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DOCTORAL THESIS

Organising Ancillary Services for Electric Power Systems

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Abstract

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Grid and system operators apply ancillary services to ensure that the network is utilised within its quality parameter ranges. The power sector evolves rapidly, driven by the trends decarbonisation, digitalisation, and internationalisation. From these developments, new challenges emerge for grid and system operations. Therefore, policymakers need to adapt existing designs of ancillary services.

For policy-making in this context, the present thesis provides a generic evaluation framework for ancillary services designs. The framework entails a novel approach to use price mark-ups as a performance indicator for ancillary service interactions and design efficiency. The agent-based Ancillary Service Acquisition Model (ASAM) enables testing of various ancillary designs by simulations. In a use-case regarding redispatch designs in the Netherlands, it is shown that the framework and ASAM jointly enable the investigation of interactions of ancillary services and markets. Furthermore, both are generic and scalable enough to contribute to the development of policy advice.

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Finally, a statement regarding affiliations:
During this study, I was employed at TenneT TSO B.V. and my employer supported this development also financially. However, I bear the sole responsibility for the content, which may not reflect the position or opinion of this affiliation. Furthermore, the TenneT TSO B.V. has not influenced the content or publication of the thesis to their benefit.

Samuel Glismann, Nijmegen, 15/12/2022

Contents

List of Abbreviations

ASAM	Ancillary Service Acquisition Model
BCM	Balancing Capacity market
BEM	Balancing Energy Market
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CHP	Combined Heat and Power facility
CPS	Central Post System
DAM	Day-ahead Market
DAP	Day-ahead price
DSO	Distribution System Operator
EU	European Union
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
GOPACS	Grid Operators Platform for Congestion Solutions
IBM	Imbalance Market/Mechanism
IBP	Imbalance price
IDCONS	Intra-Day Congestion Spread
IDM	Intra-Day Market
ISO	Independent System Operator
ISP	Imbalance Settlement Period
KDE	Kernel Density Estimate
KPI	Key Performance Indicator
LOPF	Linear Optimal Power Flow
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PDF	Probability Density Function
RDM	Redispatch Market
RES	Renewable Energy Sources
ROP	Reserves for Other Purposes
RR	Replacement Reservers
SRMC	Short-run marginal cost
TenneT	TenneT TSO B.V.
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

Chapter 1

Introduction

1.1 Background: Electric power systems in transition

Societies rely on electricity. Electrical energy is used in many crucial processes that strongly determine societies. The fictitious novel 'Blackout' (Elsberg, 2012) vividly describes the evolution of a long-lasting blackout in Europe. The thriller illustrates how the availability of electricity in European countries is taken for granted and how a sudden interruption of electricity supply can unsettle the fundaments of such societies. Security of electricity supply is, therefore, of particular importance in highly electrified societies.

Energy supply was state-business. Given the importance of electricity for governments, it is not surprising that the electricity supply chain is traditionally organised in state-owned utilities. In a typical configuration, a power supply utility integrates the value chain from planning, building and maintaining generators as well as networks (i.e. central planning), to dispatching generators and grid operations (i.e. central dispatch). Loads are typically planned (i.e. choice of connection point) decentrally and dispatched by the asset owners (i.e. self-dispatch).

From integrated state-owned utilities to unbundling. Following a world-wide trend of energy supply chain liberalisation, also the electricity supply configuration has faced significant changes in many regions. Pollitt (2012) describes liberalisation as a process which involves the introduction of competition, the establishment of energy sector regulators, and often (but not always) privatising state-owned energy assets. The introduction of competition includes unbundling of integrated utilities to enable non-discriminatory access to monopoly networks as well as the establishment of wholesale and retail markets. Such a configuration thus moves the planning and dispatch of generators to the responsibilities of the market. The focus of unbundled monopolistic entities, which plan and operate the network, moves from (national) electricity supply security to continuous (international) 'access provision' for market parties. Nobel (2016) characterises this set-up as a transmission system configuration. While various studies on the effects of liberalisation conclude that there is evidence for efficiency improvements and decarbonisation of the power sector, some other studies express doubts concerning such positive impact (at least for some countries), with reference to distributional effects on the expense of end-consumers (Pollitt, 2012).

Unbundled grid and system operation require ancillary services. The liberalisation of the power sector started in the USA in the early 1990s, while in Europe the EU Directives and regulations from 1996, 2003 and 2009 paved the way for unbundling and the 'internal energy market' of the European Union (Pollitt, 2012). With unbundling, a new technical and administrative challenge emerged: Grid and system operators need to ensure that the network is utilised within quality parameter ranges, without being allowed to build generation assets or centrally optimise the asset dispatch. In order to control the frequency, the voltage, and currents, operators plan the network according to expected capacity developments of loads and generators. During operation, they use grid topology changes and apply services that grid and system users provide to the operators. These ancillary services imply specific behaviour of generators and loads. Such behaviour may be in contradiction to the benefit maximising behaviour of the providing grid and system users. Therefore, ancillary services often, but not always, involve financial remuneration for providers. Design of ancillary services thus includes the definition of desired provider behaviour as well as a definition of a process for the service acquisition. For the latter, market-based procurement mechanisms are often applied, such as tenders and auctions.

Three drivers are rapidly changing electricity sectors. The Paris Agreement within the United Nations Framework Convention on Climate Change marked in 2016 another step towards world-wide decarbonisation of societies. The agreement has subsequently been translated in regional and national action plans, which define measures per sector to keep the increase of the average global temperature well below 2 °C and best effort to limit the increase to 1.5 °C (e.g. Dutch Climate Agreement Commission, 2019). These measures can be considered as a major driver for changes in the power systems. A second driver with a major impact on the electricity sector is the trend of increasing interconnection of power systems. In the EU, this development is characterised by expanding the international transmission network and by harmonising electricity market regulations (e.g. the 'clean energy package' European Commission, 2019a). A third driver with disruptive effects on the electricity sector is digitalisation: increasing availability of data and connectivity enables many technological trends, which are often labelled as 'smart' (e.g. IEA, 2017).

Subsequent phenomena in power systems materialise at pace. Decades ago, the drivers of change triggered various trends in power systems, which only recently started to materialise at scale. These trends may be summarised as follows:

- Increasing share of supply-driven, intermittent, central and decentral renewable energy sources (RES) (EurObserv'ER, 2018).
- Changing load patterns due to (partial) electrification of transport and heat sector as well as digitalisation of appliances ("internet of things") (Oeko-Institut, 2016; Bloess, Schill, and Zerrahn, 2018; IEA, 2017).
- Regulatory push to decrease barriers for (price elastic) demand response (Joint Research Centre, 2016).
- Emerging new market players with new business models as well as decentral community co-operations that conquer market shares of the incumbent businesses (Amelang, 2019).
- Increasing interconnector capacities and cross-border market arrangements between regional and national power systems (ACER/CEER, 2019).

Rethinking grid development, maintenance and operations. Power transmission systems need to be transformed to cope with the drivers and trends above. Complex social processes negotiate important questions regarding the power system transition, involving governments, industries and NGOs. Decisions are required concerning supply technologies (e.g. how much RES, and where to place it), infrastructure (e.g. how much grid expansion, how much storage and where to place it), and distribution of costs and benefits (e.g. how to distribute freedoms and obligations between market and operators, and how to structure grid and system user tariffs).

Ancillary services need to evolve in this transition. In this context, policymakers also need to adapt existing ancillary services, to cope with new physical challenges (i.e. changing ancillary service demand) and new market situations (i.e. changing ancillary service supply). Inadequate design of ancillary services would restrain operators from providing access to grid and system users effectively, and it would eventually lead to interruptions of electricity supply. Therefore, ancillary service design may be considered as an essential enabler of the energy transition.

1.2 Context of ancillary services in Europe

1.2.1 Roles and responsibilities in power system designs

Natural monopolies organised in operator roles. In liberalised power systems, several operator roles are typically defined for natural monopolies and assigned to designated entities. The names and configuration of the roles depend on the jurisdiction. Typical roles in the USA are Independent System Operator (ISO) as well as Transmission and Distribution Utilities. European regulation distinguishes the roles of the Transmission System Operator (TSO), the Distribution System Operator (DSO), and the Nominated Electricity Market Operator (NEMO). TSOs and DSOs have the task to build, maintain and operate the electricity network and to connect grid users to it. DSOs operate regional networks with lower voltage levels, down to the connection of households, while TSOs operate high voltage transmission networks and interconnectors. TSOs additionally need to operate many administrative processes that enable trading of electricity across borders, whilst ensuring a stable frequency by controlling the physical power balance of electricity consumption and production in the system. The TSO tasks may be summarised as *enabling the physical delivery of traded electrical energy*[1]. NEMOs are power exchanges which have various regulated tasks in the context of European market coupling [2].

EU regulation specifies numerous user roles. While the non-operator roles are often summarised by the term market participant or market party, EU regulation additionally defines various (sub-) roles related to wholesale markets, retail markets, as well as roles related to the physical connection and the connected assets. An essential role from a system perspective is the Balance Responsible Party (BRP). The BRP is a "*market participant or its chosen representative responsible for its imbalances in the electricity market*" (European Union, 2019b, Artikel 2(14)). The imbalance of a BRP is the delta between the energy that has been injected or withdrawn from the grid and the energy that has been traded (i.e. trade position) per imbalance settlement period (ISP)[3].

[1] This formulation has been developed by Frank Nobel, Ph.D. (TenneT TSO B.V.) in 2018.

[2] There are also power exchanges without the role of the NEMO. Such power exchanges have no access to the market coupling. The term NEMO is not used in the remainder of this text for simplicity reasons. The context then shows whether a power exchange with NEMO status is meant.

[3] The length of an ISP still varies in Europe. However, the target ISP has a length of 15 minutes (European Union, 2019b)

Energy balance is the responsibility of the market. "*Without appropriate trades, withdrawal of energy would amount to theft from, and injection of energy to dumping into the power system. So dispatch by grid users has to be covered by trades, with other system users or with operators*[...]" (Nobel, 2016, p.27). The responsibility for energy balance [MWh] per ISP is thus assigned to the market parties (i.e. to BRPs), while the TSOs are responsible for the power balance [MW] of their control block, and TSOs are jointly responsible for the frequency of all control blocks in a synchronous frequency area (Nobel, 2016).

Market parties have three conditional freedoms. The design of roles and responsibilities in Europe has been characterised by three fundamental freedoms for market parties (see also (Nobel, 2016; Haan, 2016; Hirth and Glismann, 2018):

- **Freedom of connection.** Market parties have the right to receive a physical connection to the grid as well as connection agreement. However, specific costs of the connection may be assigned to the market party as well as other location-specific conditions.
- **Freedom of trade.** Market parties may trade electricity with every other market party at any time. In contrast to market designs with central trading pools, bilateral trading within a bidding zone is thus allowed. However, in order to enable the TSO to administer and financially settle imbalances, BRPs have an obligation to nominate all trades (i.e. trade schedules) at the TSO. Moreover, trading across bidding zones is subject to available transmission capacity. TSOs determine this capacity and allocate it via auctions. This zonal-pricing design implies that the wholesale market has no locational price differences within a bidding zone.
- **Freedom of dispatch.** Market parties have the right to withdraw or inject power from and to the grid within the contractual limits of their connection agreement. Market parties choose how to optimally use their assets connected to the grid according to their own benefit (i.e. self-dispatch). This so-called portfolio optimisation also used to mitigate the market parties imbalance risk (i.e. when some assets deviate from the market parties' dispatch schedule or forecast, the market party can alter the dispatch of other assets in its possession to match the energy volume of its trade position).

1.2.2 Electricity market processes

High-level process of the wholesale market starts with long-term. Market parties start selling and buying electricity long before the delivery period. On this forward market, bilateral contracts are concluded which may have structures comparable to financial derivatives. Contract prices may be linked to other commodities, and contract execution may be optional.

Markets are being coupled on day-ahead. On the day before the day of delivery (D-1), a day-ahead auction is executed for all delivery hours of the following day. Market parties provide their buy and sell orders to power exchanges. The order books of power exchanges are jointly cleared in the day-ahead market-couplings-process (clearing starts at noon, D-1). This clearing is subject to available transmission capacity between the bidding zones. The day-ahead market thus gives access to interconnector capacity and enables electricity trading across the EU (see figure 1.1).

FIGURE 1.1: Countries participating in single day-ahead coupling as of July 2019. Non-EU participants indicated blue. (Adapted from ENTSO-e, 2019a)

Continuous trading on intra-day. Market parties may continuously trade bilaterally (also called 'over-the-counter' or OTC) or through power exchanges, which facilitate intra-day auctions and continuous trading with open order books. For the latter, market parties provide buy and sell orders that are displayed to other market parties. In contrast to an auction, these orders are instantaneously cleared when orders fulfil the matching requirements regarding prices, delivery periods and order types. Besides trading within an (often national) bidding zone, power exchanges also provide access to an international intra-day market coupling with continuous trading and with auctions. This access is again subject to available (remaining) transmission capacity between bidding zones. The international intra-day market closes one hour before the hour of delivery. However, trading continues within a bidding zone until the ISP of delivery, and in several countries (e.g. the Netherlands) it is even possible to trade 'ex-post' (e.g. until 10:00 D+1). Ex-post trading may be beneficial for market parties with opposite imbalance positions, whereby the imbalance price per direction (i.e. long and short) differs (i.e. dual pricing).

Market parties continuously optimise their portfolio dispatch. In parallel to the markets, market parties adjust their asset dispatch schedules based on trading results, updated forecasts of own load and RES dispatch as well as in case of asset outages. Cross-border markets will have 15-minute market time unit. Today the day-ahead and the intra-day market coupling are organised with a one hour market time unit (MTU). Recent EU regulation requires this market time unit to be shortened to 15-minutes. When this change is implemented, the MTU length of the market coupling is harmonised with the ISP length (European Union, 2019b).

Markets are facilitated by TSOs. The system operation task of TSOs entails facilitation of market processes. Market facilitation includes administration of trade nominations, determination of available cross-border capacity and allocation thereof to the market (i.e. selling transmission rights), matching of cross-border trade schedules with other TSOs, data publication for market parties, and settlement of congestion income from capacity allocation among TSOs. National regulation usually determines for which purpose the congestion income has to be used (e.g. tariff reduction or grid expansion) (see European Commission, 2015; European Commission, 2016; European Commission, 2017a).

Ancillary services processes run in parallel. The acquisition processes (e.g. tenders and auctions) of various ancillary services are organised in parallel to the electricity market processes. Some ancillary services are procured months before the delivery period (e.g. black-start services), others are obtained during day-ahead or the intraday (e.g. redispatch services), and others even in real-time operation (e.g. some balancing energy services).

Simplified market processes. Figure 1.2 illustrates the high-level sequences of market and ancillary services processes. Chapter 5 explores the processes and market activities in more detail. Please note that various tasks for market parties and operators are not included in this simplified illustration (e.g. provision of dispatch schedules and grid security analyses). Moreover, it has to be noted that the acquisition periods of ancillary services are indicative, as timings vary in different European justifications.

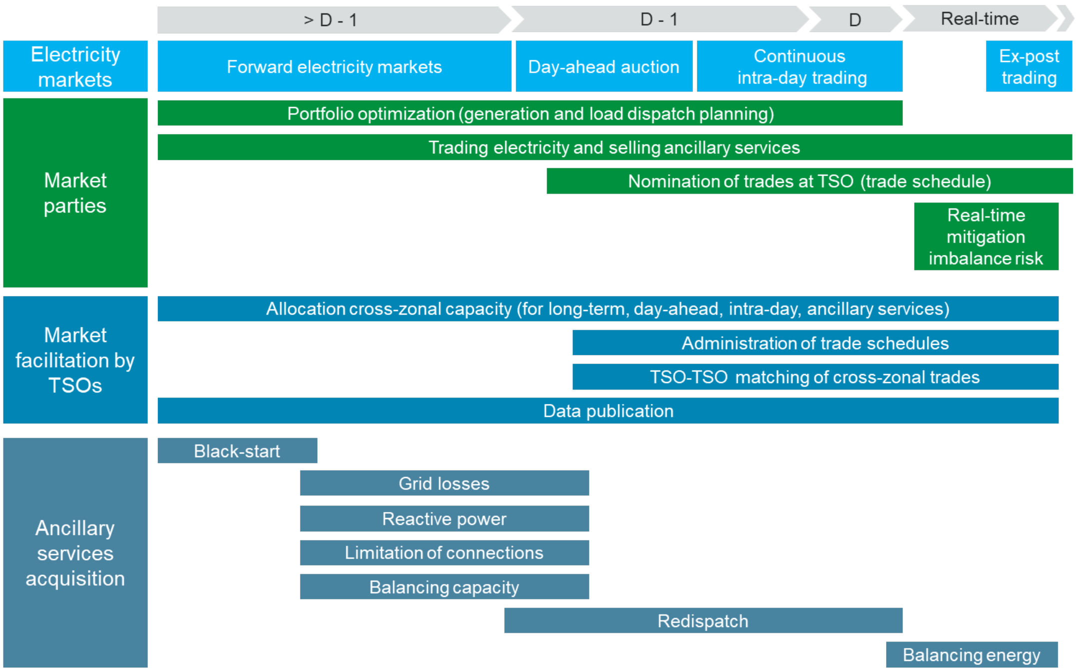


FIGURE 1.2: Simplified processes and activities in European wholesale electricity markets (own illustration). D means delivery day.

1.3 Current practice: Overview of ancillary services in the Netherlands

Designs of ancillary service through-out Europe are still diverse, despite efforts for regulatory harmonisation. Table 1.1 provides an exemplary overview of the various ancillary services applied by the TSO in the Netherlands. The table includes the objective of application by TenneT TSO B.V. (TenneT)[4], the acquired quantities per

[4]If not stated otherwise, TenneT refers to the Dutch TSO TenneT TSO B.V.

TABLE 1.1: Ancillary services in the Netherlands 2017 & 2018

Ancillary Service	Objective of using ancillary service	Acquired quantity per year		Costs per year (mio.€)		Source
		2017	2018	2017	2018	
Frequency Containment Reserves (FCR)	Stabilization of frequency disturbances in European frequency areas	107 MW	111 MW	13.8	14.3	[1][2][*]
automatic Frequency Restoration Reserves (aFRR)	Restoration of real-time power balance in TSO area	504 GWh	608 GWh	28.6	42.7	[1]
manual FRR scheduled activated (mFRRsa)	Restoration of real-time power balance in TSO area	2 GWh	2 GWh	3.1	4.3	[1]
manual FRR directly activated (mFRRda)	Restoration of real-time power balance in TSO area	6 GWh	9 GWh	3.1	4.3	[1]
mFRRda balancing capacity	Contract to ensure sufficient available FRR in real-time	350 MW upward, 200 MW downward**	700 MW upward, 692 MW downward**	7.4	72.5	[1][2][*]
aFRR balancing capacity	Contract to ensure sufficient available FRR in real-time	340 MW	335 MW**	30.4	57.6	[1][2][*]
Reserve for other purposes (ROP)	Mitigation of grid congestions	664 GWh	688 GWh	46.1	53.5	[2]
Intra-day Congestion Spreads (IDCONS)	Mitigation of grid congestions	not operational 2017	not operational 2018	na	na	
Limitation connection capacity	Mitigation of grid congestions in case of grid maintenance	na	na	***	***	[2]
Grid losses services	Compensation of grid losses	5080 GWh	5040 GWh			[3]
Reactive power services	Control of grid voltage	na	na	na	na	
Black-start services	Re-energizing the grid after blackout	na	na	na	na	

[1] www.tennet.eu
[2] TenneT Annual Market Update 2018
[3] TenneT Holding Integrated Report 2018
[*] Cost based on volumes from [1] and average prices from [2]
[**] Average of auction quantities
[***] Cost included in ROP cost

year (2017 and 2018) as well as an approximation of the cost made by TenneT. Since the official costs are not published, various data on quantities, prices, and yearly average prices are used to calculate an estimate. The costs represent the remaining expenditures for ancillary services after deducting the return from ancillary services. Annex A provides a short description per ancillary service.

DSOs use subset of ancillary services. Ancillary services related to frequency and balancing as well as black-start services are not needed for DSOs, as these tasks are exclusively designated to TSOs. Compensation of grid losses, congestion management and voltage control are in scope of DSO tasks. However, DSOs in the Netherlands only recently started to engage in congestion management actively (GOPACS, 2020).

Harmonised rules and international platforms emerge. The European guidelines on electricity balancing (European Commission, 2017b) and on system operations (European Commission, 2017a), as well as the internal energy market regulation

(European Commission, 2019a), aim for a harmonisation of ancillary services design in the EU. Moreover, the regulations require the TSOs to share and exchange ancillary services across borders, to coordinate its application, and to reduce overall costs. In this context, European balancing platforms for aFRR, mFRR, and replacement reserves (RR) are under development (ENTSO-e, 2020). To coordinate and solve grid congestions, regional security coordinators have received the task to develop systems and processes to share and jointly apply remedial actions, including redispatch (European Commission, 2017a). The development of standard ancillary services and coordination platforms may have a severe impact on the current design of ancillary services in the Netherlands.

1.4 Research goal and research question

Sound policy advice needed on process interaction. Many decisions on ancillary service designs will be taken in the coming years in order to adapt existing arrangements to the fast-changing context of power systems. Yet, the discourse in politics and research often seems to focus on single physical issues to be solved by ancillary service changes. Design interactions of various ancillary services are given less prominence. The physical impact of ancillary services is largely linked by physical laws, while socio-economic dynamics determine the interdependencies of transacting ancillary services from the provider to the grid or system operator (i.e. the acquisition process). Given the need for methods from social science, the evaluation of the latter may be more ambiguous than the first. Therefore, it is of particular importance that policymakers receive advice based on comprehensive evaluation methods regarding ancillary service acquisition before they adapt design changes.

Goal. In order to support sound policy advice during the on-going power system transition, the goal of this research is the development of assessment methods and performance indicators to evaluate design options for the ancillary services acquisition processes.

Research question. Based on the research goal, the following research question is derived: *Is it possible to evaluate acquisition process options, given potential interaction of ancillary services?*

Chapter 2

Review state-of-the-art

2.1 The term 'ancillary services'

A directional definition. The European Directive 2009/72/EC defines ancillary service as "*a service necessary for the operation of a transmission or distribution system*" (European Union, 2009, p. 63). This definition does not include an explicit directionality (i.e. who is providing to whom) as it is proposed by EURELECTRIC (2000): " *'System services' are all services provided by some system function (like a system operator or a grid/network operator) to users connected to the system. 'Ancillary services' are services procured by a system functionality (system operator or grid/network operator) from system users in order to be able to provide the system services*" (p. 12). Nobel (2016) contributes, in line with this directional definition, a 'decomposed service model'. In this model, the term user services is proposed as "*a more general term for all the services that users may be required to provide to the operators. User services are here not restricted to 'ancillary services'* [...]" (p. 26). Nobel specifies system services, on the other hand, as services enabling economic power transfer. These system services include: "*Grid access in form of physical connection and a connection agreement, which allocates physical capacity to a grid user for energy exchange*", "*System access by trading accreditation as well as imbalance settlement*", "*System access to cross-border capacity allowing for trades over interconnectors*", and "*The provision of stable frequency and stable voltage serve system integrity*" (Glismann and Nobel, 2017, p. 2).

Early struggles with scoping during unbundling. There are numerous lists of ancillary services. The challenges of defining a set of ancillary services can be observed by the recommendations of the U.S. Federal Energy Regulation Commission during the early stages of unbundling in the U.S. electricity sector. The first inquiry of 38 ancillary services was later reduced to 12, which, as criticised by Hirst (1999), did not distinguish between ancillary services and system services. Finally, the following six ancillary services where adopted: (1) scheduling and dispatching services, (2) load following service, (3) energy imbalance service, (4) system protection service, (5) reactive, power/voltage control service, and (6) loss compensation service (FERC, 1996).

Unidirectional definitions persist. However, also in Europe there is still no consensus on the scope and definition of ancillary services. For instance, a recent publication of German Energy Agency GmbH describes ancillary services as "*measures to keep frequency, voltage and load of grid operating equipment within the approved limits, or return them to the normal range after malfunctions*" (Dena, 2018, p. 8). The authors also do not distinguish ancillary services and system services: "*Ancillary service products are sourced from the grid operators' operating resources, but also from grid users, i.e.*

through power generating units or flexible loads" (p.9). Their lists of ancillary services subsequently also include switching of grid operating equipment and transformer gradation and switchover. According to Nobel (2016), such measures would be applied by the grid operator to provide system services to the grid users.

Recent definition by European Union is rather political than conceptual. Glismann and Nobel (2017) note that ancillary services "*include (but are not limited to) balancing reserve (capacity) provision, balancing energy provision (i.e. real-time activated balancing reserves), reactive power provision, active power redispatch and black-start capability*" (p. 2). However, the recently published European directive (2019/944) shows that even this short list cannot be considered as consensus. The directive redefines ancillary services as "*service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management*" (European Union, 2019a, Article 2 (43)). As non-frequency ancillary service, the directive lists state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability (Article 2 (49)). The explicit exclusion of congestion management in the definition of ancillary services is hard to place into a consistent concept. Especially when reading the definition of redispatch in the regulation (2019/943) " *'redispatching' means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*" (European Union, 2019b, Article 2 (26)). Redispatch is thus clearly a service provided from a grid user to a grid operator. The definition of the European Union seems, therefore, to be rather a political compromise than a conceptual definition for the use in research.

Working definition. For the remainder of this study, the definition introduced in Glismann and Nobel (2017) will be used: "*all services that system users provide to the system operator and the network operator for the operation of the transmission system and the distribution system*".

2.2 Fields of research on ancillary services

Categorisation by ancillary services objectives. Explicit categorisation, applied in research with multiple ancillary services, is mainly based on ancillary service objectives. Examples for objective categorisation can be found in Hirst and Kirby (1996), EURELECTRIC (2004), Rebours (2008), Cigre (2010), Holttinen et al. (2012), and Dena (2018).

Categorisation by regulatory terms. A second categorisation of multiple ancillary service research uses names of ancillary services or ancillary service types from local regulation. Typical examples are frequency containment reserves, frequency restoration reserves, and replacement reserves in EU jurisdictions (e.g. ENTSO-e, 2012) and the U.S. terminology of regulation services, spinning reserves, and non-spinning reserves (e.g. Soft, 2002 and Zhou, Levin, and Conzelmann, 2016).

Categorisation by research focus. Research on ancillary services is mainly dedicated to one specific ancillary service or ancillary service objective like frequency, voltage, current or restoration after disturbances. However, the research methods and findings of such studies can be relevant for more generic ancillary services assessments. Therefore, a literature distinction by assessment focus is used.

2.2.1 Physical performance and technological feasibility

One field of research focuses on the physical performance of ancillary services and the feasibility of specific technologies to deliver these ancillary services.

Power system performance. Rebours et al. (2007a) provide, for instance, a set of technical requirements and features of frequency and voltage control related ancillary services, which are observed in 11 different power systems. Also ENTSO-e (2012) describes technical design variables of frequency-related ancillary services. They furthermore elaborate per ancillary service type on recommended performance indicators. Maree et al. (2000) can also be categorised as physical performance literature because they provided a technical ancillary service process with a focus on voltage control. This study, however, excludes prices from the scope and elaborates whether the reactive power offers generally can ensure system security. Frunt (2011) analyses with a power system model on a millisecond scale the physical balancing performance in interconnected high-RES scenarios. Another good example of a physical performance analysis is provided by Haan (2016), who analyses the physical consequences of various cross-border balancing arrangements in Europe. In this context the author couples a power flow model to a frequency performance model.

Dimensioning. Literature regarding dimensioning of required quantities of ancillary services is also closely linked to physical performance questions of ancillary services. Examples for this field of research are the probabilistic method for dimensioning of balancing services by Consentec and Haubrich (2008) and the quantile regression approach of Jost, Braun, and Fritz (2015). Holttinen et al. (2012) present an overview of various dimensioning methods in practice.

Validation of delivery. Studies regarding methods for validation of ancillary service delivery after activation by the system operator are another physical performance-related field of research (e.g. Lampropoulos et al., 2012).

RES impact. Research investigating the impact of renewable energy penetration on frequency quality, voltage and congestions may also be considered as a part of this category (e.g. Hirth, 2015).

Providers feasibility. Another research area that may be grouped with the topics above are studies regarding technology specific feasibility to provide ancillary services. Examples are feasibility studies concerning various storage types (Dowling, Kumar, and Zavala, 2017), electric vehicles (Sarker, Dvorkin, and Ortega-vazquez, 2015), RES technologies as well as large-scale and small-scale demand responds appliances (Dena, 2018). Also, ancillary service in island-systems is a related study subject (e.g. Datta et al., 2011; Delille et al., 2012). In order to also show the economic feasibility, this field of research is often closely linked to research on economic self-optimisation in ancillary services markets.

2.2.2 System-cost minimisation

Ancillary service research with the focus on system-cost minimisation is a macroeconomic system planning category and often related to engineering studies.

Redispatch optimisation. Nüssler (2012) developed a two-stage model for power plant dispatch optimisation and cost-based redispatch optimisation, using Power Transfer Distribution Factors (PTDF). The approach includes constraints for power plants from balancing capacity auctions. However the effect of this potential interaction is not further assessed. Related to redispatch as well, Kunz and Zerrahn (2015) explore the benefits of TSO coordination in congestion management by applying a generalised Nash equilibrium model.

Balancing energy and balancing capacity optimisation. Havel et al. (2008) provide an extensive 7 step framework for the acquisition of balancing services, which suits the physical performance and the cost minimisation literature groups. It includes dimensioning modeling with a stochastic area-control-error model. Power plants offer their available capacity with a mixed integer and linear programming approach, whereby assumed market prices for spot and ancillary services are provided by TSO experts. *"In other words, the model tells the TSO what amount of the AS reserves are expected to be available on the market if their prices are given"* (p. 5). This step thus implies perfect knowledge of market parties and TSO. The TSO subsequently optimises the procurement of balancing capacity between the various products through linear programming. In the last step, a sophisticated model to mimic automatic and manual activation of balancing energy products is proposed, using Monte-Carlo simulations. Finally, reliability performance indicators are evaluated to assess the ancillary service planning choices.

Imbalance netting. Vandezande (2011) explores potential cost reductions for balancing as a consequence of cross-border imbalance netting between Belgium and the Netherlands. Vandezande uses public data on the total BRP imbalances per country, price indicators for the FRR bid ladder and available cross-border capacity. The author approximates the change in FRR costs in both countries.

As shown by the examples above, this literature cluster focuses on cost minimisation, utilising system operator methods. Market party behaviour and incentives are highly simplified, often assuming cost-based bidding and constant, design-independent behaviour.

2.2.3 Economic self-optimisation

Studies exploring profit-maximising strategies in a given set of rules for ancillary services and electricity markets are here considered as economic self-optimisation studies.

Two markets. Wen and David (2002) provide a stochastic optimisation model for bidding strategies for a 'California-like' reserve market. The approach addresses both the day-ahead spot market and the spinning reserve market. Furthermore, inter-temporal power plant parameters are considered as well as competitor dependent strategies. The modelled market parties estimate probability density distributions for the bidding coefficients of all their rivals.

Multi-unit auctions. Swider and Weber (2007) present a methodology for economic-self optimisation in a day-ahead, multi-unit and pay-as-bid procurement auction for balancing capacity and energy. In this study, they define strategic bidding as a situation where a market party bids other than marginal costs, in order to exploit the imperfections of the market design. Furthermore, they define market power as a situation where "the bidder can increase his profits by strategic bidding or by any means other than lowering his costs" (p.1299). The approach follows a Bayes-strategy, where one market party assumes price-functions and behaviour of the competitors. They point to the methods challenge that "*In fact, in a real-world application* *much effort is necessary to find an appropriate density function*[...]" (p. 1301) to avoid underestimation of the probability of bid acceptance. Ocker, Ehrhart, and Ott (2017) also developed a multi-unit bidding strategy for the German and Austrian FRR auctions. Market parties offer bids, based on an expected profit function, containing the components costs, merit-order position and TSO demand probability. They also apply the concept from Müsgens, Ockenfels, and Peek (2014), which distinguishes the behaviour of infra-marginal power plants and extra-marginal power plants, i.e. the variable costs of a power plant are lower (infra-marginal) or higher (extra-marginal) than the relevant market price.

Self-learning in the day-ahead markets. Wehinger (2010) and Wehinger et al. (2013) built an agent-based model of the day-ahead spot market with self-learning agents per generation technology, executing market power in a four-country electricity market setting with a focus on Germany. Interactions of different markets or ancillary services are out of scope. However, the multi-factor auto-regressive model to determine hourly price-forward-curves certainly contributes to economic self-optimisation literature regarding ancillary services.

2.2.4 Analyses of market behaviour

Closely linked to the research on economic-self optimisation is literature regarding market behaviour analyses. The difference between both literature groups is that the underlying question is not about profit maximisation for specific market parties, but instead on identifying incentives and distortions in market designs. These analyses can be qualitative, empirical and based on simulations. For the latter, models include profit functions, which may be similar to the economic self-optimisation literature.

Incentive compatibility. A fundamental theoretical study is published by Chao and Wilson (2002). Based on an 'incentive compatibility' principle, they establish a set of rules for scoring and settlement of multi-unit balancing auctions (i.e. with a capacity part and an energy part). Subsequently, Müsgens, Ockenfels, and Peek (2014) illustrate the role of the scoring rule and the settlement rule. These rules are considered as key elements of the market design, which they discuss by using the concept of infra-marginal power plants and extra-marginal power plants. Both references argue that in a situation with perfect competition but with uncertainty about competitors' costs, uniform pricing is a more efficient settlement rule than pay-as-bid. They conclude that suppliers under uniform pricing are incentivised to bid at their cost-level, while such a strategy under pay-as-bid would not be optimal for the suppliers.

Agent-based modelling with self-learning. Weidlich (2008) developed an agent-based simulation model to represent the day-ahead electricity market, the 'minute reserve' balancing market, as well as CO_2 emission trading in a German scenario setting. The study aims to provide a model that realistically represents the various markets with self-learning software agents. Furthermore, the model is used to address market behaviour questions regarding the balancing and day-ahead market in Germany. She shows that day-ahead prices increase with increasing capacity for minute reserves, procured in preceding auctions. Moreover, the market power of the six largest market parties in Germany is analysed by simulating divestiture scenarios. Weidlich also addresses the settlement rule question by simulations. In contrast to the literature above, she concludes that, for the minute reserves in Germany, prices would increase under uniform pricing compared to pay-as-bid.

Game-theory. The assessment of different balancing auction designs is further advanced by Ocker (2018), who discusses the characteristics of bidders, interdependencies with the electricity market as well as implications of a harmonised European balancing power market. With game-theoretical models, he argues that neither under pay-as-bid nor under uniform pricing market parties would reveal their true costs in German multi-unit balancing auctions. He sees the reason for this behaviour "*in the regular repetition of the auction with (almost) the same set of bidders*" (p. 102).

Interrelation of balancing and day-ahead market. Another contribution to the fundamental interrelation of balancing market and day-ahead market is published by Just and Weber (2008). As part of an equilibrium model, they use an indifference condition (the market party is indifferent whether to profit on the balancing market or the day-ahead market) to derive the 'reserve price' per power plant. The day-ahead market merit-order is subsequently transformed by considering must-run obligations of cleared reserved capacity. The model is used to estimate the expected reservation price development over the last years in Germany.

Empirical incentives in imbalance. The same authors published a study on incentives and interrelations of the German spot market and the imbalance mechanism (confusingly they use the term 'balancing mechanism' whereas EU regulation uses 'imbalance mechanism') (Just and Weber, 2015). They empirically investigate the correlation of day-ahead, intra-day and imbalance prices. They state that the high correlation of these prices, thus the predictability of the imbalance price, is an arbitrage possibility that can be exploited by market parties. A stochastic model is used to illustrate the incentive for BRP's to take imbalance positions strategically.

Passive balancing. In this line of research is also Veen, Abbasy, and Hakvoort (2012), who use an agent-based model to analyse risks and opportunities of BRPs from imbalance mechanisms in different design settings. In contrast to Just and Weber (2015), these authors do not approach intentional imbalances as a thread for the system, which needs to be avoided.

Compatibility balancing energy pricing and imbalance pricing. The perspective of Veen, Abbasy, and Hakvoort (2012) on intentional imbalances corresponds to the balancing market design theory developed by Nobel (2016). Nobel provides a comprehensive 'decomposed service model' of actors with corresponding freedoms and responsibilities. In his analysis of balancing markets with different designs, he distinguishes grid operators, system operators, (physical) grid users and (commercial) system users. With a focus on incentive compatibility and exclusion mechanisms, Nobel (2016) provides a conceptual model as well as empirical tests regarding the design of pricing, imbalance settlement period, transparency and financial incentives for system operators. The author shows that imbalance prices compete with balancing energy prices. Furthermore, he shows that BRPs in the Netherlands have an incentive to reduce individual imbalance as well as the system imbalance, while in Germany, the imbalance price provides hardly any incentive[1]. Nobel argues that an imbalance system with compatible incentives for intentional imbalances reduces exclusion mechanisms because BRPs can participate in balancing without barriers related to balancing services (e.g. pre-qualification). Moreover, he formulates a necessity to imbalance pricing designs, that (at least on average) no positive arbitrage between the electricity (commodity) market and the imbalance market should exist

[1] Based on Dutch data for 2013 and German data for 2013 Q2 to 2014 Q1. Meanwhile the German imbalance price mechanism has changed.

for market parties. This condition is analysed with delta prices of imbalance prices and the day-ahead prices.

Liquidity on intra-day trading. A particular field of literature is dedicated to market behaviour in continuous intra-day trading. Hagemann and Weber (2013) contribute a theoretical and empirical analysis of the liquidity in intra-day electricity trading. They test a 'fundamental' and a 'trading' model regarding market party behaviour. The fundamental model is empirically rejected. To test their hypotheses, they measure the liquidity indicators buy-ask-spread, high-to-low-difference, price variance, number of trades and trading volume.

Volume and timing decision on intra-day. Garnier and Madlener (2014) provide an intra-day trading concept with options valuation and dynamic programming to optimise quantity and timing decisions of market parties. They assume a stochastic process with a correlated arithmetic Brownian-motion for forecast errors and with a geometric Brownian-motion for intra-day prices. The simulation results suggest different heuristic intra-day bidding strategies for situations with high transaction costs, late trading surcharges, RES forecast volatility and intra-day-price volatility.

Impact of RES volatility on intra-day strategies. Henriot (2014) developed a simple analytical model to assess different strategies of market parties being exposed to wind forecast errors. They find that oscillating forecast errors might lead to rather passive market parties on the intra-day market, trying to avoid transaction costs.

Comprehensive intra-day modelling. Selasinsky (2014) provides an approach to analyse continuous intra-day markets with a focus on managing forecast errors from RES. First, a mental model is presented to display the possible strategies of market parties on intra-day trading. Secondly, an empirical analysis exhibits that market parties act according to their technical properties. Finally, an extensive computational model is developed to estimate BRP costs resulting from forecast errors of renewable energies in the German market. Participation in the balancing energy market and profits by intentional imbalances are out of scope. Furthermore, there is no redispatch considered in this setup. The author uses the concept of an 'indifference offer price' and an 'optimal offer price'. He furthermore states in his mental model that "*placing strategic offers is not 'objectionable' but a direct consequence of the design of a continuous double auction. Indeed, Zhan and Friedman (2007) showed that mark-ups and mark-downs are important for the coordination in CDAs* [continuous double auctions] *and contribute to efficient market outcomes*" (p. 37). A sophisticated pricing method is presented, which determines the indifferent price and an optimal price on a Weibull-shaped cumulative distribution function, representing the probability of clearing success. An adapted Newton-Raphson method helps to find the profit maximising price. These believe functions have to be constructed, based on various approaches and assumptions. This is, however, a small downside of this very outstanding work. A less complicated pricing assumption might have been sufficient because the study focus is not on finding strategies for economic self-optimisation, but on insights about market party behaviour and the impact of RES volatility.

The dedicated intra-day trading literature mentioned above unanimously treat imbalance mechanisms as a penalty risk, which is to be mitigated by intra-day trades. In line with the perspective of Just and Weber (2015), intentional imbalance as a strategic option is out of scope in these studies.

Interrelation congestions and imbalances. Chaves-Ávila, Veen, and Hakvoort (2014) call these intentional imbalances 'passive balancing'. They contribute to ancillary service literature by discussing potential adverse incentives of imbalance prices in relation to network congestion based on public data in Germany.

Strategic behaviour in congestion management. Strategic behaviour in the context of congestion management is studied by Veit, Weidlich, and Krafft (2009). The authors assess price effects in a market setup whereby Germany is split into six bidding zones in order to solve congestions. For the study, an agent-based model with self-learning agents is applied. Strategic behaviour in the form of 'increase-decrease gaming' (ing-dec) is recently also studied and discussed in the context of a large research project regarding redispatch design on behalf of the German ministry of economics and energy. Hirth and Schlecht (2019) contribute to it with a stylised model which exhibits that profit from inc-dec strategies between the day-ahead market and a redispatch market is possible without executing market power. They furthermore show that inc-dec strategies increase the redispatch demand. These findings are further investigated by Consentec (2019), who use an extensive model to quantify these effects for a German 2030 scenario. The authors compare a regulatory cost-based redispatch to a market-based (pay-as-bid) redispatch design. For the regulatory redispatch benchmark, power plants provide short-run marginal cost to the day-ahead market simulation as well as to the subsequent regulatory cost-based redispatch simulation. Under the market-based regime, power plants provide expected local marginal prices to the day-ahead simulation and short-run marginal cost (SRMC) to the redispatch simulation. The results show much higher cost and redispatch volumes for the market-based simulations. The authors argue that the results indicate a significant incentive incompatibility of market-based redispatch designs. Yet, the research project did not assess empirical evidence of the strategy nor the impact of potential exclusion mechanisms from regulated redispatch for small and distributed energy sources on the energy transition.

2.2.5 Design frameworks for policy-making.

A distinguished group of ancillary services literature concerns research on methods for ancillary services design. The literature on market behaviour also often entails assessments of design options, as well as policy recommendations for design improvements. However, dedicated ancillary services design literature focuses in particular on the design process and the policy recommendation, rather than primarily investigating market behaviour with the subsequent derivation of policy recommendations. Yet, there is an overlap, because the design evaluation requires information about market behaviour.

Bottom-line test for policy advice. Soft (2002) proposes that every market design should undergo at least a minimal testing before being applied. Soft provides a bottom-line test, not restricted to ancillary services, which consists of three steps. (1) model the cost function of markets actors, (2) compute the minimum possible costs for serving the load, (3) compute the cost increases under the proposed design.

Policy advice from agent-based models. Besides a substantial contribution to agent-based modelling in power systems, Tesfatsion (2018) provides numerous recommendations for model validation and structured energy policy advice. She uses the term 'transactive energy systems', which also includes ancillary services. Tesfatsion proposes nine policy-readiness-levels for explicit use in normative design research.

Ancillary service design processes. Various authors, somehow affiliated to the Technical University of Delft, have published on structural design approaches in the context of electricity markets and ancillary services (Doorman, Veen, and Abassy, 2011; Abbasy, 2012; Veen, 2012; Veen, Abbasy, and Hakvoort, 2012; Doorman and Veen, 2013; Iychettira, Hakvoort, and Linares, 2017; Poplavskaya and Vries, 2019). Likewise Rebours et al. (2007b), the authors elaborate on design variables and design options of the ancillary services studied. Additionally, the authors systematically approach the various design options with a design space.

Balancing frameworks. For instance Doorman, Veen, and Abassy (2011), Veen (2012), and Doorman and Veen (2013) provide an extensive design framework for national and cross-border balancing with a variety of design variables, design options, performance criteria, performance indicators and expert-based multi-criteria analyses as well as an agent-based modelling approach. With a different focus, but also with a structural design approach, Borne et al. (2018) as well as Poplavskaya and Vries (2019) analyse barriers for distributed energy resources in European balancing markets.

Generic policy design. Iychettira, Hakvoort, and Linares (2017) developed a design framework with the target to "*analyse existing policies and their impact on the socio-technical system, but also help explore the full policy design space in a structured fashion, by incorporating the institutional context into the analysis*". They explicitly derive their design approach from process design theory and the generic conceptual design framework of Herder and Stikkelman (2004). To incorporate the socio-technical system to the policy research, they also lend the institutional analysis and development framework from Ostrom (2005). Ostrom's institutional analysis distinguishes exogenous variables in the group's biophysical conditions, attributes of the community and rules in use. Central in his framework is the description of action situations, which are defined as: "*Whenever two or more individuals are faced with a set of potential actions that jointly produce outcomes, these individuals can be said to be 'in' an action situation*" (p.32). Iychettira, Hakvoort, and Linares (2017) show the applicability of the joint framework to the design assessment of RES support schemes. They use an agent-based model for the 'testing' phase of the interactions. The authors find that the framework assists policymakers with a structural identification of levers or variables that go beyond just quantity and price. As a limitation of the approach, they point out that, even though the agent-based model incorporates bounded rationality of agents, they remain rational. They conclude that a emotional or political person is not captured and that the framework, therefore, is somewhat technocratic.

2.3 Contribution to literature

Overview. The previous section presents an overview of state-of-the-art ancillary service research. The overview shows that the broad area of research can be categorised in five groups, given their research focus: physical performance and technological feasibility, system-cost minimisation, economic self-optimisation, market behaviour analyses and policy design frameworks. As the present research question concerns evaluation methods for acquisition processes, this thesis would be part of the design framework category. Figure 2.1 illustrates the identified research categories of ancillary services as well as the positioning (in red) of the present study.

Gaps. The identified design framework literature turns out to be either tailored to specific ancillary services, such as balancing services (e.g. Doorman, Veen, and Abassy, 2011; Veen, 2012; Doorman and Veen, 2013; Poplavskaya and Vries, 2019) or the proposals are very generic for power system design (e.g. Soft, 2002; Iychettira,

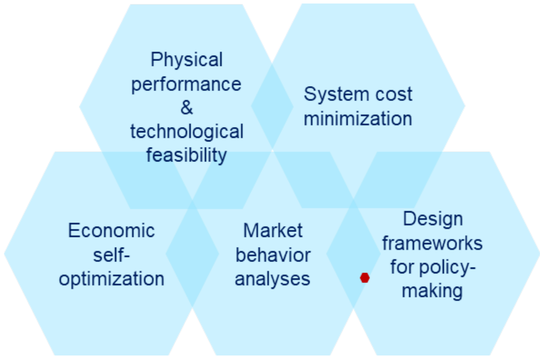


FIGURE 2.1: Research categories and positioning of the present thesis.

Hakvoort, and Linares, 2017; Tesfatsion, 2018). Structured design frameworks dedicated to acquisition processes of all types of ancillary services were not identified. Among the market behaviour analyses literature, various interactions of ancillary services and electricity markets have been studied. A structured method to evaluate these interactions as part of ancillary service design has not been found. Moreover, models for testing ancillary service interactions are either very specific to the research question or not accessible for other researchers (i.e. closed-source).

Contribution. By assessing the research question above, the present study can provide the following contributions to ancillary services literature:

1. A generic framework ancillary services design;
2. Performance indicators for interactions of acquisition processes;
3. An open-source model to test interactions of acquisition processes;
4. Results of applying a framework and a model to an exemplary design question.

Chapter 3

Research description

3.1 Hypothesis

Organisation means integrated design. Acknowledgement of potential physical and economic interaction of ancillary services in a power system leads to the question of whether of and how to consider such interaction in policy development. The approach to design multiple ancillary services in an integrated way is here described as organising ancillary services. "*The organisation of ancillary services in a regulatory area or region thereby aims at jointly optimising the design of all ancillary services in accordance with respective quality targets of the power system*" (Glismann and Nobel, 2017, p. 2). Organising ancillary services ultimately leads to a set of choices regarding design variables of ancillary services.

Hypotheses defined to test supplementary methods. The literature review reveals that, as yet, there is a lack of research published on the organisation of ancillary services. This is consequently a research gap that limits the value of prevailing policy recommendations, as they are mainly based on technical assessments or (isolated) optimisation of specific ancillary services. However, it may be the case that adding organisational aspects to existing evaluation methods would not add value to respective policy recommendations, or it could make the assessment impracticable. The hypotheses of this study should, therefore, test the feasibility of supplementary methods for the organisation of ancillary services. The focus is placed on the evaluation of ancillary service interactions as well as corresponding performance indicators. The hypotheses are formulated as:

1. *It is possible to evaluate the interaction of ancillary services.*
2. *The additional value from evaluating the interaction of ancillary services justifies the additional research effort.*

3.2 Methodology

1. **Development of a framework to evaluate ancillary services designs.**
   This framework is required to answer the research question, as it enables a generic way to evaluate ancillary services. Furthermore, it reveals at which point of the assessment the interaction can be examined.
2. **Development of model for the ancillary services acquisition process simulation.**
   The Ancillary Service Acquisition Model (ASAM) is an agent-based model to

simulate the acquisition processes of different ancillary services. This model is an instrument applied in the evaluation framework.

3. **Application of the framework on redispatch design options.**
The application of the framework on a practical design question shows the possibilities and limitations of both the framework and the developed simulation model (see figure 3.1). The use-case assesses a (sub-)research question on redispatch services in the Netherlands, including its interaction with and the intra-day (electricity) market, the balancing energy market, and the imbalance market.

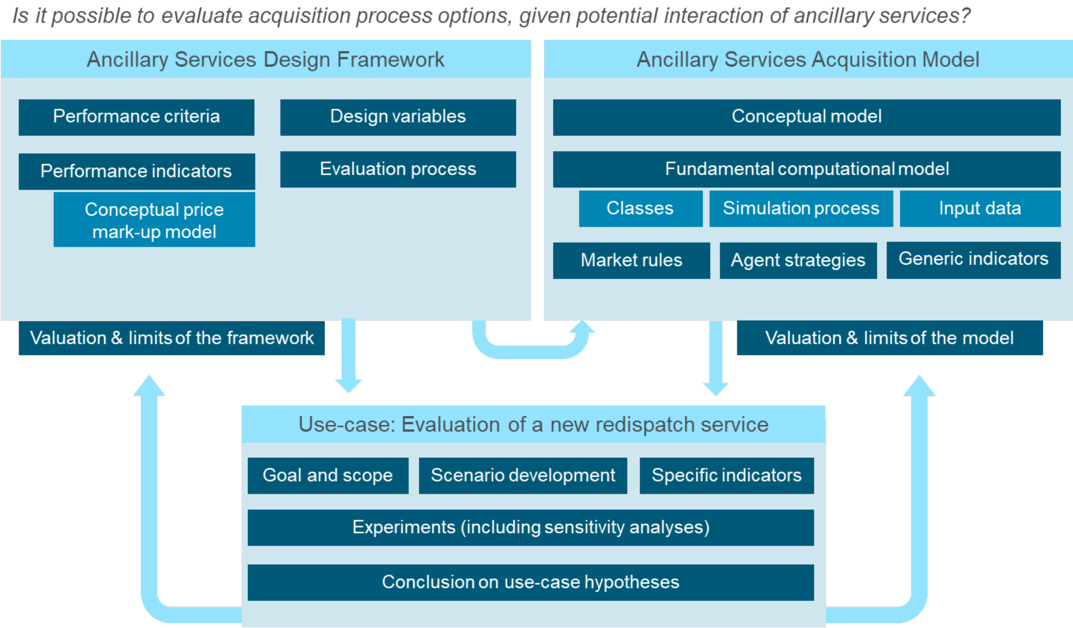


FIGURE 3.1: Illustration of research methodology

Scope and boundary conditions. The following scope and boundary conditions apply to the thesis:

- The focus lies on European power systems, assuming current roles and responsibilities. If not stated otherwise, the Dutch implementation of the EU law is taken as starting point.
- Assumed high-level of generation and transmission unbundling, and self-dispatch.
- Not in the focus of this study are the integration and harmonisation of regulatory areas (i.e. countries) and exchanging ancillary services across areas.
- Not in focus is the evaluation of physical system behaviour with various ancillary services designs. However, the physical system behaviour needs explicit placement in the methodology and analyses.

Chapter 4

Framework for ancillary services design evaluation

4.1 Definition of the ancillary services acquisition process

Framework distinguishes three basic elements. The organisation of ancillary services, as defined in section 3.1, describes a joint design optimisation of multiple ancillary services. Following Glismann and Nobel (2017), the present evaluation framework also distinguishes three basic elements to structure ancillary services (p. 3):

1. *"Ancillary service objective is the purpose for which the system/grid operator intends to use an ancillary service means (e.g. for voltage control)*
2. *Ancillary service product is a technical and administrative set of specifications that define the content of a service to be provided by the system user to the operator (e.g. voltage-dependent reactive power control).*
3. *Ancillary service acquisition is the transactional process of an ancillary service product from the system user (i.e. provision through a contract with the provider) to the possession of the operator."*

Acquisition instead of procurement. The third element is also often called procurement in literature. However, the working definition of ancillary services (2 does not exclude obligatory services which are provided without remuneration. To incorporate such ancillary services in the framework, the term acquisition is used instead of procurement.

Basic elements used to structure ancillary services. The basic elements as described above and as illustrated on figure 4.1 are used to structure ancillary services designs. As shown further below, the structuring may be applied to design variables, comparisons of existing ancillary services and to scoping of studies.

4.2 Scope of ancillary services design

The purpose is policy-making. The purpose of an ancillary service design framework determines its perspective and scope. The literature review (chapter 2) describes five research categories of ancillary services:

1. Physical performance & technological feasibility
2. System-cost minimisation

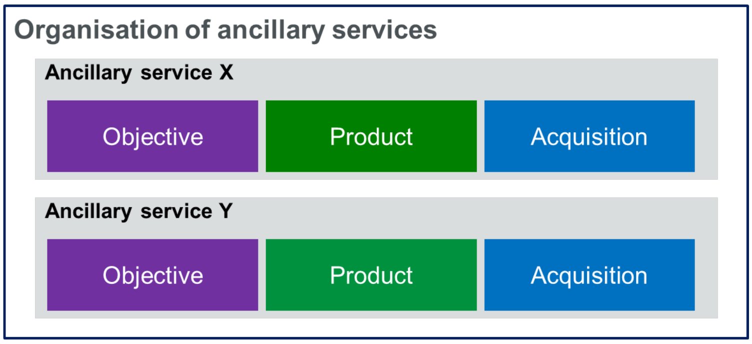


FIGURE 4.1: Basic elements to structure design of ancillary services (adapted from Glismann and Nobel, 2017)

3. Economic self-optimisation
4. Market party behaviour
5. Design frameworks for policy-making

The latter category focuses on the process of designing ancillary services and on formulating policy recommendations. Given the research target (section 1.4) it is obvious that the design framework is made for this purpose.

Focus lies on policy evolution. The framework furthermore focuses on policy changes, in opposition to green-field system design for long-term scenarios. Such green-field or 'revolutionary' design is expected to overlap more with the categories system-cost minimisation and technological feasibility. Consequently, the framework presumes an existing regulatory framework for the power system, including roles and responsibilities as well as specific regulations for ancillary services.

Some regulatory aspects are out of scope. Since ancillary service designs are usually, to a certain level of detail[1], defined in regulation, the design framework should support analyses and recommendations for changes of existing regulation. However, as it is a framework for ancillary services design and not for power system design as a whole, it is reasonable to place some regulatory aspects out of scope. Therefore, quality targets of the power system, as well as roles and responsibilities of power system entities, are not considered as design variables of the framework, but as a regulatory input for the design of ancillary services.

Design impacted by regulation and operations. Given the scope of regulatory aspects in ancillary service design, the regulatory domain illustrated in figure 4.2 may be considered as static and unidirectional: Power system quality targets define "what" needs to be achieved by using ancillary services. Regulatory roles and responsibilities define for which operator tasks ancillary services may or must be used, and to what extent system users may or must offer their services. Hence, roles and responsibilities also define who has to accept and manage what risks (e.g. imbalance risk is borne by balancing responsible parties, see Nobel, 2016). In contrast to this regulatory domain, there is an operational domain which may be considered as rather dynamic and bi-directional when designing ancillary services: operators as well as market parties react on design choices and on each other's behaviour. It is a

[1]Other details are defined in product specifications and contracts

challenging task for ancillary services design to anticipate the response of actors to design changes. Ancillary service design, therefore, relies on theories and models.

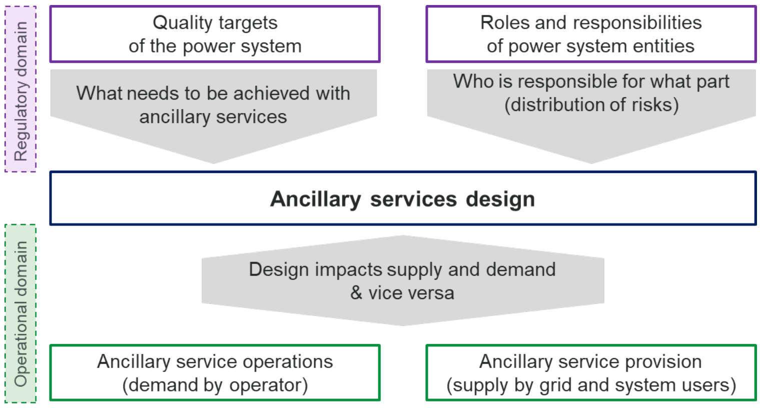


FIGURE 4.2: Scope of ancillary services design

Interactions driven by quantity, quality and alternatives. Grid and system operators adapt their behaviour in response to ancillary services designs and ancillary service supply. The demand for a specific ancillary service is thus determined by the quality and the available volumes of that service, but also by available alternatives and their costs. For instance, to reach the frequency quality targets in Europe, the European TSOs procure a specific quantity of ’frequency containment reserves’ with the purpose to stabilise the system frequency after disturbances (see Haan, 2016). Fonteijn (2016) discusses how a faster frequency containment product would reduce the required quantity. However, also providers of ancillary services adapt their behaviour to ancillary service designs and to operators demand. High prequalification requirements, for example, may reduce the number of ancillary service providers and thus lead to lower ancillary service supply. Moreover, when an operator acquires regularly large volumes of an ancillary service or when remuneration for a service is high, potential providers may decide to focus on this ancillary service and thus reduce the supply of other ancillary services. In order to answer hypothesis 1 (see 3, the framework for ancillary service design requires methods and indicators to assess the above described incentives and behaviour of the actors.

Required framework components. Given the purpose of the design framework, several components are needed to assess design questions and to develop policy recommendations. In line with other frameworks (e.g. Doorman, Veen, and Abassy, 2011; Veen, 2012), the present framework consists of the following generic components:

1. Design variables
2. Performance criteria
3. Performance indicators
4. Evaluation process

The components 1 to 3 are applied in the evaluation process. The four components are described in the following sections.

4.3 Design variables of ancillary services

Compromise between generality and detail. Glismann and Nobel (2017) derived a set of relevant design variables from literature. The authors suggest that design variables must be generic enough to be applicable to various ancillary services, while, at the same time, the variables need to be specific enough to enable in-depth comparisons and evaluations. The present framework uses the proposed set of design variables by Glismann and Nobel (2017), however, a few adaptions are applied.

Adaptions in wording and one additional variable. Figure 4.3 illustrates the design variables (5 product variables and 10 acquisition variables). It has to be noted that sub-variables may be defined for all these proposed design variables. Deviating from the set of Glismann and Nobel, the scoring method is here proposed as a primary design variable and not as a sub-variable of the acquisition method. Furthermore, the variable product underlying is renamed to product subject and reformulated, in order to avoid confusion with financial derivatives. Pricing mechanism is renamed to pricing method for consistency reasons. For the rest is the following description of the generic design variables, except for a few grammatical changes, literally adapted from Glismann and Nobel (2017, p. 4-5). Possible values of design variables are here named design options.

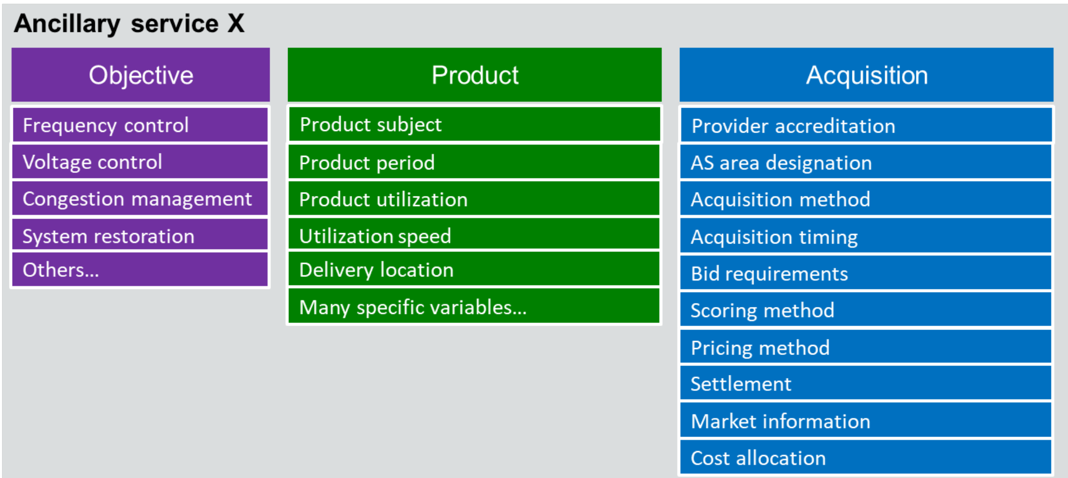


FIGURE 4.3: Design variables of the ancillary services framework

1. **Product subject**
   The product subject defines quantifiable services, which are provided to the grid or system operator when an offer from the provider is accepted. The product subject design options include physical injection or withdraw of energy (MWh), active power (MW), or reactive power (MVar) to-, respectively from the grid, but also options on delivery (e.g. availability of specified capacity).

2. **Product period**
   The product period is the design variable that determines the basic settlement time unit. The product delivery period is, therefore, one or more settlement time units at a specific moment.

3. **Product utilisation**
   Product utilisation is a design variable that generally defines how the operator

accesses the product. Design options concern automatic or manual activation and the option to partially activate bids. The communication infrastructure and protocols regarding activation (and possibly deactivation) are further sub-variables.

4. **Utilisation speed**
   Time to respond to a utilisation signal, activation increment and profiles, as well as deactivation specifications are sub-variables of utilisation speed. Arguably, the utilisation speed could also be designated as a sub-variable to product utilisation.

5. **Delivery location**
   This design variable defines if, and how the delivery location of a product is specified (e.g. connection identification, electrical area, postcode or geographical coordinates).

In the following, the ten design variables designated to ancillary service acquisition are described:

6. **Provider accreditation**
   Every ancillary service requires rules and processes that entitle system users to provide ancillary service products (e.g. pre-qualification for provision of FCR). Accreditation is also needed when ancillary service provision is obligatory (e.g. grid connection requirements accredited in connection contract).

7. **Ancillary service area designation**
   This design variable describes a geographic or electric or administrative system area from where located providers may offer the ancillary service product. The size and variability of that area are sub-variables. The ancillary service area designation defines, for example, that a product may only be offered by providers in the control area of a specific operator. In contrast, the delivery location design variable defines whether the product may be delivered anywhere in the network or if the delivery location must be specified.

8. **Acquisition method**
   A principle design variable on how an ancillary service product is obtained from the system users (i.e. providers). Possible design options are obligatory non-remunerated provision, obligatory remunerated provision, bilateral contracts, public tenders, auctions and real-time markets.

9. **Acquisition timing**
   The timing of the acquisition process has to be chosen relative to the product delivery period and relative to other market processes (e.g. before or after day-ahead market clearing). The frequency of acquisition is a sub-variable.

10. **Bid requirements**
    Bid requirements define how an offer for an ancillary service product can be submitted to the operator. Quantitative requirements like minimum and maximum bid sizes, minimum bid increment or rules for block bids are more related to acquisition process needs, while the quality of a bid (e.g. MWh for a certain delivery period) is defined in the ancillary service product specifications.

11. **Scoring method**
The scoring method defines criteria and rules for the selection of offered products. Scoring method options may be as simple as the lowest price or highest price. In multi-unit auctions, the scoring methods define the weighting of various product attributes. Scoring methods may be quite complex algorithms, e.g. when security constraint optimal power flows are used to select redispatch offers. The scoring method is arguably a sub-variable of acquisition method.

12. **Pricing method**
Pricing method is a relevant design variable for all acquisition methods entailing remuneration. Market-based acquisition methods could remunerate the ancillary service providers based on a single price (i.e. uniform pricing/common clearing price/marginal pricing) or based on the bid price per provider (i.e. pay-as-bid/discriminatory). Sub-variables include methods to determine regulated prices and price caps.

13. **Settlement**
Settlement entails the moment and the frequency of executing the financial transactions of ancillary service acquisition. A measurement process is a sub-variable as well as penalties for non-delivery.

14. **Market information**
The type and timing of information relevant for market facilitation may include cleared ancillary service prices, acquired volumes, information about system state, and operator information regarding the acquisition process.

15. **Cost allocation**
Cost allocation is the design variable that defines how the acquisition costs for the operator are allocated. This design variable has a welfare distributional aspect that incorporates the presence or absence of incentives for desired market party behaviour and for desired operator behaviour.

4.4 Performance criteria of ancillary services

In this section performance criteria of ancillary services are proposed. However, at first, objectives and constraints of the power systems are formulated, which serve as input for performance criteria.

Power system objectives are often overlapping. Many formulations for power system targets exist. For instance, the 'energy union', governed by the EU commission, aims "*to give consumers secure, sustainable, competitive and affordable energy*" (European Commission, 2019b, p.1). However, this and other sets of objectives are not always mutually exclusive but often overlapping: For sustainability, external costs of power systems are included into performance indicators. Sustainability and affordability may, therefore, be considered as equivalent targets, unless sustainability is pursued for other than anthropocentric reasons (e.g. to protect all living individuals because of their species-independent equal value).

One power system objective, many constraints. This proposal limits the definition of the power system objectives to one overall goal: A reliable supply of electricity to all system users. The specification of 'reliable', i.e. the target value for security of supply, is considered as a result of a societal negotiation process, which finally constitutes in regulatory quality targets for the power system. In this process, various stakeholders discuss and negotiate conflicts with other objectives outside the power system domain. The other objectives include:

- (Inter-generational) costs for society
- Acceptable environmental impact
- Acceptable risk for health and safety of society
- Distribution of costs and benefits (e.g. minimal distance of wind power plants to domestic houses, the definition of market power abuse, polluter pays principle, impact on regional employment)

The result of the negotiation process is administered in the juridical system. Laws and technical codes thereby provide the 'societal requirements'. These requirements are here summarised as 'regulatory constraints' to the power system's quality targets.

Efficient cost instead of minimal cost. It has to be highlighted that power system design is subject to many and complex societal constraints, whereby minimal cost is only one aspect, which furthermore has non-trivial geographical and timely boundaries (i.e. cost for whom?). Therefore, it is proposed to use the term 'efficient cost' as a synonym for lowest costs possible, given all constraints.

Grid and system operator performance. Hirth and Glismann (2018) discuss incentives (and discentives) for grid operators to efficiently reach quality targets in the context of congestion management. The use of ancillary services is not always the only instrument for grid and system operators to reach quality targets. For instance, grid expansion and operational grid topology changes may be alternatives to the use of redispatch services. Therefore, it has to be noted that the following performance criteria are not meant to evaluate grid and system operator performance, but specifically evaluate the performance of ancillary service designs.

Characteristics of performance criteria. In line with Veen (2012), it is acknowledged that the performance criteria of this ancillary service framework have the following characteristics:

1. More or fewer performance criteria than here proposed may also be suitable for specific evaluation cases.
2. Performance criteria are of different importance for the overall ancillary service performance.
3. Performance criteria can be contradictory to others, which requires decisions on preferences or a determination of an "optimum".

Six ancillary service performance criteria are defined. The proposed performance criteria are composed of effectiveness, efficiency, and compliancy as well as acquisition, utilisation and prices (see figure 4.4):

1. **Effective acquisition** describes to what extent the grid and system operators are able to obtain the required amount of ancillary services to maintain the quality targets.
2. **Effective utilisation** describes to what extent the grid and system operators successfully apply available ancillary services in order to maintain the quality targets.

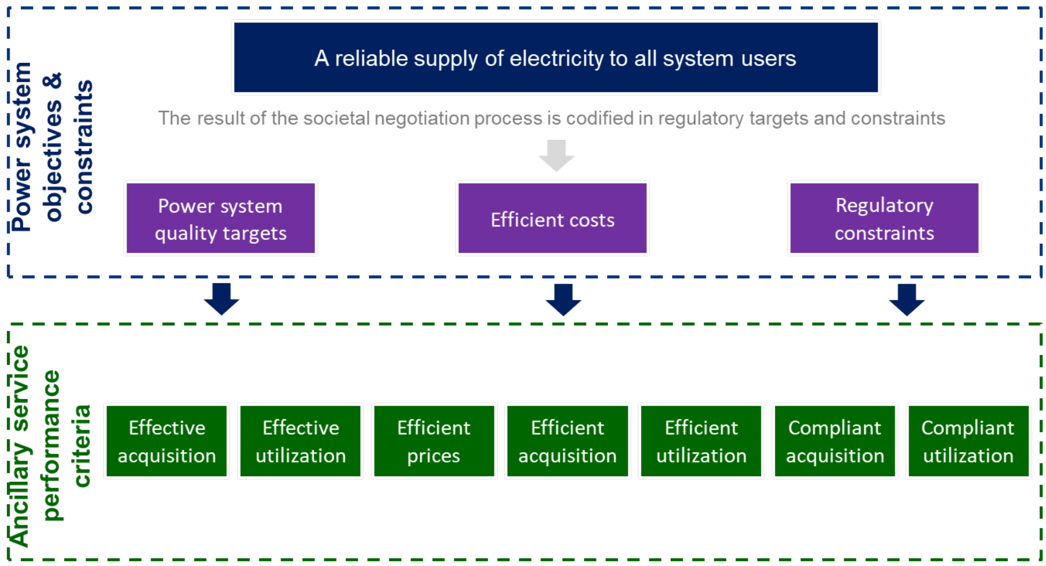


FIGURE 4.4: Performance criteria of the ancillary services framework

3. **Efficient prices** describe the level of strategic and risk-based price mark-ups.
4. **Efficient acquisition** describes transaction cost for operators and providers during the acquisition process. It furthermore describes to what extent the grid, and system operator acquire more ancillary services than needed and to what extent acquired services are not delivered by the provider.
5. **Efficient utilisation** describes the cost-minimal application of available ancillary services by the grid operator.
6. **Compliant acquisition** describes whether the acquisition process is in line with regulatory constraints.
7. **Compliant utilisation** describes whether ancillary services application is in line with regulatory constraints.

Various second-level criteria exist. In literature, other criteria are proposed, such as robustness, transparency, and non-discrimination. However, these criteria are considered as sub-criteria, because they contribute to at least one of the performance criteria of this framework. For instance, non-discrimination may contribute to efficient prices, efficient utilisation, and compliant acquisition, as it reduces exclusion mechanisms, and thus may increase competition (i.e. reduction of strategic mark-ups), reduce acquisition cost for the operator (i.e. better offers available), and contribute to compliance with regulation.

4.5 Performance indicators for ancillary services

This section provides an overview of generic performance indicators for ancillary services, grouped in physical indicators and acquisition indicators. Usually, a subset of these performance indicators is needed to assess an ancillary service design. The relevant design options of the assessment determine whether additional, more specific indicators are required as well.

4.5.1 Physical performance indicators

Physical indicators often based on incident statistics. Statistics on the ancillary service objective (e.g. frequency control, voltage control, congestion management, restoration control) provide insights about the impact of existing ancillary services designs on the physical behaviour of the power system. Multiple types of incidents may be defined for every control objective (i.e. violations of quality criteria) for statistical evaluation. These statistics concern the number of instances and the duration of incidents as well as their magnitude. The latter, however, is often covered by the definition of the incident (e.g. incident X means more than 50 % of maximum, incident Y is 75 % of the allowed maximum). See for example the indicators for TSO reporting, required by the European guideline on system operations (Article 15 and 16), as well as the classification of system states normal, alert, emergency, blackout and restoration (European Commission, 2017a, Article 18). European Commission (2017a) and ENTSO-e (2012) are used to derive the following list of generic physical performance indicators:

- Number of tripped net elements triggered by the ancillary service objective.
- Number of tripped generators and demand facilities triggered by the ancillary service objective.
- Number of local blackout states and system blackouts caused initially by the ancillary service objective.
- Time duration and number of ancillary service objective deviations exceeding the defined standard ranges.
- Time duration and number of ancillary service objective deviations exceeding X % and 100 % of the allowed maximum of ancillary service objective deviations.
- Number of instances where the time to restore the ancillary service objective to standard ranges exceeded the allowed maximum time to restore.
- Number and duration of events where all ancillary services for a given control objective are exhausted.

Physical indicators on service provider level. Next to these indicators for physical utilisation of ancillary services, there are physical performance indicators related to the quality of physical delivery of ancillary services. These are statistics on the response to ancillary service utilisation signals. Measurements are typically compared to a reference behaviour with the added utilisation quantity. The reference behaviour may be sent ex-ante by the provider (e.g. aFRR in the Netherlands) or it is interpolated from measurements right before and after the ancillary service utilisation (e.g. mFRRda in the Netherlands). A classification of insufficient response is applied to the result of the comparison. Again, these classifications are very ancillary service specific. This framework, therefore, proposes only a generic, high-level indicator for physical delivery with the characteristics described above.

4.5.2 Acquisition performance indicators

Indicators based on economic statistics. Performance indicators for ancillary service acquisition may be based on statistics of offered services, cleared (i.e. accepted) services, the structure of providers, as well as cost and profit distributions.

Generic indicators and relation to performance criteria. Table 4.1 displays the proposed generic performance indicators for acquisition processes. It furthermore shows the estimated relationship with the performance criteria regarding acquisition. The link with compliant acquisition is assumed when an indicator is either closely related to grid and system operator actions or when the indicator may be related to cost-benefit distribution, as both are expected to have regulatory constraints.

Demand and supply indicators. A set of indicators is proposed to assess the supply volume compared to the operator demand (i.e. volume offered, unsupplied ancillary service demand, ancillary services not delivered). These indicators provide insights for the criterion of effective acquisition. Over-procured ancillary service demand and ancillary services not delivered are indicators to measure efficient acquisition. Prices offered and cleared as well as indicators about supply competition (i.e. number of providers, market power & liquidity, profit and loss) provide information regarding efficient prices of the design. The profit and loss per market participant can furthermore give insights about the efficiency of the acquisition process (i.e. costs for participating in the process).

Interdependency indicators. In order to evaluate the interaction of ancillary service acquisition with other markets and acquisition processes, interdependency indicators are proposed. A set of these indicators provide a value regarding price and volume per market (offered and cleared). When comparing various design options, these indicators show how other markets may have changed as well. Moreover, the differences in prices and volumes per market, in particular when they operate in overlapping time frames, may trigger interesting questions regarding design driven actor behaviour.

Indicators cope with difference of trading periods and MTUs.Markets and acquisition processes may have a continuous set-up with many possible offer and clearing moments for a single MTU. Alternatively, markets may be design with a single or few auction moments per MTU. In other words: the frequency of acquisition may differ. When comparing offered or cleared volumes of different markets, it may be miss-leading to simply used the sum of offered quantities for a specific MTU, as this would be much higher in case of continuous trading compared to a single auction. Instead, it is proposed to use the average offered-, respectively cleared volume per MTU and then take the average over all MTUs of the assessed period. In this case, the average seems to be more intuitive than the median because the median may be zero, although volume was offered and cleared during the assessed period. For offered and cleared prices, it is proposed to calculate per MTU the weighted average and then take the median over the assessed period as price indicator.

Relative interdependency indicators. In order to compare markets and acquisition processes to each other, it is proposed to measure the traded (i.e. cleared) volume per market relative to the total traded volume of all markets and acquisition processes. Analogously, the relative return per market may be used as an indicator. These indicators show the significance of the certain market for the entire market and, when comparing different design options, it also shows shifts in market sizes.

Cost and profit indicators. The total system costs are of interest as well to explore the design impact on the overall costs, despite potential interactions. However, for this ancillary service framework, the often-used levelised cost of electricity is not suited, as investments in grid or power plants are out of scope. Instead, producer (dispatch) costs, producer profit, system operator cost and cost of electricity (i.e. producer cost

TABLE 4.1: Acquisition performance indicators and their relation to performance criteria

Acquisition performance indicators	Acquisition performance criteria			
	Effective acquisition	Efficient acquisition	Efficient prices	Compliant acquisition
Ancillary service volume & prices				
Volume offered	x			
Prices offered			x	
Cleared prices			x	
Ancillary service demand fit				
Unsupplied ancillary service demand	x			x
Over-procured ancillary service demand		x		x
Ancillary services not delivered	x	x		x
Ancillary service supply competition				
Number of providers			x	
Market power & liquidity indicators		x	x	
Profit and loss per participant		x		x
Ancillary service interdependency				
Median of w.average offered & cleared prices per MTU and per market.		x	x	
Average of average offered & cleared volumes per MTU and per market.	x		x	x
Cleared volume per market, relative to total cleared volume.			x	
Return per market relative to total return.			x	x
Producers cost, producers profit, system operators cost (per MWh consumption).		x	x	x

+ system operator cost) are proposed as generic indicators. To make these indicators comparable for studies with different assessment period lengths, their values are provided relative to the electricity consumption of the examined period.

Availability of data is a challenge. Researchers may not have access to all data required for these generic indicators. In such cases, simulation models are required to generate the data.

Impact of design variable on indicator. Veen (2012) has written extensive texts to estimate the impact per design variable on the total performance. The estimation consists of the following three points: (1) estimation of the impact level of individual design variables, (2) estimation of the influence of the contextual factors on the impact of each design variable, and (3) consideration of the existence of a 'best' variable value. Other approaches to evaluate the relationship between design variables and performance indicators may involve model simulations, laboratory tests or field test (e.g. by pilot projects such as BMWi, 2020). However, these tests can be very extensive and not always realisable in practice. For those cases expert estimation is a reasonable method, as shown by Veen (2012) and Doorman, Veen, and Abassy (2011).

4.5.3 Conceptual price mark-up model

Price mark-ups are one indicator for design efficiency. *"The efficiency of markets can also be assessed by the presence, or absence, of perverse incentives to those involved. Such incentives may result in ineffective or inefficient behaviour and/or inefficient mark-ups in* *prices*" (Nobel, 2016, pp. 11). Thus, decomposition and analysis of price mark-ups is one way to assess the performance criterion of efficient prices.

Price mark-ups analyses also examine cost components. A price mark-ups analysis is not only aimed to determine the delta prices to a 100 % efficiency price. Price mark-up analyses may also help to reveal costs included in the mark-ups as a consequence of the acquisition design choices.

Benchmark cost require assumptions. It is challenging to determine the 'true' marginal costs of a provider as an objective benchmark (i.e. 100 % efficient price) for the mark-up analysis. Firstly, market parties are not willing to reveal their costs publicly to competitors and customers. Secondly, all costs are also a product of historic competitive pressure. In highly competitive markets, it is assumed that market parties seek to lower costs in order to increase profits. In less competitive situations and under the assumption of bound rationality, market parties might rather accept the current level of profits or increase strategic mark-ups instead of investing in cost reductions. Moreover, in ancillary service acquisition designs with regulated cost remuneration (instead of market-based prices), market parties are by definition in a non-competitive situation with little, if any, incentive to decrease cost. Given this benchmark challenge, it is hence required to make cost assumptions for the mark-up analyses. Furthermore, it shows that mark-up analyses are in particular useful in comparative studies of ancillary service designs, as in such analyses the 'true costs' are relevant

Price mark-up approach to supplement empirical and analytical methods. Empirical methods as well as analytical methods also require benchmark costs to evaluate price efficiency. When such assessments just assume fixed or only fundamental 'efficient cost' for all ancillary service designs studied, the research fails to exhibit the design-driven costs, which are not related to strategic behaviour. Here, a price mark-up analysis can contribute by revealing how acquisition process designs impact costs at market party level and thus affect price efficiency of the system.

Three types of mark-ups are distinguished. In order to use price mark-ups as a performance indicator for ancillary services design, it is proposed to distinguish marginal costs that are fundamental to service delivery and (rather) independent from the ancillary service design, opportunity and risk mark-ups from the market design as well as strategic mark-ups stemming from market power (see figure 4.5).

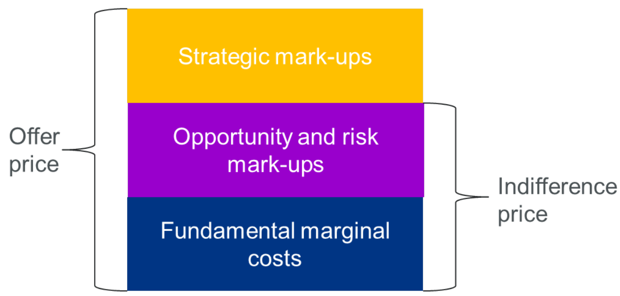


FIGURE 4.5: Concept of price mark-up model

Fundamental service cost. Fundamental costs are the assumed marginal costs for delivering the ancillary service. The cost components of the fundamental costs can be examined with respect to their dependency regarding the ancillary service design. When the main profit of ancillary service providers is generated on other markets, it may be assumed that fundamental costs (e.g. fuel cost) are not determined by the design of ancillary services, but instead by the competitive pressure of the other markets. When the main profit of a market party is generated from an ancillary service process, it is to be analysed whether design-driven changes in competition would affect fundamental costs of that market party. Hence, fundamental costs are equal or higher than the approximated 'true' short-run marginal costs (SRMC).

Risk and opportunity mark-ups. It is assumed that costs, which potentially occur as a consequence of offering ancillary services are transformed into price mark-ups. Such costs can be based on risks and based on foregone opportunities. Both costs are, however, based on the expectations of the market party. Generally, the costs are determined by an expected risk or expected opportunity price as well as an expected risk or expected opportunity quantity. As forgone opportunities can also be considered as risks, a simple generic form to determine risk and opportunity mark-ups may be expressed as follows:

$$RiskMarkup = \frac{(exp.RiskPrice * exp.RiskQuantity)}{OfferQuantity} \tag{4.1}$$

Market parties choose methods to determine expected risk price and quantity. The expected risk prices and risk quantity are specific for each market party. The determination is subject to the market parties' believes about the market and to their risk aversion.

Strategic mark-ups added on indifference price. Swider (2007) uses the term 'strategic bidding' for all prices exceeding the marginal costs: "*In single-shot uniform-priced auction markets, the bidding problem is defined by imperfections. Can this market be seen to be perfect, any bidder would be a price-taker. Following microeconomic theory this would result in an optimal bidding price equal to the marginal costs. As soon as a bidder bids other than marginal costs, he tries to exploit the imperfections in the market setting. Such a behaviour is called strategic bidding. If the bidder can increase her profits by strategic bidding or by any means other than lowering her costs, she is said to have market power.*" (p. 6). However, this definition does not incorporate the (non-fundamental) risk costs, as explored above. Selasinsky (2014) uses the term 'indifference price', which is the offer price including risk mark-ups. For this price, market party would be indifferent about being matched or not. Any price beyond this indifferent price thus includes strategic mark-ups.

Strategic mark-ups are also based on market parties' believes. Strategic mark-ups are also subject to beliefs on expected profits, which may take into account expected responses of competitors (e.g. Selasinsky, 2014; Ocker, 2018).

Example of fundamental costs and opportunity mark-up. The federal association for the German energy and water industries (BDEW) published a guidance proposal for the costs to be remunerated with regulated cost-based redispatch in Germany. The explored cost components provide an overview of costs that market parties may need to include in redispatch service acquisition processes to determine the indifference price (BDEW, 2018):

1. Asset short-run marginal costs [€/MWh]. Variable cost components related to producing one unit of power. Usually determined by fuel costs, asset efficiency rating, CO_2 certificate costs.

2. Operational cost [€]. This includes administrative costs for altering dispatch plans.
3. Cold start and warm start costs [€]
4. Shut down costs [€]
5. Incidental additional costs [€], e.g. for alternative process steam production, distributed heat systems and additional imbalance costs, etc.
6. Asset value depreciation [€/h].
7. Opportunity costs of alternative markets [€/h]
8. Opportunity costs from min. and max. fuel consumption contracts and emission allowances [€]
9. Costs for rescheduling asset maintenance [€]
10. Costs for grid usage fees [€/MWh] or[€/MW]

Note that some of these costs components can be negative if the ancillary service provider is actually saving expenditures. Opportunity cost of alternative markets, incidental additional cost, and (in some cases) grid usage fees would be dedicated to opportunity and risk mark-ups. Such costs are not yet known for a fact and are, therefore, based on expectations. The other costs mentioned are considered as fundamental costs. However, administrative cost for altering redispatch plans as well as the cost for rescheduling asset maintenance may include strategic mark-ups in case the redispatch design provides little competitive pressure on the market party.

Various price mark-ups are explored in more detail in section 5.2.

4.6 Ancillary services evaluation process

Generic policy framework used as a basis. As explored in the literature review (chapter 2), Iychettira, Hakvoort, and Linares (2017) propose a generic policy design framework, which they apply on an analysis of RES support schemes. Their design framework is built by merging the conceptual framework for process design of Herder and Stikkelman (2004) with the institutional analysis and development framework from Ostrom (2005). Ostrom defines action situations as: "*Whenever two or more individuals are faced with a set of potential actions that jointly produce outcomes, these individuals can be said to be "in" an action situation*" (p. 32). In line of these developments (illustrated in figure 4.6), the here proposed evaluation process for ancillary services design is based on Iychettira, Hakvoort, and Linares (2017).

Framework dedicated to ancillary services assessments. To adapt the generic policy design framework to an ancillary services design framework, some generic items are modified to specific items related to ancillary services analysis. Furthermore, under consideration of the balancing design frameworks applied in Doorman, Veen, and Abassy (2011), Veen (2012), and Doorman and Veen (2013), the performance criteria and performance indicators are made explicit in the evaluation process.

An explicit assessment set-up is recommended. In the present evaluation framework, several process steps are clustered as assessment set-up. This structure aims to encourage a detailed and explicit formulation of ancillary service design studies, which helps to make such studies more comparable.

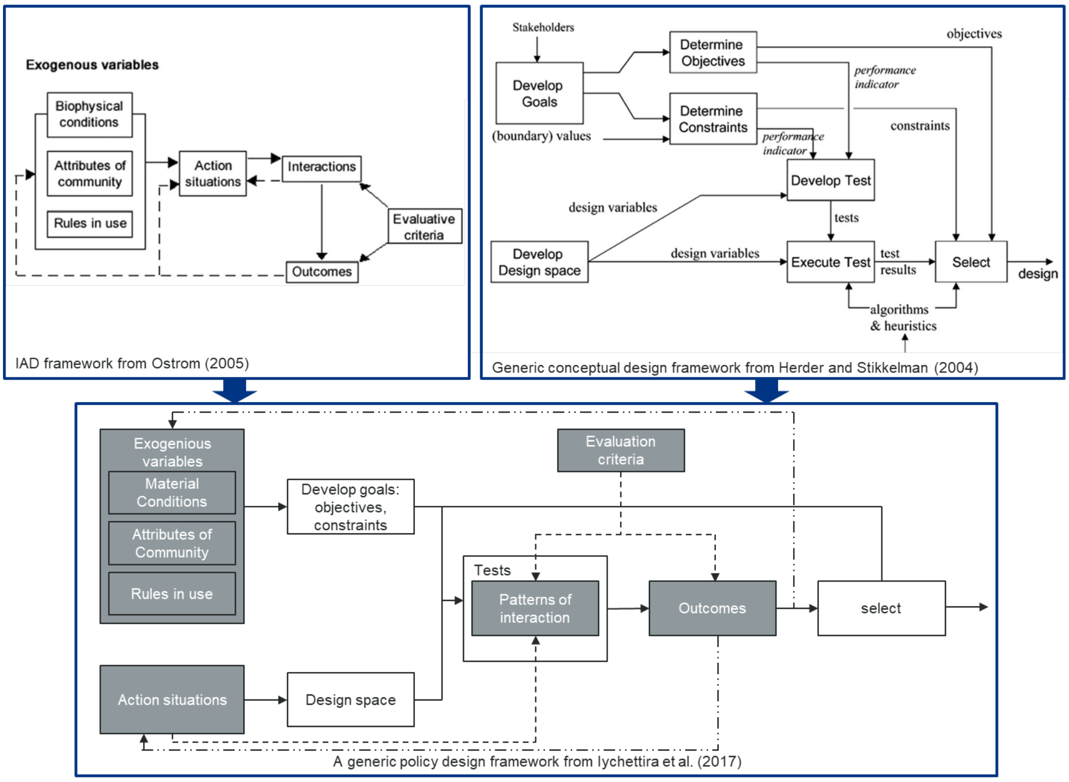


FIGURE 4.6: Generic frameworks from other publications

Dependency estimate added regarding other markets and ancillary services. In line with the research question formulated in section 1.4, the evaluation framework aims to capture potential interactions of markets and various ancillary services. Therefore, the framework entails a dedicated evaluation step concerning a dependency estimate of ancillary services. This estimate is further discussed in section 4.7.

For testing the developed design options, models are required. The evaluation framework does not recommend a specific modelling type (e.g. empirical, conceptual or analytical). However, it is recommended to discuss the need for an ancillary service acquisition model and for a utilisation model (i.e. for physical performance indicators). Not all assessments may require both or a joint model.

The evaluation process has a recommended order. The numbers in figure 4.7 indicate a recommended process order. However, some process steps may require iterations.

4.7 Ancillary services dependency estimate

Input to an assessment of unwanted side-effects. The dependency estimate for ancillary services has the objective to identify relevant other ancillary services and electricity markets that might be impacted by the design question at hand. It is the input for the assessment of potential unwanted side effects on other ancillary services and electricity markets. The dependency estimate is an important input for the decisions on scope, design space, and on details of the assessment models.

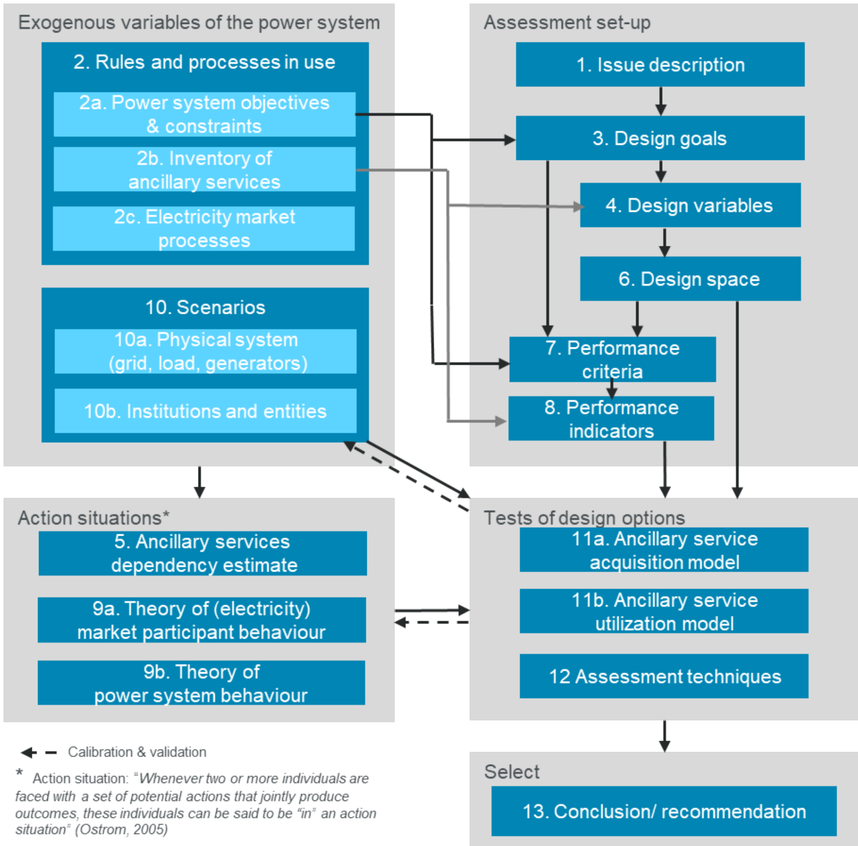


FIGURE 4.7: Evaluation process of the design framework

Literature accompanied by expert interviews and market data. The main input for the dependency estimate should be the theory of the market party behaviour, analysed for the action situations. Techniques of expert interviews and multi-criteria analyses can help to describe the dependencies and support decisions (see for a good examples Doorman, Veen, and Abassy, 2011; Veen, 2012; Doorman and Veen, 2013). On a small scale, empirical analyses can be used to find and underpin relationships. However, the dependency estimate is more of a 'preparation step' for scoping. If extensive data analyses are required, it should be considered to include these analyses in the testing process.

Feedback loop from the test results needed. It is recommended to include a feedback loop from the tests and analyses to the ancillary services dependency estimate because the initial description and assumptions could include false positives and false negatives. Intermediate findings may reveal reasons to change the dependency estimate and the assessment set up. It has to be noted that there is still a process risk that false negatives are not identified by the chosen assessment methodology as the estimate may have resulted in placing relevant aspects out of scope.

Four questions for elaboration. The following generic questions are suggested to be used in the ancillary service dependency estimate:

1. What are the ancillary services with the same objective as the examined ancillary service? Here, the scope is not the jurisdiction of the assessed ancillary service, but all ancillary services that are accessible to the grid and system

operators of the jurisdiction. Therefore, it may include cross-border ancillary services if sharing or exchange procedures exist.

2. Which ancillary services were (historically) provided by the same potential providers of the examined ancillary service? This question indicates potential decision problems of market parties. In case historical data is missing, an assessment of suitable technology can be used instead. However, there may be technologies that can theoretically provide many ancillary services. Such an approach would, therefore, not always help to narrow the scope.

3. Which markets are operated in parallel or after the examined ancillary service? If flexibility from an asset can be sold in parallel or subsequent markets, the offer price is subject to opportunity cost. Precedent markets cannot impose opportunity cost on the assessed ancillary service.

4. Are opportunity costs in preceding markets (significantly) affected? Prices and volumes of earlier markets can also be affected by the design of an ancillary service. It is vital to estimate the magnitude of impact on the preceding markets. Otherwise there is a risk that theoretical interdependencies for any study indicate that all ancillary services and markets must be studied in detail.

4.8 Applicability and scalability of the framework

Scalability by various checks. The ancillary service design framework is only practicable when the effort is reasonable compared to the additional insights. Therefore, the evaluation process entails checks during several steps to determine the necessary amount of detail and the required quality of the subsequent steps.

The first evaluation steps are always required. The evaluation steps of describing the issue, formulating the design goals and inventory of the existing ancillary services in the system are needed for any ancillary service design study. The issue and the research question determine the required details and scope of the inventory.

Variable number of relevant design variables. The relevant design variables should be derived from the issue and the goal of the investigation. The details of subsequent steps should be limited to these variables. The argumentation of the relevance of design variables makes the scoping explicit.

Dependency estimate determines international character. The ancillary services dependency estimate gives the scope regarding jurisdictions. The scope may be limited to one jurisdiction, in case the relevant ancillary services are not shared with other jurisdictions and 'foreign' providers are not allowed.

Possibility to limit tests to acquisition process or utilisation. It can turn out that for the research question only one of the two dimensions is sufficient during the design test: Ancillary service acquisition or ancillary service utilisation. If all relevant design variables are designated to ancillary service acquisition (as clustered in 4.3), it is a good indication for a valid limitation on the acquisition process. In case the relevant design variables include product utilisation or utilisation speed, it is recommendable to consider ancillary service utilisation in the following steps.

Some variables point to qualitative analyses. Design changes often change business cases for existing and potential ancillary service providers. Research questions regarding the design variables 'settlement' (including the process of delivery verification) and provider accreditation (including pre-qualification process) are very much about data exchange, financial guarantees, invoicing procedures, requirements for assets, tests and audits. It is obvious that these aspects should be designed in lean processes, without unreasonably high requirements to ancillary service providers, and it should be non-discriminatory. However, simplicity and harmonisation of processes, tools and requirements may conflict with the target of low-barrier requirements and non-discrimination. Before modelling and simulating, it should be checked if qualitative cost-benefit distribution analyses could suffice. Examples for such a qualitative discussion regarding settlement, accreditation and cost allocation variables are:

- Transaction costs for all parties changing from current rules in the context of harmonisation
- One market party wants to provide a more complex product, do all others need to adapt?
- Cost-benefit and risk distribution between:
  - Incumbent versus new providers
  - Market parties versus grid and system operators
  - TSO versus DSO,
  - Grid and system operators of different jurisdictions
  - Providers of grey electricity versus providers of green electricity
  - Large versus small market parties
  - Balancing service provider versus balance responsible party.
  - Consumers versus producers versus prosumers.

Explicit choice of conceptual model and numerical model. In case the research goal and the design options at hand can be evaluated based on axioms from existing theories and available data, it may have little additional value to apply a computational simulation model. If little theory or data is available regarding the research goal, computational models can provide an explorative contribution. The need for computational models should be explicitly underpinned when formulating the test set-up.

Statement on expected policy-readiness-level of simulations. The research goal as well as time, budget and maturity of the study subject, give indications about a realisable and by stakeholders accepted policy-readiness-level of the assessment. Tesfatsion (2018) distinguishes policy-readiness-levels by empirical fidelity of applied models and the number of salient real-world aspects in it (see table 4.2). The targeted policy-readiness-level should be stated explicitly. The applied model then should be limited to this level. The scenarios should also be consistent with the policy-readiness-level concerning details of the physical system, entities and institutions.

TABLE 4.2: Policy-readiness-levels (PRL),
adapted from Tesfatsion (2018)

Development level	PRL	Description
Conceptual idea	PRL 1	Conceptual formulation of a policy with desired attributes
Analytic formulation	PRL 2	Analytic characterization of a policy with desired attributes
Modeling with low empirical fidelity	PRL 3	Analysis of policy performance using a highly simplified model
Small-scale modeling with moderate empirical fidelity	PRL 4	Policy performance tests using a small-scale model embodying several salient real-world aspects
Small-scale modeling with high empirical fidelity	PRL 5	Policy performance tests using a small-scale model embodying many salient real-world aspects
Prototype small-scale modeling	PRL 6	Policy performance tests using a small-scale model reflecting expected field conditions apart from scale
Prototype large-scale modeling	PRL 7	Policy performance tests using a large-scale model reflecting expected field conditions
Field study	PRL 8	Performance tests of policy in expected final form under expected field conditions
Real-world deployment	PRL 9	Deployment of policy in final form under a full range of operating conditions

4.9 Valuation and limits of the framework

Guidance with a structured set of evaluation components. For every ancillary service design question, a structured set of components is provided for a comprehensive analysis. The framework proposes per component (i.e. scope, design variables, performance criteria, performance indicators, evaluation process, dependency estimate, and scalability checks) a set of generic values. Yet, it is not proven that the proposed values are exhaustive or truly generic. However, it is expected that only very specific ancillary service assessments would require a different, non-overlapping set of values, as most values are derived from literature.

Comparability and compatibility. The framework application contributes to improved comparability or even compatibility of the study results as a consequence of a harmonised approach and a common language. This, however, is true for most study frameworks. Nonetheless, the proposed evaluation process provides explicit answers to the following questions:

- Which ancillary services are taken into account, which are out of scope and why?
- Which design variables are taken into account and are there potentially relevant design variables excluded because of practical reasons?
- Which design options are evaluated, and why not others?
- What is the targeted policy-readiness-level?
- Which performance indicators are selected, and why?
- What test procedures and models are applied, and why?

Framework suitable for studies on physical and acquisition aspects. A specific feature of this framework is its suitability for policy studies with a focus on both utilisation of ancillary services and acquisition of ancillary services. Moreover, it addresses the challenge of ancillary services interactions explicitly. However, the ancillary service design framework is limited to the research category of policy-making (see chapter 2).

Generalisation conflicts with the importance of details. Necessary abstraction and simplification to structure, e.g., generic design variables and performance indicators, conflict with the view that ancillary service design is really about the details. These details include the design options of all ancillary services as well as the entire socio-economic context of a region. Therefore, additional interdisciplinary studies may be needed to tackle this general policy design challenge and counter-act on the shortcomings of this arguably technocratic design framework.

Applicability is tested in use-case. The literature-based framework is tested in a use-case in chapter 6. This framework application discusses additional insights regarding generalisability and scalability of the framework for ancillary service design evaluation.

Chapter 5

Agent-based model for ancillary services acquisition simulation

The entire content of this chapter has been developed as part of this thesis. However, due to the long review and publication process, a part of the text has already been published in a journal paper and a supplementary pre-print. Furthermore, the source code, test scripts and a wiki are available on GitHub. The wiki contains additional information about classes and variables as well as a description of all input parameters.

- Samuel Glismann (2021a). "Ancillary Services Acquisition Model: Considering market interactions in policy design". In: *Applied Energy* 304. DOI: 10.1016/j.apenergy.2021.117697
- Samuel Glismann (2021b). "Ancillary Services Acquisition Model: heuristic agent strategies". Preprint exerpt of dissertation. Europa-Universität Flensburg. DOI: 10.5281/zenodo.4756543
- Samuel Glismann (2021c). *ASAM repository*. URL: https://ancillaryservicesacquisitionmodel.github.io/ASAM/

5.1 A conceptual model for ancillary service acquisition

In this section, a conceptual model of ancillary services acquisition in European context is described. The models' target is to translate assumptions from other studies and expert interviews into a numerical model, which is described in later sections of this chapter. The experts interviewed to develop and contribute to this chapter are listed in appendix C.

First, the agents in electricity market are defined, followed by a description of the market and acquisition processes. Finally, the agent strategies per market are conceptualised.

5.1.1 Agents in electricity market

Model distinguishes only a few roles within the power system. As explained in section 1.2.1 there are various roles and responsibilities in electricity systems. Following the decomposed service model of Nobel (2016), one can distinguish grid user, system user, grid operator and system operator. EU regulation defines numerous roles to describe rights, obligations and processes in electricity systems (European Union, 2019b). However, for a simplified structure in the conceptual model, only a few roles are distinguished. These roles are represented by agents in the model, which can be further specified in sub-agents, if necessary. The main agents are market parties, grid & system operators and market operators.

Market parties own assets. Generation, consumption and storage facilities connected to the grid are owned and controlled by market parties. Market parties can use the physical characteristics of these assets to their own benefit (i.e. financial and comfort). The model does not distinguish specific market party roles (e.g. BRP or BSP).

Grid & system operator as high-level role. Grid & system operators are agents with the responsibilities of TSOs and DSOs (typical EU roles) or ISOs and T/D Utilities (typical U.S. roles). Grid & system operators are considered as non-competitive, monopolistic, highly regulated agents. If required, sub-agents are defined to represent the sub-tasks of different operator agents. For example, a DSO would be initiated as an inherent member of the grid & system operator class, but without the system tasks, such as the provision of cross-border capacity, administration of market trade schedules, balancing, and administration of imbalances (see section 1.2.1).

Market operators provide services to market parties and grid & system operators. Market operators are agents that facilitate wholesale market processes such as receiving of orders, matching of orders and settlement of transactions. In the EU context, these are typically power exchanges or some local market operators. However, for the purpose of this model, market operator agents also operate ancillary service acquisition processes, even though these processes are often executed by grid & system operators or grid & system operator owned entities (e.g. Joint Allocation Office). Market operators are in this model assumed to be non-competitive, highly regulated agents. This assumption is certainly a simplification which is to be kept in mind when assessing regulations on market operators.

Regulators are not considered in this operative model. The rules in place, including penalties for non-compliancy, are assumed to be in accordance with regulation and to be static per scenario. Therefore, regulators are not considered as acting agents in the model.

5.1.2 Markets and acquisition processes

Ancillary service acquisition processes assume a single buyer. There are electricity market processes and ancillary service acquisition processes. A difference between the two is that electricity markets have multiple buyers and sellers, while in this model ancillary service processes have a single buyer, which is the grid & system operator. Even if multiple grid & system operators are involved in such a process (e.g. TSOs and DSOs), they are assumed to coordinate the acquisition, before a transaction is closed with market parties. Hence, multiple grid & system operators do not act as competing buyers of ancillary service markets but as a joint buyer in the model.

Distinction of short-term and long-term markets. Following European market structures (see 1.2.2), long-term and short-term timeframes of markets and acquisition processes are separated by a single day-ahead electricity auction. The following processes take place before this day-ahead auction:

- Bilateral forward energy trading

- Trading of (financial) energy derivatives
- Trading of long-term transmission rights
- Various tenders and auctions for ancillary services acquisition, e.g. balancing capacity auctions, tenders for voltage control services, tenders for (temporary) connection capacity limitation and tenders for black-start services.

The following markets and acquisition processes are designated to the short-term timeframe:

- Day-ahead auction
- Intra-day continuous electricity trade
- Intra-day electricity auctions
- Intra-day bilateral trading (i.e. over-the-counter)
- Redispatch mechanism/market[1]
- Balancing energy market
- Imbalance mechanism/market[2]
- Other potentially real-time activated ancillary services (e.g. reactive power services)

Day-ahead auction is an important reference for subsequent processes. This separation of long-term and short-term is somewhat ambiguous because all markets and processes before a 'real-time' market (i.e. delivery period) can be considered as forward markets (Glachant and Saguan, 2007). However, in European context this day-ahead auction is of conceptual importance because the cross-zonal transmission capacity is implicitly allocated in the so-called market-coupling, and single day-ahead prices are established per zone. These prices are also used as the underlying price for long-term transmission rights and long-term energy contracts. Moreover, as shown by Just and Weber (2015) and Nobel (2016), the prices of the day-ahead market and of the (real-time) imbalance mechanism are closely linked. Therefore, the day-ahead prices may also be considered as a reference point for subsequent short-term markets and ancillary services processes.

Fundamental market assumptions are Europe-centric. All these markets and ancillary service acquisition processes are characterised by the acquisition design variables described in section 4.3. The model incorporates the following Europe-centric market design assumptions:

1. **Imbalance settlement period (ISP).** The discrete time interval for accounting obligations of balance responsible parties (Nobel, 2016) is 15 minutes, as required by (European Union, 2019b).
2. **Market parties are allowed to conduct self-dispatch and bilateral trading.** Compared to central dispatch and market designs with central pooling obligations (e.g. U.S. markets), market party agents have a higher degree of freedom

[1]The redispatch design determines whether it is referred to as a redispatch market or as a mechanism.

[2]The imbalance pricing design determines whether it is referred to as a imbalance market or as a mechanism. Moreover, some authors see imbalance as an integrated part of the balancing market (i.e. capacity + energy + imbalance). See section 2.

of dispatch (i.e. use of their grid connection) and a higher degree of freedom of trade, as they may bilaterally trade electricity with non-standardized products.

3. **Day-ahead market design.** The day-ahead market is organised via a single, sealed, double-sided auction with a MTU of one hour[3]. Allowed order types are limit orders. This is a simplification, as many day-ahead auctions in Europe also allow for complex orders.

4. **Intra-day continuous trading.** After the day-ahead auction, an intra-day market starts with continuous double-sided auctions and with an open order book:
   (a) The MTU is assumed to be 15 minutes. This is a simplification, because in some countries also intra-day auctions exist and trading with hourly MTU is available.
   (b) Pricing rule for matched orders: The 'older' order (i.e. first placed in the order book) determines the clearing price (Selasinsky, 2014).
   (c) Allowed order types are limit orders and market orders. Other existing order types are out of scope, following the judgment of relevance obtained from interviews with traders. Limit orders are quantity-price pairs for specific delivery periods, whereby the price (€/MWh) expresses an acceptable price limit of the trader. The order must be executed at this price or a better price (i.e. lower prices in case of buy orders/bids, higher in case of sell orders/asks). However, the limit order may be matched for a part of the order quantity (MW). The remaining quantity stays in the order book. Market orders only have a quantity for a delivery period. Market orders express the wish to trade this quantity for the best available prices. These orders have an "immediate or cancel" restriction, meaning that the order can also be partially executed, but any unexecuted quantity is cancelled (EPEX, 2019). This selection of allowed order types corresponds to the assumptions of the trading model of Selasinsky (2014).

5. **Zonal pricing in electricity markets.** Zonal pricing is assumed instead of nodal pricing, because it is current practice in most EU countries. Within a zone, electricity can be traded without capacity limits, though the transactions are subject to physical delivery (i.e. subject to imbalance mechanisms). This means that prices within a bidding zone have no locational component, whereas trades between bidding zones may exhibit locational price differences as a consequence of cross-border capacity allocation. "*Cross-zonal capacity allocation is a congestion management instrument that prevents congestions by limiting the allowed electricity trades between bidding zones*" (Hirth and Glismann, 2018, p. 16). Cross-zonal capacity in day-ahead and intra-day markets is allocated implicitly: Market parties provide orders to power exchanges with access to the market-couplings process. In the market coupling, all order books are jointly cleared, subject to available cross-zonal capacity. Additional congestion management instruments, such as redispatch, are required to cope with bidding-zone internal congestions and to mitigate inaccuracies of cross-zonal capacity calculations.

[3]The MTU of the day-ahead market will be changed to 15 minutes in the coming years (European Union, 2019b)

6. **'Pro-active' redispatch process.** In line with Hirth and Glismann (2018), redispatch service acquisition is considered here as a 'pro-active' process with discrete moments of redispatch. Grid operators determine expected congestions and apply measures, including redispatch, to mitigate operational security violations before they occur. It is furthermore assumed that redispatch actions are taken after the day-ahead market clearing and after the first dispatch schedules from market parties are sent to the grid operator. It is assumed that real-time congestions are mitigated by other means than redispatch (e.g. commandeering of dispatch or load-shedding in emergency state).

7. **Balancing capacity, balancing energy and imbalance are three services of the balancing market.**

   (a) **Balancing capacity ensures available balancing energy.** EU regulation requires TSOs to organise sufficiently available balancing energy. Dimensioning rules determine how much balancing energy must be available per TSO (European Commission, 2017a). Balancing capacity is thus an ancillary service which ensures available balancing energy. Providers of balancing capacity have agreed to make a specific quantity of balancing energy available for the TSO during the delivery period. The model assumes, in line with EU regulation, that the balancing energy is provided in the form of bids.

   (b) **'Reactive' balancing energy activation.** A reactive balancing approach means that system operators only activate (i.e. procure) balancing energy in response to the control parameter of their load-frequency controller. The control parameter is usually the delta of scheduled and measured (real-time) power exchange with other load-frequency control blocks, subject to coordinated correction factors (e.g. the k-factor in continental EU synchronous area) (see TenneT TSO B.V., 2019g; European Commission, 2017a). A pro-active balancing approach, based on anticipated control errors, is applied in south-western Europe. Such system operator strategies are not in scope of the model .

   (c) **Imbalance may be organised as markets.** Imbalance mechanisms may have a design to primarily redistribute balancing energy cost to market parties and to penalise any market imbalance. Other imbalance mechanisms may have a design which penalises market imbalances that worsen the balancing control situation, whilst market imbalances improving the balance control situation are incentivised (see TenneT TSO B.V., 2019g; Nobel, 2016). In the latter case, intentional imbalance is to some extent allowed, which enables an additional marketing possibility for the flexibility of market parties. Such design is, therefore, considered as an imbalance market.

Retail market processes out of scope. The process of contracts and transactions between electricity suppliers and consumers, respectively prosumers, is not an explicit part of the model. It is assumed that the retail market results in energy delivery obligations for market parties, which they try to cover by asset dispatch and wholesale trading.

Market interactions caused by agent behaviour. As described in chapter 3, there are various studies assessing the interactions of markets and ancillary service acquisition. In this model, interdependencies of markets and ancillary services acquisition processes are perceived as a result of agent strategies in the respective markets (Weidlich, 2008). On high-level, the following market attributes can be interdependent:

1. Prices are interdependent when an asset can produce alternative products for a parallel or subsequent market. These opportunities are incorporated as mark-up in prices, as described in section 4.5.3.
2. Supply volume of a market or an acquisition process can increase or decrease by transactions in preceding, parallel or subsequent markets. This means that, for instance, even if a grid & system operator is willing to pay very high prices, insufficient supply volume may be available, because desired asset capabilities are already sold in preceding markets.
3. Demand volume of a market or an acquisition process can increase or decrease by transactions in preceding, parallel or subsequent markets. This means that, for instance, if demand is satisfied by preceding markets, suppliers of a product cannot find buyers. Moreover, transactions on a market or acquisition process may cause additional demand on a different market or process. Such demand increase may happen if, for example, a transaction causes imbalance positions for a market party in surrounding delivery periods of that transaction.

Other markets are out of scope. There are adjacent markets to the electricity markets and ancillary services processes which have a strong interrelation with prices. Such markets are fuel markets and CO_2 markets. These markets are not considered explicitly in the model. The impact of these markets is implicitly considered by asset production and consumption costs. This approach implies that electricity markets and ancillary services of the model have no impact on these adjacent markets.

Notation of transactions, dispatch and imbalances. The model uses the notation illustrated in figure 5.1. An imbalance position concerning a future ISP is also called open (short or long) position or scheduled imbalance position (as opposed to realised imbalance position). Delivery of downward balancing energy or downward redispatch is considered physically as relative withdraw of electricity from the grid. From a transactional perspective, it is considered as energy bought. Likewise, delivery of upward balancing energy or upward redispatch is considered physically as a relative injection of electricity to the grid. From a transactional perspective, it is considered as energy sold.

Distinct terminology regarding orders. Bid is a confusing term, as it is used on power exchanges to indicate a wish to buy (as opposed to the term ask) while balancing markets use bid as a general term for offers. Therefore, this model uses the term order as the most general term for anything a party can trade on a market. This term is then combined with other terms to specify an order direction (sell, buy, upward, or downward), an order product (e.g. FRR), or an order status (offered, cleared). The latter may also be called offer respectively transaction.

Definitions regarding capacity, quantity, and volume. As the model considers various products, the units may be different. However, to enable a generic description, three arbitrary terms are used in the model as follows:

- Capacity means the rated maximum output of an asset.
- Quantity describes the size of a product. This may have units such as MWh, MVAh, MVarh, and Ah. However, products may also be defined with units

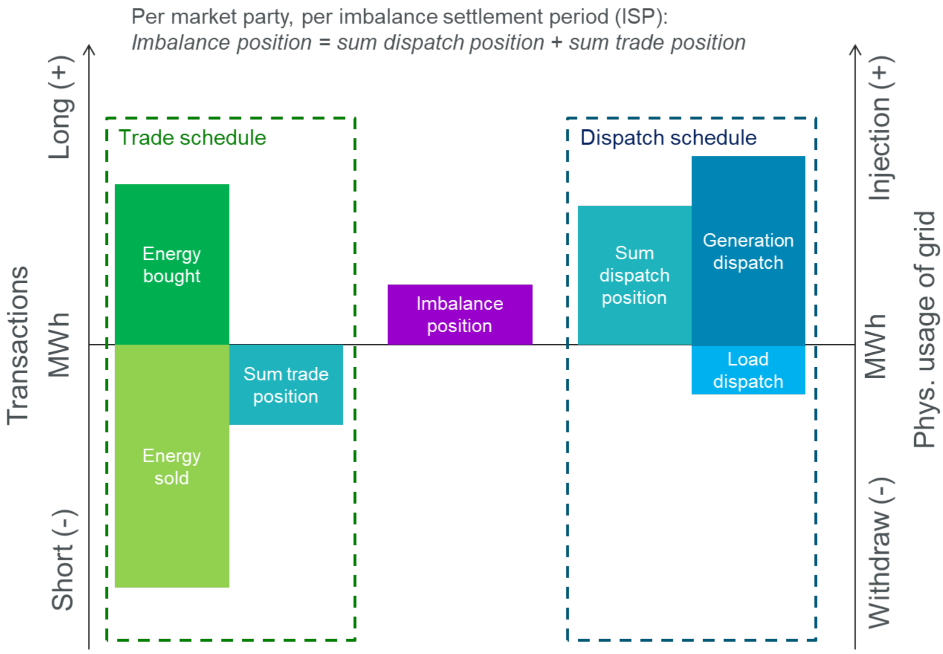


FIGURE 5.1: Illustration of model notations

such as MW, MVA, MVar and A. The term volume is also often used to describe the size of a product. However, to keep a generic terminology for services that may be traded as MW for a specific duration or in MWh, only the term quantity will be used.

- The term volume is used to describe the sum of order quantities (i.e. aggregated supply and demand) and transaction quantities of a market.

5.1.3 Agent strategies

General assumptions on agent strategies. It is assumed that agents act with bounded rationality, i.e. they "*are goal oriented and try to be rational but face cognitive limits*" (Ostrom, 2005, p. 104).

Three fundamental choices per market and acquisition process. The agents have per market and ancillary service three fundamental strategic choices:

1. **Quantity.** What quantity (including zero) of the respective product to be placed in the market or process?
2. **Price.** What price to offer?
3. **Timing.** When (relative to the delivery period) to place orders on a market or acquisition process?

Different needs of market parties in different timeframes determine the strategies per market and acquisition process.

Long-term market and ancillary service acquisition strategy assumptions. Market parties are assumed to participate in forward electricity markets and on long-term ancillary service processes in order to mitigate quantity risks and pricing risks. The forward markets enable market parties to ensure that a certain quantity of electricity is sold from their assets (i.e. generators) or bought for their assets (i.e. loads) respectively clients (i.e. retail customers). These long-term contracts hedge the risk of affected asset operation (i.e.. interruptions) in case of temporary scarcity of supply or demand. Long-term contracts furthermore hedge the risk of large price variations. The long-term price signals from forward markets can also be used for investment decisions.

Day-ahead market strategy assumptions. It is assumed that the day-ahead auction is of great importance for market parties, as it is a single, highly standardised auction which brings together supply and demand from the entire market-coupling region. It is a reference point for preceding and subsequent markets.

Intra-day market strategy assumptions. It is assumed that the intra-day markets (i.e. continuous on power exchanges and bilateral over-the-counter) is mainly driven by managing the following remaining imbalance risks:

- Infeasible trading positions from day-ahead market.
- Forecast errors regarding consumption (load) and generation (RES)
- Forced outages of assets

Market parties with an open position on intra-day are characterised by Hagemann and Weber (2013) as impatient traders. Market parties with a closed position, which only act on the intra-day market to increase profits, are characterised as patient traders.

Ancillary service strategy assumption. Market parties are assumed to participate in ancillary services processes because of regulatory obligations and they may participate to increase profits, in case of high regulatory remunerations or in case of market-based acquisition processes.

General strategies per market. Table 5.1 summarises the general strategy assumptions of the conceptual model. The long-term markets and acquisition processes are highly stylised (e.g. long-term ancillary services not explicitly discussed). Strategies of generators, loads, RES and storage are not further distinguished. Instead, flexible assets and inflexible assets (i.e. non-flexible demand and must-run generation) are considered. The remainder of this section provides the reasoning behind these high-level strategies.

Pricing assumption for long-term markets. Long-term products for electricity and for ancillary services are usually structured like derivatives known from financial markets (i.e. various forms of options and obligations). As such, it is assumed that market parties determine offer prices based on derivative evaluation techniques. It is furthermore assumed that market parties determine a risk-premium which reflects their willingness to pay for assuring dispatch and income. For long-term ancillary services (e.g. reactive power contracts) there may be additional opportunity mark-ups, which are linked to the expected day-ahead price and the expected asset dispatch.

Quantity assumption for long-term markets. It is assumed that market parties would determine the desired quantity which they want to hedge on long-term markets to ensure minimum stable operation. When current forward prices are better or worse than their minimum acceptable price, market parties would trade more or less quantity, in accordance with their risk appetite. For long-term ancillary services

TABLE 5.1: Summary of assumed agent strategies per market and ancillary service process

	Pricing strategy	Quantity strategy	Timing strategy
Long-term markets	Derivative valuation techniques + individual risk premium (i.e. assurance rent).	Forward markets: Desired minimum asset dispatch. Ancillary service auctions/tenders: all available capacity.	Forward markets: buy/sell as soon as offered prices are below expected value. Much re-buy and re-sell possible to increase profit.
Day-ahead market (DAM)	Flexible assets: SRMC. Inflexible assets: maximum willingness to pay.	Trade position from long-term markets + available flexible asset capacity + open positions of inflexible assets.	Before gate-closure time of single auction.
Intra-day market (IDM)	SRMC + opportunity mark-up + (strategic) open order book mark-up. (when applicable: + mark-up for increased asset outage risk).	Small offer quantities provided iteratively. (to hide position in open order book).	Patient traders: Immediately when profitable. Impatient traders: strategy depending on expected imbalance price, forecast volatility, and market liquidity.
Redis-patch market (RDM)	SRMC + opportunity mark-up + various design-dependent mark-ups.	All available capacity. Reduction when: 1. Transaction costs are high 2. Double-score risk is high 3. Advantages possible from withholding.	Timing depends on quantity strategy (i.e. withholding). Moreover, reaction on grid operator announcements of redispatch order request.
Balancing energy market (BEM)	SRMC + various design-dependent mark-ups	All from balancing capacity contracts + all available (prequalified) capacity	Short before gate-closure time.
Imbalance market (IBM)	No orders and thus no prices. Expected imbalance prices are used for intentional imbalance decisions.	Avoidance of imbalance that worsen balancing control situation + small intentional imbalances in balancing control supporting direction.	Time-dependent actions to avoid scheduled imbalances (i.e. impatience curve). Decision on intentional imbalances taken within delivery ISP.

auctions or tenders, it is assumed that all available capacity would be provided as long as the price is high enough.

Timing assumption for long-term markets. In case of electricity forward markets with a continuous trading design, the timing is assumed to be driven by actual prices, the actual trading position, as well as expected prices (i.e. agent belief). For long-term markets with a limited number of auctions, such as balancing capacity markets (BCM), it is assumed that market parties offer all available capacity for respective prices. Generally, it is assumed that, under consideration of transaction costs, market parties would repetitively (re)buy and (re)sell the same product as long as the transactions increase the expected profit.

Quantity assumption for day-ahead markets. Market parties assumingly place their sold trade position (i.e. short position) from forward markets to the day-ahead market as buy orders. This allows market parties with electricity producing assets to save generation costs which lie above the day-ahead market price. Unsold available generation capacity is also offered as sell orders. Market parties with demand-side response assets follow the same strategy, but in opposite trading direction. Inflexible assets dispatch, which is not yet covered via forward markets, is also placed on the day-ahead market (buy orders for inflexible demand and sell orders for must-run generation).

Pricing assumption for day-ahead market. Market parties on this liquid market with uniform pricing are assumed to place orders with prices based on SRMC of underlying flexible assets. Prices of orders from inflexible assets reflect the maximum willingness to pay. It has to be noted that this pricing assumption may not be correct for all market parties at all times, as strategic mark-ups may be applied (e.g. Hirth and Schlecht, 2019; Möst and Genoese, 2009). However, given assumptions of other day-ahead models (e.g. Selasinsky, 2014) and given interviews with traders, it is assumed that market parties do not apply strategic mark-ups in average trading situations, i.e. in absence of increased scarcity. Furthermore, based on expert interviews, it is assumed that market parties neither include price mark-ups for non-marginal long-term costs, nor do they use complex orders. Instead, it is assumed that agents use the intra-day market to correct infeasible trading positions (i.e. positions impossible to exactly dispatch) from the day-ahead auction. Yet, it is assumed in line with Möst and Genoese (2009) that marginal assets on the merit order would apply mark-ups for start-stop costs.

Timing assumption for the day-ahead market. Given the assumption of a single day-ahead market auction, it is assumed that market parties place all their orders before the gate-closure time of the day-ahead market.

Quantity assumption intra-day. In line with the 'trading model' by Hagemann and Weber (2013) and the model of Selasinsky (2014), it is assumed that both patient traders and impatient traders offer only part of their available capacity, respectively of their open position. This strategy of small order quantities for intra-day open order books is used with the aim not to reveal the market parties' trading position to competitors. Small order quantities are furthermore used as a coordination mechanism in continuous markets to iteratively and anonymously negotiate quantities and prices. Furthermore, quantities from start-up and shut-down of an asset are assumed not to be offered in the open order book. The reason is that this capacity cannot be delivered partly, as the asset would need to operate below its minimum stable level (Pmin). A partial match of such limit orders would thus imply an open position for the market party with the risk of imbalance. It is assumed that large order quantities over long periods are rather traded bilaterally over-the-counter. Such transactions (including start-stop capacity) may occur as a consequence of a forced power plant outage.

Pricing assumption intra-day. It is assumed that prices on intra-day trading include an opportunity mark-up for subsequent intra-day trading possibilities and for subsequent ancillary service acquisition processes. Moreover, in case a transaction would imply operating an asset on a level with a different outage risk, it is assumed that this outage risk would also be considered in a mark-up. Zhan and Friedman (2007) state that strategic mark-ups are not 'objectionable' as they are an important coordination mechanism in continuous markets. Therefore, it is assumed that intra-day prices include an open order book mark-up.

Timing assumption intra-day. Patient traders are considered to be indifferent about the timing of trades. Impatient traders, conversely, need to trade-off between various, time-dependent risks when mitigating imbalance risks of an open position. Garnier and Madlener (2014) argue that high intra-day price volatility would suggest early trading with the benefit of higher liquidity, whilst high volatility of forecast regarding the open position (e.g. driven by RES) would favour later trading with more certainty about the required quantities.

Quantity assumptions for redispatch. Generally, it is assumed that market parties offer all available capacity to grid operators, given prices would cover all occurring of costs. However, market parties assumingly consider providing less than all available capacity:

1. When transaction costs are high for keeping placed orders up-to-date.
2. When double-score risks with parallel markets (e.g. intra-day) are high.
3. When withholding capacity provides strategic advantages with regards to competitors or grid operators.

Pricing assumptions for redispatch. Market parties are faced with a number of risks and opportunities in the context of redispatch, which they assumingly include in price mark-ups. Potentially applied mark-ups depend on the redispatch design and may include the mark-ups discussed in section 5.2.

Timing assumptions for redispatch. It is assumed that the timing depends on the quantity strategy. Additionally, it is assumed that market parties try to anticipate the periods of a day where most redispatch takes place. This includes reacting on operational announcements of the grid operator. As such, they save transaction costs for managing redispatch offers of irrelevant periods.

Quantity assumption balancing energy. It is assumed that all market parties with balancing capacity contracts provide this contracted capacity in the form of agreed balancing energy orders. Furthermore, it is assumed that market parties that have available capacity from pre-qualified assets would provide all of it, if the balancing rules allow for non-contracted orders. It is thus generally assumed that no available capacity is withheld by market parties for mitigating own asset outages in real-time. Moreover, the assumptions imply that no capacity is reserved for deliberate imbalances aiming to profit from imbalance prices. In case the imbalance prices would be structurally higher than balancing energy prices, this 'all-capacity' assumption could be questioned. However, it is argued that in such cases deliberate imbalances would be prohibited.

Pricing assumption balancing energy. Pricing for orders related to contracted balancing capacity may have different pricing restrictions than other orders. The following pricing assumptions are largely based on the examination of Nobel (2016) regarding incentive compatibility between balancing energy prices and imbalance prices. Balancing energy prices assumingly do not include opportunity mark-ups, when there are no opportunities left for the market parties in real-time via structurally higher imbalance prices. Even if real-time trades on intra-day are possible, it is assumed that the prices would converge in real-time with the imbalance price. Yet, high financial penalties for non-delivery (i.e. higher than the imbalance price) assumingly lead to a risk mark-up in balancing energy prices. Strategic mark-ups, however, strongly depend on the design of balancing energy pricing and its relation to the imbalance prices. It is assumed that strategic mark-ups are lower, if any, when both conditions are true:

1. Uniform pricing per ISP exists for balancing energy
2. Imbalance prices per ISP correspond to the balancing energy prices

However, when pay-as-bid regimes apply for balancing energy, the effect described e.g. by Chao and Wilson (2002) may incentivise mark-ups in order to guess the marginal price. Furthermore, when high balancing energy prices of an ISP do not imply similar high imbalance prices during that ISP, price mark-ups (e.g. in a collusion game) can be applied for balancing energy with only little, if any, increase of the market parties' own imbalance risk.

Timing assumption balancing energy. Balancing capacity contracts as well as regulation may include specific times for providing balancing energy orders. It is assumed that such rules would be followed. For non-obligatory balancing energy orders, it is assumed that they would only be placed shortly before the gate-closure time. This strategy is expected to imply less transaction cost for the market party, whilst the expected profit in a reactive balancing regime remains similar.

Quantity assumption imbalance. Some market parties are assumed to react on imbalance price signals with small quantities of intentional imbalances. Reacting with large quantities is considered an invalid strategy, as it would deplete potential profits and even cause financial losses. In particular, market parties with assets which are not pre-qualified for balancing energy products, are assumed to actively steer their imbalance to generate profits.

Pricing assumption imbalance. As no orders are provided, no prices are provided either. However, published imbalance prices serve as trigger for market parties to manage their imbalances. Market parties provide quantities (i.e. intentional imbalance) given a (near-real-time) price assumption because final imbalance prices are usually determined with some delay.

Timing assumption imbalance. Imbalance market decisions take place during the ISP of delivery. Scheduled imbalances are considered as too risky on average. Exceptions from floors in market design may exist.

5.2 Price mark-ups

5.2.1 General assumptions

The assumed price mark-ups [€/MWh] follow the conceptual price mark-up model outlined in section 4.5.3. While mark-ups are defined individually per market party, this section proposes generic methods to approximate the mark-ups for the model. It has to be noted that some market designs may require adaptions of these approximations.

Fundamental costs are simplified. For this model, the fundamental service costs are summarized in short-run-marginal costs (SRMC) and considered static over time. This is a strong simplification. However, since not all adjacent markets and processes are modelled (e.g. fuel and emission markets), it is valid to assume average fundamental costs for the simulation periods.

Generic mark-ups considered in the model. Figure 5.2 depicts all mark-ups considered in the model. As shown in section 4.5.3, there may be other risk-related mark-ups, e.g. mark-ups for potential increases of grid usage charges or costs from quantity constrained fuel contracts. Mark-ups related to adjacent markets and processes are out of scope.

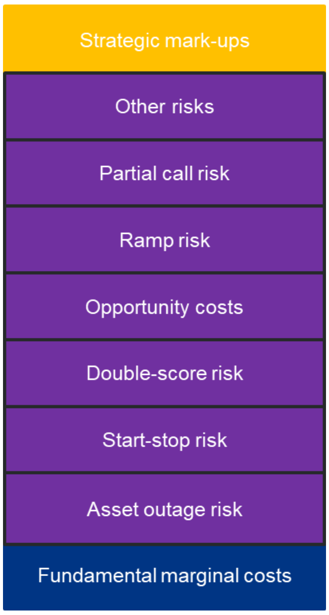


FIGURE 5.2: Various price mark-ups

Positive risk values are considered as cost for market parties. The costs of the mark-up calculation are notated positive when a market party needs to pay, and negative when a market party saves cost. Mark-ups are added to the fundamental marginal cost in case of upward offers and deducted from the fundamental marginal cost for downward offers.

Asset outage mark-up assumption. It is assumed that risks from asset outages are covered by forward markets and, at the latest, by mark-ups in the day-ahead market. In line with feedback from expert interviews, it is assumed that mark-ups for outage

TABLE 5.2: Variables of equations regarding price mark-ups

Variable	Meaning
t	ISP $\in \mathbb{N}$
Ts	Start ISP of delivery period of offer $\in \mathbb{N}$
Te	End ISP of delivery period of offer $\in \mathbb{N}$
SD	Scheduled dispatch [MW/ISP]
$OfferQuantity$	Quantity to be offered [MWh]
$MaxRamp$	Maximum ramp per ISP [MW/ISP]
$OfDi$	Offer Direction of the order $\in \{up, down\}$
$PreRamp$	Required dispatch to dispatch OfferQuantity at beginning of delivery period [MW/ISP]
$PostRamp$	Required dispatch to dispatch OfferQuantity at end of delivery period [MW/ISP]
$PreOvlp$	Start or stop overlap with period of $PreRamp \in \{True, False\}$
$PostOvlp$	Start or stop overlap with period of $PostRamp \in \{True, False\}$
$FixCostFactor$	Factor to considering fixed start and stop cost $\in \{-1, 0, 1\}$
RQ	Risk quantity [MW/ISP]
RP	Risk price [€/MWh]
$eIBP$	Expected imbalance price [EUR/MWh]
$srmc$	Short-run marginal cost [EUR/MWh]
$MinTime$	Min. up time for upward offers en min down time for downward offers
$DeliveryPeriod$	Delivery period of offer
$StartPeriod$	Time to reach Pmin [ISP/start]
$StopPeriod$	Time to reach 0 MW [ISP/stop]
$Pmin$	Minimum stable dispatch level [MW]
$OfferQuantity$	Quantity to be offered [MW]
$eCalledQuantity$	Offed quantity that is expected to be matched [MW]
$MinQ$	Minimum allowed matching quantity [MW]
FC	Fundamental costs are marginal costs of providing a service. $FC \geq srmc$.

risks in short-term markets and acquisition processes are only considered in two cases:

1. Changed dispatch levels imply a significant change in the likelihood of an asset outage. The delta of the expected outage quantities (with and without order delivery) define the expected risk quantity (considered in the generic mark-up equation 4.1)

2. Non-delivery of the order implies significantly higher penalties than the imbalance price. The delta of the expected penalty and the expected imbalance price define the risk price (considered in the generic mark-up equation 4.1

These two cases, however, are currently out of the scope of the model.

Expected imbalance price approach is validated. Various mark-ups contain expected imbalance prices. An approach to determine these imbalance prices is discussed and validated in section 5.9.

Table 5.2 summarises the variables used in equations in the following sections regarding mark-ups.

5.2.2 Ramp mark-up

Ramp mark-up assumption. When offer quantities exceed the remaining available ramp of associated assets, the offered product cannot be delivered without changing the scheduled dispatch before or after the delivery period. The adjusted dispatch schedule before the delivery period is called pre-ramp, the adjusted dispatch after the delivery period is named post-ramp. Open trading positions occur during pre-ramp and post-ramp. Such open positions are here called (scheduled) imbalances, although the market parties may still have time prevent (realized) imbalances by trading these quantities. Besides the imbalance cost, there are additional fuel cost, respectively fuel cost savings, during the pre-ramp and the post-ramp (see illustration 5.3).

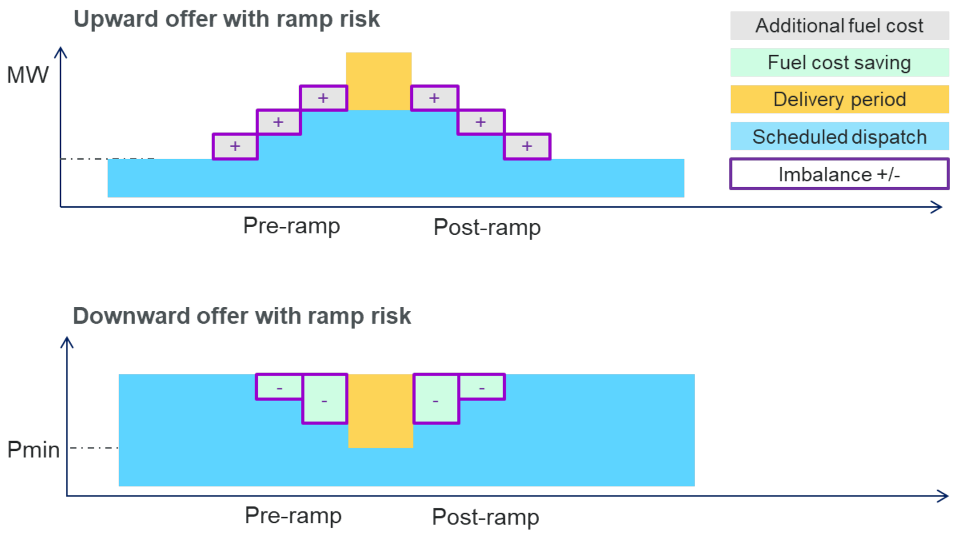


FIGURE 5.3: Examples of Ramp risk in upward and in downward direction

Ramp risk quantity determination. The risk quantity of the ramp mark-up $RQ_{ramp,t}$ is determined by the delta of the scheduled dispatch SD_t and the $PreRamp_t$, respectively $PostRamp_t$. The applicable maximum ramp limit [MW/ISP] depends on the offer direction, downward or upward:

$$PreRamp_t = \left\{ \begin{array}{ll} SD_{Ts} - (Ts - t) * MaxRamp_{up}, & if > SD_t \wedge OfDi = up \\ SD_{Ts} + (Ts - t) * MaxRamp_{down}, & if < SD_t \wedge OfDi = down \\ SD_t, & else \end{array} \right\} \quad \forall t < Ts \tag{5.1}$$

$$PostRamp_t = \left\{ \begin{array}{ll} SD_{Te} - (Te - t) * MaxRamp_{down}, & if > SD_t \wedge OfDi = up \\ SD_{Te} + (Te - t) * MaxRamp_{up}, & if < SD_t \wedge OfDi = down \\ SD_t, & else \end{array} \right\} \quad \forall t > Te \tag{5.2}$$

$$RQ_{ramp,t} = PreRamp_t + PostRamp_t - SD_t \tag{5.3}$$

where Ts is the starting ISP of the offer delivery period and Te is the end ISP of that delivery period.

Ramp risk price determination. The risk price of the ramp mark-up $RP_{ramp,t}$ is composed of the expected imbalance prices for the respective ISPs in the respective direction (i.e. $eIBP_{short}$ or $eIBP_{long}$) and the SRMC for additional dispatch and reduced dispatch per ISP. Due to the notations of imbalance and cost for mark-ups, the imbalance prices need to be multiplied by -1 (i.e. market parties with imbalance long receive IBP_{long} when the price is positive and thus save costs):

$$RP_{ramp,t} = \left\{ \begin{array}{ll} -eIBP_{long,t} + srmc, & if\ RQ_{ramp,t} > 0 \\ -eIBP_{short,t} + srmc, & if\ RQ_{ramp,t} < 0 \\ 0, & else \end{array} \right\} \tag{5.4}$$

Ramp mark-up determination. The mark-up is calculated by determining the expected cost and divide it by the quantity of the order [MWh]. As $RQ_{ramp,t}$ is a quantity [MW], it is divided by four to get MWh.

$$Markup_{ramp} = \frac{\sum_t (RP_{ramp,t} * RQ_{ramp,t})}{OfferQuantity} * \frac{1[h]}{4[ISP]} \ \forall t \in DeliveryPeriod \tag{5.5}$$

5.2.3 Start-stop mark-up

Start-stop mark-up assumption. It is assumed that market parties define discrete cost per start and per stop of each asset. These costs take into account the specific heat-rates, asset value depreciation, and outage risks associated with starting an asset to minimum stable operation, respectively shutting an asset down. However, when offering quantity with an implied start or stop of an asset, imbalances occur during the pre-ramp and the post-ramp. Moreover, imbalances occur when the delivery period is shorter than the minimum up-time or minimum down-time of an asset. These imbalances are long (+) or short (-), depending on the scheduled dispatch. Expert interviews exhibited that these imbalance risks are included as price mark-ups. The cost components for offers related to start-stop capacity are illustrated in figure 5.4.

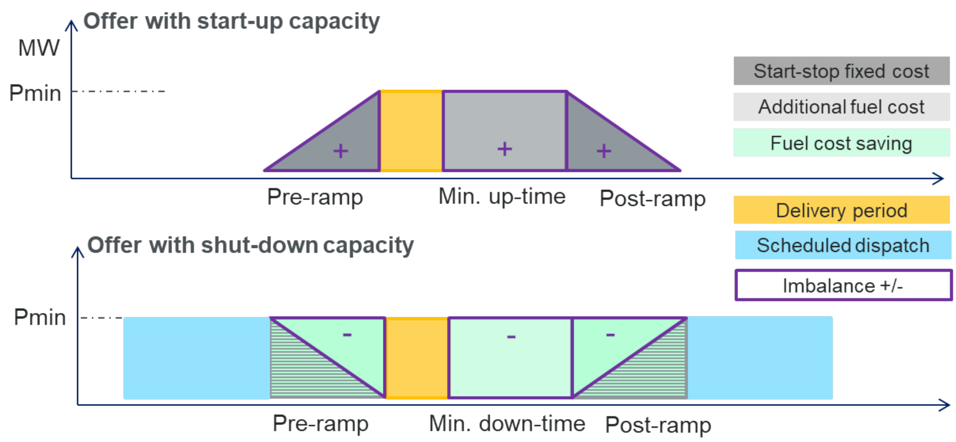


FIGURE 5.4: Examples of start-stop risks (simple case)

Start-stop risk quantity determination. The risk quantity of the start-stop mark-up, $RQ_{stasto,t}$, is – similar to the ramp mark-up – determined by the delta of the scheduled dispatch SD_t and the required $PreRamp_t$, respectively $PostRamp_t$. However, several start-stop specificities are adding complexity to the quantity determination:

- SD_{Ts} and SD_{Te} are by definition either 0 MW for downward offers or $Pmin$ for upward offers. Any scheduled dispatch below, respectively above these limits is considered in non-start-stop offers.
- In case minimum up-time exceeds the delivery period of upward offers, the exceeding period implies additional fuel cost and imbalance long. When minimum down-time exceeds the delivery period of downward offers, the exceeding period implies additional fuel cost savings and imbalance short.
- The applicable $StartRamp$ and $StopRamp$ [MW/ISP] depends on the offer direction. The $StartRamp$ determines the $StartPeriod$ [ISP/start] to reach $Pmin$. Analogously, the $StopRamp$ determines the $StopPeriod$ [ISP/stop] to reach 0 MW.
- When the pre-ramp or the post-ramp overlap with a scheduled start or a scheduled stop, fixed start and fix stop cost, respectively, are saved per overlapping ramp. Moreover, such an overlap of pre-ramp or post-ramp leads to additional fuel cost (upward offers) or less fuel cost savings (downward). Additionally, the imbalance quantity changes in the case of overlaps. Figure 5.5 illustrates an overlap of the pre-ramp for an upward offer as well as a post-ramp overlap of a downward offer.

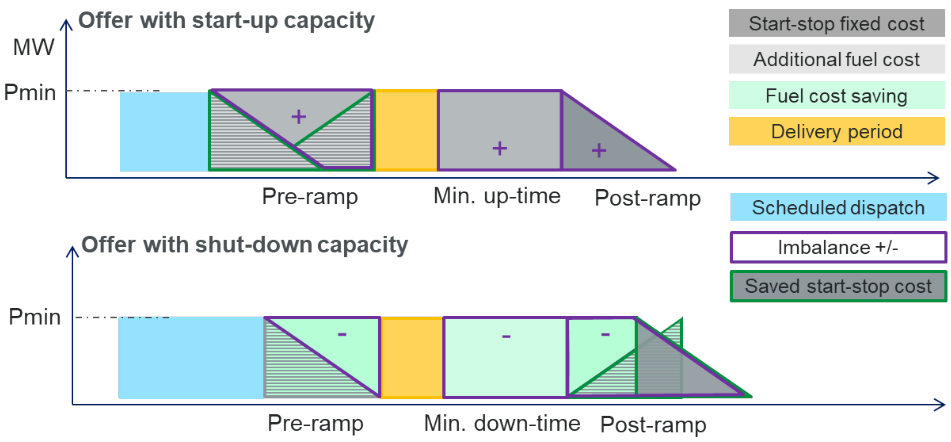


FIGURE 5.5: Examples of start-stop risks (case with overlaps)

The risk quantity of minimum up-time or down-time $RQ_{mintime,t}$ exceeding the delivery period is calculated as follows.

$$addMinTime = \left\{ \begin{array}{ll} 0, & if\ MinTime \leq DeliveryPeriod \\ MinTime - DeliveryPeriod, & else \end{array} \right\} \tag{5.6}$$

Where $MinTime$ is minimum up-time [ISP] for offer direction upward and minimum down-time for offer direction downward.

$$RQ_{mintime,t} = \{SD_{Te} - SD_t\} \forall t \in \{Te < t \leq Te + addMinTime\} \tag{5.7}$$

Two binary variables are determined to calculate the start-stop ramp risk quantity. The variables indicate a start or stop overlap during the pre-ramp respectively post-ramp:

$$PreOvlp = \left\{ \begin{array}{ll} False, & if\ SD_t = 0 \wedge OfDi = up \\ False, & if\ SD_t \geq Pmin \wedge OfDi = down \\ True, & else \end{array} \right\}$$
$$\forall t \in \{Ts - StartPeriod - StopPeriod < t < Ts\} \quad (5.8)$$

$$PostOvlp = \left\{ \begin{array}{ll} False, & if\ SD_t = 0 \wedge OfDi = up \\ False, & if\ SD_t \geq Pmin \wedge OfDi = down \\ True, & else \end{array} \right\}$$
$$\forall t \in \{Te < t < T + addMinTime + StartPeriod + StopPeriod\} \quad (5.9)$$

The risk quantity of the the start-stop ramps RQ_{stasto} are separately calculated for imbalance risks and fuel cost risks.

$$RQ_{stasto,imbalance,t} = \{PreRamp_{imbalance,t} + PostRamp_{imbalance,t} - SD_t\} \quad (5.10)$$

$$RQ_{stasto,fuel,t} = \{PreRamp_{fuel,t} + PostRamp_{fuel,t} - SD_t\} \quad (5.11)$$

PreRamp and *PostRamp* are defined for imbalance risk quantity and fuel risk quantity separately, as the imbalance risk quantity only covers the non-scheduled dispatch in case of overlaps. The fuel risk quantity, however, concerns the entire quantity of $Pmin$ (or equivalently SD_{Ts} respectively SD_{Te}):

$$PreRamp_{imbalance,t} =$$
$$\left\{ \begin{array}{ll} SD_{Ts} - (Ts - t) * StartRamp, & if > SD_t \wedge OfDi = up \wedge PreOvlp = False \\ SD_{Ts} + (Ts - t) * StopRamp, & if < SD_t \wedge OfDi = down \wedge PreOvlp = False \\ SD_{Ts}, & if PreOvlp = True \\ SD_t, & else \end{array} \right\}$$
$$\forall t \in \{Ts - StartPeriod - StopPeriod < t < Ts\} \quad (5.12)$$

$$PreRamp_{fuel,t} =$$
$$\left\{ \begin{array}{ll} SD_{Ts} - (Ts - t) * StartRamp, & if > SD_t \wedge OfDi = up \wedge PreOvlp = False \\ SD_{Ts} + (Ts - t) * StopRamp, & if < SD_t \wedge OfDi = down \wedge PreOvlp = False \\ SD_{Ts} + SD_t, & if\ OfDi = up \wedge PreOvlp = True \\ SD_{Ts}, & if\ SD_t \geq Pmin \wedge OfDi = down \wedge PreOvlp = True \\ SD_t, & else \end{array} \right\}$$
$$\forall t \in \{Ts - StartPeriod - StopPeriod < t < Ts\} \quad (5.13)$$

$$PostRamp_{imbalance,t} = \left\{ \begin{array}{ll} SD_{Te} - (Te - t) * StopRamp, & if > SD_t \wedge OfDi = up \wedge PostOvlp = False \\ SD_{Te} + (Te - t) * StartRamp, & if < SD_t \wedge OfDi = down \wedge PostOvlp = False \\ SD_{Te}, & if PostOvlp = True \\ SD_t, & else \end{array} \right\}$$
$$\forall t \in \{Te + addMinTime < t < T + addMinTime + StartPeriod + StopPeriod\} \tag{5.14}$$

$$PostRamp_{fuel,t} = \left\{ \begin{array}{ll} SD_{Te} - (Te - t) * StopRamp, & if > SD_t \wedge OfDi = up \wedge PostOvlp = False \\ SD_{Te} + (Te - t) * StartRamp, & if < SD_t \wedge OfDi = down \wedge PostOvlp = False \\ SD_{Te} + SD_t, & if\ OfDi = upward \wedge PostOvlp = True \\ SD_{Te}, & if\ SD_t \geq Pmin \wedge OfDi = down \wedge PostOvlp = True \\ SD_t, & else \end{array} \right\}$$
$$\forall t \in \{Te + addMinTime < t < T + addMinTime + StartPeriod + StopPeriod\} \tag{5.15}$$

Moreover, to cope with the fixed start-stop cost and potential savings of scheduled start-stop cost, a *FixCostFactor* per direction is determined as displayed in table 5.3.

TABLE 5.3: FixCostFaktor of shut-down and start-up

$FixCostFactor_{shutdown}$		PreOverlap			PostOverlap	
		True	False	+	True	False
Offer Direction	upward	0	1		-1	0
	downward	-1	0		0	1

$FixCostFactor_{startup}$		PreOverlap			PostOverlap	
		True	False	+	True	False
Offer Direction	upward	-1	0		0	1
	downward	0	1		-1	0

From table 5.3 it is obvious that in all cases $FixCostFactor_{startup} = FixCostFactor_{shutdown}$. Therefore, the distinction of start-up and shut-down is not displayed in the following equations.

Start-stop risk price determination. Risk prices are determined separately for imbalance risks and fuel cost risks. Again, expected imbalance prices are multiplied by -1, due to the notations of imbalance prices and costs.

$$RP_{mintime,t} = \left\{ \begin{array}{ll} -eIBP_{long,t} + srmc, & if\ RQ_{mintime,t} > 0 \\ -eIBP_{short,t} + srmc, & if\ RQ_{mintime,t} < 0 \\ 0, & else \end{array} \right\} \tag{5.16}$$

$$RP_{stasto,imbalance,t} = \left\{ \begin{array}{ll} -eIBP_{long,t}, & if\ RQ_{stasto,imbalance,t} > 0 \\ -eIBP_{short,t}, & if\ RQ_{stasto,imbalance,t} < 0 \\ 0, & else \end{array} \right\} \tag{5.17}$$

$$RP_{stasto,fuel,t} = \{srmc\} \tag{5.18}$$

$$\begin{aligned} &Markup_{stasto} = \\ &\left(\frac{\sum_t (RP_{mintime,t} * RQ_{mintime,t})}{OfferQuantity} + \frac{\sum_t (RP_{stasto,imbalance,t} * RQ_{stasto,imbalance,t})}{OfferQuantity} \right. \\ &\left. + \frac{\sum_t (RP_{stasto,fuel,t} * RQ_{stasto,fuel,t})}{OfferQuantity} \right) * \frac{1[h]}{4[ISP]} \\ &+ \frac{FixCostFactor * (StartUpCost + ShutDownCost)}{OfferQuantity} \\ &\forall t \in TotalStaStoPeriod \end{aligned} \tag{5.19}$$

Where TotalStaStoPeriod $\subseteq \{t|Ts - StartPeriod - StopPeriod < t < Ts,\ and\ Te < t < Te + addMinTime + StartPeriod + StopPeriod\}$

Overlapping start-stop periods lead to significant cost savings. When offers from start-stop capacity have an overlapping pre-ramp and an overlapping post-ramp with scheduled start-stop dispatch, cost savings may be substantial. This is due to savings of costly start-stop cost in exchange for additional but less costly fundamental marginal cost and expected imbalance cost. In such cases, market parties may be willing to offer negative prices for upward offers and very high prices for downward offers.

5.2.4 Partial-call mark-up

Partial-call mark-up assumption. When a market design allows for partial matching of order quantities (e.g. limit orders on intra-day markets), and the offered quantity can only be delivered by a specific asset (e.g. no alternative capacity available or in case of locational products such as redispatch) market parties are faced with two principal risks:

1. Discrete (fix) costs, included in the offered prices via a mark-up, are based on the total quantity of the order. The return of a partial-call may, therefore, lie below the costs.
2. The new trade position may require a dispatch in an unstable operating area of the asset(s) (e.g. below Pmin). In that case, the trade position must be increased or decreased against the expected imbalance price, to ensure a stable operating level.

To fully mitigate the two risks, both costs (fixed cost and imbalance risk) should be covered, even when the smallest allowed call has taken place (i.e. equal to order granularity). However, this would imply a likelihood of the minimum partial-call of 100%. To avoid unnecessary margins, a probability distribution of partial-call quantities must be assumed.

Uniform probability distribution assumption. The partial-call mark-up considered in the present model is limited to partial-call risks from offers associated with start-stop capacity . Furthermore, it is assumed that historic clearing events from some markets or acquisition processes are insufficient to create usable probability distributions for partial-calls. For such markets, it is therefore presumed that market parties consider an equal likelihood for all possible partial-clearing events of an order (i.e. discrete uniform probability distribution). This approach is considered appropriate for, e.g., the Dutch redispatch market, due to the relatively rare redispatch events in the Dutch power system and due to a closed order book. For other markets, specific probability distributions may be developed.

Partial-call risk quantity determination. The risk quantity of a partial-call is the order quantity that is expected not to be matched. Offer quantity and the called quantity are assumed to be constant during the delivery period (i.e. block order design assumption).

$$RQ_{partialcall,t} = OfferQuantity - eCalledQuantity \; \forall t \in DeliveryPeriod \tag{5.20}$$

The expected called quantity $eCalledQuantity$ is, in case of equal likelihood assumption, determined by the expected value of a discrete uniform distribution. The smallest allowed matching increment is assumed to be $\in \mathbb{N}$.

$$eCalledQuantity = \frac{MinQ + OfferQuantity}{2} \tag{5.21}$$

Where $MinQ$ is the minimum allowed matching quantity.

Partial-call risk price determination. The prices associated with the partial-call are the expected imbalance price and the start-stop mark-up of the offer. For locational products (i.e. redispatch), it is assumed that adjusting the trade position in the opposite direction of the offer direction is not allowed. For these cases, a partially called upward order would lead to a dispatch of the full order quantity and thus to a long imbalance position (downward vice versa). Without this directional constraint, a different risk price approach is required. Due to the notations, IBP_{long} is multiplied by -1, as positive prices mean less cost for the market party. In contrast to start-stop mark-up calculation, IBP_{short} is not multiplied by -1, because $RQ_{partialcall,t}$ is always >0.

$$RP_{partialcall,t} = \left\{ \begin{array}{ll} -eIBP_{long,t} + Markup_{stasto}, & if\ OfDi = up \\ eIBP_{short,t} + Markup_{stasto}, & if\ OfDi = down \\ 0, & else \end{array} \right\} \quad \forall t \in DeliveryPeriod \tag{5.22}$$

The partial-call mark-up is finally calculated as follows.

$$Markup_{partialcall} = \frac{\sum_t (RP_{partialcall,t} * RQ_{partialcall,t})}{OfferQuantity} * \frac{1[h]}{4[ISP]} \quad \forall t \in DeliveryPeriod \tag{5.23}$$

5.2.5 Double-score mark-up

Double-score mark-up assumption. When a market party offers quantities which can only be delivered by a specific asset (e.g. no alternative available capacity or in case of locational products such as redispatch) at multiple markets or acquisition processes, it faces the risk of being matched multiple times, without being able to deliver a part of the orders. If market parties applied such strategies, they would need to decide which orders to deliver and for which orders to accept the alternative costs (i.e. penalties). A possible approach would be a ranking of all non-delivery costs, whereby the order with the highest non-delivery costs is assumed to be delivered. This order contains risk mark-ups for non-delivery of the lower-ranked orders. Also, the other orders have risk mark-ups for non-delivery of lower-ranked orders. A simple case of offering at only two markets or acquisition processes is here considered as double-score risk.

Double-score risk quantity determination. The risk quantity is the expected called quantity of the offer on the other market.

$$RQ_{doublescore,t} = \left\{ \begin{array}{ll} eCalledQuantity_{OtherMarket,t}, & if \leq OfferQuantity \\ 0, & else \end{array} \right\}$$
$$\forall t \in DeliveryPeriod \quad (5.24)$$

Analogously to the expected partial-call approach, a discrete uniform probability distribution may be assumed when no better information is available.

$$eCalledQuantity_{OtherMarket} = \frac{MinQ_{OtherMarket} + OfferQuantity_{OtherMarket}}{2} \quad (5.25)$$

Double-score risk price determination. The applicable risk price depends on the rules for non-delivery. Non-delivery of sold electricity on the intra-day market would have the expected imbalance price as risk price. In case of non-delivery of ancillary services, there may be explicit penalty prices. Yet, in some cases, there may be other penalties such as withdraw of market accreditation or a juridical process. Here a translation into a monetary risk would be required. However, expert interviews suggested that the presence of such penalties would usually be a reason not to offer available capacity on multiple markets with double-score risk. For markets where the imbalance price would be the risk price, the determination may be as follows:

$$RP_{doublescore,t} = \left\{ \begin{array}{ll} -eIBP_{long,t}, & if\ OfDi = up \\ eIBP_{short,t}, & if\ OfDi = down \\ 0, & else \end{array} \right\} \forall t \in DeliveryPeriod \quad (5.26)$$

The double-score mark-up is then determined as

$$Markup_{doublescore} = \frac{\sum_t (RP_{doublescore,t} * RQ_{doublescore,t})}{OfferQuantity} * \frac{1[h]}{4[ISP]}$$
$$\forall t \in DeliveryPeriod \quad (5.27)$$

5.2.6 Opportunity mark-up

Opportunity mark-up assumption. When offering asset capacity to a market or acquisition process, market parties may lose potential profits from parallel or subsequent markets. When multiple alternative options exist to generate profit, the option with the highest expected profit determines the opportunity mark-up, as also other options would need to take that best option into account. Given the markets and acquisition assumptions of the model, prices in short-term markets are expected to converge towards a real-time price. Thus, possible transactions before real-time are also assumed to consider the expected real-time price as an alternative. Moreover, the imbalance price is considered as real-time price, which is consistent with the assumed balancing energy market design (see section 5.1.2).

Valuation approach from Weber is adapted. The determination of the opportunity profit follows the option evaluation approach by Weber (BDEW, 2018), which aims to determine opportunity cost in redispatch mechanisms related to opportunities in intra-day markets. This approach views assets as (European-style) call-options for upward service provision, and as put-options for downward provision. The fundamental marginal costs of the asset represent the strike-price for both options. In case the market price lies above the strike-price of the call-option, the asset would deliver in upward direction and generate a profit. Below the strike-price, the call option has no value as the asset would generate losses when delivering in upward direction. For the put-option, vice versa, a market price below the strike-price generates profit for downward delivery, while prices above the strike-price would not add value for downward flexibility. The options' values are illustrated as two areas underneath the probability density curve of the market price (see figure 5.6). The Weber-approach uses the day-ahead price, which is already known when making the offer, to determine the expected market price. However, the Weber-approach presumes that the market price follows an arithmetic Brownian-motion, which allows the use of analytical equations of normal distributions. This simplification is not applied in the present model. Yet, in line with the Weber-approach, it is assumed for redispatch products that changes of asset dispatch are constraint in the opposite direction of a called redispatch order[4]. Opportunity losses in this opposite direction are not considered in the opportunity mark-up. It is assumed that a redispatch providing market party would not lose an opportunity in this opposite direction, given common existing non-remunerated dispatch restrictions for all assets in an area after redispatch is applied (ACM, 2016).

$$RP_{opportunity,t} = \left\{ \begin{array}{ll} \int_{MC}^{\inf}(ibp_{long} - FC) * f_{IBPlong}(ibp_{long}) dibp_{long}, & if\ OfDi = up \\ \int_{MC}^{\inf}(FC - ibp_{short}) * f_{IBPshort}(ibp_{short}) dibp_{short}, & if\ OfDi = down \end{array} \right\} \quad \forall t \in DeliveryPeriod \qquad (5.28)$$

$f_{IBP}()$ may include a time component t. Fundamental costs FC are $\geq srmc$ (see section 4.5.3). An approach to determine $f_{IBP}()$ is discussed in section 5.9.

Opportunity quantity determination. Short-term markets may be quite illiquid. Therefore, it may not be possible to successfully trade the entire offered quantity on an alternative market or process. However, when the opportunity price is high, it can be assumed that there are sufficient possibilities to trade the offered quantity in

[4]For example, an asset with $Pnom$ = 100 MW has a scheduled dispatch of 80 MW and it provided a called order in upward direction of 10 MW. This asset is subsequently required to dispatch (at least) 90 MW. The remaining 10 MW can be used in later trading. However, 90 MW in downward direction cannot be used, as the dispatch is restricted in opposite direction of the called redispatch order.

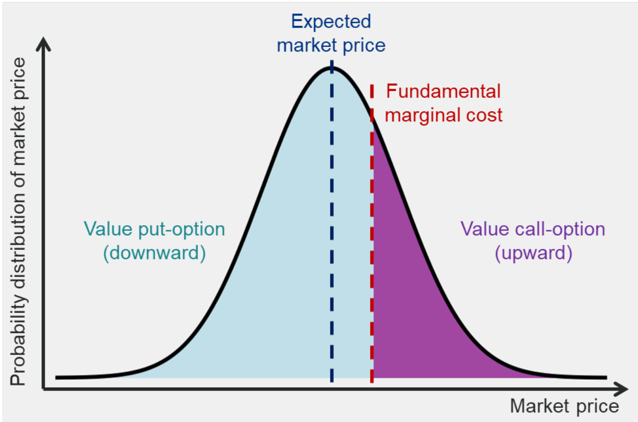


FIGURE 5.6: Example of opportunity valuation of asset flexibility (adapted from BDEW, 2018).

alternative markets. When the opportunity price is low, it is less likely to trade large volumes at a later moment successfully. Moreover, when the offer is placed close to the delivery period, alternative trades may be constraint by ramping limitations of the asset or by utilization speed of the product (e.g. aFRR activation speed). Yet, in this model, the opportunity quantity determination is simplified by assuming that it is equal to the offer quantity, irrespectively of the opportunity price.

$$RQ_{opportunity,t} = OfferQuantity \; \forall t \in DeliveryPeriod \tag{5.29}$$

The mark-up is subsequently determined as

$$Markup_{opportunity} = \frac{\sum_t (RP_{opportunity,t} * RQ_{opportunity,t})}{OfferQuantity} * \frac{1[h]}{4[ISP]} \quad \forall t \in DeliveryPeriod \tag{5.30}$$

5.2.7 Intra-day open order book mark-up

Intra-day mark-up assumption. It is assumed that strategic mark-ups in open order book intra-day trades are a fundamental coordination mechanism for continuous trading (see section 5.1.3). Expert interviews did not reveal much information about the secret strategies of market parties. However, it was stated that some market parties use automated trading routines, which react to prices and quantities in the open order book. Still, much trading decisions are taken by human traders, which may have a certain degree of freedom to experiment with 'gut-feeling'. The expert interviews further suggested that strategies vary from straight-forward approaches to very sophisticated methods (see, for instance, the approach of Selasinsky, 2014). For this model, a very simple, risk-averse heuristic is assumed, which increases the indifference price of an offer up to the price of the next order in the merit order. It represents thus a lower-bound mark-up, which does not cover sophisticated and more risk-friendly strategies.

Orders are sorted in order book. Price, quantity and delivery period of intra-day orders are published in an open order book. Buy orders are sorted per delivery period from high prices to low prices and sell orders from low prices to high prices. The orders on top of the order book are orders with the 'best price'. When determining an offer price, it is thus possible to see where the offer would be placed in the order book. The delta price of the top sell and buy order is called buy-ask (price) spread.

Instantaneous clearing. As soon as a new sell offer is added with a price above the top buy order price, clearing of orders takes place, whereby the older order determines the clearing price. Analogously, clearing is triggered when a new buy order has a price below the top sell order price.

Extra-marginal and infra-marginal offers are distinguished. The strategic mark-up distinguishes between extra-marginal offers and infra-marginal offers (e.g. see Müsgens, Ockenfels, and Peek, 2014). The extra-marginal offers are placed in the open order book without clearing, as no counter orders are available with a matching price. Infra-marginal offers are matched instantaneously for the price of the older order (thus not the offer price). In case only a part of an order is cleared, the remaining offer quantity stays on top of the order book.

Next-best price determination. The next-best price of an extra-marginal order is the price of the following order in the order book (i.e. the next lower rank).

Intra-day strategy quantity determination. The quantity of the strategic mark-up equals the offer quantity.

$$RQ_{intraday,t} = OfferQuantity \; \forall t \in DeliveryPeriod \tag{5.31}$$

Indifference price determination. In line with the approach of Selasinsky (2014), an indifferent price is determined. This indifferent price includes the opportunity mark-up, as defined above, before the strategic mark-up is added. Depending on the quantity strategy of the market party, also other mark-ups may be included in indifference price.

$$IndiffPrice_t = \left\{ \begin{array}{ll} srmc + Markup_{opportunity}, & if \; OfDi = up \\ srmc - Markup_{opportunity}, & if \; OfDi = down \\ 0, & else \end{array} \right\} \quad \forall t \in DeliveryPeriod \tag{5.32}$$

Intra-day mark-up determination. The strategic mark-up for extra-marginal offers is the order price of the next-best order price plus 1 EUR/MWh or minus 1 EUR/MWh for buy orders and sell orders, respectively. For infra-marginal offers, a profit margin (p.u. of indifferent price) is applied to negotiate a better price and to ensure that the remaining quantity after partial clearing also includes a strategic mark-up. The strategic mark-up is expressed as delta price to the indifference price.

$$RP_{intraday,t} = \left\{ \begin{array}{ll} NextBestPrice_t + 1 - IndiffPrice_t, & if \; OfDi = up \land ExtraMarginal = True \\ IndiffPrice_t - NextbestPrice_t - 1 & if \; OfDi = down \land ExtraMarginal = True \\ ProfitMargin * IndiffPrice_t, & if \; InfraMarginal = True \end{array} \right\} \quad \forall t \in DeliveryPeriod \tag{5.33}$$

Delivery MTU x

Buy quantity [MW/MTU]	Buy price [EUR/MWh]	Sell price [EUR/MWh]	Sell quantity [MW]
1	35	40	1
1	30	45	1
1	28	50	1
1	26	55	1
1	24	60	1
1	22	65	1
1	21	65	1

Two examples:

Extra-marginal buy offer:
- Indiff. price: 34 EUR/MWh
- Mark-up: 3 EUR/MWh
- Offer price: 31 EUR/MWh

Infra-marginal sell offer:
- Indiff. price: 30 EUR/MWh
- Mark-up: 3 EUR/MWh
- Offer price: 33 EUR/MWh

FIGURE 5.7: Examples of intra-day mark-ups for an extra-marginal offer and an intra-marginal offer in an open order book.

The mark-up is finally determined as

$$Markup_{intraday} = \frac{\sum_t (RP_{intraday,t} * RQ_{intraday,t})}{OfferQuantity} * \frac{1[h]}{4[ISP]} \quad \forall t \in DeliveryPeriod \tag{5.34}$$

Historic prices used when order book is empty. The order book may not always contain orders for the delivery period of the offer. If the order book is empty because no orders were placed, the profit margin is again applied as mark-up. When the order book is empty because all orders have already been matched, then the highest (for upward offers) or the lowest (for downward offers) clearing price of the previous trading period is used as NextBestPrice to determine the mark-up.

5.3 Agent-based modeling in electricity system research

Agent-based models broadly used in energy system research. Agent-based models are today one simulation approach next to equilibrium models and optimization models (see Ringkjøb, Haugan, and Solbrekke, 2018 for a model review). Weidlich (2008) and Tesfatsion (2018) have substantially contributed to the incorporation of valid agent-based analyses into energy system research. Fields of application include the investigation of bidding strategies in electricity markets (see Veen, Abbasy, and Hakvoort, 2012; Wehinger et al., 2013; Rashedi, Tajeddini, and Kebriaei, 2016; Rashidizadeh-Kermani et al., 2018), decision-making in grid expansion investments (Blijswijk, 2017), benefit distributions as well as the effectiveness of policies for renewable energies expansion (see Reeg et al., 2013; Nuñez-Jimenez et al., 2020; Ramshani et al., 2020), and the interaction of different electricity markets and ancillary services (see Weidlich, 2008; Petitet et al., 2019; Poplavskaya, Lago, and Vries, 2020).

Agent-based models suit policy design studies. Multiple characteristics of agent-based models support their suitability for policy design testing: (1) The "bounded rationality" of agents enable robustness tests of policy options with "imperfect" behaviour (Ostrom, 2005, p. 104). (2) agent-based models can be combined with classical optimization methods (e.g. linear-programming) as well as with self-learning methods. Klein, Frey, and Reeg (2019) call this characteristic "models within models". (3) agent-based models can also provide bottom-up exploration and communication for policymakers, by showing emergent system behaviour as a result selected assumptions on agent level (Klein, Frey, and Reeg, 2019).

Availability of open-source models. In recent years, various open-source and open-access energy system models (e.g. Oemof) and power system analyses tools (e.g. PyPSA) became available (see open energy models initiative Openmod, 2020). PyPSA is a renown python-based toolbox, that includes linear least-cost optimization of power plant and storage dispatch within network constraints (Brown, Hörsch, and Schlachtenberger, 2018; Brown et al., 2020). Still, comprehensive agent-based models like AMIRIS, SiStEM and Enertile (previously named PowerACE) are not openly available for researchers. The open-source Java-based AMES is an exception. The model is developed as a "test bed" for policies regarding United States (U.S.) market design (Battula, Tesfatsion, and McDermott, 2020).

The literature review showed that, currently, an open-source agent-based model does not exist for design tests of electricity markets and ancillary services in the European Union (EU) context.

5.4 Target of the computational model

The model aims to explore acquisition processes on two levels. In order to evaluate the consequences of various ancillary service acquisition designs, including potential interactions with other acquisition processes and markets, the numerical model aims to explore both emergent system behaviour as well as agent behaviour. The model supports assessments of policy implications by simulating designs which may not (yet) be available in the real-world. Hence, the model may produce out-of-sample results (Windrum, Fagiolo, and Moneta, 2007). Given these objectives, the model is called ancillary service acquisition model (ASAM).

Model scope limited to structural analyses. The model is not suited to develop optimal trading strategies. It is also not designed to generate forecast. Moreover, the transactional model is not appropriate for detailed analyses of physical system behaviour. Yet, ASAM may be combined with models that focus on physical behaviour in order to analyse the interaction of physics and transactions in more detail (e.g. load-flow-models, detailed frequency control models or voltage control models).

A number of model requirements for generic application can be derived from the above defined target of ASAM:

1. Structure. The model needs to have a structure that supports the implementation of various market processes from forward markets up to real-time markets with various designs.
2. Agents. Different agents must be configurable according to study needs. In particular market parties with assets, grid & system operators, as well as market operators are required.

3. Strategies per agent. Every market party agent may have individual strategies to act per market or acquisition process.
4. Market and acquisition rules. Configurable rules for markets and ancillary service acquisition processes are required. The market rules should correspond to generic design variables discussed in section 4.3.
5. Performance indicators. Configurable performance indicators are required to measure the impact of design options.
6. Open source. For scientific integrity and for further development the model must be publicly available without pay-wall (i.e. open source and open access).

Limitations. However, the model has neither the aim nor the capability to be ready-to-use for every ancillary service design evaluation possible. Therefore, it is important to notice that it is a basic model which needs to be adapted, extended and calibrated to become feasible for the specific research purpose.

Combination with other models. In particular detailed models of physical system behaviour need to be combinable with the generic modules and functions of ASAM.

5.5 Overall model structure

ASAM is built on various Python libraries. ASAM is implemented in Python 3.5.6. It uses various Python libraries. It uses classes of the agent-based modeling framework MESA (Kazil, Masad, and Crooks, 2020), that is model class, agent class, scheduler class. Instances of PyPSA (Brown, Hörsch, and Schlachtenberger, 2018) are applied for dispatch optimization of market parties and for day-ahead and redispatch market clearing. The classes are depicted in figure 5.8. Methods and attributes per ASAM class are listed in annex B and in more detail on GitHub (Glismann, 2021c). Moreover, an overview of variables, functionalities and the (possible) link to physical models is illustrated on figure 5.9.

The model concept of time. As is common in agent-based simulations, time progresses in discrete steps. During each step, agents take actions, given the stage of the simulation. This basic functionality is provided by MESA. One simulation step corresponds to one ISP of 15 minutes. The time is expressed in tuples of day ($\in \mathbb{N}$) and ISP of the day ($\in \mathbb{N}\{1, \ldots, 96\}$).

Actions are taken for the schedules horizon. Actions of agents related to short-term markets do not only consider the current simulation step but also all simulation steps up to the last delivery period of the latest day-ahead auction (i.e. inter-temporal agent strategies).

Random agent rank during a simulation step. The sequence of agents executing their actions within a simulation step is randomized per round. The agents' actions per step are in a fixed sequence. In some-cases agents already know the consequences of a previous action within the same step. For instance, when placing orders on intra-day market, the orders are cleared instantaneously, while orders for redispatch are only cleared once per round following the grid operators actions.

Time class serves as a global clock for agents. The time class manages all time-related methods, which can be used by other classes. The methods and attributes are shown in B. Although the step size is configurable, a 15-minute step-size is currently the only available option in ASAM.

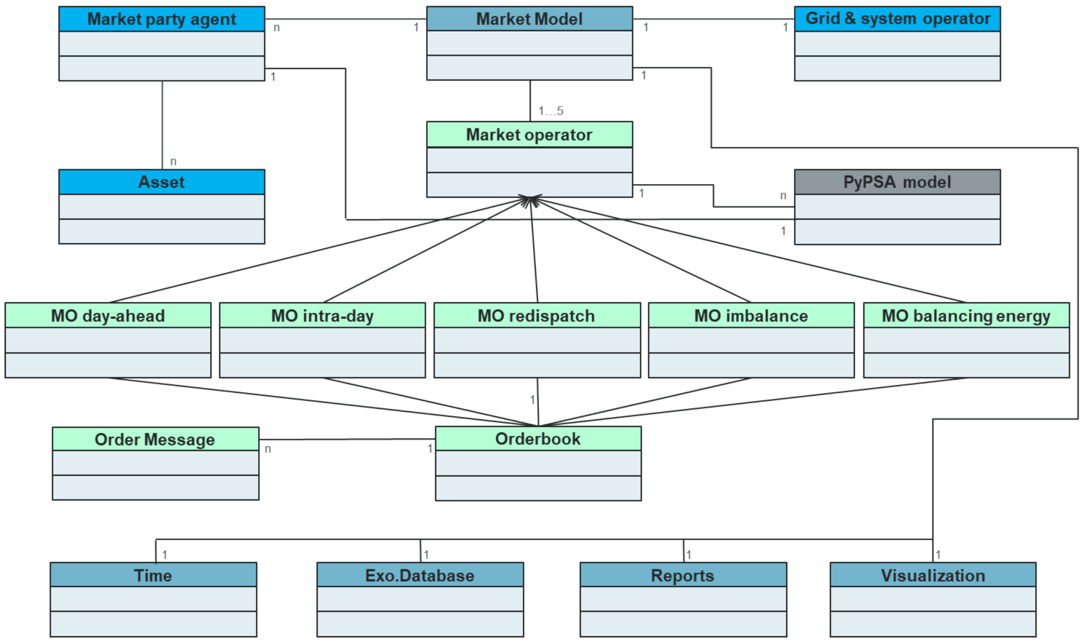


FIGURE 5.8: Overview of classes in ASAM.

Market model handles the global level. The market model is the overall model of ASAM, which initializes most other classes. It holds model-level attributes, and it manages the simulation steps. It has two methods: init() for initialization of the simulation model and step() to advance the simulation by one step.

Reports class collects and administers results. The generic reporting class collects per round simulation data and processes it for the simulation results. The reports enable an investigation of the evolution of the simulation. This means that not only, e.g. the final volumes and prices traded for a delivery period are reported, but it is also possible to examine simulation stages preceding the final stage on system-level and agent-level. Some reports are also used by other classes during the simulation process (e.g. published prices).

Visualization class provides all figures. The visualization class uses the result of the Reports class and computes figures. However, for comparative simulations, additional visualization methods are required to combine the results of various simulations. Such ex-post processing methods are currently not in the scope of ASAM.

Input data are managed in exogenous data class. Simulations with ASAM require a large number of input parameters. The input parameters include:

- Simulation task
- Market party agents and their asset portfolios
- Agent strategies
- Market rules
- Time series of day-ahead residual load
- Time series of residual load forecast errors (optional)
- Time series of asset unavailability's (optional)

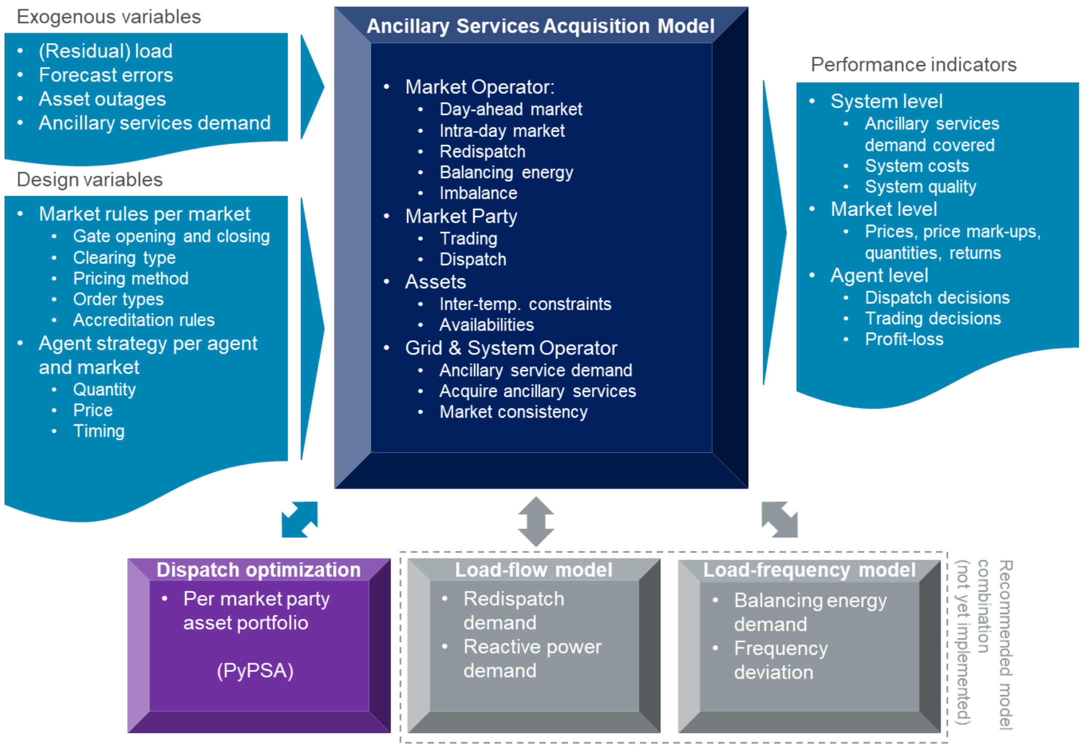


FIGURE 5.9: ASAM overview and link to other models (only PyPSA is currently implemented).

When physical ancillary service parameters are not simulated but provided as exogenous demand, the following input may be required:

- Redispatch demand
- Probability distribution of balancing energy control states
- Probability distributions of imbalance prices

When markets are not simulated but a market's output is needed for the simulation, it may be required to use default market outcomes. Such default values are also provided by the exogenous data class.

Forecast errors may be allocated per simulation step. The method allocate_exo_errors() may be applied once per simulation step before the agents execute their simulation task. This method uses exogenously provided residual load forecast errors. These forecast errors are assigned to the trade schedule of the respective agents. The open position from forecast errors is subsequently taken into account when the imbalance position per ISP is determined. Two error allocation modes are available: The input may define the forecast error per market party or a given system forecast error is randomly distributed among market parties. In the latter mode, the errors are allocated randomly in proportion to the market parties' total installed asset capacity. A uniform distribution is applied, whereby not only the system forecast error is allocated, but also up to 25% of the forecast error is allocated in the opposite direction.

Market rules set parameters for market operator methods. The class Market Operator has only an init() method and the attributes obook, market_rules and the parent model. The inherent classes of the various markets have market-specific methods with design variables which are set by the market rules.

Generic design variables but specific options. The market rules for every market in ASAM require a design choice regarding a number of variables. The variables are a subset of the generic design variables (defined in subsection 4.3), as not all variables are useful for an agent-based simulation (e.g. communication protocols):

- Acquisition method. This design variable specifies the general type of the market or acquisition process. However, it includes also the scoring method.
- Pricing method. This design variable defines which price is settled.
- Order types. This is a sub-variable of the design variable bid requirements. It specifies which order types are allowed.
- Gate-opening time. This is a sub-variable of the design variable acquisition timing.
- Gate-closure time. This is a sub-variable of the design variable acquisition timing.
- Provider accreditation. This is a variable specifying which agents or assets may participate in an acquisition process.

Agents require three basic strategies per market. Market party agents receive a defined strategy regarding quantity, prices and timing for every market and acquisition process. The strategies may be different per agent. Although there are currently no self-learning methods implemented in ASAM, such self-learning parameters would also be provided as input to the agents' strategies.

Process of one simulation step shown in flow diagram. A process overview of one simulation step is illustrated in figure 5.10. However, starting (i.e. initialization) and ending (i.e. saving results) tasks of the simulation are not included in the figure. The method depicted will be further outlined in the sections below.

Only short-term markets implemented in ASAM. Long-term markets, as defined above, are not implemented in ASAM. As depicted in figure 5.10 only the markets and acquisition processes day-ahead (DAM), intra-day continuous (IDM), redispatch (RDM), balancing energy (BEM) and imbalance (IBM) are considered in the computational model. Furthermore, bilateral OTC trade is not modelled, and thus it is assumed that all intra-day trade takes place on continuous trading platforms. However, forward markets, bilateral over-the-counter trade10, balancing capacity auctions, and other ancillary services can be modeled in future, using ASAM.

5.6 Markets and acquisition process implementation

This section describes how the markets and acquisition processes are implemented.

The variables used in the equations of the following sections are listed in table 5.4. As PyPSA is applied in market clearing methods and in agent dispatch optimisation, the variable names are largely aligned with the names of the PyPSA documentation. However, it has to be noted that the PyPSA models are not used in ASAM for load-flow analyses. So, depending on the context, a generator dispatch $g_{n,s,t}$ may be a cleared order or scheduled dispatch of an asset (SD).

TABLE 5.4: Variables of equations regarding markets and agents in ASAM

Variable	Meaning
t	ISP, index for time steps in schedules horizon $t \in T = \{0, \dots \lvert T\rvert - 1\}$
A	Index for agents
OB	Index for order books of different markets
bu	Index for buy order
se	Index for sell order
n	Index for grid areas (respectively agent portfolios) $n \in N = \{0, \dots \lvert N\rvert - 1\}$
s	Index for the generators $s \in S = \{0, \dots \lvert S\rvert - 1\}$
$g_{n,s,t}$	Dispatch of a generator at a time step [MW].
$u_{n,s,t}$	Time series of binary status variables for inter-temporary constraints $\in \{0, 1\}$
$p\_min\_pu_{n,s,t}$	Time-variant minimum stable level in p.u. of P_{nom}
$p\_max\_pu_{n,s,t}$	Time-variant maximum output in p.u. of P_{nom}
$min\_up\_time_{n,s}$	Minimum up time [ISP]
$min\_down\_time_{n,s}$	Minimum down time [ISP]
$srmc_{n,s}$	Short-run marginal costs
$suc_{n,s,t}$	Start-up cost when started at t [EUR]
$sdc_{n,s,t}$	Start-down cost when shut-down at t [EUR]
$ru_{n,s}$	Ramp-up limit [MW/ISP]
$rd_{n,s}$	Ramp-down limit [MW/ISP]
$minSD_{n,s,t}$	Must-run (minimum) scheduled dispatch [MW]
$maxSD_{n,s,t}$	Maximum scheduled dispatch [MW]
$av\_cap\_up_{n,s,t}$	Available upward capacity of asset s[MW]
$av\_cap\_down_{n,s,t}$	Available downward capacity of asset s[MW]
$SD_{n,s,t}$	Scheduled dispatch of asset [MW]
$rr\_av\_cap\_up_{n,s,t}$	Remaining ramp constraint av_cap_up [MW]
$rr\_av\_cap\_down_{n,s,t}$	Remaining ramp constraint av_cap_down [MW]
$TP_{m,n,t}$	Trade position of agent n at market m [MW]
$FE_{n,t}$	Forecast error of agent n [MW]
$Pmin_{n,s}$	Minimum stable dispatch level [MW]

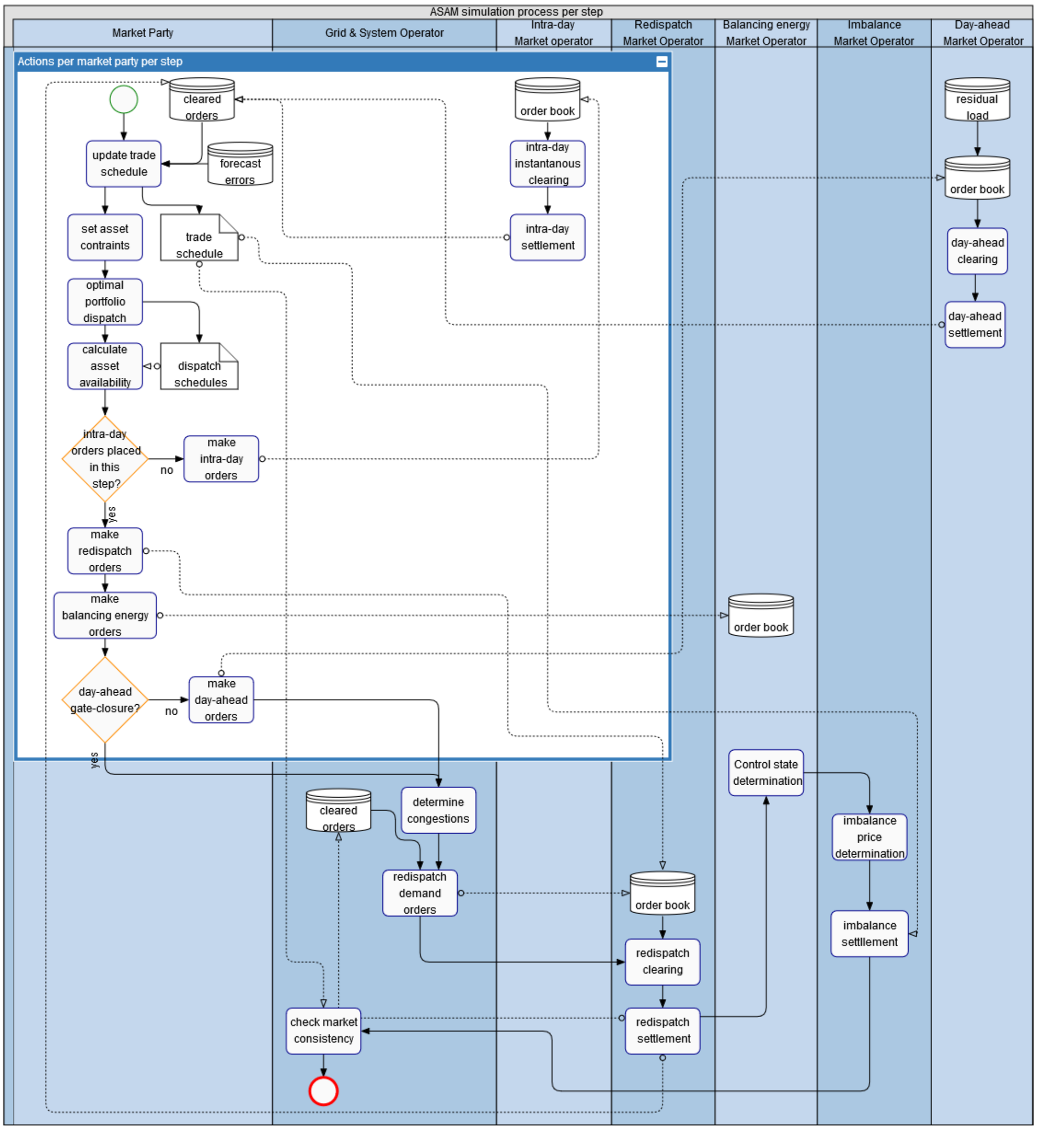


FIGURE 5.10: Process of one simulation step in ASAM.

Generic order messages are used for all markets. All markets which use orders (i.e. not the imbalance market) are implemented with the same order message format. Order message is a class instance which contains as main attribute a table (i.e. a Python Pandas DataFrame) where every row corresponds to an order. When an order message is initiated by an agent, a control on the format is executed. For intra-day orders, it is also checked if there are potential matches within the order message. Those orders are then excluded (smaller order) respectively adjusted (larger order). Order books only accept instances of the order message class. Every order has the following attributes:

- agent_id [string]
- associated_asset [string]
- delivery_location [string]

TABLE 5.5: Market rules implemented in ASAM

	Acquisition method	Pricing method	Order types	Gate-opening time	Gate-closure time	Provider accreditation
DAM	single_hourly_ auction exo_default	uniform	fill_or_kill	D-1, MTU 44	D-1, MTU 45	all
IDM	continous_IDM	best_price	limit_and_market limit_market _ IDCONS	D-1, MTU 56	deliveryMTU-1	all
RDM	cont_RDM_thinf cont_RDM_th0 cont_RDM_th5 cont_RDM_th50	pay_as_bid	all_or_none_ISP all_or_none_block limit_ISP limit_block IDCONS_orders	D-1, MTU 56	deliveryMTU-1 deliveryMTU-3	all
BEM	control_states_ only	none	mFRR aFRR	D-1, MTU 56	deliveryMTU-1	all
IBM	realtime	Dutch_IB pricing fixed single price	na	deliveryMTU	deliveryMTU	all
BCM						

- quantity [int]
- price [int]
- delivery_day [int]
- delivery_time [int]
- order_type [string]
- init_time [float] (current MTU of simulation + current step rank of agent divided by 1000)
- order_id [string]
- direction [string]
- delivery_duration [int] (number of MTU)

Overview of implemented design options per market. For the above-introduced design variables per market, various options have been implemented. To implement a new option, a name for the option needs to be defined. Subsequently, if-conditions have to be programmed to the respective market operator methods (i.e. clearing or settlement). Table 5.5 shows the options that are already implemented in ASAM.

Day-ahead market clearing with single auction. The clearing method of the DAM uses a linear optimal power flow of PyPSA[5] with a one-node grid[6].The absence of grid constraints in a one-node grid transforms the LOPF function to an optimal dispatch function. The resulting marginal dispatch costs determine the uniform day-ahead price. In line with the assumptions in section 5.1.3, all generators of the simulation are participating in selling electricity. Moreover, exogenous time series of generators' unavailability are taken into account. A single load represents the buy orders of the market, which corresponds to the exogenous residual load time series

[5]PyPSA version 0.13.1. is used. For a detailed description, the reader is referred to Brown, Hörsch, and Schlachtenberger, 2018 and the Brown et al., 2020.

[6]Cross-zonal market coupling are not yet implemented in ASAM. For an extension, each bidding zone would need to be represented by a node and a cross-border capacity allocation processes would need to be implemented.

of the system. Hence, the DAM is implemented with a single-sided auction instead of the real-world double-sided auction.This simplification determines initial trading positions of agents and it avoids assumptions regarding individual load time series and long-term electricity contracts. However, for studies on detailed DAM strategies or demand-side flexibility, a double-sided auction method would be required.

Simplified offer process is implemented. In opposite to the other markets which clear provided orders, the day-ahead market implementation skips the agents' task to submit day-ahead orders. Instead, the clearing method collects all relevant data directly from the assets. This computation time-saving approach is only possible because there is currently no other agent strategy for the day-ahead market implemented than offering all available capacity at SRMC. The process flow in figure 5.10 does not correctly present this simplification.

Trading period of day-ahead market varies. The ASAM day-ahead market has an MTU of one hour. The trading period usually entails all 24 MTU of the next day. However, in the first simulation step, all remaining hours of the current day are traded as well. When the simulation's end-time lies in the current day, the day-ahead market for day + 1 is simulated.

Day-ahead settlement with uniform pricing. ASAM has only uniform pricing implemented for the day-ahead market. The day-ahead clearing price per MTU is determined by the highest SRMC of all committed assets. It has to be noted that marginal generators face losses during a trading period as a consequence of start-up costs and shut-down costs. The settlement method transforms the LOPF results to cleared orders, which are subsequently provided to all agents. Furthermore, it publishes the day-ahead prices to make them available for all agents.

Intra-day market clearing is instantaneous. As shown in the process flow, the continuous intra-day market is instantaneously cleared when an order message is added. Therefore, the intra-day order book may be cleared multiple times per simulation step (i.e. each time an agent adds intra-day orders). The clearing method has three steps:

1. Filter all relevant orders of the order book for matching the new orders. This step results in four sorted sets (see also section 5.1.3).
   (a) $P^{A}_{se,t,k}$ and $P^{A}_{bu,t,l}$ are sets of order prices of agent A triggering the clearing which have the direction sell (*se*) respectively buy (*bu*) and the delivery period *t*, whereby $k \in \{1, \ldots K\}$ and $l \in \{1, \ldots L\}$ are the indexes of the order sets. $P^{A}_{se,t,k}$ is sorted by ascending order price. $P^{A}_{bu,t,l}$ is sorted by descending order prices.
   (b) $P^{OB}_{se,t,i}$ and $P^{OB}_{bu,t,j}$ are sets of order prices in the order book OB which have the direction sell (*se*) respectively buy (*be*) and the delivery period t, whereby $i \in \{1, \ldots I\}$ and $j \in \{1, \ldots J\}$ are the indexes of the order sets. $P^{OB}_{se,t,i}$ is sorted by ascending order price and by ascending init_time. $P^{OB}_{bu,t,j}$ is sorted by descending order prices price and by ascending init_time.
   (c) Analogously to the notation above, the sets $RemQ^{A}_{se,t,k}$, $RemQ^{A}_{bu,t,l}$, $RemQ^{OB}_{se,t,i}$, and $RemQ^{OB}_{bu,t,j}$ are defined, which refer to the remaining quantity of the respective order.
2. Match of new orders with a clearing price of the 'older' order (i.e. with the lower init_time). The matching process of intra-day orders is illustrated in

figure 5.11. Note that the clearing method only allows for order duration_time of one ISP.

3. Remove matched orders and adjust quantities of partially matched orders. Keep unmatched limit orders and remove unmatched market orders, as the latter has an immediate-or-cancel constraint.

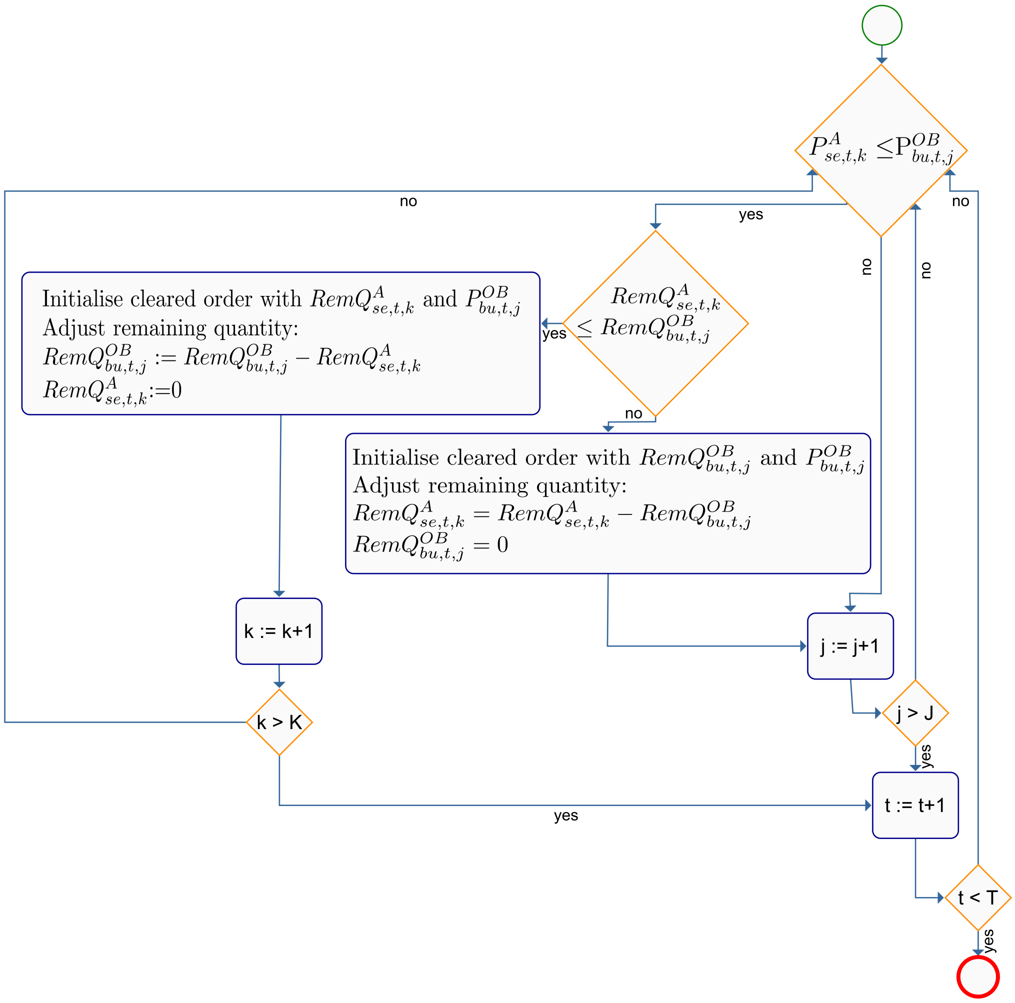


FIGURE 5.11: Intra-day matching process with the example of sell orders placed by agent A.

Intra-day settlement method. The intra-day settlement method provides the cleared orders to the involved market parties. It furthermore calculates the due amount of the transactions by multiplying the cleared quantity with the cleared price. This due amount is added to, respectively deducted from the bank account of the involved market parties.

Redispatch market implementation without grid model. ASAM includes a simplified redispatch market scoring algorithm [7]. As a starting point, it has to be noted that the physical grid is currently not modeled in ASAM. The model considers physical

[7]Although the terms "redispatch market" and "redispatch orders" are used, the model functionality may also be used for highly regulated redispatch mechanisms

characteristics of power plants and residual load. An (approximate) redispatch demand is, therefore, to be derived from congestion and then provided as exogenous data to the model. The grid operator agent places this demand in the redispatch order book. Redispatch demand is defined as a MW value from an area (downward) to an area (upward). Given this exogenous redispatch demand approach, market parties cannot influence the redispatch demand with their behaviour.

Scoring algorithm is based on PyPSA functionality. The redispatch market operator class uses PyPSA to find a redispatch solution. Each redispatch area that is defined in the redispatch demand is initiated as a node in a power system without connections to other nodes. The redispatch demand per area is implemented as a load, and redispatch supply orders are implemented as generators, using generator parameters to emulate order attributes. The generator parameters are established as follows:

- *Pnom* is set to the order quantity.
- The generator parameter *p_max_pu* is set to 0 for all simulated MTUs which lie outside the delivery period of the respective order, and else it is set to 1.
- The generators *p_min_pu* attribute is used to define whether an order can be partially called (limit order) or only fully called (all-or-none). In the first case, *p_min_pu* receives the value 0, in the latter case the parameter is set to 1.
- The generators *min_up_time* (for upward orders) and *min_down_time* (for downward orders) are used to define multi MTU block orders. This parameter is thus set to the delivery duration of the order.
- The *srmc* of the generators is set to the respective order prices. However, in areas with downward redispatch demand and thus generators representing buy orders, the additive inverse of the order price is used. This is to cope with the notation of buy order prices, which indicate a willingness to pay, when positive. With the additive inverse, it is ensured that with a cost-minimizing optimization function, high buy order prices are preferred over low buy order prices.

The effectivities of delivery locations are assumed to be equivalent. As outlined in Hirth and Glismann (2018), the order effectivity varies with the order delivery location. This is usually approached with matrixes of so-called power distribution factors (PTDFs). However, since the ASAM redispatch method has no physical electricity grid modelled, it is assumed that all orders from the same area have a similar effectivity. For radial DSO networks, this assumption is fairly appropriate, but for meshed networks, the simplification may affect the accuracy of results.

PyPSAs optimal power flow function determines which orders are cleared. The optimal power flow of PyPSA with the respective inter-temporal constraints is applied to the model. The resulting dispatch of the generators shows which orders are cleared to what extent. This approach allows for the simulation of block orders as well as limit orders.

Slack generators in every area capture under-procurement and over-procurement. In order to enable feasible solutions in case the redispatch demand in an area is not exactly matched, every area has slack generators. Generators capturing under-procurement (i.e. a lower redispatch quantity is cleared than the actual redispatch demand) have SRMC set to 10000 EUR/MWh and *Pnom* of 10000 MW. Slack generators for over-procurement (i.e. a higher redispatch quantity is cleared than actual redispatch demand) have a negative *Pnom* of -10000 MW and an operating area defined by *p_min_pu* of -1 and *p_max_pu* of 0. The *srmc* is set to -1000, which means that the penalty of over-procurement is lower than the penalty of under-procurement. Still, a penalty is needed for over-procurement as otherwise slack generators may be dispatched before generators that represent redispatch orders.

Two custom constraints added to optimal power flow. Two additional self-defined constraints are given to the solver. The first constraint ensures that block orders are cleared with the same quantity (MW) for all MTUs. The second constraint is a threshold for the 'equilibrium constraint' as described in Hirth and Glismann (2018): "*In order to avoid (large) imbalances as a consequence of redispatch, network operators aim to apply downward redispatch volume (MWh) and upward redispatch volume per imbalance settlement period (ISP) in equilibrium*" (p. 17). The threshold defines the maximum delta between the cleared volumes per MTU in upward and in downward direction. The four acquisition methods shown in table 5.5 represent thresholds of infinite MW, 0 MW, 5 MW, and 50 MW.

Objective function. In line with the description by Brown et al. (2020), the optimization function can be expressed as follows. Irrelevant variables for this redispatch approach are neglected, such as grid expansion cost, generator investment cost, storage state and capacity, and weighing factors per timestamp. The optimization function minimizes the cost over the schedules horizon.

$$min \left[\sum_{n,s,t} srmc_{n,s} * g_{n,s,t} \right] \tag{5.35}$$

where $n \in N = \{0, \dots |N| - 1\}$ represents the label of the grid areas (i.e. the one-node grids), $t \in T = \{0, \dots |T| - 1\}$ represents the simulated time steps of the schedules horizon, $s \in S = \{0, \dots |S| - 1\}$ is the index for the generators in an area. $srmc_{n,s}$ is the marginal cost and $g_{n,s,t}$ is the generators' dispatch.

The cost minimization is subject to the following constraints.

Nodal power balance constraint. In every redispatch area (i.e. grid node) the sum of generators dispatch (i.e. cleared redispatch supply orders) must equal the load (i.e. the redispatch demand) $d_{n,t}$.

$$\sum_{n,s,t} g_{n,s,t} = \sum_{n,t} d_{n,t} \; \forall \; n, s, t \tag{5.36}$$

Operating-level constraint. All generators may only be dispatched within their operating level from *Pmin* to *Pnom*. As these two parameters may vary over time, PyPSA expresses this generator availability in per unit of the nominal generator capacity *Pnom* for all timestamps t.

$$u_{n,s,t} * p\_min\_pu_{n,s,t} * Pnom_{n,s} \leq g_{n,s,t} \leq u_{n,s,t} * p\_max\_pu_{n,s,t} * Pnom_{n,s} \tag{5.37}$$

Where $u_{n,s,t} \in \{0, 1\}$ is a time series of binary status variables used to implement inter-temporary constraints.

Minimum up-time constraint. Orders with a delivery duration larger than 1 MTU (i.e. block orders) make use of the minimum up-time constraint. Let $min\_up\_time \in$

$\mathbb{N}$ be the number of MTUs which a generator at least has to operate when being dispatched.

$$\sum_{t'=t}^{t+min\_up\_time} u_{n,s,t'} \leq min\_up\_time(u_{u,s,t} - u_{n,s,t-1}) \; \forall \; n, s, t \tag{5.38}$$

This implies that when a generator is started in t, then $u_{n,s,t-1} = 0$, $u_{n,s,t} = 1$ and $u_{n,s,t} - u_{n,s,t-1} = 1$. Consequently, the generator has to run for at least min_up_time periods.

Additional block order constraint. Generators representing block orders must be dispatched with the same quantity for all MTUs of the order duration (i.e. min_up_time). This is not foreseen in a usual PyPSA power flow. However, PyPSA allows for formulating custom constraints. The block order constraint can be expressed as follows.

$$g_{n,s,t} = g_{n,s,t-1} \; \forall \; \{t \mid \; p\_max\_pu_{n,s,t-1} = 1 \wedge t \in \; DeliveryPeriod\} \tag{5.39}$$

This constraint thus applies to the delivery period of the order.

Equilibrium constraint with a threshold. The equilibrium constraint requires that the sum of cleared order quantity in upward direction $g_{up,s,t}$ equals the sum of cleared order quantity in downward direction $g_{down,s,t}$, while taking into account a threshold.

$$-threshold \leq \sum_{s} g_{up,s,t} - \sum_{s} g_{down,s,t} \leq threshold \; \forall t \tag{5.40}$$

Redispatch settlement method. Similar to the settlement method of the intra-day market, the redispatch settlement method determines the due amount per cleared order and administers money transfer to and from the agents' bank accounts. The cleared price, however, is pay-as-bid and not determined by the 'older' order. All cleared orders are sent to the respective market parties and to the grid & system operator for later processing.

Balancing energy market implementation. The balancing energy market is currently implemented with a high degree of simplifications. As of yet, the market operator has neither a clearing method nor a settlement method. Exogenous balancing energy activation data or a (physical) balancing model would be required for a clearing algorithm. However, the implemented order book allows for the analyzing of received orders, which may provide insight into market interactions (e.g. mark-ups and offered quantities). Moreover, a method is available to allow the market operator to determine a balancing control state per simulation step, based on an exogenous probability distribution. The balancing control state indicates whether upward orders, downward orders, both or none are activated to control the balance. This control state may provide input for imbalance mechanism simulations (see below). In absence of activated orders, the current BEM implementation of ASAM is not yet suitable for studies on detailed BEM designs.

Balancing control state. The balancing control state is a parameter in the Dutch imbalance pricing method that determines the imbalance price per ISP. Simplified, it can be said that:

1. The control state is 0 when no balancing energy is activated.

2. The control state is +1 when only balancing energy in upward direction is activated during an ISP.
3. The control state is -1 when only balancing energy in downward direction is activated during an ISP.
4. The control state is 2,-1 or 1 when balancing energy is activated in upward and in downward direction during an ISP. The evolution of the balancing delta (i.e. upward activation minus downward activation) then determines the control state.

It is referred to imbalance pricing method TenneT TSO B.V. (2019g) for details.

Random draw based on probability distribution. ASAM applies a discrete probability distribution of control states to take a random draw per simulation step. The probability distribution is conditional for every ISP of the day 1,. . . ,96. The current control state of the simulation step is a global variable of the balancing energy market operator. Later in the process, it is used by the imbalance market operator.

Imbalance market implementation. The imbalance market is implemented with two rules for the pricing methods. The fixed single price method considers only a default imbalance price for all simulation steps. The second implemented pricing method resembles the Dutch imbalance pricing regime. Although the imbalance market operator receives no orders, it has a clearing method. The imbalance clearing method determines the imbalance price. The imbalance settlement method allocates costs and profits among market parties (more specifically: among BRPs) depending on their imbalance.

Imbalance price determination. An imbalance clearing method determines the imbalance price. An imbalance settlement method allocates costs and profits among market parties depending on their imbalances. Two design options for market rules are currently implemented for the imbalance mechanism or market: (1) A fixed single price method considers only a default imbalance price for all simulation steps, (2) the imbalance pricing regime used in the Netherlands (see TenneT TSO B.V., 2019g). The latter applies an exogenous conditional probability distribution function to determine the imbalance price. The conditional variables are the DAM price and the balancing control state.

The Dutch 'mid-price' is assumed to be equal to the day-ahead market price. The imbalance price for long positions and for short positions are the same (i.e. single pricing), only in control state 2 both prices may be different (i.e. dual pricing). In control state 0 and in some situations of control state 2, the imbalance price of the Netherlands is determined by the so called mid-price. The mid-price is the average of the lowest price of upward orders and the highest price of downward orders for balancing energy of the respective ISP (TenneT TSO B.V., 2019g). It is assumed that this price usually lies around the day-ahead market price. The model, therefore, uses the day-ahead market price where the mid price applies.

Payment direction depends on sign of imbalance price. When the imbalance price is determined, the imbalance position of each market party for the current ISP is collected by the settlement method. The imbalance position is multiplied with the imbalance price. However, the payment direction depends on the sign of the applicable imbalance price (i.e. positive or negative) and the direction of the imbalance position of the market party (i.e. long or short). Table 5.6 shows the applicable imbalance price as well as the payment direction (adaption from TenneT TSO B.V.,

TABLE 5.6: ASAM imbalance price determination under consideration of control state, imbalance position, and day-ahead price

Control state	Imbalance position of market party	Imbalance price and sign [+ if > 0,- if < 0]		Direction of payment
0	Short position	$IBP_t = dap_t$ [+]		BRP → TSO
		$IBP_t = dap_t$ [-]		TSO → BRP
	Long position	$IBP_t = dap_t$ [+]		TSO → BRP
		$IBP_t = dap_t$ [-]		BRP → TSO
+1	Short position	$IBP_t = f_{IBP\|CS=+1,DAP=dap_t}(ibp)$ [+]		BRP → TSO
		$IBP_t = f_{IBP\|CS=+1,DAP=dap_t}(ibp)$ [-]		TSO → BRP
	Long position	$IBP_t = f_{IBP\|CS=+1,DAP=dap_t}(ibp)$ [+]		TSO → BRP
		$IBP_t = f_{IBP\|CS=+1,DAP=dap_t}(ibp)$ [-]		BRP → TSO
-1	Short position	$IBP_t = f_{IBP\|CS=-1,DAP=dap_t}(ibp)$ [+]		BRP → TSO
		$IBP_t = f_{IBP\|CS=-1,DAP=dap_t}(ibp)$ [-]		TSO → BRP
	Long position	$IBP_t = f_{IBP\|CS=-1,DAP=dap_t}(ibp)$ [+]		TSO → BRP
		$IBP_t = f_{IBP\|CS=-1,DAP=dap_t}(ibp)$ [-]		BRP → TSO
2	Short position	If $f_{IBP\|CS=+1,DAP=dap_t}(ibp) \geq dap_t$	IBP_t [+]	BRP → TSO
			IBP_t [-]	TSO → BRP
		If $f_{IBP\|CS=+1,DAP=dap_t}(ibp) < dap_t$	dap_t [+]	BRP → TSO
			dap_t [-]	TSO → BRP
	Long position	If $f_{IBP\|CS=-1,DAP=dap_t}(ibp) \geq dap_t$	IBP_t [+]	TSO → BRP
			IBP_t [-]	BRP → TSO
		If $f_{IBP\|CS=-1,DAP=dap_t}(ibp) < dap_t$	dap_t [+]	TSO → BRP
			dap_t [-]	BRP → TSO

2019g). IBP_t means imbalance price, dap_t means day-ahead price of current ISP t, and CS means Control state.

5.7 Market party agents

Market party class holds the mark-up methods. The market party class is an inherent of the MESA agent class. The step() method is called in every simulation step and directly or indirectly executes the other agent methods. The mark-up methods, as explored in section 5.2, are implemented in this class.

Update trade schedule method. The update_trade_schedule() method is called first in every agent step. It sums the quantity of the cleared orders from the last step per ISP and per market, and it adds the result to the attribute trade_schedule. The notation introduced in section 5.1 is applied. Likewise, the method adds the due amount of all cleared orders from the last step per ISP and per market to the attribute financial_return. Finally, the total trade position and total return per ISP is updated, by taking the sum over all markets per ISP.

Set_asset_constraints() considers obligations from redispatch transactions. Besides the endogenous asset constraints (e.g. $Pmin$ and ramping limits), assets receive operational constraints when redispatch services from that asset were sold. The redispatch product requires that the scheduled dispatch ($SD_t^{transaction}$) from the moment of transaction is not changed below respectively above the following levels:

$$minSD_t = \left\{ SD_t^{transaction+ClearedQuantity}, \quad if\ OrderDirection = up \right\} \quad \forall t \in DeliveryPeriod \tag{5.41}$$

$$maxSD_t = \left\{ SD_t^{transaction-ClearedQuantity}, \quad if\ OrderDirection = down \right\} \quad \forall t \in DeliveryPeriod \tag{5.42}$$

Asset method calculates and administers constraints. Per asset, all new redispatch obligations from the last simulation step are summed per ISP and provided to the asset method calc_dispatch_constraint(). This asset method also takes into account exogenously provided asset unavailability. The output of calc_dispatch_constraint() are two time-series, which can be used as temporary constraints, p_min_pu and p_max_pu, in the generator model of PyPSA. Moreover, $minSD_t$ is provided to the PyPSA model as a must-run constraint (see equation 5.48).

Portfolio_dispatch() optimizes the asset commitment. In every simulation step, the dispatch schedules of all assets are updated. The scheduled dispatch is determined by portfolio_dispatch(), which makes use of the optimal power flow functionality of PyPSA. Every agent has a one-node grid model with all its assets implemented as generators. The total trade position is implemented as a load in the PyPSA instance. The optimization considers the entire schedules horizon (see section 5.5). Similar to the above-described redispatch clearing method, each PyPSA model also has two slack generators to capture short positions and long position, when the trade position cannot be dispatch by the assets. These slack generators use the agent attribute imbalance_risk_price as SRMC. This attribute is per default set to 1000 EUR/MWh. imbalance_risk_price thus represents the agents' willingness to avoid imbalances by dispatch.

Objective function. The objective function of portfolio_dispatch() is an operational cost minimisation function similar to redispatch_clearing() (see equation 5.35). However, this objective function also considers start-up cost ($suc_{n,s,t}$) and shut-down cost ($sdc_{n,s,t}$). It has to be noted that, when only one bidding zone is simulated, then n = 1 (i.e. the market party has only one trade schedule and one portfolio of assets).

$$min \left[\sum_{n,s,t} srmc_{n,s} * g_{n,s,t} + \sum_{n,s,t} suc_{n,s,t} + \sum_{n,s,t} sdc_{n,s,t} \right] \tag{5.43}$$

Some constraints are similar to redispatch_clearing() function. The nodal power balance constraint (see equation 5.36), operating-level constraint (equation 5.37), and minimum up-time constraint (equation 5.38) are similar to the constraints used in redispatch_clearing().

Minimum down-time constraint. Similar to equation 5.37, $u_{n,s,t} \in \{0,1\}$ is a time series of binary status variables used to implement inter-temporary constraints. Let $min\_down\_time \in \mathbb{N}$ be the number of MTUs which a generator at least needs to be stopped when being shut-down. The constraint then is analogously

$$\sum_{t'=t}^{t+min\_down\_time} (1 - u_{n,s,t'} \leq min\_down\_time(u_{u,s,t-1} - u_{n,s,t}) \ \forall\ n, s, t \tag{5.44}$$

Start-stop cost constraint. $suc_{n,s,t}$ and $sdc_{n,s,t}$ are also determined by using the status variable $u_{n,s,t}$.

$$suc_{n,s,t} \geq suc_{n,s}(u_{n,s,t} - u_{n,s,t-1}) \; \forall \; n, s, t \tag{5.45}$$

$$sdc_{n,s,t} \geq sdc_{n,s}(u_{n,s,t-1} - u_{n,s,t}) \; \forall \; n, s, t \tag{5.46}$$

Ramping constraint. Ramping limit upward $ru_{n,s}$ and ramping limit downward $rd_{n,s}$ are in PyPSA provided as per unit values of $Pnom_{n,s}$. These parameters define the maximum allowed change of dispatch between two timestamps.

$$-rd_{n,s} * Pnom_{n,s} \leq g_{n,s,t} - g_{n,s,t-1} \leq ru_{n,s} * Pnom_{n,s} \tag{5.47}$$

Redispatch must-run constraint. The asset variable *p_min_pu* is determined by the method calc_dispatch_constraint(). However, the PyPSA optimal power flow considers this value as the minimum dispatch when the asset is committed. In case upward redispatch is sold from an asset, the respective asset also has a must-run obligation, $minSD_t$. This must-run obligation is implemented as an additional constraint to the model. $maxSD_t$ is provided to the asset variable *p_max_pu* in case of downward redispatch. Therefore, no additional constraint needs to be defined.

$$minSD_{n,s,t} \leq g_{n,s,t} \tag{5.48}$$

Initial status of assets is based on previous dispatch schedule. For the dispatch optimisation, it is relevant whether an asset is considered to be operating (1) or to be shut down (0) at the start of the optimisation period. The initial status is determined by the previous dispatch schedule. In the first simulation step, the PyPSA default value 1 is used for the initial status.

Dispatch schedule assigned to every asset. The result of the PyPSA dispatch optimization is the asset dispatch $g_{n,s,t}$ for all assets of the agent and for the time period of the schedules horizon. This scheduled dispatch provided to each asset.

$$SD_{n,s,t} := g_{n,s,t} \tag{5.49}$$

Available capacity is determined with new scheduled dispatch. Moreover, the available capacity of each asset ($av\_cap\_up_{n,s,t}$, $av\_cap\_down_{n,s,t}$) is calculated as well as the available capacity under consideration of the remaining ramp ($rr\_av\_cap\_up_{n,s,t}$, $rr\_av\_cap\_down_{n,s,t}$). For the latter, the scheduled ramps before and after MTU t are deducted from the ramp limits of the asset.

$$av\_cap\_up_{n,s,t} = p\_max\_pu(n, s, t * Pnom_{n,s,t} - SD_{n,s,t} \tag{5.50}$$

$$av\_cap\_down_{n,s,t} = SD_{n,s,t} - p\_min\_pu_{n,s,t} * Pnom_{n,s,t} \tag{5.51}$$

$$rr\_av\_cap\_up_{n,s,t} = \\ max\left(min\left(\begin{array}{l} ru_{n,s} * Pnom_{n,s} - (SD_{n,s,t} - SD_{n,s,t-1}), \\ ru_{n,s} * Pnom_{n,s} - (SD_{n,s,t+1} - SD_{n,s,t}), \\ av\_cap\_up_{n,s,t} \end{array}\right), 0\right) \tag{5.52}$$

TABLE 5.7: Agent strategies implemented in ASAM

Market	Timing	Quantity	Pricing
DAM	• at_gate_closure	• all	• srmc
IDM	• instantaneous	• small_random • all_operational • all_operational _+_conditional _start-stop	• srmc +/-1 • marginal_order_book_strategy • marginal_order_book_strategy _+_startstop_+partial_call
RDM	• instantaneous	• small_random • all_operational • all_operational_+_start-stop • not_offered_+_start-stop	• srmc • opportunity mark-up • ramping mark-up • double-score mark-up • start-stop mark-up • partial-call mark_up • all mark-ups
BEM	• at_gate_closure	• available_ramp	• srmc
IBM	• instantaneous • impatience_curve	• all • small_random • impatience_curve	• market_orders_strategy • marginal_order_book_strategy • impatience_curve

$$rr\_av\_cap\_down_{n,s,t} = \\ max\left(min\left(\begin{array}{l} rd_{n,s} * Pnom_{n,s} - (SD_{n,s,t-1} - SD_{n,s,t}), \\ rd_{n,s} * Pnom_{n,s} - (SD_{n,s,t} - SD_{n,s,t+1}), \\ av\_cap\_down_{n,s,t} \end{array}\right), 0\right) \quad (5.53)$$

Imbalance of agent is determined with new scheduled dispatch. To determine the imbalance position of the market party agent, the portfolio_optimization() method furthermore uses the sum of the dispatch schedules of all agents' assets $s \in S$ and the sum of all trade positions TP of all markets $m \in M$ from the trade schedule. Moreover, the exogenous residual load forecast error FE of the agent is added, if provided to the simulation. The (scheduled) imbalance position per ISP is added to the trade schedule. With the notation introduced in section 5.1 (i.e. physical power injection to the grid is positive, sold electricity is negative) the imbalance position is determined as follows:

$$Imbalance_{n,t} = \sum_{s} SD_{n,s,t} + \sum_{m} TP_{n,m,t} + FE_{n,t} \quad (5.54)$$

Dispatch cost updated based on new scheduled dispatch. The total dispatch costs per ISP of all assets are determined and added to the agents' attribute financial_return. Next, the dispatch costs are deducted from the total return per ISP to determine the profit per ISP, which is also stored in the financial_return attribute.

Various strategies per market are implemented. Table 5.7 depicts the agent strategies currently implemented. The pricing strategies make use of the respective mark-up approaches outlined in section 5.2.

Agents have methods to place orders for a subset of markets. place_ID_orders(), place_RD_orders(), and place_BE_orders() are methods to determine timing, quantities, and prices for orders, which are send to the respective order books. As mentioned above, the day-ahead market has currently not an order placement method, as the day-ahead clearing method directly collects all asset data to simplify the simulation process. The imbalance market works without orders because the realized dispatch position and the trading position determine the imbalance quantity. However, market party agents manage their imbalance risk by trading on the intra-day market to reduce their scheduled imbalance (i.e. expected imbalance which is not yet realized). Therefore, the strategy options of the imbalance market are implemented in place_ID_orders().

First step of placing orders is removing existing orders. ASAM does not work with adjustment of placed orders. Instead, the agents remove all their orders from the order book before they place new orders. Secondly, agents determine the timing of placing orders. Next, the agents determine the order quantity. Finally, the order prices are determined, and the agent sends an order message with all orders to the respective order book.

Determination of orders considers entire schedules horizon. The order placement methods always determine orders for all ISPs of the schedule horizon. Orders with a quantity of 0 are removed before the order message is sent to the order book.

Quantity strategy all_operational. Agents may apply the quantity strategy all _operational for the intra-day market and for the redispatch market. With this strategy agents offer the available capacity ($av\_cap\_up_{n,s,t}$, $av\_cap\_down_{n,s,t}$) of all assets. The orders are placed per asset and per MTU (i.e. no block orders).

Quantity strategy available_ramp. Agents place orders for the balancing energy market with the available_ramp strategy. This means that per asset and ISP the remaining ramp ($rr\_av\_cap\_up_{n,s,t}$, $rr\_av\_cap\_down_{n,s,t}$) is offered.

Quantity strategy small_random. In line with the approach of Selasinsky (2014), agents may place orders with small quantities in continuous markets (see section 5.1.3). When agents apply the small_random strategy, the agent method small _random_quantity() is used to determine the offer quantity. This method returns random draws from a discrete uniform distribution. The random draws take into account the method parameters min_quantity (default value 5) and max_quantity (default value 20) as well as the available capacity of the respective asset.

Quantity strategies including start-stop. Several quantity strategies include the offering of start-stop capacity from assets. For these strategies, the agent method start_stop_blocks() is applied. The method identifies all feasible start blocks and all feasible stop blocks. These feasible blocks are sequences of ISPs where the scheduled dispatch $SD_{n,s,t}$ of an asset is 0 (for start blocks) respectively $Pmin_{n,s}$ (for stop blocks) for periods $\geq min\_up\_time$, respectively $\geq min\_down\_time$. The feasible start-stop blocks are in a second step subdivided in block orders. The delivery periods of block orders are determined in a process starting from the smallest t of all feasible blocks. The delivery period of the next block order is equal to min_up_time respectively min_down_time, when the remaining feasible block is $\geq 2 * min\_up\_time$, respectively $\geq 2 * min\_down\_time$. The delivery period is equal to the remaining feasible block when it is $< 2 * min\_up\_time$, respectively $< 2 * min\_down\_time$. The determined block orders have no overlapping delivery period. The order quantity of start blocks and stop blocks equals $Pmin_{n,s}$.

Quantity strategy with conditional start-stop. Agents may only conditionally offer start-stop capacity on the intra-day market. The condition currently implemented in ASAM is related to the redispatch market design whereby specific intra-day orders are used for redispatch. Start blocks are only offered for delivery periods which overlap with redispatch upward demand of the previous simulation step. Stop blocks are analogously offered for periods of previous redispatch downward demand.

Quantity strategy not_offered. With the aim to avoid double score situations (see section double score mark-up in section 5.2) market parties may avoid offering available asset capacity on various markets. The quantity strategy not_offered is implemented for placing orders on the redispatch market. The offered quantity is determined by the available capacity ($av\_cap\_up_{n,s,t}$, $av\_cap\_down_{n,s,t}$) minus the offered quantity on the intra-day market from the respective asset. This strategy is combined with the start-stop quantity strategy.

Imbalance quantity strategies. When a market party has scheduled imbalance during the schedules horizon, it has to mitigate the imbalance risk on the intra-day market. The assumptions regarding this risk mitigation are outlined in section 5.1.3. When the agent is impatient, it may choose quantity strategy all, which means placing the entire imbalance position instantaneously on the intra-day market. Alternatively, the agent may apply the small_random strategy, as explained above. A third strategy currently implemented in ASAM is impatient_curve, which couples the timing strategy to the quantity strategy and the pricing strategy. The impatient curve defines how much of the scheduled imbalance (%) is placed on the intra-day market as a market order (i.e. immediate or cancel) in dependency of the remaining time until the delivery ISP of the imbalance. The imbalance which is not offered as market orders is (partially) offered as limit orders using the small_random_quantity() method. The standard impatience curve currently implemented in ASAM is derived from the intra-day trading moments presented in TenneT TSO B.V. (2019b). Figure 5.12 shows the trading volume in the Netherlands and the derived standard impatience curve.

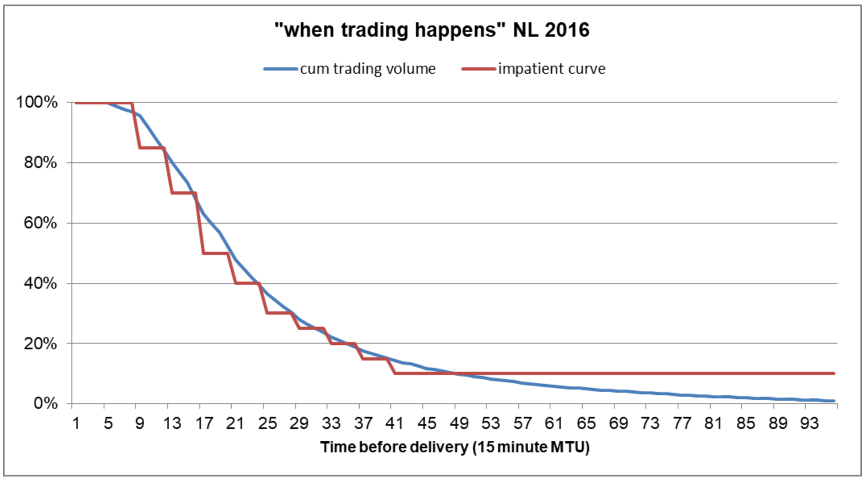


FIGURE 5.12: Cumulative trading volume in MTU before delivery MTU (adopted from TenneT TSO B.V., 2019b)

$$MarketOrderQuantity_{n,t} = \{ImpatienceCurve(t - t_{current}) * imbalance_{n,t}\} \quad \forall \{t | imbalance_{n,t} \neq 0\} \tag{5.55}$$

$$LimitOrderQuantity_(n,t) = \{small\_random\_quantity((1 - ImpatienceCurve(t - t_{current})) * imbalance_{n,t})\} \quad \forall \{t | imbalance_{n,t} \neq 0\} \tag{5.56}$$

Pricing strategy srmc. The pricing strategy srmc just uses the asset SRMC as order price. The strategy srmc +/-1 uses the asset SRMC + 1 for sell orders and SRMC -1 for buy orders.

Mark-ups implemented as outlined in section 5.2. The various mark-ups introduced in section 5.2 are implemented in the respective order placing methods. The order price is composed of the SRMC plus the mark-up of the pricing strategy. The pricing strategy all_mark_ups jointly applies the mark-ups for opportunity, double-score, ramp, start-stop and partial-call.

5.8 Grid and system operator agent

Grid & system operator agent executes its task when market parties are done. In every simulation step, the grid & system operator executes its methods when the market parties have finished their actions. At first, new congestions are identified with the method determine_congestions(). Second, redispatch demand is provided as orders to the redispatch market operator. The third action is a market consistency check followed by an update of the system imbalance and financial returns of the grid & system operator.

Exogenous congestions are read from input data. As mentioned in section 5.6, congestions are provided exogenously to the simulation in the form of redispatch demand. The exogenous redispatch demand specifies from which area (downward) to what area (upward) redispatch is needed. Furthermore, it defines the redispatch quantity, the period as well as the moment of identifying the congestion. The method determine_congestions() checks whether new congestions are identified, while redispatch_demand() formulates redispatch demand orders under consideration of previous redispatch acquisitions.

System operator checks whether sell volumes are equal to buy volumes. The system operator applies the method check_market_consistency() to collect all trades of the simulation and compare the sum of the sell quantities with the sum of the buy quantities. If both are not equivalent, the market is not consistent, and a simulation error must have occurred.

System operator administers imbalances and financial returns. In every simulation step, the system operator keeps track of the three types of imbalances.

1. Scheduled market imbalance, which is the sum of all future imbalances of market parties per ISP (according to their trading schedules).

2. Realized market imbalance, which is the sum of all imbalances of market parties per ISP which lie in the past.

3. Imbalances from redispatch, which is the sum of all imbalances per ISP which are caused by the grid operators' redispatch actions (i.e. where upward and downward redispatch have not same quantity).

Moreover, the financial returns from redispatch, balancing energy and imbalances are administered.

5.9 Validation

The type of model determines the validation methods. Validation aims to check whether the model accurately represents the assessed system, given the research targets (Weidlich, 2008). Model verification usually describes the validation of correct programming implementation, whilst choosing parameter values is referred to as model calibration (Weidlich, 2008; Reeg et al., 2013). The target of the model, as well as its modelling approach, determines suitable validation methods (Windrum, Fagiolo, and Moneta, 2007). ASAM is an agent-based model which produces out-of-sample results to assess policy implications of ancillary service designs (see section 5.4). Simulation results can, therefore, not directly be compared with empirical data. However, empirical input validation and empirical process validation (i.e. how realistic are physical, institutional, and social processes reflected in the model) can be applied (Tesfatsion, 2018). Furthermore, the "*validity of the theory relative to the real-world system (theory-validity)*" and "*validity of the model relative to the theory (model-validity)*" (Weidlich, 2008, p. 29) may be assessed.

Model verification with small scale examples, unit tests and integration tests. The model is tested on its correct implementation in python by specific unit tests as well as integration tests. These can be found, together with the source code, in the Github repository of ASAM (Glismann, 2021c). Moreover, an intuitive small scale example of an ASAM simulation has been peer-reviewed and published (Glismann, 2021a).

Theory validity and model validity shown by literature review and conceptual model. Theory validity is shown by explicitly elaborating on accordance and differences with state-of-the-art literature as well as expert interviews in section 5.1. Model validity is explored by discussing simplifications and limits of both the conceptual model (section 5.1) as well as the computational model (sections 5.2, 5.6, and 5.7,). It has to be noted that the theory and the model are only valid for assessments of ancillary services in unbundled, European-like power systems.

ASAM simulations support policy-readiness-level 4 and 5. Following Tesfatsion (2018) it should be stated for what level of policy advises the model can contribute results. Given the detailed representation of various market processes, the asset portfolios of market parties (as opposed to asset representation only) as well as the price mark-up concept, it is concluded that it is valid to use ASAM for assessments of policy-readiness-level 4 and 5 (see table 4.2).

Generalisability of the model tested with use-case. As formulated in section 5.4, ASAM should have a structure that allows the implementation of various markets with adaptable market designs. A use-case is applied to reveal limits of the generalisability of the model (chapter 6).

Empirical process validation and calibration by use-case application. The generic ASAM needs to be adapted to become fit-for-purpose regarding the study questions at hand. Hence, a general empirical process validation and calibration is not possible because a specific research objective is needed. However, the use-case explores whether ASAM can be calibrated and validated regarding its empirical process.

Empirical input data validation is principally study-dependent. Most input data are use-case dependent and can only be evaluated per study and not generally for ASAM. However, ASAM applies a specific concept regarding expected imbalance prices. Conditional probability density functions are applied by ASAM, which consider at least day-ahead prices as a conditional variable. While input data for these conditional probability density functions may vary, the fundamental concept of this input remains the same. The empirical validation of this approach is outlined in the remainder of this section by comparing it to alternative approaches used in Germany as an industry guideline. However, for the partial-call mark-up as well as double-score mark-up, a uniform distribution is assumed. This assumption is not based on empirical evidence, but it is chosen as a next-best solution in the absence of validation data.

Average imbalance price approximations used by market parties. The opportunity mark-up requires a probability density distribution of the imbalance price for short and long positions. Expert interviews revealed that imbalance price predictions are very challenging for ISPs that lie more than 3 hours ahead in time. Experts stated that market parties might use average imbalance price approximations for forecast horizons of 3 to 36 hours.

The known day-ahead price is an important estimator. In line with the above introduced Weber-approach (section 5.2), the day-ahead market price is used to approximate the imbalance price[8]. For various day-ahead price bins, the probability density function of the imbalance price long (IBPlong) and imbalance price short (IBPshort) is determined. These probability density functions are applied to determine the opportunity costs (see equation 5.28).

TABLE 5.8: Selected day-ahead price bin edges

-200	20	22	34	25	27	28	29	30	31	32	34	35	37	38	40	42	43	44	45	47	49	50	52	55	57	60	65	70	76	200

Weber-approach used as reference. As it is challenging to validate the appropriateness of the imbalance price approximations, the Weber-approach is used as a reference method, since it is adopted as an industry guideline in Germany (BDEW, 2018).

Price data from the Dutch power system are used. The following validation of the expected imbalance price approach uses day-ahead and imbalance price data from the Netherlands from 2016 to 2018.

Day-ahead price bins selected based on a minimum number of samples per bin. In order to ensure that each day-ahead price bin has sufficient data samples to generate a probability density function, an iterative process is established to select price bins. The price bins are selected between a minimum day-ahead price (-200 EUR/MWh) and a maximum day-ahead price (200 EUR/MWh). Each bin has to have a minimum number of data samples (300 samples). However, to avoid very small price bins, the bins have a minimum size of 1 EUR/MWh. Given the input data of the Dutch power system (2016 to 2018), the following day-ahead price bins are selected (see table 5.8). Note that for all day-ahead prices within a price bin the same probability density function for imbalance prices is applied.

[8] The Weber approach also uses the prices of a German intra-day auction. Moreover, the approach approximates intra-day prices shortly before the delivery period instead of imbalance prices. However, both prices are used as real-time prices for the opportunity cost determination.

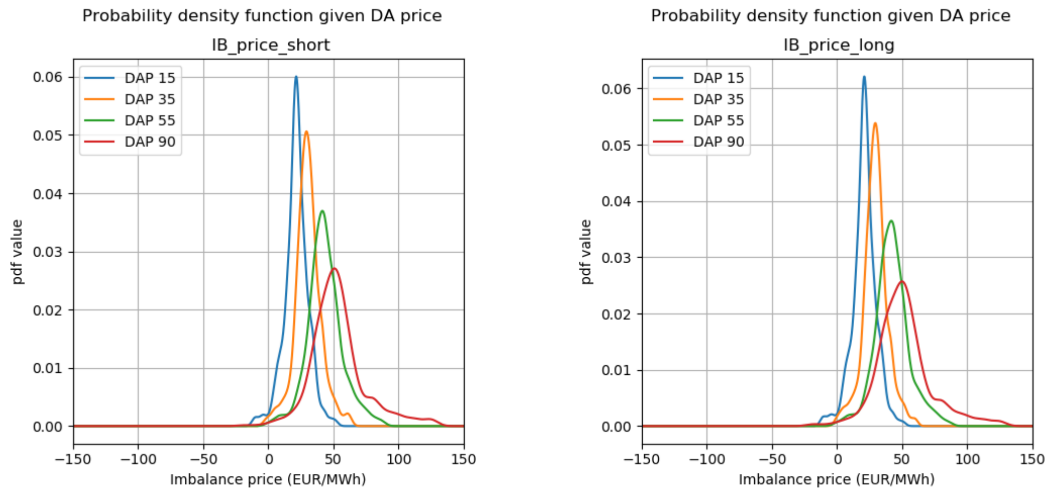


FIGURE 5.13: Probability density functions of imbalance prices (long and short) for given day-ahead prices

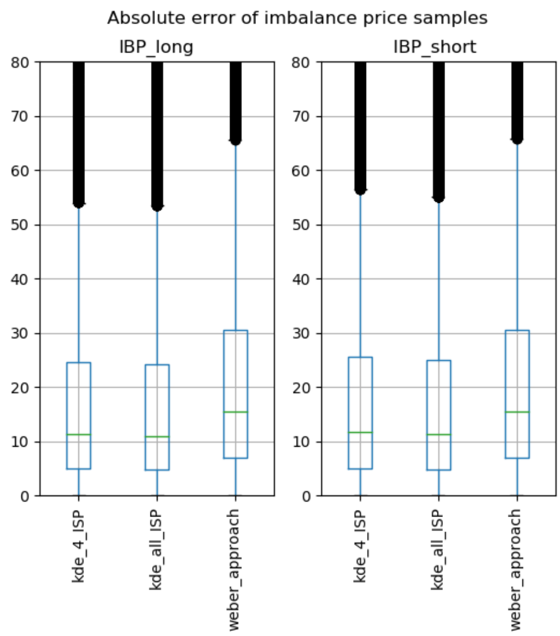


FIGURE 5.14: Comparison of absolute errors of imbalance price samples of three approaches [EUR/MWh]

Kernel density estimation instead of normal distribution. The Weber approach assumes for simplicity reasons a normal distribution of the targeted opportunity prices. However, examples of imbalance price distributions for a few day-ahead price bins suggest that a kernel-density estimate may be more appropriate than the assumption of a normal distribution. As shown in figure 5.13, the probability density functions from kernel density estimates are skewed to the right. Furthermore, the distributions may be multimodal. A uniform distribution would thus underestimate the positive imbalance prices and overestimate the negative imbalance prices.

The ISP of an hour is used as additional condition. The Weber approach takes into account the so-called deterministic frequency deviations caused by the hourly day-ahead market schedules (ENTSO-e, 2019b). Therefore, the approach uses different probability density functions for the first, second, third and fourth ISP of an hour, as systematic imbalances may cause systematic differences between day-ahead price and imbalance prices. Two kernel density estimation (KDE) approaches are considered here: kde_4ISP, which also uses different probability density functions for the given ISP of an hour, and kde_allISP, which does not distinguish between ISPs of an hour.

Absolute errors of generated samples are compared between three approaches. The Weber approach, kde_4_ISP, and kde_all_ISP are trained with two-third of the data set. Subsequently, imbalance prices for one-third of the data set are sampled with the three approaches, and the absolute error is compared. Figure 5.14 shows that the median absolute errors of the kernel density approaches are obviously better. The median absolute error of kde_all_ISP is slightly lower compared to kde_4_ISP. The reason may be the reduced sample size per price bin of the training data in case of kde_4_ISP.

Errors are larger with high and with low day-ahead prices. Figure 5.15 and 5.16 show the absolute errors as box-plot per day-ahead price bin. For the Weber approach as well as for kde_all_ISP, the errors are larger for imbalance prices in the lowest and highest day-ahead price bin.

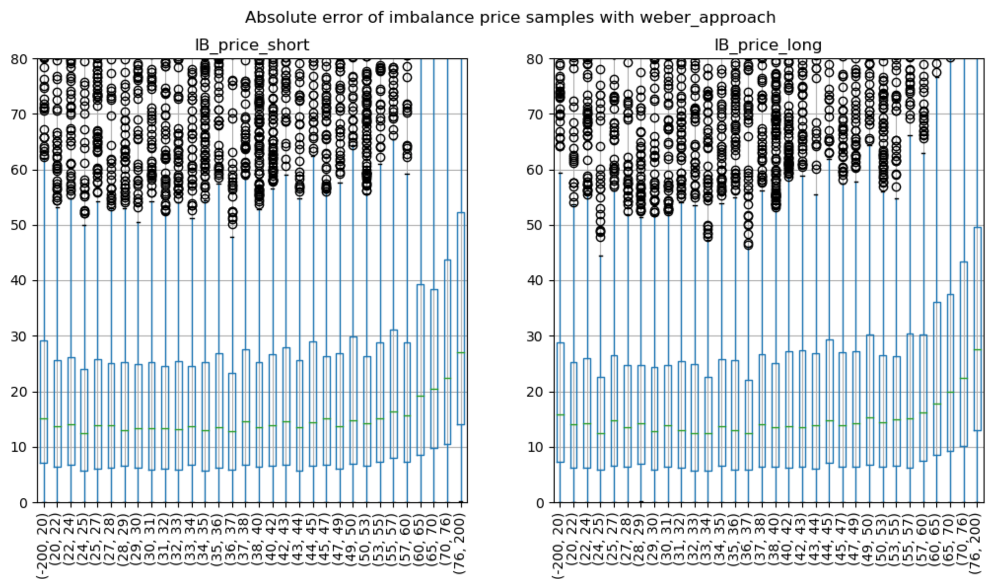


FIGURE 5.15: Absolute errors per day-ahead price bin of imbalance price samples with Weber approach [EUR/MWh]

Lower errors validate the use of the KDE approaches. The figures 5.15 and 5.16 furthermore show that the error of the Weber approach is for all price bins higher than with kde_all_ISP and with kde_4_ISP (which is not shown on the figures). Therefore, it is argued that the KDE approaches perform well enough (i.e. better than an industry guideline) to be applied in the numerical model.

Expected value shows differences of KDE approaches. Figure 5.17 displays the expected value per day-ahead price bin for the kde_all_ISP (all_ISP line) and for

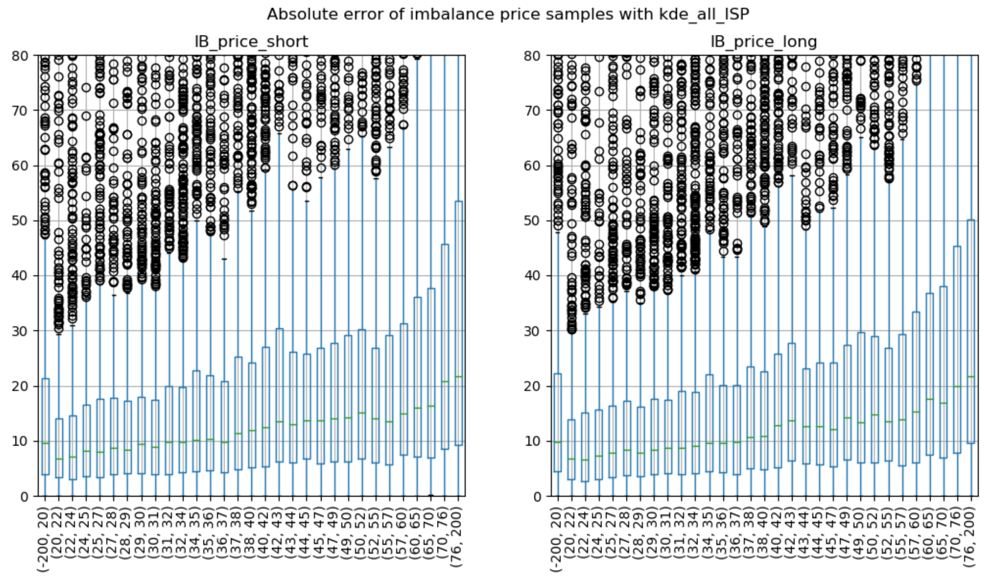


FIGURE 5.16: Absolute errors per day-ahead price bin of imbalance price samples with kde_all_ISP approach [EUR/MWh]

kde_4_ISP. The expected value is determined by (numerically) integrating the product of imbalance price and probability density function. It can be observed that the first ISP of an hour often exhibits the highest expected value of the IBPshort and the lowest value of IBPlong. Without distinction of the ISP of an hour (all_ISP) the expected value lies quite in the middle. The expected value of the imbalance is used as risk price in the mark-ups for ramping, start-stop, partial-call and double-score.

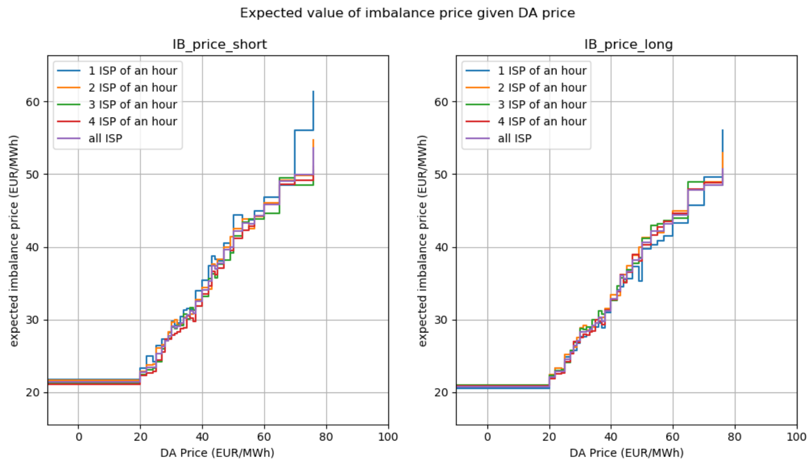


FIGURE 5.17: Expected value of imbalance prices, given day-ahead prices

Opportunity price for selected asset costs. The opportunity price as explored in equation 5.28 is determined for specific marginal asset costs. Figure 5.18 shows the opportunity price for four different asset costs, given the day-ahead price. For simplicity reasons, only the kde_all_ISP approach is shown. In the case of upward offers, the opportunity price is highest for assets with low marginal costs. This explores the expectation that market parties would have many opportunities to sell (far) above the marginal costs. Moreover, the opportunity price increases with increasing day-ahead price. For downward offers, the highest opportunity price is determined for assets with high marginal cost. These assets are expected to have many opportunities to profitably decrease production. The opportunity prices decrease with increasing day-ahead prices.

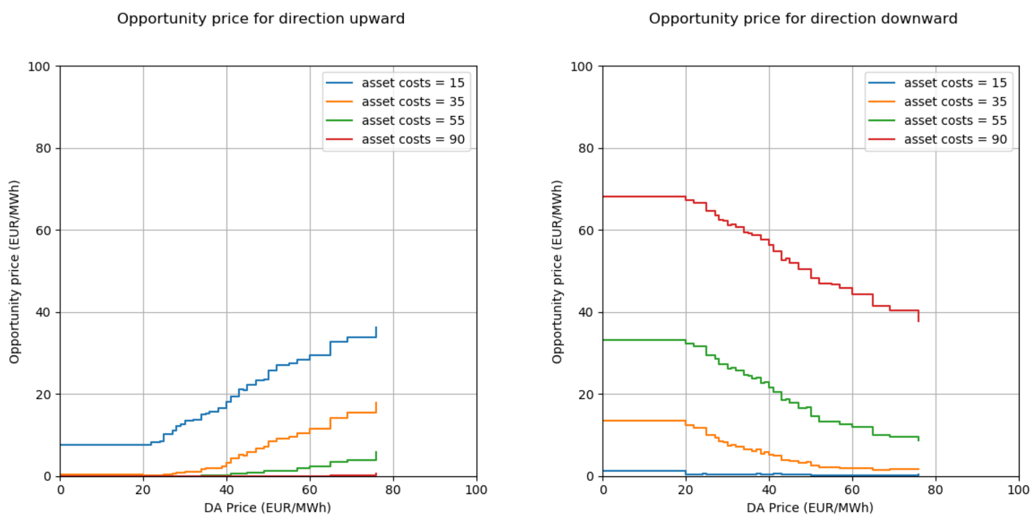


FIGURE 5.18: Opportunity prices per day-ahead price for various asset SRMC

Specific probability density functions applied to imbalance price simulations. As outlined in section 5.1.2 and 5.6, the Dutch imbalance mechanism implementation is simplified by taking random draws from a probability density function. This imbalance price in ASAM is determined after the respective ISP has been realised (i.e. ex-post). This is in contrast to the application of the expected imbalance prices for mark-ups. Therefore, the control state of the balancing energy market is already known for the respective ISP. This means that it is known whether the imbalance price is determined by balancing energy prices for upward and/or for downward direction. Consequently, the probability density functions for the imbalance price simulations are built from a subset of the historic imbalance price data: The probability density functions for IBPshort consider only historic prices during control state 1 and 2, while only price samples during control state -1 and 2 are used to build the probability density function for IBPlong. These approaches are named kde_4_ISP_cs and kde_all_ISP_cs.

Absolute error decreases under consideration of control state. As depicted in figure 5.19, the median of the absolute error is lower with the approaches kde_4_ISP_cs and kde_all_ISP_cs compared to the other approaches.

Delta prices show consistency with model theory. TenneT formulates the following two principles in their description of the Dutch imbalance price method: "*(1) It is uneconomical for market parties to increase the power imbalance. (2) It can be advantageous to reduce the power imbalance.*" (TenneT TSO B.V., 2019g, p. 8). As introduced in the

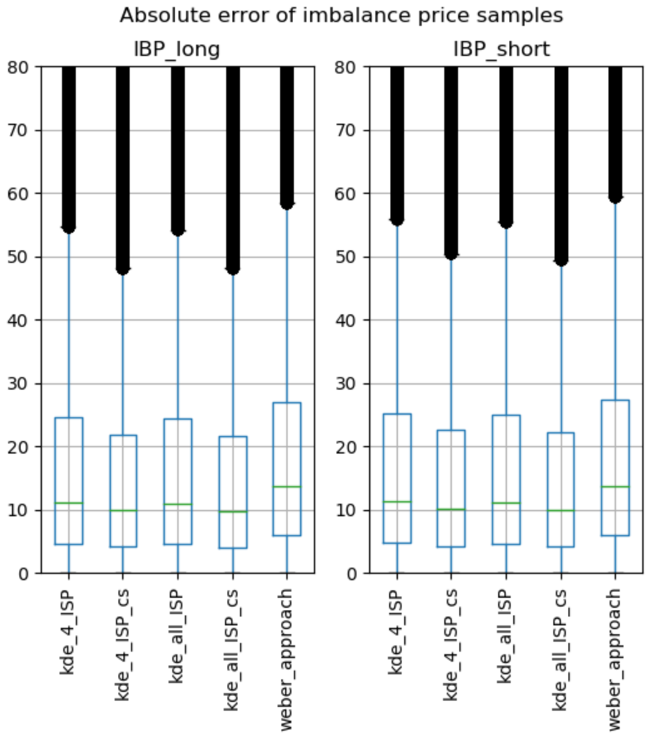


FIGURE 5.19: Comparison of absolute errors of imbalance price samples corrected on balancing control state [EUR/MWh]

literature review and discussed in section 5.1.3, the model follows assumptions and findings regarding incentive compatibility as studied by Nobel (2016). Nobel argues that it is a necessary condition for imbalance mechanisms that (at least on average) no positive arbitrage between the electricity market and the imbalance market can be obtained by market parties. This is analysed with the delta price of the imbalance price and the day-ahead market price. The expected imbalance market behaviour is thus that the delta price applicable to market parties with a short position (IBPshort – day-ahead price) is mostly positive; The delta-price applicable to market parties with a long position (IBPlong – day-ahead price) is expected to be mostly negative. Otherwise, market parties could structurally benefit from not dispatching according to their trade position. Figure 5.20 shows real delta-prices of the period 2016 to 2018 in the Netherlands, as well as sample results. IBPshort samples are only considered when the balancing control state is 1 or 2, and IBPlong samples are only considered when the balancing control state is -1 or 2. The figure shows that the Weber-approach, as well as kde_4_ISP and kde_all_ISP, are not compatible with the expected market behaviour, as the results display negative median delta prices for long positions. However, kde_4_ISP_cs and kde_all_ISP_cs present valid results in line with the model theory.

ASAM supports both kde_all_ISP and kde_4_ISP. Although it is shown that considering deterministic frequency deviations by distinguishing the four ISPs of an hour (i.e. kde_4_ISP) leads to slightly higher absolute errors compared to kde_all_ISP, this approach is still supported by the numerical model ASAM. The reason is that in specific studies, it may be relevant to analyse the differences between the four ISPs of an hour. However, kde_all_ISP is also implemented in ASAM.

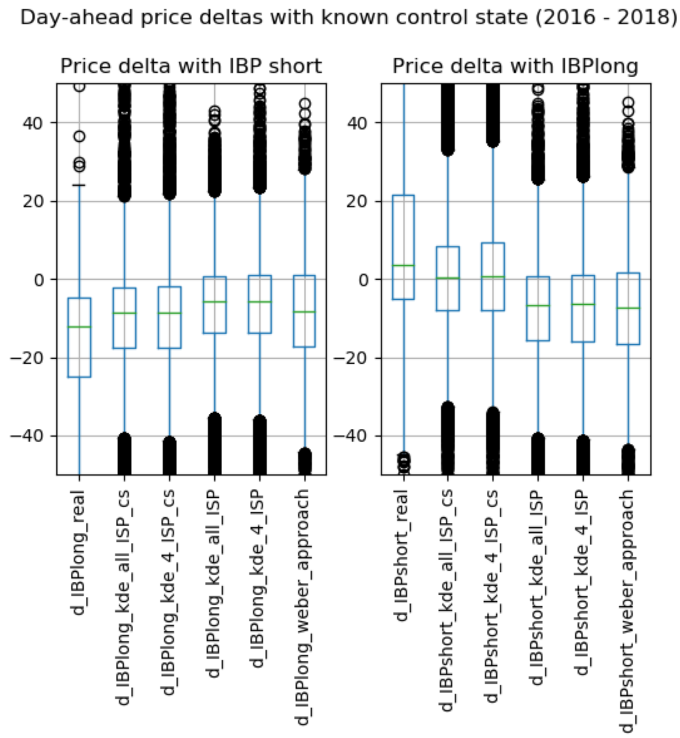


FIGURE 5.20: Comparison of day-ahead price deltas with known control state [EUR/MWh]

The expected imbalance prices are input data to the model. A numerical integration method is required to calculate the opportunity value with the Python-based KDE probability density function (see 5.28). The Python method scipy.kde.gaussian_kde is used to determine the probability density functions. The method scipy.integrate.simps is used to integrate the KDE probability density function numerically. However, since the probability density functions, as well as the integrated values, are input data for ASAM, more sophisticated methods may also be applied without changing the model. See Jansen (2016) for methods and discussion on improving Python-based KDE approaches for power system research.

Chapter 6

Application evaluation method

In this section, the evaluation framework and the simulation model are tested by applying both on a use-case.

6.1 Assessment setup

6.1.1 Use-case description

In January 2019, the transmission system operator, TenneT, and a majority of the Dutch distribution system operators - Stedin, Liander, Enexis Groep and Westland Infra - jointly launched a pilot project to procure redispatch services via Energy Trading Platform Amsterdam (ETPA) (GOPACS, 2020).

The grid operators set up a joint IT-system with a governance structure, Grid Operators Platform for Congestion Solutions (GOPACS). On GOPACS, solutions for congestions are calculated and offered redispatch orders are activated. Market parties offer redispatch orders at a commercial trading platform, ETPA, in the form of the product Intra-day Congestion Spread (IDCONS) (see GOPACS, 2019a).

With this initiative, grid operators aim (1) to unlock flexibility for redispatch in DSO and TSO networks and (2) to coordinate solutions for congestions between grid operators. At the same time, the grid operators strive to avoid unwanted side-effects on the imbalance system (Hirth and Glismann, 2018; GOPACS, 2019b).

This use-case evaluates the acquisition process of IDCONS compared to another redispatch service used by TenneT, Reserve Power for Other Purposes (ROP) (TenneT TSO B.V., 2019e).

6.1.2 Issue description

Increasing redispatch cost. The cost for redispatch in the transmission network jumped from about five million Euro per year in 2015 to about annually 50 million Euro in the years after (see TenneT TSO B.V., 2018a; TenneT TSO B.V., 2019a).

Further increase of congestions expected. To solve congestions in 2017 and 2018 , TenneT activated an average redispatch quantity of 55 GWh/month, respectively 57 GWh/month (TenneT TSO B.V., 2019a). At the same time, TenneT expects the number and magnitude of congestions to increase further, driven by additional international electricity trading, the connection of additional offshore and onshore wind farms to the transmission network, and delay of network reinforcements (GOPACS, 2019b). Meanwhile, DSO's are announcing expected congestion issues in many parts of the distribution network. The drivers here are fast-growing renewable energy capacity in the distribution network as well as increased electrification of energy consumption (Liander, 2019; Enexis, 2019).

Regulation is updated. Hirth and Glismann (2018) discuss five basic regulatory options to solve congestions and their interchangeability: Grid development, grid operation, connection management, dispatch management and trade management. Redispatch is a regulatory option of dispatch management, which shifts the dispatch geographically in order to reduce the flow on congested grid elements. The rules regarding congestion management in the Dutch grid code, however, are being updated. The revision aims to prepare the regulatory options for increasing congestions on all voltage levels and to ensure compliancy with the EU clean energy regulation. During the writing of this study, the revision went through a regulatory process of several years. In May 2022 the revision was published (Autoriteit Consument en Markt, 2022).

Risk of insufficient redispatch supply. Increasing congestions require additional supply of redispatch services. Insufficient redispatch supply can lead to (real-time) operational security incidents, when thermal, voltage, short-circuit or stability limits of grid elements cannot be maintained. Moreover, insufficient redispatch supply can also cause balancing issues, in case the redispatch action violates the 'equilibrium constraint'. Following Hirth and Glismann (2018) "[...]*network operators aim to apply downward redispatch quantity (MWh) and upward redispatch quantity per imbalance settlement period (ISP) in equilibrium. Redispatch-caused imbalances transfer part of the redispatch costs and benefits to balancing service providers and balancing responsible parties. This can distort incentives for both balancing- and redispatch-related instruments.*" (p. 17).

Potential providers are not participating. Small market parties in distribution networks rarely participate in redispatch with ROP product (GOPACS, 2019b). This may be due to exclusion mechanisms, such as product requirements and pre-qualification requirements but also due to transaction costs relative to potential benefits of participating in the redispatch acquisition process.

Research question. This context of increasing congestions and changing congestion management rules raises the following question: *has IDCONS a more suitable redispatch acquisition design than the current ROP product, to mitigate the above operational security risks in TSO and DSO networks at efficient costs?*

Scope. The research question focuses on the acquisition process of the ancillary services. This scope determines the selection of relevant design variables, performance indicators and test setups. Consequently, aspects of redispatch utilisation (e.g. impact on voltage or optimisation with operational alternatives to redispatch), congestion forecasting, DSO-TSO coordination, and cross-border redispatch are out of scope.

6.1.3 Rules in use

Rules in use are described earlier. The rules in use for this study are described in previous sections. For the objectives, constraints, roles and responsibilities of the power system, see section 1.2.1 and 4.4. For an inventory of ancillary services in the Netherlands, see section 1.3. For current market processes in the Netherlands, see section 1.2.2.

6.1.4 Goals of changing current ancillary services design

Goals. For this use-case, the goals of changing the redispatch acquisition process are derived from the above-described security challenge and the cost challenge:

1. Increase supply volume for redispatch
2. Attract new and small redispatch service providers to enhance competition
3. Decrease risk related price mark-ups for redispatch orders
4. Decrease imbalances caused by redispatch

For the evaluation the current redispatch service, ROP, is the base case.

Hypotheses. The hypotheses test whether the goals can be reached by the redispatch service IDCONS (1) and whether the design change implies unwanted effects on the performance of other ancillary services (2):

- Hypothesis 1a: Redispatch service IDCONS increases supply volume
- Hypothesis 1b: IDCONS services attract new and small market parties
- Hypothesis 1c: Redispatch service IDCONS decreases risk related price mark-ups for redispatch orders
- Hypothesis 2a: IDCONS application decreases imbalances caused by grid operators
- Hypothesis 2b: The supply orders for balancing energy are not diminished

Policy-readiness-level. Given the available time and resources for this study, the expected policy-readiness-level 4, as defined by Tesfatsion (2018): "*policy performance test using small-scale model embodying several salient real-world aspects*".

6.1.5 Identification of relevant design variables

Generic variables used from the framework. The generic design variables, as introduced in section 4.3, provide the starting point for the selection of relevant design variables. A description of both ancillary services using these design variables allows for a detailed comparison in table 6.1 (TenneT TSO B.V., 2019e; GOPACS, 2019a).

Some specifications might be out-dated soon. During the period surrounding the publication moment of this study, both product specifications of IDCONS, as well as product specifications of ROP are subject to changes. This is a result of first obtained experience with GOPACS and a consequence of the updated congestion management rules in the Dutch grid code (Autoriteit Consument en Markt, 2022). However, both ancillary services are still in use in 2022.

From comparison via differences towards relevant design variables. The detailed comparison in table 6.1 allows for explicit formulation of design differences. These differences are used to transparently elaborate on the potential impact on the assessment goals (see table 6.2). The relevant design variables for the comparative study are highlighted in green.

TABLE 6.1: Application of generic design variables to describe reserves for other purposes (ROP) and intra-day congestion spreads (IDCONS)

Design variable	Design ROD	Design IDCONS
Product subject	• Delivery of energy at a specific delivery location, relative to a reference production/consumption. • Acceptance of ex-post BRP imbalance correction on transaction quantity. • Dispatch restriction in opposite delivery direction.	• Delivery of energy at a specific delivery location, relative to a reference production/consumption. • Sold energy is administered in a trade with another market party by means of so-called single-sided transaction. • Dispatch restriction in opposite delivery direction.
Product period	• Minimum 4 MTU, specified in delivery period of bid.	• 1, 4, 8, 12, 16, 20, or 24 MTU, specified in delivery period of order.
Product utilization	• Manual activation by TSO of the scheduled service via electronic message (EDINE standard). • Relaxed energy neutral ('equilibrium') activation (i.e. with threshold).	• Scheduled activation via GOPACS and the market platform. • Clearing two orders of an IDCONS results in a firm transaction. • Strict energy neutral ('equilibrium') activation.
Utilization speed	• Activation at the latest 3 MTU before delivery period. • 'Preparation period' can be specified in bid. No ramps.	• Activation at the latest 1 MTU before delivery period. • No preparation period. No ramps.
Delivery location	• Specific connection points (EAN) in Dutch network. • Locational aggregation not possible.	• Specific connection points (EAN) in Dutch network. Locational aggregation possible.
Provider accreditation	• Access to 'central post system' (CPS) of TenneT. • Registration of provider information at TenneT. • No asset tests, no bank guarantees.	• Access to participating market platform. • Registration of provider information at GOPACS. • Participation agreement with GOPACS grid operators. • No asset tests, no bank guarantees.
AS area designation	• Acquisition from NL area only.	• Acquisition from NL area only.
Acquisition method	• Sealed, continuous, one-sided auction.	• Sealed, continuous, one-sided auction.
Acquisition timing	• Acquisition between D-1 15:00 and 3 MTU before delivery period.	• Acquisition between D-1 15:00 and 1 MTU before delivery period.
Bid requirements	• Bids in MW and €/MWh at TenneT. • Minimum bid size 1 MW. • Bids are provided separately for downward (relative energy withdraw) and upward (relative energy injection) direction. • Bids only fully granted regarding quantity (MW) and delivery duration (number MTUs) (i.e. all-or-none).	• Intra-day orders at participating market platforms with IDCONS tag. • Minimum order size 0.1 MW. • Buy orders for downward (relative energy withdraw), Sell orders for upward (relative energy injection). • Orders can be partially activated regarding quantity (MW), but only entirely regarding delivery duration.
Pricing method	• Pay-as-bid.	• Pay-as-bid.
Scoring method	• Bid price and location considered in optimisation to solve congestions at minimal cost.	• Bid price and location considered in optimisation to solve congestions at minimal cost. • Also congestions of other grid operators taken into account.
Settlement	• Weekly invoicing. • Validation of delivery ex-post. • No formalised penalties for non-delivery.	• Instantaneous settlement via market platform. • Validation of delivery ex-post. • No formalised penalties for non-delivery.
Market information	• Current activated quantity. • Total offered and available quantity per MTU. • Cost published on yearly basis. • Announcements for additionally required orders with delivery period, order type and potential delivery locations.	• Orders cleared as part of IDCONS are indicated and visible per market platform with price. • Cost published on yearly basis. • Announcements for additionally required orders with delivery period, order type and potential delivery locations.
Cost allocation	• Consumer tariffs, deduction from congestion income and deduction from TSO revenue.	• Consumer tariffs, deduction from congestion income and deduction from grid operator revenue.

TABLE 6.2: Design differences per design variable and relevance for use-case

Design variable	Difference	Relevance for goals of assessment
Product subject	• Administration of sold energy via BRP imbalance correction (ROP) vs. via single-sided transaction with commercial trade schedule of BRP (IDCONS).	• Administration of sold energy is relevant for attraction of new participants, because of potential differences in transaction cost.
Product period	• Minimum of 4 MTU (ROP) vs. minimum of 1 MTU for IDCONS and multiple choice options for longer periods.	• Block orders are relevant for price mark-ups in the context of min. up and min. down times of assets. • Delivery period selection in MTU granularity versus multiple choice is less relevant, provided sufficient choices are available.
Product utilization	• Activation via RESIN (ROP) vs. activation via GOPACS (IDCONS). • Relaxed energy neutrality (ROP) vs. strict energy neutrality (IDCONS).	• Activation system is relevant attraction of new participants, because of differences potential in transaction cost. • Energy neutrality of activations is relevant for the decrease imbalance by redispatch.
Utilization speed	• Activation time at the latest 3 MTU before delivery period (ROP) vs. at the latest 1 MTU before delivery (IDCONS). • Preparation period specifiable (ROP) vs. no preparation period specifiable (IDCONS).	• Activation time and preparation period not relevant for assessment goals, because the difference is captured by the gate-closure time and the preparation period could be managed by the market parties by withdrawing orders.
Delivery location	• No difference	• Not relevant as there is no difference.
Provider accreditation	• Registration at TenneT (ROP) vs. registration at GOPACS . • Access to Central post system (ROP) vs. access to participating market platform (IDCONS).	• Relevant for attraction of new participants, because of differences potential in transaction cost.
AS area designation	• No difference.	• Not relevant as there is no difference.
Acquisition method	• No difference.	• Not relevant as there is no difference.
Acquisition timing	• Gate-closure time 3 MTU before delivery period (ROP) vs. 1 MTU before delivery period (IDCONS).	• Relevant for risk mark-ups because of potential double-score risk with other markets (e.g. balancing energy) and consequently also potential impact on redispatch driven imbalance.
Bid requirements	• Bids at TenneT (ROP) vs. Intra-day orders at market platform (IDCONS). • All-or-none (ROP) vs. limit orders (IDCONS).	• Relevant for attraction of new participants, because transaction cost for manual bidding at one market instead of 2 markets may be lower. • Relevant because of impact on bidding behaviour on intra-day markets. Order type is relevant for the risk mark-ups.
Pricing method	• No difference.	• Not relevant as there is no difference.
Scoring method	• Different redispatch algorithms, whereby the GOPACS algorithm is more sophisticated.	• Not relevant because assessment is focused on acquisition process and not physical redispatch efficiency.
Settlement	• Weekly (ROP) vs. instantaneous (IDCONS).	• Timing of invoices is not relevant for the assessment goals.
Market information	• No prices published (ROP) vs. IDCONS prices visible at market platform. • Available offered quantity published (ROP) vs. no available offered quantiy published (IDCONS).	• Market information is relevant for attracting new participants.
Cost allocation	• No difference.	• Not relevant as there is no difference.

6.1.6 Design space

The relevant design variables for this redispatch acquisition design study have been identified above. All the relevant design variables together span the design space (Veen, 2012).

Comparative study starts already with promising design options. This section would be more extensive if the study aim would be ’find concepts to improve the situation’. The reason is that in such a case, as shown e.g. by Veen (2012), various promising design options need to be developed from the design space, before a comparative assessment of design options can start. In the present case however, it is asked to assess whether a specific set of design changes regarding a limited number of design variables could positively contribute to a number of goals. Therefore, it is for this use-case not required to identify further design options.

6.1.7 Relevant ancillary service performance criteria

Considering the generic ancillary service performance criteria from section 4.4, the following performance criteria are relevant for the given goals of the use-case:

1. **Effective acquisition** of redispatch services is a relevant criterion, as it evaluates to what extent the required services can be acquired. This is closely linked to the assessment goal ‘increasing redispatch supply volume’.

2. **Efficient prices** of redispatch services is a relevant criterion, as it evaluates cost-reflection of the prices, respectively the magnitude of price mark-ups. This is closely linked to the assessment goal of attracting new participants (and by that increasing competition). It is furthermore linked to the goal of decreasing price mark-ups.

3. **Efficient acquisition** relates to transaction costs for market parties and system operators as well as to the degree of spilling regarding acquired quantities (i.e. over-procurement). It is a relevant criterion for the assessment, because it is linked to attracting new participants (i.e. transaction costs can cause entry barriers for new participants).

4. **Compliant acquisition** of redispatch is also relevant because the assessed should fit into EU and Dutch regulation.

6.1.8 Development of performance indicators

Generic performance indicators are suitable. The generic performance indicators from section 4.5 can be applied on the redispatch services and on the relevant other ancillary services and markets in order to measure the performance of the two designs. The link between the generic indicators and the performance criteria is also outlined in section 4.5.

Gaming and breaches out of scope. For this study, most of the framework’s generic indicators are somehow relevant to evaluate the performance criteria and to derive conclusions for the assessment goals (see table 6.3). This means that they are applied to the redispatch acquisition as well as to the interdependent ancillary services and markets. However, since gaming and non-delivery of sold services are not in the focus of the use-case, related indicators about market power and non-delivery of contracts are consequently not considered.

TABLE 6.3: Generic performance indicators and further specification for use-case application

Generic performance indicators	Specification for comparative assessment	Contribution to goals
Ancillary service volume & prices		
Quantity offered	Comparison of redispatch volume offered	Increase quantity
Prices offered	Comparison of redispatch prices offered	Decrease mark-ups
Cleared prices	Comparison of redispatch prices cleared	Decrease mark-ups
Ancillary service demand fit		
Unsupplied ancillary service demand	Comparison of unsupplied redispatch demand	Increase quantity
Over-procured ancillary service demand	Comparison of over-procured redispatch demand	Decrease mark-ups
Ancillary service not delivered	Not measured, as 100% delivery assumed	N.a.
Ancillary service supply competition		
Number of participants	Comparison of participating market parties in redispatch	Attraction new participants
Market power & liquidity indicators	Not measured, as market power out of scope	N.a.
Profit and loss per participant	Comparison of profit per participant	Attraction new participants
Ancillary service interdependency		
Median of w.average offered & cleared prices per MTU and per market	Evaluation of price effects on intra-day market, balancing energy market, and imbalance	Avoid unwanted effects
Average of average offered & cleared volumes per MTU and per market	Evaluation of volume effects on intra-day market, balancing energy market, and imbalance	Avoid unwanted effects
Traded volume per market, relative to total traded volume	Evaluation of volume effect on intra-day market and Balancing energy market	Avoid unwanted effects
Return per market relative to total return	Evaluation of return effects at intra-day-market	Avoid unwanted effects
Producers cost, producers profit, system operators cost (per MWh consumption)	Evaluation on system-costs and benefit distribution	Avoid unwanted effects and decrease mark-ups

TABLE 6.4: Illustrative example of supply-demand ratio

Delivery period	Delivery location	Trading moment	Demand	Supply	Ratio
1	North	1		100	-
		2	200	100	0.5
		3	100	0	0
		4	100	400	4
		5		300	-
2	North	1	100	300	3
Median ratio					**(0.5+3)/2=1.75**

Specific alternative indicator needed for quantity. The generic quantity indicator measures the average of the average quantity offered (respectively cleared) per simulation step. This calculation of averages is needed because continuous markets have various moments of offered quantities, while single auctions have only one relevant quantity offered per delivery period (i.e. quantity at gate-closure). While this indicator may be interesting for the interdependency assessment, it provides little information about the grid operators ability to solve congestions. In other words: the indicator does not help to analyse the amount of usable redispatch supply orders. For this use-case an indicator is needed that measures offered quantities in a continuous single-buyer market, whereby next to the delivery period, also the delivery location is relevant.

Ratio proposed as volume indicator. It is proposed to measure the median ratio of supply to demand volume per delivery period. Only such trading moments are taken into account, where the grid operator tries to solve its redispatch demand. In case the grid operator has a remaining redispatch demand after procuring redispatch, this demand would be placed in the next trading moment. If again not enough supply is available, the median ratio will further decrease (i.e. under-procurement effect). However, under-procurement may also occur even though redispatch supply is higher than demand. This is the case when the equilibrium constraint prohibits further procurement of all-or-none orders, as this would cause higher imbalances than the threshold. The indicator must take these situations into account, because otherwise such under-procurement has a misleading positive effect on the ratio. Furthermore, it is required to correct the supply volume by its effectivity regarding the congestion to be solved. For the simplified redispatch approach in this study, congestions are translated into two-area redispatch demand, whereby all orders within an area are assumed to have the same effectivity. Table 6.4 illustrates a simple case of the redispatch supply-demand-ratio indicator calculation:

6.2 Action situations

6.2.1 Theory on market party behaviour and (physical) power system behaviour

The basic theory and assumptions about market party behaviour in Dutch short-term power markets are discussed in section 5.1. It is referred to Hirth and Glismann (2018) for the physical behaviour of the system and the general concept of redispatch, i.e. shift load and production geographically in order to solve congestions.

6.2.2 Ancillary Services dependency estimate

In order to explicitly elaborate on the required scope for taking interdependencies into account, the proposed guiding questions from the framework are applied (see section 4.7).

1. **What are the ancillary services with the same objective as the examined ancillary service?**
IDCONS are a redispatch service with the objective to alter (expected) power flows in order to maintain operational security limits of network elements.
    (a) ROP has the same objective as IDCONS.
    (b) TenneT concludes bilateral contracts to limit the use of connection capacity of grid users during planned grid outages. These contracts are concluded days and weeks before the day-ahead market. The contracts can theoretically influence the day-ahead price. Furthermore, the contracts temporarily reduce redispatch demand. However, since the contracts are currently[1] linked to outages, the dependency is considered not to be relevant for this design study.
    (c) TenneT has contracts with neighbouring TSO's for cross-border redispatch procedures. On request of other TSO's, TenneT can activate ROP, while the other TSO activates the opposite action in its area (and vice versa). Even though EU regulation pushes towards more international redispatch coordination and optimisation (European Commission, 2015), cross-border redispatch is currently rarely used. It is usually only used in alert (or nearly alert) situations and not for financial optimisation. Therefore, it is not required for this study to consider foreign redispatch demand and supply.
2. **Which ancillary services were (historically) provided by the same potential providers of the examined ancillary service?**
All large electricity producers in the Netherlands are able to participate in ROP. These companies provided also aFRR, mFFRRda and FCR. Also new and smaller market parties (interested or already participating in the IDCONS pilot) stated that they were active in mFRRda and FCR in the Netherlands (GOPACS, 2019b). Some of the large producers also have black-start contracts and reactive power contracts with TenneT.
3. **Which markets are operated in parallel or after the examined ancillary service?**
The gate-opening (D - 1, 15:00)[2] and gate-closure time (MTU – 3, resp. MTU – 1) of ROP and IDCONS shows that the markets operate in parallel to the intra-day market. While aFRR and mFRRsa can be offered in parallel (gate-closure time MTU – 2), the utilisation speed of all FRR products ensures that they are only activated from MTU – 1 onwards. In the case of ROP, market parties have hence one MTU time to shift available capacity from the (closed) ROP market to the FRR market. In the case of IDCONS, there is no lead time between the markets. Therefore, a practical overlap exists between the offer

[1] This has changed with the revision of the Dutch grid code. As of this change grid operators may also use these so called 'capacity limitation contracts' without planned outages (Autoriteit Consument en Markt, 2022).

[2] This is not a mandatory gate-opening time, but the typical start of the redispatch process at TenneT

periods of IDCONS and FRR. Moreover, the subsequent imbalance market in the Netherlands induces opportunity costs from passive balancing to the redispatch markets.

4. **Are opportunity costs in preceding markets (significantly) affected?** Balancing capacity for FRR, FCR contracts, reactive power contracts[3], forward electricity markets and the day-ahead electricity market are preceding markets with a potential dependency with redispatch via opportunity cost. However, opportunity cost can be very low if redispatch does not occur on a daily basis. This is in particular true if the gate-closure time of the preceding markets lies far before gate-opening of the redispatch market or if the product periods are longer than a day, as these conditions imply uncertainties which reduce the expected profit from redispatch. For the Netherlands, it can still be argued that redispatch events are too rare to imply significant opportunity cost on preceding markets.

It is concluded from this elaboration that, given the potential interactions, the study shall focus on the redispatch market, intra-day market, balancing energy market and imbalance market. Other market interactions exist, but they may have a smaller impact on the design comparison of IDCONS and ROP.

6.3 Scenario development for the design experiment

Three aspects to be covered by scenarios. The scenarios for the assessment should be in line with the defined policy-readiness-level 4 (see section 6.1) and thus be suitable for a small-scale model embodying several salient real-world aspects. The scenarios should cover various situations of available capacity, various redispatch demand quantities and various day-ahead prices, because these three aspects significantly determine redispatch offers and prices.

Scenarios must be plausible and consistent. To avoid that the comparison of redispatch designs is strongly influenced by unrealistic combinations of input parameters, it is reasonable to reflect the Dutch power system to some extent. Installed capacities, typical residual load patterns as well as redispatch quantities are, therefore, based on data of the Dutch power system. Nonetheless, it has to be kept in mind that the assessment is a structural analysis with comparative results and not a forecast model for redispatch cost.

Typical-days scenarios. A clustering method is used to generate typical-days that represent the time series data of the Dutch power system. The Python-based Time Series Aggregation Module (Tsam) is used for the clustering. It is referred to Kotzur et al. (2018) for documentation.

Focus on estimated north-south congestions. The character of congestions determines the required redispatch and thus the scoring of redispatch orders (Hirth and Glismann, 2018). However, the most frequent congestion in the Netherlands in recent years required a redispatch from north (downwards orders) to south (upwards orders). Therefore, the scenarios only take these congestions into account. Even

[3]Reactive power may also be considered as a parallel market instead of a preceding market, as utilization may happen in parallel to the redispatch market.

though the congestion location and the redispatch location are not explicitly published, an analysis of the redispatch quantities in combination with TenneT's operational messages (TenneT TSO B.V., 2019f) about market restrictions is used to determine an estimate. Redispatch quantities are interpreted as north-south redispatch when concurrent market restrictions in downward direction referred to areas in the north of the cities Lelystad and Zwolle. Furthermore, redispatch quantities (MWh) are transformed to quantities (MW) to be consistent with residual load data.

Process to select cluster settings. Tsam is used to identify typical periods of 48 hours because the short-term markets of the use-case always start the day before the day of delivery. Given the scenario requirements above, the clustered time series are day-ahead residual load (+ export, – import) and north-south redispatch quantities[4]. Experimentation showed that the mean absolute error hardly decreases when searching for more than 13 typical periods in the data. The k-medoids cluster method yielded a lower mean absolute error than the alternative methods (i.e. k-means and hierarchical).

Infrequent redispatch events depict larger error. The result of applying the clusters to the two-year time series is depicted in figure 6.1. It is obvious that redispatch is observed in only 10 % of the cases. Therefore, only two of the thirteen cluster periods contain redispatch. This explains why the mean absolute error of the normalised residual load is lower (0.021) than the mean absolute error of the normalised redispatch quantity estimation (0.061).

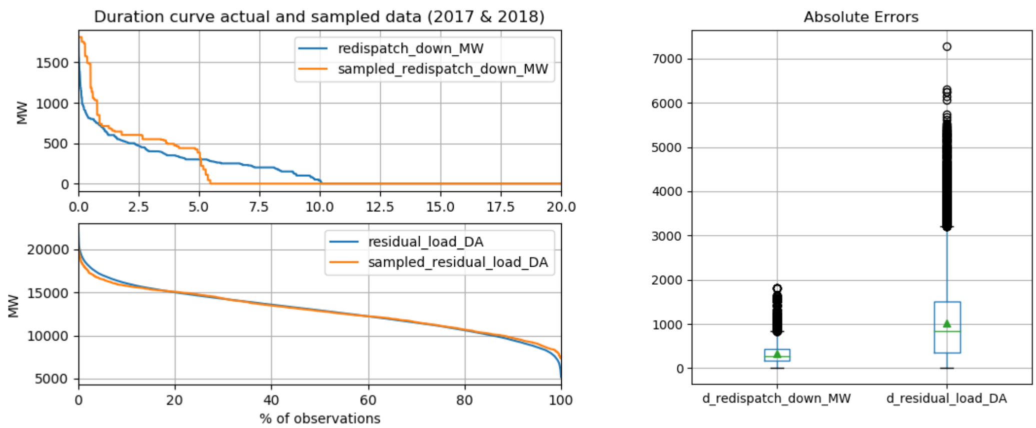


FIGURE 6.1: Duration curves and absolute errors of time series aggregation

Only typical periods with redispatch are chosen. From the typical 48 hour periods, only the two periods with redispatch events are chosen for the assessment. Figure 6.2 displays the selected typical periods together with the closest neighbour from the original time series. The figure exhibits events with low redispatch quantities as well as events with very high redispatch quantities. Furthermore, it can be observed that the typical periods include days with rather high residual load and days with rather low residual load curves.

[4]The published data of downward redispatch is used to create the scenarios.

Original data used instead of sampled data. Given the obvious over-estimation of the redispatch quantities, the original values for residual load and redispatch are used for the selected days. This approach also allows for the calculation of respective day-ahead forecast errors (FE_residual_load) based on forecast data and actual data as published. Furthermore, it allows for the inclusion of power plant outage data into the simulations.

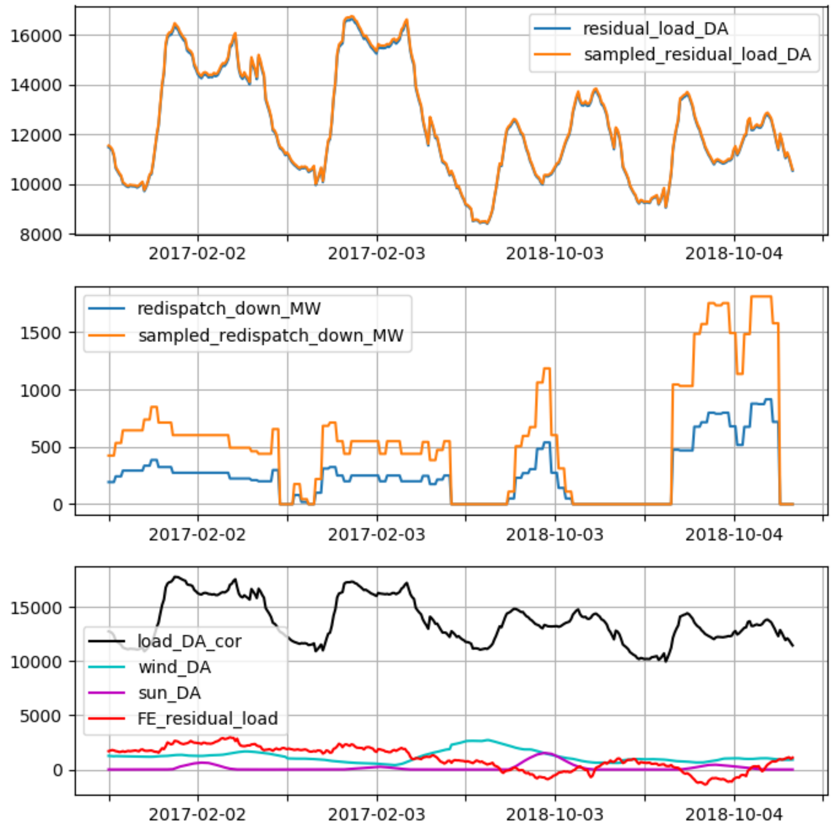


FIGURE 6.2: Selected typical days

Power plant list from ENTSO-e adapted with information from TenneT. The installed capacity of large power plants is published on the transparency platform of ENTSO-e. However, some information is outdated. Therefore, this list of power plants is supplemented with expert information from TenneT. These non-RES power plants have a total installed capacity of 18.296 GW, while the ENTSO-e publication shows 18.421 GW. TenneT information was also used to add the owning market parties to the list (status July 2019)[5].

Power plant parameters from grid development plan. The fuel category per Dutch power plant from TenneT TSO B.V. (2015) is used in order to retrieve the technical parameters per fuel category from the ten-year-development-plan (TYNDP) publication (ENTSO-e, 2019c). Moreover, the TYNDP fuel prices are used from the '2020 Expect Progress scenario'. Based on this information the SRMC as well as the warm-start costs are determined. These start costs are also assumed as stop costs. Cold-start costs are not considered due to simplicity reasons.

[5]It is not advised to reuse this ownership list for other purposes, because owners as well as owner names may have changed.

Ramping limits adjusted to cope with 15-minute simulations. TYNDP data assume that all power plant types can ramp their installed capacity within one hour. The present use-case, however, applies a 15-minute granularity to examine possible market imbalances per ISP. Hence, it is assumed that power plants with the fuel category nuclear and coal have ramping limits (upward and downward) of 25 % per 15 minutes. The category gas has an assumed ramping capability of 100 % per 15 minutes.

A list of the power plant data can be found in annex D.

Calibration uses day-ahead price. It is assumed in the mark-up approach that the day-ahead price also determines prices of subsequent markets. Therefore, the day-ahead prices are taken as a parameter for the scenario calibration. For the calibration two arbitrary quality target parameters are chosen: The median absolute error of the day-ahead price should not exceed 10 €/MWh and the median absolute percentage error of the day-ahead price should not exceed 20 %. Furthermore it is required that the 80 % confidence interval of absolute errors has a mean absolute error below 10 €/MWh and a mean percentage error below 20 %.

Small asset assumption required to improve peak prices. The total installed capacity of the selected power plants is below the maximum Dutch residual load (-import , +export). Moreover, the highest SRMC are 68 €/MWh, while the maximum Day-ahead prices exceed 150 €/MWh. This is not surprising, as the power plant list does not include small and distributed assets. In order to improve the representation of peak power plants and subsequently improve simulated peak prices, the following approach is chosen:

1. The missing installed capacity to reach maximum residual load is determined.
2. The day-ahead price duration curve above the highest SRMC of the power plant list is determined.
3. The duration curve is discretised in 10 bins and scaled to the missing capacity.
4. This discrete price-capacity curve is used to define 20 generators with respective SRMC. Half of the generators are allocated to the north, and the others are allocated to the south of the Netherlands. These assets are designated to a fictitious market party, aggregated flexibility owner (agg_flex_owner). It is assumed that these assets are grouped with mixed fuel types and fuel categories. In the absence of specific technical specifications of these assets, it is assumed that they are entirely flexible. Therefore, no constraints on the minimum stable level, ramping and start-stop cost are added. The most expensive two generators are enlarged by 1 GW to enable the model to cope with large outage situations.

The approach is illustrated on figure 6.3.

Calibration targets not met without outage data. Day-ahead price simulations with ASAM (see section 5) showed that the quality targets above are not met, despite the added agg_flex_owner. Experimentation showed that planned asset outages have an important impact on peak prices. Therefore, published asset outage data from ENTSO-e of the selected days is added to the model.

Results show impact of SRMC plateaus. Figure 6.4(A) depicts the simulated day-ahead price and the original day-ahead price. The simulated prices display less

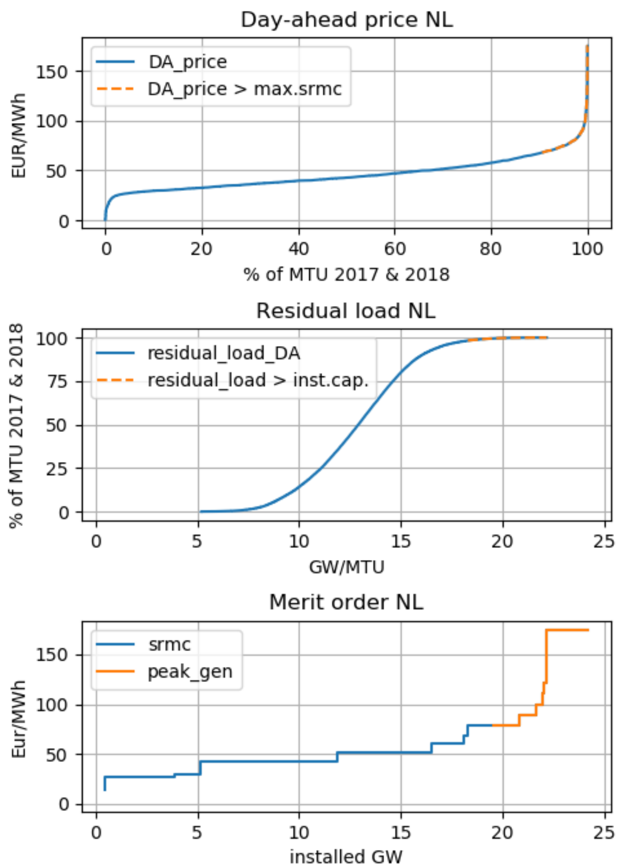


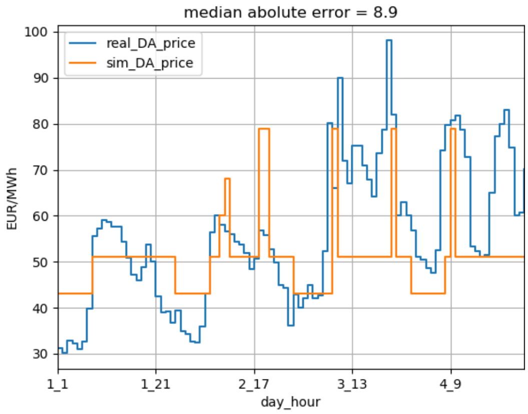
FIGURE 6.3: Illustration of approach to include flexible capacity in scenarios

variation from one hour to the next hour than the original prices. These observations may be a result of the power plant parameters, which are defined per fuel type and, therefore, have fewer differences of parameters than in reality. However, figure 6.4(B) shows that the calibration targets are met.

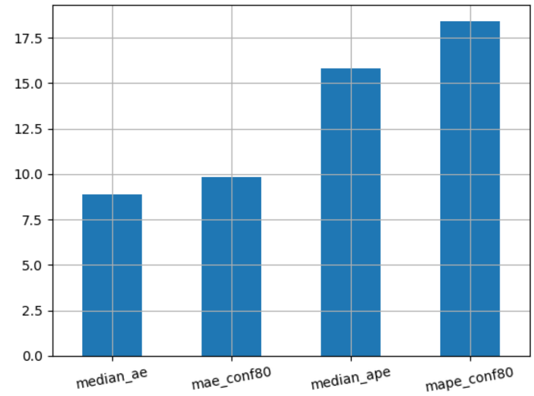
6.4 Test of design options

6.4.1 Modelling acquisition process ancillary services

A computational model of acquisition process is justified. Given the large amount of identified actions and indicators related to market party behaviour in short-term electricity markets, the use of a computational model is reasonable to test the hypotheses of the assessment. A computational approach enables the examination of emergent system behaviour under simultaneous consideration of numerous axioms and assumptions. Moreover, to gain insights about the emergent price mark-ups on system level, the use of an agent-based model is a suitable method. It allows generating data regarding price-mark-ups at agent level, which are usually not available in fully empirical studies. The assessment goals and the scope clearly show that the model should focus on the acquisition process of ancillary services, while the representation of the physical system may be simplified.



(A) Prices



(B) Quality parameters

FIGURE 6.4: Calibration results

Not all design variables included in computational model. The identified relevant design variables in previous sections (i.e. product underlying, product utilisation, product period, provider accreditation, bid requirements, acquisition timing, and market information) should be represented in detail in the model. However, the added value of modelling provider accreditation seems to be low. Renaud (2019) analysed considerations of various greenhouse farmers with combined heat and power assets (CHP) to participate in IDCONS or ROP. Her discussion of bounded rationality as well as the heterogeneous situations of flexibility providers shows that adding transaction cost functions would not be straight forward. Therefore, a qualitative analysis is chosen on this aspect, thus on hypothesis 1b (i.e. IDCONS design attracts new and small market parties). The result of this analysis is subsequently considered in the scenarios for the simulations. Markets are modelled with different level of detail. The generic ASAM is used for the simulations. To evaluate not only the redispatch design but also assess the impact on other markets, an abstract model of the balancing energy market and the imbalance market are considered in the simulation. Both are, however, simplified and not complete (see chapter 5).

Balancing energy market. There is no clearing of the balancing energy market implemented. The balancing energy market only captures the offered quantities for FRR and it generates a control state per market time unit, as it is known from the Dutch balancing system (TenneT TSO B.V., 2019g). The control state is drawn from a historical probability distribution.

Imbalance market. The Dutch imbalance pricing method is implemented. For every simulated MTU, each market party receives or pays money depending on their imbalance position (i.e. MWh short or MWh long). The imbalance price is generated from a conditional probability distribution, given the sampled control state of the balancing energy market and given the simulated day-ahead price.

Balancing capacity market. There are no balancing capacity auctions considered in the model.

Consequences of balancing simplification. The imbalance of market parties does not influence the imbalance price in the proposed simulation set-up. It has to be

TABLE 6.5: Simulated market rules for ROD and IDCONS.

	DAM	IDM	RDM	BEM	IBM
Gate opening time	D-1, MTU 47	D-1, MTU 56	D-1, MTU 56	D-1, MTU 56	Delivery MTU
Gate closure time	D-1, MTU 48	Delivery MTU-1	delMTU-3 | delMTU-1	Delivery MTU-2	Delivery MTU
Clearing type	Single hourly auction	continuous	continuous sealed auction. Equilibrium constraint: inf. | 0 MW	Control states only	Real-time
Pricing method	uniform	best_price	pay_as_bid	na	Dutch_IB_ pricing
Order types	fill_or_kill	limit_and _market	all_or_none | limit_order (block)	na	na

noted that in cases where the simulation shows high imbalances, the imbalance price is thus probably underestimated. The probabilistic dimensioning of balancing capacity (see European Commission, 2017a, Article 157) would lead to an increase of balancing capacity demand, in case the market imbalance would significantly increase during a dimensioning period. Additionally procured balancing capacity would impact the supply curve of the day-ahead auctions because balancing capacity providers need to withhold capacity, respectively dump capacity (i.e. must-run obligation) for being able to provide balancing energy. These impacted day-ahead prices would influence opportunity costs for redispatch and intra-day trading.

Differences in market rules. Most variables of market rules in the model are the same for both redispatch designs (see for details section 5.6). The redispatch clearing algorithm differs only on one detail: The threshold value for the equilibrium constraint in case of ROP is infinitive, while the threshold for IDCONS is 0 MW. This is a simplification because in reality the redispatch algorithm of GOPACS (for IDCONS) and the algorithm of TenneTs application RESIN (for ROP) differ more fundamentally. The first is more advanced and includes DSO-TSO coordination aspects. Additionally, the order types are different: All-or-none block orders in case of ROP and limit block orders in case of IDCONS. The gate closure times for redispatch also differ: ROP gate closure time is 3 MTU before delivery period, whereas IDCONS gate closure time is 1 MTU before delivery period. A summary of the simulated market rules is shown in table 6.5.

Differences in agent strategies. The major differences of both redispatch design simulations concern the agent strategies on quantity and prices. The strategies and mark-ups in the case of ROP are described in the sections 5.2 and 5.7.

IDCONS quantity strategy. The open intra-day order book makes market parties to provide small offers of their operationally available capacity, in order not to reveal their position to competitors (see section 5.1). This agent strategy also applies for IDCONS, while for ROP it is assumed that agents offer their available operational capacity. In contrast to the intra-day market strategy, market parties in IDCONS design also offer their non-operational start-stop capacity at the intra-day market. In expert interviews, it was stated that start-stop capacity is usually traded bilaterally 'over-the-counter' and not on intra-day continuous market. Hence, instead of permanently offering their start-stop capacity for IDCONS, market parties only offer this capacity reactively, in case the grid operators has already acquired redispatch services for the respective delivery periods.

Identified IDCONS issue with full capacity obligation. The set-up of the agent strategies shows a potential risk of the IDCONS design: market parties are obliged to offer the full available capacity of large assets to the TSO (ACM, 2016). If IDCONS replaces ROP, and this obliged participation would also be applicable to IDCONS, then such market parties would be obliged to reveal their position to competitors. If the obligation is removed for IDCONS, then grid operators face the risk that large power plants could strategically withhold capacity from the redispatch market. However, subsequent security risks could trigger an alert state or emergency state, which provides additional competences to the grid operators. In such a system state, grid operators can force certain dispatch behaviour from market parties. It is assumed that changes of the system state are neither desirable for the large market parties (i.e. risk on compensated cost) nor the grid operators (i.e. operational performance indicators). Subsequently, it assumed that market parties would not withhold capacity when the grid operator announces the remaining need for redispatch, although they may provide this capacity in an iterative process.

Identified IDCONS issue with small offer sizes and opportunity cost. Small offer sizes for redispatch, however, place another potential risk to market parties: the product subject of redispatch services includes a dispatch restriction in the opposite direction of the redispatch transaction. If a power plant is scheduled to operate at 80 % of nominal capacity and sells 5 % in upward direction, then it is remunerated for 5 % of nominal capacity multiplied by the offer price. Consequently, the power plant is not only expected to increase production but also obliged not to dispatch the power plant below 85 % during the delivery period. Hence, the opportunity of later transactions in downward direction (80 %) is sold as well. However, by using the so-called 'market restrictions' in the Netherlands (ACM, 2016), the grid operators can announce a dispatch restriction for all connections of a specific area, in case changes of their dispatch schedule would affect the congestion for which redispatch was already applied. Assuming that grid operators continue to apply these market restrictions, all market parties (not only the one providing the small redispatch quantity) would lose their opportunity in one direction. This non-remunerated obligation diminishes opportunity cost issue of small IDCONS orders.

IDCONS pricing strategy compared to ROP pricing. Prices for IDCONS orders from operational capacity include an opportunity mark-up as well as a mark-up from the open order book strategy. These mark-ups are similar to the intra-day limit orders. Prices for IDCONS orders from start- or stop capacity include the start-stop mark-up and additionally, in opposite to ROP orders from start- or stop capacity, a partial-call mark-up (see section 5.2). However, as IDCONS orders can be matched to redispatch demand as well as to other intra-day orders, based on the continuous first-comes-first-serves principle, there exists no double-score risk. Therefore, IDCONS pricing strategy has no double-score mark-up, opposite to ROP orders. Since only small quantities of operational capacity are offered for IDCONS, the ramping mark-up is not applied, in contrast to ROP offers of large sizes (i.e. all available capacity). The remaining strategies are the same for the IDCONS simulation and the ROP simulation, as shown in table 6.6. For more details on the strategies, see section 5.1.

Randomness is identical for both design simulations. In order to avoid that randomness in the simulation leads to misinterpretations of the result, the randomness

TABLE 6.6: Simulated agent strategies

	ROP	**IDCONS**
agent	all	all
DAM_quantity	all	all
DAM_pricing	srmc	srmc
IDM_timing	instant	instant
IDM_quantity	small random (<20 MW)	small random (<20 MW) + start-stop capacity when redispatch took place
IDM_pricing	opportunity mark-up + open order book mark-up	opportunity mark-up + open order book mark-up + partial-call mark-up
RDM_timing	instant	na
RDM_quantity	all operational capacity + all start-stop capacity	na
RDM_pricing	opportunity mark-up + start-stop markup + ramping mark-up + double-score mark-up	na
BEM_timing	at_gate_closure	at_gate_closure
BEM_quantity	available_ramp	available_ramp
BEM_pricing	srmc	srmc
IBM_timing	impatience_curve	impatience_curve
IBM_quantity	impatience_curve	impatience_curve
IBM_pricing	exp. imbalance price + marginal order book mark-up	exp. imbalance price + marginal order book mark-up

is held equivalent for both simulations. This same randomness is achieved by using a specific seed in random functions. Randomness is included in the agent ranking per simulation step, which determines the sequential order of agents taking their actions. A further randomness is used when drawing the samples for the control state of the balancing energy market and the subsequent sample from the conditional probability distribution of the imbalance price. Furthermore, randomness is applied when choosing offer quantities for intra-day orders. The effect of randomness is tested in sensitivity simulations.

Simulation input data. The exogenous data is taken from the scenarios as defined above. The scenarios also define the number of simulation steps (i.e. 4 * 96 MTU).

6.4.2 Qualitative analysis regarding the attraction of new participants

Who participates with ROP, who doesn't. According to TenneT, ROP is currently mainly provided by large incumbent market parties (GOPACS, 2019a). Those market parties have a connection to the 'Central Post System' (CPS), which is used to send trade schedules, generation and load schedules and it is used to send orders for ancillary services. According to the grid operators of GOPACS, it is an aim of IDCONS to unlock flexibility from small distributed generation, demand-side management and RES for redispatch. Such market parties would currently not provide orders for ROP.

Minimum order size ROP identified as a barrier. As explored by Renaud (2019), the minimum order size for ROP is 1 MW and local pooling of assets in not yet facilitated. This currently excludes assets smaller than 1 MW from participating. IDCONS, on the other side, allows for orders of 0.1 MW, which opens the market for smaller assets[6].

No structural difference in IT cost identified. It is assumed that transaction cost for IT connection and placement of orders are very market party specific. Therefore, it is not qualitatively judged whether ROP or IDCONS generally have lower transaction costs. However, market parties that are already connected to a participating trading platform, but which are not connected to CPS would thus have lower IT transaction costs with IDCONS compared to ROP. Anyway, also the opposite is true: Market parties connected to CPS would have additional transaction costs when being required to join a trading platform for redispatch.

Transaction costs lower in case of DSO redispatch. In terms of transaction costs, a major advantage of IDCONS compared to ROP is, however, that all Dutch DSO's jointly can use IDCONS via GOPACS. Consequently, if various DSO's would instead apply an ROP like solution, market parties would be required to connect to each DSO redispatch platform in order to participate. Compared to such an ROP scenario, IDCONS would obviously have lower transaction costs for both IT and for placing orders.

Ease-of-use is a slightly attracting factor for IDCONS. Based on the theory of planned behaviour, Renaud (2019) elaborates on the perceived difficulty to participate in redispatch. For those market parties not yet being active on redispatch but

[6] It has to be noted that currently both products allow for pooling on bidding-zone level. However, as the delivery location is crucial to determine the value of an order, those offers are only used in specific situations. Therefore, this pooling option is to be seen as a temporary test period, while locational pooling is under development (GOPACS, 2019a)

being active on intra-day trading, placement of orders on that known intra-day platform appears to be easier (i.e. lower perceived difficulty), than providing orders directly to grid operators in the form of ROP. However, Renaud (2019) finds that facilitators (i.e. intermediate service providers placing orders on behalf of asset owners) would reduce the perceived difficulty of greenhouse CHP owners. Moreover, she states that "*it appears greenhouse growers can quite easily be motivated to change from current behaviour to behaviour that may increase their earnings: stickiness is not an important determinant for behaviour*" (p. vii). These two findings, although they do not distinguish ROP and IDCONS, show that at least greenhouse CHP owners might be evenly attracted to both ROP and IDCONS. Yet, greenhouses are not the only new participants targeted. RES owners and industries may exhibit a higher sensitivity to perceived difficulty and ease-of-use.

Challenge of scattered redispatch actions better supported by IDCONS. As discussed by Hirth and Glismann (2018), congestions have various properties which make it timely to find solutions. Therefore, it is a 'pro-active' process with discrete moments of redispatch. This is in large contrast to the 'reactive' balancing process, where permanently real-time actions are taken. The scattered occurrence of redispatch actions by grid operators may , hence, impose a challenge to redispatch providers: On the one hand, they must ensure that their offers are placed before the moment of redispatch procurement. They may react on grid operator announcements of redispatch needs. However, such strategy carries some risk as grid operators may sometimes only use announcements if there are remaining congestions after the first redispatch actions. Furthermore, redispatch actions may be taken short after or long after the announcements[7]. On the other hand, market parties may face transaction costs when redispatch orders are placed for longer periods (or even permanently), while most of the time these orders are not called[8]. These transaction costs stem from mitigating double-score risks on other markets. As discussed in section 5.2, market parties can either include price mark-ups or exclude capacity from the redispatch market, subject to offered positions on other markets. Anyway, the market party is required to regularly adjust the redispatch orders, when positions on other markets change. Concerning this aspect, IDCONS can be advantageous, as for assets with similar redispatch order prices and intra-day order prices, the market party can participate simultaneously with one order on both markets and thus save transaction costs.

Open order book provides additional transparency. IDCONS are also offered in an open intra-day order book. Even though it is neither visible that the orders may also be used for IDCONS nor is the delivery location visible for market parties, visible prices and quantities may be used to identify IDCONS orders to a certain extent. Furthermore, quantities and prices of cleared IDCONS orders are tagged as IDCONS transaction. This additional transparency gives more information to analyse business cases of potential redispatch providers. Moreover, it may work as a permanent advertisement for participants on the trading platform, reminding them that they are not yet part of this redispatch market.

[7] This is a consequence of the continuous acquisition set-up which has, in contrast to single auctions, no fixed procurement moment.

[8] In the Netherlands there are still periods of several weeks with barely redispatch events. Even during days with many and large congestions there are only few moments where the grid operator calls redispatch orders.

Potential conflict with exclusive market platforms. Expert interviews suggested that many of the smaller potential redispatch providers are not directly acting on the intra-day market. They would often have contracts with their supplier (who is somehow affiliated with their BRP) to trade their flexibility via an exclusive market platform of that supplier. The supplier facilitates thus intra-day trades among his clients. Furthermore, the supplier may act as market-maker to provide liquidity at pre-defined price ranges. To provide this capacity, the supplier may use its own power plants and may trade on non-exclusive trading platforms. The small market parties would profit from a broad service package, while the supplier profits from the arbitrage between the exclusive market platform and the international electricity markets and imbalance market. However, there seems to be a conflict of interest when these small market parties want to participate in redispatch markets to obtain locational value from their asset. First, this reduces the flexibility available on the exclusive market and thus the arbitrage profits for the supplier. Secondly, these small market parties suddenly become competitors for the few incumbent market parties on the redispatch market, which may include the supplier.

Renegotiation of service conditions is a barrier for new redispatch providers. Given this conflict of interest, suppliers and affiliated BRP would not unconditionally support the wish of their clients to start participating in redispatch. A renegotiation of the service agreements between potential redispatch provider and its supplier and BRP may be a prerequisite to start providing redispatch services. For such renegotiation, it is important that the potential redispatch provider has alternatives to the supplier, which allow for provision of redispatch services. It may be assumed that all the incumbent suppliers tend to discourage their clients from participating in redispatch because of the above-described conflict of interest. This means that only new and rather small suppliers or service providers are available as an alternative for the potential redispatch provider. However, another alternative for such market parties is own marketing of their flexibility on various platforms.

IDCONS might help to overcome trading pool barriers. Own marketing of flexibility requires additional expertise and additional transaction costs for market access. At the same time, transaction costs for intermediate service providers may be avoided. While a rational market party would choose for this option as soon as the expected profit is higher, Renaud (2019) explored various arguments based on the theory of planned behaviour, which may hinder the market party to start participating in redispatch. Given these potential barriers for new redispatch providers, the above-argued advantages of IDCONS regarding minimum order size, the transaction cost for platform connection, transparency, and ease-of-use may be relevant for exactly these potential providers. In particular, the last two advantages enable the evaluation of expected profits, while the perceived difficulty may be reduced. As soon as a few small market parties show that redispatch is a viable option, the renegotiation may become easier for potential redispatch providers, as suppliers may try to hold their clients.

Price determination assumed to be evenly difficult. The number of identified mark-ups for ROP (i.e. opportunity, double-score, ramping, and start-stop) and IDCONS (i.e. opportunity, open order book, start-stop, and partial-call) is equivalent. There is no qualitative argument found which indicates that the determination of mark-ups is obviously more difficult in one of the redispatch designs.

Conclusion: IDCONS is more attractive to small market parties. The qualitative arguments derived from findings from Renaud (2019) and expert interviews lead to the conclusion that IDCONS is more attractive than ROP to the currently non-participating segment of small, distributed market parties. Thus, the qualitative analysis supports the acceptance of hypothesis 1b (IDCONS design attracts new and small market parties). However, also with IDCONS those potential redispatch providers have to overcome a number of barriers. Therefore, this higher attraction does not automatically (i.e. without marketing and/or grid code obligations) unlock many new participants.

Recommendation for simulation. The qualitative analysis shows that currently no small market parties and small assets are participating in ROP. Assets smaller than 1 MW are practically excluded until locational asset aggregation is facilitated. This speaks for an exclusion of the agent agg_flex_owner from ROP market in the simulations. However, as the aggregated flexibility portfolio is a rough approximation based on day-ahead prices and residual load (see section 6.3), a full exclusion may overdraw the impact of ROP barriers in comparison with IDCONS. Moreover, assets larger than 1 MW can already today join the ROP market. Therefore, it is recommended for the simulation to include agg_flex_owner in the ROP market, but to run a sensitivity simulation on ROP where agg_flex_owner is not participating in redispatch. Furthermore, it is recommended to evaluate the obtained profits of agg_flex_owner, because relative higher (lower) profits would strengthen (weaken) the conclusion for hypothesis 1b.

6.4.3 Analysis of simulation results

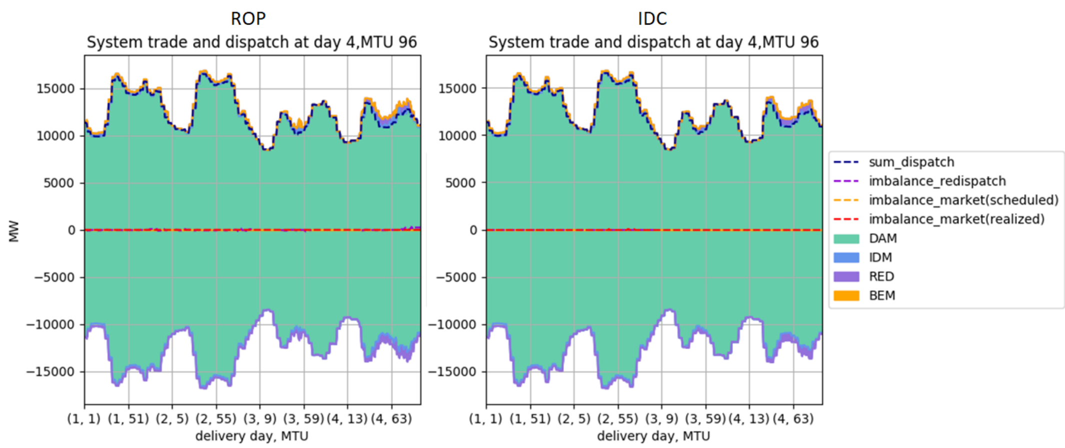


FIGURE 6.5: Overview of system trade and system dispatch after the last simulation step

Result investigation on system-level and agent-level. In the following section, the simulation results will be explored. The investigation starts with system trading and system dispatch, followed by a plausibility discussion of delta prices. The subsequent step explores the profits of specific agents. Next, the results of various redispatch performance indicators are analysed, before finally, the interdependency indicators with other markets are assessed.

A first overview of the simulation results is shown in figure 6.5. The figure shows the traded energy per market as well as the dispatch sum of the system. The figure furthermore depicts imbalances, distinguishing imbalances from redispatch (i.e. 'grid operator imbalance'), scheduled market imbalance (i.e. open positions of agents in future delivery MTUs) and realised market imbalance (i.e. imbalances in past delivery MTUs). The figure shows the system after the final step of the simulation. In this final step, scheduled imbalance and the realised imbalance are the same.

Day-ahead market is by far the largest. It is obvious that the day-ahead quantity is much larger than the other markets. Non-surprisingly, the day-ahead quantities correspond to the day-ahead residual load. Differences of both simulations regarding redispatch and intra-day transactions are barely visible on this figure. However, it can be noted that the ROP simulation shows, in contrast to IDC, a slight imbalance from redispatch (purple line). Moreover, it is visible that all market parties avoided realised imbalance.

Delta prices indicate generally expected system behaviour. Figure 6.6 shows the day-ahead delta price of intra-day transactions, redispatch transactions (upward and downward) and imbalance prices (IBPshort and IBPlong). The distribution of delta prices provides a validation of generally expected market behaviour in the simulation (see section 5.9):

1. The median delta price of IBPshort is slightly above zero. This means that producing less electricity than having sold on the day-ahead market is not structurally profitable. Likewise, no structural arbitrage is possible for consuming more than having bought on the day-ahead market.
2. The median delta price of IBPlong is below zero. This means that producing more electricity than having sold on the day-ahead market is not structurally profitable. Likewise, no structural arbitrage is possible for consuming less than having bought on the day-ahead market
3. Delta prices for downward redispatch are mainly below zero, whereas delta prices for upward redispatch are above zero. This shows that redispatch is a deviation from the cost-minimal dispatch schedules of market parties.
4. The median delta prices of intra-day transactions are negative. However, many outliners are displayed. The negative delta price exhibit that buy order prices (lower than day-ahead price) often set the price. This result indicates that market parties with a long imbalance position were more active on the intra-day market than market parties with a short position.

Simulated prices exhibit an expected relation to the day-ahead price (see section 5.9). Therefore, it can be concluded that the ordinal market behaviour is valid.

Some agents are not profitable. The profits per agent displayed on figure 6.7 show that few agents are not operating profitably during the simulation period. Furthermore, it is shown that the distribution of profits differs between the two simulations.

Negative profits for small portfolios with day-ahead marginal assets. When zooming in on the profits and losses of Eneco per delivery MTU (figure 6.8), it is visible that start-stop dispatch leads to cost spikes. Eneco has in these simulations only two (non-RES) power plants in its portfolio. Both have short-run marginal cost of 51 €/MWh in this scenario. As these assets are often marginal, they are hardly generating profits from the large day-ahead market. The profits from other markets are quite small, which is due to small obtained mark-ups (i.e. MTUs with large redispatch returns show only small profits). Note that outside this simulation scenario, Eneco also has RES assets as well as contracts with many small distributed assets. This allows in reality for more dispatch optimisation and potential profits

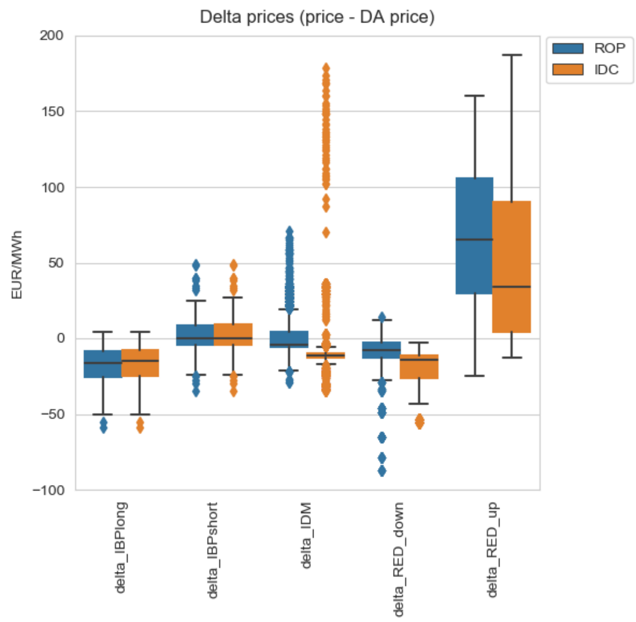


FIGURE 6.6: Delta prices

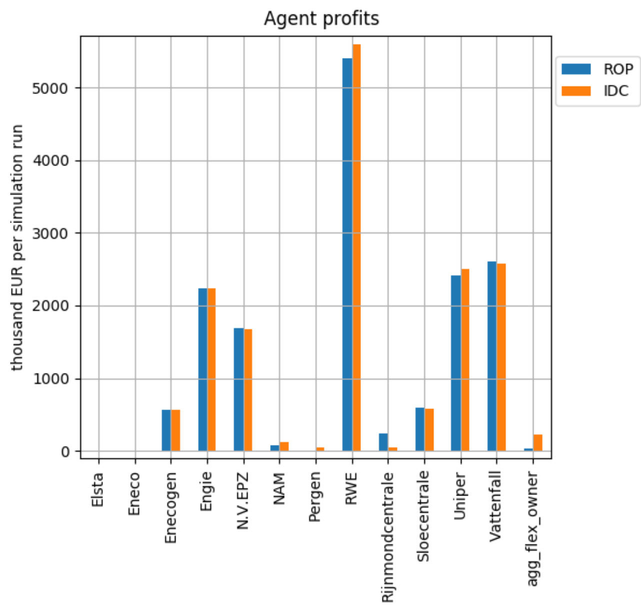


FIGURE 6.7: Profits of market party agents

than shown in this simulation. The small assets are in this simulation summarised under agg_flex_owner.

Small flexible assets profit significantly more with IDCONS. Figure 6.8 also shows that the agent agg_flex_owner has much higher profits under IDCONS compared to ROP. This may seem counter intuitive at first sight, because these assets are implemented as peak-load power plants with SRMC of more than 79 EUR/MWh. Therefore, it may seem surprising that a redispatch algorithm, that allows for partial order

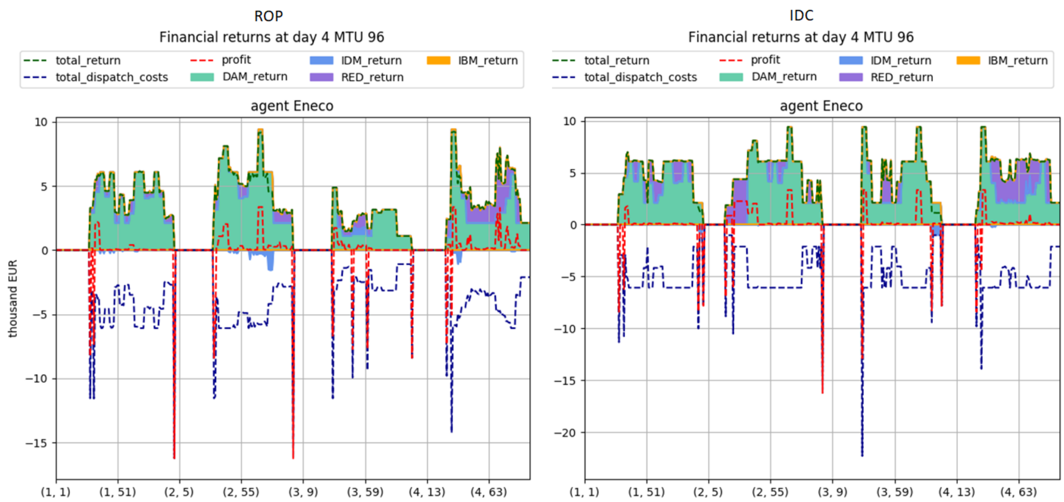


FIGURE 6.8: Return and profit per delivery MTU of agent Eneco after the last simulation step

matching, selects more often small 'expensive' orders than with all-or-none orders. This phenomenon may be explained by a consequence of the quantity strategy, and by a consequence of the pricing strategy. First, with IDCONS operational quantity is offered in small sizes. In order to cover the redispatch demand, the redispatch algorithm also calls upon more costly orders (from grid operator perspective). Second, the partial-call risk affects power plants with large minimum stable output-levels. This capacity is offered with high partial-call mark-ups. The small flexible assets, however, are implemented with a minimum stable output-level of 0 per unit of *Pnom*. Their offer prices are thus more competitive in the absence of the partial-call mark-up. This finding indicates that IDCONS may attract additional market parties to the redispatch market (i.e use-case hypothesis 1b) because potential profits are higher.

IDCONS shows lower redispatch supply. Figure 6.9 shows a comparison of the redispatch supply-demand ratio, as introduced in section 6.1. The median of usable supply of redispatch services during delivery MTUs with redispatch demand is much lower in case of IDCONS. This result is due to the IDCONS quantity strategy, which leads to small offer sizes of the available operational capacity and only incidental offers of start-stop capacity. Following the ROP quantity strategy, full available capacity is always offered. It has to be noted that the redispatch supply-demand ratio is an ordinal indicator and not a linearly scaled indicator. Nonetheless, this result leads to a rejection of hypothesis 1a (i.e. redispatch service IDCONS increases supply volume).

No straight-forward answer on mark-ups. Figure 6.10 shows price mark-ups of redispatch orders (offered and cleared) as mean, min and max as well as for three quantiles. The median mark-up for upward orders (offered and cleared) is higher in the ROP simulation (20 €/MWh). Also, the maximum upward mark-up (440 €/MWh) is obviously higher. The downward mark-ups are generally lower. Here the median mark-up for downward orders is higher with the IDCONS simulation. From section 5.2 it can be derived that the opportunity mark-ups are in both simulations rather similar, as differences in the statistic only stem from differences in dispatch (i.e. available capacity). The differences in mark-ups are thus firstly caused

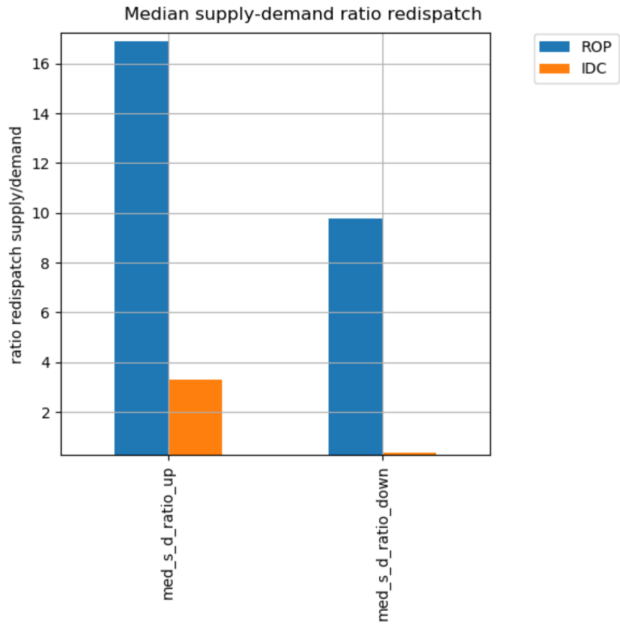


FIGURE 6.9: Redispatch supply-demand ratio

by ramping and double-score risk on ROP side, and by partial-call risk and open order book strategies on IDCONS side. Secondly, a difference may be caused by the fact that start-stop orders with respective mark-ups are only offered in specific situations, according to the IDCONS strategy. With ROP, however, start-stop orders are placed at every simulation step. Yet, a limitation of this mark-up figure is the underlying difference regarding the number of orders and order capacity. Therefore, these findings are considered as not complete enough to already drawn a conclusion for hypothesis 1c (i.e. redispatch service IDCONS decreases risk related price mark-ups for redispatch orders). This hypothesis requires more investigations by other indicators and sensitivity analyses.

Redispatch performance indicators show that ROD tends to over-procure. Figure 6.11 shows the redispatch key performance indicators. It also shows the imbalance caused by the grid operator due to incomplete redispatch. It is obvious that redispatch actions under ROP design are often higher than the actual redispatch demand (about 10 % of redispatch demand volume) due to all-or-none clearing. IDCONS, on the other hand, shows little over procurement. The over-procurement from IDCONS stems from block orders of start-stop capacity. Block orders are non-divisible in time. Therefore, it can happen that a redispatch action exceeds the congestion period. It has to be noted that also under-procurement exists, but it is too small to be visible on this figure.

Hardly any under-procurement in both simulations. Figure 6.12 shows that in a few occasions, less redispatch is procured than demanded by the grid operator. Residual demand is defined as the procured redispatch quantity in a particular direction (upward or downward) minus the actual redispatch demand in that direction. Negative values indicate under-procurement; positive values show over-procurement. The ROP simulation exhibits only very few MTUs with (little) under-procurement. IDCONS shows one high under-procurement event during the first simulated MTUs.

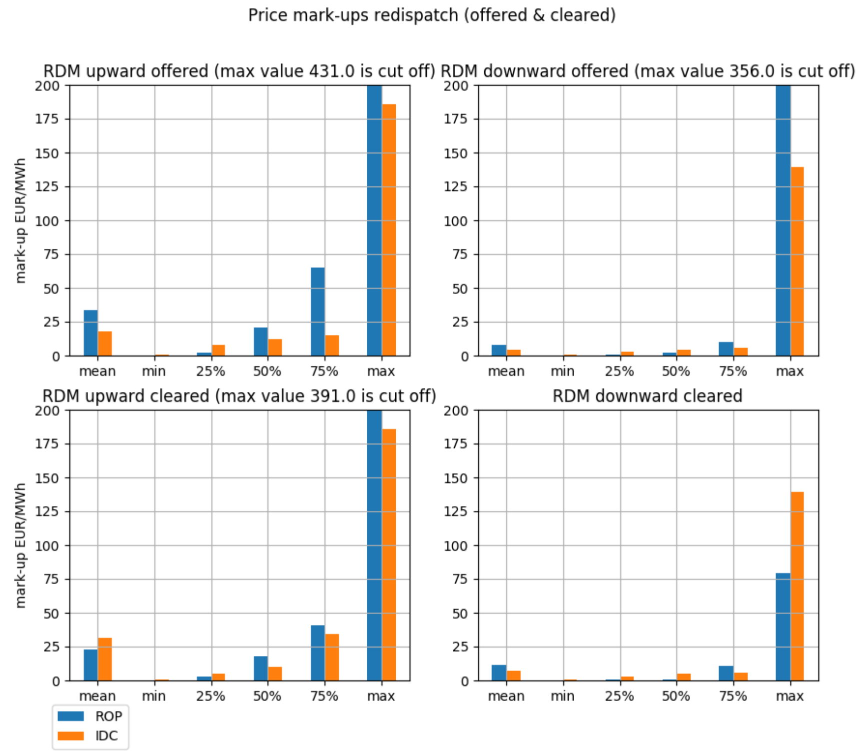


FIGURE 6.10: Redispatch price mark-ups

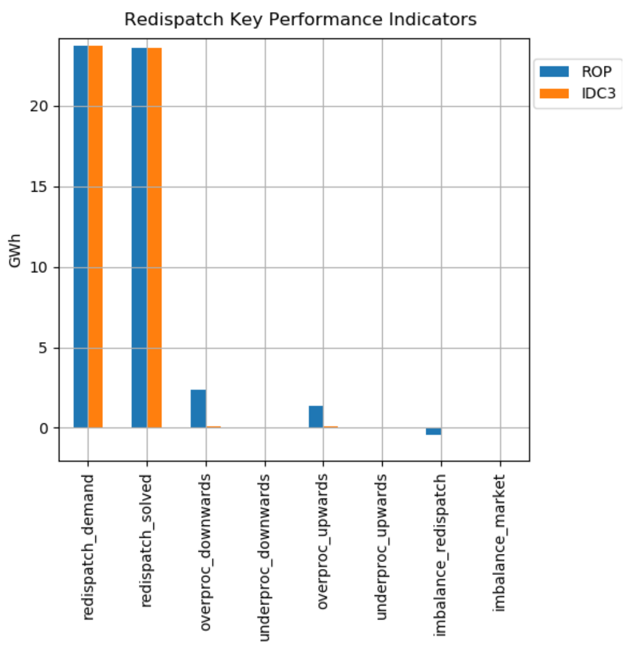


FIGURE 6.11: Redispatch performance indicators

Note that both redispatch directions are overlapping on the graph, so only one is visible.

IDCONS quantity strategy becomes critical with spontaneous redispatch. Given the agent strategy of small order sizes under IDCONS, the redispatch demand is covered in an iterative process, which requires several simulation steps. This procurement time, however, is apparently not available at the beginning of the simulation. Hence, despite the shorter gate-closure time of IDCONS (i.e. 1 MTU instead of 3 MTU) and even with the conditional start-stop strategy, it is impossible for the grid operator to cover its redispatch demand effectively. This result thus relates to the above-discussed issue with the redispatch supply obligation (section 6.4.1): It seems unlikely that market parties would only provide small order quantities if the grid operator would indicate an urgent request for offers. However, it still may happen that some market parties would want to avoid revealing their available capacity to the competitors in the open intra-day order book. These parties might rather accept 'alert-state-like' procedures, including bilateral redispatch instructions via telephone. Such considerations are not reflected in the IDC simulation.

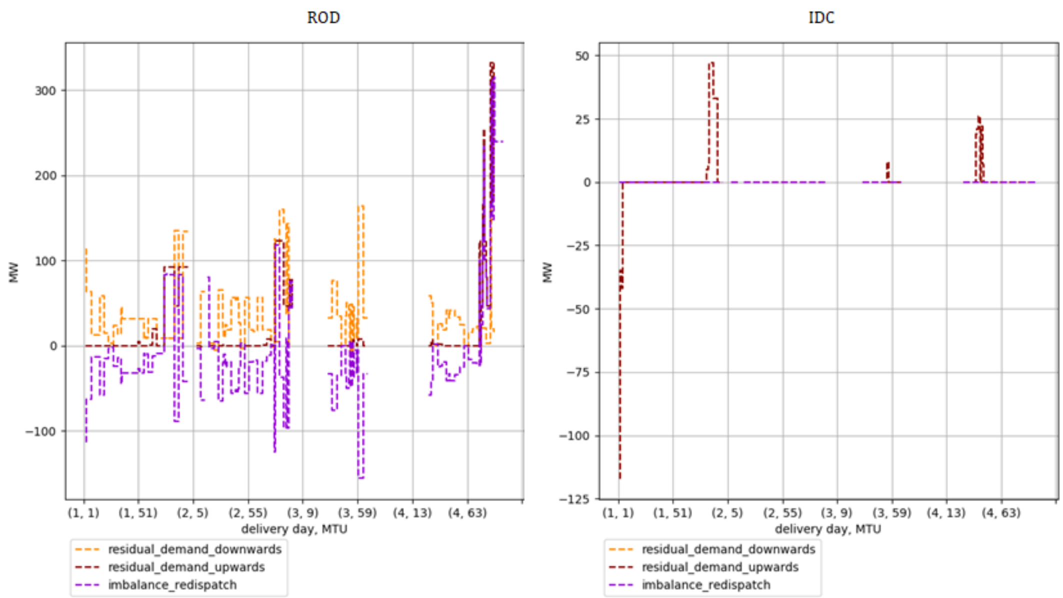
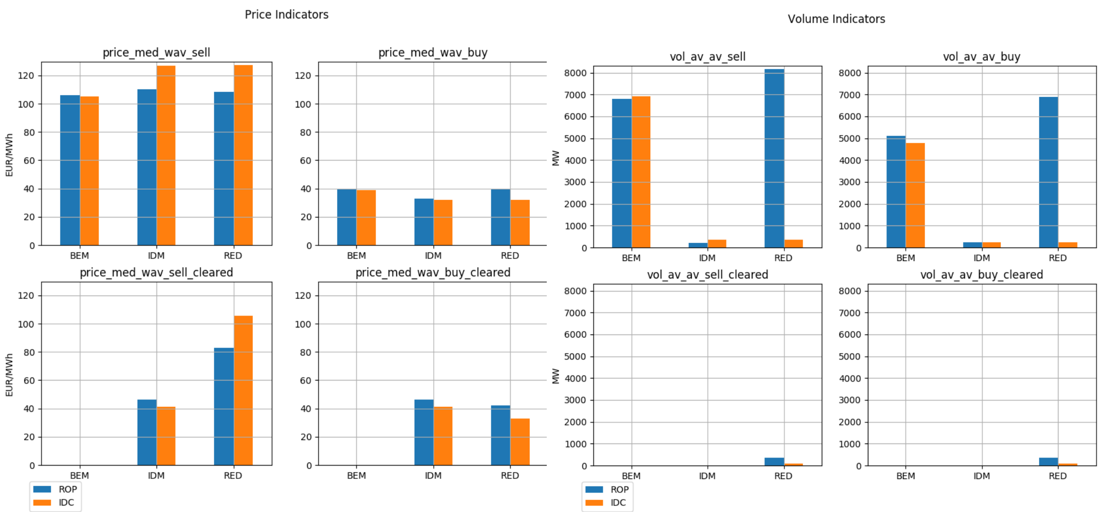


FIGURE 6.12: Residual redispatch demand and imbalances from redispatch

ROP all-or-none design causes imbalance. Figure 6.12 shows furthermore that ROP, in contrast to IDCONS, leads to imbalances caused by redispatch. This is due to the fact that the orders are non-divisible in the product design of ROP. The redispatch algorithm subsequently has fewer options compared to the IDCONS design with limit orders. For the ROP simulation the threshold of the equilibrium constraint is infinite (and 0 MWh for IDCONS). The effect of smaller thresholds for ROP will be explored in the sensitivity analyses.

Interdependency indicators show an effect on intra-day-trade. Figure 6.13 (A) presents the median (over all simulation MTUs) of weighted average order prices per delivery MTU. Figure 6.13 depicts the average (over all simulation MTUs) of the average order quantity per delivery MTU (B). Under IDCONS, the intra-day offer prices are higher (sell), respectively slightly lower (buy), while the cleared intra-day prices are lower than under ROP. This observation can be explained by the agents' quantity strategy, which in the case of IDCONS conditionally includes start-stop capacity with high mark-ups in intra-day offers. With ROP such start-stop orders are not placed on the intra-day market. The lower median clearing price may be a result of less intra-day trading volume in case of IDCONS. It can be concluded that, indeed, IDCONS leads to an increase of supply on the intra-day market while ROP tends to increase the demand.



(A) Prices (B) Quantities

FIGURE 6.13: Interdependency indicators

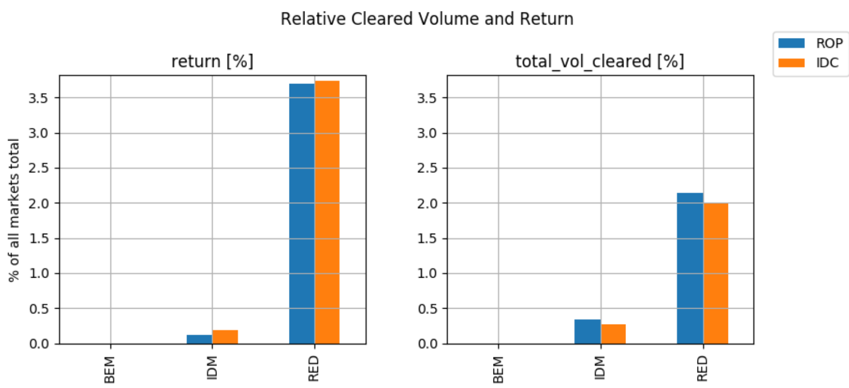


FIGURE 6.14: Relative return and relative volumes

Balancing offer quantity slightly higher for upward, and lower for downward with IDCONS. Figure 6.13 also shows the interdependency with the average offered quantity for balancing energy. While the order quantity in average for upward is slightly increasing, the downward direction shows an obvious decrease. This finding is sufficient to accept hypothesis 2b (i.e. the supply of balancing energy orders is not diminished). Moreover, the figure depicts a small reduction of the median prices for balancing energy. However, as stated above, the balancing market is highly simplified in these simulations. Therefore, it is still possible that cleared quantities and prices of balancing energy may be structurally different with IDCONS.

Relative trading volumes higher with ROP, relative return higher with IDCONS. Figure 6.14 depicts traded quantities and the return per market, relative to the respective total of all markets. The day-ahead market is not shown, as it is equivalent for both simulations and much higher than the other markets. Moreover, the imbalance quantities and returns are not shown, as they are too small to be visible. In redispatch and intra-day markets, IDCONS returns are higher, although the traded quantities are lower for both markets. This observation is an important addition to figure 6.10, which did not reveal a clear answer on hypothesis 1c (i.e. redispatch service IDCONS decreases risk related price mark-ups for redispatch orders). The relative returns and quantities indicate that the effective redispatch mark-ups under IDCONS tend to be higher when taking into account the cleared quantity. This finding speaks rather for a rejection of hypothesis 1c.

IDCONS provides more profit to the market but increases cost of electricity. In order to compare the overall efficiency of both redispatch designs, the total dispatch costs, market profits and system operation cost of the simulation are shown in figure 6.15. These indicators are presented relative to the net day-ahead load (i.e. load + export - import). It has to be noted that this is not the same as the levelised cost of electricity because investment costs are not considered. Cost of electricity is the sum of dispatch cost and market profit. System operation cost is taken into account via the market profit because the system operation cost is paid to market parties. All indicators are higher under the IDCONS design for the simulated typical-days scenario. In particular, the system operation cost differ, while the others have a small relative difference. However, it has to be kept in mind that the by far largest share of dispatch cost and market profits stem from the day-ahead market, which is equivalent for both simulations. Nonetheless, this finding provides another argument to reject hypothesis 1c (i.e. redispatch service IDCONS decreases risk related price mark-ups for redispatch orders).

Slightly higher dispatch cost explained by IDCONS quantity strategy. The higher dispatch cost of IDC may be a result of the small order quantity strategy under IDCONS. In the simulations, the grid operator does not speculate on future prices and quantities. Accordingly, the grid operator calls per step all available (suitable) orders until its demand is covered. In this way, power plants with higher SRMC may be used for redispatch, compared to a situation where all available capacity is offered in every step.

Given the analysis above, the following preliminary conclusions are drawn. These preliminary conclusions are, yet, subject to sensitivity analyses and result discussions.

- Hypothesis 1a: Redispatch service IDCONS increases supply volume (rejected).
- Hypothesis 1b: IDCONS services attract new and small market parties (accepted).
- Hypothesis 1c: Redispatch service IDCONS decreases risk related price mark-ups for redispatch orders (mark-up figures point towards acceptance, relative returns and cost figures indicate rejection).
- Hypotheses 2a: IDCONS application decreases imbalances caused by grid operators (accepted).
- Hypothesis 2b: The supply of balancing energy orders is not diminished (accepted).

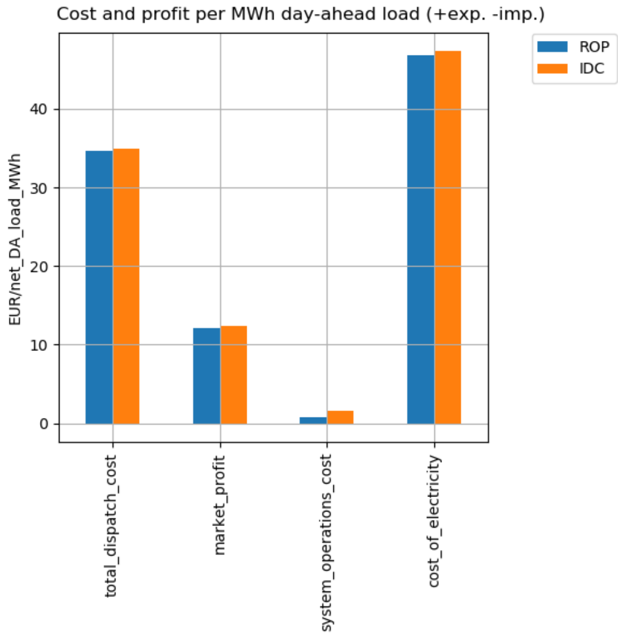


FIGURE 6.15: Cost and profits on system level

6.4.4 Analysis of sensitivities

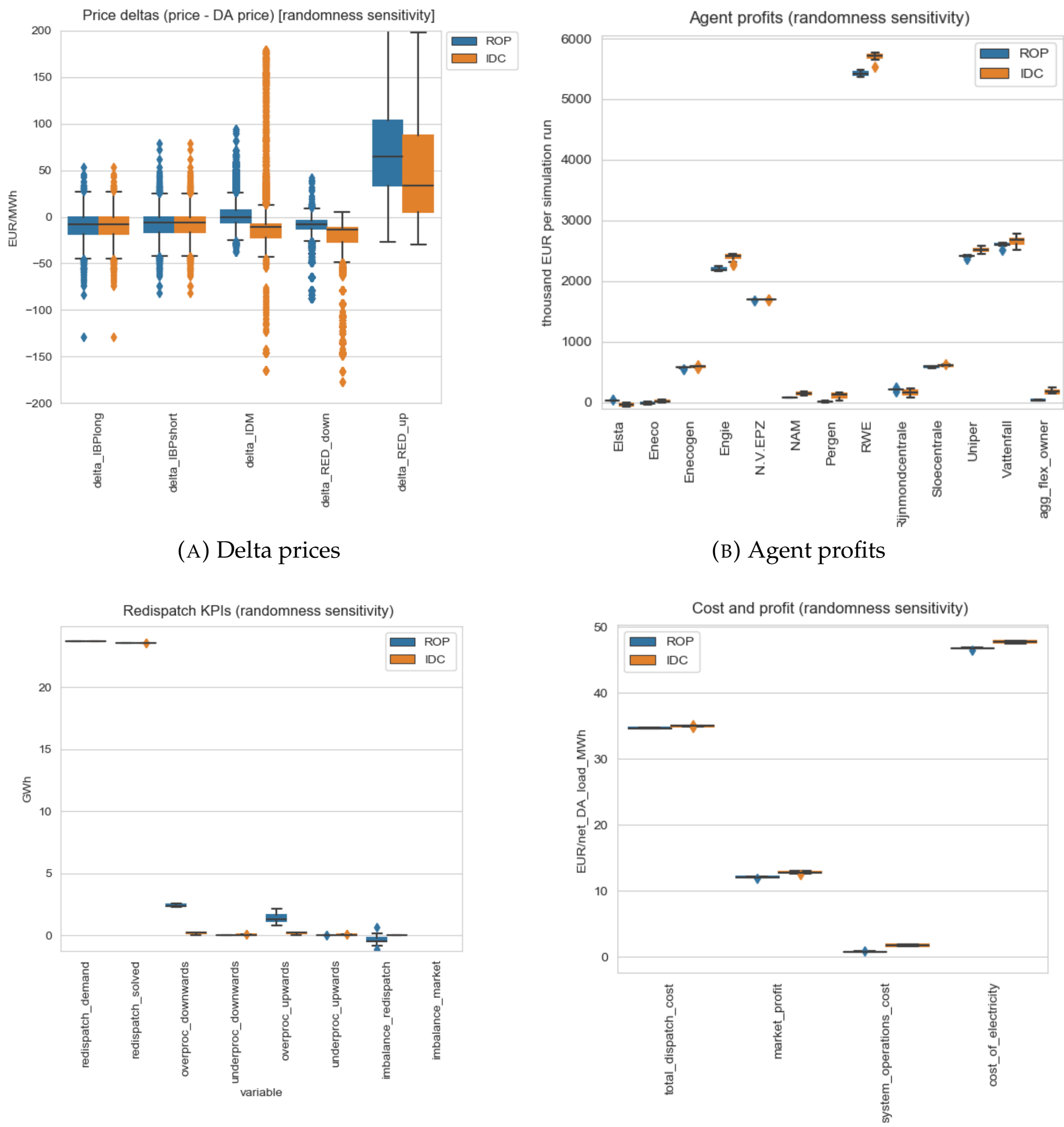
The simulation results require further scrutiny tests regarding various assumptions. Therefore, the following sensitivity analyses are conducted:

1. **Impact of randomness. For both simulations, randomness is held identical.** However, to assess the impact of the randomness, both redispatch designs are simulated with 14 different, but identical, seeds for the randomisers. The simulations differ regarding the sequential order in which agents take actions per simulation step, determination of control state for balancing energy, determination imbalance price, as well as choice regarding small offer quantity for intra-day.

2. **IDCONS quantity strategy with all operational capacity.** Hypothesis 1a (i.e. Redispatch service IDCONS increases supply volume) was rejected. However, the assumption of small quantity strategy was also identified as a reason for higher system operation cost. This sensitivity analysis is named IDCONS all-operational-capacity (IDC_aoc).

3. **ROP without small market parties.** For the simulations above, all generators participate in all markets. This is a strong simplification of reality. Therefore, the sensitivity analysis tests the impact of an alternative assumption: small market parties do not participate in ROP. The capacity of those parties is aggregated in agg_flex_owner agent. This agent is thus excluded from redispatch. This sensitivity analysis is named ROP large-agents-only (ROP_lao).

4. **High and low equilibrium constraints for ROP redispatch algorithm.** The redispatch performance indicators strongly depend on the assumption of the respective redispatch algorithms of ROP and IDCONS. ROP has an equilibrium constraint of infinite MW (i.e. no effective constraint). To analyse the impact of a different constraint for ROP, a threshold of 50 MW and a threshold



(A) Delta prices

(B) Agent profits

(C) Redispatch performance indicators

(D) Costs and profits

FIGURE 6.16: Results of randomness sensitivity analysis

of 5 MW are assessed. These sensitivity analyses are named ROP threshold 5 MW (ROP_th5) and ROP threshold 50 MW (ROP_th50).

Randomness has little impact on results. As shown in figure 6.16 the conclusions of the figures are not changing as a result of randomness effects (see for more figures appendix E). It is thus valid to use the results of the previous chapter, as the conclusions are not different because of randomness effects.

With high market imbalances, randomness impact may increase. The findings above must be reconsidered as soon as scenarios are simulated, which lead to high imbalances. In such cases, additional intra-day activity may be impacted by the agent's ranking per simulation step. Moreover, the randomness of the imbalance price calculation may materialise in different profits of agents.

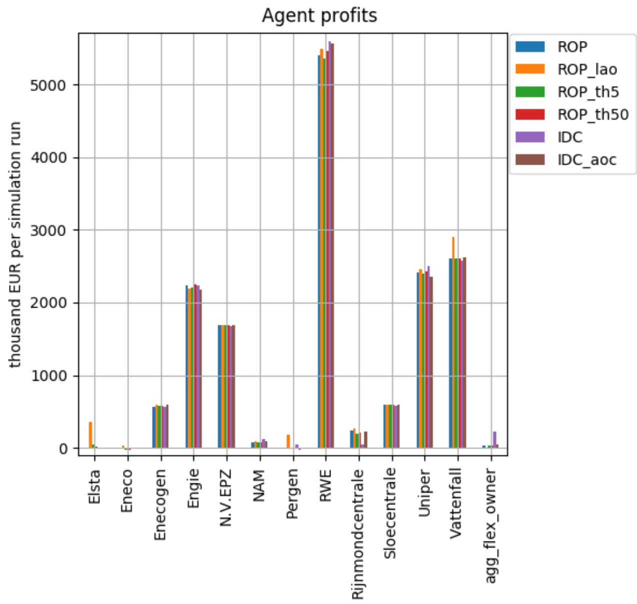


FIGURE 6.17: Agent profits [sensitivities]

IDC_aoc agents profits. Figure 6.17 shows that the profit with IDC_aoc increases for about half of the agents compared to the IDC simulation, while the profit of the other half decreases. For most agents, however, the ordinal profit with IDC_aoc compared to ROP is the same as the ordinal comparison of IDC and ROP. Only for Pergen and Uniper the profit decreases visibly to the extent that also the ordinal result changes. Moreover, agg_flex_owner shows significantly lower profits compared to the IDC simulation.

ROP_lao agents profits. A substantial majority of market parties has higher profits with ROP_lao compared to ROP. Only Engie and agg_flex_owner have fewer profits. This result is intuitive because small flexible assets are excluded from redispatch markets.

ROP_th agents profits. Profits of agents in both ROP_th simulations are quite similar to the profits under ROP. As a small tendency it is visible that profits with ROP_th50 are higher than with ROP_th5, in case both profits are not the same. An exception is the profit of Elsta where the opposite is the case.

IDC_aoc redispatch supply-demand ratio. Apparently, the IDC_aoc redispatch supply-demand ratio in upward direction is higher compared to IDC results (see figure 6.18). Also in downward direction, a much higher ratio can be observed. The sensitivity analysis confirms that the major ratio difference of the IDC-ROP comparison stems from the agents' strategy to only offer small batches of the operationally available capacity.

ROP_lao redispatch supply-demand ratio. Figure 6.18 shows that ROP_lao has a much lower median supply-demand ratio than ROP in upward direction. The reduction in upward direction can be explained by the missing orders of the excluded agg_flex_owner compared to ROP. It is also intuitive that the ratio in downward direction is not decreasing compared to ROP, because the operating capacity available

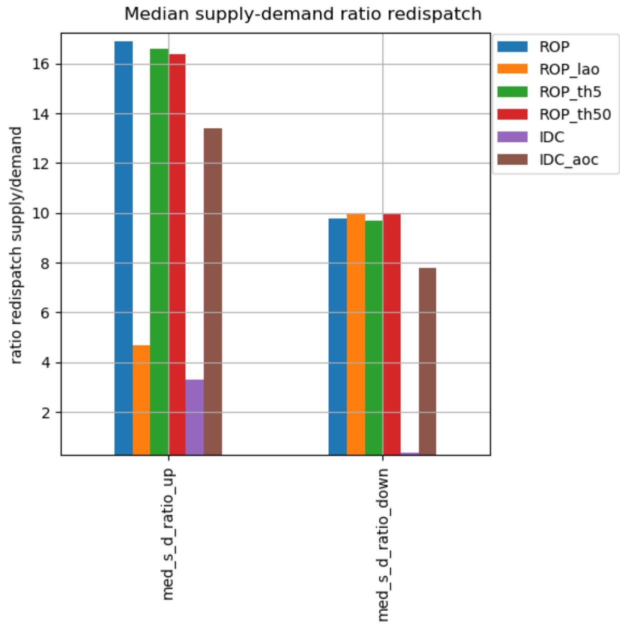


FIGURE 6.18: Redispatch supply-demand ratio [sensitivities]

to reduce production[9] does not decrease by excluding agg_flex_owner from redispatch. There is no obvious explanation found for the minor increase of the downward ratio compared to ROP.

ROP_th redispatch supply-demand ratio. It is somewhat intuitive that the ROP_th supply-demand ratio in upward direction is a little lower than with ROP, as the threshold may disqualify some orders for the solution. However, there is no obvious interpretation found for the small increase on downward side.

IDC_aoc redispatch price mark-ups. Figure 6.19 reveals a strong decrease of redispatch mark-ups for both offer and cleared orders in upward directions. Mean, quantiles, and maximum mark-ups are also lower than in the ROP simulations. This may be an effect of more offered quantity because subsequently less offers with starts-stop mark-ups are cleared. In downward direction, the mark-ups are slightly higher than with IDC.

ROP_lao redispatch price mark-ups. Mark-ups of upward redispatch with ROP_lao are much higher than observed in all other simulations both for offered and for cleared orders. In downward direction they are only insignificantly higher than ROP. This may be due to the need to start-up power plants instead of using highly flexible assets of agg_flex_owner.

ROP_th redispatch price mark-ups. Redispatch mark-ups in most cases the same as mark-ups of the ROP simulation. Only a few differences are visible in cleared mark-ups. However, no conclusion can be drawn from this mixed picture.

IDC_aoc redispatch KPIs. None surprisingly, over- and under-procurement of IDC_aoc are lower than with IDC, due to the additionally available orders.

[9]Increase consumption is also possible for downward redispatch, but this is not explicitly simulated.

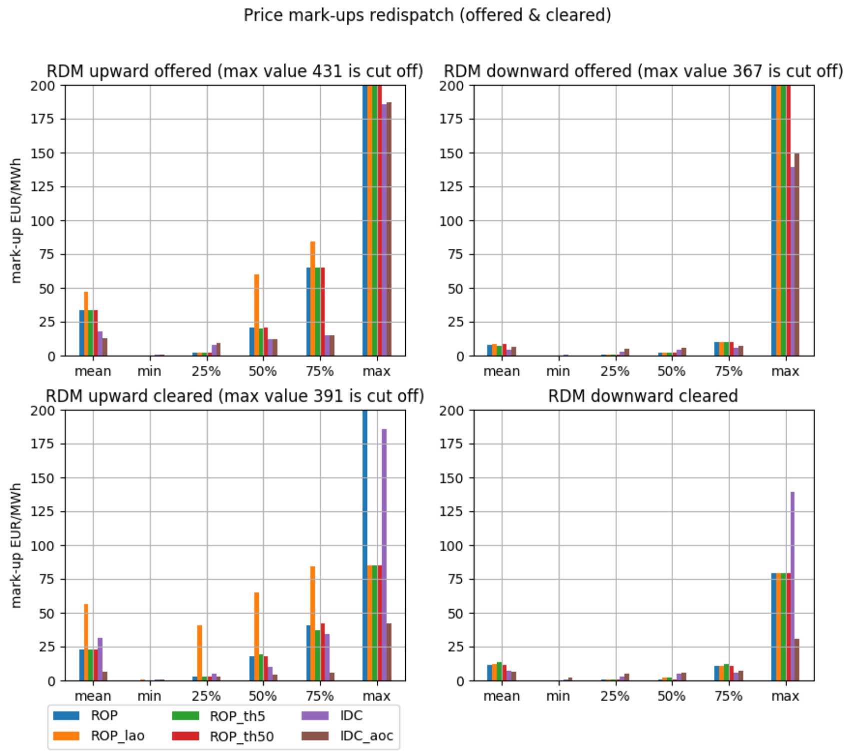


FIGURE 6.19: Redispatch price mark-ups [sensitivities]

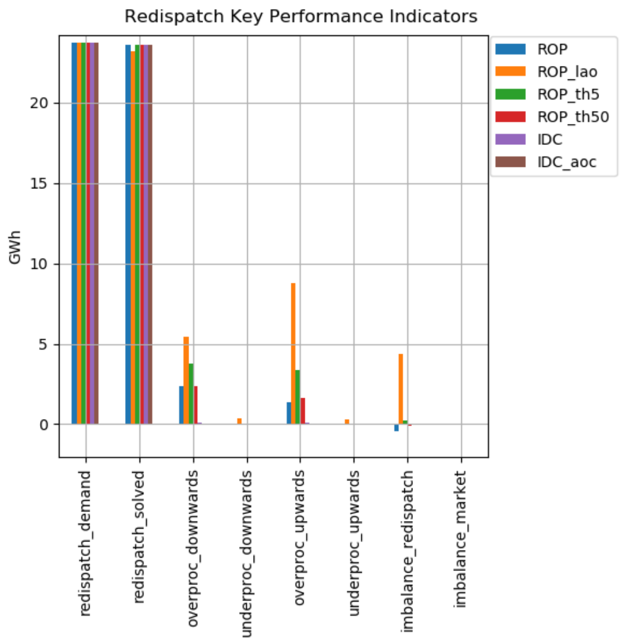
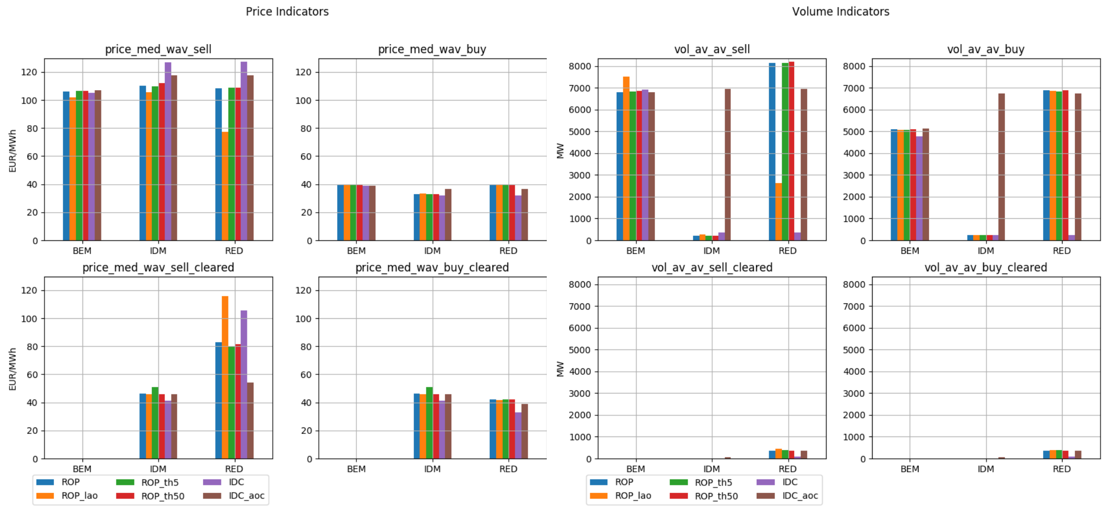


FIGURE 6.20: Redispatch performance indicators [sensitivities]

ROP_lao redispatch KPIs. Figure 6.20 shows very poor redispatch performance results for ROP_lao because over-procurement, as well as imbalance from redispatch, are very high. The simulation shows also highest under-procurement. The imbalance from redispatch amounts to about 20 % of the redispatch demand.

ROP_th redispatch KPIs. ROP_th5 shows considerably higher over-procurement than ROP_th50 and thus also more than ROP. This is due to the constraint to find a redispatch solution which respects a smaller redispatch equilibrium threshold. Therefore, it is also not surprising that the ROP_th5 imbalance from redispatch is smaller than in the other ROP simulations. Both simulations exhibit hardly any under-procurement.



(A) Prices (B) Quantities

FIGURE 6.21: Interdependency indicators [sensitivities]

IDC_aoc interdependency indicators. The median of average cleared prices on figure 6.21 (A) shows that the intra-day figure is increasing compared to IDC. Moreover, the average quantities (offered and cleared) on intra-day are increasing with IDC_aoc compared to IDC (B). Figure 6.22 shows that the relative market quantity of intra-day is increasing, whilst relative intra-day return is decreasing. This may be explained by imbalances during large ramps, as the redispatch order quantities can be larger than the remaining ramp.

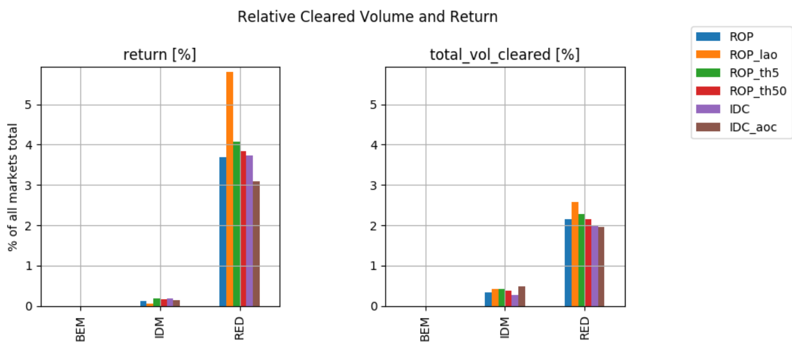


FIGURE 6.22: Relative return and volumes [sensitivities]

ROP_lao interdependency indicators. In contrast to the obvious differences of the previous indicators, ROP_lao shows a quite similar image as ROP regarding interdependency indicators. Mark-ups of intra-day trades are a little lower, while the cleared quantity is a little higher (figure 6.21). That figure also shows a positive effect of the average of offered balancing energy quantities, which may be due to the more operating large power plants for redispatch.

ROP_th interdependency indicators. Figure 6.21 and 6.22 show that the equilibrium threshold barely has an impact on the intra-day market and balancing energy market. However, the small threshold shows an increase of intra-day trading volumes and intra-day price mark-ups.

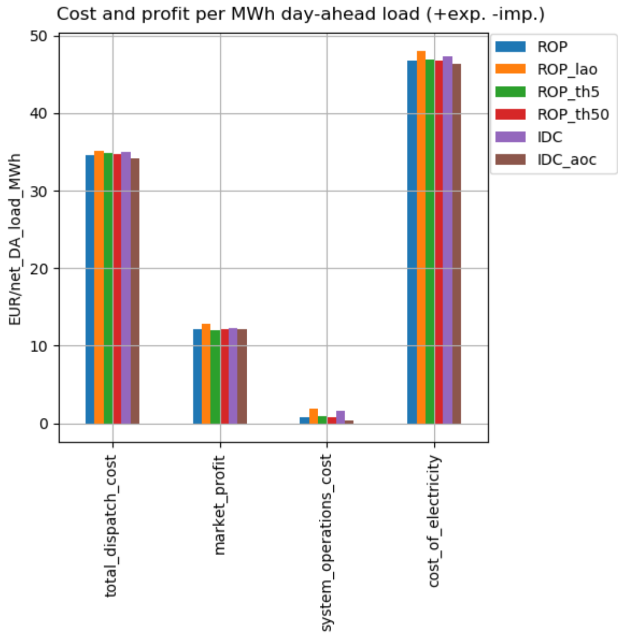


FIGURE 6.23: Costs and profits on system level [sensitivities]

IDC_aoc system-level costs and profits. Dispatch cost with IDC_aoc is lower than in both IDC and ROP simulations (see figure 6.23). System operation cost with IDC_aoc also is lower than in the other two simulations. Market profit lies between ROP and IDC levels, although the difference is very small. The cost of electricity is subsequently lower for IDC_aoc. In fact, they are the lowest of all sensitivity analyses. This result is a consequence of more available capacity on redispatch market and on intra-day market, while the redispatch algorithm has more freedom than with ROP because orders can be called partially.

ROP_lao system-level costs and profits. All four indicators on figure 6.23 regarding costs and profits have the highest value with the ROP_lao simulation. The system operation cost of ROP_lao are about twice the cost of the other ROP simulations. This is clearly a result of the absence of small flexibility providers on the redispatch market.

ROP_th system-level costs and profits. Dispatch cost, market profit, system operation cost, as well as of ROP_th50 are slightly higher than in the ROP simulation (see figure 6.23). The costs of ROP_th5 are again a little higher than ROP_th50. This consistent negative correlation of costs with the redispatch equilibrium threshold is intuitive but very small. However, it has to be noted that most dispatch cost and market profits depicted in the figure driven by the day-ahead market.

Significance of findings from sensitivity analyses for conclusions. In the following, the observations from the sensitivity analyses are placed into the context of the conclusions regarding the ROP-IDCONS comparison with the respective hypotheses. It is discussed to what extent the preliminary conclusions need to be adjusted.

Less attraction of new redispatch providers with IDC_aoc. The attraction of new participants decreases when incumbent market parties offer all their operationally available capacity as IDCONS. Such strategies lead to significantly smaller profits for agg_flex_owner. However, also for incumbent participants the profits slightly decrease in comparison to IDC. Given the qualitative analysis, the conclusion on hypothesis 1b still prevails (i.e. accepted), as there are also other attracting factors than the observed profits in IDC compared to ROP.

IDC_aoc redispatch offers have smaller mark-ups than other simulations. When only looking at IDC_aoc simulation results, hypothesis 1c would be accepted, because mark-ups on the redispatch market are obviously lower with IDCONS. This reveals that the assumption regarding offered capacity is pivotal for the valuation of the IDCONS design. Hence, the quantity strategy should be taken into account critically when concluding on hypothesis 1c.

Supply-demand ratio with ROP_lao still better than IDC. The supply-demand ratio indicator shows that, when small redispatch providers are excluded from ROP, the better supply performance of ROP compared to IDCONS becomes smaller. IDC_aoc has even a higher median supply-demand ratio than ROP_lao in upward direction. However, IDC_aoc can be considered very optimistic regarding participation of small flexible assets while ROP_lao is very pessimistic, as assets > 1MW could theoretically participate. Yet, the preliminary conclusion on hypothesis 1a (i.e. rejected) requires a remark: Higher volumes with ROP due to different quantity strategies are partly counterbalanced by expected higher participation of small flexible assets under IDCONS. The latter determinant is expected to be weaker, given the remaining entry barriers identified for IDCONS.

High mark-ups with ROP_lao show again the significance of supply quantity assumption. A further insight for answering hypothesis 1c is obtained from the significant increase of redispatch mark-ups of ROP_lao: When no small redispatch providers participate in ROP, the mark-ups strongly increase because of high start-stop costs.

Threshold impact on system is limited when market is liquid. The threshold sensitivity analyses show that the conclusion on hypothesis 2a (i.e. accepted) prevails, because imbalances from redispatch are still higher than with IDC. However, a very small threshold (5 MW) leads to large over-procurement but does apparently not per definition lead to high cost increases or increasing under-procurement. A precondition for this finding is that the redispatch market is very liquid. The absence of this precondition, however, is not covered by the threshold simulations, and therefore should be discussed critically.

6.5 Summary and discussion of use-case results

Figure 6.24 presents a summary of the use-case for the ancillary service evaluation framework. All steps of the proposed evaluation process (section 4.6) have been executed.

Design variables used to develop tests. The following seven relevant design variables are identified, based on design differences of ROP and IDCONS as well as assessment goals:

- Product subject
- Product period
- Product utilisation
- Provider accreditation
- Acquisition Timing
- Bid requirements
- Market information

Since the use-case is a comparative study regarding two redispatch designs, the design variables are not used to develop a design space. Still, the relevant design variables are considered in the development of the design tests, i.e. a qualitative analysis and a computational model.

Scenarios correspond to policy-readiness-level 4. The scenarios of the study are built with a (medoid) cluster method using data from the Dutch power system. The time-series data on north-south congestions in the Netherlands is estimated based on published redispatch data and published market restrictions. The chosen four representative days are complemented with data on power plants and ownerships. In a calibration step, the lacking data regarding small flexible assets is approximated based on a duration curve of the day-ahead price. These assumptions and estimations match policy-readiness-level 4 (i.e. small-scale model with several salient real-world aspects) as defied by Tesfatsion (2018).

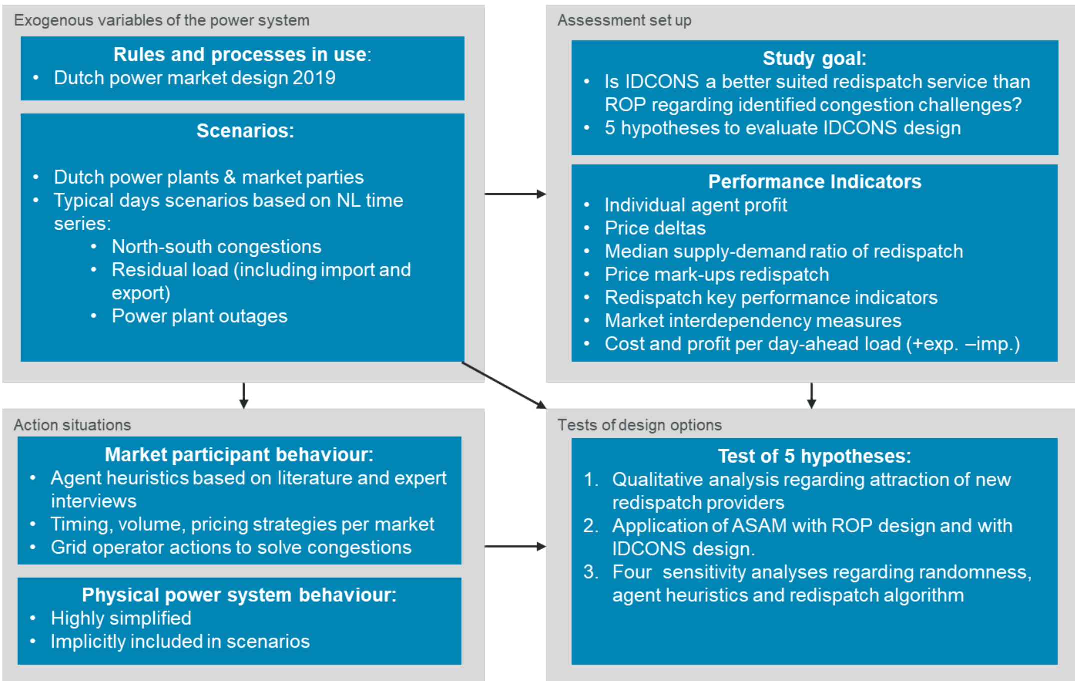


FIGURE 6.24: Summary of use-case approach

Various interactions are considered in the analysis. The application of the dependency estimate of the framework provided a focus on the following ancillary services and markets: redispatch market, intra-day market, balancing energy and imbalance market. Interdependency performance indicators are used to evaluate the design impact on volumes and prices of the markets next to the redispatch markets, as well as the impact on the costs and profits at system-level. The results are used to answer hypothesis 2.

Price efficiency evaluated with price mark-up approach. Hypothesis 1c of the use-case is about price efficiency. The price mark-up approach is applied to compare the design driven risks for providers of IDCONS and ROP.

Qualitative analysis evaluates design attractiveness to new providers. The qualitative analysis regarding attractiveness for new redispatch providers identified owners of small distributed generation, demand-side facilities, and RES as targeted parties, as they are currently not participating in ROP. Furthermore, various barriers and facilitating factors are evaluated:

- Bid requirements: Minimum order size ROP identified as barrier.
- IT related transaction costs: No structural difference in IT cost identified.
- Operational transaction costs: Transaction costs lower in case of DSO redispatch with IDCONS. Moreover, decision-challenge of scattered redispatch actions better supported by IDCONS.
- Perceived difficulty: Ease-of-use is a slightly attracting factor of IDCONS compared to ROP.
- Business case determination: Open order book of IDCONS design provides additional transparency.
- Contractual barriers: IDCONS might help to overcome trading pool barriers.

Higher attractiveness of IDCONS. The qualitative analysis concludes that IDCONS seems more attractive for small market parties than ROP. Yet, also with IDCONS entry barriers for new redispatch providers endure. Financial prospects, marketing by grid operators, and possibly regulatory obligations are needed to unlock additional redispatch providers in order to foster sufficient local liquidity.

The findings of the ASAM simulation, as well as their relation to performance indicators and relevance for the hypotheses, are summarised in figure 6.25.

Discussion item 1: Liquidity is highly determining the simulation results. Liquidity is a discussion topic, as exclusion mechanisms for small redispatch providers as well as agent strategies on order sizes have a strong impact on the result. It significantly influences supply-demand ratio and subsequently also key performance indicators of redispatch. Furthermore, the simulations show that redispatch mark-ups increase when liquidity decreases, as a consequence of orders from start-stop assets.

All-or-none orders less suited for illiquid situations. In illiquid markets, all-or-none order types may lead to high imbalances caused by redispatch. Alternatively, higher under-procurement and higher system operation costs may occur, in case the redispatch algorithm has a low threshold regarding the equilibrium constraint.

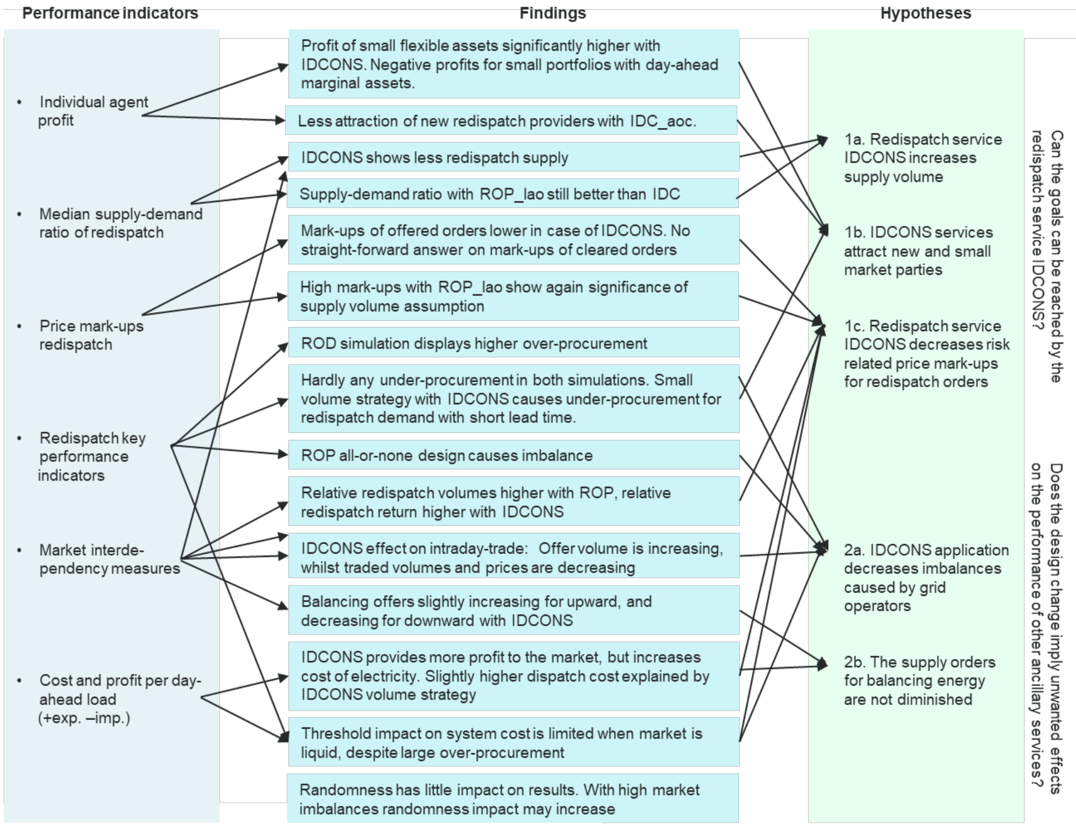


FIGURE 6.25: Overview use-case findings

Illiquid redispatch markets may be the norm. The qualitative analysis regarding the attraction of new redispatch providers shows that identified barriers, such as conflict of interest with incumbent suppliers and scattered redispatch demand, make a highly liquid redispatch market rather unlikely.

Simulations overestimate liquidity. The simulated scenarios are limited with regards to the impact of illiquid market situations. Only the ROP_lao gives some insights, as it shows the impact of excluding 5875 MW of flexible assets.

Obligatory participation may dampen effects. Nonetheless, it has to be noted that the Dutch grid code entails requirements, which can enforce obligated participation in redispatch markets for assets in structurally congested areas. This redispatch design feature may counter-act the illiquidity effects.

Discussion item 2: Physical system highly simplified. Inter-temporal characteristics of generators are modelled and the scenarios implicitly consider combined variations of load, RES and cross-border exchanges, by using respective time-series of the Dutch power system. Anyway, there are other physical aspects which are not taken into account in the simulation. These are in particular power system parameters, such as loading, voltage and frequency.

Feedback of ancillary service acquisition on physical system not considered. Physical aspects are only considered as input data. Accordingly, the ancillary service acquisition process searches a solution for an exogenously defined ancillary service demand, i.e. redispatch. The provided solution of the transactional simulation is not fed back into a physical power system model. Consequently, it is neither checked whether the proposed solution leads to other physical issues (i.e. not security constraint), nor is it possible for agents to take actions which influence the ancillary service demand.

Physical system simulation unlikely to change results. An accurate simulation of the physical system for the present use-case would change the redispatch quantities and the order selection, as it would consider order sensitivities regarding the congestions as well as constraints of other grid elements. It can be assumed that redispatch quantities would decrease because the scenarios are built on public redispatch quantities and not on congestion data. These redispatch quantities stem from an ROP design, which tends to over-procure as a consequence of all-or-none orders (see simulation results). Less redispatch acquisition may influence hypothesis 1c (i.e. mark-ups) and the agents' profits. However, the above-stated overestimation of supply liquidity somewhat compensates the overestimation of redispatch demand. Therefore, it is expected that the impact of an additional physical simulation on the study result would be limited.

Discussion item 3: Balancing markets highly simplified. Besides the simplification of the physical balancing system, also the balancing market is highly simplified. This has two different potential effects on the imbalance price: demand-driven effect and a supply-driven effect with regards to balancing energy.

Effect of changed balancing energy demand. The simulated imbalance price is not influenced by the actual imbalance of market parties, as outlined in section 6.2. Consequently, the described linkages between imbalances, dimensioning of balancing capacity, day-ahead price, balancing energy prices and imbalance prices are not properly represented in the model. However, this chain of causation only materialises with large and frequent differences in market imbalances regarding simulated design options. Nonetheless, even without a structural change of imbalance with an effect on dimensioning balancing capacity, a redispatch design may significantly change the demand for balancing energy during redispatch events. Such change is driven by emerging market imbalances and (grid operator) imbalances caused by incomplete redispatch. The simulations barely show a design impact on market imbalances. However, the scenarios represent very liquid situations. Yet, in some simulations considerable imbalance by redispatch is observed. The balancing market simplification, however, prevents a quantification of this demand effect.

Effect of changed balancing energy supply. Imbalance price differences can also occur without additional imbalance and subsequent activation of balancing energy. In case simulated designs for redispatch lead to very different supply curves (also called bid ladder) for balancing energy, imbalance prices would change as well because the balancing energy price is a determinant of the imbalance price. The small differences observed for the median of offered balancing energy prices and for the average of offered quantities suggest that the design impact on the supply side is limited. However, a robust statement on this aspect would require a comparison of cleared balancing energy prices, which is not possible with the simplified approach.

Discussion item 4: RES and demand-response contribution not explicitly modelled. RES and load are implicitly considered by the model via the residual load input for the day-ahead simulation. Moreover, the assumption of the aggregated flexibility owner does not include specific RES and demand response characteristics; although it is assumed that this asset portfolio also contains RES and demand-responds types, which is valid given the SRMC range. Therefore, the simulations do not deliver specific insights about the participation of RES and demand response. However, RES and demand response facilities are addressed in the qualitative analyses regarding attractiveness to new redispatch providers.

Discussion item 5: Cross-border aspects barely considered. The rules in use (see section 6.1.3) focus on the current Dutch regulation and Dutch set-up of entities in the power system. Cross-border redispatch, cross-border balancing, and cross-border intra-day trading are not considered in the use-case. Only the day-ahead residual load entails an assumption regarding day-ahead market-coupling by including Dutch import-export net positions.

Cross-border supply and demand of redispatch relevant for liquidity discussion. The study does not exhibit effects of cross-border supply (i.e. from market parties in other bidding zones) and demand of redispatch (i.e. for grid operators in other bidding zones). Such considerations may be relevant for the liquidity discussion above. However, the implications of different bidding zones and the available cross-border capacities are not considered relevant for the study goals. This also applies to consequences of non-harmonized regulation in a set of spatial jurisdictions: Potential arbitrage for market parties, potential coordination issues of grid operators, as well as distributional effects of welfare among tariff payers.

Discussion item 6: Results valid for DSO grids, with one remark. The input data for redispatch is based on TSO congestions and not based on DSO congestions in radial networks on medium and low voltage level. However, market parties from all voltage levels are considered in the simulation. Moreover, the effects of coordinated DSO-TSO redispatch are explicitly addressed in the qualitative analysis. Therefore, results of the use-case considered valid for redispatch by both DSOs and TSOs. However, it has to be noted that the redispatch supply-demand ratio indicator does not properly evaluate offers from small assets in DSO grids, as they can be pivotal for DSO congestion solutions. The IDCONS supply-demand ratio result may hence be underestimated for scenarios with much DSO redispatch.

Discussion item 7: ROP and IDCONS design updated soon. The use-case is a comparative assessment of two as-is redispatch services in the Netherlands. Yet, as stated above, both designs may change at the turn of 2020 and beyond. These expected changes are driven by the recent EU legislation (European Union, 2019b), changes in the Dutch grid code, and first experiences with IDCONS during the pilot phase in 2019. The conclusions of this use-case only apply to the rules in use in 2019.

Scope justifies short-term scenarios. The scenarios of the use-case are based on recent historical data (2016 -2018) and TYNDP data of a 2020 scenario. The redispatch designs are thus not tested on robustness regarding high RES scenarios. Given the as-is comparison and the expected changes of redispatch rules, a long-term scenario would add little value to the study goals. However, it has to be noted that the use-case simulations assume a day-ahead price formation (i.e. SRMC bidding) and day-ahead price correlations with subsequent markets that may be different in power systems with considerably higher RES penetration.

Discussion item 8: gaming out of scope. The agent strategies are limited to choices regarding timing, quantity and prices on various markets. The portfolio dispatch aims to minimise the agents' costs. The agents' heuristics correspond to risks and opportunities in the respective market designs. However, the agents do not apply strategies in ancillary service markets which use market power to increase price mark-ups, to decrease ancillary service supply (i.e. withholding capacity with the aim to increase clearing prices), or to increase ancillary service demand (i.e. behave in a way that increases the required ancillary service quantities). For intra-day trading, the agents still behave strategically to increase prices: agents use information of the open order book to increase price mark-ups beyond entirely risk-based mark-up levels.

Minor differences in gaming potential exist. Both redispatch designs allow for a number of gaming strategies. Hirth and Schlecht (2019) showed the theoretical possibilities of an increase-decrease game between the day-ahead market and the redispatch market. Consentec (2019) showed how such a strategy could determine redispatch costs and quantities in Germany. Although both publications do not explore empirical evidence of this game in European redispatch markets, ROP as well as IDCONS are in general equivalently prone to such a game. Yet, this increase-decrease game incorporates risks for market parties to forecast congestions and local marginal prices insufficiently. Alternatively, market parties could increase income with less forecast related risks and efforts by sending manipulated dispatch schedules to the grid operators. These generation and load schedules represent – in contrast to 'factual' trade schedules – the latest 'expected' dispatch of market parties, which may at any time and any reason change. Hence, it is easy to provide dispatch schedules that potentially increase congestions, while it is difficult to prove that these schedules are not representing the minimum cost dispatch of the agent or the best RES and load forecast. Again, this 'schedule game' is equivalently applicable to ROP and IDCONS. A third option of strategic behaviour is to iteratively increase price mark-ups of redispatch orders, based on past experiences. Regarding this option a difference exist between ROP and IDCONS: ROP has a closed order book and no clearing prices are published, while IDCONS uses an open order book. The open order book does not exhibit which orders are usable for redispatch and which orders are only usable for intra-day trade. However, cleared orders for IDCONS are indicated as such, although this publication does not include locational information. Nonetheless, this information can lead in a competitive situation to more competitive prices; while it can also lead to collusion games (see Ocker, 2018). Anyhow, collusion may also exist with closed order books based on estimated prices of competitors. A fourth option of strategic behaviour aims to increase profits by provoking higher redispatch by sending large all-or-none block orders. As such orders are indivisible in capacity and in time, pivotal market parties can force the grid operator to acquire more capacity than needed or for a longer period than needed. This 'all-or-none game' is only possible with ROP since IDCONS has no all-or-none orders. This comparison shows that the gaming potential of ROP and of IDCONS can be considered as quite similar.

Method contributes benchmark to gaming discussions. For studies focussing on gaming, it may be necessary to define a 'gaming-free' reference case, which goes beyond simply assuming SRMC. Moreover, the risk-based agent strategies can explore major differences in performance indicators driven by ancillary service designs, which supplement an entirely gaming-based evaluation.

6.5.1 Conclusion and recommendation

The use-case examines whether IDCONS has a more suitable redispatch acquisition design than the current ROP acquisition design, to mitigate identified operational security risks in TSO and DSO networks at efficient costs. A change from the current redispatch design should thus contribute to the following goals:

1. Increase supply volume for redispatch
2. Attract new and small redispatch service providers to enhance competition
3. Decrease risk related price mark-ups for redispatch orders
4. Decrease imbalances caused by redispatch

From these goals five hypotheses are derived and tested. The following conclusions are drawn given the qualitative analysis, the simulation results with respective sensitivity assessments, and under consideration of the discussion above.

Hypothesis 1a: Redispatch service IDCONS increases supply volume– rejected. IDCONS shows less redispatch supply. This is a result of the agents' strategies regarding open order books: They place small orders to hide their portfolio position from competitors. This strategy is discussed in the sensitivity analyses. However, even if market parties may choose to place larger orders for IDCONS, it is unlikely that market parties would pro-actively provide start-stop orders to open order books. Moreover, despite increasing attractiveness to new redispatch providers, it is argued that remaining barriers will prevent a significant quantity increase. Nonetheless, this statement needs to be relativised for DSO congestions, as few additional redispatch providers with small assets at relevant locations in the distribution grid may significantly increase the supply-demand ratio.

Hypothesis 1b: IDCONS services attract new and small market parties – accepted. The qualitative analyses showed that entry barriers for small redispatch providers decrease with IDCONS compared to ROP. Moreover, small flexible assets profit significantly more with IDCONS. However, this profit decreases when many market parties choose larger offer sizes.

Hypothesis 1c: Redispatch service IDCONS decreases risk related price mark-ups for redispatch orders – rejected. The mark-ups of offered redispatch orders are lower with IDC than with ROP. The difference becomes even more obvious with the sensitivity analysis IDC_aoc. This finding is a result of the agents' quantity strategy under IDCONS, i.e. they offer start-stop capacity with high mark-ups only under the condition that the grid operator has already bought redispatch services for the delivery period (i.e. reactive behaviour/iterative offer strategy). The mark-ups of cleared redispatch orders do not reveal a distinct answer. Together with the indicators on market profit and system operation cost, it appears that mark-ups of the IDC simulation lead to higher cost of electricity. However, sensitivity analyses show that this finding is very sensitive to the assumed liquidity of the scenario: ROP_lao exhibits higher costs than IDC, while IDC_aoc shows lower cost of electricity than ROP. Therefore, it cannot be concluded that both offered and cleared mark-ups effectively decrease.

Hypotheses 2a: IDCONS application decreases imbalances caused by grid operators - accepted. The ROP design with all-or-none orders causes imbalance. The threshold sensitivity analyses display that the imbalances can be reduced with respective equilibrium constraints. However, it is suggested that in illiquid markets this would lead to higher costs and potentially to higher under-procurement.

Hypothesis 2b: The supply of balancing energy orders is not diminished - accepted. Balancing offers slightly increase for upward, and decrease for downward with IDCONS compared to ROP. Therefore, the supply is not diminished. However, since the balancing market is highly simplified, the study cannot judge whether the balancing energy supply is likely to change substantially with IDCONS compared to ROP.

Recommendations for further research regarding this use-case. Additional insights and increased robustness of results are expected from the following recommendations for further research:

1. **Additional scenarios to further explore redispatch design in illiquid scenarios**. These scenarios may include high redispatch demand, low redispatch supply as well as simultaneous flexibility demand on other markets.
2. **Advanced simulation of balancing energy market.** In order to better quantify the design impact on the imbalance and balancing energy market, it is recommended to improve the balancing market model by a clearing algorithm which considers (also) endogenous imbalances.
3. **Self-learning agents to examine robustness of strategies per market.** The heuristics of agents chosen per market design are based on expert knowledge and qualitative argumentations. However, the use-case results can be checked on robustness if market parties receive the possibility to choose given strategies autonomously or if they can even develop own strategies.
4. **Open the design space based on present use-case results.** The use-case is a strict comparative study of two redispatch designs. However, the results reveal determinants for the risks and costs of market parties as well as grid operators. These insights may be used to develop additional design options regarding variables such as market information (e.g. fixed lead time between redispatch demand announcement and acquisition), acquisition timing (e.g. dedicated redispatch moments to reduce scattered acquisition), and bid requirements (e.g. maximum order sizes to reduce over-procurement with all-or-none orders).

Chapter 7

Critical discussion of results

This section discusses the findings from the use-case regarding the value and the limits of both the design evaluation framework and the acquisition model.

Proposed scalability-checks are executable. Section 4.8 discusses possibilities to scale the evaluation process to the study needs. Scalability is relevant to ensure practicability of the framework. The scalability-checks of various evaluation steps are applied in sections 6.1 to 6.4.1. The use-case shows that the framework is indeed scalable:

- Number of relevant design variables can vary.
- Dependency estimate determines focus on specific markets and international character of the study.
- Tests can be limited to either acquisition process or utilisation of ancillary services.
- Proposed design variables for qualitative analyses are useful to explicitly choose a test approach with a conceptual model or with a numerical model.
- Statement on expected policy-readiness-level of simulations helps to determine required modelling details.

Generic design variable and performance criteria are suitable for use-case. The study shows that the proposed design variables of the framework are generic enough to cover the use-case design question and it shows that they are suitable to identify the relevant differences between the two ancillary services. Moreover, the generic performance criteria are linkable with the design goals of the use-case.

Most generic performance indicators are useful. The majority of proposed performance criteria are analysed in the use-case. The non-delivery indicator and the market power indicator are not applied, as these aspects are out of scope of the assessment. The offered volume indicator, however, appears to be too generic as it does not measure its usefulness (e.g. time of offer or location of offer) given the ancillary service demand. Here a use-case specific performance indicator is applied instead.

Value from process structure, comprehensiveness, and interactions. The application of the framework exhibits a clear structure for ancillary services assessments. It furthermore provides a guideline to comprehensively and transparently discuss multiple aspects of ancillary service design, including potential interactions. Assessments of interactions between acquisition processes are facilitated by several performance indicators and a specific dependency estimate during the evaluation process.

Scalability of the framework ensures practicability. Moreover, the application of the framework may even reduce research effort, as the development and validation of an evaluation process does not need to be executed within the study.

Value and practicability of design space is not shown. The use-case is not suitable to conclude on the value and practicability of the design space. However, other studies (e.g. Veen, 2012) have proven both. Nonetheless, given the complexity of evaluating multiple design options from a design space with multiple performance criteria and indicators, the framework may be criticised for missing proposals for the step 'assessment techniques'. A generic proposal for multi-criteria analyses could indeed add value to the framework.

Empirical process validation and calibration is possible. Section 5.9 on the model validation argued that empirical validation of ASAM is use-case dependent. Empirical process validation is thus applied in section 6.4.1 by discussing the level of detail of the various markets in ASAM. The scenarios are calibrated on the day-ahead price, as shown in section 6.3. Both aspects are indeed arbitrarily but explicitly judged in context of the assessment set-up. The use-case thus exhibits that empirical process validation and calibration of ASAM is generally possible for specific use-cases. Furthermore, the simulation results of the markets and acquisition processes are also validated by comparing the day-ahead delta prices and by linking the result to theory as well as to empirical delta prices 6.4.3.

Market design variables in ASAM are generic enough. ASAM provides per market and ancillary service acquisition the following design variables: Acquisition method, pricing method, order types, gate-opening time, gate-closure time, and provider accreditation. These design variables in ASAM appear to be sufficiently generic to implement the relevant design options of the use-case. However, it has to be noted that study-specific model development is required to implement necessary design options for the variables.

Agent strategy options are generic enough, but not complete. Market party agents in ASAM have strategies per market and acquisition process, which define timing, quantity, and pricing of their offers. These dimensions are suitable to implement heuristic strategies for the given use-case. Various strategic options are implemented in ASAM (see section 5.7), and the model structure allows easy implementation of additional options, e.g. other price mark-up calculations. Yet, it is obvious that the available options cannot comprehend every possible design study. As recommended in section 6.5.1, a self-learning approach may be valid to make the agent strategies more generic.

The performance indicators of interest are obtainable from ASAM results. The reporting class of ASAM provides a variety of generic performance indicators per market as well as data for post-processing. Many indicators can also be stored to assess intermediate simulation steps. However, it is possible to implement additional indicators to the reporting class of ASAM for specific study needs.

Ancillary services and market interactions are examined. The use-case shows that (1) aspects of market interactions can be implemented in the agent strategies and the market rules of ASAM and (2) the consequences of such design scenarios can be examined with interdependency performance indicators. In the use-case, the prices as well as the volume of the RDM, IDM, BEM and IBM are compared for the different design options. Moreover, differences in relative return and cleared volume of IDM and RDM are examined as well as the impact of the redispatch clearing algorithm on the imbalance. Finally, dispatch cost, market profit, system operator cost, and cost of electricity are compared to assess the design impact on system level. These results support the acceptance of the research hypotheses.

Price mark-ups provide a valuable efficiency indicator. The use-case shows how the price mark-up model can reveal risks from ancillary service designs for market parties and the impact on system costs (e.g. partial-call risks of IDCONS). Although gaming is out-of-scope of the use-case simulation, the application explores that the implemented price mark-ups can provide a price benchmark for gaming analyses.

Feasibility of ASAM link with utilisation models is not shown. The use-case focuses on the acquisition aspects and does not simulate responses of the physical system on the acquisition process and vice versa. This is a suitable approach for some design studies, however, the simplification may go too far for others. In such cases, ancillary service utilisation models are required to provide an ancillary service demand to the grid and system operator agent. The simulated ancillary services acquisition would then need to be looped back to the utilisation model. This shortcoming of the current ASAM implementation reduces the generic applicability. However, the present link of the market party and of the redispatch market operator with PyPSA indicates that such a link would also be feasible with the grid operator and its method determine_congestions().

Model complexity may be criticised. On the one hand, good practise for simulations in research requires models to be as simple as possible. On the other hand, is a target of ASAM to provide a fundamental model to analyse interactions of various acquisition processes and markets. This inherently leads to many model assumptions and methods. To avoid unnecessary complexity, the ASAM simulation complexity is scalable by excluding markets from simulations. Moreover, transparency is ensured by publishing ASAM as open-source model.

Multiple operators supported by ASAM, with limitations. TSO-TSO coordination (i.e. cross-zonal) and DSO-TSO coordination are not simulated in the use-case. However, since multiple grid and system operators are assumed not to act as competing buyers of ancillary services, but as a joint buyer, ASAM is generally able to address these aspects (see section 5.8). Yet, additional ASAM functionality is required to simulate such coordination. Competing operator behaviour (e.g. driven by non-harmonized regulations of multiple jurisdictions) would certainly add complexity to such coordination functions.

Framework and ASAM jointly provide value to policy recommendations. The use-case evaluates effects on imbalances caused by redispatch designs, as well as the impact on prices and volumes of other markets and processes. The results exhibit that the joint application of the framework and of ASAM enables assessments of ancillary service interactions. Moreover, the results are considered valuable for the policy recommendation of the use-case. However, the above-discussed limitations of ASAM indicate that a model extension could further increase the research value. Still, the current implementation of ASAM as well as the use-case results are to be placed in the light of the pursued policy-readiness-level 4 ("*policy performance test using small-scale model embodying several salient real-world aspects*").

Chapter 8

Conclusion and recommendation

Under consideration of:

- The valuation and limits of the framework for ancillary service design evaluation (see section 4.9)
- The assumptions and simplifications in the conceptual model (section 5.1) as well as in the implementation of ASAM (sections 5.2, 5.1.2, 5.7, and 5.8).
- The validation of ASAM (section 5.9)
- The discussion and conclusion on the use case (sections 6.5 and 6.5.1)
- The discussion of the use-case findings regarding the valuation of the framework and ASAM (chapter 7)

It is concluded that:

1. The framework for ancillary service design evaluation is generic, scalable and practicable.
2. ASAM has a structure that supports the implementation of various market and ancillary service processes, various agent strategies and performance indicators.
3. ASAM implementation still has several shortcomings with regard to long-term markets, balancing processes, the link to ancillary service utilisation models, and heuristic agent strategies.
4. Framework and ASAM jointly enable the investigation of interactions of ancillary services and markets.

Given the conclusion:

- Hypothesis I ("It is possible to evaluate the interaction of ancillary services") is accepted.
- Hypothesis II ("The additional value from evaluating the interaction of ancillary services justifies the additional research effort") is accepted.

Further research is recommended on the following:

- Application of the framework and ASAM on different use-cases to further investigate generality.
- ASAM extensions regarding the balancing energy process and balancing capacity auctions.

- Combination of ASAM with utilisation models regarding grid congestions and power balancing.
- Further development and validation of agent strategies as well as possibilities for self-learning approaches.

Appendix A

Ancillary Services in the Netherlands – short description

Frequency containment reserves (FCR) used for frequency stabilisation. TSOs use FCR to stabilise frequency disturbances within European synchronous frequency areas. FCR providers change their power dispatch (MW) in a constant ratio of measured frequency changes (Hz). Within 30 seconds, the complete FCR capacity has to be activated. When the frequency drops below 50 Hz, FCR providers autonomously (i.e. without TSO signal) increase power injection to the grid (respectively decrease power withdraw from the grid), and vice versa (for more information see TenneT TSO B.V., 2019c).

FCR procured in daily auctions. European TSOs jointly determine the necessary amount of FCR capacity per synchronous area and allocate a required contribution to every TSO, depending on the system size. TenneT was required to procure 107MW in 2017 and 111 MW in 2018 of FCR capacity to fulfil the Dutch share of the total 3000 MW of the frequency area. FCR capacity is procured in a daily joint auction with TSOs of Germany, Belgium, Austria and Switzerland. FCR providers are only remunerated for their capacity provision according to auction results. Energy delivery from activation is not remunerated (for more information see TenneT TSO B.V., 2019c and www.regelleistung.net)

Frequency restoration reserves (FRR) used to control real-time power balance. While FCR stabilises instantaneous disturbances, FRR is applied to bring back the power balance (i.e. reduce the area control error) per TSO back to the allowed bandwith. TenneT uses mainly automatic FRR (aFRR) services, whereby the TSOs' load-frequency-controller sends a 4-second activation and deactivation signal to providers of aFRR balancing energy bids (see TenneT TSO B.V., 2018b). Furthermore, manual FRR services are used, which can be activated by schedule for the entire next ISP (mFRRsa, see TenneT TSO B.V., 2020[1]) and TenneT can use directly activated FRR (mFRRda), which results in a predefined instantaneous response from the provider (TenneT TSO B.V., 2019d).

Activated FRR is remunerated with a uniform price. Providers of aFRR and mFRRsa may send balancing energy bids to TenneT. aFRR bids are sorted according to their price in a so-called merit order list, and they are activated accordingly by the load-frequency controller in real-time. TenneT activates mFRR in an analogous sequence. All FRR providers receive the price of the highest-ranked activated FRR bid per ISP (i.e. uniform pricing) (TenneT TSO B.V., 2020; TenneT TSO B.V., 2019g).

[1] In 2021, the mFRRsa product was removed from the market in the Netherlands.

Balancing capacity contracts are tendered to ensure sufficient FRR bids. EU regulation requires each TSO to organise the availability of sufficient balancing energy in the form of FRR. For this purpose TenneT tenders balancing capacity, i.e. contracts with aFRR providers to send balancing energy bids for a specified quantity and for every ISP of a specified period. These tenders are currently organised on a monthly and weekly basis, but soon this will be changed to daily tenders (see TenneT TSO B.V., 2018b). The mFRRda contracts are also procured in tenders (quarterly and monthly). However, as oppose to aFRR balancing capacity, the activation price is already fixed as a formula in the contract. Moreover, the mFRRda contracts allow for more activation constraints (e.g. maximum number of activations) (see TenneT TSO B.V., 2019d). The dimensioning of required quantities of FRR balancing capacity is defined in regulation (European Commission, 2017b). It has to be noted that additional aFRR bids may be offered by both providers with balancing capacity contracts and providers without contracts. Such bids are also referred to as voluntary bids. For mFRRsa no balancing capacity is procured. Thus all mFRRsa bids are of the voluntary category (TenneT TSO B.V., 2020).

Redispatch service used to relieve grid congestions. "*Congestion in the electricity grid arises if the power flows implied by the geographic distribution of generation and load are too large to be transmitted by the grid*" (Hirth and Glismann, 2018, p. 1). Redispatch services redistribute scheduled generation and load in a way that congestions are solved. TenneT uses the bids of 'reserves for other purposes' (ROP) as redispatch services. ROP bids are activated during day-ahead (after day-ahead market results are known) and intra-day in case the grid security analyses identify congestions. When a bid of a ROP provider is activated, the provider is expected to increase (upward bid) respectively decrease (downward bid) the scheduled energy dispatch during the delivery period at the grid location indicated in the bid (see TenneT TSO B.V., 2019e). ROD is extensively discussed in chapter 6.

Coordinated DSO-TSO redispatch with IDCONS. The Dutch DSOs and the TSO started the Grid Operators Platform for Congestion Solutions (GOPACS) to coordinate redispatch actions. In 2019 they started with a pilot phase of the redispatch service, Intra-day Congestion Spread (IDCONS), in daily operations. This service uses specific orders from the intra-day market to solve congestions (see GOPACS, 2019a). IDCONS is extensively discussed in chapter 6.

Bilateral contracts used to limit connection capacity. In situations of planned grid maintenance with expected congestions, TenneT concludes bilateral contracts with market parties to limit their connection capacity. The limitation of contracted connections is activated before the day-ahead market (TenneT TSO B.V., 2019a).

Reactive power is contracted in tenders. TenneT uses reactive power contracts in order to control the voltage in the network. When a reactive power contract is activated, the provider delivers reactive power (MVar) at agreed locations in the network. The tender is conducted once per year (www.tennet.eu/ markets/ dutch-ancillary-services).

Black-start services used to restore after blackouts. The TSO has the task to coordinate the restoration of the power supply after a blackout occurred. For this task TenneT uses contracted assets that can energise the grid and delivery power in zero-voltage events. The black-start tenders are concluded for many years (www.tennet.eu/ markets/ dutch-ancillary-services).

Energy for grid losses is procured. The transmission of electricity inherently causes losses because part of the electricity is converted to heat. Consequently, when market parties trade electricity and then consume and produce the traded energy, the occurred losses would induce an imbalance to the system. TenneT concludes contracts with market parties to deliver energy for the compensation of grid losses. For this purpose TenneT allocates realised grid losses to the imbalance of the contracted market parties. The market parties may inject electricity to the grid based on their own estimation of grid losses, in order to reduce imbalance cost and thus increase profits.

Imbalance pricing method. Imbalance pricing may be considered as a crucial part of the balancing mechanism, as it may or may not incentivise the market parties to counter-act the total imbalance (MWh) per ISP of a control area.Glismann and Nobel (2017) therefore suggest that the acceptance of imbalance settlement may also be considered as an ancillary service from market parties to the TSO. The Dutch imbalance pricing mechanism is discussed in section 5.1.2. More information can be found in TenneT TSO B.V. (2019g).

Appendix B

ASAM Classes

This table lists the methods and variables of the ASAM version used in this thesis.

TABLE B.1: Methods and variables of ASAM classes

Class name	Methods	Variables
Market model	init() step()	exodata gridareas schedule TSO schedule schedule_horizon clock aTSO DAM_obook DA_marketoperator red_obook red_marketoperator IDM_obook ID_marketoperator BEM_obook BE_marketoperator IBM_obook IB_marketoperator reports asset_portfolio visu datacollector aTSO MarketParty_dict
ExogeniousDatabase	init() read_check_parameters() get_default_DA_result() get_DA_resload() allocate_exo_errors() IB_default_price()	model sim_task market_rules portfolios congestions agent_strategies forecast_errors DA_residual_load opportunity_costs_db IBP_kde_pdfs reg_state_probabilities
Time	init() get_hour() get_day() get_MTU() asset_schedules_horizon() DA_market_finish() calc_timestamp_by_steps() calc_delivery_period_end()	model startday startMTU step_size schedule_template report_time_matrix report_location_time_matrix
Reports	init()	model

Class name	Methods	Variables
	save_all_orders_per_round() save_market_stats() group_statistics() publish_DAM_prices() publish_BEM_reg_state() publish_IBM_prices() get_system_trade() get_system_dispatch() get_system_cost() get_cleared_prices() redispatch_PI() interdependency_indicators() update_expected_IBP()	gridareas all_obooks DAM_prices IBM_prices eIBP
Visualisation	init() step_stat_sellbuy() show_asset_schedules() show_trade_per_agent() show_dispatch_per_agent() show_return_per_agent() show_demand_supply_IDM() show_system_balance() show_system_cost() show_redispatch_PI() show_cleared_prices()	model outputpath simulationname
Market Party	init() step() update_trade_schedule() set_asset_constraints() portfolio_dispatch() place_ID_orders() place_RD_orders() place_BE_orders() small_random_quantity() start_stop_blocks() opportunity_markup() intraday_markup() startstop markup() ramp_markup() doublescore_markup()	model strategy assets money accepted_red_orders accepted_ID_orders accepted_DA_orders accepted_BE_orders trade_schedule financial_return PyPSA_dispatch_model ordercount unchanged_position
GridAndSystem Operator	init() check_market_consistency() update_imbalances_and_returns() determine_congestions() redispatch_demand()	model money ordercount red_demand red_procured financial_return imbalances system_transactions
Asset	init() calc_dispatch_constraints() get_as_dataframe()	model assetID pmax pmin location srmc assetowner ramp_limit_up ramp_limit_down ramp_limit_start_up ramp_limit_shut_down min_up_time min_down_time start_up_cost

Class name	Methods	Variables
		shut_down_cost schedule constraint_df schedule_at_redispatch_bidding
MarketOperator	init()	obook model rules
MO_intraday (MarketOperation)	init() match_intraday_orders() clear_settle_intraday() external_DA_settlement()	gate_opening_time gate_closure_time
MO_redispatch (MarketOperation)	init() match_redispatch_orders() clear_settle_redispatch()	gate_opening_time gate_closure_time imbalance_threshold PyPSA Networkmodel
MO_dayahead (MarketOperation)	init() DA_clearing() clear_settle_DAM()	gate_opening_time gate_closure_time PyPSA Networkmodel
MO_balancing_energy (MarketOperation)	determine_regulaging_state()	regulating_state
MO_imbalance (MarketOperation)	Imbalance_clearing() Imbalance_settlement()	IBP_long IBP_short cur_imbalance_settlement _period
Orderbook	init() add_order_message() delete_orders() update_orders() remove_matched_orders() adjust_partial_match_orders() get_obook_as_multiindex() store_orders_per_round()	model ob_type order_column_labels buyorders sellorders buyorders_full_step sellorders_full_step cleared_sellorders cleared_buyorders sell_sum_volume sell_min_price sell_wm_price sell_max_price buy_sum_volume buy_min_price buy_wm_price buy_max_price cleared_sell_sum_volume cleared_sell_min_price cleared_sell_wm_price cleared_sell_max_price cleared_sell_number_trades cleared_buy_sum_volume cleared_buy_min_price cleared_buy_wm_price cleared_buy_max_price buyorders_per_round cleared_buyorders_per_round sellorders_per_round cleared_sellorders_per_round redispatch_demand_upward redispatch_demand_downward
OrderMessage	init() consistency_check() exclude_internal_IDtrades() get_as_df()	order_df

Appendix C

Expert interview partners

For the development and validation of the agent strategies and specific mark-ups, various experts from industry were interviewed. These unstructered interviews focused on theory and practice of bidding behaviour in various markets, based on intermediate results of this thesis.

It has to be noted that neither the strategies nor the conclusion of this thesis necessarily reflect the opinion, position or strategy of the interviewees and their affiliations.

- Sven Persch (Statkraft, 3/7/2017, telephone)
- Barrie van der Merbel (Uniper, 14/8/2017, Arnhem)
- Vincent Erwig, (Vattenfal, 31/08/2017, Hamburg)
- Werner Jorissen (Essent, 03/10/2017, den Bosch)
- Pol van der Linde (ETPA, various discussions in 2017 and 2018, Amsterdam)
- Jan-Willem Meulenbroeks, (TenneT and formerly Eneco, 3/7/2017 and 21/11/2017, Arnhem)
- Paul Smeets (Eneco, 12/7/2019, Rotterdam)
- ENOVA (22/8/2022, Capelle aan den Ijssel)
- Diederik van Dijk, (Northpool, 17/10/2018, Leiden)

Appendix D

List of power plants

asset_name	asset_owner	energy_source	Type	pmax	pmin	location	srmc	ramp_limits*	min_down_time	min_up_time	start_up_cost	shut_down_cost
Elsta	Elsta	Fossil Gas / B04	CCGT old 1	455	159	South	60	1	12	12	20223	20223
Centrale Merwedekanaal 12	Eneco	Fossil Gas / B04	CCGT old 2	230	80	South	51	1	12	12	7827	7827
Centrale Lage Weide	Eneco	Fossil Gas / B04	CCGT old 2	247	86	South	51	1	12	12	8405	8405
Enecogen	Enecogen	Fossil Gas / B04	CCGT new	844	295	South	43	1	8	8	23401	23401
Bergum 10	Engie	Fossil Gas / B04	OCGT old	25	8	North	68	1	4	4	405	405
GDF-SUEZ_NL_EC4	Engie	Fossil Gas / B04	CCGT old 2	359	126	North	51	1	12	12	12217	12217
GDF-SUEZ_NL_EC3	Engie	Fossil Gas / B04	CCGT old 2	359	126	North	51	1	12	12	12217	12217
GDF-SUEZ_NL_EC7	Engie	Fossil Gas / B04	CCGT old 2	360	126	North	51	1	12	12	12251	12251
GDF-SUEZ_NL_EC5	Engie	Fossil Gas / B04	CCGT old 2	361	126	North	51	1	12	12	12285	12285
GDF-SUEZ_NL_EC6	Engie	Fossil Gas / B04	CCGT old 2	359	126	North	51	1	12	12	12217	12217
Bergum 20	Engie	Fossil Gas / B04	OCGT old	25	8	North	68	1	4	4	405	405
GDF-SUEZ_NL_FL5	Engie	Fossil Gas / B04	CCGT new	437	153	South	43	1	8	8	12116	12116
GDF-SUEZ_NL_EC22	Engie	Fossil Gas / B04	OCGT old	131	39	North	68	1	4	4	2121	2121
GDF-SUEZ_NL_CR10	Engie	Fossil Hard Coal / B05	new	731	314	South	27	0.25	20	20	35880	35880
GDF-SUEZ_NL_FL4	Engie	Fossil Gas / B04	CCGT new	435	152	South	43	1	8	8	12061	12061
Borssele 30	N.V.EPZ	Nuclear / B14	old 1	485	242	South	14	0.25	48	48	6688	6688
NAM Schoonebeek	NAM	Fossil Gas / B04	CCGT new	128	45	North	43	1	8	8	3549	3549
Pergen 2	Pergen	Fossil Gas / B04	CCGT old 1	130	46	South	60	1	12	12	5778	5778
Pergen 1	Pergen	Fossil Gas / B04	CCGT old 1	130	46	South	60	1	12	12	5778	5778
Centrale Moerdijk	RWE	Fossil Gas / B04	CCGT old 2	765	268	South	51	1	12	12	26033	26033

asset_name	asset_owner	energy_source	Type	pmax	pmin	location	srmc	ramp_limits*	min_down_time	min_up_time	start_up_cost	shut_down_cost
CCC4	RWE	Fossil Gas / B04	CCGT new	1304	456	South	43	1	8	8	36155	36155
Eemshaven A	RWE	Fossil Hard Coal / B05	new	790	340	North	27	0.25	20	20	38775	38775
Amer 9	RWE	Fossil Hard Coal / B05	old 2	631	271	South	30	0.25	24	24	33096	33096
Eemshaven B	RWE	Fossil Hard Coal / B05	new	790	340	North	27	0.25	20	20	38775	38775
Swentibold	RWE	Fossil Gas / B04	CCGT old 2	209	73	North	51	1	12	12	7112	7112
Rijnmond Centrale	Rijnmondcentrale	Fossil Gas / B04	CCGT old 2	840	294	South	51	1	12	12	28585	28585
Maasstroom Energie	Rijnmondcentrale	Fossil Gas / B04	CCGT new	426	149	South	43	1	8	8	11811	11811
Sloe10	Sloecentrale	Fossil Gas / B04	CCGT new	435	152	South	43	1	8	8	12061	12061
Sloe20	Sloecentrale	Fossil Gas / B04	CCGT new	435	152	South	43	1	8	8	12061	12061
EDH	Uniper	Fossil Gas / B04	CCGT old 2	97	34	South	51	1	12	12	3301	3301
ROCA3	Uniper	Fossil Gas / B04	CCGT old 2	220	77	South	51	1	12	12	7487	7487
Maasvlakte 3	Uniper	Fossil Hard Coal / B05	new	1070	460	South	27	0.25	20	20	52519	52519
Diemen 33	Vattenfall	Fossil Gas / B04	CCGT old 2	249	87	South	51	1	12	12	8473	8473
Hemweg 9	Vattenfall	Fossil Gas / B04	CCGT new	440	154	South	43	1	8	8	12200	12200
Velsen 24	Vattenfall	Fossil Gas / B04	CCGT old 1	350	122	South	60	1	12	12	15556	15556
IJmond 1	Vattenfall	Fossil Gas / B04	CCGT old 1	144	50	South	60	1	12	12	6400	6400
Velsen 25	Vattenfall	Fossil Gas / B04	CCGT old 1	375	131	South	60	1	12	12	16667	16667
Hemweg 8	Vattenfall	Fossil Hard Coal / B05	old 2	650	280	South	30	0.25	24	24	34092	34092
Eemshaven 30	Vattenfall	Fossil Gas / B04	CCGT new	470	164	North	43	1	8	8	13031	13031

asset_name	as-set_owner	energy_source	Type	pmax	pmin	location	srmc	ramp _limits*	min_down _time	min_up _time	start_up _cost	shut_down _cost
Eemshaven 20	Vattenfall	Fossil Gas / B04	CCGT new	470	164	North	43	1	8	8	13031	13031
Diemen 34	Vattenfall	Fossil Gas / B04	CCGT new	435	152	South	43	1	8	8	12061	12061
Eemshaven 10	Vattenfall	Fossil Gas / B04	CCGT new	470	164	North	43	1	8	8	13031	13031
peak_gen1	agg_flex _owner	mixed	small flex ag-gregated	1251	0	North	79	1	1	1	0	0
peak_gen2	agg_flex _owner	mixed	small flex ag-gregated	438	0	North	89	1	1	1	0	0
peak_gen3	agg_flex _owner	mixed	small flex ag-gregated	151	0	North	100	1	1	1	0	0
peak_gen4	agg_flex _owner	mixed	small flex ag-gregated	40	0	North	111	1	1	1	0	0
peak_gen5	agg_flex _owner	mixed	small flex ag-gregated	33	0	North	121	1	1	1	0	0
peak_gen6	agg_flex _owner	mixed	small flex ag-gregated	8	0	North	132	1	1	1	0	0
peak_gen7	agg_flex _owner	mixed	small flex ag-gregated	6	0	North	142	1	1	1	0	0
peak_gen8	agg_flex _owner	mixed	small flex ag-gregated	4	0	North	154	1	1	1	0	0
peak_gen9	agg_flex _owner	mixed	small flex ag-gregated	1	0	North	164	1	1	1	0	0
peak_gen10	agg_flex _owner	mixed	small flex ag-gregated	1005	0	North	175	1	1	1	0	0
peak_gen11	agg_flex _owner	mixed	small flex ag-gregated	1251	0	South	79	1	1	1	0	0
peak_gen12	agg_flex _owner	mixed	small flex ag-gregated	438	0	South	89	1	1	1	0	0
peak_gen13	agg_flex _owner	mixed	small flex ag-gregated	151	0	South	100	1	1	1	0	0
peak_gen14	agg_flex _owner	mixed	small flex ag-gregated	40	0	South	111	1	1	1	0	0
peak_gen15	agg_flex _owner	mixed	small flex ag-gregated	33	0	South	121	1	1	1	0	0
peak_gen16	agg_flex _owner	mixed	small flex ag-gregated	8	0	South	132	1	1	1	0	0
peak_gen17	agg_flex _owner	mixed	small flex ag-gregated	6	0	South	142	1	1	1	0	0

asset_name	asset_owner	energy_source	Type	pmax	pmin	location	srmc	ramp_limits*	min_down_time	min_up_time	start_up_cost	shut_down_cost
peak_gen18	agg_flex_owner	mixed	small flex aggregated	4	0	South	154	1	1	1	0	0
peak_gen19	agg_flex_owner	mixed	small flex aggregated	1	0	South	164	1	1	1	0	0
peak_gen20	agg_flex_owner	mixed	small flex aggregated	1005	0	South	175	1	1	1	0	0

* ramp_limits are are applied for ramp_limit_up, ramp_limit_up, ramp_limit_start_up, and ramp_limit_shut_down

Appendix E

Randomness results

Additional randomness results are depicted on the following figures.

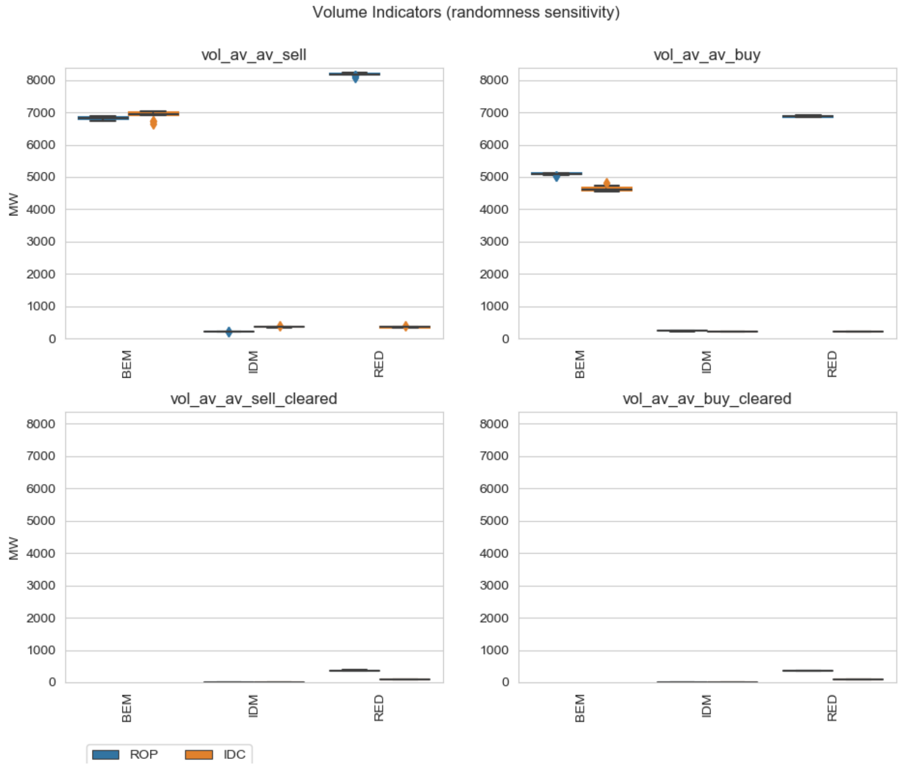


FIGURE E.1: Volume indicators [randomness]

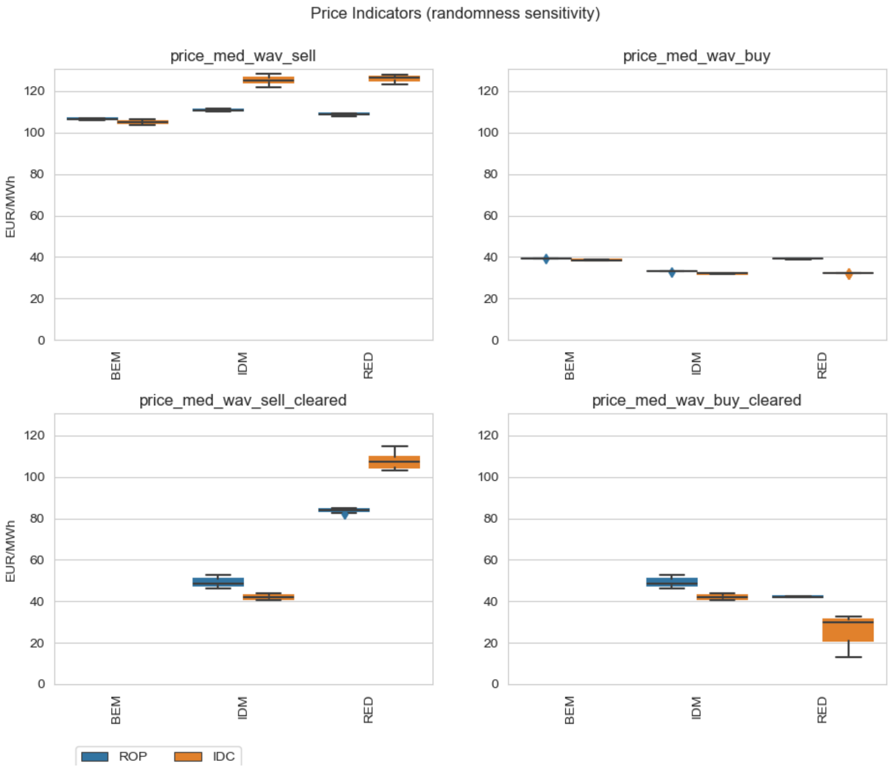


FIGURE E.2: Price indicators [randomness]

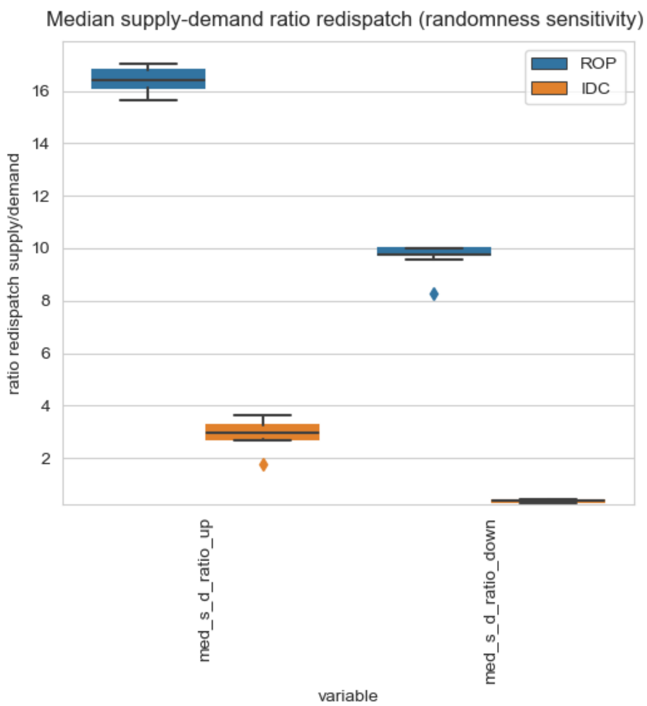


FIGURE E.3: Redispatch supply demand ratio [randomness]

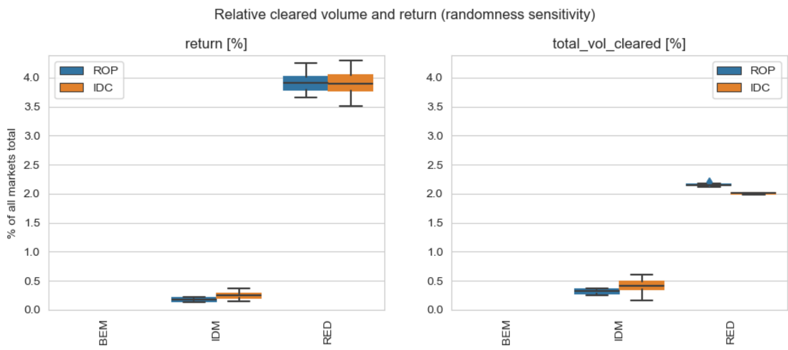


FIGURE E.4: Relative return and volumes [randomness]

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