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Operational concepts for grid services using electric vehicles

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Zusammenfassung

Das europäische Stromnetz ist aufgrund des steigenden Anteils volatiler erneuerbare Energiequellen einer zunehmenden Belastung ausgesetzt. Diese Technologien, in Verbindung mit einer höheren Volatilität der Nachfrage, stellen eine Herausforderung für die Stabilität und Sicherheit des europäischen Netzes dar, das früher von einer zentralisierteren Erzeugung in großen und relativ zuverlässigen konventionellen Kraftwerken geprägt war. Mit zunehmendem Beitrag der Wind- und Photovoltaikerzeugung am Energiemix ist eine Bewertung des Risikos für die Frequenzstabilität und mögliche Präventivmaßnahmen erforderlich. Die ungesteuerte Aufladung der zunehmenden Anzahl von Elektrofahrzeugen in Deutschland erfordert auch eine gründliche Untersuchung der Methoden für ihre Integration in das Stromnetz, um nicht nur die Stabilität der Stromnetzfrequenz zu verbessern, sondern auch einen sekundären Nutzen für die Elektrofahrzeug-Nutzer zu erzielen. Diese Arbeit analysiert die Lastfrequenzregelungssysteme auf ihre Eignung zur Integration von Elektrofahrzeugen ins Stromnetz sowie die Auswirkungen der Erhöhung des Anteils von volatilen erneuerbaren Energien auf die Frequenzstabilität in Deutschland, und zeigt einen deutlichen Anstieg der Anforderungen an Reservekapazität. Die Bewertung alternativer Ansätze zur Lastfrequenzsteuerung auf der Grundlage von Infrastrukturanforderungen zeigt, dass die Einführung eines verteilten Energieressourcen Aggregators den gesamten Infrastrukturbedarf der Netzbetreiber deutlich reduzieren kann. Die hierin vorgeschlagenen Betriebskonzepte werden anhand mehrerer Fallstudien zur Optimierung des Einsatzes von Elektrofahrzeugen für Flexibilitätsdienstleistungen im Stromnetz unter Berücksichtigung der Anforderungen der Fahrzeughalter und des Versorgungsbedarfs von Netzdiensten bewertet.

Abstract

The European electricity grid is subject to increasing stresses due to increasing share of volatile renewable energy technologies. These technologies, coupled with higher volatility in demand, pose challenges to the stability and security of the European grid, erstwhile dominated by large and relatively reliable conventional generation. As the contribution of wind and photovoltaic generation increases in the energy mix, it demands an assessment of the corresponding risk to frequency stability and possible preventive measures. Uncontrolled charging of the increasing number of electric vehicles in Germany also demands a thorough investigation of methods for their integration in the electricity grid to not only improve grid frequency stability but also to provide secondary benefits to electric vehicle users. This work analyzes the load frequency control systems for their suitability for integration of electric vehicles and the impact of increase in volatile renewable energy on frequency stability for the case of Germany, showing a significant increase in reserve requirements. Evaluation of alternative approaches to load frequency control on the basis of infrastructure requirements shows that introduction of an aggregator of distributed energy resources can significantly reduce the overall infrastructure requirements for grid operators. The operational concepts herein proposed are evaluated using several case studies for optimizing the use of electric vehicles for grid flexibility services by taking into account the usage requirements of the vehicle owner and supply requirements of grid services.

Definitions

The energy revolution in Germany and increasing share of electric vehicles has introduced a new set of acronyms and terminologies, leading to a need to define the context in which these terms are used in this report. The following terms should be understood as described here:

Aggregator: Entity responsible for managing and dispatching the flexibility of EV pool as a virtual power plant.

BEV: Electric vehicles fulfilling mobility requirements from a battery and an electric motor.

Controlled charging: Uni-directional control of the charging power of the vehicle to respond to provide flexibility services to the grid.

Demand response: Any type of grid service that allows the grid operator to control a load larger than 10 MW to either increase or decrease for a short time during a long period.

EV Pool: A set of BEVs or PHEVs collected into a pool to act as a virtual power plant.

Grid operator: Entity responsible for ensuring stability and security of the transmission or distribution grid.

Flexibility services: Services provided to the grid for frequency stability.

Flexibility services market: Procurement system used by the grid operators to fulfil frequency stability requirements.

Multi-use flexibility service: Using the same EV pool for a combination of two or more services.

PHEV: Electric vehicles using a combination of electric power and conventional fuels.

Single-use flexibility service: Flexibility service using EV pool exclusively for a single type of service.

Volatile RES: Photovoltaic (PV) and wind-based renewable energy generation.

Table of contents

1 Introduction

1.1 Background

For a large part of the last century, the European energy sector in general and Germany in particular has been dominated by vertically integrated and centralized utilities regulated by public authorities. Historically, conventional generation and stability controls operated by these utilities faced few uncertainties from demand and generation. Demand was reliably approximated using standard load curves and major losses of generation were rarely unplanned. Beginning with the liberalization of the energy sector in the 1990s, investment in smaller generation units has steadily gathered pace. Establishment of power exchanges and the resulting trading on the spot market and the introduction of feed-in tariffs has also facilitated the improvements in economic feasibility of erstwhile expensive renewable energy sources (RES). As a consequence of the aforementioned developments, the proportion of volatile RES in the energy mix, particularly wind and photovoltaic (PV) has risen significantly. The challenges to electricity frequency stability from these developments is further compounded by the increased need for highly stable electricity supply for high-tech industrial applications and digital equipment.

The contribution of wind and photovoltaic electricity generation in the German grid is expected to rise up to 60 % of the energy mix by 2030 [1], with a large share of the generation in the distribution grid in the form of distributed generation (DG), presenting a stability and security risk at a level that already has relatively lower monitoring.

At the same time, according to the forecast in [2] by Nationale Plattform Elektromobilität (NPE) in 2018, it is expected that the number of electric vehicles (EV) operational in Germany by 2025 will be between two to three million. Uncontrolled charging of these EVs can result in steep peaks and valleys in the demand curve, introducing more volatility in the vertical load and consequently the stability of the electric grid, while also straining the low and medium voltage grid infrastructure.

Curtailing the power production from RES to reduce volatility can only take place at the cost of reduced efficiency. Ideally, energy storage technologies connected to the grid can be used to balance the volatility in the grid by providing flexibility during high and low wind and PV generation, but the high cost of dedicated storage systems and the distributed nature of RES encourages an investigation of alternative approaches.

In view of the developments discussed above, the motivation for this thesis is the development of operational concepts for providing services to the grid using the flexibility provided by EVs as part of an aggregator. The role of an aggregator to act as a central point of control and coordination for the EVs is to ensure controllability and compliance with existing regulation. EVs remain stationary during most of the day, presenting a possible solution to the flexibility and also congestion issues in the grid, thanks to their decentralized availability. Controlling the charging of EVs connected to the grid to absorb unexpected peaks in load and generating power during valleys can help reduce the overall volatility in the grid. The grid operators use flexibility or ancillary services to balance the grid, usually procured through a market-based approach [3]. Depending on the region and grid operator, these services can include black start, load frequency control, voltage control and reactive power. From these services, load frequency control is activated relatively frequently and makes use of the active power flexibility provided by generators and loads [4].

1.2 Scope and structure of work

This work is focused on the investigation of role of EVs in supporting the energy revolution in Germany by providing flexibility services. The research questions answered by this work are as follows:

1. How can frequency stability be ensured with increasing renewable energy in the context of the energy revolution in Germany?
2. What role can electric vehicles play in providing frequency stability?
3. What are the operational concepts for an EV pool operator for providing flexibility services for frequency stability?

To answer these questions, the impact of the energy revolution on frequency control is investigated by measuring the influences of volatile RES in-feed on the demand for load frequency reserve. A model is used to forecast the demand for load frequency control as a function of grid volatility and alternative approaches are evaluated for frequency control in the face of high distributed energy resources in the context of the European regulatory framework. Several frequency control systems are evaluated for their suitability for EV integration. This is complemented by an evaluation of the impact of the introduction of an aggregator of distributed resources on reducing the infrastructure requirements in the European grid. The evaluation of operational concepts for the provision of grid flexibility services is performed with the help of simulation of flexibility dispatch signals based on flexibility service cases and the response of the EV aggregator.

This thesis is organized into the following chapters: Chapter 2 analyzes the structures and mechanisms used by electricity grid operators for frequency stability, their suitability for integration of electric vehicles as providers of flexibility services and the impact of high renewable energy in-feed on their demand for the case of Germany. Chapter 3 discusses the infrastructure requirements for alternative approaches to load frequency control based on an indicator-based evaluation framework. Chapter 4 describes the stochastic modeling and simulation of operational concepts for providing flexibility services based on the data obtained from electric vehicle user behavior field trials and discusses the results of the simulation with the help of flexibility service products. The conclusions drawn from the results of this work are discussed in chapter 5. This organization is illustrated in Figure 1.1.

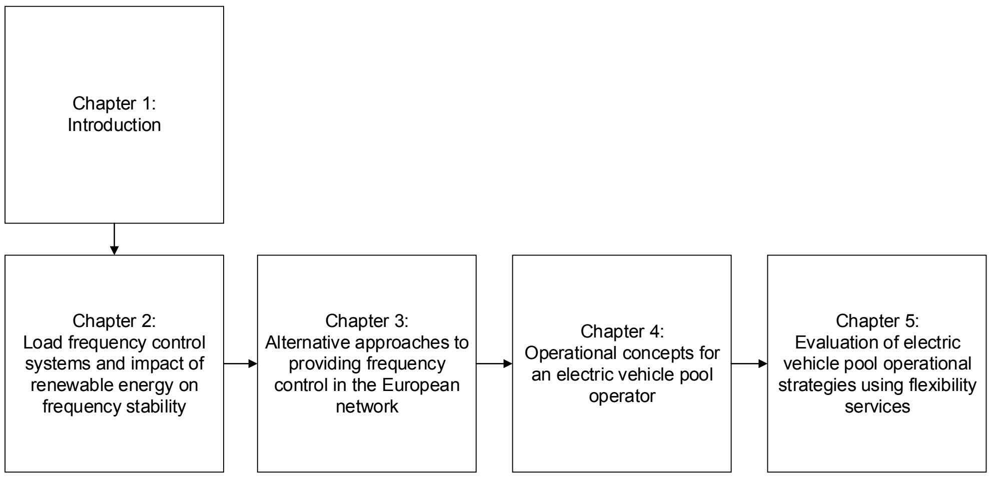

Figure 1.1: Organization of thesis

2 Load frequency control systems and impact of renewable energy on frequency stability

The liberalization of the European electricity sector began in 1996 [5] with the decision to provide more choice and free market access to both consumers and generators. In Germany, this process began with the implementation of the new regulation of the energy sector (EnWG) [6] in 1998, with the aim to provide electricity and gas to consumer at competitive rates. The liberalization policy continued with the unbundling of the electricity sector, which separated the erstwhile vertically integrated energy companies into generation, transmission and distribution companies, with each new entity separately responsible for its operations. Electricity sectors of the United States and Canada have also followed a similar path (see [7] [8] [9]).

This unbundling has enabled the entry of new market actors in the electricity sector, improving competition and providing benefits to the consumers, but also resulted in increased complexity and risk of instability in the grid. In Europe, this issue has led to the rise of energy exchanges. Trading on these markets takes place for each hour of the following day. At 12 p.m., the main market is closed and the equilibrium price for each hour is determined. In addition to the day-ahead market, energy is also traded on the intra-day market [10].

Security and stability of the electricity grid is ensured using ancillary services to control frequency, voltage and load on network resources and bringing them back under normal limits after disturbances. These services are categorized into frequency control, voltage control, re-establishment of power generation parameters and system operational management as listed in Table 2.1. A detailed discussion of these controls can be found in [11] and [12].

Table 2.1: Types of ancillary services used by grid operators

Category	Type of ancillary service
Voltage control	• Provision of reactive power • Voltage induced re-dispatch • Voltage induced load-shedding • Provision of short circuit power • Voltage regulation

Category	Type of ancillary service
Re-establishment of power generation parameters	• Switching measures to limit disturbances • Co-ordinated commissioning of feeders and sub-networks with loads • Provision of black-start capability from generators
System operational management	• Network analysis and monitoring • Congestion management • Feed-in management • Co-ordinated delivery of ancillary services across all networks
Frequency control	• Instantaneous reserve • Load Frequency Control Reserve (LFCR) • Interruptible loads • Frequency induced load-shedding • Active power reduction for over/under frequency conditions

Imbalances in periods smaller than 15-minutes are managed by reserves made available by the grid operators (GOs) using LFCR [13]. Depending on the system, this reserve power is categorized into spinning reserve as Primary (also called Frequency Containment Reserve or FCR), Secondary Reserve (also called Frequency Restoration Reserve) and non-spinning type as Minute Reserves (also called Replacement Reserve or RR). Spinning reserve is delivered traditionally by ramping up or down generators that are already online, whereas non-spinning reserve is provided by starting or shutting down generators. In addition to generators, these reserves can also be provided from pumped hydro-storage and chemical storage plants [14]. The secondary and tertiary reserves in different regions are listed in Table 2.2.

Table 2.2: Types of load frequency control

Region	Secondary LFCR Reserve	Tertiary LFCR Reserve
Europe [15] [16] [17]	Frequency Restoration Reserve	Replacement Reserve

Region	Secondary LFCR Reserve	Tertiary LFCR Reserve
USA [18]	Spinning reserve, Regulation	Non-Spinning Reserve
UK [19]	Secondary reserve, Frequency Response	Short term operating reserve, Tertiary Reserve

2.1 Mechanism of load frequency control

The LFC products in the surveyed systems are categorized according to the definitions by the European Network of Transmission Grid operators for Electricity (ENTSO-E) [20]. FCR is defined as decentralized control, activated automatically at online generators to restore the frequency to a quasi-equilibrium state in the event of small frequency deviation. FRR is defined as a reserve activated centrally by the grid operator in the event of deviations in scheduled and actual power interchanges calculated as Area Control Errors (ACE) and the resulting large frequency deviations. It is used to restore the frequency to its nominal value, whereas Replacement Reserve (RR) replaces FRR for frequency restoration [21]. In the event of a steady-state frequency deviation Δf from the nominal frequency f_n, generators participating in FCR change the power generation by ΔP_G, where the frequency is measured through the rotational speed of the shaft. The frequency response characteristic (droop) s_G [20] of the generator and the corresponding gain in the primary frequency controller is defined by (2.1):

$$s_G = -(\frac{\Delta f}{f_n}) / (\frac{\Delta P_G}{P_N}) \quad \text{in percentage} \tag{2.1}$$

where P_N is the nominal generator output. The maximal share of the nominal power that must be kept in reserve for primary control is calculated by the frequency characteristic λ_{zone} defined as:

$$\lambda_{zone} = -(P_{ae} - P_{se}) / \Delta f \tag{2.2}$$

where P_{ae} is the actual power exchange and P_{se} the scheduled power exchange from the zone to all neighborhood zones in the event of a steady state deviation Δf .

FRR is characterized by a central controller that coordinates the actions for the control area. The objective of secondary control is to bring the zone ACE_{zone} back to zero [20] based on (2.3):

$$ACE_{zone} = P_{me} - P_{se} + K_{ri}(f_m - f_t) \quad (2.3)$$

where P_{me} is the measured value of the total power exchange and P_{ae} is the actual power exchange from the zone to neighboring zones, whereas f_m is the measured network frequency and f_t is the target frequency and K_{ri} is the K-factor of the control area indicating the overestimation of the frequency characteristics of the zone calculated by (2.4) according to [22].

$$K_{ri} = \frac{1}{s_N} = \frac{1}{s_L} + \sum_{i=1}^{n_G} \frac{1}{s_{G,i}} \quad (2.4)$$

where s_N is the area frequency response characteristic consisting of the load s_L, overall generator frequency response characteristic s_G of n_G power generators where $i = 1,\ 2,\ 3 \ldots n_G$.

2.2 Characteristics of load frequency control

Although the mechanism of load frequency control activation is identical, regionally disparate grid operators use different approaches in the provision of LFCR. The development of a generalized rule-based method requires a survey of the defining features of these approaches. In this work, this survey is performed of grid operation in major world economies, whereby the attention is focused on European systems with market-based mechanisms of procuring frequency stability reserve. The survey includes Denmark as a reference for operation of a grid with high renewable energy share and Pennsylvania Jersey Maryland Interconnect (PJM) as a reference for a North American grid operator with high population density. The systems are evaluated for the regulatory and prequalification aspects of FCR and FRR with the help of published reports, network codes from grid operators and regulatory documents, as listed in Table 2.3.

Table 2.3: Surveyed load frequency control systems

Country/Region	Grid operator	Regulator	Regulatory Documents
United States	Pennsylvania Jersey Maryland (PJM) Interconnect	NERC	[18], [23], [24]
Germany	TransnetBW, Tennet TSO, 50 Hertz, Amprion	BNetzA	[15], [25], [26]
Great Britain	National Grid Electricity Transmission (NGET)	Ofgem	[19]

Country/Region	Grid operator	Regulator	Regulatory Documents
France	Réseau de transport d'électricité (RTE)	CRE	[16]
Denmark	Energinet.dk	DERA	[17], [27], [28]

PJM – the Regional Transmission Organization (RTO) serving electricity consumers in the north eastern United States, designates FRR as regulation power [29], which is supplied using open tenders. PJM fulfils its regulation requirements using self-scheduled resources as well as bilateral and market transactions. FCR is designated as frequency response, which is a mandatory requirement from generators connected to the grid not already part of the ancillary services market. Suppliers of regulation are tested over several days for reception from AGC signals and the output power is telemetered to PJM.

After unbundling in the German energy sector, four TSOs have become responsible for ensuring system stability and security of the electricity network. Competitive bidding for ancillary services supply began in 2002 and since 2007, the four TSOs jointly tender offers to fulfil system security requirements. Tendering takes place on the online platform 'regelleistung.net' [30]. Power capacity bids are accepted for FCR whereas FRR and MR hold separate cascading bids for power and energy. Generators are entitled to payments once the capacity bids are accepted. However, actual activation of FRR is based on decreasing cost of energy to the GOs.

NGET of Great Britain controls governor response to balance the grid and frequency is curtailed by reducing active power using primary and secondary response. High frequency response is only used to reduce the frequency and is not used for frequency restoration. The two types of responses are grouped together in a single product called Firm Frequency Response. NGET has the most complex payment structure among the surveyed systems, based on three types of payments: availability, utilization window and delivered energy [31].

In France, RTE is the TSO responsible for network security and stability. RTE does not operate a dedicated market platform for FCR and FRR and these are provided using bilateral contracts between RTE and generators, whereas RR is tendered through a market mechanism. In RTE's network, generation reserves are described as injection-type reserve and Demand Response (DR) reserves are called extraction-type reserve. All generators above 40 MW have an obligation to provide FCR.

Energinet.dk is the sole TSO in Denmark, operating a grid separated into Western Denmark (DK1) and Eastern Denmark (DK2), both under separate regulations. Primary reserve in DK1 and frequency-controlled normal operation reserve (FNR) in DK2 are procured daily and used to stabilize the frequency to a value close to 50 Hz, short of restoration. However, FNR is activated for a significantly smaller imbalance of ±100 mHz. Secondary reserve in DK1 and frequency-controlled disturbance reserve (FDR) in DK2 are used to restore the frequency to 50 Hz. Unlike Secondary reserve, FDR must be fully activated within 30 seconds [17]. FDR is only used to restore negative imbalances, activated upon an imbalance ranging from -100 mHz to -500 mHz [28], fitting only loosely into the category of FRR as defined for other systems due to its response times.

The characteristics of FCR and FRR of the surveyed systems are shown in Table 2.4 and Table 2.5 respectively.

Table 2.4: Market regulatory and prequalification characteristics of Frequency Containment Reserve (FCR)

Zone	PJM [32]	DE [33]	NGET [34]	FR [35]	Denmark DK1 [36]	Denmark DK2 [36]
Payment structure	-	Availability	Availability/utilization	Availability	Availability	Availability/utilization
Service time window	-	Uniform	Time blocks	Uniform	6-hour time blocks	1, 4 and 8 hour time blocks
Offer symmetry	-	Symmetric	Symmetric	Separate	Symmetric	Symmetric
Bid size (MW)	-	1	10	1	0.3	0.3
Pooling of resources	-	Allowed	Allowed	Allowed	Allowed	Allowed

Zone	PJM [32]	DE [33]	NGET [34]	FR [35]	Denmark DK1 [36]	Denmark DK2 [36]
Full activa-tion	-	≤ 30 s	Primary low ≤ 10 s Secondary low ≤ 30 s High ≤ 10 s	≤ 30 s	≤ 30 s	≤ 150 s
Full availa-bility	-	≥ 15 min	Primary low ≥ 30 s Secondary low ≥ 30 min High: continuous	≥ 15 min	≥ 15 min	Continu-ous
Pro-cure-ment period	-	Weekly	Monthly	-	Daily	Daily
Settle-ment	-	Pay-as-bid	Pay-as-bid	Pay-as-bid	Mar-ginal/CCP	Pay-as-bid
Pro-cure-ment method	Man-datory	Open tender	Open tender	Bilat-eral	Open ten-der	Open tender

Table 2.5: Market regulatory and prequalification characteristics of Frequency Restoration Reserve (FRR)

Zone	PJM [32]	DE [37]	FR [35]	Denmark DK1 [36]	Denmark DK2 [36]
Payment structure	Utiliza-tion/oppor-tunity	Availabil-ity/utiliza-tion	Availabil-ity/utiliza-tion	Availabil-ity/ utili-zation	Availability
Service time win-dow	Peak/off-peak	Peak/off-peak	Uniform	Uniform	1, 4 and 8 hour time blocks
Offer sym-metry	Symmetric	Separate	Symmetric	Symmet-ric	Only Posi-tive

Zone	PJM [32]	DE [37]	FR [35]	Denmark DK1 [36]	Denmark DK2 [36]
Bid size (MW)	0.1	5	1	0.3	0.3
Pooling of resources	Allowed	Allowed	Allowed	Allowed	Allowed
Full activation time	≤ 5 min	≤ 5 min	≤ 97 s	≤ 5 min	50 % ≤ 5 s 100 % ≤ 30 s
Full availability duration	≥ 60 min	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min
Procurement period	Daily clearing/Hourly revision	Weekly	Yearly	Monthly	Daily
Settlement mechanism	Marginal/CCP	Pay-as-bid	-	n/a	Pay-as-bid
Procurement method	Open tender	Open tender	Bilateral	Bilateral	Open tender

2.3 Evaluation of load frequency control for the feasibility of electric vehicle integration

For the evaluation of the LFC systems for EV integration, quantitative and qualitative characteristics suitable for EV aggregators are first identified, followed by selection of the corresponding indicators. Finally, the surveyed systems are evaluated for the level of compliance with these indicators. The following subchapters introduce the concept of an EV aggregator, and the criteria used for the evaluation of LFC systems. Further discussion of this evaluation approach can be found in [O-1].

2.3.1 Role of an EV aggregator

As the role of conventional steam, gas and hydro-based flexibility shrinks, the gap is filled by flexibility offered by distributed resources [14]. In this work, the aggregator is defined as an entity which serves to gather distributed resources into a pool acting as a virtual powerplant, filling the gap between the grid operators and distributed resources and reducing the complexity for the GOs and enabling smaller service providers entry into the flexibility services system.

Sufficient reserve for LFC is ensured through either mandatory provision from generators and loads fulfilling minimum criteria or through bilateral agreements with individual suppliers. Integration of electric vehicles (EVs) as part of an aggregator in LFC as controllable loads offers an opportunity for GOs to mitigate grid volatility while offering revenue potential to the EVs. The concept has been tested to be technically feasible, demonstrating the capability of fulfilling the minimum requirements in several field trials and projects, such as in [38], [39], [40] and [41]. The integration of EVs in LFC faces challenges posed by a market designed around capabilities of conventional generators. EVs, while offering fast reaction rates, are constrained by their relatively small storage capacities, which limits their capability to participate in markets with offer size barriers. The unavailability of EVs at all hours of day at grid connection points is also a limiting factor [42]. Collecting individual EVs into pools operating as a virtual power plant operated by an aggregator can help overcome these barriers.

The concept of EV aggregator participation in LFC is based on the EV acting as controllable reserve as illustrated in Figure 2.1. The supplier (EV aggregator) offers the reserve to the concerning GOs through a market mechanism. In the instance of a system frequency deviating beyond a specific limit, the GO dispatches the reserve offered by an aggregator of EVs based on its position in a merit order list of all offered reserves. Upon reception of the dispatch signal from the GO, the aggregator distributes and monitors the signal among the EVs and is entitled to a compensation for the participation based on the agreed terms.

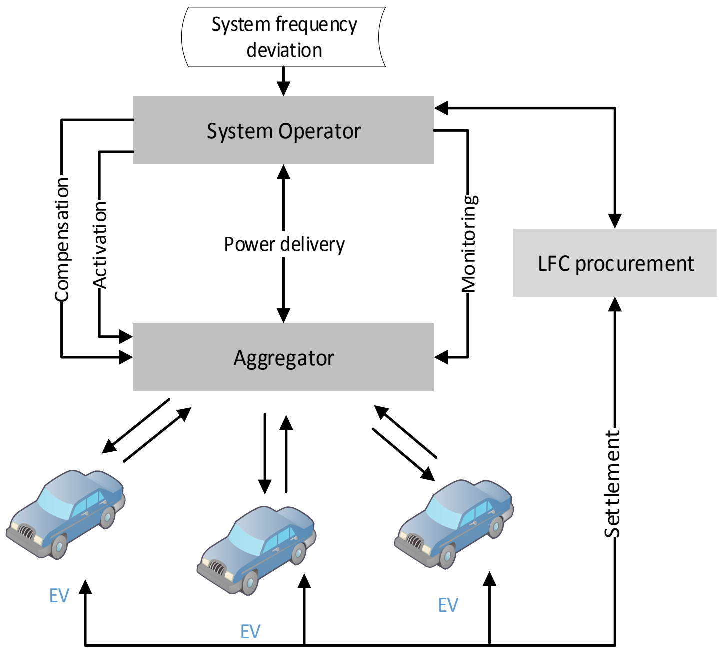

Figure 2.1: Control concept of EVs participation in LFC

2.3.2 Development of evaluation criteria

In order to determine the suitability of EV aggregator participation in LFC systems, a weighted indicator-based evaluation framework is developed and applied to the surveyed systems, as also described in the related publication [O-1]. The alignment of the systems to the set of criteria described in the fourth column (see Table 2.6) determines their suitability for EV integration. These indicators are categorized as qualitative and quantitative indicators. The selection of qualitative indicators (I-1 to I-8) of markets for EV aggregator suitability is based on objective analysis described in the following sections. Quantitative indicators (I-9 and I-10) are defined on the basis of EV response characteristics identified using results obtained from [43]. The application of the evaluation criteria is further described in 2.3.3.

Table 2.6: Market characteristics for EV suitability

Category	Indicator	Characteristics	Suitable for EVs
Qualitative Indicators	I-1	Procurement method	Open tenders
	I-2	Settlement mechanism	Pay-as-bid

Category	Indicator	Characteristics	Suitable for EVs
	I-3	Procurement period	Daily
	I-4	Payment structure	Availability & utilization
	I-5	Service time window	Time blocks
	I-6	Offer symmetry	Separate
	I-7	Minimum offer size	Small
	I-8	Pooling of resources	Allowed
Quantitative Indicators	I-9	Full activation time	≤ 30 s
	I-10	Duration of full availability	≤ 15 min

2.3.2.1 **Procurement method (I-1)**

This indicator evaluates the surveyed systems for the type of settlement mechanism used for procuring LFC reserve. Bilateral settlements are undertaken over periods ranging from several months to years due to time consuming nature of negotiations. Although this may be attractive initially to an EV aggregator as it assures steady revenues and removes uncertainty arising from the tendering process, the long-term nature of bilateral contracts removes the flexibility to change offered capacities and prices based on changing market conditions and EV availability. Therefore, open tenders are considered more suitable for EVs.

2.3.2.2 **Settlement mechanism (I-2)**

This indicator evaluates the settlement rules for systems with market based LFC reserve procurement according to Marginal Pricing (MP)/Common Clearing Price (CCP) or pay-as-bid settlement. Under MP/CCP pricing, all accepted suppliers are remunerated a common price determined by the last or marginal accepted resource. Under the pay-as-bid settlement approach, each accepted participant is paid the price of the submitted bid, subjected to market clearing and activation [44]. The merits and demerits of these mechanisms have already been discussed in the academia and industry, with [45] arguing that although uniform pricing offers higher social efficiency, markets with products largely fragmented due to operating cost, efficiency and ramp-rates benefit from pay-as-bid settlements. On the other hand, [46] and [47] argue that moving from uniform to pay-as-bid settlement approach will negatively impact social efficiency and average prices. This is confirmed by [48], which determine that in markets with inelastic demand and higher market power, pay-as-bid settlement can lead to higher inefficiencies and market collusion. The research performed in the reviewed literature focus on the effects of these settlement rules on system welfare. The merits of the settlement rules for LFC suppliers with very low marginal cost are not discussed and must be further researched.

Under marginal pricing, suppliers with low marginal costs and non-existing opportunity cost need only bid their marginal costs to ensure a successful bid. The settlement for such suppliers is generally much higher than the bid price due to higher marginal costs of conventional generators, which serve as the bulk of LFC. This effect will only last as long as EV pools and Battery Energy Systems (BES) remain in the minority of ancillary services providers. As the share of these resources is expected to rise [14], low marginal cost suppliers would result in lower clearing prices until stabilization at lower levels. In markets with CCP mechanism, suppliers guessing the marginal price correctly stand to gain the most, regardless of the cost calculation of competing suppliers [47]. Low marginal cost suppliers can statistically guarantee a successful bid if they offer a price corresponding to their costs. However, pay-as-bid system incentivize the suppliers to offer prices higher than their costs, as long as their guess of the price of the highest marginally accepted bid is correct. For EV pools, the desire to have as low a dispatch probability as possible plays a significant role in participatory decision. These suppliers can offer highly accurate frequency control but only for shorter durations due to physical capacity constraints. Hence, selecting the bid price that guarantees acceptance of bids but also allows for lower actual dispatch is the deciding factor. Pay-as-bid settlement provides such flexibility to these suppliers and is consequently considered as more suitable for EV integration.

2.3.2.3 **Procurement period (I-3)**

LFC reserve is tendered for periods ranging from yearly to daily, within which the providers must ensure complete availability of sufficient reserve to respond to signals from the grid operator. EV aggregators providing LFC must be capable of forecasting their user demand for this duration. Increasing forecasting horizons are possible at the cost of decreasing either the forecast accuracy or the available capacity. This indicator evaluates the surveyed markets based on the time between gate closures, with smaller periods ranked higher corresponding to suitability for EV integration.

2.3.2.4 **Payment Structure (I-4)**

The payment for supplying LFC may constitute multiple parts reflecting compensation for cost components of the supplier. These payments can take the form of a fixed price, availability payment, utilization payment, opportunity payment or all of the above.

Fixed payment is determined by the GO, which can be specified for a generator type and time period. Availability payments, calculated on a power basis, are made for the availability of a capacity at the disposal of the GO, regardless of actual usage. Utilization payments come into effect when the active power of resource is utilized. These payments are made for the actual metered energy delivered as the result of activation. A combination of availability utilization payment is preferable for EV integration as it compensates and incentivizes the EV user for availability at the plug-in point even if actual activation occurrence is low. Markets only offering availability payment are considered as having lower suitability, while those only offering utilization payment are ranked the lowest.

2.3.2.5 **Service time window (I-5)**

Distribution of the market into separate time-dependent products allows suppliers to participate only in markets where satisfactory capacity is available, while ensuring that the grid operator does not procure superfluous capacities at times when lower reserves are required. Due to the temporal uncertainty associated with day-time availability of EVs [49], smaller time blocks offer an opportunity where the EV participates only in time blocks where sufficient capacity is available. For this indicator, the markets are ranked based on the tendering window, where shorter time blocks are preferred for EV integration.

2.3.2.6 **Offer symmetry (I-6)**

Although EVs can provide both negative and positive LFC by respectively starting or pausing the charging process, a separation of product into positive and negative would allow an EV aggregator in selecting either one or both types, based on the available capacities and charging requirements of the users. For instance, a comparison of weekly charging requirements of private EVs shows a higher driving range and correspondingly higher charging demand on weekdays compared to weekends [49], allowing an aggregator to offer higher negative control than positive control during weekdays. This indicator evaluates the surveyed systems for this separation of products. Markets with separate products are assumed to be more suitable for EVs than markets with symmetrical negative and positive LFC.

2.3.2.7 **Minimum offer size (I-7)**

This indicator evaluates the systems for the minimum allowed offer size for each LFC product. This barrier, while on one hand reducing market complexity for the operator, also restricts smaller providers of ancillary services like EVs from participating in the market. Hence, markets with lower barriers offer more opportunity to EVs to integrate as smaller pools.

2.3.2.8 **Pooling of resources (I-8)**

This indicator evaluates the surveyed systems for pooling of units for participation in LFC. Resource pooling is categorized into unit control and pool control. Under unit control, each reserve participating in the unit must be connected through the same grid connection point. Alternatively, systems with pool control allow pooling of resources to participate in LFC as either a virtual power plant with a central pool operator receiving dispatch signals and distributing it among the pooled units according to an optimization algorithm, or the units are allowed to pool together for bidding purposes and are then activated by individual signals by the GO. For EV integration, allowance for resource pooling is a requirement due to the minimum offer size barriers and temporal unavailability of individual EVs. Accordingly, systems with allowance for pooling are considered suitable for EV integration.

2.3.2.9 **Full activation time (I-9)**

This indicator evaluates the full reserve activation requirements for the surveyed systems. The minimum allowed duration for reaching full operating capacity is predominantly established according to the capabilities of conventional generators, while EVs are capable of significantly quicker reaction and ramping rates [40][43][50]. Hence, systems requiring faster ramping rates offer a natural advantage to EVs due to lower competition from conventional generators and are consequently more suitable for EV integration. Activation time t_a is calculated by (2.5) and (2.6), where P_f is the final power of the resource after ramping, P_i is the power at incidence of the activation signal, P_o is the offered power of the resource and r_k is the resource ramp-rate.

$$P_o = P_f - P_i \tag{2.5}$$

$$t_a = \frac{P_o}{r_k} \tag{2.6}$$

2.3.2.10 **Duration of full availability (I-10)**

Similar to full activation time, the full availability duration for reserve provision in the surveyed systems is established for conventional generation, which face few capacity issues in the provision of LFC. In contrast, although EVs are capable of faster reaction and ramping rates, they are limited in the total duration of full availability due to battery capacities and temporal user unavailability [50]. Consequently, markets with shorter durations of full availability are more favorable to EVs and ranked higher. The duration of full availability t_a is calculated by (2.7), where T_{end} is the end time of activation and T_f is the time of the activation of full reserve.

$$t_o = T_{end} - T_f \tag{2.7}$$

2.3.3 Results of the evaluation

The two quantitative and seven qualitative criteria described in Table 2.6 are assigned scores between 0 and 5 for their closeness to the characteristics defined in the last column for EV integration suitability. The weightage consists of either 1 or 2, of which 1 is only assigned to the I-7 indicator as the relative importance of this barrier is diminished when resource pooling is allowed, which is already assumed for all systems in this evaluation. The final percentage fulfilment ranking x is calculated by using

$$x = \frac{\sum_{i=1}^{n}(a_i \cdot w_i)}{\sum_{i=1}^{n}(m_i \cdot w_i)} \cdot 100 \tag{2.8}$$

where a_i is the fulfilment level of the indicator i =1, 2, 3… n, m_i is the highest ranking constant at 5 and w_i is the weightage assigned to the indicator. The overall ranking of the systems is achieved by combining the individual scores for each indicator. The results of the evaluation illustrated in Figure 2.2 and Figure 2.3 indicate on a scale of 0 – 100 % the overall level of criteria fulfillment of evaluated systems for the indicators listed in Table 2.6.

The FCR evaluation in Figure 2.2 shows a very high suitability of both eastern and western zones of Denmark for EV integration due to shorter gate closures and tendering times (see Table 2.4). NGET's network in Great Britain is ranked third highest due to the monthly gate closure and large minimum offer size restriction. Germany ranks lower among the evaluated markets for FCR due to the use of symmetric bidding and peak/off-peak tendering. France ranks the lowest mainly due to the absence of an open tendering mechanism for reserve procurement. FCR in PJM is a mandatory product and is consequently not assessed further in this evaluation.

The results of the evaluation for FRR show that Denmark's eastern (DK2) zone fulfils 87 % of the criteria for EV integration suitability, with the western (DK1) zone showing much lower fulfilment levels due to longer product durations and bilateral procurement, as shown in Table 2.5. This is followed by the German and PJM's systems, which are ranked similarly due to the small offer sizes and shorter gate closures weighing against the separate control and pay-as-bid settlement mechanisms. FRR does not exist as a product in Great Britain and is consequently not ranked.

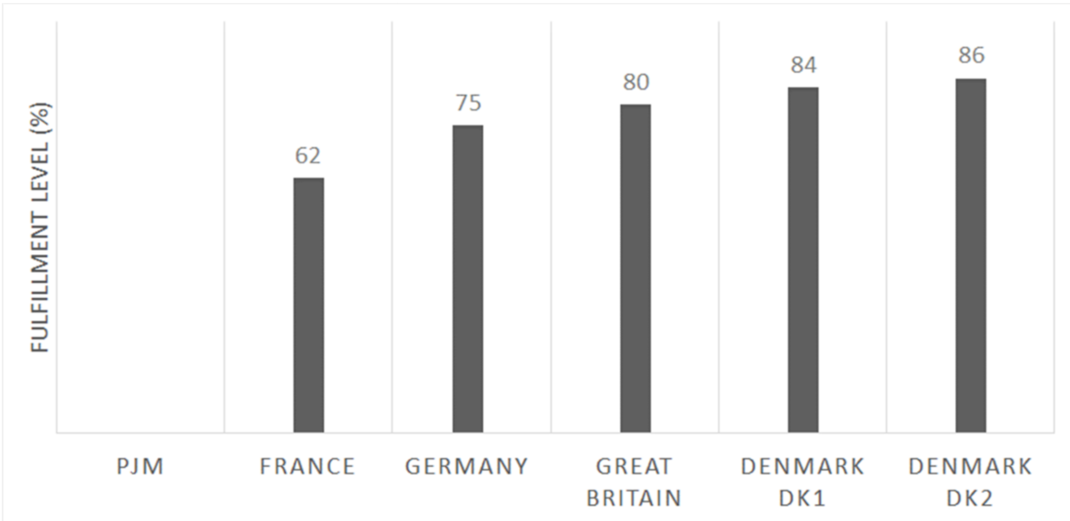

Figure 2.2: Evaluation of FCR for EV integration suitability

Denmark's DK2 zone is ranked the highest for integration of EVs in FRR due to the use of pay-as-bid mechanism, daily tendering, short service time windows small minimum offer size. It is followed by the German system at second rank with 75 % fulfilment because of weekly tendering, peak/off-peak service time and large minimum offer size. PJM ranks fourth despite having low minimum size requirement due to symmetric procurement and absence of an availability payment. Denmark's DK1 zone ranks fifth for suitability of EV integration in FRR primarily due to a uniform time window and bilateral procurement taking place on a monthly basis. France ranks consistently among the lowest for both FCR and FRR due to yearly procured reserves, which are also settled bilaterally, resulting in low suitability for EV pool integration.

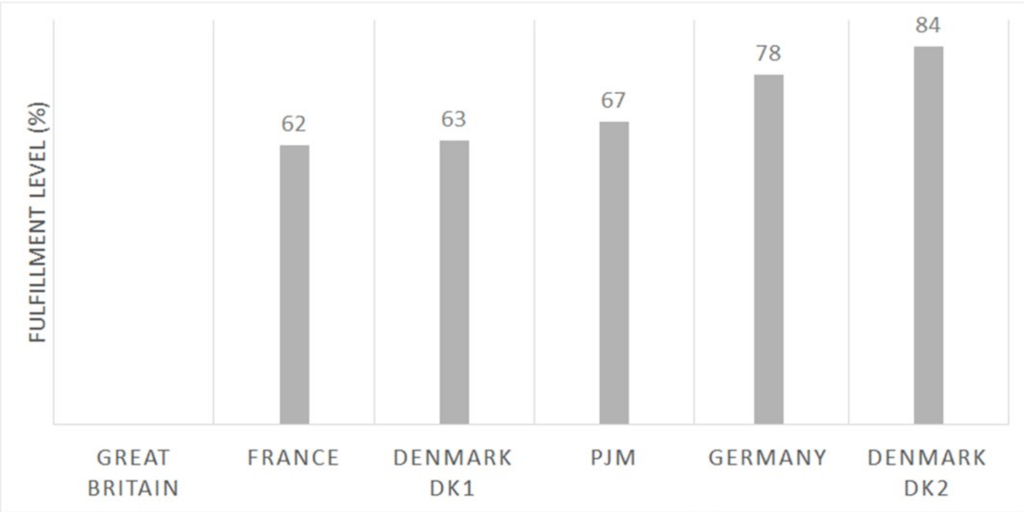

Figure 2.3: Evaluation of FRR for EV integration suitability

Although the surveyed systems are parts of liberalized energy sectors, they differ on approaches for ensuring adequate reserve for LFC. It remains at the GO's discretion to procure the reserve for some or all types of LFC through a market-based mechanism or make their provision mandatory. Additionally, the energy sector in the ENTSO-E zone is still in a process of harmonization and consequently, even the constituent systems procuring LFC reserve through a market-based approach do so under separate regulatory and technical requirements. These differences occur due to legacy systems, which although developed independently, have historically performed satisfactorily. This reason, coupled with the high availability requirement and cost of redesigning, causes the surveyed systems to differ considerably. The differences are categorized into settlement mechanism, procurement period, payment structure, service time window, offers symmetricity, minimum bid size, resource pooling, full activation time and availability duration.

France's RTE procures both FCR and FRR through bilateral contracts, whereas Denmark's DK1 uses bilateral contracts for procuring FCR and FRR respectively, while other systems in the survey follow an open tender approach. As the settlement mechanism, the GOs use either pay-as-bid with each supplier remunerated the individual bidding price subject to clearance, or the MP/CCP method, with all activated suppliers remunerated a common price determined by the last or marginal accepted resource.

The surveyed systems settle the procurement of reserve using the pay-as-bid mechanism except FCR in Denmark's DK1 and FRR in PJM's system which use the MP/CCP mechanism. The procurement period is the duration for which the bid or the contract is awarded. The German GOs procure both FCR and FRR on a weekly basis. Monthly tenders are used by NGET and Denmark's DK1 to procure FCR and FRR respectively. Both DK1 and DK2 zones in Denmark procure FCR daily while PJM and only DK1 of Denmark procure FRR using daily tenders.

The surveyed systems use a combination of availability and utilization payments, the size of which are either determined bilaterally or through competitive bidding on a market-based platform. FCR in Germany and France and FRR in Denmark's DK2 zone are remunerated only for the availability, whereas all other systems offer utilization payments in addition to the availability payment for both FCR and FRR. Only PJM uses the opportunity payment in combination with the utilization payment, although this opportunity payment is not used for suppliers using energy storage technologies [23].

For service time windows, RTE in France accepts uniform offers for the complete duration of the services, whereas GOs in Germany and Denmark only use uniform offers to procure FCR and FRR respectively. PJM and German GOs procure separate offers for peak and off-peak periods for FRR, whereas other systems in the survey procure these services in shorter time windows.

Symmetrical provision of positive and negative reserve by each supplier is required by NGET in Great Britain as well as German and Danish GOs to procure FCR. PJM, RTE in France and Denmark's DK1 also require symmetrical offers for FRR. French and Polish GOs allow separate/non-symmetrical offers for FCR. On the other hand, German GOs allow separate negative and positive offers for FRR, while Denmark's DK2 zone only procures positive FRR.

LFC supply offers must be larger than the minimum allowed bid size. All surveyed systems except France's RTE allow bids of 5 MW or less, with PJM and Denmark's Energinet.dk allowing 0.1 MW and 0.3 MW respectively. For other systems, this requirement can only be fulfilled by combining several small resources into pools.

To qualify as suppliers of LFC, resources must undergo technical prequalification testing with separate minimum requirements for FCR and FRR. Suppliers respond to test signals from GOs during a mutually agreed testing period and the response and reliability of the resources is measured to ensure compliance with all minimum performance conditions. Upon activation, the resources must be capable of ramping up generation to full activation time within the stipulated time. Following full activation, the resources must capable of sustaining generation for a minimum specific duration.

2.3.4 Discussion of LFC system evaluation results

The regulatory characteristics and prequalification requirements of most systems except for Germany and the DK2 zone in Denmark, favor slow responding resources that can supply LFC for longer durations. The use of bilateral contracts is also a legacy arrangement from an era of few and large generators, when competitive bidding was needed. This is of note in the French system, which is dominated by large nuclear generators. Other criteria like long procurement periods and allowed capacities for bidding are due to reluctance of the grid operators to introduce further complexity in their operations. As generation of electricity by smaller and decentralized generators becomes dominant, the transmission grid will experience more load and will look to resolve frequency stability issues with locally available resources. EV pools are consequently an attractive option for GOs thanks to their decentralized nature, enabling the activation of resources closest to the disturbance and avoiding grid congestions. In today's grid, fuel-based generators must make a cost benefit decision between selling their energy in the retail or wholesale market or supplying LFC services. In contrast, controllable loads such as EVs, which are only capable of providing flexibility over a short period, have lower opportunity costs and may become a more committed cost-effective resource for frequency control.

2.4 Impact of volatile renewable energy on frequency stability

To help answer the first research question of this work, namely the provision of frequency stability with increasing volatile RES, it is necessary to determine the magnitude of the challenge faced by the grid. This part of the work serves to quantify the change in frequency control reserve requirements with increasing generation of volatile renewable energy. The investigation consists of simulating the stochastic modeling-based approach used by the German grid operators to forecast the reserve required for FRR and RR. A detailed discussion of this approach can be found in [51].

Wind and PV electricity generation is volatile in nature with a forecasting error larger than conventional generation and deviations from the forecasts result in the activation of frequency control reserves, instances of which may increase with higher renewable energy generation. Therefore, the first part of this chapter analyzes this impact by using a dynamic frequency control reserve model based on a combination of historical data and future scenarios of energy mix.

Along with the analysis of the directly quantifiable effects of high RES on frequency stability, other challenges posed by uncertainty in the load side as well as the increasing number of distributed generation sources cannot be ignored. These challenges are discussed with the help of a mathematical evaluation framework outlined in the second part of this chapter.

GOs estimate the size of the reserve required to compensate for any deficit or surplus in the generation or consumption in the grid. The methodologies used for this calculation vary across the control zones and regions. Depending on the level of contingency, the financial resources available and necessary level of security, the TSOs use either deterministic or probabilistic techniques [52]. Deterministic approaches estimate the reserve size using the largest possible contingency, whereas probabilistic approach uses a stochastic means to estimate a more dynamic reserve capacity. Dynamic estimation of reserve capacity is generally used to reduce the reserve requirements and cost saving, especially in cases where open tendering of the reserve is implemented.

In the ENTSO-E control zone, the network operators use a common approach to the estimation of a combined FCR for a possible simultaneous loss of two nuclear powered generators. The activated amount is distributed among the operator zones in proportion to historical installed generation capacities [53].

Several deterministic and stochastic approaches are proposed by the ENTSO-E for the calculation of the FRR and RR reserve. The final decision on the approach used is left to the individual TSOs. The deterministic approach proposed by the ENTSO-E for calculating the reserve requirements for negative and positive FRR uses the peak load noise determined by

$$FRR_{+} = FRR_{-} = \sqrt{10 \cdot load_{\max} + 50^{2}} - 50 \tag{2.9}$$

The reserve required for FRR and RR in Germany is calculated using a stochastic approach based on the uncertainties in conventional generation, random load noise, forecasting errors of load and RES feed-in [51]. The treatment of these factors in the market model is outlined in Table 2.7.

Table 2.7: Categories of market sub-model according to causes of uncertainty

Cause of uncertainty	Sub-model
Generator failures	Conventional generation
Load noise	Renewable generation
Load forecasting error	
PV forecasting error	
Wind forecasting error	

Unplanned outages or generation failures result in the loss of generation and consequently only require positive reserve. This probability of failure of a conventional generator depends on the type of fuel, age and type of operation and maintenance of the plant. Although these outages last for days, the Balancing Responsible Parties (BRPs) in Germany are obligated to replace the lost generation capacities within one hour using their own portfolio or the market.

The forecasting errors for the load and volatile RES influences the requirement for both negative and positive LFC. Overestimating the RES generation leads to a deficit, which must be compensated for by the activating of positive LFC. Underestimation of the generation results in a surplus, which must either be absorbed by the grid or compensated for by ramping down of other generation connected to the grid. The inherent uncertainty in the generation of wind and PV has a significant impact on the volatility in the grid [51], which reduces as the forecasting horizon decreases. Any deficit or surplus in long-term generation forecasts is covered by the using the spot market, but the short-term forecasting errors leave little time for this approach, causing an increase in the activation of LFC.

2.4.1 Forecasting error stochastic model

The model is divided into conventional and renewable generation sub-models and is built on historical data and scenarios for future conventional and RES feed-in. The conventional unit commitment sub-model uses installed generator capacities obtained from [54] and historical residual load scaled linearly based on the installed conventional generation scenarios. The results from the unit commitment model are used to generate failure probabilities according to historical values obtained from [55]. These failure probabilities are used as input for the reserve requirement model. Historical values of actual RES feed-in are used to derive the usage factors and these usage factors are used to scale the scenario based installed capacities and corresponding RES feed-ins are generated. The load curve is assumed to remain identical to the reference case of 2014, whose values are obtained from the TSO platforms [56–59]. The actual and forecasted RES feed-ins are used to calculate required values for the reserve requirement model based on the convolution-based approach used by the TSOs, as given in [60]. Figure 2.4 illustrates the inputs of the model.

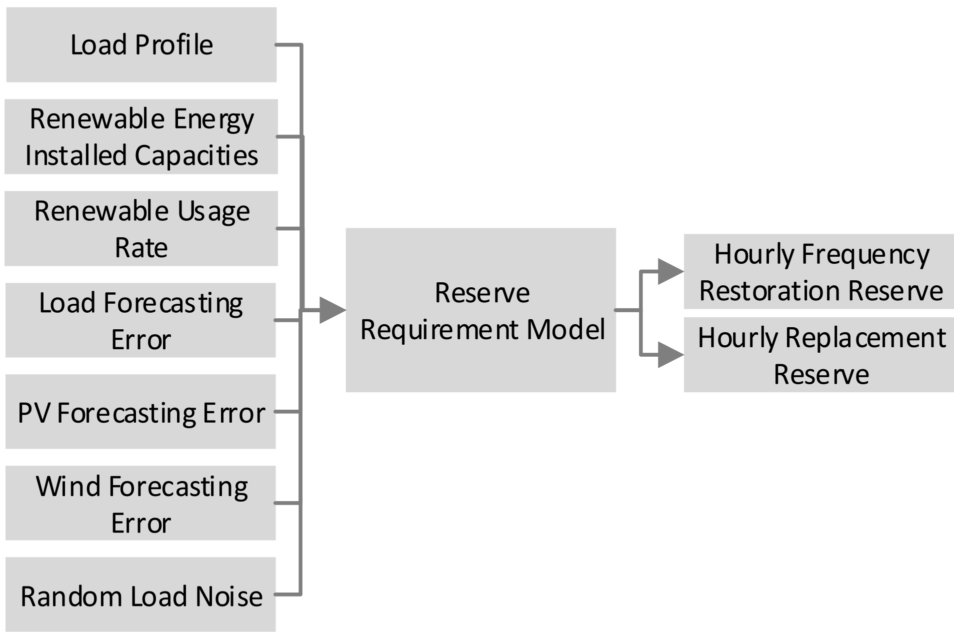

Figure 2.4: Market model for the forecasting of LFC requirements

The model development is undertaken with an assumed usage rate of wind and PV installed capacities, residual load and economic parameters of conventional generators.

Load Curve Forecast

The forecast for load are based on [61] and [62] and consist of scenarios for years 2020, 2030 and 2050. The forecasted quarter-hourly load curve $load_{forecast}$ is calculated using these scenarios by projecting the historical load curve of 2014 to the scenario using the difference between the total energy demand for 2014 (E_{2014}) and for each scenario ($E_{forecast}$).

$$load_{forecast}(t) = \left(1 - \frac{E_{2014} - E_{forecast}}{E_{2014}}\right) \cdot load_{2014}(t) \tag{2.10}$$

The values for the energy demand for the scenarios are listed in Table 2.8.

Table 2.8: Energy consumption scenarios

Scenario	Basis of calculation	2020	2030	2050
Scenario A [61]	Net electricity consumption	475 TWh	434 TWh	393 TWh
Scenario WWF-INV [62]	Net electricity consumption	-	-	324 TWh

Annual usage of wind and photovoltaic generation

The annual usage rate of Wind and PV is defined as the generating percentage of total installed capacity derived through historical data obtained from the transparency platform of the German TSOs [63]. It is important to note that the values of actual production are not exact measured values but extrapolated based on representative generators and regions. Figure 2.5 illustrates the quarter-hourly occurrences of the usage of installed capacity in Germany of PV and wind (off- and on-shore). Over 70 % of the time, the usage of PV remains below 10%. The usage of on and off-shore wind generators is relatively higher than PV generators, with the usage remaining below 10 % only 45 % of the time.

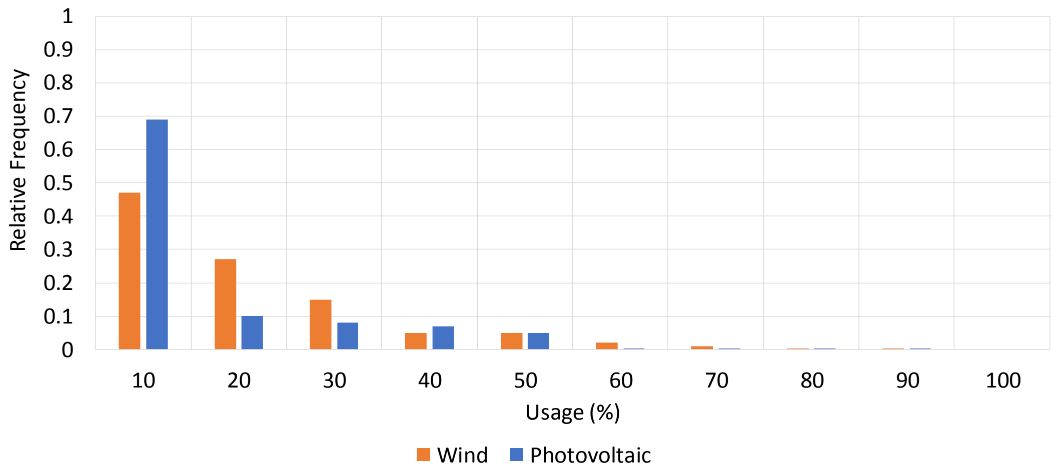

Figure 2.5: Annual usage of wind and photovoltaic installed capacities in 2014

Residual Load

Following the development of forecasted RES time-series using the annual usage, the residual load is calculated from the vertical load of all four German TSO zones for different levels of must-run capacities. The scenarios are based on minimum, medium and high levels of minimum-run requirements. The minimum-run generators are those which must always remain operational to serve frequency stability requirements.

Conventional Generation Parameters

For the development of the conventional sub- model, the total number of power plants is assumed to remain constant as given in [54], with a proportional increase in individual installed capacities scaled according to the levels obtained from the scenarios. The economic parameters for the conventional generation are listed in Table 2.9.

Table 2.9: Economic parameters for conventional generation (based on [64])

Fuel	Fuel Costs (€/MWh)	Variable Costs (€/MWh)	Start-up cost cold (€/MW)	Start-up cost warm (€/MW)
Lignite	2	26	40	25
Hard Coal	13	47	78	48
Natural Gas	25	72	50	41.3
Oil	62	202	0	0

The technical parameters for the conventional generation listed in Table 2.10 are measured under standard conditions.

Table 2.10: Technical parameters for conventional generation (based on [64])

Fuel	Start-up cold (h)	Start-up warm (h)	Minimum Up/down-time (h)	Ramp-rate (%/min)	Minimum Load (%/Net Capacity)
Lignite	6	5	4	0.58	50
Hard Coal	4	2	4	0.83	50
Natural Gas	2	1	6	0.83	40
Oil	1	0	6	20	50

Due to unavailability of required forecasting data, static values for load noise and forecasting errors are used, which are obtained from [51].

2.4.1.1 Modeling failure of conventional generation

The conventional generation model uses the unit commitment model as introduced in [65] to simulate the cost minimized operation of the generation capacity installed in Germany. The modeling is based on generator blocks according to energy source. The sum of production $P_i(t)$ of the generator i must satisfy the power demand $P_d(t)$, as given by

$$P_d(t) = \sum_{i=1}^{N} P_i(t) \qquad (2.11)$$

Where $i=1...I$ is the index number of the generating units with the total number of units as I.

The state transition is made using the decision variables $u_i(t)$ which denote the up (1) and down (-1) states of the system. If no change of state occurs between time t and $t+1$, $x_i(t+1)$ is incremented by 1. The count restarts upon occurrence of a state transition, as given by

$$x_i(t+1) = x_i(t) + u_i(t) \quad \text{if} \quad x_i(t) \cdot u_i(t) > 0 \qquad (2.12)$$

$$x_i(t+1) = u_i(t) \quad \text{if} \quad x_i(t) \cdot u_i(t) < 0 \qquad (2.13)$$

$$x_i(t+1) \geq 1 \quad \text{when} \quad x_i(t) \geq 1 \tag{2.14}$$

The minimum and maximum operating points of the generator are given by its upper $P_{i,max}$ and lower $P_{i,min}$ limits, as given by

$$P_{i,\min}(t) \leq P_i(t) \leq P_{i,\max} \qquad \text{if} \qquad x_i(t) > 0 \tag{2.15}$$

The negative and positive ramp-rate of each change in load level P_i must remain within the allowed ramp-rates Δ of individual power plants

$$[P_i(t+1) - \Delta_i] \leq P_i(t) \leq [P_i(t+1) + \Delta_i] \tag{2.16}$$

Economic and technical characteristics of individual power plants constrain the minimum number of hours T_{run} a generating unit must run before shutting down and the number of hours T_{down} it must remain shut down before starting up as defined by

$$u_i(t) = 1 \qquad \text{if} \qquad 1 \leq x_i(t) \leq T_{run} \tag{2.17}$$

$$u_i(t) = -1 \qquad \text{if} \qquad -T_{down} \leq x_i(t) \leq -1 \tag{2.18}$$

The goal of the model is to minimize the objective function F consisting of system cost based on the generation cost C_i, start-up cost $S_{i,Su}$

$$\text{Min} \quad F = \sum_{t=1}^{T} \sum_{i=1}^{N} [C_{i,f}(P_i(t) + S_{i,su}(x_i(t), u_i(t))] \tag{2.19}$$

2.4.2 Uncertainties introduced by conventional generation

The generation state and production level of generator g_i obtained from the unit commitment model are used to derive the corresponding failure probability P_f for a time t (in hours) on the basis of the historical values of operating time T_O and down time T_D is given in Table 2.11 by

$$P_f(g_i) = \frac{t}{T_O + T_D} \tag{2.20}$$

Table 2.11: Average operational and down time of generators [55]

Generator Type	Average Operating Time T_O (h)	Average Down Time T_D (h)
Lignite	494	30
Hard coal	402	30
Natural Gas Turbine	171	45
Oil powered	490	52

Similarly, the probability of a generator block not failing is given by

$$\overline{P_f(g_i)} = 1 - P_f(g_i) \tag{2.21}$$

The probability that none of the generator types from the *n* block fail during time *t* is then given by

$$P_0 = \prod_{i=1}^{n} \overline{P_f(g_i)} \tag{2.22}$$

It follows that the probability of failure of exactly *d* power of *k* number of generators in the *n* block is given by the cumulative failure probability of the concerning blocks and the probability of non-failure of the remaining generators, as

$$P_f(g_d) = P_o \cdot \prod_{i=1}^{k} \frac{P_f(g_i)}{\overline{P_f(g_i)}} \tag{2.23}$$

When the failure of power *d* can take place through several combinations of *k* number of generators, the total probability of failure is calculated by combining the probabilities as follows:

$$P_f(g_d) = P_o \cdot \left[\prod_{i=1}^{k1} \frac{P_f(g_{i1})}{\overline{P_f(g_{i1})}} + \prod_{i=1}^{k2} \frac{P_f(g_{i2})}{\overline{P_f(g_{i2})}} \ldots + \prod_{i=1}^{kn} \frac{P_f(g_{in})}{\overline{P_f(g_{in})}} \right] \tag{2.24}$$

For this investigation, the individual generators are grouped together into blocks of lignite, hard coal, gas and oil-based power plants and the probabilities of unplanned outages calculated according to the values in Table 2.11.

2.4.3 Modeling of the reservation requirement model

The demand for LFC is caused by various uncertainties described by their characteristic probability distributions, which can be approximated with the standard Gaussian distributions [51]. Momentary noise in the load is caused by disturbances contributing to the demand for frequency restoration reserve (FRR). Long-term deviations forecasted load, PV and wind feed-ins contribute to replacement reserve (RR). Excess and scarce feed-ins result respectively in the demand for negative and positive reserve. Failures of conventional generation only result in a deficit in generation and hence the demand for positive reserve. The errors and their effects on the demand for LFC are summarized in Table 2.12.

Table 2.12: Factors influencing the demand for LFC

Factor	Restoration Reserve	Replacement Reserve
Load noise	Positive/negative	Positive/negative
Generator Failure	Positive	Positive
Load Forecasting Error	No effect	Positive/negative
PV Forecasting Error	No effect	Positive/negative
Wind Forecasting Error	No effect	Positive/negative

The values for standard deviation (σ) and expectation (μ) for the distribution of forecasting error of wind and load forecasting are determined using historical data. The actual production values are extrapolated from representative regions. This also introduces an inherently unavoidable error in the source data. The individual error probability distributions are convoluted to generate a density function f_i for the overall error as

$$f_i(error) = \frac{1}{\sigma_i \sqrt{2\pi}} e^{-\frac{(x-\mu_i)^2}{2\sigma_i^2}} \tag{2.25}$$

where i is the type of error listed in Table 2.12.

Integration of the distribution function is then used to determine the necessary levels of reserve based on the allowed deficit limit in the reserve compensation. This deficit limit was recently increased from 0.1 % to 0.05 % [51] by the grid operators, which corresponds to about 4 hours in a year. Consequently, FRR as well as total reserve must be able to compensate for 99.95 % of all errors, as illustrated in Figure 2.6.

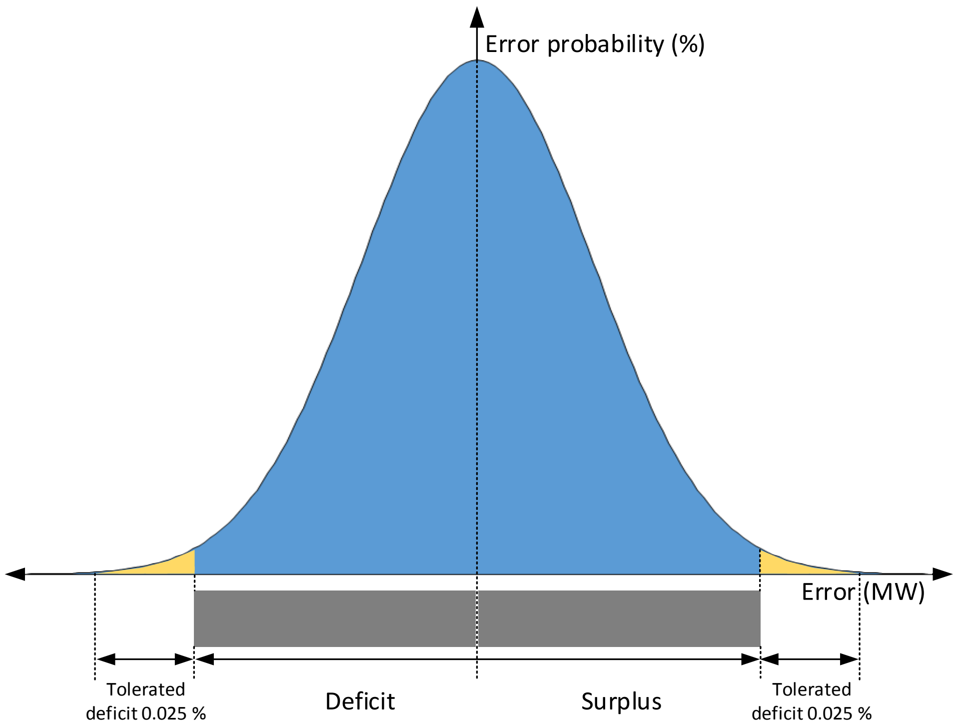

Figure 2.6: Determination of reserve requirement based on deficit probability

To determine the values for standard deviation and expectation for wind forecasting error, monthly variations in the hourly values are compared. The range of standard deviation for peak PV is illustrated in Figure 2.7, showing uniformity over the year. However, the values for expectation have a wider variation. The standard deviation for PV remains high during the winter months, dropping to its minimum values during summer as the forecasts improve.

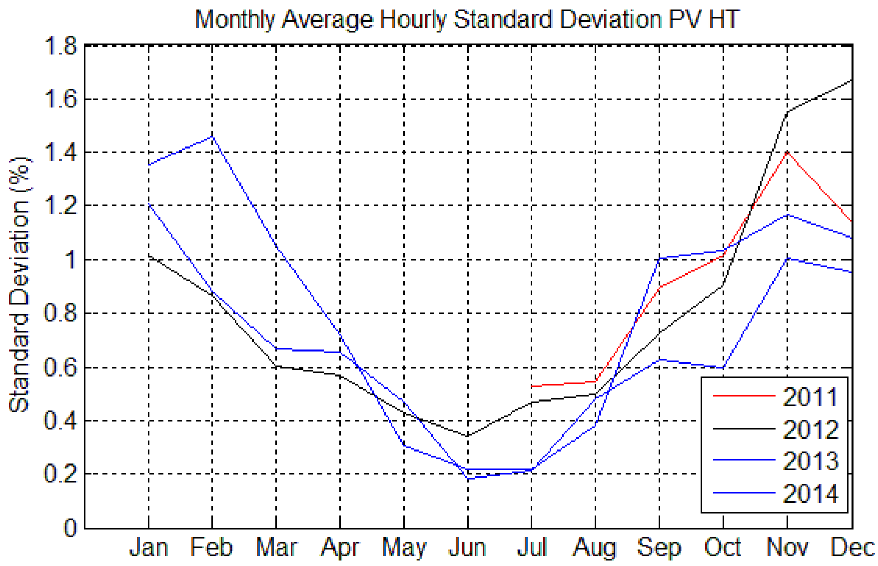

Figure 2.7: Standard deviation of peak PV forecasting error

The monthly variations in the hourly values of standard deviation for the wind forecasting error are illustrated in Figure 2.8, showing relatively less uniformity compared to PV. The trend is also the opposite of PV, whereby lower values are observed during the winter than summer.

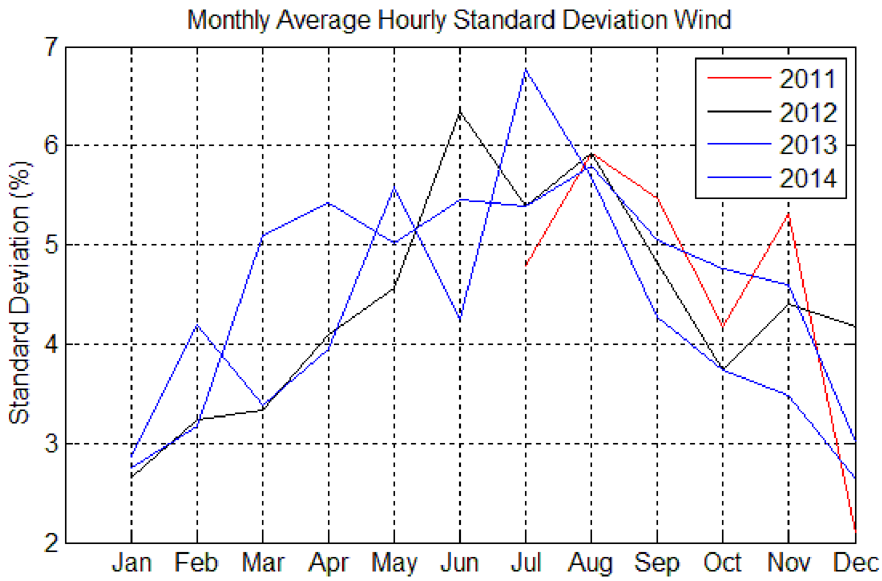

Figure 2.8: PV peak (HT) and wind standard deviations and expectations (mean) in hourly forecasting errors for the period of 2011-2014

For modeling purposes, the average monthly values from the 2011-2014 period are used. The values for PV and wind expectations for the simulation model are measured separately for the peak and off-peak periods from the historical feed-in, as given in Table 2.13.

Table 2.13: Average expectation of the hourly forecasting error calculated using historical data

Period	Wind expectation (%)		PV expectation (%)	
	Peak	Off-peak	Peak	Off-peak
January	1.44	1.12	0.40	-0.07
February	1.35	0.79	0.27	0.07
March	1.87	0.96	-0.08	-0.06
April	1.32	1.09	-0.07	-0.17
May	2.12	1.84	0.04	-0.06
June	1.12	0.92	0.22	-0.33
July	0.86	0.96	0.34	0.10
August	1.16	0.85	-0.05	-0.24
September	1.55	0.49	0.06	-0.27
October	1.15	0.16	0.33	-0.71
November	2.04	1.09	-0.19	-3.34
December	1.33	1.35	-0.19	-0.14

The average monthly values for PV and wind standard deviation for the simulation model are also measured separately for the peak and off-peak periods from the historical feed-in, as given in Table 2.14.

Table 2.14: Average standard deviation of the hourly forecasting error calculated using historical data

Period	Wind standard deviation (%)		PV standard deviation (%)	
	Peak	Off-peak	Peak	Off-peak
January	6.83	3.78	16.7	5.16
February	8.74	3.68	13.9	9.82
March	7.40	4.70	11.9	11.8
April	7.41	6.14	11.1	10.2
May	8.52	7.79	6.00	14.2
June	9.28	7.01	2.86	13.1
July	10.3	8.68	4.72	14.0
August	10.8	8.66	8.48	17.2
September	9.57	7.77	13.0	16.7
October	9.31	5.20	14.6	16.4
November	9.63	8.48	19.6	13.7
December	7.10	5.45	17.1	9.31

The values listed in Table 2.13 and Table 2.14 are used to model the probability distributions for RES feed-in, whereas due to lack of corresponding source data, static values from [51] are used for modeling the load noise and forecasting errors, as given in Table 2.15.

Table 2.15: Static values for load noise and forecasting errors [66]

Error type	Standard deviation (%)	Expectation (%)
Load Noise	0.5 – 1.5	0 – 1.4
Load Forecasting Error	1.5 – 5	0

The forecasting and load noise errors for one hour in the evening are illustrated in Figure 2.9. As shown, the probability of PV forecasting error during the evening is narrowly distributed around zero MW.

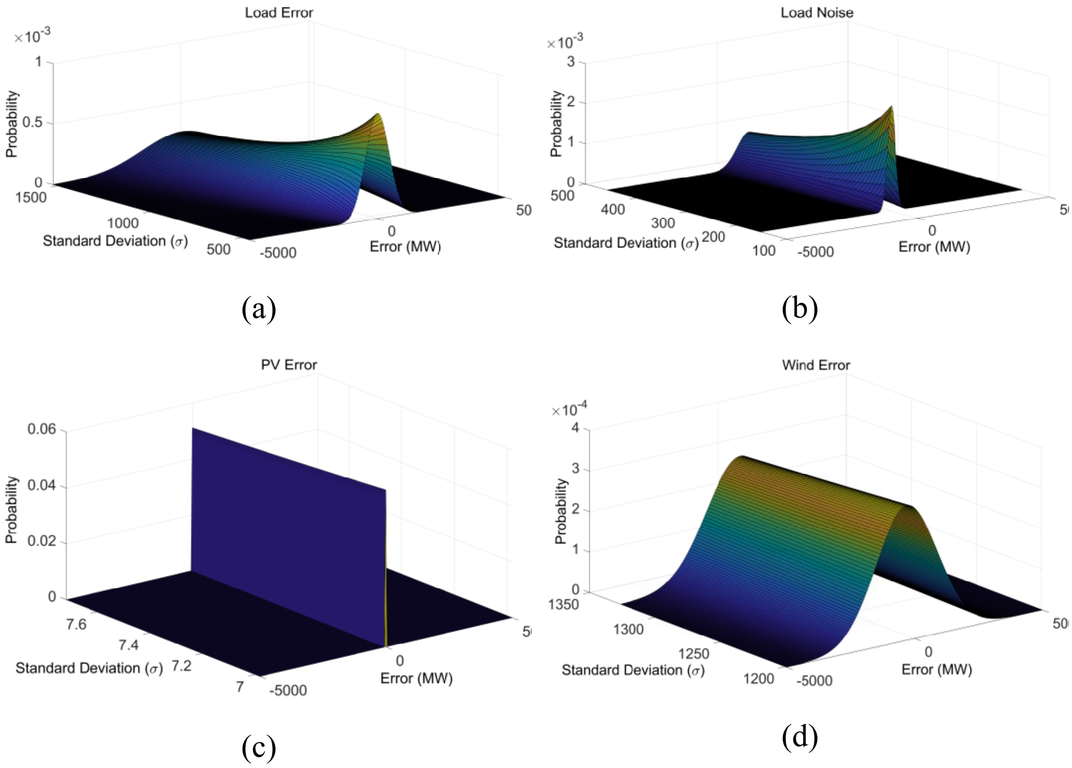

Figure 2.9: Probability distribution of (a) load forecasting error, (b) load noise error, (c) PV forecasting error and (d) wind forecasting error

2.4.4 Simulation results

Simulations from the model are performed using the official NEP 2014 estimates for 2034 [67]. The results of the market model are validated with the analysis performed in [68]. which provides two reference scenarios “Reference” and “Reference Adaptive” for the demand of FRR and RR in 2030. The difference in minimum and maximum demand is introduced by the selection of monthly average standard deviation and expectation from historical values. As mentioned earlier. the utilization of ranges for these values causes a demand that varies between two extreme values.

The results of the simulation for positive FRR in 2034 are illustrated in Figure 2.10. Comparison of these results with the values available from the simulation in [68] for 2030 shows that the values for the two scenarios (“Reference” and “Reference Adaptive”) lie within the upper and lower limits of the simulation results.

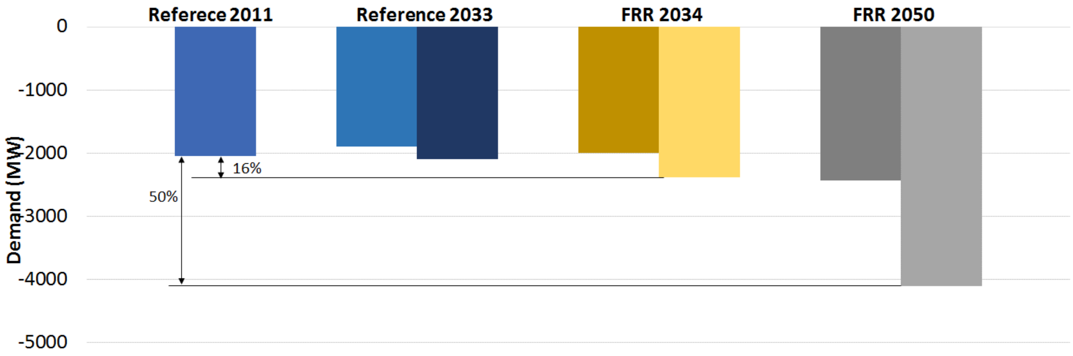

Figure 2.10: Average Positive FRR 2034 in comparison with reference values obtained from [68]

Demand for RR is forecasted to rise by about 40 % and 44 % for 2034 and 2050 respectively, as illustrated in Figure 2.11.

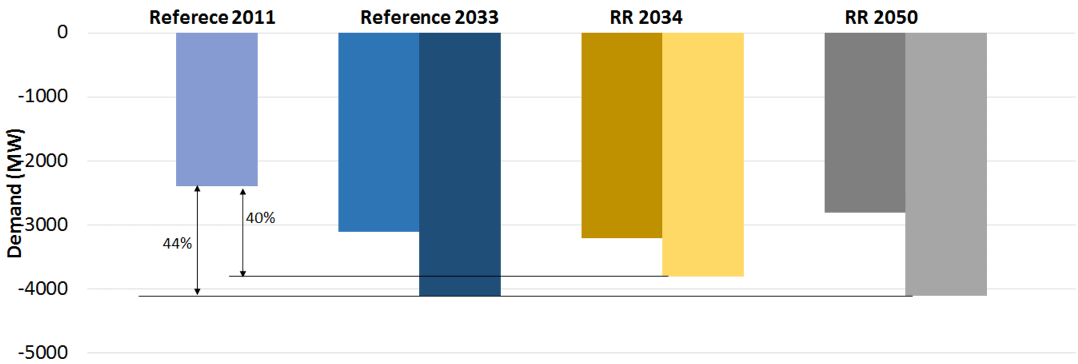

Figure 2.11: Average Positive RR 2034 in comparison with reference values obtained from [68]

The simulation results for negative FRR (Figure 2.12) show a significantly lower demand when compared with the results from the reference study for validation. This occurs because, due to unavailability of historical data, historical load curve from 2012 is used to model the demand for FRR in 2034.

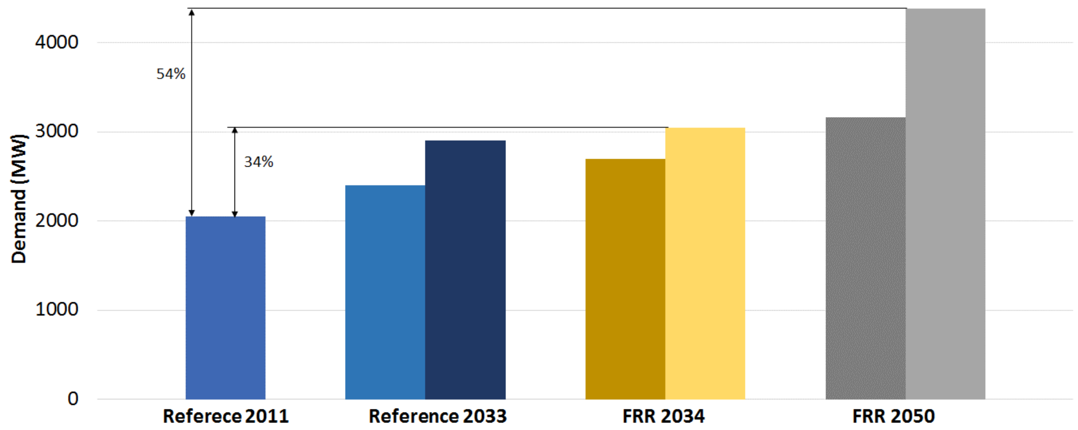

Figure 2.12: Average Negative FRR for 2034 in comparison with reference values obtained from [68]

Similar to positive RR, the simulation shows that the demand for negative RR is expected to increase by about 50 % and 51 % for 2034 and 2050 respectively, as illustrated in Figure 2.13.

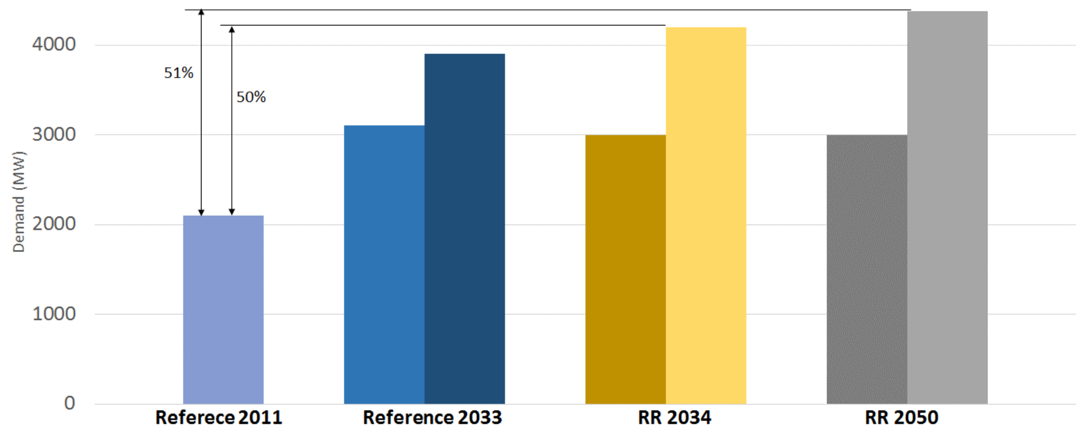

Figure 2.13: Average Negative RR for 2034 in comparison with reference values obtained from [68]

2.5 Conclusions

The simulation shows that an increase of the renewable energy share in the energy mix as planned in the NEP 2014 [69] will lead to an increase in the overall demand for frequency control reserve by up to 54 % in 2030 from 2011 under current market conditions. The results of this simulation are within the range of the results of the analysis in [68], which uses static values for wind and PV forecasting error. This rise in FRR and MR can potentially increase or reduce by any changes in the overall energy market. The wide difference between the minimum and maximum estimates is due to the wide disparity in monthly average values of forecasting error expectations. Improving forecasting methods will have a positive impact on the size of the needed reserve.

This increase in demand for reserve is evidence that increasing integration of volatile RES is detrimental to frequency stability and puts further strain on the ability of the TSOs to guarantee a stable frequency. The survey of load frequency control systems has already illustrated the legacy issues facing the current frequency control mechanisms and the changes necessary to facilitate integrate distributed flexibility in frequency control reserve. In view of this, it is pertinent to analyze alternative approaches to supporting frequency stability, as described in the following chapter.

3 Alternative approaches to providing frequency control in the European network

In addition to the increasing demand for frequency control reserve due to high renewable energy in-feed, challenges facing the grid include increasing number of transactions between market participants requiring access to real-time data and communications. Proliferation of smaller distributed generating units contributes to increasingly localized generator-load relationships, while also increasing transformer and line loading with the introduction of new loads such as EVs. These challenges are coupled with the increasing trend of regional interconnection in Europe and regional imbalances in generation and loads with offshore wind in the north and PV in the south and concentration of loads in central Europe.

To meet these challenges, the power system requires infrastructure modernization. This modernization involves data delivery mechanisms and grid expansion. Considering these challenges, it is necessary to rethink the approaches to LFC which underscores grid reliability, security and cost effectiveness but also integrate improved controls in power system management.

In the centralized control briefly discussed in chapter 2, the control centers serve as a supervisory platform and interface between grid operators and generators. The supervisory control and data acquisition (SCADA) system monitors and collects the system data in form of voltage, current, active and reactive power and circuit breaker positions; and dispatches remedial settings to the generators. Although the data collection at substations is much faster (order of milliseconds), the transfer and processing of this data slows down during communication with the control centers due to infrastructural constraints. Real-time exchange of data between distribution grid and the control centers therefore is crucial for frequency stability.

The need for decentralization of control has also been identified in [14], whereby control of distributed generation at the distribution system operator (DSO) level could serve to reduce complexity and improve overall system stability. Application of AGC at the decentralized level has been shown by [70] to be technically feasible, provided the current communication system is modified to allow flexible network communication for real time data access. An important challenge to robust decentralized frequency control is the likelihood of delays and failures while communicating under an open network and the sensitivity of system stability to these delays.

3.1 Development of evaluation framework

The evaluation is based on the weighted indicator scoring framework, with examples of use in evaluating urban regeneration practices in [71] and agroforestry in [72]. The scenarios analyzed for infrastructure requirements of frequency control are based on approaches ranging from decentralized to centralized and the compensation mechanisms. The centralized approach of reserve dispatch assumes that the development of the European interconnected grid has reached the level where grid capacity issues do not hinder transport of large quantities of power over long distances. Imbalances and deficits in any region can thus be compensated from any node of the interconnected grid. With the proliferation of electric vehicles, which are expected to be concentrated in metropolitan areas with high population densities [73], this means the unevenly distributed capacity available over the interconnected grid can be fully utilized by a central dispatching authority to support stability measures. Under the current approach for frequency restoration in Germany, the control center collects information from the grid, calculates the ACE, dispatches the required generation levels to the flexibilities in the grid and then performs the financial accounting based on the energy delivered. The ACE calculation and dispatch is performed in real-time and the financial transactions are settled at the end of the product contract period. The centralized scenario further expands this concept to a transnational level, with a control center calculating the imbalances and dispatching the reserve over multiple zones spanning several countries in the synchronous grid. The main limitation of the centralized approach is the timely exchange of information from control areas spread over distantly connected geographical territories and the associated complex computation and storage.

Decentralized control is already used to perform frequency containment, which brings the frequency deviations to a quasi-steady state [60]. However, frequency restoration requires a coordinated approach to avoid over- or under-shooting the nominal value. In the current system, this coordination is performed by the control center operated by the grid operators. The control centers collect and monitor tie-line power exchanges and control area active power imbalances and coordinates the activation of reserves to restore the frequency to its nominal value. In a completely decentralized control, no exchange of information takes place between control areas. The activation decisions are taken by the decentralized units on the basis of locally measured frequency deviations. In order for an automatic decentralized LFC to be practicable, it would need a coordination between participating reserves, which has been simulated in [74] and [75] using peer-to-peer communication. Furthermore, small-scale simulations of a decentralized LFC for an automatic frequency restoration have been performed in [76–82], albeit without an analysis of infrastructure requirements.

The investigation of the decentralized approach to frequency control is motivated by three potential developments in the future: firstly, the public opposition to extensive grid expansion with high voltage transmission and consequently a preference for decentralized solutions to stability issues; secondly, the high economic cost of grid expansion and centralized generation units; and thirdly, the apparent increase in distributed energy resources (DER) and the corresponding need for decentralized solution to instability issues in the grid. As also discussed in [14], DSOs can play an expanded role in controlling active and reactive power in areas with high DER. This is evaluated as part of the decentralized frequency control scenario, in which the real-time response to frequency deviations is performed locally either by the DSO, or the DER themselves. This means the TSOs forego the responsibility to dispatch the loads and generation for LFC.

The analysis is limited to the level of infrastructure sophistication and complexity required to implement the activation and the corresponding compensation for the participating generation and load for each scenario. Additionally, the economic feasibility of these scenarios is not taken under consideration for this analysis. The various scenarios for activation of reserves in a future LFC are categorized into centralized and decentralized systems according to their level of position in the grid with reference to the existing order in Germany and types of compensation.

3.1.1 Centralization of control

- GCC

GCC represents the scenario in which reserves are activated jointly by a group of several TSOs within a synchronous area and forms the ‘business as usual’ or reference scenario. This scenario is based on the current practice of the German TSOs as part of the Grid Control Cooperation (GCC) [83].

- Transnational

The Transnational-CEP scenario is part of the centralized scenario category, in which the activation of reserve takes place for the interconnected network of Continental Europe for a jointly dispatched LFC.

- DSO

Active role of DSOs in areas with high DER penetration can help reduce the overall complexity of decision-making, as discussed in [14]. This is explored under this decentralized scenario, LFC is performed at the distribution grid level, with the DSO cooperating with neighboring DSOs using the same principle as in GCC.

- Automatic activation

Under automatic activation, a central authority does not exist for the calculation of imbalances and activation of reserves. Automatic activation from loads means that load and generation in the power system can self-adjust their respective demand and generation of electricity based on deviations in system frequency and/or voltage. Depending on the types of load/generation as well as power system needs, the autonomous response/generation controller can adjust the operating point by simply turning it on or off, or by adjusting the settings of its control parameters.

3.1.2 Compensation mechanisms

- Capacity and energy payment

The activated generation and loads participating in the reserve provision are compensated for both capacity allocation and energy delivered during actual activation. This regime is used for FRR and RR products in the existing German zones.

- Capacity payment

Loads participating in the reserve provision are compensated only for the capacity allocation. The actual activation of the reserve is not compensated.

- Mandatory provision

Under mandatory provision, no payment is made for the allocation and activation. Instead, the activation is mandatory for all generation and loads above a threshold connected to the grid. An example of this practice can be found in North America, where the grid operator PJM uses the mandatory service Frequency Response for [84] containing frequency deviations.

The assumptions outlined above are used to generate the 12 scenarios listed in Table 3.1.

Table 3.1: Scenarios for the investigation of infrastructure requirements

Activation Responsibility	Type of financial compensation			Product Category
	Capacity & Energy (CEP)	Capacity Payment (CP)	Mandatory (M)	
GCC	GCC-CEP	GCC-CP	GCC-M	Centralized
Transnational	Transnational-CEP	Transnational-CP	Transnational-M	Centralized
DSO	DSO-CEP	DSO-CP	DSO-M	Decentralized
Automatic activation	Automatic-CEP	Automatic-CP	Automatic-M	Decentralized

The GCC scenarios with CEP/CP/M compensation approaches differ in the responsibilities of each entity and the corresponding communication requirements. Under GCC-CEP, the German TSOs calculate and dispatch reserves jointly under a network control concept called GCC based on the deviations in the system frequency. The reserve is procured through the control power market, with activation taking place from the grid operator's control center. The capacity payment for the reserve as well as the metered energy transferred during the activation is financially compensated for by the grid operator. This differs under the GCC-CP approach illustrated in Figure 3.1, where actual activation of energy is not metered or compensated. The control power market is not required for the GCC-M scenario, where activation of the reserve is not compensated.

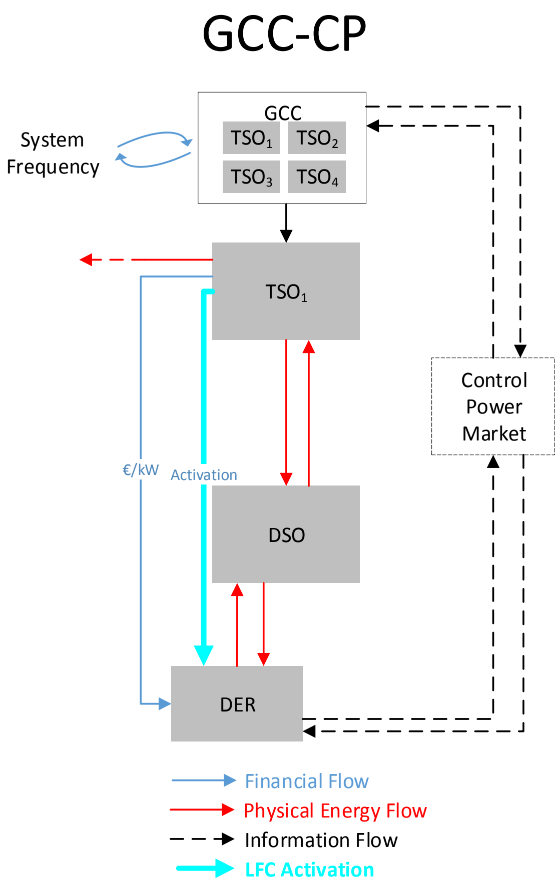

Figure 3.1: LFC mechanism scenarios with GCC control

The Transnational scenarios with CEP/CP/M approaches differ in the responsibilities of each entity and the corresponding communication requirements. Under Transnational-CEP illustrated in Figure 3.2, a larger group consisting of grid operators in the

ENTSO-E zone calculates and dispatch reserves jointly. The reserve is still procured through the control power market and the activation takes place through a control center. The capacity payment for the reserve as well as the metered energy transferred during the activation is compensated by the grid operators. Similar to GCC-CP approach, actual activation of energy is not metered or compensated for under Transnational-CP scenario. The control power market is not required for the Transnational/M scenario as the activation of reserve is mandatory.

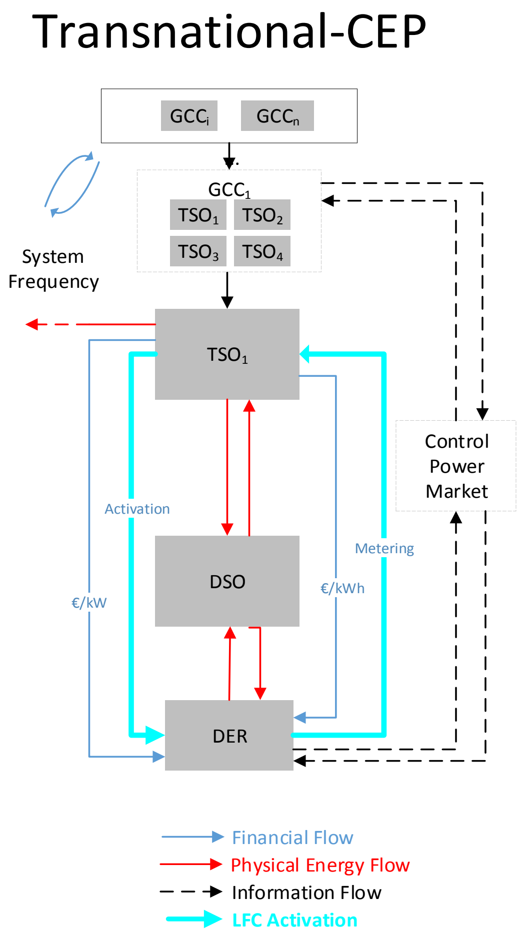

Figure 3.2: LFC mechanism scenarios with Transnational control

The DSO scenarios with CEP/CP/M approaches follow the same principle as the Transnational and GCC scenarios, with the control center located at the distribution grid operator level. The DSO-CP scenario is illustrated in Figure 3.3.

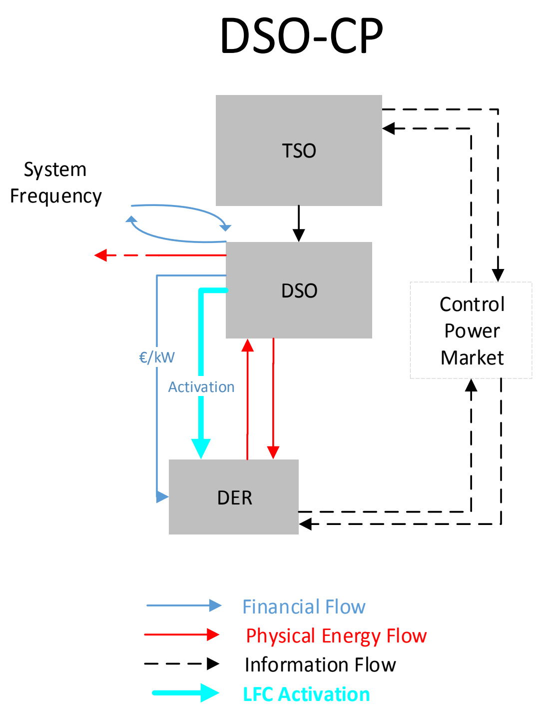

Figure 3.3: LFC mechanism scenarios with DSO control

The automatic activation scenarios with CEP/CP/M approaches differ from other scenarios due to the absence of a control center for activation and coordination of the reserve. Under the CEP/CP approaches, the reserve is activated automatically based on the system frequency and compensated for both capacity and energy or only capacity provision. Under the Automatic-M scenario, it is assumed that participation in LFC is mandatory for all loads fulfilling certain basic conditions such as controllability and capacity. The Automatic-CEP scenario is illustrated in Figure 3.4.

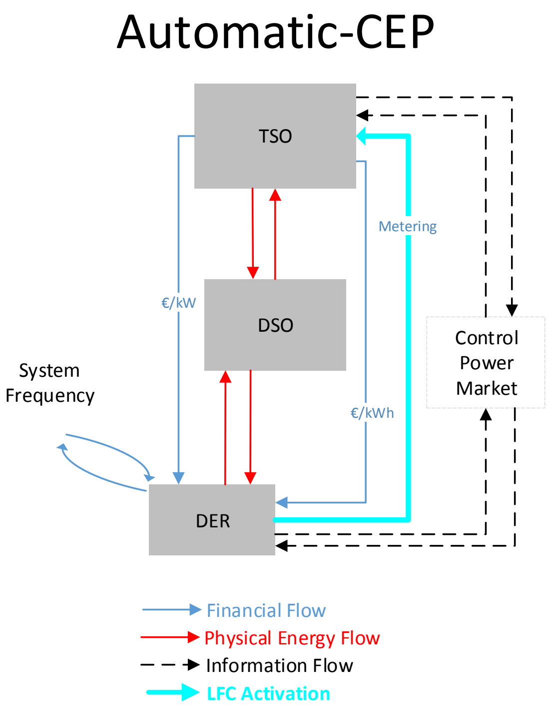

Figure 3.4: LFC mechanism scenarios with automatic activation

3.2 Indicator set for infrastructure requirements

The requirements for the scenarios are evaluated based on the following four indicators and further categorized into parameter listed in Table 3.2:

- Planning requirements for the units participating in the provision of LFC consist of the planning horizon offer and response optimization capabilities and pre-qualification testing.
- Information and communication technology (ICT) infrastructure requirements consist of parameters for communication and IT reliability, security and latency.
- The complexity indicator consists of the requirements for communication periodicity data processing and the number of entities involved in the control decision-making.
- Regulatory requirements comprise of parameters derived from the codes and standards with which units participating in LFC must comply.

Table 3.2: Parameters for the evaluation of infrastructure requirements

Planning Parameters		Description
P-1	Planning requirement for units participating in LFC	Determines the planning horizon required for units participating in LFC.
P-2	Deployment optimization	Determines the optimization requirements for the offer and reserve deployment for units participating in LFC.
P-3	Pre-qualification Test	Determines the requirement and stringency of the pre-qualification test for units participating in LFC.
ICT Parameters		Description
I-1	Information layer: Bandwidth for real time information exchange between control center, measurement devices and participating units	Determines the level of bandwidth requirement for real-life communication between control center←→measurement devices control center ←→units providing LFC
I-2	Cyber security	Determines the necessary level of data encryption.
I-3	Reliability of control and communication	Determines the necessary level of redundancy including nodes/branch redundancies and exclusive use of cables and control equipment.
I-4	Maximum allowable latency	Determines the maximum allowable latency in the communication between units. grid measurement devices and the control center.

Complexity Parameters		Description
C-5	Periodicity of communication	Determines the periodicity of communication between control center and units participating in LFC.
C-6	Change management	Determines the sophistication of the process used for change management.
C-7	Data Processing Requirements	Determines the level of sophistication of data processing required for collection of information calculation of reserve requirements as well as dispatch and monitoring of signals.
C-8	Number of components and entities	Determines the number of components involved in the chain from measurement devices to activation and monitoring of reserve.
Regulatory Parameters		Description
R-1	Reporting of failures, damages and crashes	Determines the requirement for reporting of control and communication failures damages and crashes to the grid operator.
R-2	Confirmation of the connection of unit by the grid operator	Defines the requirements for confirmation of the unit providing LFC by the connecting grid operator.
R-3	Forecasting of DER participating in LFC	Measures the capability of forecasting the availability of DER to participate in LFC.
R-4	Communication over the low voltage network	Determines whether communication over the low voltage network (PLC) is necessary.

R-5	Dedicated metering	Determines whether a dedicated meter is needed for the unit providing LFC.
R-6	Smart grid enabled metering infrastructure at the LFC provider's end	Determines whether smart grid enabled metering equipment is necessary at the LFC provider in compliance with VDE-AR-N 4101 [85].
R-7	Quality of data measurement	Determines requirement of data measurement devices for compliance with VDE-AR-N 4400 [86].
R-8	Power factor	Determines the requirement for compliance with the minimum requirement of power factor for units providing LFC.

For the weighted indicator point scoring framework-based evaluation, each parameter is assigned a score ranging between ±3 relative to the GCC-CEP reference scenario, which is assigned a score of 0 (see Figure 3.5) as it represents the current practice of the German TSOs. A positive or negative relative score is assigned corresponding to a relatively higher or lower infrastructure requirement, indicating a higher score for scenarios with higher requirement levels. The following sections describe the rules of assignment of score for individual indicators.

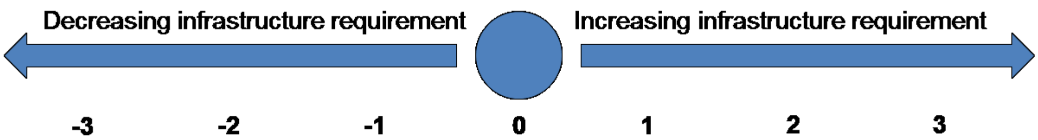

Figure 3.5: Methodology for scenario evaluation

3.2.1 Ease of planning

Planning of flexibility is a basic requirement for units participating in LFC for all scenarios. Actual tendering time window of the LFC product determines the length of the planning horizon i.e. monthly weekly or daily tenders. For the purpose of this evaluation, there is no difference in the planning horizon requirements for products with capacity and energy payments (CEP) or simple capacity payments (CP). However, products with mandatory participation would be required to maintain a flexibility band indefinitely leading to a score of -3. Similarly, automatic activation would also require a flexibility band of indefinite horizon.

Deployment optimization is necessary for all units participating in scenarios with payments for LFC reserve i.e. CEP and CEP, as these products require a cost-based optimization. For this reason, mandatory provision of LFC does not require any form of optimization due to the absence of a bidding process and is assigned a score of +3. For scenarios with energy payments (CEP), a participating provider consisting of smaller units would need to optimize its deployment at the same frequency as the base scenario (GCC-CEP) and are consequently assigned a score of 0. LFC providers in scenarios with only capacity payments (CP) need only optimize the capacity offer during tender clearing, receiving a score of +2.

Technical pre-qualification tests are conducted by the grid operators before the LFC providers are cleared for participation. These tests ensure compliance with the minimum technical capability standards as outlined by the grid operators. Scenarios with Transnational controlled LFC will require less stringent pre-qualification, as due to larger zones, the failure of one unit would be readily compensated by other units in the zone. These scenarios are assigned a score of +2. As the zones become smaller with DSO-level control, the relatively lower availability of participating units will increase the reliability requirement for the participating units, leading to more stringent pre-qualification testing and are assigned a corresponding score of -2. Under automatic participation, all units connected to the grid must fulfill the basic requirements as set by the grid operators foregoing the need for a special pre-qualification testing, with an assigned score of +3.

3.2.2 ICT requirements

Real-time exchange of information is required for all scenarios where a control center is responsible for collecting measurements, calculating imbalances and dispatching resources. Proliferation of DER requires not only greater co-ordination between DSO and control centers, but also faster reaction at the control centers and communication between the TSO, as identified by [14]. Accordingly, highly centralized control i.e. transnational scenarios will require large bandwidth for communication with equipment over a large zone and hence are assigned a score of -3. Following the same principle, scenarios with smaller zones such as those controlled by DSOs will require relatively lower bandwidth, with a corresponding score of +1. Scenarios where units respond automatically to frequency deviations will rarely require real-time communication and correspondingly are assigned a score of +2.

All scenarios with communication between a control center and measurement equipment/LFC providing units require a minimum level of communication. Communication over larger zones i.e. transnational scenarios require higher levels of security as any cyber-attack on a single point of weakness would pose risks to the overall grid and are accordingly assigned a score of -2. Similarly, the decentralized LFC faces lower risk in case of failure, and these scenarios are assigned positive scores ranging from +2 to +3.

The level of reliability adequate for a secure operation of LFC is defined by the redundancies in the nodes and branches as well as exclusive use of cables and the control and communication equipment, as instructed in [87] for the existing structure of LFC. For scenarios with trans-national activation of LFC, the requirements for reliability will be considerably higher as failure in any one location would disrupt the control in a larger area. Consequently, trans-national scenarios are given a score of -2. Similarly, scenarios with decentralized control will require lower level of redundancy and are accordingly assigned scores of +1 and +2.

Communication over wider areas demands lower latency, with trans-national scenarios assigned scores of -3. Communication for decentralized scenarios consisting of both DSO-controlled LFC and automatic activation will tolerate considerably higher latency and are assigned a corresponding score of +1 and +2 respectively.

3.2.3 Level of complexity

The periodicity of communication depends on the presence of a control center for coordinating the dispatch of participating units, with units required to communicate their operating point to the control center every 2 seconds [87]. These scenarios are assigned scores of 0 as they require the same communication periodicity as the base case (GCC-CEP). Scenarios with automatic activation are ranked higher (+2) due to the absence of a control center.

The requirement for the change and patch management is determined by the number, level and the frequency of changes and patches expected to be implemented for a scenario. This parameter evaluates the sophistication level of such a system appropriate for each scenario. Scenarios with a control center (trans-national, GCC and DSO) and CP/CEP payments require the same level of change/patch management sophistication as the base case (GCC-CEP) due to regular bidding and optimization. Similarly, among the scenarios with control centers, mandatory provision (M) requires relatively lower sophistication in change/patch management. Scenarios with automatic response require relatively lower sophistication in their change/patch management in comparison with centrally controlled LFC due to a relatively simpler system. Accordingly, mandatory response is assigned the highest score of +3 for its least requirement for change and patch management.

LFC control over relatively large areas (Transnational) will require a correspondingly large data processing capability and are assigned a negative score. As the control zone becomes smaller, the data processing requirement reduce substantially, and the scenario with GCC and DSO control are given scores of 0 and 2 respectively. It follows that automatic activation requires very little data processing, with the automatic activation with mandatory participation (Automatic-M) requiring the lowest level of data processing capabilities.

The relative increase or decrease in the number of entities involved in the calculation of imbalances and dispatch of resources are used to assigned scores to each scenario (see Figure 3.1). Automatic-M scenario is assigned the highest score of +3 due to the absence of a control center and compensation mechanism.

3.2.4 Regulatory requirements

The requirement to inform the connecting grid operator about any failures, damages and crashes is applicable for all scenarios where participation in LFC is optional and centrally controlled. These scenarios assume no departure from the existing principle and are accordingly assigned a score of 0. Automatic activation is provided by all load above a threshold capacity and must respond appropriately to changes in the system frequency. Reporting of failures, damages and crashes to the grid operator is not required for such units and these scenarios are assigned a corresponding score of +3.

Confirmation of the connecting loads providing LFC is applicable for all scenarios where participation in optional and controlled through a control center operated by the grid operators. These scenarios are assigned scores of 0. The three scenarios with automatic activation are correspondingly assigned scores of +3.

Similar to the scoring rules outlined for other parameters in the regulatory requirement indicator, LFC mechanisms with a control center are assigned scores of 0. Scenarios with automatic activation are accordingly assigned scores of +3. All units communicating with the grid through powerline communication (PLC) must comply with the relevant communication disturbance and noise regulations. This parameter is applicable only to the LFC mechanisms that require communication over the grid. A dedicated metering system is required for all scenarios with energy-based remunerations i.e. CEP. Units participating in LFC must comply with the regulations similar to those set in VDE-AR-N-4101 [85], which outlines the capability requirements for smart-grid enabled metering infrastructure. This regulation is only applicable to LFC mechanisms with energy-based remunerations (CEP).

The quality of data measurement must comply with the standards similar to those outlined in VDE-AR-N 4400 [86]. This regulation is applicable for all scenarios where a grid operator dispatches the resources i.e. GCC, Transnational and DSO scenarios. It is also applicable for Automatic activation mechanism where CP or CEP remuneration is involved. Accordingly, only Automatic activation with mandatory participation is assigned a score (+3). The requirement for a minimum power factor is applicable for all units connected to the grid.

3.3 Indicator based evaluation of infrastructure requirements

The parameters are assigned equal weights for equal significance and are combined to form the indicators, which are then evaluated for each scenario. The percentage infrastructure requirements score p_e is calculated on the basis of the actual score p_i and the maximum achievable score $p_{max},$ as given by

$$p_e = \frac{\sum_{i=1,2..n}^{n} p_i}{p_{\max}} \cdot 100 \tag{3.1}$$

The evaluation of the four indicators (Figure 3.6) shows that a decentralized approach would most strongly impact the regulatory requirements with a decrease of over 35 – 43 % in the case of Automatic activation with CEP, CP and M compensation. This is followed by a decrease of about 7 – 9 % in complexity and 10 % in ICT infrastructure requirements. Planning requirements only show a decrease of 3 % due to the requirement of maintaining a flexibility band for an indefinite period. Implementing the DSO activation scenarios results in a decrease in all indicators, again most strongly impacting the regulatory requirements, followed by the planning and ICT infrastructure requirements.

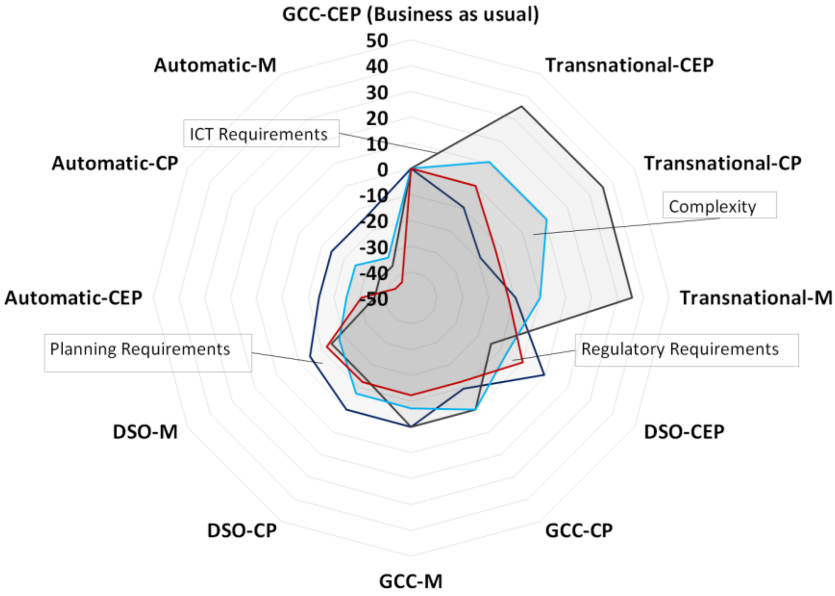

Figure 3.6: Infrastructure requirements indicator evaluation

Implementing the GCC activation approach with CP or M compensation mechanisms results in substantial reduction in regulatory and ICT requirements. Implementing a highly centralized transnational approach shows a substantial increase of 11 % in regulatory requirements when coupled with CEP compensation. The ICT requirements are also increased by 10 % under this approach. Planning requirements are reduced by about 2 – 4 % due to the existence of a larger control area.

The overall evaluation result is illustrated in Figure 3.7, with each bar representing the change in the infrastructure requirements in comparison with the base scenario (GCC-CEP). Based on this evaluation, implementation of transnational control of frequency services demands an increase of 9 % in the infrastructure requirements. These requirements are reduced with simplification of the compensation mechanism in Transnational-CP and Transnational-M. Decentralization of frequency control to the DSO level in combination with the CEP compensation mechanism results in improvements of only 3 %, whereas simplifying the compensation mechanism to only provide capacity payments within the existing control concept result in an increase of 6 %. Outright removal of a coupled compensation mechanism within the GCC concept cause no decrease in the infrastructure requirements. Similarly, using CP and M compensation mechanisms with a DSO control help reduce the requirements by 10 % and 13 % respectively. The highest improvements in infrastructure requirements is achieved by using automatic control, ranging from 28 % to 34 % for the type of compensation mechanism.

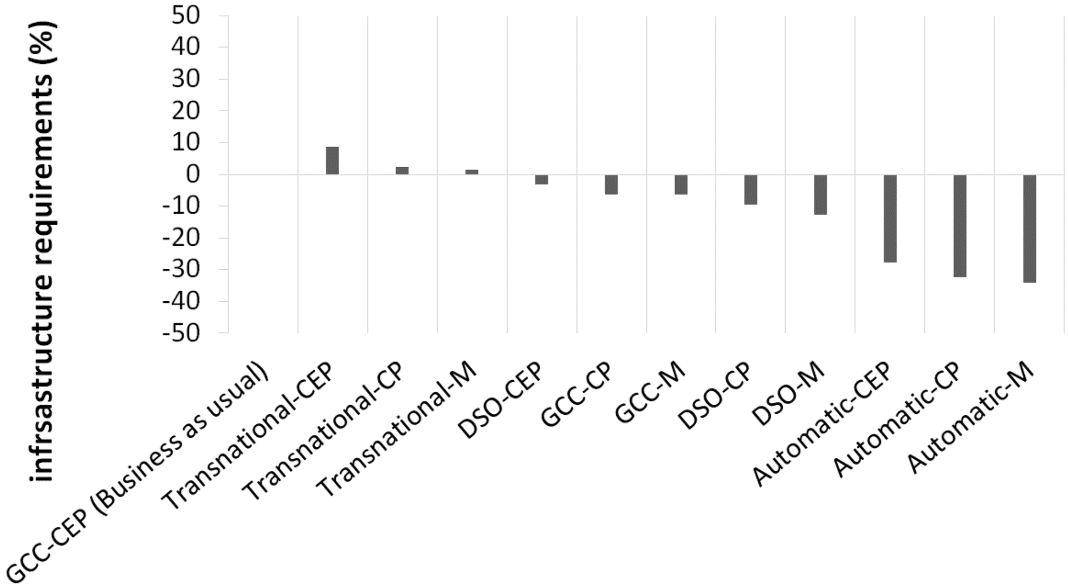

Figure 3.7: Overall comparative infrastructure requirements evaluation result

The introduction of an aggregator for pooling LFCR resources in the transnational and automatic activation approaches with mandatory compensation mechanism shows a relative reduction of 2 % and 1 % respectively due to a decrease in the ICT requirements and the associated complexity. The impact of introduction of an aggregator of small units to cross the market clearing thresholds is investigated by using the two extreme cases of high centralization (Transnational-CEP) and highly decentralized (Automatic-M) are selected. The mechanisms are illustrated in Figure 3.8.

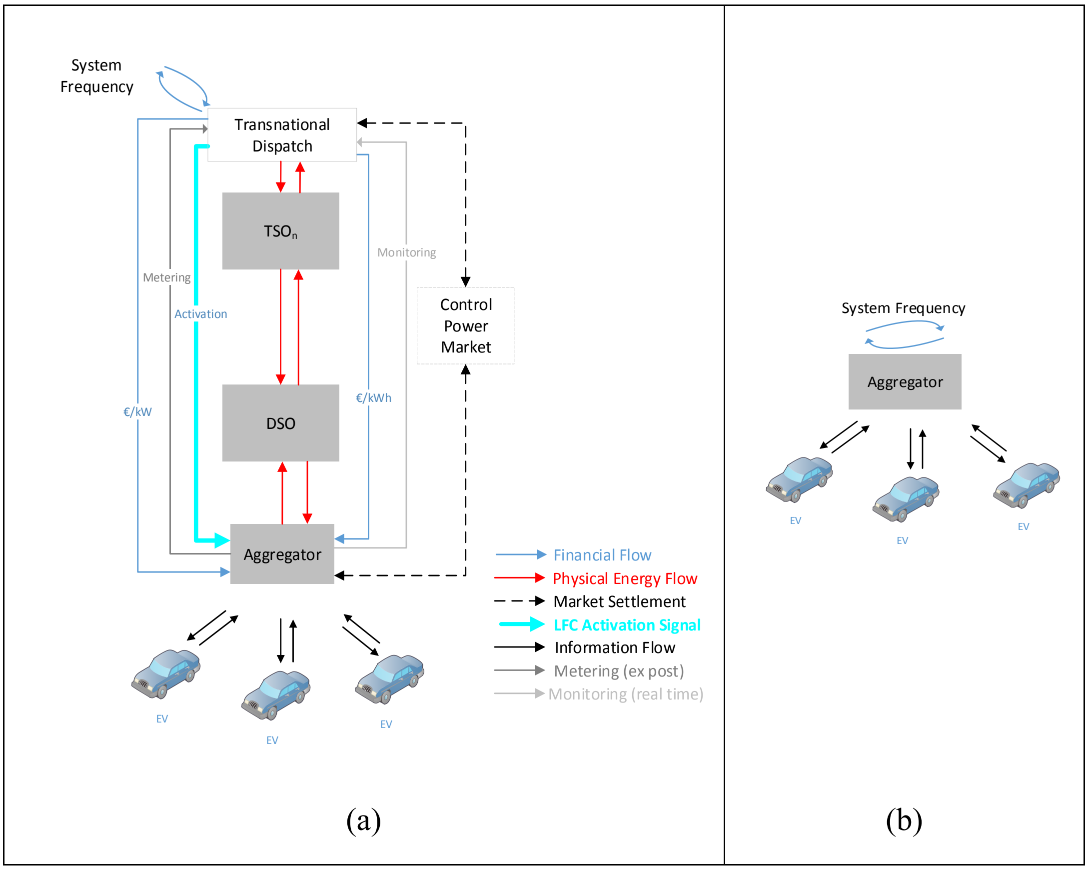

Figure 3.8: Transnational-CEP activation of LFC through Aggregators under (a) Transnational-CEP and (b) Automatic-M

The results for this analysis show that introduction of an aggregator results in a drop of 10 % in infrastructure requirements for the highly centralized scenario, as shown in Table 3.3, bringing the infrastructure requirements to below the Business-as-usual scenario, caused by a drastic reduction in the regulatory infrastructure requirements (from +11 to -11). Conversely, the inclusion of an aggregator has less significant impact on the Automatic-M scenario.

Table 3.3: Effects of aggregator on infrastructure requirement KPIs

Scenario	Planning KPIs	ICT KPIs	Complexity KPIs	Regulatory KPIs	Overall Requirements
Transnational-CEP	-10	36	11	0	9
Transnational-CEP/Aggregator	-10	36	-11	-12	-1

Scenario	Planning KPIs	ICT KPIs	Complexity KPIs	Regulatory KPIs	Overall Requirements
Automatic-M	-14	-36	-32	-43	-34
Automatic-M/Aggregator	-14	-36	-36	-43	-35

3.4 Conclusions

The weighted indicator-based framework developed and utilized for this qualitative analysis provides the basis for a quantitative analysis of actual case studies, while the use of equal weightage for each parameters and indicators keeps the evaluation framework neutral.

The quantitative evaluation shows that a centralized approach would result in increased complexity and ICT infrastructure requirements, but would also reduce the planning requirements of resources, as imbalances and deficits in one region can be compensated from any node of the interconnected grid. Consequently, unforeseeable failures of reserve can be mitigated due to a larger control area and a central authority. Conversely, decentralization would substantially reduce the regulatory and ICT requirements, but at the cost of weaker oversight by a control center.

The evaluation demonstrates that although decentralization of the frequency control results in a decrease in the overall infrastructure requirements, the integration of the aggregator as a market player responsible for controlling DER as suppliers of frequency control leads to an overall reduction in infrastructure requirements even in the highly centralized scenario. This conclusion leads to the need for further analysis of the role and operational concepts of the aggregator.

4 Operational concepts for an electric vehicle pool operator

The analysis of operational concepts for an aggregator of electric vehicles must begin with the modeling of the behavior of an EV user. Behavioral models can be categorized by granularity and the goal of the modeling approach. The granularity of the model is defined as the smallest unit of the model, such as an individual or a group of individuals sharing a common characteristic, whereas the goal of modeling approach is defined by the task for which the modeling approach is being implemented, such as prediction of the user behavior or filtering of the user groups based on given criteria with a goal to recommend products and services.

Fuzzy logic is a framework that categorizes a group or an individual as a member of set with a given influence and a corresponding uncertainty. Usually applied in recommendation systems, it enables the selection of users and the corresponding product recommendations with certain preference and patterns, derived from a database of raw user information. This application of the modeling approach has been used in [88] and [89] to recommend products for groups of users on e-commerce websites.

Another popular modeling approach is neural networking, based on modeling the information processing and decision making inspired by human brain, composed of a large network of connected information processing units called neurons which work together to solve a given problem, the model is used to recognize patterns from raw information. These models have been used to create recommendation systems for e-commerce in [90] and for movies in [91]. Prediction of the next step based on the previous choice of the users is discussed by [92]. The utility of neural networks for modeling user behavior is limited by the amount of data required for the learning and interpretability of the recommendations, as discussed by [93].

Genetic algorithms and evolutionary algorithms respectively discussed in [94] and [95] are algorithms based on natural selection, with potential solutions to a specific problem grouped into populations. Solutions discovered from one population are grouped into more populations based on their fitness to fulfill the objective criteria. The application of evolutionary algorithms in the electric grid is demonstrated by [96] and [97], where an agent-based traffic demand model is used to model the electricity demand and behavior of electric vehicle users. Limitations to evolutionary algorithms in model complex human behavior are the application for dynamic modeling and the number of decision influencing factors in combination with the number of agents.

Particle swarm optimization (PSO) discussed in [98] is a system initialized with a population of random solutions assigned a randomized variable characteristic (e.g. velocity). Each particle keeps track of its coordinates (position) for the best solution it has achieved. The overall global best solution by the whole swarm is also tracked. The resulting solution after each step is compared to the best solution achieved so far and the updated solution is selected if it has improved. The steps are repeated until an acceptable solution is reached. PSO is used to model the behavior of electric vehicle users in [99] assuming a normal distribution of EV load levels.

Modeling of electric vehicle usage for estimating distributed load during charging and discharging has been a recent topic of interest, with numerous studies modeling the behavior using randomized or deterministic approaches. These models can be classified according to data sources, which can either be based on general surveys conducted for conventional vehicle usage or information gathered from dedicated field trials of electric vehicles.

4.1 EV user behavior modeling based on real world data

Although the dedicated field trials provide feedback on novel approaches to incentives, their usability for modeling purposes is relatively limited due to the small sizes and type of users not representing the average user. A randomized distribution of electric vehicles charging at the same rate is used to model the electric nodal loads by [100]. A more nuanced stochastic approach is used by [101] and [102] based on mobility data of conventional vehicles in Germany, with the latter using the mobility data to develop characteristic load profiles. A similar approach is used by [103] to model the EV user, with assumptions made about the charging capacity and charging rates for use in the simulation of an optimization algorithm. The behavior of an average conventional vehicle user in the USA is used by [104] for an optimization model for maximizing electric vehicle charging energy and profits to provide ancillary services in California.

4.1.1 EV user behavior studies

This work makes use of field studies of actual EV usage to develop a probabilistic model with randomized parameters with constraints reflecting real-world usage identified in the surveyed field studies. The parameters such as plug-in times, distance travelled, plug-out times etc. are randomly assigned to each EV based on the probability distribution derived from the user behavior studies, as illustrated in Figure 4.1.

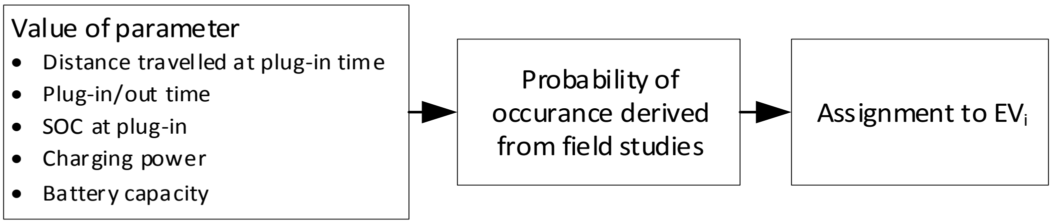

Figure 4.1: Assignment of randomly generated parameter value to individual EV

The surveys and field trials used for this modeling have been performed during the 2010-2015 period focusing on customers considered as early adopters as defined by [105] and are listed in Table 4.1.

Table 4.1. Trials and surveys used for modeling

Type of Participants	Country of study	Year	Study
Early adopters	Germany	2010	[106]
Pioneers	California, United States	1992	[107]
Early adopters	Portugal	2014	[108]
Early adopters	United States	2014	[109]
Early adopters, early majority	California, United States	2012	[110]
Early adopters	Western Europe	2011-2013	[111]
Early adopters, early majority, late majority	Canada	2013, 2015	[112]
Early adopters	United States (multiple regions)	2011-2012	[113]
Early adopters	United States (multiple regions)	2011-2012	[114]
Early adopters (Hybrids)	Japan	2015	[115]

4.1.1.1 **Charging behavior**

The surveys and field trials observe that most charging instances take place during the evening and night. Surveys [106], [107] and [108] of early adapters and pioneers show that nearly 100 % of the charging is preferred during off-peak defined as the time between 20:00 – 08:00. This observation is strengthened by [110] which observed that the majority of EV users (2/3rd) charged their EVs during 20:00 – 08:00, with a 100 % of EVs charging during 00:00 – 08:00. The survey of European EV users charging behavior furthermore showed that on average, EVs connected to the grid charged only during 48 % during the plug-in time. It was observed during the survey performed by [112] that for uncontrolled charging, the average peak charging demand was during 17:00 – 18:00.

Users who rarely interact with their batteries tend to have broadly distributed plug-in times [116]. This contrasts with users who actively monitor their SOC, who tend to only plug-in when a certain lower SOC is reached, with a normally distributed pattern. Interestingly, level of interaction with the battery is shown to have no impact on plug-in times. The statistics of available SOC at the time of plug-in varies between those in Europe and the United States. Over 66 % of German users charged their EVs with an SOC larger than 40 %, whereas about 80 % of EV users in the US also charged when SOC was below 60 %.

4.1.1.2 **Driving behavior**

Driving behavior and range requirements differ significantly for countries of survey. This is due to the ‘spread’ of the cities and the average distances between home and workplace for the surveyed users. The divide is significant between users in North America and Europe.

The survey performed for German users showed a preferred ‘available’ range of 227 km and an acceptable range of 156 km, although the average daily driven distance was only about 40 km [106]. This is an indication of range anxiety of users newly introduced to EVs, as the field trial took place in 2010. This issue must be explored further to investigate the change in behavior as EVs become more mainstream, as well as the differences in behavior between types of technology adopters.

The mean distance of each trip by the users in [114] was about 13 km, with on average 50 km driven between charging events. The average number of charging events per day is between 1.05 events for full EVs and 1.46 events for PHEVs due to smaller battery sizes.

The average number of distance travelled per day was observed to be within the a narrow range of 38 km – 40 km for European users [106], [110] and between 48 km – 65.5 km for North American users based on [108], [112] and [114], as illustrated in Figure 4.2. The average daily energy usage for each EV was found to lie between 6.3 kWh – 8.7 kWh for both Europe and North America.

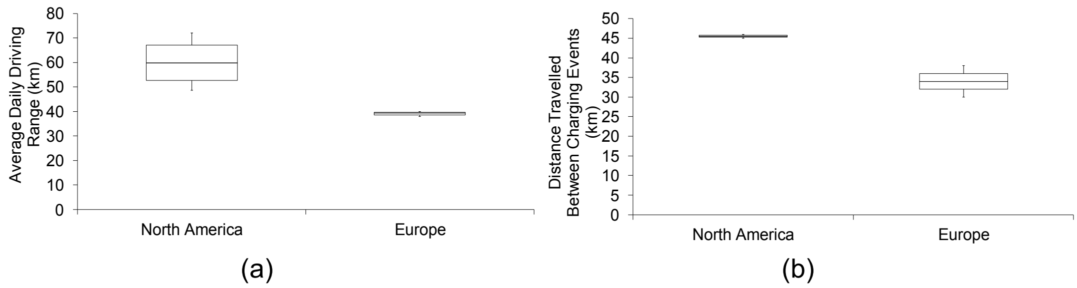

Figure 4.2: Average daily driving distances (a) and distance travelled between charging events (b) for North America [108], [112] and [114] and EU [106], [110]

4.1.1.3 **Controlled charging**

Controlled charging is defined as a charging regime where charging behavior of an EV is controlled by an external entity, which could be an aggregator or a utility for purposes such as RES integration or participation in grid balancing. The use of time-of-use (TOU) and EV-specific tariffs is observed to be effective in molding user charging behavior, as evidenced by [115] in Japan with TOU tariffs encouraging charging at 23:00 for over 50 % of users and off-peak EV-specific tariffs in California causing charging load to shift to between 00:00 and 06:00 [110].

The surveyed EV users in California willing to pay for utility charging considered level 2 charging as adequate for regular usage, with most EVs charging at home. Availability of public charging facilities was also not seen as essential by Canadian users, with about 66 % of all charging events taking place at home, with 70 % of all home arrivals involved charging. EV users in other locations also showed a similar pattern with 83.7 % of German EV and 82 % of US users charging their EVs at home. Majority of users in California were willing to pay $ 0.24/kWh for daily charging and willing to change their behavior for a reduced off-peak charging prices of $ 0.09/kWh – $ 0.15/kWh and as high as $ 1.17/kWh occasionally.

It was observed by [112] that 20 % of all EVs were available for charging at all times of the day, with almost 80 % of all users stationary at all times. The results for home charging showed that while almost 98 % of all EVs were parked during 20:00 – 08:00, only 50 % had access to charging points during this time. It can be concluded based on this survey that when assuming adequate charging facilities and capability for participating in controlled charging at workplace, home and public locations, the vast majority of EVs are available and plugged-in during off-peak periods, with a sizable number of EVs available at all times of the day.

4.1.2 Selection of parameters

The data collected during the literature survey is used as input parameters for the development of EV user behavior models. These parameters are discussed in the following subchapters.

4.1.2.1 Battery parameters

Most EVs can be charged at home with Level 1 charging, with typical charging powers listed in Table 4.2. As Level 1 charging is slow, typically taking between 15 to 20 hours to charge a 28 kWh battery, Level 2 charging is preferred for battery electric vehicles (BEVs).

Table 4.2: Classification of charging levels used for EV charging (based on [117, 118])

Level	Charger location	Power level	Charging voltage	Charging type
Level 1	Primarily home and workplace	1.9 kW (US) 3.7 kW (EU)	120 V_{ac} 240 V_{ac}	1-phase
Level 2	Home and public	7.7 - 15 kW (EU) 19.2 kW (US)	480 V_{ac}	3-phase
DC Fast	Public	50 kW or more	≤1000 V_{ac} or 1500V_{dc}	3-phase AC or DC

Both PHEVs and BEVs can be used to provide flexibility services, with varying degrees of feasibility. Over the last few years, there has been a strong growth in the availability of PHEVs and BEVs with varying battery capacities to cater to different user groups. The battery sizes of some relatively commercially successful [119] available Lithium-Ion battery based EVs in Germany are summarized in Table 4.3. For the simulation in this work, a battery size of 32 kWh with a usable capacity of 28 kWh is primarily is used.

Table 4.3: Typical BEV battery sizes (based on [119])

Make/Model	Nominal battery size (kWh)
Tesla / Model S 60	60
BMW / i3	42.2
Nissan / Leaf	40
Hyundai / Ioniq EV	40.4
Renault / Zoe	54.7
Audi / e-tron	71

Battery discharge rates are dependent on several factors ranging from environmental to driving behavior, road conditions and battery wear. For this simulation, a fixed value of 0.16 kWh/km is used based on the average consumption calculated for urban driving [120]. The EV parameters used for the modelling are listed in Table 4.4.

Table 4.4: Assumed EV parameters used for modeling

Parameter	Value
Battery size	28 kWh
Charging power	3.7 kW
Battery discharge rate	0.16 kWh/km
Charging/discharging efficiency	0.9

4.1.2.2 **Mobility behavior**

(1) Home arrival time

The home arrival times for EU, Japan and Canada are illustrated in Figure 4.3, showing the wide differences between the regions. This is primarily due to the differences in incentives and regulatory structures of EV charging management. For instance, EVs charging during off-peak periods are offered significantly lower charging rates.

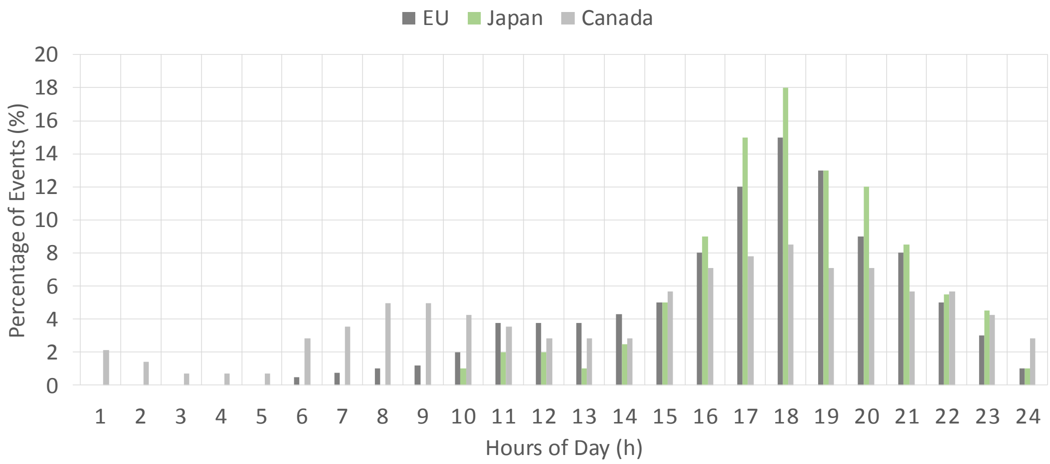

Figure 4.3: Home arrival times for EV users in the EU [121], Japan [122] and Canada [123]

(2) SOC at plug-in

The SOC at plug-in for BEVs in the EU and US (California) is illustrated in Figure 4.4. Although it is clear that a majority of EVs connect with an SOC of 40 – 60 %, the variation in the EU based data between 10 and 40 % may be caused due to the battery sizes of the EVs used in the trials.

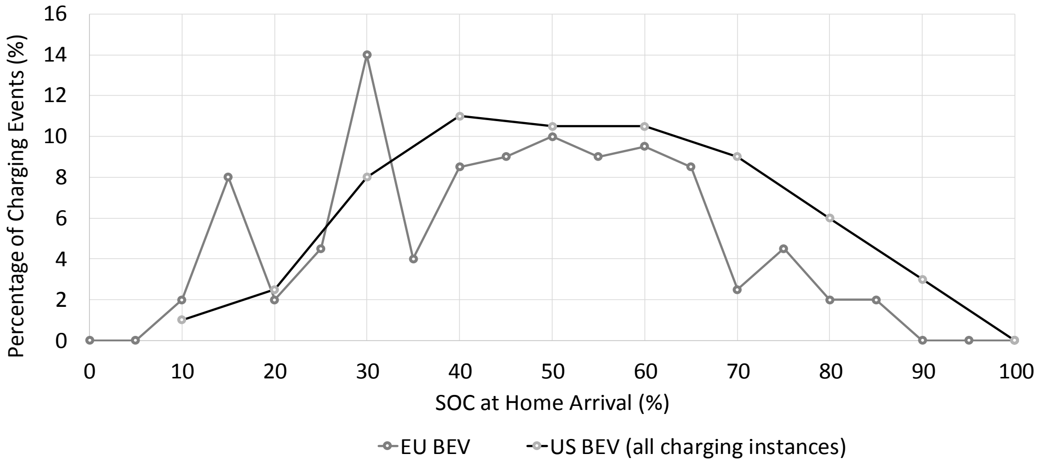

Figure 4.4: SOC at home arrival for users in EU [121] and US [124]

(3) Distance travelled between charging instances

The average distance travelled between charging instances for the EU is illustrated in Figure 4.5, showing that the majority of EVs travel 15 to 30 km between charging instances. This also matches with the statistics available for German driving behavior for conventional vehicles in [125].

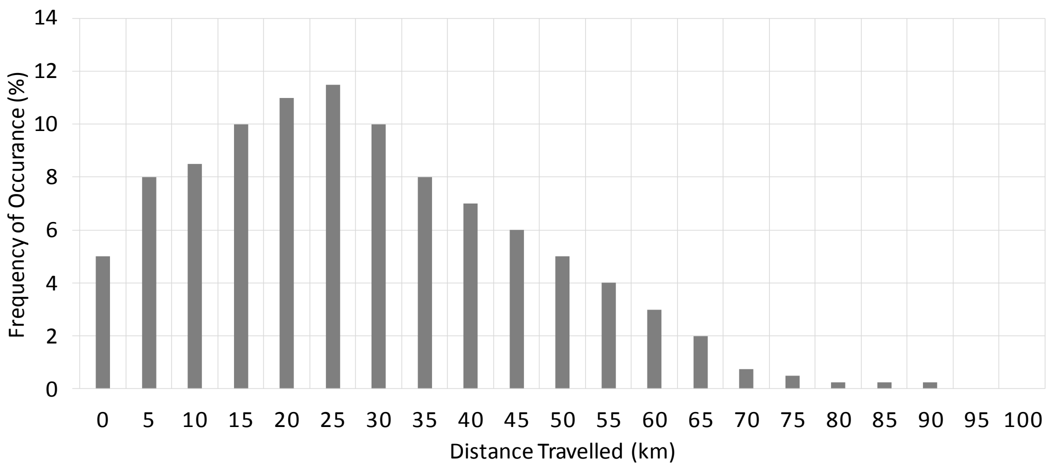

Figure 4.5: Average distance travelled between charging instances for users in EU (own illustration based on [121])

The review of the trials and surveys undertaken in this report shows that off-peak charging rates can be very effective in shaping charging behavior. However, the success of these strategies depends on the differences in the charging tariffs between normal and off-peak charging. Decoupling EV charging from regular domestic usage will also help adoption of controlled charging, as users would be able to distinguish between their normal electricity usage and EV charging needs. There is also an observable difference in behavior for users who actively monitor and modify their charging requirements and those with more predictable and passive behavior. Passive and consequently predictable behavior should be encouraged by guaranteeing a minimum charge level at every plug-out.

4.2 EV flexibility model

The aggregator flexibility to respond to external dispatch signal is determined by the simulation of the charging behavior of individual EV users. As the user behavior observed in the surveys does not correspond to any standard distribution, it is necessary to use a probabilistic model based on the characteristics identified in subchapter 4.1.2. For this purpose, plug-in and plug-out times are randomly generated constrained within the predetermined survey-identified constraints. This user behavior is then simulated in response to fictious dispatch signals and the EV pool flexibility determined, as illustrated in Figure 4.6.

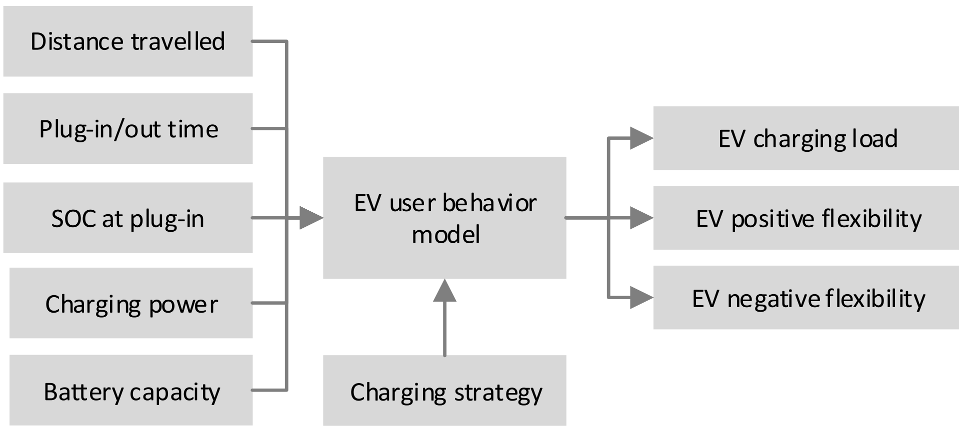

Figure 4.6: EV charging behavior simulation model

The charging behavior of the EV users is determined by its charging strategy, consisting of any number of charging power and the plug-in durations combination. The strategies are simulated with the goal to determine an optimum for maximum fulfilment of the dispatch signal. This optimization is achieved by aiming for an EV availability curve closest to a flat production level, as would be the case for a conventional generator. The following subchapters describe the model and operational strategies.

4.2.1 EV charging strategies

The operational strategies are developed using the identified user behavior parameters and are illustrated in Figure 4.7. Two types of strategies are selected for simulation, namely:

- EVs charge immediately after plug-in with minimum power (immediate charging)
- EVs wait until the last moment to charge with maximum power (wait charging)

The strategies selected define the two boundary cases, with an infinite number of possible variations between them. The strategies are further categorized into the direction of power delivery:

- Controlled charging flexibility refers to the capability of the EVs to cease charging in the event of a power reduction dispatch signal.
- Bi-directional flexibility refers to the flexibility offered by the EVs by supply power to the grid when required. This flexibility is limited to EVs with a state of charge (SOC) above 50 %.

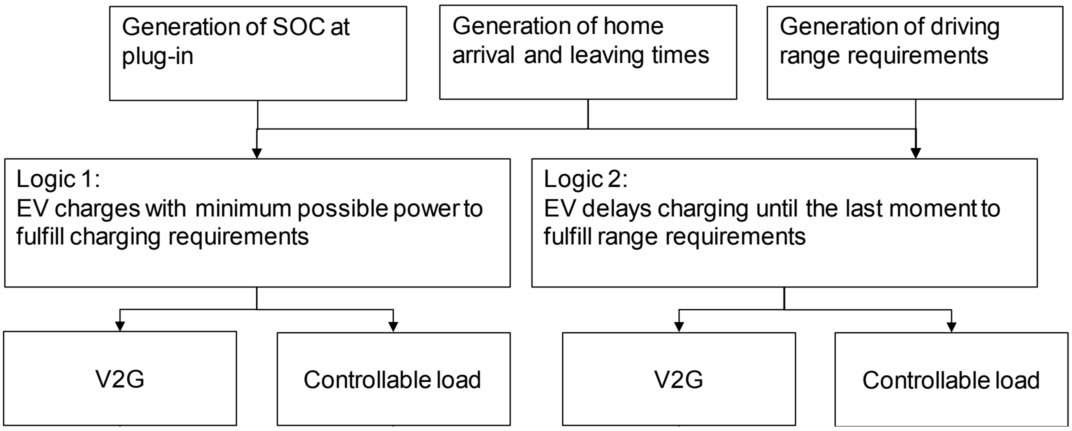

Figure 4.7: EV charging sequence and strategy

The charging strategies for EVs capable of bi-directional power flow, or vehicle-to-grid (V2G), are illustrated in Figure 4.8. Under ‘immediate charging’ (Logic 1), the EV begins charging upon plug-in with power $P(t)$, shown by the gray block in Figure 4.8 (a), the discharging (positive) flexibility $Flex_p$ becomes available immediately upon charging and is calculated from the P_{max}

$$Flex_p(t) = |P_{\max}| + P(t) \tag{4.1}$$

Charging (negative) flexibility $Flex_n$ is only available once the charging requirements are fulfilled. As immediate charging can take a value lower than the full charging power, this leaves a negative flexibility also available during charging instance as given by:

$$Flex_n(t) = P_{\max} - P(t) \tag{4.2}$$

The difference between instantaneous SOC and goal SOC determines the duration of flexibility availability, leaving a time window before plug-out with its size determined by the SOC gap, represented by the white block. Under 'wait charging' (Logic 2), the flexibility of the EV is available from the instance of plug-in until the time required to fulfil the SOC goal, as illustrated in Figure 4.8 (b).

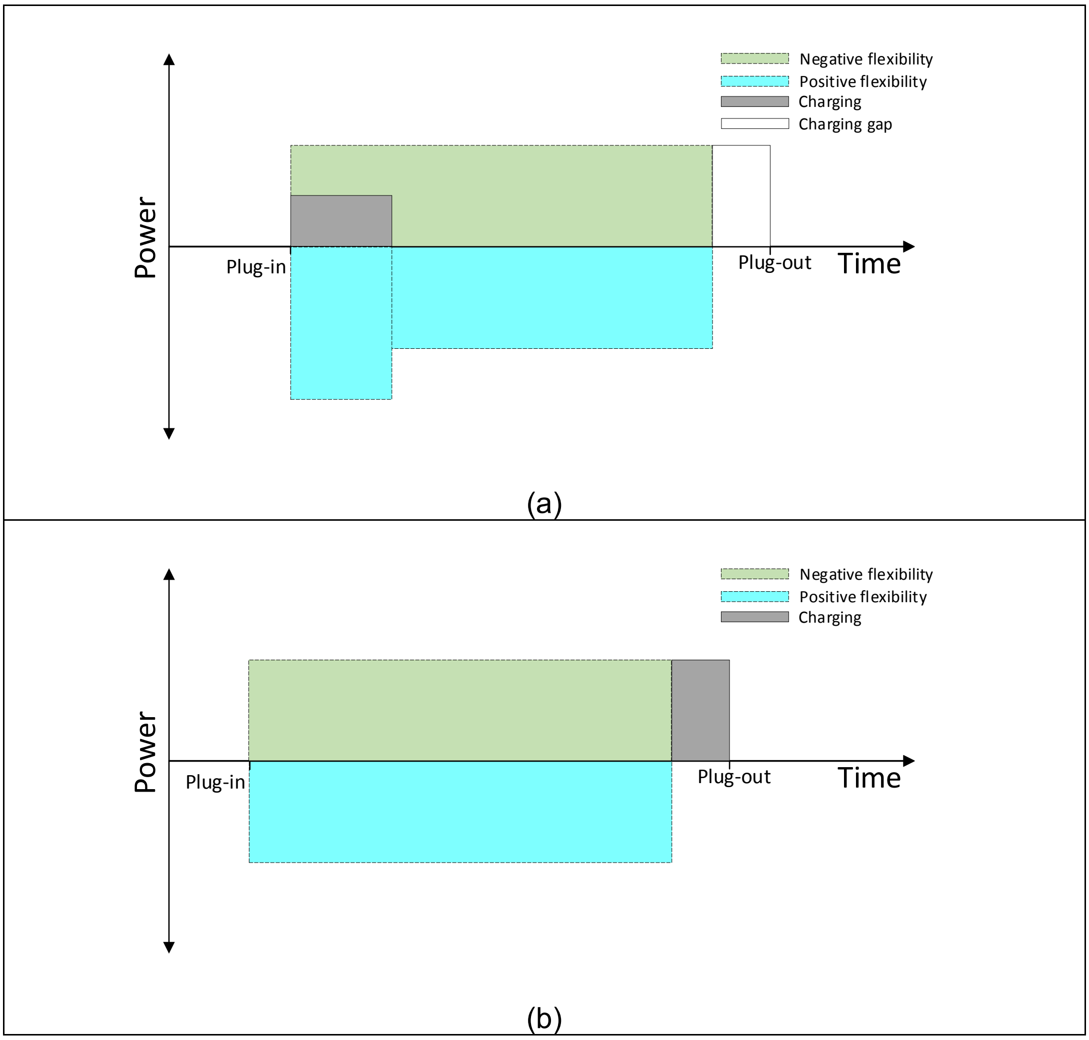

Figure 4.8: Charging strategies with V2G capability (a): immediate charging, (b): wait charging

The charging strategies for EVs only performing unidirectional power flow or controlled charging, are illustrated in Figure 4.9. Here also, under 'immediate charging', the EV begins charging upon plug-in, shown by the gray block in Figure 4.9 (a), the discharging (positive) flexibility becomes available immediately upon charging start and becomes unavailable the moment charging stops. The difference between the instantaneous SOC and goal SOC determines the duration of flexibility availability, leaving a time window before plug-out with its size determined by the SOC gap. Under 'wait charging', the negative flexibility of the EV is available from the instance of plug-in until the time required to fulfil the SOC goal, as illustrated in Figure 4.9 (b). However, under controlled charging, positive flexibility is not available during wait charging.

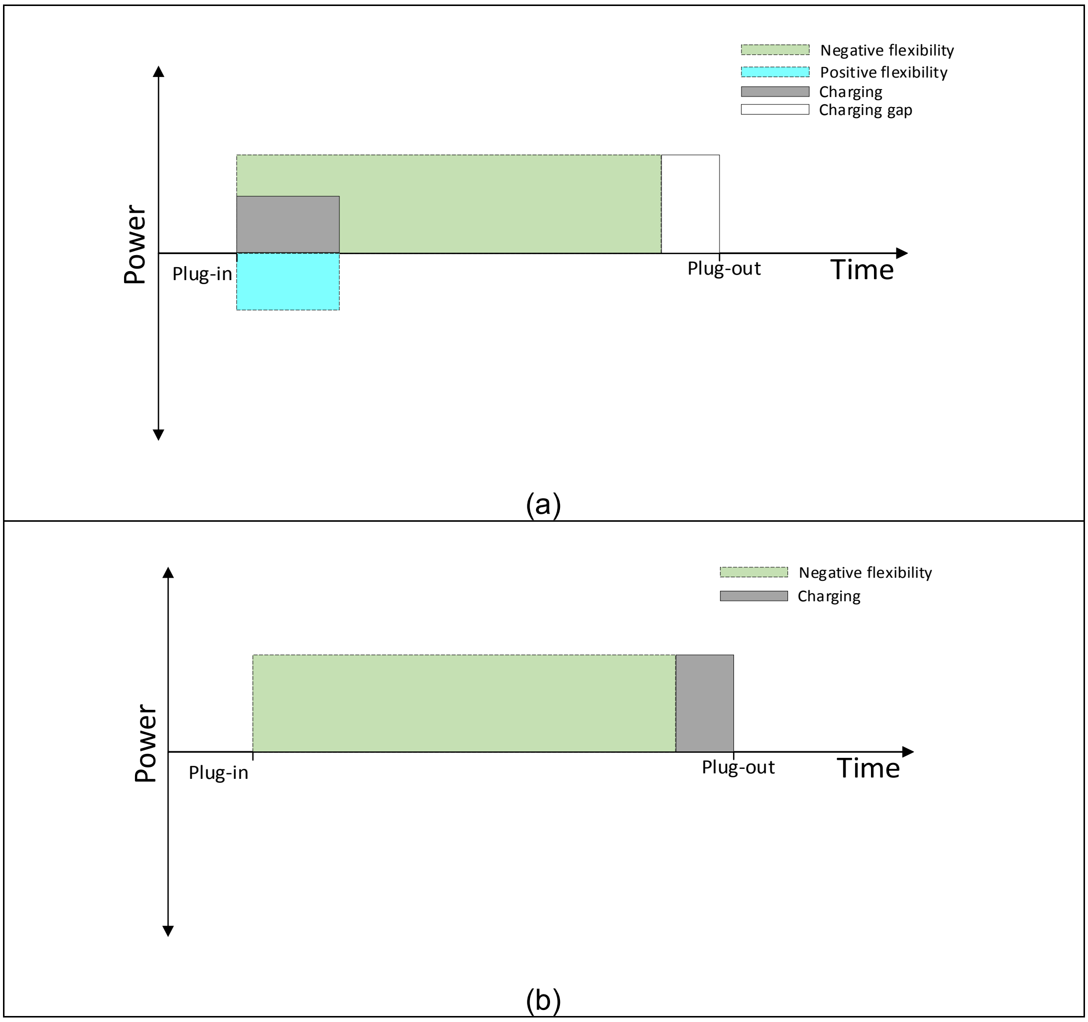

Figure 4.9: Charging strategies with controlled charging (a) immediate charging, (b) wait charging

4.2.2 EV dispatch optimization

The decision flow of the optimization of pool operation is illustrated in Figure 4.10. The aggregator receives the dispatch signal and dispatches the EVs based on activation logic illustrated in Figure 4.10. The constituent EVs in the pool are activated on the basis of local merit-orders for both charging and discharging flexibility, charging flexibility merit-order with EVs in ascending order of SOC and discharging flexibility with descending order of available flexibility. The aggregator loops through the merit-order, activating the EVs according to the merit-order until either the dispatch requirements are fulfilled, or the end of the list is reached.

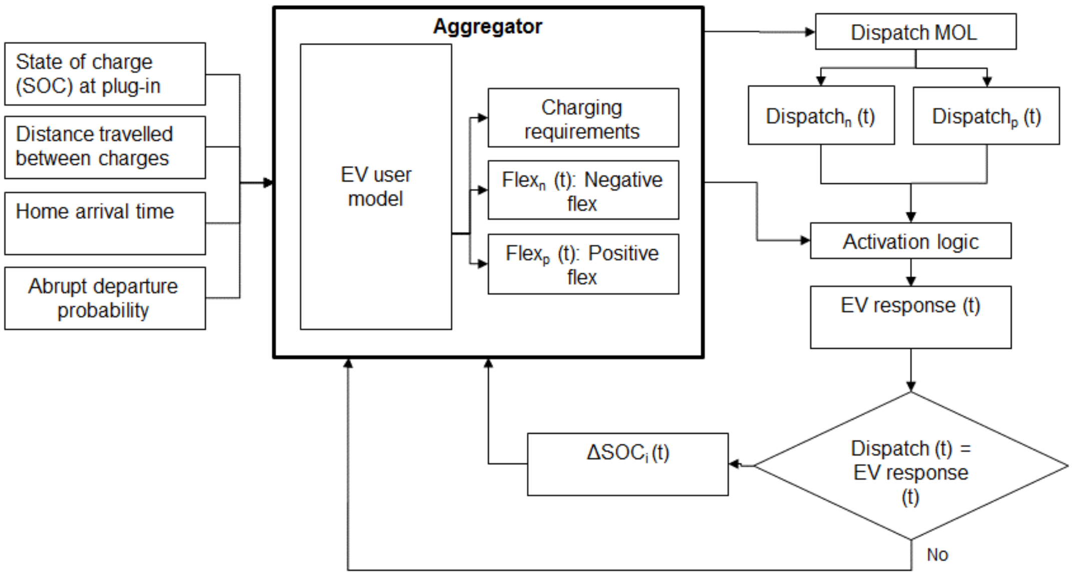

Figure 4.10: Charging decision sequence for simulations

The aggregator uses an internal MOL to prioritize the activation of individual EVs based on ascending order of SOC for negative flexibility and descending order of SOC for positive flexibility, as illustrated in Figure 4.11. The availability of positive flexibility is governed by the following conditions:

$$\begin{aligned} Flex_p > 0 \quad if \quad SOC \geq 50 \\ Flex_n > 0 \quad if \quad SOC < 100 \end{aligned} \tag{4.3}$$

The available charging power $power_c$ remains within the following limits of rated power $power_{rated}$:

$$0.5 \cdot power_{rated} \leq power_c \geq power_{rated} \tag{4.4}$$

The battery discharging during travel is calculated according to the battery discharge rate *disc* and the instantaneous distance travelled *dist*:

$$\Delta SOC(t) = disc \cdot dist(t) \tag{4.5}$$

The pool charging power P_{pool}, as well as negative $Flex_{pool,n}$ and positive flexibilities $Flex_{pool,p}$ are calculated as the sum of i EVs for the pool size k as given by

$$P_{pool}(t) = \sum_{i=1}^{k} P_i(t) \tag{4.6}$$

$$Flex_{pool,n}(t) = \sum_{i=1}^{k} Flex_{i,n}(t) \tag{4.7}$$

$$Flex_{pool,p}(t) = \sum_{i=1}^{k} Flex_{i,p}(t) \tag{4.8}$$

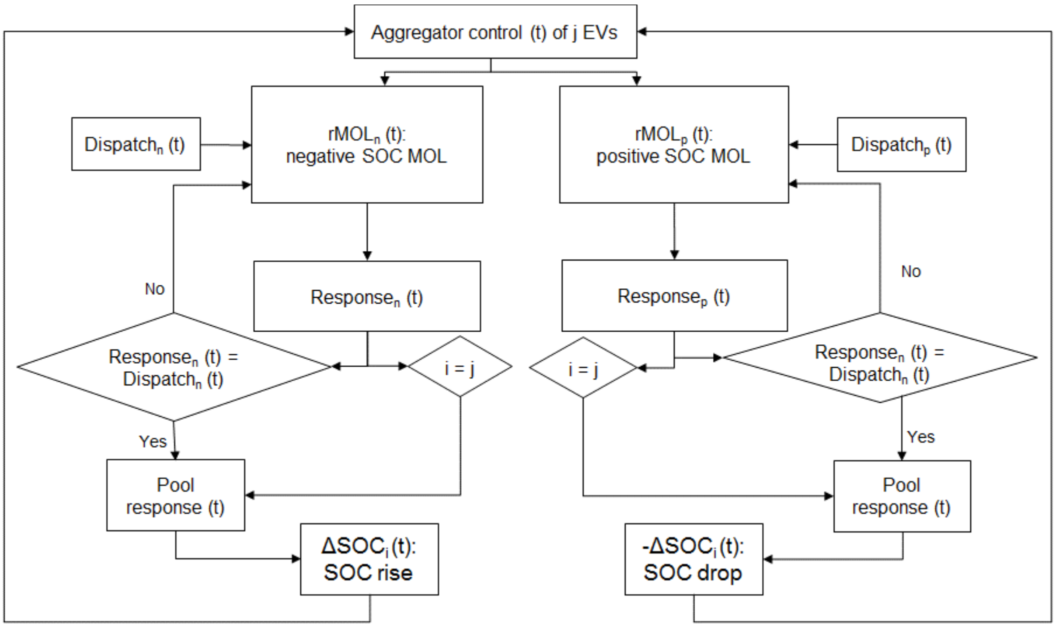

Figure 4.11. Activation decision sequence used for EV selection based on the internal Merit-Order-List

4.3 Operational concept optimization results

The simulation of the operational strategies shows that ‘wait charging’ delivers lower peaks and higher valleys (a difference of about 12 %) in the charging power as compared to ‘immediate charging’, as illustrated in Figure 4.13 and Figure 4.11.

As described earlier in the subchapter, higher continuously available minimum power $Power_{pool,\min}$ and smaller power difference $\Delta Power_{pool}$ in the EV charging curve lead to higher performance, as given by

$$\Delta Power_{pool} = Power_{pool,\max} - Power_{pool,\min} \tag{4.9}$$

$$\min\left\{\Delta Power_{pool}\right\} \tag{4.10}$$

$$\max\left\{Power_{pool,\min}\right\} \tag{4.11}$$

The overall energy delivered for both strategies during the plug-in time a and plug-out time b remains constant, as given in

$$\int_a^b Power_{pool,wait}\,dt = \int_a^b Power_{pool,immediate}\,dt \tag{4.12}$$

Figure 4.12 illustrates the charging curve for the 'immediate charging' strategy. This strategy is characterized by a peak of about 1179.2 kW and a lowest continuously available charging load of 38.2 kW.

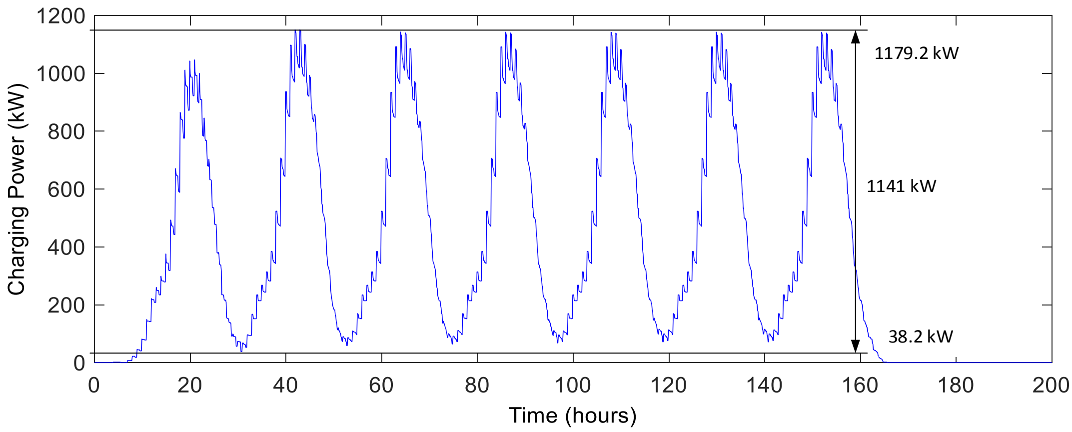

Figure 4.12: Charging load of 1000 EVs (Monday-Sunday)

Figure 4.13 illustrates the charging curve for the 'wait charging' strategy. This strategy is characterized by a peak of about 1050 kW and a lowest continuously available charging load of 118 MW.

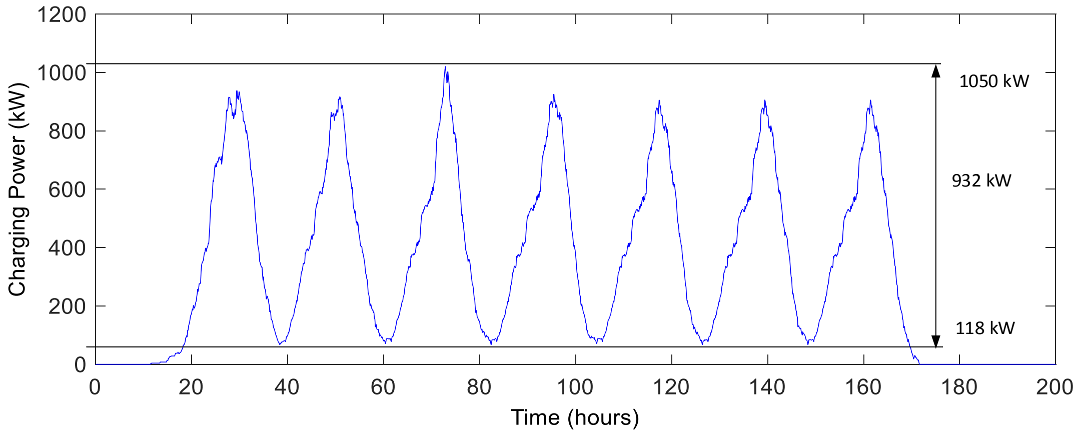

Figure 4.13: Charging load of 1000 EVs (Monday-Sunday)

The comparison of charging load of immediate charging and wait charging shows that wait charging strategy is characterized by a smoother curve, with smaller peaks and higher minimum available charging power, corresponding to the optimization goal of a flat curve.

4.3.1 EV pool signal response performance criteria

The quality of response of the EV pool is determined by the criteria set by grid operators for supplying FRR [87]. The performance criteria for all applications in the simulations is set to exceed these minimum limits given by the pre-qualification documents for FRR. Figure 4.14 illustrates the performance criteria for the EV pool response to the dispatch signals, whereby the deficit in the pool response and dispatch signal must remain under the stipulated limits for 98 % of the time, given by

$$\begin{aligned} Deficit &= Dispatch_i - Response_i \\ Deficit &\leq 0.05 \cdot Dispatch_i \end{aligned} \tag{4.13}$$

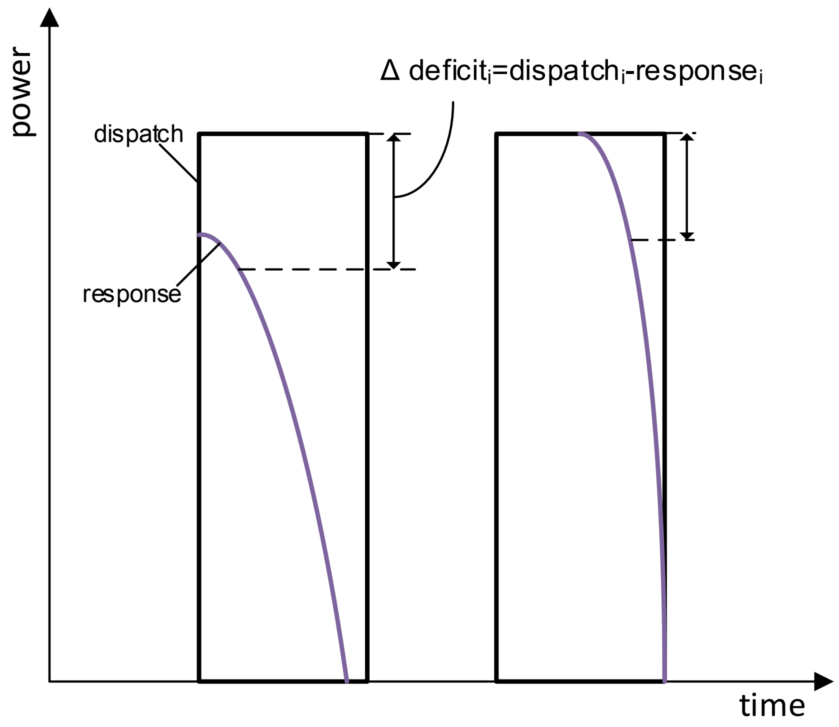

Figure 4.14: Performance criteria used for the EV response

For normalization, the performance of EV pool's dispatch response is measured for a dispatch signal of 1 MW. The minimum number of EVs required to provide 1 MW of flexibility are illustrated in Figure 4.15, showing that as anticipated, the lower positive flexibility available from controlled charging capabilities results in a significantly higher number of EVs necessary to provide the same flexibility. This is because V2G capability enables an EV to make a much larger flexibility range available. For instance, an EV already charging can provide a flexibility twice its charging power with V2G, compared to a controlled charging capable EV only providing flexibility from ceasing the charging operation.

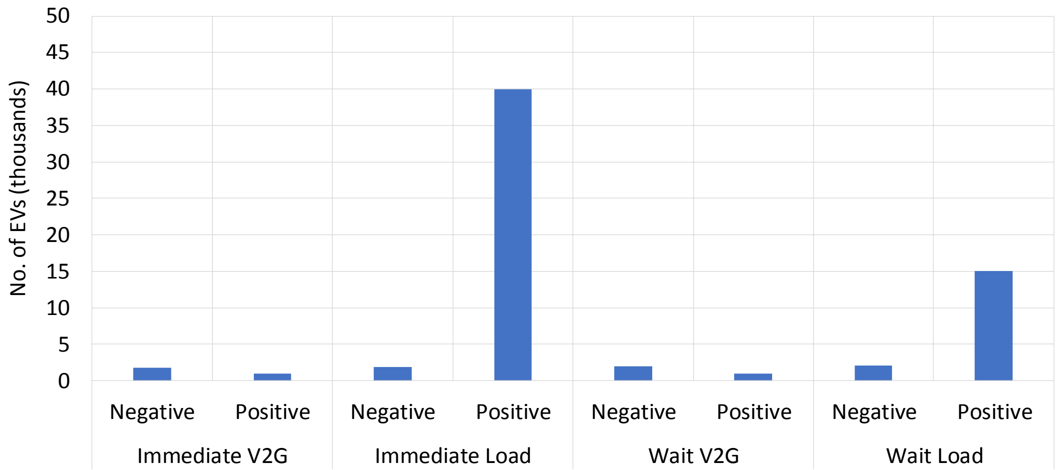

Figure 4.15: Number of EVs required for provide 1 MW negative and positive flexibility

The corresponding flexibility per charging power made available through the different charging strategies is illustrated in Figure 4.16.

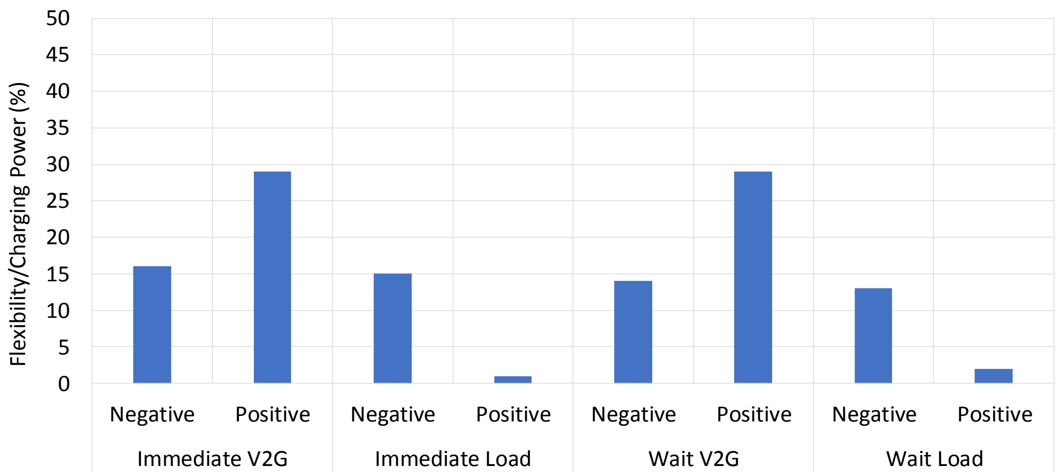

Figure 4.16: Flexibility per charging power of operational strategies

4.4 Conclusions

The analysis of user behavior studies performed in different regions shows that there is no generalized model of the charging behavior of electric vehicle (EV) users in Europe, Japan and North America, mainly due to the differences in the level of grid development, incentives provided for EV charging, topographical differences and the EV characteristics. The user behavior is simulated using a probabilistic model developed based on the characteristics identified in the studies.

The probabilistic user behavior model based simulation shows that making available the flexibility of the EV to the aggregator immediately upon plugging in and fulfilling the charging requirements of the EV user later is a clearly better approach, resulting in smoother profiles, higher continuously available flexibility and smaller pool sizes providing the same flexibility capacity. It is also noted that offering bi-directional flexibility using V2G offers clear advantages to the aggregator. However, the financial feasibility of implementing V2G must be evaluated, as performed in the following chapter.

5 Evaluation of electric vehicle pool operational concepts using flexibility services

An aggregator is conveniently located between the smaller service providers and the users of frequency control and other flexibility services. For the grid operators, engaging a large number of smaller flexibility service providers entails prohibitively high transactional cost and complexity, while the inherent supply risk associated when dealing with smaller supplier also represents a structural challenge for the overall supply chain. Due to its decentralized nature, flexibility provided by controlled charging of EVs as part of an aggregator can also be used to provide services to parties other than grid operators. Accordingly, evaluation of the operational concepts is performed for a range of flexibility services listed in Table 5.1. In order to evaluate the response of the EV aggregator to the demands of these flexibility services, fictitious dispatch signals are generated using models developed for each service case based on historical data for Germany.

Table 5.1: Functions of evaluated flexibility services

Flexibility service	Description
Frequency Services (FS)	Supply of frequency reserve (consisting of FRR and FCR) using direct load control and bi-directional flexibility of EV charging. The aggregator controls and communicates with participating EVs at home through a communication module connected to a smart meter, providing the combined flexibility of the pool to the grid operator, in this case the TSO.
Forecasting Error Minimization (FEM)	Supply of flexibility for the balancing responsible party (BRP) forecasting error minimization using direct load control and bi-directional flexibility of EV charging.
Peak Reduction (PR)	Flexibility provided for peak load shaving of a commercial facility using direct load control and bi-directional flexibility of EV charging. The aggregator negotiates time dependent charging tariffs in the market and controls EV charging to reduce the overall charging cost.

Flexibility service	Description
Charging Cost Reduction (CR)	Providing charging facility to EV users using flexible tariffs (tariffs for EV charging which include an interruption clause). The aggregator uses the EVs connected at a facility to reduce the peak load demand of the facility.

The model schematics of the simulation used to evaluate the performance capability of the EV pool to respond to dispatch signals for flexibility services are illustrated in Figure 5.1. As shown, the fictitious dispatch signals is applied to the aggregator model under charging strategies and its response to the dispatch signal simulated.

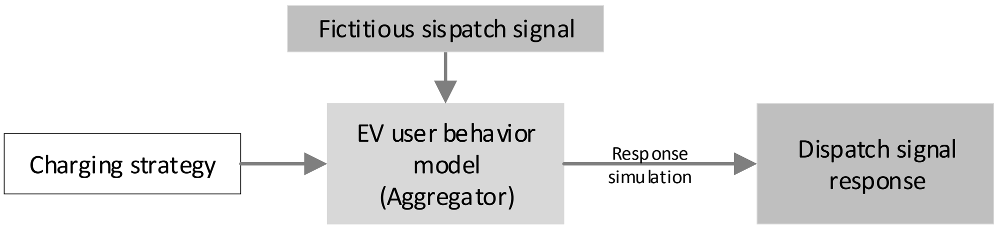

Figure 5.1: Simulation model used for investigating the EV pool response to dispatch signals

The relationships between the aggregator and users of flexibility services is illustrated in Figure 5.2, marked by red, where the grid services include both FS and DR.

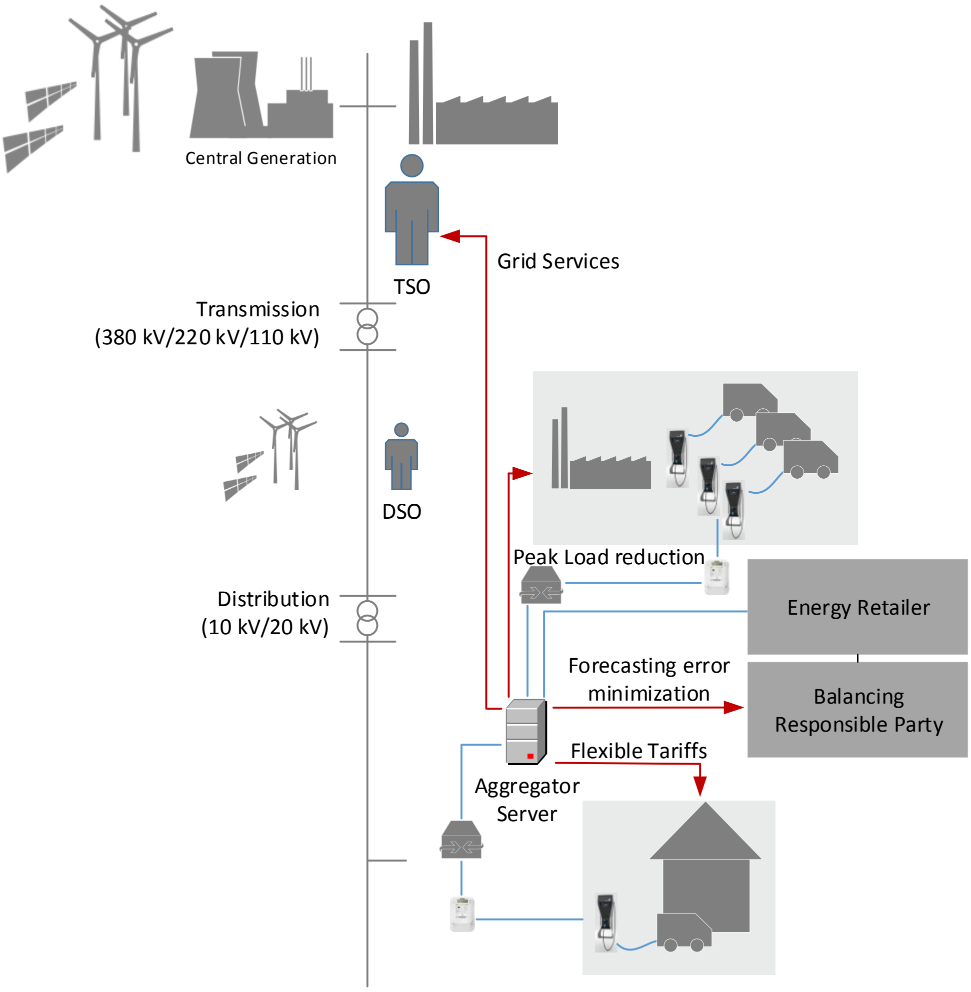

Figure 5.2: Services offered by the EV aggregator

5.1 Development of dispatch signals

The dispatch signals are generated using publicly available historical data. FRR in Germany is secured using a market platform on a pay-as-bid basis for peak and off-peak products separately. Each supplier of flexibility reserve makes an offer with a corresponding capacity and energy price. The grid operators use two separate merit-order-lists (MOL), first to determine the acceptance of the capacity and the second for the activation of the offered reserve. All suppliers accepted for FRR supply are paid the capacity price of their bids regardless of dispatch, whereas the energy prices are paid for the amount of energy delivered or curtailed/absorbed.

(1) Frequency control

The dispatch signal for FRR is generated from the anonymized bidding data from [126] for 2014, where the position of the EV pool in the (MOL) and its corresponding activation is determined by bid energy prices. The dispatch signal is calculated based on two assumed MOL positions: 10th percentile and 25th percentile. An illustration of this approach can be seen in Figure 5.3.

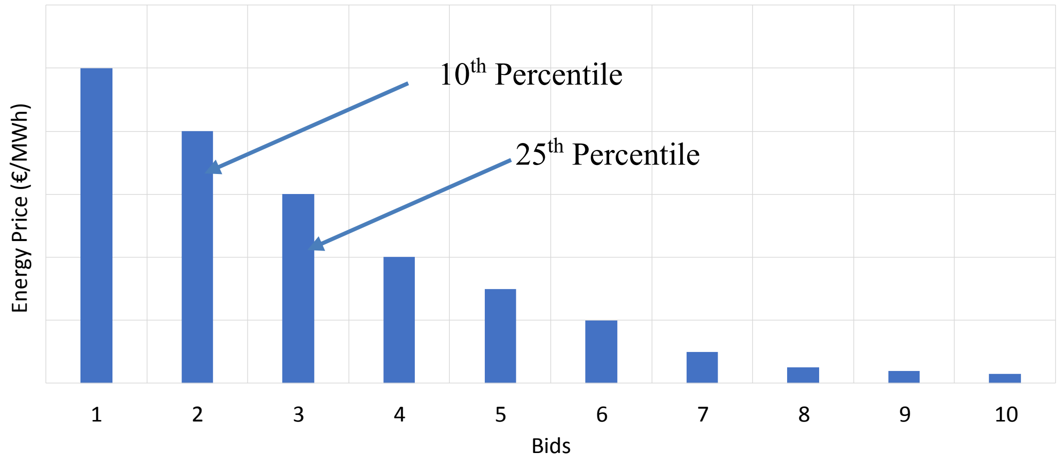

Figure 5.3: Development of simulated dispatch signal for FRR based on MOL position

A dispatch signal for off-peak FRR is illustrated in Figure 5.4, showing the activation signal generated for the 10th percentile MOL position of the EV pool.

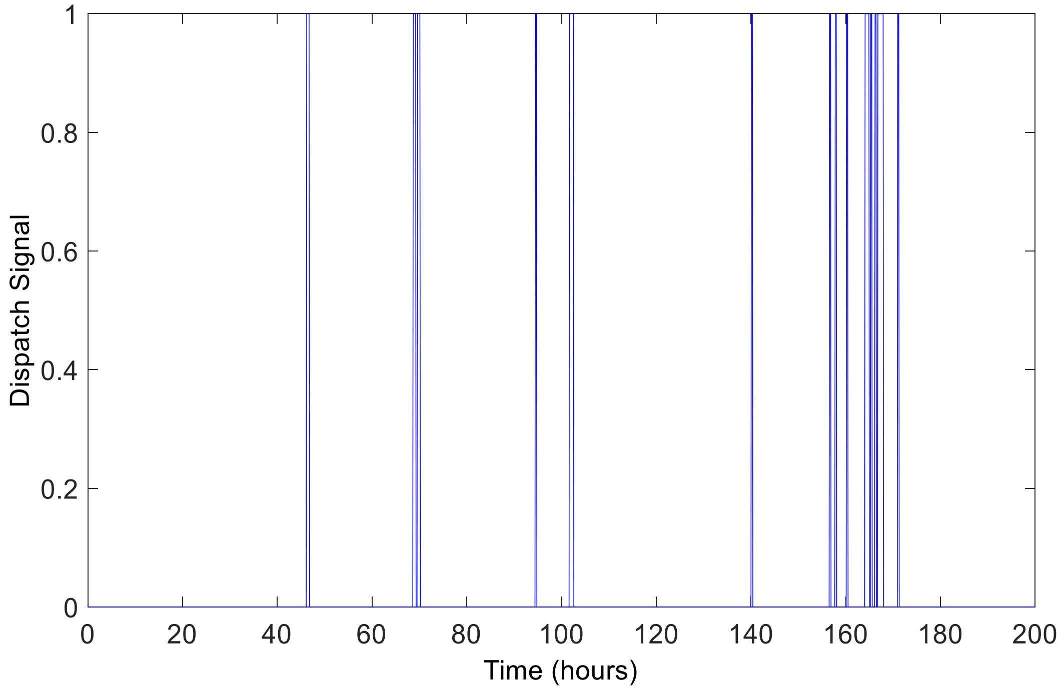

Figure 5.4: Dispatch signal for off-peak Negative FRR

The dispatch signal of positive off-peak FRR illustrated in Figure 5.5 for the EV pool shows a more frequent activation compared to the negative FRR for the same time period.

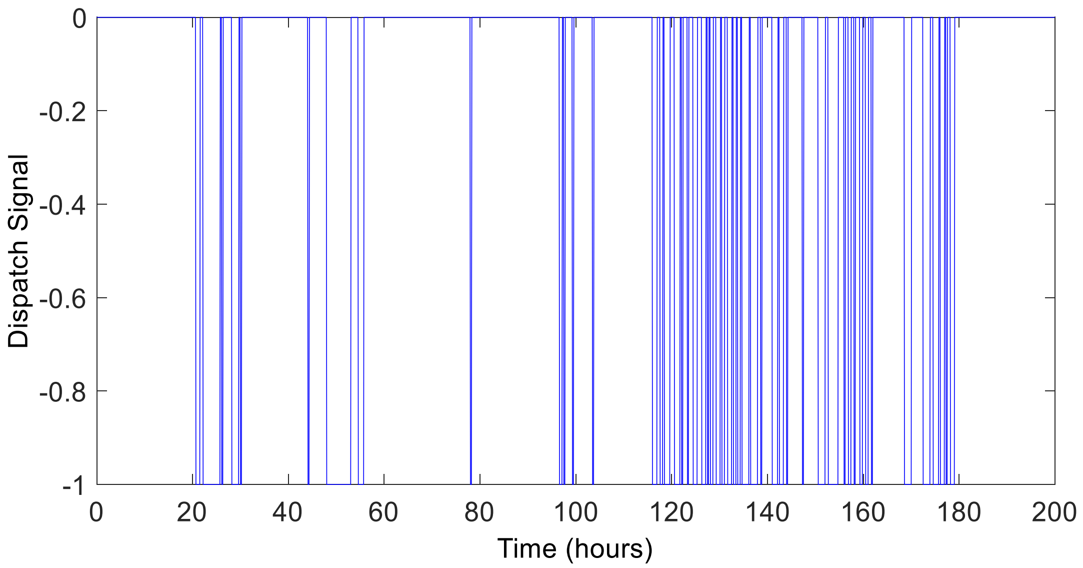

Figure 5.5: Dispatch signal for off-peak Positive FRR

FCR is used to compensate for random noise errors in the grid. Due to its nature, the negative and positive energy transferred over a period of time tends to balance out, hence the lack of energy payments by the grid operators. As actual data for the activation of FCR is not publicly available, dispatch signal for FCR is approximated (see Figure 5.6) by using random number generation with sum of the positive and negative energy transfer tending to zero.

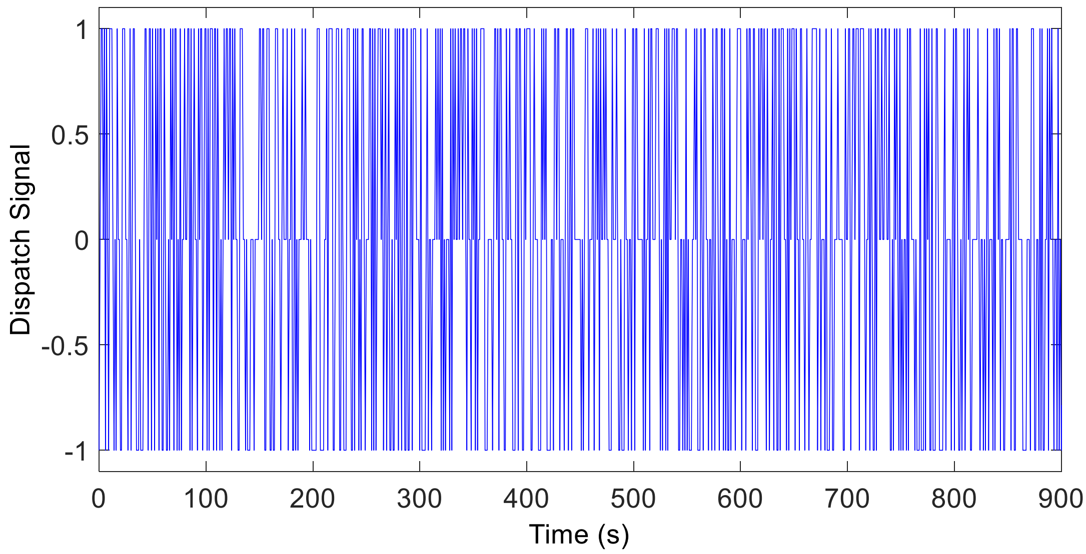

Figure 5.6: Dispatch signal for FCR

(2) Forecasting error minimization

The ENTSO-E grid operators use the principle of distributed responsibility to minimize imbalances to reduce the activation of expensive frequency control reserve. Balancing responsible parties (BRPs) are entities responsible for balancing the forecasted generation and consumption in their zones. These entities can be in the form of a large industrial unit, a large generation unit or a combination of both. BRPs compensate for their forecasting errors by purchasing capacity from the futures market on the European energy exchange (EEX) for any foreseeable and through intra-day market for unplanned deviations from the forecasts (see Figure 5.7). Inability to do so results in the application of a balancing energy price, a portion of which is then used to pay for the activation of necessary frequency reserve.

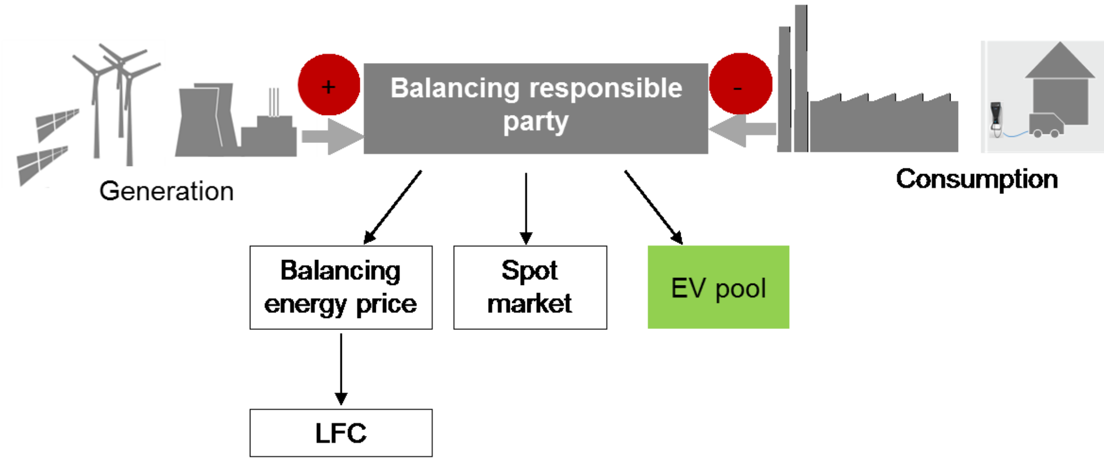

Figure 5.7: Generation of a fictitious dispatch signal for forecasting error minimization

The fictitious dispatch signal for FEM is developed with the goal to minimize the forecasting error by using data available from [127], where the forecasted and actual generation is used to calculated the forecasting error of the zone. This error is then used to determine the dispatch signal for an aggregator offering ±1 MW of reserve as shown in Figure 5.8.

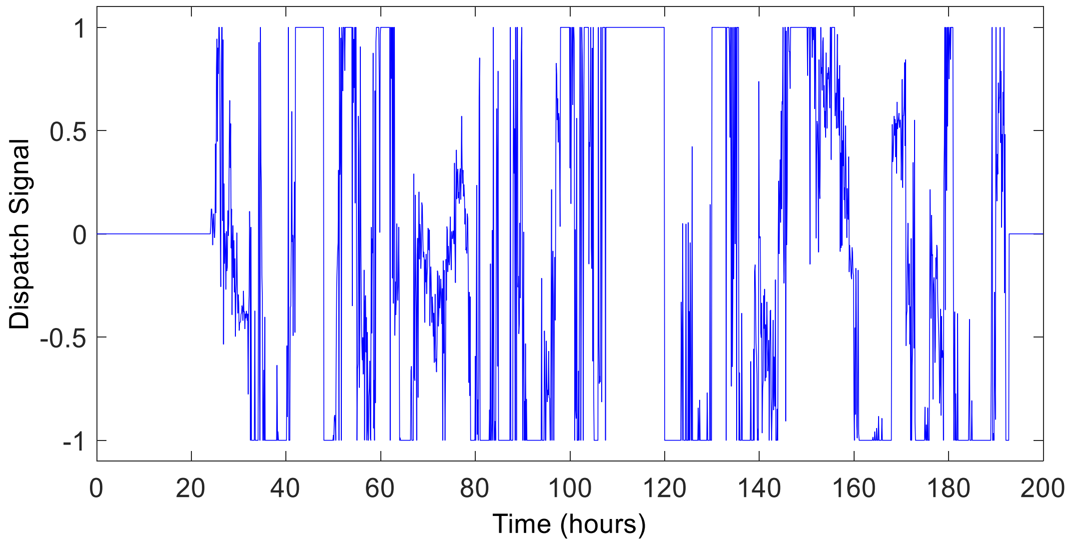

Figure 5.8: Dispatch signal for Forecasting Error Minimization

(3) Peak reduction

The dispatch signal for peak reduction shown in Figure 5.9 is generated using a standard load profile (G1) [128] scaled to a facility located in Munich, Germany with peak load 2500 kW and using prices from the city of Munich's tariffs [129].

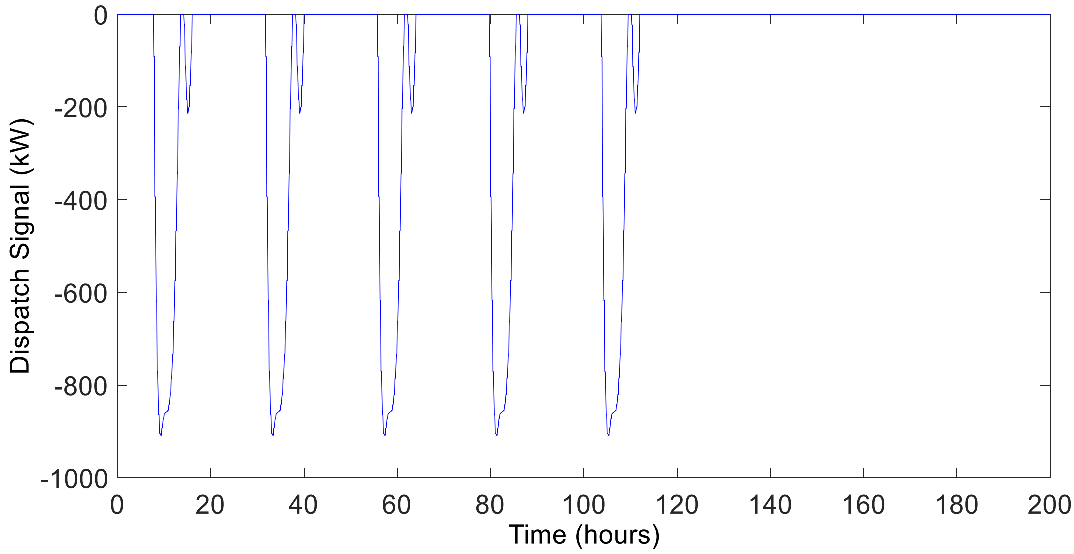

Figure 5.9: Dispatch signal for Peak load reduction of a facility

(4) Charging cost reduction

The dispatch signal for charging cost reduction is generated using spot market prices available from the [130]. The prices are separated into the 1st, 2nd and 3rd quartiles, as illustrated in Figure 5.10. These quartiles define windows, where each EV is allowed to charge, resulting in a charging signal based on the selected window (Figure 5.11).

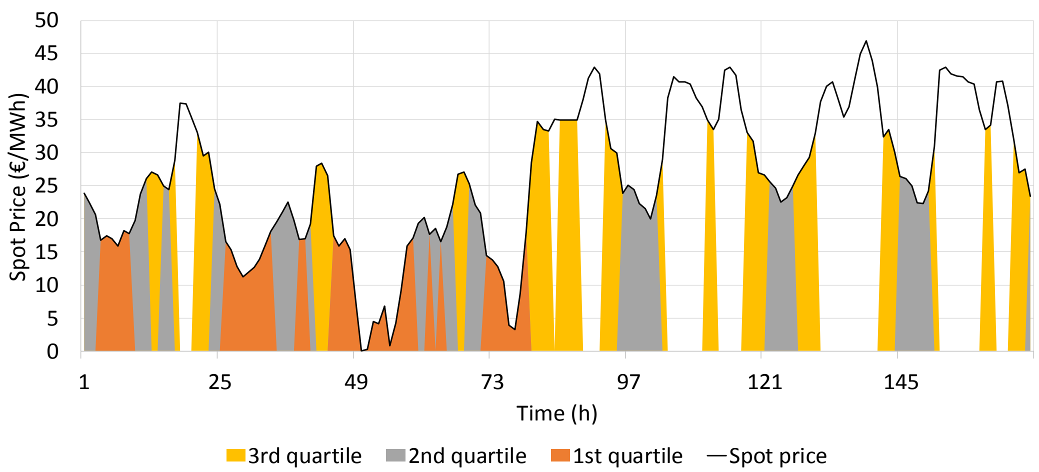

Figure 5.10: Distribution of spot market prices into quartiles

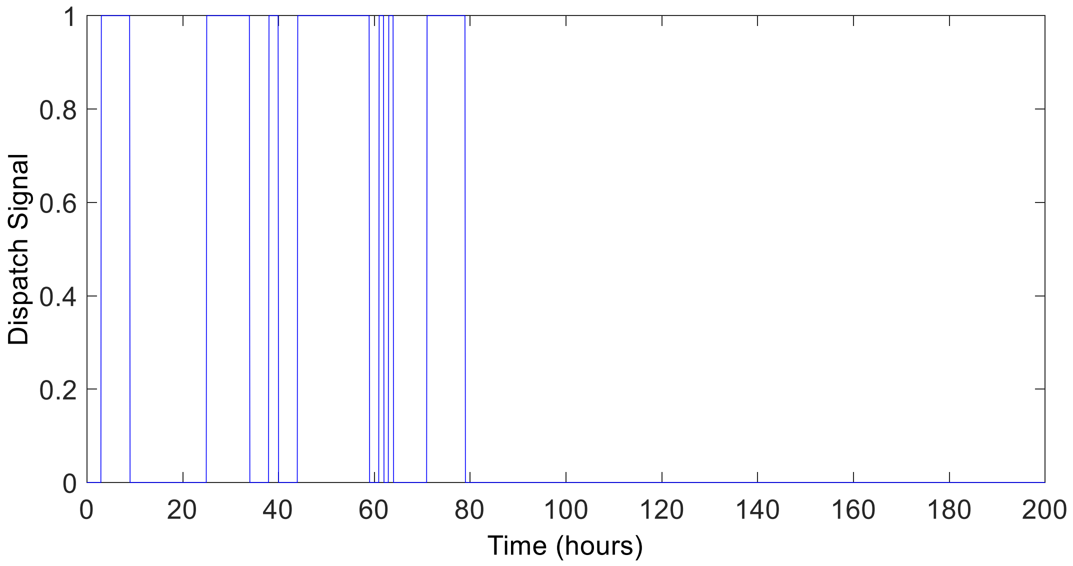

Figure 5.11: Dispatch signal for charging cost minimization (1st quartile)

For the feasibility evaluation, revenues sources for the investigated flexibility services are listed in Table 5.2, taken for the case of Germany.

Table 5.2: Revenue source for flexibility services

Flexibility service	Revenue Source
FEM	Balancing energy prices/*Bilanzausgleichsenergiepreise (reBAP)* [131] and savings from charging energy in Germany.
FRR (part of FS)	Revenue consists of the energy and capacity payments in Germany as well as the saving of regular charging energy.
FCR (part of FS)	Capacity payment for FCR.
PR	Lowering the peak demand of the facility and the corresponding lower peak tariffs based on prices in Germany. 80 % of the total revenue generated from the flexibility service is used as the revenue for the aggregator.

Flexibility service	Revenue Source
CR	Savings from flexible charging are achieved by comparing flexible charging with ‘dumb charging’ in Germany. 80 % of the total savings generated from the flexibility service is used as the revenue for the aggregator.

5.2 Investment and operational cost estimation

The investment cost for flexibility services is categorized by the communication and control infrastructure requirements based on the prevailing regulatory framework. The cost of providing flexibility services can be divided into two categories:

- Providing flexibility services from the workplace: Aggregator’s capability to utilize the EV flexibility at the third-party workplace requires a dedicated infrastructure setup. This infrastructure can be financed by the workplace, the EV user or the aggregator. Each arrangement has its consequential impact on the aggregator’s profitability. In this case, it is assumed that the aggregator bears the expense for the installation and maintenance of the control and communication infrastructure under agreement with the workplace facility and the EV user.
- Providing flexibility services from home: When providing flexibility services from EVs connected through household connections, it is assumed that the control and communication infrastructure already installed and operated by the connecting grid operator can be utilized under arrangement from the grid operator after implementing the necessary security protocols and paying a utilization fee. The smart metering rollout strategy envisioned by [132] requires the installation of smart metering equipment for domestic customers with yearly consumption of >6000 kWh beginning from 2020. Assuming the current average household consumption of 3500 kWh and a yearly EV consumption of 2000 – 2500 kWh (40 km travelled daily on average), it is safe to assume that upper middle-class households with EVs will fulfil or exceed this threshold.

The communication of the household smart meter with the flexibility aggregator takes place through a smart meter gateway. Here also, an already existing communication infrastructure can be expected [133], communicating through gateways installed as part of a neighborhood Area Network (NAN) or Wide Area Network (WAN) [134]. This infrastructure should be capable of information exchange, real-time price-based control and demand response. Once this capability is already implemented and the data is being collected by the grid operator as part of the smart grid, it is only a question of sharing this information with the aggregator following permission by the customer and implementation of security protocols. The grid operator can charge a nominal fee from the aggregator in exchange for access to this information and control.

When it comes to providing flexibility, services using EVs connected at workplace or public spaces, the installation of dedicated smart metering and communication gateways becomes a pre-requisite. This is because the aggregator must communicate and control each EV individually. The generalized cost for data collection, transfer and processing infrastructure for providing flexibility services are derived using the results from the [135] as a guideline and illustrated in Figure 5.12.

	Total cost			
	Data collection	Data transfer	Data processing	Bi-directional power capability (for V2G capability)
Investment cost	• Smart metering equipment • Communicaiton gateway • Installation of metering equipment	• Cost of communication module • Installation of communcation module	• Data processing server hardware • Server software • Other IT-related cost • Project cost	• Bi-directional power electronics
Operational cost	• Meter energy usage • Communciation gateway energy usage • System calibration • Maintenance	• Data metering, calcuation and administration • Maintenance and service • Energy usage during data transfer	• Data processing energy usage • Personnel cost • General maintenance and service • Meter reading and billing • Customer service	• Cost of battery degradation

Figure 5.12: Investment cost components of an aggregator of EV flexibility

The cost of data collection listed in Table 5.3 consists of the metering, communication gateway and the related IT and project cost. The metering and communication gateway are installed as part of the wall mounted charging unit called wall-box. The installation cost includes the man hours and travelling cost. The operational cost of data collection consists of the energy usage and calibration of the system. Finally, the maintenance and service cost for the data collection equipment is included.

Table 5.3: Investment and operational cost of data collection (partly based on [135])

Cost category	Type of cost	Cost range
Investment cost data collection	Wall-box	1000 €/meter
Operational cost data collection	Energy usage metering	13-16 kWh/a
	Communication gateway energy usage	9-22 kWh/a
	Verification	1.5-2 €/meter and year
	Maintenance and services	2-5 €/meter and year

The cost for data transfer consists of the investment and installation cost for the communication module. Although PLC communication modules are assumed for this cost estimation, characteristic cost of other technologies is also listed in Table 5.4. Additionally, the operational cost of data transfer includes the yearly cost for reading, calculation and administration for each communication module.

Table 5.4: Investment and operational cost of data transfer technologies (based on [135])

Cost category	Type of cost		Cost range
Investment cost: data transfer technologies	Investment cost communication module	PLC	14 – 28 €/Module
		Fiber optics	40-60 €/Module
		GPRS	20-50 €/Module
		Other wireless	70-90 €/Module
		DSL	14-28 €/Module
		PLC	3 – 15 €/Module

Cost category	Type of cost		Cost range
	Installation of communication module	Fiber optics	5-20 €/Module
		GPRS	3-10 €/Module
		Other wireless	15-30 €/Module
		DSL	5-20 €/Module
	Data transfer	PLC	10 €/Module and year
		Fiber optics	144 €/Module and year
		GPRS	25 €/Module and year
		Other wireless	20 €/Module and year
		DSL	144 €/Module and year
Operational cost data transfer	Data transfer	PLC	10 €/Module and year
		Fiber optics	144 €/Module and year
		GPRS	25 €/Module and year
		Other wireless	20 €/Module and year
		DSL	144 €/Module and year
	Maintenance and service		1 €/Module and year
	Energy usage		8.76 kWh/Module and year

The expansion and development of the IT-system listed in Table 5.5 involves investment in both the hardware as well as the software system, which might involve purchase of available systems or development of in-house solutions. The implementation of these solutions involves project costs which can range from 2-5% of the overall investment cost [135]. The operation of the system involves the energy usage, training of technicians and staff, reading and recording of metering data and customer service management.

Table 5.5: Investment and operational cost of data processing (based on [135])

Cost category	Type of cost	Cost range
Investment cost: expansion of data processing	Server hardware	30,000 €/server
	Server software	20,000 €/server
	Other IT costs	8150 €/server
	Project cost	2-5% of investment cost
Operational cost data processing	Energy usage	13,140 kWh/a and server
	Personal cost	14,800 €/server and year
	Maintenance and services general	15% of yearly investment
	Maintenance and services variable	0.5 €/meter and year
	Meter reading and billing	0.05-0.1 €/meter and reading
	Customer service	2-5 €/meter and year

5.2.1 Cost of battery degradation

The degradation of battery capacity due to flexibility services is an important cost factor to be considered. According to the analysis performed in [136], the impact of depth of discharge (DoD) on battery capacity degradation is insignificant compared to the overall energy throughput, However, implementation of V2G functionality requires the calculation of the cost of V2G equipment as well as battery degradation during bi-directional charging.

The cost of battery degradation for each unit of transferred energy $c_{\deg}$ is a function of the difference in the depth of discharge during the provision of flexibility services

ΔDoD, battery cost $C_{battery}$, used battery capacity $E_{battery}$ and the number of discharge cycles N_{cycle}.

$$c_{\deg} = \frac{C_{battery} \cdot \Delta DoD \cdot E_{battery}}{N_{cycle}} \tag{5.1}$$

The cost of each energy unit of battery capacity for the future is depends on the development of the lithium-ion battery technology. The analysis performed in [137] shows that the cost of each kWh capacity of li-ion batteries is forecasted to be lie between \$420 - \$200 by 2020 and \$300 - \$150 by 2030. The value of the cost of degradation due to V2G is based on the studies performed by [138] and [136] as 0.38 €/kWh (approx. 0.40 \$/kWh) based on an assumed battery cost of \$247/kWh.

5.2.2 Cost of V2G equipment

Enabling the V2G capability in the EV requires the installation of the necessary power electronics, whose cost plays an important role in the feasibility of using V2G to offer flexibility services. An estimate of this cost can be made by using the DC-AC inverter power electronics used in photovoltaic systems. The benchmark price for these electronics is estimated at about EUR 1.69 (approx. \$1.79) per W_{ac} for utility scale units by [139]. The cost for a domestic grade 3.8 kW inverter manufactured by SMA [140] lies at about EUR 0.5/W. This cost is estimated to drop to about EUR 0.15 – 0.2 by 2020 [141]. External circumstances, for instance an already installed DC-AC inverter for PV-systems can forego this cost component. The specific cost of providing frequency reserve through EVs illustrated in Figure 5.13 shows that the V2G capability increase the cost by about 50 %.

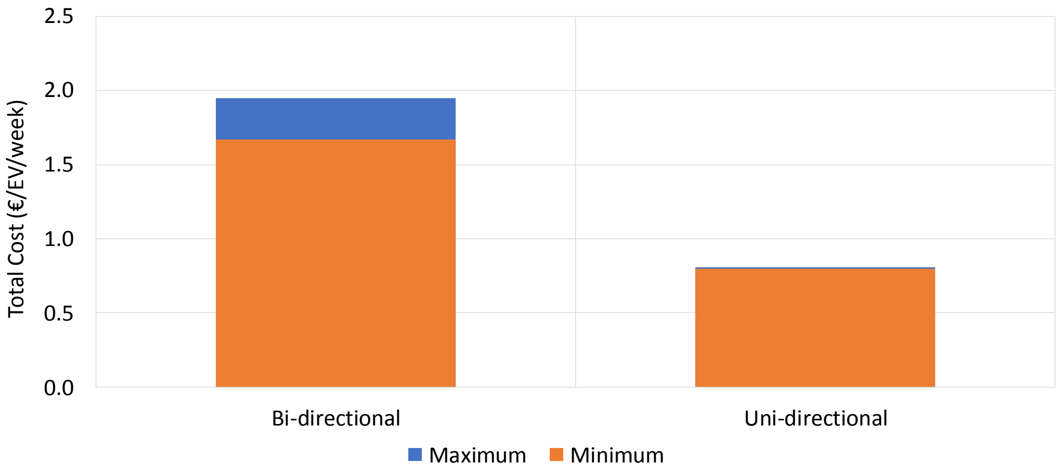

Figure 5.13: EV specific cost for an EV pool with 60,000 EVs for uni-directional and bi-directional capabilities

5.3 Simulation of EV pool response to dispatch signals

The probabilistic aggregator model of EV flexibility described in chapter 4.2 is simulated in response to the fictitious dispatch signals and the charging strategies for each flexibility service case generated using historical data to determine the pool size needed for fulfilling the minimum requirements of each flexibility service. The results of this simulation are discussed in the following subchapters.

5.3.1 Frequency Restoration Reserve (FRR) Negative off-peak

Figure 5.14 illustrates the result of the simulation of the EV pool response to the negative FRR off peak dispatch signal based on the 10th percentile MOL position.

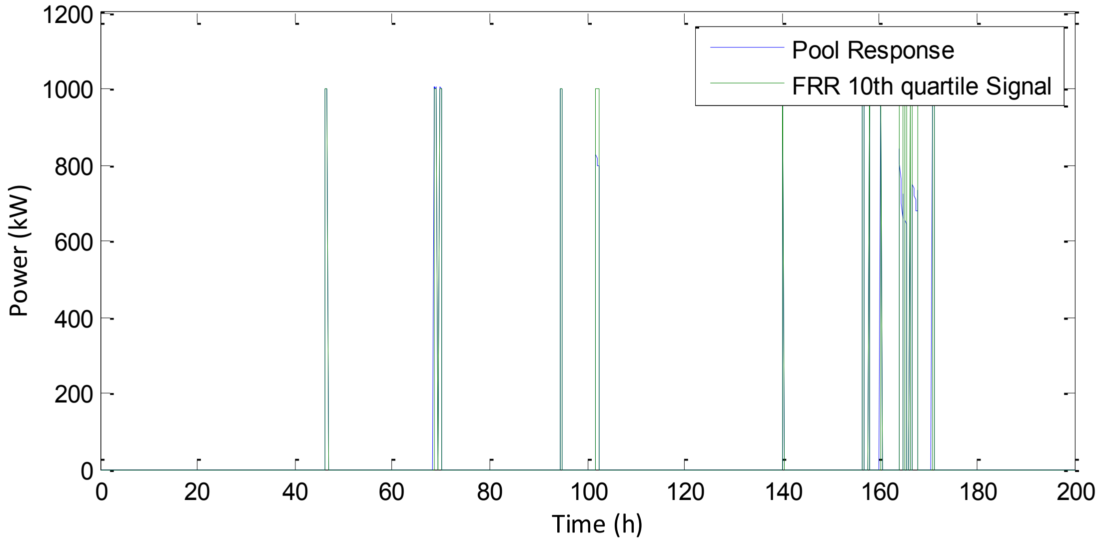

Figure 5.14: FRR negative off-peak dispatch signal fulfilment with an EV pool of 1000 EVs

The changes in the charging behavior of the EV pool in response to the negative FRR dispatch signal for off-peak is illustrated in Figure 5.15.

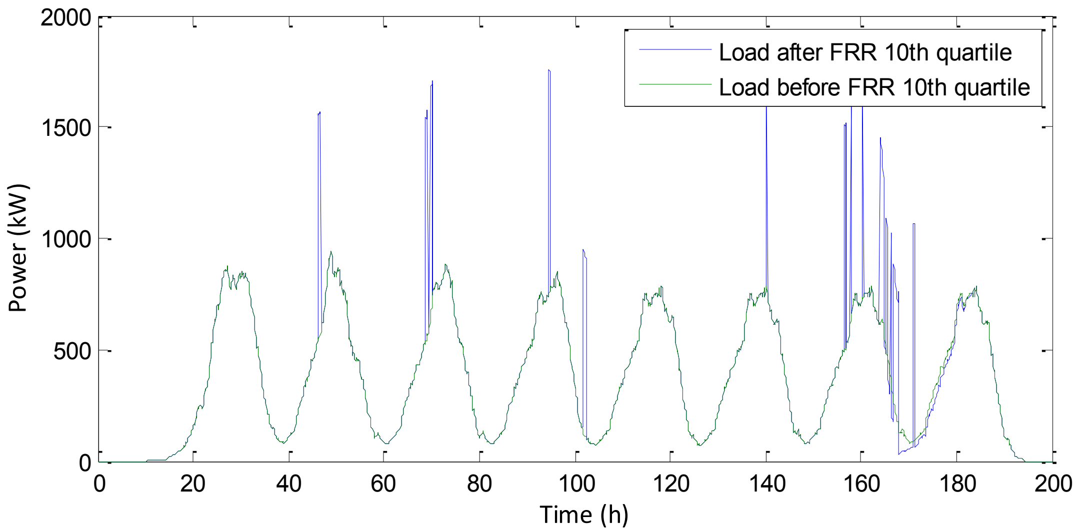

Figure 5.15: EV pool responding to FRR negative off-peak dispatch signal

Figure 5.16 illustrates the required pool size to fulfil the performance criteria while responding to the negative FRR off-peak signal, demonstrating that a pool of 1000 EVs is sufficient to adequately supply to 1 MW FRR negative off-peak by fulfilling the performance criteria described in subchapter 4.3.1.

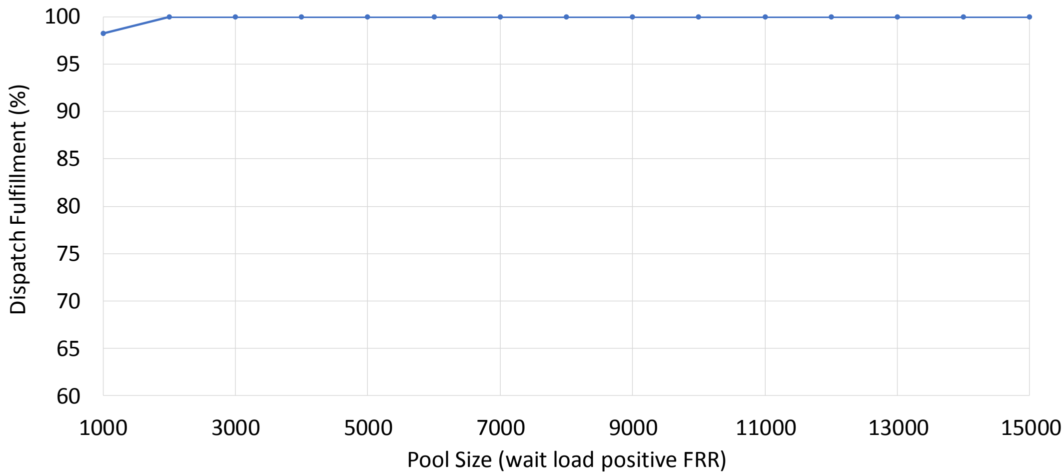

Figure 5.16: Performance of the EV pool responding to negative FRR off-peak dispatch under immediate charging

5.3.2 Frequency Restoration Reserve (FRR) Positive off-peak

Figure 5.17 illustrates the result of the simulation of the EV pool response using V2G to the positive FRR off peak dispatch signal based on the 10^{th} percentile MOL position.

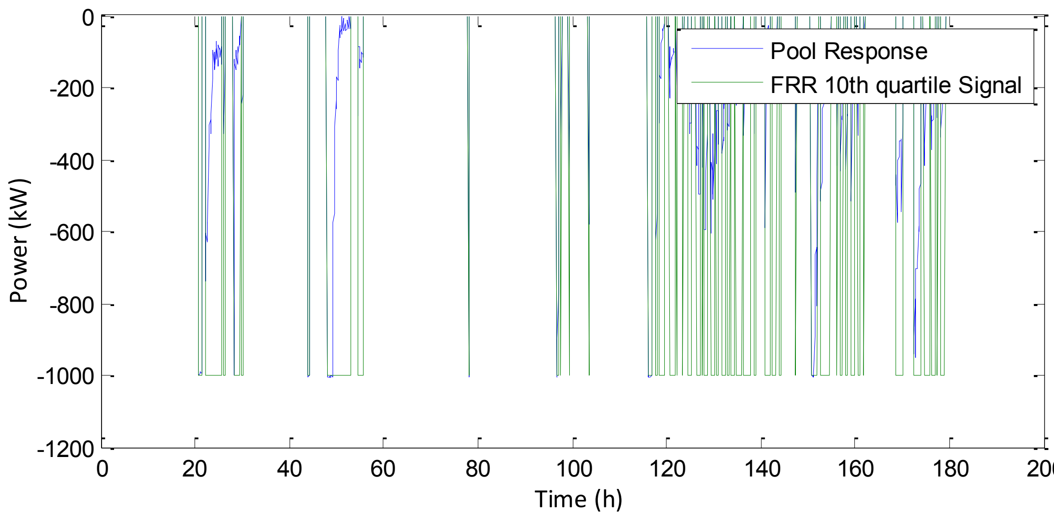

Figure 5.17: FRR positive off-peak dispatch signal fulfilment with an EV pool of 1000 EVs and V2G capability

Changes in the charging behavior of the EV pool in response to the positive FRR dispatch signal for off-peak is illustrated in Figure 5.18.

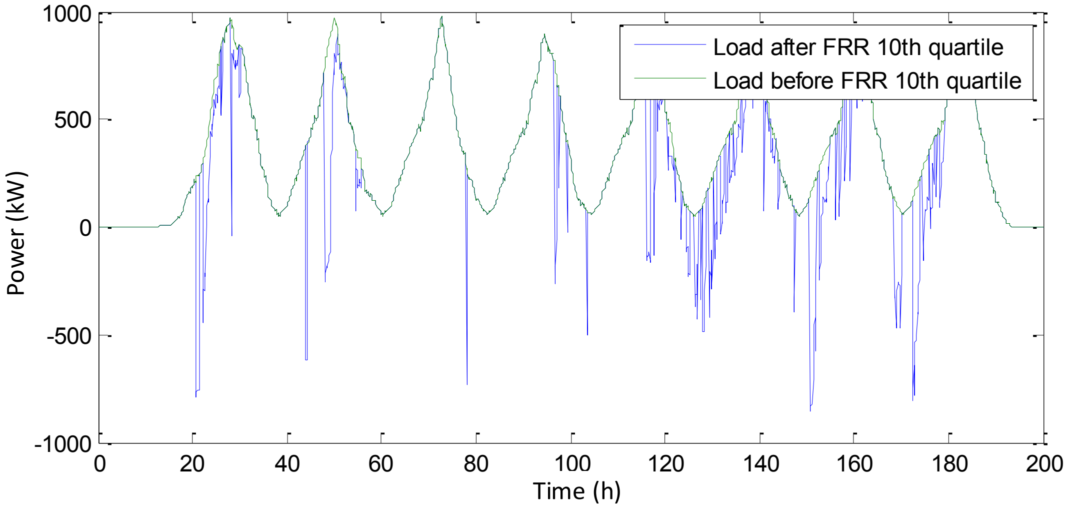

Figure 5.18: EV pool with V2G responding to FRR positive off-peak dispatch signal

Figure 5.19 illustrates the required pool size to fulfil the performance criteria while responding to the positive FRR off-peak signal using V2G capability, demonstrating that a pool of 5000 EVs can adequately supply 1 MW FRR negative off-peak by fulfilling the established performance criteria.

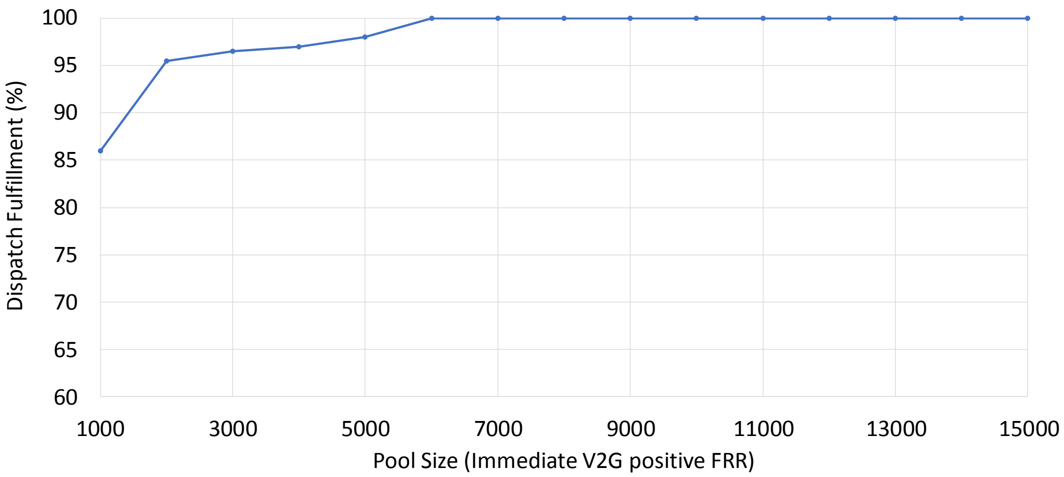

Figure 5.19: Performance of the EV pool with V2G immediate charging responding to positive dispatch

Figure 5.20 illustrates the result of the simulation of the EV pool response using controlled charging to the positive FRR off peak dispatch signal based on the 10th percentile MOL position.

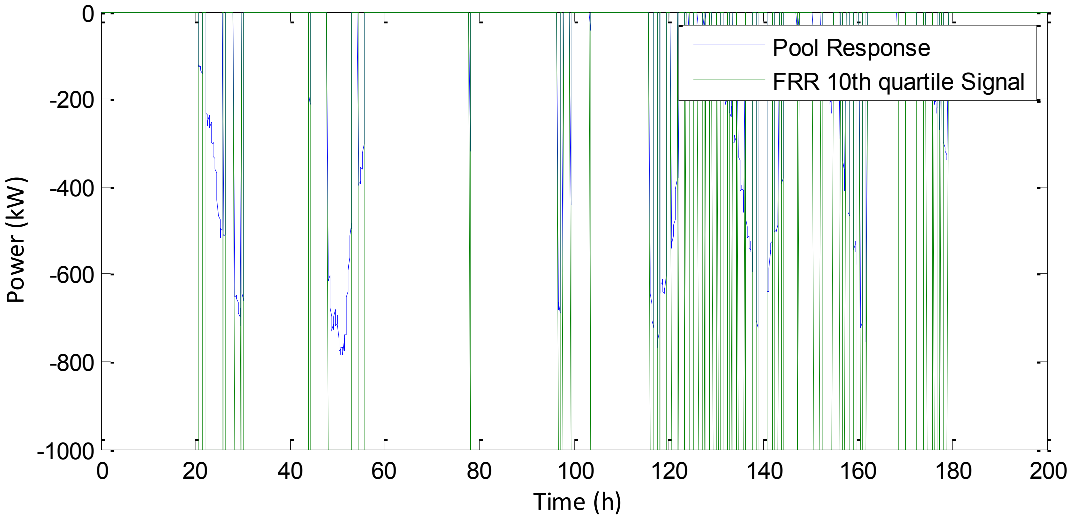

Figure 5.20: FRR positive off-peak dispatch signal fulfilment with an EV pool of 1000 EVs under controlled charging

The changes in the charging behavior of the EV pool with controlled charging in response to the positive FRR dispatch signal for off-peak is illustrated in Figure 5.21.

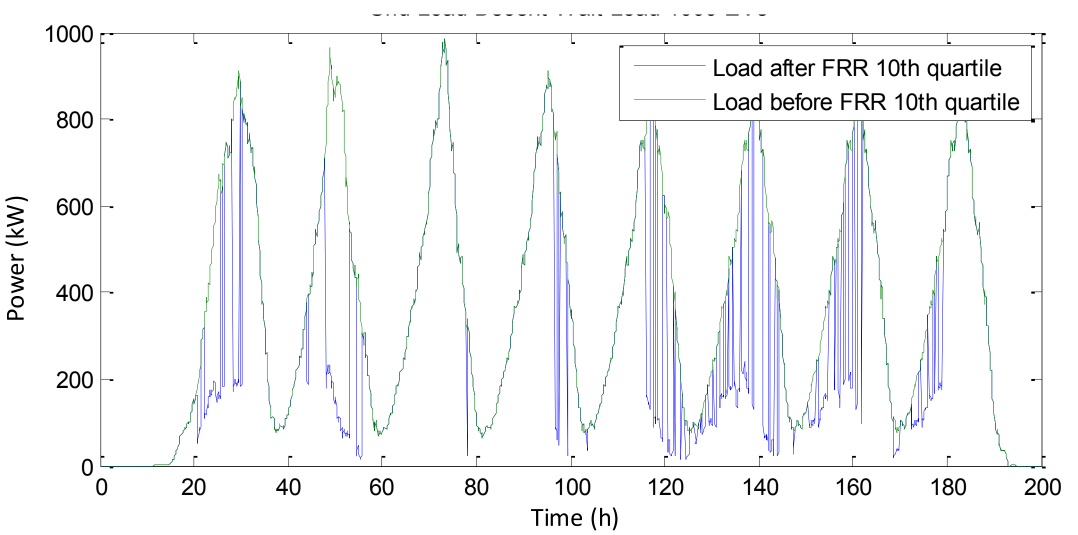

Figure 5.21: EV pool with controlled charging responding to FRR positive off-peak dispatch signal

Figure 5.22 illustrates the required pool size to fulfil the performance criteria while responding to the positive FRR off-peak signal with controlled charging. It is obvious that a pool with 16000 EVs is unable to fulfil the performance criteria.

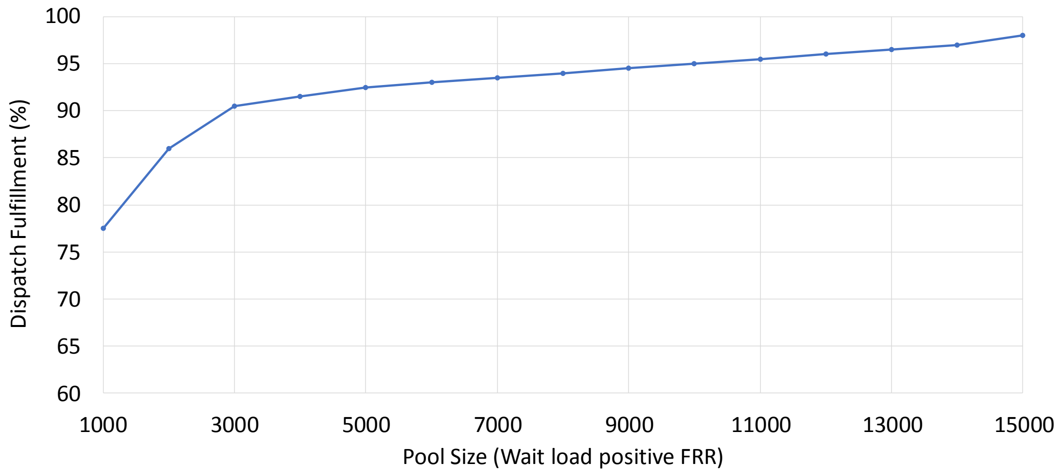

Figure 5.22: Performance of the EV pool with controlled wait charging responding to positive dispatch

5.3.3 Frequency Containment Reserve (FCR)

Figure 5.23 illustrates the result of the simulation of the EV pool response to the FCR dispatch signal using V2G capability. It is observable that 2000 EVs are able to fulfill the demand the dispatch requirements fulfilling the performance criteria.

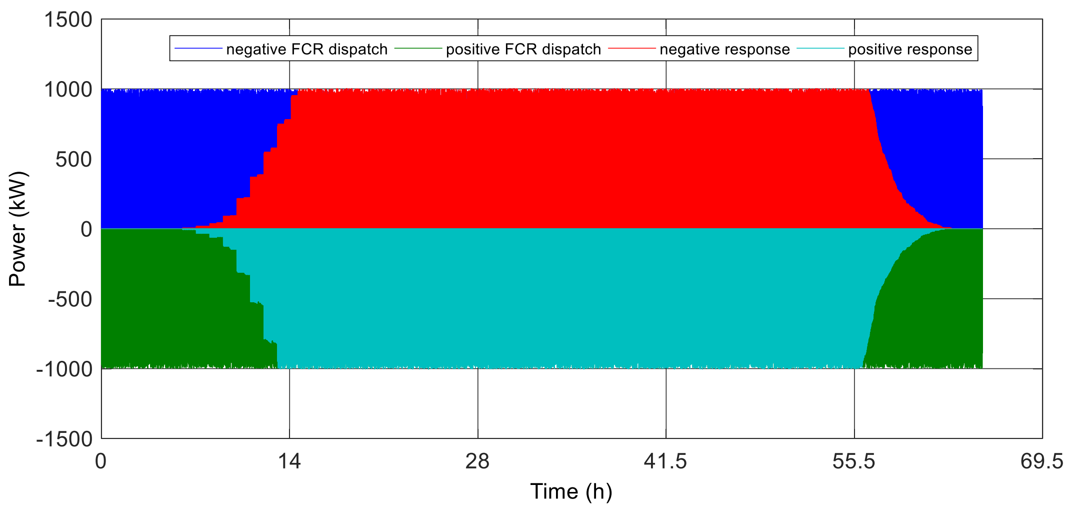

Figure 5.23: Pool response to a 1 MW FCR dispatch signal under wait V2G strategy

Figure 5.24 illustrates the result of the simulation of the EV pool response to the FCR dispatch signal using controlled charging. It is obvious that 1000 EVs are only enough to supply the negative part of the 1000 kW FCR while also fulfilling the performance criteria.

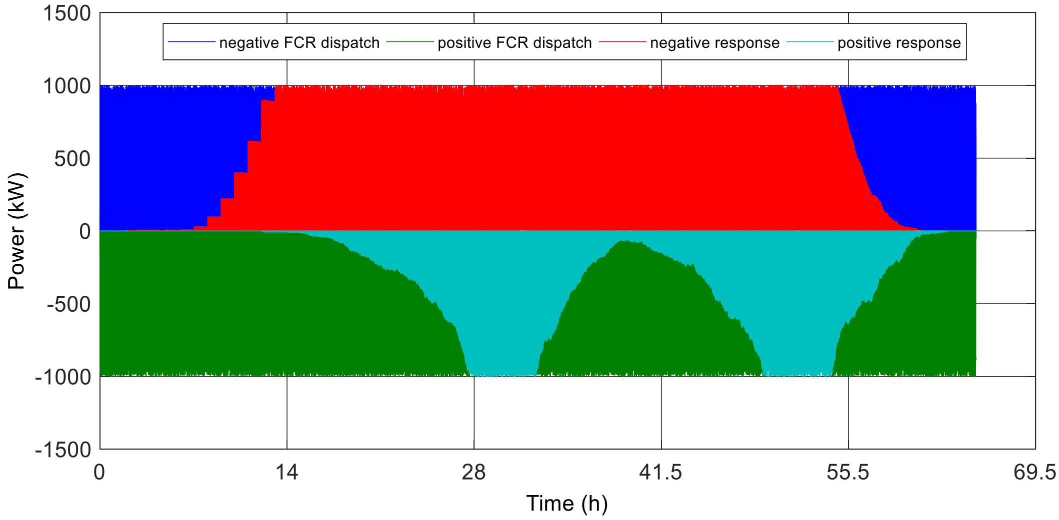

Figure 5.24: Pool response to a 1 MW FCR dispatch signal under wait charging strategy

5.3.4 Forecasting Error Minimization (FEM)

Figure 5.25 illustrates the result of the simulation of the EV pool response using V2G to the FEM dispatch signal with inadequate fulfilment.

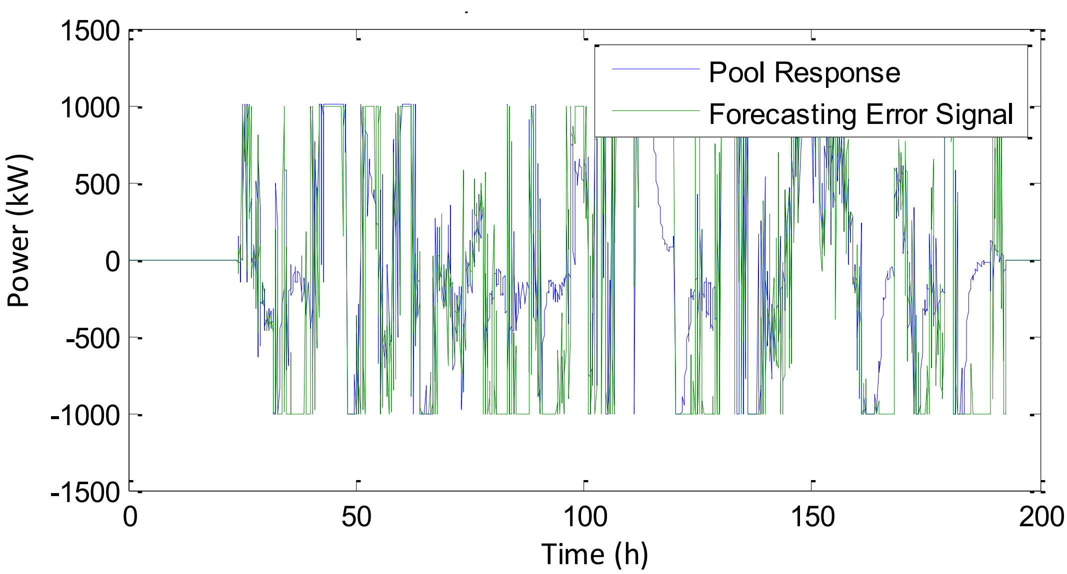

Figure 5.25: FEM dispatch signal fulfilment with an EV pool of 1000 EVs under wait V2G charging

The changes in the charging behavior of the EV pool with V2G in response to the FEM dispatch signal is illustrated in Figure 5.26.

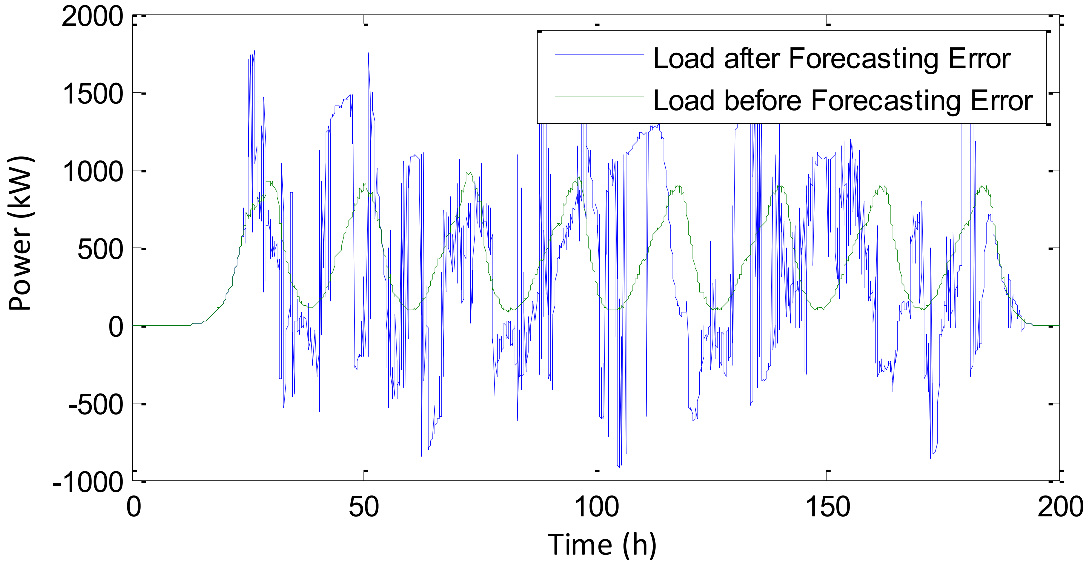

Figure 5.26: EV pool with wait V2G charging responding to FEM signal

The dispatch signal fulfilment under V2G is illustrated in Figure 5.27, showing that 1000 EVs are necessary to supply 1 MW of negative FEM demand.

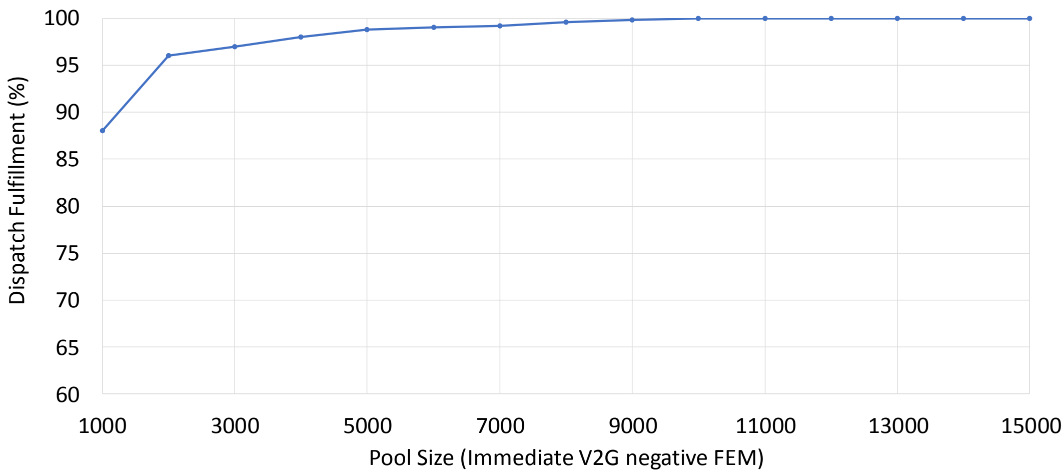

Figure 5.27: Negative FEM fulfilment level with immediate V2G

V2G capability enables the aggregator to supply both positive and negative FEM demand with 5000 EVs, as illustrated by Figure 5.28.

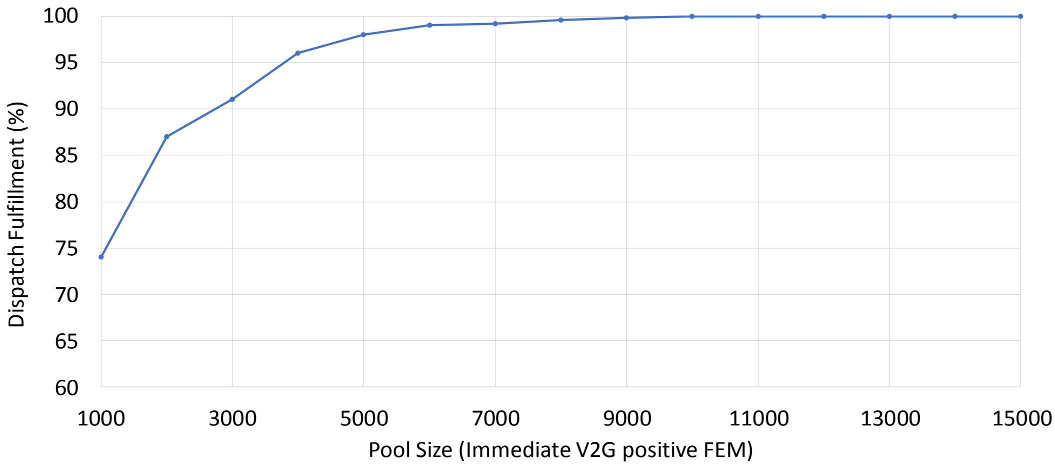

Figure 5.28: Positive FEM fulfilment level with immediate V2G

Figure 5.29 illustrates the result of the simulation of the EV pool response with controlled charging to the FEM dispatch signal with inadequate fulfilment.

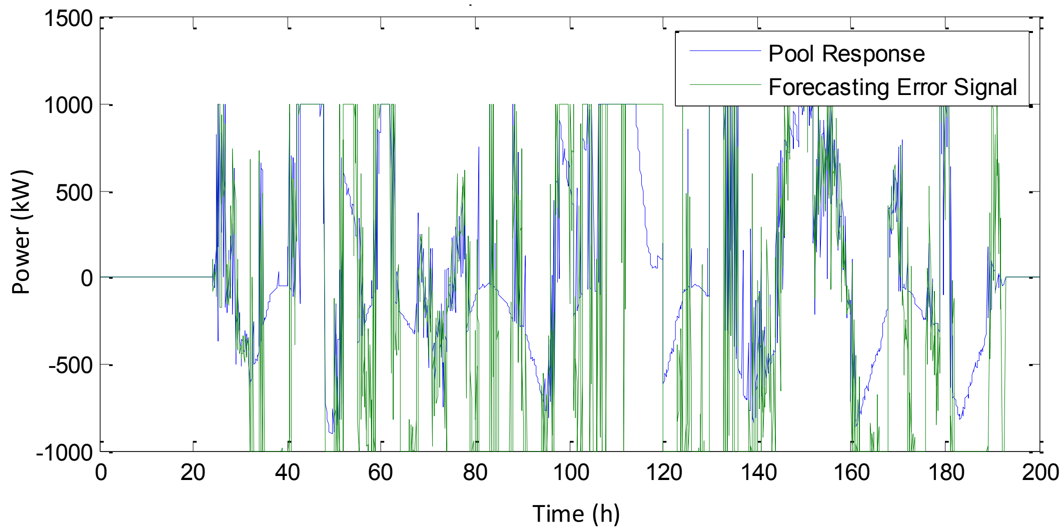

Figure 5.29: FEM dispatch signal fulfilment with an EV pool of 1000 EVs under wait controlled charging

The changes in the charging behavior of the EV pool with controlled charging in response to the FEM dispatch signal is illustrated in Figure 5.30.

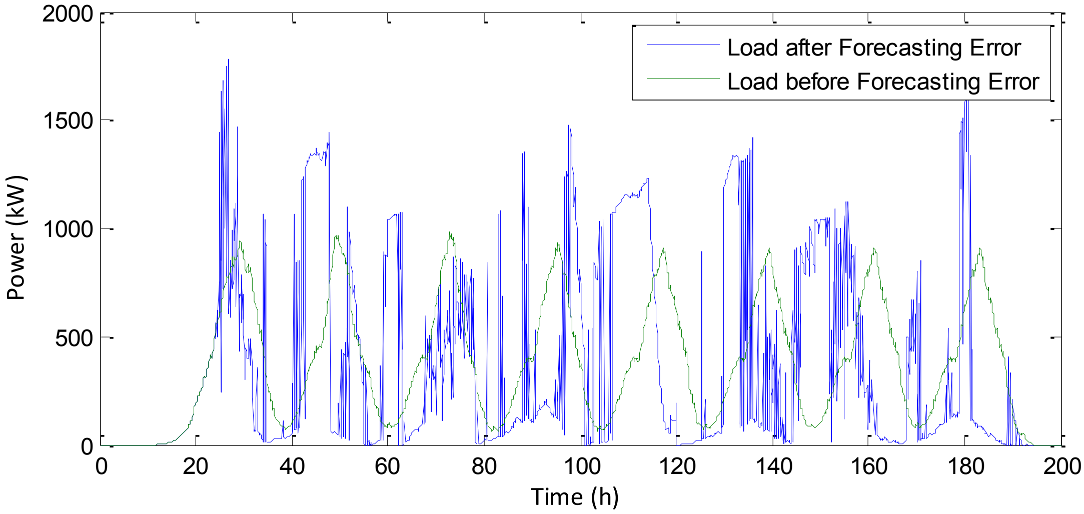

Figure 5.30: EV pool with wait controlled charging responding to FEM signal

The dispatch signal fulfilment with controlled charging is illustrated in Figure 5.31, showing that 1000 EVs are sufficient to supply 1 MW of negative FEM demand.

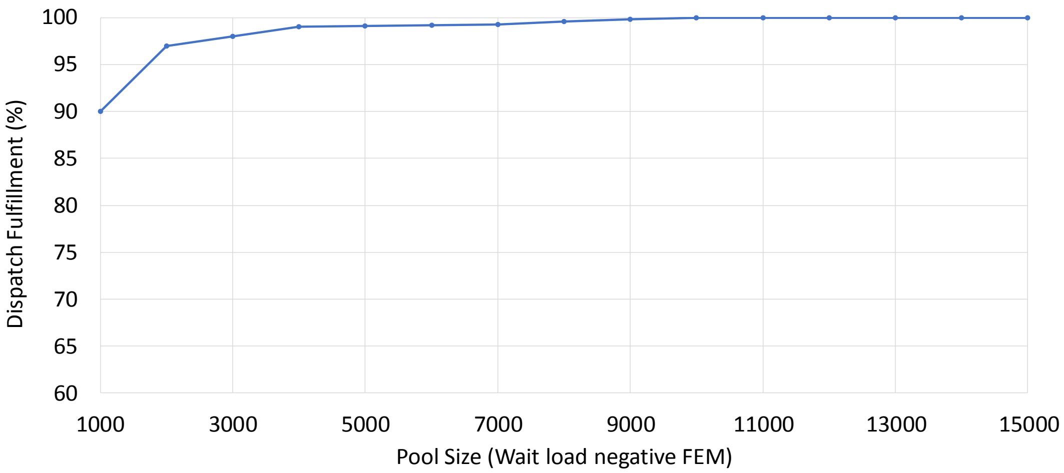

Figure 5.31: Negative FEM fulfilment level with wait controlled charging

With controlled charging, a pool of about 25,000 EVs is necessary to fulfil the performance criteria, as illustrated by Figure 5.32.

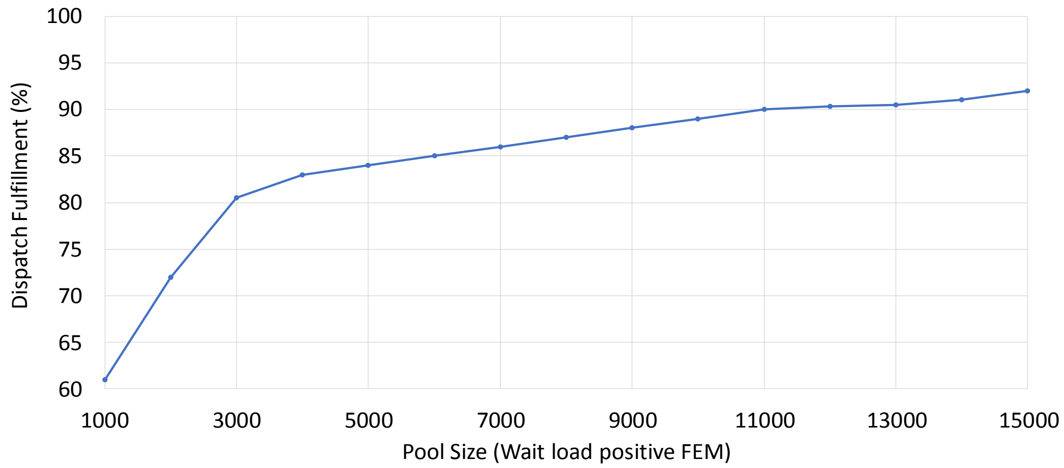

Figure 5.32: Positive FEM fulfilment level with wait controlled charging

5.3.5 Peak Reduction (PR)

The simulation of the EV pool capability to reduce peak load of the facility is illustrated in Figure 5.33. Controlled charging of a pool of 3000 EVs is capable of reducing the peak load from 4.3 MW to about 3.5 MW.

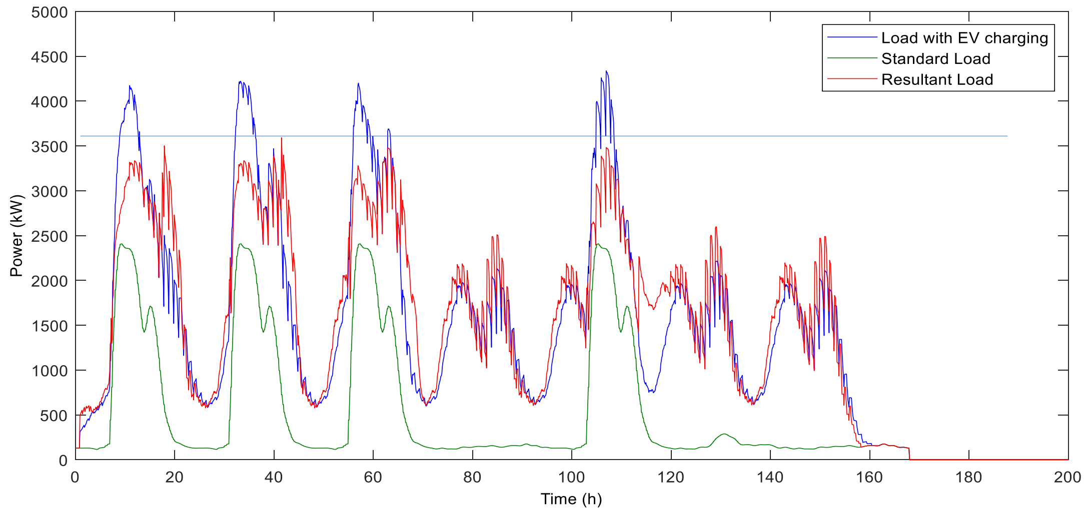

Figure 5.33: EV pool capability to reduce peak load (horizontal line indicates peak resultant load)

5.3.6 Charging Cost Reduction (CR)

Figure 5.34 illustrates the pool response to a charging signal based on the 1st quartile of the spot market prices, as described in subchapter 5.1, whereby the dispatch signal is implemented as a step signal, varying from 0 to 1. Peaks in the charging power are observable during the time when dispatch signal is positive only until the 80th hour of the week, as illustrated by the regulated charging curve, the EVs charge immediately before plug-out to fulfil their minimum SOC requirements if they were unable to charge in response to the dispatch signal.

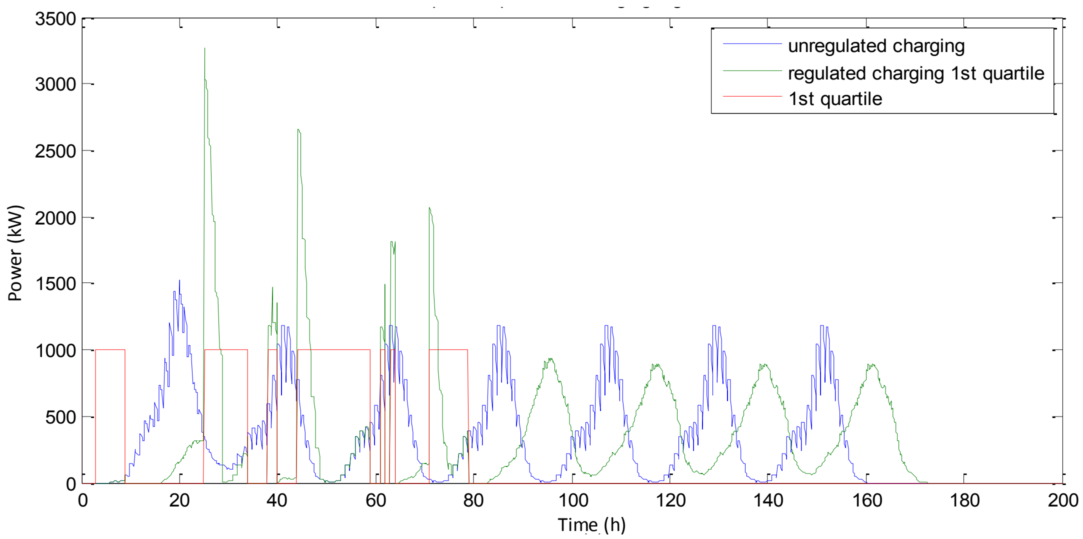

Figure 5.34: Pool response to the 1st quartile charging signal

The pool charging in response to a dispatch signal based on the 2nd quartile of spot market prices is illustrated in Figure 5.35, where peaks are observable during the whole week.

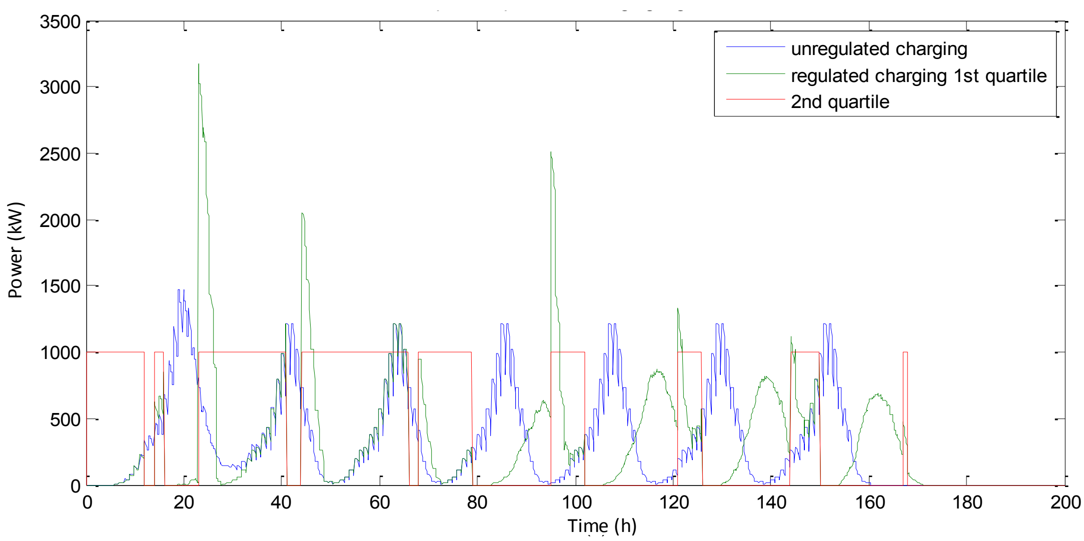

Figure 5.35: Pool response to the 2nd quartile charging signal

The dispatch signal and the pool charging response based on the spot market prices of 3rd quartile is illustrated in Figure 5.36, with longer periods of positive dispatch signal observable.

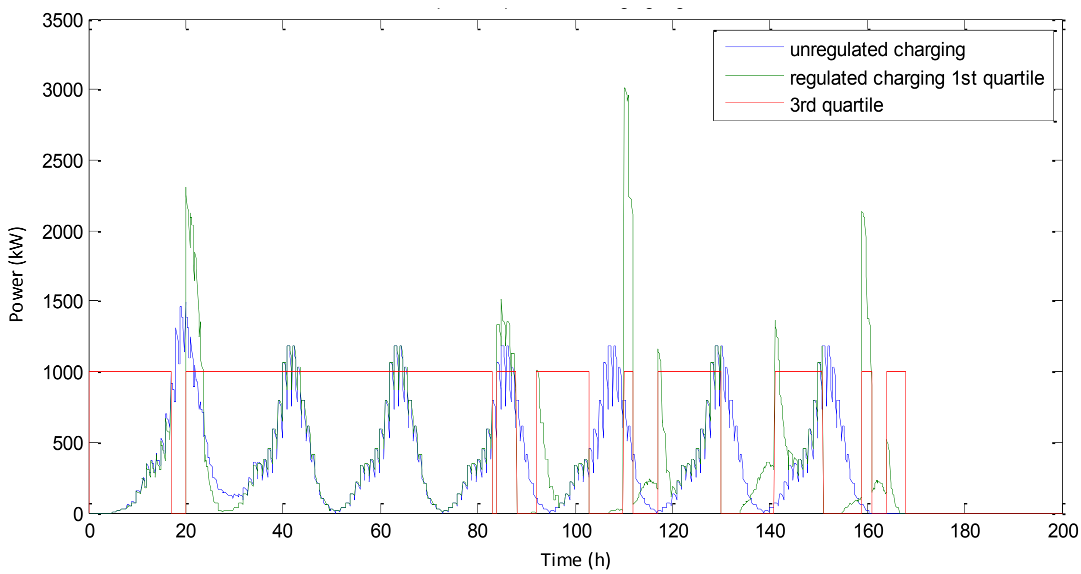

Figure 5.36: Pool response to the 3rd quartile charging signal

The savings in charging energy cost in response to the three types of the dispatch signals shows the highest savings resulting from a dispatch signal based on the median value of the spot market prices, as illustrated in Figure 5.37. This happens because signals based on the 1st quartile spot market prices are only positive for a short period of time, leading to EVs charging most of the time in the absence of any optimization. On the other hand, the dispatch signals based on the 3rd quartile closely resemble an unoptimized charging behavior by allowing charging during a majority of the time.

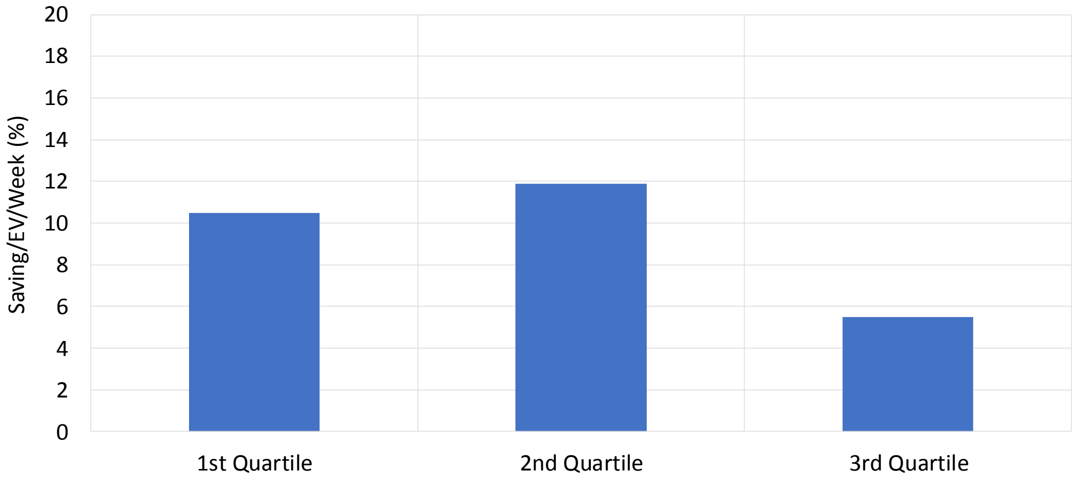

Figure 5.37: Electricity charging cost savings in response to charging cost reduction dispatch signal

5.4 Feasibility of flexibility services for an aggregator

Figure 5.38 illustrates the minimum pool size required to adequately fulfil the 1 MW dispatch signal for each flexibility service. Large pool sizes are necessary to respond to FCR, FRR positive, FEM and AbLaV (DR) signals when using controlled charging due to the smaller positive flexibility available.

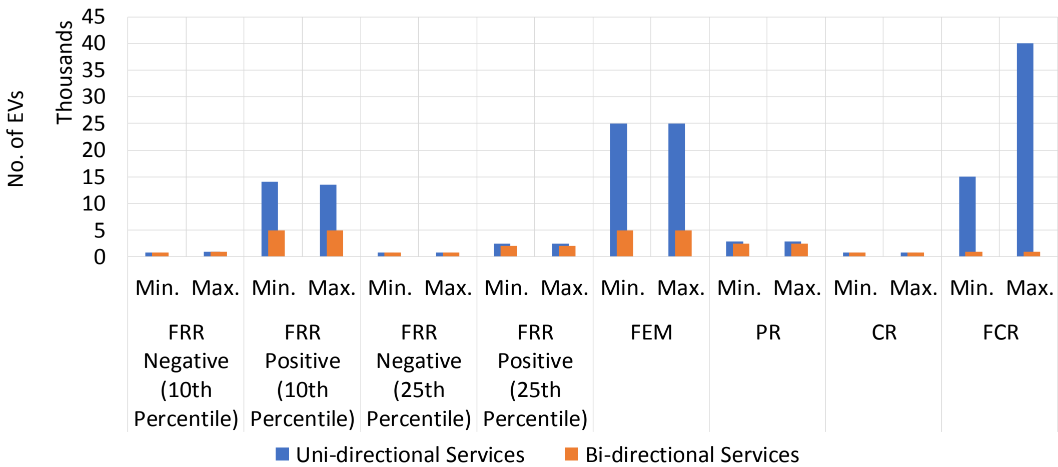

Figure 5.38: Minimum pool size necessary to fulfil the performance criteria for flexibility services

The revenue potential of the investigated flexibility services is illustrated in Figure 5.39 with the corresponding minimum pool size. The results show that negative FRR, FEM and FCR generate the highest amount of revenue for external oriented flexibility provision, with V2G enabling a significant improvement in FEM and FCR.

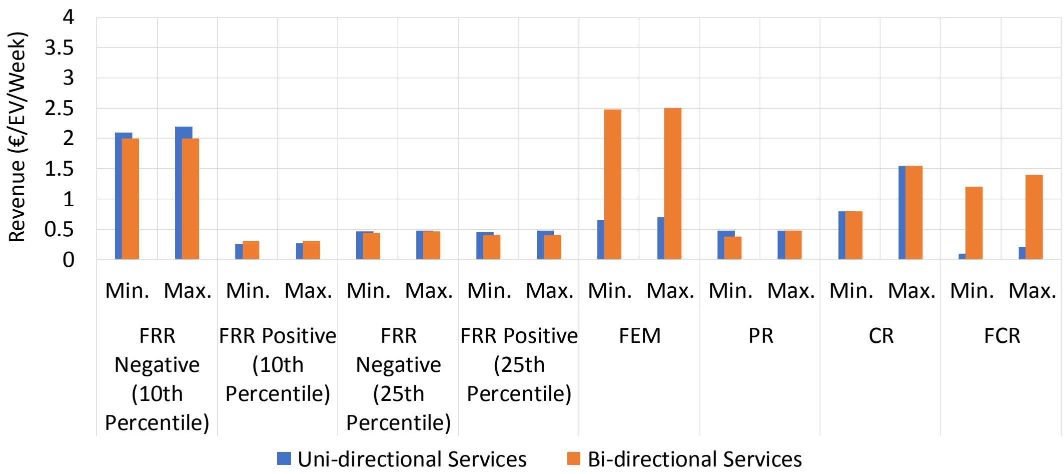

Figure 5.39: Revenue potential of EV pool for flexibility services

Profitability of the flexibility services is calculated based on the cost estimates described in subchapter 5.2 and represented by the boxplot in Figure 5.40. As can be observed, the EV pool is highly unprofitable when small. Scaling the pool size and corresponding revenues shows that the profitability of all flexibility services largely depends on the size of the pool, reaching a quasi-saturation point after about 35,000 EVs, with a maximum achievable profit of 1.73 €/EV/week.

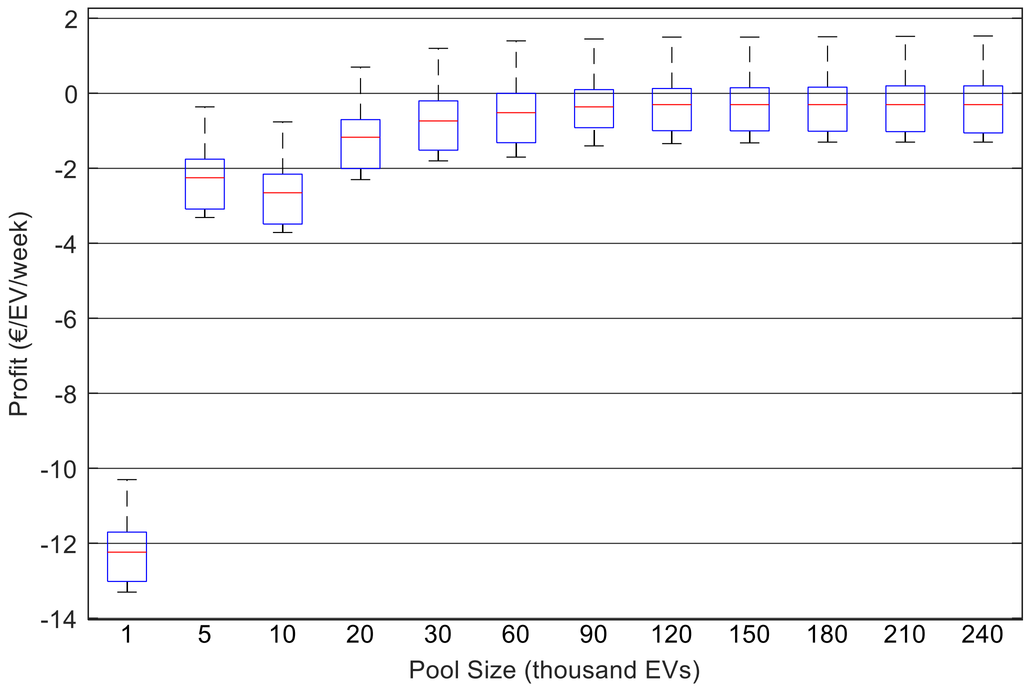

Figure 5.40: Profitability of EV flexibility provision with respect to pool size

5.4.1 Sensitivity analysis

The sensitivity analysis of the EV pool is performed on the basis of two parameters, with the values of the parameters are changed according to Table 5.6:

- Charging power
- Battery capacity

Table 5.6: Sensitivity analysis parameters

Parameter	Current value	Sensitivity test value
Charging power	3.7 kW	11 kW
Battery capacity	28 kWh	50 kWh

The sensitivity analysis illustrated in Figure 5.41 shows that increasing the charging power by 200 % results in decrease of the pool size by about 35 % in the case of positive FRR.

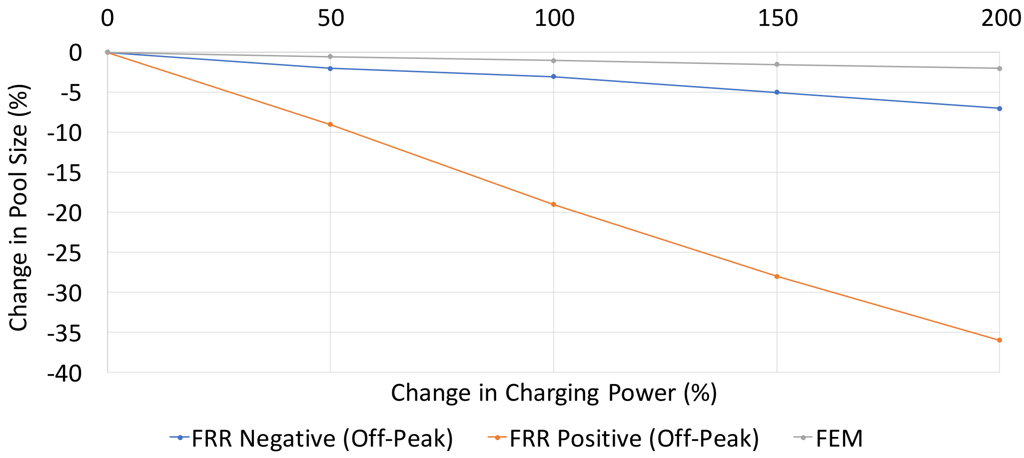

Figure 5.41: Sensitivity of required pool size to charging power

The sensitivity analysis illustrated in Figure 5.42 shows that increasing the battery capacity results in the decrease of the pool size by about 40 %. This effect is similar for both negative FRR and FEM, although to a lesser degree.

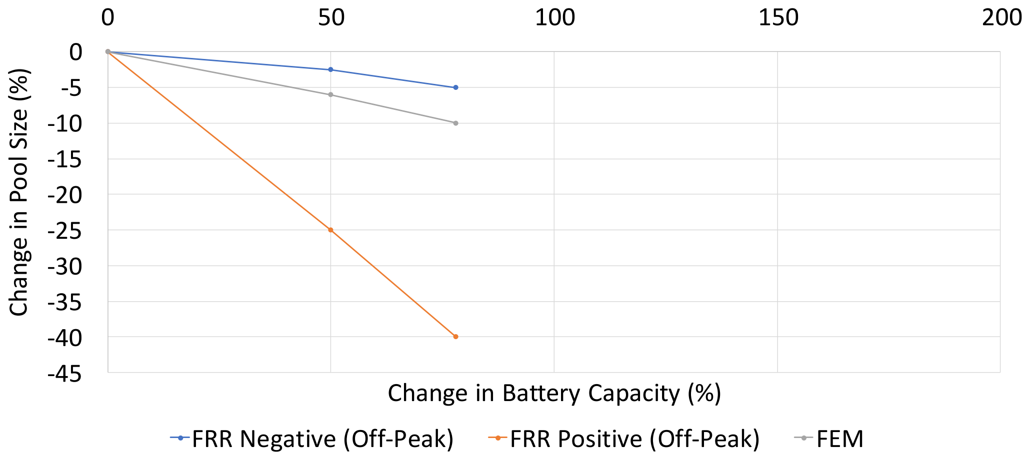

Figure 5.42: Sensitivity of required pool size to battery capacity

5.4.2 Multi-use cases of flexibility services

The types of flexibility services described above can be combined to create multi-use cases. The possible multi-use cases of the discussed flexibility services are illustrated in Table 5.7. Two conditions must be applied when considering the flexibility services multi-use cases:

1. Multiple flexibility services cannot be offered with the same EV for similar purposes. This rules out providing frequency services and forecasting error

minimization services to BRPs simultaneously due to their causal relationship.

2. Products with conflicting goals cannot be combined, ruling out the provision of peak reduction services to industrial facilities while offering reduced charging cost to users because peak reduction involves refraining from charging or discharging.

Table 5.7: Multi-use cases of the investigated flexibility services

Parameter	Frequency services	Forecasting error minimization
Peak reduction	Case 1	Case 2
Charging cost reduction	Case 3	Case 4

This results in four multi-use cases:

- Case 1 consists of providing frequency services in combination with offering peak load reduction services if there is no regulatory conflict due to frequency services contracts.
- Case 2 consists of providing flexibility for forecasting error minimization to the BRPs while offering peak reduction services to industrial facilities.
- Case 3 combines offering frequency services to GOs in combination with charging cost reduction for the EV owners.
- Case 4 consists of providing cost reduction services to EV owners while providing forecasting error minimization services to BRPs.

5.5 Conclusions

The evaluation of the operational concepts based on flexibility service provision based on the simulation model of the EV user behavior determines that the aggregator's feasibility of providing flexibility services using EVs in Germany largely depends on the infrastructure cost and correspondingly the pool sizes, whereby the breakeven point is reached with 20,000 to 30,000 EVs. It is shown that providing negative FRR, flexible tariff charging and forecasting error minimization are profitable, generating a profit of up to 1.73 €/EV/week, whereby the feasibility is strongly dependent on the pool size, the charging power used and the battery capacities. The selection of the charging strategy to charge EVs near plug-out only improves the economic benefit of the aggregator by about 3-5 %.

The success of an aggregator flexibility service depends on a number of wide-ranging factors, which include the availability of favorable regulation, fulfillment of participation requirements set by the potential users of this storage, willingness of EV owners to make available their charging schedules and charging flexibilities and the potential revenues generated from such a participation.

6 Conclusions and outlook

The energy revolution in Germany has led to a dramatic rise in electricity produced from renewable energy sources primarily based on volatile photovoltaic and wind generation, displacing the relatively reliable conventional generation and requiring proactive measures to ensure frequency stability including an investment in energy storage technologies to balance the fluctuations of electricity generation. Improvements in battery technology and an increasing concern for the environment has led to a rising share of electric vehicles in the transportation sector, with the potential of uncoordinated charging bringing another dimension to the challenges to frequency stability. There is a need to assess these issues and the role played by electric vehicles in mitigating their negative impact.

In this thesis, frequency control reserve mechanisms are analyzed for the feasibility of electric vehicle integration as a provider of flexibility services. The analysis shows that grid operators in Germany and Denmark operate their stability reserve procurement systems with rules most feasible for electric vehicle integration. The regulatory characteristics and prequalification requirements of most systems, apart from the German system and DK2 zone in Denmark, are designed for conventional generation, favoring slower acting resources capable of longer activation durations. The key characteristics identified in this work can be used to evaluate other systems and can be used as a guideline for reforms to help increase the share of distributed resources in frequency control mechanisms.

The stochastic deficit probability model-based simulation of the impact of renewable energy integration on frequency control show that the increase in volatility will result in a significant increase in the demand for frequency control reserve. This is due to larger forecasting errors from volatile renewable energy sources. As their contribution in the energy mix increases, so does the overall volatility.

The evaluation of infrastructure requirements for alternative approaches to frequency control in the face of these challenges shows that both highly centralized and decentralized approaches have their advantages and disadvantages. A centralized approach entails increased complexity and ICT infrastructure requirements, but with the advantage that imbalances and deficits in one region can be compensated from any node of the interconnected grid. Conversely, decentralization reduces the infrastructure requirements and complexity in the grid but comes at the cost of weaker oversight by a centralized control center capable of taking remedial actions. It is shown that the introduction of the aggregator as a market player responsible for controlling smaller suppliers of frequency control leads to an overall reduction in infrastructure requirements and complexity in all centralized scenario.

The simulation of the user behavior shows that making available the flexibility of the EV to the aggregator immediately upon plugging in and fulfilling the charging requirements of the EV user later is a clearly better approach, resulting in smaller pool sizes providing the same flexibility capacity. It is also to be noted that offering bi-directional flexibility using V2G offers clear advantages to the aggregator. The evaluation of operational concepts shows that the economic feasibility for an aggregator fleet of electric vehicles can be reached with 30,000 vehicles, with higher battery capacities and charging power resulting in smaller fleet sizes to fulfil the same dispatch requirements.

The evaluation of the operational concepts for providing flexibility service based on the simulation model of EV user behavior shows that the feasibility of providing flexibility services in Germany largely depends on the infrastructure cost and the aggregator's pool sizes, It is shown that it is economically feasible to use the flexibility provided by EVs to supply negative FRR, flexible tariff charging and forecasting error minimization services while ensuring the fulfillment of user charging requirements. The feasibility increases with higher charging power and EV battery capacities.

The research carried out in this work has been published in a scientific journal [O-1] and technical conferences [O-2, O-3]. The scientific contributions of this thesis can be summarized as following:

- Development of an indicator-based framework for evaluation of load frequency control system characteristics,
- Stochastic modeling-based investigation of the impact of renewable energy on the demand for load frequency control reserve,
- development of a weighted indicator-based evaluation framework of alternative approaches to frequency control with high renewable energy and
- development of a probabilistic EV user behavior model and evaluation of operational concepts for supplying flexibility service to the grid with electric vehicles.

The research questions discussed in subchapter 1.2 can be answered as follows:

- The demand for frequency control reserve in 2030 can rise to 54 % from the 2011 level. This demand can be fulfilled by utilizing decentralized resources pooled into aggregator, which can contribute to reduction of about 10 % in the overall infrastructure requirements for frequency control compared to present-day.

- Electric vehicles can contribute to frequency stability by participating in present-day frequency control reserves as controllable load as well as by providing services to balancing responsible parties for reducing the forecasting error.
- Grid services can be provided with an aggregator consisting of more than 30,000 EVs, whereby the EV flexibility is offered before charging requirements of the EV user are fulfilled.

6.1 Critical reflections and future research

The LFC systems analyzed in this thesis are undergoing rapid transformation and developments in renewable energy and EV integration targets may change the outlook for EV integration in load frequency control. The evaluation framework presented in this work serves as the basis for evaluating future changes in the regulatory and pre-qualification requirements. An analysis of the regional differences in RES integration and the corresponding developments in LFCR within North America would provide a direction of improvement for systems in other regions. The indicator-based evaluation method utilized in this thesis can be applied to the evaluation of LFC systems for a range of technologies. For example, evaluating the suitability of the markets on this framework for integration of battery energy storage would have diminished importance of procurement method, procurement period and service time window, thanks to absence of time-based availability constraints that exist for EVs. Bilateral procurement of reserve from battery energy storage facilities would remove the need for regular cost optimization required in weekly or monthly bidding. Longer procurement periods and service time windows would also reduce complexity for the system. Using this framework to evaluate the suitability of these LFC systems for biomass-based generation would result in higher scores awarded to systems that compensate for uniform service time windows and symmetrical offers, as these would mean lower complexity and maximum utilization of the generator, while other indicators would be scored similar to EVs.

The impact of RES rise on LFCR is performed for the case of Germany under the national regulatory framework, which uses the stochastic approach for determining the required reserve. An analysis of other frequency control concepts would provide an insight into the vulnerabilities of these concepts to changes in RES integration. The assumptions made in model development can be adjusted to reflect improvements in forecasting errors and changes in RES integration levels.

Several of the flexibility service cases chosen for the evaluation of the operating concepts have not been implemented in practice. As some of these flexibility services are put into practice and regulatory frameworks take shape, it necessary to adjust the models to match these changes. The feasibility of flexibility services provision using electric vehicles is strongly dependent on the aggregator pool size, EV characteristics, user behavior and the charging strategy implemented by the aggregator. Although the relative impact of the charging strategy on aggregator flexibility is minor, it can result in significant improvements in aggregator efficiency. Further work on this topic should focus on the development of a model to investigate the optimization of charging strategies. An agent-based modeling of individual EV user behavior and their response to dispatch demands from multiple flexibility services may result in improved accuracy of the aggregator response simulation and should also be explored.

Additionally, the methodology presented in this report can be implemented to other systems and flexibility services to compare the profitability potential. The flexibility services analyzed in this project consider each model in isolation. Further work should analyze the possibilities to combine the flexibility services into multi-use cases with the architecture capable of handling and optimizing usage.

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7.1 Own publications

Journal Paper

[O-1] H. Bokhari and D. Westermann, "Techno-economic evaluation of load frequency control systems for electric vehicle fleet integration," *IET Renewable Power Generation*, vol. 11, no. 6, pp. 819–826, 2017.

Conference Papers

[O-2] H. Bokhari *et al.,* "Techno-economic evaluation of electric vehicles as flexible load for providing grid services," in *2016 13th International Conference on the European Energy Market (EEM)*, pp. 1–6.

[O-3] M. Wolfram, H. Bokhari, and D. Westermann, "Factor influence and correlation of short term demand for control reserve," in *2015 IEEE Eindhoven PowerTech*, pp. 1–5.

A Appendix

Average expectations and standard deviation values

Table A-1: Average expectation values for Wind for years 2011-2014

Expectation (%)	Wind					
	Peak			Off-peak		
Month	Min.	Mean	Max.	Min.	Mean	Max.
1	1.4	1.44	1.61	0.87	1.12	1.13
2	1.35	1.35	1.92	0.29	0.79	1.86
3	1.12	1.87	1.93	0.34	0.96	1.62
4	1.06	1.32	1.41	1.07	1.09	2.02
5	1.96	2.12	2.30	1.62	1.84	1.88
6	0.42	1.12	2.04	0.57	0.92	2.17
7	0.53	0.86	1.70	0.47	0.96	1.29
8	0.50	1.16	1.45	0.33	0.85	1.03
9	0.97	1.55	1.75	0.11	0.49	1.30
10	1.00	1.15	1.40	-0.17	0.16	0.93
11	1.55	2.04	2.23	0.72	1.09	1.27
12	0.95	1.33	1.98	0.83	1.35	1.79

Table A-2: Average expectation values for PV for years 2011-2014

Expectation (%)	PV					
	Peak			Off-peak		
Month	Min.	Mean	Max.	Min.	Mean	Max.
1	-1.55	0.40	0.70	-8.6	-0.07	-0.02

Expectation (%)	PV					
	Peak			Off-peak		
2	-0.40	0.27	0.59	-6.80	0.07	0.1
3	-0.77	-0.08	0.74	-6.9	-0.06	0.25
4	-0.57	-0.07	0.16	-6.00	-0.17	0.22
5	0.00	0.04	0.46	-4.49	-0.06	0.36
6	0.05	0.22	0.44	-4.47	-0.33	0.34
7	0.03	0.34	0.74	-3.19	0.10	0.75
8	-0.29	-0.05	0.13	-3.73	-0.24	0.27
9	-0.48	0.06	0.35	-4.41	-0.27	0.26
10	-0.92	0.33	0.70	-5.30	-0.71	0.18
11	-1.54	-0.19	1.31	-7.07	-3.34	0.04
12	-1.34	-0.19	0.26	-5.53	-0.14	-0.07

Table A-3: Average standard deviation for Wind for years 2011-2014

Standard Deviation (%)	Wind					
	Peak			Off-peak		
Month	Min.	Mean	Max.	Min.	Mean	Max.
1	3.21	6.83	7.52	1.88	3.78	4.71
2	4.18	8.74	9.13	1.30	3.68	7.43
3	3.49	7.40	9.51	2.30	4.70	7.05
4	3.19	7.41	9.62	2.95	6.14	8.56
5	3.50	8.52	10.4	3.8	7.79	8.51
6	4.02	9.28	10.7	3.09	7.01	9.56
7	9.37	10.3	10.6	7.62	8.68	10.5
8	10.6	10.8	11.7	8.40	8.66	9.02

Standard Deviation (%)	Wind					
	Peak			Off-peak		
9	8.69	9.57	11.4	7.00	7.77	8.44
10	7.66	9.31	10.7	3.88	5.20	6.81
11	8.36	9.63	10.9	6.11	8.48	10.0
12	4.09	7.10	9.08	4.29	5.45	7.15

Table A-4: Average standard deviation for PV for years 2011-2014

Standard Deviation (%)	PV					
	Peak			Off-peak		
Month	Min.	Mean	Max.	Min.	Mean	Max.
1	7.90	16.7	19.2	1.31	5.16	12.2
2	6.8	13.9	17.9	3.74	9.82	16.3
3	5.5	11.9	15.3	4.53	11.8	16.4
4	4.60	11.1	12.9	3.95	10.2	18.8
5	2.04	6.00	8.4	7.01	14.2	21.7
6	1.34	2.86	4.11	5.77	13.1	18.9
7	3.28	4.72	6.89	12.1	14.0	21.1
8	7.68	8.48	9.21	13.5	17.2	22.3
9	12.2	13.0	16.4	11.4	16.7	21.1
10	12.2	14.6	17.3	11.0	16.4	24.3
11	18.1	19.6	21.1	6.56	13.7	25.3
12	16.4	17.1	20.5	3.98	9.31	14.6

B Abbreviations

AC	Alternating Current
ACE	Area Control Error
ARC/AGC	Autonomous Response/Generator Controller
BEV	Battery Electric Vehicle
BNetzA	Bundesnetzagentur
CAPEX	Capital Expenses
CCP	Common Clearing Price
CEP	Capacity & Energy Price
CHP	Combined Heat and Power
CP	Charging Price
CR	Charging Cost reduction
CRE	Regulatory Commission of Energy
DC	Direct Current
DER	Distributed Energy Resources
DERA	Danish Energy Regulatory Authority
DK1	Western Danish Electricity Control Zone
DK2	Eastern Danish Electricity Control Zone
DR	Demand Response
DSL	Digital Subscriber Line
DSO	Distribution System Operator
EEX	European Energy Exchange
ENTSO-E	European Network of Transport System Operators for Electricity
ERO	Polish Energy Regulatory Authority
EU	European Union
FCR	Frequency Containment Reserve
FDR	Frequency Controlled Disturbance Reserve

FEM	Forecasting Error Minimization
FEV	Full Electric Vehicle
FNR	Frequency Controlled Normal Operation Reserve
FRR	Frequency Restoration Reserve
FS	Frequency Services
GCC	Grid Control Cooperation
GCP	Grid Correction Point
GPRS	General Packet Radio Service
G2V	Grid to Vehicle
ICT	Information and Communication Technology
LFCR	Load Frequency Control and Reserve
M	Mandatory
MOL	Merit Order List
MR	Minute Reserve
NAN	Neighborhood Area Network
NEP	Netzentwicklungsplan
NERC	North American Electric Reliability Corporation
NGET	National Grid Electricity Transmission Plc
NRV	Netzregelverbund
Ofgem	Office of Gas and Electricity Markets
OPEX	Operational Expenses
PHEV	Plug-in Hybrid Electric Vehicle
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PLC	Powerline Communication
PR	Peak Reduction
PRL/PCR	Primärregelleistung/Primary Control Reserve
PV	Photovoltaic

RAB	Regulatory Asset Base
RES	Renewable Energy Resources
RR	Restoration Reserve
RTE	Réseau de transport d'électricité
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SO	Grid Operator
SOC	State of Charge
SRL/SCR	Sekundärregelleistung/Secondary Control Reserve
TSO	Transmission System Operator
UoS	Use of System
US	United States
V2G	Vehicle to Grid
WAN	Wide Area Network

C Units of Measurement

A	Ampere
GWh	Gigawatt hours
H	hours
Hz	Hertz
Kg	Kilogram
kW	Kilowatt
M	Meter
m^2	Squared meter
Min	Minute
Ms	Millisecond
MW	Megawatt
MWh	Megawatt hours
Nm	Newton meter
p.u.	per Unit
S	Second
V	Volt
€	Euro

D Symbols

Δf	Steady-state frequency deviation
f_n	Nominal frequency
ΔP_G	Power generation
s_G	Frequency response characteristic (droop)
Σ	Standard deviation
μ	Expectation
F	Objective function
P_N	Rated generator output
P_{se}	Scheduled power exchange
ACE_{zone}	Zone Area Control Error
K_{ri}	K-factor of the control area
P_{me}	Measured value of the total power exchange
P_{ae}	Actual power exchange from the zone to neighboring zones.
f_m	Measured network frequency and
f_t	Target frequency.
s_N	Area frequency response characteristic
s_G	Overall generator frequency response characteristic
n_G	Number of power generators
t_a	Activation time
P_f	Final power of the resource after ramping
P_i	Power at incidence of the activation signal
P_o	Offered power of the resource
r_k	Resource ramp-rate
t_a	Duration of full availability
T_{end}	End time of activation
T_f .	Time of the activation of full reserve
$load_{forecast}$	Forecasted load
E	Total energy demand for a year

$P_i(t)$	Generator power generation
$P_d(t)$,	Power demand
x_i	State of generator (1 or 0)
$P_{i,max}$	Maximum operating points of the generator
$P_{i,min}$	Minimum stable operating points of the generator
Δ	Generator ramp rate
T_{run}	Minimum number of hours
T_{down} it	Generator down time
C_i	Generation cost
$\mathrm{S}_{\mathrm{i,Su}}$	Start-up cost
P_f	Failure probability
T_O	Operating time
T_D	Generator down time
f_i	Density function of the overall error
p_e	Percentage infrastructure requirements score
p_{max}	Maximum achievable score
$Flex_p$	Discharging (positive) flexibility
$Flex_n$	Charging (negative) flexibility
$Disc$	Battery discharge rate
$power_c$	Available charging power
$power_{rated}$:	Rated power
$dist$:	Instantaneous distance travelled
P_{pool}	Pool charging power
$Flex_{pool,n}$	Pool negative flexibility
$Flex_{pool,p}$	Pool positive flexibility
$Power_{pool,\min}$	Continuously available minimum power
$\Delta Power_{pool}$	Power difference between peak and trough
$c_{\deg}$	Unit of transferred energy
ΔDoD	Depth of discharge during the provision of flexibility services

$C_{battery}$,	Battery cost
$E_{battery}$	Battery capacity
N_{cycle}.	Number of battery discharge cycles

E List of Figures

F List of Tables