, with the resulting decrease in costs, gives these sources an interesting head-start in valorising their flexibility. Research towards the possibilities of providing and increasing the amount of demand side flexibility can thus be considered to be needed and beneficial. By enlargement of the total flexibility means capacity, the number of hours during which potential flexibility shortages could occur will decrease. The fact that demand side flexibility does not require must run conditions could also decrease the flexibility deployment costs, having a societal benefit.

In the TYNDP of ENTSO-E, some estimations are made towards the contribution of thermal units (peaking power plants), DSR and batteries to contribute to the need for flexibility and adequacy [27]. Figure 2.9 shows the results of the report. It stands out that batteries are deemed to increase significantly in the coming decades, while the role for DSR is only considered to be growing towards 2040 and only in the distributed energy and global ambition scenarios.

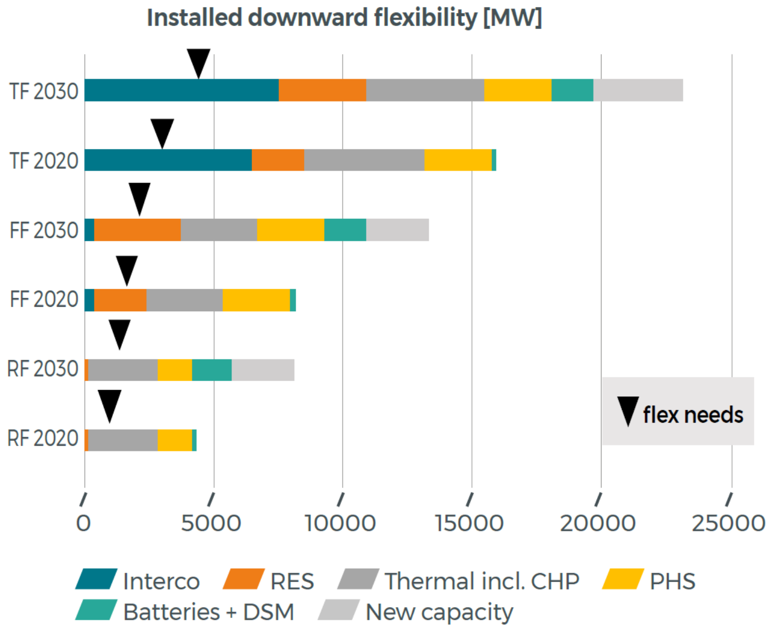

Figure 2.8: Installed available downward flexibility means according to Elia, for 2020 and 2030 [26].

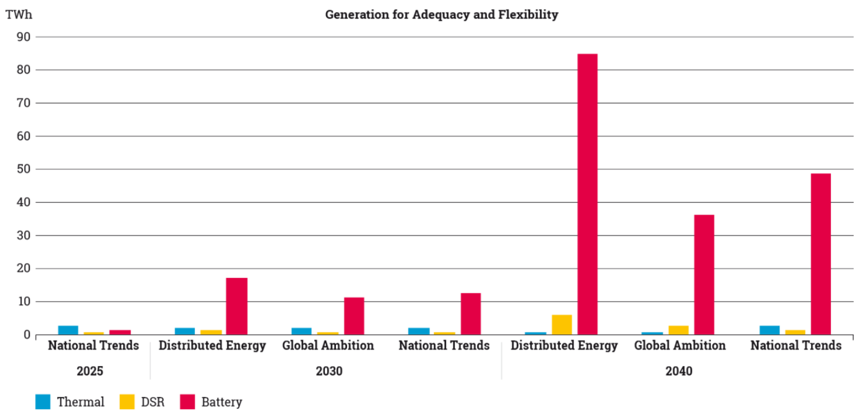

Figure 2.9: Energy volumes of peak generation, DSR and battery technology contributing to adequacy and flexibility needs [27].

2.3 ENTSO-E System Operation

2.3.1 Introduction

The ENTSO-E was established in 2009 following the Third Package for the internal energy market in the EU. It represents 43 TSOs from 36 different countries, therefore also reaching beyond the EU borders. The main objectives of ENTSO-E are the integration of RES into the power system and completing an Internal Energy Market (IEM), following the EU energy policy objectives. An ENTSO-E system operations division covers the core activity of any TSO, namely the the secure and optimal real-time operation of the grid. Operations network codes, guidelines, agreements and standards are developed and maintained as guidance for the connected TSOs [28]. The System Operations Guideline (SO GL) lays down the methodology for the management of the TSOs grid, which will be touched upon briefly.

The ENTSO-E geographical area covers five synchronous areas, with the Regional Group Continental Europe (RGCE), also known as the Synchronous Grid of Continental Europe, being the largest in the world. Figure 2.10 shows the different synchronous areas, with the Belgian TSO Elia as part of the RGCE. Within each of these synchronous areas, the grid frequency is equal. Within the synchronous area, several Load Frequency Control (LFC) blocks are present, which in their turn consist out of different LFC areas and subsequent monitoring areas. Belgium is considered as an LFC block with a single LFC area and monitoring area, with Elia being the responsible TSO [29]. The described principles and methodologies in the following sections are based on data and information from ENTSO-E and rather general. Some more detailed, potentially non ENTSO-E harmonised, information will always be given from the point of view of the Belgian system as applied by Elia.

An LFC area is physically demarcated by points of measurement of interconnectors to other LFC areas and operated by one or more TSOs fulfilling the obligations of load-frequency control [31]. Figure 2.11 shows the Belgian LFC area, which corresponds with the Belgian geographical borders, and the existing interconnectors at the time of writing. Belgium is connected with the UK via a DC link *Nemo* with a capacity of 1 GW, to France with two 400 kV AC and two 220 kV AC corridors, to Luxembourg with a single 220 kV AC line, to the Netherlands with two 400 kV AC corridors and more recently a DC link *Alegro* with Germany with a capacity of 1 GW. The capacity of the AC connections is calculated according to the Net Transfer Capacity (NTC) methodology, which takes into account various operational parameters. The total simultaneous import capacity for the winter of 2020-2021 is assumed to be 6.5 GW [32]. Within the LFC area a total nominal production capacity of 16.3 GW is available, consisting out of a majority of nuclear power plants and gas fired power plants, supplemented with onshore and

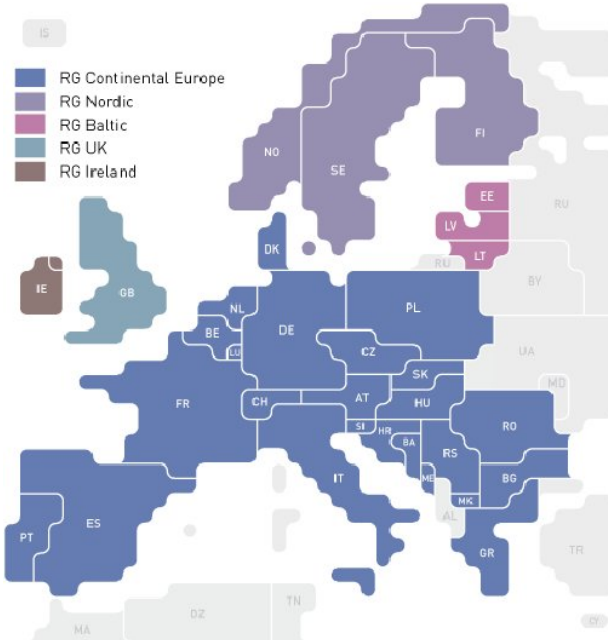

Figure 2.10: Different synchronous areas within the ENTSO-E geographical area [30].

offshore wind turbines and PV[2]. Some other production technologies are available but are only marginal in volume. The TSO grid load varies between 8 GW and 13 GW depending on the time of day and year, with some more extreme peaks and valleys noted over the past decade. A pumped hydro storage is available at Coo-Trois-Ponts and La Plate Taille with a nominal power of 1.2 GW and 140 MW respectively. Combined, an energy storage capacity of 6000 MWh is available [33]. While more details and nuances are to be made to the aforementioned short overview of the Belgian LFC area, production park and load, it gives a good impression on the magnitude of power and energy levels which is deemed beneficial in this work.

2.3.2 Principle of Maintaining Balancing in an LFC Area

Within the LFC area, it is the responsibility of the TSO to maintain the balance between injection and offtake. Part of this responsibility is outsourced to Balance Responsible Parties (BRPs), a legal role which is taken up by large consumers, producers, suppliers or traders (see § 2.6.1 for a more detailed definition). A BRP aggregates several TSO grid access points into a portfolio, for which it then submits

[2]This is the situation at the time of writing. Belgium decided on a nuclear phase-out, which will significantly alter the production park.

Figure 2.11: Belgian LFC area with the interconnectors. Colours denote technology and voltage levels, with red being 400 kV AC, green being 220 kV AC and pink being DC.

balanced nominations towards the TSO and this for each Imbalance Settlement Period (ISP). A balanced nomination means that an equilibrium between production (injection) and consumption (offtake) needs to be assured by the BRP. The nominations can be balanced by coordinating consumption and production within the portfolio or by making commercial trades on the respective energy markets or between BRPs. As every TSO access point must be part of a BRP portfolio and submit balanced nominations, a total balance between injection and offtake in the LFC area should be present. As in reality deviations in production and consumption of electricity occur, the LFC area can be long or short for energy. The Area Control Error (ACE) is the instantaneous difference between the actual and the reference value, i.e., the sum of balanced nominations, for the power exchange of the control area, taking into account the effect of frequency bias [34]. The frequency bias is based on the k-factor (a value expressed in MW/Hz) of the LFC area and the frequency deviation of the synchronous area. It is the responsibility of the TSO to counteract the ACE by activating reserves. These reserves, also known as balancing ancillary services, are sourced by the TSO in a market structure. The difference between the sum of the volumes of all upward activated reserves and all downward activated reserves is considered the Net Regulation Volume (NRV). It is the difference between the ACE and the NRV which defines the System Imbalance (SI) of the LFC area. This SI is considered a parameter for the quality of the balancing of the area and is to be minimised by the TSO. The costs which are incurred by the NRV, due to remunerating the providing parties, are borne by the TSO, who distributes them towards the BRPs which participated in causing the imbalance. This system is named the imbalance settlement system. A visualisation of this system is given in Figure 2.12.

Further details on the procured balancing ancillary services are provided in § 2.5 and the imbalance settlement system as applied by Elia is explained in § 2.4.2.

2.3.3 Imbalance Netting

To optimise the amount of reserves which need to be activated to counter the ACE, the principle of imbalance netting is implemented in most of the LFC areas within the RGCE. The International Grid Control Cooperation (IGCC) was chosen as European platform for imbalance netting in 2016, under the EBGL [36]. The main principle is that the activation of reserves (more specifically automatic Frequency Restoration Reserves (aFRR), see § 2.5 for more details) in opposite directions is avoided by communicating with one or multiple neighbouring LFC areas. The aFRR demand of participating LFC areas is communicated towards a single aFRR optimisation system. A corrected signal is returned towards the aFRR control of the respective TSOs, using it to deploy the aFRR within their area. This allows for

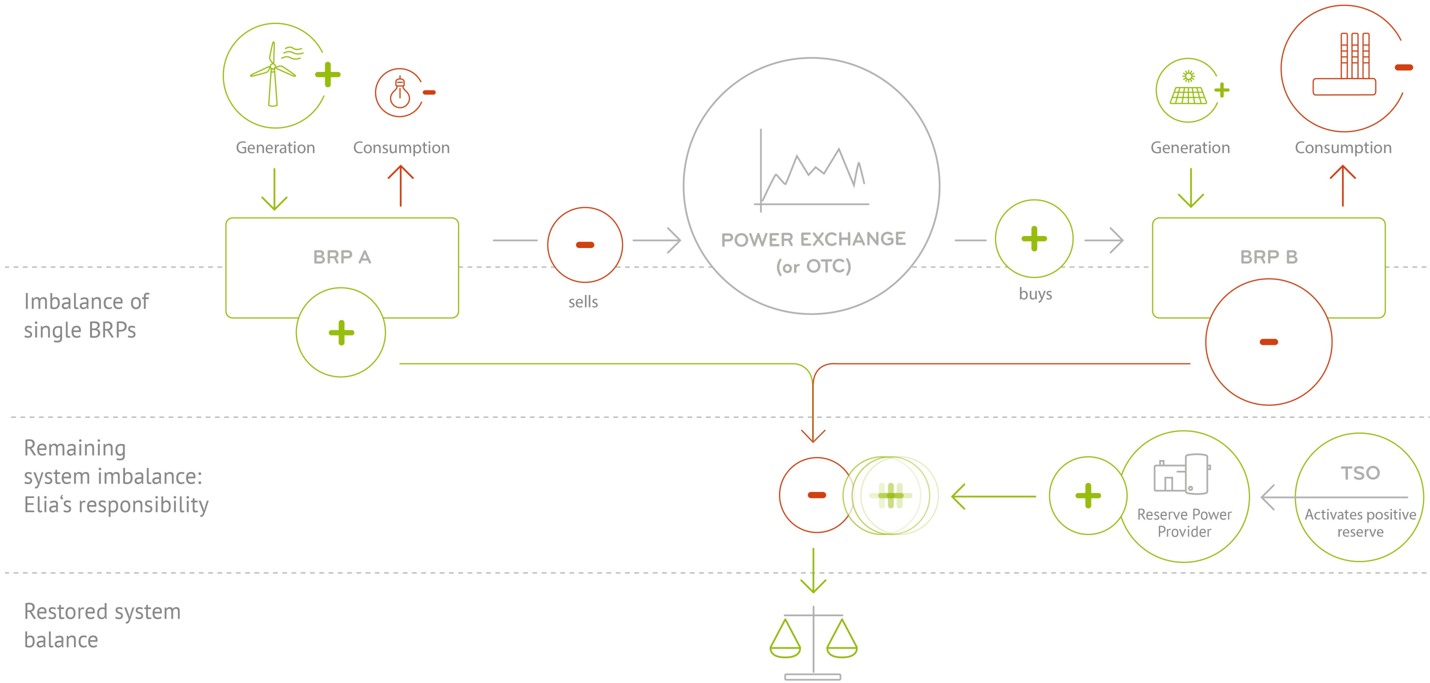

Figure 2.12: Graphical representation of the balancing system [35]

an overall decreased deployment of reserves, with a lower cost as result. The IGCC volumes are accounted for in the NRV volume, but are not taken into account to define the imbalance price.

2.4 Implicit Flexibility

Implicit flexibility is the reaction of a market party to price signals [3]. This reaction is a voluntary adapting of the power consumption or production profile. The price signals can come from different sources, of which a first and foremost obvious source are the wholesale energy markets where electricity is traded according to the principles of demand and supply. Long-term, day-ahead and intraday markets serve the purpose of exchanging large volumes[3] of electricity, each with their respective timings. The imbalance price, used as an instrument in the imbalance settlement system operated by the TSO, can also serve as signal for implicit flexibility. Despite that the imbalance settlement system is often referred to as the Imbalance Market (IM), a fundamental difference in purpose exists with the wholesale energy markets. The ability to react to price signals allows the market party to reduce costs or gain profit, i.e., the implicit flexibility is valorised. This valorisation comes in the form of a reduced invoice rather than a direct payment or remuneration.

2.4.1 Wholesale Electricity Markets

Trading electricity on wholesale markets, i.e., power exchanges or PX, is comparable to any other market where goods are traded. Long-Term (LT) markets, i.e., futures, allow the trading of volumes of electricity for years to months in advance. More close to real-time are the physical short term markets, i.e. spot markets. Here electricity is traded the day before delivery, i.e. the Day-Ahead Market (DAM), or on the day of delivery itself, i.e. Continuous Intraday Market (CIM). The LT markets offer price certainty, reducing the risk of price volatility, while on the contrary the spot markets are prone to volatility. It is this price volatility on the spot markets which could be exploited by valorising electrical flexibility. An electricity sourcing or selling strategy often limits the price volatility, i.e., the risk, for a market party by combining LT trades with trades on the spot markets. This practice is termed hedging. Considering the valorisation of electrical flexibility, the focus lies on the spot markets and not on the LT markets. The working of these markets are similar throughout Europe, yet they are not fully homogenised. When details are discussed, these will be based on the Belgian spot markets as operated by EPEX SPOT.

[3]Electricity is traded in multiples of MW, meaning that only market players with large energy consumption, production or trade can enter this wholesale market.

The electricity markets as known in Europe are *energy-only* markets, i.e., it is energy, in MWh, which is traded, rather than capacity to produce electricity. This topic is elaborate upon in § 2.5.2

2.4.1.1 Day-Ahead Market

The Day-Ahead Market (DAM) is a spot market for electricity based on a market clearing principle with inter temporal constraints. Buyers and sellers can submit bids until a fixed timing the day before delivery, i.e., the Gate Closure Time (GCT)[4], which are then put into demand and supply curves respectively. Following this GCT, the market is cleared and prices for each block are fixed and communicated to the market parties[5]. In most European markets a time block consists of a single hour, resulting in 24 prices being fixed for the next day.

Market clearing, i.e., fixing of the prices, is the practice of finding the intersection between the demand and supply curves of all the submitted bids for a single block. Figure 2.13 schematically presents such curves and the resulting market price and volume. Every supply bid with a price lower and every demand bid with a price higher than or equal to the market clearing price will be accepted. The market clearing price is thus defined by the lastly matched supply and demand bid in the market. Linking the generation technology to the supply bids results in the creation of a merit order curve, as shown in Figure 2.14. It reflects the order of the short-run marginal costs of production of electricity. Dispatching the generators with the lowest marginal cost, as is done in the DAM, is also known as economic dispatch and minimises the total cost of electricity production.

2.4.1.2 Continuous Intraday Market

The Continuous Intraday Market (CIM) is a spot market where electricity is traded continuously throughout the same day of delivery. A pay-as-bid principle is used, meaning that a continuous assessing of supply and demand bids is conducted. A price match between supply and demand immediately results in a transaction, similar to the well-known stock market. As result, no single price for a single block is set, instead it is common to have different prices for the same block, depending on the time of transaction[6]. The GCT is close to actual delivery and ranges from 60 minutes up to 5 minutes before delivery, depending on the zone specific market rules. In Belgium a GCT of 5 minutes before delivery is used.

The CIM in Belgium is upon today not very liquid, as it is mainly used as last resort to trade the remaining production volumes, e.g., due to incorrect RES

[4]In Belgium the GCT as set by the EPEX SPOT exchange is 12h00.
[5]For the Belgian EPEX SPOT platform this shall not be later than 14h00.
[6]On the Belgian EPEX SPOT, both hourly and quarter-hourly blocks can be traded.

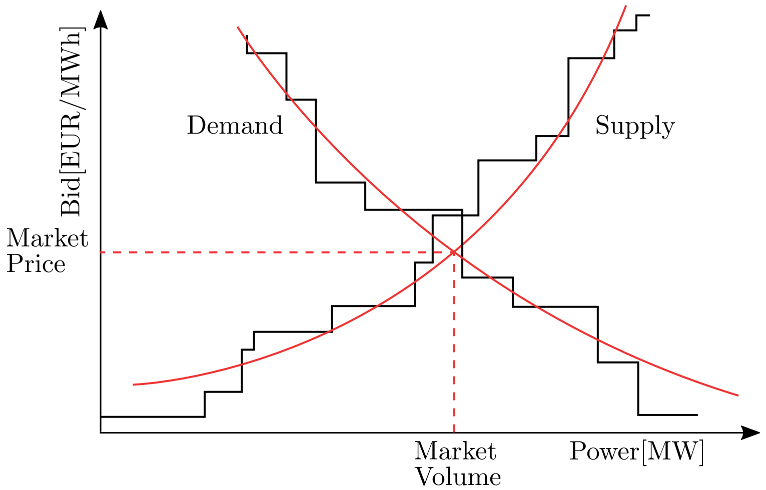

Figure 2.13: Example of a demand and supply curve, as used in the market clearing.

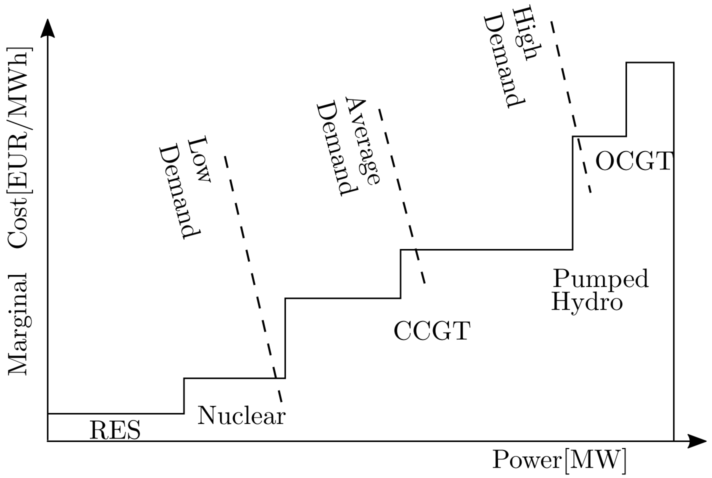

Figure 2.14: Example of a merit order curve considering the different generation technologies.

production predictions or unexpected downtime of a generator. It is expected that in the future, under the development of more RES, the CIM will gain importance.

2.4.1.3 Bidding Zones

A wholesale electricity market, such as the DAM and CIM spot markets, is operated within a bidding zone, which is the largest geographical area within which market participants are able to exchange electricity without capacity allocation, i.e., in which the copper plate principle is applied [37]. Within such a bidding zone, a single market clearing price is set for all market parties. Bidding zones are historically grown and often coincide with country or LFC borders, as the transmission grid within a country is often developed in such a way that congestion does not often occur, i.e., it acts as a copper plate. In vast countries several bidding zones might be used, such as in Norway. The counterpart of such a zonal pricing is nodal pricing, where the copper plate principle is not applied but all transmission lines are taken into account during market clearing, which could result in different prices for different geographical areas, based on congestion. The latter is mostly used in the USA, in Europe zonal pricing is preferred.

In pursuit of the single European electricity market, i.e., a European copper plate, several intermediate steps have been taken. Different market coupling systems, e.g., Single Intraday Coupling (SIDC)[7], Price Coupling of Regions (PCR) and Flow Based Market Coupling (FBMC) exist today and have as purpose to harmonise prices geographically in Europe, within the physical boundaries of the interconnection capacities. In short, the FBMC which is used in central Europe today[8] takes into account all critical grid lines when clearing the market. In this way, a larger amount of the existing physical transmission capacity is used, resulting in increased price convergence and social welfare [38]. Figure 2.15 shows an example of the DAM prices as seen on the Belgian, German, French and Dutch markets for a single week during September 2020. While prices are equal during some moments, during others they can show large differences, e.g., on the 13$^{\text{th}}$ of September a low demand (it is a Sunday) and a high wind production in Germany pushes down the DAM price. Being interconnected, this also influences Belgium and the Netherlands to a certain extent, i.e., until the import capacity of both countries is reached. France, having a limited direct interconnection capacity with Germany, especially considering its demand volume, shows the largest price decoupling.

[7] Previously known as the Cross-Border Intraday Project XBID
[8] FBMC is used on the D-NL, D-F, F-B an NL-B borders

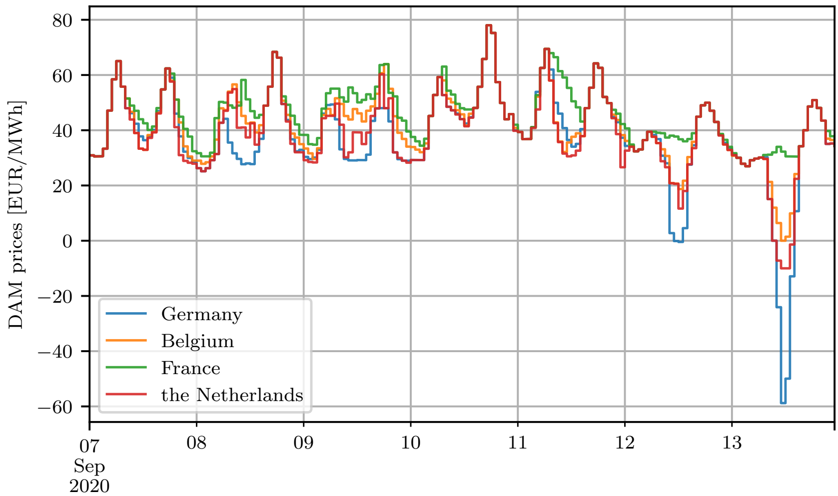

Figure 2.15: DAM prices for Belgium and its neighbouring countries in the FBMC.

2.4.1.4 Market Analysis with Relation to Flexibility

The DAM knows a daily, weekly and seasonal pattern. A heatmap visualising the weekly pattern is shown in Figure 2.16. The hour of the day is given on the y-axis and the day of the week is given on the x-axis, leading to a matrix with 168 values. The colour shows the magnitude of price, with black representing the lowest prices and white representing the highest prices. As data for 2018 and 2019 is used, each visualised datapoint is the average of 104 values, i.e., the dataset covers 104 weeks. A clear distinction between weekdays and weekend-days is visible, with lower prices during the weekend. Night hours are also coloured darker, as they have lower prices. During working days, a morning and evening price peak is observed between 06h00 - 08h00 and 17h00 - 19h00 respectively. Since the visualisation is averaged, these price peaks seems to be spread during these hours, but in fact they are depending on the period of the year. Figure 2.17 shows the seasonal pattern. On this figure, each individual DAM price of a year is visualised, with the hour of the day on the y-axis and the day of the year on the x-axis. The colour representing the value is an average of two values, considering the dataset spans 2018 and 2019. The seasonality is visible as a convex lighter pattern for the morning peak and a concave pattern for the evening peak, i.e., the morning peak prices occur later and the evening peak prices occur earlier in winter. On yearly basis, prices are higher in winter than summer. This is considered logical as the demand for electricity is higher in winter than summer. These price patterns are a result of the principle of economic dispatch and varying demand. More expen-

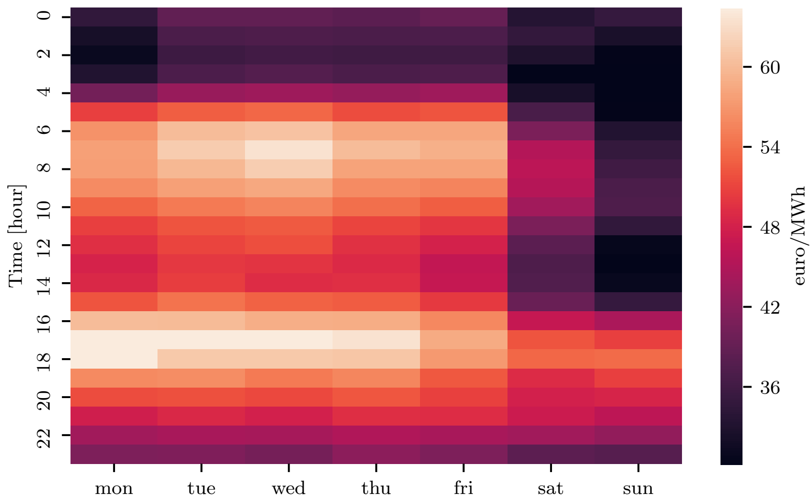

Figure 2.16: Heatmap of the BE EPEX Spot DAM prices for 2018 and 2019.

sively dispatched electricity generators drive up the DAM price at moments of peak consumption. Consumption patterns are shaped by residential habits and industrial working regimes, making them quite predictable and consistent. Households will consume electricity, for cooking, washing and heating, when family members are at home, in the morning before work and during the evening hours. The industry shows a more diverse pattern, but energy consumption is mostly focussed during the 9-to-5 working hours, partly coinciding with the household pattern. When considering valorisation of electrical flexibility, this habits based DAM pricing is favourable. The daily and weekly repetitiveness and predictability make it easier to define an adapted power pattern. This fact has been used to valorise flexibility for a long time, e.g., residential electric heating on exclusive night tariff, incentivisation to (dish)wash during weekend and night hours, electric intensive industries introducing night shifts to produce more cheaply, etc.

Despite having a large influence, the electricity demand is not the only parameter defining the DAM price. Several fundamental, operational and strategic factors have an impact on the DAM price [39]. One with increased importance over the last few years is the weather and the impact on the non-dispatchable RES production. The integration of RES and the RES subsidy schemes as rolled out by various governments to incentivise investments has the perverse effect of causing negative electricity prices. Systems such as Tradable Green Certificates (TGC), where the RES generator is rewarded with an amount of money per produced amount of electricity, introduces price insensitivity. The already low marginal cost is virtually lowered below zero with the value of the subsidy. Figure 2.18 shows an overview

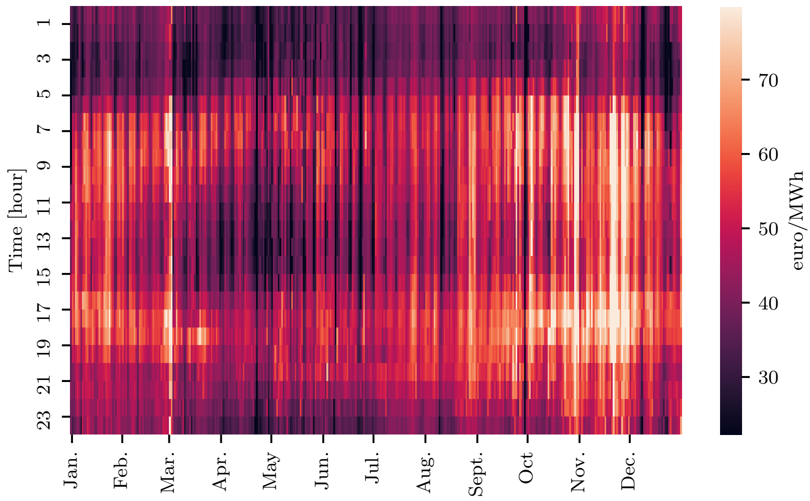

Figure 2.17: Heatmap of the BE EPEX Spot DAM prices for 2018 and 2019.

of the amount of hours with negative electricity prices on the DAM in Belgium and its neighbouring countries. Germany, the European frontrunner on RES integration, also leads the way in the number of hours with negative prices on the DAM. Belgium sees an increasing amount of negatively priced hours, with also a low average price. Countries with relatively low RES integration, such as the Netherlands and France, show a lower number of negatively priced hours. The steep increase in negatively priced hours as seen in 2020 is the result of a combination of high RES production and extremely low electricity demand during the various Covid-19 lock-downs in the respective countries. While these negative prices show an opportunity for electrical flexibility valorisation, the effects causing them are not structural. Subsidy schemes for RES have been adapted to more advanced ones and will soon even be phased out as RES investments become more profitable. After the current subsidy schemes are phased out, which could be another 5 to 10 years, periods with long, i.e., multiple consecutive hours, of extremely low DAM electricity prices are deemed to become rarer. Nevertheless, single hours with a negative price could still be maintained, e.g., during moments with a RES generation upsurge. Classical power plants based on nuclear and fossil fuel will not ramp down production in case of minor negative prices for these short moments. The technical limitations and incurred cost due to ramping will prevent this.

The short and limited negative price dips due to RES upsurges and techno-economical limitations of classical power plants do not counter the existing price spikes due to high demand [39], as both not necessarily occur simultaneously. The combination of both could, amongst other causes, result in an increased price

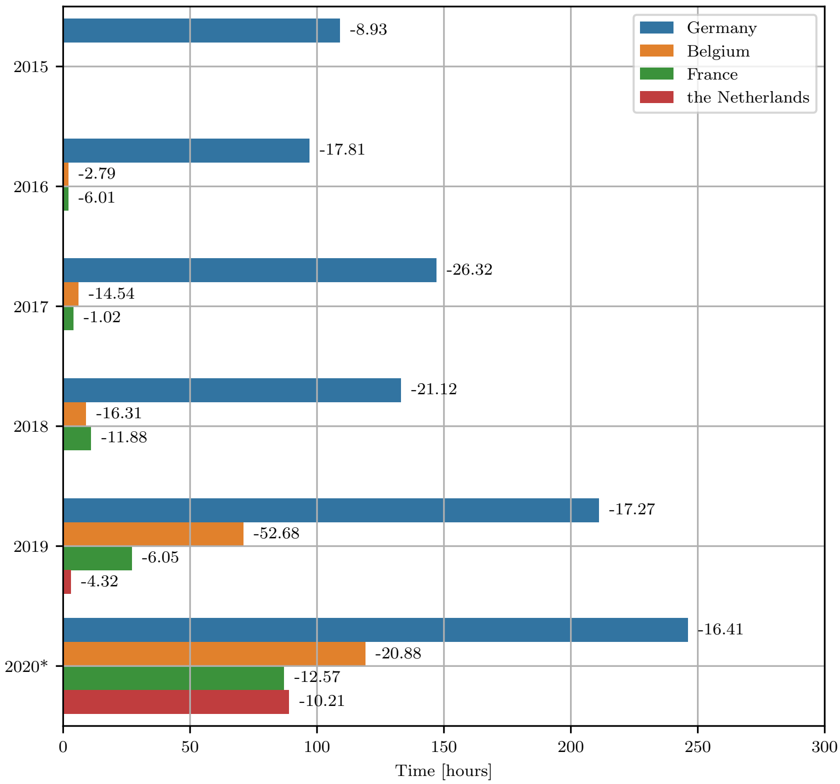

*Figure 2.18: Hours of negative DAM prices in Belgium and its neighbouring countries. Annotation shows the average price in euro/MWh. * data up to 1st of October 2020 is used.*

volatility. It is this price volatility, i.e., the degree of variation of the prices within a certain time interval, which is deemed the most important parameter considering the valorisation potential for electrical flexibility. Rintamaki et al. assessed the German and Danish electricity markets and concluded that the daily volatility does not necessarily increases with increased RES integration, as also other parameters such as dispatchable hydro power plants or grid interconnections come into play. The weekly volatility is shown to increase in both countries, as a result of the high day-to-day variability of wind and PV [40]. In [41] the Italian market is analysed and it is concluded that the increased volatility due to RES is due to the larger spread created between the low prices during high RES production and high prices during low RES production. Nevertheless, a new grid connection is shown to mitigate the occurrences of high price spikes, decreasing price volatility. It can be concluded that RES integration and production is not the only parameter influencing the price volatility of an electricity market, as also interconnections, cost of dispatchable power plants and others have a non negligible influence.

The opportunity for electrical flexibility valorisation on volatile electricity markets, i.e., exploiting short-term price differences by shifting power consumption in time, exists today on various electricity markets. Increasing RES production can increase the price volatility, but other measures, such as interconnection lines, can partly counter this effect. Also the exploiting of the price difference itself, i.e., valorising electrical flexibility, has a decreasing effect on price volatility. A balance will settle, between market parties valorising their electrical flexibility, decreasing the price differences, and the increase of non-dispatchable RES generation driving up the volatility.

2.4.2 Imbalance Settlement System

The imbalance settlement system, also termed the Imbalance Market (IM) is different from the other energy markets where volumes of electricity are traded at a certain price. While referred to as a market, it should rather be perceived as a system, set up by the TSO, to incentivise consumers and producers to maintain the production and consumption balance. The general principle of imbalance settlement is established by all TSOs throughout Europe, but a different approach and interpretation leads to individual imbalance settlement methodologies. The Belgian methodology, as implemented by Elia, will be further explained.

2.4.2.1 Principles of the Current Belgian Imbalance Settlement System

As briefly touched upon in § 2.3.2, maintaining the balance between injection and offtake in an LFC area is one of the main task of a TSO, who outsources it to Balance Responsible Parties (BRPs). These BRPs are held responsible for the balance within their own portfolio. The imbalance of a BRP is defined as the difference between its balanced nominated position and the sum of the actual electricity flows on the grid access points in its portfolio in real-time. The SI is the difference between the ACE and the NRV and can be positive, i.e. an overall surplus of electricity, or can be negative, i.e., an overall shortage of electricity. It is the general objective of the imbalance settlement system that the BRPs counter the SI in an efficient way and to incentivise market participants in maintaining and restoring the system balance [42]. An imbalance price is therefore deemed the best instrument.

An imbalance price is defined as a positive, negative or zero price defined for each ISP for an imbalance in each direction [43]. The imbalance price can be different for each direction, i.e., dual pricing, or the imbalance price can be identical for both, i.e., single pricing. The imbalance price should be cost-reflective and therefore be at least related to the average price of activated balancing energy, i.e., ancillary services or reserves, in the LFC area. As stated in the EBGL, the imbalance prices should reflect the real-time value of energy, this to make the overall energy system fit for integration of RES. Elia applies a single pricing strategy[9] and defines the imbalance price on the marginal cost of the activated reserves. In this sense the imbalance price is cost-based, as it is the real-time value of electricity as defined by Flexibility Service Providers (FSPs), offering the reserves to the TSO. These activated reserves can be in upwards or downwards direction, linked to the sign of the SI, i.e., the state of the grid. A shortage of electricity in the LFC area, i.e. a negative SI, is linked to the activation of upward reserves, e.g., increased injection or reduced offtake. A surplus of electricity in the LFC area, i.e., a positive SI, is linked to the activation of downward reserves, e.g., reduced injection or increased offtake. The cost for the most expensive reserve activated during an ISP is termed the Marginal Incremental Price (MIP) or Marginal Decremental Price (MDP) for upward or downward activated reserves respectively. The imbalance price is set to the MIP or MDP in case, on average during the ISP, a negative or positive SI is observed respectively. The MIP is higher than average electricity market prices as it represents the value of producing extra electricity during moments when there is an overall shortage on the grid. The MDP is lower than average electricity market prices as it is defined by the value of electricity on moments of oversupply.

To increase the incentive towards the BRP of being balanced, in case of large SIs a parameter α is introduced aggravating the imbalance price. The calculation method is given in (2.1). Parameters a, b, c and d are defined with a value of 0 euro/MWh, 200 euro/MWh, 450 MW and 65 MW respectively, obtaining the sigmoid curve as shown in Figure 2.19. Parameter x is defined as the moving average of the absolute value of the SI of the current and previous quarter-hour, reflecting the real-time state of the system. A tabled overview of the current Belgian

[9] As from 2012, before it used a dual pricing strategy.

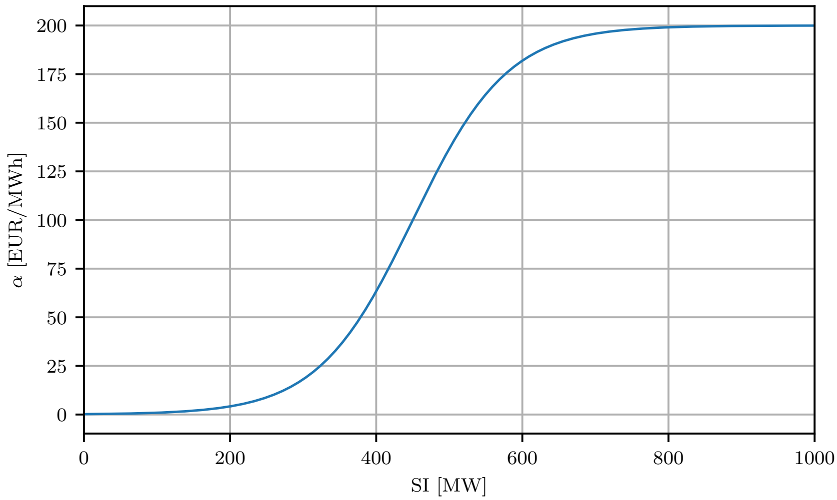

Figure 2.19: α parameter function as applied by Elia in the imbalance settlement system.

Table 2.2: Imbalance pricing rules as applied by Elia in Belgium from 1st of January 2020.

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">System Imbalance</td></tr>
<tr><td>Positive</td><td>Negative</td></tr>
<tr><td rowspan="2">BRP imbalance</td><td>Positive</td><td rowspan="2">MDP - α</td><td rowspan="2">MIP + α</td></tr>
<tr><td>Negative</td></tr>
</table>

imbalance pricing system is shown in Table 2.2.

$$\alpha = a + \frac{b}{1 + \exp(\frac{c-x}{d})} [\text{euro/MWh}]$$
$$x = \frac{|\mathrm{SI}_{\mathrm{QH}_c} + \mathrm{SI}_{\mathrm{QH}_{c-1}}|}{2} \tag{2.1}$$

The direction of payment of the imbalance price is based on the imbalance of the BRP. A BRP with positive imbalance, i.e., a BRP with less consumption or more production than nominated, will receive the imbalance price from the TSO. A BRP with negative imbalance, i.e., a BRP with more consumption or less production than nominated, will pay the imbalance price towards the TSO [10]. Electricity can thus either be resold or bought by the BRP at the imbalance price,

[10] In case of a positive imbalance price. In case of a negative imbalance price, the direction of payment reverses.

leading to the adoption of the term imbalance market. The price is nevertheless not based on the demand and supply mechanism as in the regular energy markets.

While the imbalance price presents a financial incentive for the BRPs to maintain balance, also legal obligations are implemented. First and foremost, the BRP has a day-ahead balance obligation, where it is obliged to submit **balanced** nominations right after closure of the DAM. These balanced positions are used by the TSO to perform several adequacy checks and congestion forecasts. The obligation of submitting balanced nomination after the DAM closure originated in 2002 in the first Federal Grid Code, when intraday changes in consumption or production were far from standard. Today, Elia evaluates the necessity of these balanced day-ahead nomination and considers the removal of this obligation [44]. A BRP is also obliged to plan and utilise all reasonable means to maintain real-time balance within its perimeter and this for each ISP. The latter obligation comes with the exception in case the BRP can contribute in real time to the overall objective of maintaining the balance of the LFC area by deviating from its balanced position, providing it can, upon request, restore to a balanced position [44].

2.4.2.2 Imbalance Market Analysis with Relation to Flexibility

As result of the imbalance settlement system design in Belgium, a two level pricing is observed. Figure 2.20 shows a typical imbalance price pattern, where the lower level and higher level are defined by the MDP and MIP respectively. Figure 2.21 shows the distribution of the imbalance price and DAM price in Belgium for 2019. The IM price shows a bimodal distribution with in the centred local minima the normal distribution of the DAM price. It is this price discrepancy which could be exploited to valorise electrical flexibility, i.e., by creating a negative imbalance during moments of IM prices defined by the MDP or creating a positive imbalance during moments of IM prices defined by the MIP. This practice, i.e., the implicit balancing of the grid by means of reacting on imbalance price signals, is incentivised under a single imbalance pricing mechanism.

The difficulty with this practice lies with the unpredictability of the imbalance price. As the SI of a LFC area is based on the combined remaining imbalances of the individual BRPs, it is assumed to be the sum of forecasting errors by these BRPs, accounting for the fluctuations and unpredictable events. The demand for balancing energy, i.e., energy from activating reserves, should therefore be unpredictable on either which time scale [45]. No short nor long term predictions should be possible on the imbalance price, especially not on the fact if it is set by the MDP or MIP. In [46], Klæboe et al. sum up three main causes for imbalance, under normal grid circumstances. Next to the stochastic fluctuation of both consumers and producers, i.e., the combined imbalances of BRPs, also the loss of a large generator and the weakness of the market design is considered. The latter could be modelled based on the existing markets and their characteristics. Möller [45] investigated the

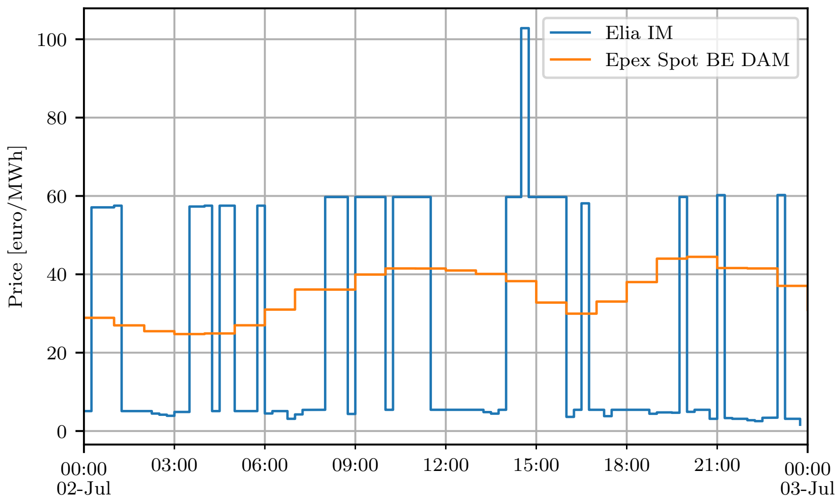

Figure 2.20: Example of a typical imbalance and day ahead market price pattern.

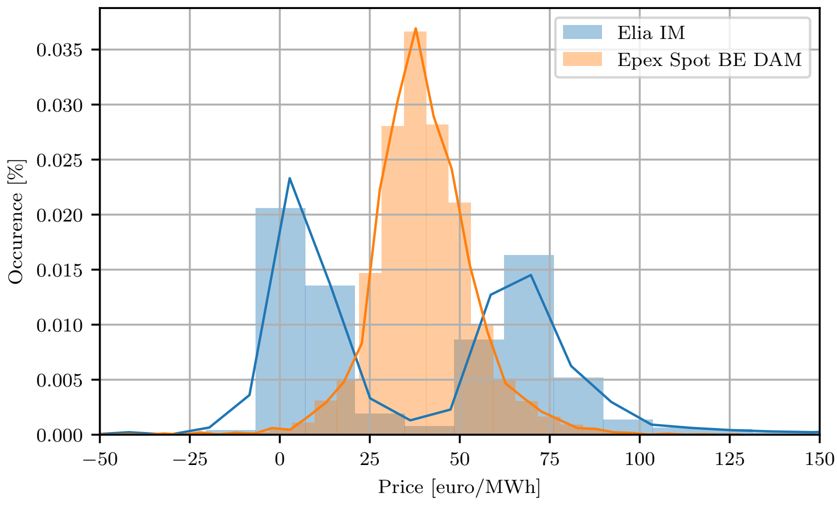

Figure 2.21: Distribution of the imbalance and day ahead market prices in Belgium in 2019.

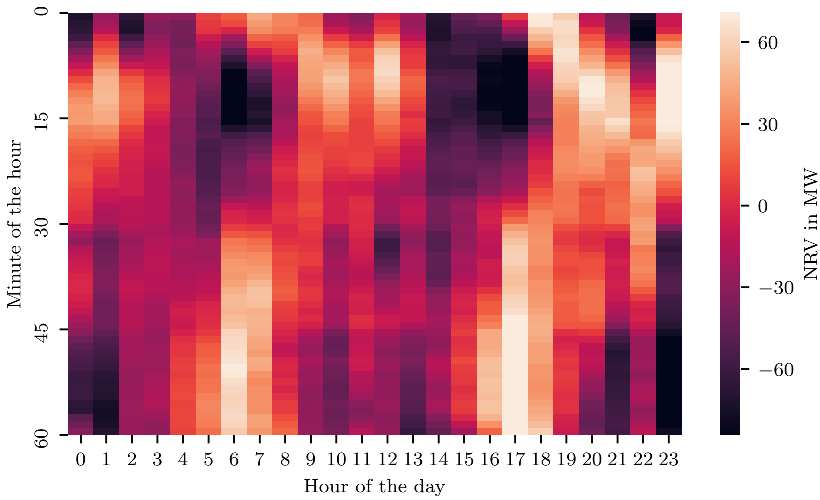

Figure 2.22: Heatmap of the Belgian NRV in 2018.

German balancing energy market for predictable components, contradicting the theoretic approach of it being fully unpredictable, and indeed found weaknesses in the market design. A similar analysis is performed on the Belgian imbalance settlement system and imbalance prices. As the level of imbalance price is defined by the predominantly activated direction of reserve, i.e., upwards or downwards, it is the NRV which is investigated. Figure 2.22 shows an averaged daily heat map of the NRVs activated in 2018 in Belgium. A pattern emerges, showing that no Gaussian distribution is present of the NRV during the day.

Figure 2.22 shows that for the hours 6 and 17, there is a high chance of having a negative NRV at the beginning of the hour, and a positive NRV at the end of the hour. For the hour 23 we see an opposite pattern. An explanation can be found in the hourly energy markets and hourly time schemes of generators. For example, the hours 6 and 17 coincide with an electricity consumption increase, due to the synchronisation of working hours of industry and energy demand in households. The amount of electricity to consume or generate during these hours is defined on an hourly basis, i.e., the hourly wholesale energy markets, while the imbalance market has an ISP of 15 minutes. The pattern shows that generators start to ramp up during these hours, to supply the needed electricity. As the ramp-up of the generators is not infinitely fast, a shortage will be seen during the first quarter-hour which reflects as a negative NRV. The generator increases its output, which will result in a surplus of energy in the last quarter-hour which reflects as a positive NRV. The load and production will be balanced on hourly basis but not on a quarter-hourly basis and balancing energy, i.e., reserves, are used to compensate for this. This phenomenon is described by Möller and named the gradient effect [45]. A similar explanation can be given for the hour 23, with the difference that a load decline occurs, resulting in a vice versa effect on the sign of the NRV. Both patterns are also visible at other hours, but less pronounced, as the slope of the demand curve is less steep.

2.4.2.3 Impact of Influencing the Nomination Profile

The imbalance settlement system is in the first place a tool to incentivise BRPs to maintain balance within their portfolio, reducing the overall SI and need for activation of reserves. The imbalance price and the imbalance settlement system should therefore be the financial incentivising instrument. The imbalance volume of a BRP can be influenced in three possible ways, being the accuracy of the nominations, over or under nomination or internal balancing [47]. A changed nomination strategy, either by adapting the accuracy or deliberately over or under nominating, does not require a change in consumption or production pattern.

To assess the impact of the nomination strategy, two different power consumption profiles are considered. Realistic consumption profiles with an average power level of 13 MW ('site A') and 200 MW ('site B'), from two distinct continuously operating industrial sites, are taken as case study. Figure 2.23 and Figure 2.24 show the power consumption profiles in blue. Site A shows a rather stable continuous power consumption, with a limited amount of peaks and valleys. Site B shows a significant amount of power consumption valleys with a large difference in power. As site B operates an electro-intensive process (electrolysis), changes in production, either planned or unplanned, have a large impact on the sites power consumption profile. Possible nomination profiles for both sites are created to be having a fixed value for a day ($N_{\mathrm{a,d}}$), week ($N_{\mathrm{a,w}}$) or year ($N_{\mathrm{a,y}}$), so that the average on year-basis results in the total actual electricity consumption, i.e., there is on yearly basis no over or under nomination. The impact of the accuracy of the nomination could hereby be investigated. Structural over and under nomination strategies are implemented by adding ($N_{+50,\mathrm{d}}$, $N_{+50,\mathrm{w}}$ and $N_{+50,\mathrm{y}}$) or subtracting ($N_{-50,\mathrm{d}}$, $N_{-50,\mathrm{w}}$ and $N_{-50,\mathrm{y}}$) 50% of the total sourced electricity, i.e., shifting up or down the average nomination profiles. All the nominated electricity is assumed to be bought on the DAM. The total commodity electricity sourcing cost (C_{tot}) is then defined as the total DAM sourcing cost (C_{DAM}) added with the cost for negative imbalance (C_{NEG}), decreased with the income from positive imbalance (C_{POS}), this summed for each ISP of the year, as shown in (2.2). Other cost components related to electricity consumption, e.g., grid costs and taxes, are not taken into account as they are not impacted by a different nomination strategy [48].

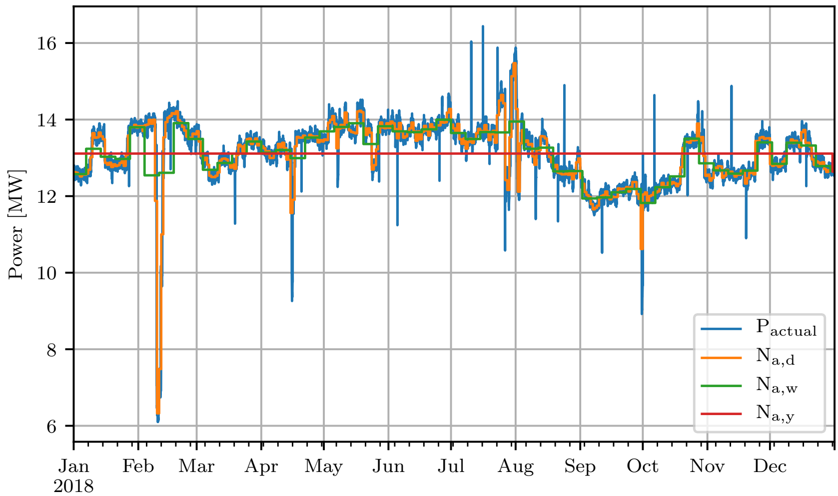

Figure 2.23: Power consumption profile and possible nomination profiles for a continuously operated industrial site with an average power level of 13 MW (site A).

$$C_{\mathrm{tot}} = \sum_{\mathrm{QH}=0}^{\mathrm{QH}=35040} C_{\mathrm{DAM,QH}} + C_{\mathrm{NEG,QH}} - C_{\mathrm{POS,QH}} \tag{2.2}$$

The imbalance volume of the analysed industrial site has an impact on the total SI and thus can have an impact on the resulting imbalance price. The magnitude of the impact is defined by the imbalance caused by the industrial site, relative to the overall SI of the LFC area. Figure 2.25 shows a distribution of the SI volumes for the Belgian LFC area in 2018. A Gaussian distribution is observed with a mean of 0 MW and a standard deviation of 186 MW. An industrial site with an average power level of 200 MW has thus the potential to create a significant impact on the overall SI and influence the imbalance price, while for an industrial site with an average power level of 13 MW the impact is rather limited.

To cope with the non-rigidity of the imbalance price, the following methodology is implemented. Historical NRV data are imported, including the volumes of the different activated reserves as well as the volume of imbalance as exchanged on the IGCC platform. The NRV on the Belgian LFC area ($\mathrm{NRV_{BE}}$) is subtracted with the IGCC volumes ($\mathrm{NRV_{IGCC}}$), so to obtain the actual volumes of reserves activated within the Belgian LFC area ($\mathrm{NRV_{BE,r}}$), as shown in (2.3).

$$\mathrm{NRV_{BE,r}} = \mathrm{NRV_{BE}} - \mathrm{NRV_{IGCC}} \tag{2.3}$$

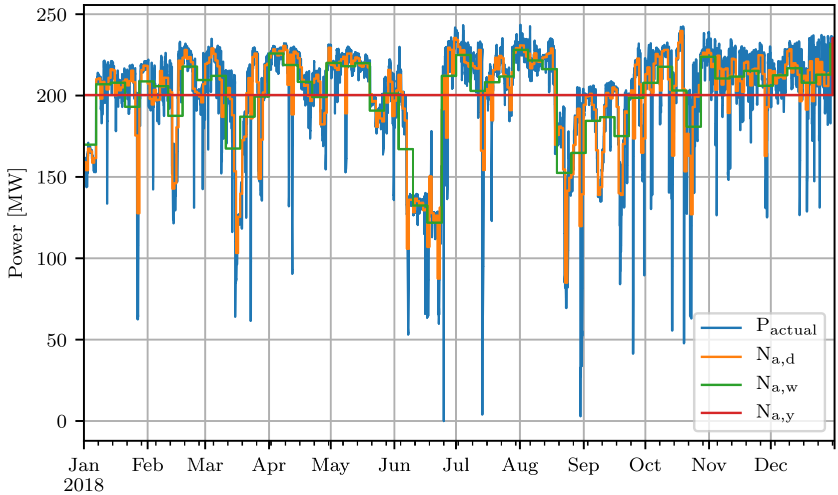

Figure 2.24: Power consumption profile and possible nomination profiles for a continuously operated industrial site with an average power level of 200 MW (site B).

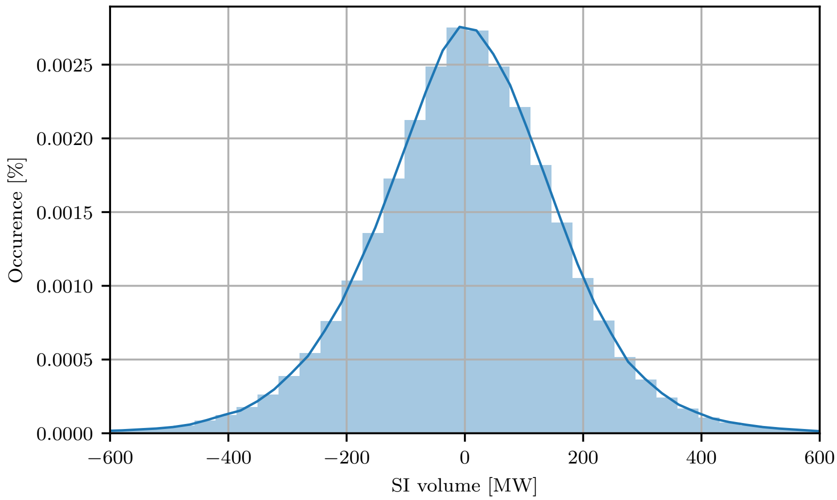

Figure 2.25: Distribution of the system imbalance volumes in Belgium in 2018.

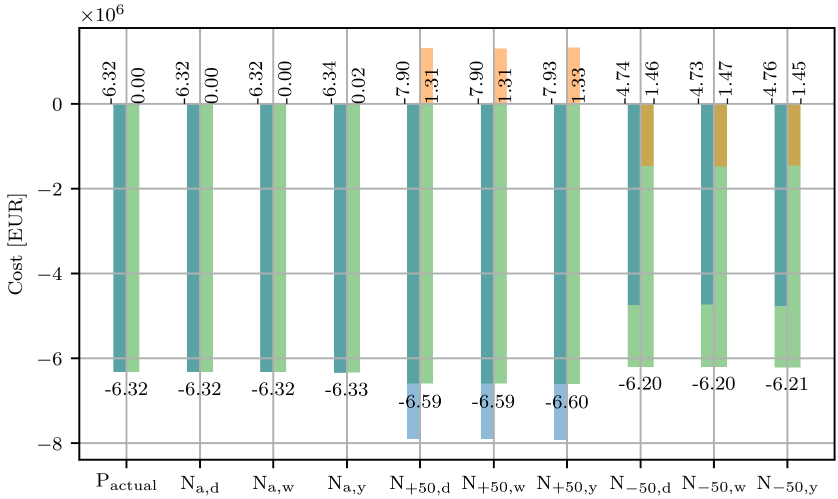

Figure 2.26: C_{DAM} (blue), C_{imb} (orange) and C_{tot} (green) considering different nomination profiles for site A.

The simulated imbalance of the industrial site is deemed to be countered by extra reserves activated within the LFC area, i.e., having an impact on the imbalance price. These extra activated reserves, $\mathrm{NRV_x}$, are considered identical in volume but opposite in sign to the introduced imbalance. The $\mathrm{NRV_x}$ are added with $\mathrm{NRV_{BE,r}}$ to form the new total NRV, $\mathrm{NRV_{BE,sim}}$, as shown in (2.4).

$$\mathrm{NRV_{BE,sim}} = \mathrm{NRV_{BE}} - \mathrm{NRV_{IGCC}} + \mathrm{NRV_x} \tag{2.4}$$

$\mathrm{NRV_{BE,sim}}$ is used to lookup the corresponding imbalance price in the Available Regulation Capacity (ARC) table as made available by Elia. This table lists all the available reserves, sorted by NRV level, and the corresponding marginal prices. The found imbalance price is supplemented with the calculated parameter α as defined as in (2.1). Data of 2018 are used.

Figure 2.26 and Figure 2.27 show the results of the simulations for site A and B respectively. The total cost C_{tot} is shown in green and is deemed to be minimised. The P_{actual} scenario serves as base case, assuming a perfect nomination, i.e., having no imbalance on ISP level. The C_{DAM} is shown in blue and the C_{imb}, as the sum of C_{POS} and C_{NEG}, is shown in orange. For site A, the influence of the accuracy of the nomination is non-existent for the daily, $N_{\mathrm{a,d}}$, and weekly, $N_{\mathrm{a,w}}$, profiles and only minor (0.3% cost increase) present for the yearly profile $N_{\mathrm{a,y}}$. For site B, a clear cost increase is visible with 1.13%, 1.95% and 5.35% for the $N_{\mathrm{a,d}}$, $N_{\mathrm{a,w}}$ and $N_{\mathrm{a,y}}$ fixed nomination profiles respectively. The main reason is to be found in the level of average power consumption, as well as the consumption

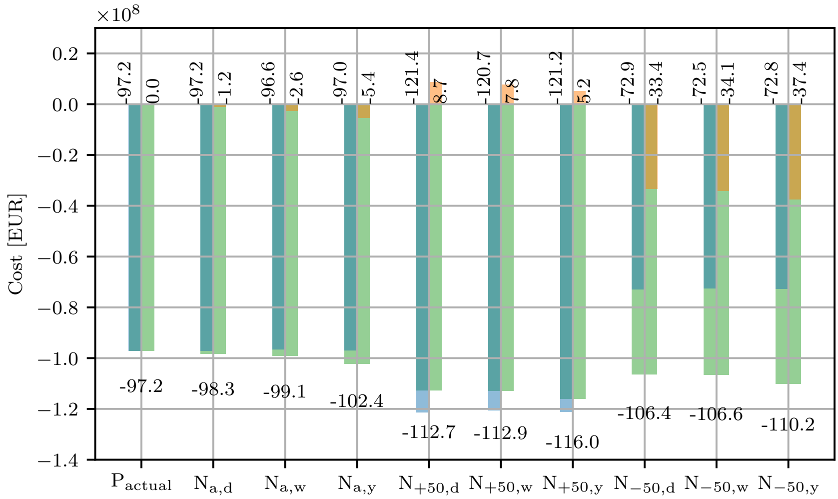

Figure 2.27: DAM cost (blue), imbalance cost (orange) and total electricity commodity cost (green) considering different nomination profiles for site B.

pattern. Site B shows a large number of downward power dips with a significant volume. During these, the overall SI is influenced by the industrial site which results in low imbalance prices. Electricity sourced at the DAM price is resold at the low imbalance prices, resulting in a total cost increase. For site A, both the frequency and magnitude of imbalances as well as the overall power level is lower, resulting in no significant influence on the total costs.

For site A, 50% over nomination (profiles $N_{+50,\mathrm{d}}$, $N_{+50,\mathrm{w}}$ and $N_{+50,\mathrm{y}}$) increases the total cost with an average of 4.4%, while 50% under nomination (profiles $N_{-50,\mathrm{d}}$, $N_{-50,\mathrm{w}}$ and $N_{-50,\mathrm{y}}$) decreases the total cost with an average of 1.9%. The reason for this can be found in the fact that during 2018 the yearly average DAM price was slightly higher than the yearly average imbalance price. It was therefore more profitable to source less electricity on the DAM and source more on the imbalance market. In case the price difference between the yearly average DAM and imbalance prices show an inverse relation, over nomination would result in a lower total cost [48]. The sign of the price difference between the DAM and imbalance market thus defines whether it is interesting to over or under nominate for site A. Site B shows a significant total cost increase for the over nomination profiles (15.9%, 16.2% and 19.3% for $N_{+50,\mathrm{d}}$, $N_{+50,\mathrm{w}}$ and $N_{+50,\mathrm{y}}$ respectively), but also an increased total cost for the under nomination profiles (9.4%, 9.6% and 13.4% for $N_{-50,\mathrm{d}}$, $N_{-50,\mathrm{w}}$ and $N_{-50,\mathrm{y}}$ respectively). The main reason is to be found in the magnitude of over or under nomination. A 50% increase or decrease in power consumption nomination for site B is an absolute value of 100 MW difference, having a significant impact on the overall SI and thus the imbalance price. In case of under nomination, the overall balance position of the LFC area is shifted towards a shortage, resulting in higher imbalance prices, which are paid by the industrial site B, increasing the total cost. In case of over nomination, the overall SI would be influenced in the positive way, leading to lower imbalance prices. The electricity sourced at the DAM price is resold at low imbalance prices, also leading to an increased total cost.

To conclude, influencing the balanced position of a BRP, either by the accuracy of the nomination or the deliberate over or under nomination, can have an impact on the total electricity sourcing cost. Mainly the magnitude of the caused imbalance, in terms of volume relative to the SI, defines the magnitude of the financial impact. Considering a rather small (13 MW average power level) industrial site, the impact of nomination accuracy is nearly non-existent. Improving the accuracy of the existing nomination profile is deemed not financially interesting. For an industrial site with a large electricity consumption (200 MW average power level), a clear benefit in a more accurate nomination is present. Investments in an improved accuracy of the nominations could be financially interesting. Such improvements could be the better forecasting of the sites consumption, as well as limiting the number of process failures with impact on the electricity consumption. Structural over or under nomination could be financially interesting, if the absolute volumes are limited with respect to the overall average SI of the LFC area. For site A, under nomination with 50% of the yearly average power level or 6.6 MW results in a total cost decrease. For site B, an under nomination with 50% of the yearly average power level or 100 MW results in a cost increase.

The applied methodology to influence the imbalance price based on the extra caused imbalance by the industrial site does not take into account market reaction. During large imbalances, both in magnitude and time, flexible market parties adapt their consumption or production pattern to actively counter the SI. The duration and magnitude of reserves activated is thus not necessarily equal to the caused imbalance by the industrial site. The results as presented here should thus be interpreted as worst case scenario, when no flexible market parties are influencing the SI. Nevertheless, the qualitative conclusions are deemed to remain valid.

2.4.2.4 Impact of Influencing the Power Profile

Next to changing the nomination strategy (see § 2.4.2.3), also adapting the power (consumption) profile has an influence on the imbalance volume of a BRP. Internal balancing, i.e., applying electrical flexibility within the BRP portfolio to impact the imbalance volume, does require a flexible asset to be controlled. The steerable process, machine or generator can be controlled to reduce the imbalance volume within the BRP portfolio or can be used to actively participate in the imbalance market, i.e., counter the overall SI. In § 2.4.2.3 the cost of having imbalance within the BRP portfolio is assessed. Whether the imbalance in the BRP portfolio is alleviated by a better nomination accuracy or by internal balancing, the potential benefit is identical. Here, the financial incentive of using the flexible asset to counter the overall SI of the LFC area is assessed. With an ISP of 15 minutes, as in the Belgian LFC area, a combination of a fast steerable process and close-to-real-time data availability is necessary to capture value in the IM. A fictive, infinitely fast controllable, electricity consuming process is assumed as well as a perfect forecast of the imbalance price, making it possible to define an upper boundary of financial incentive. Two distinct potentially interesting cases are defined. Either the process can reduce its power consumption, creating a positive imbalance position, i.e., being *long* in the BRP perimeter, during moments when the overall system is *short* for electricity. The sourced electricity by the industrial site is then resold on the more expensive imbalance market, creating an added value. This case is referred to as the *selling case*. An example can be an electrolysis process running at nominal capacity. The other possibility is that the process can increase its power consumption, creating a negative imbalance position, i.e., being *short*, in the BRP perimeter, during moment when the overall system is *long* for electricity. The extra consumed electricity is to be bought at the imbalance market, which will have low prices. This case is referred to as the *buying case*. An example can be an idling electrode boiler. A combination of both cases is of course possible as well. Both cases are based on arbitrage between an electricity commodity market and the imbalance market.

To define the potential flexibility value in the imbalance market, the arbitrage opportunities related to the DAM are calculated. For each ISP, the imbalance market value $V_{\mathrm{ISP,IM}}$ is calculated according to (2.5). The Available Regulation Capacity (ARC) table, defined with levels ranging from -1000 MW to 1000 MW and with a period of 100 MW, is used to lookup the marginal cost of the activated reserves related to the specific level, $C_{\mathrm{ISP,l}}$. Combined with the volume of activated reserves $\mathrm{NRV}_{\mathrm{ISP,l}}$, the total level value is defined. The sum of all level values defines the total IM value for the specific ISP, $V_{\mathrm{ISP,IM}}$. If the NRV during a specific ISP surpasses a level l, the volume for the specific level is set at 100 MW. To correct for the duration of the ISP, a multiplication factor of 0.25 is implemented.

$$V_{\mathrm{ISP,IM}} = \sum_{l=-1000}^{l=1000} 0.25\ \mathrm{NRV}_{\mathrm{ISP},l}\ C_{\mathrm{ISP},l} \tag{2.5}$$

The DAM energy sourcing value $V_{\mathrm{ISP,DAM}}$ for the NRV is calculated in (2.6). The potential flexibility value in the imbalance market, i.e., the IM vs DAM arbitrage opportunity, is defined as the absolute difference between $V_{\mathrm{ISP,IM}}$ and $V_{\mathrm{ISP,DAM}}$ as defined in (2.7).

$$V_{\mathrm{ISP,DAM}} = 0.25\ \mathrm{NRV}_{\mathrm{ISP}}\ C_{\mathrm{ISP,DAM}} \tag{2.6}$$

Table 2.3: Excerpt of an ARC table with available marginal balancing energy prices per volume level.

	-100 MW	100 MW	200 MW	300 MW	400 MW	500 MW
30-10-2019 11:45:00	14.74	65.63	80.00	89.90	98.81	128.74

$$V_{\mathrm{ISP,flex}} = |V_{\mathrm{ISP,IM}} - V_{\mathrm{ISP,DAM}}| \tag{2.7}$$

Example
Table 2.3 shows an excerpt of the ARC table as made available by Elia. With a NRV of 496.44 MW, the resulting IM value for the ISP $V_{\mathrm{ISP,IM}}$ is calculated to be 9911.31 euro, as shown in (2.8).

$$\begin{aligned} V_{\mathrm{ISP,IM}} = {} & 0.25\,\mathrm{h}\;100\,\mathrm{MW}\;65.63\,\mathrm{euro/MWh} \\ & +0.25\,\mathrm{h}\;100\,\mathrm{MW}\;65.63\,\mathrm{euro/MWh} \\ & +0.25\,\mathrm{h}\;100\,\mathrm{MW}\;80.00\,\mathrm{euro/MWh} \\ & +0.25\,\mathrm{h}\;100\,\mathrm{MW}\;89.90\,\mathrm{euro/MWh} \\ & +0.25\,\mathrm{h}\;96.44\,\mathrm{MW}\;98.81\,\mathrm{euro/MWh} \\ & = 9911.31\,\mathrm{euro} \end{aligned} \tag{2.8}$$

Sourcing all of the NRV energy on the DAM, with a DAM price of 39.04 euro/MWh, would have resulted in a $C_{\mathrm{ISP,DAM}}$ of 4852.72 euro. The potential flexibility value in the IM for the specific ISP, $V_{\mathrm{ISP,flex}}$, would be 5058.64 euro according to (2.7). The positive NRV denotes a negative SI, i.e., the overall system is *short* for electricity. Profit can thus be made by the *selling case*, where a total of 496.44 MW could be resold by BRPs to the imbalance market.

The flexibility value in the IM, i.e., the arbitrage value, is defined for 2017, 2018 and 2019 per volume level. The results are shown in Figure 2.28. The spread between the DAM price and the imbalance price, the total amount of activated balancing energy and the amount of time the overall system is long or short for electricity is given in Table 2.4, this for both the *selling case* (NRV $>$ 0) and the *buying case* (NRV $<$ 0). The total imbalance market flexibility value is given as well.

The arbitrage value considering the *buying case* is shown to be larger than for the *selling case*, despite that the price spread shows to be in favour of the *selling case*. The total volume of activated upwards reserves (NRV $>$ 0) is smaller than the volume of activated downwards reserves (NRV $<$ 0), as a direct result of the average SI being slightly positive on yearly average. The overall arbitrage value in the market over the past three years shows to be between 24.11 and 32.34 million euro.

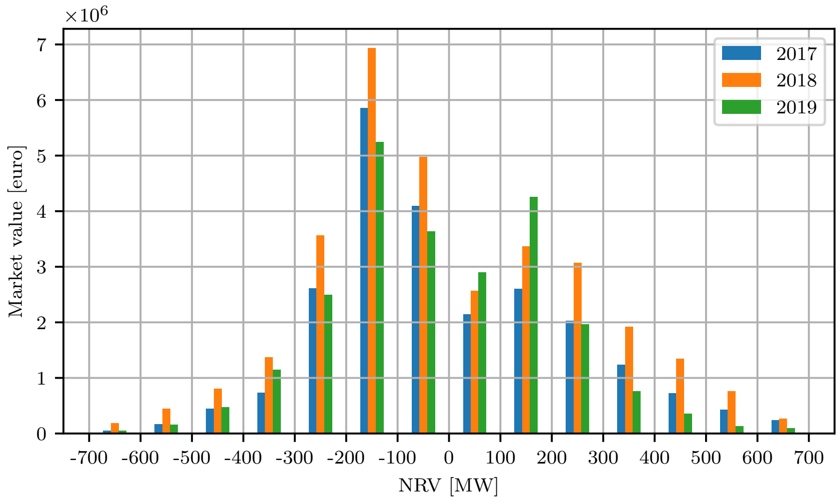

Figure 2.28: Imbalance market arbitrage values per level of activated NRV, relative to the DAM, for 2017,2018 and 2019.

Table 2.4: Price spread (DAM, IM), time, activated reserves and imbalance market flexibility value, split for positive and negative NRV. Data for 2017, 2018 and 2019.

		2017	2018	2019
Price spread	NRV <0	31.48	40.68	31.04
[EUR/MWh]	NRV >0	34.50	41.52	34.40
Time [%]	NRV <0	54.61	51.80	51.92
	NRV >0	45.38	48.19	48.08
Activated reserves	NRV <0	459.61	446.23	434.78
[GWh]	NRV >0	372.38	393.85	409.07
Imbalance market	NRV <0	13.99	18.32	13.61
flexibility value	NRV >0	10.17	14.03	10.50
[m EUR]	**Total**	**24.16**	**32.34**	**24.11**

Note that the implemented methodology makes some assumptions. A discrete valuing with the available levels of 100 MW is considered, while in reality a continuous pricing is considered. All the NRV is assumed to be delivered by activated reserves in the LFC area, i.e., every MW influences the imbalance market value. In practice, a share of the NRV is fulfilled by exchanging volumes on the IGCC platform, decreasing the amount of activated reserves. The arbitrage values in Table 2.4 should therefore be seen as an upper boundary, with the actual market value being slightly less. In practice, the valorisation of this market value is limited by the ability to correctly predict the future imbalance price, as well as the controllability of flexible processes.

This arbitrage value is defined based on a quarter hourly imbalance market and an hourly DAM. It can be expected that repeating the exercise with prices from a closer-to-real-time market, e.g., the CIM, will decrease the amount of NRV and thus the imbalance market arbitrage value.

2.5 Explicit Flexibility

Explicit flexibility is committed, dispatchable flexibility which is traded onto markets [3] and is often also termed *incentive-based flexibility*. The ability to alter the power consumption or production profile is contracted to a third party. The contract implies an obligation (to be able) to react to signals, which is different than the voluntary character as with the implicit flexibility. The contract clearly states the volumes and timings of the to be activated flexibility, as well as the obliged technical details to which it must comply. A remuneration can be composed out of a part for being standby (usually expressed in euro/MW) and/or a part for being being activated (usually expressed in euro/MWh) and is received as dedicated payment for the specific service, not as reduced invoice as with the implicit flexibility. Failure to comply to be standby or activate the electrical flexibility upon request can lead to penalties. The ancillary services as sourced by the TSO to safeguard the operation of the grid or alleviate local congestions are the main source of explicit electrical flexibility and will be the focus of this section.

2.5.1 Ancillary Services for Balancing

ENTSO-E provides an Operational Reserves framework to TSOs on implementing ancillary services to efficiently balance the electricity grid [49, 50], as well as providing guidelines such as the EBGL. These works and guidelines from a European level consists of proposals for methodologies, pricing and activation purposes of reserves as well as TSO-TSO settlement procedures, cross-zonal capacity allocation and standardised products. As these are translated to ancillary service products by each individual TSO for its corresponding LFC area - and is thus mostly country dependent - a wide variety of services exists today with significant or less significant different characteristics. Some non-frequency related ancillary services are steady-state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability [51]. Frequency related ancillary services, i.e., services used for balancing the grid, are Frequency Containment Reserves (FCR), automatic Frequency Restoration Reserves (aFRR), manual Frequency Restoration Reserves (mFRR) and Replacement Reserves (RR) [52]. The latter type of ancillary services require active power to be controlled in function of the grid frequency and are sourced on a TSO operated market.

The grid frequency of 50 Hz is directly related to the rotational speed of the synchronous generators in the conventional power plants and is a measure for the balance of the grid. The conversion of mechanical energy of the spinning turbine and generator to electrical energy delivered to the grid is in balance in normal operation. In case of a frequency deviation incident in the synchronous area, i.e., an occurrence in the grid which causes the frequency to increase or decrease, this balance will be disrupted. During a grid frequency drop, more kinetic energy from the spinning turbine and generator will be supplied towards the grid, i.e., the energy balance is tipped towards the electrical side and the turbine will decrease speed. In case of a grid frequency increase, the energy balance will be tipped towards the kinetic side, increasing the speed of the generator and turbine. This inertial response mechanism, i.e., the electric power delivered by rotating mass as result of a change in the frequency, is immediate and limits the magnitude of the frequency deviation. The inertia in the synchronous area largely defines the Rate of Change of Frequency (ROCOF) in a system. Frequency deviations thus also denote a mismatch in the balance between injection and offtake of electricity from the grid. A decreased frequency is linked to a shortage of mechanical power being converted to electrical power, e.g., as the result of a trip of a power plant. An increased frequency indicates an oversupply of mechanical power being converted to electrical power, e.g., due to the trip of an electricity consuming industrial site. Next to the inertial response, which is physics driven, the grid frequency needs to be actively managed to be kept at its nominal level. The FCR is the first to be activated reserve and serves the purpose of containing the frequency deviation within predefined boundaries. FCR delivering parties continuously monitor the grid frequency and linearly respond with active power control. The aFRR is then activated to restore the frequency back to the nominal level. A signal from the TSO dispatching centre towards the aFRR delivering party is sent every few seconds, which translates into active power being controlled. If the volume of aFRR is insufficient to restore the frequency, the subsequent manual FRR and RR are activated. The reaction speed of the balancing ancillary services variates from instant (inertia), several seconds (FCR), minutes (aFRR and mFRR) to several hours (RR). The duration

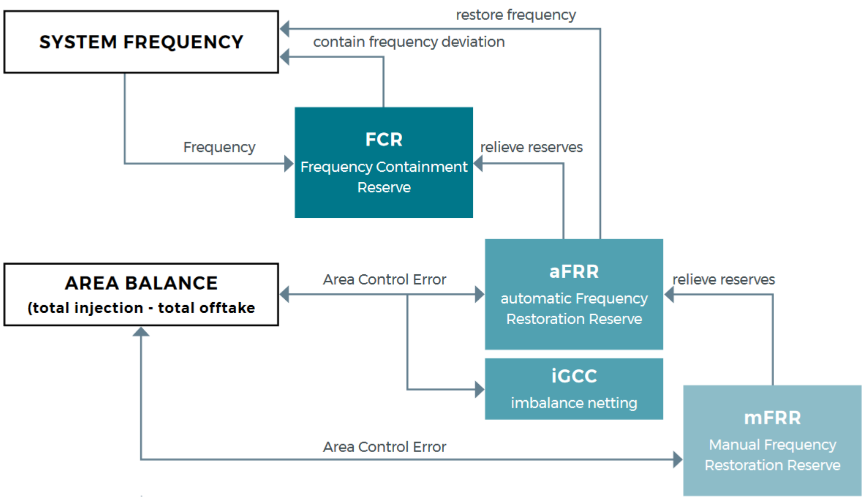

Figure 2.29: Deployment scheme of the different reserves [26].

of the activation of either of the reserves is contractually limited and depends on the magnitude of the to be solved frequency incident. Figure 2.29 schematically presents the working of the grid balancing methodology, showing the cascading effect. Figure 2.30 shows the working of these different ancillary services and the order in which they are activated. A fictional frequency incident is shown, e.g., the loss of a generator. The slope of the frequency variations is limited by the inertial response. The FCR responds linearly with the frequency variation and eventually contains the frequency at a stable, yet below nominal, level. The subsequently activated aFRR power is increased gradually, restoring the frequency back to its nominal level. While doing so, the FCR power is linearly decreased until zero. While restoring the frequency, part of the activated aFRR power is converted back into mechanical power (kinetic energy), i.e., the synchronous generators increase speed, which is visualised as a negative inertial response. While the frequency is perfectly brought back to nominal value in Figure 2.30, in reality a less perfect path to frequency restoration might be possible, with some fluctuations or overshoot. To free the aFRR, mFRR and subsequent RR could be activated, depending on the actual length of the frequency incident. Note that the schematically visualised frequency incident in Figure 2.30 is for illustration purposes, as in reality a continuous frequency variation exists as the result of mismatches between production and consumption. Therefore, there is a continuous activation of reserves, especially of FCR and aFRR, this in both upward and downward direction.

In the following subsections the frequency related ancillary services will be further discussed considering both their technical and market aspects. Implementa-

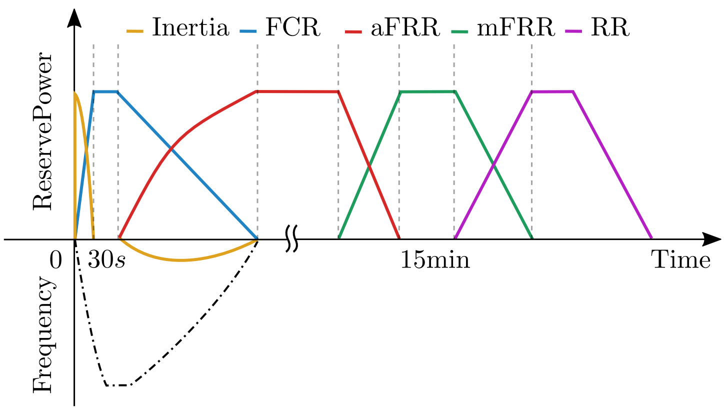

Figure 2.30: Theoretic representation of a frequency incident and the deployment of balancing ancillary services.

tion details are those of Elia, the Belgian TSO, unless otherwise stated. Figure 2.31 shows an overview of the different market timings of these balancing ancillary services, as well as the DAM and CIM SPOT markets as discussed in § 2.4.

2.5.1.1 Inertia and Fast Frequency Reserve (FFR)

The synchronous grid has historically always known a sufficient amount of inertia to limit the frequency variations within certain boundaries. The system inertia can be considered a side phenomenon of conventional synchronous power generators with large spinning masses being operational in the grid. The increase of more non-synchronous generation, e.g., wind and PV, have lead to the problem of a decreasing amount of inertia in the grid. As system inertia is a critical parameter for the frequency stability and thus the safe operation of the grid, the possibility of deploying synthetic inertia is investigated by the ENTSO-E [53]. Synthetic inertia is the mimicking of the behaviour of a synchronous generator, i.e., its inertial response, but supplied by sources which do no inherently have such a behaviour. Today, the need for deployment of synthetic inertia is still limited, as a significant amount of conventional synchronous generators are still operating within the synchronous area. While in some EU countries regulation regarding frequency response from large RES power parks are already in place, no real market for an inertia ancillary service, also noted as R0, is set up. This with the exception for Ireland, where with the DS3 program a service called Synchronous Inertial Response is contracted with market parties [54]. The SIR is defined by the kinetic energy and the ratio of it compared to the lowest output of the providing unit. The remuneration is expressed in euro/MWs^{2}h and is estimated at 0.5 eurocents. The value of delivering synthetic inertia towards the grid is, except for Ireland,

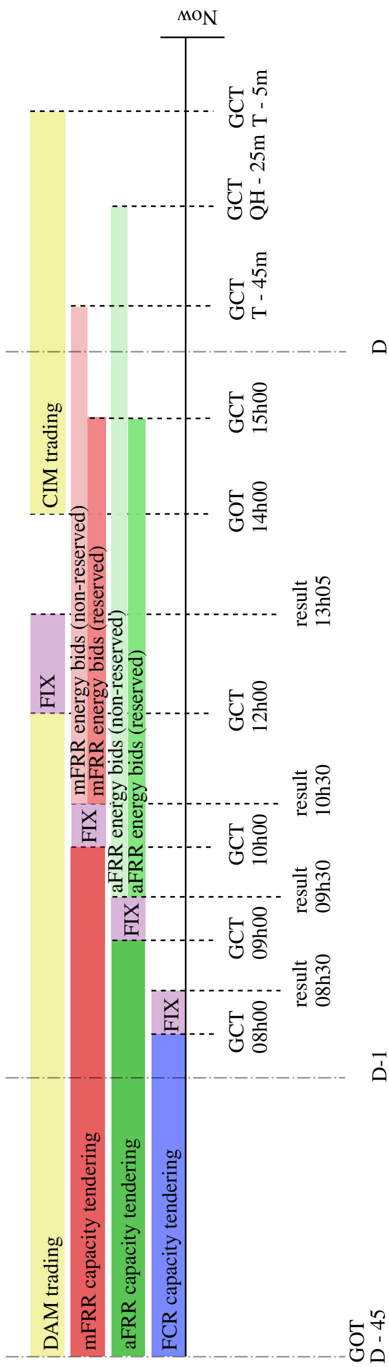

Figure 2.31: Overview of the timings of the SPOT markets and balancing ancillary services, as valid in Belgium. Based on information from EPEX SPOT Belgium and Elia.

Table 2.5: Activation frequencies and maximum activation times for the FFR as defined by the Nordic TSOs [56].

Activation Frequency [Hz]	Maximum Activation Time [s]
49.7	1.3
49.6	1.0
49.5	0.7

not existing today. In the future, assuming a significant share of non-synchronous generation will replace the conventional synchronous generators, a synthetic inertia market might be developed in certain areas. In the Regional Group Nordic, the most northern synchronous area in Europe with Energinet, Fingrid, Svenska kraftnat and Statnett the responsible TSOs, situations with low grid inertia frequently occur. These countries have already a high share of renewable energy and during moments of high RES and low conventional production face the risk of grid instability. To mitigate the arising problem, since summer 2020 the TSOs procure a *Fast Frequency Reserve*. The product is described as a complement to the FCR-D (see § 2.5.1.2), but with an even faster reaction time [55]. Three levels and corresponding maximum activation times are defined, as given in Table 2.5. As the grid inertia fluctuates throughout the year, so does the need for contracting FFR. An hourly pay-as-cleared market is operated, with the required volumes communicated on short-term [56]. The FFR can thus be seen as an intermediate reserve between the inertial response and the FCR.

2.5.1.2 Frequency Containment Reserve (FCR)

Frequency Containment Reserves (FCR), formerly known as R1 or primary reserves, are being used to stabilise the grid frequency within a short time-frame of seconds. ENTSO-E has defined an FCR dimensioning methodology, based on reference incidents within the RGCE. As stated in the SOGL, the reference incident is set at 3000 MW, in both directions. An FCR capacity covering at least this reference incident needs to be procured in the RGCE [57]. This symmetric volume of 3000 MW is divided amongst the different connected TSOs, based on their size and consumption within their LFC areas. For 2020, a volume of 78 MW of FCR was attributed to be sourced by the Belgian TSO, Elia. All contracted volume of FCR within the RGCE react simultaneously and homogeneously in case of frequency deviations within the zone. A frequency incident in a single LFC area will thus be contained by the joined forces of all connected TSOs.

The aforementioned volumes are assumed to be sourced according to the ENTSO-E standardised *200 mHz symmetrical* FCR product. The FCR supplying party is obliged to react by active power control, linearly related to the grid frequency as

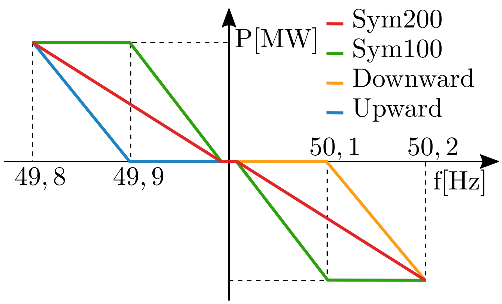

Figure 2.32: Overview of the required active power-frequency reaction for different FCR products by Elia.

given in (2.9) and visualised by the red line in Figure 2.32. A symmetrical deadband of 10 mHz around the frequency equilibrium of 50 Hz is allowed, where no active power control is obliged. The standardised FCR product foresees in a maximum reaction time of 15 seconds for 50% of the to be activated power and a Full Activation Time (FAT) of 30 seconds. Figure 2.32 shows three other products, namely the *100 mHz symmetrical*, *Downwards* and *Upwards*, each with their own respective characteristics. These FCR products are developed by Elia to allow other market parties which could not comply with the standardised products' characteristics. In the light of a homogenisation of the ancillary services on a European level, these TSO specific products are no longer contracted. Figure 2.33 shows the volume of FCR which was sourced per product.

$$\begin{aligned} 49.8\mathrm{H}z \leq f \leq 50.2\mathrm{H}z &: \\ P_{\mathrm{req,200mHz}} &= -\lambda_0 P_{\mathrm{b}} \Delta f \\ f < 49.8\mathrm{H}z &: \\ P_{\mathrm{req,200mHz}} &= P_{\mathrm{b}} \\ f > 50.2\mathrm{H}z &: \\ P_{\mathrm{req,200mHz}} &= -P_{\mathrm{b}} \end{aligned} \tag{2.9}$$

Providing FCR service to the electric grid has long been a privilege for large conventional power plants. A local market operated by the TSO was used to fix long duration contracts with the largest power plants in their LFC area to meet the required volumes. In the last few years a more technology neutral approach is taken towards provision of ancillary services, opening up the market to other market players as well. Smaller generators, consumers and batteries can now also supply FCR towards the grid, either connected to the TSO or (Closed) Distribution System Operator ((C)DSO) grid. While in 2014, only a handful of power plants had a contract with Elia to supply FCR, in 2018 the number of suppliers had risen

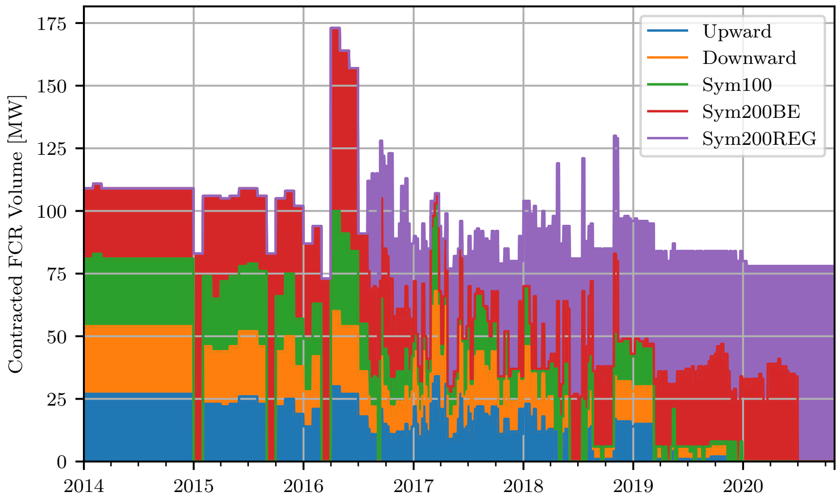

Figure 2.33: Contracted volumes of FCR for the Belgian LFC area.

to 142 of which 62 were DSO connected [58]. Also the contracting time has been declining. In 2014, Elia applied a yearly contracting period, obliging the FCR supplying parties to commit long-term in the supply of FCR. The consecutive years the contracting time has been reduced to monthly, weekly and daily. This shift has also lead towards the creation of a level-playing field for all FCR supplying parties.

As the grid frequency is continuously fluctuating, supplying FCR is a process of continuous active power control. On long-term average, the grid frequency will be very close to 50 Hz, leading to an equilibrium in supplied active power by the FCR supplying parties. This reflects in the remuneration methodology, which is based on the amount of time a party supplies the FCR service, rather than the delivered amount of energy. Figure 2.34 shows the historical Belgian FCR prices for different FCR products, expressed in euro/MW/h. As Elia applies a pay-as-bid strategy, the visualised prices are the average of the awarded bids. An overall decline of the FCR prices over the years is present and can be explained by the opening up of the market and resulting increased competition.

Starting mid 2016, the 200 mHz FCR product was not only contracted on a local Belgian market, but also on a *regional* market. This regional market for FCR originated in Germany, where a common tendering framework was set up between all four German TSOs. A common platform, Regelleistung.net, was set up where the joint calls for tenders were launched. In 2012, the Swiss TSO Swissgrid also participated in this joint tendering, leading the way for other non German TSOs to follow. At the current moment of writing, the FCR cooperation exists of all the German TSOs 50Hertz, Amprion, TenneT and TransnetBW, Belgian TSO Elia,

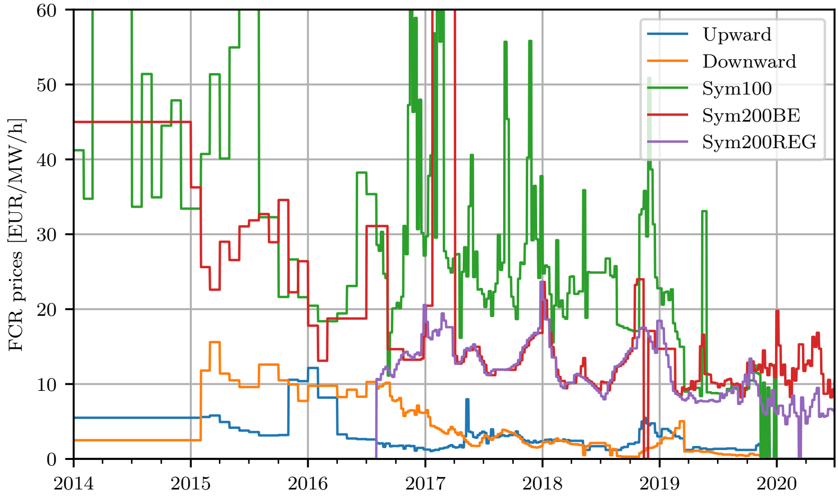

Figure 2.34: FCR prices for the different products as sourced by Elia in the Belgian LFC area.

Dutch TSO TenneT, Austrian TSO APG and Swiss TSO Swissgrid, with the participation of the Danish TSO Energinet.dk planned [59]. In total, these countries cover 46% of the total required FCR capacity of 3000 MW in the Continental Europe Synchronous Area. As from the 1st of July 2020, Elia sources all of its required FCR capacity on the regional platform and abolished the contracting via their local platform. The rules as applied by the FCR cooperation are subject to change and harmonisation, and have known some major and minor changes in the past years. A rather major change was the introduction of a shorter contracting time, i.e., product period, being a single day with a D-2 tendering, which happened on the 1st of July 2019. On the 1st of July 2020 these timings were further refined leading to a product period of 4 hours with daily tendering. Some other characteristics of the joint FCR tendering are the maximum export levels of 30% of a country's needed FCR and that a core portion of FCR still needs to be sourced from FCR suppliers in the own LFC area, i.e., local procurement [59]. The market is closed at 08h00 D-1 and results are published at latest at 08h30 D-1.

The FCR cooperation builds on a TSO-TSO model, where a Common Merit Order List (CMOL) is created containing all the offers as submitted by FCR suppliers. A central clearing system is used to calculate the optimal combination of bids to be awarded, taking into account all the rules and constraints that apply. As optimisation goal, the total procurement cost is minimised. Without reaching import or export limits, every TSO applies the Cross Border Marginal Price (CBMP) for the FCR supplier remuneration. Local Marginal Prices (LMPs) can

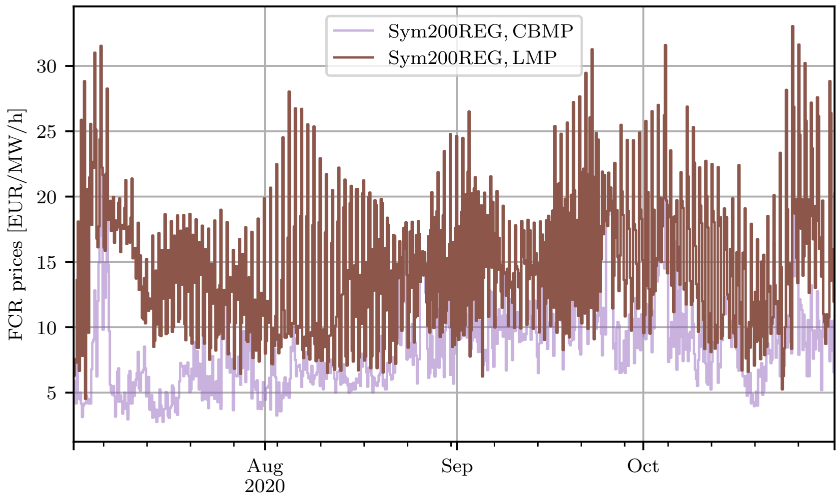

Figure 2.35: FCR Cross Border Marginal Price and Local Marginal Price for the Belgian LFC area, as from the start of complete procurement on the regional platform.

be established when either the export or import limit is exceeded. An LMP higher or lower than the CBMP is present when the import and export limit is exceeded respectively. This CBMP or LMP is used to remunerate the FCR suppliers whose bids have been accepted according to a pay-as-cleared methodology. When a country's import limit is exceeded and thus a LMP higher than the CBMP is set, all of the locally sourced FCR (the core portion) will receive this elevated remuneration. The volume which was imported will be remunerated according to the CBMP [60]. Figure 2.35 shows the CBMP and LMP for Belgium as from the start of the full use of the regional platform. Note that on most moments an LMP higher than the CBMP is set showing that Belgium is often reaching its import limit. This hints that other LFC areas within the FCR cooperation can supply FCR at a lower cost than the Belgian supplying parties. Considering the volume of 1380 MW which is sourced in the FCR cooperation and a recent CBMP price of 8 euro/MW/h, the total market value mounts up to 100 million euro. For Belgium, considering 30% is remunerated according to the LMP while the remaining is remunerated according to the CBMP, a yearly FCR market value of of 6 to 10 million euros is present.

Regelleistung makes available the FCR volume demand, tendering results including CBMP and LMPs and an anonymous list of bids of all countries, giving the possibility to gain insight in the market [61]. All bids placed on the Regelleistung platform from the 1st of July 2019 up to and including the 30 September 2020 are visualised in Figure 2.36. Note that the vertical axis in Figure 2.36 has a logarithmic scale and that thus a large portion, more than 44%, of the total bids

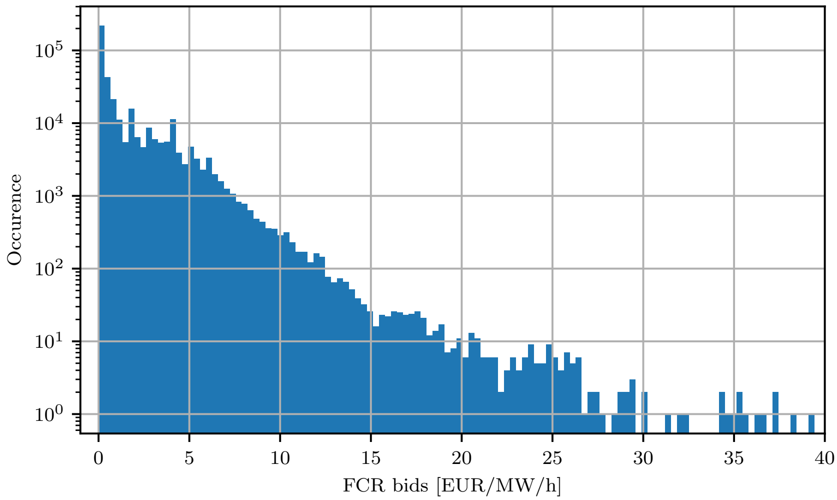

Figure 2.36: Histogram of all accepted FCR bids on the Regelleistung platform. Data from the 1 July 2019 up to and including the 30 September 2020 [62].

are placed into the market as a zero-bid. This zero bidding strategy can be explained by the pay-as-cleared method which is applied. The FCR volume demand is currently larger than the volume of zero bids, assuring the zero-bidders to obtain the CBMP remuneration without having to develop a classic profit-risk trade-off bidding strategy.

Contracting FCR with the TSO requires commitment to comply with the technical requirements and rules considering timing and power. A prequalification process (see § 2.5.1.5), consisting of, among other things, an activation test ensures the TSO of a qualitative FCR supplier. During the contracting period, Elia can perform a test to check if all obligations are met. The resulting penalties in case of non-compliance can be severe and in worst case reduce the remuneration to zero. From a TSO point of view these strict penalties are completely justifiable, as a non-compliance with the rules inhibits a risk for the safety of the complete synchronous grid. For the FCR supplying party, this remind him of the obligatory character of valorising its flexibility by delivering ancillary services.

2.5.1.3 Frequency Restoration Reserve (FRR)

Frequency Restoration Reserves (FRR) serve the purpose of bringing the grid frequency back to nominal value, i.e., 50 Hz in Europe. The FRR are divided in an *automated* and *manual* part, with each their specific characteristics. The automatic Frequency Restoration Reserves (aFRR), formerly known as R2 or secondary re-

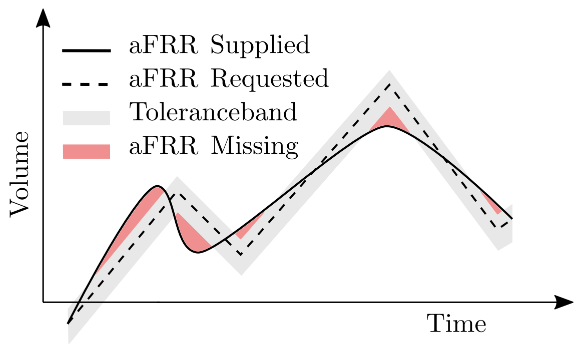

Figure 2.37: Example of aFRR setpoints, tolerance band and energy discrepancy. Based on [63].

serves, need to react based on a periodic setpoint sent from the TSOs central Load Frequency Controller. A period of 4 seconds is used by Elia. An automated control process needs to be in place at the aFRR providing party site, allowing to respond with active power control. A tolerance band of 15% allows for small control errors and delays, e.g., at ramping, as is shown in Figure 2.37. As shown in Figure 2.30, the aFRR takes over from the FCR, which is then again available for future frequency incidents. The subsequent reserve being activated, if necessary, is the manual Frequency Restoration Reserve (mFRR), formerly known as R3 or tertiary reserve. The activation of the mFRR is more rudimental, as it is a request from the TSO to increase or decrease a certain contracted volume, i.e., a block of power is being activated. A reaction time of 15 minutes is allowed, ensuring the mFRR providing party to take the necessary measures to deliver the amount of energy, e.g., an industrial process can be shutdown safely or a power plant can be started up gradually. These mFRR are activated in case the activation of the aFRR volumes are not sufficient to restore the grid frequency back to nominal level. The contracting of the necessary FRR volumes as well as the activation is the responsibility of the TSO, as they are to be deployed to counter the ACE within the LFC area.

The supplying of aFRR has long been a privilege for large conventional power plants[11]., i.e., Combined Heat and Power Plants (CHP), Closed Cycle Gas Turbines (CCGTs) and Open Cycle Gas Turbines (OCGTs). The aFRR requirements as well as the regulation did not leave any room for other parties to provide this type of reserve. On the Belgian market, this resulted in a small number of parties supplying aFRR towards Elia, preventing the existence of an actual aFRR market. The aFRR (energy) price was therefore heavily regulated, i.e., a price cap

[11]In Belgium, Elia refers to *CIPU-units*, which are power plants with a nominal power of 25 MW or more [64]

was set based on the gas price. This price cap prevented excessive profits to be made by the few existing parties able to provide the aFRR. A single symmetrical aFRR product existed, obliging the supplying party to both be able to increase or decrease the active power. Linking the supply of aFRR and FCR was possible, again from a viewpoint of conventional power plants, being the main suppliers of all ancillary services. Remuneration for providing aFRR service is twofold. A remuneration is obtained for being able to provide the service, i.e., to reserve some capacity, and is based on the volume of power and the length of the contract. The so-called *capacity remuneration*, or the *remuneration for aFRR awarded* is expressed in euro/MW/h. The total amount of aFRR which is contracted to be stand-by by the TSO is based on the needs for the LFC area. For Belgium, the needed volume of aFRR is around 145 MW (symmetrical) and is decided upon based on a yearly evaluation[12]. An overview of historical aFRR capacity prices is given in Figure 2.38. As Elia applies a pay-as-bid methodology, the given prices are averages for the awarded, i.e., contracted, bids. While an *Upwards* and *Downwards* aFRR is defined, both are linked to a symmetrical product, hence only a single capacity price exists. A shortening of the contracting period, from monthly to weekly, occurred in 2016. Some inter temporal price variations are seen, with some higher peaks during the end of 2016 and 2018. These correspond with some scarcity on the Belgian electricity market, as further explained in § 2.5.2.3. More recently, in the light of the EBGL, the aFRR market is reformed and new terms and conditions apply. As from the 3th of October 2020, a separate procurement of the Upwards and Downwards products is implemented, as well as the shortening of the contract times to blocks of 24 hours, i.e., the *all-CCTU* and 4 hours, i.e., the *per-CCTU*. This shortened Capacity Contracting Time Unit (CCTU) allows for a level playing field for market parties to participate in the aFRR market without the necessary long-term commitment. Indeed, also the technology specificities which were implemented in the regulation are removed, allowing also smaller generators, loads or storage to participate in the market. A complete overview of the current terms and conditions can be found on the website of Elia [63]. Capacity prices for the aFRR considering the new terms and conditions are shown in Figure 2.39. While preliminary, some intra-daily and intra-weekly patterns could be recognised, largely linked to the overall electricity demand. The majority of the aFRR supply parties is still presumed to be large gas-fired power plants, as a shift towards other technologies does not occur overnight. To be able to provide upwards aFRR, a power plant needs to be operational, yet not at nominal capacity. During the weekends and other low demand periods, a higher capacity price might be set to cover the costs of keeping the turbine idle. During demand peak periods, the power plant is derated to be able to deliver the aFRR. To compensate for the

[12]More recent, a daily evaluation defines the amount of aFRR to contracted. For details we refer to Elia.

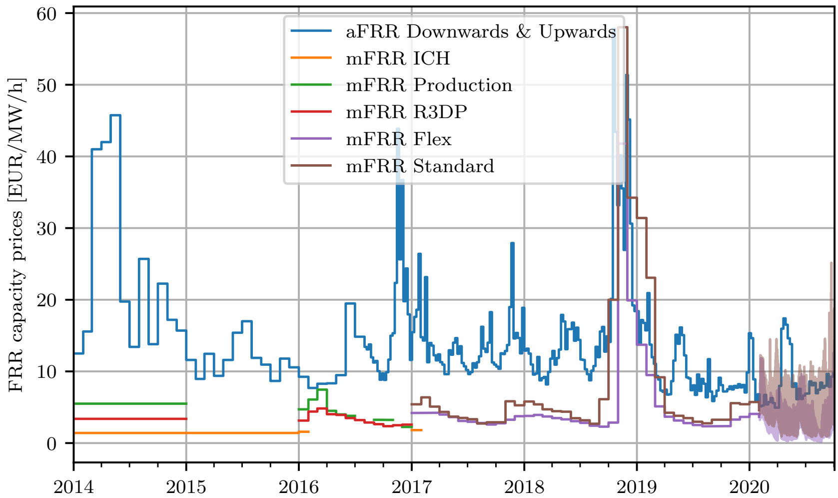

Figure 2.38: Historical capacity prices for aFRR and mFRR on the Belgian market.

loss of generation capacity, a higher capacity price can be set.

Next to the capacity remuneration, also an *energy* remuneration is foreseen. This remuneration covers the expense made by the aFRR supplier to deliver or take an amount of energy towards or from the grid. The aFRR providing party has the obligation to submit energy bids towards the TSO, for the volume it has contracted and is remunerated for by the capacity remuneration. As discussed previously, a strict price cap on these aFRR energy bids was set, preventing exuberant profits by the small number of providing parties. Since the introduction of the new terms and conditions beginning of October 2020, these limits have been virtually removed.[13] An overview of the aFRR energy prices is shown in Figure 2.40. An identical pay-as-bid methodology is implemented as with the capacity remuneration. Indeed, no extreme prices are to be seen for the aFRR Upwards and Downwards activation during the previous years, as well as for the most recent data considering the new terms and conditions. A lower price level for the Downwards product and a higher price level for the Upwards product is present. These represent the cost of the activation, e.g., delivering upwards aFRR requires more gas to be fed to the CCGT, introducing an increased fuel cost. Downwards activation results in the reduced consumption of gas, decreasing the cost. This bimodal pricing is reflected in the imbalance price as used in the imbalance settlement system as discussed in § 2.4.2. Indeed, the aFRR is frequently the most expensive activated reserve, hence setting the MIP and MDP and thus the imbalance price. A positive aFRR energy price

[13] A price cap of -1000 euro/MWh and 1000 euro/MWh for Upwards and Downwards products are set respectively [63].

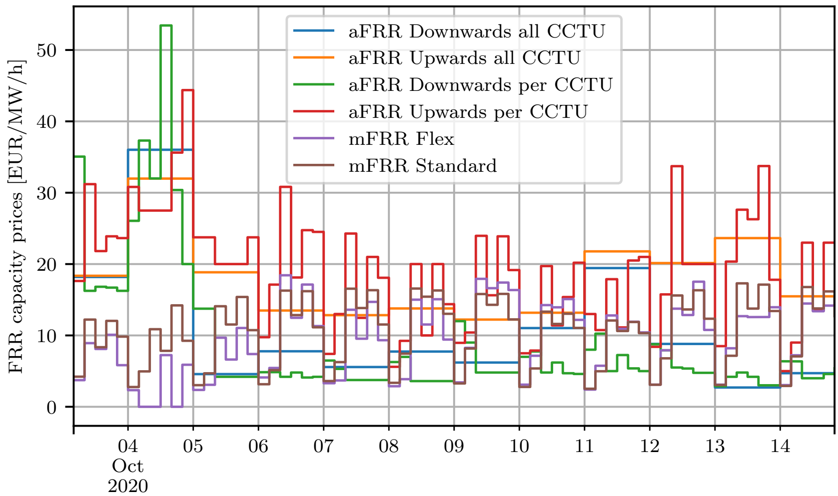

Figure 2.39: Capacity prices for aFRR and mFRR on the Belgian market according to the most recent market terms and conditions.

corresponds with a payment from the TSO towards the providing party, while a negative energy price reverses the financial flow. Next to the contractual aFRR as discussed, also *free bids* are allowed to deliver aFRR. As its name depicts, these *free* bids are not subject to price caps and can set any energy price. No contractual obligation to reserve aFRR power for a certain period is necessary, and as a result, no aFRR capacity remuneration is received. In Figure 2.40 these free bids are shown as well. The energy bids from the contractual aFRR and the free bids are grouped into a mutual merit order, allowing them to be activated in cost ascending order, as the TSO requires reserve power. The total yearly system cost for the aFRR capacity reservation is close to 30 million euros, while the activation cost, including both free bids and contracted bids, also mounts up to 32 million euros [14], this only for the Belgian LFC area.

The European Platform for the International Coordination of Automated frequency restoration and Stable System Operation (PICASSO) is an implementation project to establish the European platform for the exchange of aFRR balancing energy. All ENTSO-E connected TSOs are members of the project, either as active contributor or observer. The goal of the project is to integrate all European aFRR markets, leading to a more economic and technical efficient system. The platform is deemed to go-live mid 2021 and TSOs will connect in the following years [65].

The manual FRR have a similar operating market, but with slightly different

[14] Averaged for the period of 2014 - 2019

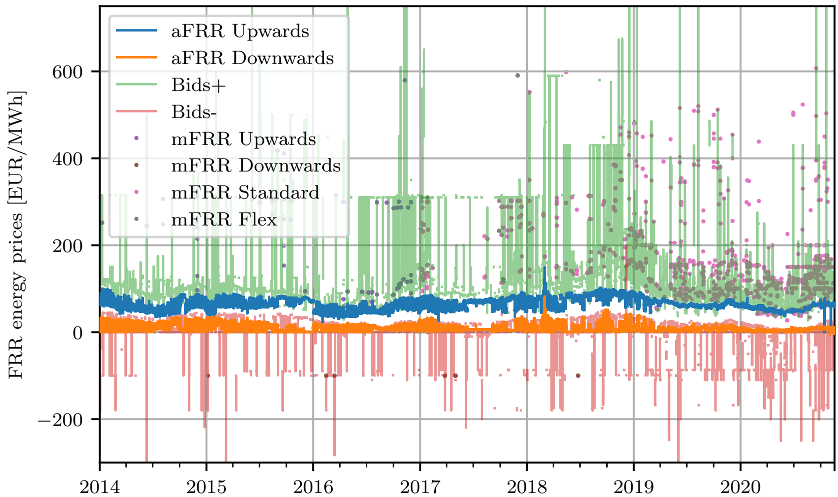

Figure 2.40: Activation prices for the aFRR and mFRR on the Belgian market.

characteristics. Supplying of mFRR is not subject to strict follow-up of a received signal as with the aFRR, rather it is the activation of a block of energy, within the Full Activation Time (FAT), being 15 minutes in the Belgian LFC area. An example of such an activation is the ramping of an idling power plant, which will then deliver significant amounts of energy within a short time frame. But also an electricity intensive consumer could supply mFRR, by shutting down some machines or a complete industrial site. Providing mFRR with loads had been possible for many years, contrary to the aFRR and FCR. Elia constructed the *ICH*, *Production* and *R3DP* products, respectively for TSO connected interruptible loads, CIPU[15] generation and non-CIPU generation and DSO connected loads. The different mFRR products were thus technology dependent, not creating a single level playing field for all. Product characteristics, such as the number of possible activations, duration of activation and remuneration methodology, varied as was deemed necessary to comply with the different needs of the providing technologies. A difference existed between the remuneration of the CIPU and non-CIPU market parties. The CIPU units received both a capacity remuneration as well as an activation remuneration, of which the latter could be supplemented with a start-up remuneration in case the power plant was offline. Non-CIPU market parties, i.e, DSR parties, only received a capacity remuneration. For the sake of brevity we refer to Elia for the details [66, 67]. As with the other ancillary services, a long-term commitment was asked to the supplying parties, as the contracting was on yearly

[15]Contract for the Injection of Production Units

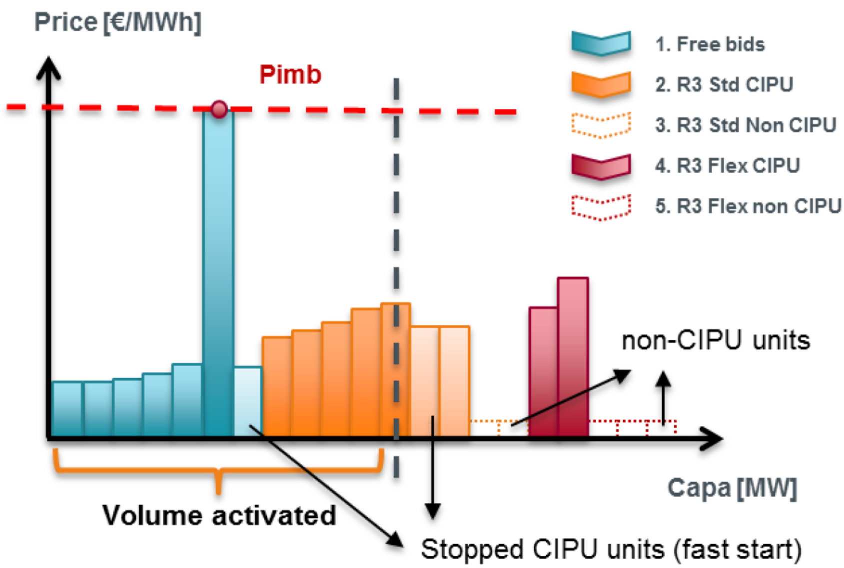

Figure 2.41: Merit order of activation of mFRR, according to the Elia rules as valid in 2017 [68].

basis. In 2017, the mFRR products were reformed and the technology specificities were largely alleviated. Two products, *mFRR Flex* and *mFRR Standard* were defined, which had distinct characteristics considering the number of possible activations, recovery time and duration of the activation, but did not pose any restrictions towards providing technologies. Yet, still the remuneration methodology was maintained. Due to the absence of an activation remuneration for non-CIPU mfRR providing parties, no single merit order could be used. Non-CIPU units were to be activated lastly, after all available volumes of contracted mFRR with CIPU units and free bids, as shown in the merit order in Figure 2.41. The activation of *mFRR Flex* providing units was put at the end of the merit order, since the number of activations, as contractually agreed, is limited [68].

To facilitate a single level playing field for the CIPU and non-CIPU providing parties, on 1 December 2018 a new regulation for the activation of mFRR was put into place. From now on, each mFRR providing party, either CIPU or non-CIPU, either contracting *R3standard* or *R3flex*, is granted an activation remuneration according to its delivered energy. This results in the need of non-CIPU units to set an activation bid price. For the activation remuneration a pay-as-bid principle is maintained. Fig. 2.42 shows the merit order curve as used under this new regulation. A common merit order is used for both the *free bids* and contracted *R3standard* and this for both the CIPU and non-CIPU units. Only the *R3flex* bids are maintained

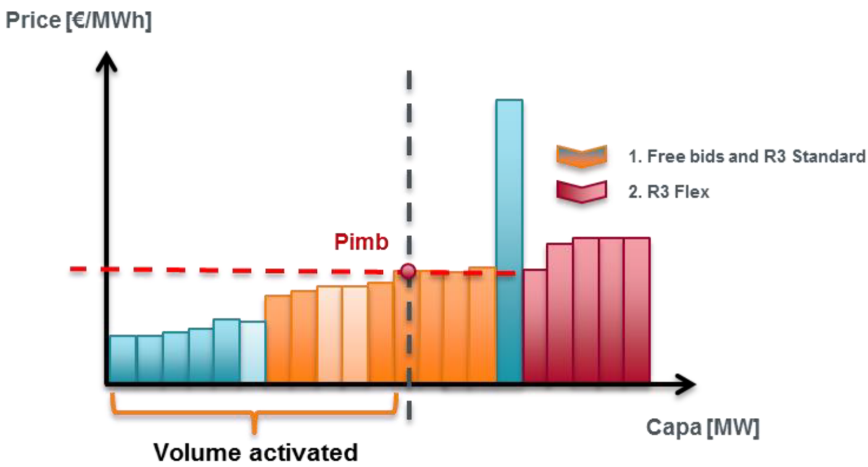

Figure 2.42: Merit order of activation of mFRR, according to the Elia rules as valid from 2018 onwards [68].

at the end of the merit order for the reason of only allowing limited amount of activations.

The main goal of harmonising and opening up the mFRR market is to increase the liquidity and the competition between providing parties. Figure 2.43 shows the volumes which were contracted during the past years. The necessary to be contracted volume for the Belgian LFC area was defined yearly and has been around 800 MW[16]. Identical to the aFRR, the mFRR remuneration is twofold. Figure 2.38 and Figure 2.39 show the mFRR *capacity* prices from the past years. The shortening of the contracting times has lead to the current CCTU of 4 hours, which is implemented since February 2020. As with the other ancillary services, this shortening has lead to the adoption of different contracting behaviours from the market parties, resulting in inter temporal price patterns. Figure 2.40 show the *Energy* or *Activation* prices, visualised as dots. The activation of mFRR is not as frequency as the FCR and aFRR products, as it is only required during moments of large imbalances. The mFRR energy price has not been subjected to such strict price caps as with the aFRR. This makes it possible for a wide variety of processes and market parties to be active as mFRR providing party, even if they have a high opportunity cost. It should be noted in Figure 2.40 that the majority of energy prices is positive, with only a few outliers on the negative side. A positive price represents a financial stream from the TSO towards the mFRR providing party and vice versa for a negative price. The main reason is that the mFRR is almost exclusively used as Upwards reserve, i.e., during times of shortages on the grid. Indeed, historically,

[16]Similar to the other ancillary services, the evaluation of the to be contracted volumes has recently been changed to daily.

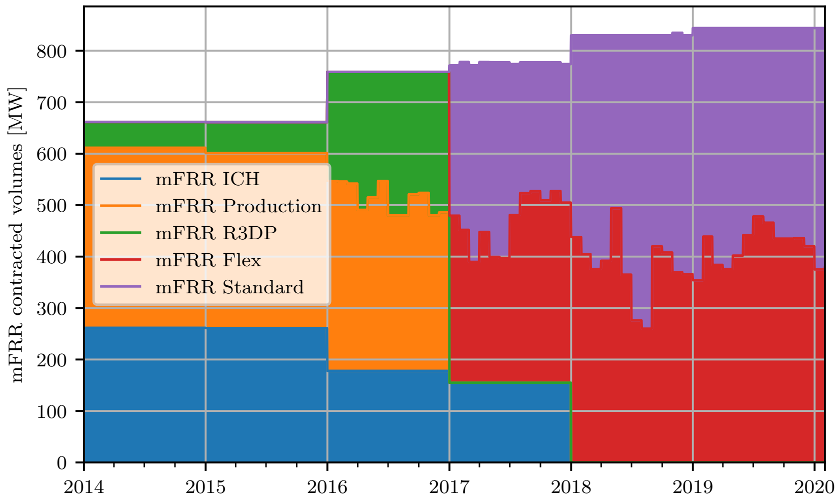

Figure 2.43: Contracted volumes of mFRR.

there was only a need for Upward mFRR reserves, as they served there purpose during large incidents, i.e., the trip of a large power plant. A situation where a sudden oversupply of electricity on the grid is seen, was rather extraordinary. Providing Upward reserve requires the consumption of fuel in power plants and the interruption of processes on industrial sites, hence requiring a rather high financial compensation from the TSO. On the contrary, a Downward reserve would require the decrease of output of a power plant, reducing fuel cost, or the increase of the consumption of an industrial site, which could produce more goods. A low mFRR remuneration from the TSO could suffice, or even a negative remuneration could be set, i.e., paying towards the TSO to take off power from the grid. More recently, considering the integration of non-dispatchable RES in the grid, more attention is given to the need of Downward mFRR. Large volumes of RES would possibly result in moments of significant oversupply, possibly endangering the stability of the grid if no Downward mFRR is available. In their adequacy and flexibility study in 2017, Elia estimated a need for 825 MW of Downward mFRR from 2021 onwards [69]. Upon the time of writing, no Downward mFRR is contracted by Elia yet [26].

The yearly mFRR market value, averaged over the years 2014 to 2019, was 25 million euros for the capacity reservation and 2.6 million euros for the activation. This complies with the idea that the mFRR are only activated rarely, in case of large imbalances. The Manually Activated Reserves Initiative (MARI) is the European implementation project with as goal to develop a fully functional European mFRR platform. The focus lies on the harmonisation of the balancing energy products, both technically as operationally. In total, 28 active members participate in the MARI project and 4 are considered observers. A platform go-live is foreseen beginning 2022 [70].

2.5.1.4 Replacement Reserves (RR)

Replacement reserves are the active power reserves available to restore or support the required level of FRR, to be prepared for additional SIs, including generation reserves [71]. The RR can thus be used to free the previously activated FCR, aFRR and mFRR, so they are available for future use, as schematically presented in Figure 2.30. These reserves typically are *slow* reserves, meaning that their FAT exceeds the Time To Restore the Frequency (TTRF), which is 15 minutes in the ENTSO-E area. Generators, loads and storage can all act as replacement reserves. Not all TSOs within the ENTSO-E acquire RR or at least not in a homogenised way, of which Elia in Belgium is one. In June 2020, the Agency for the Cooperation of Energy Regulators (ACER) published a decision on a methodology for a list of standard products for FRR and RR [72]. The Standard Product for Balancing Capacity (SPBC) methodology stipulates the required characteristics of the market, product and bids.

The Trans European Replacement Reserves Exchange (TERRE) project is an European implementation project for exchanging replacement reserves. The aim was to setup a platform on which the RR balancing energy can be exchanged between LFC areas, so creating a harmonised level playing field for the reserve providers. The project was setup from within the ENTSO-E, similar to the PICASSO and MARI projects for aFRR and mFRR respectively. In January 2019 the platform went live, with a planned nine TSOs to connect subsequently, of which also the French TSO RTE.

Elia has up until now not explicitly procured RR, as deemed not necessary for the safe operation of its LFC area. Nevertheless, Elia did contract *strategic reserves* during some winter periods (see § 2.5.2) and developed a specific *slow* balancing ancillary service product during the winter of 2018 (see § 2.5.2.3).

2.5.1.5 Prequalification Process

To be able to provide balancing ancillary services towards the TSO, a prequalification process needs to be completed. Several steps need to be taken in order to be allowed to submit bids towards the dedicated AS market platforms and deliver the reserves. A first step is to become a qualified provider and requires general administrative paper work such as company information including contact persons, a sworn statement on the solvency of the company, etc. A technical prequalification procedure is foreseen for generators, where the offline and real-time communications are checked and bids need to be made towards the Elia platforms. A simulation test is conducted, separately for FCR, aFRR and mFRR ancillary services and the reaction of the providing party is checked. Product specific application forms are required to be filled in, stating the production units which will participate including the delivery point and corresponding EAN number. In case of participating with a large generation unit, a CIPU contract is required as well. A general conditions form states the details on the general remunerations, penalties, invoicing and payments. In case a CDS is involved, i.e., when the ancillary service providing party is embedded in a CDS, also a CDS operator agreement needs to concluded. After all these general requirements are met, a dedicated framework for each individual ancillary service needs to be signed. These frameworks state all possible details on provision of the ancillary service, e.g., details on activation, procedures in case of failure to deliver, bidding platform rules, etc. Distinctions can be made based on the providing technology, i.e., CIPU or non-CIPU. In case of providing the ancillary service with multiple providing units (see § 2.6.1), i.e., with a providing group, a detailed description of each providing unit and delivery point needs to be given. After a prequalification test on the individual providing units or on the providing group, the BSP is considered prequalified and allowed to bid onto the dedicated ancillary services market platforms. Elia operates a dedicated application for the Short-Term Auctioning of Reserves (STAR) on which BSPs can submit their capacity bids. Also regional platforms, such as the Regelleistung.net platform can be used to submit bids.

The given description of the prequalification process is only a brief overview to outline the complexity of being allowed to deliver balancing ancillary services towards the TSO. A full overview and documentation can be found with Elia [73].

2.5.2 Adequacy and Security of Supply

System adequacy, or adequacy in short, is the ability of a power system to meet the demand at all times with the total available and expected capacity, i.e., to ensure the Security of Supply (SoS). Flexibility and adequacy are intertwined as both ensure a safely functioning electricity grid where demand and supply are met at any moment. Considering the high level of interconnections of different countries and LFC areas within Europe today, an adequacy methodology is developed on ENTSO-E level, taking into account harmonised inputs, system flexibility and interconnections [74]. Adequacy studies are conducted on a European level by ENTSO-E, regional level by the Pentalateral Energy Forum, as well as on local level by the TSOs, i.e., Elia in Belgium [26, 75, 76]. For Belgium, the adequacy reliability standard is defined based on the Loss Of Load Expectation (LOLE) criterium, which is the number of hours during which the grid will be unable to cover the total load. A LOLE of 3 hours is used as limit, considering a normal climate year, while a LOLE of 20 hours is used considering a statistically abnormal

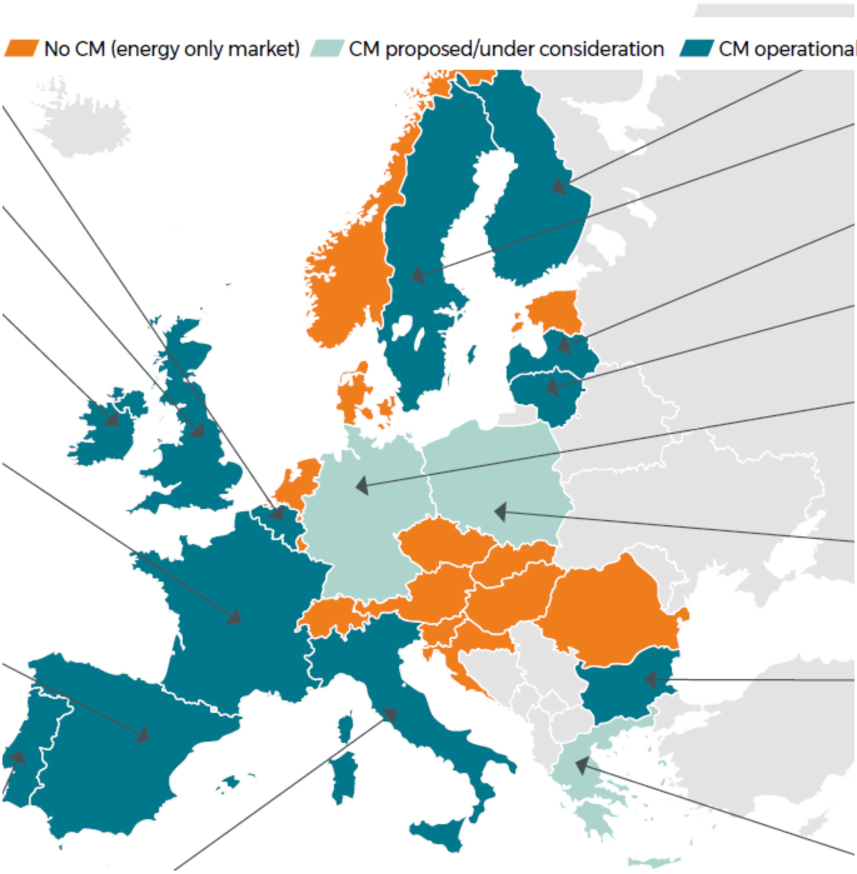

Figure 2.44: Overview of the capacity mechanisms in Europe in 2018 [26].

year [26].

2.5.2.1 Capacity Mechanisms

To meet the adequacy standards, several European countries rely on capacity mechanisms to ensure enough generation capacity is available in the market. These capacity mechanisms are somehow contradictory in an *energy-only* market which is operated today in Europe, where electricity market prices are defined based on the marginal operational cost. Nevertheless, in today's functioning energy-only market, several countries see the need for a capacity mechanism to ensure the SoS. Figure 2.44 shows the countries which currently have, are planning to or do not have a capacity mechanism in Europe.

Elia defined three distinct groups of capacity mechanisms as they are operational in the ENTSO-E area today. First, a *capacity payment* is a price-based mechanism which provides an administratively set side payment towards eligible capacity, i.e., a remuneration is given to power plants. This type is implemented in Portugal and Spain. A second type are the *Strategic Reserves (SR)* as they are implemented in Belgium, Germany, Finland and Sweden. Here, a certain capacity of generation units are withheld from the energy market and remunerated for being kept operational, so to be called upon in times of scarcity. The European Commission deemed this type of capacity mechanism beneficial to overcome short periods of adequacy concerns, considering that the capacity is available and would otherwise leave the market. A third and last type of capacity mechanism is the *Capacity Remuneration Mechanism (CRM)*. In this market-wide mechanism all technologies, whether existing or new, can participate. A certain remuneration is given to the capacity providing party, based on the support to maintain the adequacy. The capacity can nevertheless operate in the conventional energy markets and no restriction on the dispatching should be present. The EC acknowledges that such a mechanism is appropriate in case a long-term adequacy concern arises [26].

In Belgium, a SR is possible to be foreseen in the winter periods from 2014 to 2021, as an amendment to the Federal Electricity Act of 1999 was made. More specifically this amendment obliges Elia to organise, manage and activate a SR mechanism to offset any structural generation shortage during the winter period. As discussed in [77], the need for a SR is an indication that the existing capacity is not generating enough profit to remain economically viable in the electricity market. A yearly report defines the need and volumes of SR to be contracted, which can sourced at both the generation as well as the demand side, i.e., a SR delivered by Generation units (SRG) and SR delivered by a reduction in offtake on the Demand side (SRD) respectively. The latter is split into a SDR DROP TO, i.e., a product where the final level of consumption is of importance and into a SDR DROP BY, i.e., where the volume reduction is of importance [32]. Reserve providing parties receive both a capacity and energy remuneration and no fixed price caps are present. Instead, the Federal Commission for Electricity and Gas Regulation (CREG) can impose the contracting in case of unreasonable prices. For SDR, suppliers have 90 minutes to gradually shed demand, which is considerably longer than the FAT of the mFRR as discussed in § 2.5.1.3. During three winter periods, Elia decided there was a need to contract SR. An overview of the volumes, capacity and energy prices is given in Table 2.6. The capacity price does not differ much from the capacity price as seen for the mFRR (see Figure 2.38 and Figure 2.39) and also the activation prices are in the same range (see Figure 2.40). Implicitly, the SR could be seen as a prolongation of the mFRR and therefore be termed RR. From the winter period of 2018-2019 onwards, Elia does not foresee any need for a strategic reserve until 2021-2022. During the winter of 2022 - 2023 a preliminary SR capacity of 800 MW is foreseen, but is depending on the

Table 2.6: Overview of the volumes and prices of the strategic reserve as contracted by Elia [80].

Delivery Period	Type	Contracted Volume [MW]	Average Capacity Price [EUR/MW/h]	Average Activation Price [EUR/MWh]
Winter 2015 - 2016	SGR	1177.1	10.62	62.44
	SDR	358.4	9.76	736.73
Winter 2016 - 2017	SGR	750	9	75
Winter 2017 - 2018	SGR	725	7	80

timing of the nuclear phase out [78]. It has to be noted that the volumes of SR, as calculated by Elia, are prone to discussion. In the winter of 2015-2016 Elia first acquired a need for a SR of 3.5 GW, of which only 1.5 GW was contracted eventually. In the end, the SR have not been activated in this period [79]. Also, for the winter period of 2018 - 2019 no SR need was foreseen, while this period did know some scarcity and corresponding risks of SoS, as further discussed in § 2.5.2.3.

From the viewpoint of flexibility providing parties, the SR market could provide some opportunities, being it as the extension of the mFRR market. Nevertheless, opposite to the balancing ancillary services such as the mFRR, the SR is not a structural component in the balancing or operation of the grid. As stated by the EC, it is deemed an instrument for the mitigation of short term adequacy concerns. Therefore it should also be perceived likewise and could provide an extra revenue stream for existing flexible assets rather than to serve as investment signal for enlarging or creating flexibility.

More recently, another amendment was added to the 1999 Federal Electricity Act in Belgium, with the goal of allowing a market-wide CRM to be implemented [81]. The rationale behind the proposed CRM is that in the near future a structural shortage in generation capacity will exist, due to the gradual nuclear phase out starting in 2022. In total, 6 GW of dispatchable nuclear generation capacity will have left the market by 2025. Several studies have estimated the necessary new generation capacity to be installed so to foresee in the adequacy needs. While the most recent forecast of Elia mounts up to a capacity of 3.9 GW [26], the CREG put some remarks to the calculation methodology and estimated a lower needed capacity. It should be clear that such an estimation is always prone to discussion, which would lead to far for the purpose of this work. More important for this work is that the CRM would not exclude any technology from participating, i.e., that it is also possible for the demand side to participate in the tendering. The remuneration which could be obtained in the CRM is depending on the contribution and is defined according to *derating* factors. Derating factors evaluate the contribution of the different technologies, i.e., generation, demand flexibility and storage, to the Belgian adequacy. The derating is depending on the availability of the Capacity Market Unit (CMU) during moments of near-scarcity and is technology specific. The different technologies taken into account are *Thermal TSO connected*, i.e., CHP, OCGT, CCGT, etc., *DSO connected technologies*, i.e., smaller generators, *Weather dependent technologies*, i.e., wind and PV, and *Energy-limited technologies*, i.e. PHS, batteries, DSR, etc. The final terms and conditions as well as the approval by the EC for the CRM are not present upon the time of writing. Nevertheless, this mechanism might provide some opportunities for market parties, including flexible loads participating with DSR.

2.5.2.2 Scarcity Pricing

Scarcity pricing is the principle of pricing electricity at a value above the marginal cost of the marginal unit during conditions of high system stress, according to the incremental value that flexible capacity offers to the system in terms of keeping the Loss Of Load Probability (LOLP) in check [82]. More concrete, the scarcity pricing would, in times of system distress, increase the real-time price of electricity. The rationale is to also allow flexible capacity providers to recover (part of) the capital costs rather than only the operational cost as is the current practice in the energy-only market. The potential profits should attract flexible capacity investments in the market, so to counter the problem of adequacy and structural shortage of capacity. Belgium is one of the frontrunners in Europe considering scarcity pricing with CREG, Elia and UCL working out a methodology [77]. But other countries are following as well, considering the continuous increase in RES generation, creating more value for capacity, i.e., reserves, than energy. Often the opponents of a CRM, as discussed in § 2.5.2.1, consider the scarcity pricing methodology as substitute, but as discussed by Papavasiliou in [77], both can co-exist.

The principle of scarcity pricing is based on the Operating Reserve Demand Curve (ORDC). For every electricity market period, the available capacity of reserves, i.e., the sum of flexible generation and loads, is assessed and checked against a certain threshold. In case the reserves are scarce during specific moments in time, the real-time electricity price will be added with an *ORDC price adder*, ensuring the generators of a larger remuneration. In [77] the valuation of reserve capacity is proposed to be based on the Value of Lost Load (VOLL) and the LOLP. The VOLL is the estimated amount of money that electricity consumers would be willing to pay to avoid a cut-off, while the LOLP defines the probability of this cut-off. In practice, scarcity pricing would increase the occurrences of moments with higher prices but not necessarily increase the value of the prices itself.

Applied on the Belgian case, it was argued that the α parameter as applied in the imbalance settlement system (see § 2.4.2) acts as some sort of scarcity pricing. Nevertheless, the α parameter is only applied on the imbalance price and is not reflecting in the remuneration for the reserve providing parties. The EC therefore suggests to also implement the scarcity pricing function to reserve providing parties [83].

It can be concluded that scarcity pricing has the ability to solve the adequacy question raised by the combination of a marginal cost-based energy-only market and the increase of low marginal cost RES generation. In the US, the scarcity pricing mechanism has been implemented in Texas by ERCOT since 2014 and by PJM in 2019. For reserve providing parties the introduction of this mechanism could bring increased benefits.

2.5.2.3 Winter Period of 2018 - 2019

The winter of 2018 - 2019 was a remarkable period for the electricity market in Belgium, which is why this period will be discussed in more detail. As already touched upon in § 2.5.2.1, Elia did not foresee an adequacy problem for the winter of 2018 - 2019 and therefore suggested to not procure SR capacity. All of the Belgian nuclear power plants were deemed to be available, with the worst case scenario being the unplanned outage of a single unit, i.e., 1 GW. Engie Electrabel, the owner and operator of the Belgian nuclear power plants, announces in August 2018 the unavailability of 1 GW of nuclear capacity (Doel 1 and Doel 2) and in September 2018 the unavailability of another 2 GW (Tihange 2 and Tihange 3) during the winter months. Between the 20$^{\text{th}}$ of October 2018 and the 28$^{\text{th}}$ of November 2018 only 1 GW of nuclear capacity would be available. In the subsequent weeks and months several initiatives are taken to safeguard the SoS in Belgium by all means. Mothballed power plants are brought back into the market, neighbouring countries offer help ensuring interconnection capacity and decreased loop flows, capacities of existing power plants are allowed to be increased, mobile Diesel and gas generators are put in place and also (extra) DSR is found on the market. More details considering the timing and the events can be found in [84].

Despite this period is interesting from an energy expert point of view, the scope of this section will be limited to the flexibility and more specifically the DSR measures taken, as applicable to this work.

Several FSPs and energy suppliers have made efforts to allow industrial consumers to use their capacity as reserves to alleviate the grid if necessary. Engie announced to have contracted an extra capacity of 500 MW with its customers, as a combination of the existing mFRR products, *conditional bids* and implicit demand response. The extra capacity in the existing mFRR market was capacity which was already able to comply with the mFRR technical standards but were nevertheless not yet bid into the market. While Engie does not give any details, it could be presumed that the industrial consumers had not reverted to the reserves market for it being not financially viable. Considering the *need for every MW* of power, the mFRR capacity price for November had surged to nearly 60 euro/MW/h, a tenfold of the prices during previous winter periods, as shown on Figure 2.38. The *conditional bids* as named by Engie, comprised of contracts with consumers who do not wish to be active on the (spot) energy market under normal circumstances. But due to the given circumstances were willing to offer some of the (long-term) procured electricity to the DAM, for a contractually agreed price and with a prior notice from Engie. The incentive for this market parties to participate in such a program could be twofold. As a higher-than-average DAM price is expected, a significant profit could be made. On the other hand, Engie stresses the condition of the prior notice, without specifying the exact timings. It can be expected that the industrial customers who responded to these conditional bids required a (much) longer lead-time and FAT and therefore did not participate in the regular mFRR products. It was communicated that during the concerning winter period only a single contract for the duration of two hours was activated. A last measure taken by Engie to encourage industrial consumers to make available (part of) their power is the implicit demand response. With this option the industrial consumers maintain the full control over their processes, with Engie facilitating access to all electricity markets [84]. This implicit valorisation of flexibility did not differ in possibilities than was already possible before (see § 2.4), yet a larger financial gain was expected to be made, regarding extreme and volatile prices on the different markets. Also other energy suppliers and FSPs announced extra reserves to be available, with a total volume of 170 MW according to CREG [84], but without any more detailed information. A D-1 and 6 hours prior notice for activation and a 2 hour prior activation confirmation would be given to industrial sites by the FSP.

Next to the efforts of the energy suppliers and FSPs, Elia developed a new balancing ancillary service product, to allow market parties which cannot comply with the strict timings of existing mFRR products (FAT of 15 minutes) to valorise their flexibility. The product was named *Slow R3 Non Reserved Power*, hence the focus on the *slow* activation. During moments of concrete scarcity, Elia would launch a tender for the specific period, allowing market parties to place bids. A minimum volume of 1 MW, maximum activation price of 1000 euro/MWh and lead time of five hours was defined. Only the FSP REstore[17] prequalified 8.3 MW of these *slow* reserves. During the winter period, the situation was never too precarious for Elia to launch a concrete tender. Being only a temporary product ending 31st of March 2019, the product has never been used [84]. A reason for the low prequalified volume could be the relatively low maximum price of 1000 euro/MWh, considering that the price cap for the mFRR at that time was at 13500 euro/MWh. Even considering the situation was deemed precarious, industrial sites have to make a trade-off between profit due to producing and the (potential) remuneration by val-

[17] Now known as Centrica Bussiness Solutions Belgium

orising their flexibility, assuming flexibility is present.

Nevertheless the situation during the winter period 2018 - 2019 was deemed precarious, a combination of circumstances and measures caused the majority of the available flexibility to not be needed. DAM prices and imbalance prices have reached peaks up to 185 euro/MWh and 499 euro/MWh respectively. During these moments of price peaks, still a capacity of 3700 MW of which 2500 MW available on the DAM was deemed available according to the CREG [84].

To conclude, this precarious situation did provide some insights into the electricity sector in Belgium as well as into the possibilities for flexibility. The fact that Elia introduced a new type of ancillary service indicates the gravity of the situation. The focus of the product was laid on the *slow* response, i.e., on the longer lead times before activation. A (very) limited activation price cap of 1000 euro/MWh was set. It seems Elia estimated that the activation time, rather than the remuneration, was the barrier for market parties to enter. Nevertheless, the fact that only 8.3 MW of this reserve has been contracted could indicate that this was a misjudgement by Elia, and that the remuneration, i.e., the financial incentive, plays a more important role. This conclusion could also be substantiated by the fact that much more flexibility remained on the DAM (2500 MW according to the CREG), where the price cap is significantly larger. Also the *activation time*, i.e., the time the market party has to anticipate on the acceptance or decline of its bids on the DAM, is larger. An ambiguous combination of reasons for this market reaction thus remains.

The fact that still 2500 MW of flexibility (in the form of consumption DAM bids below the price cap) were present on the moments of DAM prices of 185 euro/MWh to 499 euro/MWh indicate that there are significant amounts of demand side flexibility present in the Belgian LFC area. It is thus technically possible to decrease the electricity consumption on peak moments (on day ahead notice), rather it is an economic optimisation whether to do so. Part of these DAM bids would constitute the complete shutdown of industrial sites, hence these high DAM bid prices could be interpreted as a VOLL.

2.6 Regulation and Market Roles

The electricity market is prone to European and regional regulation and includes many different market roles. Some of these market roles and regulation are briefly addressed here, all in the light of electrical flexibility. The market roles and definitions as discussed comprise those as applicable in the European and/or Belgian system.

2.6.1 Market Roles and Definitions

Started at the deregulation of the energy market in the 1990s, vertically integrated structures were broken up so to allow for competition and the more efficient deployment of capital. Up until today, the market is being optimised, new market roles are defined and regulations are fine-tuned. Market roles with a relation to the definition or application of electrical flexibility are explained here briefly

A **Balance Responsible Party** (BRP) is defined as a market-related entity or its chosen representative responsible for imbalances [3]. Every grid connection point is obliged to have attributed a BRP, who is then held financially responsible for maintaining the balance between supply and demand. The BRP role can be taken up by producers, consumers, suppliers or traders and has the obligation to daily submit quarter hourly expected injections and offtakes on each of the grid connection points in its portfolio as well as trades on the energy markets.

A **Balancing Service Provider** (BSP) is defined as a market party providing balancing services towards a TSO. Supplying this balancing services can be done with reserve providing units or reserve providing groups. These balancing services can exist out of the provision of balancing energy or balancing capacity, of which the energy bids must be attributed towards a BRP [85]. The BSP is thus a legal market role which can be taken up by each market party who provides balancing services towards the TSO and had signed a balancing service agreement. These market parties can thus be large individual consumers or producers, or aggregators who group individual market parties.

A **Congestion and grid capacity Management Service Provider** (CMSP) is a market party providing congestion management or grid capacity management services to a TSO or DSO. As discussed in 2.5, these are non-balancing ancillary services which can be provided towards the TSO.

A **Flexibility Service Provider** (FSP) is a market party offering services using flexible resources, and takes the role of either BRP, BSP or CMSP [3]. The FSP is thus a broad term, covering all market parties offering any kind of flexibility services towards the TSO.

A **Flexibility Requesting Party** (FRP) is the market party buying the flexibility from the FSP, either directly or through a market platform which can be energy or ancillary services [3]. In practice it is thus mainly the TSO who takes up the role of FRP, as it is the TSO who is the end user of the ancillary services.

A **reserve providing unit** is a single or aggregation of power generating modules, demand units and/or demand units connected to a common connection point fulfilling the requirements to provide FCR, FRR or RR [86]. A **reserve providing group** is an aggregation of power generating modules, demand units and/or reserve providing units connected to more than one connection point fulfilling the requirements to provide FCR, FRR or RR [86]. Concretising these definitions, a single industrial site which is qualified to deliver balancing ancillary services is termed a reserve providing unit, regardless of the number of machines or processes it uses to deliver these services, as long as they are behind the same single grid connection. As soon as a combination of machines or processes are used which are connected to different grid connection points, e.g., two industrial sites who offer their services towards the TSO in an aggregated way, the term reserve providing group is used.

An **Aggregator** is a service provider who pools different flexible loads or generators with varying characteristics, with the goal of offering the flexibility as standardised product towards the FRP. In case the aggregator is a dedicated market party with solely this function, often the term *independent aggregator* is used, whereas the aggregator function can also be taken up by other market parties such as energy suppliers. The main rationale of an aggregator market role is the reduction of complexity for the individual market party wishing to valorise its flexibility, reducing risk and increasing reliability by providing backup and allowing also non-standard flexibility to be valorised. The aggregator is thus the intermediate party between the FSP and FRP.

2.6.2 Transfer of Energy Regulation

With the introduction of the FSP as new market role, it is possible to valorise electrical flexibility with the help of an intermediary, i.e., the (independent) aggregator. This brings along consequences for the energy supplier, as the activation of the electrical flexibility impacts the balanced position in its BRP portfolio and thus has a financial repercussion. To mitigate this impact, the Transfer of Energy (ToE) regulation was introduced. The ToE regulation entered into force in Belgium in 2018 for the activation of mFRR *free bids* and contracted mFRR and was expanded to the strategic reserve in 2019. It is set to be implemented for the DAM and CIM, as well as for the aFRR. The FCR is exempted from this regulation, since no energy remuneration is present [87].

2.6.2.1 Market Situations with ToE

Activation of electrical flexibility can result in different market situations, either having a ToE or not. Market situations in which the ToE regulation is to be applied are:

- when the BRP of the FSP is different than those of the *source*, i.e., the BRP which has the grid connection point in its portfolio.
- when the FSP is different than the energy supplier [87].

To concretise the concept, an example is given for an industrial site, wishing to valorising its electrical flexibility by contracting mFRR. In case an industrial site sources his electricity with an energy supplier, his grid connection point is taken up in the portfolio of the BRP of the energy supplier, BRP_{sup}. When valorising its flexibility, the industrial site will contract mFRR with an intermediary party, i.e., the FSP. In case the FSP role is taken up by the energy supplier, no ToE problem arises, as one single BRP is used. Activation of the flexibility will not result in an altered balancing position of the BRP portfolio. But in case the industrial site valorises its flexibility by contracting with an independent aggregator, who operates within his own BRP, BRP_{fsp}, a situation with ToE occurs when activating the electrical flexibility. The energy which is sourced by the energy supplier to be delivered to the industrial site is accounted for on the BRP_{sup}. When the industrial site adapts its power consumption, due to an mFRR activation signal sent by the independent aggregator, his total volume of consumed electricity will change. The activated energy will be accounted for on the BRP_{fsp} and the balance perimeter of the supplier, BRP_{sup}, will be corrected with the same amount of activated energy. As a result, the balance of the BRP_{sup} deviates from the foreseen situation where the industrial site would consume all the sourced electricity. It is said that a transfer of energy occurred from the energy supplier, via the industrial site to the independent aggregator. Since having a different imbalance position has a financial impact, as discussed in § 2.4.2, a solution is imposed. Here the ToE regulation comes into play.

Different possibilities exist to facilitate and integrate the role of the FSP into the existing market design, creating different financial compensation mechanisms. USEF, the Universal Smart Energy Framework, identified seven different possible FSP implementation models [88]. In Belgium, the shift was made from an uncorrected to a contractual ToE regulation model, with the first implementation for the *free bids* mFRR. The implementation for the contracted mFRR followed later that same year, simultaneously with the implementation of the new mFRR regulation, as discussed in § 2.5.1.3.

2.6.2.2 Uncorrected Model

In the uncorrected model there is no contract between the FSP and the energy supplier and the balance perimeter of the BRP_{sup} is not corrected by the TSO with the volume of the activated energy [88]. It can be said that a ToE does occur, but there is no specific settlement. The imbalance caused on the perimeter of the BRP_{sup} is settled according to the regular imbalance settlement mechanism as explained in § 2.4.2.

Assume the case where an industrial site has contracted a certain volume of mFRR with an independent aggregator and has a contract for energy sourcing with an energy supplier, who both act as their own BRP, i.e., the case for which the ToE applies. The prior mFRR terms and conditions for non-CIPU parties applies, i.e., the industrial site is only remunerated for its contracted power and does not receive an energy remuneration when activated. When a TSO activates mFRR Upward volumes, this means the overall grid is short for electricity. The imbalance price will be set according to the MIP and will thus be on the higher price level, as explained in § 2.4.2. The industrial site, reacting to this mFRR signal coming from the TSO[18] now has a lower energy consumption compared to no activation. The energy supplier has sourced, beforehand, a certain volume of electricity which will not be consumed by the industrial site. Since the BRP_{sup} will not be corrected with the activated energy volume, a positive imbalance on its perimeter will be seen. The BRP_{sup} is remunerated with the imbalance price for its positive imbalance volume. As the activation of the mFRR is subject to large grid imbalances, the imbalance price will be evenly high, ensuring the energy supplier of a profit. The size of the profit depends on the energy sourcing cost of the energy supplier. Considering a pass-through contract between the industrial site and the energy supplier, i.e., when the energy supplier is only a facilitator to the energy markets, the industrial site is subjected to the imbalance market. In this way, the industrial site is indirectly remunerated via the imbalance price for the activation of its contracted mFRR reserve. The independent aggregator, acting as FSP, does not interfere with nor is inconvenienced by the activation of the mFRR, as only the capacity remuneration is explicitly gained.

2.6.2.3 Contractual Model

With the introduction of the new terms and conditions for the mFRR, as discussed in § 2.5.1.3, also non-CIPU market parties, e.g., an industrial site as DSR provider, are subject to an activation remuneration. This change is complemented with the principle of correcting the BRP with the activated energy, i.e., the BRP_{sup} is corrected with the volume of activated mFRR with the industrial site. The correction, i.e., neutralisation, of the BRP_{sup} implies that no positive imbalance will be created by activation of the mFRR, withholding the energy supplier - or indirectly the industrial site - from receiving a financial compensation via the conventional imbalance settlement system. The energy supplier has thus sourced electricity on the markets, was unable to sell it to the industrial site and is not remunerated for it via the imbalance market. As this ToE financially disadvantages the energy supplier, a contractual ToE model is implemented, in which an agreement needs to be found between the independent aggregator and the energy supplier [88].

A bilateral agreement needs to be set up between the independent aggregator and the energy supplier, to compensate for the electricity sourcing cost of the energy supplier. The independent aggregator is obliged to notify the industrial site's energy supplier of the contract. Three possible scenarios can occur. Either the independent aggregator and the supplier work out a financial agreement in a

[18] Or coming from the independent aggregator as intermediary, the result is the same.

bilateral contract, do not find an agreement for financial compensation or agree that no financial compensation is needed. The first case should be the most common situation. In the second situation, the CREG foresees in a *standard transfer price*, stipulating the financial compensation from the independent aggregator towards the energy supplier [89]. This standard formula is set up so to approach the average market price for electricity, using the long-term and DAM price levels, reflecting a commonly used hedging strategy by energy suppliers. Care is taken to define the formula for the *standard transfer price* as to not favour the energy supplier nor the independent aggregator. The latter case, where both parties agree that no financial compensation is needed, could occur in case the FSP, energy supplier, BRP_{fsp} and BRP_{sup} are one and the same, i.e., an implicit opt-out-regime. But also an explicit op-out-regime, for whatever reason, is possible.

This contractual model is put into place together with the new mFRR terms and conditions as explained in § 2.5.1.3. The financial compensation from the independent aggregator towards the energy supplier will take in part of the energy remuneration as received for activation of the mFRR. Assuming a pass-through contract, as in § 2.6.2.2, the industrial site would receive the full activation remuneration, tough partly via the independent aggregator, partly via the energy supplier.

2.6.2.4 Case Study

The aforementioned concrete case, an industrial site wishing to valorise its flexibility by contracting mFRR, will be further investigated. A volume of 1 MW of mFRR *Standard* is considered to be contracted with an independent aggregator. The industrial site sources its electricity with an energy supplier, with whom it has a *pass-through contract*, i.e., that the industrial site is subjected to the imbalance price for any caused imbalance. The BRP_{sup} and BRP_{fsp} are different, hence the conditions for a case with ToE are met. The potential energy remuneration, for the activation of mFRR, is calculated assuming the most up-to-date rules and remuneration methodologies. Based on historical data, the optimal energy bid price to be set, so to maximise the total energy remuneration, is defined. A comparison is made with the prior 2018 regulation, where an indirect energy remuneration via the imbalance settlement system was possible.

To define the potential energy remuneration according to the most up-to-date rules, the dataset used covers the period from 1 December 2018 until 28 May 2019. The data contain 1440 quarter-hours where either *free bids*, *mFRR standard* bids or both were activated. For the complete dataset 51.5 GWh of energy was activated with both products. The remuneration is defined according to a pay-as-bid strategy, where the bid price (P_{bid}) in euro/MWh is multiplied with the effectively delivered energy volume (E_{act}) in MWh. It is assumed that the industrial site maintained a single bid price during the complete windowed time period. As discussed

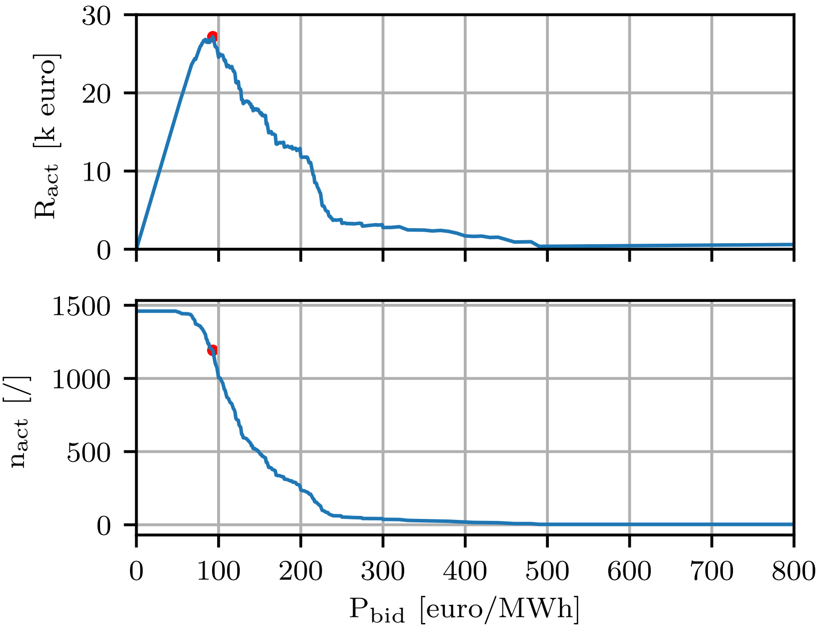

Figure 2.45: The maximum activation remuneration is 27179 euro, which would be obtained setting a bid price of 93 euro/MWh throughout the envisaged period. The reserve would be activated for a total of 1192 quarter-hours.

in § 2.5.1.3, a common merit order for both free bids and mFRR standard bids exists. For this reason, also the bid prices and volumes of the *free bids* are considered.

In Figure 2.45 it is shown that the optimum bid price to be set was 93 euro/MWh, resulting in a total activation remuneration of 27 179 euro and a total activation time of 1192 quarter-hours.

Note that this result is considered valid as a small volume was contracted. When extrapolating the results to larger volumes it needs to be taken into account that not the complete contracted power might be activated or that more expensive bids, but with a smaller volume are activated. The latter is possible due to the requested power by Elia. In case a large indivisible bid is put quite low in the merit order, but this total volume would exceed the necessary to be activated volume, a smaller bid which is higher in the merit order will be activated. The activation remuneration calculated is the total sum as received from the TSO, which is assumed to be fully obtained by the industrial site. The financial compensation from the independent aggregator towards the energy supplier is here thus of no importance, as

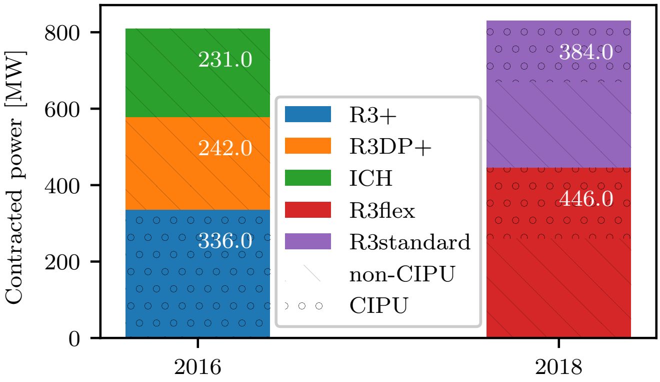

Figure 2.46: Graphical representation of the tertiary reserve volumes contracted in 2016 and 2018, with the assumed division in CIPU and non-CIPU for 2018.

the final financial stream will end at the industrial site. In practice, penalties due to non-delivery or profit margins from the independent aggregator or energy supplier could reduce the remuneration for the industrial site.

Under the prior 2018 mFRR regulation and the absence of a contractual ToE regulation, the activation of the flexibility of the industrial site would have been different. As discussed in § 2.5.1.3 and shown in Figure 2.41, the non-CIPU mFRR volumes were to be activated after the deployment of all available *free bids* and CIPU mFRR bids. While the total volume of activated *free bids* can be obtained from Elia, this is not the case for the total volume of CIPU contracted mFRR standard power, as only an aggregated number of both CIPU and non-CIPU units is published. To estimate the percentage of CIPU and non-CIPU contracted mFRR standard power, the percentage of non-CIPU contracting mFRR power in 2018 is extrapolated from the year 2016, as can be seen in Figure 2.46. This results in the assumption of 260 MW and 185 MW contracted mFRR standard power for the non-CIPU and CIPU units respectively.

As dataset, the period of 1 December 2017 to 28 May 2018 is considered. During this period the activated energy volume was 73.8 GWh for both *free bids* and mFRR standard products. The data contain 1837 quarter-hours where either *free bids*, mFRR standard bids or both were activated. The period was chosen in relation to the previously used dataset, as both are identical in length and during winter season. During the envisioned period in the dataset, for 210 quarter-hours the mFRR standard reserve was activated. The number of quarter-hours with an activated power above 185 MW was 118, i.e., the number of quarter-hours where the non-CIPU mFRR standard is assumed to be activated. The indirect energy remuneration is obtained through the imbalance price, which is high during the moments of activation of non-CIPU mFRR contracted power. The calculation results in a total indirect energy remuneration of 10 172 euro for the envisaged time period, this for a total number of 118 quarter-hours, i.e., the fictitious energy bid price set by the industrial site would be 398.91 euro/MWh. Note that the assumption of full activation when crossing the 185 MW line is the most optimal. The non-CIPU contracted mFRR standard power will be activated according to the TSO needs. Therefore the result of 118 quarter-hours of activation is the maximum and will be lower in practice, further reducing the indirect activation remuneration through the imbalance system.

To conclude, the updated terms and conditions for the mFRR as well as the introduction of a contractual model for the ToE, fosters the fair and open competition across market parties. A level playing field for the non-CIPU mFRR providing parties is created. The mFRR energy bids for non-CIPU market parties creates the possibility to optimise the energy remuneration, by setting a certain energy bid price. Before, the activation was put last in the merit order, leading to less activations but with a higher profit margin. Considering the regulatory aspect of the changes, the complexity for the industrial site is not increased. The complexity for the independent aggregator and energy supplier does increase as they will need to conclude a financial agreement, exchanging data and information.

2.7 Conclusion

This chapter introduced the concept of power system flexibility, i.e., electrical flexibility, and sketched the needs and means of it in today's energy system. The focus is laid on the European and Belgian level, with studies from ENTSO-E and Elia being highlighted. The principle of maintaining the balance within a load frequency control area is discussed, based on the operational rules as laid down by the ENTSO-E. The Belgian control area is discussed in more detail. Fostering the overall goal of this work, i.e., discussing the electrical flexibility potential in the chemical process industry, a distinction is made between implicit and explicit flexibility. Implicit flexibility is defined as the reaction of a market party to price signals. In the section on implicit flexibility, the working of the electricity markets is explained. The SPOT markets are analysed with relation to electrical flexibility potential, discussing the impact of RES integration and price patterns. The imbalance price, as used in the imbalance settlement system operated by Elia in Belgium, is considered as price signal for the implicit valorisation of electrical flexibility. The imbalance settlement system as currently operated is explained. Analysis of historical prices and price patterns is discussed.

A first main novel contribution is the simulation of the impact of the imbalance position of a market party, taking into account the imbalance market size. Two actual electricity consumption patterns from industrial sites are used to assess the financial consequences of imbalance. The caused imbalance is superimposed on the historical SI and deemed to be countered by activated NRV, which is taken into account to define the imbalance market price. The nomination strategy is found to be different for individual industrial sites, based on their overall power level. Industrial sites with a significant electricity consumption compared to the average SI of the LFC area are shown to benefit from a better nomination strategy, while for an industrial site with a rather limited power consumption level an improved accuracy is shown to be of no financial benefit. Purposefully over or under nominating is demonstrated to be interesting only in case a significant difference exists between the electricity sourcing price and the average imbalance price. The implicit balancing of the grid based on close-to-real-time information on the overall SI is discussed as well, with a case study in § 4.3 going into more detail.

In the section on explicit flexibility, the focus is laid on the balancing ancillary services as they are sourced by the TSO. The different ancillary services are discussed in detail, regarding the technical requirements and the market conditions. While focussing on the Belgian situation, the products and market are framed in a European context. The existing capacity mechanisms in Europe and the concepts of SoS and scarcity pricing are discussed as well. A final section on the regulation and market roles related to electrical flexibility touch upon the market roles of BRP, BSP, FSP, FRP, independent aggregator and reserve providing group, fostering the use of these terms in the remaining of this work. The ToE regulation, having an impact on the valorisation of electrical flexibility, is discussed as well. Here, as second main novel contribution in this chapter, the impact of this ToE regulation on the valorisation options of market parties, i.e., industrial sites, is calculated and discussed. It is observed that the introduction of a contractual model fosters the fair and open competition between market parties. It is shown that there is more freedom to optimise the electrical flexibility for non-CIPU units. The complexity of electrical flexibility valorisation is not increased for industrial sites, yet it is for energy suppliers and independent aggregators.

In general it can be concluded that electrical flexibility is of increasing importance in today's world considering the integration of RES. The need for flexibility is clearly present and the means of providing it can be found with many different market parties, including those on the demand side. Response from the demand side, e.g., from industrial sites, is seen as one of the solutions to ensure a safe and balanced grid. As a consequence, the energy markets regulation and ancillary services rules have been changed over the past decade to allow a technology neutral and fair level playing field for all these market parties to valorise their flexibility. Considering being midst into a worldwide energy transition, also future changes to these markets are expected to happen, with for example the homogenisation of the local markets into a single European energy and ancillary services market.

3

Electrical Flexibilty in Industry

3.1 Introduction

Industry in the European Union[1] has a yearly final energy consumption[2] of 3 PWh. Roughly one third, or 1 PWh, is consumed in the form of electricity. If we take a closer look at Belgium by assessing the Sankey diagram in Figure 3.1, a yearly final energy consumption of 385 TWh is recorded, of which industry consumes one third [90].

The (petro)chemical industry is by far the largest industrial sector in Belgium in terms of final energy consumption, as seen in Figure 3.2. Its energy consumption is roughly split in three thirds, made up by electricity, oil and gas as seen in Figure 3.3 [90]. It is this electrical energy which is of interest when assessing the electrical flexibility potential of the (petro)chemical industry. Note that in the future the share of electricity in the total industrial energy consumption will probably even increase. In recent years a strong push is given to the industry to decarbonise its energy consumption. Currently, direct combustion of fossil fuels is still the main method to produce (high temperature) heat, needed for processing of raw materials. Direct electrification, e.g., electrode boilers, or indirect electrification, e.g., hydrogen produced by electrolysis, of this heat could provide a less carbon-intensive alternative, provided that the electricity is produced in a carbon-reduced way, e.g., by RES. Roelofsen et al. estimate that nearly 50% of the fuel used today

[1] As the data stem from 2018, here the United Kingdom is still included, thus covering 28 countries.

[2] The final energy consumption covers all energy used, with the exception of fuels used for non-energy purposes such as oil for the production of plastics.

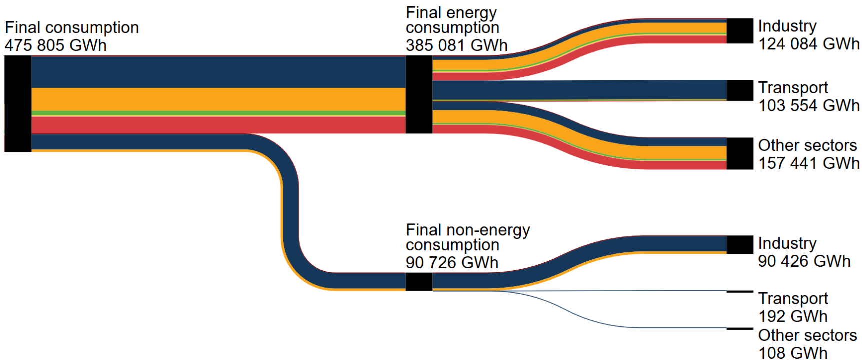

Figure 3.1: Yearly energy consumption in Belgium [90]. Oil is visualised in blue, gas in orange, renewable energies in green and electricity in red.

for energy purposes can be electrified. They state that existing technology today already can generate process heat up to 1000 °C, making it possible to electrify by a simple boiler or furnace replacement [91]. Such a practical example of electrification of high temperature heat is by making use of *firebricks* which are heated with resistive heaters. In [92] it is discussed that this technology already exists for multiple decades, yet on a small scale. For large scale applications in industry, some more development are considered to be necessary. Leading petrochemical companies announced to start exploring electrical cracking, which needs temperatures up to 850 °C [93]. In the steel industry, hydrogen direct reduction would bypass the need for a coke-blast furnace, drastically reducing the carbon intensity. This is, assuming green hydrogen produced from electrolysis [94]. It should thus be clear that electricity is essential for the industry and that it will even gain importance in the future. This shift towards electricity as main energy carrier will create several opportunities, one of which is the increased possibility to provide electrical flexibility, e.g., by providing ancillary services to the grid [95].

With such a large electricity consumption come both risks and opportunities. High power industrial sites can create a significant impact on the electrical grid. Changes in processes could result in power consumption fluctuations, potentially impacting the ACE of an LFC area and propagating to an impact on the imbalance prices. With a large electricity consumption comes thus also a large responsibility. But this impact can also be turned into an opportunity. The potential to contribute to the grid stability, e.g., by contracting balancing ancillary services with the TSO, or the economic opportunity when steering processes based on the electricity market prices, i.e. implicit valorisation of flexibility.

Focussing on the chemical process industry, some specificities are to be noted compared to other industrial sectors. A chemical process is often characterised

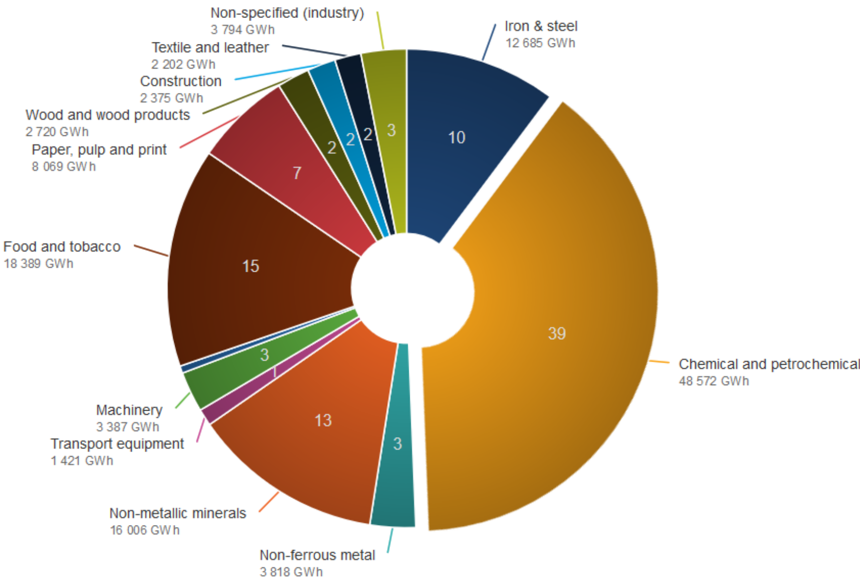

Figure 3.2: Belgian final energy consumption by industry sector, 2018 data [90].

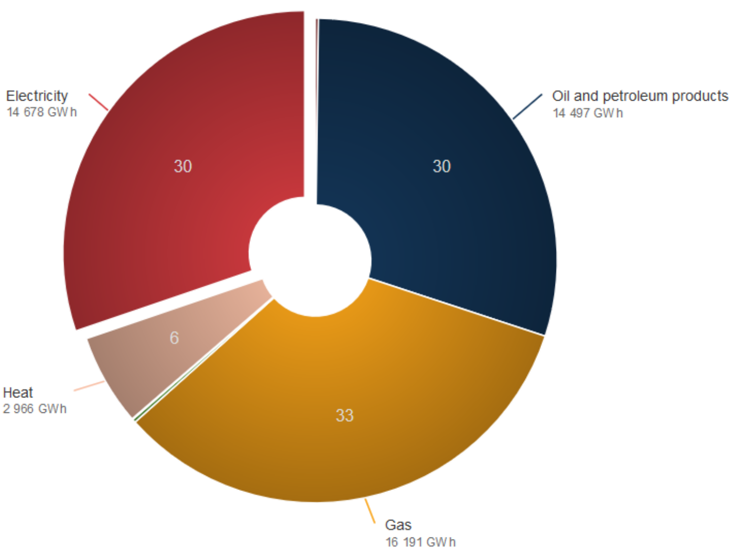

Figure 3.3: Belgian final energy consumption within the (petro)chemical industry by energy carrier, 2018 data [90].

by a continuous operation throughout the year, i.e., a 24/7/365 working regime. Also, often industrial sites are connected directly to the high-voltage transmission grid, i.e., the TSO grid, not being hindered by potential congestions on low voltage grids. Both of these factors could create a head-start in valorising flexibility, with a high availability and direct market access. A chemical process industrial site is also distinguished by the multi-energy usage. A large electricity consumption is often coupled to a high usage of other energy streams such as gas, oil, hydrogen or steam. For some processes or machines, this allows for the hybrid functioning of both, e.g., steam production in a gas boiler and electrode boiler, or a steam or electricity driven motor with coupled axis. More complex forms of energy carriers can be the chemical products themselves, which could be used as potential energy storage. A reversible process, allowing the energy to be released again from the chemical products and be purposefully used in the form of heat or electricity, i.e., *chemical buffering*, is a much researched topic considering the energy transition. All these specificities combined make the chemical process industry an interesting candidate to be a part of the solution for the energy transition question, with electrical flexibility being an important aspect.

As elaborated upon in § 2, production and consumption of electricity is prone to timing, hence the concept of electrical flexibility. The electro-intensiveness of industry raises the question whether they could contribute to this increasing need for flexibility. Are industrial sites fit to valorise electrical flexibility? Do industrial processes inherently encompass flexibility and is it technically possible to release it? If so, what processes should be considered and is there any economic or other value for these industrial sites? Could electrical flexibility be created or could the existing flexibility be enlarged? If so, what are the constraints? These questions form the basis for this chapter.

3.2 Assessing Industrial Electrical Flexibility Potential

3.2.1 Introduction

An industrial site is a complex and heterogeneous system with various processes, systems, different levels of subsystems and individual machines. Often hundreds to multiple thousands of individual electricity consuming machines are part of the industrial site. In chemical process industry those systems are often coupled in cascade or are prone to process heat integration. The assessment of the electrical flexibility potential of a (petro)chemical industrial site therefore can be a complex process.

An electrical flexibility assessment mainly consists out of two parts, being the technical and economical one [96]. Electrical flexibility has many forms, which is why in [97] the categorisation is proposed based on the controllability characteristics of the machine or process or the *load mix*. There are the storable loads, shiftable loads, curtailable loads, base loads and self-generation. A storable load is perceived as one where the electricity consumption is decoupled from the end-use service, e.g., in a battery or in a process with thermal inertia. A shiftable load can be moved in time while a curtailable load is able to be interrupted instantly. Base loads are those which cannot be controlled and are therefore deemed not interesting for flexibility purposes. Also on-site generation is considered a separate category.

On a technical level various boundaries or constraints exist, either imposed by the technical limitations of a machine or process or by the operational rules of a specific industrial site. A technical limitation can be the ramping rate of a specific motor while a minimum stock requirement is based on operational rules. These boundary conditions can be numerous, especially considering an increasing automation of processes [98].

The assessment of an industrial site with relation to its electrical flexibility is often a manual process, executed by a person with expert knowledge on both the industrial site, electrical flexibility and energy markets. In [99] the term Demand Response Audit (DRA) is used for the complete process of identification to exploitation of the electrical flexibility. An identification, quantification and valorisation step are proposed. In the identification step, both technical and economic information is assessed and the processes for which a financial benefit is expected are retained. Typically addressed topics are the current electricity contracts, consumption profile analysis and discussion with the production manager.

3.2.2 Proposed Methodology

A chemical process industrial site is characterised by a 24/7/365 operation. Therefore a different kind of flexibility can be found as in other industrial sectors where no 24/7/365 operation is present. Even within the (petro)chemical process industry sector, a heterogeneous mixture of processes is present. To try and grasp each and every one of them, a generic identification method is proposed. To assess the technical possibilities of the industrial site, a three step approach is taken.

Considering the heterogeneity of the processes, a manual approach is considered to be the most suiting, as also proposed in [99]. The described methodology is based on the power and energy levels as well as on the controllability of the processes and machines. While the power and energy levels gives a good first impression on the magnitude and importance of the machine or process compared to the complete industrial site, the controllability will define the potential valorisation options for the electrical flexibility. A process which can be scheduled but not interrupted has different valorisation options than a process which is prone to uncertainty due to varying demand, so cannot be scheduled, but which could easily be interrupted.

The hereafter described methodology for the analysis of electrical flexibility potential in the chemical process industry is focussed on power and energy levels and the controllability of the machines and processes, i.e., technical parameters, which is different than the approach taken in [96]. Here the economical analysis is decoupled from the technical analysis in the first analysis. The rationale of such a two-step methodology, first focussing on the technical aspects and later on the economical aspects, is twofold. First, the availability and type of electrical flexibility is deemed to be coupled to the identity of the processes, the methods of operation and the intrinsic properties of the machines and is therefore considered to be fixed over time. The economical parameters are deemed prone to change, considering market conditions and prices can vary over time. Indeed, considering the major transformation which has occurred in the balancing ancillary services market or the varying prices and volatility on the electricity markets, the economics of business cases are prone to change. A cascaded approach, with first a technical and only subsequent an economical analysis therefore seems more appropriate. A combination of both is of course necessary to create a sound business case and allow for the implementation and valorisation of the electrical flexibility. A second argument is the academic nature of this research. The goal of the proposed methodology is to assess if electrical flexibility potential is present at chemical process industrial sites, for current, near future or far future valorisation. Different than in an industrial economic setting, where non-favourable payback times and investment costs could be an immediate showstopper, here the technical potential is investigated.

Three main steps are considered in the proposed methodology, which will be explained in the following three subsequent sections.

3.2.2.1 Data and Information Gathering

To assess the electrical flexibility potential of an industrial site, a good overview of the plant should be obtained. Obtaining information and data is therefore a key aspect. A first starting point is a longlist of all electrical equipment on-site and a Process Flow Diagram (PFD) of all the (sub)processes. This information is typically supplied by the industrial site's energy manager, production manager or electrical maintenance engineer. An example of a PFD is shown in Figure 3.4. Care should be taken that the PFD is of sufficient detail, without going into too much detail. The PFD should only show the major equipment and their relationship, a Piping and Instrumentation Diagram (P&ID) is often too detailed for a first analysis.

The electrical equipment longlist should preferably include the nominal power, voltage level, tag number, control method, monitoring availability and short de-

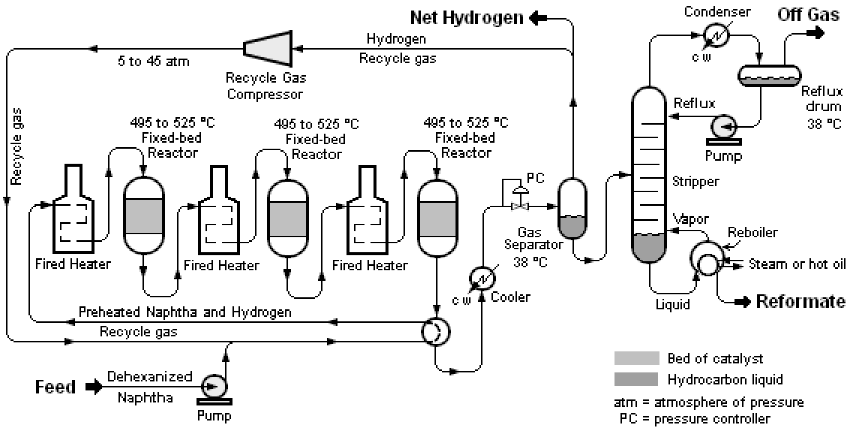

Figure 3.4: Example of a process flow diagram of a specific unit at a petroleum refinery [100].

scriptive text. The longlist can be sorted according to the nominal power, as this gives a first impression on the potential. A machine with a rather small nominal power will probably also have a low potential for use in electrical flexibility. The voltage level is of less importance for the technical assessment, but could be of interest for the financial assessment in a later stage, as it will largely define the investment cost for monitoring and/or control devices. The tag number and short descriptive text makes it possible to identify to which (sub)process the machine belongs, so it can be linked to the PFD. The monitoring availability shows the possibility of obtaining data. This is one of the more important aspects, considering data is necessary to assess the energy consumption in more detail and allowing a more substantiated case to be built.

Three aspects are important to consider considering the availability of monitoring, being the type of monitoring, the level of detail and the granularity of the data. Three main types of monitoring equipment are identified, as listed hereunder. An overview is also given in Table 3.1.

1. **Dedicated Power Monitoring System.** In the most ideal case, each individual electric equipment has a dedicated power monitoring system with a high sampling rate and logging system. Highly granular power data allow for a detailed consumption profile of the machine. In practice, the sampling time ranges from minutes to hours. This type of monitoring is often only available on the more modern industrial sites and on very large machines with a nominal power of 100's of kW to several MW. On site level, power consumption data with a quarter-hourly interval are mostly available considering the requirement for billing purposes and imbalance calculation.

Table 3.1: Schematic overview of the type of monitoring and the corresponding level of detail.

		Type of monitoring		
		Power	**Electric current**	**State**
Level of detail	**Machine**	Scarce availability, only for large multi MW machines. Depends on voltage level of equipment.	Often available for medium sized equipment. Used for condition monitoring.	Often available for smaller equipment.
	Subprocess	Sometimes available.	Sometimes available on substation level.	Not applicable
	Process	Often available, used for internal cost allocation.	Not applicable	Not applicable
	Site	Mostly available, with a high data granularity. Often used for billing purposes.	Not applicable	Not applicable

2. **Electric Current Monitoring.** While a complete power monitoring system consists out of both current and voltage measurements, it is also possible that only an electric current measurement is available. This is often the case with some smaller machines which do not have a dedicated power monitoring system. Often the main purpose of such an electric current monitoring is to provide the process operators with an indication on the state of the machine, e.g., it is possible to check if maintenance is needed or if a machine is overloaded. The availability of such electric current monitoring is not always combined with a logging system. It is possible that only a real-time read-out of the values is possible.

3. **State Logging.** A lower detailed level of monitoring is the tracking of the state of a machine. An on-off signal, or a high speed - low speed signal might be logged in the Distributed Control System (DCS). This type of monitoring is often in place for smaller machines. Again, as with the electric current monitoring, it could be that only a real-time value can be read-out, as a logging system is often limited in capacity.

Data granularity might vary between a single yearly consumption figure to a minute-based logging. An hourly or quarter-hourly granularity is considered necessary to allow for a detailed analysis of the operation of the machine or process, while monthly or yearly data can be used as guideline to define priorities. To overcome the difficulty of data availability, either due to too rudimental granularity or only state logging, a temporary power monitoring campaign could be setup. By monitoring the power consumption during different phases of a process, e.g., during multiple possible productions volumes, the electrical fingerprint of the machine or process could be identified. The electricity consumption might then be coupled to other process parameters which are monitored on the industrial site. In this way, monitoring data on the process operation, temperatures or state could act as substitute for the non-available power consumption data and being used during the electrical flexibility potential analysis of the industrial site.

Next to the PFDs and monitoring data of processes and equipment, also the operational aspects of the industrial site and processes are of importance. While a highly granular dataset allows for the construction of a load duration curve or pattern recognition, it is the *why* of the process operation which is also of importance. Information on the operational aspects of the industrial site can be obtained by meetings with the process operators, production managers and energy managers. The rationale behind a specific way of operating might contain valuable information for the assessment of electrical flexibility potential.

A last note to be made on the data and information gathering step is the aspect of data confidentiality. Sharing industrial data on operation of processes or electricity consumption of specific machines might be delicate considering the potential release of trade secrets. A balance needs to be found between sharing of data and maintaining confidentiality, as certain data are vital for the analysis or valorisation of electrical flexibility. Good practice is to arrange the sharing of data and information by a non-disclosure agreement.

3.2.2.2 Analysis of Data and Information

In this second step, the obtained data and information of the operation of the industrial site are analysed. Three main levels of analysis are defined, being the overall industrial site level, the process level and the individual machine level.

Site-level

A first parameter to assess is the normalised load duration curve. The availability of highly granular power consumption data of the industrial site allows for the plotting of a normalised load duration curve, where the quarter-hourly electricity consumption is ordered from high to low and divided by the peak load of the analysed period. As result, the overall sites electricity consumption pattern can be analysed in a graphical way. Examples of such normalised load duration curves are shown in Figure 3.9. The flatness of this curve largely defines the steadiness of electricity consumption, while a peak at the beginning or end could indicate moments of process start-up or process shutdowns respectively. A flat normalised load duration curve hints at a rather continuous and steady process operation or could mean a rather limited relation between production volumes and electricity consumption. In either case, a limited electrical flexibility might be present on the industrial site. A stepped or steep normalised load duration curve indicates a more variable electricity consumption, hinting at more opportunities for valorisation of electrical flexibility. The load profile itself could be analysed as well, to define if certain patterns are present, which could reflect the variable process operation. Discussion with the site energy engineers or process operators could bring clarity.

Process level

A second level of analysis is the process level. An industrial site is composed out of different connected processes to form the complete industrial site production process. Such a process can be a well-defined part of the industrial site, where a specific product is being produced and a certain number of machines and corresponding electricity consumption can be attributed. The industrial sites themselves often already have split the industrial site into multiple process blocks, for cost allocation or administrative purposes. Such a process can be the heart of the production of the industrial site, with the finished product being put onto the chemicals markets. In such a case, we speak of a *core process*. A core process is defined as being of highest importance to the industrial site, with change made to it having a direct impact on production volumes or quality. On the other hand are the *utilities processes*. These assist the core processes but are not directly related. The utilities process is defined as a process which does not have a direct influence on the production volumes or quality itself, but yet can be related to the core process with a buffer of any kind in between. This buffer can be in the form of a product storage, a thermal inertia or a general energy storage, e.g., a CAES. A third and last category are the electricity generating assets. Industrial sites could have own dedicated electricity generation assets. While these could also be categorised under the utilities processes, i.e., electricity could be seen as a utility as it assists the core process, it is defined as separate category for the reason of containing a different kind of electrical flexibility potential compared to electrical loads. Generation assets on industrial sites allow for the choice to either take electricity from the grid or produce it locally. This results in a larger potential for electrical flexibility compared to other utilities processes, where often this trade-off is not available, e.g., only a single cooling source is present on the industrial site, not allowing to take cooling power from a different source or grid, as is possible with electricity. The classification of the process in one of these three process categories is a first qualitative parameter for the analysis of electrical flexibility potential on process level. Do note that such a categorisation cannot always be defined objectively, as some ambiguity might be possible. The availability of only a very limited buffer between the perceived utilities process and the core process would be such an argument causing ambiguity to categorise it as core process or utilities process. A visual overview of this process categorisation is given in Figure 3.5.

A second qualitative parameter is the type of operation of the process. The main difference which needs to be made, with respect to the chemical process industry, is if the process is run as *batch* or *continuous* process. A batch process is defined as a process where the finished product is not released gradually, rather a discrete amount of finished product is delivered at once. Often such a batch process is characterised by a fixed timing, where a certain chemical reaction or multiple chemical reactions take place in a cascaded order. Process parameters such as temperature and pressure are well controlled and timings are fixed. The

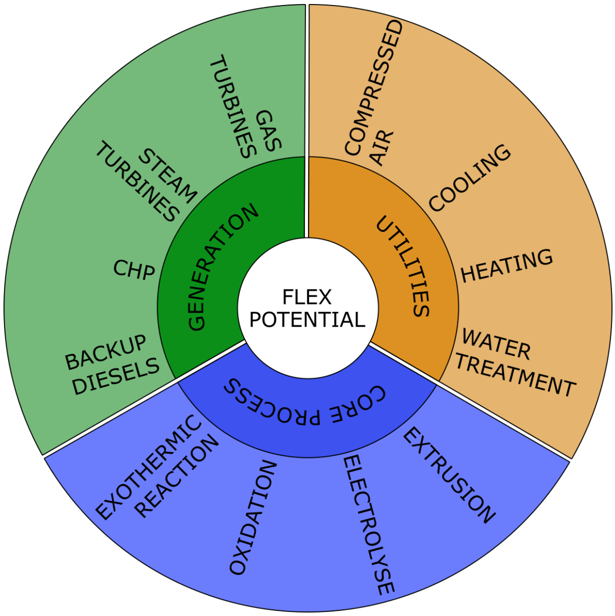

Figure 3.5: Process categorisation with relation to electrical flexibility potential.

interruption of such a batch process is often not possible without compromising all of the finished product. The other main category is the continuous process, where the finished product is released gradually, i.e., continuously. Often machines operate in a steady state, which results in a controlled reactivity of the reaction and stable process operation and product output. The type of operation of the process will often define if and what type of electrical flexibility is present. A batch process might allow for the scheduling of the consumption while a continuous process might be better fit to act as an interruptible source of electrical flexibility.

A quantitative parameter which can be assessed on process level is the electricity consumption related to the overall site consumption. While a dedicated high granularity power monitoring might not be available on process level, or at least not for every process, still a monthly or yearly average could be contributed to the specific process. A high electricity consumption for the specific process could indicate the electricity intensiveness of the process or just the importance of the process in the complete industrial site. In case highly granular data would be available, also the power consumption pattern and the normalised load duration curve, as analysed on site level, could be drawn up and analysed.

Individual Machine Level

The analysed processes as discussed in the previous step can be very different in size and nature and could encompass several tens to thousands of individual electricity consuming machines. To identify the electrical flexibility potential of all these individual machines would be time consuming and unnecessary, which is why a Pareto analysis is proposed. A Pareto analysis is a statistical technique in decision-making, used for the selection of a limited number of tasks, producing a significant overall effect [101]. A Pareto analysis, based on the electricity consumption levels, would require to look into the machines responsible for 80% of the consumed electricity of the respective process. Often this results in the identification of only a limited amount of individual machines, with a large individual nominal power and frequent usage. The remaining 20% of the process electricity consumption is then attributed to the majority of small individual machines. Care should be taken to correctly identify the individual machines and their purpose into the process, as several identical machines could be grouped, so to form a machine group with a single purpose. While individually, these could be classified in the 20% least consuming devices, in group the installed nominal power and electricity consumption might be significant. An example can be found in the cooling processes, where multiple fans are used with individually a low installed power, but grouped represent a significant power and energy consumption.

A quantitative parameter which can be defined on individual machine level is the capacity factor. The capacity factor is defined as the average electricity consumption divided by the nominal name plate power of the machine, multiplied by the analysed period. Such a capacity factor indicates the usage of the machine, where a value of one would indicate a continuous usage of the machine at its nominal working point. A value close to zero on the other hand would indicate that the machine is only very sporadically being used, or at a very low power level. This factor is important considering the analysis of the electrical flexibility potential as it indicates whether the machines allows for an upwards or downwards control. Therefore, a capacity factor of 0.3 - 0.7 would be of interest. It should be noted that this capacity factor is defined based on the nameplate installed power of the machine. Nevertheless, in industry, an over dimensioning of machines occurs frequently, where the machine is never to be operated close to its nominal power. A medium capacity factor could therefore still represent a machine which is being used continuously in time and fixed in power and thus not having an electrical flexibility potential. A solution to this problem might be the calculation of the capacity factor based on the maximum actual consumption during a certain period. But this might not be possible due to the absence of dedicated high granular power consumption data on the respective machine, as discussed previously.

A last, qualitative parameter to be assessed is the controllability of the machine. Similar to the process operation analysis, at the process level, also the controllability of the machines will contribute to the potential flexibility valorisation options. Considering individual machines based on motors, i.e., pumps, fans, compressors, etc., a difference can be made between *Direct-OnLine* (DOL) or controlled by a

Variable Speed Drive (VSD). Non-motor based consumers, such as electric resistive heating or electrolysis, can also be analysed based on their controllability, with differences between on/off thermostat control and continuous modulation control. Note that this information can change, as machines and their control can be upgraded. This upgrade could also be part of an electrical flexibility case, as the identified flexibility could only be valorised in case of more precise control.

3.2.2.3 Identification of Potential Flexibility Cases

A final step in the analysis of electrical flexibility potential on existing chemical process industrial sites is the identification of specific cases. The analysis as discussed in the previous step, combined over all three levels, will come together as a potentially interesting case for electrical flexibility valorisation. The fitness of the process or machine is defined technically, where the levels of power and energy and the controllability define whether a case is termed as interesting for future detailed analysis. In this third level, then a tailor made case is further defined and the economical parameters, such as the the potential remuneration on the balancing ancillary services markets or potential on the energy markets is taken into account, as well as the process specific technical and operational constraints. A process or machine model is developed containing all these different technical, operational and market limitations. This model can then be used to simulate the impact of the activation of the electrical flexibility on the process and/or define the potential future remunerations or cost savings. Depending on the specific case, such a model can encompass a rather limited mathematical model, with the ability to come up with a rough estimate of potential profit or could comprise a full featured thermodynamic process model combined with an optimisation method. The latter can than also be used to more detailed estimate the impact of the activation of the electrical flexibility on the process. A complete business case, taking into account the potential Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) costs of activating the flexibility and the needed potential profit, i.e., the opportunity cost, will then eventually define whether the case could be brought in practice.

Note that this methodology is constructed to analyse potential electrical flexibility within existing chemical process industrial sites, which have been operated for a prolonged time. It stools on the availability of information and historical data. In case one would want to assess electrical flexibility considering a newly designed process, or even preliminary, would want to take into account electrical flexibility in future to be built processes, i.e., a so called *design-for-flexibility* methodology, a rather different approach should be taken and more assumptions would be needed to be made.

3.3 INEOS Industrial Sites in Belgium

3.3.1 Introduction

In the course of this work, industrial sites of INEOS in Belgium have been the source for information and data so to serve as input for the assessment of electrical flexibility, input in models, evaluations, etc. A short overview is given of all current INEOS production sites in Belgium with respect to a high level overview of the processes and electricity intensiveness. It will become clear that each INEOS industrial site is a autonomous operating entity, with a unique process or processes producing a specific chemical product or products. Nevertheless, this does not mean that no link or cooperation is present nor that product or energy streams might be exchanged between industrial sites. An overview of the analysed industrial sites is deemed beneficial to get acquainted with the chemical processes and magnitudes of energy consumption. Yet, it has to be noted that confidential data cannot be disposed, therefore some care is taken to limit the level of detail. Aggregated data over all INEOS sites in Belgium are used as means of not disposing single site confidential information.

As the data have been gathered in the period of 2016 to 2020, current processes and process operation might differ in the meantime or future. Data and information are obtained from the INEOS industrial sites directly in the form of official (e.g., Energie Beleids Overeenkomsten (EBO) and accord de branche) and non-official reports, verbal and written information.

INEOS in Belgium currently has nine production sites, as shown in Figure 3.6. Note that this is a snapshot at the time of writing. In (chemical process) industry it is often the case that industrial sites change owner, merge or split into different parts or joint ventures are setup between multiple parties.

INEOS Feluy SPRL, one of the two Walloon sites, produces Linear Alpha Olefins (LAO) and Poly Alpha Olefins (PAO). The production process encompasses two continuous recycling loops and a distillation train and requires both heat (over 200 °C) and pressure (up to 190 barg). The main raw materials are ethylene and triethyl aluminium. Ethylene, being a gaseous product at the used temperatures and pressures, is handled by compressors, which are also the largest electricity consumers on the industrial site.

INOVYN Jemeppe, the other Walloon site, is one of three INEOS INOVYN sites in Belgium. The site produces polyvinyl chloride (PVC) powder. Starting from a salt brine (a solution of NaCl in water), chlorine gas, hydrogen and caustic soda is obtained by use of electrolysis. By a reaction with ethylene, ethylene dichloride (EDC) is formed, which with subsequent heating is turned into vinyl chloride and hydrogen chloride. The polymerisation of the vinyl chloride then leads to polyvinyl chloride, the well known type of plastic polymer. The Jemeppe site is a so-called *totally integrated site*, where all of the aforementioned steps occur on the industrial site itself. The main electricity consumption is located with the electrolysis process and heat is the main energy vector in the other core processes. The site has a Combined Heat and Power (CHP) plant which is used to produce both at an increased efficiency.

INOVYN Lillo, is the Flemish counterpart of the INOVYN Jemeppe site. The general production process is similar, but not all steps are taken care of on the industrial site itself. The focus is mainly on the electrolysis process, producing chlorine gas, hydrogen and caustic soda from pre-treated salt brine. The subsequent process steps to PVC powder are not present on site. A strong interaction with the INOVYN Jemeppe and INOVYN Zandvliet site and other industrial sites (BASF) is present to create the complete product chain. Therefore, even more than with the INOVYN Jemeppe site, the industrial site is very electricity intensive and the main consumption is focussed towards the electrolysis.

INOVYN Zandvliet, is a third operational site of INOVYN in Belgium and is linked to the INOVYN Lillo and INOVYN Jemeppe site. Before, also an electrolysis process was operated but has been discontinued several years ago. The main focus of the site is now the production of EDC based on chlorine from the INOVYN Lillo site, or from an intermediate product from BASF. The electricity intensiveness is much smaller compared to the other INOVYN industrial site, considering no electrolysis process is present. the INOVYN Zandvliet site is embedded in the *BASF verbund* site in the Antwerp Harbour, allowing for a significant process and energy vector integration.

INEOS Manufacturing Lillo, is a geographical neighbour of the INOVYN Lillo industrial site. The two main processes operated at the INEOS Manufacturing Lillo site produce High Density PolyEthylene (HDPE) and PolyPropylene (PP) pellets. With the main raw materials ethylene an propylene and with the use of an exothermic polymerisation process a HDPE and PP powder is produced. Subsequently, this powder is melted and formed into a pellet, with the use of extruders, which are the main electricity consumers on the industrial site. In total four extruders are present. Second large electricity consumers are the recycle compressors for circulating the ethylene and propylene in the polymerisation process.

INEOS Manufacturing Geel, belongs to the same INEOS division, also producing PP pellets. The process is similar, with a polymerisation process and subsequent extrusion process. The capacity is smaller as with the INEOS Manufacturing Lillo site, only having a single extruder present on the site. Also here the main electricity consumption is focussed in the extrusion with the second largest being the compressor in the polymerisation process. The *INEOS Manufacturing Geel* industrial site was embedded on the *BP* site, but recently INEOS has acquired the BP site, now owning the complete industrial site.

INEOS Styrolution Belgium, is an industrial site embedded on the *BASF verbund* site, similar to the *INOVYN Zandvliet* site. The main operated processes are a styrene monomer production unit (EBSM), an acrylonitrile butadiene styrene (ABS), PolyStyrene (PS) and styrene-butadiene copolymers (SBC) polymerisation and extrusion units. The EBSM and ABS units are both in production capacity and electricity consumption the largest. The largest electricity consumers in the monomer unit are ethylene compressors, fans for dehydrogenation and a compressor for a Pressure Swing Adsorption (PSA) unit. In the ABS unit, the extruders make up the main electricity consumption.

INEOS Phenol Belgium, is an industrial site located in Doel, on the left bank of the Scheldt in the Antwerp Harbour. The main raw material is cumene and the finished chemical products leaving the site are acetone and phenol. The site comprises an oxidation, concentration, decomposition and distillation process. The oxidation of the cumene takes place with air compressors, having the largest electricity consumption on site. The second largest electricity consumers are the pumps and fans operated in the cooling system. The site also features a CHP which foresees in both (part of) the electricity and steam needs.

INEOS Oxide, located in Zwijndrecht, is the very first chemical industrial site INEOS acquired. The industrial site comprises several different units, each producing a specific chemical product. The largest units, in terms of electricity consumption, are the Ethylene Oxide (EO), Ethylidene Norbornene (ENB) and Alkoxylate (AO) units. A heterogeneous mix of processes is thus available on site, with both continuous and batch processes. Next to the production units, also a large ethylene tank (C2T) is present on site, with a volume of 50 000 m^3 of ethylene stored at -103 °C. The *INEOS Oxide* industrial site hosts several other third party industrial process on its premises, as well as featuring a CHP to foresee in the need for electricity and steam.

3.3.2 Electricity as Energy Vector

Electricity is an important energy vector for all INEOS industrial sites. An overview is given of the yearly average electricity consumption in Figure 3.7, both including and excluding the electricity as used in the electrolysis processes operated at the INOVYN industrial sites. In total a consumption of 2.4 TWh is recorded, or just over 3% of the total Belgian electricity consumption as measured by Elia on the transmission grid in 2017 [102]. It is clear that electrolysis is the most electricity intensive process operated by INEOS, covering half of the total consumption.

INEOS in Belgium owns, operates or benefits from four different CHPs. The CHP plant at the INOVYN Jemeppe site comprises of two General Electric LM 6000 aeroderivative gas turbines with a nominal power of 45 MW each and a steam turbine of 10 MW, creating a total nominal electrical power of 100 MW. The gas turbines are operated with natural gas, but also hydrogen, created as byproduct in the electrolysis process, is fed into the gas turbines. The gas turbines are operated

Figure 3.6: Overview of the Belgian INEOS production sites.

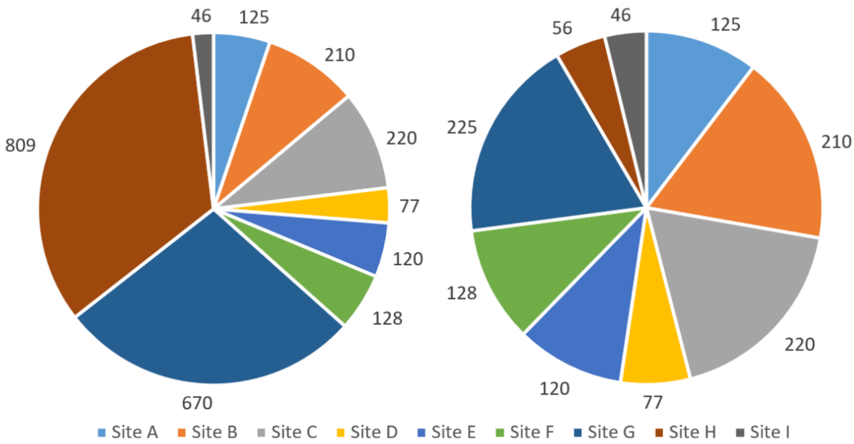

Figure 3.7: Average yearly electricity consumption by anonymised Belgian INEOS site, expressed in GWh. Left the total consumption, right the total consumption minus the electricity consumption for electrolysis processes.

steam driven, as the CHP is the main source of steam on the industrial site. The steam turbine is used to recover energy from letting down steam from a high to low pressure and is thus operated according to the demand for low pressure steam. Previously owned by Electrabel, the CHP is now fully owned and operated by INOVYN. On yearly average, the CHP can foresee in the complete electricity demand of the industrial site, with a small net amount being injected the transmission grid.

The CHP plant on the premises of INEOS Oxide has a total nominal electrical power of 136 MW, comprised out of two identical Siemens SGT-800 gas turbines with each a nominal power of 47.5 MW and a Siemens SST-400 steam turbine with a nominal electrical power of 50 MW. The steam turbine consists out of a low and high pressure turbine, allowing to generate electricity from both steam levels. The combined installation of the gas turbines and the steam turbines, i.e., the CHP named *Inesco*, is designed at a maximum nominal electrical power of 136 MW. Next to the CHP, INEOS Oxide also has gas boilers, able to provide the complete steam demand of the industrial site. This allows for the CHP to be operated more flexibly. The CHP has been put in operation in 2008 and started as cooperation between INEOS and the energy supplier Essent which was later on taken over by the German energy company RWE. INEOS Oxide acquired the full ownership of the CHP in 2019 and is now thus the responsible operator. The CHP is designed to foresee in the complete steam demand of the industrial site and is capable of producing more than the self consumed electricity, i.e; it is a net exporter.

A CHP plant of 24.5 MW nominal electrical power is present on the industrial site of INEOS Phenol Belgium. The CHP comprises a Siemens SGT-600 natural gas turbine. The owner of the turbine is Engie Electrabel and a contractual agreement with INEOS is made where steam and electricity is delivered. The turbine is mostly used flat out and steam-driven, so to cover part of the total steam demand. The total electricity demand of the industrial site can be covered, with excess electricity put onto the transmission grid.

The INEOS Styrolution Belgium and INOVYN Zandvliet industrial sites, embedded in the BASF Antwerp *Verbund* site, are connected to the site-wide electricity and steam grids. On technical level these grids are mainly fed by the on-site *Zandvliet Power Plant* with a nominal electrical power level of 400 MW. INEOS is not directly involved in the ownership nor operation of the CHP. This CHP is therefore not further discussed.

Figure 3.8 makes an abstraction of the yearly electricity consumption and the electricity flows between the INEOS owned or operated CHPs, industrials sites and CDS. In the theoretical assumption that every CHP owned or operated by INEOS is able to produce at nominal capacity during the year, nearly 50% of the total electricity demand of INEOS in Belgium could be covered, i.e., or 100% of the electricity demand could be covered when excluding the electrolysis processes.

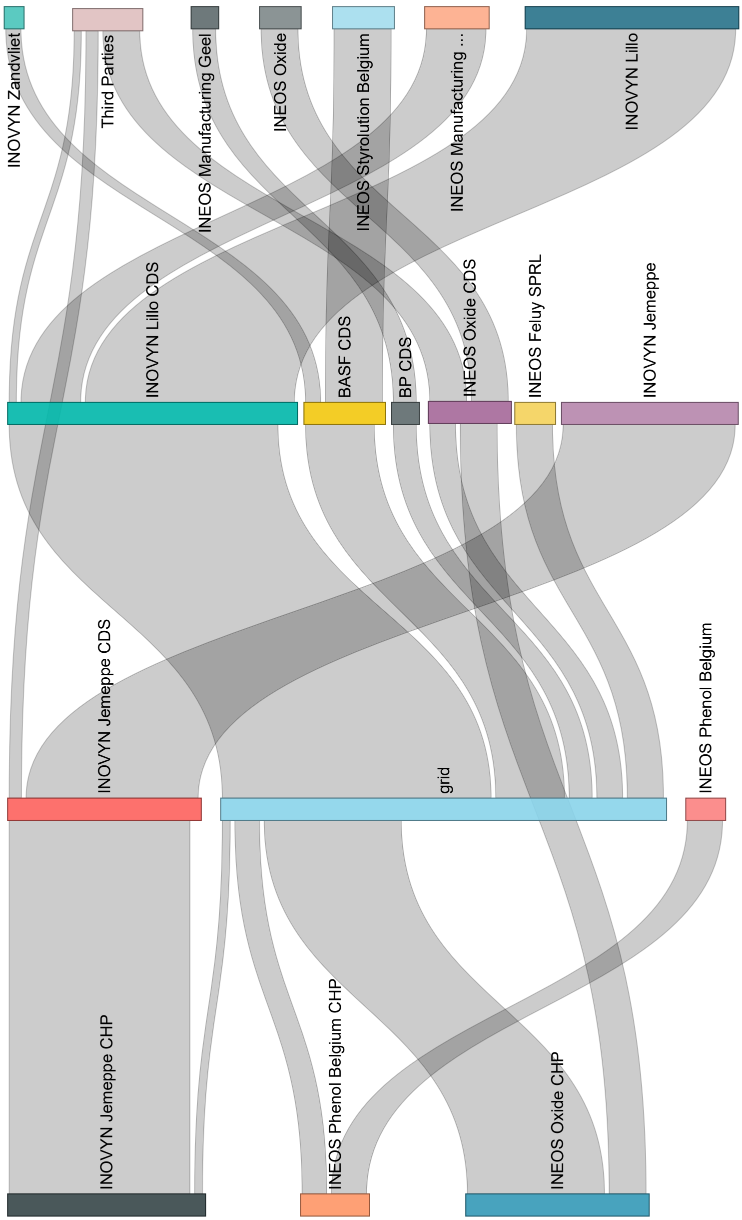

Figure 3.8: Sankey diagram of the electricity flows (yearly averaged consumption) between the Belgian INEOS CHPs, industrial sites and closed distribution networks.

3.3.3 Flexibility Assessment and Results

The INEOS industrial sites in Belgium have been analysed for their flexibility by using the methodology as described in § 3.2.2. The results of this assessment will here be laid out and discussed. Each of the found potential electrical flexibility cases will be discussed based on the analysed parameters. Also an estimated flexible power aggregated over all INEOS sites is given as well as the potential valorisation options with respect to the different options as discussed in § 2.4 (valorisation in an implicit way on the SPOT markets or via the imbalance settlement system) and § 2.5 (valorisation in an explicit way via the FCR, aFRR or mFRR balancing ancillary services). Opportunities and drawbacks are given as perceived by analysis of these INEOS industrial processes.

On industrial site level, the normalised load duration curve is analysed. Figure 3.9 shows seven distinct load duration curves from Belgian INEOS sites for a complete year. Site B shows to be having the flattest curve, with an electricity consumption between 70% and 90% of the maximum during more than 98% of the time. The steep drop on the right of the curve shows that there is only limited time during which the electricity consumption is lower than 70%. These limited time is assumed to be during start-up and shutdown of processes. Site F shows a similar pattern to site B, with the exception of a *step* in the curve, where a sudden drop from 91% to 84% is noticed. This step indicates a different operating mode of a process or machine, with a significant impact on the overall sites power level. Also site G shows a *step*, similar to site F. Sites E and G also show a continuous curve, but with a slightly higher and lower gradient respectively. In 9% of the time, site E shows a significantly reduced power consumption, with a level of 10% of the maximum consumption. An interruption of the processes, with only the baseload consumption of the industrial site could be a potential logical explanation. Site D shows a steeper but continuous profile, where electricity consumption varies between 50% and 95% of the maximum for 95% of the time. A very low number of hours with peak or valley consumption is seen. This hints at the continuous operation of the processes, yet with a varying electricity consumption, possibly related to a strong relationship between production volumes and electricity consumption. Sites A and C show a slightly different curve compared to the other industrial sites, where on the right side a more steep and stepped pattern is observed. This hints at an existing correlation between the production volumes and the electricity consumption combined with a varying process operation. Site A shows the most pronounced stepped pattern, with a prolonged duration at a level of 20% of the maximum registered power consumption during the analysed period of a single year. The sites' electricity consumption was also shown to be zero during 6% of the time, hinting at a complete plant shutdown.

The analysis of these different load duration curves shows that significant differences exist between the electricity consumption patterns of industrial sites. The

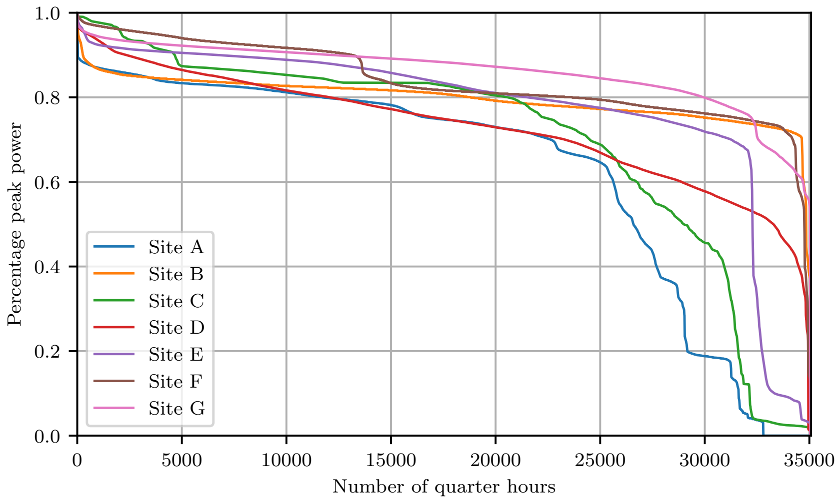

Figure 3.9: Normalised load curves of seven distinct Belgian INEOS sites.

main reason for these differences is expected to be the method of operating the processes, both due to their nature (batch and continuous processes) and the operational identity of the industrial site. But also the correlation between the operation of the process, with respect to production volumes, and the electricity consumption is deemed to play an important role. The specific electricity consumption might be either insensitive, slightly or heavily impacted by changes in production level.

Three normalised consumption profiles, of industrial sites A, F and G, are visualised in detail in Figure 3.10. Indeed, as expected, site A shows a very volatile consumption profile, with significant valleys for short periods, which could be attributed to process upsets or unexpected trips. Also different operational levels of consumption are present, which are also shown in the load duration curve. Site F shows a rather stable consumption profile, but with a clear two-level pattern, with a level at 90% and 80% of maximum consumption. This was observed in Figure 3.9 as the *step* behaviour. Site G also showed a *step* in the load duration curve, yet does show a less pronounced two-level electricity consumption.

This first level of analysis gives an impression on the pattern of electricity consumption of the industrial site. Nevertheless, only preliminary assumptions can be made based on this high level data. To go into more detail, the subsequent level, i.e., process level, is needed to be analysed. Figure 3.11 shows a process flow diagram for the INEOS Phenol Belgium industrial site, with a division into six different main processes. Within the six main processes, several other process blocks are identified. It should be noted that such an existing split between processes is often focussed on the core processes, with a redeemed interest or complete out-

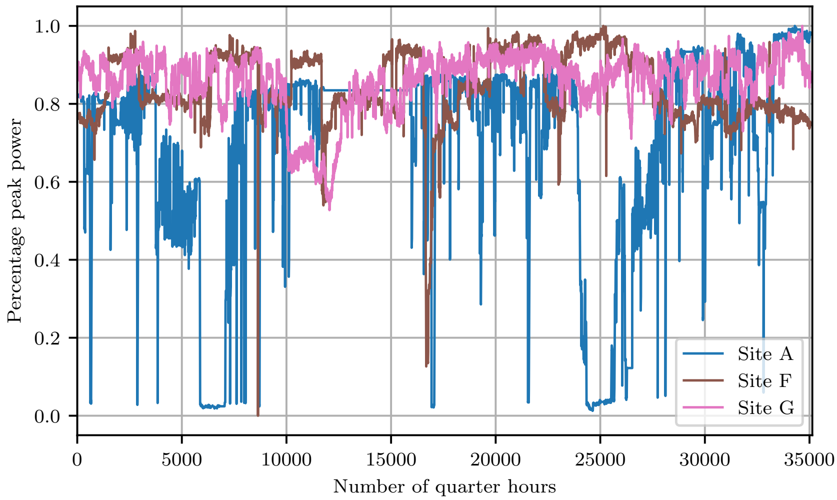

Figure 3.10: Normalised time series of electricity consumption at three distinct INEOS sites.

of-scope of the utilities processes. Here, the utilities processes are grouped into the *side units* process block, consisting out of the Waste Water Treatment Plant (WWTP), cooling towers and vacuum generation.

A first qualitative parameter to assess is whether the process can be qualified as core process or as utilities process. In the example of Figure 3.11, only the *side units* are defined as utilities, with the ones given being the WWTP, the cooling towers and the vacuum generation. Note that these are not necessarily the utilities processes with the largest installed nominal electrical power nor energy consumption. Other utilities, which are not shown on Figure 3.11 are present as well such as electric tracing or compressed air.

Addressing electrical consumption to specific processes or process blocks can be complicated by the lack of detailed power monitoring. The high and low voltage switchboards, which are often measured as discussed in § 3.2.2.1, are not necessarily attributed to a single specific process or process blocks. Several loads, spread accross different locations and categorised in different processes can be grouped in a single switchboard.

3.3.3.1 Overview of Identified Flexibility Potential Cases

The analysis of the data and information on all three described levels results in a longlist with potentially interesting cases with relation to electrical flexibility. Despite the heterogeneity of the processes at the different analysed Belgian INEOS

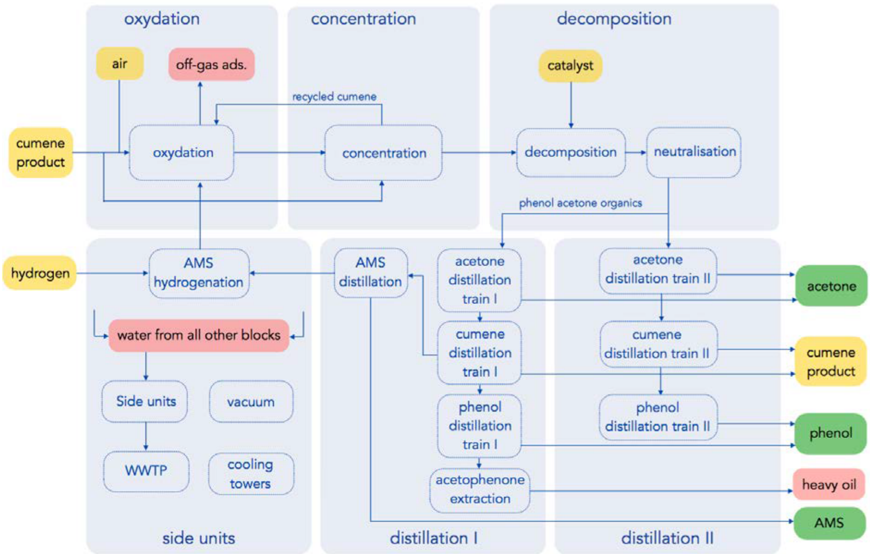

Figure 3.11: Example of a Process Flow Diagram, showing different processes on a single industrial site [103].

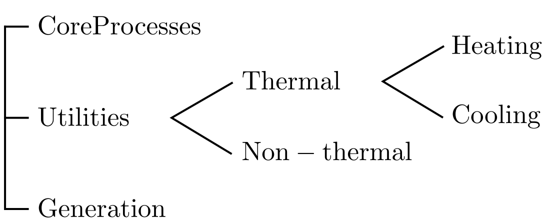

Figure 3.12: Overview of the categorisation of the identified flexibility potential cases.

sites, also some similarities and overlaps are found. The resulting identified cases are categorised based on the process category as shown in Figure 3.12. Table 3.2 shows an aggregated overview of all the found potentially interesting flexibility cases on the different Belgian INEOS sites. Different potential valorisation paths are identified as well as an aggregated estimate of the flexible power over all Belgian INEOS sites. Note that this estimated flexible power is mainly based on the installed nominal power and does not necessarily reflect any information on the amount of energy. These cases will be discussed in more detail, were the opportunities and threads are analysed.

Table 3.2: Resulting flexibility potential cases as result of the flexibility assessments on the Belgian INEOS sites.

Identified Flexible Process	Process Category	Valorisation Paths	Aggregated Flexible Power [MW]
Tracing	Utilities	FCR, aFRR, mFRR, SPOT, imbalance	1
Air Cooling	Utilities	SPOT, imbalance	1
Water Cooling	Utilities	aFRR, SPOT, imbalance	4.5
Chiller	Utilities	aFRR, mFRR, SPOT, imbalance	10
Compressed Air	Utilities	aFRR, mFRR, SPOT, imbalance	3.7
Pellet Blending	Utilities	mFRR, SPOT, imbalance	0.8
Pressure Swing Adsorption	Utilities	mFRR, SPOT, imbalance	2.6
Water Treatment	Utilities	mFRR, SPOT, imbalance	0.5
Electrolysis	Core	FCR, aFRR, mFRR, SPOT, imbalance	200
Extruders	Core Process	mFRR, SPOT	38
Cumene Oxidation	Core	mFRR, SPOT	6
Cascade Processes	Core	SPOT	1
Batch Processes	Core	SPOT	1.1
CHP	Generation	FCR, aFRR, mFRR, SPOT, imbalance	260
Backup generator	Generation	SPOT, mFRR	12.7
Total Utilities			24.1
Total Core			246.1
Total Generation			272.2
Total			542.4

Figure 3.13: Industrial electric heat tracing (orange wires) placed on pipes and vessels, without thermal insulation [105].

3.3.3.2 Tracing

Tracing is the heating of pipes and vessels with the main goal of maintaining or raising the temperature at a certain level, this to prevent solidification or freezing of the chemical substance and its container, i.e., pipe or vessel. Prevention of solidification is often necessary considering chemical products with a melting point above the normal ambient temperature. A continuous use of the tracing throughout the year is necessary. In the latter application of prevention of freezing, often the tracing is only applied in winter conditions, with ambient temperatures below 0 °C. Two main technologies of tracing are wide spread, either based on steam or heat tracing cables, of which the latter is of importance considering the electrical flexibility potential. Electric heat tracing, i.e., electric resistive wire heating, consists out of an electric conductive wire with elevated resistance. The Joule effect causes the wire to increase temperature when a certain voltage is applied. The wire is applied to the heat conducting metal pipes with an as large as possible conductive area, as shown in Figure 3.13. The pipes are afterwards surrounded with thermal insulation to prevent excessive heat loss to the surroundings. Depending on the application and the case specific conditions such as temperature and flow-rates, a different nominal power of the tracing wire is necessary. Industrial electric tracing wires with a power dissipation of 25W/m up to 160 W/m are to be found [104].

The strengths of this potential electrical flexibility case is the fact that it is a thermal utilities process and that the control can be rather simple yet flexible. The required temperature of the pipes is often defined with boundaries rather than with a very exact value. This means that a certain flexibility is already present in this system. Combined with the thermal inertia, this would allow for the flexible control of the power to the electric tracing. The technology itself, i.e., resistive wire heating using the Joule effect, is quite simple and robust, not requiring complex control. Considering the significant pipe lengths at industrial sites, the total amount of installed tracing can be substantial. The downside of the existing electric tracing in industry is that part of the installed wires are so-called *self-regulating*, where no control device is used to control the power to the wire. Instead, the wire is designed to have a positive temperature coefficient, so that it will gradually decrease power consumption when a certain temperature limit is reached. The non-self-regulating electric tracing is often controlled by thermostats with a hysteresis. The thermostat creates a discrete control of the electric tracing, i.e., it can switch on or off. Often the switching power of such a thermostat is limited, which in practice will then also limit the electric tracing wire length. When significant lengths of pipes are to be traced, several tens to hundreds of thermostats are often used to control all of the tracing wire. Another important drawback of the existing systems is that they are often very distributed over the industrial site, including the control. This makes is difficult to both attribute a certain power consumption to the aggregated electric tracing as well as complicating the control.

Several Belgian INEOS industrial sites have such an electric tracing installed, nevertheless, the identification of the installed power and consumed electricity is difficult due to the aforementioned reasons. On a single INEOS site the installed power was mapped and estimated at a volume of 1 MW with an attributed electricity consumption of 5877 MWh, i.e., a capacity factor of 67%. The possible valorisation paths for the electrical flexibility contained in this process are considered to be all the existing balancing ancillary services as well as the implicit options of reacting on price signals from the SPOT and imbalance markets. Note that these options are considered technically possible, with some requiring an adaptation or upgrade to the existing tracing and its control.

In [106], a model predictive control strategy is discussed so to use Thermostatically Controlled Loads (TCL) for the purpose of ancillary services. It is shown that it is possible to follow a specific load pattern with the developed model, with only minor deviations. Also in [107] the possibility of using TCLs for load following is investigated, without having real-time information. While focussed on residential loads, this principle could be applied on industrially TCLs as well.

3.3.3.3 Cooling

A common utilities process on each of the investigated Belgian INEOS sites is cooling. Chemical processes and reactions are often exothermal, with the need for heat evacuation during certain specific process steps. Different technologies and methods are used throughout the industry, of which three main cooling processes are found to be potentially interesting as seen on the Belgian INEOS industrial sites: **air cooling**, **water cooling** and **chillers**. The thermal inertia which is related to cooling processes is considered as one of the main opportunities for the use of these processes in an electrical flexible way. The time constants of thermal processes are often significantly larger than the needed reaction times or time constants for balancing ancillary services. While cooling is needed throughout year, the cooling capacity can vary depending on the ambient temperature and weather conditions. This has as result that a cooling process is often designed to allow cooling, even in extreme weather conditions, e.g., a heat wave. This means that the cooling capacity is seldom used to its maximum capacity, leaving room for flexible usage in both upward and downward directions. The main common thread to the use of these processes for electrical flexibility purposes is the increasingly advanced heat integration and energy efficiency of the industry and its processes. In the past, significant amounts of heat were evacuated towards the environment, by use of cooling processes. Considering the thorough energy efficiency measures taken, more and more heat is being purposefully used in other processes, to generate electricity or to feed into a heating network. As a result the cooling processes and the installed power of the electrical machines is lowered. Nevertheless, it are the energy efficiency measures which are to be promoted and have the highest priority, with the use of the electrical flexibility of these processes as of secondary importance.

A first wide-spread cooling process is **air cooling**. The technique is based on the principle of cooling due to direct interaction of cooler air with warmer surfaces. An air flow is induced by a fan, with a nominal power of several kWs up to 50 kW. Since the heat evacuation does not occur centrally (as with a cooling network), but rather directly at the required location, these units are relatively small. Summing the combined installed power or consumed electricity could nevertheless mount up to a significant value. Several INEOS sites make use of these air coolers, with an estimated total of 1 MW. Since no cooling medium is used in this technique, the thermal inertia should be present in the exothermal processes themselves, to be able to make use of the electrical flexibility potential. These smaller machines are often switched DOL and do not have complex control possibilities. The possible flexibility valorisation paths are therefore deemed to be limited to reacting on price signals. Note that some of the air coolers are used combined with batch processes. When considering the electrical flexibility potential of these batch processes, the consumption of the air coolers can be taken into account.

A second common cooling process is a site-wide water cooling network where the heat is evacuated centrally in an induced draft evaporative cooling tower, i.e., **water cooling**. Cooling water is circulated through pipes throughout the entire industrial site, where it is lead through heat exchanges located at the to be cooled processes. The water with elevated temperature is then cooled in a cooling tower by spraying the water from the top, enlarging the water-air interaction surface. An airflow is induced through the cooling tower by the use of fans, increasing the cooling capacity. The heat is transferred from the water towards the air, which leaves the cooled water to be fallen down into a water basin beneath the cooling towers, ready to be recirculated through the site-wide cooling water network. The water pumps of such a system are considerably large with installed powers of 100 kW to several MW. The cooling tower fans have a smaller installed power per unit, ranging from 50 kW to 150 kW. Aggregated on all Belgian INEOS sites, a total of 17 MW of cooling water pumps and 4.5 MW of cooling tower fans are installed. The potentially interesting electrical flexibility case considers the flexible use of the cooling tower fans. The large heat capacity of water combined with a large volume of water create a significant thermal inertia in such a cooling system. Flexible operation of the cooling tower fans could be possible without direct impact on the temperatures in the to be cooled processes. The pumps are deemed less fit for flexible operation considering a continuous water flow must be maintained throughout the different heat exchangers of the site. While a control of these pumps might be possible by using VSDs, the majority is connected DOL, leaving no real existing flexibility potential. The cooling tower fans can be controlled DOL as well, but often also feature a low and high speed setting, i.e., in case of so called Dahlander motors, or have a more updated control method, by using VSDs. While in the first case the flexibility options might be limited to implicit valorisation, the latter could also be used for more precise control and provide aFRR. This cooling process is further discussed in § 4.2, where a model is developed to allow for simulations of the process.

A third common cooling process which is identified to be potential interesting for flexible usage is a **chiller**. Where the **air cooling** and **water cooling** are useful to cool to ambient temperatures, a chiller is used to cool to sub-ambient temperatures. The working principle of a chiller is based on the removal of heat from a liquid via a vapour-compression or adsorption cycle. A phase change of the cooling medium is at the heart of these processes. On electrical level, the compressor or pump is the main machine of the chiller process. Such a compressor or pump can be a significantly large machine, ranging from 10 kW up to multi MW machines. The control is rather different compared to the previously discussed fans from **air coolers** or as present in older **water cooling** systems. The more precise control and resulting electricity consumption allows for the valorisation options to be expanded with also aFRR or mFRR. The thermal inertia in this process is linked to a chilled buffer which is often available. The heat extraction as induced by the chiller is not directly transported to the to-be-cooled process, rather it is used to create a cooled liquid buffer (often water), which is then circulated over the to-be-cooled processes. A chiller could also be integrated into the site-wide cooling water network, where an induced draft evaporative cooling tower acts as a first cooling step and the chiller further reduces the temperature. Aggregated over the Belgian INEOS sites, a total installed power of 10 MW of chillers is found. Capacity factors of 22% up to 70% are seen, with thus a potential for both upwards and downward flexibility.

3.3.3.4 Compressed Air

A rather common utilities process across industrial sites is compressed air. Electric compressors are used to pressurise common air to be used for several purposes in the different processes. A common setup is to have a site-wide compressed air network, with the compressors located centrally. Different setups might be possible. Often multiple compressors are used instead of one single large compressor, for the reason of redundancy. While some compressors might be controlled DOL, a single compressor might be equipped with a VSD, to cope with the varying compressed air demand. Another opportunity is the availability of a Diesel generator coupled to the same mechanical axis of the compressor. This Diesel generator is often present in case the availability of compressed air needs to be assured at all times. This Diesel generator requires regular testing, which could be encompassed in an electrical flexibility case. In the light of the electrical flexibility potential, the availability of a buffer between the compressed air and the site-wide network is of importance. In case of a direct coupling between the compressors and the site-wide network, limited flexibility might be available. In case a buffer is available, e.g., in the form of a vessel, the compressors could be controlled electrically flexible. This availability of a buffer, with a significant volume so to allow for a longer time period controllability of the compressors, is currently the largest drawback of the current compressed air systems. Such a Compressed Air Energy Storage (CAES) system is an existing technology where the air is used as medium to store energy, with the main goal of peak-shaving and valley filling, comparable to PHS. Air is compressed, stored and than converted back into electricity when expanded. The main difficulty lies in the thermal management, as energy is lost as heat when compressing the air while heat is needed during the expansion. In [108] the two very first CAES plants, In Germany and the USA with a nominal power of 290 MW and 110 MW respectively, are discussed. The main idea of the CAES plant in Germany, which was built in 1978, was to compress air during off-peak moments, i.e., with a low electricity price, and store it in underground salt caverns. The compressed air was then later released during peak-moments and expanded in a natural gas turbine, where it allowed to replace the otherwise necessary compression of combustion air. In [109] it is discussed whether such CAES systems might have future potential considering the need for flexibility, e.g., as a method to allow more wind energy to be integrated into the system. The point of view is here from an energy storage plant perspective, where the CAES system would be constructed and operated purely for the purpose of supplying electrical flexibility towards the grid. While the idea of using the compressors at the Belgian INEOS industrial sites is based on the CAES systems as known, both the technical implementation as the economical case would be different. The magnitude of power is lower, considering the aggregated installed power of air compressors at the Belgian INEOS industrial sites is limited to 3.7 MW. The storage of the compressed air would rather take place in above ground vessels rather than in underground salt caverns. The usage of the compressed air would remain unchanged, being the industrial processes. Rather it is thus the investigation of the usage of the existing compressed air buffers or the addition of such buffers, to allows a more flexible control of the compressors. Note that the installed nominal power of 3.7 MW is only attributed by air compressors, centrally located and used from common compressed air on the industrial site. Some processes feature non-air compressors or have dedicated air compressors to feed directly into the process. These are not included here.

3.3.3.5 Pellet Blending

A rather site specific utilities process is the **Pellet Blending**. On the INEOS industrial sites where polymerisation and subsequent extrusion processes take place, plastic pellets are produced as finished product. These pellets are stored in silos, waiting to be exported. Pellets can have slightly different characteristics due to varying process parameters. To maintain a homogeneous quality of the pellets, a pellet blending or mixing is executed. The pellets contained in the storing silos are circulated by the use of large *blowers*, i.e., electrically operated centrifugal fans. The operation of this utilities process could be interrupted or scheduled, allowing the blowers to be operated flexibly, as long as the minimum operational time is met. This process is an example of a utilities process which is not related to core processes at all, rather it is operated stand-alone. A drawback is that this is a very specific utilities process, with also a limited installed power and thus flexibility potential. Aggregated over the Belgian INEOS sites, a total installed power of blending blower of 800 kW is found.

3.3.3.6 Water Treatment

Water is an important medium on industrial sites and is used as fluid in processes, as cooling medium or just stored for safety purposes in case of incidents. For the use of water in processes, higher standards of quality could be required, creating the need for a pre-treatment of the water. Different water purification methods exist, each with a certain level of removal of salt, minerals, bacteria or specific molecules. Also post-treatment of water, after it has served its purpose in several processes, could be necessary to remove hazardous substances before evacuation to the sewage system or river. Such a water treatment facility could be considered as a utilities process, as it often has a buffer in the form of a water storage tank.

This allows for the flexible operation of the water treatment process, with the main electrical consumers being pumps and fans.

A common usage of pre-treated water is in the site-wide cooling water network as discussed in § 3.3.3.3. An open water cooling system with the use of cooling towers for evaporative cooling has a constant water loss due to the humid air leaving the cooling towers. As result, the cooling water *thickens* as the concentration of salts and minerals in the remaining water increases. When the saturation levels of these minerals are reached, they precipitate and deteriorate the machines and components in the cooling system. The number of times the water can recirculation in such a cooling system is thus limited. By the use of pre-treated water, this number of circulations can be extended. Another usage of pre-treated water is for the production of steam. Deionised or demineralised water is used as boiler feed water to prevent the formation of scale in the boiler. Deionised water has a very high quality, which has almost all of the present mineral ions removed. The production process of such deionised water exists out of an ion-exchange column with ion-exchange resins. The main electrical consumers are pumps to allow for the flow of the water through the process. The electricity consumption and installed power of such a water treatment utilities process is often rather limited compared to the overall industrial site. Nevertheless, the dimensioning of such utilities processes and the available buffers do make it potentially interesting to be used as electrical flexibility case.

On a single Belgian INEOS industrial site, pre-treatment of water occurs in a reversed osmosis process for the production of cooling water, while a part is further processed in a demineralisation process to be used as boiler feed water. The installed power of the electrical machines in these processes mount up to 560 kW, with a yearly power consumption of 1280 MWh, i.e., these utilities processes have a capacity factor of 26%. A demineralised water storage tank, which serves as buffer to the on-site steam production, has a buffering time of up to four hours in the scenario of maximum steam production. Comparable processes are found on other Belgian INEOS sites, yet are not available on each site. As several sites are encompassed in an industrial cluster, they receive steam or *demin* water from a centrally produced source, outside the boundaries of the INEOS industrial site. The usage of these pre-treatment water utilities for electrical flexibility purposes is considered potentially interesting.

Post-treatment water processes are also available on the Belgian INEOS industrial sites, yet are considered less fit for flexible operation. The electricity consumption and installed power is even more limited than the pre-treatment processes, as well as having a less flexible operation by nature. Such post-treatment utilities process is often based on biological treatments, where bacteria are used to break down certain waste products. The operational limitations are therefore quite strict.

3.3.3.7 Pressure Swing Adsorption

A specific utilities process which is identified as having an electrical flexibility potential is the process of Pressure Swing Adsorption (PSA). A PSA process is used to separate gasses from a mixture of gasses, based on pressure and absorbent material. The process is used on an INEOS industrial site to purify hydrogen, which is produced as by product. By purification, the hydrogen can be injected into an industrial hydrogen grid, which can then be further used by other industrial processes. The hydrogen rich gas can also be burned in on-site burners to produce steam. In the latter case, the hydrogen does not need to be purified and the PSA unit is not operated. The installed power of the PSA unit is 2.6 MW, of which the compressor contributes the largest share. It is thus a utilities process without impact on the core processes and with a significant installed power concentrated in a single machine. A capacity factor of 70% is seen throughout the year.

3.3.3.8 Electrolysis

The core process with the largest electricity consumption and installed power on the Belgian INEOS industrial sites is the chloralkali electrolysis. Similar to other electrolysis processes, a direct current is used to create a non-spontaneous chemical reaction, creating specific chemical products. In total an installed power of over 200 MW is present, with a yearly power consumption of half of the aggregated Belgian INEOS consumption, as discussed in § 3.3.2. The electro-intensiveness of this process is the main electrical flexibility opportunity, next to the controllability of the process and corresponding electricity consumption. The process is controlled by altering the current density which is applied to the different electrolysers. Power electronics based on Insulated-Gate Bipolar Transistors (IGBTs) or thyristors are used for this purpose. These power electronics allow for a very fast control of the electric power, allowing the electrical flexibility in the electrolysis process to be valorised in many different ways. It is one of the single existing processes, i.e., machines, which is able to provide FCR without adaptations to the process, machine or control. While the electrolysis process itself is thus quite flexible in control, there needs to be taken into account that several subsequent processes, such as the compression of the produced gasses, also needs to be able to cope with fluctuations in the production. Pressure fluctuations can have a negative impact on the lifespan of the electrolysers, due to potential ruptures in the membranes. An electrical flexibility case study considering the flexible operation of the electrolysis process is further discussed in 4.4.

3.3.3.9 Extrusion Process

A core process with a significant installed power and potential for valorisation of electrical flexibility is the extrusion process. A simplified schematic diagram is

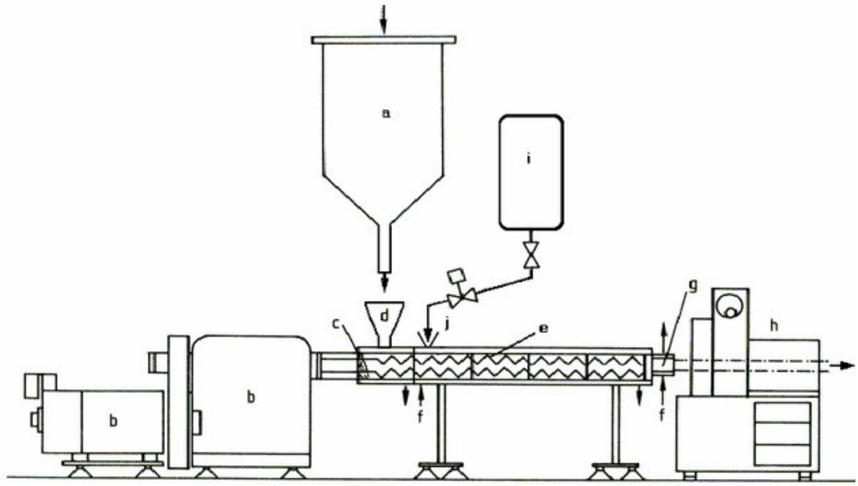

Figure 3.14: Schematic diagram of a continuous extrusion process [110].

shown in Figure 3.14. Extrusion is a production process for thermoplastics which are formed by leading them through a die at elevated pressures and temperatures. Extrusion processes for PP, PE and ABS are present at the Belgian INEOS industrial sites and are operated in a continuous way. The PP, PE or ABS powder is fed into a hopper (a), optionally by use of a premixer to add additives, which then leads it towards the screw (e). Along the length of the screw, the pressure is built up, resulting in elevated temperatures and the thermoplastic to be melted. A steady pressure at the outlet of the extruder is maintained with a gear pump (not shown on Figure 3.14), so to create a continuous flow of plastic strands towards the pelletiser (h). A pelletiser motor rotates over the die so to obtain pellets of the extruded thermoplastic. These are then cooled down and transported with a stream of air or water towards storing silos. The main electricity consumers in this process are the extruder motors, gear pumps pelletiser motors and premixer motors, while also the pumps or roots blowers for transportation contribute to the electricity consumption of the process. The total nominal power, aggregated over the different INEOS sites operating this process mounts up to 38 MW. The extruder motor is the largest machine with an individual installed power of 1 MW up to 6 MW and is mostly controlled by a VSD.

The process is operated in a continuous way, creating a homogeneous product quality. By default, the power consumption of such extrusion process is stable, with limited variations over time. The main influencing parameter of the product quality is the temperature, which is mainly being controlled by the speed of the extrusion. Altering the speed of the extruder, so to influence the power consumption and valorise electrical flexibility, is thus considered not possible.

The grade of polymer which is being extruded can vary over time, so to create pellets with different characteristics. The different grades are defined by varying rubber content or different additives, also altering the viscosity of the polymer. This viscosity is an influencing parameter for the electric power consumption of the extruder, as it determines the mechanical power which needs to be added to the screw. This property could be used so to schedule the production of certain grades based on price signals from the SPOT markets, i.e., an implicit flexibility valorisation case might be present. Nevertheless, note that these grade changes do normally not occur on daily basis, as the transition period between grades causes *off-grade* pellets to be produced, having a lower market value. The absolute difference in power consumption might also be limited, depending on the type of grades which is being produced.

Another possible option to valorise the flexibility encompassed in this process is the interruptibility. Despite that the process parameters, i.e., the temperatures, are controlled so to obtain a good and consistent quality, interruption of the process is possible without major impact on product quality or maintenance. Electric heaters are placed alongside the extruder, so to maintain the temperature in case of production stops, preventing the solidification of the polymer inside the screw. This allows for an ability to interrupt the process on a short notice, making it possible to contract mFRR. A FAT of 15 minutes is usually long enough to allow for the process to be interrupted. The restart of the process, after an activation, could require some more manual labour. Such an existing case at a Belgian INEOS industrial site is discussed in § 3.3.4.

3.3.3.10 Cumene Oxidation Process

This core process is site specific and comprises a chemical oxidation reaction. Large volumes of air are used to oxidise cumene, forming a cumene radical to be used further in the process. These large volumes of air are supplied by dedicated compressors, responsible for a large electricity consumption. As the compressors are directly linked to the core process of cumene oxidation, they are considered here separately and not discussed as utilities process. On the Belgian INEOS Phenol site, where this process is operated, an installed power of 9 MW of air compressors is present, existing out of three compressors of each 3 MW. The air feed into the reactor is directly linked to the oxidation reaction and therefore is directly influencing the production capacity.

3.3.3.11 Cascade Processes

A cascade process is defined as multiple core processes or core process blocks which are depending on each other for their raw materials and finished products, i.e., the finished product of the first process serves as raw material for the subsequent process. Cascade processes are identified as potentially interesting in case of available in-between buffers or storage and the ability to control one or more of the process blocks in the cascaded order. While this definition is quite broad, here the processes are grouped which are not discussed in any other section. For example, the production of chlorine in an electrolysis process with subsequent production of EDC is also considered as cascade process, but has been presented in § 3.3.3.8. The polymerisation with subsequent extrusion of a thermoplastic with a buffer of polymer powder in-between is also considered as cascading processes, yet as the polymerisation is not deemed flexible, as discussed in § 3.3.3.15, this case is not withheld here.

An identified potentially interesting cascade process is the ENB production at the INEOS Oxide site. Consisting out of four major production steps, i.e., the vinylnorbornene (VNB) reaction, VNB refining, ethylidene norbornene (ENB) reaction and the ENB refining. The different process blocks are operated as continuous process, with buffers between them. These buffers are already being used for process purposes, e.g., due to the characteristic of the chemical process, the ENB reactor forms NaK salts which are precipitated in the reactor. As result, the reactor needs cleaning and is stopped for a certain period every few weeks. Nevertheless, the VNB refining process and the ENB refining process can be continued to be operated as the buffers are being used. Indeed the size of the buffers would allow the process blocks to run independently for several hours to days.

The main electricity consumers in these processes are the compressor used to recycle the distilled butadiene, a compressor used to recompress flashed NH_3 vapour and recyle it into the ENB reactor and a chiller operated to cool the four process blocks. An overall installed power of 1 MW is present. The electrical flexibility potential as presented in the overview in Table 3.2 is limited to the SPOT markets, i.e., implicit electrical flexibility valorisation. Nevertheless, it could also be investigated if in this specific case also mFRR would be possible. Since the buffers are sufficiently large, also a longer duration stop should be possible, which might not be the case in other cascade processes. Also the interruptibility, considering the FAT of 15 minutes, should be further investigated.

3.3.3.12 Batch Processes

A batch process is defined as a core process where the finished product is not released gradually, rather a discrete amount of finished product is delivered at once. While the majority of processes operated at the Belgian INEOS industrial sites are continuous, some batch processes are operated as well. These are characterised by *campaigns*, in which a predefined amount of chemical product is produced following a fixed process or cascaded processes and related timings. These batch processes are defined as being flexible in case they have product storage buffers where both the raw materials and the finished products can be stored. Also the operation

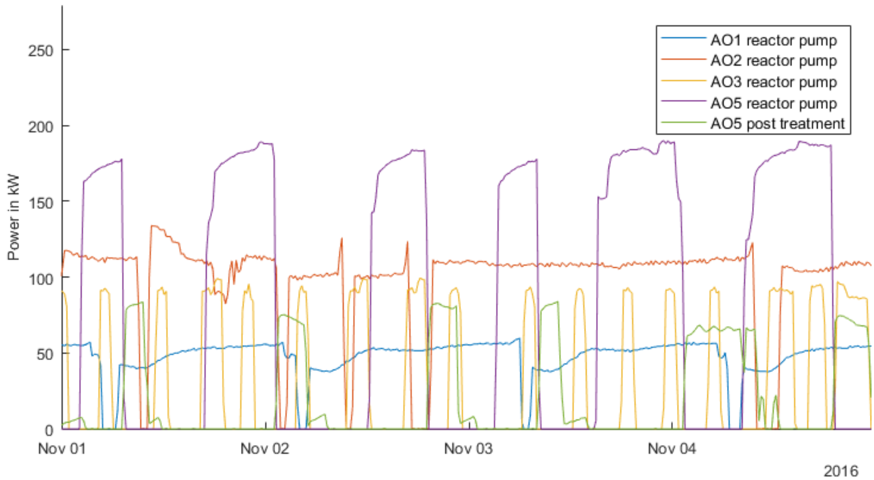

Figure 3.15: Overview of the electric current as drawn by the reactor circulation pumps of alkoxylate batch processes.

of the processes should be limited below nominal capacity, i.e., in case batches follow-up continuously due to high product demand, no flexibility is present. Assuming a below nominal usage of the process and availability of storage buffers, the batch process can be scheduled according to SPOT market prices, i.e., valorise the scheduling flexibility in an implicit way. The possibilities in explicit valorisation of electrical flexibility, e.g., in contracting mFRR, are considered limited as the process, once started, is often impossible to stop without compromising the complete batch of the chemical products. Aggregated over two Belgian INEOS industrial sites, an installed power of 1.1 MW of machines attributed to batch processes is found. Other Belgian INEOS sites do not feature any processes operated in batch or were considered to be not interesting regarding electrical flexibility.

An example of such a batch process is the Alkoxylate (AO) processes as operated at the INEOS Oxide industrial site. The main electrical consumer of this process is the reactor circulation pump, used to maintain the chemical reaction. Other electrical machines are the cooling fans, used for direct cooling, as also discussed in § 3.3.3.3, since the process is exothermal. The campaigns can have different lengths, ranging from several hours to a complete day. This is shown based on the electric current logging of the reactor circulation pumps as shown in Figure 3.15.

3.3.3.13 Combined Heat and Power Plants

A Combined Heat and Power (CHP) plant is an inherently flexible asset, considering it is in fact a dispatchable gas fired power plant where part of the produced heat is purposefully used in industrial processes. Consisting of of a combination of a single or multiple gas turbine(s) and steam turbine(s), the production of electricity is controllable and this in a most flexible way. In § 3.3.2 the different CHPs as present on the Belgian INEOS industrial sites are discussed, with a total combined installed power of 258 MW. Such a CHP is catalogued under the *generation* category together with backup generators and are therefore considered a bit different than the other identified flexibility cases considering processes as specific for the chemical process industry. The opportunity of such CHP plants lies both on the electricity markets as by supplying balancing ancillary services towards the TSO. In § 3.3.4 an existing electrical flexibility business case on the Inesco CHP at the INEOS Oxide industrial site is discussed. With the CHP at the INOVYN Jemeppe industrial site also being in full ownership and control of INEOS, an identical business case could be built.

3.3.3.14 Backup Generators

Qualified in the process category of *generation*, backup generators are often present to ensure safety on the industrial site in case of grid disconnection, i.e, during brown outs or black outs. In such a case, the backup generator is started to foresee the most crucial machines or processes with electricity, e.g., cooling water pumps to safely shutdown exothermal processes. At the Belgian INEOS industrial sites, an aggregated installed power of 12.7 MW of backup generators are installed. Most of the backup generators are Diesel engines connected to a generator, feeding an on-site emergency grid or specific machines directly. These backup generators are often frequently tested to ensure their continuous availability, being it unloaded as often the regulation prevents grid synchronisation. Indeed, as these production units are classified as emergency generators grid synchronisation during non-emergency situations is not allowed. Only after operation in island mode, i.e., due to loss of the grid connection in the first place, a synchronisation with the grid is allowed to prevent a second zero crossing of the connected machines and processes.

Nevertheless, these Diesel generators are technically fit to produce electricity. A regulatory reinspection and compliance with the technical regulations for decentralised operated production installations working grid parallel could be an option, i.e, the C10/11 regulations from Synergrid in Belgium [111]. During the winter period of 2018, as discussed in § 2.5.2.3, close to 1000 MW of extra production capacity was added for which production licenses were approved, of which a significant part were Diesel generators [84]. Indeed the CREG in Belgium also offered the idea to use the existing emergency generators as means for reducing the amount of new capacity to be installed to comply with the SoS [112], as discussed in § 2.5.2.

These existing assets at the Belgian INEOS industrial sites could thus encompass an opportunity in valorisation of its electrical flexibility, this both on an implicit way, i.e., scheduling the frequent loaded testing based on price signals from the markets, or explicit, i.e., by contracting mFRR.

3.3.3.15 Non-Flexible Processes

Some of the identified processes are deemed not fit for being used flexibly or do not possess electrical flexibility potential. An example of such a process is the **production of ethylbenzene**. In this continuous process, ethylene, being in gaseous form, is being brought into a reactor by the use of a compressor. The benzene feed towards the reactor, being in liquid form, is supplied by the use of pumps. With alkylation being an exothermal process, heat is commonly evacuated from the reactor and via a heat exchanger network transferred to endothermic processes on site. The compressor and benzene pumps are the main electricity consuming machines in this process. The volume flow control of the compressor, which is switched DOL, is based on a bypass valve which recirculates pressurised ethylene over the compressor in case no fresh ethylene is requested in the reactor. An identical volume flow control with bypass valve is used for the benzene pumps, which are also switched DOL. The cooling water pump is also switched DOL and is operated continuously, independent from the produced volume of ethylbenzene. Figure 3.16 visualises the produced volumes of ethylbenzene while also showing the electricity consumption of the largest machines in the process. Due to process specific conditions, the production volume of ethylbenzene was limited during some months of the shown year. As expected due to the energy inefficient control of the machines, the electricity consumption did not decrease accordingly. There is thus no correlation between electricity consumption and the production level, i.e., the Specific Electricity Consumption (SEC) of the produced ethylbenzene increases due to the below nominal operation of the production process. This process is thus considered not fit to be used in an electrically flexible way, since no control on the electricity consumption can be exerted by controlling the production volume or other process parameters. The complete shutdown of the process is considered the only possibility to reduce the electricity consumption, yet is not viable considering the complexity of the process and resulting production consequences.

Another example of a chemical process which does not have electrical flexibility potential is the **polymerisation process**. Polymerisation processes for PE and PP are being operated at the Belgian INEOS industrial sites. Figure 3.17 shows the principle of a PP polymerisation process by using a fluidised bed reactor. The principle of such a reactor is based on a fluid, in this case gaseous propylene, which is passed through a solid granular material at velocities high enough to suspend it and cause the solid to behave as a fluid. Indeed, by the chemical reaction occurring in the reactor, the gaseous propylene is converted to polypropylene, which acts as the suspended solid (powder). A continuous recycling stream of propylene

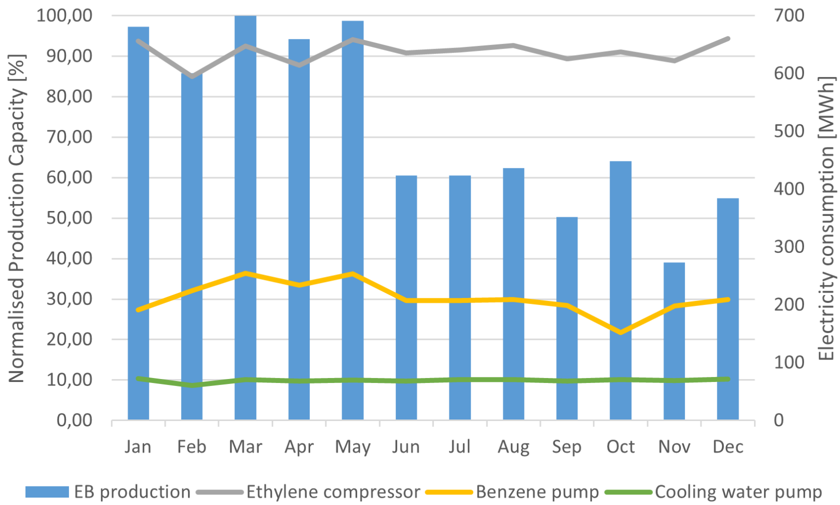

Figure 3.16: Monthly production volumes of EthyleBenzene (EB) and electricity consumption of the largest machine in the production process.

is fed through the reactor by the use of a recycling compressor, while newly added propylene is added as well to compensate for the polypropylene powder which is formed and released from the fluidised bed reactor. A booster pump might be used to increase the pressure of the propylene recycling loop. This process is operated continuously and at very specific conditions, so to create a stable functioning process. The main electricity consumers are the recycling compressor, booster pumps and compressors to pressurise the propylene before entering the reactor. It should be clear that these machines need to be controlled so to obtain a fluidised state in the reactor vessel, with a too low velocity resulting in the PP powder to fall down in the reactor and a too high velocity to transport the PP powder into the recycling compressor causing damage. This process is thus by design not fit to be controlled flexibly and no electrical flexibility potential is present. The interruption of the process, i.e., a complete shutdown, would be the only possibility to influence, i.e., reduce, the electric power consumption. Considering the complexity of creating and maintaining a fluidised state in the reactor vessel, i.e., long start-up times after shutdown, and the consequences of process interruption, e.g., PP powder sticking to the reactor and causing congestion, etc. this is not considered a viable option. Nevertheless, the power and energy levels of these processes are significant. On the two Belgian INEOS sites operating such processes, the installed electrical power related to these polymerisation processes mount up to 14 MW with a yearly consumption of 82 GWh.

Other processes identified as not having potential considering electrical flex-

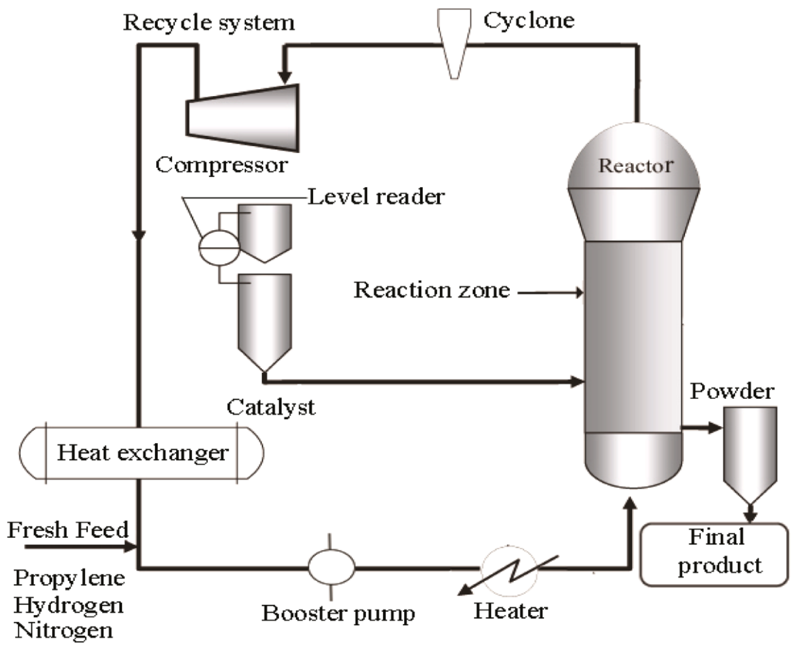

Figure 3.17: PFD of a PP polymerisation processes using a fluidised bed reactor [113].

ibility are **distillation processes and continuously operated reactors without buffers**. The direct electricity consumption in distillation processes is very limited and usually only comprises small pumps. Air coolers are present, but are considered as assisting utilities process and therefore taken into account under § 3.3.3.3. The main energy vector in this process is heat, supplied in the form of steam. As discussed in § 3.3.5, steam production is upon today mostly fossil fuel based, also here leading to no existing opportunity for electrical flexibility. Next to the ethylbenzene and polymerisation processes, other continuously operated processes with strict operational conditions, without buffer and/or without an electricity consumption versus production volume correlation are present at the Belgian INEOS industrial sites. These processes are thus by nature not able to be operated flexibly or show no effect towards the electricity consumption in flexible operation. The latter case could be further investigated if this lack of correlation is due to the nature of the process or the inefficiency in controlling the electrical machines. Upgrading to an energy efficient control might then create a certain correlation.

3.3.4 Existing Electrical Flexibility Business Cases

During the period of research at the Belgian INEOS industrial sites, already some electrical flexibility valorisation cases existed, were investigated or started up.

These existing business cases are discussed here.

The **CHP** plant at the INEOS Oxide industrial site already valorises its flexibility. As discussed in § 3.3.2, the CHP was built and operated by Essent, later to be RWE, after which it was fully acquired by INEOS in 2019. During its lifetime, the CHP, more specifically the steam turbine, has been able to deliver FCR and aFRR towards the TSO. With an installed power of more than 25 MW, it is classified as a CIPU unit by Elia and is therefore required to conclude a contract for the coordination. This CIPU contract served as basis to deliver balancing ancillary services towards the grid. The flexibility of the CHP is also valorised implicitly, as surplus electricity can be generated and sold onto the energy markets. Depending on the market conditions, the gas turbines or steam turbine are used for electricity production. It should be clear that such a CHP installation is inherently flexible as it is in fact a dispatchable power plant, comparable to a CCGT. The added complexity here is that the produced steam is being used as energy source on the industrial site and is commonly valued quite high, i.e., resulting in a *thermal mode* operation, where the electricity production is considered as secondary importance. This could hamper the full valorisation of the electrical flexibility. Nevertheless, at the INEOS Oxide industrial site, dedicated steam boilers are present as well, allowing for the complete installed power of the CHP to be used flexible in case of favourable market conditions.

Another existing electrical flexibility case is that of the **electrolysers** as present at the INOVYN industrial sites. As discussed in § 3.3.3.8, the chlor-alkali electrolysis process as operated by the INOVYN Lillo and INOVYN Jemeppe Belgian INEOS industrial sites is by nature quite flexible. This resulted in the early adoption of the supply of balancing ancillary services towards the TSO, in the form of contracting of the Elia ICH product. The ICH product was the first balancing ancillary service product to be contracted by Elia delivered by non-CIPU units, as discussed in §2.5.1.3. As it was an mFRR product, the contract stated the reservation of interruptible capacity, i.e., upon request, (part of) the electrolysis cell rooms was decreased in power. As the balancing ancillary services market reformed over the years, the ICH product was discontinued and the mFRR Flex and mFRR standard products were called into life. The electrolysis process remained contracted under these new mFRR products as the business case was still valid. This business case was based on the capacity remuneration which is gained and relied on very limited activations, i.e., interruptions of the electrolysis process. Indeed, the number of activations were very limited considering the non-CIPU units to be always activated lastly, after all the CIPU balancing ancillary services power was exhausted. This mFRR activation order remained common practice until recently (see § 2.5.1.3). Also FCR has been delivered towards Elia, being it in very limited volumes. The process control had therefore been updated to allow the needed fast active power reactions based on the grids frequency. The contracting of these balancing ancillary services has been both directly with Elia and via an FSP. With the uprise of FSPs such as the independent aggregator REstore which pioneered in Belgium in 2012, the risk of non-compliance with the strict AS product rules could be partly mitigated. The flexible electrolysis process has been valorised implicitly on the energy markets as well. With varying hedging strategies over the years, SPOT markets price signals are used in the planning of production. Also the SI signal serves as input for valorisation of the flexibility, with the main focus being on large grid incidents with an assumed prolonged imbalance as result. A manual reaction by the process operators allows then to profit from low or high imbalance prices.

A last existing case is on the extruders of a single Belgian INEOS industrial site. The extrusion process, as described in § 3.3.3.9, consists of high power motors to drive the screw. While these are not able to be controlled continuously, i.e., the speed is of importance for the production process and product quality, the process can be fully stopped within a short time frame. Therefore, the nominal power of the extruder(s) is contracted as mFRR with an aggregator. The business case is quite similar to those of the electrolysis processes, as the bulk of the profit is to be made by the capacity remuneration while a minimum of activations is to be hoped for. Considering a quite high opportunity cost, given by the loss in production capacity and the personnel costs for safe shutdown and restart, less profit is to be gained by the activation remuneration. While previously the non-CIPU was by default to be activated lastly, today an energy bid price can be set, so to influence the place in the mFRR activation merit order, as discussed in § 2.6.2.4. The existing business case can thus be maintained by setting rather high mFRR energy bids.

3.3.5 Future Electrical Flexibility Potential

The discussed processes and potential cases for electrical flexibility valorisation at the Belgian INEOS sites are based on existing processes. Here, potential future electrical flexibility opportunities are discussed. The future potential can both be given by a change of operation or control of assets on an existing industrial site, by the investment in new technology or by the specific *design for flexibility* of a new industrial production process or site.

3.3.5.1 Electrification

Electrification of the chemical process industry, or the energy-intensive industry in general, is part of the solutions in line with the 2050 net-zero emissions target in Europe and globally gaining traction in light of reaching the Paris Agreement [114]. Eurelectric presents decarbonisation pathways in its study, where indeed electrification is presented as one of the key solutions, next to energy efficiency and usage of non-emitting fuels. More specific, the electrification of heat is expected to be having the largest emission reducing impact in the industry, especially for cement and ethylene based sectors [115]. Note that the term decarbonisation is used in the context of energy and does not apply to the whole of industrial activity in general. The element of carbon is essential for the chemical industry, as it is present in many molecules such as ethylene. Steam is one of the main used forms of energy in most of the major industries today and is used for process heating, atomisation, cleaning, distillation, etc [116]. Indeed, as also seen at the Belgian INEOS industrial sites, the production of heat, often in the form of steam, is done by the burning of fossil fuels. Natural gas boilers and CHPs operated with natural gas are the two most common heating utility processes. The replacement of these heat producing processes by an electric alternative is said to be possible for temperatures up to 1000 °C by replacement of the boiler or furnace [91]. The electrification of steam production in industry in Europe is considered technically comparatively easy to implement and could represent a greenhouse gas saving of up to 15.9 Mt of CO_2 eq/annum in the long run according to [116]. Nevertheless, it should be noted that while the technology is deemed to exist and to be easy applicable according to literature, the magnitude of heat requirement in the industry should be kept in mind. Full electrification could multiply the electricity consumption of industrial sites several times, with implications to the grid connection and available (renewable) electricity. While the electrification technology on its own might be near-mature, the actual application on industrial sites might require detailed study. When such an electrification of heat case would be viable, this could result in electrode boilers or electric furnaces with a large installed nominal power, with the potential of flexible usage considering thermal inertia. An electrode boiler is a vessel in which a voltage is applied to water and which uses the conductive and resistive properties of the water to produce heat and steam. The start-up and control characteristics of such an electrode boiler allow for the participation in the balancing market. A single German manufacturer of these electrode boilers states that already 70 MW of its total installed capacity is being used for balancing purposes on the German market [116]. With several other electrode boiler manufactures in Europe, e.g., *Vapec*, which claims to be the market leader, it can be assumed that the total installed base of flexible electrode boilers is even larger [117]. The possible flexible operation of such an electrode boiler, in a hybrid setup with an existing natural gas boiler, is discussed in more detail in 4.3.

3.3.5.2 Design for Flexibility

Design for flexibility in the industry is the principle of taking into account the ability to operate the process in a flexible way during the design or adaptation of an industrial site or process, with respect of having an impact on the electricity consumption. During the design phases of an industrial site or process, the impact of design choices on the ability to alter the electricity consumption pattern of the industrial site or process could be checked. Adaptations to the design could be made in function of the potential to provide electrical flexibility, in any form.

During the design of a complete industrial site, encompassing multiple cascading processes, the ability to operate the process blocks in a circulating mode or stand-alone due to the availability of a buffer in-between could be an enabler for introduction of electrical flexibility potential. The impact of the enlargement or creation of a buffer could be significant for the electrical flexibility potential, while the impact on the design might be limited. The buffers, in any form, between the utilities processes and the core-processes should be investigated as well. For example, assuming an electrification of the steam production, a buffer between the steam production utility and the steam demanding core process could increase the potential of operating the steam production utility more electrically flexible.

The control methods of industrial machines and processes are often taking into account energy efficiency, which could be expanded with an analysis on electrical flexibility. A correlation between the control of a machine, e.g., adapting the volume flow, and the electricity consumption is one of the important parameters considering the future electrical flexibility potential of a process. A lack of correlation, due to energy inefficient control methods, would result in limited electrical flexibility to be available, even if the process itself could be operated in a flexible way.

On the intersection of energy efficiency and electrical flexibility, the production of electricity from waste heat streams or the expansion of gasses could also be an interesting case. Often low temperature heat, without any value for process heat integration, is considered as invaluable, therefore evacuated towards the surroundings by the help of a utility cooling process. Existing technologies, such as an Organic Rankine Cycle (ORC) to recuperate this low temperature heat and produce electricity, could be both an option to increase the industrial sites energy efficiency and introduce an electrically flexible process. An identical rationale is present for the expansion of gasses on industrial sites. Energy from gas expansion could be recuperated by the use of an expansion turbine in stead of an expansion valve.

Dedicated industrial sites or processes are to be built to convert future excess electricity into valuable chemical products or other materials, i.e., the *power-to-chemicals* or *power-to-X* concept. The rationale is to convert low or non-value electricity into products with a higher value. This low or non-value electricity is presumed to be available in the future during moments where renewable energy generation exceeds the total demand. These processes should by definition be electrically flexible, as they intend to use the excess electricity during high RES grid injection, while to be shutdown during moments of low RES and high demand. Examples of such *power-to-X* processes are production of hydrogen in electrolysers, which can than be further synthesised to ammonia, methanol or syngas. Also production of heat can be considered as a *power-to-X* processes as well as the production of food. Also the reconversion of the produced *X* to electricity can be considered, i.e., a so called *power-to-X-to-power* concept. Note that the number of energy conversions is directly related to the overall efficiency of such a process. Therefore, it is expected that such *power-to-X-to-power* projects will only by viable in specific cases and will have a higher final electricity cost.

While several pilot projects are being setup considering this *power-to-X* concept [118, 119], no viable industrial scale processes or sites are operational yet. The main reason for this can be found in the economics of these projects. As discussed, *power-to-X* projects rely on the availability of electricity with a low marginal cost, i.e., in practice (surplus) RES generated electricity. Such abundant cheap electricity, in large volumes, are upon today not available. This goes hand in hand with a high CAPEX of setting up such a dedicated industrial process. This CAPEX problem could be partly alleviated by scaling effects, once these project pass the pilot phase [120]. Upon today, the *X*, i.e., the products produced with the *power-to-X* process, still suffer a significant cost gap compared to their conventional counterparts. An example of this is the production of hydrogen by the use of dedicated water electrolysis processes powered with renewable electricity versus the hydrogen produced with the SMR process. An increase of the carbon (border) tax could be used to close this cost gap [120]. In Flanders, a consortium of multinationals with the name *Hydrogen Import Coalition* studied the possibility of importing renewable hydrogen from countries where sun and wind is abundantly available. Production installations with gigawatt scale, i.e., both the PV and windparks as well as the hydrogen electrolysis process, would be constructed to produce hydrogen outside of Flanders. The hydrogen would then, either directly as hydrogen or by means of a synthesised product such as ammonia or methanol, be imported with ships or pipelines. The main purpose would be to serve as feedstock in the (chemical process) industry, but the reconversion to electricity, i.e., the *power-to-X-to-power* concept is not excluded [121]. The uptake and upscaling of these *power-to-X* processes is expected to create a shift in the supply of carbon neutral energy and feedstock. When business cases based on variable operation of the *power-to-X* process become viable, this is expected to have a large impact on the availability of demand side flexibility in the grid. Large volumes of excess electricity can be converted to feedstock, while these processes could also supply fast ancillary services such as synthetic inertia and FCR by control of the electrolysis process.

3.4 Clustering

The previous sections of this chapter,§ 3.2 and § 3.3, focussed on the availability of electrical flexibility potential on individual industrial sites, processes or machines.

Upper levels, above the single industrial site, are the subject of this section. Two main levels are defined, being a geographical local cluster, where industrial site are discussed in combination with their geographical neighbouring industrial sites, and a virtual cluster level, where industrial sites can cooperate irrespective of their geographical location. The latter is limited to the virtual clustering within a single country, i.e., LFC area and electricity market bidding zone. The electrical flexibility clustering potential is analysed and described from a viewpoint of the Belgian INEOS industrial sites. These Belgian INEOS industrial sites are deemed suited for a case study, considering the heterogeneity in terms of relation to geographical neighbours and industrial clusters as well as the sites being dispersed across Belgium.

The clustering of industrial sites is here focussed on the electricity energy vector, but can be wider as well. The concept of Industrial Symbiosis (IS) is used for the study of industrial networks within which resources are shared and valorised, fitting into the concept of Industrial Ecology (IE). These resources can encompass information, materials, energy and infrastructure [122]. The electricity energy vector, and more specifically the electrical flexibility potential, could thus be seen as an element of this larger cooperation, i.e., symbiosis, across industry. Amongst the different energy vectors, electricity is unique considering the geographical limitations. While a shared heat (steam), compressed air, cooling or chemicals network is bound by geographical limitations, electricity is to be transported virtually without any limit of distance. With each industrial site having a connection to the electricity grid, interchange of electricity is possible over a large distance.

The local clustering level is discussed in the light of a Closed Distribution System (CDS), an existing electricity distribution network in a geographically confined industrial area. On a virtual level, the concept of a Virtual Power Plant (VPP) is described. Valorisation options, focussed on electrical flexibility, are discussed and a method is proposed for the setup of such a virtual cluster.

3.4.1 Local Cluster

Industrial sites are often located in dedicated areas, such as harbours or industrial parks, in the presence of other industrial sites. This geographical proximity of industrial neighbours can bring several opportunities considering the sharing of materials, energy and infrastructure. One of such shared infrastructure can be the electricity distribution system. A single high voltage grid connection with a subsequent closed distribution system can supply multiple individual industrial sites with electricity. Such a CDS resembles, on a technical level, a conventional distribution grid as operated by a DSO, where substations and cables supply the different consumers on the necessary voltage levels and with the requested power. Such CDSs have been existing for a considerably long time and are often historically grown industrial grids [123]. While originating as single industrial site with a single electricity distribution system, due to acquisitions, splits and expansions, multiple legal entities, i.e., industrial sites, could be connected to a single electricity distribution grid. Such a CDS is thus mostly created implicitly as result of splits or merges, rather than being created on purpose. In Flanders, the explicit creation of such a CDS requires the approval of the Flemish Regulator of the Electricity and Gas market (VREG). Upon today, thirteen CDSs have been acknowledged by the VREG [123]. On a legal level, the operator of such a CDS, the CDSO, has to fulfil several obligations towards its CDS participants as well as towards the TSO, comparable, yet less strict, to a DSO. In Flanders, these obligations are regulated in the *Energiedecreet* [124] which are a ratification of the European directives, e.g., directive 2019/944 [125].

Over the past years, the rules for a CDSO have been changed and fine-tuned, in line with the European directives. Before, A CDSO was not deemed to comply with the same rules as a DSO, with the result of a CDS participant not having the same rights or market access as it would have in case of a separate individual public grid connection. Today, a participant of a CDS has an equal market access right, both for electricity sourcing and valorisation of its electrical flexibility, and can go into contract with any third party to do so. The CDSO has to grant a virtual direct grid connection towards the CDS participant upon its request, facilitating the access to the market. This creation of a level-playing field for all market parties, including CDS participants, means that today no real opportunities nor threads are present. The electrical flexibility opportunities for local clustering are therefore no different than those in a *virtual cluster*. Nevertheless, an opportunity considering the financial optimisation of electricity sourcing is noticed.

The CDSO could take up the role of energy supplier towards the CDS participants. Electricity can be sourced in an aggregated way on the energy markets or produced by the CDSO, which will then subsequently be distributed and invoiced towards the CDS participants. In such a case, the physical grid connection point acts as a single entity towards the markets and grid. As result, the different electricity consumption patterns and volumes of the individual parties are aggregated and presented as one. With grid costs, taxes and levies being calculated on the overall consumption of such an individual grid connection point, a financial incentive for such an aggregation exists. Taxes and levies can incorporate a certain degressivity based on the total electricity consumption, in the form of discount rates or a ceiling of the contribution. An example is the *federal contribution*, a tax levied on Belgian level. With a discount rate up to 45% for electricity consumption above 25 GWh/year, a significant benefit might be present [126].

Of the nine Belgian INEOS industrial sites as discussed in § 3.3.1, eight are encompassed in a CDS. Three INEOS sites are the operator of the CDS, while five sites are participants. A specific case is that of INOVYN Lillo and INEOS Manufacturing Lillo, which are geographical neighbours and both INEOS sites, yet are two distinct legal entities. INOVYN Lillo acts as the CDSO while INEOS Manufacturing Lillo is one of the CDS participants. The INEOS Oxide site does not only act as a CDSO, it also hosts third party industrial sites on its own property. Other energy streams, next to electricity are shared as well. The INEOS Styrolution and INOVYN Zandvliet industrial sites are embedded on the Belgian BASF *verbund* site, the largest chemical cluster in Belgium. Also here, other energy streams are shared within the industrial cluster.

3.4.2 Virtual Cluster

The definition of a virtual cluster is linked to the concept of a Virtual Power Plant (VPP). The following definitions of a VPP are to be found in literature. *A VPP aggregates the capacity of many diverse DERs, it creates a single operating profile from a composite of the parameters characterizing each DERs and can incorporate the impact of the network on aggregate DERs output. A VPP is a flexible representation of a portfolio of DERs that can be used to make contracts in the wholesale market and to offer services to the system operator* [127]. *A virtual power plant is a cluster of dispersed generator units, controllable loads and storages systems, aggregated in order to operate as a unique power plant. The generators can use both fossil and renewable energy source. The heart of a VPP is an energy management system (EMS) which coordinates the power flows coming from the generators, controllable loads and storages. The communication is bidirectional, so that the VPP can not only receive information about the current status of each unit, but it can also send the signals to control the objects* [128]. DER or Distributed Energy Resources are decentralised, modular and flexible generators with a nominal power of 10 MW or less. A VPP in literature is often focussed on the aggregation of small-scale generation and storage, connected to the Distribution System Operator (DSO) grid. Here, the focus is laid on the clustering of industrial sites, which often are directly connected towards the TSO grid, or indirectly via a CDS. In [129], a distinction is made between a Technical Virtual Power Plant (TVPP) and a Commerical Virtual Power Plant (CVPP). A TVPP consists of DER in a same geographical location and includes the real-time network constraints of the DSO and TSO networks to which the DER are connected. Services and functions considered in a TVPP mainly comprise of local system management for the DSO as well as services for the TSO. It thus focusses on providing technical services, e.g., for the management of local network constraints. A CVPP is more focussed on the financial aspect and does not take into account the network elements nor constraints. The focus is on trading in the wholesale energy market, balancing of portfolios and provision of services to the TSO. Standard CVPP functionalities are the optimisation and scheduling of production or consumption, managing the process of constructing bids, bidding to the market and optimising the remuneration. Considering the connection level of the INEOS sites and the fact that network constraints, i.e., congestion, on TSO level does not often occur on the Belgian grid, the focus shall lay on the services as described by a CVPP. The clustering as described here is indeed limited to Belgium, which is a single LFC area as well as a single market zone with zonal pricing. The electricity market thus makes an abstraction of the Belgian grid and assumed it to be a *copper plate*. Nevertheless, this zonal pricing does not mean that in practice no congestion on the TSO grid could occur. Technical issues on the grid could indeed impose temporal grid congestion, while structural grid congestion could be present due to grid lines being overburdened by large geographically clustered offtake or injection. Temporal congestion due to technical issues might be present, but only for a small amounts of time. Structural congestion in Belgium is considered to be limited, as the TSO grid is well meshed and maintained so to meet required offtake and injections. Therefore, the problem of congestion is not taken into account here. In case the virtual clustering would be expanded beyond a single market zone, interconnection capacity would come into play. In that case, TSO network constraints should be taken into account. The same is true for clustering of lower level connected assets, such as smaller scale industrial sites, SMEs or residential neighbourhoods. The DSO grid constraints would then pose a more significant issue. The industrial equivalent of a distribution system, the CDS, might also encompass congestion issues. Nevertheless, within the current research, no concrete problems with existing installations are to be found. These issues do might arise when industrial sites plan to electrify part of their processes or expand their production facilities. In these cases, CDS grid upgrades should be taken into account.

3.4.3 Possible Services for a Belgian Virtual Cluster

An overview is given of the possible services which could be encompassed in a Belgian virtual cluster. They are evaluated based on their economic opportunities and legal possibilities.

3.4.3.1 Energy Supplier

Based on nominations coming from the industrial site, the virtual cluster could source electricity on the different markets (CIM, DAM, LT) within the Belgian market area or negotiate bilateral contracts, i.e., taking the role of the energy supplier. The potential financial benefit might be the reduction of energy supplier fees, a better access to certain markets and better bargaining potential considering larger volumes. Assessing this option in relation to the Belgian INEOS industrial sites, it can be concluded that each individual industrial site is today already able to access the electricity markets directly. The individual electricity consumption levels are of a large enough magnitude so that no aggregation is necessary to be able access the markets. Nevertheless, the current ways of electricity sourcing on the different industrial sites does not always mean to interact on the markets directly. While some sites do act on the electricity market themselves, other have a pass-through contract with an energy supplier. Other industrial sites have bilateral or hedging contracts with energy suppliers, reducing the exposure to price volatility. Considering the large volumes sourced, the energy supplier fees are low, presenting only a small financial opportunity in going to the market themselves. Each INEOS industrial site is an individual legal entity with an own energy sourcing strategy, based on its risk profile given by the type of business. While some industrial sites source all their electricity on the DAM, others hedge blocks on the LT market. It is therefore considered difficult to homogenise these electricity sourcing strategies,i.e., the risk strategies. Possible benefits in aggregated electricity sourcing might be the reduction of supplier fees or bargaining bilateral deals with large electricity producers. Nevertheless, the marginal gains are considered to be minor. This rationale deems it not interesting to further investigate the possibility of taking up the role of energy supplier in the virtual cluster. Future opportunities in electricity sourcing are expected to be on individual site level and not on virtual aggregated level. These opportunities are considered to be linked to the risk and hedging strategies.

3.4.3.2 Balance Responsible Party

As discussed in § 2.4.2, each electricity consumer or producer is obliged to be taken up in the portfolio of a BRP. This market role, which is often taken up by the energy supplier, foresees in the correct financial settlement of the imbalances which are caused by the consumer or producer. Under previous imbalance settlement system rules, i.e., the dual imbalance pricing, an optimisation could be carried out in the BRP portfolio. Adding a flexible asset to a BRP portfolio could compensate for the imbalances of the other assets, preventing or lowering the total imbalance cost for the BRP as a whole, as discussed in [130]. However, under the current imbalance settlement system rules, i.e., the single imbalance pricing, this business case no longer exists. As explained in § 2.4.2, a single imbalance pricing methodology incentivises the countering of the overall, i.e., LFC area, SI imbalance, rather than to maintain balance within the BRP portfolio. From a financial point of view there is no incentive in grouping certain specific assets together and maintaining balance within this portfolio. While the imbalance market still provides opportunities for valorisation of electrical flexibility, e.g., by the active steering of flexible assets, there is no incentive in doing this in an aggregated way. Therefore, taking up the role of BRP is considered to be not of interest as a service in the virtual cluster.

3.4.3.3 Balancing Service Provider

The role of a BSP is explained in § 2.6.1. It is a market party providing balancing services towards a TSO and can encompass reserve providing units and reserve providing groups to do so. An independent aggregator can be a market party taking up this BSP role, as well as existing energy supplier. The BSP acts as an intermediary between the industrial site wishing to valorise its electrical flexibility and the FRP. The BSP offers a gateway to the balancing ancillary services market, with the main advantages of risk mitigation, relieve of administrative burden and pooling, i.e., aggregation, effects. The BSP role is considered as potentially interesting to take up in the virtual cluster. Potential benefits compared to commercial BSPs are the possibility of fees reduction or exclusion, a more short term commitment and transparent optimised bidding.

3.4.3.4 Energy Expert

The role of an energy expert might also be of interest in a virtual cluster. The idea is to distribute data and information considering the electricity and ancillary services market towards the participating industrial sites, and this from a centralised entity, i.e., the virtual cluster. The numerous changes in the electricity markets, the addition of market roles, adaptation of ancillary services or imbalance market rules make the follow-up of the energy market quite complex. A central entity, having expert knowledge, could assist the individual industrial sites in their electrical flexibility valorisation and energy sourcing strategies. Identified potential services might be the following.

1. The provision of short-term market price forecasts and insights. This service is often provided by the energy supplier, aggregator or other commercial third party. Each industrial site has its own stream of information and data, often under the form of a contract. Centralising this role could broaden the information and data available to an industrial site while at the same time having a lower cost.

2. Assisting the industrial site in prequalifying its electrical flexibility. Before having the possibility of valorising electrical flexibility with ancillary services contracts, a prequalification process is needed, as described in § 2.5.1.5. This service would be a guide from first discovery of electrical flexibility potential to the actual bidding into the market. While this service is often also offered by the independent aggregator, confidential information and data might prevent a correct analysis. Creating this services internally, i.e., as service in a virtual cluster of industrial sites within the same group such as the INEOS industrial sites in Belgium, this threat might be avoided.

3.4.4 Belgian Virtual Cluster: Belgian BSP

To summarise the previous section, it can be concluded that the focus of creating a virtual cluster should be focussed on the creation of a BSP. A framework for such an INEOS BSP will be elaborated upon in the following sections. The valorisation options of the Belgian BSP are identical as to the options of individual industrial sites, which are discussed in § 2.4.

The proposed framework of setting up such a BSP shows several similarities with how commercial aggregators are operating today. The aggregation of the flexibility of multiple industrial sites and this for multiple possible valorisation paths is considered to be a complex topic. An economic optimisation algorithm should be developed to define which flexibility to valorise on which market, as well as on how to cluster the different flexible assets so to meet the technical requirements of the different balancing ancillary services. The details of such clustering algorithms are defined as business treasure by the commercial aggregators, as the performance of such algorithm largely defines their market value. While the literature was inspected, very limited information on such clustering algorithms is found.

3.4.5 Framework of an INEOS Belgian BSP

3.4.5.1 General Principle

An INEOS BSP is perceived as an entity which will be the intermediate party between the individual INEOS industrial sites and the balancing ancillary services market. A single INEOS industrial site is called a reserve providing unit, while a group of reserve providing units is called a providing group, as discussed in § 2.6.1. The main goal is to economically optimise the opportunities of the individual INEOS sites in an aggregated way, so to obtain a greater value, while also reducing the risk. The focus of the INEOS BSP will be on the provision of FCR, aFRR and mFRR towards the TSO, Elia in Belgium. Figure 3.18 shows the simplified principle of the proposed INEOS BSP. An internal bidding platform with marginal pricing is setup where individual INEOS sites can place bids, so called i-bids. These bids are only bound by internally agreed rules and principles, as they are not directly send to the ancillary service market platforms of Elia and/or Regelleistung. The INEOS BSP, acting as intermediary, will place the bids on the respective ancillary services markets, so called m-bids. The internal bidding process, optimisation, remuneration split and matching of bids to obtain the necessary technical characterises of standard ancillary services are all subject of this proposed framework of an INEOS BSP.

Figure 3.18: Schematic overview of the proposed INEOS BSP.

Table 3.3: Overview of the different possible business structures.

	Commercial Model	Free Service Model
INEOS group level	/	1
Separate INEOS BU	2	3
Within INEOS BU	4	5
P2P	6	

3.4.5.2 BSP Business Structure

An important part of setting up a framework for an INEOS BSP is how the entity will be created as a business structure. Two important aspects are the financial structure and the legal structure. As legal structure, the BSP could be operated from within a certain existing Belgian INEOS Business Unit (BU), could be constructed as separate Belgian BU or could be operated from an INEOS group level. A fourth possibility is a peer-to-peer structure, where no single central entity operates the BSP, rather an ad-hoc cooperation is setup. On financial level it must be decided if the BSP is seen as a *free service model*, offering the valorisation potential as a service towards the Belgian INEOS industrial sites, or that the BSP must be making profit, similar to a commercial aggregator. The different defined possibilities are elaborated upon, without being exhaustive. A structure is given in Table 3.3.

1. A first possibility is where the BSP is setup at an INEOS group level. The INEOS group level overarches the separate INEOS businesses and sites, worldwide. Considering the limitation of the BSP to operate within a single market zone and LFC area, this worldwide level might not of interest. If replicability of a country-wide BSP, such as envisaged here, would be of interest to other countries where INEOS operates, this group level might be the better choice. If such an INEOS group level structure would be chosen to

create a BSP, it should be noted that valorising flexibility is currently mostly related to country, i.e., market and LFC area, specific rules. Within Europe, in the coming years, a single market and homogenised rules will be implemented. Financially, the idea is to offer the services from the BSP freely towards the INEOS industrial sites, meaning that all generated revenue flows back to the participating sites, not making any profit at the INEOS group level.

2. A BSP can also be operated at the country level, where a separate legal entity would be created. Considering the commercial model, a Belgian *INEOS BSP company* could be created. This company should either be able to foresee in own working costs or even make profit. With the latter, a strong similarity would be present with existing commercial aggregators. Benefits of this structure would be the ability to copy-paste the concept of an existing aggregator, leaving less legal complexity to implement. On the other hand, the Belgian INEOS BSP NV would need to be able to make an interesting commercial proposition towards the INEOS sites, competing with other commercial aggregators. It is the question if INEOS sites would be interested in such a service, as to them it leads to no more financial gain than on the existing market with commercial aggregators. The only difference could be the idea that the profit remains within the INEOS boundaries.

3. Identical as in case 2, a separate legal entity, a company, is created to cover the INEOS BSP services. In case of the free service model, all revenue from valorising the flexibility would flow back to the INEOS sites. Still the similarity exists with commercial aggregators, but in this case it can be assumed that the financial benefit for the individual INEOS industrial site is larger, as no working cost nor profit are taken by the INEOS BSP. This latter assumption has to be proven, as not only the working cost and profit of the aggregator define the total profit for the INEOS site, but the size of the pool and the market strategy is also of importance.

4. The operation of a Belgian INEOS BSP can also occur from within an existing INEOS BU. Some INEOS sites already have already some experience with valorising electrical flexibility, being it only within their own industrial site perimeter. A site might have the interest in expanding its knowledge on electrical flexibility valorisation, which could be done with less resources, compared to setting op a separate BU as proposed in cases 2 or 3. This INEOS industrial site could market its expertise and service towards the other INEOS businesses, using a profit structure. Again, this shows great similarities with a commercial aggregator, where the other INEOS businesses should be incentivised, either financial or other, to valorise their flexibility with this INEOS BSP.

5. Identical to case 4, a single INEOS site could take up the BSP role, offering the possibility to valorise flexibility to other Belgian INEOS sites. When considering a free service model, the INEOS site would not make profit, instead the revenue would be fully redistributed towards the other INEOS sites delivering the electrical flexibility. A mixed form between case 4 and 5 could be taken, where only the operational costs need to be covered, but the profit is distributed towards the participating INEOS industrial sites. This case seems interesting from an *INEOS-as-a-single-company* point of view, as a fair profit distribution is used and lower operational costs as in cases 2 and 3 are expected.

6. A last and more experimental approach is to create a Belgian INEOS BSP without a central authority leading this BSP. This idea is rather different than the rest, where the electrical flexibility valorisation happens on an ad-hoc basis, without central overview, guiding or control. INEOS industrial sites would gather knowledge and distribute the BSP tasks amongst them. Rules and fair revenue distribution should be discussed on a bilateral level. It could be said that in this case no real INEOS BSP is created, rather, a loose collaboration between sites is constructed. An existing pan-INEOS industrial site network could be used to incentivise such collaborations. While not leading to the creation of an INEOS BSP immediately, this could be considered as an intermediate step, towards such an INEOS BSP. Benefits might be the reduced cost structure and a closer collaboration between INEOS industrial sites. The ad-hoc structure would make it possible to assess the benefits of clustering, before implementing a complete legal BSP structure such as in cases 1, 2 and 3 and to a lesser extent in cases 4 and 5.

3.4.5.3 General Fair-Play Rules

Services the BSP offers are largely bound to regional, i.e., Belgian, regulation and technicalities of the ancillary services as offered by Elia. But also within the BSP itself some ground rules need to be laid, so to create a level playing field amongst the INEOS industrial sites providing the electrical flexibility. The idea is to valorise electrical flexibility with multiple Belgian INEOS sites, without creating competition between them. A fair distribution of the remuneration and potential penalties is to be strived at. An open and transparent structure of the Belgian INEOS BSP is therefore deemed necessary. This is somehow different than a commercial aggregator, where often no transparency is present between different flexibility suppliers. A first and most important principle is the equality principle. If two industrial sites supply an identical amount of flexibility with an identical risk profile, they should be remunerated an equal amount of the revenue. As the definition of flexibility and risk is open for discussion, a methodology should be developed to quantify and qualify the electrical flexibility in a uniform way. The following set of ground rules for such an INEOS BSP are proposed.

1. The participation to the Belgian INEOS BSP should be on voluntary basis, no single industrial site will be forced to valorise its flexibility, either through the Belgian INEOS BSP or in any other way.

2. Only Belgian sites from the INEOS group can enter the Belgian INEOS BSP, no other third parties are allowed to valorise their flexibility. An exception to this rule can be made in case an INEOS industrial site acts as CDSO. CDS participants can, via the INEOS CDSO, valorise their flexibility with the Belgian INEOS BSP. No direct contact would be laid between the INEOS BSP and the third party, the CDSO will always be the contact point as well as held liable for the valorisation of the flexibility of its CDS participant.

3. When an INEOS site chooses to valorise flexibility with the Belgian INEOS BSP, exclusivity is obliged. No simultaneous contract with any third party commercial aggregator can be maintained during the period where flexibility is valorised within the Belgian INEOS BSP. As flexibility is a broad term, this rule stresses on the concept of explicit flexibility. Implicit valorisation of flexibility, such as energy sourcing strategies, load shifting, peak shaving, BRP balancing, etc. are allowed if done without using services of commercial aggregators.

4. When entering the Belgian INEOS BSP pool, a minimum commitment time is expected. Upon first entering, the site must maintain valorising its flexibility for at least a specified amount of time. Afterwards, the INEOS site is free to leave and re-enter the pool without any constraints, nevertheless keeping in mind the minimum contract times as set forward in the electrical flexibility valorisation contracts.

5. The INEOS site remains responsible for delivering the necessary power as requested for the specific electrical flexibility service which it has engaged in. In case of non-delivery by the INEOS site, penalties will need to be paid to the Belgian INEOS BSP. These penalties will always be defined on a fair and transparent basis, and will cover the penalty cost the Belgian INEOS BSP is deemed to pay to the TSO. In case the pooling effect of the Belgian INEOS BSP would (partially) cover the failure to deliver of the INEOS site, the INEOS site could still be asked to pay a penalty, which will be distributed to the other sites in the pool who covered for the failure of activation.

6. The revenue obtained from the electrical flexibility valorisation, the so called remuneration, is split according to a fair and transparent methodology.

3.4.5.4 Joining the INEOS BSP - Prequalification

Becoming a Qualified Delivery Point as INEOS Site

To be able to participate in the INEOS BSP, the Delivery Point (DP), i.e., the individual INEOS industrial site, must comply with certain administrative and technical rules, as briefly described in § 2.5.1.5. Some more specific points are given below.

1. A metering device needs to be foreseen so to provide validated measurements to the INEOS BSP and to Elia. In case an already installed Elia metering device is present, no further technical checks need to be performed. When a private metering device will be used, a private measurement technical info checklist is needed to be provided. Necessary data will be the technical details and a single-line diagram of where the device is installed. Also, a private measuring commissioning test will be performed, checking the accuracy and communication.

2. A signed Grid User Declaration needs to be in place, stating legal and technical information.

3. A frequency metering device must be installed, with an accuracy of 10 mHz, in case of supplying FCR service.

Initial Providing Group

The INEOS BSP needs to perform prequalification tests so to define what volume of ancillary service it can supply. It needs to do this before a first participation into the ancillary service capacity auctions. This prequalification test is executed on a providing group, consisting of several delivery points. A practical example is given, focussing on the FCR service.

Figure 3.19 shows an initial FCR providing group within a BSP. This providing group exists out of four participating industrial sites A to D. Each site is considered as a delivery point. Site A and D are part of a CDS, with site D being the CDSO and site A the CDS participant. Site A assumes to provide a total of 2 MW FCR in the upwards direction, site B assumes a volume of 5 MW in the upwards direction, site C assumes a volume of 3 MW symmetrical and site D assumes to provide a total of 3 MW FCR in the downwards direction. With site D having a direct Elia connection, it has an Elia owned metering device, visualised in orange. It therefore does not need to install an own metering device to be able to participate in the FCR service, but can use the Elia metering device. This is also true for sites B and C. Site A, being a CDS participant, does have an own EAN number, but has no own direct connection to the Elia grid. To meter site A, an own metering device is necessary to participate in the FCR service, as indicated in blue. This metering device needs to be of the right accuracy class.

Sites A, B and D are classified as DP_{PG} meaning that they will provide the FCR service with non-CIPU units. Site C is classified as DP_{SU} meaning it will provide the FCR service with a CIPU unit, e.g., a Combined Heat and Power (CHP) plant. Every DP needs to have a local frequency measurement device to be able to provide the FCR service, indicated in blue. Since site A has a virtual Elia connection, it can use the data coming from the frequency measurement device of site D.

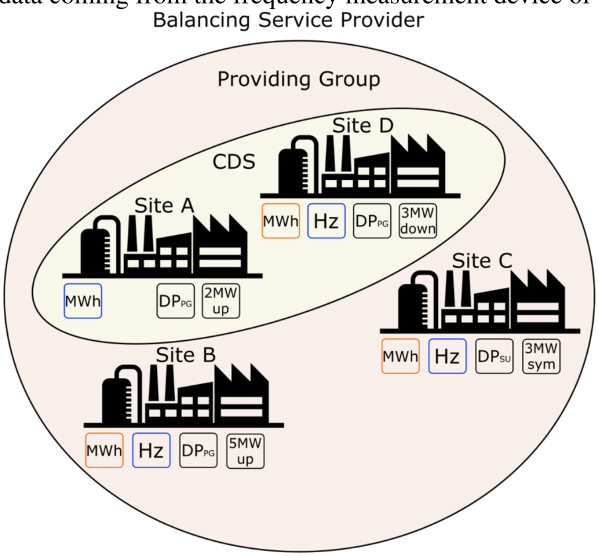

Figure 3.19: Initial FCR providing group.

To define the maximum volume of FCR the BSP can contract in the future, it will need to perform a prequalification test with its providing group. The BSP will agree with Elia a single day on which the prequalification test will be performed. During this day, all the assets in the FCR providing group of the BSP need to be available to be activated. This prequalification test consists of a certain follow-up of a synthetic frequency profile in both upwards and downwards direction, as well as a follow-up of the real frequency during 4 hours. Details on this prequalification test and the calculation methods can be found with Elia [131]. As result from this prequalification test, an FCRmax is defined. Assuming every site in our example is able to provide the volume which it was assumed to, an FCRmax of 6 MW is obtained. This value is defined as the minimum of either the upwards or downwards capacity. In this example, this value is obtained by the volume in the downwards direction, as this is the lowest (3 MW by site D and 3 MW by site C). From now on, the BSP can, with this providing group, make capacity bids for FCR with a maximum of 6 MW. Any combination of FCR volumes of the individual delivery points, which reaches a 200 mHz symmetrical product and with a maximum of 6 MW, can now be bid into the FCR market. It is the responsibility of the BSP, here thus the INEOS BSP, to combine several FCR profiles so to obtain the required symmetrical 200 mHz product. Note that in this example it was assumed that every delivery point could either provide an upwards, downwards or symmetrical FCR service. In practice, no constraints are present on the individual frequency profile, as long as the combination results in the standard 200 mHz FCR product.

Expanding Providing Group

Assuming that in a later stage other INEOS industrial sites wish to connect to the INEOS BSP, a scenario must be constructed on how these additional DP should be integrated. Three main options are defined.

1. The BSP decides to leave the FCRmax unchanged at the previous volume. No new prequalification test is needed and the new industrial site(s) can enter the INEOS BSP, assuming they are already qualified as delivery point as described in 3.4.5.4. The INEOS BSP can continue its operation and the newly added sites can participate in the internal bidding process. As the FCRmax remains unchanged, a situation could occur where in the internal bidding process a larger optimal volume is obtained. In that case, the bids of the industrial sites already in the providing group will have priority over the bid(s) of the industrial site(s) last entered into the INEOS BSP, so that the FCRmax will not be exceeded.

2. The BSP decides on requesting a new prequalification test with Elia for only the newly added site(s). The result of this new prequalification test with only the newly added sites, FCRmax,new, will be added to the existing FCRmax. Note that this action is only possible if the newly entered site(s) can, combined, offer the standard 200 mHz FCR product.

3. The BSP decides on requesting a new prequalification test with Elia for the complete providing group. A new FCRmax is defined, based on all the participating INEOS sites in the providing group at the time of the test. Note that a prequalification test is not remunerated and that during the period of execution of the prequalification test, no FCR bids can be placed in the market. This can lead to disadvantageous effects for the INEOS industrial sites already part of the INEOS BSP providing group.

The proposed methodology for the INEOS BSP for adding new DPs in an existing providing group is the following. New delivery points can join the INEOS BSP without constraints in terms of timing. No new prequalification test will be executed, maintaining the FCRmax at the existing level. The newly joined delivery points can thus bid in the internal INEOS BSP bidding process, but with the restriction that the part of the volume of their bid which would exceed the existing FCRmax would be rejected. Existing delivery points in the INEOS BSP providing group will have priority. The INEOS BSP will request a new prequalification test with Elia for the complete providing group only in case these conditions are fulfilled:

1. On explicit request of (one of) the newly joined DPs.

2. When it can be shown that the volume and type of the added FCR services of the newly added delivery point(s) will contribute to the enlargement of the FCRmax.

3. Only on predefined fixed timings. Certain periods during the year could be defined during which the INEOS BSP will be allowed to perform a new prequalification test. During this prequalification test, the existing DPs in the providing group will not be able to contract FCR volume nor be remunerated for this prequalification test.

The INEOS BSP will request a new prequalification test with Elia for the newly joined delivery points only in case these conditions are fulfilled:

1. On explicit request of all the new delivery point(s) joining the providing group

2. When the (sum of the) assumed new FCR volume of the newly joined delivery point(s) is at least 1 MW symmetrical 200 mHz.

Figure 3.20 is related to Figure 3.19 and assumes an expansion with a site E, having an own Elia connection point and an assumed FCR power of 2 MW downwards. Assuming all technical and administrative prequalification tasks to provide FCR service have been taken care of by site E, it is able to enter the providing group.

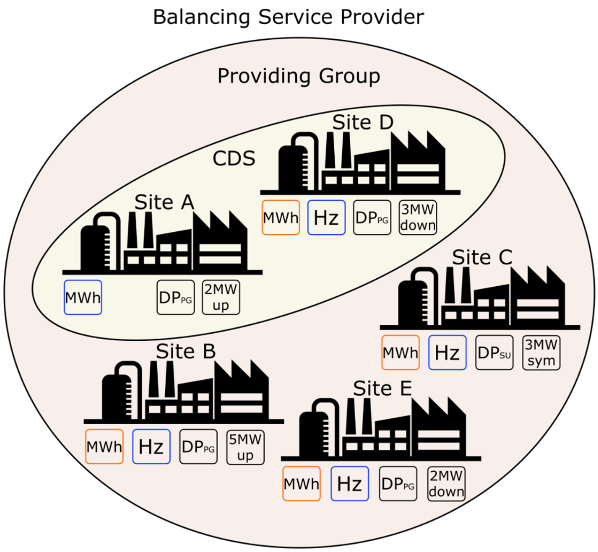

Figure 3.20: Expanded FCR providing group.

Site E wishes to enter the FCR providing group of the INEOS BSP on 12th of June with an assumed FCR volume of 2 MW downwards. The current FCRmax is 6 MW, which is restricted because of a lack of downwards volume. There is a existing total of 10 MW upwards volume and 6 MW downwards volume. If site E possesses all the needed technical and administrative documents on 12th of June, it can enter the providing group and participate in the internal bidding process. The FCRmax is retained at 6 MW. The existing DPs will maintain priority in the internal bidding process in case this FCRmax would to be exceeded. On the 1st of September, i.e., as an example fixed period during which a new prequalification test is allowed in the INEOS BSP, site E can request the INEOS BSP to apply for a new prequalification test with Elia. As indeed the current FCRmax is limited due to the shortage of downwards FCR, the total providing group has advantage in a new prequalification test, as it enlarges the FCRmax. The prequalification test will be executed in a period of 10 days following from the date of communication to Elia. Assuming the newly added site can indeed provide 2 MW downwards FCR and all other DPs are available, the FCRmax is enlarged to 8 MW. During the prequalification test to add site E, other DPs cannot bid into the FCR market, not valorising FCR potential. As this forms a financial disadvantage for the DPs already in the FCR providing group, the number of these prequalification test is limited, e.g., to a fixed number of test per year. On the other hand, enlarging the volume of the providing group is an advantage for the complete providing group. Where previously a total of 4 MW of upwards FCR reserve could not be valorised, this is reduced to 2 MW by adding the downwards FCR volume of site E. Therefore, this methodology as proposes is deemed reasonable, and does not require any compensation for lost valorisation potential towards the existing DPs in the providing groups. In the period between 12th of June and 1st of September the delivery point site E cannot request a prequalification test for its own FCR volume as it does not comply with the minimum requirement of having at least 1 MW of FCR symmetrical 200 mHz. In case another site F would also join, with an upwards volume of FCR, this latter option would be possible.

3.4.5.5 Technical Description of the Internal Bidding Optimisation Methodology

Here a methodology is proposed for the internal bidding, i.e., bids from the INEOS industrial sites towards the INEOS BSP.

Bidding Process On technical level the INEOS BSP will combine several individual bids, i.e.,*i-bids*, which might not meet the requirements for the respective ancillary service, into a market bid or *m-bid*.

An i-bid is a bid with a direction from an INEOS industrial site towards the INEOS BSP and contains the service type, volume, timing, divisibility and opportunity cost. **Service type**: the INEOS site defines for what kind of ancillary service the bid is placed. Possible service types are FCR, aFRR and mFRR. Within those service types, several subcategories might exist, e.g., for FCR the INEOS site can specify for which frequency band it wants to react. **Volume**: the amount of flexible power the INEOS site makes available to be valorised, expressed in MW. **Validity period**: the period in which the INEOS site wishes to valorise its flexibility. The validity period is defined based on a given *from date* and *to date*, in between which the bid is valid. A minimum validity period of 4 hours is required, as this corresponds to the minimum contracting time of most ancillary services. **Divisibility**: In case the bid is offered with a volume larger than 1 MW, it can be specified if the INEOS site wishes to make it divisible, meaning that it is possible that only a part of the bid will be contracted. A granularity of 1 MW is used, e.g., if a divisible bid of 5 MW is given, it is possible that only 1 MW, 2 MW, 3MW, 4MW or the full 5 MW is retained. **Opportunity Cost**: An opportunity cost defines the minimum remuneration the INEOS site requires to receive for activating its flexibility. The opportunity cost should encompass the actual cost of activating the electrical flexibility combined with a certain profit margin. The INEOS site is free to set the opportunity cost at its wishes, but must take care that a too high opportunity cost could result in the not contracting and thus not valorising its electrical flexibility. A more detailed rationale behind this principle is discussed in § 3.4.6.

Internal Bid Optimisation INEOS sites commit bids to the INEOS BSP. An internal deadline needs to be respected, which can be different for each ancillary service type the INEOS site is bidding for. The internal deadlines can be defined in relation to the ancillary services market deadline, as is given in Figure 2.31. When

Table 3.4: Example of i-bids submitted to the INEOS BSP.

	AS type	Volume [MW]	Opp. Cost [EUR/MW/h]	Divisible	Validity [blocks]
Site A	FCR up	4	5.3	yes	1 - 10
Site B	FCR down	5	6.8	yes	1 - 5
Site C	FCR up	2	9.6	yes	2 - 8
Site D	FCR up	3	5.9	no	3 - 9
Site E	FCR up	6	8.6	yes	1 - 6
Site F	FCR down	5	11.2	yes	1 - 10

the internal deadline for a specific ancillary services market product is closed, the INEOS industrial sites cannot submit any more bids. The INEOS BSP will now combine and optimise the received bids. The optimisation is based on combined profit maximisation, taking into account the probability of bid acceptance on the ancillary services market. While the general optimisation goal is defined, the process itself can differ based on which ancillary service is optimised.

In the following practical example, assume the i-bids as given in Table 3.4. For simplicity the subcategories of FCR are limited to upwards and downwards which corresponds with supplying power related to the frequency band of 49.8 Hz to 50 Hz and 50 Hz to 50.2 Hz. As five out of six bids are divisible, they can be split into separate possible bids, with a granularity of 1 MW.

The optimisation will be executed for every contracting time period, being 4 hours for the FCR service. As example, take block 1, a fictional period in time of 4 hours. The bids of sites C and D are not taken into account, as they are not valid in the considered time period. A brute-force optimisation methodology is used. First, all the possible combinations of bids are defined. As a symmetrical product needs to be supplied the TSO, only combinations where the sum of the volumes of the downwards product matches the sum of the volume of upwards bids are retained. In this specific example, this results in 139 possible combinations of i-bids. The m-bid price P_{m}, as will be set towards the ancillary services market, is defined by (3.1), i.e., it is the maximum of the opportunity costs of the individual i-bids (C_{opp}), 0 to n, in the respective bid combination. Which bid combination is retained as most optimal, is defined by calculating the potential profit R_i of each i-bid combination as given in (3.2). The probability the m-bid will be accepted by the ancillary services market, β, is multiplied with the sum of the potential profits of each individual i-bid in the i-bid combination. The m-bid price, P_{m}, is subtracted with the opportunity cost $C_{\mathrm{opp,i}}$ of the i-bid, which is then multiplied with the volume of the bid, V_i. In other words, the potential profit is defined as the difference between the bid price as would be set by the INEOS BSP towards the ancillary services market and the opportunity cost of each individual i-bid, multiplied with its considered volume. The probability of m-bid acceptance, β, is

Table 3.5: Overview of the resulting optimal bids.

	AS type	Volume [MW]	Opp. Cost [EUR]
Site A	FCR up	4	5.3
Site B	FCR down	5	6.8
Site E	FCR up	1	8.6
Combined bid 1	**FCR sym**	**5**	**8.6**
Site F	FCR down	5	11.2
Site E	FCR up	5	8.6
Combined bid 2	**FCR sym**	**5**	**11.2**

considered a reducing factor, i.e., a high m-bid price results in a low contracting probability and vice versa.

$$P_{\mathrm{m}} = max(C_{\mathrm{opp,0}}, C_{\mathrm{opp,1}}, ..., C_{\mathrm{opp,n}}) \tag{3.1}$$

$$\mathrm{R_i} = \beta_{\mathrm{FCR}} \sum_{\mathrm{bid_0}}^{\mathrm{bid_n}} (\mathrm{P_m} - \mathrm{C_{opp,i}}) \mathrm{V_i} \tag{3.2}$$

When applying these optimisation to the i-bids as given in Table 3.4, this results in the following optimised combined bids as given in Table 3.5. As shown, two resulting combined bids are obtained. This is due to a second optimisation carried out, with the remaining bids not used in the first i-bid combination.

No individual bids remain after a second optimisation. Note that the single bid of site E was marked as divisible and has indeed been split into two separate bids by the optimisation algorithm. The INEOS BSP has thus come up with a total of two bids which will be submitted to the ancillary services market, a bid of 5 MW at 8.6 euro/MW/h and a bid of 5 MW at 11.2 euro/MW/h.

3.4.5.6 Remuneration

A fair split of the remuneration between the individual INEOS industrial sites is set forward in the INEOS BSP rules. The most basic methodology is to split the remuneration according to the supplied volume of power or energy, respectively for ancillary services which are remunerated based on power or energy.

When two individual INEOS industrial sites each deliver an identical, but opposite asymmetrical part of the symmetrical 200 mHz FCR service, each of them should be remunerated with an identical amount. Assume a site A and site B which each offer 2 MW of FCR upwards and downwards respectively. While site A set an i-bid of 8 euro/MW/h, site B set an i-bid of 10 euro/MW/h. As the cleared market price is 11 euro/MW/h, the combined bid would be accepted and the INEOS BSP will receive a remuneration based on the cleared market price as given in(3.3).

$$\text{Remuneration CCTU} = 11\text{euro/MW/h} \cdot 4\text{hours} \cdot 2\text{MW} = 88\text{ euro} \quad (3.3)$$

As only together sites A and B can valorise their flexibility in the market, both will obtain half of the remuneration as given by (3.4)

$$\begin{aligned} \text{Remuneration site A} &= 88\text{euro} \cdot 50\% = 44\text{ euro} \\ \text{Remuneration site B} &= 88\text{euro} \cdot 50\% = 44\text{ euro} \end{aligned} \quad (3.4)$$

In a case where more than two individual INEOS sites participated into the combination of a single bid, the remuneration split is done based on the contribution of each of the individual INEOS sites. Assume three INEOS sites, together providing the 2 MW FCR 200 mHz symmetrical. Site A provides 2 MW downwards, site B provides 1 MW upwards and site C provides 1 MW upwards. Then the remuneration split is according to (3.5).

$$\begin{aligned} \text{Remuneration site A} &= 88\text{euro} \cdot 50\% = 44\text{ euro} \\ \text{Remuneration site B} &= 88\text{euro} \cdot 25\% = 22\text{ euro} \\ \text{Remuneration site C} &= 88\text{euro} \cdot 25\% = 22\text{ euro} \end{aligned} \quad (3.5)$$

A point of discussion might be that the INEOS site delivering the downwards part of the FCR has a higher or lower cost than the INEOS site delivering the upwards part of the FCR. This is nevertheless case and process dependent and cannot be proven under the concept of a concealed opportunity cost calculation as is proposed. Only in case of a uniform and transparent opportunity cost calculation this would be possible. Note that in § 3.4.6 it is discussed why such a transparent way of working is considered to complex or even not possible. It should therefore be taken into account by the INEOS site when setting its opportunity cost. Therefore, this most basic approach for remuneration splitting is deemed reasonable. It avoids complexity while not having major drawbacks.

3.4.5.7 Penalties

Supplying ancillary services towards the TSO is not voluntarily, as discussed in § 2.5. Failure to comply with the contractually agreed timings or volumes could therefore result in penalties. The penalties as described here are specifically for the FCR service, other ancillary services might have a different type of penalties or penalty calculation. Several penalties can be given based on the type of failure to deliver a certain aspect of the FCR service. Elia has two possible ways of checking the failure to deliver, either by performing an announced test (capacity availability test or energy availability test) or by regularly checking the delivered power and energy by assessing grid frequency variations. As announced tests, the capacity availability test and the energy availability test will be performed at least once a year. The capacity availability test can be tested maximally twelve times per year, while the energy availability test can be tested three times per year. The implications of these penalties, more specifically on the split of the penalty between the different INEOS industrial sites, will be discussed.

In a capacity availability test, Elia will check if the total contracted volume in MW is indeed available and will penalise for the missing MWs. The penalty formula is given by (3.6). α denotes a penalty factor with as default value 0.75. In case of a second consecutive failed availability test, the value is increased to 1.5. The $P_{\mathrm{FCRmissingMW}}$ is the volume of missing FCR, as calculated by a fixed formula by Elia. $\mathrm{CP}_{\mathrm{WA}}$ is the weighted averages of capacity prices (in euro/MW/h) corresponding to all awarded FCR capacity bids for the BSP for a 30 day period prior to and including the day of the test. The CCTU is the period of four hours during which the BSP has a contract to deliver FCR. $\mathrm{CCTU}_{\mathrm{m}}$ is the number of CCTUs the BSP has contracted FCR during a 30 day period prior to and including the day of the test. $\mathrm{hours}_{\mathrm{CCTU}}$ are the number of hours of a CCTU, i.e., 4.

$$P_{\mathrm{FCRmissingMW}} = \sum_{\mathrm{Month\ M}} \alpha \cdot \mathrm{FCR}_{\mathrm{MissingMW}} \cdot \mathrm{CP}_{\mathrm{WA}} \cdot \mathrm{CCTU}_{\mathrm{m}} \cdot \mathrm{hours}_{\mathrm{CCTU}} \tag{3.6}$$

For simplicity it is assumed that the BSP has contracted 10 MW of FCR during every CCTU of the complete month M, with an average remuneration of 6 euro/MW/h. This would result in a total remuneration of 43 200 euro, as given by (3.7).

$$R_{\mathrm{FCR}} = 30\ \mathrm{days} \cdot 24\ \mathrm{hours} \cdot 6\mathrm{euro/MW/h} \cdot 10\mathrm{MW} = 43\,200\ \mathrm{euro} \tag{3.7}$$

Note that this is the total remuneration for the INEOS BSP and that the 10 MW can be supplied by a providing group with different INEOS sites, which can vary every CCTU of 4 hours. Now assume that a single capacity availability test was performed by Elia in the month M. First assume that a total of 2 MW FCRmissing was seen, i.e., that only 8 MW instead of 10 MW was supplied. This would then result in a penalty of 6 480 euro as given by (3.8)

$$P_{\mathrm{FCR\ missing\ MW}} = \sum_{\mathrm{Month\ M}} 0.75 \cdot 2\mathrm{MW} \cdot 6\mathrm{euro/MW/h} \cdot 180\mathrm{CCTUs} \cdot 4\mathrm{hoursperCCTU} = 6\,480\ \mathrm{euro} \tag{3.8}$$

The penalty would thus reduce the monthly remuneration with 15%. When such a capacity test fails, Elia has the right to trigger a second one. Assume in this second capacity availability test again not the full capacity can be delivered, now with 3 MW missing. The penalty would be 19 440, as given by (3.9)

$$P_{\text{FCR missing MW}} = \sum_{\text{Month M}} 1.5 \cdot 3\text{MW} \cdot 6\text{euro/MW/h} \cdot 180\text{CCTUs} \cdot 4\text{hoursperCCTU} = 19\,440\text{ euro} \tag{3.9}$$

Both penalties combined add up to 60% of the total monthly remuneration. In case two capacity availability tests fail consecutively, as in this example, the FCRmax of the BSP will be lowered with the minimum of the missing MWs of either tests. In this example, in the next month the BSP will thus see a lowered FCRmax by 2 MW.

In an energy availably test a penalty for the FCR missing time is calculated as follows according to (3.10). Here, α is defined as a penalty factor proportional to the percentage of the *Failed Energy Factor*, which is calculated by Elia based on the result of the energy availably test. A value of 0.5, 0.75 or 1 is possible. A value of 1.5 is used if this is a second consecutive failed energy availability test. The FCRmissingtime is the amount of seconds between the moment the supplied FCR power was inferior to the FCR requested capacity and the end of the energy availability test. The energy availability test takes 1560 seconds. CV_A is the average volume corresponding to all the FCR capacity bids awarded to the BSP for a 30 day period prior to and including the day of the test.

$$P_{\text{FCR missing time}} = \sum_{\text{Month M}} \alpha \cdot \frac{\text{FCR missing time}}{1500} \cdot \text{CP}_\text{WA} \cdot \text{CV}_\text{A} \cdot \text{numberofCCTU} \cdot \text{hours}_\text{CCTU} \tag{3.10}$$

For simplicity the previous result of (3.7), where a total monthly remuneration of 43 200 euro is supposed to be obtained, is resumed. Now assume that a single energy availability test was performed by Elia in the month M. Assume a total FCRMissing Time of 1400 seconds, i.e., that the first failure is observed after 160 seconds after the start. Also assume the worst *Failed Energy Factor*, resulting in an α of 1. This would result in a penalty of 40 320 euro as given by (3.11).

$$P_{\text{FCRmissingtime}} = \sum_{\text{MonthM}} 1 \cdot \frac{1400}{1500} \cdot 6\text{euro/MW/h} \cdot 10\text{MW} \cdot 180\text{CCTUs} \cdot 4\text{hoursperCCTU} = 40\,320 \text{ euro} \tag{3.11}$$

The penalty would thus reduce the monthly remuneration with 93%. Note that the values taken here are quite severe, but are to show that indeed most of the monthly remuneration can be consumed by a penalty in case of faulty or non-delivery.

A second possible penalty type are those of the activation control. Elia checks on a monthly basis that the FCR supplied by the BSP meets the contractual obligations. Elia does this by taking a single or multiple frequency variation(s) which occurred during the month M and checks if the volumes as stipulated in the FCR energy bids are activated correctly. Elia will penalise the non-compliant activations in according to (3.12), with a failure factor FF as defined in (3.13).

$$P_{\text{non-comp. act.}} = \sum_{\text{all anal. freq. var. of month M}} 0.2 \cdot \text{FF} \cdot \text{remun month M} \tag{3.12}$$

$$\text{FF} = \max\left(\frac{\text{FCRreq}_{\text{freq. variations}} - \text{FCRsup}}{\text{FCRreq}_{\text{freq. variations}}}; 0\right) \tag{3.13}$$

Again, the assumed remuneration of 43 200 euro as given in (3.7) is used. It is assumed that Elia performed three frequency variation checks during month M, during which one there was a non-compliance with a volume of 2 MW, e.g., the FCR requested during the specific analysed frequency variation was 7 MW and only 5 MW was supplied, the failure factor is thus 2/7 or 0.285. The penalty would thus be 2 468.5 euro, as given by (3.14)

$$P_{\text{non-compliant act.}} = 0.2 \cdot 0.285 \cdot 43200 \text{ euro} = 2\,468.5 \text{ euro} \tag{3.14}$$

This corresponds with 5.7% of the total monthly remuneration of the BSP, due to non-compliance during a specific moment during which Elia performed, ex-post, a frequency variation check. To conclude, it is clear that the penalties given for non-compliance, either during normal activation or during an availability test can be severe. In certain cases, the total monthly remuneration can be completely reduced to zero by the penalties. An important last rule is that the total penalty can never be higher than the total monthly remuneration. The BSP will thus never have to pay to Elia. In the most extreme case, the remuneration can only be zero euro.

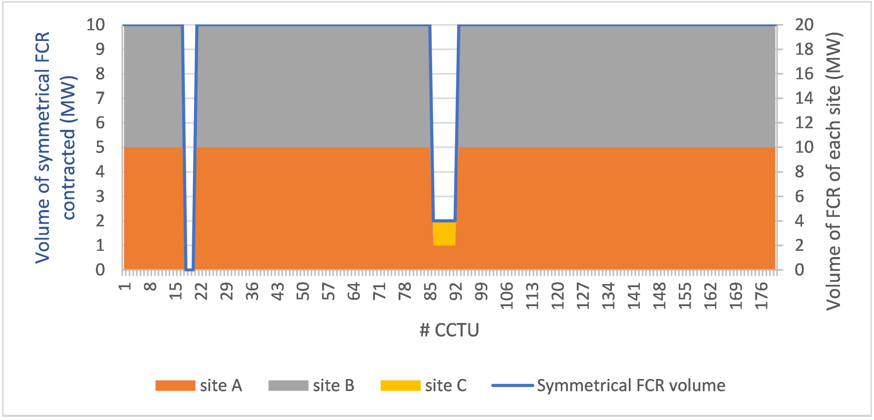

Figure 3.21: Example of contracted volumes of FCR by different INEOS sites.

Implications for the INEOS BSP concept

It should be clear that the implications of not complying with the ancillary services rules set forth by Elia are quite severe. Therefore, the impact on an aggregated group of INEOS sites providing ancillary services in an INEOS BSP should be investigated. The focus here lays on the question how the costs should be split in case a penalty is imposed by Elia. On BSP level, no financial deficit can be seen, as the penalty can never be larger than the remuneration obtained. The difficulty lies within the penalty or remuneration split between the single INEOS sites.

Assume an INEOS BSP with three individual INEOS sites involved. All of them would provide the FCR service. Site A is prequalified for 10 MW of upwards FCR volume, site B for 10 MW downwards FCR volume and site C for 2 MW of downwards FCR volume. All are entered into the INEOS BSP at the same time and are prequalified as a single providing group. Thus, the total FCRmax is set at 10 MW. At first, assume that during month M, mostly site A and B have had FCR capacity contracted, due to the INEOS BSP internal bidding process, i.e., the opportunity cost of site C is higher and therefore not selected. Assume during 170 out of 180 CCTUs in month M, site A and B have provided FCR with a volume of 10 MW and an average capacity price of 8 euro/MW/h. During seven of the remaining CCTUs, site A and site C combined have provided FCR, with a volume of 2 MW at an average remuneration of 10 euro/MW/h. During the remaining three CCTUs, no FCR volume is contracted. This is visualised in Figure 3.21.

The total remuneration of the INEOS BSP for providing FCR in this month M will be 54 960 euro, as given by (3.15)

$$\begin{aligned}
&R_{\text{monthM}} = \\
&170\text{CCTUs} \cdot 4\frac{\text{hours}}{\text{CCTU}} \cdot 10\text{MW} \cdot 8\text{euro/MW/h} \\
&+7\text{CCTUs} \cdot 4\frac{\text{hours}}{\text{CCTU}} \cdot 2\text{MW} \cdot 10\text{euro/MW/h} \\
&= 54\,400 \text{ euro} + 560 \text{ euro} = 54\,960 \text{ euro}
\end{aligned} \tag{3.15}$$

If the obtained remuneration is split according to the rules as proposed previously, the split is defined as in (3.16)

$$\begin{aligned}
&\text{Site A} = 50\% \cdot (54\,400 \text{ euro} + 560 \text{ euro}) = 27\,430 \text{ euro} \\
&\text{Site B} = 50\% \cdot 54\,400 \text{ euro} = 27\,200 \text{ euro} \\
&\text{Site C} = 50\% \cdot 560 \text{ euro} = 280 \text{ euro}
\end{aligned} \tag{3.16}$$

Assume that Elia does an activation check based on a frequency variation which occurred during a CCTU where site A and site B were providing the FCR service. This frequency variation was one in the downwards direction, i.e., the frequency was to high thus a power decrease was necessary. The downwards part of the FCR service was taken care of by site B. Out of the 6 MW which was needed to be supplied, only 4.5 MW was actually supplied. A penalty of 2 748 euro is thus obtained, as given by (3.17).

$$\text{P}_{\text{non-compliant act.}} = 0.2 \cdot \frac{6\text{MW} - 4.5\text{MW}}{6\text{MW}} \cdot 54\,960 \text{ euro} = 2\,748 \text{ euro} \tag{3.17}$$

Assume no other penalties were received in the same month M. The question is how this penalty should be split amongst the parties, and who should bear the costs. As it is clear that the penalty was received due to the failure to deliver of site B, one could argue that site B must take full responsibility for the penalty. As the total remuneration of site B is larger than the penalty, this is possible. The remuneration split would then be given by (3.18).

$$\begin{aligned}
&\text{Site A} = 50\% \cdot (54\,400 \text{ euro} + 560 \text{ euro}) = 27\,430 \text{ euro} \\
&\text{Site B} = 50\% \cdot 54\,400 \text{ euro} - 2\,748\text{euro} = 24\,452 \text{ euro} \\
&\text{Site C} = 50\% \cdot 560 \text{ euro} = 280 \text{ euro}
\end{aligned} \tag{3.18}$$

Again, assume an activation check performed by Elia, but now during one of the CCTUs where site A and site C where supplying the FCR service. The performed frequency variation check occurred on a downwards frequency variation, i.e., site C was responsible for providing the FCR volume. Out of the 1.2 MW which was deemed to be provided, only 0.7 MW was delivered. A penalty of 4 580 euro is then obtained as given by (3.19).

$$P_{\text{non-compliant act.}} = 0.2 \cdot \frac{1.2\text{MW} - 0.7\text{MW}}{1.2\text{MW}} \cdot 54\,960\,\text{euro} = 4\,580\,\text{euro} \quad (3.19)$$

This penalty is larger than the remuneration site C was expected to receive. This is due to the fact that a large remuneration for month M was built up by sites A and B. Applying the same rule as above, the remuneration split would be given by (3.20)

$$\begin{aligned} \text{Site A} &= 50\% \cdot (54\,400\,\text{euro} + 560\,\text{euro}) = 27\,430\,\text{euro} \\ \text{Site B} &= 50\% \cdot 54\,400\,\text{euro} = 27\,200\,\text{euro} \\ \text{Site C} &= 50\% \cdot 560\,\text{euro} - 4\,580\,\text{euro} = -4\,300\,\text{euro} \end{aligned} \quad (3.20)$$

In practice, this would mean there should be a payment form site C towards the INEOS BSP to provide sites A and B with their remuneration. As this is a perverse situation where site C is exposed to a high penalty risk partly due to the large remuneration as built up by other sites, a risk mitigation strategy needs to be found. Note that the example as presented here is rather exceptional, this to show what a skewed distribution of both the time of FCR supply as the volume between individual INEOS sites can have as effect. The advantage of the pool effect, where another site could fill in the FCR volume not delivered by site C and so avoid a penalty, is here not applied.

Considering the current example, a smaller INEOS site whishing to valorise its electrical flexibility in the INEOS BSP is discouraged if such high penalties could be implied. It is also a matter of chance whether the frequency deviation checks Elia executes are during a specific CCTU, where certain sites are providing the FCR. This could create an unfair situation, where a site A is performing poorly, by having frequent missing FCR volumes, but never during Elia frequency deviation checks. Another site could have a single unique failure, but unfortunately during this failure Elia performs a frequency deviation check, leaving the latter site with the penalty. A proposed possible solution is to perform delivery checks internally, by the INEOS BSP. An identical way of analysing frequency deviations as does Elia could be introduced, this for the largest frequency deviation of each CCTU. These checks could be performed ex-post. Each frequency deviation check of each CCTU gets a magnitude based on the relative missing volume, a so called Failure Factor or FF, and is addressed to a single or multiple individual INEOS sites which is (are) responsible for the missing MW during this CCTU. In case no abnormality during the provision of the FCR service, the Failure Factor is of course set to zero. The proposed FF is defined by (3.21)

$$\text{FF}_{\text{CCTU}} = \max\left(\frac{\text{FCRreq}_{\text{freq. variations, CCTU}} - \text{FCRsup}}{\text{FCRreq}_{\text{fred.variations, CCTU}}}; 0\right) \quad (3.21)$$

All the Failure Factors (FF) of a specific INEOS site during the month M are summed and divided by the total Failure Factors of every site in the INEOS BSP during the month M, as given in (3.22)

$$\mathrm{FF}_{\text{Month M, site N}} = \frac{\sum \text{all CCTUs of Month M} \cdot \mathrm{FF}_{\text{CCTU, site N}}}{\sum \text{all CCTUs of Month M} \cdot \mathrm{FF}_{\text{CCTU}}} \tag{3.22}$$

Each individual INEOS site will than have a certain percentage of the complete FF, representing its performance to deliver the FCR service correctly. This percentage is then used to split the penalty. Note that this solution does not eliminate the risk of a penalty larger than the remuneration for an individual INEOS site. Assume that each INEOS site in the INEOS BSP delivering FCR service does so, without having missing MW, except for a single INEOS site. In that case, the full penalty would still be with a single INEOS site. The risk of obtaining a penalty as single INEOS site which is larger than the possible remuneration thus still exists, but with an ever so small chance. Also, an uneven distribution between the sites exists if taking into account the respective absolute volumes of the delivered FCR service. Two sites with a missing volume of 25% during a specific CCTU will be incurred with a Failure Factor of the same magnitude, even if in absolute values the missing MW are different. This could still present a threat towards smaller INEOS sites participating in an INEOS BSP with a large total volume of a specific ancillary service, because the monthly remuneration ís based on the absolute volumes. An adaptation of the proposed solution might be to take into account the absolute values, but this might have the perverse effect that the INEOS sites with larger volumes take a larger share of the risk. In general the proposed solution with FFs calculated based on relative missing MWs is deemed fair, as it penalises all the participating INEOS sites based on their performance level. The risk aspect, of being penalised as single INEOS site based on a random check by Elia, is hereby avoided.

The proposed remuneration and penalty split methodology is shown here. Assume a random distribution for the potential failure to deliver the FCR service correctly, this for all the individual INEOS sites. Assume 25 of the 180 performed frequency deviation checks would result in a certain Failure Factor, with a normal distribution, ranging from a very slight to some more severe missing volumes of FCR. The resulting FFs for the individual sites would be 0.51 for site A, 0.45 for site B and 0.04 for site C. Here site C has a low share in the total Failure Factor, which is deemed logic, as it only provides FCR service during 7 out of 180 CCTUs or 3.8% of the total time. Again, the assumption is taken that a single frequency deviation would be analysed by Elia, during a CCTU where site C delivers the FCR downwards volume. The penalty results in 4 580 euro. The remuneration split would be as given in (3.23).

$$\begin{aligned} \text{Site A} &= 50\% \cdot (54\,400 \text{ euro} + 560 \text{ euro}) - 4\,580 \cdot 0.51 = 25\,144 \text{ euro} \\ \text{Site B} &= 50\% \cdot 54\,400 \text{ euro} - 4\,580\text{euro} \cdot 0.45 = 25\,139 \text{ euro} \\ \text{Site C} &= 50\% \cdot 560 \text{ euro} - 4\,580 \text{ euro} \cdot 0.04 = 97 \text{ euro} \end{aligned} \tag{3.23}$$

Each site has a positive remuneration and pays a share of the imposed penalty by Elia, based on their level of performance to provide the FCR service. The proposed methodology is thus deemed fair and reasonable.

3.4.6 Rationale Behind the Arbitrary Choice of Opportunity Cost

This paragraph elaborates on the rationale on the proposed idea to let each individual INEOS site define themselves the opportunity cost, used to set the i-bid price. Defining an opportunity cost for the valorisation of electrical flexibility can be a tedious process, due to several factors. First there is the complexity. Defining the cost of operating a specific process and the cost-impact on operating it differently can be defined by many different cost-vectors. Some of those can be own to the process itself, but others to the way of accounting used on a specific INEOS site. For example, the activation of electrical flexibility has an impact on the maintenance timing, and could therefore be taken into account in the opportunity cost calculation. Also the CAPEX of a machine could be included, due to the shorter lifetime due to frequent ramping. Also the risk, e.g., of non-delivery to customers, could be quantified and taken into account. It should be clear that the calculation of the opportunity cost is prone to subjectivity.

Second there is data confidentiality. To define the opportunity cost, several confidential data such as raw material costs, electricity prices or process efficiencies might be necessary. Even considering all the participating sites are INEOS, some information does remain confidential to the individual INEOS site. Considering these arguments, it might not be possible or not wanted to have a transparent and uniform way of calculating the opportunity cost. Therefore, the idea is proposed to let each individual INEOS sites decide individually on which opportunity cost, expressed in euro/MW/h or euro/MWh depending on the ancillary service, to be set. Two important aspects which should be assessed when introducing this idea, is the possibility of convergence towards a single common opportunity cost and a potential internal competition which are introduced. The opportunity cost is deemed to consist out of three main parts.

1. The **actual cost** is the actual attributable cost of reserving and/or activating the electrical flexibility and can include the operational cost as well as depreciation of assets, increased maintenance costs, etc.

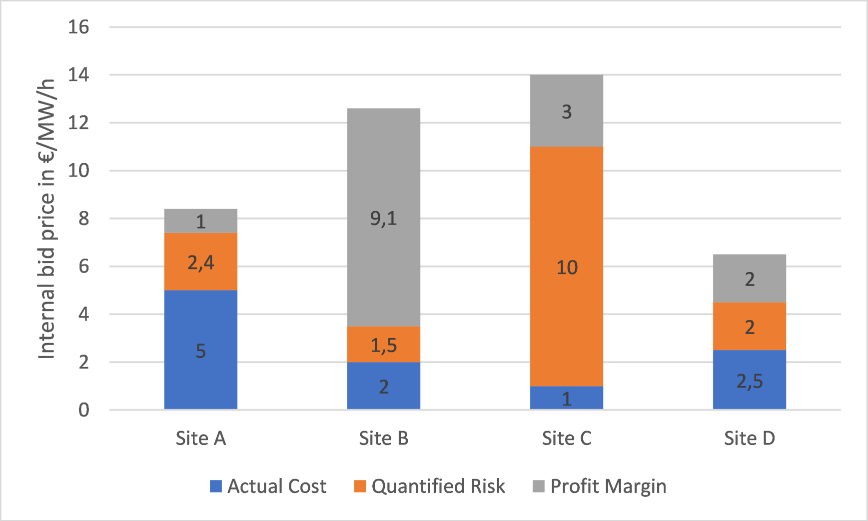

Figure 3.22: Opportunity costs of four different INEOS sites.

2. The **quantified risk** is the risk of non-deliverance to customers, the risk of process failure and resulting costs, risk of safety incident, etc. The quantification of these risks are prone to subjectivity.

3. The **profit margin** is the part which serves as incentive to actually use the electrical flexibility and participate in the INEOS BSP. An INEOS site would only valorise its electrical flexibility when a certain return is expected.

Assume four INEOS sites, bidding to the INEOS BSP for the FCR product, but all with a different bidding price, as shown in Figure 3.22. Figure 3.23 show the contributed volumes of FCR.

Site A operates a CHP and is able to deliver 10 MW upwards FCR. To do this it has a quite high operating cost, as therefore gas needs to be burned and a steam turbine needs to be kept warm, hence the high actual cost. Site B operates an electrolysis process, which is not run to full capacity. Therefore, some room is left for increased production and thus power consumption, making it possible to provide downwards FCR service with a volume of 8 MW. Operating an electrolysis room at a higher setpoint reduces efficiency, which is one of the potential costs for site B. There is a risk of process upsets due to the delivery of FCR, which is also quantified. A for site B reasonable profit margin is decided of 9.1 euro/MW/h. Site C operates an electrode boiler to produce on-site steam. It is the only steam producing asset and is therefore important for the process operation. Site C also has a small steam buffer, making it possible to deliver upwards FCR of 5 MW and still meeting the steam-requirement of the process, this for short moments. The

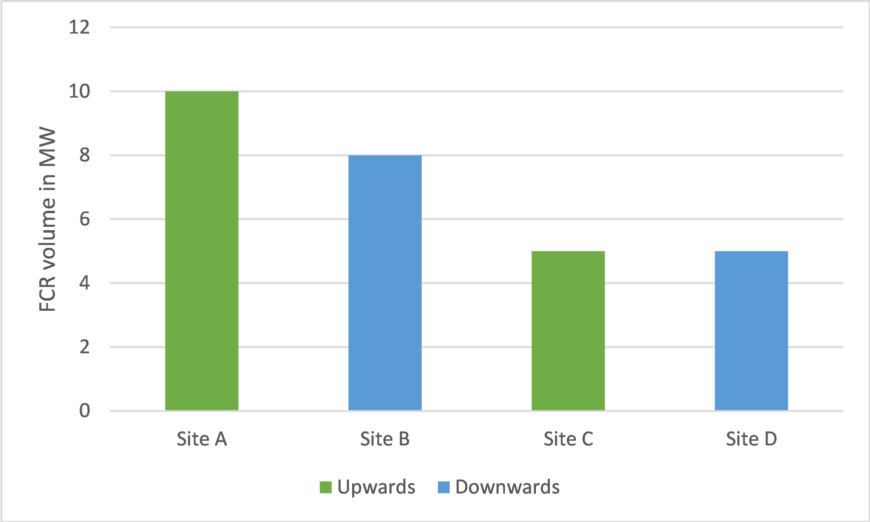

Figure 3.23: Contributed volume of FCR from four different INEOS sites.

Table 3.6: Result of the internal INEOS BSP bid optimisation.

	AS type	Volume [MW]	Opp. Cost [EUR]
Site A	FCR up	10	8.4
Site D	FCR down	10	6.5
Combined bid 1	**FCR sym**	**10**	**8.4**
Site B	FCR down	5	12.6
Site C	FCR up	5	14
Combined bid 2	**FCR symm**	**5**	**14**

actual cost for providing the FCR is therefore quite low. The quantified risk on the other hand is high, as a failure of the boiler would result in a process shutdown. Site D also operates an electrode boiler, used to produce steam for the processes on-site. The electrode boiler is only a part of the site's steam production facility, next to gas boilers. The site keeps the electrode boiler at a minimum operational level, so to be able to deliver downwards FCR volume of 5 MW. The actual cost is thus quite low. Also the risk is quite low as a failure of the electrode boiler can be covered by the other gas boilers on-site.

Letting the internal optimisation process run, according to the previously discussed methodology, this results in two combined bids, as given in Table 3.6. A total volume of 3 MW of FCR by site B is then not valorised.

Both combined bids will be put into the market by the INEOS BSP, at respectively 8.4 and 14 euro/MW/h. Note that for the FCR service a marginal pricing applies. Let us assume that the market clears at a price of 15 euro/MW/h. This would mean that both bids are accepted, and that the INEOS BSP will receive a remuneration of 15 euro/MW/h for the 15 MW of FCR delivered. In case the market clearing price would only be 9 euro/MW/h, this would mean only the first bid was accepted. The INEOS BSP gets a remuneration of 9 euro/MW/h for the first bid of 10 MW. The idea is to make the INEOS BSP a transparent working entity. This would mean that every INEOS site can see the internal merit order curve. Also the results are of course shared within the INEOS BSP. Nevertheless, the sites only see a total bid price, not the calculation method as used by the sites. This information can then be used by the individual INEOS sites to adapt their bid price for future biddings. For example, in the future, site B might decrease its profit margin, so to lower the total bid price and increase its chances of getting selected. Also other market parties can alter their bids, based on the outcome of this or other previous results. Here it is elaborated on the risk of price convergence, i.e., where every INEOS sites could set an identical price, so hampering the functioning of the INEOS BSP. As every INEOS industrial site has a different cost structure or different quantifying methods of risk, the possibility of converging towards a single price is deemed unlikely. Note that no single INEOS industrial site would place a bid with in case of a certain profit loss. For example, site C has only limited capacity of lowering its total bid price as is has high risk costs. On the other side, sites who are selected in the internal bidding process and gained value in valorising their flexibility will not increase their bid price as long as they are keep getting selected, since a cleared pricing is used for FCR, having thus no impact on their overall remuneration. A second topic of discussion is internal competition. Indeed, by using this methodology, there is a certain level of internal competition between INEOS sites. This could result in the decreasing of the profit margins, so to have a higher chance of getting selected internally in the INEOS BSP. Nevertheless, as the FCR product is remunerated based on a cleared market price, the total profit as obtained by the INEOS BSP would not see a negative effect in this. The latter based on the assumption that the volume of the INEOS BSP is rather small compared to the overall market volumes, thus not influencing the merit order curve. In general, the proposed methodology is deemed robust and fair. A price convergence nor a race-to-the-bottom, two major concerns, are not expected to happen

3.5 Conclusion

In this chapter, a methodology is proposed to analyse the electrical flexibility potential of chemical process industrial sites. This novel methodology is based on the power and energy levels as well as on the controllability. The proposed methodology is composed out of three main steps, being the gathering of data and information, the analysis of the obtained data and the identification of potential flexibility cases. Three main levels are distinguished, being the overall industrial site level, the process level, and the individual machine level. The methodology is applied on all Belgian INEOS chemical process industrial sites. After introducing the INEOS sites in Belgium and putting the overall electricity consumption level in perspective, each individual site is analysed according to the aforementioned methodology. This results in a list of potentially interesting cases, discussed according to the process specifics.

A first type of processes which are identified as having a large potential are the thermal utilities processes. Electric tracing, air cooling, water cooling and chilling are defined as having a combined installed flexible power of 16.5 MW. Chillers are analysed to make up 10 MW of this installed flexible power, with calculated capacity factors of 22% to 70%, thus providing potential for both upwards and downwards flexibility. The aggregate power of core processes identified as flexible mount up to 246.1 MW, of which 200 MW are electrolysis processes. Indeed the chlor-alkali process as present on two INEOS sites is identified as flexible and shows a large installed power. Also extrusion processes, present on three INEOS sites, is considered a flexible process with the main opportunity being load shedding. A total of 38 MW of installed power is considered to entail flexibility. With a total nominal electrical production capacity of 258 MW, the CHPs at the INEOS industrial sites present a significant opportunity for flexible operation. An existing business case to valorise this flexibility is present on a single CHP, yet could be enhanced and/or expanded to the other CHPs.

An overview of the processes which do not contain electrical flexibility opportunities are given as well. The identified processes are continuously producing core processes such as the production of ethylbenzene, polymerisation processes and distillation processes. Reasons for these processes to not encompass electrical flexibility are twofold. A first main reason can be found in the technical nature of the process, e.g., fluidised bed reactors, which prevent them from being operated flexibly. The second main reason is the inefficient partial operation of machines, with as result a limited impact on the electricity consumption. An example can be the control of a compressor by use of a bypass valve. While the product flow might be controlled flexibly, this then has no or very limited impact on the electricity consumption. To conclude, a look into the future is given, considering electrification and design for flexibility. Concepts of *power-to-X* and *power-to-X-to-power* are touched upon.

The second main part of this chapter deals with clustering of industrial sites, considering the possible opportunities and benefits regarding electrical flexibility. The local and virtual cluster level are discussed. The potential for such a virtual cluster, from the viewpoint of the Belgian INEOS industrial sites, is given and a framework is proposed to setup such cluster. This framework covers the main aspects needed to setup such a virtual cluster with a BSP role. Some possible business structures are described as well as fair-play rules. A detailed description on how to create and join the BSP is given, with concrete fictitious examples for illustration purposes. The main novelty in this second part of the chapter is the development of an internal bid optimisation algorithm. This algorithm, with a combined profit maximisation as optimisation goal, defines the most optimal combination of ancillary services bids under the ancillary service market constraints. A second novelty is the proposed methodology to split the remuneration and penalty amongst the participating industrial sites. The rationale of allowing a certain level of competition between the cluster members is explained as well.

In general it can be concluded that electrical flexibility potential is present in the chemical process industry. Several processes have been analysed resulting in potential flexibility cases. Utilities processes show to be interesting considering the buffer with the core process, i.e., with the production of the industrial site. Thermal buffers are considered interesting, with cooling processes being the most common utility today. Electrification of heating, e.g., steam production, is considered as one of the cases with the largest future potential for electrical flexibility. Also specific core processes show to be able to operate in ways so to create electrical flexibility, with a special attention given to electrolysis processes. Processes considered to be not flexible are mainly continuously operated core-processes, such as the production of ethylbenzene, distillation and polymerisation reactions occurring in fluidised bed reactors. Existing electrical flexibility valorisation cases at INEOS industrial sites are discussed. The focus of the existing cases is clearly on the provision of mFRR, i.e., on the contracting of the interruptibility of the process. The processes with the largest electricity consumption and ability to interrupt are contracted, being extruders and electrolysis processes. These are considered to be the *low hanging fruit*, and that other (future) cases would go into more complex control rather than interruption based on a TSO signal.

4 Case Studies

4.1 Introduction

In this section three different case studies will be described. These are selected based on the results of the electrical flexibility potential results of the Belgian INEOS sites analysis as discussed in § 3.3. A short overview is given here.

- An induced draft evaporative cooling system is modelled with the goal of simulating the encompassed thermal inertia, evaluating the potential flexible usage of the cooling tower fans. Two distinct modelling approaches, a black box model based on an adaptive neuro-fuzzy interference system and a white box model based on the thermodynamic equations, are developed. The models are validated with data from an industrially sized system and allow for the cooling water temperature to be simulated based on a fan switching strategy.

- A theoretical hybrid steam production setup, consisting out of a natural gas fired boiler and an electrode boiler is considered as flexible process. An imbalance price prediction methodology is developed based on the predictability of the NRV due to market design weakness. The predicted imbalance price is used to control the electrode boiler, so to operate during the lower imbalance price level.

- The optimisation of a chlor-alkali electrolysis process is the core of this case study. The inherent flexibility encompassed in this process is used to optimise the control based on DAM prices and the supply of FCR towards the TSO, while taking into account all of the operational and technical constraints of a real industrial chlor-alkali process. A k-factor model of the electrolysis process is used. DAM and FCR market price forecasting models are developed and applied as input, which introduced uncertainty. This uncertainty is then mitigated by the use of stochastic modelling.

4.2 Modelling of an Induced Draft Evaporative Cooling System

4.2.1 Introduction

The usage of industrial cooling systems for the purpose of electrical flexibility is shown to have a high potential, as discussed in § 3.3.3.1. A thermal utilities process has the benefit of having a certain thermal inertia being linked to the core process, which would allow it to be controlled in a flexible way. Nevertheless, it is an important utilities process, directly linked to process efficiency and safety. The amount of thermal inertia which is present and the subsequent ability of the cooling process to be controlled flexibly cannot be estimated directly. Cooling towers are designed based on static calculations taking into account the maximum heat load to be dissipated. Often, no dynamic thermal model is available, resulting in the inability to assess the impact of fan control without practical tests. To be able to verify a fan control strategy, the temperature of the cooling water needs to be simulated. Therefore, this case study proposes two modelling methods for predicting the water basin temperature of an induced draft evaporative cooling tower system. The proposed white box model and black box model find an equilibrium between model complexity and model response accuracy, fostering the implementation in a real-life industrial setting.

The system as under investigation is based on a discrete number of operating modes of the cooling system, i.e., the cooling tower fans are not controlled using a VSD, rather DOL switched Dahlander motors are used to drive the fans. The operation of such process is based on a setpoint temperature, which is pursued by switching fans. Nevertheless, a hysteresis as shown in Figure 4.1 is often used to prevent the necessity of continuous control of the fans. A minimum (T_{min}) and maximum temperature (T_{max}) is set to ensure the process efficiency and safety. It is this hysteresis zone combined with the other control zones which could be beneficially used to develop a control strategy for the fans, beneficially using the flexibility contained in this system. This is shown in Figure 4.1.

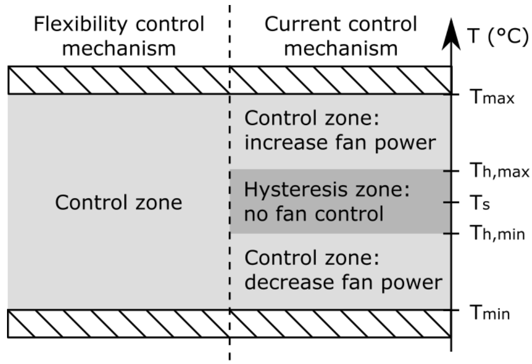

Figure 4.1: Graphical representation of control zones for non-VSD controlled cooling systems.

4.2.2 Forced Draft Evaporative Cooling System

The cooling system under investigation is based on evaporation. The physical state change from a fluid, i.e., water, to a gas, i.e., water vapour, requires latent heat. This heat is extracted from the water, resulting in a temperature decrease. Together with the heat evacuation, also mass leaves the system under the form of water vapour. In an industrial setting, this physical phenomenon is exploited by spraying warm water in a cooling tower, where a counter airflow is induced by fans to maximise the air–water interaction. As a result, the water falling down in the basin underneath has dropped in temperature and can be recirculated through the process. For a more detailed description of an induced draft evaporative cooling system, we refer to [132]. The models created in this work are based on the design and verified by the data from an industrial cooling system as available at a chemical industrial site of INEOS in Belgium. The system details and parameters are given in § 4.2.2.1.

4.2.2.1 INEOS Cooling System

Figure 4.2 is a simplified graphical representation of the existing system at a chemical industrial site of INEOS in Belgium. Cooling water is circulated by use of induction motor driven pumps P1 and P2. The water flows through the Heat EXchangers (HEX) evacuating the heat from the production process. There are two cells in the cooling tower, each with a fan (F1 and F2) driven by a Dahlander motor, i.e., a two-speed motor. One single water basin is available for both cells and has a capacity of 900 m^3.

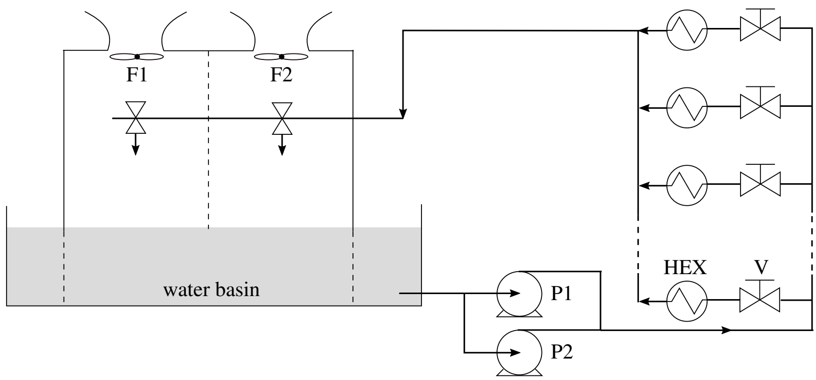

Figure 4.2: Simplified graphical representation of an induced draft evaporative cooling system.

The cooling system is designed for a water flow rate $\dot{m}_\mathrm{w}$ of 950 kg/s with a process water temperature T_p of 36°C and a range of 9°C while the wet bulb temperature is 22°C [133]. The heat to be evacuated, i.e., process heat Q_P, at these design parameters is thus 35.79 MW according to (4.1) with a basin water temperature T_b of 27°C and the correct specific heat capacity of water c_w. These given process heat to be evacuated is a theoretical design value and does not necessarily represent the actual heat which is dissipated, which varies over time.

$$Q_\mathrm{P} = \dot{m}_\mathrm{w}\, c_\mathrm{w}\, (T_\mathrm{p} - T_\mathrm{b}) \tag{4.1}$$

Both cooling tower cells are identical and feature a 12-blade fan with a diameter of 6.1m and a cell size of 11m by 11m [133]. One cooling water pump, P1, is active in normal operation, delivering a flow close to the designed water flow rate of 950 kg/s. P2 is used as a backup pump with a nominal flow rate of 639 kg/s. Multiple heat exchangers are installed throughout the industrial site, which can be controlled by valves (V) at the upstream side. In this work, the focus lies on the cooling tower side of the cooling network, therefore a single heat source for the process heat is assumed and the individual heat exchangers are out of scope.

The Dahlander motors used to drive the cooling tower fans have a rated nominal power of 110 kW when operating at high speed and 25 kW when operating at low speed, with the rated speeds being 1500 rpm and 750 rpm respectively. The motor efficiencies are given in the datasheet [133] for three motor load points per speed, as shown in Figure 4.3.

As discussed in § 3.2.2.1, the availability of dedicated power consumption measurements on industrial sites is often limited to site level or the largest individual machines. Indeed, only a state monitoring is present for the cooling tower fans, logging the fan speed setting. As the actual power consumption of the Dahlander motor is representative for the induced air by the fan, a dedicated mobile power monitoring device is used. During the different operational modes of the fans, i.e., low speed and high speed, the electric power consumption was monitored. A power level of 89.73 kW and 20.50 kW is obtained in high speed and low speed respectively. The available state logging of the fans can now be used as substitute for a power monitoring, assuming the power consumption maintain stable over time. The latter can be assumed as long as the pitch angle of the blades remains unchanged, as it being the largest influencing factor. Considering the identical setup of both fans, i.e., identical cooling tower cells and pitch angles, these power levels are also valid for fan F2. By interpolating between the two given motor load points of 75% and 100% nominal power in the datasheet, efficiency values of 0.946 and 0.924 are obtained for the high speed and low speed modes respectively. In Figure 4.3, these efficiencies are shown in red. The Dahlander motor is connected to the fan by means of a gearbox with a ratio of 11.6 to 1, resulting in fan speeds of 129 rpm and 64 rpm in high speed and low speed modes respectively. No efficiency is given for the gearbox.

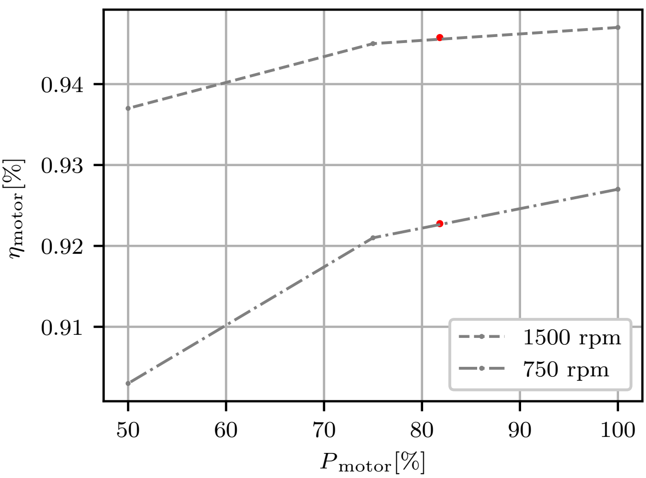

Figure 4.3: Efficiencies of the Dahlander motors driving the fans. The working point is indicated with a red dot.

The cooling system is controlled by skilled process operators, switching the fans in function of the water basin temperature. In practice, as the fan control is not automated, the fans are switched infrequently. A summer and winter regime is applied, where the fans are both switched on to high setting or one fan is switched on to high setting and the other is switched off respectively. Only in the case of process upsets or extreme weather conditions, i.e., when the cooling water temperature is expected to exceed the safety boundaries (T_{max}, T_{min}), the fans are controlled. A very stable water flow rate is observed as no changes are made to the valves or pumps during operation. The cooling water system is thus operated with fixed operational conditions, with limited control of the fans, resulting in a stable process operation but fluctuating cooling water temperature.

A SCADA system is used on the INEOS industrial site to collect and organise all the data from various systems. Available measurements on the cooling system are given in Table 4.1. The data have a logging periodicity of 15 minutes. The logged states of the cooling tower fans, S_{f1} and S_{f2}, are *off*, *low speed* or *high speed*. The water basin temperature T_{b} is measured at a medium height of the basin below the cooling towers, while the process water temperature T_{p} is measured at the inlet of the spray nozzles in the cooling towers. An on-site ambient temperature measurement T_{a} is available as well. The total water flow rate in the complete cooling network $\dot{V}_{\mathrm{w}}$ is measured at the pressure side of the pump. The pumps have a dedicated electric current logging, I_{p1} and I_{p2}, which is mainly used by the process operators to check the functioning and possible overloading. Obtained data from the SCADA system is preprocessed before being used. Some data are noisy as they contain raw values from the onsite sensors. Corrupt records, due to faulty sensors, and outliers are removed. In total, 32 617 rows of data are retained.

Table 4.1: Available data on the INEOS industrial site.

Symbol	**Description**	**Unit**
S_{f1}	State of cooling tower fan F1	speed setting
S_{f2}	State of cooling tower fan F2	speed setting
T_{b}	Water basin temperature	°C
T_{p}	Process water temperature	°C
T_{a}	Dry bulb ambient air temperature	°C
$\dot{V}_{\mathrm{w}}$	Water flow rate of circulated process water	m^3/h
$\dot{V}_{\mathrm{add}}$	Water flow rate of fresh water added to the basin	m^3/h
I_{p1}	Electric current of pump P1	A
I_{p2}	Electric current of pump P2	A

4.2.3 Cooling Tower Modelling

The goal of the developed forced draft evaporative cooling tower model is to simulate the water basin temperature based on the change in fan state settings, taking into account all other influencing parameters and process specificities. As result, the thermal inertia of the cooling system can be defined which, together with the operational constraints, can be used to assess the electrical flexibility options for the cooling tower fans. These operational constraints are mainly the process water temperature boundaries, as discussed in § 4.2.1. It should thus be clear that the main goal of this research is to develop a model which is able to accurately simulate the water basin temperature based on a fan switching strategy, preferably limiting the needed inputs to the commonly available process data on industrial sites as given in Table 4.1. A black box and white box modelling approach is considered, evaluating both accuracy and complexity regarding this final goal. Other modelling approaches, such as Advanced Process Control (APC) where the system could be parametrised by means of step-tests during the operation of the system have not been investigated in this work.

4.2.3.1 Black Box Modelling Approach

Black box modelling is useful when the first objective is to fit the data and identify the dynamics of the system regardless of particular differential equations and mathematical structures of the model. In this way, the response of the model to input changes can be evaluated. Black box models can be constructed making use of system identification techniques, e.g., Artificial Neural Networks (ANN) or an Adaptive Neuro-Fuzzy Interference System (ANFIS). The method is also referred to as a soft computing technique due to the lower engineering effort compared to white box modelling [134].

In [135] a multi-model method for assessing the performance of a cooling tower based on Local Model Networks (LMN) is proposed. To structure the data into groups where linear models can be applied, the Fuzzy C-Means (FCM) clustering technique is used based on Lloyd's algorithm [136]. An algorithm is used to integrate the FCM into the LMN, so to automatically optimise the amount of created clusters [136]. A method to assess the operating performance of a cooling system is proposed in [137]. The studied cooling system is made up with absorption, water-cooled and air-cooled chillers of which the primary sides are connected to a cooling tower. The followed methodology as described in [137] is to optimise the output of the ANFIS-based FCM or Fuzzy Subtractive Clustering (FSC) with Accelerated Particle Swarm Optimisation (APSO).

The development of a black box model requires the availability of data to train the model, implying that the system needs to be fully operational for some time and that data are collected. The developed model is only valid within the range of the inputs and outputs of the used training dataset. As an induced draft evaporative cooling tower is subject to weather influences and seasonality, the model should thus be developed using a dataset covering the complete spectrum, i.e., including very low and very high temperatures. Indeed, to develop the black box model in this work, a dataset spanning a complete year is used, with ambient temperature extremes of -5.84 °C and 34.6 °C.

The developed black box model is limited in use to the specific cooling system at the INEOS industrial site, from which data it is constructed. Evaluating the electrical flexibility potential of other forced draft evaporative cooling systems would require a complete new model to be developed. Adaptations to the existing system at the INEOS industrial site, e.g., the addition of a cooling tower cell or the change of the pitch angle of the fans, would also require a new model to be trained. In the latter case, the system would also need to run for a certain amount of time with the new configuration to collect enough data to train a new model.

To implement the black box modelling approach, it was decided to create an Adaptive Neuro-Fuzzy Interference System (ANFIS) model. While the ANFIS technique was already developed in 1993 as described in [138], only quite recently the technique was applied on cooling systems [134, 135, 137]. As the goal of the developed black box model is to simulate the water basin temperature in a practical way and in an industrial setting, the input parameters are limited to the readily available information on the INEOS industrial site. This approach yields a total of five input parameters, being S_{f1}, S_{f2}, T_{a}, $\dot{V}_{\mathrm{add}}$, and I_{p1}, and one output parameter being T_{b}. Details on these inputs and output can be found in Table 4.1. The electric current of pump P2, I_{p2}, could also be included, but is here neglected as the pump was not active during the considered time period. The water flow rate $\dot{V}_{\mathrm{w}}$ is correlated to I_{p1} and is therefore not maintained as an input parameter.

The ANFIS technique is based on the training of an Artificial Neural Network (ANN) with an interference system based on fuzzy rules. The INEOS dataset is split into a non-overlapping training and testing dataset with a commonly used size of 70% and 30% respectively. The random division ensures that the seasonality of the data is not reflected in either only the training or testing dataset. More extensive data pre-processing is done before modelling, using a min-max normalisation on all five inputs, as there are large differences in value ranges. This prevents a bias from the inputs with larger values.

The Fuzzy C-Means (FCM) method is used to generate a Sugeno type initial Fuzzy Interference System (iFIS) from the given training data. The used criteria of 0.5 for the radii and inclusion of the outer values for both the inputs and output yields an iFIS with five clusters, five rules and five Membership Functions (MFs). The iFIS is now used to train the model so to tune the parameters. A hybrid learning algorithm combining the back-propagation and least-squares gradient descent methods is used. Figure 4.4 gives a schematic representation of the used methodology. The testing dataset is used to verify that the number of training cycles, i.e., epochs, is chosen correctly to prevent the possible over-training of the network, which would result in overfitting. In Figure 4.5, it can be seen that the optimal number of epochs for the generated cooling tower FIS is 232, resulting in a Root Mean Square Error (RMSE) of the testing data of 0.879.

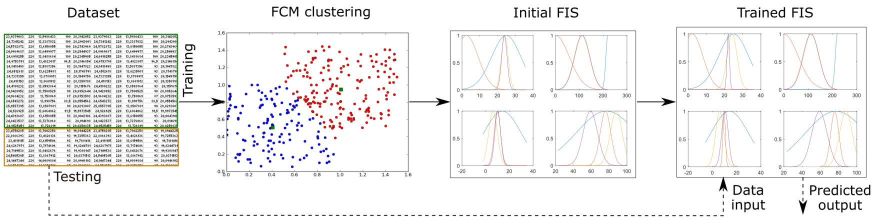

Figure 4.4: Structure of used ANFIS modelling methodology.

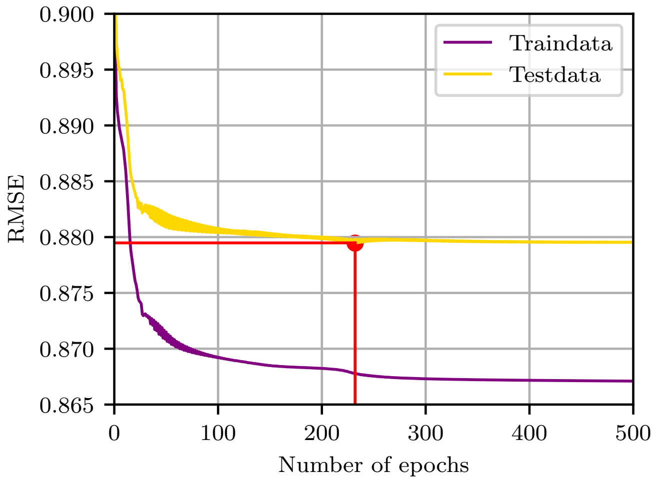

Figure 4.5: The optimal number of training epochs is 232, resulting in an RMSE of the testing data of 0.879.

This RMSE is based on the testing data, i.e., a random 30% of the total dataset, containing data points for all system states and possible transients between those states. As the purpose of the model is to define the change in water basin temperature following a fan switching, detail is given to these water basin temperature responses. A total of 13 fan state changes are available in the used dataset. Figure 4.6 shows one of the water basin temperature responses, during a period of 6 hours starting from the fan state change. The RMSE for the water basin temperature during this specific fan state change is 3.441 averaged over the first hour and 2.039 averaged over the first 6 h, and is notably higher than the RMSE of the testing data. It can also be visually verified that the immediate water basin temperature response of the black box model simulation shows a large error.

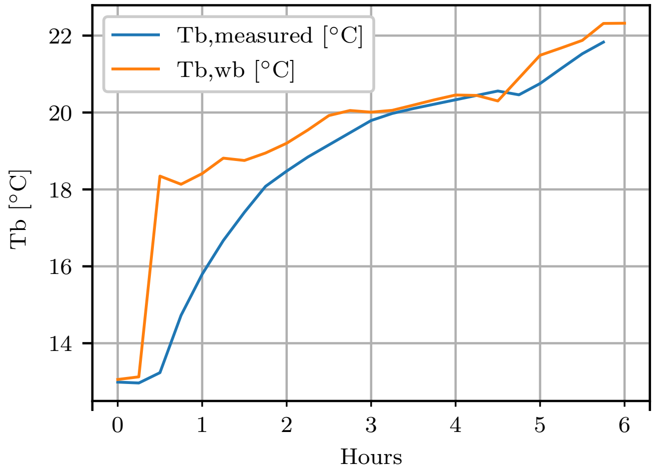

Figure 4.6: Water basin temperature response for a fan state change, both actual data as simulated by use of the black box model.

To verify this observed behaviour, the black box model was used to simulate all 13 temperature transients due to fan state changes in the dataset. Figure 4.7 shows a box-plot, for both the first hour and first 6 h after the fan state change. Average RMSEs of 2.895 and 1.473 were obtained, respectively.

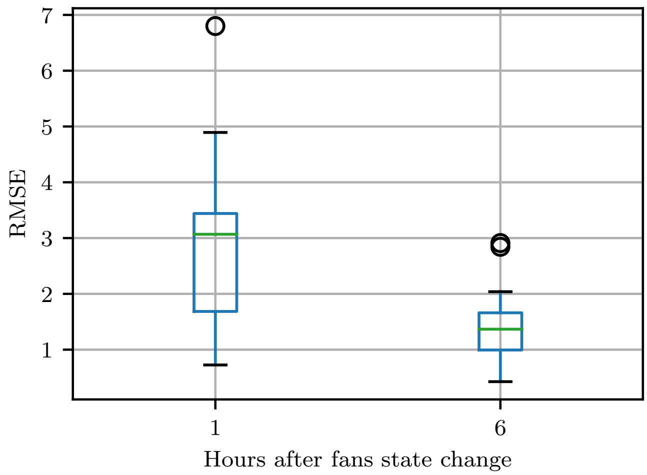

Figure 4.7: Box-plot of the RMSE of the water basin temperature responses for the black box model, considered after one hour and 6 hours.

This analysis shows that the black box model is well trained to simulate the water basin temperature in general, with an RMSE of 0.879, but it cannot simulate the temperature transients due to fan state changes with the same accuracy. The reason for this might be that, even though the model is trained with a large dataset (22,832 rows), only 13 fan state changes are included. Indeed the fans of the cooling system of the industrial site are switched infrequently. Increasing the accuracy of the black box model on this particular aspect could be done by training the model with a dataset containing more fan state changes. In practice, this means the industrial sites cooling system operation should be adapted to obtain these data. This can be seen as a major drawback in using the black box method.

4.2.3.2 White Box Modelling Approach

The development of an induced draft evaporative cooling tower model using a white box modelling approach is well described in literature. Already in 1925, Merkel [139] pioneered in developing a thermal evaluation model for a cooling tower. Several assumptions are taken for granted in this theory, e.g., the air leaving the cooling tower is assumed to be saturated with water vapour, the reduction of water flow rate of evaporation is neglected and the Lewis factor (Le_{f}), relating the relative rates of heat and mass transfer, is considered to be 1. In the early 1970s, Poppe and Rogener [140] developed the Poppe model, not taking the simplified assumptions made by Merkel for granted. Later, in 1989, the Number of Transfer Units (NTU) method on counterflow and crossflow cooling towers was applied, resulting in a simplified solution procedure [141]. The NTU method, also referred to as effectiveness-NTU or e-NTU is based on defining the maximum possible heat transfer. Scientific papers dealing with cooling towers often refer to one of the previously mentioned methods. In [142] a cooling tower performance evaluation between the different methods is made, concluding that if only the outlet water temperature is of interest, i.e., the water basin temperature, the less accurate Merkel and NTU approaches can be used. In this case, all the models predict practically identical water outlet temperatures [142]. In [132] the dynamic modelling of an induced draft cooling tower including the heat exchangers, pumps and fans is investigated. Some initial assumptions regarding the cooling tower model are made. Two important assumptions are that the air leaving the cooling tower is saturated with water, i.e., the air has a relative humidity of 100%, and that the total mass of the water in the basin has an equal temperature, i.e., that the heat is evenly distributed.

The development of a white box model requires a complete knowledge of the mathematical equations and system parameters describing the cooling process. As the only needed output parameter of the developed model is the water basin temperature, some assumptions can be made identical to the Merkel and NTU methods [142]. The used assumptions are listed here.

1. The air leaving the cooling tower is saturated with water vapour, i.e., $\mathrm{RH_l}$ = 100%.
2. The temperature of the air leaving the cooling tower, $T_{\mathrm{a,e}}$ is equal to the sum of the water basin temperature T_{p} and half of the design range.
3. The process heat Q_{p} is considered an input parameter and is defined by Equation (4.1).
4. The total volume of water in the basin V_{w} has an equal temperature.
5. The total volume of water in the basin is considered to be constant, as water lost by evaporation is complemented by newly added water. The temperature of the newly added water is assumed to not influence the water basin temperature.
6. The Lewis factor Le_{f} is considered to be 1.

The white box model is implemented in Python 3 in a Jupyter Notebook environment. The Python Data Analysis Library (Pandas), NumPy and Matplotlib libraries were used for data handling, computation and visualisation. All required data were extracted from the SCADA system at the industrial site, with the exception of the relative humidity ($\mathrm{RH_e}$) and ambient air pressure (P_{a}). $\mathrm{RH_e}$ and P_{a} historical data were obtained from [143] with an interval of 30 min. Data from the SCADA system have an interval of 15 min. A simulation time step of 15 min was used.

To implement the white box modelling method, thermodynamic equations are used to model the working of the cooling tower, based on the laws of heat and mass conservation. The used model parameters and abbreviations are shown in Table 4.2, as well as the values for constants.

The enthalpy of the entering $H_{\mathrm{a,e}}$ and exiting air $H_{\mathrm{a,l}}$, together with the airflow through the cooling tower $\dot{m}_{\mathrm{a}}$, define the cooling capacity Q_{t}. Including the process heat Q_{P} and the total volume of cooling water V_{w} yields the increment or decrement of the cooling water temperature $\dot{T}_{\mathrm{b}}$. The enthalpy of the air is calculated using empirical formulas according to the method presented in [144], with the air temperature T_{a}, water vapour saturation pressure P_{s}, ambient air pressure P_{a} and relative humidity RH as input parameters. First, the water vapour saturation pressure is calculated using the revised Arden Buck Equation (4.2) or (4.3), for positive and negative dry bulb temperatures, respectively [145]. Next, the humidity ratio w is computed by (4.4). The enthalpy of the moist air H_{a} is then found by (4.5).

$$P_{\mathrm{s}}(T_{\mathrm{a}}) = 0.61121 \exp\left(\left(18.678 - \frac{T_{\mathrm{a}}}{234.5}\right)\left(\frac{T_{\mathrm{a}}}{257.14 + T_{\mathrm{a}}}\right)\right), \text{for } T > 0°\mathrm{C} \tag{4.2}$$

$$P_\mathrm{s}(T_\mathrm{a}) = 0.61115 \exp\left(\left(23.06 - \frac{T_\mathrm{a}}{333.7}\right)\left(\frac{T_\mathrm{a}}{279.82 + T_\mathrm{a}}\right)\right), \text{for } T < 0°\mathrm{C} \tag{4.3}$$

$$w(P_\mathrm{s}, P_\mathrm{a}, \mathrm{RH}) = \gamma \, \frac{\mathrm{RH}\, P_\mathrm{s}(T_\mathrm{a})}{P_\mathrm{a} - \mathrm{RH}\, P_\mathrm{s}(T_\mathrm{a})} \tag{4.4}$$

$$H_\mathrm{a} = C_\mathrm{p,da}\, T_\mathrm{a} + w(P_\mathrm{s}, P_\mathrm{a}, \mathrm{RH})\,(h_\mathrm{vap} + C_\mathrm{p,vap}\, T_\mathrm{a}) \tag{4.5}$$

The airflow through the cooling tower $\dot{m}_\mathrm{a}$ is related to the electric power supplied to the cooling tower fans P_f [135]. The relation between the supplied electric power and the generated airflow is given by (4.6) which was proposed in [146]. Rewriting the formula to obtain the airflow results in (4.7). Needed parameters are the air density ρ_a, frontal tower area A_fr, fan casing area A_fan, fan efficiency η_fan, motor efficiency η_motor and eliminator coefficient K_el.

$$P_\mathrm{f} = \frac{\dot{m}_\mathrm{a}^3 \left(6.5 + K_\mathrm{el} + 2\frac{A_\mathrm{fr}^2}{A_\mathrm{fan}^2}\right)}{2\,\rho_\mathrm{a}\, A_\mathrm{fr}^2\, \eta_\mathrm{fan}\, \eta_\mathrm{motor}} \tag{4.6}$$

$$\dot{m}_\mathrm{a} = \sqrt[3]{\frac{2\, P_\mathrm{f}\, \rho_\mathrm{a}\, A_\mathrm{fr}^2\, \eta_\mathrm{fan}\, \eta_\mathrm{motor}}{6.5 + K_\mathrm{el} + 2\frac{A_\mathrm{fr}^2}{A_\mathrm{fan}^2}}} \tag{4.7}$$

The fan efficiency can be determined by using (4.8), for which the total pressure drop in the cooling tower δp_t and the specific fan power (SFP) are required. The SFP is defined by (4.9) and the δp_t by (4.10). The total pressure drop in the cooling tower is defined by the pressure drop over the fill and the miscellaneous pressure drop, given by (4.11) [147].

$$\eta_\mathrm{fan} = \frac{\delta p_\mathrm{t}}{SFP} \tag{4.8}$$

$$\mathrm{SFP} = \frac{P_\mathrm{f,md}}{\dot{m}_\mathrm{a,d}} \tag{4.9}$$

$$\delta p_\mathrm{t} = 1.667\,(\delta p_\mathrm{fl} + \delta p_\mathrm{misc}) \tag{4.10}$$

$$\delta p_\mathrm{misc} = 6.5\, \frac{\dot{m}_\mathrm{a,d}^2}{2\,\rho_\mathrm{a}\, A_\mathrm{fr}^2} \tag{4.11}$$

The value for the pressure drop over the fill is 107.1 Pa, as read from the chart of the manufacturer [148]. When using the above formulas with the values in Table 4.2 and for operation in high speed mode, a fan efficiency η_fan of 0.558 is

Table 4.2: Model parameters.

Symbol	Description	Unit	Value
A_{fan}	Fan casing area	m^2	29.19
A_{fr}	Tower frontal area	m^2	121
A_{s}	Surface area	m^2	
$c_{\mathrm{p,da}}$	Specific heat capacity of dry air	$kJ/kg \cdot K$	1.006
$c_{\mathrm{p,vap}}$	Specific heat capacity of water vapour	$kJ/kg \cdot K$	
c_{w}	Specific heat capacity of water	$kJ/kg \cdot K$	
G	Heat conductance	$W/m^2 \cdot K$	
$H_{\mathrm{a,e}}$	Entering air enthalpy	$kJ/kg \cdot K$	
$H_{\mathrm{a,l}}$	Leaving air enthalpy	$kJ/kg \cdot K$	
h_{vap}	Evaporation heat of water	kJ/kg	2500
K_{el}	Eliminator coefficient	/	1
$\dot{m}_{\mathrm{w}}$	Mass flow of water	kg/s	
$\dot{m}_{\mathrm{a}}$	Mass flow of air	kg/s	
$\dot{m}_{\mathrm{a,d}}$	Designed volume flow of air	m^3/s	329.24
P_{a}	Ambient air pressure	Pa	
P_{f}	Electric fan power	W	
$P_{\mathrm{f,md}}$	Designed mechanical shaft fan power	kW	95
P_{s}	Water vapour saturation pressure	Pa	
Q_{t}	Tower cooling capacity	W	
Q_{P}	Process heat	W	
RH_{e}	Relative humidity of the air entering the cooling tower	%	
RH_{l}	Relative humidity of the air leaving the cooling tower	%	100
SFP	Specific Fan Power	kPa	
T_{a}	Dry bulb air temperature	°C	
$T_{\mathrm{a,e}}$	Temperature of air entering the cooling tower	°C	
$T_{\mathrm{a,l}}$	Temperature of air leaving the cooling tower	°C	
$\dot{T}_{\mathrm{b}}$	Basin water temperature increment	°C/s	
T_{b}	Basin water temperature	°C	
T_{p}	Process water temperature	°C	
t_{pc}	Pre-cooling time	min	
V_{w}	Water volume	m^3	900
w	Humidity ratio	kg_{water}/kg_{air}	
γ	Psychometric constant	kPa/°C	0.622
$\delta_{\mathrm{p,t}}$	Total pressure drop in the cooling tower	kPa	
$\delta\rho_{\mathrm{fl}}$	Fill pressure drop	Pa	107.1
$\delta\rho_{\mathrm{misc}}$	Miscellaneous pressure drop	Pa	
ρ_{a}	Air density	kg/m^3	
ρ_{w}	Water density	kg/m^3	
η_{fan}	Fan efficiency	%	
η_{motor}	Motor efficiency	%	see § 4.2.2.1
η_{t}	Total efficiency	%	
τ	Time constant	s	

obtained. Note that this is the efficiency for the fan, starting from the mechanical shaft power. Including the motor efficiency η_{motor} of 0.946 for the high speed mode, a total efficiency η_{t} of 0.527 is obtained. This total efficiency may be low, considering the AMCA Standard 205 [149] with a threshold of 65%. Note that the cooling system at the INEOS industrial site has been commissioned in 1995 and the AMCA Standard 205 has been issued in 2011, hence the result of a lower total efficiency.

Using (4.5) with both the entering and leaving air parameters combined with (4.7), the cooling capacity of the tower is obtained by using (4.12). The basin temperature change $\dot{T}_{\mathrm{b}}$ is found by using (4.13). The water basin temperature at time t is found by summing the temperature at $t - \delta t$ with the increment or decrement in temperature during δt, calculated with (4.14).

$$Q_{\mathrm{t}} = \dot{m}_{\mathrm{a}} \left(H_{\mathrm{a,e}} - H_{\mathrm{a,l}}\right) \tag{4.12}$$

$$\dot{T}_{\mathrm{b}} = \frac{Q_{\mathrm{p}} - Q_{\mathrm{t}}}{c_{\mathrm{w}}\, V_{\mathrm{w}}\, \rho_{\mathrm{w}}} \tag{4.13}$$

$$T_{\mathrm{b}}(t) = T_{\mathrm{b}}(t - \delta t) + \dot{T}_{\mathrm{b}}\, \delta t \tag{4.14}$$

Figure 4.8 shows the water basin temperature response of both the black box model ($T_{\mathrm{b,bb}}$) and white box model ($T_{\mathrm{b,wb}}$). The RMSE for the water basin temperature response of the white box model results in 0.256 for the first hour and 0.178 for the first 6 hours. This specific water basin temperature response is visualised to highlight the difference in accuracy between the white box model and black box model. To verify the observed behaviour, i.e., the white box model is more accurate in simulating water basin temperature responses to fan switches, all 13 fan switches were simulated and visualised. Figure 4.9 shows a box-plot for both the first hour and first 6 hours after the fan state change. Average RMSEs of 1.513 and 0.998 were obtained for the first hour and first 6 hours respectively.

4.2.3.3 Model Comparison

In § 4.2.3.1 and 4.2.3.2, both developed models are described and a first analysis considering the water basin temperature response to fan switches has been analysed. Here a complete fourteen-day period is envisaged during which both models are used to simulate the water basin temperature T_{b}. At the start of the period, the measured basin temperature was set as starting point for the simulation. From then on forward, the basin temperature was only defined by the model's calculated $\dot{T}_{\mathrm{b}}$ as no synchronisation with measured data was executed. During the windowed time period, three different cooling system states were used. From the start of the simulation until day 3 at 09:15 one fan was operated at high speed. Next, as the

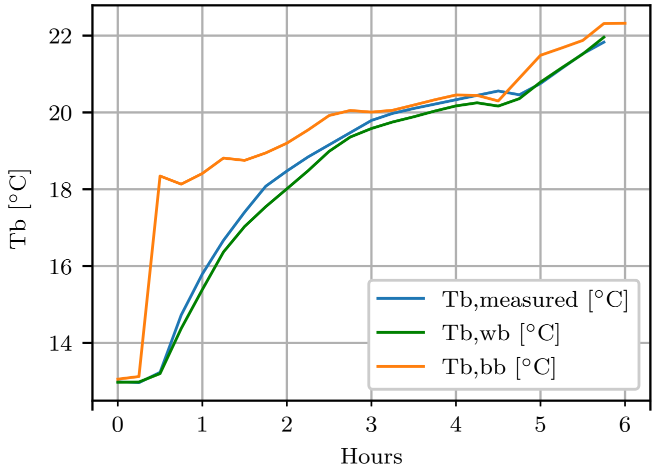

Figure 4.8: Water basin temperature response for a fan state change, actual data and simulated by use of the black box model and white box model.

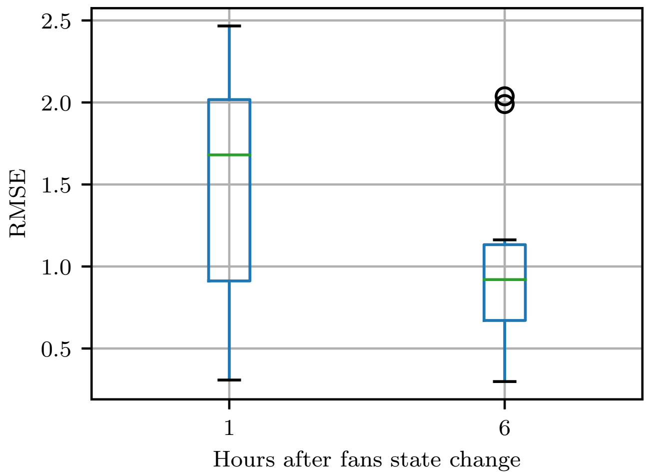

Figure 4.9: Box-plot of the RMSE of the water basin temperature responses for the white box model, considered after one hour and 6 hours.

Table 4.3: Model accuracy comparison.

Model	Description	RMSE
White box	fourteen-day period	0.445
Black box	fourteen-day period	0.570
White box	6 h after fan switch	0.998
Black box	6 h after fan switch	1.473
White box	1 h after fan switch	1.513
Black box	1 h after fan switch	2.895

basin temperature was lower than necessary for the process, the active fan was shut down. The cooling system was now operating without active fans. On day 12 at 16:00, both fans were activated to run at high speed, resulting in a water basin temperature drop.

Figure 4.10 shows a time series plot of both the measured and simulated water basin temperatures $T_{\mathrm{b,wb}}$ and $T_{\mathrm{b,bb}}$ for the white box and black box modelling methods respectively. For both models, the RMSE was calculated for the fourteen-day period, resulting in 0.445 and 0.570 for the white box and black box models respectively. Table 4.3 gives an overview of the obtained RMSEs for the different evaluated timings.

The engineering effort for both methods is different. The white box method requires quite extensive research towards the physics of evaporative cooling and investigation of the particular industrial cooling system parameters. For the black box method, the MATLAB ANFIS toolbox is used with the dataset containing the five inputs and one output. Very little knowledge of the system is needed and no parameters, dimensions or efficiencies of the particular industrial system are required. Another important difference is the applicability of both constructed models. While the black box model is system specific, the white box model is generic. Inputting the parameters of a different cooling system to the white box model would result in a direct usable simulation tool. Applying the black box model to another cooling system would require a new iteration of the training and testing, i.e., constructing a completely new model. It can be stated that both methods have their advantages and disadvantages and it should be carefully considered which approach to use, keeping in mind the desired applicability. As a final note, it should be stated that both models are developed with the idea of achieving an as high as possible accuracy while keeping the required data and information level as low as possible, to foster the easy implementation in an industrial setting. Accuracy of both models could be enhanced, but would result in a higher degree of complexity, dataset requirements and computing power.

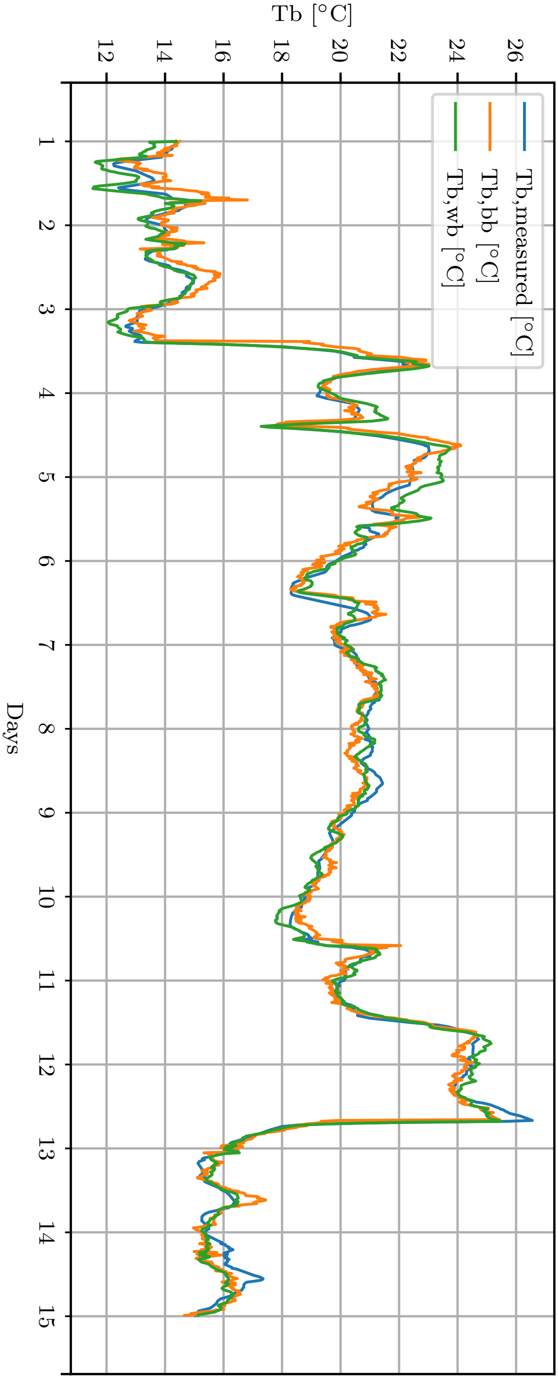

Figure 4.10: Time series plot of the measured and simulated basin temperature, for the white box model ($T_{b,wb}$) and the black box model ($T_{b,bb}$).

4.2.4 Use for Flexibility

Considering the final purpose of the developed models, i.e., defining the electrical flexibility encompassed in the forced draft evaporative cooling tower system, this section covers the topics of thermal mass and pre-cooling. Altering the thermal mass of the system might be possible in the light of *design for flexibility* while pre-cooling might be a solution to increase the existing flexibility potential.

4.2.4.1 Thermal Mass

Both developed white box model and black box model are fitted with parameters and data from the forced draft evaporative cooling system as present at the INEOS industrial site. The black box model is limited in use to the existing system considering it is fitted for these specific parameters. For the generic white box model, this is not the case. When designing a new or adapting an existing cooling system, it might be interesting to take into account the electrical flexibility the system can offer, i.e., *design for flexibility*, as discussed in § 3.3.5. It is the thermal time constant of the system which defines the controllability of the fans, taking into account the limiting minimum and maximum temperatures should not be exceeded. The white box model can be used to simulate the impact of the total volume of water in the cooling circuit on the thermal time constant. The thermal time constant or time constant for the thermal response of the system τ is defined as the time required to change 63.2% of the total difference between the initial and final temperature when subjected to a step, i.e., a fan state change. In [150], the thermal time constant is defined by (4.15). The thermal time constant is proportional to the total heat storing mass in the system $\sum(m\, c_\mathrm{p})$ and inversely proportional to the heat conductance G.

$$\tau = \frac{\sum(m\, c_\mathrm{p})}{G} \tag{4.15}$$

According to (4.15) the thermal time constant can be enlarged by decreasing the heat conductance G or increasing the mass in the system $\sum(m\, c_\mathrm{p})$, i.e., the water volume. As the goal of the cooling system is to evacuate heat, decreasing the heat conductance is not desirable. The other possibility is to increase the mass of the system. Applying this on an induced draft evaporative cooling system, this translates into a larger basin and total volume of water.

Figure 4.11 shows the simulated water basin temperatures for different water volumes in the cooling system for a period of 14 hours. The blue curve is shown as reference with V_w = 900 m^3, i.e., the actual total volume of water in the basin at the INEOS industrial site. Simulations 1 to 6 assume a total volume of water V_w of 450 m^3, 1800 m^3, 3600 m^3, 5400 m^3, 7200 m^3 and 9000 m^3. In Table 4.4, the thermal time constants are given for each simulation. To define the thermal time constant, the initial conditions, i.e., the process heat and weather influences of the system at the initial simulation starting point were fixed for the complete duration of the simulation. This way, a steady state temperature could be reached to calculate the thermal time constant. An expected increase of the thermal time constant due to increase of the total volume of water in the cooling system is validated by the simulations.

$$\tau = \frac{\rho_w \, c_w \, V_w}{G \, A_s} \tag{4.16}$$

Table 4.4: Thermal time constants for the basin enlarging simulation.

	Sim 1	Sim 2	Sim 3	Sim 4	Sim 5	Sim 6
$V_w[m^3]$	450	1800	3600	5400	7200	9000
τ[min]	32	115	216	330	443	545

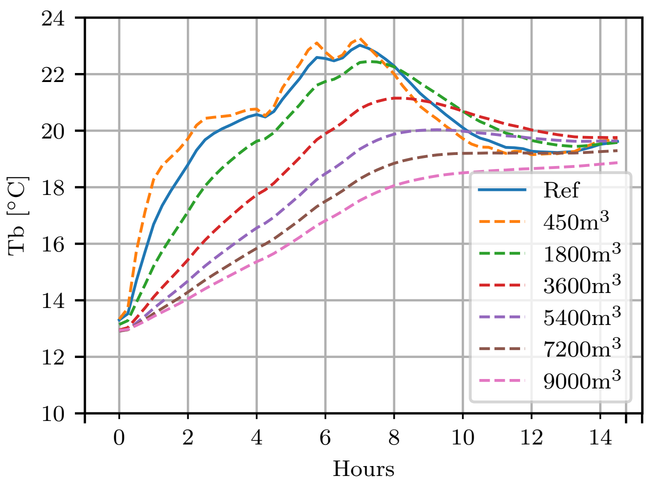

Figure 4.11: The effect of the total water volume on the thermal inertia.

4.2.4.2 Pre-Cooling

As discussed in § 4.2.1 and shown in Figure 4.1, often a temperature range is present for operating an induced draft evaporative cooling system on an industrial site. Setpoint temperatures of cooling systems as used on industrial sites can vary, as well as the temperature boundaries and hysteresis. A narrower allowed temperature hysteresis, being it due to operational or safety constraints, reduced the potential for the fans to be controlled flexibly. Often it is the maximum temperature T_{max} which is the limiting factor, as a higher temperature reduces efficiency of the production processes or creates a safety issue. To increase the period of possible fan control, i.e., especially reducing fan power, the concept of pre-cooling can be applied.

The idea of pre-cooling is straightforward, the temperature of a certain medium is lowered before a period of temperature increase. The uttermost used reason for applying pre-cooling in combination with a *switch off period* is electricity peak consumption avoidance and the associated cost savings while keeping the temperature within the preset boundaries [151–153]. In [154] pre-cooling is investigated for buildings. It is concluded that the pre-cooling period is independent from the temperature reduction, has a certain maximum duration and that the duration of the *switch off period* is dependent on the pre-cooling period [154].

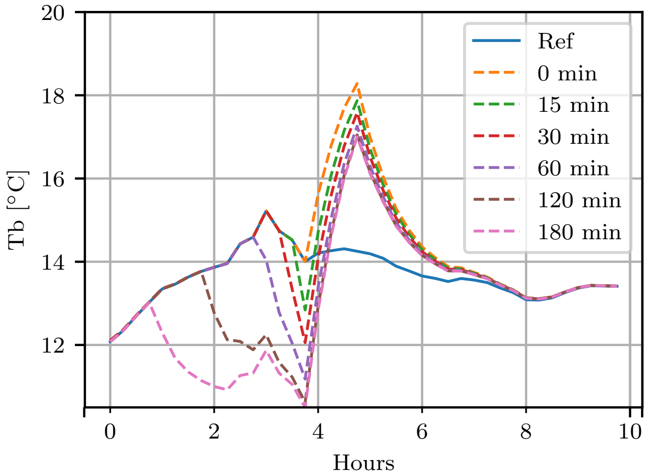

Figure 4.12: The effect of pre-cooling on the water basin temperature.

Figure 4.12 shows the water basin temperature for a period of 10 hours. The blue curve is shown as reference, where no fan state change occurs and one fan is active at high speed, i.e., $P_f = 89.73$ kW. A first simulation (noted on Figure 4.12 as *0 min*) shows the temperature curve in case the active fan is shutdown for one hour (from 03:45 to 04:45), after which it is switched back on, this without pre-cooling. To limit the resulting temperature spike from this first simulation, pre-cooling was applied in simulations 2 to 6, with durations of 15 minutes, 30 minutes, 1 hour, 2 hours and 3 hours, respectively. During pre-cooling, both fans are switched to high speed, i.e., the other fan which was not used is not switched on so that the total power P_{f} equals 179.46 kW. Table 4.5 shows the reached maximum temperatures for each simulation.

Table 4.5: Reached maximum temperatures for the pre-cooling simulations.

	Sim 1	Sim 2	Sim 3	Sim 4	Sim 5	Sim 6
t_{pc}[min]	0	15	30	60	120	180
T_{b}[°C]	18.28	17.87	17.58	17.26	17.05	17.01

The reached maximum temperatures show that the beneficial duration of the pre-cooling period is limited, as also given by [154]. Longer pre-cooling would only lead to extra power consumption without benefits towards maximum temperature. It can be concluded that, for this specific case, a pre-cooling time of 200% (2 hours of pre-cooling for a switch-off period of 1 hour) is considered the limited beneficial time. A temperature spike reduction of 1.23°C is obtained. Note that, while pre-cooling might be beneficial to elongate the duration of the switch-off period, fostering the electrical flexibility purpose of the cooling system, an increase of total energy consumption is observed.

4.2.5 Conclusions

In this case study two models for an induced draft evaporative cooling tower are developed, based on a black box and white box methodology. The cooling tower models are developed with the purpose of simulating the water basin temperature so to define the temperature response of the switching of the cooling tower fans. Combined with the temperature hysteresis as allowed for the specific cooling process, the electrical flexibility of a cooling system can be analysed by these models, focussed on the control of the cooling tower fans. A black box model, based on an Adaptive Neuro-Fuzzy Interference System is developed with a total of five input parameters and the water basin temperature as single output. A white box model is developed as well, based on the thermodynamic equations of an induced draft evaporative cooling system. Assumptions are made so to limit the needed input parameters to the available data as present on the INEOS industrial site. Both models are used to simulate a fourteen day period as well as a specific fan switching. By comparison of the RMSE, it was shown that the developed white box model is more accurate and therefore deemed superior over the ANFIS black box model. The most probable reason for the black box model to be less accurate, especially considered during fan state switches, are the limited switching events in the used dataset. This obstacle might be similar in case other modelling techniques such as APC might be used. To overcome this obstacle, several dedicated step-tests should be performed on the industrial cooling system during normal operation.

The white box model is used to define the impact of the total volume of water in a cooling system in relation to the thermal inertia, which is considered an important parameter considering the electrical flexibility potential of the cooling tower fans. The concept of pre-cooling is touched upon, with simulations showing that pre-cooling can be beneficial to limit the maximum reached temperature of the water basin in case of a fixed *switch off period*. For a specific case, it was shown that a maximum pre-cooling time of 200% is still beneficial, resulting in a temperature spike reduction of 1.23 [°C].

Considering the cooling systems flexibility potential, increasing the total water volume and applying the technique of pre-cooling can both be useful to lower the reached maximum temperatures and increase the timeframe in which the fans can be controlled without exceeding the limiting maximum temperature.

The main novel contribution in this case study is the development of tractable models which can be used to simulate fan control strategies and hereby assess the potential flexible operation of the cooling system. The models find an equilibrium between complexity and tractability, with input parameters limited to readily available data and information on industrial sites.

4.3 Hybrid Steam Production Setup Operation Based on Imbalance Market

4.3.1 Introduction

The electrification of processes in industry is discussed in § 3.3.5 to be having a large potential regarding decrease of greenhouse gas emissions and provision of electrical flexibility. One of the domains where the largest potential for near-future electrification lies is in the heating processes. Steam production is conventionally done by burning fossil fuels, mainly natural gas, in a dedicated natural gas boiler or CHP. An electrode boiler is an electricity driven alternative for such a gas-fired steam boiler. The start-up and control characteristics of an electrode steam boiler are suited to participate in the balancing market. This is proven by an estimate of 70MW of control power which is already being provided to the German balancing market by a single manufacturer of electrode boilers [116].

The idea of the operation of such an electrode boiler based on the imbalance price is given by the fact that the imbalance settlement system, as explained in § 2.4.2, comprises a bimodal distribution. A lower and higher price level characterises the system as used by Elia in Belgium. Hereby, an incentive is given to implicitly maintain the balance of the LFC area, which is even enlarged by the introduction of a parameter α, creating more extreme prices in case of large imbalances. It is shown by the CREG that the volatility of the imbalance price increased over the years 2015 and 2016, while at the same time the total activated energy of balancing ancillary services (reserves), decreased [155]. While the price volatility can be seen as a risk compensation in the market [156], it improves the conditions for electrical flexibility valorisation using implicit demand response.

As the imbalance price is only defined ex-post, this case study presents a prediction algorithm for the imbalance price based on market structure patterns in combination with close to real-time grid data. The predicted quarter-hour imbalance price is used as input for the electrode boiler control in a hybrid steam production setup. The prediction time horizon is thus very short. In [157], Salem et al. look into the forecasting on intra-hourly imbalances in the Norwegian system. They as well make use of a method which relies on historical imbalance and features related to date and time. This is a quite novel technique, other publications on this topic, such as [158] and [46], focus on time series prediction methods such as Seasonal Autoregressive Integrated Moving Average (SARIMA) models.

4.3.2 Prediction Strategy of the Imbalance Price

As discussed in § 2.4.2.2, the NRV is not fully unpredictable. The NRV does show temporal patterns, due to a market design discrepancy between the hourly wholesale energy markets and the quarter-hourly ISP. This discrepancy is exploited by encompassing it in a prediction strategy for the imbalance price.

It was decided, for this case study, to use the constructed averaged NRV day pattern in § 2.4.2.2, visualised in Figure 2.22, in combination with close to real-time data of the NRV as made available by Elia. On average, a delay δ, of 2 minutes is observed for the publication of this NRV data on the Elia website, which is also the value used here. The estimated NRV of the current quarter-hour, $\mathrm{NRV_{qh,e}}$, is defined as the average of 15 datapoints. Depending on the current time, T, part of the datapoints ($\mathrm{NRV_r}$) are obtained through the close-to-real-time datastream from Elia, part are taken from the predefined heatmap set ($\mathrm{NRV_p}$).

$$\mathrm{NRV_{qh,e}} = \sum_{0}^{t} \mathrm{NRV_r}(t) + \sum_{t}^{15} \mathrm{NRV_p}(t) \tag{4.17}$$

$$t = T - \delta \tag{4.18}$$

Figure 4.13 shows the timings. In Figure 4.13 the current time T=2, e.g. at 13h47, and no close-to-real-time data for the current quarter-hour is available, i.e., t=0. The $\mathrm{NRV_{qh,e}}$ is completely defined by the sum of the $\mathrm{NRV_p}$. In Figure 4.13b, T=8, e.g. at 13h53, and six close-to-real-time datapoints of the NRV of the current quarter-hour $\mathrm{NRV_r}$ are made available by Elia. $\mathrm{NRV_{qh,e}}$ is defined by the average of six $\mathrm{NRV_r}$ datapoints and the sum of nine $\mathrm{NRV_p}$ datapoints. At last, in Figure 4.13c, T=15, e.g., at 14h00 and thus the end of the quarter-hour. No more control opportunity is present as the quarter-hour has passed and $\mathrm{NRV_{qh,e}}$

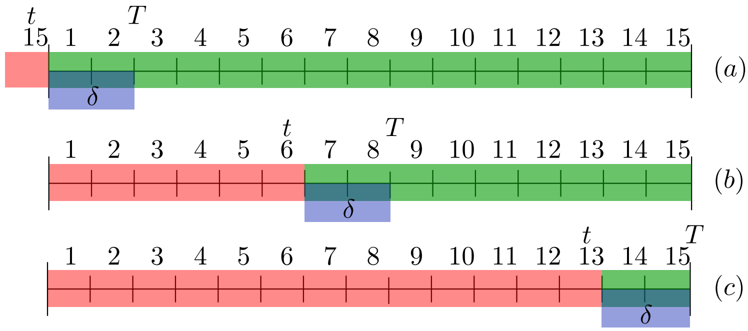

Figure 4.13: Representation of the data availability, with the close-to-real-time data of the current quarter-hour in red, the time delay δ in blue and the predefined heatmap values in green.

is defined by thirteen $\mathrm{NRV_r}$ datapoints and two $\mathrm{NRV_p}$ datapoints. Note that uncertainty about the actual averaged quarter-hourly NRV still exists at this point, as only thirteen $\mathrm{NRV_r}$ datapoints are available at the end of the quarter-hour.

Also, a simple average of the quarter-hourly NRV is calculated, $\mathrm{NRV_{qh,a}}$, based on the available datapoints of the current quarter-hour, $\mathrm{NRV_r}$. Here $\mathrm{NRV_{qh,a}}$ is defined by a variable length dataset of 1 to 13 datapoints. For $T < 2$, $\mathrm{NRV_{qh,a}}$ is set to zero. For $3 < T < 15$, $\mathrm{NRV_{qh,a}}$ is defined by 1 to 13 $\mathrm{NRV_r}$ datapoints respectively.

To benchmark, the optimum NRV value, $\mathrm{NRV_{qh_o}}$, is also defined and is set according to the validated quarter-hourly value as published ex-post by Elia. This value encompasses all possible corrections which needed to be applied to the close-to-real-time data and therefore represents a perfect prediction algorithm. Indeed, note that the data which are made available close-to-real-time by Elia are unvalidated and could be corrected afterwards if necessary.

4.3.3 Hybrid Steam Production Setup and Control

In this case study a theoretical hybrid steam production setup is considered as practical case to show the potential flexible usage of an electrode boiler on the imbalance market. Figure 4.14 shows a simplified representation of such a hybrid setup. As discussed in § 3.3.5, current common steam production practice in industry is to use fossil fuels in a dedicated gas fired boiler or a CHP. A fossil fuel, e.g., natural gas, is burned and the hot fumes are used to heat and evaporate water. This setup is highly flexible but is fossil-fuel based, causing a large CO_2 emission. An electrode boiler generates heat by applying a high voltage to a tank of water, using the water's resistance to induce an electric current. This technique only uses electricity and is therefore, depending on the origin of the electricity, considered less CO_2 intensive. The theoretical setup here is assumed to consist of a natural

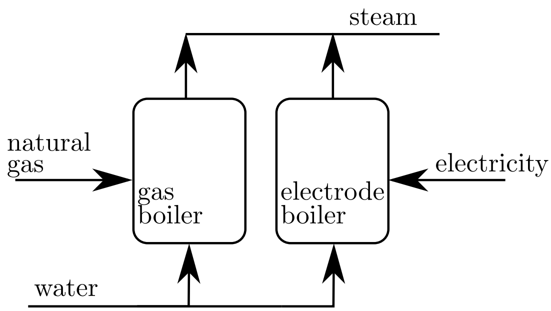

Figure 4.14: Simplified representation of a hybrid steam production setup with a natural gas boiler and an electrode boiler.

gas boiler and electrode boiler, each individually able to foresee the complete industrial site of the necessary steam production, with the produced steam injected into the industrial sites common steam header. This allows for the freedom to steer either boiler in its complete operating range, i.e., from zero output to nominal capacity. The full installed capacity of the electrode boiler is thus assumed to be available for flexible control, while maintaining the necessary steam production.

The dynamics of an electrode boiler are quite similar to the ones of a gas-fired boiler, with a warm ramp-up time of 30 seconds from zero output to full load. Assuming a linear ramp-up characteristic, a correction factor of 0.75 is taken into account for the electricity consumption of the boiler during the first minute of operation, considering a simulation time step of 1 minute. The ramp-down is assumed to be instantaneous, therefore no correction factor is taken into account.

The control strategy of the steam production setup is to keep the gas boiler as main steam producing unit, while the electrode boiler would assist in steam production during low imbalance prices. As no electricity consumption would be nominated for the operation of the electrode boiler, all of the consumed electricity is indeed to be invoiced via the imbalance settlement system. A pass-through contract between the energy supplier and the industrial site is then of course necessary to be able to be exposed to these imbalance prices and profit from this strategy. During these moments, the gas boiler would ramp down, maintaining the total steam demand. As discussed in § 4.3.2, an optimum $\mathrm{NRV_{qh,o}}$, simple average $\mathrm{NRV_{qh,a}}$ and heatmap estimation $\mathrm{NRV_{qh,e}}$ value for the quarter-hourly NRV is defined. For each of the $\mathrm{NRV_{qh}}$s, the imbalance price is looked up in the ARC table. This Available Regulation Capacity table gives an overview of the reserves which are available to Elia, with the marginal price for different levels of NRV, as discussed in more detail in § 2.4.2. As the table is published beforehand, this data is available during the envisioned real-time quarter hour. The imbalance price is defined based on the ARC value and the parameter α as defined by (2.1). The predicted imbalance price is used to steer the electrode boiler, i.e., if the predicted

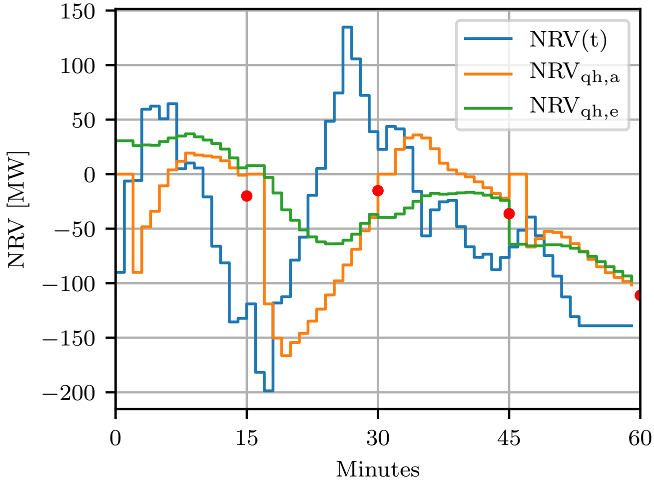

Figure 4.15: In blue the actual NRV values as communicated by Elia, in orange the calculated simple average $\mathrm{NRV}_{\mathrm{qh,a}}$ *and in green the calculated heatmap average* $\mathrm{NRV}_{\mathrm{qh,e}}$*. The red dots represent the actual validated average NRV for the past quarter-hour.*

imbalance price is below a certain threshold, the boiler's output is increased to full load, else the boiler is kept at lowest hot operating point.

4.3.4 Simulations & discussion

The presented NRV and subsequent imbalance price predictions are calculated for a complete year, using historical data as obtained from Elia [33]. By using these price predictions, the electrode boiler control is simulated.

Figure 4.15 shows the calculated $\mathrm{NRV}_{\mathrm{qh,a}}$ and $\mathrm{NRV}_{\mathrm{qh,e}}$ for a specific hour, i.e., four quarter-hours, during this simulation period. The actual NRV as communicated by Elia is shown in blue while the orange and green curve represent the calculated simple averaged $\mathrm{NRV}_{\mathrm{qh,a}}$ and the heatmap $\mathrm{NRV}_{\mathrm{qh,e}}$ values. Note that during the first two minutes of each quarter-hour $\mathrm{NRV}_{\mathrm{qh,a}}$ is zero, as no data is available for the current quarter-hour yet. During these first minutes, $\mathrm{NRV}_{\mathrm{qh,e}}$ is fully based on the daily averaged NRV heatmap, therefore already showing non-zero values. Also note that the $\mathrm{NRV}_{\mathrm{qh,a}}$ shows a more volatile profile while the $\mathrm{NRV}_{\mathrm{qh,e}}$ is shown to be more flattened. This is the result of the used data, as during the first minutes the $\mathrm{NRV}_{\mathrm{qh,a}}$ is defined as average of few datapoints, making it prone to volatility, while the $\mathrm{NRV}_{\mathrm{qh,e}}$ is always based on an average of fifteen datapoints.

The calculated NRVs as visualised in Figure 4.15 are then used to lookup the

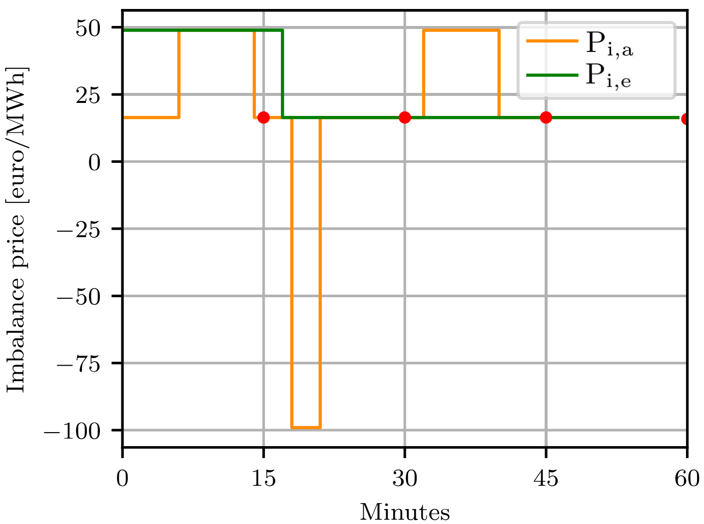

Figure 4.16: In orange the predicted imbalance prices based on the simple average $P_{\mathrm{i,a}}$, in green the heatmap predicted imbalance price $P_{\mathrm{i,e}}$. The red dots represent the actual imbalance price for the past quarter-hour.

imbalance price in the ARC table. Figure 4.16 shows the predicted imbalance price for both the heatmap estimation $P_{\mathrm{i,e}}$ and the simple average $P_{\mathrm{i,a}}$. Due to the more extreme predicted NRV with the simple average method, on minute 17, $\mathrm{NRV}_{\mathrm{qh,a}}$ drops below -100 MW and therefore $\mathrm{P}_{\mathrm{i,a}}$ also drops to a lower price level. This phenomenon is the result of the variable length dataset used to define $\mathrm{P}_{\mathrm{i,a}}$, e.g., as T = 3, only one datapoint is used, making the $\mathrm{NRV}_{\mathrm{qh,a}}$ susceptible to extreme NRV values at the beginning of the quarter-hour.

In Figure 4.17, the electrode boiler electricity consumption is shown, for a threshold imbalance price of 20 euro/MWh, i.e., the electrode boiler is ramped up from idle to nominal capacity in case the imbalance price is below the threshold price. The warm ramp-up time of the boiler translates into a $P_{\mathrm{boiler}} = 0.75\ P_{nom}$ for the first minute as can be seen at minute 17 for E_{a}. Since a discrete modelling, with a time step of 1 minute, is being used, this is visualised as step.

The described simulation is executed for the complete year 2018 and for different threshold imbalance prices. The result is shown in Figure 4.18. The top graph represents the number of hours the electrode boiler would have been operated, correlated to the threshold imbalance price which would be set. The boiler is assumed to be operating as soon as the predicted imbalance price drops below the set threshold price. A rising curve is seen, starting at a slightly negative imbalance price, ranging up to nearly 6000 hours of usage in case a threshold price of 100 euro/MWh would be set. The middle graph shows the averaged price which would

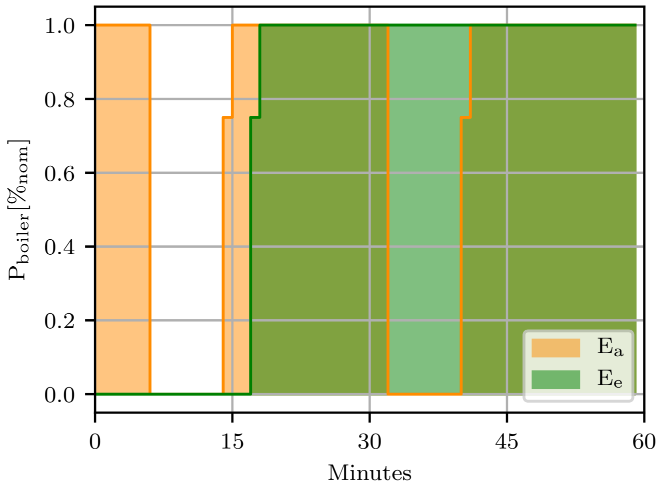

Figure 4.17: Boiler energy consumption with a threshold imbalance price of 20 euro/MWh, in orange for the simple average method, in green for the heatmap method.

be paid for electricity to operate the electrode boiler, again correlated to the set threshold price. Again rising curves are seen, as a higher set threshold price would also result in a higher averaged specific electricity cost. The bottom graph shows the number of times the electrode boiler is switched on, i.e., the load is increased from warm idling position to nominal capacity. Here concave curves are obtained, as the boiler is less switched in case of low or high threshold prices, while with medium threshold prices, a more frequent switching between the electrode boiler and gas boiler is seen.

As example, assume a threshold price of 40 euro/MWh to be set throughout the entire simulation period, i.e., 2018. The top graph shows both $t_{\mathrm{on,a}}$ and $t_{\mathrm{on,e}}$ to be higher than $t_{\mathrm{on,o}}$, suggesting that the boiler is operated more than optimally required. This can be explained due to the forecasting errors, which results in steering the boiler to full load, while in reality the validated imbalance price will be higher than the set threshold imbalance price. The green curve, i.e., $t_{\mathrm{on,e}}$, is showing a better performance than the orange curve, i.e., $t_{\mathrm{on,a}}$, hinting at a better accuracy of the heatmap method over the simple average method. Regarding the average electricity cost of operating the electrode boiler, the heatmap method shows a slightly better performance until threshold prices of 60 euro/MWh. For example, at a threshold price of 40 euro/MWh, the averaged paid electricity cost for the heatmap method, $P_{\mathrm{i,e}}$, equals 23.5 euro/MWh, while for the simple average method $P_{\mathrm{i,a}}$ equals to 24.5 euro/MWh. A significant gap is seen with the optimal scenario, where an average cost of 9.6 euro/MWh would be obtained. This average cost is the result of all periods during which the electrode boiler is operated, multiplied by the actual validated imbalance price and the boilers nominal power. It should be clear that there is thus still room for improvement of the prediction of the imbalance price and the steering of the electrode boiler. On the bottom graph, at a threshold price of 40 euro/MWh, the number of times the electrode boiler is switched on is significant with the simple average method (3451 times), while being only switched on 2738 times with the heatmap method. This can be explained by the increased volatility with the simple average method, as explained previously. Considering the optimal, i.e., crystal ball method, the number of switches would remain below 1000 for a single year for all threshold prices, for a total operating time which is very close to those of the other two methods. This suggests that longer periods of boiler operation or non-operation are to be strived at.

Note that a realistic price range to operate the electrode boiler, considering the hybrid system as discussed in § 4.3.3, is dependent on the gas price and CO_2 price. A price fork of 15 euro/MWh to 50 euro/MWh is considered viable, considering the prices of the past years. Therefore, the right half of Figure 4.18 is deemed to never be used to operate the electrode boiler.

4.3.5 Conclusions

In this case study, a novel method is developed to forecast the imbalance market price by exploiting the predictability of the NRV, combined with the availability of close-to-real-time data. The ability to predict the NRV is caused by the gradient effect, which is a result of the discrepancy between the DAM and the imbalance market timings as present in Belgium. A yearly averaged daily pattern is constructed, visualising this gradient effect. The forecasted NRV is combined with the available ARC table to predict the imbalance market price. The predicted price is then used to steer an electrode boiler in a hybrid setup, i.e., in combination with a natural gas boiler. A simulation of a complete year results in the ability to assess the performance of the proposed method, compared to an optimal crystal ball and a simple averaging method. The proposed novel methodology is shown to be more performant considering the averaged cost to operate the electrode boiler, as well as in the number of times the boiler is switched. Based on the benchmarking curve, it is clear that still improvements are possible.

Note that here only the electricity operational cost of the electrode boiler is taken into account. To create a business case, an inclusion of other costs such as the grid connections costs, CAPEX costs of the electrode boiler, maintenance costs due to switching, variable gas costs, etc. should be taken into account. The results here are also only valid in case a rigid imbalance price is considered, i.e., that the power consumption of the electrode boiler does not impact the ACE and possibly the imbalance price. This can be considered valid for an electrode boiler

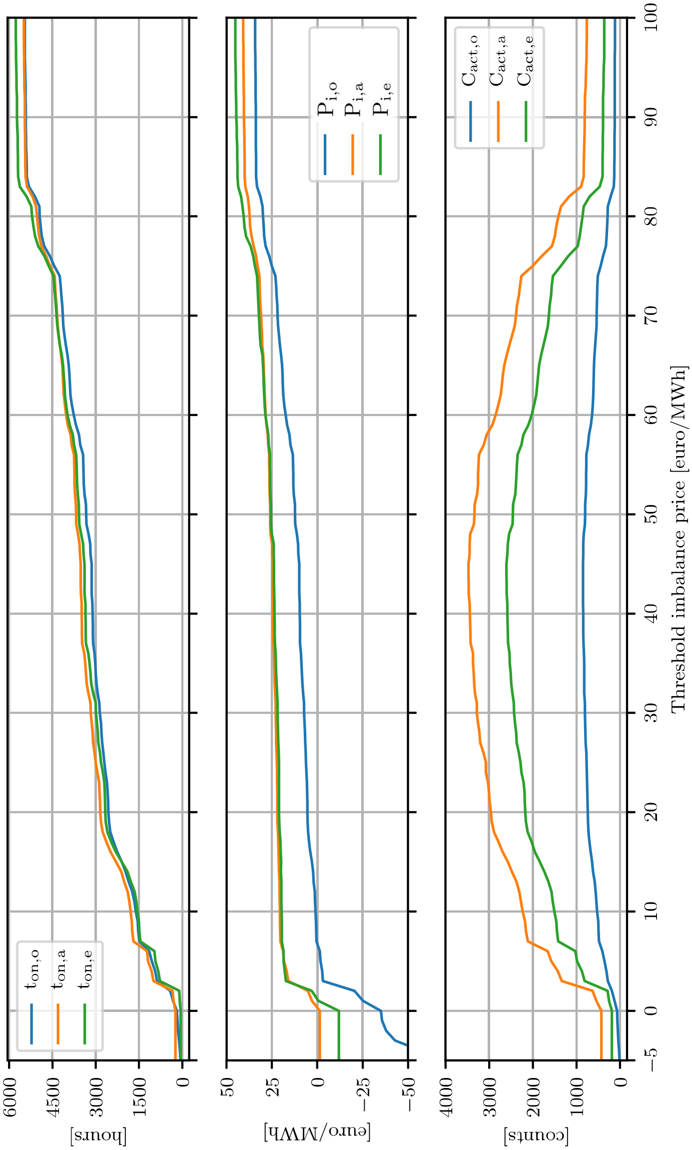

Figure 4.18: Results of a year simulation for different threshold imbalance prices. The top graph shows the number of hours the electrode boiler would be switched on, the middle graph shows the averaged paid imbalance price and the bottom graph shows the number of times the boiler would be switched on, this all for the optimum, simple average and heatmap method.

with limited nominal power compared to the LFC area. The potential impact of larger volumes on the imbalance price is discussed in more detail in § 2.4.2.3. As final conclusion it can be stated that the electrification of steam production in the industry might come with extra opportunities, such as the flexible control of these assets.

4.4 Optimisation of Chlor-Alkali Electrolysis Process Operation Considering DAM and FCR Market

4.4.1 Introduction

The chlor-alkali electrolysis process is one of the most electrical energy intensive processes in the chemical process industry. As discussed in § 3.3.3.1 the two main drivers for this process to consider valorisation of its electrical flexibility is its electro-intensiveness, i.e., the amount of electricity which is used per unit of produced product, and the inherent flexible controllability of the process, with direct impact on the electricity consumption. The latter is given by the power electronics used to control the current density as supplied to the different electrolysis cell rooms. Due to its electro-intensiveness, the chlor-alkali sector has always been a front runner in flexible process operation, with the restrained storage of chlorine and caustic soda [159] and a large energy-related Operating Expenditures (OPEX) as main drivers. Taking opportunities in the current energy and ancillary services market are therefore no exception.

This case study addresses the issue of cost-optimal process operation considering production under variable electricity prices and the supply of FCR towards the TSO. The inherent uncertainty considering future DAM prices and FCR remuneration is dealt with by using stochastic modelling. Provision of FCR with (industrial) loads is a much discussed research topic, especially considering the diminishing operation of classical power plants, the usual providers of FCR. Recent publications on the provision of FCR by Battery Electric Vehicles (BEVs) [160], electric arc furnaces [161], electrolysis [161–164], heat pumps [165] or HVAC systems [166] prove this.

A single process operation optimisation, either based on varying electricity prices or on the provision of ancillary services, is investigated in [159, 162–164]. Combining both is the subject in [160], where it is applied on BEVs, or in [167] where the operation of power plants on the Italian market is investigated. While the varying electricity price or the FCR remuneration is considered known information in some works [159, 162–164], the actual uncertainty they bring is modelled as a stochastic variable in [160, 167]. In [160] the market price and the chance of being selected by the TSO to deliver ancillary service are considered the uncertain parameters. In this case study a co-optimisation is envisaged, considering both the DAM price and the FCR remuneration. The uncertainty which is introduced is due to the forecasting of market prices which are prone to errors and not due to bid acceptance, either by the DAM or FCR market. As further explained the uncertainty of bid acceptance is mitigated.

Closely related and recent works are [168–171]. In [168, 169] the demand response potential of chemical processes, focussing on the dynamics of the complete plant, is investigated. As case study, a chlor-alkali electrolysis plant is considered. In [168] an optimal production scheduling problem is defined where the production level profile is optimised based on minimising the cost of electricity over a period of 72 h. The short-term market prices are assumed to be known, i.e., a deterministic optimisation is carried out. In [169] the single optimisation is expanded with a second scheduling problem so to also provide frequency regulation service with the chlor-alkali process. While this work also addresses the electrical flexibility potential of a chlor-alkali process, identical to this work, the focus is different. A dynamic modelling approach is taken in [169], allowing to conclude on the ability of the process to be operated flexibly with relation to cell temperature and ramping speeds. The optimisation is limited to process-technical constraints and do not incorporate the uncertainty of electricity prices or the unpredictability of grid frequency nor the FCR market structure. In this work, a more high level discrete k-factor analysis model of the electrolyser is considered, without including the utilities processes. The optimal operation of the chlor-alkali electrolyser is considered under both variable electricity pricing and supply of FCR according to the current market rules at time of writing. Short-term market price prediction models are made and uncertainty is mitigated by way of stochastic modelling.

In [170] research is conducted on a bidding strategy on the German FCR market for application with energy intensive processes. A two-stage stochastic approach was taken to minimise the expected production costs, considering a trade-off between contracting FCR and optimising the exploitation of the spot market spreads. While showing similarities with this case study, in [170] the defined FCR bidding price is the uncertain parameter, as at the time of the research, a pay-as-bid strategy was in order on the German FCR market. The FCR contracted capacity was considered to be fixed for a single week. In this case study, the current applicable rules for FCR contracting are used as discussed in § 2.5.1.2, applying a pay-as-cleared methodology and 24 hour contracting. These different market rules are assumed to impact the results due to a more flexible FCR contracting and different bidding behaviour. In [170] the short term FCR bidding price is predicted by using an ARMA model with Gaussian distribution. The probabilities needed for the stochastic optimisation are derived from the forecast distribution. They concluded that a flexible operation can create savings up to more than 20% for certain periods and that an optimal participation on the FCR market can offer significant higher profits than by exploiting the spot market price differences.

In [171] the real-time market participation of a chlor-alkali process in which an optimisation is carried out for bids on the DAM and real-time markets under both price and product demand uncertainty is investigated. As the work is USA based, the so-called Fifteen-Minute Market (FMM) is comparable, but not identical, to the balancing market as it is known in most European countries. A Hammerstein-Wiener modelling approach is used to decrease the computational time to come to a converged solution, this in comparison to using a full-order physics based model of the chlor-alkali process. The bidding in the DAM is considered to be the first stage decision, while the product demand and FMM prices are considered to be the second stage decisions in the stochastic formulation. Four FMM price scenarios are defined heuristically considering the available data. These are scenarios with a significant price spike, a moderate price spike, near-zero prices and close to DAM prices. They conclude that the stochastic optimisation approach is superior to the expected value problem definition. While showing similarities in approach with this case study, some important differences exist. The DAM and FMM are substitutes for sourcing electricity, being it at different moments in time. Therefore a trade-off needs to be made between bidding in the DAM and FMM. In this case study, all electricity is sourced on the DAM, being it under constraint by the volume of FCR which is contracted. No energy sourcing trade-off is made between energy markets, instead a complementary service is contracted, applying inter-temporal and no volume constraints on the DAM electricity sourcing.

In this case study, a methodology is developed for the optimisation of the operation of a chlor-alkali electrolysis plant under hourly variable electricity prices and provision of FCR. A chlor-alkali model is proposed, based on a k-factor analysis. A cost function is combined with the technical and operational constraints of an industrial chlor-alkali electrolysis plant as present at Belgian INEOS sites as well as the market constraints and formulated as a constrained optimisation problem. Short term market price forecasters are developed for both the DAM and FCR market, which serve as input for the constraint process operation optimisation. A stochastic modelling approach is developed to mitigate the uncertainty of the next days DAM price under the RES and load forecasts. The main novelties in this case study are the following:

- The chlor-alkali process is described based on a k-factor analysis, leading to a tractable mathematical model. This serves as purpose to obtain a computationally efficient optimisation while still maintaining the process specifics and required accuracy.

- A methodology for co-optimising the power consumption and ancillary service provision schedule is developed, this under DAM price uncertainty. The Regelleistung.net platform FCR market rules are implemented, with daily FCR prices and a pay-as-cleared pricing system. A two-stage stochastic modelling approach is used, allowing for a timely optimised decision making considering the consecutive Gate Closure Times (GTCs) of the DAM and FCR market.

This case study first elaborates on the construction of short-term price prediction models for the FCR and DAM prices. The chlor-alkali process and the k-factor model is explained and applied to an actual process at the Belgian INEOS sites. The definition of the constrained optimisation problem is then given, again implementing actual technical and process constraints. The optimisation, both deterministic and stochastic is then carried out, leading towards the results and conclusions.

4.4.2 Frequency Containment Reserve Price Prediction Model

Considering that the FCR Regelleistung market, in its current form, is fairly new and that major changes in product period and tendering have taken place over the last few years, prediction of future market prices is considered challenging. The historical prices spanning the period from the 1 April 2020 up to the 1 October 2020 are shown in Figure 4.19. Prior to the 1 July 2020 daily prices were used, and a weekly pattern seemed to emerge with higher prices during weekend days. The shift to a 4 hour contracting period seems to have resulted in a different bidding behaviour of market parties, abolishing the weekly price periodicity. The limited availability of data with these new market rules and the changed bidding strategy impede the use for forecasting purposes. Therefore, a market price prediction model is trained based on the available daily price dataset ranging from the 1 July 2019 until the 30 May 2020, leaving a testing dataset with daily prices ranging from the 1 June to the 30 June 2020. The integration of 4 hour contracting prices is considered to be for future work, when a larger dataset will be available. SARIMA models are made by using the pmdarima package in Python [172], which constructs, evaluates and defines the best fitting model based on the AIC [172]. A SARIMA model is noted as $\mathrm{SARIMA}(p,d,q)(P,D,Q)_m$ where p, d and q are the non-seasonal parameters, P, D and Q are the seasonal parameters and m is the number of periods per season. The parameter p (P) notes the order of autoregression (AR), the parameter d (D) is the degree of differencing and q (Q) the order of moving average (MA). The resulting best-fit model is a SARIMA(2,1,2)(1,0,2,7), has a RMSE of 1.29 and a MAPE of 18.32 considering the testing dataset. Figure 4.20 shows the actual and predicted FCR prices during a part of the testing period. It is seen that the weekly periodicity is captured by the model.

4.4.3 Day-Ahead Market Price Prediction Model

The principles of the DAM as is applicable to Europe in general and Belgium in specific is elaborated upon in § 2.4.1.1. In this case study, all the electricity

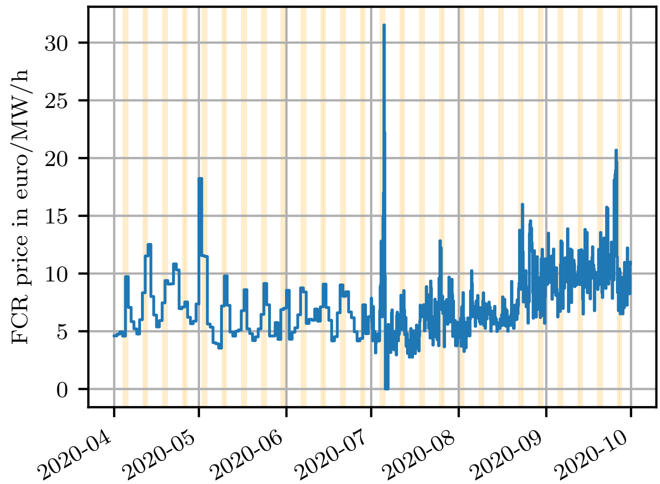

Figure 4.19: Time series of the FCR cross border marginal price on the Regelleistung platform Data from 1 April 2019 up to and including the 30 September 2020 [62]. Weekend days are indicated with orange bars.

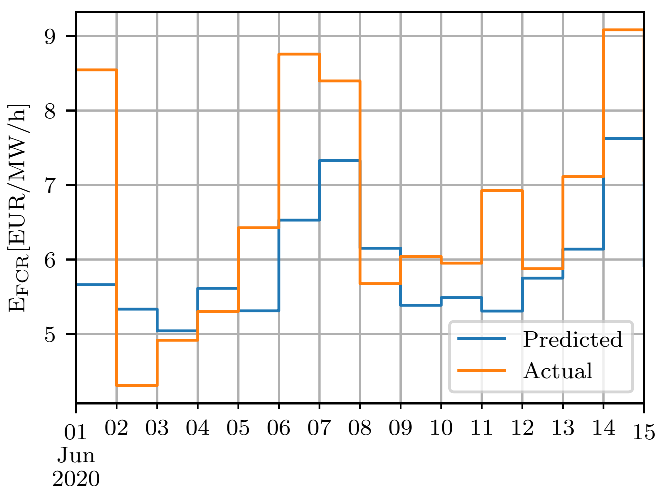

Figure 4.20: FCR price prediction example using the constructed FCR SARIMA model.

consumed for the chlor-alkali electrolyser is considered to be bought on the DAM. The industrial site is considered to be a price-taker, i.e., that the volumes of the bids of the plant are sufficiently small compared to the total market volume, so that it does not influence the outcome of the DAM prices. Next, the assumption is made that the set bid price is sufficiently high so that at any moment the industrial site can be assured of buying electricity on the DAM, evading the uncertainty of bid acceptance. This is a commonly used strategy within industry, where a DAM limit bid price is based on the profitability of production, which can be a multiple of the actual DAM prices. Only in extreme situations, during moments of (perceived) scarcity as discussed in § 2.5.2.3, it could occur that DAM bids are not awarded. In that case, the industrial site either has the option to revert to the CIM or operate on imbalance, or to not operate their processes. These extreme situations are not considered here.

Time-series prediction of the DAM price is a popular research topic, and can be done by applying various methods such as (S)ARIMA(X) modelling [173–175], artificial neural networks [176, 177] or deep learning [178]. The DAM has been an established electricity trading platform for many years, hence leading to a large available dataset on the historical prices which can serve as input to a prediction algorithm. Periodicities in the DAM price are known to be daily, weekly and seasonal, and could be modelled as such. As elaborated upon in [39], also several fundamental, operational and strategic factors have an impact on the DAM price. Considering the increasing amount of Renewable Energy Sources (RES), the weather conditions are one of those factors. In [179] extreme prices on the German DAM are investigated. It is concluded that price spikes are mainly observed when a high demand and low supply is forecasted while negative prices are mainly seen when a high wind power production and low demand are expected. In general it can be stated that the effect of RES is clear in the study of extreme price behaviour. These finding could be extrapolated to the Belgian system, considering Belgium is one of the leading countries in (offshore) wind power production [2], as well as having a high production from solar PV systems [180].

Considering both the given facts of multiple periodicities and impact of external regressors, a choice of method needs to be made. A Trigonometric seasonality, Box-Cox transformation, ARMA errors, Trend and Seasonal components (TBATS) model allows for multiple periodicities to be included but has as major drawback that no external regressors can be included. Considering the importance of the latter in the DAM pricing, it is decided to create a short-term Belgian DAM price prediction model by using the SARIMA with eXogenous factors (SARIMAX) method. As the SARIMAX method only allows for a single direct periodicity, a second periodicity is included indirectly by using Fourier terms. As exogenous parameters the actual wind and PV production as well as the grid load are added. The latter are considered to be known, i.e., the uncertainty of future wind and PV production are not taken into account here. The historical data for the external regressors are obtained from Elia [181–183] and data on historical DAM prices are obtained from the ENTSO-E transparency platform [184]. The model is trained based on a dataset ranging from the 1 June 2019 to the 30 May 2020, with June 2020 serving as test dataset. Identical to the FCR price prediction model, the pmdarima package in Python is used. The resulting best fitting model is a SARIMAX(3,1,2)(2,0,2,24). Figure 4.21 shows the actual and predicted DAM prices during a part of the testing period. An RMSE of 10.16 is obtained (The MAPE is not calculated because it is considered to be not representative since the dataset contains negative and zero prices). The model shows to grasp periodicities as well as encompassing the part of the variability of the exogenous parameters, nevertheless forecast errors are still present. The Auto-Correlation Function (ACF) and Partial Auto-Correlation Function (PACF) plots of the residuals show remaining lags within the significance bands, hinting that a higher-order SARIMAX model might provide a better prediction. Nevertheless, based on the AIC, no improved SARIMAX model is found. To investigate the potential heteroscedasticity of the time series, the residuals are subjected to Engle's Test for Autoregressive Conditional Heteroscedasticity (ARCH), as implemented in the Python statsmodels package [185]. The null hypothesis is confirmed, i.e., the residuals are found to be homoscedastic, and no ARCH term is considered to improve the model. The constructed SARIMAX model will be used to forecast the next-day DAM prices, so to serve as input for the optimisation algorithm, as will be further explained in § 4.4.6. Considering the constraints, as defined in § 4.4.5, the intraday relative price differences are of importance, rather than the absolute price levels. Note that this model is constructed based on the actual values of the exogenous parameters, i.e., it has perfect knowledge on the future wind and PV production as well as on the grid load. In practice, only forecasts of these parameters are available which are prone to uncertainty. Coping with this uncertainty is further explained in § 4.4.7.

4.4.4 Chlor-Alkali Electrolysis Model

The chlor-alkali electrolysis process is very electricity intensive, with an electricity consumption between 2 and 2.4 kWh/kg of Cl_2 produced by using the membrane technology [186]. With a European chlorine production of 9424 kton in 2018 [187], the corresponding electricity consumption is comparable to a country with the size of Ireland. Because of this electricity intensiveness of the process, the chlor-alkali industry has been a front runner in valorising its process flexibility.

The constructed model focusses on the membrane technology, as is present at the Belgian INEOS sites, and is considered for the operation in a discrete way, with time steps of a single hour. This time step size has been chosen in function of

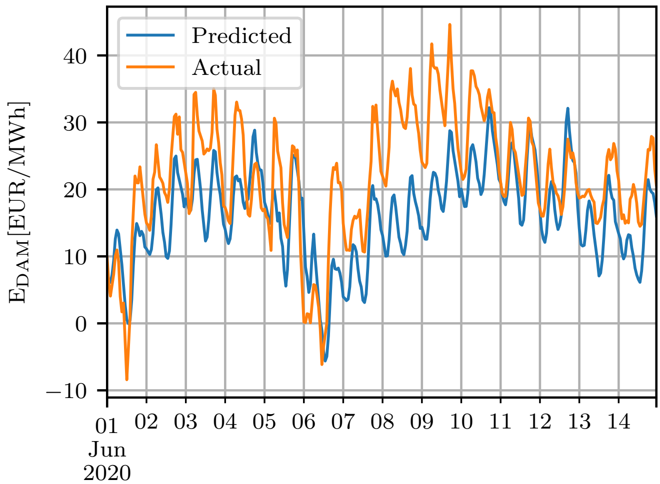

Figure 4.21: DAM price prediction example using the constructed DAM SARIMAX model.

the smallest granularity in the used data, i.e., the DAM with hourly varying prices and the practical control of the electrolyser. No full dynamic model is envisioned, which would be too computationally intensive and deemed not necessary for the purpose of case study. In [168] a more detailed chlor-alkali plant model is described and it is shown that fast fluctuations in current density have a quasi instant power fluctuation as result, proving the possible use for provision of FCR.

The starting point of the described model is the relation between the cell voltage and the current density. The cell voltage U_c is a sum of six different voltages, being the decomposition voltage, membrane potential, electrode overpotential for chlorine and hydrogen, the ohmic voltage drop in the membrane, electrolytes, electrodes and conductors [188]. The cell voltage U_c has a nonlinear relation with the current density J, mainly caused by the electrode (anode and cathode) overpotential. The nonlinearity is strongly present in the lower current density area and a linear relationship can be considered from J equal to 1.5 kA/m^2 and more. As the day-to-day modulation of membrane electrolysers is limited in terms of current density, a linear relationship can be assumed for the model. Only for a brief moment, when ramping up from or down to a complete shutdown, the nonlinear zone is crossed. This simplification is referred to as a k-factor analysis. The k-factor [Vm^2/kA] can be considered the pseudo-ohmic resistance, and is the parameter for the slope of the linear part of the voltage-current density curve. The k-factor method is widely used in the chlor-alkali industry to characterise the overall performance of an electrolyser [189] and has a value between 0.08 Vm^2/kA and 0.5 Vm^2/kA, depending on the bipolar membrane cell technology and the cell condition [190]. Here we consider a k-factor of 0.10, with a linear increase of $2.08\ 10^{-3}$ per equivalent membrane lifetime month m_l, as given in (4.19). More specific models are available in literature, defining the k-factor based on various process parameters [191].

$$k = 0.10 + 2.08\ 10^{-3}\ m_\mathrm{l} \tag{4.19}$$

A cell voltage $U_{\mathrm{c}0}$ of 2.35 V is considered at zero electric current. The cell voltage U_c is then given by (4.20)

$$U_\mathrm{c} = U_{\mathrm{c}0} + k\ J \tag{4.20}$$

The current efficiency ϵ is introduced, which is considered to be linearly related to the equivalent membrane lifetime m_l. The current efficiency can be obtained through an anodic balance using the sulphate key method. In (4.21), a starting value of 0.96 for a new cell and a degradation of $8.33\ 10^{-4}$ per equivalent lifetime month is considered, which are both defined experimentally [188]. Besides the decrease of the current efficiency due to membrane ageing, also more dynamic effects exist, e.g., short term current efficiency changes due to interruption of operation. As the level of detail of these effects are not considered the core of this case study, [192] can be consulted for a more detailed description.

$$\epsilon = 0.96 - 8.33\ 10^{-4}\ m_\mathrm{l} \tag{4.21}$$

Wishing to obtain the electric power density of a cell P_c, we combine the cell voltage U_c with the current density J and current efficiency ϵ, obtaining (4.22).

$$P_\mathrm{c} = \frac{(U_{\mathrm{c}0}\ J + k\ J^2)}{\epsilon} \tag{4.22}$$

Industrial electrolysers have multiple cells in series combined, forming a single unit. By adding the number of cells N_c which are put in series and the Electrically Active Surface Area (EASA), we can obtain the power consumption of a complete electrolyser unit.

$$P_\mathrm{e} = P_\mathrm{c}\ A_\mathrm{easa}\ N_\mathrm{c} \tag{4.23}$$

Stoichiometric equations for the production of Cl_2, H_2 and NaOH are given in (4.24), (4.25) and (4.26) respectively.

$$Q_{\mathrm{Cl}_2} = \frac{N_\mathrm{c}\ \epsilon\ J\ A_\mathrm{easa}}{756} \tag{4.24}$$

$$Q_{\mathrm{H}_2} = \frac{N_\mathrm{c}\ J\ A_\mathrm{easa}}{5487.16} \tag{4.25}$$

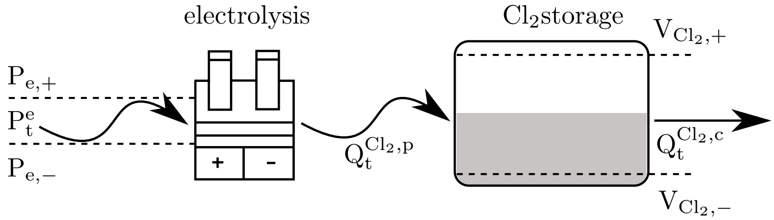

Figure 4.22: Schematic overview of the electrolysis process setup.

$$Q_{\mathrm{NaOH}} = \frac{N_{\mathrm{c}}\ \epsilon\ J\ A_{\mathrm{easa}}}{670.20} \tag{4.26}$$

Note the quadratic current density term in (4.22), which is not present in (4.24), (4.25) and (4.26). This results in an inverse relationship between the consumed electric power and the production of Cl_2, H_2 and NaOH. It is thus more energy efficient to run the process at a lower current density, and not at nominal production capacity, which is different than most industrial processes. This inverse relationship should be kept in mind when assessing the power profile as result of an optimisation. Despite this inverse relationship between efficiency and utilisation level, industrial electrolysis processes are often operated close to nominal capacity, due to the high Capital Expenditures (CAPEX) in constructing electrolysers.

4.4.5 Constrained Optimisation Problem Definition

The operation of an industrial process is bound to several constraints, both technically and economically. Describing these constraints combined with a cost function allows for optimisation of the operation of the chlor-alkali process. A schematic overview of the electrolyser setup as used in this case study is shown in Figure 4.22. The cost function C is defined in (4.27).

$$\begin{aligned} C = E_{\mathrm{H_2}} \sum_{t=0}^{24} Q_t^{\mathrm{H_2,p}} + E_{\mathrm{NaOH}} \sum_{t=0}^{24} Q_t^{\mathrm{NaOH,p}} + E_{\mathrm{Cl_2}} \sum_{t=0}^{24} Q_t^{\mathrm{Cl_2,p}} \\ - \sum_{t=0}^{24} E_t^{\mathrm{DAM}}\ P_t^{\mathrm{e}} + \sum_{t=0}^{24} E_t^{\mathrm{FCR}}\ P_t^{\mathrm{FCR}} \end{aligned} \tag{4.27}$$

The value of the produced products, $E_{\mathrm{Cl_2}}$, $E_{\mathrm{H_2}}$ and E_{NaOH}, is assumed to be fixed in time and is expressed in euro/ton, while the production volumes, $Q_t^{\mathrm{Cl_2,p}}$, $Q_t^{\mathrm{H_2,p}}$ and $Q_t^{\mathrm{NaOH,p}}$, are dictated by the current density and thus variable in time. Variable electricity costs for operation of the electrolysis process are accounted for by using the hourly variable DAM price E_t^{DAM} and the electrolyser power P_t^{e}. Since the power consumption of the electrolyser is directly related to the current density as given by (4.22), it can be considered a proxy for the current density. A last term accounts for the FCR remuneration, with P_t^{FCR} the contracted FCR power and E_t^{FCR} the CBMP expressed in euro/MW/h.

A first constraint (4.28) considers the obligation to deliver to customers. A continuous flow of chlorine, $\mathrm{Q}_\mathrm{t}^{\mathrm{Cl_2,c}}$, is sent to the customer, which is assumed to be constant during the complete simulation. $Q_t^{\mathrm{Cl_2,c}}$ is fixed at 3.2 tons per hour, corresponding to 85% of the production capacity of the chlor-alkali electrolysis plant, defined as the average Nominal Utilisation Level ($\mathrm{NUL_a}$) of the electrolyser. While the $\mathrm{NUL_a}$ can vary over time due to market demand, it is expected to be rather high during most periods. In this work a $\mathrm{NUL_a}$ of 85% is considered in all simulations. The flexibility of the plant is inversely related to the $\mathrm{NUL_a}$, i.e., a high $\mathrm{NUL_a}$ relates to a low potential for flexibility.

$$Q_t^{\mathrm{Cl_2,c}} = cte \tag{4.28}$$

A minimum $V_{\mathrm{Cl_2},-}$ and maximum $V_{\mathrm{Cl_2},+}$ chlorine storage constraint is taken into account in (4.29), set at 5 tons and 45 tons respectively, representing a physical storage of 50 tons with a safety margin of 5 tons.

$$V_{\mathrm{Cl_2},-} \leq V_t^{\mathrm{Cl_2}} \leq V_{\mathrm{Cl_2},+} \tag{4.29}$$

This storage capacity volume is sized according to industrial reality and can be considered rather small in size. The main reason is the safety consideration in storing chlorine, making it a limiting factor in the chlor-alkali process [159]. The chlorine storage tank is used as buffer for production fluctuations. The size of this storage tank could thus also influence the flexibility potential of the plant. A fixed volume of chlorine in storage in the beginning and end of the simulation is ensured by (4.30), which are both set at 25 tons. The storage volume of H_2 and NaOH is deemed unlimited in this case, were in practice storage limits do apply. Nevertheless, the storage capacity of H_2 and NaOH is significantly larger than that of Cl_2, justifying the assumption of a no limit storage.

$$\begin{aligned} V_{\mathrm{Cl_2,beg}} &= \mathrm{cte} \\ V_{\mathrm{Cl_2,end}} &= \mathrm{cte} \end{aligned} \tag{4.30}$$

The operation of an electrolyser is limited in current density. A minimum $J_{\mathrm{m},-}$ and maximum $J_{\mathrm{m},+}$ current density boundary is implemented in (4.31) between which a continuous control is possible, with the only exception of a shutdown of the electrolyser, when the current density is zero. $J_{\mathrm{m},-}$ is set at 1.85 kA/m^2, while the $J_{\mathrm{m},+}$ is set at 6.67 kA/m^2. These current densities can be translated to power levels using (4.22), leading to a minimum power level $P_{\mathrm{e},-}$ of 2.26 MW and a maximum power level $P_{\mathrm{e},+}$ of 9.84 MW.

$$J_{\mathrm{m},-} \leq J_{\mathrm{t}} \leq J_{\mathrm{m},+} \vee J_{\mathrm{t}} = 0 \tag{4.31}$$

As discussed in § 2.5.1.2, a minimum bid size of 1 MW, a bid step size of 1 MW and a contracting period of 4 hours are implemented by the Regelleistung platform as most up-to-date rules. In § 4.4.2 it is discussed that due to dataset length constraints a daily price prediction model is developed. Nevertheless, the 4 h contracting period constraint is implemented in the optimisation model, as given by (4.32) and (4.33). This implies that during the 24 hour optimisation, a single FCR market price will be used, yet it is made possible to have varying FCR capacities contracted in blocks of 4 hours.

$$P_t^{\mathrm{FCR}} \in \mathbb{N} \tag{4.32}$$

$$\forall \frac{t}{4} \in \mathbb{N} : P_t^{\mathrm{FCR}} = P_{t+1}^{\mathrm{FCR}} = P_{t+2}^{\mathrm{FCR}} = P_{t+3}^{\mathrm{FCR}} \tag{4.33}$$

Constraints as given in (4.34) are implemented to assure the possibility of fulfilment of the FCR contractual obligations, by reserving a band for the symmetrical power fluctuations around the power set point with the size of the contracted FCR volume P_t^{FCR}.

$$\begin{aligned} P_t^{\mathrm{e}} - P_t^{\mathrm{FCR}} &\geq P_{\mathrm{e},-} \\ P_t^{\mathrm{e}} + P_t^{\mathrm{FCR}} &\leq P_{\mathrm{e},+} \end{aligned} \tag{4.34}$$

In practice, a ramp-rate limitation ΔJ_{r}, for both the upwards and downwards modulation of the electrolyser, is used to maintain a safe process operation. A value of 0.3 kA/min, i.e., 18 kA/hour is implemented in (4.35). With a nominal current density of 6.67 kA/m^2 and an EASA of 2.7 m^2 as used in this work, it is thus possible to ramp up to nominal or ramp down to zero current within the time of one hour. In a discrete model with hourly time periods, this constraint will thus not impact the optimisation.

$$\mid J_t - J_{t+1} \mid \leq \Delta J_{\mathrm{r}} \tag{4.35}$$

The cost function C will be maximised taking into account the aforementioned constraints, leading to an optimal power consumption profile and contracted FCR volumes.

4.4.6 Deterministic Optimisation

Maximisation of the cost function C as defined in (4.27) is only possible in case a value for each parameter is available. As explained in § 4.4.2 and § 4.4.3, future prices of energy and ancillary service markets are not known in advance and are prone to forecasts. A SARIMA(X) model for the FCR and DAM prices is constructed and used as deterministic price input for E_t^{FCR} and E_t^{DAM} respectively. For the DAM SARIMAX model, the actual data for wind, PV and load are used, as obtained from Elia [181–183]. The optimisation as described here, i.e., where the predicted FCR and DAM prices are used as deterministic input, is termed the *forecast scenario*. The constrained optimisation problem is defined in the Pyomo language, which is a Python based, open-source optimisation modelling language [193]. For optimisation, the BONMIN solver from the open-source Coin-Or project is used [194].

To evaluate the performance of the optimisation with the predicted DAM and FCR market prices as input, a *Crystal Ball (CB) scenario* is taken as reference where the actual DAM and FCR market prices are used. To define the benefit of electrolyser modulation, a flat load operation of the electrolyser is assumed as well, where a steady power consumption level and a maximum FCR contracting is assumed while producing an identical amount of chlorine as with the forecast and CB scenarios, i.e., the *flat load scenario*. Figures 4.23 and 4.24 show optimised power consumption and FCR bid profiles for two distinct days. Table 4.7 summarises the results, with a detail of the electricity sourcing cost on the DAM (C_{DAM}), obtained FCR remuneration (C_{FCR}) and a total cost (C_{tot}). The difference with the CB scenario, for both the flat load and forecast scenarios, are calculated and shown in the table as well. Since a fixed value for the chemical product costs is used during the complete simulation and an identical amount of product is produced in each scenario, these values are not discussed in the results. An overview of the parameter values as used in the simulations in this work are shown in Table 4.6.

The results of the simulation with data from the 2th of June show that practically no improvement, i.e., only a cost decrease of 0.01%, could be made by better forecasting the DAM and FCR prices. Nevertheless, the absolute price forecasts are not perfect. The results are influenced by the inter-temporal relative price differences, since a fixed volume of chlorine needs to be produced during the simulation time window (see constraints in § 4.4.5). Indeed, this is also seen in the results of the simulation with data from the 6th of June, as the DAM prediction shows inter-temporal differences with the actual DAM prices. A higher morning peak and lower evening peak are predicted while the actual prices show a vice versa pattern, resulting in a total cost increase of 25.88%.

To assess the flexibility opportunity profit of the electrolyser, the total cost increase in case of flat load operation is calculated. The results for the 2th of June show an increase of 7.22% while the results for the 6th of June show an increase of 56.38%. The cost increase is compared to the CB scenario. The influencing criterion is the intraday DAM price volatility as defined by (4.36). Considering the examples, indeed a low intraday price difference of $\Delta E_{\mathrm{DAM}} = 17.35\mathrm{EUR}$ is seen during the 2th of June and a larger price difference of $\Delta E_{\mathrm{DAM}} = 30.06\mathrm{EUR}$ is

Table 4.6: Overview of the parameters as used in the simulations.

Parameter	Abbr.	Value	Unit
Membrane lifetime	m_l	6	eq. op. months
Cell voltage	U_{c0}	2.35	V
Current Efficiency	ϵ	0.96	-
Electric Active Surface Area	A_{easa}	2.7	m^2
Cells in series	N_c	166	Nbr. of cells
Value of H_2	E_{H_2}	50	euro/ton
Value of Cl_2	E_{Cl_2}	200	euro/ton
Value of NaOH 32w%	E_{NaOH}	250	euro/ton
Avg. nom. utilisation level	NUL_a	85	% of max.
Min. Cl_2 storage level	$V_{Cl_2,-}$	5	tons
Max. Cl_2 storage level	$V_{Cl_2,+}$	45	tons
Beg. sim. Cl_2 storage level	$V_{Cl_2,beg}$	25	tons
End. sim. Cl_2 storage level	$V_{Cl_2,end}$	25	tons
Min. current density	$J_{m,-}$	1.85	kA/m^2
Max. current density	$J_{m,+}$	6.67	kA/m^2
Ramp rate limitation	ΔJ_r	0.3	kA/min

Table 4.7: Results of optimisation as shown in Figures 4.23 and 4.24.

		C_{DAM}(EUR)	C_{FCR}(EUR)	C_{Tot}(EUR)	Δ CB (%)
2^{th} of June	CB	−4 285.79	155.09	−4 130.70	0
	Flat load	−4 532.34	103.20	−4 429.14	7.22
	Prediction	−4 287.42	155.09	−4 132.34	0.01
6^{th} of June	CB	−1 118.77	245.22	−873.55	0
	Flat load	−1 558.67	192.65	−1 366.02	56.38
	Prediction	−1 301.86	315.29	−986.57	25.88

seen during the 6^{th} of June. Operation in a non flat load manner is more beneficial in case of larger intraday price differences.

$$\Delta E_{\mathrm{DAM}} = E_{\mathrm{DAM,max}} - E_{\mathrm{DAM,min}} \tag{4.36}$$

The optimisations and corresponding results as presented here either assume a perfect knowledge for the FCR and DAM prices, i.e., the Crystal Ball scenario, or assume forecasted prices but with perfect knowledge on the exogenous parameters influencing the DAM price, i.e., the forecast scenario. Either which are not realistic given the fact that no perfect knowledge is present. Instead, a FCR and DAM price prediction needs to be made under uncertainty of the exogenous parameters. A way of coping with this uncertainty is to apply a stochastic modelling

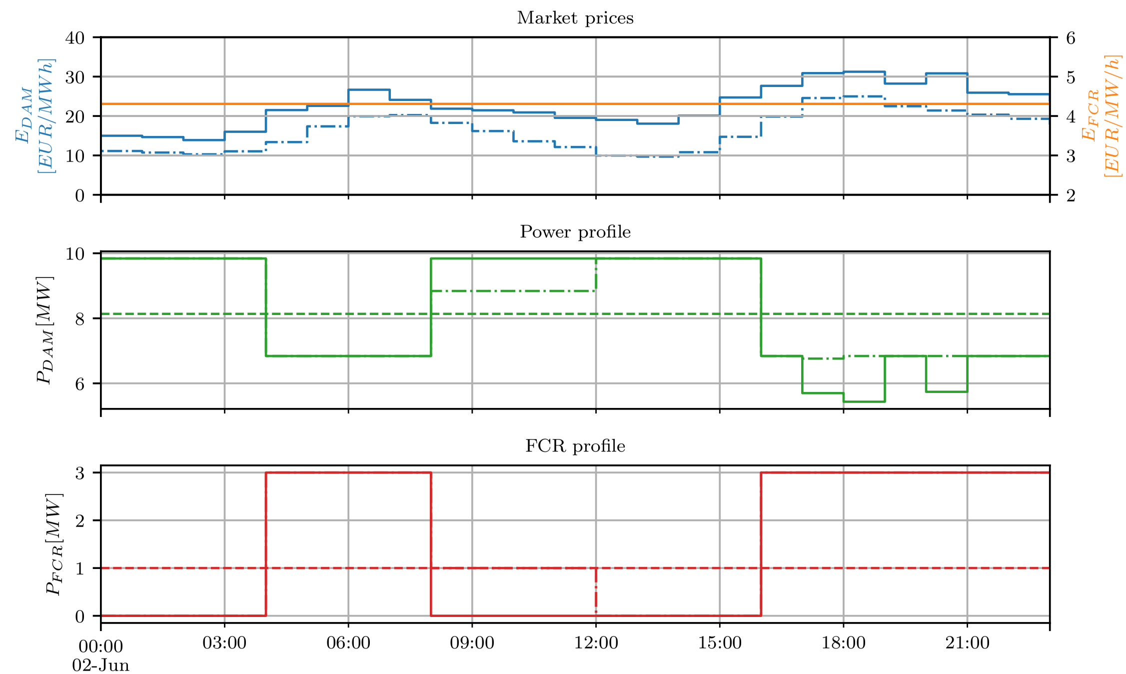

Figure 4.23: Optimised electrolyser power consumption (green) and FCR bid profile (red) considering flat load scenario (dashed line), CB scenario (full line) and forecast scenario (dash dotted line). The dash dotted line shows the predicted market prices. Data from the 2^{th} of June 2020.

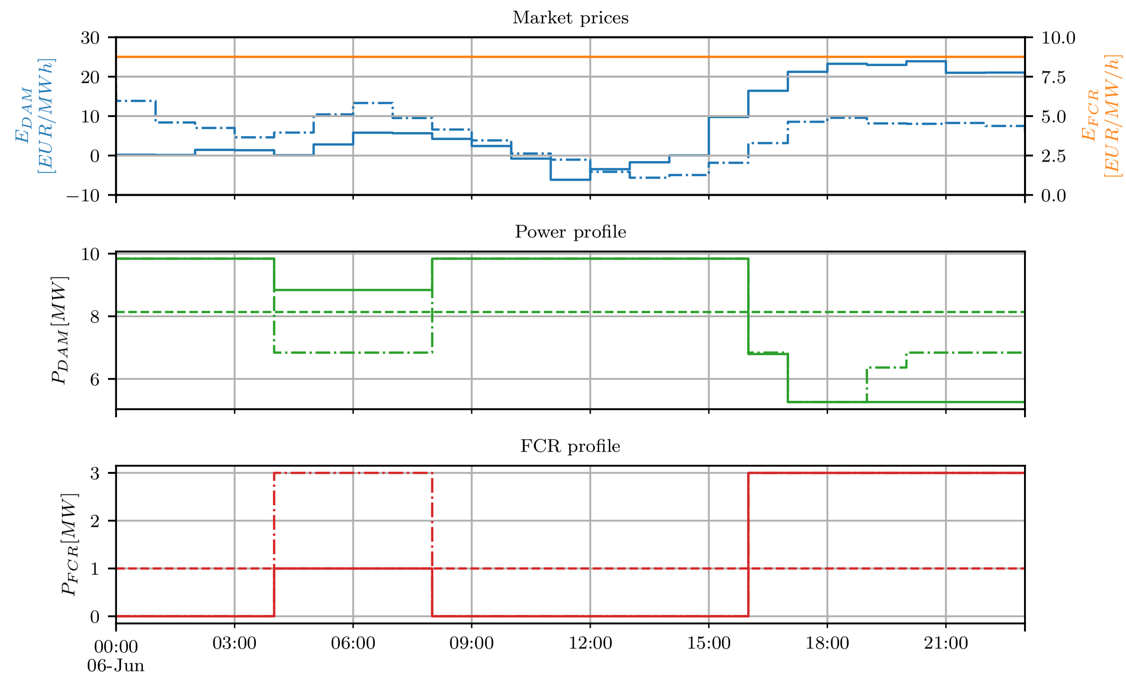

Figure 4.24: Optimised electrolyser power consumption (green) and FCR bid profile (red) considering flat load scenario (dashed line), CB scenario (full line) and forecast scenario (dash dotted line). The dash dotted line shows the predicted market prices. Data from the 6th of June 2020.

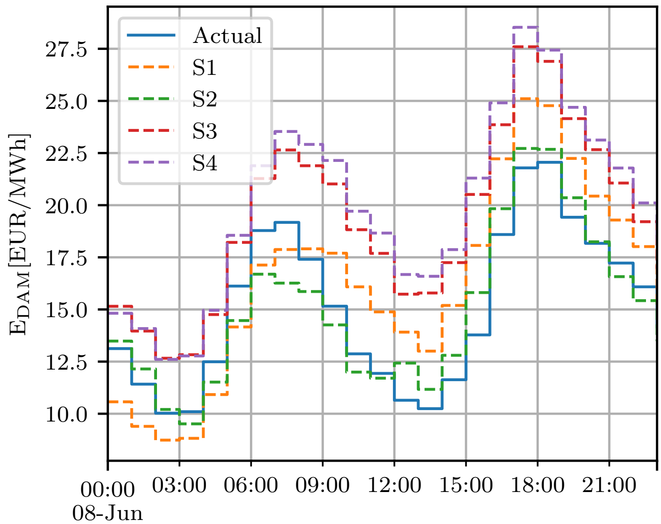

Figure 4.25: Example of DAM prices as in the defined scenarios (dashed lines) and actual DAM price.

approach as is done in § 4.4.7.

4.4.7 2-Stage Stochastic Optimisation

In § 4.4.6 the results from the optimisation by using the FCR and DAM actual prices or considering price predictions based on actual values for the exogenous parameters are discussed. Nevertheless, the applicability of this approach in real life is not possible due to the inter-temporal constraints of the exogenous parameters. Indeed, the actual production values for wind and PV and the total grid load are not known in advance. Instead, timely available predictions for these values need to be used for the DAM price prediction model. Elia makes available forecasts for these parameters and updates them on a regular basis [181–183]. To cope with the uncertainty of these predictions and the impact on the predicted DAM price, a two-stage stochastic optimisation approach is taken. Four different scenarios are constructed, based on a combination of wind and PV power production and grid load, and this for each single optimisation period. An example of the scenarios and their probabilities is given in Figure 4.25 and Table 4.8.

The cost function as defined in (4.27) can be reformulated, obtaining the optimisation function (4.37). The first stage decision consists out of bidding into the FCR market. A second stage decision will then define the volumes of electricity which will be bought on the DAM, under DAM price uncertainty due to

Table 4.8: Overview of the defined scenarios.

Scenario	RES	Load	Probability
S1	Low	Low	14.94
S2	High	Low	48.54
S3	Low	High	10.45
S4	High	High	26.07

wind and PV power production and grid load forecasts. Considering the GCTs of both markets, FCR volumes indeed need to be bid into the market before supplying bids into the DAM. While the FCR market is no substitute for the DAM, as no electricity is sourced, the committed FCR volumes do impose a constraint on the operation of the electrolysis process, having an effect on the DAM electricity sourcing. Note that the volumes and cost of the produced chemical products represent the total value generated. Considering static product unit prices as given in Table 4.6 the operation of the chlor-alkali process is always profitable considering the DAM prices as used in this case study. The calculated value would therefore not influence the results of the optimisation. In case of more dynamic and volatile product costs, these could influence the outcome of the optimisation.

$$\begin{gathered}\max \sum_{t=0}^{t=24} E_t^{\mathrm{FCR}}\, P_t^{\mathrm{FCR}} - \mathbb{E}_\xi \sum_{t=0}^{t=24} E_{t,\xi}^{\mathrm{DAM}}\, P_{t,\xi}^{\mathrm{e}} \\ + E_{\mathrm{H_2}} \sum_{t=0}^{24} Q_t^{\mathrm{H_2,p}} + E_{\mathrm{NaOH}} \sum_{t=0}^{24} Q_t^{\mathrm{NaOH,p}} + E_{\mathrm{Cl_2}} \sum_{t=0}^{24} Q_t^{\mathrm{Cl_2,p}} \\ \mathrm{s.t.}\, \xi \in \Xi\end{gathered} \tag{4.37}$$

The stochastic package PySP is used [195], combined with the aforementioned Pyomo language and BONMIN solver. A total of 30 daily simulations are conducted during June 2020, covering both week and weekend days, days with high and low RES production and days with negative DAM prices. An overview of the results is given in Table 4.9. The Value of Stochastic Solution (VSS), as it is defined in [196], is used as criterion to define the added value of solving the problem in a stochastic way. It is defined according to (4.38), being the difference between the solution of the deterministic expected value optimisation ($\mathrm{sol(EV)}$) and the solution of the two-stage stochastic problem ($\mathrm{sol(2SSP)}$).

$$\mathrm{VSS} = \mathrm{sol(EV)} - \mathrm{sol(2SSP)} \tag{4.38}$$

Table 4.9: Simulation results.

n°	Simulation Date	CB[€]	Flat Load Incl. FCR[€]	Deterministic, Pred. [€]	Expected Value [€]	2-Stage Stochastic [€]	VSS [€]
1	6th of June	873.55	1366.02	986.57	1132.89	1082.62	50.27 (4.43%)
2	5th of June	3 401.83	3 798.87	3 440.36	3 505.57	3 447.52	58.05 (1.71%)
3	4th of June	3 991.56	4 360.88	4 025.44	4 086.38	4 050.24	36.14 (0.91%)
4	22th of June	5 335.93	5 814.42	5 336.01	5 367.06	5 336.01	31.05 (0.59%)
...	...	...	...	...	...	...	...
27	19th of June	5 447.76	5 819.63	5 449.25	5 452.22	5 467.22	−15.00 (−0.28%)
28	7th of June	3 036.43	3 562.26	3 061.05	3 066.43	3 079.21	−12.78 (−0.42%)
29	3th of June	4 807.04	5 115.39	4 817.54	4 837.37	4 868.18	−30.81 (−0.64%)
30	10th of June	5 622.97	5 974.71	5 661.56	5 698.20	5 739.73	−41.53 (−0.74%)
	Total	137 935.68	149 917.61	139 549.35	141 129.21	140 424.03	705.18 (0.51%)

4.4.8 Discussion

Regarding the Crystal Ball deterministic optimisation as shown in § 4.4.6, Figures 4.23 and 4.24, a rather rational result is obtained. The power consumption is optimised based on the DAM prices, by running the electrolyser at nominal production capacity when the prices are lowest and reducing the power when prices are highest throughout the simulation period, i.e., a single day. As result, during the hours with the lowest electricity prices, no FCR is contracted as the contractual obligations of the FCR could not be fulfilled, i.e., no upward operational band is present when running at full capacity. Considering the constraints as defined, a fixed volume of product, i.e., chlorine, needs to be produced within a single optimisation period. As result, only the relative DAM price differences are of importance for the optimisation of the operation of the electrolyser. Improvement of the DAM price prediction should thus be focussed on the price pattern rather than on the absolute values of the prices. The profit obtained by supplying FCR towards the TSO is considered rather limited with respect to current Regelleistung.net CMBP prices. The rationale of the optimisation results can be interpreted as the electrolyser being scheduled based on the relative price differences of the DAM, with as second level order contracting as much FCR as possible under the given constraints as defined by the optimised power consumption profile.

Operating the electrolyser flexibly is shown to be mostly interesting in case large intraday DAM price differences. Figure 4.24, with a ΔE_{DAM} of 30.06 euro shows a potential profit of 56.38%. An intraday price delta ΔE_{DAM} of 17.35 euro as present on the dataset used for the simulation as shown in Figure 4.23 shows to only create a potential profit of 7.22% by flexible operation.

Introducing a two-stage stochastic modelling approach to mitigate the uncertainties due to DAM price predictions with exogenous parameters is shown to have a beneficial effect, considering the test dataset of June 2020. In total a VSS of 0.51% is obtained, i.e., the stochastic solution brings a benefit, being it rather limited, in comparison to the deterministic Expected Value solution. When assessing the VSS for each simulation separately, we see that for some simulations the EV solution shows better results than the stochastic solution. This is as to be expected since the stochastic methodology approaches the problem with probabilities, which are per definition the quantification of how likely an event is expected to occur. Only on average the solution will be more performant.

4.4.9 Conclusions

This case study proposes a methodology for the economical optimisation of the operation of a chlor-alkali electrolysis process which is modelled by using the k-factor method. A set of industry-based constraints combined with a cost function forms the basis for a constrained optimisation problem. The electrolyser is assumed to be operated on electricity sourced on the Day-Ahead Market (DAM) and has the possibility to deliver Frequency Containment Reserve (FCR) to the grid. First, a deterministic optimisation considering predicted DAM and FCR market prices with SARIMA(X) models with known exogenous parameter values is considered. A comparison is made between the Crystal Ball scenario, i.e., where the DAM and FCR prices are assumed to be known upfront, and with a flat load scenario, i.e., where the power consumption is stable throughout the simulation period. A flexible operation of the electrolyser is concluded to be interesting in case of larger intraday DAM price differences. The exogenous parameters as used in the SARIMAX DAM price prediction model, i.e., the wind and PV production and grid load forecast, bring uncertainty, as these are in reality based on predictions. To mitigate these uncertainties, a two-stage stochastic modelling approach is used. The stochastic solution is shown to be slightly more beneficial compared to the deterministic Expected Value solution, with a benefit of 0.51%. The two stage stochastic optimisation modelling approach, applied on a chlor-alkali electrolysis process considering both electricity sourcing on the DAM and supplying FCR to the grid is considered novel as it has not been described in literature before.

In general, it can be concluded that a flexible operation of a chlor-alkali electrolyser, under both varying electricity market prices and delivery of FCR service is deemed beneficial compared to a flat load operation. To optimise the flexible operation of the electrolyser, an as good as possible forecast for the future market prices is necessary, especially focussed on the relative price differences within the simulation period. A two-stage stochastic modelling can serve as solution to the introduced uncertainties.

5
Conclusion and Future Research

5.1 Overall Conclusions

The goal of this research was to look into the possibility of the chemical process industry to operate processes in an electrically flexible way and to valorise this flexibility implicitly or explicitly.

In chapter 2 the concept of power system flexibility, i.e., electrical flexibility, is defined and framed into today's energy landscape. The needs and means of electrical flexibility considering the current energy landscape are discussed, with a focus on the European and Belgian system. A distinction is made between the implicit and explicit way of valorising electrical flexibility. The wholesale energy markets and the imbalance settlement system are discussed as they are operational in Belgium, with a focus on the price signals and potential to use as input for the valorisation of implicit flexibility. A first main novel contribution in this chapter is the simulation of the impact of the imbalance position of a market party, taking into account the imbalance market size. The possibilities of nomination accuracy improvements, structural over or under nomination and actively counter steering based on the SI of the LFC area are assessed. The simulated imbalances are superimposed on the historical SI and deemed to be countered by activation of NRV. The latter is then taken into account so to define a new imbalance price.

In a second part of this chapter, the explicit flexibility options are discussed by assessing the balancing ancillary services as being contracted by the TSO. Focussing on the FCR, aFRR and mFRR, the possibilities for market parties to provide these services are discussed as well as giving an insight in the current market rules and opportunities. A final section deals with the market roles and regulation as applicable to electrical flexibility. A second main novel contribution in this chapter is the assessment of the impact of the Transfer of Energy regulation on the valorisation options of market parties, e.g., industrial consumers. The redesign of the mFRR market combined with the introduction of a contract based ToE is shown to increase the freedom to optimise the electrical flexibility for non-CIPU market parties, on the other hand, it does increase the complexity for energy suppliers and BSPs.

In general it is concluded that the need for flexibility in the electricity system is clearly present today and that a combination of solutions will be necessary to meet these needs. One of these will be the flexibility as can be provided by the demand side. The energy markets and ancillary services markets have known a tremendous change in the past decade and are leading towards a technology neutral competitive market structure. This indeed creates a fair level playing field for all market parties, including these on the demand side. The planned European homogenisation of the markets in the near future is deemed to significantly increase the competition.

In chapter 3 the electrical flexibility potential as present in the chemical process industry is discussed. The first main part of the chapter deals with the development of an innovative methodology to analyse the electrical flexibility potential of chemical process industrial sites. The methodology consists of three main steps being the gathering of information and data, a three level analysis and the subsequent construction and definition of high potential flexibility cases. The gathering of data is discussed in relation to the commonly available measuring infrastructure on today's industrial sites. The three level analysis covers the complete industrial site, the process level and the individual machine level. The analysis is technically oriented with the focus on power and energy levels as well as the controllability of machine and process. The proposed methodology is applied on the nine different INEOS chemical process industrial sites as present in Belgium. The identified potentially interesting flexibility cases are aggregated based on the type of process and the total flexible installed power grouped over all sites is given. It can be concluded that utilities processes, having a certain kind of buffer in relation to the core process, are often fit to be controlled flexibly. Thermal utilities processes, i.e., cooling and heating, show a large potential on today's industrial sites or for future use respectively. The largest installed capacity of thermal utilities processes is in the chilling, where 10 MW is assumed to be showing flexibility potential with capacity factors of 22% to 70%. Certain specific core processes also show flexibility potential, with in total an amount of 246.1 MW of installed capacity. The chlor-alkali electrolysis processes make up the largest part with a total of 200 MW available on two of the Belgian INEOS sites. The second main core process is are the extruders, which are deemed fit for load shedding, i.e., mFRR. Already today, some of the extruders are valorising this flexibility. Identified non-flexible processes are discussed as well and mainly comprise continuously operated core processes, such as the production of ethylbenzene, polymerisation processes and distillation processes. The main reason for the absence of flexibility potential is twofold. The first main reason is the technical nature of the process, which prevent the process from being operated flexible. Examples are fluidised bed reactors with very tight operational conditions. The second main cause is the inefficient control of machines, creating only a very limited impact on the electricity consumption. An example of such a case is the control of the volume flow of a compressor by the use of a bypass or throttle valve instead of a direct control using a VSD. The process and corresponding compressed volume flow of product might be controlled flexible, yet the impact on the electricity consumption and therefore the electrical flexibility potential, is limited. Finally, in this first part of the chapter, also a look into the future is given by considering electrification and design for flexibility. Concepts such as *power-to-X* and *power-to-X-to-power* are touched upon.

The second main part of this chapter deals with the clustering of industrial sites, considering the possible opportunities and benefits regarding electrical flexibility. The main novel contribution in this section is the development of a framework covering the main aspects needed to setup a virtual single company cluster taking up the role of BSP. The main focus is on the development of an internal bid optimisation algorithm with as goal a combined profit maximisation. The proposed solution finds the most optimal combination of individual bids and this under the ancillary services market constraints. Also, a methodology is proposed to split the obtained remunerations or penalties amongst the participating industrial sites. The rationale of allowing a certain level of competition between the industrial sites in the cluster is given as well. The main difference between the proposed virtual cluster framework and existing commercial aggregators is the level of process transparency and a shorter commitment.

In chapter 4 three case studies are defined and worked out in detail. Considering the defined large potential of cooling utilities processes as discussed in chapter 3, a model is developed of an induced draft evaporative cooling tower. Being a common utilities process, this model can be used to analyse the available electrical flexibility potential in cooling tower fans by simulating the water basin temperature. A comparison between a black box and white box modelling method shows to in favour of the white box modelling. Such a white box model, based on the thermodynamic equations, allows for a wide use. Next to simulating existing cooling processes, it can be also be used to assess the opportunity of thermal inertia enlargement by creating a larger water buffer or assess the benefit of pre-cooling. Depending on the operation, with respect to the limiting temperatures of the water basin, such cooling system are deemed fit for flexible usage. The main contribution of this case study is the development of a tractable yet sufficiently accurate model, limiting the input parameters to readily available data on most industrial sites. The model is developed with the main goal of allowing fan switching strategies to be simulated so to define the electrical flexibility potential of the cooling process.

A second case study deals with another utilities process, being the electrode boiler. As the electrification of steam production is today only being started, a theoretical case of a hybrid steam production setup is discussed. The main idea of the case is to operate a hybrid steam production setup, with a conventional natural gas boiler and an electrode boiler. The latter is then allowed to being used in a flexible way, here based on price inputs of the imbalance market. With the imbalance price showing a bimodal distribution, due to the implementation of a single imbalance pricing methodology, these price signals are deemed particularly suitable as input. The main innovative part in this case study is the development of an imbalance price prediction algorithm, based on the combination of the gradient effect and the close-to-real-time availability of data on the NRV. The predicted NRV is combined with the ARC table to define the imbalance price. These are then used as input for the control of the electrode boiler. The proposed novel methodology is shown to be more performant, assessed by the average cost to operate the electrode boiler, as well as the number of boiler switches. Based on the benchmarking curve, which assumes a perfect forecast of the imbalance price, still improvements are possible.

A third and last case study elaborates on the chlor-alkali electrolysis process. This electricity intensive process is by nature to be operated flexibly, as power electronics are used to control the electric current density and thus the power supplied to the cell rooms. Short control times allow for the flexibility to be valorised both by supplying of the balancing ancillary services, including FCR, as well as implicitly on the energy markets. This results in the investigated approach of optimising the operation of the electrolysers based on price signals from the DAM and supply of FCR towards the TSO. A DAM and FCR price prediction algorithm is developed, based on historical data, which are then used as input for the optimisation of the process operation. As price predictions introduce uncertainty, a stochastic modelling approach is applied mitigate this problem. Optimal production profiles are generated, both in a deterministic and stochastic way, and are compared to a crystal ball and flat load operation scenario. It can be concluded that the flexible operation of chlor-alkali electrolysers show a significant benefit, while the mitigation of risk by using a two-stage stochastic modelling can further improve these benefits. The main novel contribution in this case study is the two stage stochastic optimisation modelling approach which is applied on a chlor-alkali electrolysis process considering both electricity sourcing on the DAM and supply of FCR towards the grid.

In general, it can be concluded that the possibilities of valorising flexibility have been increased over the past decade. The opening up of the energy and ancillary services market have allowed for the creation of a level playing field across all technologies. With a large installed power and electricity consumption, the chemical process industry does show potential in providing electrical flexibility to the market and grid. This supply of flexibility from the demand side is also considered to be one of the solutions, or even prerequisites, to allow for a future with a fully decarbonised electricity system consisting out of non-dispatchable renewable generation.

5.2 Future Research

This work fits into the worldwide research on the topic of the energy transition. With the path towards a net zero greenhouse gas emission economy and a fully decarbonised electricity system still being walked, research will continue to be necessary along the way. In this section some recommendations are given to guide this future research, based on acquired knowledge and experience in this field.

In chapter 2 an overview is given on the different balancing ancillary services and how they have developed over the past years. It is discussed that this development is still ongoing, with the ultimate goal being the creation of a technology neutral European homogenised market as foreseen by the PICASSO, MARI and TERRE projects. With the details not yet fully worked out, future research could contribute to these by looking into the implications for all different market parties involved. A specific example for Belgium is the opening of the aFRR market to non-CIPU market parties and the possibility of aggregation. This opening of the aFRR market might create opportunities for specific market parties and new business cases might arise.

Also in chapter 2 the electricity markets, with a focus on the DAM SPOT and the imbalance market, are discussed. With a decarbonised electricity system as final goal, the amount of renewable electricity generation in the grid is still increasing. Combining this with a decrease in electricity demand, as seen past year due to the Corona crisis, this has led to an increased number of hours with negatively priced electricity and increased price volatility. These market conditions could provide incentives to reassess business cases which might not deemed financially feasible before. Specific examples might be the flexible operation of existing assets but also the development of *power-to-X* projects. But will there be negative electricity prices and high volatility in the near and long-term future? Therefore, more research is to be done on the market design as well. Is the current energy only market fit for an electricity system dominated by near zero marginal cost renewables? Already today, measures are taken to assure that enough dispatchable production capacity will be available so to assure the security of supply. Discussions on capacity remuneration mechanisms are still ongoing in Belgium and Europe, as well as other options such as scarcity pricing.

Research on a higher level than market design might look into the energy policy of Belgium and Europe. While the clearly defined goal is a net-zero greenhouse gas emission economy, different paths might lead us there. Does renewable energy need to be harvested closest to the area of consumption, or can it be transported to these areas? Will there be mainly direct or indirect electrification and what role has hydrogen to play? These policy choices still need to be made and they should be well supported by scientific research.

In chapter 3 a methodology is proposed to analyse the electrical flexibility potential of industrial sites and is applied on all chemical process industrial sites of INEOS in Belgium. As result a descriptive longlist of potentially interesting processes and machines is created, including the aggregated flexibility volume and the possible valorisation options. The methodology focused on the power and energy levels as well as on the controllability of the process, i.e., on technical aspects. Future research might expand this flexibility assessment with other non-technical aspects. A specific example might be the aspect of risk by flexible operation. Processes, designed to be operated continuously but are used flexibly, might have an increased likelihood of failure. Combined with the consequences which can be severe, perceived risk can prevent the flexibility from being valorised. Another path of research is the inclusion of economic aspects, such as maintenance or start-up costs. Inclusion of these can then lead to economic feasibility studies, concrete business cases and implementation projects.

Another proposed line of research is to explore electrical flexibility beyond the borders of the chemical process industry. The proposed methodology can be, possibly with some adjustments, used to assess the flexibility potential of other sectors such as steel, cement or agriculture. But also in the residential sector, options for demand side flexibility are to be found. With the electrification of residential heating, e.g., heat pumps, and mobility, i.e., electric vehicles, being the largest opportunities.

The second main topic of chapter 3 deals with aggregation of flexibility and the creation of a virtual cluster, mainly focussing on the role of BSP. Already today commercial aggregators are active, offering the opportunity of risk mitigation and value stacking. Nevertheless, there are deemed future research opportunities in the creation of specific aggregated groups of flexible assets, such as the proposed framework for assets of a single company. Perceived benefits are the open and transparent working while drawbacks might be the technical and administrative complexity. A full SWOT analysis of this option might bring clarity and could result in a feasible project.

Some of the defined high potential flexibility cases are worked out in more detail in chapter 4.The optimised operation of the chlor-alkali electrolysis process is to be further fine-tuned so to be able to enter the implementation phase. An automatisation of the electrolyser control could enhance the ramping times or control opportunities, even expanding the valorisation options to other markets, such as the imbalance market. The implementability of the flexible control of the cooling tower fans should be assessed taking into account risk and safety measures, since this is a critical utilities process. Future research on the possibility to also supply ancillary services, i.e., by the use of VSD controlled machines, is recommended. An economic feasibility study, where the possible gains from these different types of flexibility are quantified is considered to be a next step in this research. The hybrid steam production case study, giving a first hint at the upsides of electrification in industry, shows opportunities for further research. A next step to be considered is developing a feasibility study, where also other influencing aspects are taken into account. An example might be the impact on the grid infrastructure and the possibilities of connecting such a system to an existing industrial site. Also on the broader topic of electrification and the link with electrical flexibility, future research is possible and recommended.

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