Norwegian University of Life Sciences
Faculty of Environmental Sciences
and Natural Resource Management

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Demand flexibility in electricity markets

Forbrukerfleksibilitet i kraftmarkeder

Aleksandra Roos

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PREFACE

This PhD project was a long journey where, between writing papers, I changed workplaces three times and gave birth to three kids. It started in 2012 at the Norwegian University of Life Sciences (NMBU) as a part of an Industrial PhD programme, funded by the Norwegian Research Council and a private company, Enfo, that was working with demand response. Later, the project was transferred to a Norwegian IT company, Sysco. And finally, the project was completed at the Norwegian Water Resources and Energy Directorate (NVE).

I believe that the project benefited from this diversity of workplaces and the people I met. I was able to look at the topic from different angles and get interdisciplinary insight. I worked with people who develop demand response technology and sell technical solutions to customers, people who work with market design, researchers who study power and energy systems on the macro-economic level. I also worked with demand response topic on the governmental level, close to the national regulator. The papers in this PhD are therefore thematically diverse and use a variety of research methods, which I hope is a good thing.

There are many people that I would like to thank for providing me with inspiration, ideas and support during this work. First of all, a big thanks to my first supervisor, Torjus Folsland Bolkesjø, for giving me a lot of support during the whole project and keeping me focused on completing the work, even when things were challenging. A special thanks to Thomas Martinsen for stepping in as the second supervisor at short notice and giving me very useful feedback.

Thanks to Terje Gjengedal, who started the whole project out of nowhere by asking NMBU and Enfo whether they were interested in taking a newly graduated student on as an industrial PhD to study the topic.

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Thanks to all my former colleagues at Enfo, Sysco and NMBU for always being interested in my work, discussing and brainstorming different topics with me and giving me useful feedback.

Thanks to my wonderful family and friends for believing in me all the way and helping with all possible practical things while I was away and writing, from making food to putting the children to bed. And a very big and special thanks to my husband for being so patient and supportive and for sharing this journey with me. I am submitting this thesis on the ninth anniversary of our wedding, and let it be my gift to you that this work is done.

Oslo, 30th October 2020

Aleksandra Roos

TABLE OF CONTENTS

SUMMARY

Demand flexibility integration is an important measure for the decarbonization of energy systems and a more efficient use of resources. Demand flexibility can provide multiple benefits to the power system and reduce system costs. Adjusting electricity demand to match variable production supports the integration of larger shares of variable renewable energy (VRE). Using demand response for system services provided by network operators can contribute to a more cost-efficient use of infrastructure and resources.

Demand flexibility is a large and complex field of study which includes different markets, different grid voltage levels and different actors. The aim of this PhD project is to study how demand flexibility can be optimally integrated into electricity markets, taking account of the benefits to the power system as a whole and the interplay between different markets. Demand flexibility is studied from the perspective of the whole system, as well as from the private economic perspective of aggregators and electricity consumers.

The thesis includes separate studies which go in depth about specific topics. The whole system perspective is studied in Paper I, which focuses on the value of demand flexibility in spot and reserve markets in power systems with high shares of VRE. The perspective of TSO and DSO is studied in Paper II, which proposes a marketplace for procurement of transmission and distribution system services from demand flexibility. The perspective of demand flexibility aggregator is studied in Paper III which develops an optimization framework for an aggregator participating in the wholesale and the regulation capacity markets. The perspective of private electricity consumers is studied in Paper IV which studies price-based demand response and investments in load control in an energy system.

The results of these studies offer various useful insights. Firstly, demand flexibility was found to significantly decrease the system cost when large shares of VRE are integrated into the system. This happens primarily by replacing reserve provision from coal and gas plants but also by reducing peak load generation due to price response on the wholesale market. Optimal allocation of demand flexibility between reserve and wholesale markets maximizes the system benefits. The results suggest that in systems with large shares of VRE and small shares of base load, more demand flexibility should be placed in the reserve market than in the wholesale power market.

Demand flexibility also benefits the distribution system, and it was also found that new market designs and better coordination between the transmission and distribution levels are important for efficiently integrating demand flexibility and minimizing the total procurement costs. New market designs can ensure that demand flexibility is used to maximize the value for the whole system and not only for single actors.

Next, the results of the studies illustrate that demand flexibility access to many markets is beneficial, from both the system and private economic perspectives. It increases the value of demand flexibility, gives incentives to aggregators' business and ensures that demand flexibility is optimally allocated between markets based on price. However, market interplay can also have negative effects, as when demand flexibility providers favour one particular market with higher profitability and flee from other markets. New market designs for demand flexibility should consider the interplay between different markets.

Finally, modelling demand response to electricity price shows that private investments in demand flexibility are governed by the cost of load control, the daily electricity price variability and the price flattening effect. The price flattening effect implies that demand response to price reduces price volatility in the market, and at some point, no more demand response is feasible. To achieve this optimal demand response level in the wholesale market, it is important to have correct feedback between the market and consumers so that they do not respond more is optimal from the system perspective.

To sum up, the results of this PhD research suggest that efficient integration of demand flexibility into electricity markets implies giving it access to many markets, strengthening the role of aggregators, improving coordination between the distribution and transmission system levels and promoting market designs that optimize demand flexibility use and system value. This thesis illustrates the importance of studying demand response in a holistic perspective, including different markets, actors and system levels.

LIST OF PAPERS

This thesis consists of the following papers:

Paper I	Roos, A., Bolkesjø, T.F. (2018). Value of demand flexibility on spot and reserve electricity markets in future power system with increased shares of variable renewable energy. *Energy,* 144: 207–217. doi:10.1016/j.energy.2017.11.146.
Paper II	Roos, A. (2017). Designing a joint market for procurement of transmission and distribution system services from demand flexibility. *Renewable Energy Focus,* 21: 16–24. doi:10.1016/j.ref.2017.06.004.
Paper III	Roos, A., Ottesen, S.Ø., Bolkesjø, T.F. (2014). Modelling consumer flexibility of an aggregator participating in the wholesale power market and the regulation capacity market. *Energy Procedia*, 58: 79–86. doi:10.1016/j.egypro.2014.10.412.
Paper IV	Roos, A., Ericson, T., Kirkerud, J.G., Bolkesjø, T.F. Analysis of residential demand response in Norway using energy system modelling. *Submitted 23rd October 2020 to International Journal of Electrical Power & Energy Systems.*

LIST OF ABBREVIATIONS

AMS	Advanced metering systems
AS	Ancillary services
BRP	Balance responsible party
CAISO	California Independent System Operator
CHP	Combined heat and power
CPP	Critical peak pricing
DER	Distributed energy resources
DR	Demand response
DSM	Demand-side management
DSO	Distribution system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
GAMS	General Algebraic Modelling System
HV	High voltage
ICT	Information and communication technologies
ISO	Independent system operator
LP	Linear programming
LV	Low voltage
MILP	Mixed integer linear programming
MISO	Midcontinent Independent System Operator, Inc.
NYISO	New York Independent System Operator
PJM	Pennsylvania New Jersey Maryland Interconnect
PV	Photovoltaic (power generation)
RPM	Regulating power market
RTP	Real-time pricing
SG	Smart Grid
ToU	Time-of-use tariff
TSO	Transmission system operator
USEF	Universal Smart Energy Framework
VPP	Virtual power plant
VRE	Variable renewable energy

1. INTRODUCTION

1.1 Role of demand flexibility in power systems

Integration of demand flexibility into electricity markets is an important measure that can contribute to the decarbonization of the energy sector and a more efficient use of resources. Global demand for energy services is increasing in line with population growth and economic development. Many countries have committed to the integration of variable renewable energy (VRE) and the electrification of consumption as major parts of their energy transition plans. The recent global energy transition outlook published by DNV-GL (2020) estimates that VRE will deliver over 60% of the global power mix in 2050, with solar PV and wind power as the largest producers. At the same time, digitalization is creating new opportunities for optimizing energy use. Active flexible consumers can be integrated into the power system and adjust their demand according to the variable production patterns of renewable generation. They can respond to signals from the power system, supporting the integration of larger shares of VRE and contributing into a more optimal use of the energy system infrastructure.

Demand flexibility is not a new resource in the sense that flexibility from large industrial consumers and consumers with large single loads has been used in power system operation for a long time. What is new is the possibility to include flexibility from smaller consumers in the commercial and residential sectors due to the development of smart appliances and control systems. The demand flexibility of these consumers often exists in combination with local generation (e.g. solar panels) or energy storage (e.g. batteries or thermal storage) such that these resources are viewed in combination and referred to as distributed energy resources (DER). Smart integration of DER into a power system will create what is called a smart grid, making the system cheaper, more efficient and more environmentally friendly (IEADSM, 2008).

The advantages of demand-side management in power systems were first discussed as early as 1985 (Gellings & Smith, 1989). The focus at that time was the role of demand-side management in reducing the uncertainty related to future demand, fuel prices and construction costs of power plants. Utilities were facing the need for major investments in production capacity, and demand-side management was expected to make a significant contribution to meeting the future demand. Over the years, the focus has shifted towards emphasizing the role of demand flexibility in successful energy systems' transition towards a low-carbon future and a more sustainable use of resources.

At the general level, the need for demand response arises from the mismatch between power system costs and consumer prices (Northwest Power and Conservation Council, 2016). Power system costs vary significantly from hour to hour because demand and supply change, and balancing power and frequency control are dispatched when needed. At the same time, consumers generally see prices that change very little in the short term. This ultimately results in building more electricity production capacity and transmission infrastructure than would be necessary if customers responded to signals from the market.

Demand flexibility can be studied from different perspectives. As pointed out by the IEA (IEADSM, 2008), the two major perspectives on demand flexibility are energy markets and network management. The energy market perspective includes the benefits that demand flexibility can provide to energy markets, like reducing peak load and supporting the integration of VRE. Network management is concerned with the use of demand flexibility for cost-efficient management of electricity transmission infrastructure. It can be further subdivided into transmission system and distribution system benefits of demand flexibility. A lot of research on demand flexibility focuses on one of these domains, going into depth regarding specific uses of demand flexibility for specific purposes (e.g. Huber et al., 2014; Poudineh & Jamasb, 2014; Zakariazadeh et al., 2014; Göransson et al., 2014; Brouwer et al., 2016; Tveten et al., 2016).

This thesis attempts to study the integration of demand flexibility in a holistic perspective, across different markets and voltage levels in the power system. Both the energy market and the network management perspectives are included in the study.

1.2 Electricity market architecture

The integration of demand flexibility into electricity markets is affected by the electricity market architecture in a given power system. European and U.S. electricity markets are examples of two different market architecture types that create different possibilities and barriers for demand flexibility integration.

The electricity market is fundamentally different from other markets because the traded commodity is a power flow that occurs in real-time and is subject to different technical and transmission constraints (Wilson, 2002). Within a short time frame, it is not feasible to rely only on the wholesale power market because specific kinds of resources are needed immediately and in particular locations. The wholesale power market is just the first in a cascade of options to balance energy flows and maintain reliability. Ancillary services markets are necessary to allow the real-time dispatch of reserves with different response times. Different market architecture handles this special nature of electricity markets in different ways.

Two main approaches to electricity market architecture distinguished in literature are integrated and unbundled. In the *unbundled approach,* the market operator and the transmission system operator (TSO) are different entities, and energy markets are separated from ancillary services markets (Wilson, 2002). This approach is used in European electricity markets, where, historically, the primary objective has been to enable trading of electricity between large national balancing areas (IEA, 2016). The role of the energy market operator (e.g. electricity exchanges such as Nordpool or EPEX) is to settle supply and demand, while the role of national TSOs is to maintain reliability by running their own sequential markets.

An integrated approach implies that an independent system operator (ISO) functions both as the 'system operator' for coordinating reliability and the 'market operator' for establishing market prices (Wilson, 2002). This approach has been adopted by most U.S. power markets, including NYISO, PJM and CAISO, where historically the primary goal has been to ensure the coordination of small balancing areas that were poorly interconnected (IEA, 2016). In the integrated approach, the ISO solves a complex multistage optimization problem called security-constrained unit commitment and dispatch so that the whole system is optimized simultaneously (Chow et al., 2005; Wu et al., 2004).

The integrated approach is more complex than the unbundled approach in terms of system optimization, but it offers greater possibilities to integrate demand flexibility into electricity markets. Firstly, all markets are under the responsibility of the same entity (ISO) so that demand flexibility participation in the wholesale and AS markets can be better coordinated. The ISOs already apply complex optimization techniques and powerful software, which makes it easier to include demand flexibility resources. Secondly, integrated markets are often 'high-resolution' markets (IEA, 2016) with respect to geographical and temporal resolution, meaning they can optimize resources with respect to more detailed information about their grid location and determine electricity price frequently and nearly in real time.[1] They incentivize the use of demand flexibility because it benefits from better grid localization possibilities and dynamic price setting.

In European unbundled electricity markets, the integration of demand flexibility is more fragmentary. TSOs create their own arrangements for demand response focusing on the AS markets. Wholesale market operators incentivize demand response by developing new forms of bids for the demand side and promote their intraday market solutions (Nordpool, 2018). In addition, distribution system operators look for ways to use demand flexibility on a local level for specific distribution system services (Eurelectric, 2013). Therefore, it is especially important to study interdependencies between markets and system levels in the context of demand flexibility integration in Europe.

1.3 Goal and scope

The main objective of this PhD thesis is to study the use of demand flexibility in the power system and answer the following research question: ***What is the optimal way to integrate demand flexibility into electricity markets?*** To answer this question, the following sub-objectives are defined:

- to analyse demand flexibility from a whole system perspective including both wholesale and ancillary services markets;
- to analyse demand flexibility from the perspective of different actors in the power systems to understand their needs and implications for demand flexibility integration. The thesis considers the perspectives of the following actors:
    - transmission system operators,
    - distribution system operators,
    - aggregators, and
    - commercial and residential electricity consumers.

[1] An illustrative example of an integrated 'high-resolution' market is PJM. At PJM, day-ahead wholesale and AS markets are cleared simultaneously using least-cost, security constrained resource commitment and dispatch algorithm (PJM 2017). On an intraday basis, a centralized algorithm calculates prices at 10,000 separate nodes every 5 minutes, and the settlement takes place every hour (IEA 2016). PJM is one of the leading system operators in the U.S. to integrate demand flexibility into wholesale and ancillary services markets (SEDC 2015).

Demand flexibility is not the only source of flexibility in power systems, as will be discussed in Chapter 2.1. There is ongoing research that compares demand flexibility to other flexibility sources, but this topic is outside the scope of this project. This work is based on the assumption that demand flexibility is a valuable resource and should be integrated into electricity markets.

The background for this thesis is the architecture of the European market with its unbundled approach to electricity market organization, as described in the previous chapter. The insights from this thesis are therefore most useful for the European public and in policy debates about electricity markets.

The main focus of this work is the flexibility of small- and medium-sized consumers (residential and commercial sectors), also called distributed demand flexibility (RTE 2020). Flexibility in industry is only considered as part of the national aggregated demand flexibility potential in the study of the whole system perspective.

As mentioned in Chapter 1.1, demand flexibility is often found in combination with other DER (energy storage, distributed generation). This project does not explicitly address other DER; however, the applicability of this research to DER is discussed where relevant.

Business models of aggregators, contractual issues and redistribution of profit between aggregators and customers are outside the scope of this project. It is assumed that as long as the use of demand flexibility in the market is profitable, aggregators will find the best business model and fair settlement rules for their customers.

The first part of this thesis is the synthesis report. It consists of Chapter 1, which gives an introduction into the topic, Chapter 2, which explains the terminology and provides the necessary context, Chapter 3, which describes and discusses the methodology, Chapter 4, which summarizes and discusses the results, and Chapter 5, which offers concluding remarks. The second part of the thesis includes the four papers written during this PhD project.

2. DEMAND FLEXIBILITY IN ENERGY SYSTEMS

2.1 Sources of flexibility in energy systems

Flexibility is broadly defined as a power system's ability to cope with variability and uncertainty in demand and generation (Ma et al., 2013). Traditionally, flexibility from different kinds of power plants with different response times has been used to achieve the balance between generation and consumption. An increase in shares of VRE has started to challenge the traditional way energy systems operate. Due to increased variability and uncertainty of supply, the need for flexibility in energy systems has increased.

Demand flexibility is not the only source of flexibility in the energy system. Other sources of flexibility include flexible generation, energy storage, coupling of the thermal and power sectors and increased network interconnection (Huber et al., 2014; Lund et al., 2015).

Flexible generation is the resource that has traditionally been used by power system operators to balance power systems. Hydropower plants in the Nordic countries are an example of a flexible generation technology that offers the possibility of quickly regulating production at a low cost (Wangensteen, 2012). Pumped hydropower also acts as a battery in the power system and increases flexibility. Many VRE technologies are not very flexible because they have to produce when the input factors are present (wind is blowing, sun is shining). However, techniques exist for regulating the production of some VRE types, such as wind turbines controlling for frequency regulation (Camblong et al., 2012).

Energy storage includes various electric and thermal storage technologies that can be used to shift the energy flow in time and balance VRE production. The scale of storage technologies varies from large-scale grid-level technologies to small-scale technologies of end-users. The development of electric vehicles (EV) has contributed to increasing the potential electric storage capacity of the distribution grid, and a lot of research is being done on the smart use of EV in power system balancing (Kiviluoma & Meibom, 2010; Babrowski et al., 2014; Taljegard et al., 2019). In addition, power-to-hydrogen and power-to-heat energy storage technologies are important flexibility providers (IRENA, 2019). Storage capabilities of district heating systems are widely studied with respect to their flexibility potential (e.g. in Kiviluoma et al. 2017; Kirkerud 2017).

Power and thermal sector coupling includes measures that enable using the flexibility that lies in thermal energy production (heating or cooling) to balance the variable production of VRE. There is a great deal of research on power and thermal sector coupling (e.g. Kirkerud 2017; Arabzadeh et al., 2019; Heinisch et al., 2019; Kiviluoma & Meibom, 2010).

Network interconnection can contribute to reducing the costs of VRE integration and is important to provide security of supply in systems with increasing shares of VRE (Scorah et al., 2012). Both grid strengthening and integration of separate power grids are considered to be means of increasing the power system flexibility (Lund et al., 2015).

Comparison of different flexibility options to mitigate wind and solar power variability is a highly relevant research topic, and there is a significant body of literature comparing the value of different types of flexibility. Brower et al. (2016) found that in systems with large shares of VRE, flexible gas power plants give the largest reduction in system cost, followed by flexible demand, flexible VRE generation and increased interconnection capacity. Kiviluoma et al. (2017) found that, in a big power system with a large amount of reservoir hydropower and VRE, the best flexibility options are heat and power sector coupling and transmission grid expansion, followed by demand response and energy storage. Johansson and Göransson (2020) compared variability management by demand flexibility, electric boilers, batteries, hydrogen storage and biomass-based thermal and power generation and find that load shifting and absorbing the excess electricity using electric boilers or hydrogen production increases the cost-optimal VRE investments in systems with a high VRE share initially. The authors also found synergies between different variability management strategies such that their combination results in a greater increase of VRE capacity. Nagel et al. (2020) found that for a large interconnected power system, demand flexibility has the largest impact on the system cost at low climate targets, but as climate targets get more ambitious, sector coupling and more interconnections become more important.

Comparing different flexibility options is outside the scope of this project, and the general assumption for the rest of the thesis is that demand flexibility has a positive impact on the system cost and is therefore a valuable resource.

2.2 Definition of demand flexibility, demand response and demand-side management

In the literature, different terms are used to describe the flexible capabilities of demand, such as demand flexibility, demand response and demand-side management. It is useful to point out the difference between these terms and clarify their meaning.

Demand flexibility is the share of demand that can potentially be modified. Demand flexibility can be understood as a resource in the energy system that can be activated through different incentives. The International Renewable Energy Agency defines demand-side flexibility as 'the portion of demand in the system (including electrified heat and transport) that can be reduced, increased or shifted within a specific duration' (IRENA, 2019). Their definition includes such sources of demand-side flexibility as sector coupling (power-to-heat, power-to-gas, power-to-hydrogen), smart charging of electric vehicles and smart appliances. It is important to keep in mind that though demand flexibility can be related to other energy carriers than electricity, the ultimate purpose of demand flexibility is related to *changing the electric load*.

Demand response (DR) is the active change in demand in reaction to any kind of signal from the system, or in other words, the utilized demand flexibility potential. This is reflected in the widely used definition published by the U.S. Department of Energy (2006): *'DR is changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.'* As pointed out by Katz (2016), not only price or system signals but also environmental signals can incentivize demand response.

Demand-side management (DSM) is a broader term that includes all measures that *can influence the time pattern or/and amount of electricity demand*, including demand response and load management, strategic conservation, electrification, customer generation and so forth (Gellings & Smith, 1989). The main differences between energy conservation and demand response are the time perspective and the level of consumer comfort. Conservation is an increase in efficiency that reduces energy use in the long term, leaving consumers' levels of service unchanged. Demand response is a change in electricity usage at particular times that may sometimes change the quality or the level of service and even cause overall increase in energy use (Northwest Power and Conservation Council, 2016).

From the point of view of energy system planning, different DSM measures can be hierarchically positioned with respect to how they should be implemented. Measures that permanently reduce electricity consumption should be implemented first, while load control should be the last measure considered. The potential for load control will be reduced as the measures at the bottom of the hierarchy are implemented (Lislebø et al., 2012).

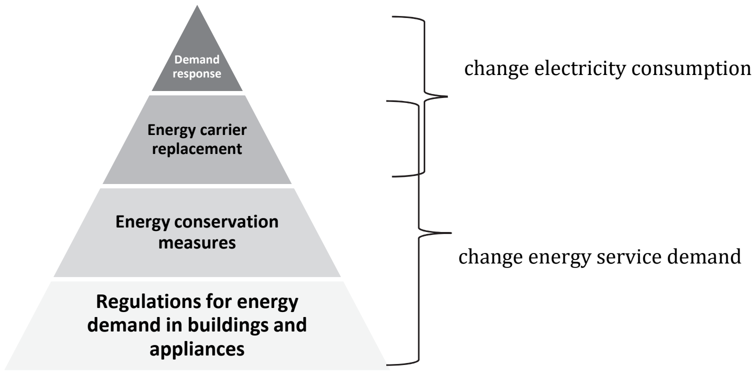

Figure 1. Hierarchy of DSM measures with respect to energy system planning and optimal use of resources. Adapted from Lislebø et al. (2012)

2.3 Classification of demand response

The most commonly used classification is the division of demand response into *explicit* and *implicit* (U.S. Department of Energy, 2006; COWI, 2016):

- ***Explicit (incentive-based)*** demand response refers to a situation where consumers or agents working on their behalf are allowed to participate and provide demand-side resources in different power markets.
- ***Implicit (price-based)*** demand response refers to a situation where consumers can choose to be exposed to time-varying electricity prices or grid tariffs and react to such signals.

One type of demand response that falls between these two categories is *autonomous* demand response. It is defined as load response to decentralized system-based signals (e.g. frequency) rather than to control signals or price signals from a central dispatch centre (Donnely et al., 2012; Molina-García et al., 2011). Autonomous demand response can provide primary frequency regulation through decentralized response to a large number of demand units and is especially relevant in systems where frequency response of generation units is expensive.

This division of demand response into explicit and implicit is also not very precise with respect to small consumers that are represented on the market by balance responsible parties (BRPs). BRPs are agents that are responsible for forecasting electricity consumption, purchasing electricity on the market on behalf of consumers and customer settlement. Their primary task is to be in balance with respect to their market obligations. When the amount of implicit (price-based) demand response becomes significant, BRPs will have to consider this demand response in their forecasting and market bidding processes, for example through flexible electricity purchase bids or imbalance trading on the intraday market. Therefore, implicit demand response will eventually also become a form of explicit demand response.

A similar classification, but with an emphasis on the perspective of power system utilities, is used by the Northwest Power and Conservation Council (2016). Demand response is divided according to its reliability into *firm* and *non-firm*:

- ***Firm*** demand response allows load curtailments to be directly controlled by the utility or scheduled ahead of time. It is characterized by high reliability for meeting system needs.
- ***Non-firm*** demand response involves resources that are outside the utility's direct control since curtailments are based on customer response to pricing signals. It is characterized by low reliability for meeting system needs.

There also is the possibility for overlap in assumed potential between firm demand response programmes and any pricing structure initiatives; in other words, the same DR resources can participate in both. This classification can be applied to demand response with respect to both transmission and distribution system levels.

Another useful classification is the division of load management methods into *direct* and *indirect* (Kostková et al. 2013), presented in Table 1. This classification generally reflects the abovementioned divisions into explicit and implicit, and firm and non-firm, but also includes energy efficiency and customer education as indirect load management methods.

Table 1. Classification of load management approaches (Kostková et al., 2013).

Direct load management	Indirect load management
Direct load control Interruptible tariffs Load curtailment programmes • Demand bidding programmes	Pricing programmes • Time-of-use tariff (ToU) • Real-time pricing (RTP) • Critical peak pricing (CPP) • Extreme day pricing • Extreme day critical peak pricing Rebates and subsidies • Subsidies or rebates for purchasing energy efficient appliances • Rebates for peak demand reduction Educational programmes • Customer information about energy consumption and energy efficient appliances etc.

As new business models for aggregators of demand flexibility emerge, these classifications may become less relevant. For example, a service company for electricity consumers may offer a wide range of services, from direct load control in response to electricity prices to market bidding of aggregated demand flexibility. Electricity consumers may even not be aware of what programmes their flexibility is engaged in as long as load management is done cautiously and does not influence their comfort and as long as they receive sufficient remuneration or energy payment savings for being part of the portfolio.

Depending on the level of automation, demand response can be divided into manual, semi-automated and fully automated (Piette et al., 2006):

- ***Manual demand response*** involves a labour-intensive approach such as manually turning off or changing comfort set points at each equipment switch or controller.
- ***Semi-automated demand response*** involves a pre-programmed demand response strategy initiated by a person via a centralized control system.
- ***Fully-automated demand response*** does not involve human intervention, but is initiated at a home, building, or facility through receipt of an external communications signal.

The level of automation influences the costs of demand response, as discussed in Chapter 2.5.

Demand flexibility resources are often grouped by consumption sector into industrial, tertiary and residential demand flexibility. An equally useful grouping according to the size of consumers and the grid level is used by the French TSO (RTE 2020) that distinguishes between industrial demand response and distributed demand response. ***Industrial demand response*** is different from distributed demand response in that large industrial sites are often connected to the high-voltage grid and have significant load sizes. Industrial demand response is often able to participate in markets directly, without having to be aggregated. ***Distributed demand response*** involves smaller flexibility volumes dispersed in the distribution grid, and market participation requires this flexibility to be aggregated.

2.4 Demand flexibility in different markets

Demand flexibility is a resource that can be used by different actors and in different markets. In some cases, DR gives some specific benefits related to the business or the field of responsibility of a given actor, for example when demand flexibility is used for specific services by TSOs or DSOs, or when it participates in portfolio balancing of a BRP. In other cases, DR is beneficial for the whole system and no particular actor is responsible for adopting its use, as when electricity consumers respond to electricity price and contribute to peak load reduction.

There is extensive literature that elaborates on the benefits of DR for different actors and in different markets. Table 2 summarizes the most important markets for DR, with respect to specific actors in the power system as a whole. The table is based on comprehensive overviews from previous reports (IEADSM 2008; Belhomme et al. 2009; Eurelectric 2013; USEF 2020) and is extended by including the classification of Kostková et al. (2013) to systemize DR programmes according to whether or not they require aggregation with direct load control.

Some of the services mentioned in the table already exist, such as frequency control by TSOs, and the integration of demand flexibility only involves adjusting the market design to make these markets accessible for demand-side resources. Other services have not yet been widely adopted or do not exist. For example, distribution system services from demand flexibility will become relevant only when the DSO's role changes from passive to active distribution system management (Eurelectric, 2013). It is also probable that new markets for demand flexibility will emerge to deliver existing or new services to different actors, as described in the Universal Smart Energy Framework (2020).

Table 2. Overview of markets where demand flexibility participation is relevant as direct or indirect load control.

Market	Main goal of using demand flexibility	Direct load control	Indirect load control
Wholesale electricity market	Meeting peak load. Better demand elasticity. Integration of larger shares of VRE.	Demand response to electricity price (load control by a third party). Direct market bidding (via third party).	Demand response to electricity price (consumers' own response).
AS market for transmission system operator (TSO)	Increased security of supply (especially with respect to larger shares of VRE). Competition with similar services from generation. Avoiding or postponing investments into the grid.	Primary, secondary and tertiary frequency control (as load control by aggregator; as autonomous DR[2])	-
		Short-term congestion management (as load control by aggregator)	-
		Long-term grid capacity management (e.g. national capacity markets[3] where TSOs can enter long-term contracts with aggregators).	Demand response on the wholesale market leading to peak load reduction will affect long-term grid capacity planning.
		Other system services: controlled islanding, network restoration, redundancy n–1	-

[2] **Autonomous DR** is defined in Chapter 2.3.
[3] **National capacity markets** (including strategic reserves) are markets that aim to increase the security of supply by organizing sufficient long-term peak and non-peak capacity. This capacity can be delivered by either the production or the consumption side (USEF, 2020).

		support[4] (load control by aggregator).	
AS market for distribution system operator (DSO)	Handling challenges in the distribution grid due to DER. More cost-efficient distribution grid management.	Short-term congestion management by direct load control (via aggregator)	Short-term congestion management by consumers' response to grid tariffs (e.g. dynamic, variable or CPP[5])
	Avoiding or postponing investments in the grid.	Long-term grid capacity management by entering contracts with aggregator	Long-term grid capacity management by consumers' response to grid tariffs (e.g. ToU[6])
		Voltage control by aggregated demand response (via aggregator)	-
		Other system services: loss management, controlled islanding (load control by aggregator)	-
Services for balance responsible party (BRP)	Minimizing portfolio costs/maximizing profit.	Day-ahead and intraday portfolio optimization[7] (load control by aggregator)	-

[4] ***Controlled islanding*** aims at preventing supply interruption in a given grid section when a fault occurs in a section of the grid feeding into it. ***Network restoration and redundancy (n - 1) support*** refers to actions that help to reduce the duration of outages and restore the system after an outage (USEF, 2020).

[5] ***CPP, variable and dynamic*** grid tariffs are tariff signals from DSOs to consumers that are sent when grid overload is expected. CPP and variable grid tariffs are sent day-ahead, while dynamic tariffs are sent during the day of operation (Rasmussen et al., 2012).

[6] ***Time-of-use*** is a distribution grid tariff with a fixed pattern which is determined for long periods of time (Rasmussen et al., 2012).

[7] ***Day-ahead and intraday portfolio optimization*** implies load shifting from high-price to low-price time intervals on a day-ahead or intraday basis or longer in order to reduce BRP's overall electricity purchase costs and create additional value by intraday trading (USEF, 2020).

Table 2 illustrates that there are many ways of potentially using aggregated demand flexibility in the power system, not only with respect to VRE integration but also in general by making the use of resources and infrastructure more cost-efficient. It also illustrates that direct load control provides more reliable demand response that can be used for more services than indirect load control.

Several services described in Table 2 require demand flexibility with specific technical characteristics (e.g. primary frequency control requires quick response time or autonomous DR). Still, many services can be provided by the ordinary demand flexibility resources, such as disconnecting or shifting of heating, cooling or car charging by residential and commercial consumers. Therefore, we can think of aggregated demand flexibility in the distribution grid as a common pool of resources that can be used in different markets. The following examples illustrate this: electric car charging in Norway is increasing and can either be used to perform load shifting in response to prices using the system developed by (Tibber, 2020) or can potentially contribute to frequency control performed by the Norwegian TSO (pilot testing by Statnett (2019)). Another example is residential electric heating in France, which on the one hand is subject to time-of-use tariffs and contributes to reducing peak load on the grid (IEADSM, 2020) but on the other hand can participate in ancillary services for the TSO via an aggregator (DR program by Voltalis (RTE, 2020)).

We can conclude that there is competition for demand flexibility resources between different markets and actors. While single actors can argue for their own benefit, it is still important to look at different alternatives together and evaluate the best ways to allocate flexibility from a socio-economic point of view. Coordination between different actors is increasingly important, especially between TSOs and DSOs. An aggregator of demand flexibility can be an intermediary that optimizes resources and makes them available for different uses by different actors at different points in time.

2.5 Cost and price of demand response

At a general level, the cost components of demand response include system costs and participant costs (U.S. Department of Energy, 2006). System costs include all types of costs that are incurred during the establishment of a demand flexibility programme. The participant costs include several components, which are illustrated in Figure 2. Just like for generation technologies, two major cost components of demand response are initial costs and operational costs.

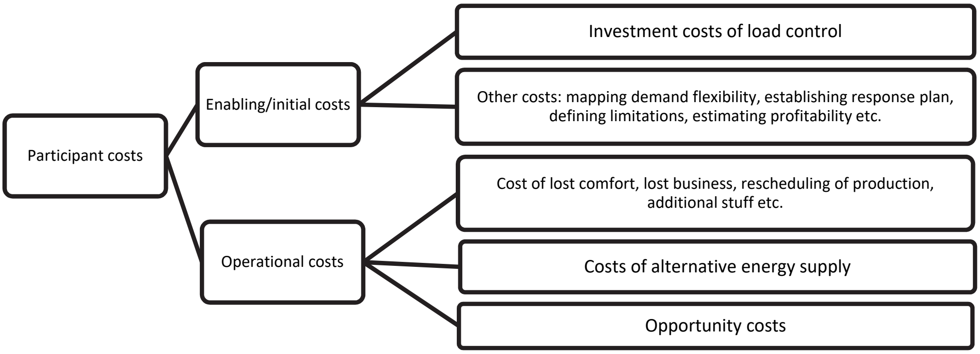

Figure 2. Costs of demand response for electricity consumers. Based on U.S. Department of Energy 2006; Northwest Power and Conservation Council, 2016; Rebours, 2008.

Initial costs include investment costs related to the purchase and installation of the load control technology. For residential customers, this might be the extra cost of purchasing of a smart appliance instead of a usual appliance. For commercial actors, this might be the cost of establishing a more advanced building automation system with load control. Investment cost can be defined per MW if it is divided by the standard load reduction (Northwest Power and Conservation Council, 2016).

The investment cost of demand response will increase with a higher level of automation. Manual demand response (e.g. switching off an electric appliance by hand) can have an investment cost of zero but at the same time a very high variable cost (related to the need to follow price signals, unwillingness to respond or loss of comfort). Previous research has shown that automatic control may be crucial for getting sufficient response, especially for larger consumers (Katz, 2016).

Operational costs are related to the use of demand flexibility and can include the cost of using an alternative energy supply, the cost of loss of comfort, the cost of production shutdown and so forth. If demand flexibility providers participate in several markets or programmes, the variable cost of demand response will include the opportunity cost reflecting the income lost in another market or programme (Rebours, 2008).

The profitability of demand response to electricity price depends on whether or not it is possible to shift load from high price to low price hours. The feasibility of investment in such demand response will depend on the income potential from daily price variation and the variable costs of load shifting. If the variable cost of shifting demand is higher than the price difference between two hours, than demand response is unprofitable. Time-differentiated grid tariffs that are applied on the top of wholesale electricity prices can increase the profitability of such demand response.

Demand flexibility used in AS markets (both for transmission and for distribution systems) receives a direct payment from TSOs/DSOs and is not dependent on wholesale electricity price variations. Just like generation technologies, demand flexibility providers that participate in AS markets should have a two-tier price structure (Rebours, 2008; Rud, 2009) which implies that the price for AS must include

- the reservation price paid to reserve capacity, regardless of whether the capacity is activated or not; and
- the activation price paid to activate the capacity.

For demand flexibility, the reservation price will cover the investment and operational costs and eventually any opportunity costs of not using demand flexibility on the other markets. The activation price will cover any variable costs related to the actual demand response activation. It is important that both transmission and distribution AS markets have a price structure that accurately compensates for the costs of DR.

3. METHODOLOGY

A variety of methods and tools were used in this project, as the different studies had different angles, objectives and scopes. Power system modelling was used to study demand flexibility on a national level over a long time-horizon. The General Algebraic Modeling System (GAMS) software was used to implement the self-developed optimization problems of the joint TSO-DSO market clearing and aggregator's portfolio optimization. TIMES energy system modelling was used to study investments in residential demand response over a long time horizon. Also, R statistical software was used to perform a statistical analysis of solar and wind power variation to determine dynamic reserve requirements for the national power system.

3.1 General aspects of using modelling in demand flexibility studies

Boßmann and Eser (2016) present a comprehensive overview of 117 models studying demand response. They distinguish between three main types of DR models: prescriptive optimization models, descriptive simulation models and econometric models (Boßmann & Eser, 2016). *Optimization models* optimize the choice of technology alternatives in system planning and operation to find the least-cost path. Their aim is to find the system optimum by minimizing or maximizing system variables, which can be system cost, system welfare or system emissions. *Simulation models* lack this system optimization perspective and have more of a descriptive character with respect to a predefined set of assumptions. *Econometric (techno-econometric) models* measure energy system relations using statistical techniques, taking into account cause and effect relationships from microeconomic theory.

Econometric models have traditionally been being used by economists, and in DR studies they are often used to compare different DR pricing schemes or policy (Boßmann & Eser 2016). They are highly dependent on correct input on price elasticity. However, the use of elasticity raises questions like whether demand elasticity can correctly represent automatic demand response (Katz, 2016), whether elasticity measured in one country can be applied to another country and whether it is correct to use the same elasticity in long-run simulations.

Optimization and simulation models provide a more sophisticated representation of the energy system and capture more technical details than econometric models. Therefore, they are well-suited for analysing complex interactions between electricity consumption and VRE. Optimization modelling can be used to study system-wide impacts of DR, small-scale DR applications and individual DR optimization problems.

Important common features of optimization and simulation models that are intended to be used in DR studies can be summarized as follows:

1. ***Disaggregated electricity demand***. Traditionally, the majority of energy and power system models have been highly detailed on the supply side, while the demand side has often been represented at an aggregated level (Martinsson et al., 2014). However, disaggregating demand and finding a balance between the level of detail for the demand and supply sides is important for studying future energy systems with active DER. It is easier to model specific properties of demand flexibility in different sectors when demand is disaggregated. In their review of DR models, Boßmann and Eser (2016) point out that very few models investigate DR measures across three or more energy demand sectors, though it would be an advantage. In addition, Martinsson et al. (2014) discuss the importance of a better representation of the residential and commercial sectors in optimization models. The transport sector is also becoming increasingly important due to increasing electrification. In this project, the TIMES energy system model with disaggregated representation of demand-side is used in Paper IV.
Disaggregating the representation of demand-side by geographical or grid location can be important for studying particular markets (e.g. TSO and DSO markets, like in Paper II) but may only be possible in smaller models. Spatial disaggregation is computationally challenging and requires much more detailed input data.
2. ***The possibility to include different markets*** is an advantage in demand flexibility studies because, as shown in Table 2, demand flexibility can participate in many markets. The biggest challenge is limiting the scope of the modelling problem in order to keep the computational time acceptable. In Paper I, demand response in both wholesale and reserve power markets is modelled, but at the expense of a more aggregated representation of demand side and a limited time horizon.
3. ***The possibility to include sectors other than electricity*** can be important because, as discussed in Chapter 2, demand-side flexibility can come from sector coupling,

including power-to-heat and power-to-hydrogen. Again, the biggest challenge with expanding the model is to keep the computational time acceptable. The TIMES model used in Paper IV includes all sectors of the national energy system, but at the expense of a simplified representation of the system operation and exogenous representation of neighbouring countries.

4. ***Hourly time resolution*** is a standard choice in the models that study demand flexibility (Boßmann & Eser, 2016). In several ancillary services markets where demand flexibility participation is relevant, the time resolution is sub-hourly. However, keeping an hourly temporal resolution may be a sensible trade-off between exactness and computational time (Boßmann & Eser, 2016).

5. ***Technical properties of demand response.*** Important technical properties of demand flexibility resources include the time frame of load shifting, limits on load reduction duration, minimum time between load reductions, response time, energy loss, reconnection peak, linear or non-linear load reduction costs and so on. Not all of these properties can be implemented in a linear optimization. Mixed-integer linear programming (MILP) techniques can be used to capture various properties of demand flexibility (as in Papers II and III) but they may be more suited to specific modelling and simulation problems with limited system boundaries. For full-scale power or energy system models, MILP can greatly increase computational time; therefore, linear approximations of the technical constraints may be a better choice.

Generally, including demand-side resources in energy system modelling implies that the model's demand side becomes more detailed and less aggregated, which makes the whole model more complicated and challenging to solve within an acceptable time frame. Simplifying parts of the model (Martinsson et al., 2014) and model coupling (European Comission Joint Research Centre, 2014) are possible solutions. Also, models that have a modular structure (such as TIMES) are useful because they allow us to increase the complexity of some modules while simplifying other modules and change modules in different projects.

3.2 Power system modelling for studying the benefits of demand response

The objective of Paper I is to model the power system in Germany in 2030 with increased shares of VRE and estimate the cost of power system operation and the value of demand flexibility participation on the spot and reserve markets. To perform the analysis, a special model for power system operation, BalmoREG, was developed based on the Balmorel model.

Balmorel is a partial equilibrium bottom-up linear programming (LP) model originally developed for the power and district heating sectors of the Nordic and Baltic countries by Ravn et al. (2001). The basic version of Balmorel is an open access model available at Balmorel's website (2020) and thoroughly described in Wiese et al. (2018). The model is under constant development and updated for a wide range of research projects, and different research institutions have their own versions of the model with the extensions and updates that they find necessary to implement. In this PhD, the Norwegian University of Life Sciences' version of Balmorel is used; this version was developed and thoroughly documented in previous doctoral research (Tveten 2015; Kirkerud 2017).

The idea behind BalmoREG is to rerun one of the years modelled in Balmorel for only one country and with more details about the balancing power requirements and demand flexibility participation in electricity trade and balancing power provision. BalmoREG's formulation is based on Balmorel, including the objective function, the balance equation and various constraints, but the equations are modified to include demand response and regulation power market, and the model horizon is limited to one year. BalmoREG is soft-linked to Balmorel such that the Balmorel model first runs through all modelled years and BalmorREG only models one chosen year using input from Balmorel.

3.3 GAMS as a tool to simulate market participation of demand flexibility providers

Both Paper II and Paper III present novel modelling frameworks for chosen actors in the power system. Paper II studies the combined optimization problem for a TSO and a DSO that procure demand flexibility services in a joint market. Paper III studies the optimization problem of an aggregator of demand flexibility that is participating in spot and reserve electricity markets. In both papers, classic mathematical optimization problems are formulated, and MILP is used to reproduce the technical characteristics of demand flexibility with a sufficient level of detail. In Paper II, the objective function is the minimization of the total procurement cost for the TSO and the DSO. In Paper III, the objective function is minimizing the total portfolio cost for the aggregator.

Both mathematical optimization problems are implemented in GAMS (GAMS Development Corp., 2020). GAMS is widely used in the academic and industrial energy community for mathematical modelling and optimization purposes, but alternative tools such as Python and Julia (Weibezahn & Kendziorski, 2019) also exist. The TIMES and Balmorel models used in the other papers of this thesis are also implemented in GAMS.[8]

3.4 Energy system modelling for demand response potential assessment

The objective of Paper IV is to study demand response potential in the energy system, and the modelling tool chosen for the study is the TIMES energy system model generator developed within the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA-ETSAP, 2020) and thoroughly documented in Loulou et al. (2016). TIMES is a partial equilibrium bottom-up LP model that solves the surplus maximization problem for an energy system with the level of detail, spatial and geographical resolution that is appropriate for the specific research project. The main advantages of TIMES with respect to demand flexibility modelling is that it is easy to disaggregate demand by defining as many demand technologies as necessary, and it is easy to model investments in technologies; thus the model is well suited for studying demand flexibility potential endogenously. Another advantage of the model is that it is modular, meaning it is easy to simplify some sectors while increasing the level of detail about others.

The implementation of the Norwegian energy system in TIMES has been documented (IFE, 2013). In Paper IV, the model is updated with the latest energy system data and the structure of the residential sector is modified to implement demand flexibility. Soft-linking TIMES to two other models is used to limit the scope of the modelling problem. Also, a model setup with exogenous prices is tested in the paper. This is easily done due to the modularity of TIMES – electricity supply and exchange sector modules are replaced with a module containing electricity price data.

[8] TIMES model generator is implemented in GAMS, but there is an interface for model input and output, so the user is not working in GAMS directly.

4. RESULTS AND DISCUSSION

4.1 System-wide impacts of demand flexibility

System-wide impacts of demand flexibility are studied in Paper I based on the example of the German power system with increasing shares of VRE. An important contribution of this paper is that we study demand flexibility as a resource in both the wholesale and reserve power markets to understand the total value of demand flexibility and to see how it should be optimally allocated between different markets.

The need to provide reserves increases the cost of power system operation because a share of generation is reserved for power system balancing. Larger shares of VRE lead to increased reserve requirements because of increasing uncertainty and variability of supply. At the same time, technologies that normally provide reserves are being phased out. In Paper I we study four scenarios for the phase-out of thermal technologies in Germany with different rates of coal plant phase-out, different rates of VRE integration and different roles for gas power plants. We find that the need for reserve provision adds 0.6–8.6% to the total system cost in 2030 depending on the scenario. The lower range corresponds to the scenario where the coal phase-out and VRE integration take place slowly so that there is still a significant share of conventional generation in the system in 2030. The higher range corresponds to the scenario with the largest share of VRE and the smallest share of conventional generation.

Demand flexibility decreases the additional system cost related to reserve requirements in all scenarios. It has the largest impact in scenario with the highest VRE share and the smallest share of conventional generation. Reserved demand flexibility provides between 75% and 86% of the up-regulation reserve in different scenarios replacing reserve provision by coal and gas plants.

In this study we allow the model to determine the optimal allocation of demand flexibility between the wholesale market and the reserve market. The model can either perform actual demand shifting in the wholesale market or keep demand reductions reserved for up-regulation. The more demand flexibility actively responds to wholesale market prices, the less is available for reservation as regulation power. Both ways of using demand flexibility contribute to reducing the total system cost. In the wholesale power market, demand flexibility contributes to reduction of price variability and better adjustment of demand to supply variations. In the reserve market, demand flexibility replaces reserve provision from conventional power plants.

We find that in all scenarios the model allocates a share of demand flexibility to the wholesale market and a share to the regulation power market, but the latter share is always larger. The optimal allocation of demand flexibility between the wholesale and the reserve market varies from 37/63% to 30/70% depending on scenario, with a tendency towards more demand flexibility on reserve markets with larger shares of VRE. This indicates that the system benefits of using demand response to create reserves are more significant than the system benefits of demand response on the wholesale market. The benefits of utilizing demand flexibility for reserves instead of in the wholesale market are most evident in scenarios with small amounts of baseload technologies.

The role of demand flexibility is especially evident for days with either very low or very high VRE production. In the first case, expensive peak-load and back-up units are started to compensate for low VRE production, leading to high electricity prices. In the second case, high VRE production leads to high reserve requirements and the need to keep conventional generation spinning, resulting in electricity surplus, zero prices and VRE curtailment. In both cases, the use of demand flexibility relieves the situation, reducing the need to start peak-load units or curtail VRE.

4.2 Market design for optimal use of demand flexibility

While Paper I illustrates the value of having demand flexibility in wholesale and reserve power markets, Paper II studies reserve provision from demand flexibility in more detail. This paper looks at the market design for the optimal utilization of demand flexibility as ancillary services and considers not only the transmission system but also the distribution system level.

Demand flexibility is a common pool of resources located in the distribution grid that can be used for both transmission and distribution system services. Previous research has demonstrated that aggregated demand response can be used for power system regulation services, congestion management, balancing and other kinds of system services procured by TSOs. At the same time, DSOs can also utilize demand flexibility for short-term or long-term congestion management, voltage control, power quality support and other services.

Different services have different procurement time frames and require demand flexibility with different technical properties and levels of aggregation. In Paper II we investigate two services that are similar with respect to technical properties and procurement time frame: tertiary power system regulation for TSOs and short-term distribution system congestion management for DSOs. These services can, in principle, be procured from the same sources of demand flexibility with a maximum response time of 15 minutes and possible disconnection time of at least 1 hour. The time frames for procurement of these two services would also be similar, with a reservation market running prior to the wholesale electricity market (e.g. day-ahead), and an activation market running in real time. The main difference in service procurement would be the level of aggregation with respect to high-voltage and low-voltage grids.

In Paper II we investigate the possibility of having a joint market for procurement of these two services by TSOs and DSOs and study the advantages of such a market design. We suggest a design where demand flexibility operators (or DER operators if the portfolio also includes distributed generation or storage) make load reduction bids to the joint market specifying the price, the volume and the location of load reduction with respect to different feeders in the distribution grid. The TSO and the DSO specify their demand for service per grid level. We develop a joint clearing procedure for the reservation market, where flexibility bids are optimally allocated between the TSO and the DSO, taking into account their location in the grid and the fact that the TSO can also procure the same service from the generation units. The objective of the market clearing is the minimization of the total procurement cost.

The proposed market framework is tested using a numerical example to illustrate its overall system impact and implications for the TSO and the DSO. We compare simultaneous market clearing with sequential market clearing where the DSO runs a separate market first, and the TSO runs a separate market afterwards. We illustrate that in simultaneous market clearing the total procurement cost for the system is lower than in sequential market clearing because the bids are more optimally allocated between the TSO and the DSO. In sequential procurement, all cheap load reduction bids are taken on the first market by the DSO, which incurs a lower procurement cost. In simultaneous procurement, several cheap load reduction bids are instead allocated to the TSO because this results in a lower total procurement cost. Procurement costs for the DSO alone are thus higher, but from the system perspective, the joint market clearing ensures a cheaper solution.

Joint market clearing also solves several other problems related to the procurement of ancillary services from demand flexibility; for example, it can prevent demand flexibility resources from fleeing a particular market, as can happen with sequential markets for DSOs and TSOs. The clearing prices on TSO markets might be higher if the bids from demand are cleared together with the bids from generation. Therefore, demand flexibility providers can prefer to bid to TSO markets or set a higher price on DSO markets to compensate for the opportunity cost. In a centralized design like the one described in this paper, demand flexibility providers will only have one market platform to place their bids which will prevent demand flexibility from favouring one particular market.

4.3 Participation of aggregated demand flexibility in wholesale and reserve electricity markets

Paper III studies market participation of demand flexibility from the perspective of an aggregator. The aim of the paper is to investigate how an aggregator of demand flexibility from medium-sized commercial consumers can optimize its portfolio and participate in the wholesale electricity market and ancillary services market.

Medium-sized consumers (e.g. process industry, food production sites, office buildings) represent a significant share of demand flexibility potential. These consumers need to be aggregated in order to have sufficient volumes to participate in power system markets. Aggregation and optimal bidding strategies are important to maximize the value of their flexibility.

In this paper we use actual data on Norwegian commercial customers to study what technical parameters are important to consider in the aggregator's portfolio optimization and market bidding problem. The bidding model is based on the Nordic electricity market architecture. Wholesale electricity trading takes place on the day-ahead market run by Nordpool. Regulation power is procured on the regulation power market run by a TSO (which includes a reservation and an activation market).

The objective of the aggregator is to minimize the total energy costs of a portfolio of energy consumers. Demand flexibility can come from load shifting or energy carrier substitution. We find that the most important parameters characterizing demand flexibility in the portfolio with respect to the studied markets are

- response time (must not exceed 15 min) in order to be relevant for the regulation power market
- load share to reduce
- maximum duration of reduction
- maximum time between two reductions
- reconnection peak
- cost of load reduction
- availability during the day/week

When demand flexibility is reserved for regulation power, it becomes unavailable for response on the wholesale electricity market. And conversely, when demand flexibility is used to respond to wholesale market prices, less potential is left for reserve. The aggregator's problem is to find the optimal amount of flexibility to place into each market, depending on the expected clearing price, flexibility costs and the eventual penalty for not being available for activation on the regulation power market. Optimization therefore implies that the volume of flexibility on one market is influenced by the volume on another market.

The developed optimization and bidding framework is tested using actual Norwegian market data from the winter season in 2011 and 2012 when different price levels and price variations were observed on the markets. The value of having automatic load control and energy storage in the portfolio is also tested.

We find that daily price variation is crucial for profitability of flexibility on the wholesale power market, and in the chosen test periods it does not seem to be significant enough, so the model chooses to reserve most of the flexibility for the up-regulation reserve. Capacity payments from the regulation power market strongly increase the value of flexibility for the aggregator. Less demand flexibility is available on the regulation power market in hours 8–11 and 17–19 because demand flexibility is used on the wholesale market during those times to respond to high prices.

Automatic load control and the use of energy storage are found to increase the value of flexibility in the portfolio. Automatic load control has the largest impact because it extends the availability period for demand response (e.g. creates the possibility to shift load at commercial sites outside the normal working hours) which is especially important for income on the regulation power market where resources must be available during many hours.

4.4 Residential DR to electricity price and investment in demand flexibility

Paper IV studies demand response from residential consumers in Norway. In this paper we use energy system modelling with endogenous investments in demand technologies and load control technologies to study residential demand response potential in Norway. We assume that residential consumers in Norway are already able to respond to electricity price as a result of smart meters installed in all households and the possibility of entering spot price hourly contracts. Still, the profitability of investing in load control depends on electricity price variability and the cost of demand response.

Our results show that electricity consumption from residential heating technologies slightly decreases in Norway towards 2040 as a result of energy efficiency, better building standards and decreased heating demand. On the other hand, electricity consumption from car charging and its theoretical demand response potential are increasing due to the electrification of the transport sector.

The economic potential of DR to electricity price will gradually increase towards 2030–2040 as the price variation in Norway grows and the costs of residential load control are reduced. Depending on the scenario, it may reach 37–69% of the theoretical potential in 2040. Based on modelling of investment in demand flexibility, we find that 7– 17% of residential heating appliances and 57–60% of residential car chargers can become flexible by 2040, resulting in a maximum load reduction of between 1940 and 3258 MW due to price response on a normal winter evening.

We observe that demand response from electric cars is more profitable compared to demand response from heating technologies because it has a lower investment cost per kWh/h and because it can benefit from the largest price differences between the daytime and the night-time hours. Demand response from heating technologies is limited by the hours just before/after the morning peaks because heating technologies cannot shift load over long periods of time. Shifting windows have a significant effect on the profitability of demand response.

Modelling results show that there exists an optimal level of demand response in the wholesale market when electricity price volatility is sufficiently reduced, and more demand response becomes unprofitable. The price flattening effect acts as a natural restriction on the economic demand response potential, and our results show that investments into demand flexibility may be overestimated by 10–18% if this effect is not considered.

It is important to have correct feedback between the market and consumers, so that consumers do not perform more DR than necessary from a system perspective. A third-party aggregator performing "controlled" DR on behalf of residential consumers can adjust the level of DR with respect to intraday and real-time market prices.

4.5 Discussion and further work

The work performed for this thesis illustrates the importance of including several markets and different grid levels in demand flexibility studies. Demand flexibility is useful for many actors in the power system, and the same resources can often participate in different markets and DR programmes. The participation of demand flexibility in one market can influence its participation in another market. It is also not straightforward what is the best way to use demand flexibility at a particular time and location from a whole system point of view. Optimization that considers several markets and different grid levels is more complex but gives a more accurate picture of how it is best to allocate demand flexibility.

Demand and other distributed resources are not the only sources of flexibility in energy systems. It is therefore important to compare the value of demand flexibility against other flexibility options in different power systems, especially in those where other cheap sources of flexibility are available. For example, the Scandinavian power system possesses significant flexibility in the form of hydropower which can deliver various services to the power system at low cost. However, the distribution system cannot benefit from this flexibility, so demand-based grid services or demand response to grid tariffs will still be relevant.

Individual differences between power systems will determine the main drivers behind the integration of demand flexibility into electricity markets. In hydropower-dominated regions, the primary focus may be on benefits for the distribution system, while in thermal systems with large shares of VRE, price response and balancing power from flexible demand may be of major interest. At the same time, it is likely that interest in using demand flexibility in one market will trigger its use in other markets. As soon as flexibility is enabled by implementing load control and management technologies, the threshold for using it will become lower.

The role of the aggregator is central to achieving the optimal use of demand flexibility in the power system, and it is important that the regulations clearly define this role. Among European countries, France, Belgium, Ireland and the United Kingdom have all defined the roles of demand flexibility aggregators and given them access to a number of markets (IEA, 2020). France is the only country in Europe that has opened both AS and wholesale power markets to independent aggregators, which was made possible by standardized agreements between BRP and aggregators established in 2013 (Bertoldi et al., 2016). Given access to several markets, an aggregator will optimize its portfolio between the markets in order to maximize profit. This will lead to the optimal demand flexibility allocation based on prices.

In this PhD thesis, we did not study models of customer settlement within an aggregator's portfolio because there can be many models depending on customer size, available markets and whether the aggregator is also a BRP and has other DER or generation assets. As drivers of demand flexibility integration into electricity markets are power system–specific, a variety of business models for aggregators can be expected to emerge in different power systems.

Demand flexibility and DER have transformed the power system, making it less centralized and creating new and more complex types of relations between actors. Therefore, research tools for studying power systems have also become more sophisticated. In this thesis, demand flexibility was studied from different perspectives, and various modelling tools were used, including Balmorel and TIMES energy system models. The general observation from demand flexibility modelling is that it makes the models more complex and requires better model resolution and granularity. Capturing strained power system situations and extreme electricity prices becomes important because these are what trigger the value of flexibility. Methodologically, this can be done by increasing the temporal and geographical resolution of the model, disaggregating technologies, or using stochastic programming. All these methods significantly increase the computational time and make it difficult to model long time horizons and large systems. Soft-linking different models is another possible solution, and the challenge here lies in finding a suitable boundary between the models. Investigating modelling strategies for demand flexibility studies (and DER studies in general) should be an important field of research for the future.

5. CONCLUSIONS

The objective of this PhD has been to answer the research question 'What is the optimal way to integrate demand flexibility into electricity markets?' The performed research demonstrates that it is important to consider the whole system point of view and the interplay between different markets and grid levels when demand flexibility is integrated into power systems.

Demand response has many benefits for the power system. In the wholesale market, DR reduces the peak load generation and supports the integration of VRE. In the reserve market, DR removes the need to keep thermal generation spinning when VRE production is high. Our results indicate that there may be more benefits from allocating more demand flexibility to the reserve market than to the wholesale market in power systems with large shares of VRE. The need to hold reserves constitutes a significant cost in such systems, which can be decreased if demand flexibility is used as a reserve instead of generation units.

It is important to give demand flexibility aggregators access to many markets. An aggregator will optimize its portfolio between markets in order to maximize profits. If the profitability on one market is low, the availability of other markets can support the incentives for the aggregator of demand flexibility. In reserve markets, DR receives a reservation price in addition to the activation price (energy payment) which increases the profitability for aggregators. In the wholesale market, the profitability of demand flexibility is solely determined by the size of electricity price variations as demand flexibility only gets the energy payment.

Daily price variation is important for the profitability of demand response on the wholesale market. A number of markets (e.g. the Nordic power markets with large hydropower shares) do not currently offer sufficient incentives for DR because of small price variations. However, even in Nordic markets, price variation is expected to increase due to larger shares of VRE and more interconnections with European markets. This will incentivize demand response on the wholesale markets and investment in load control and smart appliances.

Demand flexibility can be used for power system services at both the transmission and distribution system levels. An active role for DSOs in distribution system management and better coordination between DSOs and TSOs are widely discussed topics today. Large shares of demand flexibility resources in the distribution grid have technical characteristics that make them suitable for several markets and several types of services. Given a free choice to participate in one market or another, the aggregator will choose the market with the highest price level. If several AS markets run sequentially, for example a DSO market and a TSO market, the aggregator may allocate flexibility to only one market, decreasing liquidity in another market. New approaches to market design and coordination between TSOs and DSOs are important to address these types of challenges. In this project, we propose a joint market clearing for TSOs and DSOs as one of possible ways to optimally allocate flexibility between different voltage levels.

For residential consumers, price-based (implicit) demand response is often considered to be a relevant solution because it does not require aggregation. Residential consumers will only invest in load control solutions and perform demand response if the price variation is large enough. We find that an important factor that determines profitability is the time window for load shifting. For example, electric car charging can be shifted from day to night, making use of the largest price variations in the market, while heating loads have very limited time windows for shifting and are therefore less profitable.

When a large number of residential customers respond to electricity price, the electricity price variation on the wholesale market is reduced. Our results show that there is an optimal level of demand response in the wholesale market when the price variation is sufficiently reduced so that no more demand response is required, and the market reaches a new equilibrium.

All in all, the work done in this PhD thesis suggests that the optimal use of demand flexibility can be achieved through market arrangements that facilitate the use of demand flexibility in many markets, better coordination between distribution and transmission system levels and a stronger role for the aggregator to optimally allocate demand flexibility between markets. Modelling several electricity markets at the same time, including different grid levels and other parts of the energy system, is useful to achieve better insight into the optimal integration of demand flexibility in electricity markets.

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Paper I

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Value of demand flexibility on spot and reserve electricity markets in future power system with increased shares of variable renewable energy

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The growing share of variable renewable energy (VRE) generation and the reduction in conventional power plant capacity creates challenges for power system operation. Increased variability of production causes increased reserve requirements while the number of reserve providers is reduced. For this reasons, power systems' flexibility is a major topic of research nowadays, and electricity demand is considered one of the most valuable flexibility sources.

This paper analyzes the impacts of demand flexibility participation in spot and reserve markets in the German power system in 2030. We model the power system dispatch with and without reserve requirements using a partial equilibrium linear programming model, BalmoREG, to quantify the cost of reserves, the value of demand flexibility, and the optimal allocation between the spot market and reserve market. We find that the costs of providing reserves add 0.6–8.6% to the total system cost in the German 2030 power system. According to sensitivity studies, the cost of reserve provision increases substantially with reduced baseload shares or increased VRE shares, while transmission opportunities to neighboring countries reduce the cost. The modelled electricity price is especially sensitive to the addition of reserve requirements in situations of either very high VRE or very low VRE production.

1. Introduction

Increasing the flexibility of power systems is an important measure to support the transition to low-carbon and carbon-free electricity production. Different sources of power system flexibility are thoroughly discussed in Ref. [1], where demand-side management is described as one of the major sources. Demand flexibility is acknowledged by ENTSO-E as “*a main contributor to more effective markets and to system security with a high penetration of fluctuating generation*” [2].

The potential value of demand flexibility delivering various services in the electricity sector is studied in Ref. [3], which distinguishes between two main purposes of demand flexibility utilization: economics and reliability. The first purpose, economics, entails creating demand response programs to increase the price sensitivity of demand in electricity markets, and to improve market efficiency by allowing the demand to follow the production to a larger extent. The second purpose, reliability, entails provision of various ancillary services from flexible demand (e.g. operational reserves, grid services, etc.) that support secure and reliable power system operation.

Procurement of operational reserves from demand flexibility will become increasingly important to support the transition towards low-carbon power systems with a gradual phase-out of dispatchable coal and gas power plants [4]. Reserve requirements will increase due to higher variability and uncertainty of production [5], while the number of reserve providers will decrease. Such challenges are already occurring in countries like Denmark, where the share of variable renewable energy (VRE) in the power mix is relatively large so it is highly relevant to utilize demand flexibility both for power system regulation and on the electricity spot market [6]. Germany is another example of a country with fast-growing shares of VRE. According to the German energy transformation plan *Energiewende*, at least half of the electricity supply will come from renewable energy sources by 2030 [7]. Previous studies have estimated that reserve requirements in Germany will increase by 4–6% of the additional VRE capacity [8]. Since dispatchable nuclear and coal power plants are being gradually phased out, utilization of

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Nomenclature

Sets

S	Weeks, $s = \{1, 2, ...52\}$
T	Time segments in a week, $t = \{1, 2, ...168\}$
D	Days in a week, $d = \{1, 2, ...7\}$
DT	Subsets of time segments $t \in T$ defining hours of the day for each $d \in D$
R	Neighbor countries, $r = \{Denmark, Sweden, Norway, Netherlands\}$
I	Power generation technology type, $i = \{I_{TH}, I_{HY}, I_{CHP}, I_{VRE}\}$
I_{TH}	Thermal power generation technologies (coal, oil, and gas)
I_{HY}	All hydropower with reservoir generation technologies
I_{PHS}	Pumped storage hydropower generation (PHS) technologies, $I_{PHS} \in I_{HY}$
I_{CHP}	CHP technologies
I_{VRE}	VRE technologies (solar, wind, run-of-river)
I_R	Generation technologies that deliver reserves $I_R \in I$

Parameters

$\overline{g}_i$	Installed capacity of generation technology type i, MW
$g_{s,t}^{avail}$	Availability of generation capacity at time step t, % (based on maintenance, outage rates etc.)
$\underline{ramp_i}$	Maximum capability of ramping down between hours, % of capacity
$\overline{ramp_i}$	Maximum capability of ramping up between hours, % of capacity
$r_{i_R}^{max}$	Maximum technical upregulation potential (load gradient per minute * required response time), % of capacity
k_{i_R}	Spinning coefficient determining the relationship between the generation level and the available upregulation reserve
$\overline{v_s}$	Maximum available hydropower generation per week, MWh
$RR_{s,t}$	Dynamic reserve requirement at time step t, MW
K_i^{VOM}	Operation and maintenance costs, €/MWh
K_i^{FUEL}	Fuel costs, €/MWh
K_i^{EMIS}	Emission costs, €/MWh
$K_{i_R}^{RES}$	Reservation cost, €/MWh
$d_{s,t}^{base}$	Electricity demand, MWh
$d_{s,t}^{red\_ST}$	Technical demand reduction potential with a short-term shifting horizon, % demand
H	Short-term demand shifting horizon, hours
$d_{s,t}^{red\_LT}$	Technical demand reduction potential with a long-term shifting horizon, % demand
$\overline{X_r}$	Transmission capacity limits with neighbor countries, MW
$P_{r,s,t}^{EL}$	Electricity prices in neighbor countries, €/MWh
K^{TRANS}	Cost of transmission, €/MWh
X^{LOSS}	Transmission loss, % per MW

Variables

$g_{i,s,t}$	Electricity generation at time step t, MWh
$imp_{r,s,t}$	Electricity import from neighbor countries at time step t, MWh
$exp_{r,s,t}$	Electricity export to neighbor countries at time step t, MWh
ω_s^{pump}	Water amount pumped by PHS per week, MWh
$d_{i_{PHS},s,t}$	Electricity used for water pumping at time step t, MWh
$d_{s,t}^{change\_ST}$	Demand change at time step t due to short-term demand shifting on the spot market, MWh
$d_{s,t}^{change\_LT}$	Demand change at time step t due to long-term demand shifting on the spot market, MWh
$R_{s,t}^{D}$	Upregulation reserve from flexible demand at time step t, MW
$R_{i_R,s,t}^{G}$	Upregulation reserve from generation at time step t, MW

demand flexibility will become increasingly important [9]. In 2010, a large-scale study on VRE integration in Germany was performed [10], and the provision of balancing from flexible demand was one of the topics. The study concluded that flexible demand may be able to provide up to 60% of the positive balancing energy in 2020, causing a reduction of the total macroeconomic cost of electricity generation by 481 mill EUR.

There is a large body of literature addressing the utilization of demand flexibility to support the transition towards low-carbon power systems. However, most of the publications address either the domain of economics or the domain of reliability. This fact is pointed out in Ref. [9], where the author distinguishes between two types of demand flexibility services—system-oriented and market-oriented—and asserts that while both types of services are important for VRE integration, not many studies have considered both at the same time. In addition, most of the research on demand flexibility services focuses on various optimization algorithms and smart strategies for flexible demand, while the total power system impacts of demand flexibility utilization are either only briefly covered (e.g. using case studies, as in Ref. [11]), or it is taken for granted that the impacts will be positive (e.g. Ref. [12]). Only a limited number of publications address the total system impacts of demand flexibility utilization in real power systems, and an even smaller number take into account both economics and reliability. In Ref. [13], the total economic impacts of demand response on the electricity spot market are estimated for several European and Scandinavian countries in 2030, while in Ref. [14] the impact of demand rescheduling on investments and VRE integration on Flores Island is analyzed. Neither of these studies, however, consider reserve provision from flexible demand. In Ref. [15], the cost of system operation in Denmark is analyzed using a Balmorel power system model while looking at demand flexibility both on the spot market and reserve market. The study finds that the total system cost is reduced by 27 mill EUR when flexible demand participates on the spot market, and by 59 mill EUR when flexible demand provides reserves. In Ref. [16], a stochastic unit commitment and dispatch model for the Irish power system is developed, with both active demand response on generation fluctuations and reserve provision from flexible demand. The study focuses on investigating the changed patterns of generation units' operation and improved power system reliability, but does not quantify the economic impacts.

Studies that consider a broad system perspective with demand flexibility utilization for both economics and reliability are very important for understanding the complex technical and economic relationships between the various resources in the power system, and for evaluating the total value of flexible demand. This paper seeks to contribute to this body of research by analyzing the impacts of demand flexibility on the electricity spot market and reserve market in future power systems with increased shares of VRE.

In this study, we model the power system in Germany in 2030 with increased shares of VRE, and estimate the costs of power system operation and the value of demand flexibility participation on the spot and reserve markets. We simulate several future generation capacity development scenarios and draw conclusions about the important drivers behind power system cost and the value of demand flexibility.

The scope of the study is limited to *secondary/tertiary positive control reserves* because these reserves are considered to be most affected by the increased shares of VRE [8,17], and these reserves can be easily provided by flexible demand [18]. Secondary/tertiary control is employed during normal power system operation to compensate for frequency deviations caused by variations in load and generation, as well as during operational disturbances caused by power plant and line outages. The purpose of secondary/tertiary control is to restore frequency to its normal bandwidth within a timeframe of 1–10 min. It can be provided by spinning and fast-starting non-spinning generation units that are able to change their output within the mentioned timeframe, or by electricity consumers (large or small aggregated) that can change their consumption within this timeframe.

We do not consider primary regulation reserves[1] and provision of *secondary/tertiary negative control reserves* in this study. Previous studies have shown that primary regulation requirements will not be much affected by the increased shares of VRE because VRE variability in this timeframe is very small [8], [17]. Besides, it is more technically difficult and expensive to provide these reserves by flexible demand. Negative control reserves can be provided by VRE itself so the impact of increased shares of VRE on this type of control will not be significant.

The structure of this article is as follows: Section 2 describes the methodology used for power system modeling and calculation of reserve requirements in Germany in 2030, and presents the assumptions of different modeling scenarios; Section 3 presents the results of the simulations and discusses the important findings of the study; and Section 4 concludes the article.

2. Methodology

2.1. Power system modeling

To simulate the power system in Germany in 2030, we have developed a quantitative model, BalmoREG, which is soft-linked to the existing energy system model Balmorel, developed in Ref. [19] and updated in Ref. [13]. Both models are linear programming (LP) equilibrium models that simulate generation, transmission, and consumption of electricity under the assumption of competitive markets. Balmorel models a vast geographic region (Scandinavia and several European and Baltic countries) and includes a detailed modeling of hydropower reservoirs and heating sectors, while BalmoREG is limited to one country and one year and has a specific focus on power system operation, reserve provision, and demand flexibility. The link between Balmorel and BalmoREG is illustrated in Fig. 1.

The objective of BalmoREG is to minimize the total system cost, which is defined as the sum of production costs, reservation costs, and import costs minus export income:

[1] Primary regulation reserves are symmetric reserves with a response time of several seconds used to contain frequency deviations both during normal operation and in case of contingencies.

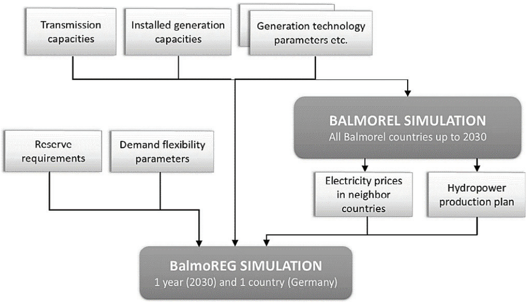

Fig. 1. Soft-link between Balmorel and BalmoREG power system models.

$$min \sum_{i\in I}\sum_{s\in S}\sum_{t\in T}\left(g_{i,s,t}*\left(K_i^{VOM}+K_i^{FUEL}+K_i^{EMIS}\right)\right)+\sum_{i\in I_R}\sum_{s\in S} \times\sum_{t\in T}\left(R^G_{i_R,s,t}*K^{RES}_{i_R}\right)+\sum_{r\in R}\sum_{s\in S}\sum_{t\in T}\left(imp_{r,s,t}*\left(P^{EL}_{r,s,t}+K^{TRANS}\right) - exp_{r,s,t}*P^{EL}_{r,s,t}\right) \tag{1}$$

The electricity balance equation ensures that electricity production and exchange are at each time step equal to electricity demand ($d^{base}_{s,t}$) adjusted by demand response actions ($d^{change\_ST}_{s,t}+d^{change\_LT}_{s,t}$), plus the total PHS demand:

$$\sum_{i\in I} g_{i,s,t}+\sum_{r\in R}\left(imp_{r,s,t}*\left(1-X^{LOSS}\right)-exp_{r,s,t}\right) = d^{base}_{s,t}+d^{change\_ST}_{s,t}+d^{change\_LT}_{s,t}+\sum_{i\in I_{PHS}} d_{i_{PHS},s,t} \tag{2}$$

Electricity demand in Germany in 2030 is calculated using the measured hourly demand profile scaled up to year 2030 based on the expected increase in total electricity consumption. Electricity exchange is limited by the transmission capacity available in 2030 (see equations (3) and (4)). Electricity production is limited by the available capacity of the generation technology (see equation (5)).

$$imp_{r,s,t}\le \overline{X_r} \tag{3}$$

$$exp_{r,s,t}\le \overline{X_r} \tag{4}$$

$$g_{i,s,t}\le \overline{g}_i*g^{avail}_{s,t} \tag{5}$$

Production of hydropower technologies (I_{HY}) is limited by the total amount of disposable water per week $\overline{v_S}$, which is obtained from the Balmorel simulation. Pumped storage is defined as a subset of hydropower technologies (I_{PHS}), and water pumped into the reservoir during the week changes the weekly limit imposed by $\overline{v_S}$. Equation (6) shows the total constraint for all hydropower technologies:

$$\sum_{t\in T}\sum_{i\in I_{HY}} g_{i_{HY},s,t}\le \overline{v_S}+\omega^{pump}_S \tag{6}$$

where ω^{pump}_S is determined by equation (7) as the electricity consumption for pumping in each time step ($d_{i_{PHS},s,t}$) multiplied by the pumping process efficiency of 75% [20]. Electricity consumption for pumping is included in the balance equation (2).

$$\omega_s^{pump} = 0.75 * \sum_{i \in I_{PHS}} \sum_{t \in T} d_{i_{PHS},s,t} \tag{7}$$

For thermal generation technologies, ramping constraints are included into the model. They are based on a LP formulation of ramping constraints proposed in Ref. [13]. For each type of generation technology three operating modes are defined: *low-ramping*, *medium-ramping*, and *high-ramping*.

$$j = \{low, medium, high\}$$

$$g^j_{i_{TH},s,t} = \begin{cases} g^{low}_{i_{TH},s,t} \\ g^{medium}_{i_{TH},s,t} \\ g^{high}_{i_{TH},s,t} \end{cases}$$

For each operating mode, different capabilities of ramping up/down and different VOM-costs are specified, with increasing ramping capability and increasing VOM-costs for higher ramping modes. Ramping capability parameters define the technology's ability to change its output between hours:

$$\underline{ramp}^j_{i_{TH}} \cdot \overline{g}_{i_{TH}} \le g^j_{i_{TH},s,t} - g^j_{i_{TH},s,t-1} \le \overline{ramp}^j_{i_{TH}} \cdot \overline{g}_{i_{TH}} \tag{8}$$

The total generation for the given thermal technology at each time step is the sum of generation in each operating mode (see equation (9)). This forces the model to choose one of the modes of operation at each time step. An increased need for ramping between hours will therefore force the model to choose more expensive ramping modes, resulting in increased total production cost.

$$\sum_{j \in J} g^j_{i_{TH},s,t} = g_{i_{TH},s,t} \tag{9}$$

Start-up and shut-down constraints can not be perfectly captured in a linear optimization model. Therefore, in BalmoREG, the increased cost associated with a less optimal dispatch of thermal technologies includes the ramping cost only, and can be considered to be a lower estimate, while the actual cost increase may be higher.

Production of VRE technologies have given profiles exogenously, calculated from the measured hourly production scaled up to year 2030 based on the expected increase in VRE generation capacity:

$$g_{i_{VRE},s,t} \le \overline{g}_{i_{VRE},s,t} \tag{10}$$

Production profiles of CHP technologies are also given exogenously, based on the Balmorel simulation, since we do not model the heating sector in BalmoREG. CHP technologies are defined as must-run technologies:

$$g_{i_{CHP},s,t} = \overline{g}_{i_{CHP},s,t} \tag{11}$$

The electricity prices in Germany in 2030 are determined in the model as the marginal values of the balance equation (2).

2.1.1. *Demand flexibility modeling*

In BalmoREG we assume a demand reduction potential of 6% of the total demand in Germany in 2030, which corresponds to 2 GW–5 GW reduction available per hour (see Fig. 2). For comparison [21], estimate an average *theoretical* demand reduction potential in Germany as high as 14 GW based on 2010 data, while [10, p. 532] estimate an average *economic* potential in Germany in 2020 to be 5.7–6.6 GW.

The approach to demand flexibility modeling in BalmoREG is

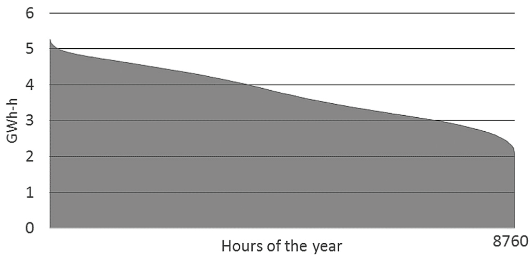

Fig. 2. Hourly available maximum demand reduction in Germany in 2030. Sorted values.

based on [13] and [15], but a more detailed representation of demand flexibility is developed. We divide demand shifting in electricity spot markets into two types, depending on the shifting timeframe:

- short-term shifting – reduced demand must be recovered within 4 h
- long-term shifting – reduced demand must be recovered within the same day

This division is based on evaluation of demand flexibility from different consumption sectors and the estimates of the average demand shifting timeframes from Ref. [21]. According to this division, two free variables $d^{change\_LT}_{s,t}$ and $d^{change\_ST}_{s,t}$ are defined, which are negative for demand reduction and positive for demand recovery, and their lower limits are determined by the maximum technical potential for demand reduction:

$$d^{change\_LT}_{s,t} \ge -d^{base}_{s,t} * d^{red\_LT}_{s,t} \tag{12}$$

$$d^{change\_ST}_{s,t} \ge -d^{base}_{s,t} * d^{red\_ST}_{s,t} \tag{13}$$

Constraints (14) and (15) impose the requirements that demand must be recovered within one day, while constraint (16) imposes the requirement that short-term shiftable demand must be recovered within 4 h:

$$\sum_{t \in DT} d^{change\_LT}_{s,t} = 0 \quad for\ each\ d \in D \tag{14}$$

$$\sum_{t \in DT} d^{change\_ST}_{s,t} = 0 \quad for\ each\ d \in D \tag{15}$$

$$\sum_{t \in DT}^{t+H} d^{change\_ST}_{s,t} \ge 0 \quad for\ each\ d \in D, \quad where\ t + H = 4\ hours \tag{16}$$

Upregulation reserve from demand is limited by the technical potential for demand reduction in every hour (17), as well as demand reduction events on the spot market if there are any in the given hour (18):

$$R^D_{s,d} \le d^{base}_{s,t} * \left(d^{red\_ST}_{s,t} + d^{red\_LT}_{s,t}\right) \tag{17}$$

$$R^D_{s,d} \le d^{base}_{s,t} * \left(d^{red\_ST}_{s,t} + d^{red\_LT}_{s,t}\right) + d^{change\_LT}_{s,t} + d^{change\_ST}_{s,t} \tag{18}$$

Demand reduction and recovery on the spot market is included in the electricity balance equation (2), while upregulation reserves from demand are included into the reserve balance equation (22).

2.1.2. Reserve provision modeling

BalmoREG equations defining reserve provision from demand flexibility are described in Section 0. The subset of generation technologies (I_R) that can provide secondary/tertiary upregulation in BalmoREG includes coal-, gas- and hydropower with reservoir plants. Within the LP framework three constraints are used to describe reserve provision from these technologies, based on [15]: *technical constraint, spinning constraint,* and *capacity constraint*.

The technical constraint implies that the upregulation reserve available from a technology is limited by the technical upregulation potential $r_{i_R}^{max}$, which depends on the technology's load gradient (MW/min) and response time (10 min in case of secondary/tertiary regulation):

$$R_{i_R,s,t}^G \le r_{i_R}^{max} \tag{19}$$

The spinning constraint ensures that the reserve is only provided by the spinning units:

$$R_{i_R,s,t}^G \le g_{i_R,s,t} * k_{i_R} \tag{20}$$

We apply an arbitrary coefficient k_{i_R} to define the proportion of the spinning capacity that can provide reserves. Our assumptions about k_{i_R} are presented in Table 1 and are based on the technical upregulation potential of different technologies. For technologies with high technical upregulation potential (hydropower and gas) we assume coefficient 1, which implies that the reserve is limited by the total spinning capacity. For technologies with low technical upregulation potential we assume coefficients below 1, which means that the available reserve is not more than a given share of the spinning capacity. This formulation is an LP approximation of the unit commitment formulation taken from Ref. [15]: it imposes higher production levels on technologies to provide reserves, which corresponds to starting more units.

The capacity constraint ensures that the reserve does not exceed the available upregulation capacity (full capacity minus production):

$$R_{i_R,s,t}^G \le g_{s,t}^{avail} - g_{i_R,s,t} \tag{21}$$

Reserve balance equation is given by (22). The total reserve requirement must be satisfied by the sum of reserves provided by all generation technologies from subset I_R plus reserves provided by demand side. A dynamic reserve requirement $RR_{s,t}$ is specified for each time step using the methodology described in Section 2.1.3.

$$RR_{s,t} = \sum_{i \in I_R} R_{i,s,t}^G + R_{s,t}^D \tag{22}$$

2.1.3. Reserve quantification methodology

General guidelines for quantification of secondary and tertiary control reserves in European countries are given in the Operational Handbook of [22], but the final decision on quantification methodology is left to individual transmission system operators (TSOs). As a result, the level of secondary and tertiary control reserves varies widely between countries—from 5% of average load in France to 14% in Belgium [8]. In this study, we define requirements for positive secondary/tertiary control reserves in line with the practices of German TSOs, based on four sources of imbalance:

- short-term forecast errors of solar power production
- short-term forecast errors of wind power production
- short-term forecast errors of electricity demand
- power plant outages

Similar to German TSOs, we use probabilistic reserve sizing methodology with a security level of 99.9% [10] (i.e. the reserve is expected to be sufficient during 8751 h of the year). We define specific probability distribution functions for all sources of imbalance, but we only determine a joint probability distribution for load and VRE forecast errors and handle the probability of plant outages separately. Methodology of reserve sizing used in this study is illustrated in Fig. 3.

We use the probability distribution of forecast errors to calculate a *dynamic* reserve requirement that varies each hour based on the production level of VRE technologies and load. This approach is in line with the reserve sizing methodologies in VRE integration studies [23], [24]. It allows us to follow the contribution of VRE to the total reserve requirement in any given hour and relate reserve requirement to power system operational conditions.

Using the above methodology, the model calculates the total dynamic requirement for positive secondary/tertiary regulation reserves in Germany in 2030 for each generation capacity development scenario.

2.2. Description of scenarios

The composition of the generation fleet in 2030 and the possibility of electricity exchange with neighbor countries have a particularly strong effect on the cost of reserve provision. Therefore, we define 4 modeling scenarios, which are described in Table 2 and illustrated in Fig. 4.

3. Results and discussion

3.1. Cost and price impacts of reserve requirements

The requirement to hold reserves increases the total cost of power system operation and affects the price of electricity. Table 3

Table 1
Assumptions about the proportionality coefficient k for the spinning constraint.

Technology type	k_{i_R}
Hydropower with reservoir	1
Coal power plants	0.43–1 depending on technology subtype
Gas power plants	1

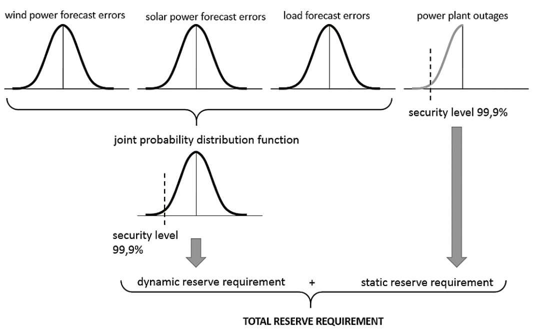

Fig. 3. Methodology of determining dynamic positive secondary/tertiary control reserve requirements used in this study.

Table 2
Description of model scenarios in this study.

Scenario for generation fleet	Description
BASELINE	Scenario assumptions correspond to the assumptions in Refs. [13] and [10]. By 2030, a complete phaseout of nuclear power is assumed, as well as a considerable increase of VRE capacity (by ca. 66%). Electricity generation based on coal and oil gradually decreases, while generation based on gas and biomass gradually increases.
BASELINE/0 EXCHANGE	The same generation capacity as in BASELINE scenario is assumed, but we assume no electricity transmission opportunities with neighbor countries.
LOW COAL	Scenario assumptions are based on Energy Technology Perspectives [25]. The phaseout of coal power plants is substantially faster than in BASELINE (i.e. coal capacity in 2030 is 90% less than in BASELINE). Instead, more gas power plants are built (+29 GW). Assumptions about other technologies are similar to BASELINE. This scenario represents a power system with high VRE shares and almost no baseload capacity.
LOW COAL/HIGH VRE	LOW COAL/HIGH VRE is similar to LOW COAL, but the capacity increase (+29 GW) is equally divided between gas power and VRE. Therefore, this scenario is a more extreme version of the previous scenario with very high VRE shares.

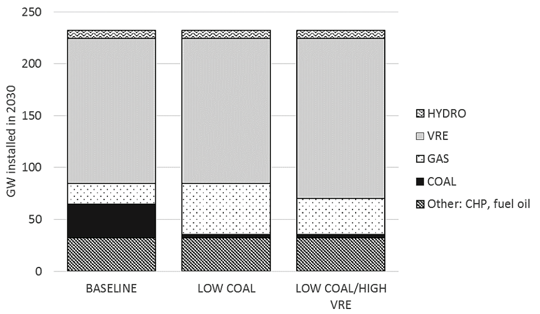

Fig. 4. Assumed capacity mix in model scenarios for Germany in 2030, as described in Table 2.

and Figs. 5–7 present the results of the simulations with only reserve requirements added to the model, without demand flexibility. The cost of providing reserves is equal to the difference between the system cost with and without reserve requirements.

With our baseline assumptions regarding the generation capacity in Germany in 2030, the reserve requirements increase the total power system cost by 0.62%. The cost of reserve provision is determined to be 109.7 mill EUR. The power system generally has sufficient available upregulation capacity to provide the necessary reserve. This is confirmed by the fact that even in case without reserve requirements the system has enough *surplus upregulation capacity*[2] - the surplus upregulation capacity is sufficient during 8706 h of the year.

The most significant impact of reserve requirements on the system cost is observed in scenario LOW COAL/HIGH VRE. The cost of reserve provision in this scenario is 1963 mill EUR, equal to an 8.6% increase of the system cost. The high cost of reserve provision is primarily due to an increase in the operational costs of production from 17,089 mill EUR to 19,033 mill EUR due to a more frequent dispatch of high-cost marginal units (gas- and oil-based power plants). The increase in hourly prices as a result of inclusion of reserve requirements is shown in Fig. 7.

The higher costs in LOW COAL/HIGH VRE, as well as in LOW COAL, are due to higher shares of VRE and more reserves being provided by gas power plants instead of coal power plants (see Fig. 5). Gas power is more expensive as a reserve provider because gas power plants have higher production costs, so keeping them spinning for reserve provision is expensive. In addition, gas turbines have generally lower efficiency at part-load operation than coal plants, leading to a higher reservation cost. Reservation costs in LOW COAL and LOW COAL/HIGH VRE scenarios are around 30 mill EUR, compared to 19 mill EUR in BASELINE.

Moreover, higher VRE production levels in scenario LOW COAL/HIGH VRE lead to increased hourly reserve requirements: they are on average 2.4% higher in this scenario compared to BASELINE scenario.

The power system in LOW COAL/HIGH VRE also experiences more hours of expensive back-up generation unit start-ups, leading to an additional production cost of 1818 mill EUR. This is illustrated in Fig. 8. Generation capacity scarcity takes place in hours with high residual demand[3] (i.e. low VRE production), which reflects the sensitivity that a system with large shares of VRE and reduced baseload generation has to variations in VRE production level.

Electricity exchange is another important factor for the cost of reserve provision after the composition of the generation fleet. To quantify the impacts of trade, we have run BASELINE while removing the possibility to trade electricity across borders (BASELINE/0 EXCHANGE). Without exchange, the cost of reserve provision is 739.6 mill EUR, compared to only 109.7 mill EUR in BASELINE. Adding reserve requirements in BASELINE/0 EXCHANGE drastically increases the number of capacity scarcity hours from 129 to 258 h, alone causing an additional cost of 676 mill EUR to the system. This illustrates that electricity exchange plays a very important role when it comes to the cost of reserve provision in a power system with high shares of VRE. The need to hold reserves in the power system amplifies the impacts of generation capacity scarcity in days with low VRE production and the impacts of generation capacity surplus in days with high VRE production. Possibilities of importing electricity in days with low VRE production and exporting electricity in days with high VRE production help to significantly reduce the cost of power system operation.

As illustrated in Fig. 7, the electricity price change due to reserve requirements has a similar pattern in all scenarios. The electricity price is most sensitive to the addition of reserve requirements when VRE production is either at its maximum or at its minimum. In hours with high VRE production (residual demand close to 0%), there is a tendency for price drops when reserve requirements are added to the system. This is a result of electricity surplus, which takes place when high VRE production leads to high reserve requirements and the system keeps a number of units spinning (unnecessary for energy provision only). On the contrary, in hours with low VRE production (residual demand close to 100%) the system dispatches the most expensive generation units more often due to capacity reservation for reserves.

[2] Surplus upregulation capacity is inherent upregulation capacity that is available at no additional cost when scheduling the energy only [4]).

[3] Residual demand is defined as the share of electricity demand not supplied by VRE generation [13].

Table 3
System cost of reserve provision in Germany in 2030 in different scenarios. No demand flexibility.

Scenario	System cost without reserves, mill EUR	System cost with reserves, mill EUR	Cost of reserve provision, in mill EUR and as % increase in system cost	Change in the total production of different technologies due to reserve requirements, GWh	
BASELINE	17 592	17 702	109	Gas	**+879**
			+0.62%	Coal	−691
				Hydropower	**+485**
				VRE	−1113
				Oil/backup	**+45**
BASELINE/0 EXCHANGE	18 485	19 224	739	Gas	**+56**
			+4%	Coal	**+636**
				Hydropower	**+156**
				VRE	−1348
				Oil/backup	**+708**
LOW COAL	21 786	22 012	226	Gas	**+2544**
			+1.04%	Coal	**+254**
				Hydropower	**+1189**
				VRE	−1096
				Oil/backup	**+50**
LOW COAL/HIGH VRE	22 793	24 756	1963	Gas	**+1304**
			+8.6%	Coal	**+315**
				Hydropower	**+71**
				VRE	−1574
				Oil/backup	**+1778**

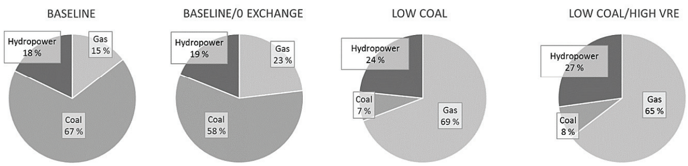

Fig. 5. Reserve provision from different technologies in Germany in 2030 in the 4 scenarios. No demand flexibility.

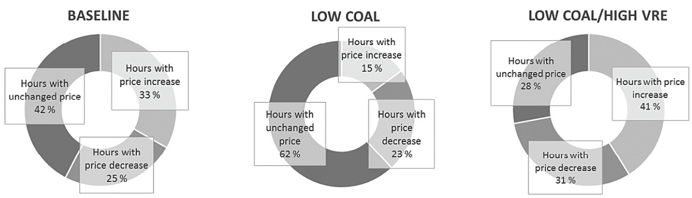

Fig. 6. Distribution of hours with different impacts of reserve requirements on electricity price in different scenarios for generation fleet. No demand flexibility.

It is also important to note that in all scenarios there is a significant VRE curtailment when reserve requirements are added to the system. VRE curtailment takes place in situations of considerable electricity surplus, when VRE production is high but the system still must keep spinning capacity in order to provide reserves. Electricity exchange plays an important role in reducing the amount of VRE curtailment (in BASELINE scenario, additional 235 GWh are produced by VRE, compared to BASELINE/0 EXCHANGE scenario).

3.2. *Value of demand flexibility on spot market and reserve market*

To evaluate the total effects of demand flexibility with respect to both electricity and reserve provision, the power system with reserve requirements was simulated under scenarios BASELINE, LOW COAL, and LOW COAL/HIGH VRE, allowing the model to determine the best allocation of demand flexibility between the spot market and the reserve market. The results are presented in Table 4, Figs. 9–11.

In all scenarios, utilization of demand flexibility reduces the impacts of reserve provision on the system cost. The largest reductions can be observed in LOW COAL/HIGH VRE. Potential demand reductions provide between 75 and 86% of the upregulation reserve in different scenarios and thus replace reserve provision by coal and gas plants. As a result, there is less change in the production levels of generation technologies and VRE is curtailed less often (Figs. 9 and 10).

The average price is reduced due to demand flexibility, and there

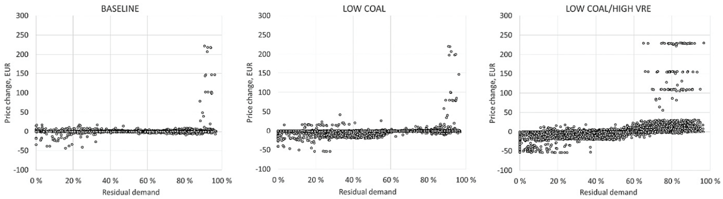

Fig. 7. Electricity price change due to reserve requirements vs. Residual demand in different scenarios for generation fleet. No demand flexibility.

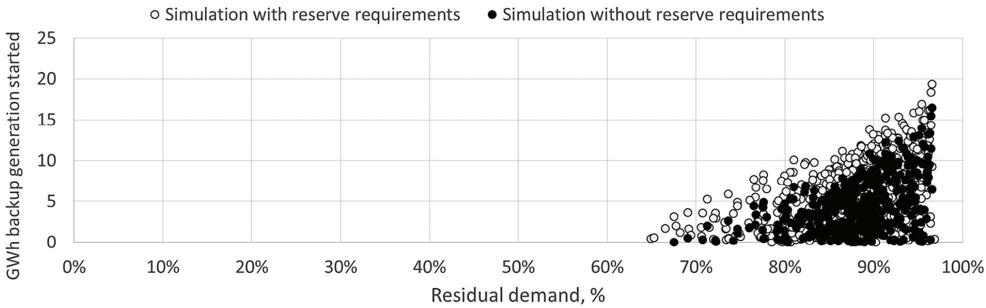

Fig. 8. Generation capacity scarcity hours when expensive peak load generation was started in scenario LOW COAL/HIGH VRE.

is a considerable reduction in price variability. This finding is in line with the results of a similar study [13]. The reduction in price variability is due to demand shifting from high-price hours to low-price hours, so that while price tops during the day are reduced, the night prices will often increase because of the need to recover demand.

In all scenarios, most of the demand flexibility is allocated to the reserve market rather than to the spot market (see Fig. 11). This result is in line with the findings in Ref. [15] and indicates that the system benefits of demand response providing reserves are more significant than the system benefits of demand response on the spot price. The benefits of utilizing demand flexibility for reserves instead of utilizing it on the spot market are most evident in scenarios with small amounts of baseload technologies.

When demand flexibility providers participate in both the spot and reserve market, the effect of demand flexibility on the spot price is lower than if demand flexibility is available in the spot market only. In the BASELINE case without reserve requirements, the price variability in the spot market with demand response is 14 EUR. In the case with reserve requirements, the price variability in the spot market with demand response increases to 22 EUR.

3.2.1. *Impact of demand flexibility on the load profile*

Comparing the results of the simulations with and without demand flexibility on the spot market, we have observed that due to demand response the load variability increases (see Table 4) and new peak loads may occur during the day. The mechanism behind this effect is illustrated in Fig. 12. Demand shifting from high price periods results in a new peak load appearing in hours 14, 15, 16 due to demand recovery.

Such new peak loads can be expected when most of the demand flexibility is shiftable (as opposed to purely reducible demand that does not need to be recovered) and homogenous (i.e. there is a large number of similar consumers with exactly the same price response — e.g. automatic price response systems — and similar patterns of demand recovery). This illustrates that while demand flexibility participation on the spot market can have some positive economic effects, it can also create challenges for power system operation. New or increased load peaks can lead to congestion in the grid, and higher load variability can increase the uncertainty and the need to hold additional reserves. Therefore, when designing market programs for demand response, it is important to take into consideration both the needs of the market and the needs of the power system operation, and to favor a more heterogeneous demand response.

As a concluding remark, it should be noted that these results are based on a linear optimization model that can accurately model most of the constraints in the power system, but it disregards a

Table 4
Summary of the impacts of demand flexibility participating in the spot and reserve market on a system providing reserves.

	BASELINE	LOW COAL	LOW COAL/HIGH VRE
Reduction in the total cost of system operation with reserves due to demand flexibility	349 mill EUR (2%)	378 mill EUR (1.7%)	2814 mill EUR (11.3%)
Reduction in the cost of reserve provision due to demand flexibility	100 mill EUR	213 mill EUR	1658 mill EUR
Change in average price due to demand flexibility, %	−3.4	−1.9	- 25.8
Change in price variability (standard deviation from average) due to demand response, %	−58	−59	−27.3
Change in load variability (standard deviation of load changes between hours) due to demand response, %	+17	+8.5	+15.6
Change in the highest hourly demand registered, %	+12%	+7%	+9%

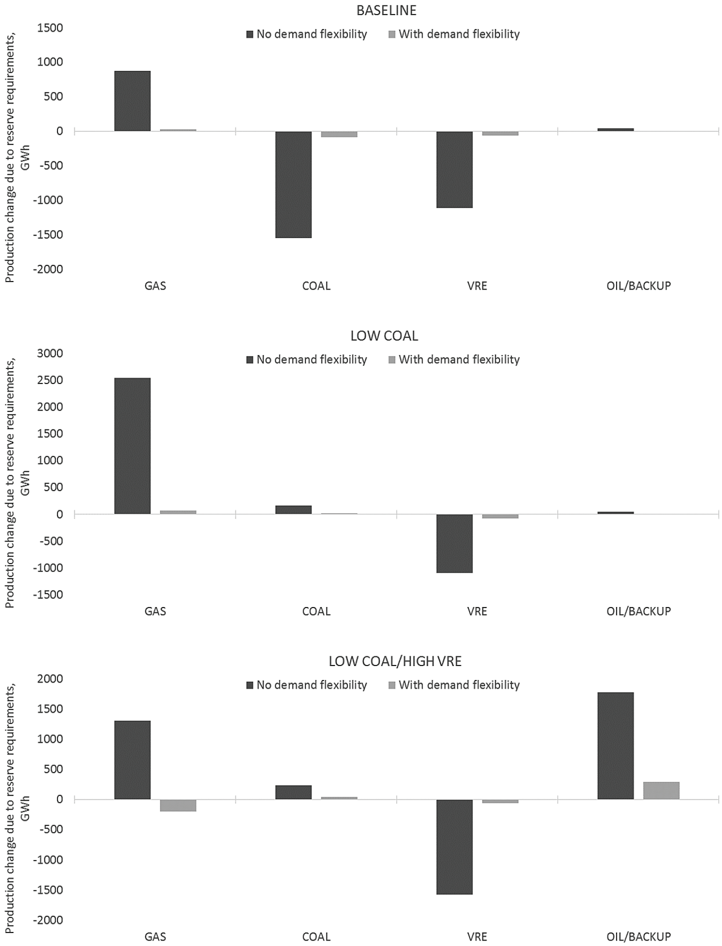

Fig. 9. Impact of demand flexibility on the change in the total yearly production of different technologies due to reserve requirements.

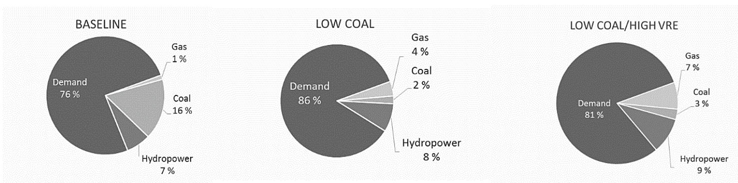

Fig. 10. Total reserve provided by generation technologies and demand flexibility in 2030 in different scenarios for the generation fleet.

number of non-linear constraints, such as start-up and shut-down costs for thermal generation technologies. As a next step of the research, a unit commitment model may be developed on the basis of the linear model, in order to get a more detailed representation of the unit dispatch problem.

4. Conclusions

We find that the costs of providing reserves add 0.6–8.1% to the total system cost in the German 2030 power system. The cost of reserve provision increases substantially with reduced baseload

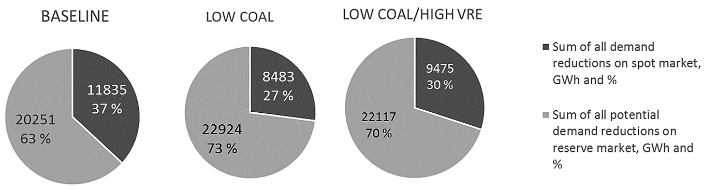

Fig. 11. Model-based allocation of demand flexibility between electricity spot market and reserve market in different scenarios for the generation fleet.

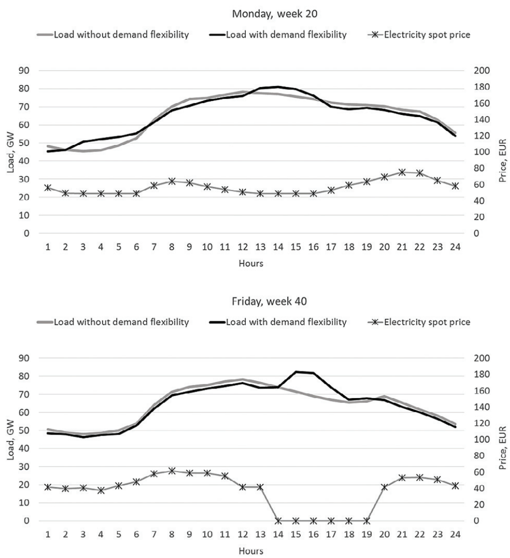

Fig. 12. Two representative days that illustrate the appearance of a new load peak in hours 14–16 due to demand response on the spot market. Demand is reduced in higher price hours and increased in lower price hours.

shares or increased VRE shares. Transmission opportunities to neighboring countries strongly reduce the cost of reserve provision. The system cost is especially sensitive to the addition of reserve requirements in situations of either very high VRE or very low VRE production. In the first case, high VRE production leads to high shares of spinning capacity kept for providing reserves, which results in a significant electricity surplus, zero prices, and VRE curtailment. In the second case, reserve requirements lead to generation capacity scarcity when expensive peak-load or back-up units are started, leading to high electricity prices.

Further, it is concluded that reserve procurement from demand flexibility can significantly reduce the cost of reserve provision and the amount of VRE curtailment, supporting the integration of higher shares of VRE into the power system. This study suggests that in systems with high shares of VRE and reduced baseload capacity, reserve procurement from demand may be more beneficial than demand response on the electricity spot market. Opening up reserve markets for demand flexibility participation is thus an important measure to support the transition towards carbon-free power systems. At the same time, spot market programs for demand flexibility must be designed taking into account the security of the power system operation, since we observed that demand shifting on the spot market can create operational challenges, such as increased load peaks and increased load variability. The study demonstrates the importance of a holistic approach to the analysis of future power systems, where operational aspects are evaluated together with economic aspects.

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Paper II

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ORIGINAL RESEARCH ARTICLE

Designing a joint market for procurement of transmission and distribution system services from demand flexibility

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Abstract

Demand flexibility and other distributed energy resources (DER) have potential to provide ancillary services (AS) to the power system on both transmission and distribution level. AS markets for transmission system operation have existed for many years. The development of Smart Grid has led to an idea of introducing similar markets for distribution system services. Since DER represent a common pool of resources located in the distribution grid which can be used for either transmission or distribution system AS, a more holistic approach to the power system operation with a greater coordination between the transmission and the distribution level is being encouraged by energy regulators today.

In this paper, we propose a market framework for joint procurement of transmission and distribution system services from demand flexibility. To better illustrate the idea, we use the Danish market for tertiary control reserves as an example of a market that can be linked to a potential distribution system market for congestion management services. We discuss the details of the market design and formulate the joint market clearing procedure where demand flexibility offers are allocated to either transmission system service or distribution system service. A numerical example illustrates the economic benefit of the joint market clearing, and we further discuss some other advantages of the proposed design.

Introduction

Demand flexibility, as well as storage facilities and small-scale generation located in the distribution grid, are often referred to as distributed energy resources (DER). DER is an important source of flexibility for the power system that is becoming more important with increasing shares of renewable energy generation. Utilization of DER for various power system services has been widely discussed in literature. Reports by Smart Grid Task Force [1] and Universal Smart Energy Foundation [2] give a good overview of different services that can be provided by DER, see Table 1.

Demand flexibility from large industrial consumers have been utilized for power system services for many years. Today, due to advances in informational technology (IT), medium and small commercial and residential consumers aggregated by demand flexibility operators can deliver such services as well. Potential benefits from utilization of demand flexibility for transmission and distribution system AS include avoidance or deferral of infrastructure investment costs, reduced grid losses, optimized asset use, reduced frequency and duration of outages, improved quality and security of supply, reduced need for peak generation capacity [1,2].

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Transmission system services

Historically, TSOs procured ancillary services (AS) mainly from generation resources and energy intensive industry. In recent years, there has been an increasing focus on possibilities of AS provision from DER. A number of TSO/ISOs have already opened up AS markets for aggregated demand-side resources, e.g. American PJM [3] and French RTE [4]. Aggregated demand flexibility resources can in many cases be easily integrated into the existing AS procurement arrangements, e.g. TSO can facilitate the access of demand flexibility by reducing the minimum bid size [4].

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Nomenclature

I	set of nodes $i \in I$
J	set of sub-nodes $j \in J$
A	set of DER operators $a \in A$
G	set of generation units $g \in G$
B	set of price-volume blocks in the offer curve $b \in B$
D_j^{DSO}	demand for distribution system AS at sub-node j, MW
D^{TSO}	demand for transmission system AS, MW
$F_{j,a}^{\max}$	maximum volume of load reduction available from DER operator a, MW
$R_g^{\max}$	maximum positive tertiary control reserve available from generation unit g, MW
$p_{j,a,b}$	price of the bth block of the offer curve from DER operator, EUR
$V_{j,a,b}$	volume of the bth block of the offer curve from DER operator, MW
$p_{g,b}$	price of the bth block of the offer curve from generation unit, EUR
$V_{g,b}$	volume of the bth block of the offer curve from generation unit, MW
$F_{j,a}^{DSO}$	load reduction accepted by DSO for congestion management, MW
$F_{j,a}^{TSO}$	load reduction accepted by TSO for tertiary control, MW
R_g^{TSO}	positive reserve from generation units accepted by TSO for tertiary control, MW
λ_j^{DSO}	clearing price for DSO at each subnode, EUR
λ^{TSO}	clearing price for TSO, EUR
C^{DSO}	total procurement cost for DSO, EUR
C^{TSO}	total procurement cost for TSO, EUR
$\alpha_{j,a}^{flex\text{-}DSO}$	binary variable equal to 1 if the offer from DER operator is chosen by DSO, being 0 otherwise
$\alpha_{j,a}^{flex\text{-}TSO}$	binary variable equal to 1 if the offer from DER operator is chosen by TSO, being 0 otherwise
$\alpha_g^{gen\text{-}TSO}$	binary variable equal to 1 if the offer from generation unit is chosen by TSO, being 0 otherwise
$\beta_{j,a,b}^{flex\text{-}DSO}$	binary variable equal to 1 if the bth offer block from DER operator is the last accepted by DSO, being 0 otherwise
$\beta_{j,a,b}^{flex\text{-}TSO}$	binary variable equal to 1 if the bth offer block from DER operator is the last accepted by TSO, being 0 otherwise
$\beta_{g,b}^{gen\text{-}TSO}$	binary variable equal to 1 if the bth offer block from generation unit is the last accepted by TSO, being 0 otherwise
$\Lambda\left(F_{j,a}^{DSO}\right)$	price-volume function of DER operator accepted by DSO
$\Lambda\left(F_{j,a}^{TSO}\right)$	price-volume function of DER operator accepted by TSO
$\Lambda\left(R_g^{TSO}\right)$	price-volume function of generation units accepted by TSO

Alternatively, new types of AS and new procurement arrangements can be created by TSO to draw benefits from flexible demand, e.g. TSO can implement congestion management by demand response, as proposed in [5].

TABLE 1

Overview of services for TSO and DSO that can be delivered by DER, based on [1,2].

Transmission system operators (TSO)	Distribution system operators (DSO)
Frequency control (primary, secondary, tertiary)	Long-term and short-term congestion management
Transmission grid congestion management	Voltage control
System balancing	Power quality support
Grid losses	Grid losses
Controlled islanding	Controlled islanding
Redundancy ($n-1$) support[a]	Redundancy ($n-1$) support

[a] Redundancy ($n-1$) support refers to actions that help reduce the frequency and duration of outages. An example is load shedding in the event of a severe power shortage [2].

Distribution system services

A more active role of DSOs will become crucial in the future, as the power system experiences new challenges due to an increasing share of DER. The concept of ''active'' distribution system management and procurement of flexibility-based services from decentralized demand and generation is thoroughly discussed in the position paper of the European Distribution System Operators [6]. In the report by Eurelectric [7] the technical aspects of the ''active'' distribution system management and the principles of coordination between the TSO and DSO are presented.

Different forms of market solutions for distribution system AS have been suggested in literature. In [8] a spot market for voltage control is proposed where DSO can procure reactive power from microgrids. In [9,10] different types of auctions for long-term capacity contracts with DER are proposed, that can be used to handle distribution line overloads. In [11,12] a marketplace is designed where DSO can procure various flexibility-based services for managing congestions caused by overload and voltage oscillations.

TSO and DSO coordination

The Council of European Energy Regulators [13] points out that the relationship between DSO and TSO is a ''*key area for change in many European countries*'', and identifies the following principles for the new type of relationship:

- a whole system approach, in order to avoid inefficiencies;
- greater coordination between DSO and TSO with respect to procurement of system services and network planning;
- data exchange and cyber-security;
- use of flexibility;
- fairer cost sharing.

Scope and structure of this work

In the light of the described developments and the changing approach to power system operation, we would like to suggest and discuss a possible novel market framework for procurement of system services from flexible demand. In this work, we propose a design of a joint market for transmission and distribution system AS, where the chosen AS are simultaneously procured by TSO and DSO from the same pool of demand flexibility using a joint market clearing procedure. In order to better illustrate the proposal, the existing Danish market for tertiary control reserves is taken as an example of a market that can be linked to a potential DSO market for congestion management services.

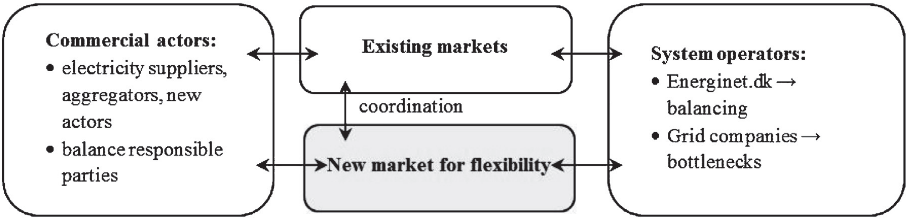

FIGURE 1
New market for flexibility in the current market framework. Adapted from [15].

Denmark is a very representative case in this respect. Compared to other European countries, it has quite an urgent need to transform its electricity markets due to increasing shares of wind power production [4,14]. Therefore, a lot of research and development in Denmark is focused on flexibility-based services and the use of DER to optimize the power system operation. E.g. procurement of tertiary control reserves from flexible demand is thoroughly studied in [14]; a market for procurement of congestion management services from flexible demand is proposed in [12]. The idea of a common market framework for flexibility procurement by TSO and DSO has already been identified in the Danish Smart Grid strategy [15], see Figure 1.

Danish electricity and AS trade is organized as an exchange type of market (Nord Pool Spot) preceded and followed by a number of sequential markets for transmission system AS[1] managed by the Danish TSO Energinet.dk [16,14]. The idea of a common market implies that one of these sequential AS markets (market for tertiary regulation reserves) is extended to incorporate offers from demand flexibility, and cleared jointly by TSO and DSO, since DSO would also like to reserve a share of demand flexibility for its own purposes (congestion management).

The structure of this work is as follows. Firstly, the tertiary regulation service, the congestion management service and the procurement arrangements of TSO and DSO are described. Than, the details of the proposed market design and the mathematical formulation of the joint market clearing are presented. The "Numerical example" section provides an illustration of the joint market clearing. The last section discusses various aspects of the proposed design and concludes the work.

Transmission system market for tertiary control reserves

The Danish power market is an example of an exchange type of market with sequential procurement of AS. Electricity trade takes place on the Nord Pool Spot, while a number of separate AS-markets ensure the provision of necessary reserves, being cleared by TSO either before or after the Nord Pool Spot [14,16].

Tertiary frequency control reserve is deployed within a timeframe of 15 min after a frequency deviation event, in order to replace previously activated primary and secondary regulation and restore the generation/consumption balance. Danish TSO Energinet.dk uses the term *manual reserve* to underline that this reserve is manually activated from the Control Center [17].

Tertiary control reserve is the most accessible AS market for demand flexibility in Denmark today due to the way the market rules are formulated [4]. The overview of the market rules can be found in [17]. The minimum bid volume is currently 10 MW, and positive and negative regulation is procured separately. It is allowed to make a bid by aggregating a portfolio of consumption units as long as the aggregated portfolio response satisfies the requirements. However, aggregated bids from both demand and generation units are not allowed.

It is possible to further adapt the market rules to make the Danish tertiary regulation market even more accessible for medium-size and small-size flexible electricity consumers [4]. E.g. the minimum bid volume can be further reduced, as it has already been done in Norway where the TSO can accept down to 5 MW bids for the tertiary control reserve [18].

Distribution system market for congestion management services

Congestion management refers to avoiding the thermal overload of system components by reducing peak loads. This service has a short-term character, compared to e.g. grid capacity management which has a long-term perspective. Normally DSOs would use grid reinforcements, such as laying cables and building transformers, to handle the problem of overloads. Utilization of flexible demand may be a feasible alternative to defer or even avoid these investments [2].

It is widely discussed today that peak load reduction can be achieved by time-variable or dynamic tariffs. However, as pointed out in [19], it may be extremely complicated to define a tariff structure to achieve the desired result, and the effectiveness of the tariff cannot be guaranteed since the customers are not obliged to respond on the tariff. A market-based approach to peak load reduction for DSO has been proposed in [12] and detailed market specifications have been further developed in [20]. The following

[1] Similar market organization can be found in Scandinavian countries, most European and Baltic countries. In the US, on the contrary, a pool type of market with simultaneous procurement of several AS is more common [22]. The proposed design can still be applied to the latter type of market by being integrated into the unit commitment problem.

products for peak load reduction are suggested in these publications:

- *Power Cut Planned* for handling the predictable daily peak loads – e.g. load reductions are scheduled day-ahead;
- *Power Cut Urgent* for handling unexpected peak load events – e.g. load responds on real-time control signals with a response time of 15 min and duration of activation of 2 h.

A dual market setup with a reservation market and an activation market is further suggested, equivalent to the one that exists for tertiary regulation reserves. The timing of the reservation market clearing must fit into the DSOs planning cycle since the alternative to flexibility purchase is reinforcing the grid components. The activation market is an additional market that allows new demand flexibility operators bid the same service at a lower price closer to real-time, but without promising the certainty needed by the DSO [20].

Design of a joint AS market

We have previously described individual market frameworks for the procurement of tertiary control reserve by TSO and the procurement of congestion management by DSO. In this paper, we suggest a novel market approach where TSO and DSO procure the needed volumes simultaneously, using the common list of offers from demand flexibility operators. For the TSO it is relevant to evaluate these offers together with the offers from generation providing the same service, therefore generation is included into the market clearing procedure.

Market structure and timing

The proposed market structure is shown in Figure 2. It is based on the dual market setup which is recommended for AS markets [21]. First, a reservation market takes place, where the accepted providers receive an availability payment and are obliged to bid into the activation market. Than an activation market takes place, where reserved providers and new providers send their bids and receive an utilization payment in case of activation.

Flexibility reservation market (FRM)

FRM can have a timing from year-ahead to day-ahead, depending on the needs of TSO and DSO. Long-term reservation markets give more certainty with respect to long-term operational planning, while short-term reservation markets create a more competitive market environment, enable new providers enter the market closer to real-time and allow an easier adjustment to the updated information [20]. It may be an advantage to arrange several rounds of FRM – a longer-term FRM supplemented by one or several shorter-term FRMs (such market organization exists e.g. in Norway where tertiary regulation market has several rounds: the first one just before the coming winter season, e.g. in October, and a new one every week during the winter season [18]). TSO and DSO must agree on the timing of the market rounds so that they suit them both.

Flexibility activation market (FAM)

The activation of AS in real-time can be arranged either by directly contacting the AS providers, or by selecting bids on a real-time activation market (FAM) according to a merit order principle. Basically, the activation of AS can be arranged differently by TSO and DSO, e.g.:

- Bids from demand flexibility reserved for tertiary regulation can be included into the common merit-order list together with bids from generation and activated in real-time;
- Bids from demand flexibility reserved for congestion management can be activated directly by DSO.

Definition of demand

In the proposed market model, the demand for the service is defined per grid level, i.e. TSO determines demand for the transmission grid level, and DSO determines demand for the distribution grid level.

Figure 3 illustrates the usual setup of an electric grid. Medium-voltage (MV) and low-voltage (LV) lines are connected to high-voltage (HV) lines via transformer sub-stations *i*. Several feeders

	Flexibility operators	**TSO**	**DSO**
Procurement of reserves	Submit bids to **reservation market** (volume/reservation price)	Defines demand	Defines demand
		Joint bid ranking based on reservation price. Joint market clearing. Feedback to participants.	
Day-ahead planning of the system operation	**Day-ahead Wholesale Power Market clearing**		
	Submit bids to **activation market** (volume/hour/ activation price)	Ranks bids from demand flexibility and generation based on activation price.	Ranks bids from demand flexibility based on activation price.
System operation in real time	Receive activation signal from TSO or DSO	Activation of bids on the merit order.	Activation of bids on the merit order
		Possibility to exchange demand flexibility reserves	
Ex post settlement		Payment based on reservation price λ^{TSO} and clearing price on the activation market.	Payment based on reservation price λ^{DSO} and clearing price on the activation market.

FIGURE 2

Design of a joint market for transmission and distribution AS.

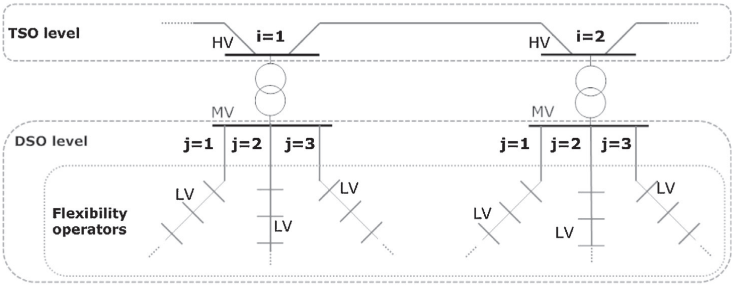

FIGURE 3
Physical system representation in the proposed market design.

j may be connected to the MV bus of a sub-station i. Further, several MV/LV transformers can be placed along each feeder j. Flexible consumers are connected to either MV or LV lines.

Demand for distribution system AS is defined per subnode j (D_j^{DSO}). If due to faults or maintenance on radials the grid location of flexibility may change with respect to the location of the AS demand, it may be preferable for DSO to know a more exact position of the demand flexibility in the grid, i.e. with respect to LV subnodes. The same is true if the service is needed on a specific LV feeder.

Demand for transmission system is defined for the whole area (D^{TSO}). In special cases, TSO's demand can be defined per node i or a group of nodes.

Definition of supply

Offers from demand flexibility are defined by demand flexibility operators (or DER-operators if the portfolio includes other DER such as storage or distributed generation). Volumes and prices are aggregated and used for defining a single bid for each subnode j. Each bid includes the maximum volume of load reduction ($F_{j,a}^{\max}$) and may consist of several price-volume blocks b, as illustrated in Figure 4, reflecting that some types of resources incur higher costs than others.

Transmission system AS can be supplied by both flexible demand and generation. Offers from generation are formulated similarly to the offers from demand (Figure 4): they include the maximum volume ($R_G^{\max}$) and may consist of several price-volume blocks b, reflecting that different generation technologies have different reservation costs.

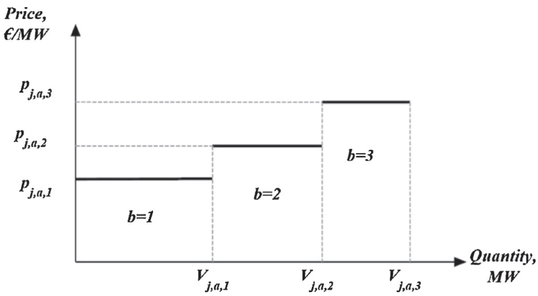

FIGURE 4
Stepwise linear offer price function from a demand flexibility operator.

Market clearing formulation

Uniform pricing mechanism is suggested as a settlement rule, in line with general recommendations for AS markets [22] and the practices of Energinet.dk [17]. The clearing price for the DSO is defined per subnode (λ_j^{DSO}) while the clearing price for the TSO is defined for the whole system (λ^{TSO}).

The market clearing procedure is based on the consumer payment minimization, i.e. the objective function is the minimization of the total AS payment of TSO and DSO:

$$\min f = C^{DSO} + C^{TSO} = D^{TSO} * \lambda^{TSO} + \sum_{j \in J} D_j^{DSO} * \lambda_j^{DSO} \tag{1}$$

s.t.

$$D_j^{DSO} = \sum_{a \in A} F_{j,a}^{DSO} \tag{2}$$

$$D^{TSO} = \sum_{j \in J} \sum_{a \in A} F_{j,a}^{TSO} + \sum_{g \in G} R_g^{TSO} \tag{3}$$

$$F_{j,a}^{DSO} \leq F_{j,a}^{\max} * \alpha_{j,a}^{flex\text{-}DSO} \tag{4}$$

$$F_{j,a}^{TSO} \leq F_{j,a}^{\max} * \alpha_{j,a}^{flex\text{-}TSO} \tag{5}$$

$$R_g^{TSO} \leq R_g^{\max} * \alpha_{j,a}^{gen\text{-}TSO} \tag{6}$$

$$\alpha_{j,a}^{flex\text{-}TSO} \leq 1 - \alpha_{j,a}^{flex\text{-}DSO} \tag{7}$$

Eq. (2) ensures that demand for distribution system AS on each feeder j is covered by load reductions offered by DER operators on this feeder. Eq. (3) ensures that demand for transmission system AS is covered by load reductions offered by DER operators and reserves offered by generation. Eqs. (4)–(6) limit the maximum available AS volumes from DER operators and generation, and Eq. (7) prevents the allocation of demand flexibility to transmission system AS and distribution system AS at the same time.

According to the uniform pricing mechanism, the clearing prices λ_j^{DSO} and λ^{TSO} for transmission and distribution system AS are the prices of the last accepted bid, either from a DER operator or from generation:

$$\lambda_j^{DSO} = \max\left\{ \Lambda\left(F_{j,a}^{DSO}\right) \middle| F_{j,a}^{DSO} > 0 \right\} \tag{8a}$$

$$\lambda^{TSO} = \max\left\{ \Lambda\left(F_{j,a}^{TSO}\right) \middle| F_{j,a}^{TSO} > 0 \text{ or } \Lambda\left(R_g^{TSO}\right) \middle| R_g^{TSO} > 0 \right\} \tag{8b}$$

Eqs. (8a) and (8b) make the problem a Non-Linear Mixed Integer Problem. In order to avoid non-linearity we apply a technique described in [23] which transforms the problem into a MILP problem by replacing (8a) and (8b) by a set of constraints with binary variables $\beta_{j,a,b}^{flex\text{-}DSO}$, $\beta_{j,a,b}^{flex\text{-}TSO}$ and $\beta_{g,b}^{gen\text{-}TSO}$.

For the DSO we get the following set of constraints:

$$\sum_{b \in B} \beta_{j,a,b}^{flex\text{-}DSO} = \alpha_{j,a}^{flex\text{-}DSO} \tag{9}$$

$$0 \le F_{j,a}^{DSO} \le V_{j,a,b} * \beta_{j,a,b}^{flex\text{-}DSO} + F_{j,a}^{\max} * \left(1 - \beta_{j,a,b}^{flex\text{-}DSO}\right) \tag{10}$$

$$F_{j,a}^{DSO} \ge \beta_{j,a,b}^{flex\text{-}DSO} * V_{j,a,b-1} \quad \forall\, b > 1 \tag{11}$$

$$\lambda_j^{DSO} \ge p_{j,a,b} * \beta_{j,a,b}^{flex\text{-}DSO} \tag{12}$$

The corresponding set of constraints for the TSO is:

$$\sum_{b \in B} \beta_{j,a,b}^{flex\text{-}TSO} = \alpha_{j,a}^{flex\text{-}TSO} \tag{13}$$

$$\sum_{b \in B} \beta_{g}^{gen\text{-}TSO} = \alpha_{g}^{gen\text{-}TSO} \tag{14}$$

$$0 \le F_{j,a}^{TSO} \le V_{j,a,b} * \beta_{j,a,b}^{flex\text{-}TSO} + F_{j,a}^{\max} * \left(1 - \beta_{j,a,b}^{flex\text{-}DSO}\right) \tag{15}$$

$$0 \le R_g^{TSO} \le V_{g,b} * \beta_{g,b}^{gen\text{-}TSO} + R_g^{\max} * \left(1 - \beta_{g,b}^{gen\text{-}TSO}\right) \tag{16}$$

$$F_{j,a}^{TSO} \ge \beta_{j,a,b}^{flex\text{-}TSO} * V_{j,a,b-1} \quad \forall\, b > 1 \tag{17}$$

$$R_g^{TSO} \ge \beta_{g,b}^{gen\text{-}TSO} * V_{g,b-1} \quad \forall\, b > 1 \tag{18}$$

$$\lambda^{TSO} \ge p_{j,a,b} * \beta_{j,a,b}^{flex\text{-}TSO} \tag{19}$$

$$\lambda^{TSO} \ge p_{g,b} * \beta_{g,b}^{gen\text{-}DSO} \tag{20}$$

The result of this market clearing procedure is the allocation of demand flexibility offers to either the transmission system service or the distribution system service, where demand flexibility offers allocated to the transmission system service are evaluated together with the generation offers. The offers assigned to the transmission system service will only be activated on request from TSO, whereas the offers assigned to the distribution system AS will only be activated on request from DSO.

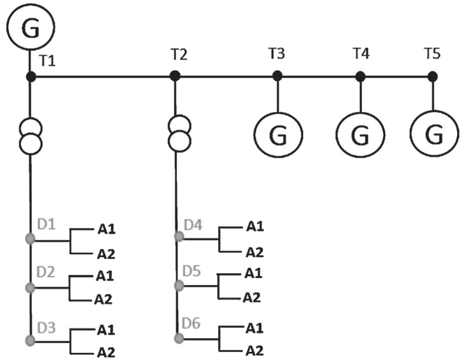

FIGURE 5

Test system used for the illustration of the joint market clearing.

Numerical example

This section demonstrates the outcome of the joint market clearing procedure using a simplified representation of an electric grid, data from tertiary regulation market from Energinet.dk [17] and assumptions about demand flexibility from [24].

Test system and input data

The test system is illustrated in Figure 5. It consists of 5 transmission nodes (T1–T5) and we assume that there are no transmission constraints between these nodes. Nodes T1 and T2 are represented down to low-voltage level because there are DER operators on these nodes that offer AS. On other nodes, there are only generation units that offer AS.

All test system data is presented in Appendix A. There are two DER operators (A1 and A2) that manage load reductions on the distribution feeders D1–D6. Load reduction offers on each feeder range between 5 and 8 MW and the reservation cost ranges between 5 and 150 EUR/MW.[2] The total potential load reduction in the test system is 69 MW. Generation offers range between 5 and 10 MW with a reservation cost of 20–70 EUR/MW.[3]

We assume that the minimum bid volume that can be accepted by TSO is 5 MW. This is lower than the current rule of Energinet.dk, however it is possible that the minimum bid volume can be reduced in future as it has already been done in Norway where the TSO can accept 5 MW bids on the tertiary regulation market [18].

TSO's demand for positive tertiary control reserve in the test system is 30 MW. DSO's demand for load reduction reserves on different feeders is between 2 and 4 MW.

Market clearing results

Table 2 compares the results of the joint market clearing with results of two separate market clearings where DSO market clears first, and TSO market clears afterwards. The total procurement cost

[2] Numbers are based on demand flexibility cost estimates from [24].

[3] Numbers are based on typical tertiary control reserve prices from Energinet.dk [17].

TABLE 2

Comparison of procurement costs in the two alternative market designs.

	Sequential AS procurement		Simultaneous AS procurement	
	DSO	TSO	DSO	TSO
Procurement cost for the system operator, EUR	140	4500	155	3600
Total procurement cost, EUR	4640		3755	

is reduced in the joint market clearing, and a redistribution of cost burdens between the TSO and DSO takes place.

In sequential procurement the DSO chooses first, between the cheapest offers, and thus incurs a lower procurement cost than in simultaneous procurement. The TSO has to choose afterwards, between more expensive offers, and thus incurs a higher cost than in simultaneous procurement.

The clearing of sequential markets is illustrated in Figures 6 and 7, while the clearing of the simultaneous market is illustrated in Figure 8.

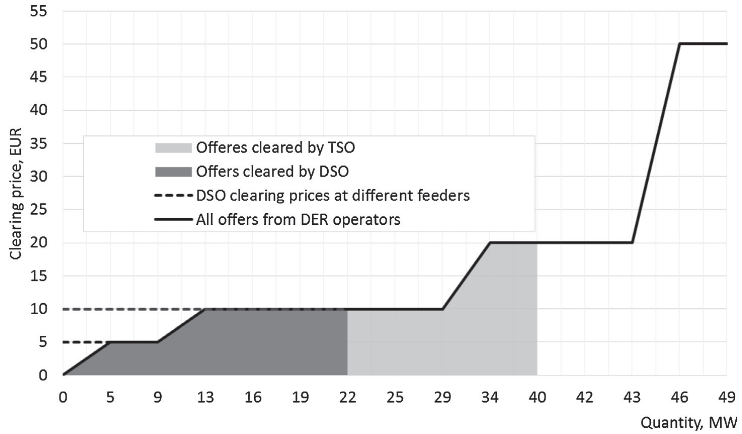

FIGURE 6

Illustration of separate market clearing: first DSO chooses the cheapest offers, than TSO chooses between more expensive offers.

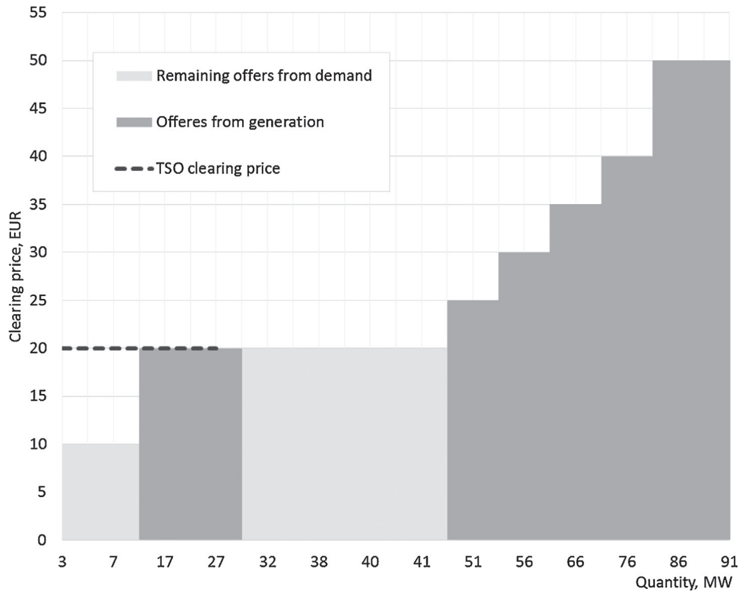

FIGURE 7

Illustration of the separate market clearing: offers from demand that were not accepted by DSO are included into the TSO's merit order list and cleared together with generation offers.

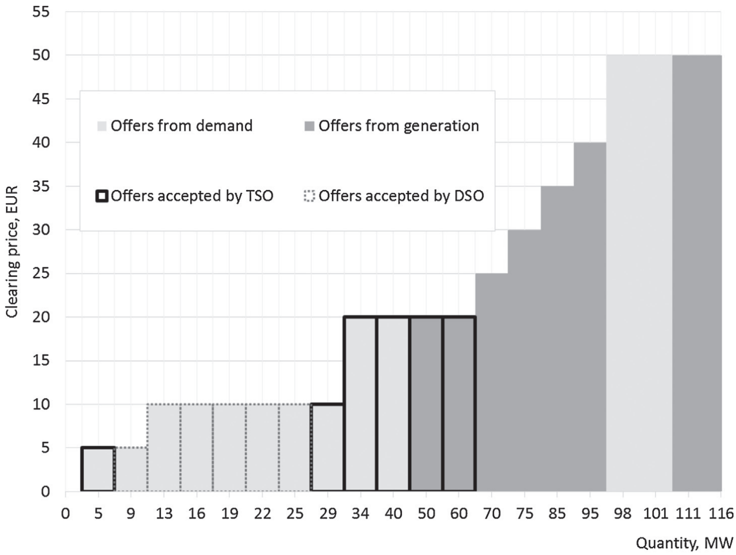

FIGURE 8

Illustration of joint market clearing: a number of cheap offers are allocated to TSO, reducing its total procurement cost. This solution is more optimal from the point of view of the total procurement cost for the system.

Discussion and conclusion

As illustrated in ''Numerical example'' section, simultaneous procurement of services from demand flexibility by transmission and distribution system operators reduces the total procurement cost, i.e. from the system perspective the joint market ensures the cheapest solution. In this respect, the proposed market design meets the requirements defined by CEER about the whole-system approach, greater coordination between the TSO and DSO and a fairer cost sharing (see ''TSO and DSO coordination'' section). The joint market reveals the value of demand flexibility to the power system as a whole, and not just to the transmission or the distribution level as in case with separate markets. It also saves on transaction costs for all participants.

Another important advantage is that the joint market framework prevents undesired price coupling that can occur in case of separate markets. In case of two separate AS markets where DER operators can participate, they will prefer the one where the prices are higher. The TSO market will normally have higher prices, because the bids from DER operators will be cleared together with the bids from generation, as illustrated in our numerical example (Figures 6 and 7). Therefore, DER operators will either refuse to participate in DSO market, or increase the offer prices according to their lost opportunity cost. This may reduce the liquidity of a separate DSO market or considerably increase the costs for DSO. On the joint market, on the contrary, the participants will not know beforehand how the offers will be allocated between TSO and DSO. They will only have one contact point for the bud submission and thus less possibilities for strategic behavior.

The proposed design can be applied to all kinds of DER resources (demand flexibility, distributed generation, EV-vehicles and other types of electricity storage) as long as they are managed and optimized by a DER operator (aggregator or Virtual Power Plant) and as long as the aggregated offer can be defined as described in ''Definition of supply'' section. It should be noted that this implies that TSO accepts such mixed aggregated bids. E.g. Energinet.dk does not currently allow aggregated delivery of tertiary control reserves from a mix of generation and demand.

The proposed market design can also be applied to other types of system services. Besides tertiary control reserves and congestion management services, TSO and DSO can jointly reserve demand flexibility for e.g. emergency reserves or local balancing services. Demand flexibility and other DER represent one common pool of resources in the distribution grid that can be used by either TSO or DSO. A coordinated approach to AS procurement from DER will therefore yield total system benefits compared to separate arrangements. Joint procurement may be more complex than separate procurement arrangements, creating new tasks for TSO and DSO and challenging the traditional operational practices. Still the growing complexity of the power system calls for more complex solutions and a more holistic approach to the power system operation. The advances within ICT and new technological developments can help to handle this complexity.

Appendix A. Test system data

Data for the offer price curves is presented in Tables 3 and 4. We assume that all offer price curves from all AS providers consist of two price-volume blocks. DSO's demand on different feeders is presented in Table 5.

TABLE 3

Assumptions about the offer price curves of DER operators.

Feeder j	DER operator a	Price-volume blocks, EUR – MW				Total bid volume, MW
		$p_{j,a,b=1}$	$V_{j,a,b=1}$	$p_{j,a,b=2}$	$V_{j,a,b=2}$	
D1	A1	5	5	10	2	7
D1	A2	10	3	20	2	5
D2	A1	20	5	150	2	7
D2	A2	10	4	50	2	6
D3	A1	50	3	100	2	5
D3	A2	10	3	50	2	5
D4	A1	5	4	10	1	5
D4	A2	10	4	20	1	5
D5	A1	20	6	150	2	8
D5	A2	10	3	50	2	5
D6	A1	50	3	100	3	6
D6	A2	10	3	50	2	5
Total maximum volume, MW						69

TABLE 4

Assumptions about the offer price curves of generation units.

Unit g	Price-volume blocks, EUR – MW				Total bid volume, MW
	$p_{g,b=1}$	$V_{g,b=1}$	$p_{g,b=2}$	$V_{g,b=2}$	
G1	25	10	35	10	20
G2	20	10	30	5	15
G3	40	10	50	10	20
G4	20	10	50	5	15
Total maximum volume, MW					70

TABLE 5

Distribution system's demand for load reductions.

Feeder j	D_j^{DSO}
D1	3 MW
D2	4 MW
D3	3 MW
D4	3 MW
D5	2 MW
D6	2 MW
Total	17 MW

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Paper III

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Modeling consumer flexibility of an aggregator participating in the wholesale power market and the regulation capacity market

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Abstract

This paper presents an optimization framework for a load aggregator participating in the wholesale power market and the regulation capacity market. The objective of the aggregator is to minimize the total energy costs of a portfolio of energy consumers. The market organization is based on the Nordic model. The optimization model includes a detailed representation of the physical system at each consumer. Flexibility may come from load reductions, substitutions between energy carriers and from use of energy storage. A case study is performed using actual data from a set of Norwegian electricity consumers to test the model and estimate the value of aggregation in the current market framework.

Peer-review under responsibility of the Scientific Committee of RERC 2014
Keywords: Ancillary services; Load management;Power Markets; Smart grid.

1. Introduction

Balancing and regulating power systems becomes increasingly challenging with increasing shares of variable renewable energy (VRE), and increased flexibility of energy consumption is one of the options for handling this

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challenge. Procurement of regulation power and other ancillary services from flexible electricity consumers has been explored in different power systems today, especially in the USA (e.g.[1] and [2]). Enhancement of demand flexibility and its utilization for power system regulation is also relevant for the Nordic countries, as described in [3] and [4]. An aggregator is an agent that takes the responsibility for planning and operation of several small and medium flexible consumption units within one distribution network [5]. Optimizing several load profiles with respect to several markets is not straightforward. Previous research has addressed some aspects of load aggregation and market participation of demand flexibility, such as optimal bidding of flexible consumers into the wholesale power market [6] and aggregator's participation in the wholesale power market [7] and [8]. In this paper we develop a detailed optimization model for a load aggregator with regard to simultaneous participation in the wholesale power market and the regulation capacity market. The market participation is modeled in the context of the Nordic power market using a deterministic approach. The model is applied to quantify and compare the value of load control and aggregation for a real portfolio of medium-size flexible electricity consumers in Norway.

Nomenclature

EES	Electric Energy Storage
$\chi^{EL}_{y,t}$	input of electricity from grid into system y at hour t
$O^{DIS}_{y,t}$	discharge of EES into system y at hour t
O^{CHAR}_{t}	charge of EES at hour t
η^{EL}_{y}	efficiency of electricity conversion in system y
$W_{y,l,t}$	load prognosis for load l in system y at hour t
$S^{SCH}_{y,a,t}$	scheduled substitution of energy from electricity by energy from carrier a
$S^{POT}_{y,a,t}$	potential substitution of energy from electricity by energy from carrier a
$\omega^{SCH}_{y,l,t}$	scheduled load reduction of load l in system y at hour t
$\omega^{POT}_{y,l,t}$	potential load reduction of load l in system y at hour t
$R^{SCH}_{y,l,t}$	reconnection top from a scheduled load reduction in system y at hour t.
V^{RP}_{t}	volume of up-regulating power available from the portfolio per hour
V^{RPO}	weekly capacity reserved for up-regulation
$\theta_{y,l}$	cost of load reduction
P^{CARR}_{a}	price of an input unit of energy for carrier a
P^{EL}_{t}	hourly electricity price
P^{RPO}	reserved capacity price
I^{RPO}	capacity market income
φ	significance of the undelivered reserve penalty on the weekly option market
Ψ_t	volume of unavailable up-regulation capacity

1.1. Nordic wholesale electricity market and regulation power market

The Nordic wholesale electricity market (Elspot) operates on a day-ahead basis with hourly resolution. The participants submit their bids for the following day before 12:00, and the cleared hourly prices and volumes are published around 12:30. The type of bid on Nordic wholesale electricity market that is most suited for bidding flexible electricity demand, is a price dependent single hourly order – an hourly bid that may consist of up to 62 price steps with corresponding volumes. Using this bid type the actors can hedge themselves from high power prices.

Regulation capacity market is used for procurement of the tertiary regulation service. Tertiary regulation can be provided by generation and consumption units that are able to respond to a system signal within 15 minutes and remain activated for at least 1 hour. Market participants receive a capacity payment for reservation of regulation capacity during a specified period (a day, a week or a season). Providers of accepted capacity bids are obliged to bid regulation power into the common Nordic Regulating Power Market during the whole specified period. The bid price on the Regulating Power Market (RPM) reflects the activation cost of the reserve, and all activated reserve providers receive the marginal price. If hourly regulation capacity is unavailable or below the level stated in the capacity bid, the provider receives a penalty for undelivered reserve, i.e. there is a capacity payment reduction. Specific rules for the capacity market vary between the Nordic countries. In our work we use the Norwegian approach where the option market clearing takes place weekly and the minimum bid volume on the regulating power market is 10 MW.

2. Methodology

2.1. Model description

The model is formulated as a deterministic mixed integer linear programming problem with an objective to minimize the total portfolio cost by optimally allocating consumer flexibility between the markets. The customers in the aggregator's portfolio are medium and large electricity consumers. The load aggregator is assumed to have a communication and control infrastructure to the customers, and manages the total power purchase on the day-ahead market as well as delivers tertiary up-regulation service via the RPM (Fig.1a). The model has an hourly time resolution.

We adopt an approach of physically based modeling of consumer flexibility from [9] and [10]. The energy system of each customer is represented by a set of subsystems (Fig. 1b). Each subsystem includes a set of loads and converters. A load is defined as demand for an energy service and a converter is an electric installation with a specified conversion efficiency that supplies the load. For example, a heating load may be supplied by two converters – an electric boiler and an oil boiler. This representation makes it possible to capture flexibility that comes from energy carrier substitution.

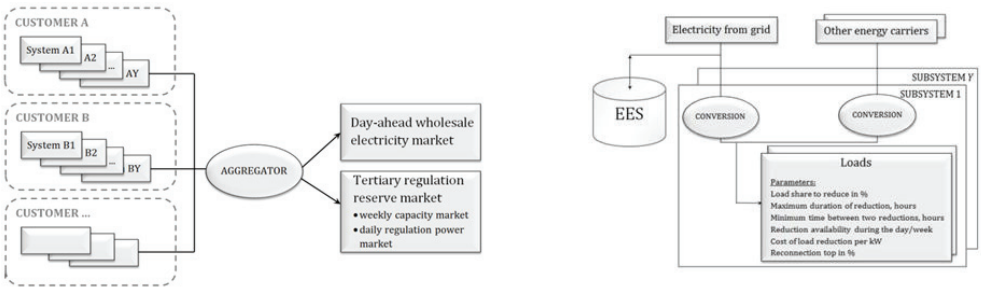

Fig.1. (a) conceptual framework for the optimization model; (b) generic representation of physical energy systems in the model.

As shown in Fig. 1, the aggregator can also operate an electric energy storage (EES) located in the same distribution grid as the portfolio customers. For this purpose one can use a stationary EES such as a lead acid battery pack, a lithium ion battery pack, or a non-stationary EES such as plug-in electric vehicles. We model a stationary EES applying the same modeling technique as described in [11].

The model ensures that in each subsystem *y* there must be a balance between the total input of energy carriers and the total load plus possible reconnection tops (1).

$$\left(\chi^{EL}_{y,t} + O^{DIS}_{y,t}\right)\cdot \eta^{EL}_{y} + \sum_{a\in A} S^{SCH}_{y,a,t} = \sum_{l\in L}(W_{y,l,t} - \omega^{SCH}_{y,l,t}) + \sum_{l\in L} R^{SCH}_{y,l,t} \quad (1)$$
$$\forall y \in Y, a \in A, l \in L, t \in T$$

2.2. Modelling flexibility allocation between the markets

Different options for flexibility allocation defined in the model are shown in Fig.2. Utilization of flexibility on the day-ahead wholesale market requires scheduling of load reductions and/or energy carrier substitutions, as well as scheduling of the use of storage. On the other hand, capacity reserved for the weekly regulating power market comes from potential load reductions and potential energy carrier substitutions that are still available after the scheduling has taken place. When an actor participates in both markets, the challenge is to determine an optimal scheduling plan for the whole week so that there is still capacity available for delivery of the regulation reserve.

Load reductions	scheduled →	Day-ahead wholesale electricity market
	potential →	Tertiary regulation reserve market
Energy carrier substitutions	scheduled →	Day-ahead wholesale electricity market
	potential →	Tertiary regulation reserve market
Electricity storage	→	Day-ahead wholesale electricity market

Fig.2 Matrix of flexibility utilization options defined in the model.

Scheduled and potential load reductions as well as a trade-off between them, are modeled using a modelling approach with binary variables described in [10]. The volume of up-regulating power available from the portfolio per hour is found in (2) as the sum of all potential load reductions and all potential energy carrier substitutions. Constraint (3) ensures that this volume does not exceed the total power input at hour t. The weekly capacity bid V^{RPO} may be set higher than the available up-regulating volume V_t^{RP}, but in this case the actor gets a penalty for the unavailable regulation capacity Ψ_t, as defined in (4).

$$V_t^{RP} = \sum_{y \in Y} \left(\sum_{l \in L} \omega_{y,l,t}^{POT} + \sum_{a \in A} S_{y,a,t}^{POT} \right) / \eta_y^{EL} \qquad \forall y \in Y, a \in A, l \in L, t \in T \tag{2}$$

$$\sum_{y \in Y} \chi_{y,t}^{EL} + O_t^{CHAR} \geq \sum_{y \in Y} V_{y,t}^{RP} \qquad \forall y \in Y, t \in T \tag{3}$$

$$\psi_t = \begin{cases} 0 & , V_t^{RP} \geq V^{RPO} \\ V^{RPO} - V_t^{RP} & , V_t^{RP} < V^{RPO} \end{cases} \qquad \forall t \in T \tag{4}$$

2.3. Objective function

The objective function (5) is minimizing the total portfolio cost which consists of the cost of power purchase on the wholesale power market, the cost of energy carriers used for scheduled substitutions and the cost of scheduled load reductions. The income from the capacity reservation (I^{RPO}) is subtracted from the cost function.

$$\min \sum_{t \in T} \left(\left(\sum_{y \in Y} \chi_{y,t}^{EL} + O_t^{CHAR} \right) * P_t^{EL} + \sum_{a \in A} \sum_{y \in Y} S_{y,a,t}^{SCH} / \eta_{y,a} * P_a^{CARR} + \sum_{l \in L} \sum_{y \in Y} \omega_{y,l,t}^{SCH} * \theta_{l,t} \right) - I^{RPO} \tag{5}$$

$$\forall a \in A, l \in L, t \in T$$

The income I^{RPO} is defined in (6). To avoid non-linearities in the model we used an exogenous parameter φ which controls the significance of the penalty for the undelivered volume Ψ_t. The default value of φ is 0.01 but different levels were tested in the case study.

$$I^{RPO} = V^{RPO} \cdot P^{RPO} - \sum_{t \in T} \psi_t \cdot P^{RPO} \cdot \varphi \qquad \forall y \in Y, a \in A, l \in L, t \in T \tag{6}$$

3. Case study

The customer portfolio in the case study is composed of 9 medium-size commercial electricity consumers including shopping centers, food production sites, district heating site and greenhouses. Flexibility comes from reducing heating loads, substitution between electricity and oil/gas in providing energy for heating loads, reducing air conditioning and reducing lightning. Hourly electricity consumption data is obtained from an existing commercial database of Enfo Consulting AS[1]. The cost of load reduction for medium commercial electricity consumers is set to 127 €/MWh based on [12] and [13]. Sensitivity analyses for cost levels 0 €/MWh and 64 €/MWh are performed. The cost of using a lead-acid based EES is calculated to be 157 €/MWh based on [11] and [14]. Prices for electricity, oil, gas and regulation capacity used are obtained from [15], [16], [17] and [18].

The model is applied to simulate flexibility utilization on the power markets for two selected time periods; weeks 2 – 6 in 2011 and 2012. These periods were chosen because of illustratively different price development: In 2011 the price level was high but within-day price variations were small; in 2012 the price level was lower but within-day price variations were larger. The capacity payments were significantly higher in 2012 and gradually increasing over the period from week 2 to 6. In 2011 the capacity payments remained at rather low levels for the entire period. The following simulation cases were defined:

- Base case – no aggregation
- Participation on the wholesale power market
- Participation on the wholesale power market and regulation capacity market

For each case, several subcases were tested to determine the value of using EES and the value of installing an automatic control - implying an extended availability of flexibility outside the ordinary working hours.

4. Simulation results and discussion

4.1. Flexibility allocation

Fig. 3a shows a typical daily pattern of the portfolio flexibility allocation for the weekdays in 2012 for the simulation case where the aggregator participates in both markets. The simulated total portfolio electricity consumption during the working hours is around 8-9.5 MWh/h and the flexibility share is around 5-6 MWh/h. Most of this flexibility comes from energy carrier substitutions, but there are also load reductions between hours 11 – 17. A small share of flexibility utilization is scheduled for usual peak price hours during the day (see Elspot prices in Fig. 3b). However the model chooses to reserve most of the flexibility for the up-regulation reserve. The corresponding weekly capacity bid is shown in Fig. 2b and is around 3.5 MW. This volume does not always correspond to the hourly regulation power available, so a penalty for the unavailable capacity is expected in hours 5 – 6 and 20 – 24.

4.2. Value of load control and aggregation

The total portfolio costs for all simulation cases for the five week periods are shown in Table 1. The average electricity price level was higher in 2011 and the total portfolio costs are hence generally higher that year.

[1]Enfo Consulting AS is a Norwegian company that develops Smart Grid solutions and i.a. delivers control systems for flexible electric loads.

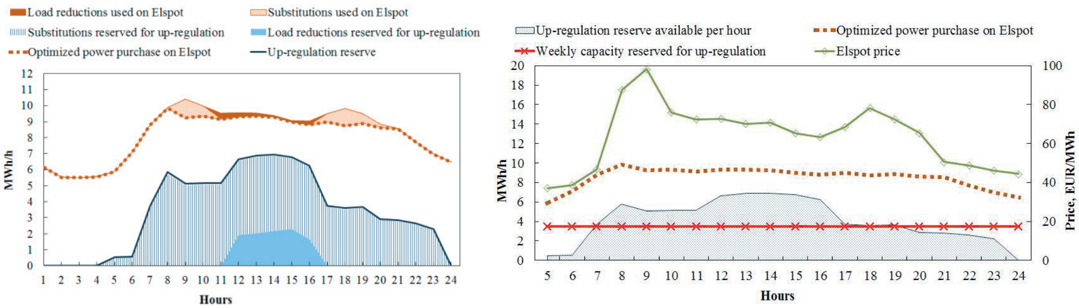

Fig.3. (a) modelled flexibility allocation, average for the weekdays in 2012, subcase with no EES, non-automatic control, load reduction cost 64 EUR/MWh; (b) optimal weekly capacity bid, average for the weekdays in 2012, subcase with no EES, non-automatic control, load reduction cost 64 EUR/MWh.

Table 1.Comparison of the total portfolio cost in different cases.

Case	Portfolio cost, 2011, 1000 EUR	Portfolio cost, 2012, 1000 EUR
1. Base case	410,91	317,00
2. Participation in the wholesale power market		
non-auto system, no EES	410,91	316,94
non-auto system, with EES	410,91	316,90
auto system, no EES	410,91	316,81
auto system, with EES	410,91	316,71
3. Participation in the wholesale power market and regulation capacity market		
non-auto system, no EES	410,53	314,18
non-auto system, with EES	410,53	314,18
auto system, no EES	409,19	303,77
auto system, with EES	409,19	303,74

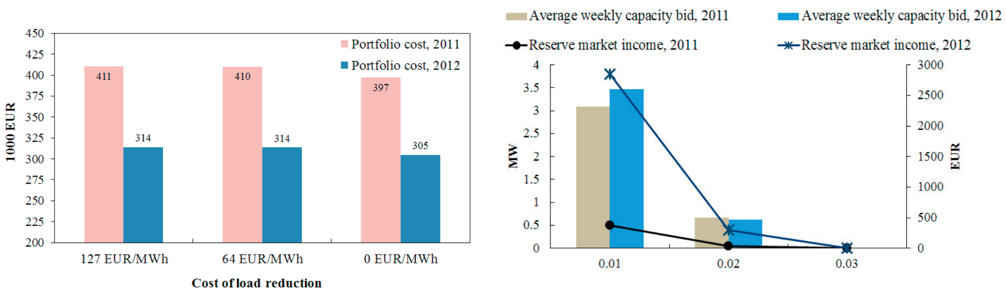

Fig.4. (a) sensitivity of the portfolio cost to the cost of load reduction; (b) sensitivity of capacity market income to the significance of penalty for unavailable regulation capacity

The value of flexibility scheduling for the wholesale power market alone is close to zero both years, unless an automatic control and an ESS are used. Still we see that larger within-day price variations in 2012 tend to increase the value of aggregator's participation in the wholesale power market. Due to increasing wind power investments and more transmission capacity to Continental Europe, the Norwegian within-day price variations are expected to increase in the future, and the value of demand flexibility use on the markets is hence also likely to increase.

Participation in the both markets during the 5-week period in 2011 gives the aggregator a small value of €1720 (0.4% portfolio cost reduction). However in 2012, participation in both markets gives a value of €13260 due to higher capacity payments (4% portfolio cost reduction). Fig. 4a shows the results of the sensitivity analysis for different reduction cost levels.

Analysis of the case study simulations shows that one of the reasons for a rather low profitability of the regulation capacity market today is definition of the market periods. Most small and medium commercial electricity consumers have flexibility available during normal working hours. Outside these hours they would incur significant penalties for non-complying with their obligations on the weekly capacity market. The significance of penalty for the unavailable regulation reserve turns out to be very high (Fig 4b), and seems to be crucial for the income of small and medium consumers as those included in this portfolio. The simulations showed that the use of automatic control and EES can increase the aggregator's value by up to 3%. Increasing availability of flexibility due to automatic control has a stronger effect in the model than utilization of the ESS. This is largely due to the high cost of the chosen lead-acid storage technology.

5. Conclusion

This paper presents a methodological framework for the optimal allocation of flexibility by an aggregator participating in the wholesale power market and the regulation capacity market. It includes a detailed representation of the physical system at each consumer which allows an accurate modelling of different flexibility sources.

The model is tested using actual data from a set of Norwegian electricity consumers to estimate the value of load aggregation and market participation, as well as the value of utilizing electric energy storage and automatic control. The simulations show that the aggregator's value largely depends on within-day price variations, flexibility availability and definition of market periods. The Norwegian power market has generally low short term price volatility, but still, in the simulations for a 5-week period in 2012 we find a portfolio cost reduction potential of 4%

In most cases a mix of load reductions in the wholesale spot market and the regulating reserve market is found to be optimal, illustrating the importance of considering both types of markets for a load aggregator. The aggregator's penalty for the unavailable regulation capacity is found to be critical to the potential for small and medium consumers attending the market. Furthermore, the optimal allocation between participation in wholesale electricity market and the tertiary regulating market depends to a large degree on the consumer's cost of load reduction. Electricity storage is generally found too costly to be activated given realistic storage cost levels. However due to technological progress, this may be a more economically interesting option in the future.

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Paper IV

Analysis of residential demand response potential in Norway using energy system modelling

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ABSTRACT

Demand flexibility of residential consumers is an important resource in the energy system. Demand response (DR) to electricity price can contribute to reduction of peak load and more accurate price setting in the electricity market. The potential for price-based DR can be estimated using different methods. In this paper we use long-term optimization modelling with endogenous investment in residential load control to study DR potential. Integrated investment and dispatch modelling of the Norwegian energy system towards 2040 is used. We model the development of the stock of residential demand technologies and investment in load control technology, taking account of the long-term development of the whole energy system and the impact of demand response on electricity price. We find that 7– 17% of residential heating appliances and 57–60% of residential car chargers in Norway can become flexible by 2040, resulting in 1940–3258 MW maximum load reduction for a winter evening in 2040. Reduction of investment cost for load control technology and increasing daily price variation towards 2040 are the main drivers of investment in residential demand response.

Keywords: demand flexibility; energy system modelling; electricity markets; demand response; investments

1 INTRODUCTION

Residential demand flexibility is an important resource in the energy system that can contribute to more efficient system operation, integration of larger shares of variable renewable energy (VRE) and a more efficient use of energy system infrastructure. Residential demand response (DR) on electricity price can help to reduce peak load, defer investment in new transmission capacity and avoid starting peaking thermal generation units. Exposing electricity consumers to correct price signals from the market results in a more accurate price setting, as electricity demand becomes more elastic and is able to better follow the supply.

Demand flexibility in the residential sector is gradually becoming more available as households invest in smart appliances and home automation systems. Ongoing electrification introduces new flexible loads in the residential sector, such as electric vehicles and heat pumps. Many countries have already

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implemented hourly measurement and settlement of residential consumers, paving the way for residential DR.

Residential demand flexibility is different from commercial and industrial demand flexibility in that it consists of a large number of small flexible units. Direct control and optimization of these units by a third party can be complex and expensive. Therefore, price-based DR programs are often considered to be a more suitable alternative for residential demand flexibility. Price-based DR implies that electricity consumers are exposed to time-varying electricity prices or grid tariffs [1] and it does not require aggregation.

Assessment of residential DR potential on a national level is important and can be done in different ways. One way is to assess the potential in a static context, using information about present-day electricity consumption in different sectors, and then evaluate the feasibility of DR based on historic electricity prices. However, using long-term energy system modelling to assess DR potential adds a valuable time dimension to such analysis, capturing the dynamics of the residential sector and the cost development for different technologies. An important advantage of optimization models is that electricity price is determined endogenously, which is necessary to correctly evaluate the economic potential of DR. Load shifting reduces the electricity price variability, and DR becomes gradually less profitable as more and more actors enter the market. In this study we use integrated capacity and dispatch optimization modelling to analyze residential DR potential.

This study is based on the case of Norway. Demand flexibility in Norway has been the subject of little analysis [2] even though its potential is significant due to large shares of electricity-based heating and increasing penetration of electric transport. The limited interest in the topic shown until now is partly due to the fact that there is little incentive to use demand flexibility in Norway because of large hydropower resources that are flexible and cheap to regulate [3]. However, the interest in demand flexibility is increasing, and in recent years Norway has taken several steps to better integrate demand flexibility [4]. All Norwegian households are already equipped with smart metering systems [5] and can enter spot price contracts based on hourly settlement. Mobile applications that show hourly consumption and electricity price are available on the market. The most innovative actors in the electricity sector already offer automatic optimization of consumption according to hourly price [6]. Norway is considered to be one of the most suitable markets in the world for home automation and associated services, and the share of households with smart appliances is rapidly increasing [7]. Therefore, price-based residential DR is a very relevant topic, and Norway is a good modelling case because technology cost data is available.

In this study we implement endogenous investment in residential DR in a model of the Norwegian energy system. The objective of the study is to estimate theoretical and economic residential DR potential in Norway towards 2040 considering decreasing costs of load control and increasing electricity price variation. We use TIMES modelling platform which is a good tool for integrated capacity and dispatch optimization. TIMES is technology-rich and makes it possible to disaggregate the demand sector. We implement possibility to invest in DR for residential room heating, water heating and electric car charging. In addition to the main model runs with endogenous electricity prices, we perform model runs with exogenous electricity prices to evaluate the impact of the price flattening effect on DR investments. The methodological findings of this study related to modelling DR investments in an optimization model are relevant for any country and energy system.

The rest of the paper is organized as follows: Section 2 presents a literature review on different methods of analysing price-based DR. Section 3 provides more details about the residential DR in

Norway and an overview of previous studies that evaluate DR potential. Section 4 describes how DR is implemented in the Norwegian TIMES model. Section 5 presents the results of the model runs. Section 6 discusses the results while Section 7 offers concluding remarks.

2 METHODS OF ANALYSING PRICE-BASED DR

There exists a large body of literature that addresses price-based DR potential in different demand sectors. Various publications study the subject from either the private economic or the whole system perspective. The private economic perspective typically analyses the potential for price-based DR using detailed representations of end-user systems and historic price levels, like e.g. [8] and [9]. Conclusions about DR's economic potential are based on the present-day market situation and do not include long-term assessments. Gottwalt et al. [10] simulate the changes in the load profile of residential consumers when they are exposed to time-varying electricity prices. They use historic prices from European Energy Exchange (EEX) as input and find that household savings from smart appliances are moderate compared to the investment required. The study does not consider future possible developments in electricity price variation and reduction in investment costs. Feuerriegel and Neumann [11] use historic EEX data to compare the private economic benefit of load shifting as response to price, as balancing power and as reserve power. They conclude that load shifting as response to price implies the highest benefits, although they point out that the price picture may change in future.

Another large strand of literature addresses the system perspective and the interplay between price-based DR, generation capacities and network expansion. Within this strand there are studies that also use historic electricity prices as input. For example, Finn et al. [12] use historical data on the Irish power market to demonstrate how price-based demand response can support the integration of wind power. However, approaches based on economic equilibrium modelling with endogenous electricity prices are to be preferred because they capture the dynamic market impacts of demand response [13].

Economic equilibrium modelling of price-based DR can be based on econometric models or system optimization models. Econometric models are normally used in DR studies to compare different DR pricing schemes [14]. Such models, including those used in [15], [16] and [17], use demand elasticity to model demand response to electricity price. Elasticity is the crucial input in the model. It can be obtained from pilot projects, like in the study of residential demand response in the U.S. by Faruqui and Sergici [18]. However, the use of elasticity raises questions, like whether demand elasticity can correctly represent automatic demand response [16], whether elasticity measured in one country can be applied to another country and whether it is correct to use the same elasticity in long-run simulations.

System optimization models are more detailed and computationally challenging than econometric models, but they are a good method of assessing DR potential [40]. The advantage of using optimization modelling for analysing price-based DR is that it gives a long-term perspective, considers the development of the whole system and captures the price flattening effect due to DR in the market. The technical potential of demand response can be more directly assessed by looking at the usage of different appliances, as opposed to assessing the more abstract concept of price elasticity [13].

Price-based DR in energy or power system models can be implemented as storage-like technologies, like in [19], [20] and [21]. Many power and energy system models are highly detailed on the supply side and much less detailed on the demand side [22]. Therefore, they may use exogenous assumptions about demand response potential and aggregated representation of demand flexibility. For example, Kirkerud et al. [20] implement price-based DR in the energy system model for North-European and Baltic countries (Balmorel) using exogenous adoption curves for load control technology towards 2050. Johansson and Göransson [23] integrate demand flexibility and other flexible technologies suitable for variability management into a regional investment model to study the investment in VRE technologies. Demand flexibility is defined using exogenous assumptions about the maximum delayed and maximum served demand, in relation to the original total demand profile. Aggregated representation and exogenous assumptions about DR are sufficient when the focus of the study is on how DR impacts the other parts of the system.

There are fewer publications that model investment in demand flexibility endogenously and have disaggregated representation of demand. Cepeda and Saguan [24] model investment in DR and in generation technologies to study the impacts of regulatory design in a power system with demand response in the long-term. Ambrosius et al. [25] use a long-run optimization model to evaluate demand response investments in the German industrial sector. Fehrenbach et al. [26] analyse the economic potential for thermal load management within the residential sector based on endogenous investments in capacities of micro-CHP, heat pumps, thermal and electricity storage technology. They use TIMES energy system modelling. Paulus and Borggrefe [21] model investments in industrial demand response in the German electricity market using an integrated dispatch and investment model, DIME. The focus of the study is the long-term impacts of industrial price-based DR on dispatch and investments in generation technologies.

To sum up, the literature review shows that the primary aim of using optimization modelling in DR studies has been to analyse how DR impacts the other parts of the energy system. Only a couple of publications, [25] and [26], actually focus on investment incentives for DR itself and use modelling to evaluate DR potential. This study attempts to contribute to the knowledge base on using energy system modelling to study DR investments and potential in the long-term.

3 RESIDENTIAL DEMAND RESPONSE IN NORWAY

Residential demand response in Norway is largely based on electric heating and a growing share of electric vehicles. Electricity consumption for room heating and water heating in the residential sector in 2018 was 30 TWh, which constitutes around 22% of the total electricity consumption in Norway [27], [28]. In 2018 electricity consumption from electric vehicles was 0.4 TWh, and due to favorable policy, it is expected that the number of electric vehicles may reach 1.5 million by 2030 [29], resulting in 4 TWh of additional electricity use.

A number of previous studies have attempted to quantify DR potential in Norway. In a 2006 report, Meland et al. [30] studied the substitution between electricity-based and wood stove heating systems and concluded that the flexibility potential from substitution is 2–3 TWh per year. In a 2009 study, Stokke et al. [31] found that households respond to a demand charge tariff with an average of 5% load reduction. Applied to the whole residential sector this gives flexibility potential of 1.5 TWh per year. In two studies of Norwegian households, Ericson [32] and Sæle et al. [33] found that on a national level a load reduction of 600 MW and 1,000 MW, respectively, can be achieved by disconnecting electric water heaters. Bröckl et al. [34] roughly estimate 1,700–3,500 MW flexibility potential in Norwegian households based on the assumption that each household can switch 1–2 kW from peak to off-peak hours. Theoretical DR potential in Norway is evaluated in Gils [35]. The author uses data on load profiles, consumption and installed capacities of various appliances to determine DR potential and estimates a potential for shifting 5,937 MW of load from storage heater and 284 MW of load from storage water to an earlier time point. In addition, the study reports a potential of shifting between 135 and 811 MW of load from other appliances such as dishwashers and washing machines. In the most recent report by the Norwegian TSO [36], it is estimated that household appliances in Norway presently contribute around 10,500 MW to the Norwegian top load of 25,000 MW. The authors roughly estimate that around 25%, or 2,750 MW, of this residential load may be flexible.

Previous studies of DR potential in Norway have typically provided a snapshot of the present-day situation and made rough assumptions regarding economic potential. There are no studies that use long-term capacity and dispatch optimization modelling to analyse DR potential in Norway on the national level.

4 METHODOLOGY AND DATA

4.1 TIMES ENERGY SYSTEM MODEL

TIMES is a model generator developed within the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency [37]. It is a powerful tool for integrated capacity and dispatch optimization that allows the user to define the energy system with any level of detail and spatial and geographical resolution desired for a specific research question or project.

In this study we use a TIMES model for the Norwegian energy system (TIMES Norway), which includes all demand sectors (residential, commercial, industrial and transport), all types of energy services (heating, hot water and electricity specific), power systems and district heating systems in Norway. TIMES Norway is technology-rich and highly disaggregated on the demand side. The initial version of TIMES Norway was developed by the Norwegian Institute of Energy Technology and the Norwegian Water Resources and Energy Directorate and is thoroughly documented in [38]. In this study a modified version is used where residential sector is restructured (see Figure 1) and the time resolution is changed to 13 representative periods with 24 hours in each period.

TIMES Norway is soft linked to a building stock model for Norway [39] and a European power system model [40]. The building stock model produces energy services demand for TIMES Norway based on rehabilitation and building rates and assumptions about energy efficiency. The European power system model produces electricity prices in neighbouring countries for TIMES Norway based on modelling power generation and exchange.

The objective function of TIMES Norway is minimizing the cost of supplying the energy demand. Eq.1 shows a generalized formulation of the objective function [41, p. 58]. For each region, TIMES computes a total net present value of the stream of annual costs for all types of technologies, discounted to a user-selected reference year. These regional costs are then aggregated into a single total cost, which constitutes the objective function to be minimized by the model [37, p. 144]:

$$\boldsymbol{NPV} = \sum_{r\in R}\left[\sum_{y\in Y}\boldsymbol{DISC}(\boldsymbol{y}) * \begin{pmatrix} \sum_{p\in PROD}\boldsymbol{INV}(\boldsymbol{y},\boldsymbol{p}) + \boldsymbol{FIXOM}(\boldsymbol{y},\boldsymbol{p}) + \boldsymbol{VAROM}(\boldsymbol{y},\boldsymbol{p}) \\ \sum_{t\in TRANS}\boldsymbol{INV}(\boldsymbol{y},\boldsymbol{t}) + \boldsymbol{FIXOM}(\boldsymbol{y},\boldsymbol{t}) + \boldsymbol{VAROM}(\boldsymbol{y},\boldsymbol{t}) \\ \sum_{d\in DEM}\boldsymbol{INV}(\boldsymbol{y},\boldsymbol{d}) + \boldsymbol{FIXOM}(\boldsymbol{y},\boldsymbol{d}) + \boldsymbol{VAROM}(\boldsymbol{y},\boldsymbol{d}) \\ \sum_{dr\in DR}\boldsymbol{INV}(\boldsymbol{y},\boldsymbol{dr}) + \boldsymbol{FIXOM}(\boldsymbol{y},\boldsymbol{dr}) + \boldsymbol{VAROM}(\boldsymbol{y},\boldsymbol{dr}) \end{pmatrix} - \boldsymbol{SALVAGE}\right] \tag{1}$$

The minimization problem is subject to a large number of constraints that describe the physical characteristics of the energy system. One of the most important constraints is the commodity balance equation which requires that the disposition of all commodities in each time period and each region balance its procurement [41, p. 68]. The commodity balance equation for electricity in the TIMES model with demand response is described below, see Eq. 2.

4.1 Assessing different types of DR potential in TIMES

A comprehensive overview of different categories of DR potential is provided in [42] and includes theoretical, technical, economic and achievable potential. The installed capacity of flexible appliances is the baseline for identifying these potentials. *Theoretical potential* is determined by the electricity consumption of appliances suitable for DR and their load profiles. *Technical potential* is the amount of the load that is available for load shifting considering technical constraints. *Economic potential* describes the cost-efficient way of managing load. And finally, *achievable potential* is a subset of economic potential which takes into account the level of customer acceptance, as well as attitudinal, societal and market barriers.

In an integrated capacity and dispatch energy system model like TIMES, theoretical DR potential is determined as the model optimizes investments into all demand technologies. For instance, the replacement of fossil fuel cars with electric cars and of fossil boilers with direct electric heating or heat pumps will affect the theoretical potential for DR from the residential sector in the long term. Technical potential is limited by the technical restrictions on the load control technology, such as hours when load shifting is possible and maximum demand response from appliances.[1] Finally, economic potential is determined as the model optimizes investments in load control and performs the actual demand response on the market, taking account of DR profitability. Due to increased shares of VRE in Norway and Europe, the electricity price becomes more variable in the long term, affecting the profitability of DR. In the short term, the price flattening effect of DR actions limits profitability. Achievable potential related to customer acceptance could be modelled in TIMES by placing more restrictions on investments or using technology-specific discount rates to limit their attractiveness. We do not study achievable potential in this paper.

4.2 Modelling residential demand flexibility

In TIMES Norway we model demand flexibility related to residential electric boilers, heat pumps, electric space heaters, electric water heaters and home charging of electric vehicles in Norway. Figure 1 shows the structure of the residential sector. Residential buildings in each spot price area are characterized by four types of energy services – electricity-specific demand, heating demand, hot water demand and demand for residential electric car charging. The first three types of demand are given exogenously (from the building stock model, see Section 4.1), while the last one, demand for electric car charging, is determined endogenously based on the transport demand and the competition between electric and fossil fuel cars. Heating, electricity and hot water demand each have their own hourly profile extracted from data for Norwegian households. Residential car charging profile is based on a measured profile from [29].

Heating demand can be met by various technologies (water-based heating system with electric or non-electric supply; local heating system based on electric or non-electric technologies) and the optimal technology mix is determined by the model, taking account of the initial stock, a set of constraints on technology combinations and replacement rate.

[1] In the model used in this study, the electricity consumption of a given type of appliance is aggregated by consumer type and geographical region; therefore, maximum response for appliance type is defined per consumer type and region.

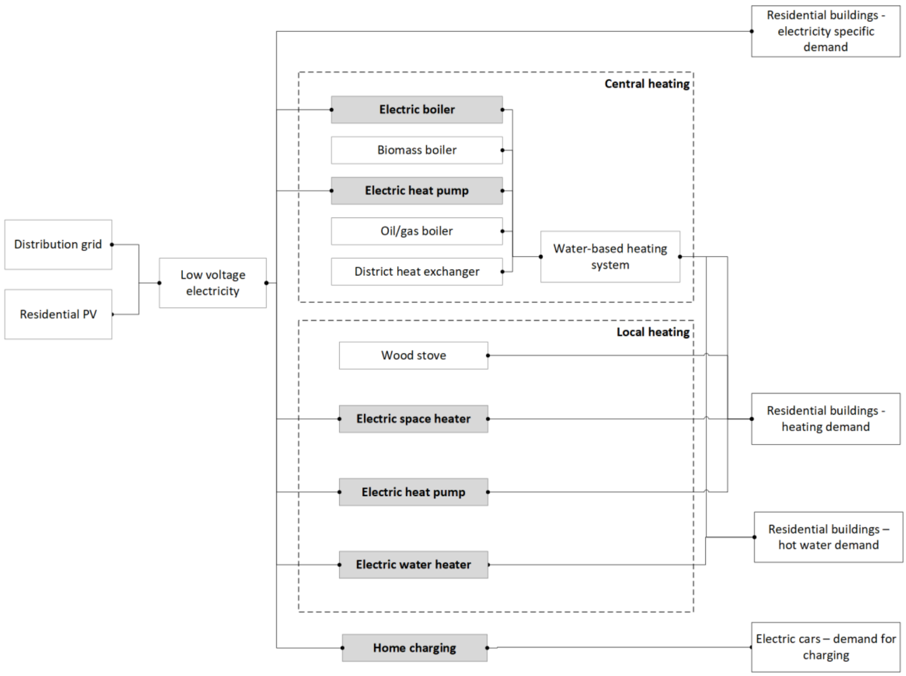

Figure 1. The structure of the residential sector in the TIMES model for Norway. Technologies marked with dark grey color are those that have demand flexibility potential.

We model demand response as a storage process. This storage process makes it possible to shift the electricity consumption of the corresponding demand technology in time while the amount of the delivered energy service remains the same. 'Storage charging' represents increased electricity consumption, 'storage discharging' represents decreased electricity consumption. Eq.2 shows the commodity balance equation for electricity flow from the grid/solar panels (PV) to residential demand technologies with a storage technology for demand shifting. In each time slice and spot price region, the total electricity outflow from the grid and from PV must be equal to the electricity inflow into demand technologies plus an eventual inflow into a demand response technology ('storage charging') minus an eventual outflow from a demand response technology ('storage discharging'):

$$\sum_{d \in DEM} (FLOW\_OUT_{elGRID,d,r,ts} + FLOW\_OUT_{elPV,d,r,ts}) \\ = \sum_{d \in DEM} (FLOW\_IN_{elGRID,d,r,ts} + FLOW\_IN_{elPV,d,r,ts}) \\ + \sum_{dr \in DR} FLOW\_IN_{elINC,dr,r,ts} - \sum_{dr \in DR} FLOW\_OUT_{elRED,dr,r,ts} \tag{2}$$

The model can choose whether to invest into the storage process representing demand shifting or not, depending on how feasible it is. The most important factors for investment in demand response are the expected electricity price variation and the cost of the load control technology.

Demand response of all technologies is restricted by time windows shown in Table 1 which reflect that their electricity consumption cannot be freely shifted during the day. For heating technologies, load shifting windows are limited to a few hours around the morning and the evening peaks. For residential car charging, load shifting windows are limited to the evening, night and early morning hours, when the cars are normally on charge.

Table 1. Time windows for load shifting of residential technologies

	Time windows when load shifting is possible
Heating technologies	Hours 5–10 Hours 16–21
Residential car charging	Hours 17–07

There is also a restriction in the model which says that for each technology type the maximum load reduction in a given spot price area in a given hour cannot exceed 80% of the total load in this area. This is because, for various reasons, it is unlikely that all consumers in a spot price area will respond to price.

4.3 ELECTRICITY PRICE

In TIMES, the electricity price is a result of the market equilibrium between production and consumption of electricity [41, p. 31]. For investments in demand flexibility, the most important factor is the daily variation in electricity price. Figure 2 shows the daily price variation in TIMES Norway without DR. Daily price variation increases significantly by 2040, especially in summer. The reasons for this are the increasing exchange between Norway and neighbouring countries where the share of variable renewable generation (VRE) is growing, and the increasing share of wind and solar power in the Norwegian power system.

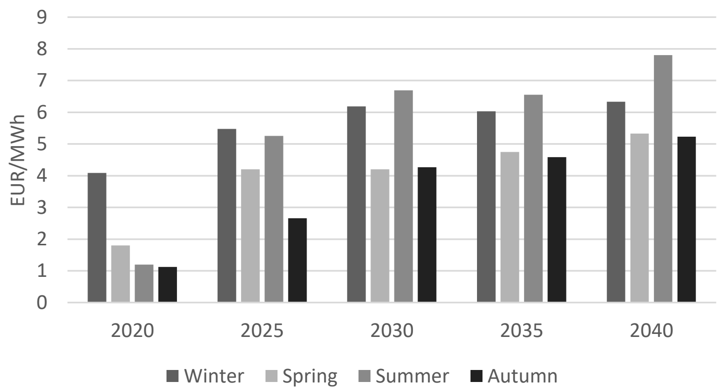

*Figure 2. Average daily price variation in TIMES Norway (2*standard deviation from daily average) in different years and seasons. BASELINE model run without demand response.*

As different technologies have different shifting time windows (Table 1), the electricity price variation within these time windows will determine the feasibility of load shifting. Figure 3 illustrates the difference between the highest and lowest price within each time window and indicates the expected size of the income potential from demand shifting. We expect that car charging will profit more from load shifting than heating technologies because it has a longer shifting time window with larger differences between the highest and the lowest price. Heating technologies are limited by shorter time windows. They are also limited by the duration of the heating season so that they cannot profit from the increasing electricity price variation in summer the same way as electric car charging.

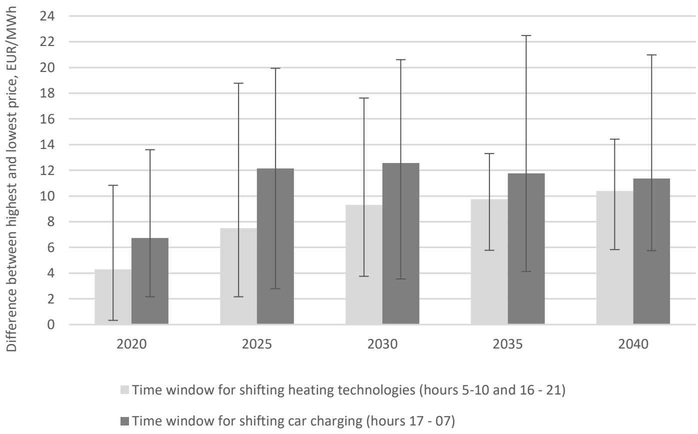

Figure 3. Typical difference between the highest and the lowest electricity price within different time windows in TIMES Norway (BASELINE model run without demand response). Indicates income potential from load shifting within these time windows. Columns show the average for all regions and seasons, error bars show the spread between seasons. Shifting time windows are taken from Table 1.

It is important to note that TIMES only captures a share of the real price variation in the electricity market. TIMES modelling is based on a normal year and average normalized profiles of electricity production technologies, which is a legitimate assumption for a long-run investment model. The model does not capture the most extreme high and low prices that occur in several hours of the year. Extreme price situations could be better captured in TIMES by disaggregating the time resolution or running the model in a stochastic mode, which, given the model size, would greatly increase the computational time. Mathematically, extreme price situations would still have to occur with a particular frequency to make a greater investment in DR feasible with respect to a higher investment cost. It is unclear whether making the model more complicated would significantly improve the results. Therefore, demand flexibility modelling in this study is based on expected normal price variation, and there is a chance that it underestimates the amount of investment based on more extreme prices.

4.1 COSTS OF DEMAND RESPONSE

The cost of demand response includes investment cost and variable cost. Investment cost is the cost of purchasing and installing an external load control technology or an extra cost of purchasing a smart appliance instead of a usual appliance. Variable cost can represent willingness to shift load, lost comfort or a minimum expected income from a load shift. From the modelling perspective, this cost determines how often demand response is activated and how much is shifted. With a large variable cost, the model only shifts load in a few extreme situations in winter. With a small variable cost, the model shifts load as often as possible during the whole year. Variable cost is also related to the level of demand response automation. With a fully automatic load control, the variable cost may be zero and the load is optimized automatically in response to any price difference on the market.

Table 2 summarizes our assumptions about the costs of different load control technologies based on a study by [43] and an extensive Internet search about existing load control solutions and smart appliances in Norway. Automatic DR implies a smarter load control functionality than manual DR, for instance a home management system or automatic price-based optimization. For electric water heaters, electric boilers and heat pumps, the investment cost is higher because it also includes the cost of professional installation.

Table 2. Assumptions about the costs of residential demand response technology based on research about actual prices for load control equipment on the Norwegian market. We assume that in new buildings all of these are 20% lower.

	Manual DR		***Automatic DR***	
	Investment cost, EUR/kW	*Variable cost, EUR/kWh*	*Investment cost, EUR/kW*	*Variable cost, EUR/kWh*
electric car charging*	0	0.014	67	0
direct electric heating	36	0.014	192	0
heat pumps (air-air)	36	0.014	192	0
electric water heaters	128	0.014	246	0
electric boilers (water-based heating)	135	0.014	259	0
heat pumps (water-based heating)	135	0.014	259	0

* The cost for electric car charging only includes the extra cost of having a smart charger instead of a 'usual' charger. The cost of the charger itself is included in the cost of buying an electric car and is considered by the model when it optimizes investments in electric cars vs. fossil fuel cars.

The investment cost development for load control technologies in the future is uncertain. We assume that cost reduction will be in the same range as for electric car batteries which are supposed to become 60% cheaper by 2030 [29]. We perform a sensitivity analysis on the investment cost development where we test cost reductions between 35 and 85% by 2030. After 2030 we assume no further technological improvement, and the investment costs remain at the 2030 level. Table 3 summarizes all model runs performed in this study. In addition to the main model runs with endogenous electricity prices, we perform a similar set of runs with exogenous electricity prices to evaluate the impact of the price flattening effect on the DR investments. The exogenous electricity prices are obtained from the BASELINE scenario and are then used to replace electricity production sector and electricity trade in the model, while all other model assumptions are kept the same.

Table 3. Overview of modelled scenarios.

	Model runs with endogenous electricity prices	**Model runs with exogenous electricity prices**
No demand response	BASELINE	
With demand response	35% investment cost reduction	35% investment cost reduction
	45% investment cost reduction	45% investment cost reduction
	55% investment cost reduction	55% investment cost reduction
	65 % investment cost reduction	65 % investment cost reduction
	75% investment cost reduction	75% investment cost reduction
	85% investment cost reduction	85% investment cost reduction

5 RESULTS

5.1 THEORETICAL DR POTENTIAL

Figure 4 shows the electricity consumption of residential technologies with DR potential in Norway towards 2050 in a BASELINE scenario. Electricity consumption from heating technologies decreases while electricity consumption from residential car charging increases. This result is in line with the Norwegian Water Resources and Energy Directorate [44], which predicts that electricity use for heating in buildings will decrease as a result of reduced heating demand for new buildings, better isolation, energy efficiency and warmer climate.

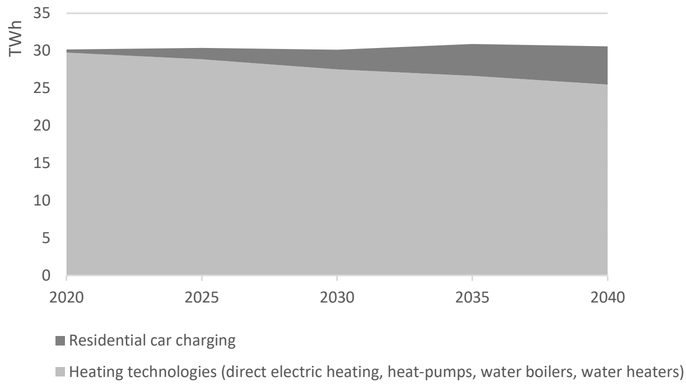

Figure 4. Modelled consumption of electricity by technologies with demand response potential in Norway towards 2040 in BASELINE scenario.

Figure 5 shows the modelled electricity consumption of residential heating technologies and car charging in Norway in a morning peak hour and an evening peak hour for a normal winter day. These technologies account for 27–30% of the peak load in Norway. It should be noted that the load from residential car charging shown in Figure 5 is not the maximum load for car charging because most charging actually takes place in the later evening hours.

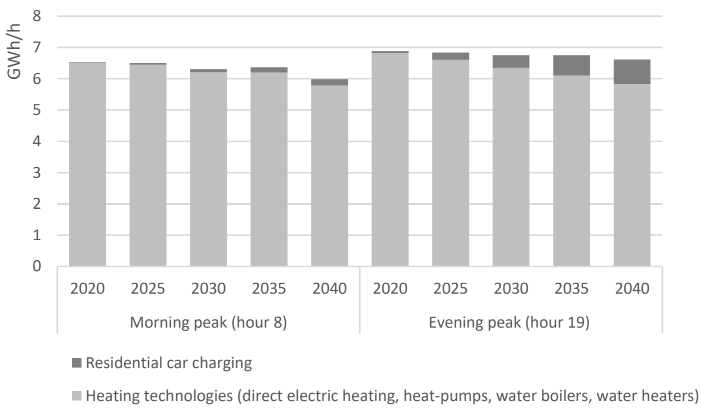

Figure 5. Modelled load of heating technologies and electric car charging in the morning peak hour and the evening peak hour for a winter day, in BASELINE scenario.

5.2 ECONOMIC DR POTENTIAL

5.2.1 Installed capacity of flexible technologies

According to the model simulations in TIMES, 37–69% of the theoretical potential of DR is realized by 2040 given our assumptions about the cost development (Figure 6). Most investments take place after 2030 because the investment cost decreases and the daily price variation increases. In the first modelling years in scenarios with high cost reduction (65–85%) less investment is made than in scenarios with small cost reduction (35–55%). This can be explained by the perfect foresight of the model [41, p. 8] as it postpones investments until their cost is significantly lower.

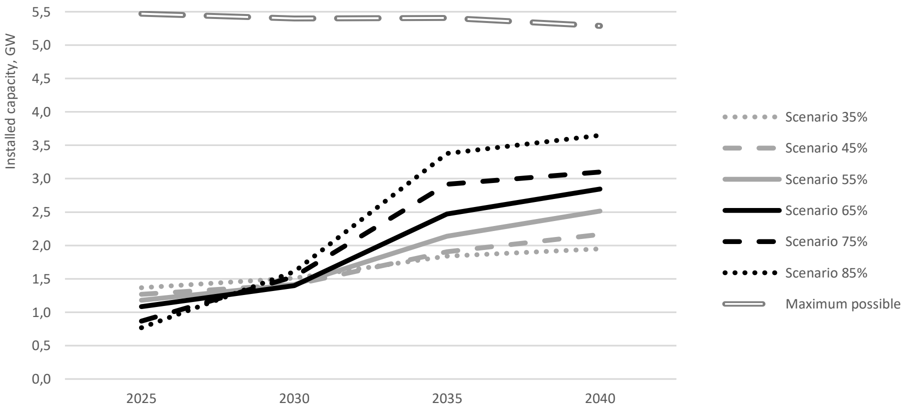

Figure 6. Installed capacity of appliances with load control in different scenarios for investment cost reductions (35–85% by 2030). The maximum possible level is determined by 80% of the evening top load shown in Figure 5, in line with model assumptions in Section 4.2.

The largest load reduction in different scenarios is shown in Table 4. It is slightly lower than the installed capacities shown in Figure 6 because different loads produce their maximum response in different hours: for example, car charging has maximum load reduction at night, while for heating appliances, it is in the morning or in the evening.

Table 4. Largest load reduction in different scenarios, normally occurring in winter evening peak hours.

	2030	**2035**	**2040**
	MW	**MW**	**MW**
Scenario 35%	1415	1770	1940
Scenario 45%	1379	1895	2128
Scenario 55%	1398	2093	2482
Scenario 65%	1374	2406	2745
Scenario 75%	1503	2854	2911
Scenario 85%	1546	3223	3258

Figure 7 illustrates that DR takes place throughout the whole year. Investment decisions for load control are based on the total annual profit that can be obtained from load shifting. The installed capacity of appliances with load control corresponds to the largest load reduction they perform during a year. For heating technologies, we see a large unused potential in winter. The reason for this is that to perform larger load reductions in winter, the model would have to invest more in load control, which is apparently infeasible considering the total annual income from DR.

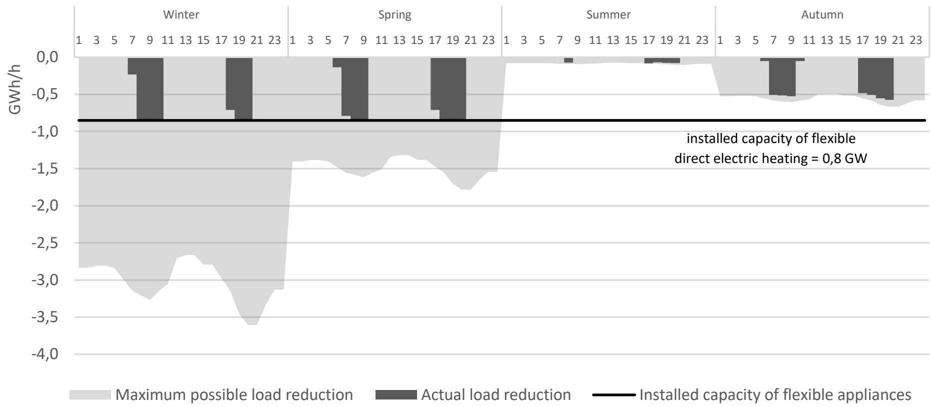

Figure 7. Example of DR from direct electric heating in different seasons in 2030, 55% scenario. Maximum possible load reduction corresponds to 80% of the total load, in line with model assumptions in Section 4.2. The figure only shows load reductions, not increases, to illustrate how the installed capacity is dimensioned.

5.2.2 Comparison of heating technologies and car charging

Figure 8 shows that in terms of GW, residential heating technologies contribute more to the total flexibility potential than car charging because they consume significantly more electricity. But in terms of share of stock, shown in Figure 9, flexible residential car chargers constitute around 60% of all car chargers in 2040, while flexible heating appliances actually constitute only 12% of all heating appliances. Moreover, error bars in Figure 8 illustrate that investments in flexible car charging are less sensitive to cost assumptions in different scenarios, meaning that the model 'prefers' DR from electric cars and invests in electric car charging flexibility in all scenarios. This result is consistent with our hypothesis in Section 4.3 that DR from electric car charging is more profitable than DR from heating technologies because car charging can benefit from larger price differences and shift load during the whole year. Flexibility from car charging also has lower costs per kW of load reduction (Table 2).

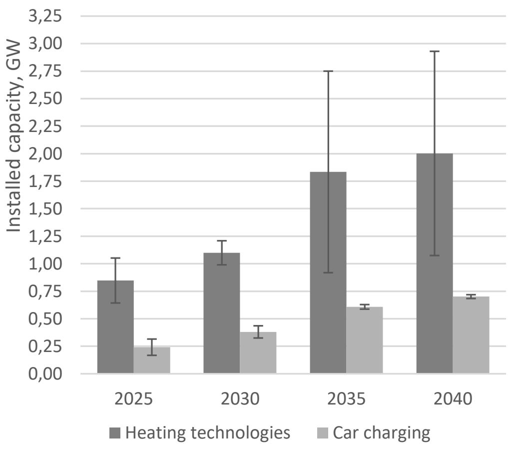

Figure 8. Installed capacity of appliances with load control by type. Average of all scenarios, error bars show the spread between scenarios.

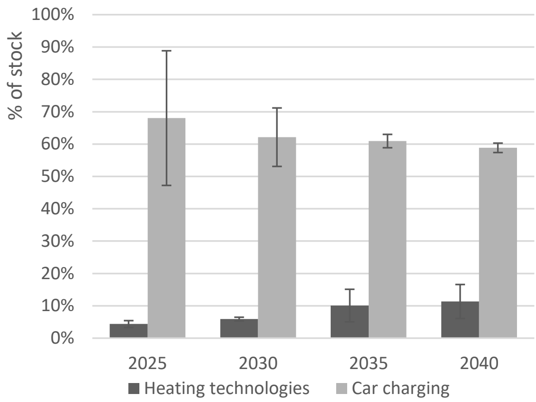

Figure 9. Appliances with load control as percentage of the total appliance stock. Average of all scenarios, error bars show the spread between scenarios. Note that stock of electric car charging is significantly lower in 2025 than in 2040.

5.2.3 Comparison of automatic and manual DR

According to the model results, investments are primarily directed to automatic load control. Flexible appliances with manual load control account for well below 10% of all flexible appliances (Figure 10). The main reason for this is that even though automatic systems are initially more expensive, they are also much more profitable because load can be shifted in response to any price difference, while manual DR is only performed a few times a year. Investments in manual load control are primarily made in the early years of the modelled period, and the model does not reinvest in these technologies at the end of their lifetime. In the 35% scenario, the share of manual load control is higher because no major cost reductions in automatic load control are expected.

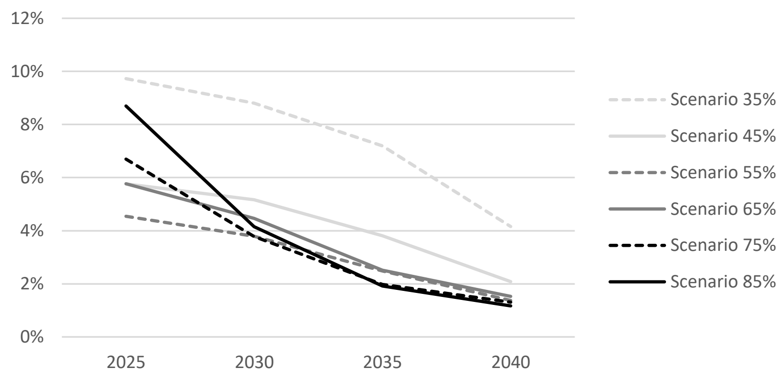

Figure 10. Share of flexible appliances with manual load control among all appliances with load control.

5.2.4 Impact of load shifting on electricity price

When load is shifted, the price profile becomes flatter (Figure 11). The price increases during the night-time hours due to shifting of car charging, and in the hours close to the morning peak and the evening peak due to pre-heating. The price decreases in the hours 7–11 and 18–20 because the load is shifted away from these hours. The reduction of price differences between hours makes it unprofitable to shift more load and acts as a natural restriction on economic DR potential when the model achieves a new equilibrium.

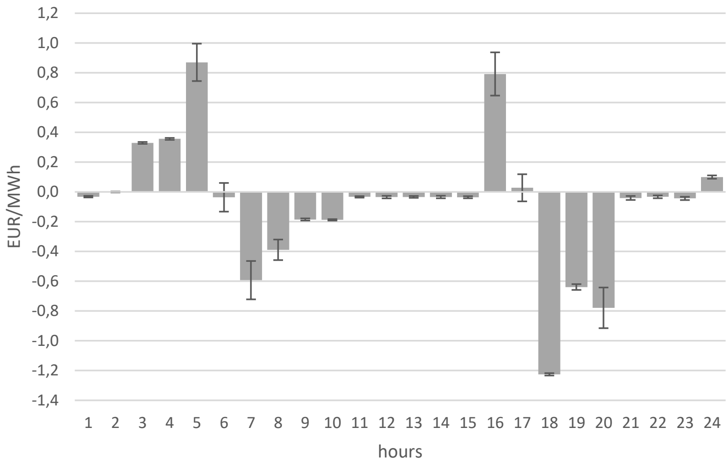

Figure 11. Price change each hour due to DR in 2030. Average of all scenarios and all periods. Error bars show the spread between scenarios.

In Figure 11 no price change is observed in hours 6 and 17, though there is typically a load increase due to pre-heating during these hours. The reason for this is that the sensitivity of electricity price to DR in TIMES can vary depending on the shape of the electricity supply curve for each hour. This is illustrated in Figure 12. The electricity supply curve in the model is less granulated than the actual supply curve on the electricity market, and there are large plateaus when the electricity price does not change even if demand changes. These large plateaus in the electricity supply curve are formed because the power plants in the model are aggregated into groups with the same marginal cost, and because electricity prices in neighbouring countries are given exogenously with fixed transmission capacity to each country.

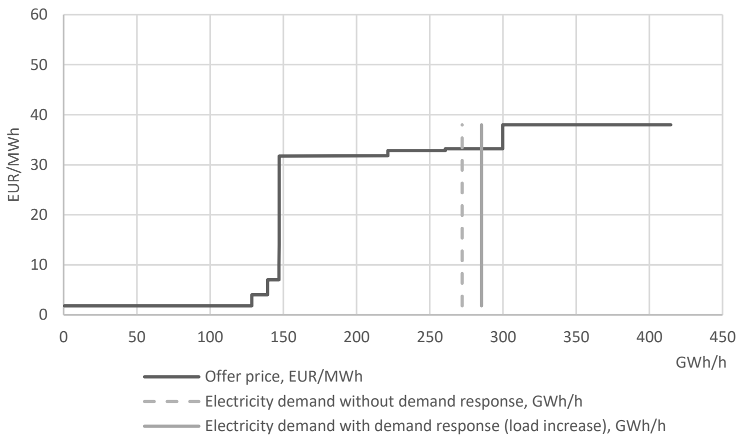

Figure 12. Example of the electricity supply curve in hour 6 in winter 2030, BASELINE scenario. Electricity demand with DR is from the 85% scenario and illustrates a load increase in hour 6, while the price remains unchanged.

The sensitivity of the electricity price to DR is an important factor for DR investment modelling because it controls the price impact and the profitability of DR. The sensitivity can be improved by disaggregating the supply side into more technology cost classes and by expanding the model to include the optimization of electricity generation in neighbouring countries.

5.2.5 Impact of price flattening effect on DR investments

To illustrate the impact of the price flattening effect, we compare the results of the model runs with endogenous and exogenous electricity prices (Figure 13). We observe that in the model runs with exogenous electricity prices the investments in DR and load reductions are higher. On average, the investments in DR are overestimated by 10–18% if the price flattening effect is not considered. This supports the observations made by researchers in previous studies about the importance of using equilibrium modelling with endogenous electricity prices for DR analysis (e.g. [25], [16]).

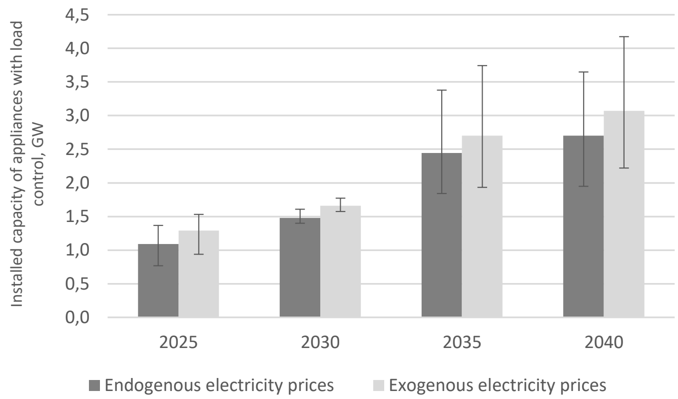

Figure 13. Installed capacity of appliances with load control, comparison of results from model runs with endogenous and exogenous electricity prices. Average for all scenarios. Error bars show the spread between scenarios.

6 DISCUSSION

This study demonstrates how integrated capacity and dispatch modelling of an energy system can be used to analyse price-based DR on a national level and in the long term. The model used in this study is highly disaggregated on the demand side, which makes it possible to capture more details about DR and differences between technologies. At the same time, this makes the model more complex and requires simplifications in other parts of the model to reduce the number of variables (e.g. use of exogenous electricity prices in neighbouring countries, more aggregated representation of generation, limited possibilities to increase time resolution or run the model in a stochastic mode). It is typical of models focusing on energy demand in the residential and commercial sector that they simplify the rest of the energy system, but it is still important to find a good balance between the level of aggregation to include both demand and supply in the long-term capacity and dispatch optimization [22].

TIMES modelling used in this study is based on the assumption that residential consumers act perfectly rationally. This assumption is subject to uncertainty because individuals take many decisions about investments for non-economic reasons [22]. In the case of demand flexibility investments, the biggest question is whether residential consumers will base their investment decisions on extreme price situations or on normal price variation. It is possible that actors selling load control technology to the residential sector will argue for the profitability of load shifting based on the normal price variation, and this is the case that we have implemented in TIMES. On the other hand, it is also possible that consumers might invest in load control irrationally based on a few extreme price situations. Such considerations, as well as an overall assessment of consumer behavior, can lead to valuable improvements in TIMES modelling.

The results of the study show that the price flattening effect acts as a natural restriction on economic DR potential as it becomes unprofitable to shift more load when price variation is reduced. This illustrates the importance of having a form of feedback between the market and consumers so that consumers do not perform more DR than necessary from a system perspective. Today, residential consumers in Norway are settled according to the day-ahead prices, and these are the prices they see on their mobile applications and can use for load shifting. If a large number of consumers plan the same load shifting based on the same price forecast, the synchronization of DR can create problems for the power system, and the level of the price-based DR on the market will be far from optimal. One way to avoid this for actors purchasing electricity on behalf of residential consumers to make forecasts about the expected level of DR and include them in electricity purchase bids as price-sensitive demand. Another way is for a third-party aggregator to perform "controlled" DR on behalf of residential consumers adjusting the level of DR with respect to intraday and real-time market prices.

7 CONCLUSION

In this study we have used integrated capacity and dispatch optimization modelling of the energy system to study residential price-based DR in Norway towards 2040. We have shown that this method of DR analysis has many advantages compared to other methods. Equilibrium modelling makes it possible to capture the impact of DR on price, which is an important constraint on the economic DR potential. Taking a long-term perspective allows us to study the evolution of the whole technology system, the development of the technology stock and increasing variations in electricity price. Detailed representation of the demand side allows us to capture the differences between single technologies.

Development of the stock of residential heating technologies and electric car chargers determines the theoretical potential for DR in Norway in the long term. The economic potential depends on the daily price variation and the costs of load control. Modelling results show that the economic potential in 2040 may reach 37–69% of the theoretical potential, depending on how fast the costs of load control technology decline. This may result in a maximum load reduction of between 1,940 and 3,258 MW. Our results also show that DR from electric car charging is more profitable than DR from heating technologies, and that automatic DR is more profitable than manual DR.

8 ABBREVIATIONS

$\boldsymbol{NPV}$	net present value of the total cost for all regions
$\boldsymbol{DISC}$	general discount rate
$\boldsymbol{R}$	set of regions
$\boldsymbol{Y}$	set of years within the modelling horizon plus a year after when the salvage value is acquired
$\boldsymbol{TS}$	set of time slices
$\boldsymbol{PROD}$	set of production technologies
$\boldsymbol{TRANS}$	set of transmission technologies

$\boldsymbol{DEM}$	set of demand technologies
$\boldsymbol{DR}$	set of load shifting processes (only defined for demand technologies with DR)
$\boldsymbol{INV}$	investment cost
$\boldsymbol{FIXOM}$	fixed operation and maintenance cost
$\boldsymbol{VAROM}$	variable operation cost
$\boldsymbol{SALVAGE}$	salvage value of capital costs of technologies whose life extends beyond the modelling horizon
$\boldsymbol{FLOW\_OUT}$	variable that defines the flow of commodity out of technology
$\boldsymbol{FLOW\_IN}$	variable that defines the flow of commodity into technology
$\boldsymbol{elGRID}$	electricity from grid (commodity)
$\boldsymbol{elPV}$	electricity from PV (commodity)
$\boldsymbol{elINC}$	electricity consumption increase due to load shifting (commodity)
$\boldsymbol{elRED}$	electricity consumption reduction due to load shifting (commodity)

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