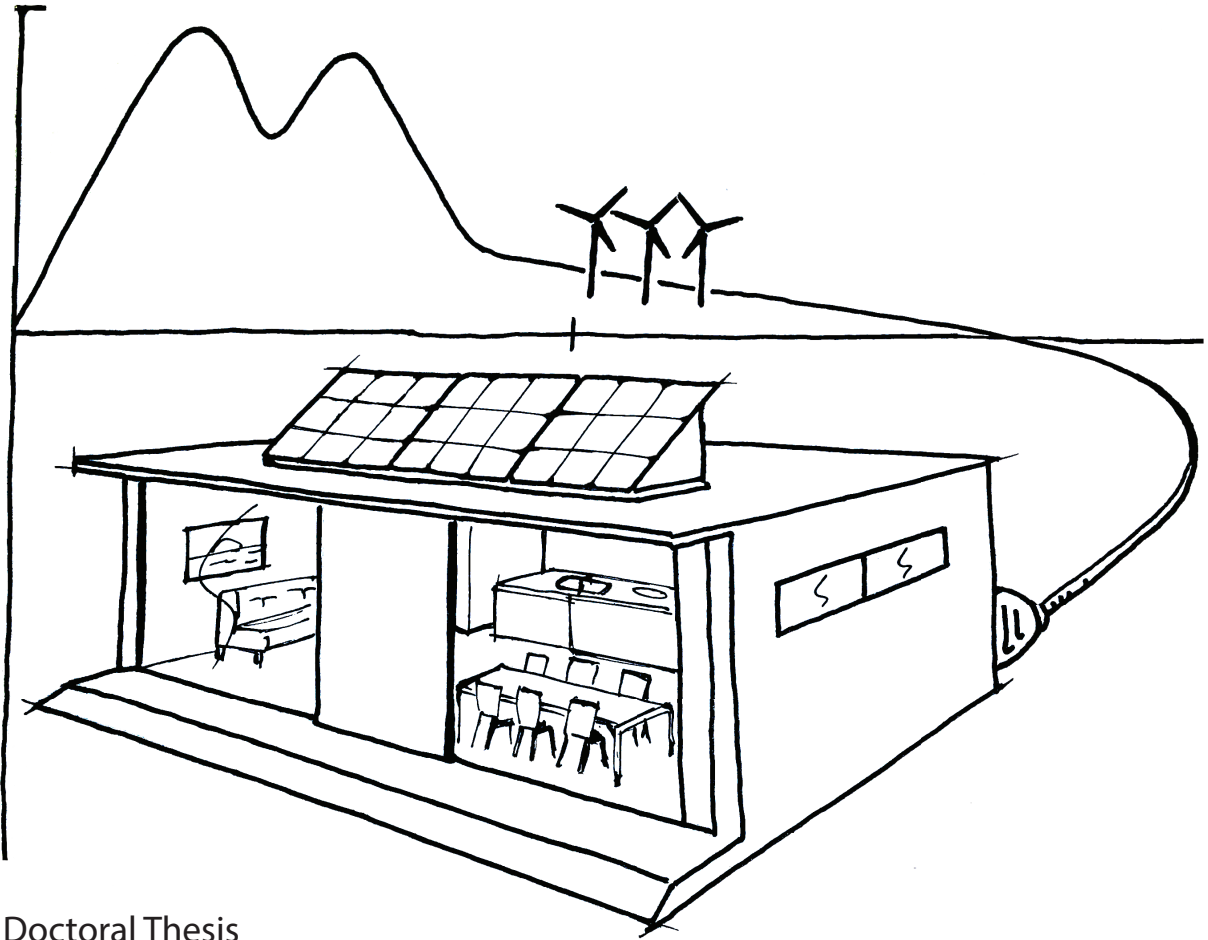


Demand Response Policies for the Implementation of Smart Grids

Elta Koliou



Doctoral Thesis
Delft, The Netherlands 2016

Demand response policies for the implementation of smart grids

Elta Koliou

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DEMAND RESPONSE POLICIES FOR THE IMPLEMENTATION OF SMART GRIDS

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SETS JOINT DOCTORATE

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This Thesis is a part of the examination for the doctoral degree.

The invested degrees are official in Spain, the Netherlands and Sweden, respectively.

SETS Joint Doctorate was awarded the Erasmus Mundus **excellence label** by the European Commission in year 2010, and the European Commission's **Education, Audiovisual and Culture Executive Agency**, EACEA, has supported the funding of this programme.

The EACEA is not to be held responsible for contents of the Thesis.



This book is dedicated to my dad Leter, the greatest advocate for education and my biggest supporter. Through everything that we have been through he has always put my and my sister's education as the priority. This book is as much his hard work and dedication as it is my accomplishment.

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Elia Koliou

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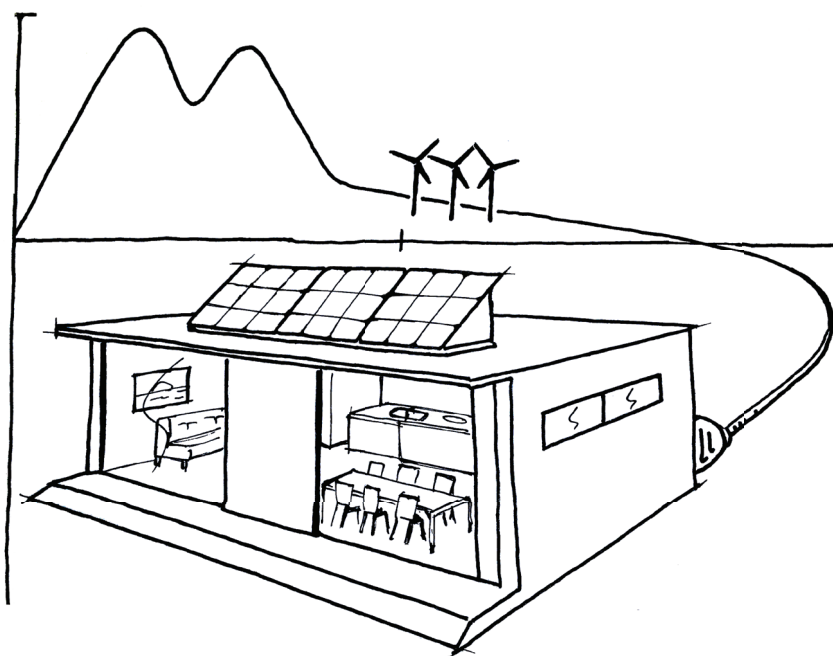
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CHAPTER 1

INTRODUCTION TO THE SMART GRID

Traditional power systems consist of large scale generation interconnected to meet the electricity needs of end-users, succeeding electrification as the greatest engineering achievement of the 20th century (U.S. National Academy of Engineering, 2003). Hence, policy-makers and engineers of today are left to deal with the externalities resulting from electrification: climate change mitigation via the decarbonization of the traditional energy model. Specifically, constant and rising demand for electricity worldwide have prompted a transformation in both production and consumption processes inclusive of accommodating large scale renewable energy sources (RES) and local integration of a variety of distributed energy resources (DER): distributed generation (DG), local storage, electric vehicles (EVs) and an overall active demand (Ackermann et al., 2001; Pérez-Arriaga et al., 2013). Specifically, the current large centralized generation supply following stochastic end-user consumption patterns will move towards a system paradigm that is far more intricate and interactive. In future power systems, suppliers and consumers are expected to cooperatively optimize system decision making. This concept, with its wide array of functions and capabilities is branded as a 'smart grid'.

BACKGROUND

Schweppe et al. (1980) introduce the smart grid more than three decades ago as a philosophy where suppliers of electricity (i.e. generators) and consumers remain in equilibrium via mutual cooperation and response to price and system reliability signals. This approach is initially referred to as "Homeostatic Utility Control" a concept that takes advantage of *"the economic response to price on the part of suppliers and consumers combined with the revolutionary developments occurring in the fields of communication and computation to develop an efficient, internally-correcting control scheme* (Schweppe et al., 1980)". Schweppe et al. (1981) emphasize that such changes *"... may appear to be revolutionary but are actually evolutionary"* and that *"... the implementation of Homeostatic Control can have major impacts on costs and how we as a society treat electric energy."* The smart grid, in essence, is an upgraded version of the existing electricity system. Presenting this early state of the art literature on the topic is critical to illustrate that the smart grid is a byproduct of societal developments worldwide to improve the quality of energy services to end-users.

On this foundation, the European Union is taking a user-centric stance to developing smart grid systems as *"electricity networks that can intelligently integrate the behavior and actions of all users connected to it generators, consumers, and those that do both in order to efficiently deliver sustainable, economic and secure electricity supplies (ETP, 2011)"*.

THE SMART GRID AND THE ENERGY TRANSITION

A smart grid requires a strong penetration of renewable generation (both large scale and locally distributed) in addition to undertaking the electrification of transport and heating. Such a transformation will be facilitated by the integration of control and communication technologies which enable: (i) active demand participation, (ii) energy conservation and efficiency measures, (iii) the creation of new services and business models at the retail level and (iv) the integration of local electricity markets into national ones and beyond (Pérez-arriaga, 2013). Hence, physical smart grid developments are imposing big technical and financial challenges for sustaining reliability in power systems (Seebach et al., 2009; Torriti et al., 2010), especially due to services being met by systems demanding central control, in turn ensuring security of supply via overcapacity.

Following the restructuring of the electricity sector resulting in liberalization of markets, discussions have shifted the focus of system security measures away from generation capacity. Apart from modifying the supply side, demand may also be exploited (Lijesen, 2007). Specifically, demand response (DR) is the concept of consumer load modification as a result of price signaling generation adequacy or state of grid reliability (Braithwait

and Eakin, 2002; DOE, 2006). Implementation of DR mechanisms (in various forms) is one of the smart grid solutions investigated towards improving the efficiency of electricity markets and maintaining system-wide stability.

Enabling an active and reactive demand side

Aggregate production and consumption in a power system needs to instantaneously and continuously match. In order to help the system operator achieve this necessary generation/load balance several types of controllable reserves are retained (Kirby, 2003). Accordingly, power systems are traditionally built and operated under a 'supply follows demand' philosophy which can be criticized for a variety of reasons (Schweppe *et al.*, 1980):

- inefficient use of fuel with the fast activation of reserves;
- average and peak load differ significantly therefore extra generation and transport capacity must exist to supply the peak demand;
- fixed electricity prices for end-users discourage 'demand to follow supply';
- isolating consumers from real-time supply side matters prompts vulnerability to both short term (e.g. blackouts) and long term (e.g. capacity) emergencies.

The existing preventative archetype of surplus grid and generation capacity cannot financially or operatively keep up with the increasing grid and market complexities. Although energy efficiency in appliances and a financial crisis have helped mitigate the rise in electricity demand in recent years, the electrification of different sectors such as heating and transport pledge an overall demand increase in the smart grid. Rising demand requires further grid and generation capacity investments. The current overcapacity approach is not financially sustainable in the future where by 2020 alone, European electricity networks alone require an estimated 600 billion Euros in investments (Eurelectric, 2014). Moreover, deep penetration of renewable and decentralized generation needs real-time monitoring and reactivity which entails further technology investment.

Liberalization forcing unbundling has altered the relationship between market players and the system operator, while technology has progressed to allow loads to be responsive and reactive (Kirby, 2003). In order to keep the power system supply and demand in balance, several countries in Europe have an established tradition of contracting large energy intensive end-user flexibility either through dynamic pricing schemes or direct load control (Torriti *et al.*, 2010). Large industrial consumers make up approximately 36.1% of the total electricity demand in the EU (EEA, 2013). Besides, residential demand represents 30.9% of the total (EEA, 2013), that is almost one third of a flexibility resource that remains to be tapped. Strbac (2008) reasons that with policy committed to market-based operation in a deregulated electricity sector, consumers become the focal point of decision-making at every level of the process.

End users, the smart grid and demand response

For end-users, developments in the electricity sector correspond to rising bills. On average, household electricity prices in Europe have risen 4% yearly (EC, 2014). The current fixed tariff schemes shield consumers from continuous price instabilities. Nevertheless, such an approach to billing is not sustainable, especially with an emergent changing supply system implying increasing volatility in prices. As the system evolves, so must the end-users of electricity. The previously static demand side is expected to follow generation more closely, with price signals as the driving stimulus to change.

Specifically, the concept of demand response in Europe implies *"changes in electric usage by end-use consumers from their normal load patterns in response to changes in electricity prices and/or incentive payments designed to adjust electricity usage, or in response to the acceptance of the consumer's bid, including through aggregation (ACER, 2012)."* Provision of demand response can be broken down into two broad categories (which are not mutually exclusive): (i) controllable demand response which is dispatchable similar to generation and (ii) price-based demand response consisting of dynamic tariff schemes (DOE, 2006). The concept of 'demand response' implies savings in accordance with the forgone consumption which in turn point to market oriented solutions.

A recent press release from the European Commission appropriately titled *Energy: New market design to pave the way for a new deal for consumers*¹ sums up the focus on end-users and demand response for Europe: *"Europe's electricity system finds itself in the middle of a period of profound change. The share of electricity produced by renewables will grow from 25% today to 50% in 2030 [...] New enabling technologies such as smart grids, smart metering, smart homes, self-generation and storage equipment are empowering citizens to take ownership of the energy transition, using these new technologies to reduce their bills and participate actively in the market (EC, 2015a)."*

STATING THE PROBLEM: ISSUES WITH DEMAND RESPONSE INTEGRATION

When looking at future power systems warranting the incorporation of demand side flexibility, there are some unavoidable barriers to market. Initial issues arise with the low priority consumers place on load modification on account of the relatively low cost of electricity (when compared to other factors of household expenditure). Moreover, smart grid investments enabling DR are costly and therefore access to capital is limited and realized by few. Finally, DR can be considered a secondary attributed of other 'products and services' in electricity markets that, until now, has received little attention in design and implementation (OECD/IEA, 2007).

Overall, the low consumer prioritization, limited access to capital and deficient market mechanisms lead to inadequate coordination of DR flexibility. Such barriers to implementation yield overall split-incentives of system stakeholders warranting the use of DR for different purposes (Hakvoort and Koliou, 2015; OECD/IEA, 2007). In essence the integration of DR flexibility falls under the umbrella of a *principle agent problem*, where two parties engaged in a contract have different goals and different levels of information. Accordingly, information asymmetry, uncertainty and risk arise (OECD/IEA, 2007).

Bellow follows a brief discussion of the coordination problem and arising split-incentives in the context DR. Note, although coordination and split-incentives are discussed separately, the topics are interrelated results of market barriers to harvesting DR. When tackling split-incentives, coordination is indirectly affected and vice-versa, see Figure 1 (Hakvoort and Koliou, 2015).

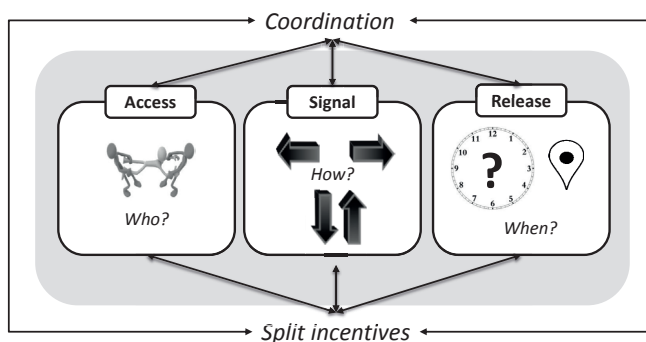


Figure 1: Demand response implementation

Coordination of demand response flexibility

DR flexibility requires coordination of access, signal and release to the system. Coordination of access deliberates the actor allotted the available DR, because it may be that several parties aspire to use flexibility at different moments or even simultaneously. Thus, coordination clarifies who can access the available load so that different actors are not (jointly) *signaling* an increase, decrease or nullification of DR with conflicting directions to dedicated participants. Depending on intentions to impact the system i.e. network versus market objectives, *release* of DR can have significantly opposing outcomes.

Coordination is critical when consumers decide who can access their flexibility and under which circumstances it is available, i.e. to meet long term versus short term objectives. Ensuring confidence of release at the moment of signaling (by the different actors) is the main concern. Nevertheless, such coordination doesn't come cheap and benefits are not always allocated to those incurring the costs and therefore we come to the issue of *split-incentives* (Hakvoort and Koliou, 2015).

Split-incentives of implementation

In order to fully reap the benefits of DR from smart grids large investments are needed on every level of the electricity system, for both physical and virtual (economic) interaction to take place. Nevertheless, this does not result in equal allocation of costs and benefits to involved parties (big or small) due to their overall differing (and at times opposing) intentions. When costs are incurred by some while benefits fall with others, this leads to a problem of *split-incentives* inhibiting the development of smart grid systems facilitating demand response integration (Hakvoort and Koliou, 2015).

Research objectives

In order for deregulated and competitive power markets to function efficiently and effectively it is regarded as a well-established and necessary condition that consumption flexibility must increase. Essentially, this work deals with market based means of (successfully) promoting a change in household energy end-use of electricity. The focus of the research remains on economic incentives inclusive of, dynamic pricing contracts, dynamic distribution signals and the aggregation of DR for participation in the various short-term electricity markets.

As a market provision, the availability of customer flexibility should be financially compensated at a level which stimulates customers to engage. From the perspective of the end-user (who is delivering the flexibility), the choice of DR should remain active since a change in consumption habits can have a slight or significant effect on desired living comfort. This work will discuss the ways in which end-users can become active demand response flexibility providers and the (possible) associated benefits.

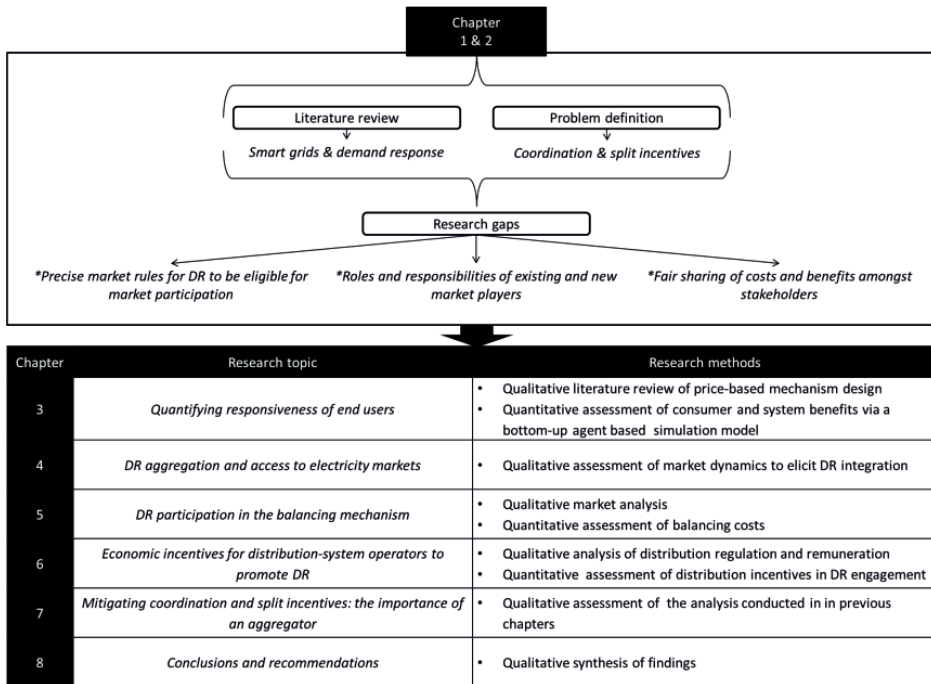
This research aims to answer this research question: *How can residential end-user consumption flexibility be promoted successfully through demand response methods in a smart grid?*

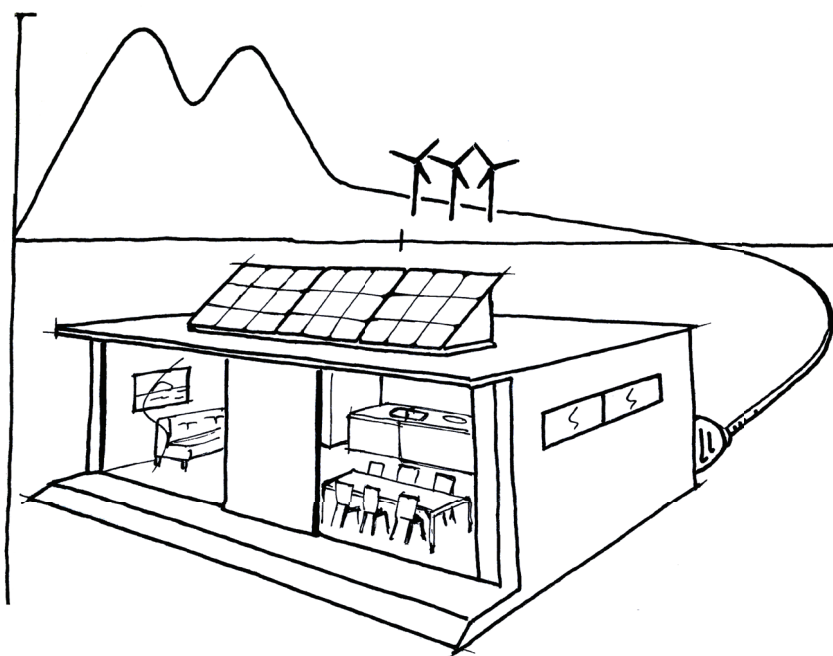
To help answer this question, the following set of sub-questions is also answered:

1. What is motivating the utilization of aggregated demand response flexibility in the European power system?
2. Amongst the options of demand response mechanisms and deemed flexible load, what is the value to the actors in the electricity value chain of utilizing the available flexibility?
3. What are the barriers impeding the large-scale introduction and utilization of aggregated demand response in electricity markets and how can they be overcome?
4. Who will drive the aggregated demand response engagement in the smart grid paradigm? Will it be a market stimulus or regulatory intervention?

THESIS OUTLINE

DR implementation falls with the domain the smart grid, a complex socio-technical energy system with a multiplicity of physical, economic, political and social interactions. The research thus employs both qualitative and quantitative research methods in order to address the main question and sub-questions, see summary Figure 2. The research begins in Chapter 2 with a literature review of the emergence of the smart grid notion and how DR plays a focal role. Moreover, chapter 2 also deduces the theories, mechanisms, implementation and overall implications of integrating end-user flexibility into the larger system, in this way identifying the research gaps to be filled in the subsequent chapters. Chapter 3 thus focuses the discussion on the feasibility of demand response in terms of load which can be activated for flexibility. Also, Chapter 3 investigates the significance of price responsiveness for individual households and the system via the quantification of consumer elasticity; a simulation model is built bottom-up to gain further insights. Chapter 4 analyses the implications of aggregation and, along with it, the complexity of market access for aggregators and end-users. Chapter 5 focuses on the arrangements to accessing balancing markets. Chapter 6 deals with the impact of demand load shifting on the costs to distribution system operators. Chapter 7 summarizes the motivating factors, and gives advice to tackling the problems of coordination and split incentives. Finally, chapter 8 provides concluding remarks for policymakers and researchers on the topic of demand response policies for the implementation of grids.

**Figure 2:** Research topics and methods



CHAPTER 2

DEDUCING DEMAND RESPONSE FOR SMART GRIDS

The previous chapter introduced the smart grid and emerging notions for the shifting paradigm in power system design and operation, giving special attention to the incorporation of demand activation through demand response (DR) in Europe.

The following chapter begins with a summary of the state of the art and policy introduction of the smart grid and DR, accordingly identifying the research gaps. Basic theories and concepts pertaining to the implementation of DR policies for smart grids are also discussed. The synthesis conveys a literature review and research conducted in Koliou et al. (2013¹) and Hakvoort and Koliou (2015²).

¹ Koliou, E.; Eid, C.; Hakvoort, R.A., Development of Demand Side Response in liberalized electricity markets: Policies for effective market design in Europe, in 10th International Conference on the European Energy Market (EEM), Stockholm, 27-31 May 2013.

² Hakvoort, R.A., Koliou, E., 2015. Energy Management and Demand Side Response, in: U.C. Sharma et Al., Energy Management, Energy Science and Technology Series. Studium Press LLC, USA, pp. 53–97.

THE SMART GRID

In order to assess the smart grid it is import to take a look at the state of the art research development in smart grids. A Scopus³ search reveals that 'smart grid' as academic nomenclature surfaced in 2002 with few publications. Starting in 2007 smart grid academic literature increases exponentially to this day. In 2007 it is also observed that demand response (DR) research publications also spike significantly, with an influx of publications to date (Scopus, 2015). The combined research on 'demand response' and 'smart grids' begins in 2007 as well, and to date continues to rise significantly every year since. The research areas of main focus are energy, engineering and computer science, Figure 3. A majority of the research on the combined topics is taking place in the United States (US) and Europe (Scopus, 2015), see Figure 50 in Appendix.

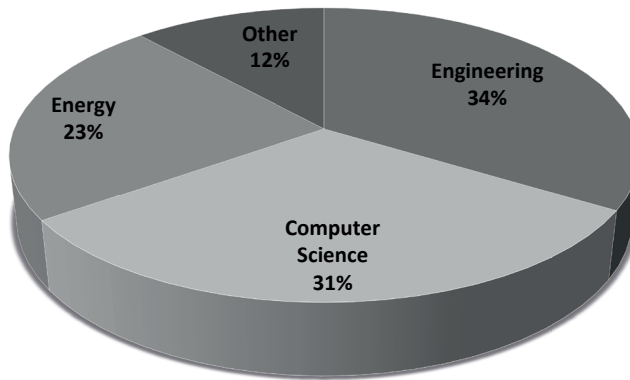


Figure 3: Scopus search "smart grid" AND "demand response" research areas from 2007 to 2014 (Scopus, 2015)

The surge for smart grids and demand response research

Since the spike in both 'smart grid' and 'demand response' publications in observed in 2007 in the US and Europe, it is important to take a closer look at the policy arena which motivated research.

The U.S. smart grid

In 2007 President Bush signed the Energy Independence and Security Act which outlines the policy of the US to support the modernization of the transmission and distribution grid

³ Scopus is the largest abstract and citation database of peer-reviewed state of the art literature inclusive of scientific journals, books and conference proceedings. Scopus includes smart tools to track, analyze and visualize research data (Scopus, 2015).

in order to maintain reliable and secure infrastructure that can meet prospective demand. For the US the smart grid aims to bring greater energy independence and security while promoting the use of information and communication technology (ICT) and incorporation of clean production. Title XIII, Section 1301 of the Energy Independence and Security Act of 2007 outlines the smart grid should achieve the 10 goals summarized in Table 1 (EPA, 2007). What characterizes the US smart grids is defined by and large, with the activation of end user participation in the modernized electricity system, i.e. the smart grid.

Table 1: Quoted text from Title 13 on Smart Grids, Section 1301 (EPA, 2007)

Statement of policy on modernization of electricity grid

It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

1. *Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid;*
 2. *Dynamic optimization of grid operations and resources, with full cybersecurity;*
 3. *Deployment and integration of distributed resources and generation, including renewable resource;*
 4. *Development and incorporation of demand response, demand-side resources, and energy efficiency resources;*
 5. *Deployment of 'smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation;*
 6. *Integration of 'smart' appliances and consumer devices;*
 7. *Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal storage air conditioning;*
 8. *Provision to consumers of timely information and control option;*
 9. *Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid;*
 10. *Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.*
-

The European smart grid

The European Technology Platform (ETP) SmartGrids commenced its work in 2005 for the purpose of assessing and strategizing for European energy needs and limitations in 2020 and beyond. Within a year, in April of 2006, the European Commission (EC) put forth Directive 2006/32/EC on energy end-use efficiency and energy services, aimed at making end-use of energy more economic and efficient (EC, 2006a). Later that year, the EC published a Green Paper pointing to the need for a coherent and consistent set of policies and measures which will bring Europe into a new energy era of sustainability, competitiveness and security of supply. That same year the 'Smart Grids' vision launched, as an initiative of the ETP SmartGrids to reform and modernize electricity markets and networks in a bold and visionary program of research, development and demonstration

(EC, 2006b). Smart grids for Europe employ both products and services in combination with ICT to meet the challenges and opportunities of the 21st century (ETP Smart Grids, 2006). The specific goals of the European smart grid are summarized in Table 2, and just like the US smart grid, aims are heavily concentrated on the activation of consumers.

Table 2: Quoted text from the European Technology Platform SmartGrids description of smart grid aims for Europe (ETP Smart Grids, 2015)

What is a Smart Grid?

The concept of SmartGrids was developed in 2006 by the European Technology Platform for Smart Grids, and concerns an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies. A smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies in order to:

- *Better facilitate the connection and operation of generators of all sizes and technologies;*
 - *Allow consumers to play a part in optimizing the operation of the system;*
 - *Provide consumers with greater information and options for choice of supply;*
 - *Significantly reduce the environmental impact of the whole electricity supply system;*
 - *Maintain or even improve the existing high levels of system reliability, quality and security of supply;*
 - *Maintain and improve the existing services efficiently;*
 - *Foster market integration towards a European integrated market.*
-

Linking U.S. and European smart grids

As Table 1 and Table 2 summarize, the objective for both sides is to achieve a smart grid; on a higher level, it is clear that both approaches agree on the smart grid as an enabler to achieve strategic policy goals set forth. Overall policy objectives revolve around achieving a more secure and sustainable energy supply through the integration of renewable energy sources and the inclusion of consumers in electricity markets. Both smart grid definitions agree on a market driven implementation with differences in the formulation. The EU smart grid points to '*innovative products and services*' while the U.S. smart grid features '*characteristics*'. The paradigm shift is notable in both definitions, making it clear the impact will be on all pieces of the electric power system, both physical and economic. Implementation will further define the smart grid, on either side of the ocean, in terms of technologies, functionality and resulting benefits which may differ even between projects within U.S. and Europe. Deployment will take place according to system needs and financial feasibility.

Defining the smart grid research domains

The National Institute of Standards and Technology (NIST) in the US has created the basic conceptual model which represents the end-to-end building blocks of a smart grid system consisting of 7 domains: bulk generation, transmission, distribution, markets, operations, service provider and customer (NIST, 2010). The NIST model (as seen in Figure 4) is

used by the European Commission (EC) Smart Grid Task Force⁴ as the foundation for defining the reference architecture for the smart grid. For European purposes the model has been extended to include the domain of Distribute Energy Resources (Figure 4).

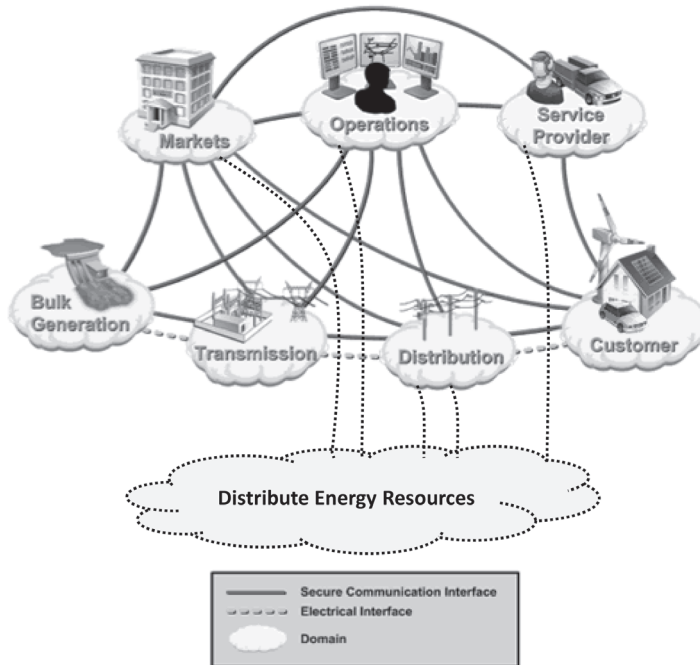


Figure 4: Original NIST smart grid model and adaption to the EU context with integrated distributed energy resources as an additional domain (Bossart and Giordano, 2012)

As mentioned in the previous chapter, the smart grid is not a revolutionary concept but rather an evolutionary one. Smart grids address the full range of current and anticipated challenges of electricity supply. Siano (2014) points out that the majority of smart grid advantages come from the improvement of grid reliability performance and responsiveness of customers, in turn, encouraging more efficient decisions to be taken by consumers and power providers (Forte, 2010; Potter et al., 2009). Hence, any demand side action to modify consumption load accounts for an integral part of the smart grid (IEA, 2007; Saffre and Gedge, 2010; Vos, 2009; Zhong et al., 2010)

⁴ The European Commission set up the Smart Grids Task Force in 2009 to advise on issues related to smart grid deployment and development. The Task Force consists of five Expert Groups who focus on specific areas in order help shape EU smart grid policies.

For Europe specifically, the smart grid definition⁵ emphasizes an ultimate goal to establish an electricity system that fosters the involvement of all connected users for coordination to mutually optimize the delivery of electricity. Nevertheless, steering the transition towards a smart grid is a complex and long-term process rather than a task, requiring a balance between market profitability and energy policy goals (Bossart and Giordano, 2012). It is communicated time and time again that demand side activation is an integral part of this transition.

As pointed out in chapter 1, the involvement of end-users in the smart grid is beset by an existing electricity system built under a philosophy of generation follows demand. Accompanying market processes and regulation have been established in order to cater to large scale generation to meet demand. Below follows a summary of ways in which demand can become active followed by an analysis of the benefits. Concluding remarks will illustrate the research gaps in market processes and regulations for the implementation of an active demand side this thesis will address.

ACTIVATING DEMAND IN THE SMART GRID

Producing a load shape change is regarded as demand side management: in all forms, it incorporates the planning and implementation of activities aimed at influencing end-users of electricity to modify consumption and related patterns with the use of technology and programs (Gellings, 1985), inclusive of energy efficiency (strategic conservation) and DR (peak clipping, valley filling and load shifting). See Figure 5 for a summary of the load modifications.

Load modification measures have both short and long term benefits in accordance with the demand side management that is incentivized. End-users can adjust their consumption in the following ways (see Table 3 for a detailed assessment) (Chuang and Gellings, 2008; Gellings, 1985; Hakvoort and Koliou, 2015):

- *Peak clipping* refers to a consumption reduction at peak hours; as load decreases so does the demand during peak hours.
- *Valley filling* considers the exploitation of low utilization (i.e. valley) hours, at which time electricity use is stimulated to increase; such a modification improves the ratio between the peak and minimum load of the entire system (i.e. the load factor) which can bring overall benefits in electricity prices.

⁵ European smart grids are “electricity networks that can intelligently integrate the behavior and actions of all users connected to it generators, consumers, and those that do both in order to efficiently deliver sustainable, economic and secure electricity supplies (ETP, 2011)”.

- *Load shifting* refers to incentivizing shifting of end-user consumption to another time of the day, a modification that relieves the system peak; customers obtain a financial advantage by purchasing cheaper electricity.
- *Strategic conservation* refers to the reduction of the total energy use due to increased efficiency i.e. energy efficiency.
- *Load building* considers the strategic increase of consumption for an agenda, e.g. tax benefit for electric vehicle owners, in turn promoting mobility electrification and consequently strategic load growth.
- *Dynamic energy management* focuses on the system in real-time operation where supply and demand flexible loads mutually optimize the system load.

In the above analysis a clear description has been given regarding each type of load change. Like so, it is important to take the time and make an even further distinction between DR and energy efficiency. On the one hand, energy efficiency is aimed at the overall lesser use of energy while maintaining the same level of comfort for a certain service, e.g. clothes washing with an energy efficient washing machine versus a washing machine that is 20 years old. DR on the other hand is mainly concerned with keeping the same total consumption, but shifting it to a different point in time. When taking up DR end-users provide flexibility to the electricity system by manually or automatically altering their electricity consumption; simultaneously they receive economic benefits (Eurelectric, 2015). Below follows a discussion on the specifics of DR measures for end-users. Demand response and mechanisms.

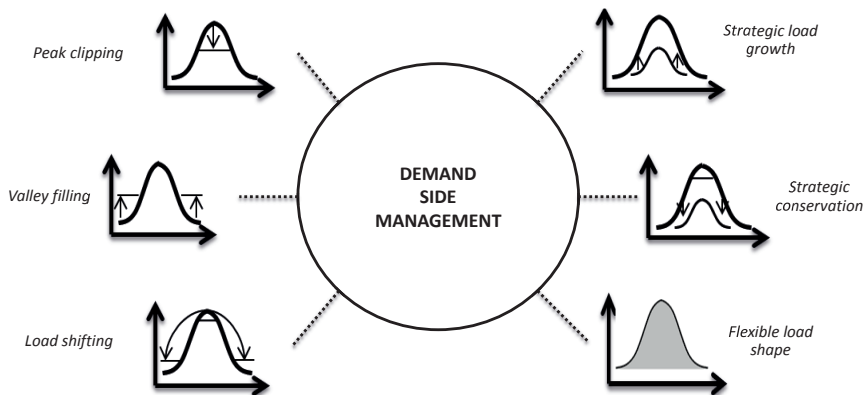
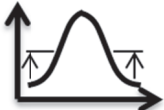
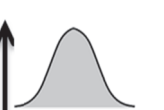


Figure 5: Demand side management load shape objectives, adapted from Gelling (1985)

Over the years DR has received many definitions, but the essence of end-user activation remains. The most commonly cited definition of DR comes from the United States Department of Energy (DOE, 2006) as: "*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*

Table 3: Demand Response: Load Shape Impact (Hakvoort and Koliou, 2015), adapted ref. (Chuang and Gellings, 2008; Gellings, 1985)

Shape	Impact	Implication
	<i>Peak Clipping</i>	- reduction of system peak load by utilities using direct load control - means to reduce peak capacity procurement - programs are expanded to also address transmission distribution congestion management.
	<i>Valley Filling</i>	- building off-peak loads (especially useful at times when long run incremental cost is less than the average price of electricity, in this way decreasing average cost to customers) - space and water heating systems can provide such flexibility
	<i>Load Shifting</i>	- shifting load from on-peak to off-peak periods (i.e. from high prices periods to low price periods) - displacing conventional appliances served by electricity - use of storage water heating, storage space heating - programs are expanded to address transmission distribution congestion management
	<i>Flexible load shapes (dynamic energy management)</i>	- concept related to reliability and planning constraints - when the anticipated load shape is forecasted customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives - interruptible/curtailable load - dynamic (manual and automated) control of devices
	<i>Strategic Conservation (energy efficiency)</i>	- results from overall efficiency (such as the installation of energy efficient light bulbs, buying energy efficient appliances, unplugging appliances when not in use, etc.) - changes in the overall patterns of appliance use - programs reduce overall electricity consumption, also at times of peak demand
	<i>Load Building (Strategic Load Growth)</i>	- general increase in the consumption of electricity (stimulated via certain incentives) - heat pumps, electrification of mobility and heating

high wholesale market prices or when system reliability is jeopardized." Other widely cited definitions and variations thereof are summarized in Table 4. For the purposes of this work ACER (2012) is adopted.

Accordingly, DR is further broken down into two mechanism categories, widely referred to as controllable and price-based programs. The former can also be described as explicit volume-based DR where consumers receive a reward for changing consumption upon a short term request. Controllable flexibility is triggered by electricity prices or network constraints. The latter price-based DR is regarded as implicit, referring to customer

choice and exposure to time-varying electricity pricing (DOE, 2006; Eurelectric, 2015). Although both types of DR programs are discussed separately bellow, it is important to keep in mind that design and implementation is not mutually exclusive (Koliou et al., 2013a). See Figure 6 for a summary of the roles each type of program plays in the time-scale of electricity markets. The subsequent sections discuss each program typology in detail, followed by an assessment of the dualities DR mechanisms present.

Table 4: Widely cited definitions of Demand Response

Citation	Definition
Definition is an extension of IEA (2003), quoted from (Albadi and El-Saadany, 2008, p. 1990)	<i>"DR includes all intentional electricity consumption pattern modifications by end-use customers that are intended to alter the timing, level of instantaneous demand, or total electricity consumption."</i>
(Torriti et al., 2010, p. 1)	<i>"Demand Response (DR) refers to a wide range of actions which can be taken at the customer side of the electricity meter in response to particular conditions within the electricity system (such as peak period network congestion or high prices)."</i>
(L. Greening, 2010, p. 1519)	<i>"The very broad definition of demand response includes both modification of electricity consumption by consumers in response to price and the implementation of more energy efficient technologies."</i>
(ACER, 2012, p. 8)	<i>"Changes in electric usage by end-use consumers from their normal load patterns in response to changes in electricity prices and/or incentive payments designed to adjust electricity usage, or in response to the acceptance of the consumer's bid, including through aggregation."</i>

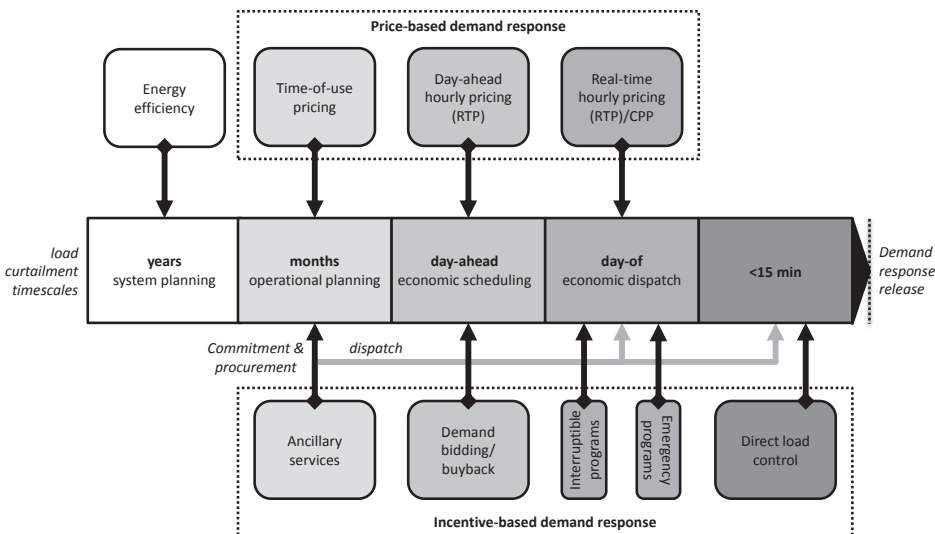


Figure 6: Roles of demand response in the electricity system by time scale, adapted from ref. (DOE, 2006) pg. 15

Explicit demand response

Explicit DR entails pre-contracted agreement with a customer for a specified amount of load and compensation. Such flexibility is considered dispatchable and is directed towards improving reliability during periods of low reserves, in this way providing relief and/or reducing costs at times of high market prices. Participation by end-users is considered voluntary; a penalty scheme is usually established to ensure that enrolled customers comply with their agreement (Bossart and Giordano, 2012; Braithwait and Eakin, 2002). Explicit DR programs include the following (DOE, 2006):

- *Direct Load Control*, which entails the cycling and on/off control of appliances for a pre-defined period.
- *Interruptible/Curtailable Services* that involve a customer choosing a fixed power level to which they must reduce load upon an announced event.
- *Demand Bidding/Buyback* consisting of flexibility being traded in the short term markets (day-ahead, intraday and balancing) in the same way as generation.
- *Emergency Demand Response* which is short term reliability driven, such that participating customers receive incentive payments for quick and direct load reductions in an event.
- *Ancillary Services* that consist of bidding load for curtailment into the reserve markets of the system operator to be paid the market price for energy and/or a pre-set capacity premium for committing to be on standby.

Explicit DR is more geared towards helping the system under distress in the short term and usually consists of pre-specified payments, not always reflective of the market price in real-time (*Demand Bidding/Buyback* is an exception). In the subsequent section the menu of price-based measures available for consumers is discussed.

Implicit demand response

Implicit DR programs are designed on the premise of dynamic price changes in electricity production. Traditionally, end-users have been charged a fixed none time varying price for electricity; price-based mechanisms are alternatives to this traditional paradigm. The idea is that customers will 'follow generation' mirrored in the electricity market prices. Consumers are incentivized to reduce electricity use according to the actual value of energy in the market, in turn conceding implementation success to end-user behavior and related characteristics (Bossart and Giordano, 2012; Braithwait and Eakin, 2002; Masiello et al., 2013). Price-based signals consist of (DOE, 2006):

- *Time-of-Use (TOU)* prices varying by season, week and day of the week ; depending on the time of day unit prices are sent for at least 2 (but usually 3 or more) different time blocks of the day.
- *Critical Peak Prices (CPP)* are designed as utility simulated system contingencies reflective of critical peak periods in a day presented with abnormally high prices; such

periods occur 40 to 150 hours per year with a discount (or rebate) for noncritical periods of event days.

- *Real Time Pricing* (RTP) fluctuates with the price of electricity in the spot market on an hourly basis.

Implicit demand repose programs expose customers to more sophisticated tariffs, guiding demand in line with the supply and network situation. Consumers participating and reacting to such price-based signals can save that amount per kilowatt hour of forgone use.

Understanding the dualities of demand response programs

Each program typology in the above compilation (implicit/explicit) has a different purpose, trigger factor, signal origin, type, motivation method and control (Conchado and Linares, 2010). DR, can be driven by reliability (avoiding involuntary customer curtailment) or an economic stimulus (saving money). Triggers for flexibility are either compelled by (market) price or (emergency) system contingencies. Hence, load modification can be signaled either from the market or system. Accordingly, end-users are communicated a price (passive request where the customer is in control) or a direct request to immediately modify consumption. The resulting release of DR flexibility into the system is either direct or passive (ACER, 2014; Conchado and Linares, 2010), see Table 5 and Figure 6.

Table 5: Demand response motives and alternatives, adapted from ref. (ACER, 2014; Conchado and Linares, 2010)

Classification	Alternatives (Dualities)	
<i>Purpose</i>	Reliability	Economics
<i>Trigger factor</i>	Emergency	Price
<i>Signal origin</i>	System	Market
<i>Type of signal</i>	Load response	Price response
<i>Motivation method</i>	Explicit	Implicit
<i>Control</i>	Direct load control	Passive load control

The types of DR that are implemented in a certain market context are influenced by market design elements, see Table 6. For instance, European countries differ significantly in their levels of liberalization. A highly liberalized environment is hospitable to a menu of market based DR initiatives versus a centralized regulated market. Within the set market context, the financing for promoting DR (programs and technologies alike) is either assumed by the regulator or market parties. Moreover, the DR participants will differ by customer segment (residential, commercial, industrial) and therefore will be targeted according to their best fit response method which will be either manual (with none too little enabling technology) or automatic (with enabling technology) (Conchado and Linares, 2010).

Table 6: Demand response differentiating factors, adapted from ref. (Conchado and Linares, 2010)

Factors	Alternatives (Dualities)	
<i>System/market structure</i>	Vertically integrated regulated system	Liberalized market
<i>Promotion and financing</i>	Regulator	Market parties
<i>Targeted customers</i>	High-voltage (industrial and large commercial)	Low-voltage (small commercial and domestic)
<i>Automation of response</i>	Manual response (with none to little enabling technologies)	Response via automation (with enabling technology)

IMPLEMENTATION OF DEMAND RESPONSE

Programs intended to encourage demand side response assume energy use costs and the comforts are the dominant motivators of consumption and load modification (Dietz, 2015). Dietz (2015) points out the obvious; we consume electricity in order to enhance our wellbeing through heating, cooling lighting and overall technology use. Demand (load) characteristics vary temporally amongst appliance categories in the proximity to flexibility engagement of consumers (Drysedale et al., 2015). In this way, appliances are characterized as critical (time sensitive to consumption with low consumption flexibility) and non-critical (flexible in time). Exploiting flexibility from end-users requires the identification and therefore accessibility to a sufficient load size, timely and durable response in addition to accepting change in the type of DR called e.g. load shedding versus shifting. For end users to participate in DR programs they need sufficient and appropriate incentives (Drysedale et al., 2015).

DR is regarded as an essential service to offset both production and network capacity investments. Since most over-capacity investments occur on account of peak demand, flexibility is often discussed in terms of reducing peak load. The fact is activation of generation and use of transport grid infrastructure is sizably lower than the design capacity. DR aims at reducing the peak consumption so that network limits do not have to be met. Thus, the network will be efficiently utilized, in turn reducing reinforcement and extension costs over time and improving short term reliability. Likewise, when reducing demand expensive generation will not be needed for dispatch, therefore reducing overall electricity prices (Hakvoort and Koliou, 2015). See Figure 7, where with a DR trigger (DR) initial quantity of electricity demand Q shifts to Q_{DR} consequently reducing prices from P to P_{DR} .

A performance metric used to measure how price changes influence electricity use is *price elasticity of demand*, that is consumer responsiveness i.e. elasticity of the quantity of electricity demanded to a change in the price, other things being equal. The character of the implicit/explicit DR program design will impact consumers' inclination to respond to price changes. Consumers predisposition and motivation to act on a DR, is on a higher level, influenced by factors inclusive of the general health of a country's economy which

impacts overall income and in turn overall behavior towards electricity consumption (both short and long term). When a menu of DR programs is offered, consumers weigh several factors in their responsiveness: the frequency of price changes and duration of a DR event, time of day, day of the week, month and season of the year, all which factor into the degree of responsiveness (Neenan and Eom, 2008).

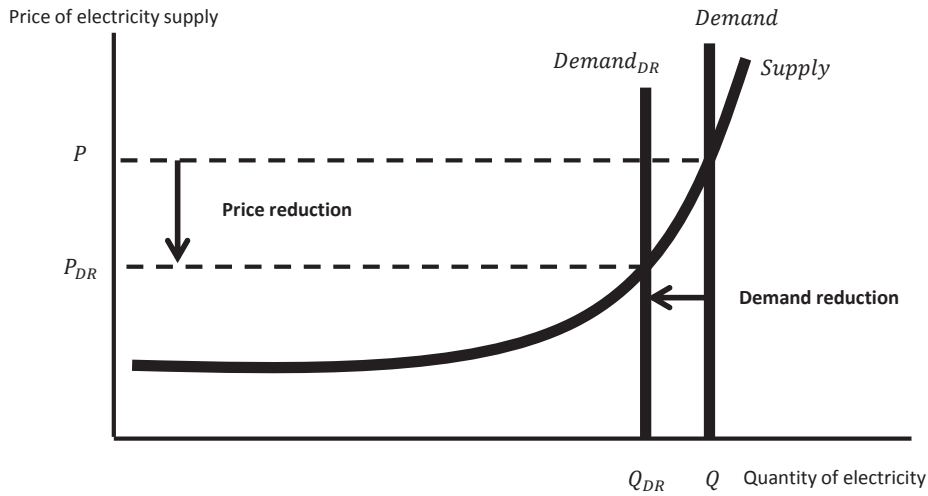


Figure 7: Demand response impact on quantity and price (DOE, 2006)

Summarizing the possible benefits of implementation

The policies that support the implementation of DR programs should aim to achieve one of the following eight benefits outlined by Bradley et al. (2011):

1. Relative and absolute decreases in demand for electricity;
2. Short run cost savings from utilizing DR to shift the peak demand;
3. Displacing new power plant investment by using DR to shift the demand at peak to off-peak;
4. Use of DR as a reserve for emergencies and/or unforeseen events;
5. The provision of DR as a standby reserve and balancing for renewable generation;
6. The use of DR in conjunction with other distributed energy resources;
7. The reduction in transmission network investment via a decrease in network congestion and avoiding transmission grid reinforcement
8. The use of DR for improving efficiency in distribution network investment and reducing losses, especially in light of Smart Grid investments.

The estimation of benefits then can be exploited from DR programs depends on several factors for the customer (L. a. Greening, 2010): customer load profile; customer demand elasticity; level of response at peak periods; fixed and variable costs avoided in transmis-

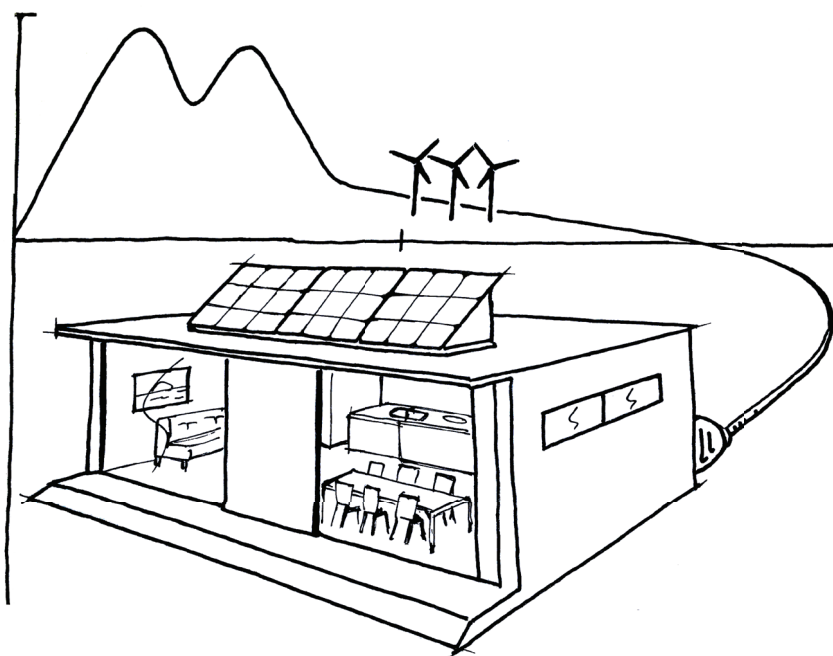
sion, distribution and generation; pricing and incentives for compliance (and penalties for noncompliance); cost of implementing the program.

Research gaps

It cannot be denied that DR will play a role which some believe to be critical, in the implementation of smart grids in Europe. Nonetheless, there are important research areas that require further investigation in order to stimulate the discussion on regulatory and policy recommendations. Specifically, in order to ensure access to all parties a closer look should be taken at (Siano, 2014): (i) the precise market rules for DR to be eligible for market participation; (ii) the roles and responsibilities of existing and new market players and; (iii) assurance of the fair sharing of costs and benefits amongst stakeholders.

SYNTHESIS

In this chapter the smart grid origins in academic literature were presented as a policy vision of the European Commission for the realization of sustainable, secure and affordable electricity supply. Therefore, the basic underlying theories of DR, mechanisms and impact of flexibility system release have been presented. With the above discussion having established implications of implementing DR, the subsequent chapters will address the research gaps (3.2) in policy and regulation, market organization and realization of benefits from implemented programs. The research will reveal why policymakers, regulators, system operators and market parties are demonstrating renewed interest in demand side measures on the premise of reducing peak demand, improving operational efficiency, averting incremental capacity (grid and generation) costs and enhancing the overall system reliability. Ultimately, the remaining chapters will focus on revealing the true incentives (if any) for implementing in demand DR programs.



CHAPTER 3

QUANTIFYING PRICE RESPONSIVENESS

The previous chapter served as a backdrop for the theory of implementing demand response (DR) as a power system flexibility resource. In order to gain further insight into the value of DR, this chapter focuses on the design, feasibility and overall consumer and system benefits of adopting price-based DR mechanisms. The analysis and assessment in this chapter is based on Koliou et al. (2013b)⁶ and work conducted in collaboration with Mahalingam (2013)⁷.

⁶ Koliou, E., Mahalingam, A., Hakvoort, R., 2013b. Assessment of Residential Demand Side Response: Implementation of Price-Based Mechanisms in the Dutch Day-Ahead Market, in: IAEE Europe, Düsseldorf, Germany.

⁷ Mahalingam, A., 2013. Modeling of residential demand response of smart electricity grids to day ahead markets. Master thesis, Delft University of Technology, the Netherlands.

INTRODUCTION

Demand response (DR) improves security of supply while access to flexibility in electricity markets prompts efficiency and liquidity (Albadi and El-Saadany, 2008). As discussed in Chapter 2, DR provision can be broken down into two broad program classifications for implementation: (i) controllable DR which is dispatchable similar to generation and, (ii) price-based DR consisting of sophisticated dynamic tariff schemes (DOE, 2006). The evaluation of DR behavior under a price-based tariff portfolio remains a subject of limited exploration in literature (Dave et al., 2013); this chapter aims to fill this knowledge gap in the following sections.

DEMAND AND ENERGY USE

Household energy use varies significantly as a result of physical and behavioral factors. Total power use of a household (inclusive of both consumption and production) results from the available electrical appliance stock. Quantity of electricity use depends on the frequency and habit of use patterns resulting from the type of household and time (hour of the day, day of the week, season of the year) (Du et al., 2011; Paatero and Lund, 2006). End-use behavior differs with respect to family size, age of household members and gender. Lutzenhiser (1993)⁸ concludes that “...the residential sector consumption seems to be characterized by variability and change, with human behavior playing a central role in both the short-term and long-term initiation, maintenance and alteration of energy flows.”

Consumer behavior

As a social science, economics observes the choices people make based on their available alternatives. Like so, economics is considered the ‘dismal science’ because it always points out the tradeoffs people face (MIT, 2011). The social part of economics examines people’s behavior while a scientific approach is taken to observing choices. Overall, individual consumers purchase goods or services and seek to gain the most ‘bang for their buck’, this is referred to as utility maximization of rationally behaving consumers (Rittenberg and Tregarthen, 2011). When considering electricity consumption behavior of consumers, price and income are the key determinants in their utility maximization (Neenan and Eom, 2008). Nevertheless, utility is subjective and varies widely from one person to the next not to mention the fact that consumers are not always rational.

When considering consumer behavior it is important to note that it is highly complex to analyze and seldom follows traditional and rational economic decision-making theories.

⁸ An extensive review of studies from the 1970s leading the 1990s on the variations in energy use in and between individual households.

On a daily basis individuals are faced with immense amounts of information and choices. Although the options are there, humans are 'boundedly rational' with limited cognitive resources of information gathering and processing, naturally constraining them from making optimal decisions (Frederiks et al., 2015; Simon, 1959). Hence, household decisions regarding energy consumption systematically deviate from utility-maximization rational (Friedman and Hausker, 1988), and more accurately towards one that is satisficing. A satisficing decision is one that is a good enough option, but is not necessarily the optimal one (Simon, 1956). Specifically, *"Decision makers can satisfice either by finding optimum solutions for a simplified world, or by finding satisfactory solutions for a more realistic world. Neither approach, in general, dominates the other, and both have continued to co-exist in the world of management science (Simon in Lindbeck (1992, p. 350)."*

End-user decision making is not reliably predictable in accordance with what people know is the 'best' or sense is the 'right' action to take. What people actually do and what they say they will do are often very different (Frederiks et al., 2015). In the domains of human behavior Frederiks et al. (2015) note action gaps in knowledge, value, attitude and intention. For energy use this simply translates to people knowing the importance of energy savings for mitigating climate change, yet not proceeding with practical actions towards the transformation of their energy use.

Although individual end-user behavior varies significantly and illustrates patterns of irregularity, there are several high level factors influencing how consumers are predisposed and motivated to respond to electricity price signals that are derived with confidence and predictability. Such factors include the general health of the economy, which in turn, impacts the income of consumers and overall profitability in addition to the availability of substitutes (or in the case of electricity lack thereof) essential to maintaining the overall welfare with price changes. Fundamentally, mechanisms that impact load modification behavior are the result of changes in consumer income and electricity market prices (Neenan and Eom, 2008). In the section below follows a discussion on the electricity prices in the European Union (EU).

Electricity prices in Europe

Prior to discussing price-based DR it is important to make explicit what energy prices and costs entail. The prices paid by consumers reflect several components of the system which are influenced by both markets and implemented policy. Accordingly, the energy component of the bill consists of wholesale prices, retailing, network, taxes and levies. Wholesale prices represent the costs incurred by generators inclusive of capital, operational and decommissioning expenditures. In a well-functioning competitive market environment, market clearing price is determined by the marginal cost of production. This means the market price is equal to the cost of bringing in that last (i.e. marginal) unit of capacity in any given clearing period (generally on an hourly basis). In a well-designed wholesale market that is

sufficiently competitive, generation units with the lowest cost are called first and high-cost units run infrequently in periods of peak demand. Hence, the mix of generation capacity in the system is managed economically efficiently on an hour-by-hour basis.

Retailing represents the supplier costs for procuring and providing electricity to final users based on the clearing prices of wholesale markets or via long term bilateral contracts. Network charges encompass both transmission and distribution costs for operation, maintenance, expansion and network losses. On top of the network costs, charges for public service obligations⁹ and technology support¹⁰ are added. Moreover, taxes and levies are also applied in the end-user bill, as part of the taxation instruments, e.g. the EU value added tax (VAT)¹¹, and targeted levies for achieving energy and climate policy objectives (EC, 2014). Figure 8 illustrates the cost of electricity for end-users in the EU member states; in the figure energy prices, taxes and levies are illustrated. Network charges for households are not included since they vary significantly amongst the member states, for example, absolute charges range from 0.022 €/kWh to 0.097 €/kWh (EC, 2014). Average EU prices are observed in the Netherlands, see Figure 8.

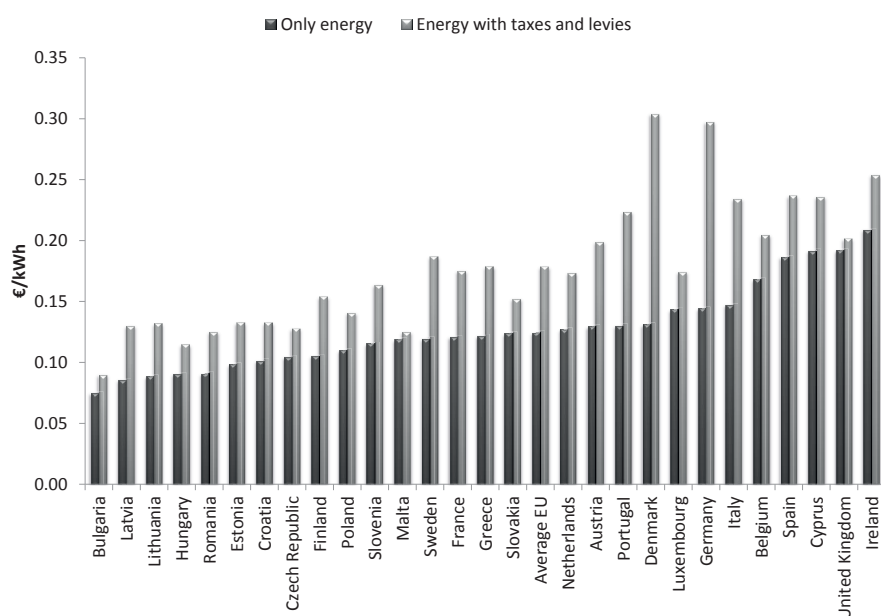


Figure 8: Electricity cost €/kWh in the EU 28 (Eurostat, 2014), not including network charges

⁹ For example, decommissioning of nuclear power plants.

¹⁰ For example, renewable support schemes.

¹¹ The EU VAT is an additional tax on goods and services within the member states ranging from 17% to 27% among the member states. For more information see http://ec.europa.eu/taxation_customs/resources/documents/taxation/vat/how_vat_works/rates/vat_rates_en.pdf.

EC (2014) points out that the brunt of attention from end users falls on energy price levels. An increase in energy prices further stimulates demand side measures to take effect. Improved efficiency in generation and related processes may yield decreasing energy only prices. Still, end-users may not see such a decrease in their bill since their overall consumption may increase as a result of further electrification, e.g. electric heating and electric vehicle adoption (EC, 2014).

Price-based demand response mechanisms

Price-based DR programs provide customers with varying tariffs reflective of value and cost of electricity in different time periods, in this way signaling market conditions. Such tariffs can be designed from simple uniform pricing throughout to complex pricing indicative of real time market conditions. Variations of such tariffs arise from one of the following pricing categories: fixed-price (FP), time-of-use (TOU), critical peak pricing (CPP) and real-time-pricing (RTP) (DOE, 2006). A discussion on the design of such tariffs in the European context is provided below, using the Netherlands as a case study. As indicated above, the Netherlands represents average energy costs in the EU.

Tariff design for the Netherlands

At the most basic level, fixed prices are uniform throughout the day and can have seasonal variations. Average FP in the European residential sector are 0.20 €/kWh, inclusive of taxes and levies. When looking at the Netherlands, consumers pay approximately 0.21 €/kWh. Supply (wholesale generation) is a non-varying component in the bill accounting for approximately a quarter of total cost; price varies in accordance with the retailer generation mix (ranging between 0.047 Euro and 0.064 Euro per kWh), the energy tax is usually a fixed at 0.12 €/kWh which is paid with another levied fixed tax of 0.0036 €/kWh to finance sustainable energy projects. Retailers also include a VAT of 21% to the whole bill (Energievergelijken, 2015). As of 2009 Dutch consumers pay a fixed capacity tariff (€/kW) for network usage (Eurelectric, 2013) which ends up being an additional 20 percent cost to the energy charges discussed¹².

With a dynamic tariff schemes (TOU, RTP and CPP) the electricity price, inclusive of all its components, has the possibility to vary on an hourly basis with short term prices of the day-ahead, intra-day and balancing markets (Bossart and Giordano, 2012; Braithwait and Eakin, 2002; DOE, 2006; Masiello et al., 2013). Widely cited work on dynamic tariff design consider day-ahead market prices as the optimal signal for price-based DR (Faruqui et al., 2009; Hamidi et al., 2009) because of the ability to plan 24 hours in advance, since households currently employ manual response with the possibility of automation under smart grid conditions (Abdisalaam et al., 2012). For the Netherlands

¹² Total yearly network costs are a fixed price of 227.80 Euro per year per household (Energievergelijken, 2015).

we take the values from the Power Spot Exchange for the Netherlands (APX)¹³, see Figure 9.

More reflective of dynamic market conditions, real-time-pricing fluctuates hourly with day-ahead market clearing of supply and demand conditions. Time-of-Use-Pricing consists of pre-defined prices for two or three different time blocks which vary daily, weekly, monthly and seasonally. APX NL defines hour blocks for base (08:00 to 09:00 and 20:00 to 21:00), peak (09:00 to 20:00) and off-peak (01:00 to 08:00 and 21:00 to 24:00) which can be used as the blocks of time for TOU; for each time block the price is derived by taking the average of the prices over the defined hours. Critical-Peak-Pricing is a type of TOU program which simulates system contingency for approximately 90 hours per year (15 days) with abnormally high prices (over five times that of the FP) during event blocks (approximately 6 hours) with a discount for noncritical hours¹⁴ (Faruqui et al., 2009). Under the consideration of electricity prices in the Netherlands at peak hours electricity costs are 1.04 €/kWh and 0.12 €/kWh at off-peak hours. Faruqui et al. (2009), widely cited literature on the construction of CPP programs, consider the system peak between 12:00 to 18:00 hours. See Figure 9 for a detailed representation of each program throughout a 24 hour time period (every 15 minutes). Price mechanisms illustrated in Figure 9 include taxes and levies but not network costs.

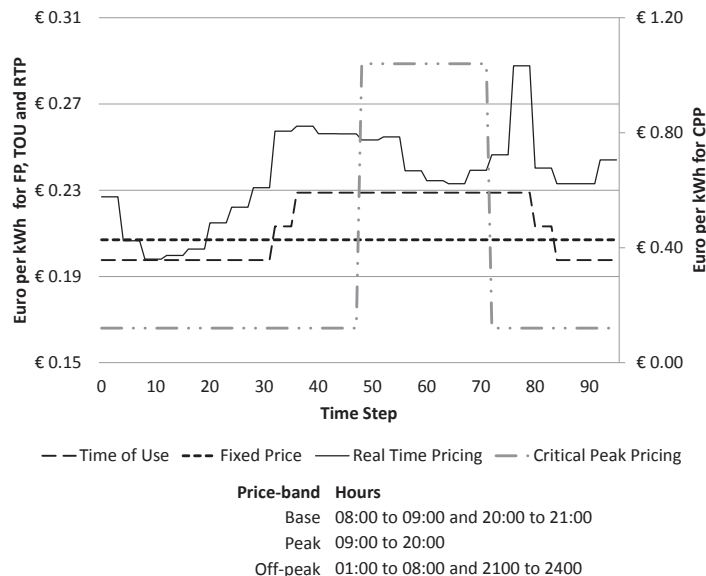


Figure 9: Dynamic tariff programs over 24 hours in 15 minute time steps (Mahalingam, 2013)

¹³ The average traded volume is approximately 45% of yearly electricity consumption in the Netherlands (APX, 2014b).

¹⁴ The discounted price is below the usual fixed price on none CPP days.

Value of price-based programs

Dynamic tariffs are not a new phenomenon, yet a new wave of interest has emerged focusing on measurement of flexibility provided with such rates. Electricity market stakeholders are interested in dynamic pricing as a way to improve overall efficiency in system operation, reduce demand during peak periods and alleviate incremental costs of capacity investment (Neenan and Eom, 2008).

The Department of Energy and Climate Change of the UK reports a literature review of 30 trials which indicate that residential end-users do indeed shift electricity demand in response to dynamic pricing signals. However, the size of the a shift varies across tariff types and trials, anywhere from 0% to 38% (DECC, 2013). It is also highlighted that efforts to automate the provision of flexibility is shown to deliver the greatest and most sustained shifts. Generally, a combination of automation, dynamic pricing programs and enhanced information deliver the highest level of demand responsiveness. Evidence remains inconclusive on whether or not real-time pricing will be adopted by residential users; to date this price program has not produced the desired shift in demand (DECC, 2013).

When considering a menu of tariff programs, end-user sensitivity to price changes can be measured by calculating the elasticity of consumer demand (Neenan and Eom, 2008). See the following sections for a detailed description.

EVALUATION OF PRICE-BASED DEMAND RESPONSE: THE THEORY

As communicated by the law of demand, all other things being equal, end-users consume more of a good when prices are low and less when prices rise. The question at hand is how much more or less will they consume when considering the different price-based mechanisms described above?

Price elasticity of demand

Consumer behavior under price changes is referred to as the 'price elasticity of demand' or 'own-price elasticity' (E_d), in essence determining the consumers' ability to take advantage of the change in price. Associating the responsiveness of consumers according to sector (residential, commercial, industrial) is the 'value' market stakeholders are interested in deriving prior to implementing large scale DR programs (Neenan and Eom, 2008). Specifically, E_d is the change in consumer demand for a good or service that results from a unit change in the price calculated as follows (see):

$$(1) \quad E_d = \frac{\% \Delta Q}{\% \Delta P}$$

where $\% \Delta Q$ represents the percent change in quantity of electricity demanded (in kWh) resulting from the percent change in the price $\% \Delta P$ of electricity (in €/kWh). The resulting value is usually negative due to the (desired) consumer response: when the price of electricity increases, consumers should tend to demand less. Like so, the value of E_d characterizes the degree of consumer price responsiveness as the estimation in the level of demand change.

The degree of consumer price response is determined by the frequency of price change, time of day or season of the year and by how much and for how long the signal is triggered (Neenan and Eom, 2008). Along these lines, there are significant regional differences as a result of climate, level of substitute prices and demographic variables (Bernstein and Griffin, 2006). See Figure 10 for a summary of average own-price elasticity values from residential dynamic pricing programs, where E_d ranges from -0.055 for TOU¹⁵, -0.08 for RTP¹⁶ and -0.535 for CPP¹⁷; overall these studies indicate that demand is relatively inelastic since the increase in price is proportionately larger than the decrease in quantity of electricity demanded. Specifically, demand is considered to be elastic with values less than -1 . Table 28 in the Appendix provides further details about the own price elasticity values for pilot studies, including commercial and industrial customers.

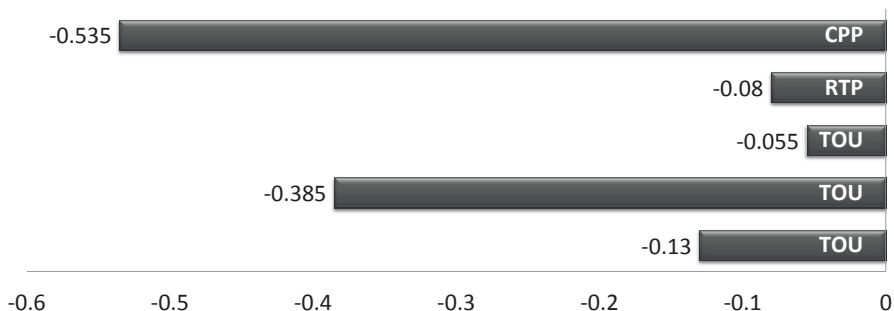


Figure 10: Average own-price elasticity from residential pilot projects for residential consumers in Europe and the United States, ref. (Cooke, 2011; Kohler and Mitchell, 1984; Summit Blue Consulting, 2007; Taylor and Schwarz, 1990; Tishler, 1984)

Elasticity of substitution

Another critical element of price response is temporal substitution, indicating that consumers treat the time of consumption as a characteristic of the commodity. Specifically, there is a reduction in consumption when prices are high and an increase (in the same amount of electricity) when prices are low. As a result, temporal swapping of consumptions at

¹⁵ (Tishler, 1984)

¹⁶ (Summit Blue Consulting, 2007)

¹⁷ (Cooke, 2011)

different periods are treated as substitute goods. This measurement is referred to as the 'elasticity of substitution', where time of consumption changes but not the overall level. Elasticity of substitution (E_{sub}) measures a customer's shift in consumption across time periods. DR, interest lies in the percentage change in the ratio of consumption in two periods, from a peak to an off-peak period, as a reaction to a given percent change in the price ratio between periods) (Neenan and Eom, 2008) formulated as follows:

$$(2) \quad E_{sub} = \frac{\% \Delta(Q_P/Q_O)}{\% \Delta(P_P/P_O)}$$

where, E_{sub} is price elasticity of substitution, calculated from the percent change in peak (P_P) to off-peak P_O price ratio $\% \Delta(P_P/P_O)$, and the peak Q_P to off-peak Q_O demand ratio $\% \Delta(Q_P/Q_O)$. Note, an increase in relative electricity price in one period (either from one hour to the next, time period blocks during one day, between days of the week) prompts the consumption ratio to fall (Neenan and Eom, 2008). See Figure 11 for a summary of average elasticity of substitution from residential pilot projects where values range from 0.05¹⁸ to 0.375¹⁹ for CPP programs and from 0.14²⁰ to 0.37²¹ for TOU. Values for RTP residential programs were not encountered, see Table 29 in the Appendix for a summary of industrial and commercial values which range from 0.03²² to 0.27²³. From the values obtained in pilot projects it is evident that demand is relatively inelastic; only with E_{sub} values greater than 1 is demand considered to be elastic.

The calculation of price elasticity of demand and elasticity of substitution are regarded as robust measurements for price responsiveness to price-based DR programs, however, they required detailed data on both load and price households pay (Goldman et al., 2007).

Factors impacting elasticity values

Price elasticity is a way of anticipating the expected consumer response to a modification in the price level of electricity. Since this is a way of forecasting expected consumer savings, system impact and retailer revenues, reliable predictions are critical in attracting participants to demand-response programs. Therefore, certain factors must be considered when seeking responsive consumers: time frame, technology and learning and overall price levels.

¹⁸ (Charles River Associates, 2005)

¹⁹ (Braithwait, 2000)

²⁰ (Caves et al., 1984)

²¹ (Caves et al., 1989)

²² (Schwarz et al., 2002)

²³ (Boisvert et al., 2004)

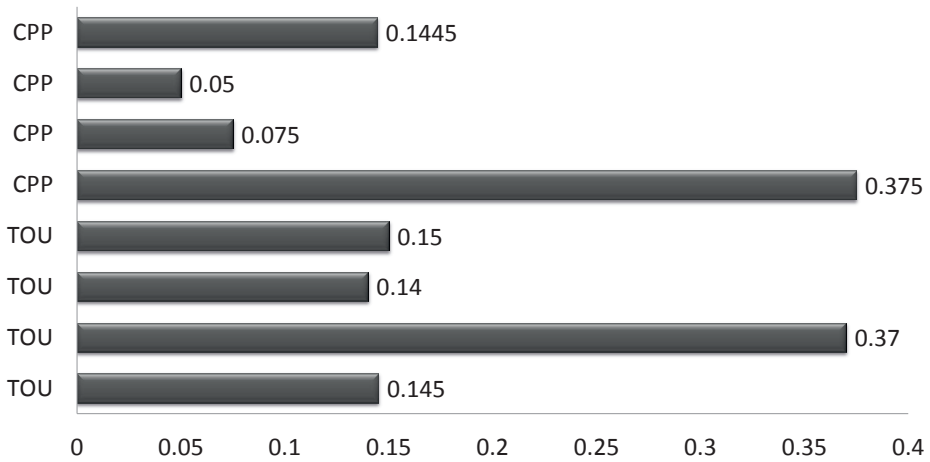


Figure 11: Average elasticity of substitution from residential pilot projects in the United States, ref. (Aigner and Ghali, 1989; Baladi et al., 1998; Braithwait, 2000; Caves et al., 1989, 1984; Charles River Associates, 2005; Faruqui and Sergici, 2008)

Time and technology impact on elasticity

In the long-term, price responsive demand is expected to count as a resource in capacity planning for the system. When considering elasticity in relation to price, the time frame is a critical component denoting the level of change in consumption. In the short-run, consumers seek to make adjustments in their initial demand within their available means of comfort, appliance stock and sensitivity to price. With time and persisting price increases, consumers are further motivated to replace their appliance stock with more efficient devices in addition to adjusting their behavior. Overall, in the long-run, the load modification associated with changes in price is greater than in the short-run, since consumers' change the way they value and consume electricity, in turn yielding more elastic demand. Such a modification may take years to implement due to behavioral adjustment in addition to the capital investment needed to alter the appliance stock (Neenan and Eom, 2008).

Elasticity values are estimated to fit each sector in the economy (residential, commercial, transport, industry etc.). However, overall heterogeneity within the sector of consumers exists as a result of the appliance stock of each household. Access to technology has proven to increase levels of consumer elasticity (Braithwait and Eakin, 2002; Charles River Associates, 2005). In Figure 10 (and Table 28 in the Appendix) and Figure 11 (and Table 29 in the Appendix), the studies with the higher values of elasticity had incorporated enabling technology (Neenan and Eom, 2008). In a meta-analysis including 36 studies from 1947 to 1997 on residential electricity price sensitivity, own price elasticities range from -0.076 to -2.01 in the short-run and -0.07 to -2.5 in

the long-run. Average short-run own-price elasticity is -0.28 and -0.81 for the long run (Espey and Espey, 2004).

Effects of learning and experience on price elasticity

Studies have shown that over time consumers illustrate a higher elasticity, both for price and substitution (Taylor and Schwarz, 1990). For example, Duke Power conducted an 8 year study on an RTP program where participating commercial and industrial firms collectively exhibited an hourly elasticity of substitution below 0.2 in 1995, increasing to 0.25 by 1999 (Schwarz et al., 2002). Such learning over time is a point to note in rate design as a result of the evolution in the institutional context. Nevertheless, such a case may not always hold true.

Although consumers may acquire more efficient appliances over time, it is important to note that end-users become increasingly dependent on electricity acquiring more technology and gadgets. Chang and Hsing (1991) conducted an aggregated-level analysis of the American residential sector not partaking in time-of-use programs during the years 1950 to 1987. The study revealed that in the long-run, own-price elasticity for electricity demand had declined steadily from -2.1 to -1.2 as result of the increasing dependency of consumers on electric appliances that provide convenience, entertainment or both for which there are few direct substitutes.

Impact of the price level (in the market) on price elasticity

Over the years electricity prices have not remained constant as result of rising fuel costs, new technologies and levels of consumption in a European-wide economic recession. Neenan and Eom (2008) suggest that the level of electricity prices impacts values of price elasticity of demand which make elasticity subject to thresholds in prices and quantities (see 2.2). Such a response to price levels may be attributed to the set of appliances deemed available for flexibility use. Gupta and Danielsen (1998) find that when considering RTP programs, consumers with access to local generation will only 'respond' if the price is above a certain threshold.

Below follows an assessment of the above mentioned factors impacting DR via price-based mechanisms under a simulation case study of the Dutch residential sector from Koliou et al. (2013) and Mahalingam (2013).

PRICE-BASED DEMAND RESPONSE IN PRACTICE

A very important part of DR involves consistent evaluation of demand-side to supply-side alternatives to assess their cost-effectiveness (Gyamfi et al., 2013) which can be done when consumers are given price-based signals to modify consumption (Dave et al.,

2013). Household load data is of high value to stakeholders in the energy sector, but nevertheless, such figures remain sensitive and difficult to obtain in a smart grid environment concerned with cyber security.

For end-users the consideration of DR programs is still in an exploratory phase, with little understanding on the attainable value (Torrìti et al., 2010). This work seeks to obtain insight through the use of simulation as a useful tool towards understanding the impact of relevant programs.

Modeling of the residential load

Literature points to three main types of modeling methods for the residential sector (Grandjean et al., 2011): (i) top-down modeling; (ii) bottom-up; (iii) hybrid. Top-down models of residential load analyze total load curves which can have different levels of granularity, but overall treat the residential load as a giant energy pool without consideration of individual household consumption. Ideally it is measured aggregated are representative end-uses cases. Bottom-up modeling methodologies entail a construction of the load starting from the smallest possible system units, the individual appliances, and successively aggregate such units in order to reach higher system levels (Widén et al., 2009). Ideally, this data results from observed and measured household activity which is specific to each appliance and household of the geographic area of study. A bottom-up construction can be achieved with actual measured data of households or can be simulated. A hybrid approach combines both bottom-up and top-down approaches.

Models can be developed according to each typology described. Note, access to actual household data and appliance use profiles is ideal for each method. But, this data is not easy to access on account of associated privacy and security issues. Top-down models (commonly) employ past measures and are not capturing future changes and evolutions in load (Bartels et al., 1992) and hence are better suited for determining supply-side requirements (Swan and Ugursal, 2009).

Grandjean et al. (2011) find that top-down and hybrid methods do not explicitly capture future changes in residential load which result from individual domestic appliances and occupant behavior. Bottom-up models have the ability to incorporate individual electricity use of appliances and households, in this way extrapolating the data to exemplify a representative region or country (Swan and Ugursal, 2009).

Swan and Ugursal (2009) point out that bottom-up modeling as a way to identify both the individual contribution in addition to the aggregate impact of consumption to the total. There are two bottom-up approaches consisting of statistical and engineering methods to modeling. Statistical methods are used for attributing historical household behavior to particular uses (Swan and Ugursal, 2009, p. 1824). Differently, engineering bottom-up modeling does not require historical information and can fully develop consumption performance on the basis of current data (Swan and Ugursal, 2009, p.

1828). For the purpose of this work we use the engineering method consisting of three identified techniques which have been adapted to this work:

1. *Distribution* of appliances among consumers which pertain to the appliance ownership and use profile for the country.
2. *Archetypes* to classify end-user consumption profiles which can be scaled to represent the whole country.
3. *Sample* of actual consumption data representative of each end-user consumption profile representative of the country.

Agent-based modeling allows for simulations to capture the heterogeneous nature of actors (agents) and their respective behavior, which Bryson et al. (2007) reason makes it useful for investigating socio-technical complexity. Accordingly, bottom-up agent based modeling is applied in this work to explore how DR allows consumers to change their time dependent electricity consuming behavior considering techniques 1 to 3 from Swan and Ugursal (2009). This work makes use of the bottom-up modeling the residential sector of the Netherlands using an agent-based method in Repast Symphony²⁴ open source simulation platform.

Choice of agent based-modeling and Repast Symphony 2.0

An agent based modeling approach allows for the simulation of actions and interaction of autonomous heterogeneous agents with a goal of assessing their effects on the system as whole (Hong et al., 2013; Jennings, 2000). In particular, agent-based modeling is rooted in individual decision making and human social and organizational behavior (Hong et al., 2013). Nevertheless, no simulation approach is perfect and a model is only useful for the purpose which it is constructed. Agent-based modeling drawbacks may arise from the very granularity and level of detail; they tend to be very sensitive to initial conditions and to small variations in interaction rules. The model inputs determine if the outputs should be used for qualitative or quantitative insights (Crooks, 2006). For this use case agent based modeling allows the capture of the heterogeneity of the residential sector, where end-users possess different characteristics and exhibit complex behavior giving rise to aggregate system level implications.

As an open source software under continuous development, Repast Symphony 2.0 offers flexibility in model development and use with its wide range of tools and plug-ins. For effective model design and simulation of experiments, Repast uses Java as the machine-user level language, therefore laying the foundation for simple communication. This environment allows for the development of a model that is thorough, flexible and extendable. Extendibility and flexibility are key in this model; changes in the user panel can be adapted to study other country residential sectors. Moreover, this environment

²⁴ http://repast.sourceforge.net/repast_symphony.php

allows for a friendly user panel interface (Figure 12) that can be operated by individuals who do not have experience with Java coding and seek to gain actionable insight.

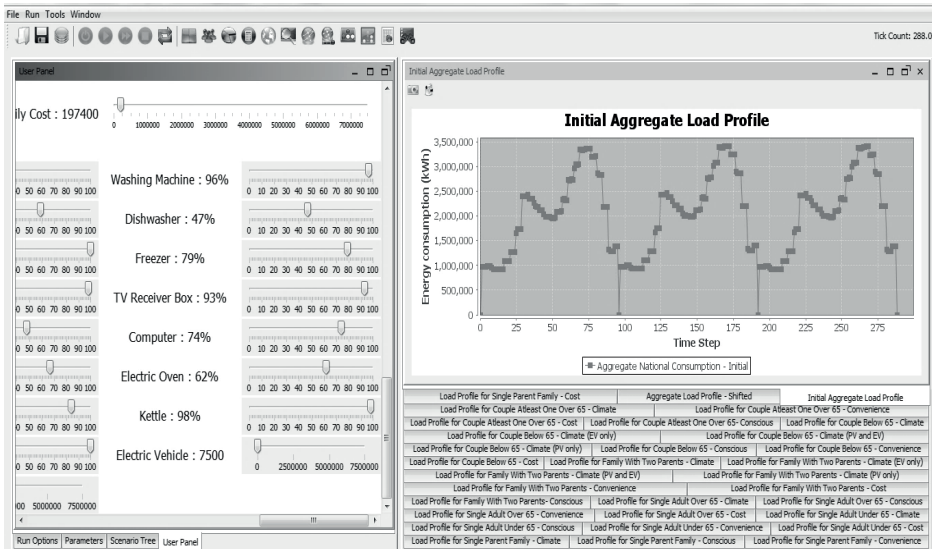


Figure 12: Repast Simphony 2.0 Simulation environment user interface

Appliance ownership and use

Residential appliance stock can be deduced by examining the penetration level i.e. ownership rate in households at a country level (Abdisalaam et al., 2012; Swan and Ugursal, 2009). In the Netherlands, for instance, refrigerators have a 100 percent penetration rate while dishwashers less than 50 percent (see Table 7). Household appliances are classified by category (Hamidi et al., 2009): cold appliances (refrigerator, freezer); wet appliances (washing machine, dryer, dish washer, electric water heater); cooking appliances (electric oven, microwave oven, kettle/coffee maker); lighting (all lights); entertainment (computer, printer, DVD player, Television, TV receiver box); green appliances (Electric Vehicle (EV), Solar Photovoltaic Systems (PV)); miscellaneous occasional loads (iron, vacuum, hair dryer etc.). Figure 13 illustrates the share of total consumption per appliance in a typical household in the Netherlands.

For the purpose of DR, appliances can be characterized further as controllable and non-controllable (Abdisalaam et al., 2012). Non-controllable loads (cooking, entertainment, lighting and other miscellaneous loads) cannot be easily displaced in time and are therefore considered as part of the base-load consumption along with standby power. In fact, when looking at a typical household in the Netherlands, around 60% of the energy consumed is a result of non-controllable load demand (Figure 13). Controllable loads (wet, cold and green appliances) can be used for DR flexibility, accounting for

approximately 40% of the total demand. See Table 7 and Figure 14 for consumption figures and profiles of controllable appliances. Flexibility from end-users can also be attained with production from solar photovoltaic systems (PV); households can consume the produced electricity or sell it back to the system for a profit equal to the price of electricity i.e. price-based mechanism in place (see Figure 15 for an average production profile). It is estimated that the penetration rate of solar PV micro-generators in Dutch households is approximately 0.4 percent²⁵.

Table 7: Characteristics of controllable appliances in a household (Seebach et al., 2009)

Controllable appliance category→	Wet				Cold		Green
Appliance→	Washing Machine	Dryer	Dish Washer	Water Heater	Refrigerator	Freezer	Electric Vehicle
Energy consumption per cycle (kWh)	0.89	2.46	1.19	2.7	0.79	1.1	28.73
Duration per cycle (hours)	2	2	2	1	0.66 to 1	0.66 to 1	5*
Appliance penetration rate (%)	96	59	47	18.2	100	79	0.1
Standby power consumption (Watts)	0.51	0.51	1.79	0	N/A	N/A	N/A
Maximum load shifting capability (hours)	3	3	6	N/A**	1	1	4

* Indicates full charge of vehicle batter

** Shifting depends on household profile

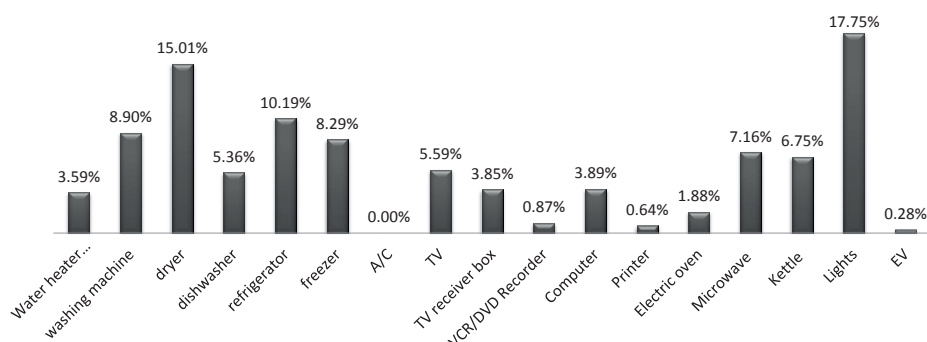


Figure 13: Electricity consumption of appliances as a percentage of the total currently in an average Dutch household (Abdisalaam et al., 2012; Agentschap, 2012; Seebach et al., 2009)

²⁵ It is estimated that approximately 28,000 households have photovoltaic systems installed (estimations are derived from survey data on the average capacity installed) (ECOFYS, 2011).

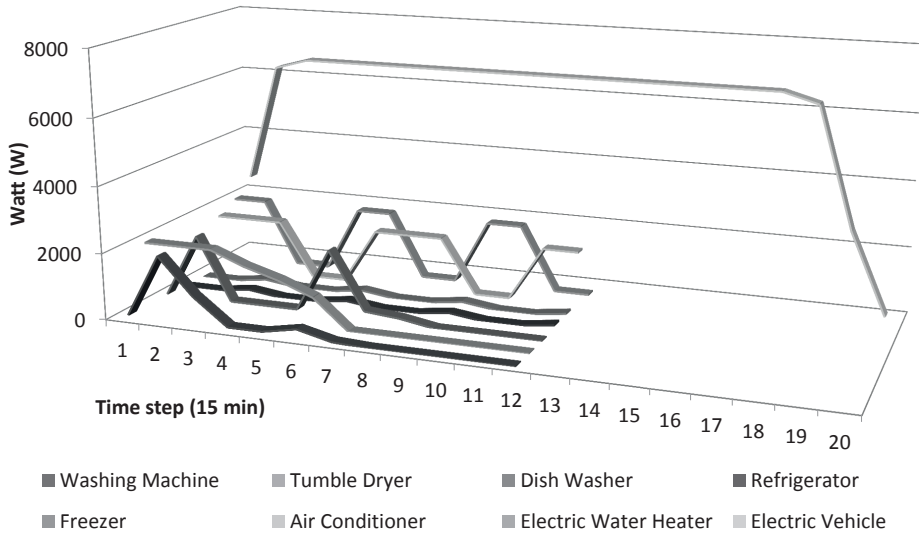


Figure 14: Consumption profile of controllable appliances, constructed in Mahalingam (2013)

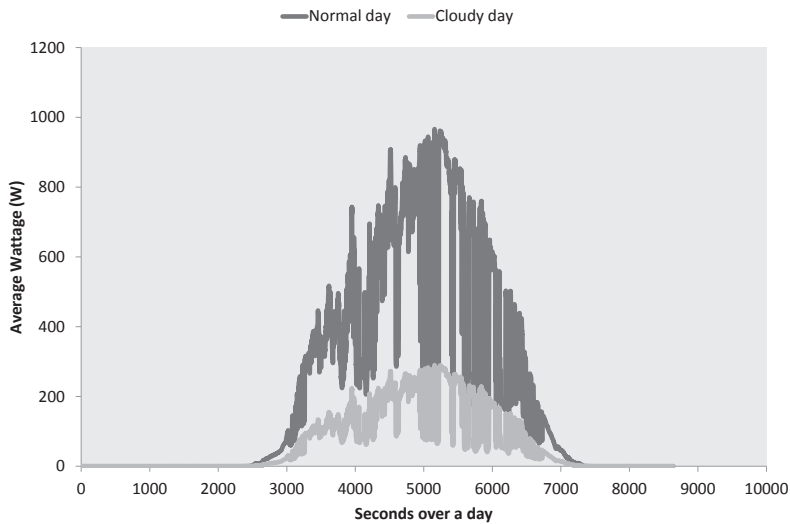


Figure 15: Production of household PV installation on a normal and cloudy day in the Netherlands (every 15 minutes throughout 24 hours of an average day), constructed in Mahalingam (2013)

Consumer archetypes

End-users rationality with respect to electricity consumption can be assessed on the basis of archetypes which reflect real-world consumers (David and Li, 1991; Kirschen et al., 2000; Venkatesan et al., 2012). For the Dutch residential sector, these profiles have been deduced in Paauw et al. (2009) on the basis of Van Raaij and Verhallen (1983) work on energy related consumer attitudes:

- *Comfort (convenience)* profile end-users are only concerned with ease of electricity use and have no interest in the cost; their interests lie in the short term (immediate) satisfaction of consumption.
- *Mindful (conscious)* profile consumers like to have ease of consumption to meet their needs, but are aware of the financial and environmental consequences of their electricity use.
- *Frugal (cost)* profile users are especially aware of the cost of electricity use, and consume in such a way that will save money.
- *Environmental (climate)* profile users solely consume electricity in a way that will be beneficial for the environment.

Statistics Netherlands (CBS)²⁶ contains extensive information about the categorization of the Dutch households into different types based on the household composition and age groups. The CBS classification was modified and extended with the Eurostat data classification of household profiles in order to ensure model extendibility to other European countries. The final classification of Dutch households adapted to this case, consists of: single, two adults below the age of 60, couple one adult over the age of 65, single parent family, two parent family and senior over the age of 60. In the Netherlands there are approximately 7.1 million households which are made up of these classifications (CBS, 2013). Weights of household preferences (comfort, mindful, frugal, environmental) are determined from a survey in Paauw et al. (2009), specifying each type of household and weight attributed to a specific attitude profiled above²⁷. These weights were ratio-scales to the results summarized in Table 8. On this basis, we can conclude that according to attitude and type, the Dutch residential sector consists of the following profiled households: 16% comfort, 28% mindful, 40% frugal and 16% environmental, Table 8 and Figure 16. Household activity of consumers is discussed next.

Table 8: Dutch household archetypes, own calculations (Koliou et al., 2013b; Mahalingam, 2013)

Profile ↓	Percent of total households ↓	Households in each group (in thousands)					
		Single	Single elderly adult	Couple below the age of 65	Single parent family	Two parent family	Couple, at least one adult over age 65
<i>Comfort</i>	15.8%	180.1	84.95	375.9	49.35	191.3	243.6
<i>Mindful</i>	28.4%	540.3	254.85	375.9	197.4	573.9	81.2
<i>Frugal</i>	40.2%	900.5	424.75	250.6	197.4	765.2	324.8
<i>Environmental</i>	15.6%	180.1	84.95	250.6	49.35	382.6	162.4

²⁶ Statistics Netherlands is responsible for collecting and processing data for the Netherlands to be used in practice, by policymakers and the scientific research community.

²⁷ See Appendix Figure 51 for weights of attitudes/archetypes and household classification.

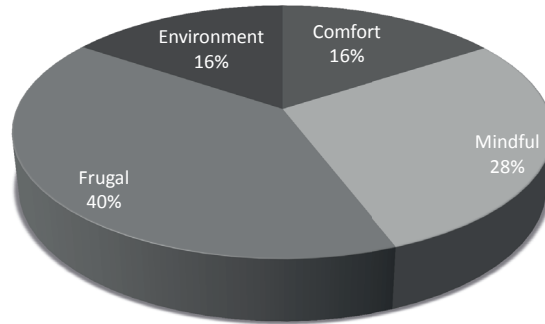


Figure 16: Division the Dutch residential sector (7.1 million households), own calculations (Koliou et al., 2013b; Mahalingam, 2013)

Activity

The main parameters needed for simulating household power use activity consist of (Paatero and Lund, 2006; Arslan, 2012): (i) the total number of households, see 4.1.3; (ii) appliance penetration rates, 4.1.2; (iii) appliance load profiles, 4.1.2 and ; (iv) start-up probabilities²⁸ of appliances indicating whether or not they are in use. The activity of the different archetypes (comfort, mindful, frugal and environmental) are constructed from occupancy²⁹ and time of use survey data of the profile groups (Linderhof, 2001; Paauw et al., 2009). Individual household activity is constructed in 15 minute time steps for one day.

When combining the archetypes and groups in Table 8, the result is 24 agents with distinct activity profiles which capture the heterogeneity between the different households and archetypes amongst them (see Appendix Table 32 for details). From these, only couples under the age of 65 and families with two parents have either a micro-generator (PV systems) installed, own an electric vehicle or both³⁰. The consumption activity of the 24 households is scaled to depict the entire residential load of the country. Figure 17 illustrates the steps in the bottom-up construction of the residential load, starting first with the individual household, followed by activity of the different archetypes and finally scaling to a country level. Such a superimposition technique is widely used in industry and state of the art simulations, e.g. Abdisalaam et al. (2012); Boots (2011); Du et al.

²⁸ Start-up probabilities for this work are obtained from widely cited literature on the topic and simulation approach Paatero and Lund (2006).

²⁹ Occupancy is derived from a model on light use constructed by (Richardson et al., 2008) and (Richardson et al., 2010) for the residential sector in the United Kingdom. Dutch light use is approximately 1.5 times less when compared to British end-users (Bertoldi and Atanasiu, 2006) therefore appropriate scaling was applied. When lights are on, this indicated household occupancy.

³⁰ Result was drawn after consulting with a Dutch PV installation company (Joop Keyzer BV) about their customer demographics.

(2011). In order to confirm the representativeness of the load, the curve is validated³¹ by existing literature on the load demand curve for the Dutch residential sector: Movares (2013); Van Ouirsouw and Cobben (2011); Agentschap, (2011); Abdisalaam et al. (2012). Figure 18 illustrates the result of using the modeling technique described herein.

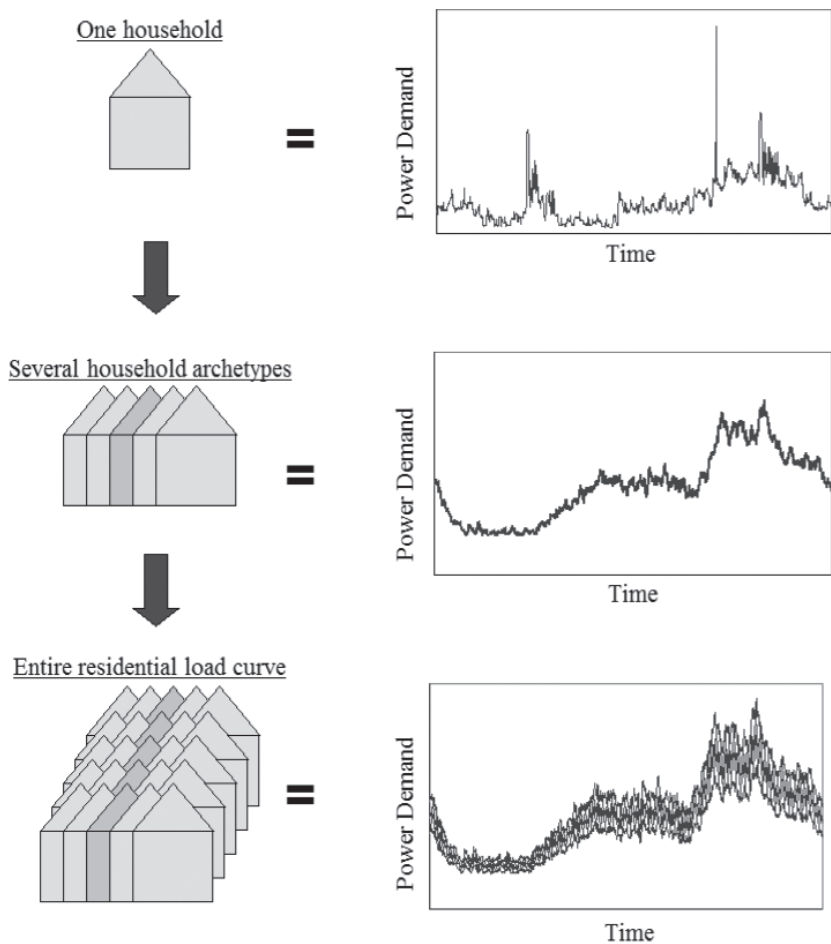


Figure 17: Bottom up construction of a residential load curve (Boots, 2011)

³¹ Further validation and verification is discussed below in section 6 and in Appendix Table 31.

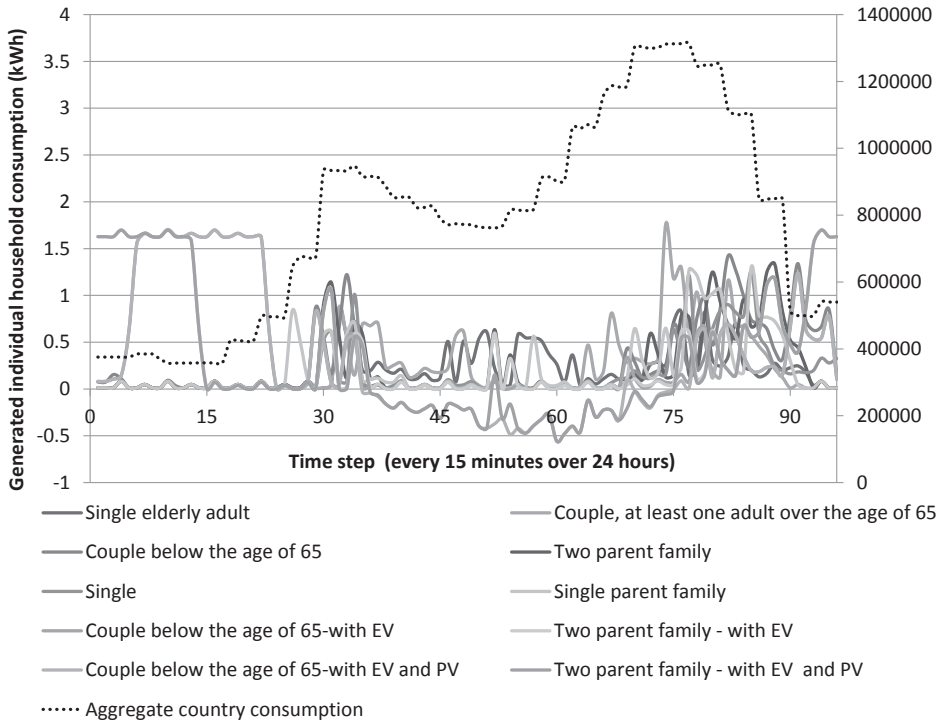


Figure 18:³² Individual household consumption in each archetype in Table 8 (primary axis) and aggregate country consumption (secondary axis) in one day consisting of 96 time steps (every 15 minutes for 24 hours), generated from simulation model in Mahalingam (2013)

Load shifting

Basic requirements for a demand responsive system to become operable consist of three factors: (i) the necessary number of participants (ii) duration that a household can participate in demand-response programs and (iii) the amount of load that can be curtailed or shifted (Dave et al., 2013). Moreover, the stimulus should come from the program in place, in this case price-based mechanisms: fixed-pricing, time-of-use pricing, real-time-pricing and critical-peak-pricing illustrated in Figure 9. For this work another CPP program has been added which coincides with the peak of the residential load (CPP-R). Widely cited literature on the topic of tariff design Faruqui et al. (2009) recommend the critical peak hours coincide with the system peak (CPP-S), but since this work evaluates price-based mechanisms for end-users the residential peak is also considered at 19:00 hours, in this way shifting the critical hours from 16:00 to 22:00, see Figure 19.

³² The negative consumption represents excess power produced by PV installation system which is sold back to the system at the market price given by the specified price signal in that time step.

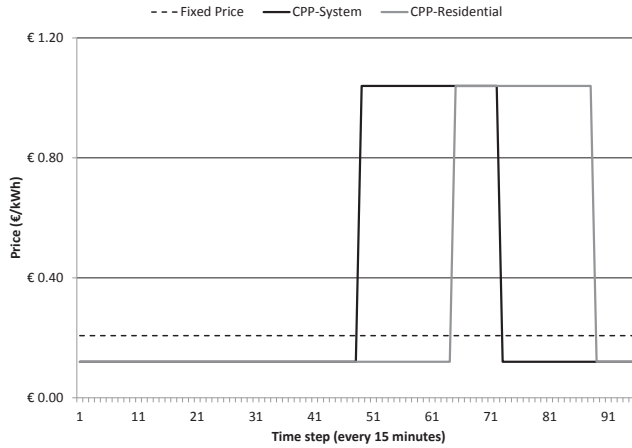


Figure 19: Critical peak pricing programs constructed for system and residential peak (Koliou et al., 2013b; Mahalingam, 2013)

Prior to the implementation of a dynamic price program, the load curve for the country is aggregated assuming activity in households is happening under a FP program with a uniform price throughout the 24 hours (every 15 minutes yielding 96 time steps); Figure 18 aggregate country consumption. Upon signaling of a DR mechanism via one of the dynamic tariffs (TOU, RTP, CPP-System and CPP-Residential), the consumer archetypes (i.e. the agents in the model) identify their controllable appliance stock and check the price at that time step. Each agent reacts according to their energy consuming preference profile described in section 4.1.3. To summarize all agents employ a satisfying approach in their consumption decision making strategy, searching through their available alternatives to meet their acceptability threshold: *comfort* agents are static price takers that do not respond to price signals; *mindful* agents respond to TOU and CPP programs; *frugal* agents respond to TOU, CPP and RTP signals and; *environmental* agents respond to TOU, CPP and RTP programs allowing for automation of their controllable appliances according to the lowest total cost of consumption. For a more detailed assessment of agent activity see Figure 20 and Table 9. Agents then check the household occupancy (to see if they are home to 'respond') and then finalize their new time for appliance activity. The start probability of appliances is then shifted to the new time step where the new (shifted) appliance activity takes place. Solar PV production is regarded as 'negative consumption'; the Dutch net metering scheme *Salderingsregeling* indicates that when end-users produce electricity this energy is subtracted from the total household energy bill (Autoriteit Consument and Markt, 2015). In the model, the excess power produced by PV that is not consumed by the household is sold back to the system at the market price given by the specified price signal in that time step. The load for each

Table 9: Description of consumer archetypes and detailed activity in the simulation (Mahalingam, 2013)

Archetype	Activity description
All	- Look at 'start price' of time step (block) to shift load(s) - Those who own EV, plug-in to charge upon arrival at home but the charging is done by automation algorithm (find cheapest cycle during evening hours to charge) - EV always charges batter to full and charging stops automatically when batter is fully-charged - Electric water heater switched off promptly after its cycle and switched on again if necessary - Shower only after the water heater cycle is completed - All consumer know dryer is more energy intensive than washing machine - Dryer always goes after the washing machine
Comfort	- Do not respond to any price mechanism - Do not have smart appliances installed (i.e. no automation) - Make use of microwave for cooking hot meals all the time - Excess use of lights (mostly unnecessary) - All appliances are on standby when not in use - Dryer 'immediately' follows washing machine
Mindful	- Only respond to TOU and CPP programs - No smart appliances installed (i.e. no automated) - They do not shift usage of water heater to any price signal - Lights are not unnecessarily on - Load shifting for certain appliances :maximum shift for washing machine and dryer = ± 3 hours; max shifting for dishwasher = ± 6 hours (Stamminger and Friedrich-Wilhelms, 2008) - Only look at start price of the time block to make a shifting decision - Dryer 'immediately' follows washing machine; they take the lowest start price for the washing machine to begin washing - Have to be at home and awake in order to do laundry/dyer - Dishwasher switched on only 30 minutes after dinner time (19:00)
Frugal	- Respond to TOU, CPP and RTP programs by looking at the start price in the time block they want to use their controllable appliances - No smart appliances installed (i.e. no automation) - They shift water heater - Only look at start price of the time block to make a response decision - Wait to do washer, dryer and dishwasher until prices are low - Have to be at home and awake in order to do laundry/dyer and dishwasher - Use the dryer if they own one - Willing to shift dinner time to accommodate the use of dishwasher at cheapest starting price - Willing to shift dinner time in case of conflict with cheapest water heater starting price time step/block
Environmental	- Respond to TOU, CPP and RTP programs - Have smart appliances installed (automated) to react to price signals - Have combo washer/dryer (no need to change clothes to dryer manually) - Automated washing and drying (pre-programmed) so they do not have to be home or awake to wash/dry - Aware of time-step power requirements of the appliances and so find the cheapest 'cycle' to shift their loads - Have the possibility to own PV and/or EV - Refrigerator and freezer are smart devices and automatic load control applies - Use energy saving lighting bulbs (CFL³³ 75% more efficient) and light not unnecessarily on - High-efficiency water heaters/PV-based water heating - Standby power consumption for all appliances is zero - Willing to shift their dinner time to accommodate the use of dishwasher at cheapest cycle - Willing to shift their dinner time in case of conflict with cheapest water heater cycle

³³ Compact fluorescent light bulb

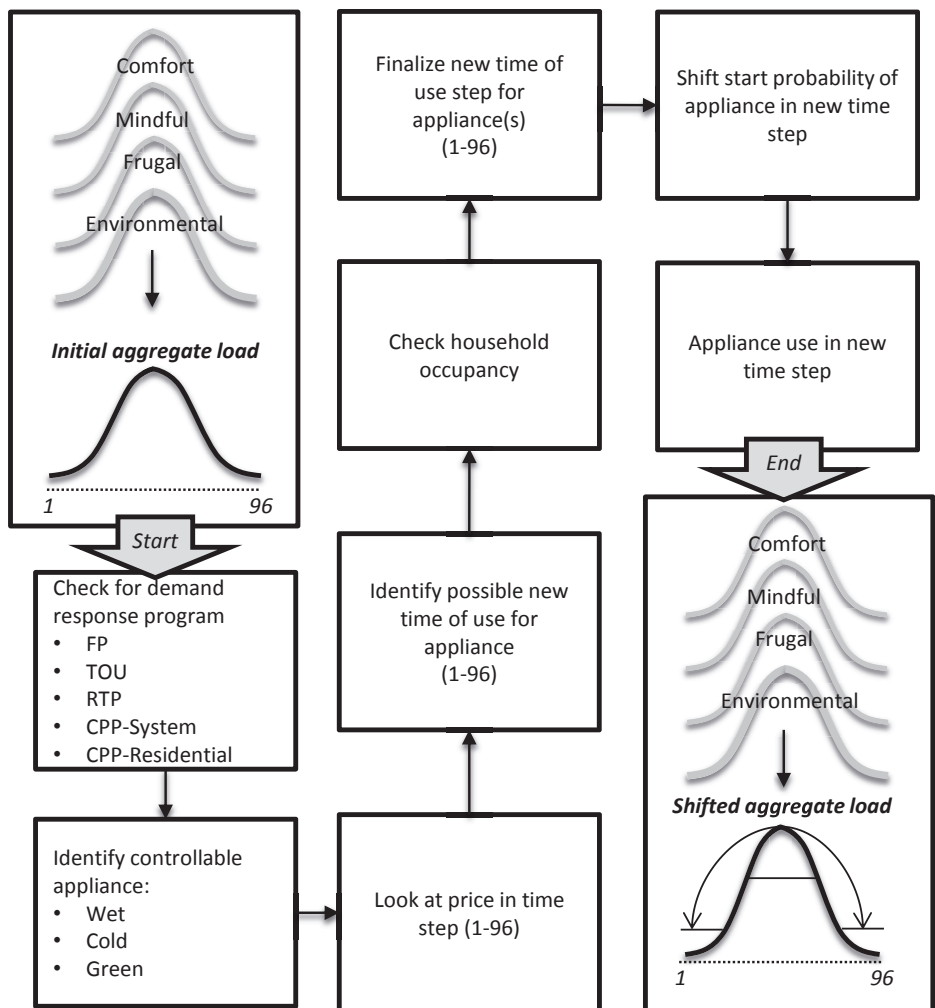


Figure 20: Load shifting activity

archetype is aggregated once again at a country level for assessment. See Figure 21 for the load profile of each customer archetype when subject DR.

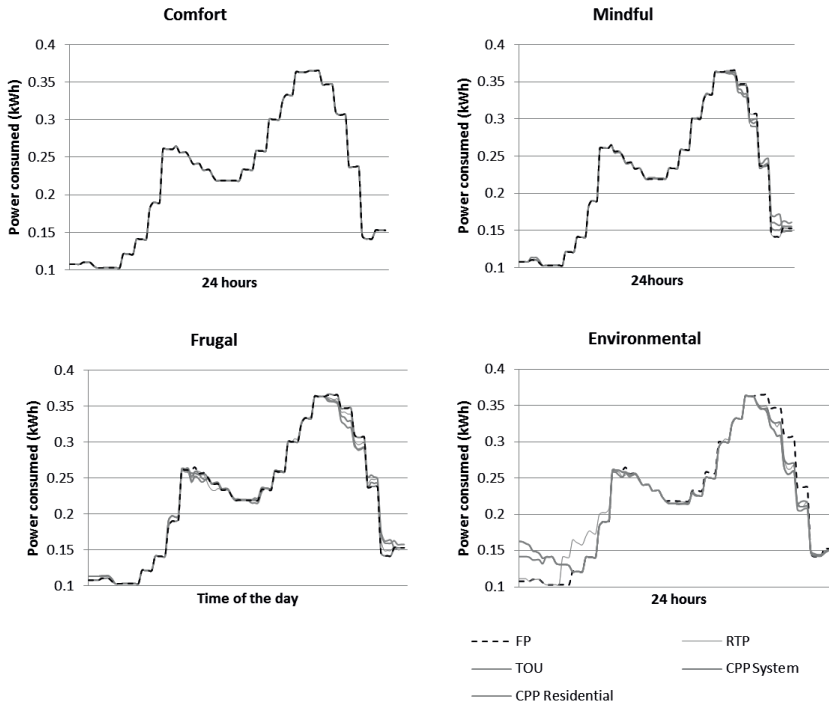


Figure 21: Load profile for and average household of each preference archetype, generated from (Mahalingam, 2013)

PRICE-BASED DEMAND RESPONSE SIMULATION ASSESSMENT

Costs, benefits and flexibility of end-user demand under currently system conditions

Each price-based mechanism yields different benefits for the end-users and the system. As a result, the impact of DR is assessed in three ways: (i) in accordance with the costs incurred by individual households and the system under current conditions, (ii) the impact on peak demand and (iii) the resulting elasticity. The analysis considers the current system conditions and increasing penetration levels of electric vehicles and PV micro-generators.

Individual and system costs under current conditions

Under current system conditions of fixed pricing a household in the Netherlands pays a little over 2 euro a day for electricity resulting in an aggregate country cost of approximately

€16 million. Table 10 provides a summary of the individual household expenditure³⁴ in addition to the total daily expenditure on electricity by the whole residential sector. See Figure 22 for the whole country and Figure 21 for each of the household archetypes.

Table 10: Daily expenditure according to DR program implemented

	FP	TOU	RTP	CPP-System	CPP-Residential
Average cost per household	2.32€	2.23€	2.59€	2.63€	5.29€
Country cost (millions of €)	16.39€	16.47€	18.45€	31.29€	34.25€

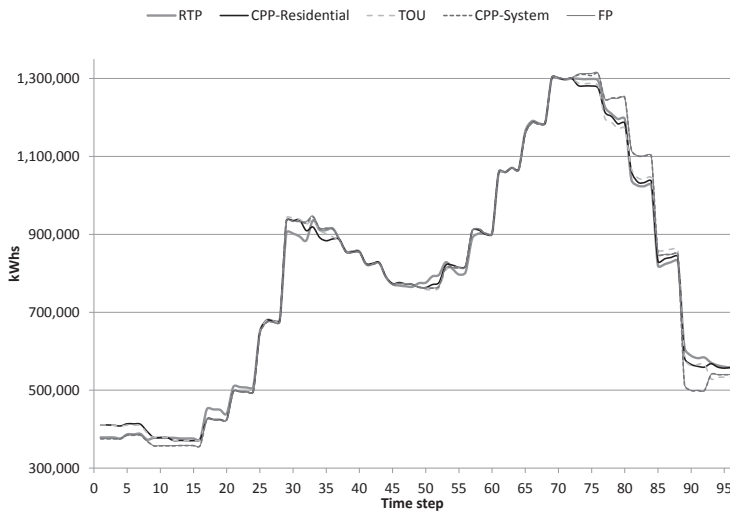


Figure 22: Country residential load (system) per price-based mechanism

On average, if end-users are prompted by a menu of price-based DR mechanisms in a single day CPP programs (both residential and system) are the most expensive options for individual households. CPP-Residential is about double the cost for an average household when compared to the other programs, indicating that during these peak hours there is the most potential for DR load shifting. RTP and FP are the following options, with TOU fairing as best option with an average cost of 2.23 Euro per day. For the system the cheapest option remains FP followed by TOU. When considering total load shift in one day RTP triggers the largest load shift³⁵ followed by CPP-R, TOU and CPP-S. The most responsive consumer archetypes are *environmental* followed by *frugal*, *mindful*

³⁴ The daily expenditure on electricity by an average Dutch household is defined by the weighted sum of the expenditures of all the households and number of households of each preference and type, divided by the total number of households in the Netherlands.

³⁵ Approximately 894,400 kWhs in each direction

and *comfort*. Such responsiveness is expected on account of *environmental* consumers allowing for complete automation of controllable appliances under the consideration of total cost (see Table 9 for details of shifting decisions).

DR is evidently time dependent: if consumers are not home they cannot modify consumption (unless there is automation of appliances). Hence, it is important to take note of the hours where the majority of consumption takes place and focus on those for tariff design.

Implications of demand response in different time steps

Residential load is equal to more than 25% of the total country consumption over less than 7 hours of the day (see Appendix Figure 52 and Figure 23 below). During these hours almost 43% of the total residential load (32,581,552 kWhs) is consumed a figure that is equal to about 10% of the total country load for the day³⁶. Specifically, the hours between 15:00 and 20:45 are considered the peak consumption segment since almost 90% of this consumption takes place (28,847,529 kWhs), see Figure 23. For the same day in consideration, from 15:00 to 20:45 there is a need for absolute imbalance management of over 550,000 kWhs and an additional 640,000 kWhs of intraday market trading opportunity, respectively this is flexibility that is equal to 1.9% and 2.2% of the total residential load during those same hours. Throughout the day RTP, CPP-R and TOU can provide about half of the balancing and intraday load modification needed. Table 11 summarizes the load shifting that each price mechanism prompts and from the figures presented, each mechanism (except for CPP-S) can instigate about half of the total flexibility; the question is can be guaranteed in the hours of need for system operation? This then becomes a mechanisms design issue and the way it is communicated to the customers. Per household in the Netherlands the DR needed is small (less than 0.1 kWhs), but how flexible are consumers (really) i.e. how elastic per mechanism.

Table 11: Change in load according to each mechanism

DR price mechanism→	TOU	RTP	CPP-S	CPP-R
Load modification throughout the day				
<i>Total load shift of residential sector in one direction (kWhs)</i>	719,980	894,412	14,214	792,828
<i>Load shift as a % of total country consumption for that day</i>	0.95%	1.18%	0.02%	1.05%
<i>Average shift per household (kWh)</i>	0.100	0.124	0.002	0.110

³⁶ Total country load for the day amounts to 335,649,000 kWhs of consumption, data obtained for March 27th 2013 from ENTSO-E (2013).

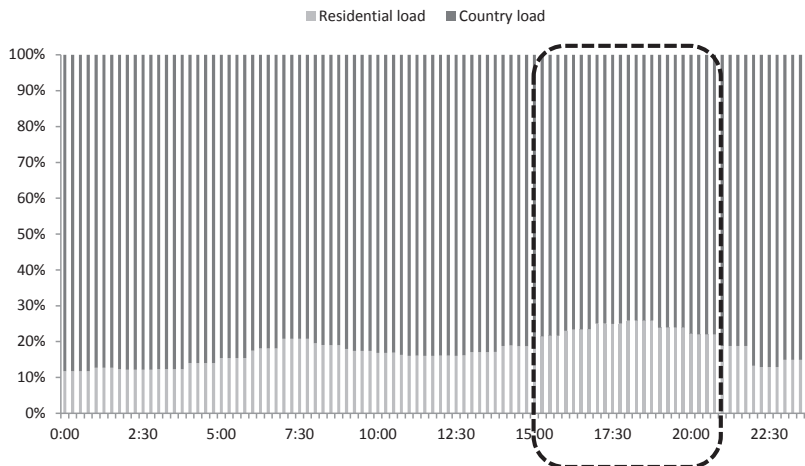


Figure 23: Residential load as a percent of total country load³⁷, highlight represents the hours between the hours of 15:00 and 20:45

Flexibility in accordance with price mechanism

When considering average own price elasticity of demand for each price-mechanism in the simulation, TOU pricing (-0.048) is the most elastic followed by CPP-R (-0.040). RTP on average yields inelastic while CPP-S demonstrates an insignificant level of average elasticity of demand, see Figure 24 and Table 12. These elasticity values indicate that demand is actually relatively inelastic; a given increase in the price of electricity is proportionately larger than the decrease in the quantity demanded. Nonetheless, these values indicate at least some consumer sensitivity to price when given a TOU or CPP-R program; respectively when TOU and CPP-R prices increase by 10% there will be a decrease in demand of 0.48% and 0.40%, these values are in line with what has been derived from pilot projects discussed above in 3.1.

The elasticity of substitution from peak to all off-peak hours (shoulder and base) as defined by APX (Figure 9), overall RTP is the most elastic followed by CPP-R. TOU and CPP-S exhibit no elasticity of substitution from peak to off-peak hours of consumption. In this case respectively, an average RTP and CPP-R elasticity of substitution of 0.11 and 0.05 between off-peak and peak consumption indicates that a 10% increase in the peak/off-peak price ratio leads the average consumer to substitute 1.1% and 0.5% of on-peak consumption for off-peak.

Differently, when considering peak to base hours of substitution, yielding a 3.1% on peak to off-peak consumption substitution with a 10% increase in the peak/off-peak price ratio. For peak to base hours substitution RTP (0.08) and CPP-R (0.05) are also

³⁷ Country load obtained from ENTSO-E data March 27th 2013, the same day that is used to construct the RTP price calculation.

inducing consumer responsiveness. CPP-S elasticity of substitution is only significant from peak to shoulder hours with a value of 0.25, otherwise it remains inelastic.

TOU is significant in most instances and illustrates some overall elasticity with almost every calculation of elasticity of substitution, see Table 12 and Figure 24. The assessment of both own-price elasticity and elasticity of substitution prove to be in line with the findings in case studies Figure 10 and Figure 11.

Table 12: Average elasticity of demand and substitution for each demand response program (peak, shoulder and base hours are taken from APX defined hours), grey highlight indicates the most significant values.

	TOU	RTP	CPP-S	CPP-R	Most elastic
<i>Average own-price</i>	-0.04768	0.10163	-0.00009	-0.03964	TOU
Peak	-0.12722	0.01826	0.00012	-0.00417	TOU
All off-peak shoulder and base	0.01962	0.17218	-0.00026	-0.06965	CPP-R
<i>Average substitution</i>	-6.48559	0.10606	-0.45662	0.05992	RTP
Shoulder	2.38947	-0.17600	0.00048	0.02593	RTP
Base	-0.41127	0.23548	-0.00040	-0.08703	TOU
<i>Average substitution (Peak shoulder)</i>	-0.05324	-0.10376	0.24973	-0.16100	CPP-S
<i>Average substitution (Peak base)</i>	0.30933	0.07755	-0.30155	0.04796	TOU
<i>Average substitution (Shoulder base)</i>	-5.81001	-0.74740	-1.20748	-0.29788	CPP-R

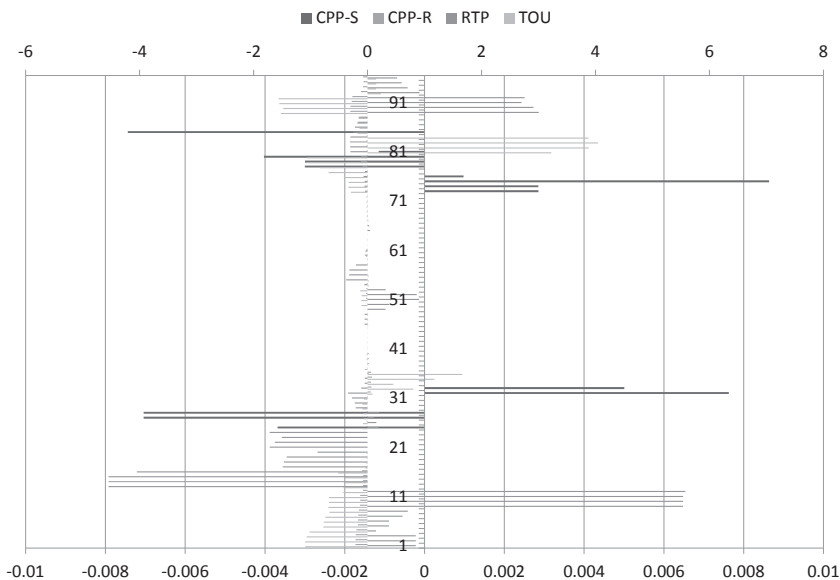


Figure 24: Elasticity of demand at each time step

Peak demand

When considering DR, a main focus is peak shaving and shifting to valley periods. When looking at each price mechanism, all dynamic prices induce a slight decrease in peak demand which in all cases is less than one percent of the initial load (Figure 22). Specifically as summarized in Table 13, CPP-R reduces the peak by 0.870% (11,432 kWhs) followed by RTP (-0.868%), TOU (0.855%) and CPP-S (0.050%).

Under current conditions, simulation results indicate the impact of price-based demand response on the peak residential load to be relatively low at less than 1%. Consumers are regarded to be relatively inelastic to price changes. Overall prices per remain low, unless a CPP event is called.

Thus far, the current appliance penetration rates have been assessed, but as theory suggests deeper penetration of controllable loads may have a significant impact on consumer behavior under the consideration of different price-based DR mechanisms. Below follows an assessment of consumer and system costs, elasticity evaluation and peak demand impact of price-based mechanisms under the consideration of increasing levels of PV micro-generation and electric vehicles.

Table 13: Change in peak demand per price mechanism, grey highlight indicates the most significant values.

	<i>FP</i>	<i>TOU</i>	<i>RTP</i>	<i>CPP-S</i>	<i>CPP-R</i>
Percent (%) change in peak demand	0.00000%	-0.85514%	-0.86829%	-0.05023%	-0.87058%
kWhs change in peak demand	0.00	11,228.58	11,401.19	659.38	11,431.28

Technology impact and demand response evaluation of price based mechanisms

In a smart grid it is expected that consumers will increasingly adopt micro-generation and mobility electrification. In this section we take the current base case of 7,500 EVs and 27,700 solar PV systems and assess each technology separately and together on a one to one ratio in the following scenarios, Figure 25:

1. Increasing PV penetration while keeping EVs steady at the current level of 7,500.
2. Increasing EV penetration while PVs steady at current level of 27,700.
3. Increasing PVs and EVs simultaneously in a 1 to 1 ratio.

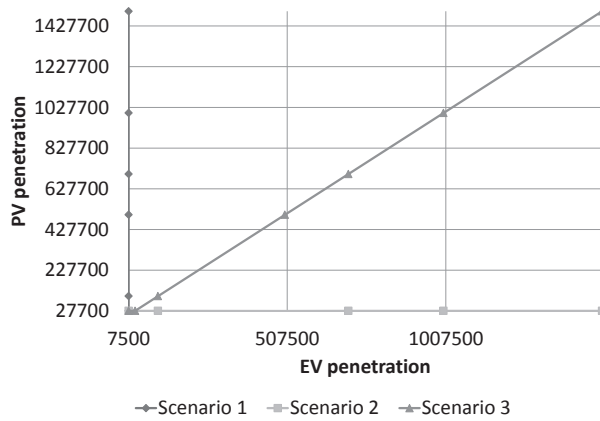


Figure 25: Scenario analysis for technology impact

Cost of electricity

Overall individual households and the system experience lower costs with all price mechanisms when there is a deeper penetration of PVs, followed by a 1 to 1 ratio of EVs to PVs. With 1.5 million PVs and steady EVs at 7500, CPP-S costs for the country are 10.83€ million; such costs are in line with FP at 10.65€ million and TOU at 10.41€ (see Table 30 in Appendix). These values indicate savings of about 6 million Europe daily for the residential sector, which in turn could result in savings of over 300Euro per household per year in the Netherlands.

Both individual households and system costs increase with more EVs in scenario 2; for individual households, average prices are the lowest with TOU followed by FP, RTP, CPP-S and CPP-R while for the system, FP have the lowest average cost followed by TOU, RTP, CPP-S and CPP-R.

When looking at a one to one ratio in scenario 3 with FP, TOU and RTP average household costs increase with deeper PV and EV penetration levels. Differently, with CPP-S household costs increase until EVs are equal to PVs at 27,700, after that costs continue to fall. From the three scenarios, TOU is the cheapest option for individual households followed by FP, CPP-S, RTP and CPP-R. For the system, the cheapest option is FP followed by TOU, RTP, CPP-S and CPP-R; see Figure 26 and Figure 27 below and Table 30 in the Appendix. For the system (Figure 27) the difference between total cost with TOU and FP is 0.33% while for an individual household the difference is 4.19%. Since individuals are impacted more by the difference than the system, TOU is recommended as a mechanism for implementation since it induces behavioral change and therefore overall lower system costs may result.

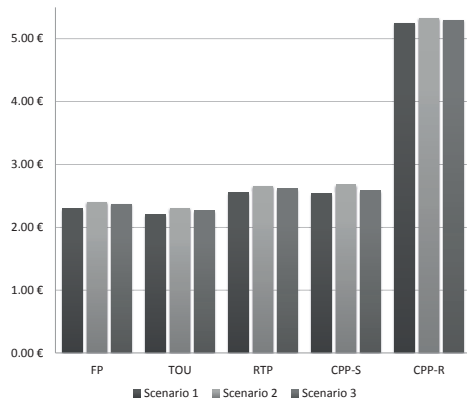


Figure 26: Average household costs per price mechanism (Euro per household)

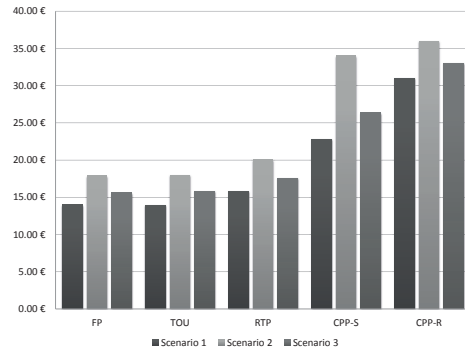


Figure 27: Average country cost per price mechanism (Millions of Euro)

Elasticity of consumers

When considering response to price mechanisms the behavioral response of consumers is assessed with own-price elasticity of demand, as discussed above in section 3. With a PV penetration of 1.5 million in scenario 1, consumers demonstrate average price responsiveness with each mechanism. As illustrated in Figure 28, RTP (-0.27) is the most elastic followed by TOU (-0.050,) CPP-R (-0.042) and CPP-S (-0.013). These elasticity values are still comparable to the base case above; only RTP becomes more interesting of a price, which makes sense considering the option to sell flexibility back to the system with PV micro-generation. Note, even with more PVs in the system, the increase in electricity prices is still proportionately larger than the decrease in quantity demanded.

In scenario 3 with a one-to-one penetration level of EVs to PVs at 1.5 million, TOU yields an elastic demand with an average own price elasticity of demand at -1.52. Also, TOU pricing with a penetration level of 1 million EVs in scenario 2 results in average elasticity of -1.07. Respectively, a 10% increase in the average TOU pricing would result in a 15.2% decrease in demand in scenario 3 and 10.7% decrease in consumption in scenario 2. These changes are interesting since the decrease in quantity of electricity demanded is proportionately higher than the increase in price.

CPP-R is interesting for PV penetration levels of less than 500,000 in scenario 1 and 1.5 million EVs in scenario 2 and the one-to-one case in scenario 3, indicating that this is a good choice to implement under current conditions and in the case of large penetration levels but not in between values. Overall, average own price elasticity is higher with TOU mechanisms and consumers are more elastic with a one-to-one ratio of PVs to EVs (scenario 3) followed by more EVs (scenario 2) and finally PVs (scenario 1), see Figure 28.

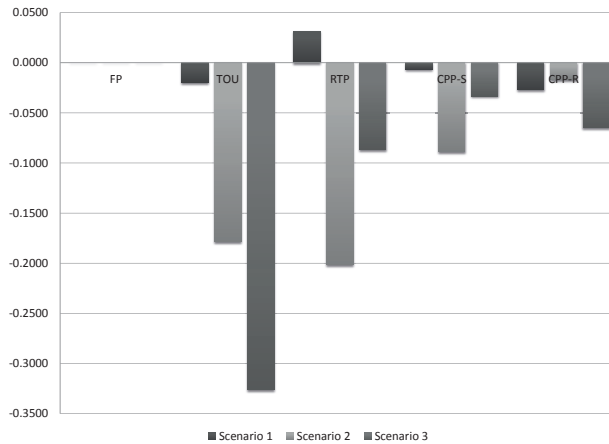


Figure 28: Average own price elasticity per scenario

Peak demand

When considering, increasing PV levels in scenario 1, TOU is the best option with penetration levels being optimal at around 700,000 PV micro-generators. For increasing EV levels in scenario 2, CPP-S is the best overall option with 700,000 electric vehicles integrated. For scenario 3, CPP-S and RTP also indicate a steady peak reduction. Optimal load reduction results are obtained with a penetration level between 500,000 to 1 million PVs and EVs. System peak demand is lower with a CPP-S followed by RTP, TOU and FP; see Figure 29 and Figure 30.

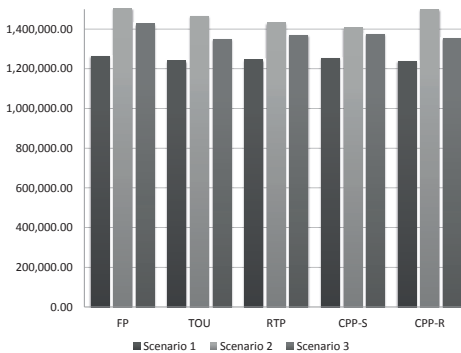


Figure 29: Average peak demand

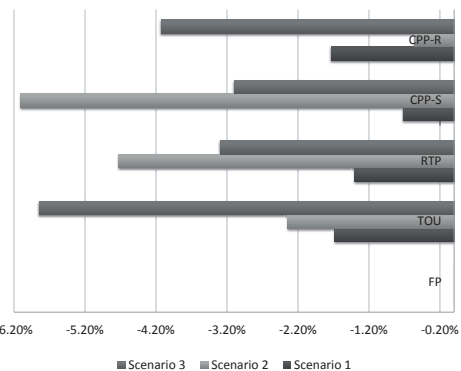


Figure 30: Average change in peak demand

EV and PV penetration discussion

Overall, TOU mechanisms perform the best in the base case assessment (5.1) and in the increasing technology penetration scenarios followed by CPP-S. RTP becomes interesting

in the case of reducing peak demand with more EVs in scenario 2 and 3. Moreover, favorable results for reducing total costs, increasing consumer elasticity and reducing peak demand are produced with a combination of both PVs and EVs in the system at a level of about 700,000; above this penetration level the aggregate residential load becomes negative which may in turn negatively impact system prices in the short term electricity markets. Overall, costs remain the lowest with more PVs for both individual households and the system. But in this case, consumers are the least elastic and produce the lowest percent change in peak demand since overall PV production occurs at the system peak and not the residential peak. PV generators can only produce during certain hours of the day; elasticity is therefore limited unless there is storage integration. The simulation results indicate that EVs should be promoted with PVs in order to keep costs lower and induce an elastic demand.

MODEL VERIFICATION, VALIDATION AND SENSITIVITY³⁸

Model verification

Verification is the process of determining that the model implementation is executed appropriately, in such a way that it accurately represents the desired conceptual descriptions and specifications. This model was built in Repast Symphony and for verification of accuracy and consistency manual calculations were conducted in MS Excel. In essence, model verification ensures the accuracy of the model. For agent based modeling there are 4 parts to verification (Dam et al., 2012): (i) recording and tracking agent behavior; (ii) single agent testing; (iii) interaction testing; (iv) multi-agent testing. See Appendix **Table 31** for a detailed model verification assessment.

Validation

The application of price-based demand response with a menu of price options (FP, TOU, CPP and RTP) has not been extensively applied to the residential electricity sector of the Netherlands. Current investigations consist of a few executed pilot projects and several others in pipeline, but not all information is publicly available, in turn making historical validation difficult to execute. A face validation was conducted with smart grid expert Dr. Rudi Hakvoort³⁹ (TU Delft) on the underlying model assumptions and methodology. A literature review from international studies on the application of price-based demand response in the residential sector corroborates the conducted analysis above. For instance, Faruqi et al. (2009) determine that dynamic tariffs for have the potential to reduce

³⁸ See Mahalingam (2013) for a further detailed assessment.

³⁹ (Netherlands Enterprise Agency, 2014)

system peak demand from 1% to 9%; such results are consistent with the findings of the simulation outputs in this work. When considering elasticity values, the model outputs are in line with those summarized in Neenan (2008) and in the review above in section 3 for all the simulated price mechanisms.

Sensitivity analysis

In order to understand the sensitivity of the modeling parameters used for simulation, two sets of experiments were carried out considering: (i) the appliance penetration levels and (ii) number of households of each archetype. For a reference comparison, the percent of peak reduction in considered, see appendix Figure 53 and Figure 54.

The sensitivity analysis reveals that the frugal household archetypes are the most critical parameter for most price-mechanisms. Moreover, with a change in the penetration rate or appliances, EVs are the most sensitive of all appliances, having the greatest influence on reducing peak demand. Moreover, on account of their potential to shift the time when system peak occurs, electric water heaters and dishwashers are also regarded as critical parameters.

CONCLUDING REMARKS

At the individual household level electricity load curves vary a great deal (Paatero and Lund, 2006) as a result of consumers' behavior and therefore consumption patterns are not fully rigid (He et al., 2013b), although frequently habitual (Lopes et al., 2012). The correlation between 'predictability' and 'flexibility' of load is not straightforward. Being predictable doesn't necessarily mean that a load could be more easily shed or postponed (He et al., 2013b). Accordingly, the above results corroborate these facts about end-user consumption and the possibility for DR activation through price-based mechanisms.

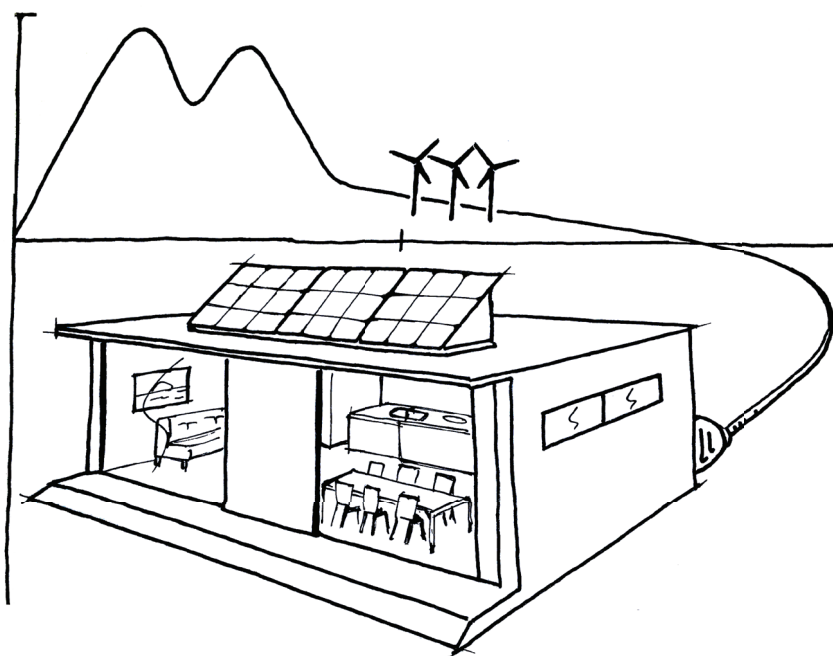
Under current conditions, simulation results indicate the impact of price-based demand response on the peak residential load to be relatively low at less than one percent; consumers are relatively inelastic and overall prices per average household and for the country remain low, unless a critical peak pricing event is called for specified hours. A critical-peak pricing mechanism considering the residential peak (CPP-R) yields double the costs of average fixed pricing for households on the day of an event, indicating that during these peak hours there is the most potential for DR load shifting to occur.

As evidence from other studies and pilot projects in addition to the simulation analysis above, an increase in the price of electricity is proportionately larger than the decrease in the quantity of electricity end-users demand. The values resulting from the simulation indicate some consumer sensitivity to price when given blocks of dynamic prices to

respond to, specifically TOU and CPP. For an average consumer the brunt of daily consumption occurs during a specific time block, tariffs should focus their design on targeting those hours of consumption making it as simple as possible for consumers to respond (especially by finding ways to invest and promote automation).

Overall, average own price elasticity is higher with TOU mechanisms and consumers are more elastic with a one-to-one ratio of PVs to EVs, followed by only more EVs and finally only more PVs. These results indicate that if we want a better balance in the system the mass of increasing production should be stimulated alongside that consumption but not past a level where the residential load yields negative aggregate consumption (unless this is the system objective).

When promoting demand response through price, attention should be paid to the desired level of response. Although demand is currently inelastic, the right mix of technology penetration may result in high levels of response. Regulators should take note of the level of response they desire from end users.



CHAPTER 4

AGGREGATION AND ACCESS TO ELECTRICITY MARKETS

In the previous chapter the estimation of responsive load was discussed in detail followed by an analysis of the design of price based mechanisms. A simulation case study revealed that residential load is relatively unresponsive, but nonetheless can be stimulated through a carefully designed price-based mechanism. In this chapter, the facet of alleviating system distress through explicit (volume-based) demand response is considered in work resulting from Koliou et al. (2015a, 2015b)⁴⁰ and in the collaboration of Abdul Muhaimin (2015)⁴¹.

⁴⁰ Koliou, E., Abdul Muhaimin, T., Hakvoort, R.A., Kremers, R., 2015a. Complexity of demand response integration in European electricity markets, in: 12th International Conference on the European Energy Market, Lisbon Portugal.

Koliou, E., Abdul Muhaimin, T., Hakvoort, R.A., Kremers, R., 2015b. Complexity of end-user access to European electricity markets: The case of aggregation for demand response. Working paper at Delft University of Technology, the Netherlands.

⁴¹ Abdul Muhaimin, T., 2015. Electricity market of the future: assessing economic feasibility and regulatory constraints for demand response aggregators in Europe. Master thesis, Delft University of Technology, the Netherlands.

INTRODUCTION

The contracting of demand response (DR) for volume-based services will be done by an 'aggregator'. The aggregator will pool the demand flexibility offered by customers acting "...towards the grid as one entity, including local aggregation of demand (Demand Response management) and supply (generation management)" (EC TF for Smart Grids, 2011). In the transforming European electricity system, the aggregator is not a clearly identifiable actor. Roles and responsibilities of this emerging party are still in development and so is the market structure for appropriate integration. As the coordination of flexible load from consumers is an intricate process of procurement and execution, this chapter examines the deemed 'aggregator' with the aim of understanding which market party is best fit to participate in the various short term electricity markets. Using the Netherlands as a case study, a detailed analysis of the processes, costs and potential gains from active spot market participation is presented. The aim of this chapter is to bring to light some of the complexities facing aggregated DR incorporation in the European electricity system.

4

MOTIVATION

The European Commission (EC) addressed the need for the implementation of intelligent metering systems to assist active participation of consumers in the electricity supply markets back in 2009. In Directive 2009/72/EC it is specified that at least 80 percent of households shall be equipped with intelligent electricity metering systems by 2020 (EC, 2013a). More recently, the Energy Efficiency Directive 2012/27/EU (EC, 2012), ENTSO-E⁴² Demand Connection Code (ENTSO-E, 2013a), and the ACER⁴³ Framework Guidelines on Electricity Balancing (ACER, 2012) communicate the need for end-user activation. Such documentation conveys to member states that DR resources through aggregation should be facilitated to participate alongside supply in both wholesale and retail markets (Koliou et al., 2014). Specifically, Article 15.8 of the Energy Efficiency Directive (2012/27/EU) provides a legal basis for further development of DR in the European member states (EC, 2012). Thus far there have not been any consequences on member states for not complying with the energy efficiency directive 'requirements' on demand side response. A brunt of the focus remains to getting end- users access to smart meters.

⁴² European Network of Transmission System Operators for Europe (ENTSO-E) (ENTSO-E, 2013a)

⁴³ Agency for the Cooperation of Energy Regulators (ACER) (ACER, 2012)

Note, the above mentioned communications place an emphasis on the aggregation of small end-users (EC, 2013a). The consensus is that the residential sector is an untapped pool of system-wide flexibility, a more cost-effective solution when compared to increasing large scale generation capacity and grid reinforcement (both transmission and distribution) (Ikäheimo et al., 2010; Strbac, 2008). This cost efficient solution is increasingly interesting on account of recent developments in information and communication technology which have opened new opportunities for demand side initiatives in the innovation of the residential electricity business (Strbac, 2008; Torriti et al., 2010). But, the success of DR is highly dependent on effective knowledge of consumer characteristics and respective behavior patterns (Paatero and Lund, 2006). Below follows a discussion on the complexity of DR and the entity appointed for aggregation of such flexibility.

DEMAND RESPONSE ACTIVATION

When it comes to residential electricity consumption there are some undeniable characteristics to consider, which are discussed extensively in Chapter 3. Essentially, household electricity consumption (and production) results from the use of electrical appliances, which means that consumers are not always aware of the consumption and/or production taking place. Moreover, demand fluctuates widely within a household and from one household to the next according to time of day, day of the week and season (Paatero and Lund, 2006). Owing to such characteristics, the activation of flexibility entails careful examination of the capability of individual loads and groups (Valero et al., 2006). Such an examination can be provided by an aggregator (EC TF for Smart Grids, 2011; FENIX, 2009; Prügler, 2013). Below the authors present an analysis on the access to flexibility and scale followed by a discussion on the deemed aggregating entity.

Aggregation at each level

DR flexibility comes in different sizes which must be pooled. Aggregation takes place in individual households and neighborhoods/communities for service provision to market parties in need of flexibility: transmission system operators (TSOs), distribution system operators (DSOs), retailers, generators and balance responsible parties (BRPs) (FENIX, 2009).

Individual household level aggregation

For individual households, aggregated DR is dependent on access to distributed energy resources and enabling technology to provide flexibility. Specifically, such technology includes controllable (smart) appliances (heat pumps, air conditioning systems, electric heating systems, electric water heaters, dishwashers, washing machines, clothes dryers, freezers/refrigerators, electric vehicles, home storage systems etc.) and micro-generators

such as solar photovoltaic (PV) systems (Geelen et al., 2013). See Figure 31 and Table 7 in Chapter 3 for a summary for the household controllability characteristics. For instance, in the Netherlands it is estimated that approximately 40 percent of the total electricity consumption in a household comes from controllable loads (Koliou et al., 2013b; Mahalingam, 2013).

Appliances and micro-generators need to be centrally monitored and controlled in a household. The smart meter provides the initial gateway for aggregate measurements in the household. Moreover, home energy management systems are necessary for access to information ranging from an aggregate level to a breakdown at the individual appliance level in addition to allowing for automation control. Such systems in combination with smart metering stimulate household awareness and have the potential to instigate savings from the provided insight. Home energy management systems act as the interface between a consumer's flexibility device and the aggregator coordinating flexibility scheduling. The existing supplier of a consumer, deemed aggregator, or the consumer himself can install this interface. Note that in home energy management systems differentiation is indispensable. Provided that *'one size does not fit all'*, different forms of feedback interaction and visualization will be required for the various target types of households (Geelen et al., 2013).

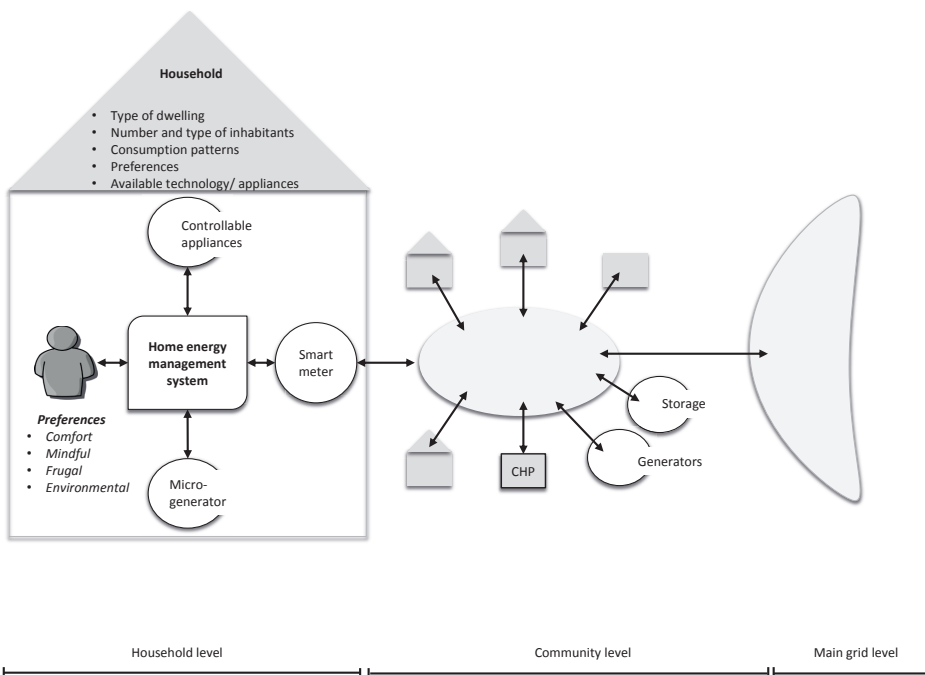


Figure 31: Household controllability characteristics in the Netherlands at different load levels, adapted from ref. Geelen et al. (2013)

Community level

Access to more DR products and services becomes available when a collection of appliances, micro-generators and storage devices form a community of pooled flexibility (Figure 31). For instance, at a community level shared distributed generators (DG) include several photovoltaic systems in addition to micro-wind turbines. At times when there is excess wind or sunlight, electricity from such generators can be stored in community storage systems or individual household battery systems. Moreover, at a community level electric vehicles can, for instance, charge at community charging stations from locally produced electricity. Community combined heat and power units (CHP), generators, batteries and charging stations are managed individually by the owners or by community cooperatives. All these sources of flexibility can be pooled into the portfolio of one aggregator or several (Ikäheimo et al., 2010).

Building up a large and flexible portfolio which provides both local and system support is a complex task to undertake by multiple 'agents' in the system, whether it is through automation or manual control. For individual households and the community, an aggregator can aid in the access, signaling and the scheduling of DR release in order to keep the balance between supply and demand (Ikäheimo et al., 2010). In a dynamic multi-agent system an appropriate market-based control approach for matching supply and demand in electricity systems is needed for appropriate coordination (Kok et al., 2005); such a task has been undertaken in the PowerMatcher conceptualization and implementation (Flexiblepower Alliance Network, 2015; Geelen et al., 2013; Kok et al., 2005). This platform was developed in the Netherlands by a consortium of researchers (academic and industry) along with regulated and commercial market player (Flexiblepower Alliance Network, 2015).

PowerMatcher aggregation conceptualization

PowerMatcher works under market-based control theory, i.e. to optimally achieve local control action objectives in a setting where a large number of agents are competitively negotiating and trading on the same exchange platform. The matching of supply and demand is based on microeconomic theory, where end-users make decisions concerning the allocation of limited resources. Accordingly, PowerMatcher utilizes available electricity consuming and producing devices to derive system operation that optimally matches supply and demand, see Figure 32 (Kok et al., 2005).

In PowerMatcher the aggregator is defined in terms of a 'device agent', 'concentrator agent', and 'central auctioneering agent' representing the aggregator's actions at individual appliance level, a collection of devices level, and the central optimization and dispatch level respectively (see Figure 32). Each household appliance is regarded as a device agent aiming to optimally (in economic terms) execute DR based on a marginal cost price and volume bid. Note, each appliance values DR differently and can be

programmed to include all preferences. The concentrator agent i.e., the chosen home energy management system fetches and pools the bids and prices for all the devices connected to it and in this way implements the local energy management strategy of the household. The pooled bid is then sent to the central aggregator, where the central auctioneering agent optimizes the flexibility schedules based on market conditions (Flexiblepower Alliance Network, 2015; Kok et al., 2005).

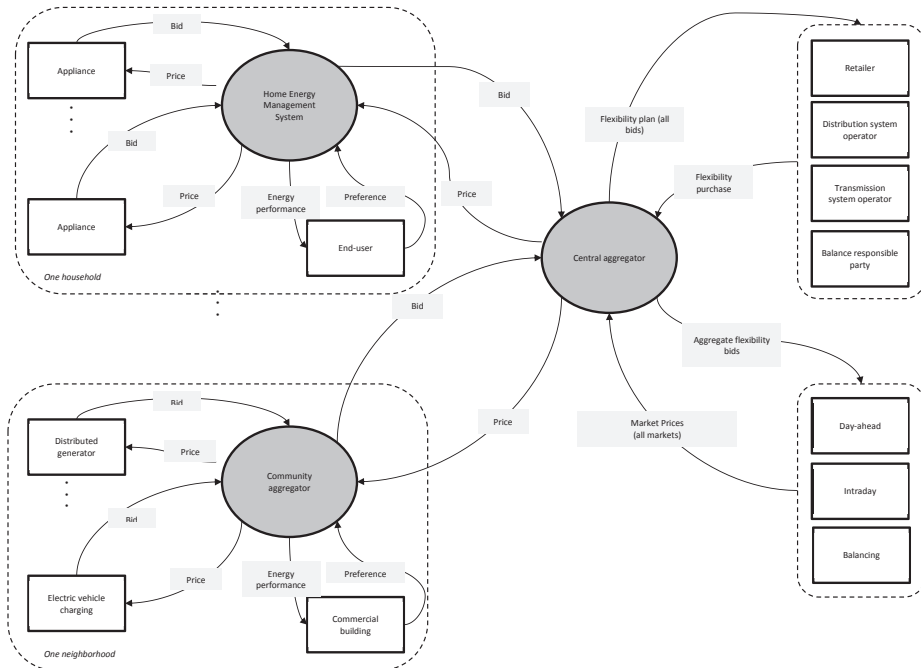


Figure 32: PowerMatcher concept, adapted from ref. (Flexiblepower Alliance Network, 2015; Kok et al., 2005)

Household application of PowerMatcher

PowerMatcher has been in development since the early 2000s and has recently become open source. As a result, the programming of device agents can be done with a simple RASPBERRY PI⁴⁴ and the home energy management system can be a laptop or a tablet that communicates with the smart meter. Such an approach allows the consumer/prosumer to remain in control while ensuring scalability prior to flexibility provision at the central aggregator's level, who finally trades the optimized flexibility schedules to the larger system (Flexiblepower Alliance Network, 2015). A similar concept can be applied at the community level for the larger flexible loads described in 3.1.2. The

⁴⁴ <https://www.raspberrypi.org/>

aggregate price and volume bids are communicated to the market parties and traded as pooled flexibility via bilateral contracts, in the different markets, or are offered for system support services to the system operator(s).

The aggregator

An aggregator will enable consumer participation in markets, define DR programs and requirements, provide services for the measurement and verification of the programs, settle payments and associated risks (SEDC, 2014). In the current European electricity market model, the function of aggregation is seen as an added service which gives electricity customers the opportunity to reap the full benefits of their flexibility potential (Eurelectric, 2015). Specifically, it is expected and desired that the aggregator is a competitive actor – either an independent entity or a retailer seeking new business opportunities (EC TF for Smart Grids, 2011; Eurelectric, 2015). For this research, we conducted a set of stakeholder interviews in order to see who should take up the role of an aggregator in Europe, see Figure 33.

The 11 respondents of this survey include six large utilities (from both within Netherlands and outside), one distribution system operator, a representative from the Dutch Ministry of Economic Affairs, a European industry lobby group, one established independent aggregator from France, and one potential aggregator (a start-up awaiting market penetration), see Figure 33 for a summary of the ranking⁴⁵. The survey corroborates that the aggregator should be a competitive market party. Most parties consider that a regulated entity such as a distribution system operator is not suitable to perform the aggregator role in Europe. In this context, the discussion continues under the premise that an aggregator for end-users under will be a competitive market party.

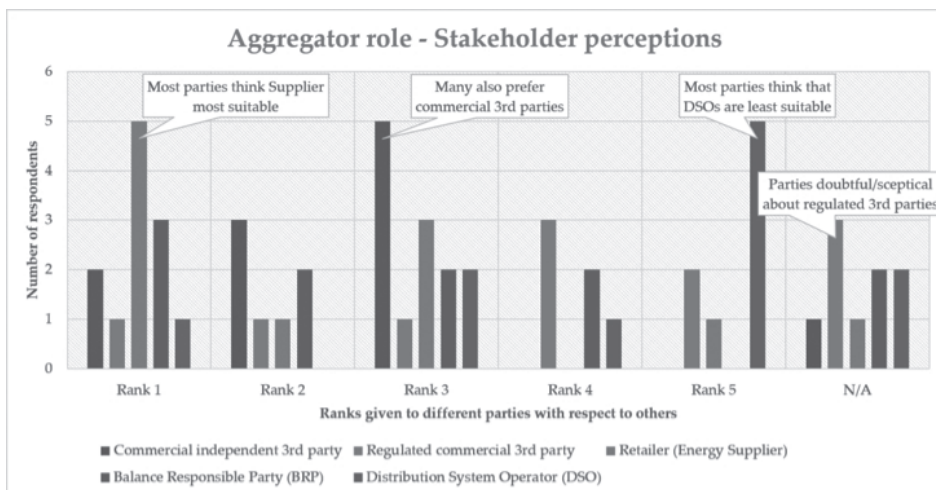


Figure 33: Survey of who should take up the aggregator role in the European context

⁴⁵ Specific names of the respondents are not provided in order to protect their privacy.

The retailer

In the current 'supplier-hub' model of the post liberalized electricity markets in Europe, energy retailers act as the customer point of contact. For European consumers, the retailer deduces the intricate value-chain relationships of electricity production and transport into one bill⁴⁶. Retailers charge consumers (monthly, bi-monthly and/or yearly) to act as the intermediary responsible for procuring their electricity. While retailers are only responsible for procurement of generation supply to customers, in most European countries they combine the billing for the supply component (generation and retail), network (transmission and distribution), related taxes and other fees such as metering. In some European countries (e.g. Sweden) customers receive a separate bill for network charges (Eurelectric, 2013).

It can be argued that retailers are currently in the best position to become aggregators since they have established relationships with balance responsible parties, network operators and customers. As the direct contact to customers, suppliers have contractual access to the data of end users. Moreover, retailers also carry balance responsibility and have access to all electricity markets, both short and long term. Note, retailers range from over 1000 in Germany to just half of that in Italy, 45 in the Netherlands and only 13 in Portugal (EC, 2013b), so it does not mean that all can enter the aggregation business and become profitable.

Independent aggregator

Independent aggregators consist of competitive (and often new) market parties looking to make a profit by providing DR aggregation and additional services to end-users and market parties. Aggregation value maximization may come from attempting to offer as many services as possible, including trading aggregated flexibility of individual household appliances in the various markets and providing household data analytics services for optimizing electricity usage (Eurelectric, 2015; Eurelectric, 2015; FENIX, 2009). Differently, aggregators can also maximize profits by specializing in a flexibility service depending on their customer base, available technologies and costs. For instance, with a large electric vehicle fleet an aggregator can focus his business model on aggregation, charging coordination and 'release' of demand flexibility to the system (Ikäheimo et al., 2010). Currently in the Netherlands you have companies such as PlugSurfing (2015) and GreenFlux (2015) which focus on electric vehicle charging. Companies such as BELECTRIC (2015) combine a variety of distributed energy resource services for both households and communities including rooftop and community photovoltaic systems, electric vehicle charging and energy storage. This type of specialization may result in such parties becoming aggregators on account of having access to larger loads than the

⁴⁶ In some European countries (e.g. Sweden) customers receive separate bills for supply and network charges.

average household. The specialized aggregator model may prevail since different types of loads compel the use of different technologies (Ikäheimo et al., 2010). There is also the possibility that these new parties may become the new point of contact with the consumers, taking the contract handling responsibility away from the retailer (but this is unlikely).

Currently in the Netherlands there are four active aggregators in the market: Powerhouse (RWE Group), Agro Energy, Energie Data Maatschappij⁴⁷ and NL Noodvermogenpool⁴⁸. These aggregators are pooling demand-side resources from greenhouses, hospitals, small industries with CHP and load shedding capabilities (DRIP, 2015). As of now, households are not in the portfolio of these aggregators.

Bellow follows a discussion on the value of such flexibility as it is currently perceived by the stakeholders warranting the use of aggregated DR.

Value of demand response flexibility

As indicated above, the aggregator actively pools together flexibility from energy resources of its customers and offers them to electricity market participants. Such interactions become feasible through bilateral contracting or by submitting offers in the organized electricity markets. Flexibility buyers can be either regulated, competitive or both and will activate technical DR that requires location specific aggregation, commercial DR necessitating distributed aggregation or even both, see Table 14. Regulated actors include distribution and transmission system operators concerned with the physical delivery of electricity, at the lowest possible cost to consumers and with the highest quality possible. Competitive actors include retailers, generators and balance responsible parties wanting to use DR for profit maximization in electricity trading.

Table 14: Summary of parties interested in flexibility and their respective use of demand response

<i>Type of demand response→</i>	Technical	Commercial
<i>Entity contracting flexibility↓</i>	(location specific aggregation)	(distributed aggregation)
<i>Distribution System Operator (DSO)</i>	✓	
<i>Transmission system operator</i>	✓	
<i>Generator</i>	✓	✓
<i>Retailer (Energy Supplier)</i>		✓
<i>Balance Responsible Party (BRP)</i>		✓

Transmission system operator

The (transmission) system operator can use the flexibility of customers as reserve capacity to maintain stability in the system at the lowest possible cost. With an increase in RES

⁴⁷ Energy Data Company

⁴⁸ NL Emergency Power Pool

generation capacity the local contribution to system stability is gaining relevance. For instance, one reason is the simultaneous failure of several wind turbines in a wind farm, leading to the dispatch of fast reserves to compensate for the imbalance. Because of the limited size of (mainly gas) spinning reserves, an appropriate (and maybe even cheaper) solution seems to be the deployment of local flexibility (Hakvoort and Koliou, 2015).

Distribution system operator

As a network manager subject to regulatory oversight, distribution system operators have the responsibility to transport electricity to their customers at the lowest possible cost with the highest quality. For the distribution grid, DR has a twofold physical application: mitigation of grid overload at peaks and system balance maintenance of supply and demand (Strbac, 2008). The physical release of DR will reduce costs related to grid losses, investments and overall maintenance (Hakvoort and Koliou, 2015; E Koliou et al., 2014).

Generator

Generators can use customer flexibility to absorb electricity production at times of overcapacity. This can be especially useful for the rapid mitigation of unexpected fluctuations in the output of intermittent production recourses, such as wind and solar power. In turn, this would help reduce system balancing costs for the balance responsible party (Hakvoort and Koliou, 2015). Generators can employ storage systems close to the production site in order to reduce 'spillage' and trade this as flexible load (Pandzic et al., 2014).

Retailers (energy suppliers)

Energy suppliers will use flexibility to reduce demand during system peak, at which time the purchase of energy is expensive, and shift the load to a time when electricity is cheaper. If suppliers are confident in the responsiveness of their customers, they can procure the purchase of electricity at times when prices are low. In the case where the supplier is the deemed aggregator he will also sell the flexibility from his customers to other market parties in either bilateral contracts or in the short term markets (Hakvoort and Koliou, 2015). Large suppliers are also balance responsible parties for themselves and other parties. As a balance responsible party, the retailer is also in charge of monitoring own power balance and that of the parties for which they carry balance responsibility. Having access to DR flexibility gives them significant leverage in the optimization of their imbalance position (Eurelectric, 2015).

Balance responsible party

Balance responsible parties create schedules of electricity supply and demand at connecting points to the grid for their customers (suppliers and generators alike). The derived

schedules are provided to the TSOs on a daily basis, with BRPs carrying the penalties for deviations from the set schedules. Using DR flexibility, a balance responsible party can balance his own electricity supply and demand at the lowest cost possible, in this way creating added value for himself and his customers. Note, balancing costs are directly passed down to consumers (Eurelectric, 2015; FENIX, 2009).

INTRICACIES OF MARKET PARTICIPATION FOR DEMAND RESPONSE

In the same way large-scale generators operate production plants central aggregators will control their 'virtual' power plants of aggregated flexibility. Accordingly, trading entails access to the various short term spot markets inclusive of day-ahead and intraday. As part of system support management to the transmission system operator aggregators can also participate in the balancing markets. Such activities involve flexibility operation that does not necessitate location specificity. If transmission and distribution system operators need aggregated flexibility for congestion management, then DR has location specific components attached (FENIX, 2009).

The market convolution

Inherently, once electricity is generated it must be consumed or stored, which, in turn, makes the planning of supply a critical matter. Planning is done at different time scales classified as various markets: forward/future market, spot markets (including the day-ahead market and the intra-day market) and real-time/balancing market. Forward markets operate within a range of a few days to a year (or more) prior to actual delivery (ERGEG, 2009). This analysis focuses on the spot markets, day-ahead and intraday.

General overview in Europe

The day-ahead market operates one day before the date of delivery (D-1) and clears the market for each hour of the delivery day (D). The intra-day market operates in near real-time, one-hour ahead or even closer to the delivery time. Trades in each market (day-ahead, intra-day and balancing) must be finalized before the 'gate closure' time when the balance responsible parties of generators and loads notify the expected physical positions of connected parties to the transmission system operator. After gate closure no further trade can occur in the respective market (ERGEG, 2009). Program time units (PTUs) are used for scheduling and settlement of programs from the electricity market participants. PTUs can be 15 minutes, 30 minutes or 1 hour depending on the market design characteristics of the member state (Mott MacDonald, 2013). The market functions in such a way that balance responsible parties and/or generators of electricity try to balance supply and demand first in the day-ahead market and then in

the intra-day market (for remaining imbalances), followed by real-time balancing in the imbalance/reserve markets operated by the system operator. System operators may also call on balancing bids before the gate closure of intra-day market (ERGEG, 2009; Mott MacDonald, 2013).

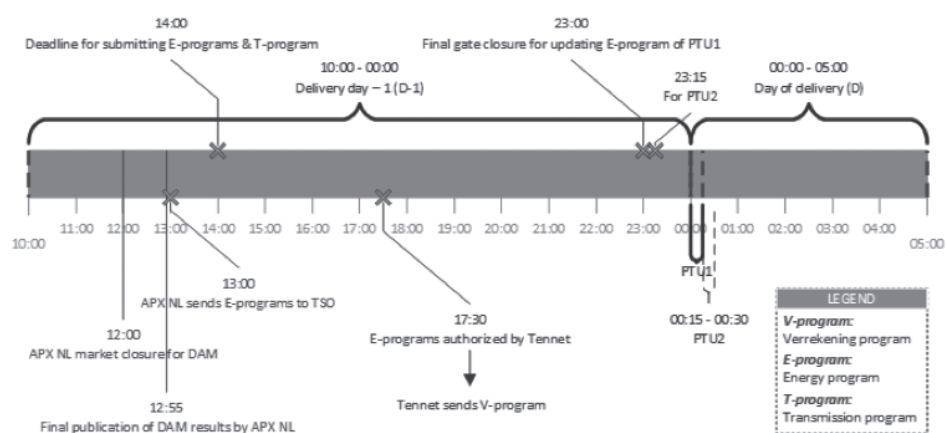
The market structure, as it currently stands, is built from the perspective of large scale generation plants i.e., generation is always made to follow demand. Accordingly, both the European commission and industry lobby groups emphasize that DR proliferation is inherently vulnerable to institutional barriers arising from an existing system design framework which caters to large generation units (Eurelectric, 2015; SEDC, 2014). The Smart Energy Demand Coalition (SEDC), a dedicated industry group representing the requirements of programs involving demand side participation, provides some general guidelines for bringing DR to market, namely, timing, volume, and program specifications (SEDC, 2014), see Table 1.5 for a summary. Timing specifications are very much related to the design of the DR program and the notice, duration, frequency and intervals of flexibility release; volume is concerned with the minimum and maximum limits for activation and; program specifications focus on the pricing methods, measurement and verification techniques and the associated penalties for non-compliance. The analysis continues with a deduction of the timing specifications in the spot markets in the Netherlands, touching upon the volume and program specifications.

Market specifications in the Netherlands

The Netherlands electricity market is regarded as the archetypal model for electricity market design (Correli  and De Vries, 2008). Figure 3.4 gives an overview of the important events along the timeline of day-ahead (**D-1**) and date of delivery (**D**) in the electricity market of Netherlands. Every day at 12:00h on **D-1**, market participants are required to send consumption bids and production offers to the power spot exchange (APX-NL). When the market is cleared in **D-1** for the following day **D**, the accepted bids and offers are published at the accepted market clearing price for each hour of **D** (APX, 2014a). After the publishing of **D-1** results, the balance responsible parties are required to send their Energy-programs (E-programs) to the system operator (Tennet) before 14:00 hours on the same day **D-1**. The E-programs contain information about the aggregate energy for each hour of the next day. Such programs include all injections and withdrawals from the grid by generators and consumers (typically consumers are represented in the market by retailers). Each generator and consumer connected to the grid has a unique EAN code that identifies them; this code is used in the detailed E-program provided to Tennet (TenneT, 2012).

Table 15: Summary of timing volume and program specifications (SEDC, 2014)

Timing requirements	
Notice time	<u>Time to the release</u> considers the call time to fully activate load for feeding the flexibility into the system; the more time consumers have to prepare for an event, the higher the expected participation level at a lower risk and consequently lower cost.
Duration of event	<u>Duration of demand response</u> release to the system; for small users this should be as short as possible with multiples of such bidding periods.
Frequency of event(s)	<u>Frequency</u> of demand response events; this is regarding the total number of activations.
Intervals between activations	<u>Intervals</u> between activations; the time from one activation to the next (seconds, minutes, hours, days, etc.)
Volume requirements	
Mini/ max load size to join aggregator's pool	<u>Non-discriminatory access to aggregator's pool</u> ; no minimum load size for any single consumer who joins an aggregated pool.
Min/max flex quantity to partake in markets	<u>Minimum and maximum</u> quantity of flexibility to partake in markets; this is a proven critical barrier for new smaller entrants that do not have the capacity of large power plants or large industrial users.
Program specifications	
Bid pricing	Pricing for bids should be transparent, efficient and uniform for all markets; e.g. where there is a capacity mechanism in place aggregated load should not be excluded from remuneration.
Penalty for non-compliance	<u>Penalty for non-compliance</u> when scheduled to participate; a critical design factor in the business model for end-user aggregation, where the main risk should be absorbed by the deemed aggregator
Measure and verification	<u>Measurement and verification</u> communication methods; such requirements should be different for a large industrial consumer and small end-user.
Call method	<u>Call method</u> for signaling a demand response event; for small users this will likely be through automation of pre-contracted loads in this way minimizing 'discomfort'.

**Figure 34:** Timeline with important milestones in Dutch electricity spot market (APX, 2014a; TenneT, 2012)

Before 14:00 hours on **D-1**, balance responsible parties also send a Transmission-program (T-program) to relevant distribution system operators, indicating the transmission flows for the next day. This will tell the distribution system operators how much electricity needs to be sourced from or fed into the grid at different connection points. At 15:30 hours on **D-1**, Tennet authorizes the E-programs after performing a consistency check with the T-programs; this is referred to as a V-program⁴⁹. Tennet uses the V-program to notify BRPs about discrepancies and departures from their submitted E-program after actual set-off calculations and settlements are made. The idea here is that BRPs should have a zero balance in their file since the procured supply should match the demand forecast in their submitted E and T programs. The transfer of all these programs between the players is done through a standard messaging format known as EDINE (TenneT, 2012).

Note, after submitting the E-program and T-program to Tennet (at 14:00 on **D-1**), BRPs cannot make amendments to their schedules until Tennet has approved them at 15:30. After approval, the BRPs can keep modifying their E-programs until 1 hour before the delivery PTU (set at 15 minutes in line to the balancing market settlements in the Netherlands) on **D**. For instance, BRPs can change their respective E-programs for the PTU on **D** from 00:00 to 00:15 hours until 23:00 hrs on **D-1**. Amendments to original programs are checked and approved by Tennet once every 15 minutes, until 1 hour before the PTU of delivery (TenneT, 2012).

From 1 hour before the delivery PTU until the gate closure of intra-day market, BRPs can balance their portfolios through the intra-day market. In APX-NL, the gate closure time for the intra-day market is 5 minutes before the respective PTU on **D** (APX, 2014a). The spot intraday and day-ahead market deals with trades amounting to approximately 45 percent of yearly consumption in the Netherlands (APX, 2014b). In a situation where the BRPs fail to balance their portfolios, Tennet activates the primary, secondary, and tertiary reserves in the balancing mechanism and then charges the BRPs for their individual imbalances depending on whether they are short or long. In general, prices in the balancing market are above the spot market prices. Therefore, large deviations from provided schedules can lead to a significant financial bearing for the balance responsible parties (Koliou et al., 2014).

Implications for end users

As a result of the above timing specifications some form of automation scheduling will be necessary such that the end-users through their aggregation communication interface, i.e. their home energy management system, directly pass the specifications of their consumption, production and available flexibility on to the relevant market parties. Currently in the Netherlands balance responsible parties do not have access to real time injection

⁴⁹ Verrekening program, set-off program in Dutch.

and withdrawal of end-users, rather they create schedules based on the retailers' account of the set standard average load profiles of households. In the above market processes end-users are 'passive' and their dynamic consumption is not taken into consideration. This is an issue in the shift towards a smart grid system. Loads will become increasingly stochastic and might endanger the above market operation procedures and threaten system security, unless, (close to) real time consumption/production is explicitly communicated. Closer to real time data will only become feasible with the deeper penetration of smart metering which is currently underway to meet the 2020 target.

An example of aggregated end-user flexibility in the spot market

Entrance into the short term electricity markets is complex and costly for parties seeking opportunity. Initial fixed costs are to the tune of 41,500€, of which almost seventy per cent amount to the membership fee. Additional transaction fees apply for intraday and day-ahead trading and clearing per megawatt hour (MWh) (APX, 2015), see Table 16.

Table 16: APX fees to partake in short term markets in the Netherlands (APX, 2015)

<i>Fixed fees for APX spot market</i>			
Membership	Entrance fee	Membership fee	Technology fee
Trading	€ 5,000	€ 28,500	€ 5,000
Clearing	-	€ 3,000	-
<i>Transaction fees</i>			
	Intraday	Day Ahead	
Trading (t)	€/MWh 0.095	€/MWh 0.07	
Clearing (c)	€/MWh 0.01	€/MWh 0.01	

An aggregators' revenue for participating in these market can be calculated as follows:

$$(1) \quad R = V^* \cdot P - V(t + c)$$

Where R is equal to the total revenue from the market (either intraday or day-ahead), V^* is the volume demand side flexibility in Mwhs, P the price in the market, t the trading fee and c the clearing fee per MWh in the respective market.

To participate in the spot markets, traders must have a minimum volume of 0.1MWh (APX, 2015, 2014a). A summary of average, maximum and minimum allowed prices and those actually reached in the spot markets is given in Table 17. If an aggregator is seeking to provide the minimum load in order to participate in the spot market he needs to have load V that is equivalent to about 70 household dishwashers.⁵⁰ In the day-ahead

⁵⁰ At 65°C a dishwasher consumes approximately 1.44 kWh at very use (Carbon Footprint, 2015)

market, an aggregator is looking at approximate revenues of 4€ with an average market price (39.16€/MWh) and a maximum of 14.2€ with the highest price reached for the year. The maximum threshold price in APX-NL for the day-ahead market is set at 3000€/MWh, if this price is reached the aggregator is looking at a revenue of 300€. It is important to keep in mind that such a price has not been reached in recent years, and if the market continues to work properly such prices will not appear in the coming years as well. If the same calculations are done for the intraday market, the aggregator will earn approximately 6€ with average prices and 50€ with the maximum price. If the maximum allowed price of 99,9999€ is reached then the aggregator can make up to 10,000€; but again this case is highly unlikely if the market is working properly. It is important to keep in mind that such revenues must be divided amongst the customers, include underlying transaction costs and still leave enough room for the aggregator and customer to make a profit. See Table 18 for a summary of the possible revenues.

Table 17: APX-NL spot market prices, ref. (APX, 2014a, 2012; Nordpoolspot, 2012)

	Allowed max in APX	Max price reached	Yearly average price	Min price reached	Allowed min in APX
<i>Day ahead market prices in €/Mwh</i>	3,000.00€	142.38€	39.16€	0.01€	-5,000.00€
<i>Intraday market prices in €/Mwh</i>	99,999.90€	500.00€	59.96€	0.00€	-99,999.90€

Table 18: Spot market revenues with average APX-NL prices (own calculations)

	Total revenue for the aggregator		Revenue per customer	
	<i>Day ahead</i>	<i>Intraday</i>	<i>Day ahead</i>	<i>Intraday</i>
Min offer once (€)	€ 3.94	€ 6.03	€ 0.06	€ 0.09
Offer once per week over the year (€)	€ 204.42	€ 313.19	€ 2.92	€ 3.93
Offer every day of the year (€)	€ 1,434.89	€ 2,198.32	€ 20.50	€ 31.40

Spot markets become more interesting once more load becomes available. Taking the sample of 70 customers in the previous example, if these customers offer flexibility from their dishwasher (1.44 kWh⁵¹) in addition to their washing machine (2.3 kWhs), clothes dryer (3.3 kWhs) (Carbon Footprint, 2015) and TESLA PowerWall home battery (7 kWh) (TESLA motors, 2015), the spot market value of flexibility becomes more interesting. When aggregated, this flexibility adds up to 1MWh and yields almost a tenfold increase in revenues with average prices in the spot markets.

As the simplified illustration indicates, it is possible to aggregate the minimum load needed for aggregated DR to participate in the spot markets. In the following section a

⁵¹ Kilowatt-hour, 1 Khw is equal to 0.001 Mwhts

discussion on the further intricacies of market trading brings to light further complexities in trading for aggregators.

The real value from trading DR flexibility

The above examples are given in order to illustrate the access requirements and thus the involved complexities for an independent aggregator in a competitive market environment. Accordingly, it is important to keep in mind that the spot market clears on a merit order basis of supply (ascending order of price) and demand bids (descending order of price); the intersection determines the market clearing price and quantity of supply for that hour. When DR flexibility is traded, for instance, in the day-ahead market the demand curve during that hour will shift, in turn yielding a new clearing point for volume and price. See Figure 35 for the case of negative demand in one hour (demand reduction) that is shifted for consumption to another hour. The highlighted area indicates the total money saved by the aggregator in hour n with DR shifting the demand curve to the left (Abdul Muhaimin, 2015). Specifically, a volume of flexibility V MWhs is traded as a negative demand bid i.e. removing a block of demand from the merit order, in turn shifting the demand curve by V MWhs to the left. It is important to keep in mind that the supply curve is not completely flat and although V is the amount of MWhs removed in the market by the aggregator the difference between the old market clearing volume and new one is not equal to V but rather to V multiplied by a constant $\epsilon_{\text{saved}, \text{hour}-n}$ which keeps decreasing as the slope of the supply curve keeps increasing. $\epsilon_{\text{saved}, \text{hour}-n}$ is a function of

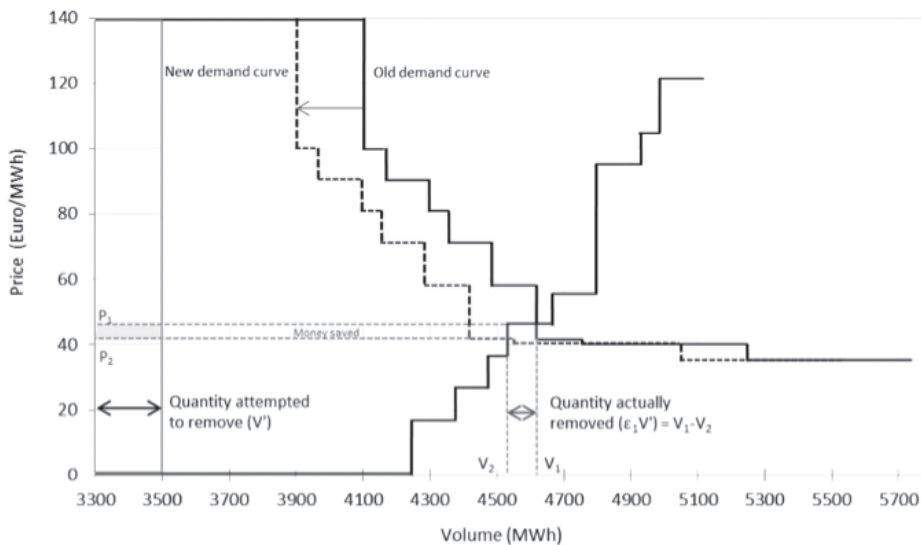


Figure 35: Money that is saved in the hour where DR flexibility is provided in the spot market (Abdul Muhaimin, 2015)

the slope of the supply curve in each hour and represents the percentage of the volume that actually gets cleared (Abdul Muhaimin, 2015). Therefore, the money that is saved with the provision of DR flexibility in one hour is calculated as follows:

$$(2) \quad \text{Savings from flexibility} = (P_{1 \text{ saved},n} - P_{2 \text{ saved},n}) * V_1 + \epsilon_{\text{saved},\text{hour}-n} * V' * P_{2 \text{ saved},n}$$

where $P_{1 \text{ saved},n}$ is the market clearing price before the trade of DR V' , $P_{2 \text{ saved},n}$ is the expected market clearing price after DR flexibility is removed, V_1 is the volume cleared in the market prior to the removal of flexibility, and $\epsilon_{\text{saved},\text{hour}-n} * V'$ is the actual volume of DR flexibility that is removed in hour n of trade to yield savings in Euro in that hour n (Abdul Muhaimin, 2015).

Once the aggregator notes this difference in volume between the volume of demand that is removed and the actual flexibility that is traded, only a fraction of $\epsilon_{\text{saved},\text{hour}-n} * V'$ is also cleared in the trading for another hour; this volume is denoted as $\epsilon_{\text{spent},\text{hour}-n} * V'$. As a result, the total money that is spent in the hour where load is shifted is calculated as follows:

$$(3) \quad \text{Spending from load shifting flexibility} = [(P_{2 \text{ spent},n} - P_{1 \text{ spent},n}) * (V_1 + \epsilon_{\text{saved},\text{hour}-n} * \epsilon_{\text{spent},\text{hour}-n} * V')] + \epsilon_{\text{saved},\text{hour}-n} * \epsilon_{\text{spent},\text{hour}-n} * V' * P_{1 \text{ spent},\text{hour}-n}$$

where, $P_{1 \text{ spent},n}$ equals the market clearing price in hour n prior to DR trade, $P_{2 \text{ spent},n}$ is the expected market clearing price in hour n after removing the DR flexibility in that hour of trade, V_1 is the market clearing volume before adding DR flexibility and $\epsilon_{\text{saved},\text{hour}-n} * \epsilon_{\text{spent},\text{hour}-n} * V'$ is the volume of DR actually added, shifting the demand curve to the right as illustrated in Figure 36. The total revenue that is generated from trading flexibility in the day-ahead market is the difference between money saved in one hour and the amount of money that is spent in another hour n :

$$(4) \quad \text{Revenus for the aggregator} = \text{savings} - \text{spending}$$

Nevertheless, the complexity does not lie just in the valorization of DR but rather in its ownership in the trading process.

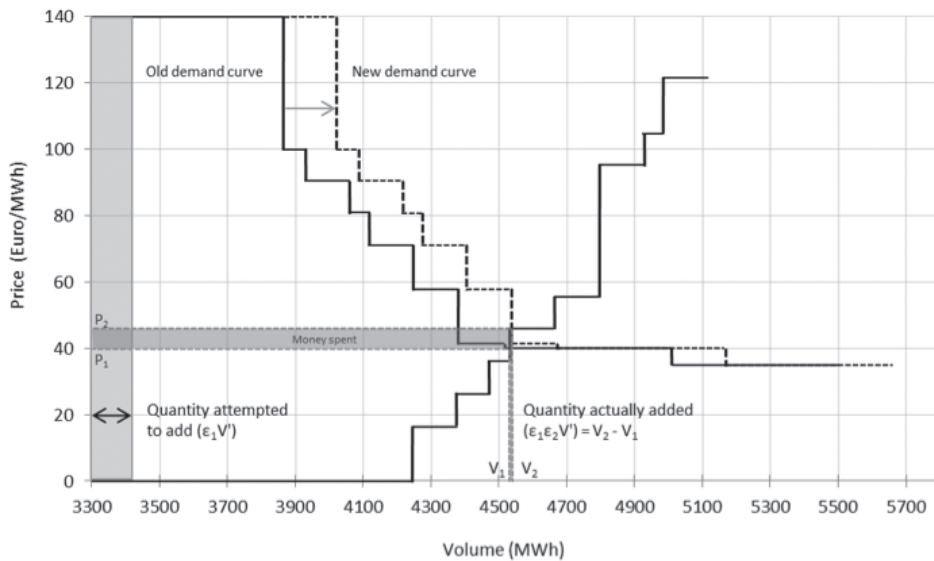


Figure 36: Money spent by the aggregator in the hour where flexibility is sold for release

THE COMPLEXITY OF DEMAND RESPONSE, THE ‘GOOD’

Policymakers are openly dedicated to integrating DR in the energy value chain and market parties are ready to stir up the market in order to find new streams of profit. Nevertheless, incorporating demand in market practices is a daunting and complicated task on account of the variance in requirements for sourcing flexibility at the state level. As a result, each country is pursuing distinct DR policies with no coherent guiding framework (EC, 2013a; Eurelectric, 2015). Specifically, regulators need to pay immediate attention to the balance responsibility of aggregators.

Ownership of ‘demand response’ by independent aggregators

There is a fundamental issue with respect to the ownership of DR “good” that is traded by an independent aggregator who is not a retailer. An aggregator contracts flexibility with the consumers and primarily trades it in the spot markets. In practice, neither the aggregator nor the consumer owns the traded energy “good” because neither of them has purchased it yet; the purchase actually happens in real time. Until the point of consumption, electricity is essentially owned by the supplier who forecasts demand and then purchases and schedules a certain amount of energy for each consumer. Hence, by trading DR flexibility, both consumers and aggregators trade something that they do not own. The change in schedules of balance responsible parties and suppliers may lead to significant financial penalties for them in real time. As illustrated in Figure 37, consumers

reduce consumption in one period as they shift it to another period, which may result in a 'rebound' effect where a new peak is created therefore offsetting the benefits from demand side flexibility (Eurelectric, 2015).

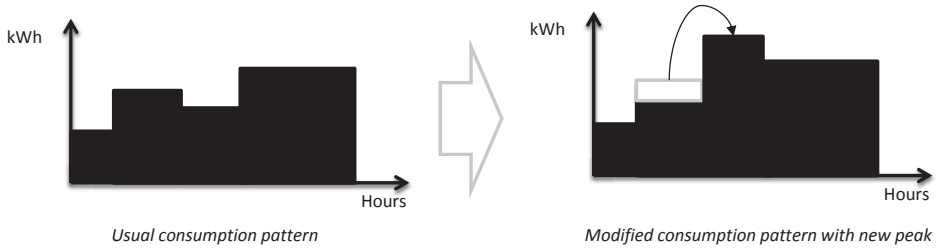


Figure 37: Demand response event trigger (adapted from ref. (Eurelectric, 2015))

Demand response impact on supplier and BRP portfolio

Let us take the example where an independent aggregator contracts 20 MWh of DR, a volume that is equivalent to that of flexibility from 1 5000 dishwashers. Within the market where the flexibility is offered, the shifted or curtailed consumption is treated as 20 MWh of electricity produced and sold by a generator (Eurelectric, 2015; SEDC, 2015, 2014). Meanwhile, the supplier of these consumers sources an amount of electricity (for example, in the day-ahead market) based on the a demand forecast of 100 MWh; this indicates that the appointed BRP is balanced upfront in his E-program. The trigger of a DR event in real-time gives rise to the following two issues: (i) an imbalance for the BRP which must be settled accordingly with the high prices/arrangements in the balancing mechanism; (ii) a retailer and/or BRP experiences a change in energy position, which means that the retailer sources 100 MWh for a given PTU but in reality sells 100 MWh minus 20 MWh to consumers (Eurelectric, 2015; SEDC, 2015). Figure 38 illustrates how a BRP's and/or supplier's portfolio is affected by the market integration of an independent aggregator. The DR ownership issue can be resolved as follows: (i) the independent aggregator can plan flexibility trades in co-operation with the BRP of the contracted DR consumer and (ii) a compensation mechanism can be put in place between the independent aggregator and the BRP for all imbalances caused as a result of the energy re-routing by the aggregator. Below follows a further elaboration on these resolutions.

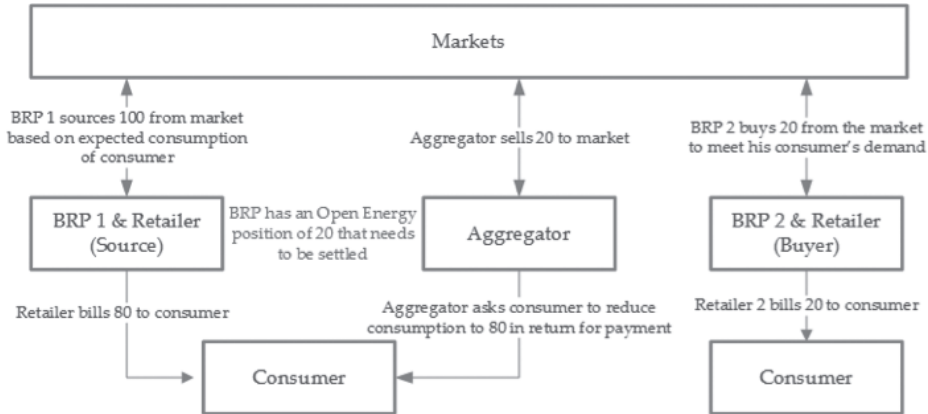


Figure 38: Impact of aggregation on BRP/Supplier portfolio (adapted from ref. SEDC (2015))

Resolving the ownership of demand response: balance responsibility for aggregators

European electricity market players have an implicit responsibility to balance the system through a market-based mechanism. This approach to balance responsibility gives the appointed BRPs a financial incentive to keep their own scheduled position in real time. Until delivery, BRPs try to minimize their deviations as much as possible (ACER, 2012). An aggregator trading DR flexibility is the same as trading production from a generator in the different wholesale markets. Hence, input should be equal to its output and therefore aggregators should also be balance responsible. For instance, if a customer does not fully react to the scheduled DR event contracted for, then the aggregator should bear imbalance costs for the system. Otherwise, the BRP and supplier of the customer will bear additional imbalance costs from DR. Eurelectric (2015) propose three methods to reformulating the relationship with BRPs in such a way that incorporates information and financial flows. Firstly, the independent aggregator and the BRP can come to a bilateral agreement on data exchange and remuneration for DR (and resulting imbalances). In this way they will come to a mutually beneficial solution to monetary and data exchanges. Secondly, the relationship can also be regulated in such a way that the compensation mechanism and data interaction are specified by the aggregator at a regulated price. The third approach to deal with flexibility imbalances is to have the system operator manually bring the BRPs back to balance after an event. Based on the activated DR, the resulting imbalances caused by the customer to the BRPs portfolio are then charged back to the customer. The customers then get compensated by the aggregator for the flexibility they provided in accordance with their contract. All three solutions are feasible, but no single one is the best solution, see Table 19 for a summary and assessment. We propose each member state can make a decision based on their current market design. Ideally, the more market based the solution the better in the liberalized market setting.

Table 19: Compensation options for BRP, aggregator and consumer (adapted from ref. Eurelectric (2015))

Method	Financial compensation	Assessment
<i>Bilateral agreement established amongst the parties</i>	Final compensation is agreed between the aggregator, BRP and supplier.	(+) If such contracts are standardized this may initiate a large scale roll-out and therefore facilitate market access for independent aggregator (-) Incumbent BRPs and suppliers may exhibit market power and refuse contracts to aggregators
<i>Regulated agreement established by the regulator</i>	The aggregator directly compensates the respective BRP and or supplier at a regulated price for accessing their scheduled consumption as demand response flexibility.	(+) Diminishes apprehensions over the exercise of market power by incumbent BRPs and suppliers (-) Hinders innovative pricing solutions by aggregator (-) Running the risk that this type of pricing may not compensate the supplier and BRP appropriately (-) Such remuneration gives way to "none-market based arbitration" between the set regulated price and wholesale market prices
<i>Corrective 'action' agreement based on metered data on what has been sold to the supplier and what has been taken by the aggregator</i>	BRP and supplier are compensated by their customers at the contracted Rates. In turn, the aggregators compensate the customers for proving flexibility to them.	(+) The pricing process is transparent (-) Meter data adjustments may not be fully transparent for the customer (-) Considerable effort to correct adjusted volumes is needed by the system operator (-) Difficult to implement for small customers

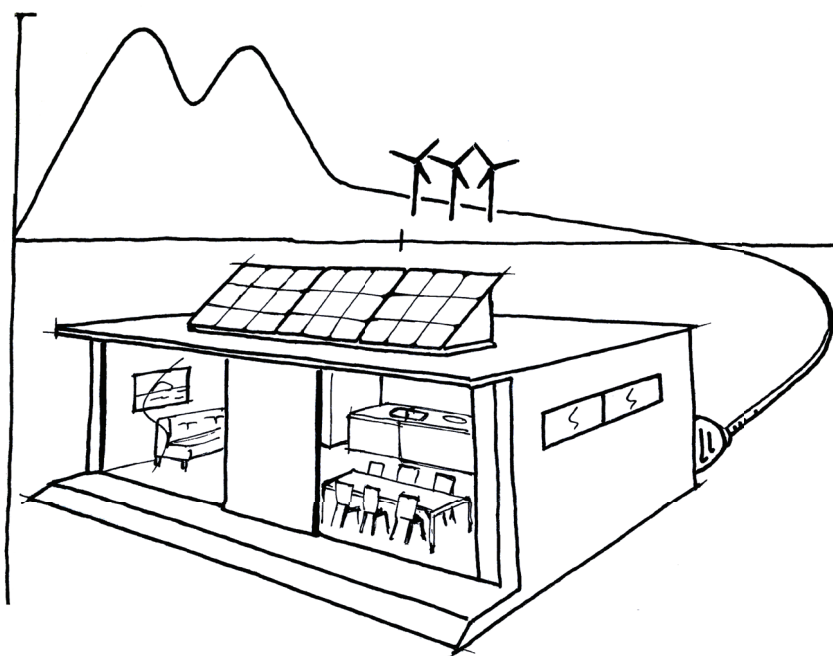
CONCLUSIONS AND RECOMMENDATIONS

The benefits from DR flexibility range from short term real time operation to long term investment planning. In the above analysis it has become evident that integrating demand side flexibility into the system is a complex task on account of the aggregation complexity specifications that have not yet been deduced.

In the current European context of liberalized electricity markets it is expected that aggregators will be competitive market parties, either independent aggregators or retailers with flexibility as an additional service. In essence, retailers are in the best position to become the deemed end-user aggregators participating in the various markets because of the existing consumer base, balance responsibility, market access and financial stability. It can also be argued that this is a way to hedge against the complexity of the retailer, BRP and independent aggregator relationship (5). Nevertheless, it will be tricky for retailers to gain this position since their business essentially depends on selling

MWVs, and with DR they are 'curtailing' their own profits. So the way in which they will provide the aggregation services will vary from an independent aggregator since their core business model in electricity markets differs. Independent aggregators can also exist and occupy a certain portion of the aggregation market, if they make a move at an early stage and occupy a large enough portion of the end-users with larger flexible loads such as electric vehicle and solar photovoltaics. Independent aggregators may become more common and overall profitable with community level aggregation (3.1). As illustrated in section 4.1.2 gaining access to markets is not a simple nor cheap task and the resulting revenues with small trading volumes are virtually none. For independent aggregators to survive in the long run they need to sophisticate their business model through the use of data to create new and innovative services not provided by retailers such as data analytics, e.g. consulting on which supplier and contract to choose).

Aggregated demand side response in European electricity markets is an inevitable and vital component for achieving the European smart grid. The current approach towards aggregation in electricity markets has no coherent European tactic. The Energy Efficiency Directive (2012/27/EU), ENTSO-E Demand Connection Code and the ACER Framework Guidelines on Electricity Balancing provide the basis by acknowledging the importance of DR but do not offer specifics for implementation with respect to timing, volume and program specifications. From this research, it is recommended that national regulatory bodies lead the way in the next phase by consolidating the issue of balance responsibility. The stimulus of mutual cooperation between balance responsible parties, retailers and aggregators is critical in achieving end-user market integration. Although the deemed aggregators will lead the flexibility movement, regulators hold the key in both birth and sustainability of demand side activation and integration.



CHAPTER 5

DEMAND RESPONSE PARTICIPATION IN THE BALANCING MECHANISM

In the previous chapter the concept of aggregation for demand response (DR) and complexity of access to spot markets was discussed in detail revealing the intricacies in exchanges and the importance of balance responsibility. To continue is this line of complexity assessment, this chapter considers an analysis of the German balancing mechanism for the participation of aggregated DR based on work from Koliou et al. (2014)⁵².

⁵² Koliou, E., Eid, C., Chaves-Ávila, J.P., Hakvoort, R.A., 2014. Demand response in liberalized electricity markets: Analysis of aggregated load participation in the German balancing mechanism. *Energy* 71, 245–254. doi:10.1016/j.energy.2014.04.067

INTRODUCTION

Previous research reveals that the most dominant share of “intermittency costs” in a power system are the result of balancing costs due to imperfect wind and solar forecast, followed by transmission and distribution network costs (Seebach et al., 2009; Strbac, 2008). Due to measures in restructured markets focusing on the short-run modifications of behavior (L. Greening, 2010), this work concentrates on the participation of aggregated demand response (DR) in the real-time balancing energy market, which is considered the last market in which electricity can be traded (Van der Veen, 2012). Exploitation of demand side flexibility is expected to yield positive benefits in the economic efficiency of deregulated electricity markets, enhance reliability and relieve congestion and network constraints (L. Greening, 2010; Strbac, 2008).

So far, there has been a lot of discussion on the importance of utilizing DR in European electricity markets (with large renewable energy resource (RES) penetration). Nonetheless, there has been minimal analysis of existing electricity market organization and how DR participation is impeded with current requirements; the work aims to fill this knowledge gap.

MOTIVATION AND INITIATIVES FOR ENGAGING DEMAND RESPONSE

Power systems have some inherent undisputable characteristics. Firstly, in real time, supply and demand must always be in balance. Secondly, electric power is not economically storable at a large scale. Moreover, costs of producing electrical energy vary considerably with respect to technology and fuel input. Finally, consumption of electric energy varies over time on account of consumer behavior. As a result of these properties, the provision of electricity requires balance management necessary to safeguard the security of electricity supply from producers to consumers through the electricity network (Aghaei and Alizadeh, 2013; Van der Veen, 2012). The European power system has a set point of system frequency balance which must be narrowly maintained at 50 Hertz. Electricity is thusly traded in organized markets in accordance with the prescribed system limitations. In this way, electricity markets can be classified with the time of delivery in forward, day-ahead, intra-day and balancing markets (see Figure 39 for details). Note: about half of the electricity consumed is traded in forward markets, which take place days and even months ahead of delivery usually consisting of long-term bilateral contracts. The day-ahead spot market plays an important role in terms of volumes traded, taking supply and demand bids for every hour of the next day until the settlement of clearing price.⁵³

⁵³ Combined traded volume in day-ahead European wholesale power trading platforms amounted to 318.5 TWh, 52% of the total electricity consumption (EC, 2013c).

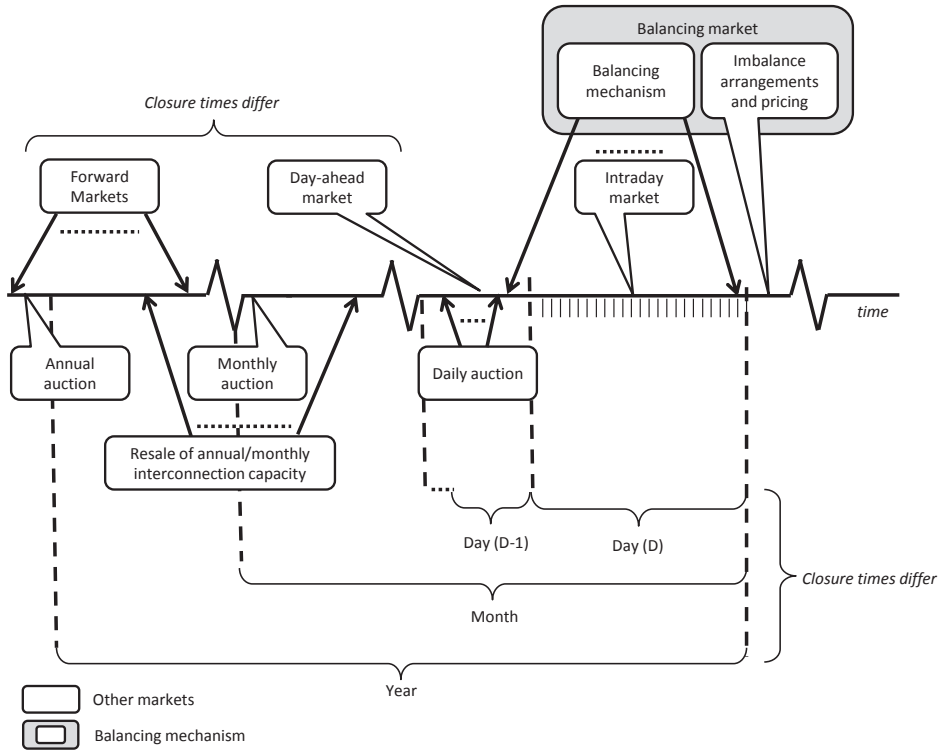


Figure 39: Time sequence of electricity markets (ERGEG, 2009)

There is also the possibility to trade in the intra-day markets (Chaves-Avila and Hakvoort, 2013).

Currently, Transmission System Operators (TSOs) in Europe own their network but are still subject to regulatory supervision. The TSO is responsible for power transport and system operation, including balance management within a power system⁵⁴ (Van der Veen, 2012). Transmission services deal with physical transport of electricity through the network while system operation services have public good characteristics, since benefits are for all connected entities. System users cannot be denied the service (non-excludability), and the entry of a new system user does not reduce the benefits for other users (non-rivalry) (Van der Veen, 2012).

As a result of a liberalized (unbundled) electricity market, a lot more institutional provisions are needed for the 'public good' of balance management. Without control over generation, market participants need to be stimulated to supply resources for system balancing and have a limit on amount of imbalances through rules and regulation (Van der Veen, 2012). More specifically, as of 2003 European legislations (2003/54/EC

⁵⁴ System operation services also consist of voltage control and black-start capability.

and 2009/72/EC) have prescribed the implementation of a transparent market-based mechanism that is cost-reflective of the supply and purchase of electricity needed in the framework of balancing requirements (EC, 2009, 2003; Niesten and Jolink, 2014). Balancing is defined as *“the situation after markets have closed (gate closure (GC)) in which a TSO acts to ensure that demand is equal to supply, in and near real time”* (ENTSO-E, 2013b) and thusly a balancing market is considered an institutional arrangement that establishes market-based balance management (Van der Veen, 2012). Below, the follows a summary of the current organization of the European balancing mechanism in liberalized European electricity markets (Figure 39).

The European balancing mechanism

In the synchronous zone of continental Europe, market participants use periods for scheduling and settlement of the “Energy Programs” commonly referred to as Program Time Units (PTUs). For instance, Germany and the Netherlands make use of 15 minute PTUs. In principle, producers and consumers alike, have the legal ex-ante responsibility to provide the TSO with schedules of electricity consumed and injected in the network (Mott MacDonald, 2013). Any party that has one or more connecting points to a grid bears program responsibility for these connecting points. This is referred to as balance responsibility, where the party concerned (referred to as the Balance Responsible Party or BRP) is supposed to draw up programs relating to their expected electricity supply and demand. BRPs supply these Energy Programs to the TSO on a daily basis. While BRPs are responsible for balancing their own electricity supply and demand in accordance with their schedules, the TSO is responsible for balancing electricity supply and demand in real time for the entire electricity network. Because BRPs are often not able to achieve their own balance in real time, the TSO resolves these individual imbalances for the entire network. The BRPs are penalized through balance pricing for their deviations and surpluses in consumption. These prices are time-dependent and need to be paid to the TSO. The total imbalance of the system (and individual BRPs) is the net value of positive and negative deviations. To maintain the real-time and system-wide balance, BRPs can supply so-called balancing power in the reserve market to the TSO, which is rewarded through an availability payment (Van der Veen, 2012).

When an energy firm wishes to supply balancing power to the TSO, it needs to be registered as a BRP. More specifically, the TSO procures balancing power for a certain period from any Balancing Service Provider (BSP) and sells it to the Balance Responsible Parties that cause the imbalance in the control area (Van der Veen, 2012). For instance, currently in Germany, there are over 5000 BSPs (Hirth and Ziegenhagen, 2013). Firms that are registered by the TSO as BRPs may take over the program responsibility of other actors in the industry. Balancing energy can be provided by generation and consumption sources that are technically capable of meeting the requirements.

The balancing market lies at the intersection of financial transactions (the energy market) and physical exchanges (the power system). The balancing mechanism serves to procure electricity that corresponds directly to the real-time adjustment (regulation) of generation and consumption, in order to maintain the system in balance (Van der Veen, 2012). Balancing services differ in terms of function, activation time, method, scope and duration. The European Network of Transmission System Operators for Electricity (ENTSO-E) considers the terms Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR) (ENTSO-E, 2012). For the purpose of this work, the authors use the classification of Union for the Coordination of the Transmission of Electricity (UCTE): primary, secondary and tertiary control (see Table 20 for further details) (Van der Veen, 2012).

The balancing market has two distinct features: (i) it's a single buyer market with the Transmission System Operator as the single buyer (instead of a two-sided auction), and (ii) the demand is determined by the system imbalance volume, which is small but highly volatile, and must be met (Van der Veen, 2012). The TSO procures for balancing services via an organized market or through bilateral contracts. The amount of available reserve capacity (MW⁵⁵) is based on the expectations of real-time needs in capacity markets. The selected bids receive an availability payment. When the capacity market is separated from the energy component (MWh⁵⁶), the contracted capacity bidders are usually obliged to bid into the energy market at a predefined price (within a certain price range) or they can set the price independently (Chaves-Avila and Hakvoort, 2013).

When BRPs deviate from their schedules (i.e. Energy Programs), imbalance charges are applied for positive and negative deviations. The pricing approach differs from one country to the next. Some countries have single pricing tariff structures while others implement dual pricing. Single imbalance pricing uses a single price for all positive and negative imbalances. Dual imbalance prices charge differently according to negative or positive effect of the imbalance, with respect to the system imbalance. If the imbalance is in the opposite direction of the system imbalance (helping the system), it receives a different price from the reserves' cost, usually corresponding to the day-ahead market price. The imbalance price is generally based on the last activated reserve (marginal cost pricing) or the average costs of the procured services. Participants can change their bids up until the Gate Closure Time (GCT), after which time bids cannot change (Chaves-Avila and Hakvoort, 2013). Moreover, flexibility providers have strict rules and commitment requirements in the procedure in terms of bid volume, duration and up-and-down bids (He et al., 2013a).

⁵⁵ Megawatt

⁵⁶ Megawatt hour

Table 20: Balancing Services (Hirth and Ziegenhagen, 2013; Tennet et al., 2011)

Classification	Reserve					
UCTE	Primary	Secondary			Tertiary	
ENTSO-E	Frequency Containment Reserves	Frequency Restoration Reserves			Replacement Reserves	
Germany	Primary Reserve	Secondary			Minute Reserve	
Response time	≤1 min	1.....15 min			≥15 min	
	Automatic	Automatic	Manual		Manual	
Reserve and sourcing	Firm capacity	Firm capacity	Firm capacity	Active market	Firm capacity	Active market
Activation	Fast activation (ramp to 50% in 15 sec – 100% within 30 sec), also able to remain active for at least 15 min	Activation in the area of disturbance within 30 sec and completed within 1 PTU			Activation within 15 min for “fast” control or longer lead times (30min, 1 hr, etc)	
Typical suppliers	Synchronized generators and large consumers	Synchronized generators, stand-by hydro plants and large consumers			Synchronized and fast starting stand-by generators and large consumers	
Magnitude of control capacities ^a	3 GW ^b (0.8% of peakload ^c)	20 GW (4% of peakload)			21GW (4.2% of peakload)	

^a Values based on European figures from (Lilliestam and Ellenbeck, 2011)^b Gigawatts^c % of peak-load refers to the percent of the continental ENTSO-E peak-load

Balance management complexity in liberalized electricity markets

Van der Veen (2012) points out that balance management is first and foremost concerned with operational security of supply, a real-time process subject to ensuring adequate capacity to meet the demand at all times. As mentioned above, at each point in time the total production of electricity must equal the total consumption in order to keep the system frequency stable. If the system is out of balance, power stability and quality of electricity supply will deteriorate, which may trigger the disconnection of system components (production and consumption alike), and ultimately result in power blackouts.

In a report for the EC Directorate General of Energy, Mott MacDonald (2013) states that under the classic framework of planning, operating and governing European power systems, the energy policy drivers of security of supply, sustainability and economic efficiency are not “*naturally aligned vectors*”. Precisely, the increasing penetration of less-predictable renewable and distributed energy technologies, energy market liberalization and the more active participation of market actors (both producers and consumers) may call for a parallel increase in corrective action by TSOs (Mott MacDonald, 2013).

Traditionally, power systems are designed under a prevention oriented operating philosophy. On the generation side, the total capacity of installed generation is larger than the system maximum demand. Therefore, system security is achieved through preventive

measures, with no need for any immediate corrective action to be taken following a contingency. Such decisions ensure the security of supply in the face of uncertainty, with ample availability of generation to meet the unforeseen variations in demand (Strbac, 2008). Adopted sustainability targets for the integration of 27% RES in European power systems will inevitably increase both the size and frequency of short-term adjustments in power flows to correct for real-time imbalances. As a result, current provisions under which TSOs maintain power balance and system control may no longer be able to reliably and efficiently cope with the increased requirements for balancing needs in real-time (Mott MacDonald, 2013). Preventative measures will still be necessary for overall efficiency, but corrective actions will become increasingly important in real time operation. Strbac (2008) argues that policy commitment to market-based operation and deregulation of the electricity industry places consumers of electricity in the center of the decision-making process.

Just like in Europe, in the mid-1990's, the United States (US) also experienced electricity sector unbundling which prompted interest in facilitating the development of competitive electricity markets. Arising issues consisted of price volatility and spikes, perceived market power, reliability concerns during system peak demand conditions and failure to produce expected benefits to consumers. Such dilemmas led policymakers to conclude that DR, in all of its different forms, is essential to the efficient functioning of wholesale electricity markets. It is important to keep in mind that such a demand-centric approach was recognized much earlier in the US. Interest in demand-side flexibility sprang in the early 1970's from the penetration of air conditioning in American homes, resulting in needle peaks and reduced load factors in demand profiles. At this time there was increasing recognition of rising system costs to meet the peaking loads, and thusly utilities began to view demand load management as a reliability resource (Cappers et al., 2010). Currently, the majority of demand resources are provided by large industrial and commercial users—roughly half of all energy consumption in the US (FERC, 2012). Programs offered often concentrate on peak clipping to mitigate concerns of security of supply, consequently explaining the strong focus to date on incentive-based programs that deliver more controllable forms of load response (Cooke, 2011). FERC (2012) reports a total of 20,256 MW of actual peak reductions from demand resources. The following four DR programs made up 80 percent of the total reported potential in peak reduction: load utilized as a capacity resource 29%; Interruptible/Curtailable service 24%; Direct Load Control 15%; and Time-of-Use tariff 12% (FERC, 2012). The Federal Energy Regulatory Commission (FERC) articulates that to a certain degree, demand response resources can be utilized as substitutes for generation and transmission depending on the location of generation or demand resource. When substituting generation, demand flexibility serves as an adequacy resource for local peak generation replacement assisting in optimal dispatching (FERC, 2008),

The European Smart Energy Demand Coalition (SEDC) has published a report on recommendations for a *Demand Response Action Plan for Europe*, emphasizing that Europe should take example from the US market for demand response, especially since in 2012 businesses and homeowners earned over 2 billion Euro in direct revenues above bill savings and avoided investment. A majority of such savings were within the balancing and capacity markets (SEDC, 2012). This is the aim of having DR available and tradable in the real-time operation of the European power system. Recent European level initiatives, which have recognized demand response as a future component of European power system operation, include the Energy Efficiency Directive (EED (EC, 2012); Demand Connection Code (DCC) (ENTSO-E, 2013a); and the Framework Guidelines on Electricity Balancing from the Agency for Cooperation of European Regulators (ACER) (ACER, 2012).

European level recognition of demand response flexibility

The Energy Efficiency Directive (2012/27/EU) establishes a common framework for the promotion of energy efficiency in order to achieve the 20% headline target for 2020 (EC, 2012). The Directive states that national regulatory authorities should be able to ensure that the taken measures support price-based and controllable DR which enables equal market opportunities to consumer loads alongside supply. Such measures include access and participation of aggregated demand in balancing, reserve and other system services markets. The promoted measures are subject to the inherent technical constraints of network management. TSOs and distribution system operators (DSOs) are encouraged to have close cooperation with aggregators and consumers in order to define the technical requirements of market participation and scope of demand side capabilities. Currently, incentives arising from transmission and distribution tariffs are hampering the participation of DR in balancing markets and ancillary services procurement (EC, 2012). The directive has explicitly recognized DR as a valuable resource in future power system operation, laying down some guidelines for removing energy market barriers and overcoming market failures impeding efficiency in the supply and use of energy. Identified obstacles include (EC, 2012):

- Inequality of market entry opportunities alongside generation in wholesale and retail markets
- Incentives for investment in transmission and distribution tariff remuneration
- Regulation hampering participation in balancing markets and ancillary services procurement
- Lacking cooperation between TSOs, DSOs, aggregators and consumers
- Missing outline of technical requirements for the capabilities of demand side participation
- Specification of aggregation standards and requirements.

In order to aid European-wide system and market integration, in 2011 the European Commission mandated the establishment of European Network Codes⁵⁷. Among the codes developed by ENTSO-E is the Demand Connection Code (DCC), identifying the connection requirements necessary for the preservation or the restoration of electricity network stability from demand-side facilities (including end users and/or households). ENTSO-E assures that the DCC embraces Smart Grid models for achieving the fundamental principles of European policy: RES penetration, security of supply and the integration of a European electricity system and market (ENTSO-E, 2013a, 2013c).

In addition to the Energy Efficiency Directive and the Demand Connection Code, ACER also identifies the participation of DR and RES for balancing in the Framework Guidelines on Electricity Balancing (ACER, 2012). The terms and conditions related to balancing explicitly state that network codes shall facilitate the participation of DR in the balancing mechanism. As a result, codes must allow for the aggregation of small units (both demand and generation) in addition to permitting load entities and intermittent generation units (whether through aggregators or not) to become providers of balancing services (sec. 2.3). Accordingly, the procurement of balancing services requires the standardization of products (e.g. technical constraints, speed of activation, minimum bid size, etc.) Product standards stipulated in the codes shall take into account the technical characteristics of available balancing resources (demand and renewable generation units, as well as smaller generation units) across Europe such that they satisfy the needs of TSOs to balance the system (sec. 3.2). In order to ensuring an economically efficient use of DR as a balancing resource, harmonization of pricing methods is recommended. In this way, correct price signals and incentives may be passed on to market participants for balancing energy products (sec. 3.3.1). For the procurement of contracted reserves, ACER (2012) recommend that the code limits the duration of contracts that inhibit the participation of new entrants (demand response and renewable generators as well as small generators) (sec. 3.4.1).

Demand response in the balancing mechanism

On account of the integration of intermittent generation (both small and large scale), a coherent framework for system control must be adopted in line with the drastically different physical characteristics, cost structure and attributes of future power systems (Mott MacDonald, 2013). Demand response potential and feasibility are dependent on the shape of electricity markets; this is influenced by the generation mix and amount of available reserve capacity, amount of variable RES and capacity needed to balance intermittency, and the level of consumer peak demand that can be considered as shiftable load, along

⁵⁷ Network Codes (or Grid Codes) refer to the parameters and technical specifications of connected users to the electricity network in order to ensure proper and secure functioning of the system.

with time and duration of availability (Cappers et al., 2012; Prügler, 2013). Demand response capacity in Europe is in the magnitude of 25 GW⁵⁸, accounting for 5% of the peak-load capacity (Lilliestam and Ellenbeck, 2011). European-wide initiatives are focusing on demand response from residential load, motivated by recent progress in ICT and control systems. Such actions enable the deployment of aggregated interconnected Distributed Energy Resources placed in different locations by managing them to work as a Virtual Power Plant. Operation by an aggregator allows even the smallest user to participate in electricity markets and contribute to the process of energy cost reduction (Aghaei and Alizadeh, 2013). In EC taskforce for Smart Grids (2011) argue that the more local the balancing of the network, the less losses incurred in overall flow.

Accordingly, demand response is motivated by maintaining efficient operation of the power system and is materialized by the market which utilizes it (see Table 21 for details for a summary of forward, spot and balancing market). Aggregated flexibility is recommended to participate in the correction of short-term operational deviations (Seebach et al., 2009). Balancing requires a fast response time compared to spot and forward markets. Consumer loads have advantages, which include fast reaction, smooth activation, low expected costs, and are well dispersed in the distribution grid (Xu et al., 2011). Timely delivery of flexibility can be provided by aggregators acting as BRPs contracted for balancing reserves and/or energy. It is important to note that requirements differ depending on the type of balancing services. Hence, aggregated DR is not suitable for all controls.

Table 21: Participation of aggregated demand flexibility in Electricity markets (Abdisalaam, 2011)

Market	Forward	Spot		Balancing		
		Day-ahead	Intra-day	Primary	Secondary	Tertiary
<i>Financial Compensation</i>	<i>Energy (€/kWh)</i>	✓	✓		✓	✓
	<i>Capacity (€/kW)</i>			✓	✓	✓
<i>Event Trigger</i>	Economic Dispatch	Economic Dispatch	Economic Dispatch	System Imbalance	System Imbalance	System Emergency
<i>Response Time</i>	Years to 1 day ahead	1 day-ahead	Minutes to hours ahead	≤1 min to ≤15 min	<30 sec to >15 min	≥15 min
<i>Duration</i>	Minimum of 1 day	1 day	Several hours	Up to 15 min.	Up to 30 min.	Up to hours
<i>Performance Metric</i>	Difference in terms of energy between scheduled and actual load					

Primary reserves in Europe are determined on a synchronous area-wide basis. Typically, they are either unpaid or remunerated only for capacity (Euro/MW) and not for

⁵⁸ Gigawatt

energy (Euro/MWh). Currently, primary control is dimensioned to handle a maximum power deviation of ± 3000 MW equal to the simultaneous outage of the two largest generation units in the continental European network. This volume is non-negotiable since it is set to automatically activate in under one minute to maintain a system frequency of 50 Hertz (Vandezande et al., 2010), and is therefore not considered as a current viable option for a market in which DR can participate. For this work, the participation of aggregated load is not extensively considered for primary control. Secondary control is automatically activated to relieve primary control, while tertiary control is dispatched in cases where the deviation in the control area lasts more than 15 minutes (see Table 20). Aggregated small loads can be disconnected quickly and shortly with limited disturbances to appliances and customers comforts. This is especially ideal for reserves that are the thermostatically controlled (e.g. electrical heating or cooling appliances) loads since they can act as energy storage (Xu et al., 2011).

Advances in ICT show progress in the evolution of feedback technology, which can facilitate a shift towards the optimal utilization of further corrective measures in power systems with deep RES penetration (Mott MacDonald, 2013; SEDC, 2012; Strbac, 2008). Accordingly, the technology will be ready to support the utilization of demand side flexibility resources (Strbac, 2008). Many modern appliances (e.g. washing machines and refrigerators) are equipped with advanced electronic control. In such cases, cost of integrating the frequency control will be limited. The critical challenges facing practical implementation of such technology include the monitoring issues and a feasible market model for electricity market integration (Strbac, 2008; Xu et al., 2011). Specific limitations arise from strict rules and commitment requirements in the procedure in terms of minimum bidding volume, minimum bid duration and binding up and down bids (He et al., 2013a). The fact is that small customers have always had the potential to shift their demand (Smithers, 2013) but have not been incentivized to do so in the past largely due to the institutional arrangements in the electricity markets and of the current power system (L. Greening, 2010). The following sections will analyze the balancing mechanism in Germany as it currently functions with the introduction of interruptible load participation as of December 2012.

GERMAN ELECTRICITY SYSTEM

Germany belongs to the synchronous zone of continental Europe and has liberalized its electricity sector with unbundling of activities in addition to having one of the most reliable systems in ENTSO-E (Niesten and Jolink, 2014). As a nation, Germany has pledged to meet the EU 2020 and 2030 targets in addition to having a unique ambition to phase out nuclear energy and have a system that is at least 80% renewable by

2050. As of today, Germany only allows industrial users to provide demand response for balancing. The analysis shows that small user aggregation is impeded by the current strict participation requirements for balancing, which will be elaborated on below (see Table 22 for a summary of the balancing provision).

Table 22: Balancing participation in Germany (Chaves-Avila and Hakvoort, 2013; Hirth and Ziegenhagen, 2013; Regelleistung, 2013; Tennet et al., 2011)

Reserve	Primary	Secondary	Tertiary
Capacity	Weekly tenders	- Weekly capacity tenders - Separately for positive and negative - Pay-as-bid	- Daily capacity tenders - Separately for positive and negative always with six 4-hour time slices - Pay-as-bid
Energy		Tender specifies both capacity and energy bid; election on capacity bid	Tender specifies both capacity and energy bid; selection based on capacity bid
Amount	Minimum ± 1 MW	Minimum supply offer at 5 MW with an increment of 1 MW	- Minimum supply offer 5 MW - Offers up to a maximum of 25 MW

Overview of the German balancing mechanism

In the German system there are four control areas, each managed by a TSO (TenneT, EnBW Transportnetze, Amprion, 50Hertz Transmission). As of 2001, in accordance with the provisions of the Federal Cartel Office the TSOs have procured primary, secondary and tertiary control power in an open, transparent and non-discriminatory joint control power market (Regelleistung, 2013). Since 1st December 2007, German TSOs have been meeting their control requirements through shared calls for tender. Balancing service markets have been fully integrated as of 2009. The German imbalance mechanism/settlement uses an average cost structure. The TSO concerned commits to providing the power control products for up to 60 minutes after the occurrence of a power imbalance, after an hour the Balance Responsible Party concerned must take care of the compensation. The TSOs ask for capacity and energy bids on a weekly market for both primary and secondary control power. During the capacity phase, just the capacity price is considered and real time activation is based on the energy price. Both prices of secondary and tertiary control are set pay-as-bid. Tertiary control is a daily call for tender (Chaves-Avila and Hakvoort, 2013; Hirth and Ziegenhagen, 2013; Regelleistung, 2013; Tennet et al., 2011). Below the follows a discussion on the participation of demand response in the form of interruptible load for balancing in Germany, which hinders the deeper penetration of smaller aggregated loads as a result of three design aspects

of the mechanism argued in He et al. (2013a): minimum bidding volume, minimum bid duration and binding up and down bids.

Interruptible loads in the balancing mechanism

Since 20 December 2012 regulation has made it possible for interruptible load to participate in the German balancing mechanism as a result of the Ordinance on Interruptible Load Agreements (AblaV)⁵⁹. For balancing purposes of secondary and tertiary control, DR interruptible loads are defined as major consumption units connected at least at 110kV voltage level. The German transmission system operators issue a call for tenders each month for 3,000MW of equal amounts⁶⁰ of immediately interruptible loads (SOL) and quickly interruptible loads (SNL). SOL loads are dispatched by the TSO (or automatically by frequency relays) within a second of frequency deviations and SNL is activated within 15 minutes. Interruptible loads have a minimum tender quantity of 50MW and a maximum of 200MW with the following three availability options: (i) at least four times a week several times a day for at least 15 minutes at a time for a duration of up to one hour per day or (ii) once every seven days be available continuously for at least four hours at any given time or (iii) once every 14 days continuously for at least eight hours at any given time. Participants earn 2,500 Euros per month per MW of reduced capacity. Since the inclusion of interruptible loads in balancing in July 2013, flexibility providers have earned between 395-400 Euros per megawatt hour (€/MWh) from the market. Since July 2013 and until the end of September 2013 demand response has contributed a total of 1,936MWhs of balancing flexibility (736MWhs SOL and 1,200MWhs SNL). These figures constitute a small amount of the total positive system imbalances consisting of 1,887,549MWhs during the same timeframe (Regelleistung, 2013).

Thus far, the current design has stimulated little participation in the German balancing market from individual demand side sources, with none coming from aggregation. Note, common tendering of tertiary reserve rules state that "pooling is possible within a control area; cross-control-area pooling is only permissible if conducted with a view to reaching a minimum supply offer (Regelleistung, 2013)."⁶¹ Below other fundamental barriers are identified which need to be overcome in order for aggregated demand response from small loads to be considered as a viable balancing resource, utilizing Germany as an example.

⁵⁹ An amendment of the Energy Industry Act (EnVG).

⁶⁰ 1500MW of SOL and 1500MW of SNL.

⁶¹ <https://www.regelleistung.net/ip/action/static/ausschreibungMrl>

BARRIERS TO DEMAND SIDE FLEXIBILITY

Even though initiatives on a European level insist on demand side participation in the balancing mechanism, there are still setbacks to aggregation as a viable resource. DR barriers are linked to the vertically integrated structure that used to be the foundation of the electricity sector. Existing market rules and regulation for flexibility services have been developed in a context without demand response and largely focused on generation side resources (Strbac, 2008; Torriti et al., 2010). This may imply the undervaluation of DR resources compared to traditional ones in the existing market models (He et al., 2013a). The remaining discussion will focus on the aggregator barriers to participation in the balancing market in line with the three pillars to the mechanism: (i) balance responsibility, (ii) balance service provision and (iii) imbalance settlement (Chaves-Ávila et al., 2014).

Balance responsibility

Balance Responsible Parties are financially accountable for deviations from the binding schedules submitted to the system operator but can also transfer this responsibility to another actor. As discussed in the introduction, an emerging actor in European electricity markets is the aggregator. In an unbundled sector the role of the aggregator lacks a clear definition in terms of roles and responsibilities in the value chain of electricity. Today retailers take over balance responsibility for end-users and it is unclear with the provision of DR who the consumer will transfer this responsibility to—will it remain the retailer, the aggregator or will they be one and the same? In the European market context, the aggregator is most desired as a competitive actor since he has access to electricity markets. To this end, electricity retailers are expanding their business or new independent entities (solely functioning as aggregators) are entering the market (Hashmi, 2011).

As of early 2014, Entelios AG was the only commercial independent aggregator in Germany (with retailers gearing to take up new business opportunities)⁶². Entelios AG offers a fully automated industrial Demand-Response-as-a-Service™ (DRaaS™). The DRaaS™ solution can provide fully automated pooling meeting up to secondary control reserve requirements.⁶³ Such a service provision is still not market accessible for small users (even though devices from Entelios AG can be installed which allow for pooling capability⁶⁴). In order to provide the flexibility and controllability necessary to support secure system operation, aggregated load from small end users must take over

⁶² Since this research was conducted Entelios AG has been taken over by the American company EnerNoc. EnerNoc continues to provide the same services as Entelios. For further details on the acquisition see <<http://investor.enernoc.com/releasedetail.cfm?releaseid=825659>>

⁶³ <http://entelios.com/entelios/>

⁶⁴ <http://entelios.com/solutions/entelios-e-box/>

the responsibilities from large conventional power plants. It is still uncertain if small end users can provide the magnitude of necessary balancing load, a minimum of ± 1 MW when an average household consumes a few kilowatts on a daily basis. Load availability from end-users is determined by two factors: the number of customers in the market who have demand response capability and the elasticity of each customer (Masiello et al., 2013). In the case where end-users become active market participants through demand response with an aggregator as the gateway, their consumption behavior is monitored and penalized for deviation in accordance with the mechanism in place. In such a system participating end-users should not be responsible for subsidizing the imbalances created by others since their role is now different. End-users should be rewarded for aiding in alleviating system imbalances and penalized when exacerbating the system imbalance.

Balance service provision

Provision of balancing services is dependent on the procurement schemes and the remuneration to producers (Chaves-Ávila et al., 2014). German tenders for capacity and energy are put out together by the four TSO's for the whole system on a weekly basis for secondary and day-ahead for tertiary control. For a commercial aggregator, shorter planning periods would decrease forecasting error in addition to risks associated with non-compliance penalties. Currently interruptible loads can only participate once a week in accordance with the tendering dates calendar (Regelleistung, 2013).

For an aggregator, as an up and coming player lacking experience in balancing participation, shorter planning periods would decrease forecasting error in addition to risks associated with non-compliance penalties. Primary and secondary requirements have been reduced in Germany in recent years⁶⁵, but are still too high for aggregated DR to participate. The current mechanism has fixed units for participation with a minimum capacity the balance service provider must have in addition to bidding with fixed intervals of ± 1 MW. Due to the aggregator dependence on the real-time electricity demand of its group of consumers, which consequently define the level of available DR, such strict requirements impede the participation of aggregated load.

A critical variable of the balancing market is the time at which bids become final (Chaves-Ávila et al., 2014). Flexibility of market participants is highly dependent on the gate closure time being closer to real time. In Germany, gate closure provides less flexibility for actors since the closest GCT is day-ahead. For an aggregator more flexibility allows for further certainty in the service provision. For instance, in the Netherlands, gate closure is up to an hour prior to delivery (Chaves-Ávila and Hakvoort, 2013). For an aggregator, such flexibility allows for more certainty in the service provision.

⁶⁵ For instance, the minimum supply offer for tertiary control was 10 MW since 1st December 2011 and has been reduced to 5 MW as from 3rd July 2012 with the introduction of automatic activation.

Imbalance settlement

The settlement of imbalances is concerned with costs and pricing of imbalances (Chaves-Ávila et al., 2014). In future scenarios, demand response may not be competing with traditional balancing sources since more RES implies a system in demand of great flexibility (Aghaei and Alizadeh, 2013). From a cost perspective, for an aggregator to financially recover his provision of demand response from the market, the costs related to activation should be lower than the marginal cost of conventional balancing units. However, the variable costs are related to signaling DR for activation, monitoring, administration and data storage in real-time resulting in increasing volatility as a result of ex-post transactions needed for billing purposes. Such aspects are still in the pilot phase and are very specific to the market design and project specifications (Hashmi, 2011).

Chaves-Ávila and Hakvoort (2013) argue that correct imbalance price signals are also highly dependent on the energy pricing of reserves. In Germany this is done via a pay-as-bid mechanism. The German market participants rely on imbalance prices which are calculated as the average cost of the energy component of secondary and tertiary control. Economic theory attests to pricing based on the system marginal cost as the transparent and efficient way to allocate imbalance costs (Chaves-Avila and Hakvoort, 2013; Tennet et al., 2011). Vandezande et al. (2010) and ACER (2012) support that imbalance pricing should be based on marginal pricing, unless, the TSOs provide a detailed analysis to the national regulatory authority demonstrating that the use of a different price method is more efficient. The ACER (2012) guidelines express a need for pricing method harmonization in the network codes in order to give the correct price signals and incentives to market participants (sec. 3.3.1). TenneT, E-Bridge and GEN Nederland (2011) argue that dynamic transparency and cost reflective pricing diminishes incentives for gaming in a competitive market.

In order for DR to participate in the real-time energy markets, it would be important to consider how their performance is to be monitored (Masiello et al., 2013). Demand response through aggregation requires independent verification of the activated load for balancing. On the one hand, forecast in a balancing environment with minimal transparency and long lags in disclosure time could create incentives for gaming, since bid quantities depend on the forecast of demand which cannot easily be verified by the TSO (Chaves-Avila and Hakvoort, 2013). Thermal generation sources, on the other hand, determine their supply with much more certainty for bidding into different markets. However, activated demand response resources depend on forecasted demand, the monitored real-time demand and participation of DR after activation or signaling by the aggregator for a large group of consumers. It should be corroborated that, for example, an aggregated load curtailment is purely coming from DR. Forecasting and monitoring of the DR should be confirmed, for instance by an independent party possibly the Balance

Group Manager⁶⁶ in the control zone. This similar issue arises with other unconventional flexibility resources such as wind participation in balancing mechanisms (Chaves-Avila and Hakvoort, 2013; Hirth and Ziegenhagen, 2013). Verification monitoring will be crucial in order to avoid gaming, especially when the network is congested and need for alternate flexibility is higher.

Balance responsibility and cost allocation

Hirth and Ziegenhagen (2013) point out that the German balance mechanism is designed to be cost-neutral, such that all costs for control energy⁶⁷ are paid by unbalanced BRPs who then distribute it to their consumers. To illustrate the cost and benefits of having balance responsibility, the authors have taken a look at the imbalances of Vattenfall AB (a BRP in Germany) in the distribution area of Berlin for the year 2012 (see Table 23). In total, Vattenfall AB paid the TSO 58,147.06Euros for its yearly imbalances, while the TSO paid the BRP 61,455.93Euro for helping with system imbalances. The costs for imbalances of the BRP are equally socialized amongst all end-users through the so-called reconciliation mechanism (EC, 2010). In the Vattenfall AB situation (summarized in Table 23), the imbalance costs are recovered with a profit of over 3,000Euros from the TSO for consuming in the opposite direction of the system imbalance. These calculations are based on actual program deviations and imbalance prices which were posted one month after deviations occurred. If there was more transparency, closer to real time, in the direction of which the system was going, then BRPs could stimulate consumers to become more responsive. In turn, they would gain system flexibility, which they could aggregate to sell to the TSO for a profit or simply use it to take advantage of the profits to be gained from helping the system.

Table 23: Vattenfall (VTT) 2012 Imbalances and costs in Berlin, own calculations from data sources (Amprion, 2013; Stromnetz Berlin and FOKUS, 2014)

Imbalance Direction and Payment	(Volume) MW	Total Cost (Euros)
VTT absolute imbalances	1783.76	119 602.99
VTT receives money from the TSO (VTT consumes less)	629.23	49 547.40
VTT receives money from the TSO (VTT consumes more)	218.14	11 908.53
VTT pays TSO (VTT consumes more than scheduled program)	830.19	53 167.43
VTT pays the TSO (VTT consumes less than scheduled program)	106.03	4 979.63

⁶⁶ The Balancing Group Manager is responsible for a balanced quarterly hour balance (trade balance) and the outstanding deviations balance in control zone in Germany.

⁶⁷ Capacity costs are added to grid fees and are not allocated via the imbalance price (Hirth and Ziegenhagen, 2013).

Thus far the discussion has been focused on imbalance prices for demand response remuneration. Intra-day prices are updated every 20 minutes⁶⁸ and are more volatile than day-ahead prices, yet more stable and transparent than imbalance prices (which are made public one month after settlement). Once again, utilizing the imbalances for Vattenfall AB, the authors calculate the possible cost impact of DR using intra-day prices rather than imbalance pricing can have. Assuming 10 percent DR when intra-day prices are lower than imbalance prices in Berlin, the costs for Vattenfall AB are almost four times as much with imbalance prices (see Table 24). Such insight may motivate the BRP to hedge against imbalances in the intra-day markets rather than balancing. Additionally, such findings may prompt TSOs to publish prices closer to the time of imbalance occurrence for better forecasting. For instance, in the Netherlands, system imbalances and imbalance prices are made public in real time, allowing for an indirect provision of balancing services (Chaves-Avila and Hakvoort, 2013). Masiello et. al (2013) articulate that the provision of demand response is impacted by the frequency of the price signal availability. Nonetheless, it is important to keep in mind that if the market perceives a supply shortage in a certain direction and does not expect demand to react, it might dispatch supply by an amount that equals the entire imbalance. With more transparency demand may become more price-responsive, ultimately yielding an imbalance of the opposite magnitude (Masiello et al., 2013).

Table 24: Cost of imbalances to Vattenfall AB customers when intraday prices are lower than imbalance prices, own calculations from data sources

Scenario for having 10% Demand Response	Flexibility (MW)	Cost (Euro) with imbalance prices	Costs (Euro) with intra-day prices
VTT pays less to TSO (VTT consumes more than scheduled program)	44.52	4785.14	1997.76
VTT pays less to TSO (VTT consumes less than scheduled program)	3.60	410.24	117.78

The above calculations illustrate that in a distribution area the gains from demand response are quite small. On the contrary, when taking a closer look at the control area of 50Hertz in 2011, unbalanced BRPs were charged 120Euro million⁶⁹ (Hirth and Ziegenhagen, 2013). In this case, the consideration of DR may have a much larger impact on imbalance costs and allocation.

⁶⁸ <http://www.epexspot.com/en/market-data/intraday/intraday-table/-/DE>

⁶⁹ From these costs 90Euro million were distributed to other (counter-balanced) BRPs and 30Euro million were used for activating control power.

CONCLUSION AND RECOMMENDATIONS

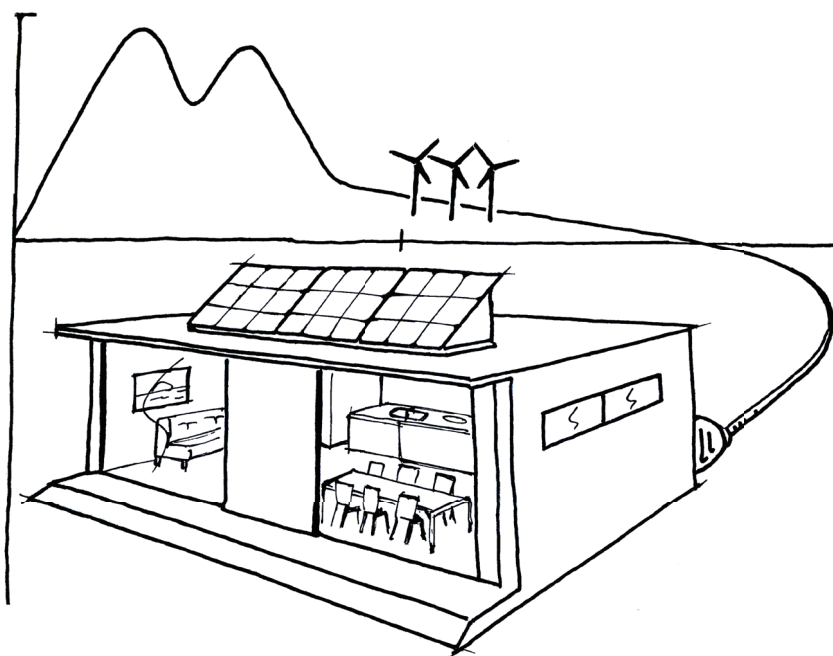
The above discussion has provided an overview of the European markets, where aggregated demand-side-flexibility from small users may be of most value to the system, markets and individual consumers. An analysis of the balancing mechanism illustrates that aggregated load for DR has potential as a flexibility resource but is undermined by the vagueness in the specifications for (i) balance responsibility, (ii) balance service provision and (iii) imbalance settlement. Specific limitations arise from strict rules and commitment requirements in the balancing procedure.

This work serves as an illustration of how the utilization of aggregated load as a flexibility resource implies added complexity in the process, in addition to costs along the way. In a liberalized setting, a competitive aggregator is expected to yield high profit margins from DR which will be passed onto participating consumers. Nevertheless, commercial aggregation exists virtually while technical operation is a real-time event. Procurement of balancing services requires the standardization of products which should take into account the technical characteristics of available balancing resources (in this case demand response) in such a way that satisfies the needs of TSOs to balance the system.

On account of increasing intricacies in the production and consumption processes of electricity, full transparency of network function is critical. The regulator may appoint a new party as aggregator or extend the functions of existing regulated actors such as the DSO. The distribution system operator is the closest physical connection to consumers and is already aiming to minimize costs with a high quality of service provision. However, difficulties could arise with the desired nature of DR utilization. Demand side flexibility can both aid distribution system reliability and help the TSO in the balancing mechanism. DSOs would need more location-specific aggregation (so aggregation of demand in their control area) while for balancing of the system this is less of a need due to the fact that it is then seen as a single node system. Regulation of activities requires aggregators to adhere to a set of pre-defined efficiency targets regarding the administrative process (ex-ante, real-time and ex-post) of load aggregation for balancing in addition to a clear definition of what purpose the DR will be used for. Aggregators need control of the load and TSOs need a guarantee of the supply flexibility. Balance management is designed for the security of electricity supply to all connected users which must be guaranteed by the TSO. As a result standardization (e.g. technical constraints, speed of activation, minimum bid size, etc.) is crucial in the diversified participation of a range of products from sources other than traditional generation. The authors suggest that an aggressive approach to mitigate constraints to entrance barriers for DR is to allow priority access to aggregators in the balancing market. In the European setting, where CO₂ mitigation, RES penetration and energy efficiency are of high importance on energy

policy agendas, priority access to aggregated DR is an interesting consideration since it is then comparable with the RES priority access in electricity markets. This can be tried in the German market as balancing provision by interruptible loads becomes more common practice.

Regulation which considers DR should facilitate a level-playing field for participating actors. As a viable market resource, aggregated DR is still in infantile stages of consideration, and the above investigation simply serves as an illustration for the drivers and emerging barriers in market design. There are others who argue that accurate monitoring of reserves from many small-sized, autonomous appliances is economically impractical and technically unnecessary. Nevertheless, European power systems are in the midst of radical changes, which will need innovative, new solutions for markets and operation. Aggregated demand response is one alleviation strategy to a system of increasing need of flexibility resources.



CHAPTER 6

ECONOMIC INCENTIVES FOR DISTRIBUTION-SYSTEM
OPERATORS TO ENGAGE DEMAND RESPONSE

The previous chapters focused the assessment of demand response on signals derived from electricity markets. Note, residential demand response will essentially occur at the low voltage grid level, therefore having a significant impact on the capital and operational expenditure of the distribution system operator. This chapter investigates the economic effect of consumption flexibility under current regulatory remuneration on distribution-system operators with a Swedish case study based on work conducted in Koliou et al. (2014; 2015c)⁷⁰ and Eklund (2014)⁷¹.

⁷⁰ Koliou, E., Eklund, T., Picciariello, A., Söder, L., Bartusch, C., Alvehag, K., Hakvoort, R.A., 2014. Economic Impact of Demand Response on Costs to Distribution System Operators, in: 37th IAEE International Conference. New York, NY, USA.

Koliou, E., Bartusch, C., Picciariello, A., Eklund, T., Söder, L., Hakvoort, R.A., 2015c. Quantifying distribution-system operators' economic incentives to promote residential demand response. Util. Policy 35, 28–40. doi:10.1016/j.jup.2015.07.001

⁷¹ Eklund, T., 2014. Impact of Demand Response on Distribution System Operators' Economy. Master thesis, KTH Royal Institute of Technology, Stockholm Sweden.

INTRODUCTION

Electricity networks are in the midst of a radical smart-grid transformation which will accommodate the local integration of a variety of distributed energy resources (DER): distributed generation (DG), local storage, electric vehicles (EVs) and overall active demand (Ackermann et al., 2001; Pérez-Arriaga et al., 2013). Along these lines, local distribution networks will compel greater flexibility. One flexibility resource that remains largely untapped is residential demand response (DR). The value of this opportunity will vary according to the type of service, location in the system, agent accessing the flexibility and the time at which the flexibility becomes available (Pérez-Arriaga et al., 2013). When subject to demand-response programs, general actions that a customer can take include decreasing consumption during peak periods where prices are high and shifting consumption during peak periods to off-peak (Albadi and El-Saadany, 2008).

The proliferation of DR in an electricity system will have multiple effects in terms of inducing cost management and mitigating environmental impact (Strbac, 2008). DR is of great interest as a flexibility resource, but nonetheless has not been thoroughly investigated in order to assess the range of potential savings that can be achieved in the electricity value chain; electricity distribution is one of these lacking domains. For the distribution-system operator, both peak shaving and peak-load shifting will have the same effect on the grid in terms of reduced power flow through the network at a given time (Pérez-Arriaga et al., 2013). Hence, DR has a twofold application for the grid: to add a flexibility resource for system balancing, and to mitigate both transmission and distribution overload (Strbac, 2008). This chapter will focus on exploring the latter influence for distribution-system operators to reduce the level of load variations in the system.

Fundamentally, "*bringing demand response to fruition*" (Bartusch and Alvehag, 2014) via implementation programs is a matter of technical system operation; that is, a real-time strategy requiring transparency of grid activity. At present, DR (from small end-users) as a competitive activity is difficult to achieve due to escalating complexities in both the production and consumption of electricity. Distribution-system operators provide the closest physical connection to customers. With full access to information about the status of the local network, including consumption and production profiles of so-called "prosumers," distribution-system operators are the most pragmatic entity to signal and access end-user flexibility under present system design (Elta Koliou et al., 2014).

By 2020, it is estimated that European electricity networks will require investments in the range of 600 billion Euros, of which over half will be in distribution grids. It is estimated that by 2035, investments in distribution will grow 75 percent compared to current levels (Eurelectric, 2014). It is thus important to focus on mitigating distribution system costs and optimizing smart-grid investments. This study provides insight into the impact of DR on the minimization of costs for the distribution-system operator.

DISTRIBUTION IN THE EUROPEAN SMART GRID: ROLE, RESPONSIBILITIES AND TARIFFS

Role and responsibilities

Traditional

As regulated natural monopolies, distribution-system operators exhibit high fixed (sunk) costs, economies of scale, loss of efficiency with competition, and the provision of a public good to which citizens cannot be denied access. Traditional electricity networks are designed to handle extreme cases of maximum power flow that seldom occur due to the hourly, daily, weekly, monthly and seasonal variance in grid load. Tailoring the grid to fit such dimensions is costly (Forsberg and Fritz, 2001), but nonetheless consistent with current tariffs set by European regulators.

Smart grid

In a smart-grid environment, the roles and responsibilities of actors in the value chain of electricity evolve in order to accommodate the integration of distributed generation, energy-efficiency services, electric vehicles and their charging points, local balancing, flexibility procurement, smart-energy systems, and large volumes of data (FSR and BNetzA, 2014). Distribution-system operators are at the heart of successfully implementing changes at the consumer level all while warranting to end-users a high level of reliability and quality of service via optimal system planning, development, connection, operation and facilitation of the retail market (Eurelectric, 2013). Escalating intricacies in system architecture are increasing the complexity and dynamics of service provision, in turn bringing to light the paucity of accurate economic signals to grid users under the regulated tariff (Pérez-Arriaga et al., 2013).

Distribution remuneration

Economic incentives for distribution-system operators (and therefore customers) are pre-defined in the tariffs set by the regulator. Strictly speaking, “power regulation” is an umbrella concept referring to both the remuneration of total (or allowed) network costs and the allocation of these costs to network users. It is important to make the distinction between network regulation (in a strict sense limited to the remuneration of total allowed network costs and the incentives this offers to network operators) and network tariffication (which is then dedicated to the allocation of these costs to the users, yielding full-cost recovery). Such costs consist of operational expenditure (OPEX) and capital expenditure (CAPEX). The former pertain to daily operational expenses of power-flow management while the latter consist of long-term investments made in physical assets (Hakvoort et al., 2013).

Underlying theory of network pricing

Fundamentally, when looking at network pricing, there is a conflict between short-term and long-term objectives. Active distribution management is concerned with short-term grid operation, which signals long-term network expansion depending on how the network is being used. Electricity distribution exhibits a high degree of asset-specificity, with capital expenditures that are exponentially larger when compared to operational expenditures (de Joode et al., 2009).

In theory, optimal tariffs (with respect to allocative efficiency) are reached on economic principles of marginal cost, with a change in the total cost arising when the quantity produced increases by one unit. In Europe, wholesale electricity markets have evolved towards sending optimal economic signals via marginal-cost pricing for energy trading on at least an hour-by-hour basis to incorporate the short-term costs of electricity production. If such an approach is taken in pricing distribution it would entail the use of energy sale or purchase prices as pertaining to each node in the grid (Reneses and Rodríguez, 2014). Along these lines, marginal-cost application would be inclusive of power losses and congestion constraints, taking the network capacity as a given. The setting of tariffs based on short-run marginal costs has several shortcomings. At the distribution level it requires locational marginal pricing, that is, nodal pricing⁷², which is theoretically optimal for communicating losses and congestion in real time. However, at the distribution level, the network is rarely used to its full capacity. As a result, congestion is virtually nonexistent (except when manifested into relatively rare outages). In turn, little to no recovery of the total cost of service provision is signaled at present, which in turn provides very little incentive for future demand-side developments (Reneses and Rodríguez, 2014). Reneses and Rodríguez-Ortega (2014) point to an application in Pérez-Arriaga et al. (1995) and Ponce de Leão and Saraiva (2003) where cost recovery is below 25 percent for transmission and estimated to be even lower at the distribution level. Full cost recover requires the addition of extra costs, which in turn distorts the message that short-run marginal pricing is meant to send. The short-run marginal-cost method is optimal for pricing operational expenditures in distribution (Economics, 2013; Gómez, 2013; Hakvoort et al., 2013; Similä et al., 2011), at least for Europe if not elsewhere.

Furthermore, investments in networks are considered discrete and therefore take the existing grid as a baseline and optimize expansion for a given trend in demand (Reneses and Rodríguez, 2014). When considering investments, marginal pricing then considers long-run costs, which are exponentially larger. In this sense, long-run marginal pricing can be calculated via demand and technology forecasts in two forms. First, the marginally

⁷² Nodal pricing is applied in the United States, but there are some fundamental differences in system operation and market. Basically, in the United States there is a pool where market and physical system are optimized simultaneously while in Europe the market and physical grid clear separately on a day-ahead basis and optimize coordination until the moment of delivery at the day.

incremental approach takes into consideration permanent demand increments over the relevant years and looks at the present value of future costs. Second, through an average incremental-cost approach, demand and technology developments are also forecasted but project costs are averaged yearly by dividing by the present value of the change in demand (Economics, 2013; Gómez, 2013; Hakvoort et al., 2013; Similä et al., 2011).

The marginal incremental approach is the theoretical ‘pure’ estimate of long-run costs, but is more difficult to calculate. Specifically, in a smart-grid investment environment that fosters the energy-efficient appliances and demand-response programs, technology risk is high and demand forecasts difficult to appraise. An average-cost approach allows the incorporation of investment lumps to be smoothed. Simultaneously, future levels and trends in costs of rising demand are reflected over time (Similä et al., 2011). In the long-term, the calculated network remuneration must promote efficient development of the grid for the benefit of network users. In the tariff it may be important to provide customers incentives to use the network efficiently, which may include location-specific and time-specific rates (Hakvoort et al., 2013; Similä et al., 2011). Tariff regulation at a minimum has to meet three objectives (Hakvoort et al., 2013):

1. *The total tariff revenue must cover the incurred costs*, i.e. the capital and operating cost of the infrastructure should be fully covered by the grid tariffs.
2. *Tariffs must be non-discriminatory*. Similar network use (by the same or other market party) should result in the same conditions for the same rate in order to not disturb the electricity market.
3. *Tariffs must be transparent*. The methodology for determining the rates should be clear to all network users.

Below follows a discussion of the specific tariff design elements.

Tariff design

For the distribution-system operator, network use refers to consumption (electricity withdrawal), production (electricity injection), and prosumption (combined withdrawal and injection). Distribution network fees have three critical facets: (i) the initial network connection charge (a one-time flat payment in Euro); (ii) network tariff level (use-of-system charge) for allowed revenue during the regulatory period and; (iii) the network tariff structure⁷³, i.e. network charges according to consumer categories, periods of grid use, and the mobility of loads when considering DER (Eurelectric, 2013). The initial connection charge becomes critical when connecting own distributed generation (e.g. solar photovoltaics) since it pertains to who bears the cost responsibility for externalities

⁷³ The customer charge is at times incorporated in the use-of-system charge.

imposed to the system.⁷⁴ The tariff level pertains to the amount of remunerated recovery for the distribution system operator during the regulatory period, an aspect that becomes critical under the consideration of new investments in the (smarter) grid. Finally, the network tariff structure is relevant with regard to stimulating end-user flexibility (Pérez-Arriaga et al., 2013). All three aspects are important with respect to distribution-system operator remuneration, but we focus the remainder of our discussion on the smart-grid tariff structure.

A widely cited publication on network tariff design (Pérez-Arriaga and Smeers, 2003) finds that in a perfect system: (i) network charges are computed *ex-ante* (i.e. prior to delivery of electricity to customers); (ii) network charges do not depend on commercial transactions (i.e. electricity market trading); and (iii) network costs are allocated to those who cause them or who benefit from the deployment of the assets (on the basis of the beneficiary-pays principle). The problem with the current method is that although the rates cover costs, limited economic incentives are given to network users (Eurelectric, 2013; Similä et al., 2011).

Tariff structure

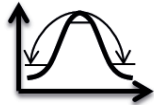
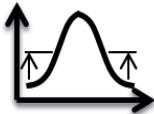
The network tariff is commonly referred to as the use-of-system charge paid periodically by consumers (either monthly or bi-monthly), incorporating volumetric and/or capacity components (Gómez, 2013). Design of the use-of-system charge requires the identification of cost drivers followed by the determination of appropriate rate schemes. As briefly mentioned above, general cost drivers consist of CAPEX and OPEX in addition to other miscellaneous expenditures deemed either variable or fixed costs (de Joode et al., 2009; Eurelectric, 2013). Volumetric charges are proportional to the energy demand charged in Euros per kilowatt-hour (€/kWh). Capacity charges are a reflection of the load contribution to peak demand in the network charged in Euros per kilowatt (€/kW) or Euros per kilowatt per month, depending on the structure of the tariff. Other fees include customer charges for management and support that (more often than not) are a part of the use-of-system charge (Gómez, 2013).

Table 25 summarizes the distribution-tariff design options with their direct impact on load: strategic conservation (overall energy efficiency resulting in reduced consumption); peak shaving (only a reduction at peak hours); load shifting (displacing load from peak hours to off-peak); and valley filling (increasing load consumption at off-peak hours). Recent studies (Pérez-Arriaga et al., 2013; Ramos et al., 2014; Reneses and Rodríguez, 2014) on the future of distribution recommend that at the most basic level tariffs should

⁷⁴ This charge can be shallow, shallowish, or deep. A shallow charge means the developer of the DG bears the grid connection cost; a shallowish charge indicates that the DG owner (household) bears the connection and a share of the grid reinforcement cost; a deep charge puts the full responsibility of the grid connection and grid reinforcement cost on the DG owner. In most European countries DG owners are subject to a shallow charge.

veer away from exclusive volumetric charges (€/kWh) and move towards incorporating a capacity charge (€/kW) (otherwise referred to as a demand-based tariff) to properly reflect the impact of agents' consumption and/or production on network costs. TemaNord (2014) point out that the introduction of capacity-based distribution pricing has the potential to reduce costs in the grid and increase end-user flexibility. Overall, capacity-based tariffs can reduce the grid utilization, even when capacity is not deemed scarce.

Table 25: Impact of major tariff options on load and network costs (adapted from Eurelectric (2013))

Type of network tariff	Design	Direct load impact
<i>Volumetric charge</i>	• Energy (€/kWh)	 Strategic conservation
<i>Two-part tariff (capacity & volumetric energy charge)</i>	• Power (€/kW) • Energy component (€/kWh) with a flat rate or time-of-use energy charge	 Peak shaving
<i>Time-of-use volumetric</i>	• High €/kWh (peak) • Low €/kWh (off-peak)	 Load shifting
<i>Capacity-based</i>	• Power (€/kW) • Can also have a 'dynamic' component with high prices at peak hours and low or no charge at off-peak hours	 Valley filling

Peak demand is a main driver for grid cost, yielding a tendency to over-size the grid due to reliability constraints. Tariffs should therefore encourage peak-load mitigation via capacity-based tariffs as the optimal approach (Eurelectric, 2013). To illustrate, starting in 2006, a Swedish distribution-system operator, Sala Heby Energi Elnät AB, ran a pilot project with 500 residential customers involving a demand-based, time-of-use distribution tariff to incentivize DR. The results of the study suggest that customers had a positive attitude to the program in question, adapting their electricity consumption pattern to price signals by decreasing peak load in peak hours and shifting consumption from peak to off-

peak hours. During the study's six years, for the summer and winter periods respectively, there was an average reduction in households' individual peak demand of 9.3 and 7.5 percent, and in the peak distributed demand of 15.6 and 8.4 percent; this in turn led to a shift in electricity consumption from peak to off-peak hours by 2.4 and 0.2 percent (Bartusch and Alvehag, 2014). Costs to households decreased in the range of 14 to 41 percent during the pilot, but the analysis also revealed that these savings were affected by low tariff rates (Bartusch et al., 2011).

Distribution in Europe

In European distribution systems, differences start with the physical grid in terms of voltage levels. In Italy, for instance, distribution begins at 200kV, Sweden at 130kV, and France at 20kV (Pérez-Arriaga et al., 2013). In addition, the current tariff structure in member states is inherited from earlier regulatory regimes, where the end-user tariff consolidated generation and distribution and revenue requirements. Moreover, within Europe, the use-of-system charges incorporate one or all three tariff-design elements: a fixed charge, a capacity charge, and an energy charge (see Table 26). When considering distribution as part of the total end-user electricity bill among the member states, costs range between 10 to 30 percent (Geode, 2014).

Table 26: Residential use-of-system charges for select European countries, ref. data Eurelectric (2013)

Country	Fixed Charge (Euro)	Capacity charge (Euro/kW)	Energy charge (Euro/kWh)
Belgium	Yes	No	Yes
Czech Republic	Yes	No	Yes
Germany	Possible	No	Yes
Denmark	Yes	No	Yes
Estonia	Yes	No	Yes
Spain	No	Yes	Yes
Finland	Yes	No	Yes
France	Yes	Yes	Yes
Greece	No	Yes	Yes
Italy	No	Yes	Yes
Lithuania	Possible	No	Yes
Netherlands	Yes	Yes	No
Norway	Yes	Seldom	Yes
Poland	Yes	No	Yes
Portugal	No	Yes	Yes
Sweden	Yes	Seldom	Yes

ASSESSMENT OF DISTRIBUTION COST DRIVERS AND SIGNALING OF DEMAND RESPONSE

In a survey conducted by Eurelectric (Eurelectric, 2014), distribution-system operators across Europe consider smart metering, network automation, and investments in DR and integration of distributed and renewable generation to be the most important investments for smart-grids. For distribution-system operators, the signaling of a demand-response program can have an economic influence on the minimization of costs with respect to power losses in the grid and peak load, both factors consequently affecting ongoing grid investments (Bartusch and Alvehag, 2014; Eurelectric, 2013).

Cost structure of distribution-system operator

The structure of full costs differs from one distribution-system operator to another in Europe, but the basic cost factors remain the same. In Capgemini (2008a), a comparison of gross distribution costs per MWh delivered reveals a variation from 9 Euro per MWh to more than 50 Euro per MWh. As Figure 40 reveals, for the average cost European distribution-system operator, 25 percent of costs are related to asset financing and depreciation, 34 percent to network operation, 20 percent to transmission access and 5 percent to losses. The remaining costs pertain to taxes and customer service. More than 40 percent of annual costs are directly linked to the volume of net delivered energy; such costs pertain to transmission access, power losses, and customer service. More than half of the total costs are deemed either fully or partly controllable. The consensus among European policymaker and lobbyists is that improved consumption efficiency can improve distribution-system operators' long-term economic performance (Capgemini, 2008a; EC, 2015b; Eurelectric, 2013). This is in line with the theory of tariff pricing that takes the long-term performance of distribution into consideration.

Optimizing costs of short-term distribution operation

A widely held view is that distribution network tariffs should be implemented to the extent that they reflect underlying grid costs (Eurelectric, 2013; Hakvoort et al., 2013; TemaNord, 2014). Tariffs are the signal to consumers to optimize (i.e. minimize) costs. As mentioned above, the level of allowed revenue for distribution-system operators is set by the regulator. This level affects the overall investment behavior of operators, and is thus a critical factor for the development of smart grids. The tariff level has an impact on investment recovery; hence the emphasis placed on the identification of cost drivers for pricing. Moreover, network tariffs are paid by customers and therefore the price structure should affect customer behavior (Eurelectric, 2013). See Figure 41 for a summary of the signals provided by grid network tariffs to both distribution-system operators and consumers.

TemaNord (2014) highlight that when it comes to grid operation, the only thing that varies with the amount of load is the losses incurred in the energy delivery. Such losses increase when the grid is operated closer to its maximum capacity limit, at which time distribution assets are used sub-optimally (decreasing their overall service life).

A series of interviews conducted with the CEO of Sala-Heby Energi Elnät AB, a distribution-system operator experienced in successfully implementing demand-response programs (Mårtensson, 2013a, 2013b), emphasizes the importance of mitigating costs by optimizing for losses, peak loads, and grid investment through DR. Optimization will have at least some impact on about 75 percent of the distribution system cost drivers in Europe (see Figure 40).

In the next section follows a description of a generally applicable simulation approach developed in Koliou (2014) and Eklund (2014) for assessing the cost factors for distribution, using Sweden as a case study. The proposed model can be adapted to all distribution-system operations within similar market structures and to inform regulators of the magnitude of benefits that can be obtained from implementing a demand-response program.

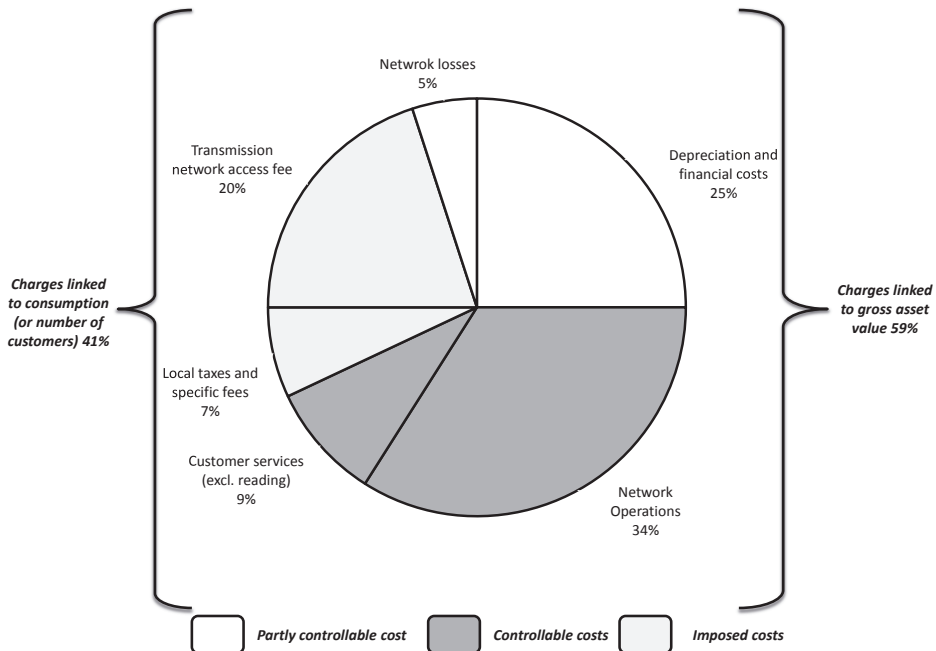


Figure 40: Average cost structure for a distribution-system operator in Europe, ref. Capgemini (2008a)

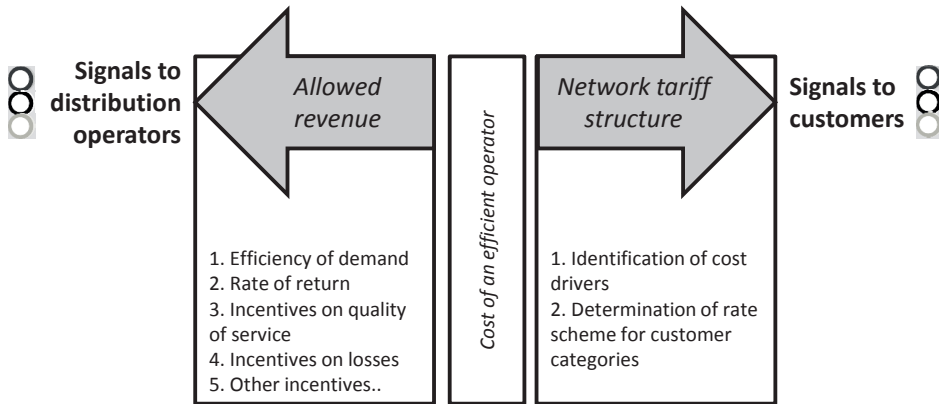


Figure 41: Signals provided by network tariffs, adapted from Eurelectric (Eurelectric, 2013)

QUANTIFYING DEMAND RESPONSE

Assessing the economic effect of DR in distribution requires the consideration of factors related to power losses, peak loads, and grid investments. Using distribution data from a Swedish operator, an analysis was conducted to quantify the impact of DR. We begin with an introduction to the Swedish regulatory model in order to understand how tariffs are set, followed by an assessment of the costs subject to potential optimization.

Swedish regulatory model

Regulatory oversight from the Energy Markets Inspectorate (the Swedish regulator) runs for a four-year period. The current regulatory period is from 2012 to 2015, with distribution tariff remuneration determined via an ex-ante revenue cap. As illustrated in Figure 42, distribution costs are split into capital and operating expenditures. CAPEX are the costs associated with the 'asset base'⁷⁵ for distribution (equipment and depreciation during the supervision period). OPEX are split into controllable costs (e.g. staff and services) and non-controllable costs (including network power losses, taxes, authority fees, and charges for connecting to the sub-transmission level, known as the feeding-grid charge). Under the current framework, costs regarded as controllable are subject to an efficiency target, while costs regarded as non-controllable are not (EI, 2009; NordREG, 2011). Note, with the right framework of incentives some losses may be controllable as discussed below.

Distribution is comprised of complex processes of physical system operation that are governed by regulatory arrangements (ERGEG, 2008). The added flexibility of DR is aimed at improving system efficiency, but it also intensifies the already intricate processes

⁷⁵ The asset base includes power lines, cables, substations, transformers, systems for operating assets, and meters.

of the distribution-system operator (Balijepalli et al., 2011; Capgemini, 2008b; Shaw et al., 2007). At present, the traditional system comprising of downstream power flows is challenged by the integration of distributed energy resources. Distribution-system operators along with regulators are reacting to developments in upstream generation patterns and prices while simultaneously managing local developments in both production and consumption (Pérez-Arriaga et al., 2013).

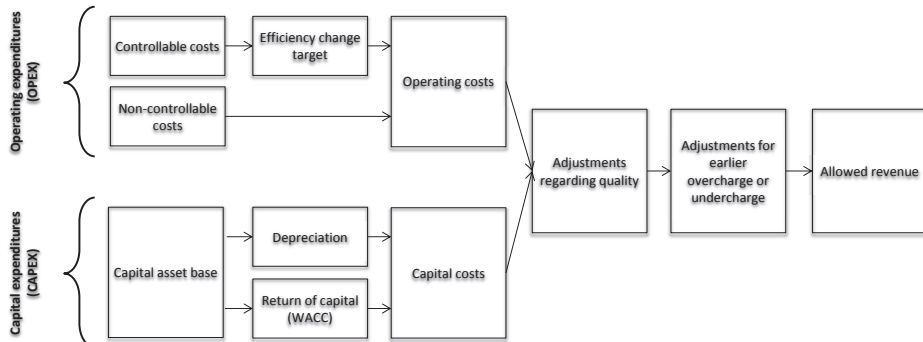


Figure 42: Structure of regulatory model for Sweden (NordREG, 2011) WACC—weighted average cost of capital calculation.

Quantifying the impact of demand response

Determining the tariff scheme for recovering allowed revenue in accordance with costs requires the consideration of several aspects (Eurelectric, 2013; Similä et al., 2011):

- Load (consumption) versus generation (local production) within the grid;
- Load profiles and size of consumption (energy transferred);
- Network structure (urban versus rural and voltage size);
- Temporal variations (seasonal, monthly, weekly, daily, peak and off-peak etc.)

In order to determine the total grid demand, average initial load is aggregated⁷⁶ in kilowatt-hours as follows:

$$(1) \quad \bar{E}_{IL} = (x_1 + y_1, \dots, x_n + y_n)$$

where $\bar{E}_{IL}$ is the total 'Initial Load' prior to DR, x is the hourly electricity imported through the upper grid level and y the electricity production within the distribution system (see Figure 43).

⁷⁶ This includes both the energy fed into the distribution grid through the sub-transmission level and the electricity that is locally produced within the distribution area from 2007 to 2012. The DSO providing the data is considered to be one of the smallest in Sweden with 13,211 customers in the distribution area and a total yearly demand of 199,690 megawatt hours.

As stated earlier, peak load is a main cost driver for distribution, making it important to isolate the peak-load periods for the design of appropriate demand-response programs. In the subject system, peak grid use is observed to occur between the hours of 09:00 and 20:00, while off-peak use falls between 21:00 and 08:00. Peak hours of consumption vary per distribution system and over time and should be defined accordingly. For instance, in Bartusch and Alvehag (2014) the peak hours are from 07:00 to 19:00 in the respective distribution area, while in Sweco (2012) peak hours for distribution fall between 06:00 to 22:00.

The authors consider peak and off-peak hours in the distribution area to simulate a two-band time-of-use demand-response program under two scenarios. Scenario 1 explores an arbitrary but reasonable 10 percent load shift from peak consumption and evenly distributes the load to off-peak hours, such that overall consumption remains the same but the load is more evenly distributed (represented by the red line in Figure 43).⁷⁷ Scenario 2 looks at the optimal case of DR, where the load from peak-hours is evenly distributed throughout the off-peak hours in order to yield a flat distribution load curve (the green line in Figure 43). A flat load simulation is aimed at representing the ideal power-demand curve that a smart grid seeks in order to improve system efficiency, cost effectiveness, and overall reliability and power quality. One of the means used to achieve these smart grid goals is via flattening of the power-demand curve. Along these lines, recommendations for the utilization of DR point to a more evenly distributed load without changing the total amount of electricity consumed i.e. minimizing discomfort for the consumer. Simulating a flat load is a means of capturing the optimization all distributed energy resources in a distribution area (Carillo Aparicio et al., 2014).

Both scenarios illustrate the impact of a time-of-use distribution tariff specifically targeted at incentivizing the use of the grid below a certain capacity threshold. As mentioned above, capacity based tariffs aid in promoting optimal utilization of the distribution system (see 2.2.2.1 and Table 25).

On the basis of the above analysis, load shift ($\tilde{E}_{LS}$) from DR is constructed as follows:

$$(2) \quad \tilde{E}_{LS} = f(\tilde{E}_H) = (z_{1,LS}, z_{2,LS}, \dots, z_{n,LS})$$

$\tilde{E}_{LS}$ is comprised of hourly load data from $\tilde{E}_H$ and is then adjusted by the demand-response load shifting estimation(s) (for both scenario 1 and 2), $f(x)$, where z corresponds to each hour with DR which is calculated as the respective modification per peak hour to an off-peak hour per scenario. For scenario 1, at each of the peak hours per day for the

⁷⁷ Evidence from Bartusch and Alvehag (2014) indicates that such a load shift is feasible from consumers. Ibrahim and Skillbäck (2012) corroborate that a 5 to 15 percent load shift is feasible with the implementation of a two-band time-of-use tariff for distribution.

year there is a 10 percent load reduction that is then shifted and evenly distributed to the off-peak hours. For scenario 2, the load is optimized to yield a flat load curve over one year such that the overall consumption for a specific year does not change. See Figure 43 for average values of one day over the year.

Considering a feasible 10 percent load shift and an optimal flattened load, we continue with an analysis of the cost factors that can be optimized by engaging DR: power losses, peak loads, and grid investments (via postponement or avoidance).

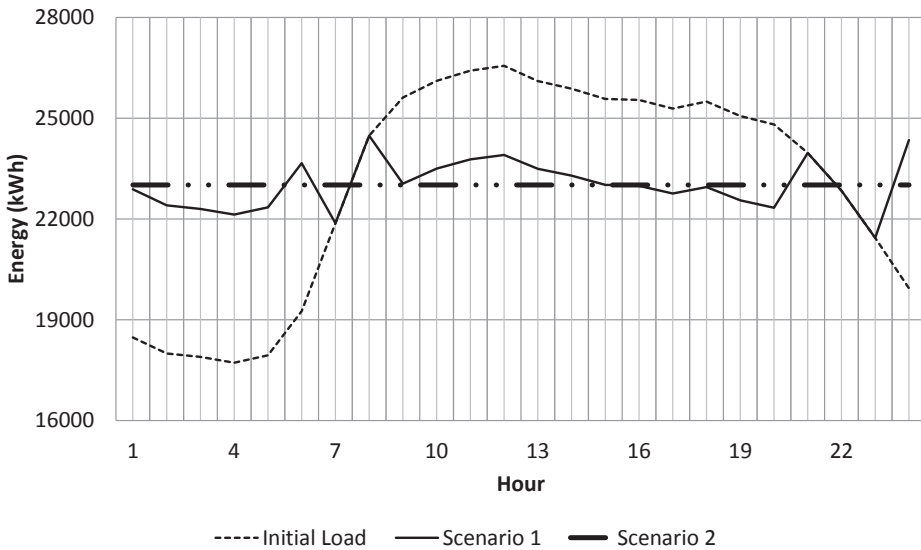


Figure 43: Average daily load in the distribution system

Demand response for the reducing power losses

Since we are concerned with the aggregate impact of power losses, the simulation assumes that load is equal in all parts of the distribution grid (which is not the case in reality). Total distribution network power losses are the aggregated differences between the measured power entering the grid and that which is consumed (measured at the customer meter) (ERGEG, 2008). Swedish distribution-system operators are required to purchase electricity from the spot market (Nord Pool⁷⁸) to cover power losses occurring within their grid (as is the case in other European countries, including the Netherlands); this is regarded as the cost of covering losses (EI, 2009; NordREG, 2011).

Power losses in a distribution system can be both non-technical and technical and both fixed and variable. The implementation of a demand-response program can only impact the minimization of variable technical losses in the distribution system. Non-technical

⁷⁸ More information, see <http://www.nordpoolspot.com>

losses consist of delivered electricity that is not compensated, such as theft, errors in metering, non-metered delivery,⁷⁹ and own consumption by the operator (ERGEG, 2008). Such losses can be costly but cannot be affected by DR. Fixed technical losses are independent of power flow, such as those resulting from iron loss in transformers (ERGEG, 2008), and are therefore not affected by load management. Comparatively, variable technical losses (occurring in transformers as well as power lines) can be mitigated by DR since they are the direct cause of natural resistance in power lines (Shaw et al., 2007). In Sweden, electric power transmission and distribution losses equal approximately 7 percent of total yearly electricity production (World bank, 2015). For the distribution-system operator analyzed in this simulation,⁸⁰ average losses for the year are 4.3 percent, below the European average (see Figure 40).

Variable power losses are proportional to the squared power flow within the grid (that is, precisely yielding a quadratic value relative to load). As a result, the simulation considers this proportionality to create a loss vector (Δ_l) varying with the load output when the load goes from P_a to P_b :

$$(3) \quad \Delta_l = \frac{P_a^2 - P_b^2}{P_a^2}$$

For both the initial load curve $\tilde{E}_{ll}$ and shifted $\tilde{E}_{ls}$ curves (feasible and optimal) average variable losses (L_v) are calculated as follows:

$$(4) \quad L_v = 0.043 (1 - L_f)$$

L_v corresponds to the proportion of fixed to variable ones (Shaw et al., 2007), set at 1 to 5 for this system (Mårtensson, 2013a). Total (variable) losses can then be compared using $\tilde{E}_{ls}$ and $\tilde{E}_{ll}$ (before and after DR for both scenarios), in this way determining the impact of DR in kilowatt-hours, which can then be multiplied by the spot market price for economic evaluation purposes.

Demand response for alleviating peak loads

Distribution-system operators incur costs at the connection point to the high-voltage transmission grid (Gómez, 2013; Rodríguez Ortega et al., 2008). In order to pass electricity from the transmission to the distribution grid, Swedish distribution-system operators pay a 'feeding-grid' charge for the withdrawal from or injection to the grid. The fee is divided into three parts that are updated on a yearly basis and paid for monthly by customers

⁷⁹ For example, public lighting

⁸⁰ Sala-Heby Energi Elnät AB.

(E.ON, 2013; Fortum Distribution, 2013; Vattenfall Distribution, 2013). The first part is a fixed capacity fee that is paid in Euros regardless of the amount of power or energy transferred. Since the remuneration is fixed ex-ante, load shifting has no impact on this charge. The second component is a variable charge for the actual energy transferred during the year, calculated on the basis of a pre-specified fixed price per kWh; only overall load reduction will have an effect so this charge will not be affected by load shifting (since the total energy consumed remains the same). Finally, a variable capacity component (€/kW) is charged to the distribution-system operator for staying within a subscribed level of maximum power on the grid. Once this pre-specified level is surpassed, the operator is charged a higher fee per kW. In the past year, the distribution-system operator paid 20€ per kW for the agreed level and 30€ per kW for deviations⁸¹.

When signaling DR, load shifting from peak to off-peak hours decreases the peak capacity level (Mårtensson, 2013b). The maximum level of power is a complicated component to calculate due to the stochastic nature of end-user consumption patterns. To illustrate, Sweden has a capricious climate and homes are heated with electricity, with potentially devastating consequences for distribution-system operators. From one year to the next, electricity consumption from residential customers may vary ± 10 percent as a result of home heating (ERGEG, 2008). In this context, minimizing the pre-defined peak capacity leads to overall lower costs for the distribution-system operator (Mårtensson, 2013b).

At each distribution connection point this power level is optimized differently, depending on the connection to the high-voltage operator⁸². For this simulation we take the Vattenfall approach (Vattenfall Distribution, 2013) to optimize the subscribed power level by averaging the 2 maximum load values per month over the year, as indicated in equation 5.

$$(5) \quad E_{Lm,max} = \frac{x_1 + x_2}{2}$$

$E_{Lm,max}$ is the maximum subscribed power defined by regional grid operator for a given load curve of year m where x_1 and x_2 are the two highest capacity values in the grid for the year m . Any penalty for deviating from the set subscribed level is settled for a given year by comparing the actual maximum capacity (E_d) with the subscribed maximum power ($E_{Lm,max}$) in the contract. Total costs for the feeding grid for any given year are calculated as follows:

⁸¹ 182 SEK for the agreed level and 273 SEK for deviating (December 8th, 2014 exchange rate).

⁸² Fortum changes the level on a weekly basis using the mean of the two highest hourly values during each calendar week (Fortum Distribution, 2013). For comparison, E.ON takes seasonal variations into consideration and separates winter weekdays from the rest of the year. The maximum power is then calculated by using the mean of the two highest monthly load values for the year for winter and non-winter days (E.ON, 2013).

$$(6) \quad C_{lm} = E_d * C_d + E_{lm,max} * C_p$$

where C_{lm} is the total cost for year m , C_d the deviation cost per kW and C_p the cost for the contracted capacity level. Yearly variations allow the simulation to capture demand fluctuations between years. The model therefore optimizes the maximum level with the accessible load data over the 5-year period as a result of the lowest possible sum of costs for the difference between the initial and shifted loads for both scenarios:

$$(7) \quad \Delta_{fee} = C_{llc,opt} - C_{LSc,opt}$$

where Δ_{fee} represents the change in costs for the specific regional capacity level contract, $C_{llc,opt}$ is the change in cost for the optimal capacity value of the initial load without DR and $C_{LSc,opt}$ is the optimized cost for the shifted load capacity with DR calculated for both scenario 1 and 2.

Demand response for postponing network investments

Distribution investment costs come in two forms that cannot be considered as mutually exclusive since equipment has long lifecycles: investing in new equipment at the end of their lifecycle, and upgrading existing assets to cope with higher demand (Mårtensson, 2013a). The standard lifetime for distribution assets is estimated at 40 years; in order to mitigate short-run marginal costs, increasing the depreciation rate by 5 to 10 years has been recommended (Sweco, 2010). It can be argued that if demand variations are minimized, grid assets could be better utilized over their lifetime and their service lives extended. Specifically, peak-load shifting decreases load fluctuations as long as extreme demand variations remain low (Eurelectric, 2013). With cautious use of distribution assets, equipment upgrades and replacements can be postponed by several years or even avoided altogether (which might further extend lifetimes). Subsequently, our simulation mainly considers investments that are mostly geared towards grid upgrades to existing equipment to cope with rising demand rather than the full replacement of equipment.

We use the net present value (NPV) methodology, commonly used to sum up the current value of cash flows over the time that investments are active:

$$(8) \quad NPV = \sum_{i=0}^n \frac{C_i}{(1+r)^i} - K$$

where n is the number of years of active investment, C_i the cash flow for year i , r the rate of discount pre-set at 0.052⁸³. K is the initial investment in year zero and it is disregarded in this part of the simulation since incorporating it in the calculation for postponing future investments presents a negative cash flow; we present the values as

⁸³ Prescribed value by the Swedish Energy Markets Inspectorate for the regulatory period 2012-2015 (EI, 2011).

positive in the economic outcome below. The net worth of this distribution-system operator is approximately 15 million Euro ⁸⁴, with increasing assets at an approximate average rate of 1.6 percent yearly (PROFF.se, 2013).

For the simulation, we consider the optimal case, where the grid is utilized to its full capacity. We therefore model the actual maximum capacity instead of the subscribed (agreed upon) level discussed in in section 4.2.2. Savings are reflected in the decrease in asset investment until the point in time (the year) when the grid load is expected to surpass the available physical network capacity.

The impact of DR is represented as the maximum peak ratio (E_{max}) between the initial peak load ($E_{IL,max}$) and shifted peak load ($E_{LS,max}$).

$$(9) \quad E_{max} = \frac{E_{IL,max}}{E_{LS,max}}$$

The inverse of this ratio yields the number of years that demand-response implementation can postpone future investments in the grid per our simulation:

$$(10) \quad E_{max} = (1 + l)^n$$

where l is the estimated increase in grid assets⁸⁵, (in this case $l=0.016$, representing the yearly average 1.6% increase in grid assets of the distribution-system operator in question) and n the years of investment load shifting saves. To solve for n , the equation can be written as follows:

$$(11) \quad n = \frac{\ln E_{max}}{\ln (1 + l)}$$

Postponed investments are then valued and discounted over years n to obtain the *NPV*. However, a value for the postponed investments for each year must be established first. The investment at year zero (C_0) is calculated as the multiplication of the maximum peak ratio (E_{max}) with the current distribution asset-base A :

$$(12) \quad C_0 = l * A$$

⁸⁴ Specifically, 14,410,0854 Euro with the exchange rate of December 8th, 2014 (133,989,000 SEK).

⁸⁵ Average yearly increase in distribution assets is derived from historical values of capital assets for the distribution-system operator from 2009 to 2012 (PROFF.se, 2013).

In order to properly reflect the rising cost of investments, the total cost (C_i) must be increased each consecutive year by I :

$$(13) \quad C_i = C_{i-1}(I + 1)$$

ECONOMIC OUTCOME

Our results are biased since the simulation was designed to illustrate the positive economic impact of load shifting in terms of optimizing costs for the distribution-system operator. Lower overall consumption in the distribution system will yield additional savings as well as decreased revenues (Eurelectric, 2013). Although we do not consider these effects, it is important to keep in mind when analyzing the results reported in the following sections. Table 27 summarizes the simulation results from implementing a demand-response program in the distribution system: scenario 1 represents a 10 percent (feasible) load

Table 27: Savings from demand response^a

		Scenario 1: 10% load shift	Scenario 2: uniform load
<i>Power losses</i>	Reduction in losses during one year (kWh)	346,756	1,635,036
	Decrease in mean arithmetic loss over the year (%)	4%	19%
	Reduction in cost per year (Euro)	27,058 €	121,064 €
	Annual difference in cost per customer (Euro)	2.1 €	9.2 €
	Total reduction in cost per year (percent)	8%	36%
<i>Peak demand</i>	Optimized value for subscribed maximum power (kW)	38,499	19,770
	Reduction in the level of maximum power (%)	2%	51%
	Annual reduction in cost per year (Euro)	43,578 €	471,071 €
	Annual reduction in cost per customer (Euro)	3.3 €	35.6 €
	Reduction in cost per year for the operator(%)	5%	46%
<i>Grid investments</i>	Difference in annual cost (Euro)	109,571 €	114,420 €
	Years of delayed investments	2	43
	Annual cost decrease per customer (Euro)	8.3 €	8.6 €

^a Initial calculations in Swedish Krona (SEK), using exchange rate December 8th 2014 (1 SEK equal to 0.11 Euro).

shift from peak to off-peak hours and scenario 2 illustrates the optimal case of load management by flattening the consumption curve in the distribution service area.

Overall, we see that under scenario 1, DR brings about the highest annual savings per customer from investment savings, followed by peak capacity optimization and losses. For scenario 2, maximum savings are achieved from optimizing the peak capacity level followed by losses and postponing investments. In the following section, we discuss in detail the results related to each cost factor.

Discussion of simulation results

Power losses

The simulation indicates that the theoretically available maximum DR would help the distribution-system operator reduce up to 19% of annual losses, in turn yielding savings of more than 36%, which in this case corresponds to 121,000 Euro⁸⁶ (approximately 2% of yearly turnover⁸⁷). Per customer⁸⁸ savings from the annual minimization of losses amount to about 9 Euro per year. Interestingly, the authors observe that when shifting losses from peak day-time hours to off-peak night-time hours, the use of day-ahead spot market prices results in lower overall purchasing costs related to power losses for the distribution-system operator.

In this distribution system, with a yearly demand of 199,690 megawatt-hours (MWhs), losses are approximately equal to 8,587 MWhs (considering average losses of 4.3% mentioned above 4.2.1). When considering losses, savings can be achieved in different orders of magnitude depending on the procurement pricing method: fixed ex-ante contracting (no real time dynamics), day-ahead pricing, intraday pricing, and imbalance pricing. Although real-time market transparency for procurement is optimal, current regulation regards losses as non-controllable and these costs are passed to consumers, which gives distribution-system operators little incentive to seek the engagement of consumers in demand-response programs.

In most European countries, the distribution-system operators are responsible for the procurement of electricity for losses (e.g. Austria, Belgium, Switzerland, Germany, Denmark, Estonia, Finland, France, Lithuania, Netherlands, Poland and Sweden); otherwise, this responsibility falls to the electricity suppliers although this does not necessarily mean that the distributors do not receive incentives with regard to losses reductions (Eurelectric, 2013).

⁸⁶ Euro value of December 8th 2014.

⁸⁷ Yearly turnover is approximately 6€ million from 2008 to 2012 (PROFF.se, 2013).

⁸⁸ Customer refers to residential customers.

Peak loads

An optimal flattened load curve suggests that the subscribed level of power could theoretically be decreased by a maximum of 51%, resulting in 46% cost savings and corresponding to more than 471,000 Euro⁸⁹ for the distribution-system operator. With a 10-percent load shift, the subscribed level of peak load can decrease by 2% and reduce annual costs for the distribution-system operator by 5%. Since there is no guarantee of end-user DR, capitalizing on this potential is still a high-risk endeavor. Even if DR is able to reduce part of the load fluctuations, some peaks will still persist and those will ultimately determine the costs related to the peak-capacity charge.

Peak demand has been and continues to be the main driver for network costs (Rodríguez Ortega et al., 2008). In this way, distribution-system operators can 'buy' lower risk by increasing their maximum level of subscribed power or promoting consumption flexibility through demand-response programs. Hedging for risk of maximum subscribed power implies the existence of an optimal level that will be different for each distribution-system operator (considering regional, seasonal, monthly, weekly, and hourly variations).

The current design of capacity tariffs places the brunt of the burden with the distribution-system operator. DR may result in a smoother load curve, from which higher grid levels will reap all the benefits without having any of the responsibilities involved in program implementation. Under Swedish law, this capacity fee is considered yet another non-controllable cost that is passed directly to the consumer. Consequently, both costs and benefits accumulate to the customer and not the distribution-system operator.

Individual contribution to peak

The data for our case study consist of almost 90-percent energy transferred to residential customers; we therefore see fit to have a simple assessment of what load shifting collectively means for the distribution area and possibly other customer groups. For instance, reducing the level of maximum subscribed power means a collective set level at 39, 269 kW; individual households in the distribution contribute only about 3kW to this maximum. When looking at DR it is important to keep in mind these individual contributions to the total energy use. In accordance with the initial consumption curve derived above in Figure 43, we can construct an average load for each household as shown in Figure 44.

Individual consumers have an average maximum hourly consumption of 2 kWh at peak hour and a minimum of 1.3 kWh at an off-peak hour. The difference between the maximum and minimum consumption is roughly equal to the displacement of a load of laundry⁹⁰. With a 10 percent load shift, maximum average consumption is 1.8 kWh

⁸⁹ Euro value of December 8th 2014.

⁹⁰ EU energy label A-rated gives an average consumption at 40°C using a 2kg load to be 0.63 kWh (Carbon Footprint, 2015).

with a minimum of 1.6 kWhs, a difference roughly equal to heating 2 liters of water in a kettle⁹¹. These figures illustrate that on an individual basis, households have to do very little to shift load from peak to off-peak hours. Key questions, though, are how important is it for consumers to do things at a specific time and what appliances are they willing and able to have controlled in order to comply with demand-response programs? With visual aid from smart meters, in-home displays, and smart-phone applications, the set level of power for the distribution system and individual contributions to the peak can be communicated to end-users. Consumers can consciously decide to stay below the threshold by manually choosing not to use certain appliances at communicated hours. In order to not disturb comfort, household appliances can also be programed to automatically respond to the distribution system needs at times of distress either signaled by peaking conditions or congestion.

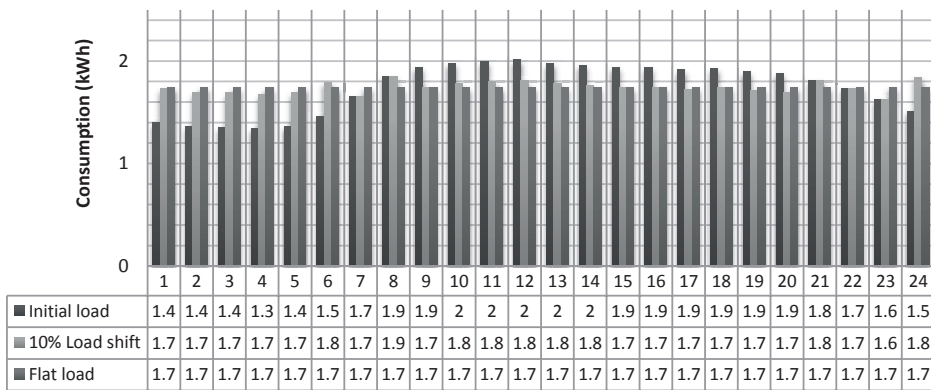


Figure 44: Average individual contribution to total energy use in the system for every hour of the day (1 to 24)

Grid investments

The relevance of the simulation for grid infrastructure investments is surrounded by the most uncertainty, and yet is of most interest when considering optimal grid utilization over the long term. Distribution-system operators face specific and changing needs that are hard to plan for in advance (for example, which distributed generation technologies will be favored by consumers or the penetration level of electric vehicles). Moreover, distribution equipment has long lifecycles; as a result upgrades and re-investment needs are difficult to forecast. On this basis, it is difficult to estimate with accuracy the expected new investments and upgrades over the coming years. Delaying investments for 2 years is a way of optimizing for short-term operational objectives (2.2.1). An investment delay

⁹¹ A measure from ref. carbon footprint (Carbon Footprint, 2015).

of 43 years allows the simulation to capture the cumulative long-term effects of optimal operations. It was indicated that the average lifetime of distribution assets is at least 40 years (Sweco, 2010), with maintenance and upgrades needed over the lifetime but not necessarily replacement. A 43 year outlook with DR is an indication that equipment can be used to its full lifetime without needing replacement.

Overall, the simulation shows that in the optimal case of DR, the grid could be designed to cope with only half of the current demand, yielding nearly a one-third reduction in the net present value of the current asset base. The simulations suggest that postponing future investments over a period of 43 years can accumulate savings of greater than 117,000 Euro⁹² and 8.6 Euro⁹³ per customer (with maximum shifting capability), whereas a modest 10 percent DR over a period of 2 years still saves more than 109,000 Euro per year for the distribution-system operator and 8.3 Euro per customer. Both scenarios involving postponed investments display similar yearly savings potential for both the distribution-system operator and customers. Such results further support a shift in focus towards signals that impact peak load and losses, especially since grid investments are directly affected by power losses and the maximum load levels reached. As pointed out by Rodríguez-Ortega et al. (2008), operators' incurred costs for covering power losses are in the same order of magnitude as costs of grid investments. This means that if one or both of these factors are targeted via demand-response programs, grid infrastructure investments will be directly affected.

These quantified benefits can be captured by end-users upon implementation of a demand-response mechanism. Currently in Sweden and most European countries, regulatory periods span an average of 4 years for distribution-system operators, a short time frame that may not allow consumers to realize financial savings during the same period. One recommendation from a European perspective is to increase the regulatory period to greater than 4 years (as is the case in the RII model of the UK, which allows for an 8-year period) such that resulting benefits produced from smart-grid investments and services are more associated to the regulatory period during which they are implemented (Pérez-Arriaga et al., 2013).

DISTRIBUTION SMART-GRID COSTS AND DEMAND RESPONSE

As mentioned above, when it comes to quantifying the benefits of DR, the impact on investments is uncertain. This uncertainty escalates when taking into consideration the capital expenditure for investments in smart-grid equipment needed for the full exploita-

⁹² Euro value of December 8th 2014.

⁹³ Euro value of December 8th 2014.

tion of demand-side flexibility. Using the Swedish case, we quantify some of these costs for the distribution-system operator.

The smart-grid environment

Tariff design is concerned with the allocation of network costs and the stimulus of appropriate incentives by establishing a process for determining who pays for what services and how much (Rodríguez Ortega et al., 2008). Significant changes are expected in the current Swedish regulatory model for the coming 2016 to 2019 period based on the impact of distributed energy resources (Eurelectric, 2014). Capital expenditures will see an initial temporary spike when accounting for future costs that incorporate vast enabling technology. Returns on these investments will likely not be realized during a short regulatory period, hence the consideration of long-term average costs as discussed in section 2.2.1. Operational expenditures will also see an increase as a result of the new roles and responsibilities of the distribution-system operator as a market facilitator in smart-grid implementation (Pérez-Arriaga et al., 2013).

Costs for incorporating smart-grid upgrades

In order to stimulate DR in households it is important to install the necessary equipment for such capability. For the distribution-system operator, this entails upgrades to the current physical system, which is difficult to estimate due to the limited availability of cost figures for intelligent infrastructure and the information and communication technologies needed for DR (Prüggler, 2013). Considering calculations from Meisl et al. (2012), costs for demand-response enabling infrastructure amount to about one thousand Euro for a single household (which is about 5 times the calculated cost of the smart meter rollout⁹⁴ per household in Sweden). This five-fold difference in cost is a result of integrating information and communication technology, specifically a micro-grid controller and sensors and actuators (Meisl et al., 2012; Prüggler, 2013). This estimate is evenly divided in terms of smart-grid investments in the distribution-control aggregation system and the installation of sensors and other software (both in the grid and households). Meisl et al. (2012) also expect equipment maintenance costs at an average 50 Euro per household per year. In our simulation, the cost of an upgrade to a 'smart-grid' system would be upwards of 13.2 million Euros, compared to a smart-meter rollout cost of approximately 2.7 million Euros. To put these values in perspective, the smart-grid investment is comparable to the current net worth of the distribution-system valued at 14.5 million Euros. Essentially, the upgrade to a smart grid entails doubling of the current asset base. Given this investment scale and associated technological risk, it is understandable why Eurelectric (2014),

⁹⁴ The cost of smart-meter implementation in Sweden was approximately 200€ per household, resulting in a total implementation cost of approximately 1 to 1.5 billion Euro for the country. See Renner et al. (2011)

emphasizes the role of predictable and stable of regulation in attracting the necessary financial capital.

The truth of the matter is that upgrading a system smart-grid status increases overall investments and therefore costs; this is a fact that regulation needs to embrace. Pursuing the implementation of a time-of-use demand-response program at this stage allows for savings to accrue in the coming years. Specifically, in Sweden where customers already receive a separate bill for network charges (Eurelectric, 2013), this type of program may prevail to incentivize customer load modification. It can be argued that separate billing causes more confusion for end-users. In the case of countries like Sweden where such billing practices are the norm, the existing system design can be used for the proliferation of demand-response programs at the distribution level. Our case study indicates that a modest DR of 10 percent at peak hours can be incentivized under present conditions with little to no additional costs through a change in the tariff that provides a time varying capacity charge to consumers. The accrued savings of almost 200 thousand Euros⁹⁵ yearly (see Table 27) can either go towards smart-grid investments or reduce customer bills. Once the cloud of uncertainty over which type of smart-grid investments should prevail in a specific system settles and costs are made more clear, appropriate regulation will catch up, conventional investments will be displaced, thus reducing long run capacity costs and enabling the effective integration of distributed energy resources without compromising the quality of supply. Our proposed approach simply allows for an incremental action to be taken in the short term until smart-grid practices become further entrenched.

CONCLUSIONS AND RECOMMENDATIONS

Distribution-system operators will bear the brunt of investments needed as passive end-users become active agents in both consumption and production. The stimulus of DR is one way of curbing rising electricity costs. This study developed a way of analyzing and quantifying the effects of a tariff-based demand-response program in this context. The above taken approach can be adopted by other distribution-system operators and regulators seeking insight into the economic benefits they can amass from the implementation of a time-of-use capacity tariff.

Based on our analysis, it is evident that moving load from peak to off-peak hours has several direct effects on distribution costs with different ranges of magnitude. In our simulated case study, we assess power losses, peak loads, and grid investments under a feasible 10 percent load shift scenario and an optimal scenario of a flattened

⁹⁵ Euro value of December 8th 2014.

distribution load. The overall assessment indicates that decreasing peak consumption will reduce overall costs both for the distribution-system operator and consumers since it directly impacts about 75 percent of the cost drivers for an average European operator (see Figure 40).

As mentioned earlier, due to their resistive nature, power losses increase proportionately to power flow (load squared) and therefore both losses in the system and costs for covering them will decline significantly when load is shifted from peak to off-peak hours. Although losses in an average European distribution system account for approximately 5 percent of total distribution costs, optimizing can have other direct impacts. Losses increase when the grid is operated closer to its maximum capacity when assets are not used optimally. Specifically, operating the grid near its maximum capability on a long-term basis will decrease the average lifetime of assets and equipment, in turn raising investment costs which might otherwise be postponed or avoided. More certainty about the utilization of grid allows for better forecasts in grid planning and therefore more robust tariff design. A time-varying capacity-based tariff that promotes efficient use of the grid is recommended. Moreover, pricing can also decrease the maximum subscribed level of power to upper levels of the system while additionally minimizing the likelihood of surpassing the set threshold.

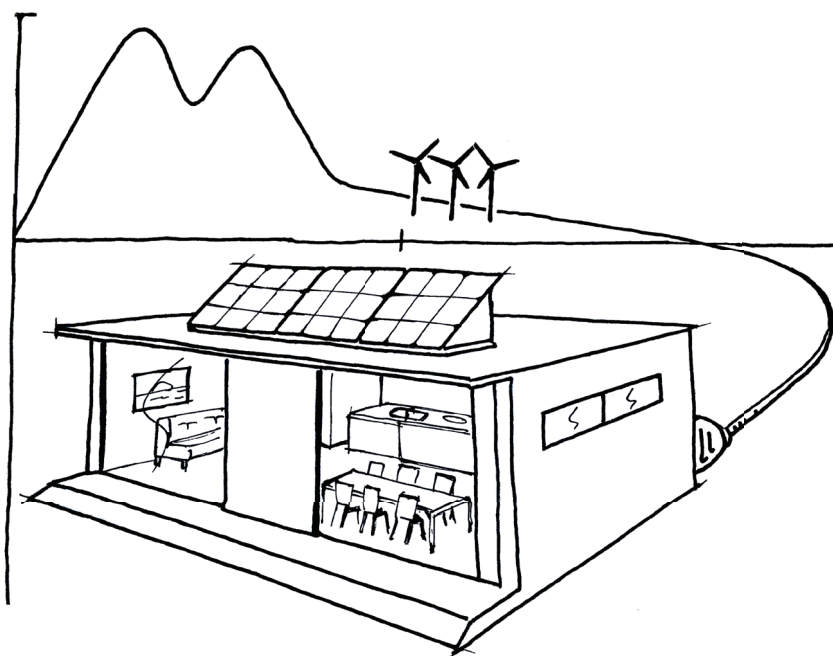
The above simulation indicates that 10 percent DR at peak hours reduces the overall level of maximum subscribed capacity by 2 percent and reduces the yearly costs of the distribution-system operator by 5 percent. If all customers within the distribution area were incentivized to collectively remain below a certain threshold, then further savings can accrue. We recommend a simple way of approaching consumers collectively for initial engagement and incremental smart-grid changes thereafter.

Incentivizing a flatter load via load shifting in the distribution level throughout the day will affect the system overall (as residential demand is a quarter of the total demand in most European countries). An initiative to smooth load via energy efficiency and load shifting methods will lead to cost savings at the wholesale electricity level, which implies lower procurement costs for suppliers, and savings in grid investment for the network operator in terms of supply and network investments. At peak-demand times, potentially more expensive generation is dispatched at higher wholesale generation prices. A more uniform load throughout the day should yield lower costs and prices overall. Moreover, as illustrated in the simulation, peak demand determines the amount of network capacity that is required for both transmission and distribution.

Regulators have a daunting task in designing innovative remuneration schemes that ensure the alignment of short-run operational and long-run investment and recovery objectives. Our analysis on distribution costs recommends that variable capacity-based tariffs are the proper approach to signaling the short-term status of the grid to end users which

in turn instigates load responsiveness that will yield long-term benefits in the form of optimal use of grid assets.

Our study offers insight into quantifying the magnitude of economic benefits that can be achieved with demand-response flexibility in the distribution system. The simulation approach provides the first step in quantifying the considerable benefits that can be gained from implementing a time-of-use demand-response program tailored to an electricity distribution area.



CHAPTER 7

THE AGGREGATOR IN PRACTICE

The previous chapters discussed the complexity of access, signal and release of demand response flexibility. In order to have value for the system and participating customers there is a need for appropriate coordination and alignment of involved actors' incentives; such a an assessment will be conducted in this chapter on the basis of Hakvoort and Koliou (2015)⁹⁶.

⁹⁶ Hakvoort, R.A., Koliou, E., 2015. Energy Management and Demand Side Response, in: U.C. Sharma et Al., Energy Management, Energy Science and Technology Series. Studium Press LLC, USA, pp. 53–97.

DEMAND RESPONSE AND EMERGING PROBLEMS TO OVERCOME

As it has been presented in the previous chapters, different actors want to take advantage of the available customer flexibility. Through explicit and implicit programs consumers will be given signals (price and rewards) for increasing, decreasing and declining the participation in demand response (DR). Hence, the problems of coordination and misalignment of actor incentives emerge. Although in the following sections the problems are discussed separately, it is important to note that they are not mutually exclusive and are interdependent.

Coordination

The coordination problem arises when dealing with the signaling of a DR program and the way in which customers react and prioritize response in line with the five value propositions (Abdul Muhaimin, 2015; Koliou et al., 2015a, 2015b):

1. **Balance responsible party (BRP) and supplier portfolio optimization through a reduction of imbalance costs.** With confidence in the provision of demand response, energy suppliers can better procure the purchase of electricity. Large suppliers may also be BRPs for themselves and others. Regardless of being retailers or not, BRPs are in charge of observing power balance for those which they carry balance responsibility. Having access to demand response flexibility gives them significant leverage in the optimization of their imbalance position with the system operator. Portfolio optimization is critical since all costs are passed down to end users.
2. **Balancing market trading participation.** The balancing mechanism is regarded as the most profitable when compared to day-ahead and intra-day markets since it corresponds to higher prices. On account of market design specifications, aggregated demand response is best suited to participate in the secondary reserves.
3. **Trading in the spot markets (day-ahead and intra-day) can be done for both consumption and production flexibility.** Such trade will allow for aggregated demand response to participate on equal footing with generators.
4. **Congestion management for the transmission system operator (TSO).** This value proposition is more relevant for large industrial users connected to the high voltage grid.
5. **Congestion management and voltage control for the distribution system operator (DSO).** As a system operator, the DSO has to maintain a certain quality of service to the users in the distribution grid. Demand response can be a tool for managing injections and withdrawals from the distribution network. This value proposition will become increasingly valuable in future smart grid context incorporating an array of distributed energy resources.

In principle, Hakvoort and Koliou (2015) point out that there are nine possible mitigation strategies to the coordination problem (illustrated schematically in Figure 45 where the arrow is pointing to the party selling the flexibility); in which arrangements for access to flexibility can be made either by the supplier or independent aggregator in order to meet these five objectives. The methods are described in detail in Table 33 in the Appendix.

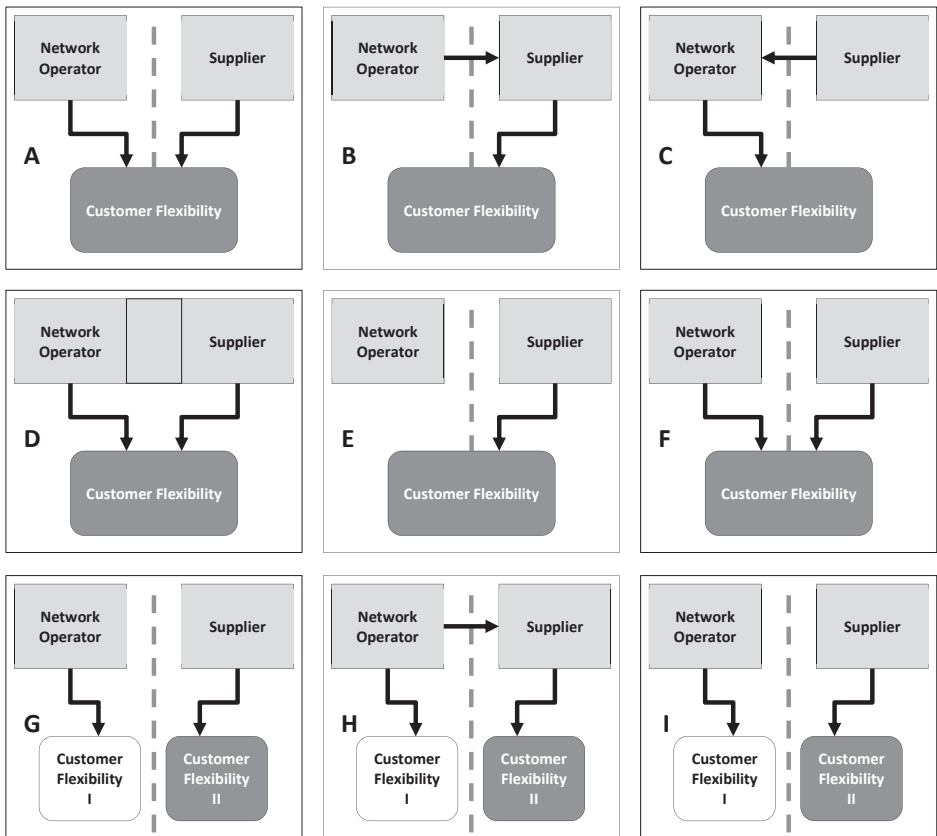


Figure 45: Nine (conceptual) models in which access to customer's flexibility can be arranged either by the supplier or aggregator (Hakvoort and Koliou, 2015)

Evidence from the previous chapters confirms that coordination is not a problem related to the technical specifications of DR. Coordination becomes imperative as customers make the decision of who will have access to their flexibility and under which terms it will be signaled and released at the moment it is needed by the different actors. With multiple value propositions, consumers may be inclined to provide their DR simultaneously to more than one interested actor, e.g. the retailer and DSO (in accordance with all models Figure 45 and Table 33 except E and F). In such a case, one actor has to be awarded priority access to the flexibility, this is a negotiation that takes place between

them or with a 3rd party aggregator making the arrangements objectively (model A, D, G, H, and I in Figure 45). At the household level, the home energy management system can have a programmed algorithm to make that choice. For instance, as in the chapter 4 example of PowerMatcher which creates rules for DR at the household, community and system level.

The bottom line is that as long as actors in the electricity system depend on DR flexibility there needs to be appropriate coordination of access, signal and release which an aggregator can provide. Each value proposition can be met if proper arrangements are put in place. Nevertheless, one optimal solution does not exist, but an aggregator can plan the coordination that fits the consumers' needs. Accordingly, the coordination mechanism will depend on the flexibility needs of the buyers which are either regulated or competitive, have different system objectives and flexibility needs (see Figure 46).

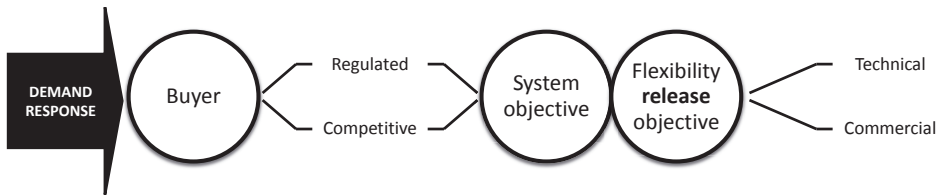


Figure 46: Demand response flexibility in the system and its use (simplified illustration)

Demand response for commercial use and coordination

As discussed in detail in chapters 2 and 5, market trading and contracting occurs in the long term (more than a year in advance in reserve procurement or bilateral contracting), the near short term (day-ahead and intraday) and at or close to the delivery time (balancing). DR access to such markets depends on the release conditions which are sensitive with respect to program specifications; timing and volume requirements (see Figure 47 and chapter 4 for a detailed assessment). Once these design variables are clearly defined, they will ease coordination problems for DR in the various markets. It is important to keep in mind that commercial flexibility use does not carry location specificity. These arrangements are in line with the models in Figure 45 where the supplier has access to the flexibility.

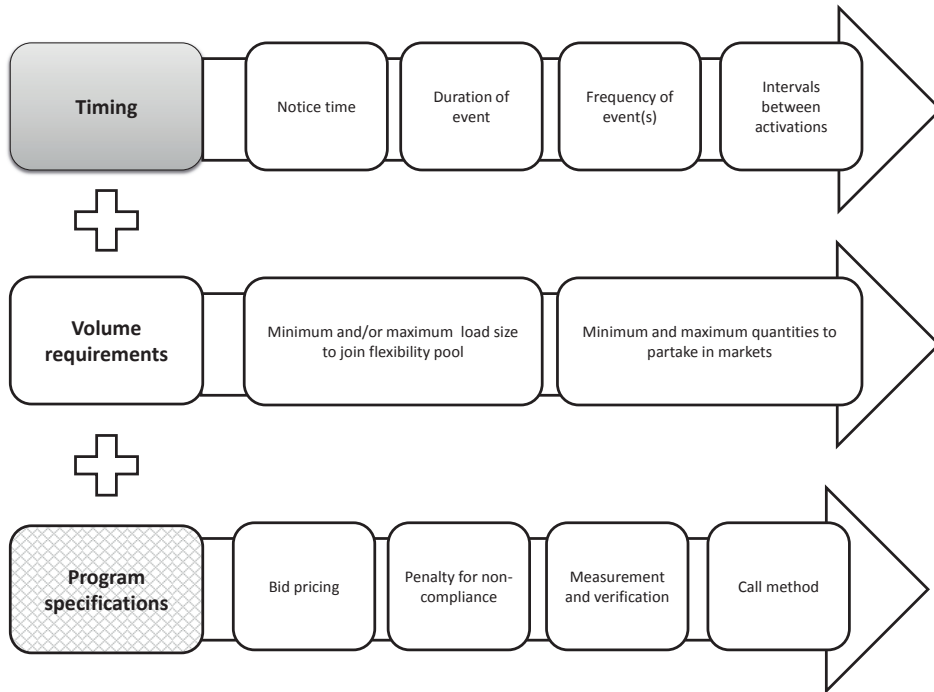


Figure 47: Design variables to consider for easing coordination problems for signaling, adapted from information found in SEDC, (2014)

Demand response for technical use and coordination

The value propositions for the grid operators are specific to congestion management and for the DSO possibly even voltage control. Demand response can be incorporated in network management in several ways (Hakvoort and Koliou, 2015):

- *Congestion management* through demand response can be achieved with all models in Figure 45, there is no best fit model in this case.
- *Dynamic grid tariffs* can provide time dependent signals which will alleviate peaks and capacity shortages in certain hours when the network is observed to be constrained and stimulate a more uniformly distributed load throughout the day, in turn reducing peaks (see chapter 6 for more details). Such an approach to flexibility access can be best achieved with model A in Figure 45.
- Grid operators can offer *interruptible/curtailable load contracts* along with suppliers; in these contracts it can be made explicit that the grid operator has priority access to the flexibility as with model C in Figure 45.
- Network operators can *refuse the transport to specific consumers*. Such a mechanism can only work if it is implemented on the basis of objective criteria and properly

communicated to the customer with an appropriate financial compensation provided.

This can be achieved with model F in Figure 45.

An aggregator can communicate the program in place to other market parties in order to allow for optimal coordination between commercial and technical signals that do not impede nor oppose each other.

Split incentives

The implementation of demand-response programs brings about benefits but also extra costs for the parties involved which are not equally distributed; costs sometimes fall with one party while the benefits accrue with another. Such allocation inhibits the further integration of DR flexibility and is called the split-incentives problem which plays on many levels of electricity system.

Issues on different levels

Suppliers, consumers and network operators

As mentioned in chapter 4, the supplier business model depends on selling kWhs to their consumers in turn questioning if suppliers are in the best position to provide a menu of DR options that will be appropriately profitable for the end user. Furthermore, suppliers provide market related signals to customers which are not always in line with the status of the grid therefore giving rise to the question of grid versus market signaling: which should have priority and how can this incentive differentiation be communicated to consumers providing flexibility? These incentive issues are heavily interrelated to coordination and can be overcome with transparent arrangements possibly made by the aggregator as a neutral facilitator.

Micro-generation from small users

At a lower system level, households are increasingly investing in own micro-generation (mostly solar photovoltaic (PV) systems). Ultimately, micro-generation may result in higher overall costs for the supplier since he has to hedge for providing electricity when solar generation is insufficient to meet demand in the system (Hakvoort and Koliou, 2015). Furthermore, system imbalances may increase due to the volatility of both supply and demand, in turn worsening the position of BRPs and suppliers. Grid operators in turn, will need to cope with bi-directional power flow and re-evaluate their investments in terms of the peak system demand and losses incurred.

Eid et al. (2014) conclude that the remuneration scheme for end users with micro-generation presents an important dilemma between incentivizing the proliferation of distributed renewable generation and securing the distribution system operators' financial stability, especially because of the prevailing net metering arrangements. Through the

current netting mechanisms consumers get financial benefits. By consuming their own production end-users evade network charges and energy taxes⁹⁷. Consumers who do not have solar panels still bear the costs of renewable support schemes, value added tax etc., while those without bypass them. To illustrate, let us take the example of the Dutch netting mechanism *Salderingsregeling*.

According to *Salderingsregeling*, if a household consumer generates electricity from renewable sources for own consumption or delivery back to the grid, the total energy produced and supplied back to the system is subtracted from the total consumption in the energy bill (in accordance with the meter reading) (Autoriteit Consument and Markt, 2015). The caveats in the regulation state that (i) there is a limit i.e. a netting boundary (*salderingsgrens*) and (ii) that electricity that is supplied back into the grid must be fed through the same line as the one through which the consumer receives electricity from the larger system (i.e. you cannot feed excess electricity to your neighbor). Each consumer has a different netting boundary which is equal to the total energy supplied to the customer from the system. If a consumer feeds more electricity into the grid than his netting limit, then the supplier pays a feed-in tariff for the energy to the consumer. If net consumption is more than what is fed back into the grid then the consumer pays that amount to the energy supplier (inclusive of energy and network charges). If production is more than the contracted consumption the consumer is paid the feed-in tariff for the excess production. The boundary limit along with the bypassing of charges provide misleading incentives for the adoption of micro-generation and should therefore be re-evaluated (Abdul Muhaimin, 2015).

Perverse incentives

The main focus of DR tends to remain with load shifting in order to minimize peaks both in the market and network, but such a concentration on one facet can lead to severe perverse effects for the system. Torriti (2012) points to the case of implementing a mandatory time-of-use tariff in Italy where the intended overall peak load shifting was achieved but with some perverse affects. The total energy bill of customers decreased while the total energy consumption increased by about 13%, in turn creating new system peaks and large shoulders.

It may very well be the case that customers decide to completely opt out of any and all demand response programs that are offered to them. In such a case end-users do not incur any costs but nevertheless experience benefits directly from the measures taken by other parties in the system.

⁹⁷ Energy taxes corresponding to over 30% (on average) of the electricity bill in Europe calculated as a fixed percentage of energy delivered by suppliers to consumers (EC, 2014), for a more in depth analysis see chapter 3, section 2.1.

Correcting the split incentives problem

Issues arising from split incentives can be mitigated with the appropriate design of arrangements so that benefits lie with the parties involved in realizing the implantation of DR. The fact is some parties bare relatively high costs while others have relatively high benefits and mutual financial compensation is not easily agreed upon. Designing any mechanism in a smart grid environment with a multitude of players involved that do not share the same goal is no easy task. This is where an aggregator can play a critical role as a facilitator, illustrated schematically in Figure 48 (Hakvoort and Koliou, 2015):

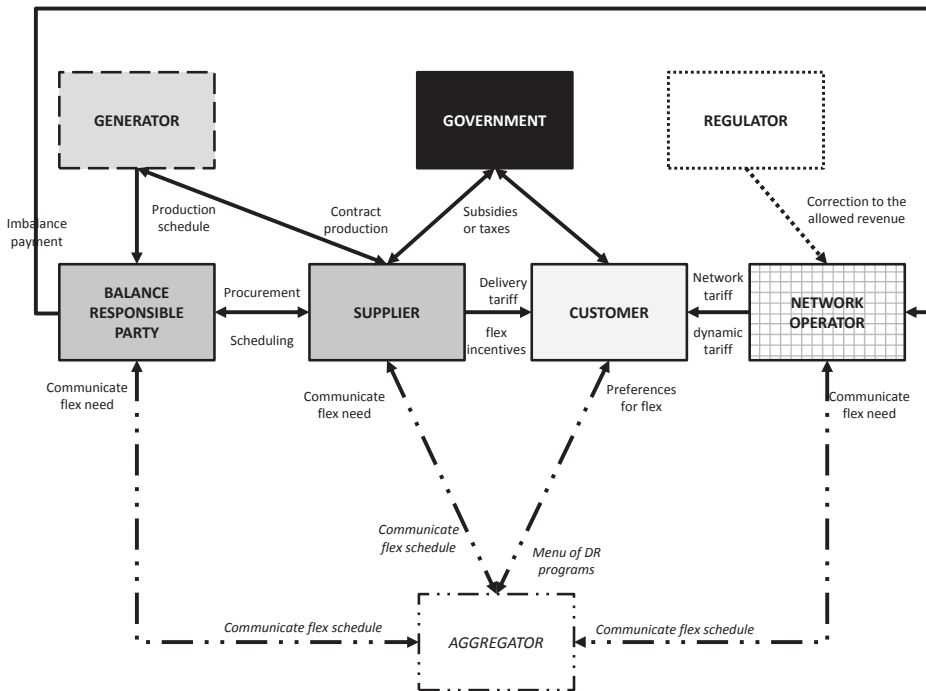


Figure 48: Schematic overview of how financial compensation between the various parties that can be given and the role a third party aggregator can play adapted from Hakvoort and Koliou (2015)

- Suppliers can directly transfer benefits to their customers through reduced fixed tariffs, dynamic tariffs or even individually tailored tariffs. Otherwise, 3rd party aggregators can provide the menu of options from suppliers to consumers and in this way define a contract with consumers.
- Network operators can directly pass the benefits of DR to consumers through a network tariff. Consumers can opt for a dynamic grid tariffs (see chapter 6 for details) or decide on other specifications for providing flexibility. Although flexibility provision

arrangements can be done directly between the customer and network operator, an aggregator can step in and make the necessary contractual agreement.

- Balance responsible parties (who are usually the supplier of a customer) communicate the flexibility needs to the supplier and the provision of DR is obtained in that manner. Otherwise, an aggregator can make arrangements between the BRP and the customer.
- Aggregators in the system can make contractual agreements between consumers and market parties in need of flexibility. Such an entity removes coordination problems, strengthens trust in the provision of DR flexibility and most importantly allows the customer to get the best deal for his/her flexibility at the time of release.
- Apart from the previously mentioned compensation, overall smart grid benefits will be redistributed to customers through taxes and subsidies, in this way ensuring a balance of costs and benefits in the system.

In each instance discussed above, it is important to keep in mind that the extent to which suppliers, network operators, BRPs, aggregators and the government understand the costs and benefits to the whole system and to all other actors is critical in determining exactly what component from the benefits can be passed on to the consumers (Hakvoort and Koliou, 2015). Again, this is why the role of the aggregator is emphasized, since he acts as a neutral organizer and implementer seeking to get the best 'contract' for the flexibility of the customers because that is the only way he will make a profit as well. Hence, the interests of the aggregator are more aligned with the consumer than other parties in the system.

AGGREGATOR MODELS IN PRACTICE

In previous sections aggregators have been discussed in terms of what they can achieve. It is important to note that on the industry side of things certain models are already implemented while other are in the development phase taking note of best practices along the way. Below follows a summary on successful aggregators practicing in the European market along with a discussion on a framework developed for operating a fully functional flexible European energy system.

Successful aggregators

Energy Pool

Energy Pool⁹⁸ is a demand response service provider working mostly in France with operations in Belgium, United Kingdom, Norway, South Korea and Japan (Chamoy, 2015). The aggregator identifies a flexibility margin for large-scale end users, and on a process by process basis coordinates their participation in electricity markets through their network operations centers. Current customers include cement factories, paper mills, steel works, food processing facilities, hospitals and cold storage facilities. These customers are spread out across and thus are not geographically bound. Profit is generated from end-user participation in the aggregate energy pool resources which are optimized for participation in markets through: (i) load curtailment at peak hours or grid constrained instances and; (ii) load stimulation to increase consumption at off-peak hours. Customer remuneration is achieved either via a fixed rate per MW that is available for curtailment or through a variable rate per MWh of consumption that is shifted. In order to enhance DR performance, Energy Pool provides the energy market stakeholders it is involved with (producers, dispatching centers, traders, system operators, TSOs, DSOs, suppliers) a Demand Response Management System which they have developed. Energy Pool has over 2000MW of flexibility capacity in its portfolio (Chamoy, 2015). In France alone the aggregator manages a virtual capacity of 1500MW which yield investment savings of €800 million and annual emissions reductions of 300,000 metric tons of CO₂ (EnergyPool, 2016).

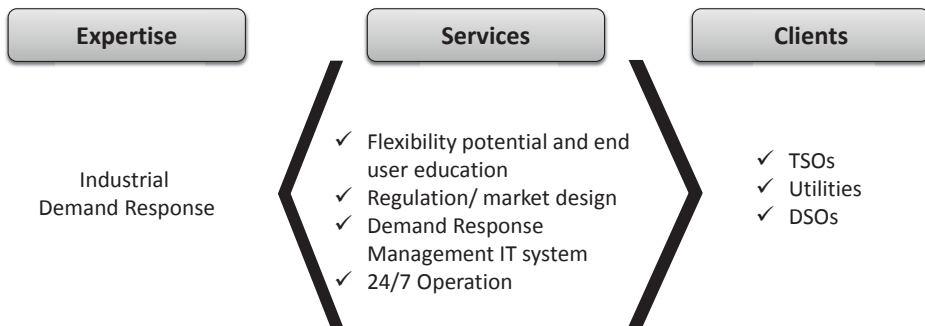


Figure 49: Energy Pool Demand Response (Chamoy, 2015)

⁹⁸ <http://www.energy-pool.eu/en>

Voltalis

Voltalis⁹⁹ is a French energy management provider specializing in the aggregation of flexibility from small companies and households. The aggregator has developed a hardware technology the 'BluePod'; a wireless transmitter and electricity modulator that is applicable to all flexible loads (HVAC¹⁰⁰, water pumps etc.) for remote controlled operation. The BluePod provides real time detailed metering in addition to distant and short load shedding. Specifically the business model is focused on controlling electric heating by providing the BluePods for free to customers. Voltalis has a contract with the French system operator RTE to reduce electric heating in short time intervals (typically 15 to 30 minutes) when signaled. RTE pays Voltalis a fixed sum to have their capacity (maximum of 500MW) available 24/7. Customers who are in position of a box are automatically enrolled in the program, but have the option to opt out. Note, enrolled customers do not receive a financial compensation every time their load is modified; rather they see a reduction in their overall electricity bill as a result of these interruptions (Bivas, 2015; Voltalis, 2016). This aggregator approach has a direct benefit for the consumers on their monthly electricity bill and even greater benefits for the system in the short and long term. In the short term it helps manage grid constraints and reduces the need for peaking expensive generation while in the long term it deters investment in both network and generation.

A European demand response framework

Although there is a lot of interest in demand response flexibility, there is still a need for the development of market models for appropriate incorporation and value extraction. The Universal Smart Energy Framework (USEF) is attempting just that with definitions on roles and responsibilities, process flows and information flows. USEF was founded in 2013 by seven key European market players¹⁰¹ who are active across the smart energy value chain. As part of the European Smart Grid Task Force Expert Group 3 on the establishment regulatory recommendations for smart grid deployment, USEF provides an extended market model revolving around the use of locational energy flexibility. USEF recognizes that small business and residential consumer flexibility has value when aggregated; this value can be monetized by an aggregator who is responsible for buying and selling. Essentially, the framework delivers a common standard for delivering a smart energy future by defining each stakeholder roles in the energy market, how they interact and how they can benefit from exchanges (USEF, 2016). This framework is an attempt

⁹⁹ <http://www.voltalis.com/>

¹⁰⁰ Heating, ventilation, and air conditioning.

¹⁰¹ ABB, Alliander, DNV-GL, Essent, IBM, ICT Automation, Stedin

towards defining a European approach to aggregation that fits on top of existing market models.

DEMAND RESPONSE AND THE GREATER SYSTEM PERSPECTIVE

Bossart and Giordano (2012) point to the *coordination* and *split incentives* problems as inhibiting factors in achieving the expected social value of smart grids. Demand response is a tool for achieving decarbonization of the electricity sector for climate change mitigation and will ultimately bring about affordability for the present and future consumer energy costs.

The actual impact of small end-user demand response

The European Union 2030 targets include increasing the share of renewable electricity production to at least 27% of total consumption in each member state and decrease emissions by 40% when compared to 1990 levels. In chapter 3 it was concluded that optimal levels of PV and electric vehicle integration peak between 700,000 and 1 million. Once again using the Netherlands as an example, where in 2014 decentralized¹⁰² generation was approximately 30 TWh¹⁰³ (CBS Statistics Netherlands, 2015), less than 1 million PVs yield a maximum production that is less than 1 TWh at midday. Such figures indicate that small consumers will have little impact on achieving the European headline for renewable energy resource integration (Abdul Muhaimin, 2015).

The impact of storage, 'more grid' and grid defection

Electricity storage is considered to be a complementary (and maybe even a substitution) to DR for absorbing fluctuations from renewable generation and in turn enhancing flexibility on all system levels. On upper levels of the grid, storage can absorb excess RES production and make a profit by participating in both the spot and balancing markets. On a local level similar absorption and release can be achieved, especially through the use of electric vehicles and batteries. Note, when considering the installed capacity of storage value decreases as the size of the storage system increases; cost reduction in the system resulting from storage is shared by more kW of installed capacity. Overall, storage can reduce the cost of the system, all while generating profit for the storage operator. Depending on the merit order of generation in a system, storage may result

¹⁰² Sources include thermal power plants which deliver to an industrial grid or to the medium and low voltage grid in addition to all production of electricity by wind energy, hydro and solar energy.

¹⁰³ Terawatt-hour

in the increase of CO₂ emissions from electricity production, which goes against the European climate and energy targets (Mavrokapnidou et al., 2015).

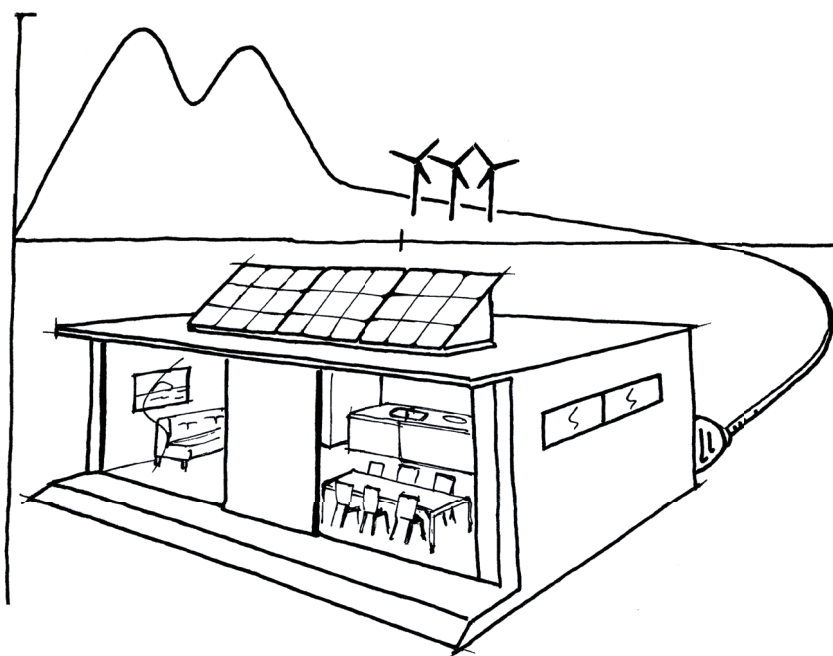
Mavrokapnidou et al. (2015) also find that the value of storage decreases slightly when more 'grid enters' the system, but overall system costs decline very little. Therefore, 'more grid' for the larger system mainly acts as a substitute for storage and not as a complement for improving the economic performance of the system. DR and 'more grid' experience a similar interplay. For instance, 'more grid' at the transmission and distribution level diminish the need for DR in 2 out of the 5 value propositions. Moreover, Mavrokapnidou et al. (2015) point to (depending on the generation mix and hence merit order) storage increasing emissions while 'more grid' keeps emissions at current levels.

The majority of the analysis has focused the discussion on DR to the larger system, to which connection proves to be costly in itself. A recent study from the United States Rocky Mountain Institute (Bronski et al., 2014) outlines a detailed analysis on grid deflection using storage in conjunction with micro-generation from PV systems. The study suggests that PV together with storage can make the electric grid an 'option' without compromising the reliability and even produces a lower electricity price than the current retail price.

REMARKS

The success of DR depends on the active participation and appropriate coordination of all relevant parties, hence giving rise to a need for a common framework. Because of the array of split incentives between parties, barriers arise which inhibit and even prevent implementation. Problems with coordination and split incentives are prevalent in the wide spectrum of distributed energy resource solutions that will need harmonization in the smart grid. A third party which is deemed the 'aggregator' can aid in alleviating arising problems and improve the transparency in the system processes.

The majority of the analysis in this work has been done based on the current system perspective and the flexibility that small consumers can provide with the possibility of creating added value for individuals and the system. But it is also important to consider other aspects, inclusive of alternatives in this assessment in accordance with innovation to support sustainability and value creation that can accrue for the system and actors.



CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

The aim of this final chapter is to provide a summary of findings and research contributions of demand response implementation in the evolving smart grid paradigm. Recommendations are made for aggregation services, market design, tariffs, policy and regulation in addition to providing suggestions for future research.

CONCLUSIONS AND ANSWERS TO RESEARCH QUESTIONS

Although interest in demand response research has seen a surge in recent years, it is important to note that the implementation of such mechanisms is not a byproduct of the smart grid shift. Rather, the development of information and communication technology has made the application of demand response mechanisms a possibility on a superior scale than ever before. Investigating demand response from small end-users in this work is motivated by the growing interest of policymakers to have active end-user participation in a system where households have traditionally remained passive.

It is clearly communicated that demand response proliferation is an inevitable and vital component to achieving the European climate policy objectives and targets in emerging smart grid systems. This work provides: insight into the complexity of market arrangements for the eligibility of demand response to participate in various short term electricity markets; an examination and breakdown of the roles and responsibilities of existing and newly emerging market players and; recommendations on the fair allocation of costs and benefits amongst the various (smart grid) stakeholders. As a result, the following research question is answered: *How can end-user consumption flexibility be promoted successfully through demand response methods in a smart grid?*

End-user demand response flexibility will have value for the system and added value to the individual customer when implemented through the various demand response programs.

Price-based demand response

Dynamic pricing is aimed at improving the overall efficiency of system operation and reducing demand at peaking hours. Load responsiveness will also serve to alleviate incremental costs of investment in capacity for both generation and the grid, in turn yielding both direct and indirect benefits for all parties in the electricity value chain. For households, time varying tariffs encourage load shifting but do not necessarily aim to induce overall load reduction. Price-based mechanisms are offering an opportunity to save money and gain insight into own electricity costs resulting from their consumption patterns.

The brunt of attention in demand response focuses on electricity market prices. Fact is that prices for households are relatively low and may not be the right incentive for promoting an active demand side. The final spending on electricity for the average household is a small percentage of total expenses. Findings indicate that demand response may only save cents per day for an average consumer. Larger savings are in store with automated response, which is currently not a mass market solution. From this work it is concluded that the promotion of real-time pricing is not the optimal savings choice for a customer. Even with automation, savings are not significant enough to offset the investments in

technology that are needed. From this work (and in agreement with other research in the field) it is determined that time-of-use tariffs derived from prices in the day-ahead market are the current advised approach to dynamic pricing for end-users.

Price-based demand response mechanisms are low cost means of offering load management services to all European households through the retail electricity contract. Especially with time-of-use pricing variations (including critical-peak pricing), price-based demand response can be integrated with different levels of complexity under current system conditions, with or without smart metering and other embedded information and communication technology.

Similarly, a price-based demand response can also be signaled through the distribution tariff, in turn incentivizing an overall flatter load throughout the day in the distribution area. Specifically, the analysis conducted on distribution costs endorses that a variable capacity-based time-of-use tariff is a way of signaling the short-term status of the grid to end-users. Such a tariff instigates load responsiveness that can also yield long-term benefits resulting from the optimal use of grid assets. Specifically, shifting load from peak to off-peak hours has several direct effects on distribution costs in terms of peak load alleviation, loss reduction and postponement of investments. The reduced peaking consumption will decrease overall costs for the distribution-system operator and consumers. Demand response can have a direct impact on approximately 75 percent of the cost drivers for an average European distribution grid operator.

Volume-based demand response

Volume-based demand response needs aggregation for participating in the various electricity markets, in addition to being eligible as system support service to grid operators. In the current European system, gaining access to markets is not a simple nor cheap task and the resulting revenues with the small trading volumes of aggregated end-user load are low to nearly none. Flexibility aggregators have strict rules and commitment requirements to abide by that are inherently in place for large industrial and commercial parties. The existing market procedures do not address the program specifications, volume and time requirements of aggregated flexibility to be an eligible and competitive product/service.

Hesitation on the aptness of aggregated flexibility is in many ways a consequence of the vagueness surrounding the party which will be the aggregator. In the current European context, where liberalization prompts market based-solutions, it is expected that aggregators will be competitive market parties. Thus, aggregators can be independent third parties or retailers with flexibility as an additional service. The way in which each aggregator will provide services varies.

Independent aggregators can have a first mover advantage in the market for end-user flexibility aggregation, occupying a specific portion of customers with larger flexible

loads such as electric vehicles and solar photovoltaics. Specifically, independent aggregators may gain from community level aggregation. Results indicate that revenues from trading small volumes which meet the minimum requirements are near null. Independent aggregators cannot survive if their business depends exclusively on trading in the short term electricity markets.

The trading of demand response by an independent aggregator in the day-ahead, intra-day and balancing markets brings to light a vital concern of ownership of demand response, the “good”. A third party (that is not the retailer) contracts demand response flexibility from the consumer which is then aimed for trade, and herein lies the problem. In fact the neither the third party aggregator nor the consumer own the energy “good” they are trading since neither of them has purchased it yet.

The purchase of energy happens in real time; electricity is owned by the supplier and it is not until the point of consumption that it is owned by the consumer. Both consumers and third party aggregators are actually trading a good they do not own. Retailers are the ones who forecast demand for their customers and then purchase and schedule a certain amount of energy for each. Moreover, suppliers take on balance responsibility for their contracted customers. With the trade of demand response, aggregators are generating schedule disruptions for suppliers and appointed balance responsible parties. The change in forecasted schedules of balance responsible parties and suppliers results in real time balancing activation and overall financial penalizations for deviations.

Demand response participation in the markets can only be achieved through transparent arrangements instigating mutual cooperation between balance responsible parties, retailers and aggregators. It is expected that aggregators will lead the demand response flexibility movement, but it is the regulators holding the keys to both birth and sustainability of demand side activation and integration.

On the one hand, appointing the retailer as an aggregator is a way to avoid scheduling disruptions from demand response flexibility trade. On the other hand, a supplier's business model depends on selling more kilowatt-hours which complicates the incentives for promoting volume-based demand response. Practically speaking, retailers are in the best position to become aggregators for end-user flexibility. When considering participation in the various electricity markets retailers have an existing customer base, they carry balance responsibility for their contracted customers in addition to having established market access and financial stability.

An analysis of the balancing mechanism points to the frequency restoration reserves market as a profitable platform for aggregators to explore. Demand response activation for balancing is undermined by the vagueness in the balancing specifications for: (i) balance responsibility of an aggregator; (ii) balance service provision specifications of procurement and activation and; (iii) imbalance settlement.

Balance responsibility is required for all connected users in the grid; retailers appoint a balance responsible party for their contracted customers. Independent aggregators do not yet carry balance responsibility nor do they have a contract with a balance responsible party. For the trade of aggregated demand response flexibility, no clear guidelines exist in the retailer, balance responsible party and independent aggregator relationship. Such ambiguity complicates the provision of aggregated flexibility, especially when considering the long planning periods for reserves procurement and activation. Overall, there needs to be trust in the use aggregated flexibility which can only occur through proper monitoring for final imbalance settlement payments to take place.

RECOMMENDATIONS

Policymakers are urged to take into consideration that the smart grid paradigm proposes a radical transformation to a system that already works quite well when it comes to matching supply and demand (both physically and economically). Incremental steps to achieving this transformation are advised, in this way best practices can be deduced along the way. The following recommendations are derived from this research for the implementation of demand response.

Aggregation and aggregators

The application of demand response is an inherently complex process on account of the multitude of actors involved for the access, signaling and release of flexibility. In both price-based and volume-based solutions facilitation is key to smoothing the process, hence the emergence of aggregators. Retailers have an easier transition into the aggregator role, but nonetheless have self-interests that do not align with those of maximizing demand response value for customers. Regulators need to assure retailer-aggregators are acting in the best interest of the customers; providing end-users with a full menu of load management options, not just ones that serve the retailers best interest for portfolio optimization.

The objectives of independent aggregators are more transparent and in line with those of the customers, but nevertheless third parties face obstacles when integrating into an electricity system that is dominated by few large players. If the market is to work properly, it is advised that national regulatory bodies lead the way in the next phase by consolidating the issue of flexibility ownership, starting with a mandate for aggregators to carry balance responsibility. This will allow for transparency in the demand response processes for the market parties involved and minimization of overall costs of unforeseen imbalances. In turn, trust is ensured in the services independent aggregators are providing.

Independent aggregators do not have the market share nor experience which suppliers possess. In order to ensure long-run success in the competitive electricity market, third party aggregators need to cultivate a more sophisticated business model which comprises of more than flexibility trade. Business opportunities need to be innovative, new and not already provided by a supplier. New business opportunities can come in the form of data services and analytics, e.g. consulting customers on technology investment, supplier choice and contract options.

Market design

Existing market instruments for the provision of flexibility services have been drafted in a context without load bundling and a large focus on generation side resources. In order to value demand response on equal footing as traditional services, some recommendations are derived for market integration into the balancing mechanism.

Notably, availability and activation of balancing services is directly dependent on the procurement schemes. For an aggregator, shorter planning periods would decrease forecasting error and in turn associated non-compliance penalties. Participation in the balancing mechanism is also subject to rigid minimum capacity units for admittance in addition to fixed bidding intervals. Regulators and system operators should re-visit these strict requirements and allow for aggregated capacity to meet such conditions. Monitoring and verification are also vital components of flexibility activation. In order to avoid gaming, especially at times when the grid is congested and demand for alternate sources of flexibility are higher.

The time at which bids become final is a critical variable of market design. Hence, available flexibility is highly dependent on the gate closure time being as close to the delivery time as possible, in this way ensuring the delivery of scheduled products. The Dutch gate closure time, set at one hour prior to delivery, is advised for adoption by other member states on account of its proximity to real-time delivery. Devising a specific gate closure time for demand response flexibility scheduling may also be a good way to integrate demand response. The access to demand response flexibility is also impacted by the frequency of price signal availability. Therefore, prices should be made available as close to the end of delivery as possible.

Letting the market work is the desired approach to integrating demand response, but it may need a helping hand from regulation. An aggressive approach towards integrating demand response as a reserve can be to allow priority access to independent aggregators in the balancing market.

A flexibility market that runs in parallel with the existing markets can also be considered as a way to optimize use of the wide range of from various distributed energy resources. This market can be overseen by the system operator in order to ensure transparency and effective operation.

Tariffs

Regulators have a daunting task at hand which is monitoring and stimulating competition, all while designing innovative remuneration schemes that ensure the alignment of short-run operational and long-run investment and recovery objectives for grid operators.

Electricity consumption and production are time dependent; both sides should have transparency and co-optimize the matching of supply and demand. For electricity billing, regulators need to communicate to retailers the importance of introducing more dynamic pricing options to end-users and together come up with an action plan that will result in adoption in the coming years. From this work, a time-of-use tariff is recommended in accordance with the hours pertaining to the base, shoulder and peak hours of the spot market exchange. More tailored tariffs can also be designed per distribution system with the grid operator in order to make sure that peak grid hours coincide with the tariff as well. Dynamic transport rates can also be designed with a capacity component in such way that incentivizes consumers to stay below a certain threshold power level. Real time tariffs are not advised at this time, but if consumers want them they should be given the option.

Policy

Article 15.8 of the Energy Efficiency Directive (2012/27/EU) provides a legal basis for further development of demand response in the European member states with support from the ENTSO-E Demand Connection Code (ongoing) and the ACER Framework Guidelines on Electricity Balancing. Although these European level communications provide the foundation by acknowledging the importance of demand response from end-users, they do not offer detailed specifications for European-wide implementation. Future communications should consider strict guidelines on what Europe needs to achieve as a whole. Such legislation should provide a 'demand response' target such as that of renewable generation, energy efficiency and emissions.

FUTURE RESEARCH

This thesis has covered a wide range of topics for the implantation of demand response. Research to follow is therefore suggested to have more focus on specific issues which have been brought to light.

Market specifications

Existing market mechanisms accommodate large consumers and producers as flexibility resources, in this way considering small consumers to be passive entities. In order to activate demand response, future work needs to concentrate on addressing the timing,

program and volume specifications that will facilitate the integration of aggregated flexibility. Timing specifications directly reflect the design of a demand response program and the notice, duration, frequency and intervals of the release of flexibility. Program specifications concentrate on the definition of pricing options, measurement and verification techniques and related penalties for non-compliance. Volume requirements refer to minimum and maximum limits for eligibility and activation. Minimum bid requirements and bidding up and down bids are still catering to large flexibility providers, system operators and regulators need to revisit the technical requirements and see how they can lower the sizes without jeopardizing system operation.

Aggregation business

Above, it is recommended that aggregators sophisticate their business model and further develop revenue streams that do not pertain to direct electricity trade in the various electricity markets. As data from households with smart meters, smart thermostats and in-home-displays becomes increasingly available, an investigation is encouraged into the innovative business solutions that can emerge. Together with the business innovation, policy and regulation, research on the mitigation of privacy and security concerns is also suggested.

As retailers seek to become aggregators of demand response services from end-users and other distributed energy resources, there is fundamental concern that arises: with demand response suppliers are curtailing their own profits. Is it really profitable for retailers to be aggregators? This is a question that can be further investigated along with the upcoming sophisticated business models of independent.

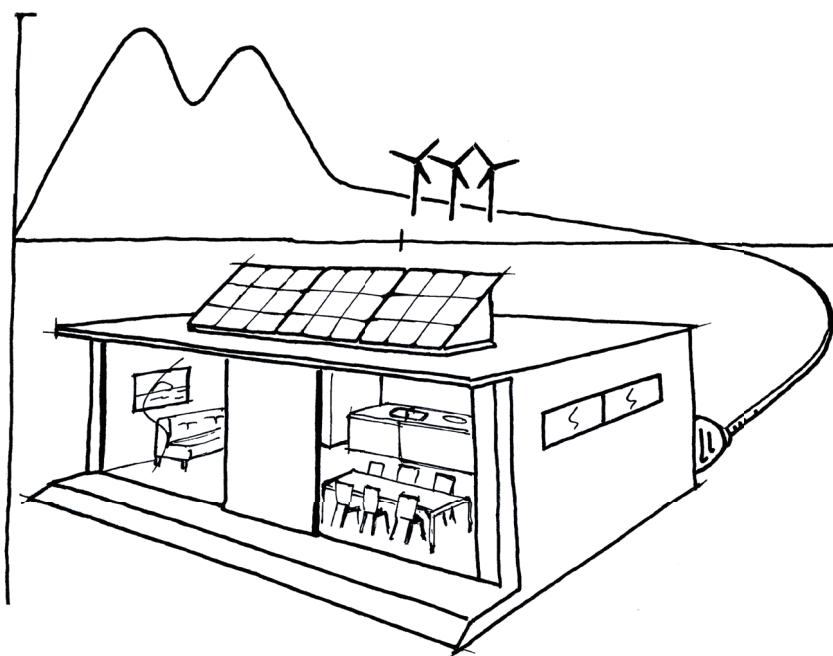
Tariff design

Earlier it was mentioned that dynamic grid and retail tariffs should not be giving opposing signals. An investigation on combinations of the various tariff options for distribution and retail can reveal the benefits and drawbacks of coordinated tariffs.

FINAL THOUGHTS

As a viable market flexibility resource, aggregated demand response is still in infantile stages of consideration, and the above investigation simply serves as an illustration for the drivers and emerging barriers to application. In this research it is concluded that the smart grid shift is expected to bring out the best that the existing infrastructure and market organization offer. Upgrades and modifications should be tailored to make better the system that is in place and not concentrate on achieving a perfect paradigm which does not exist.

From day one I have tried to answer this question to myself "*what are policies for the implementation of smart grids?*" Now, I can say with some degree of certainty that they are the strategies that will pave the way to a more sustainable future and that a smart grid is a means to an end but not an end in itself. End-users are a small piece of the electricity system puzzle, physically and economically, but in turn are the most powerful in making change happen. Getting consumers involved in the dynamics of the electricity system may not yield great financial benefits for them, but will result in overall understanding of the functionality of the smart grid. Knowledge is power which produces strategies for implementing smart grids.



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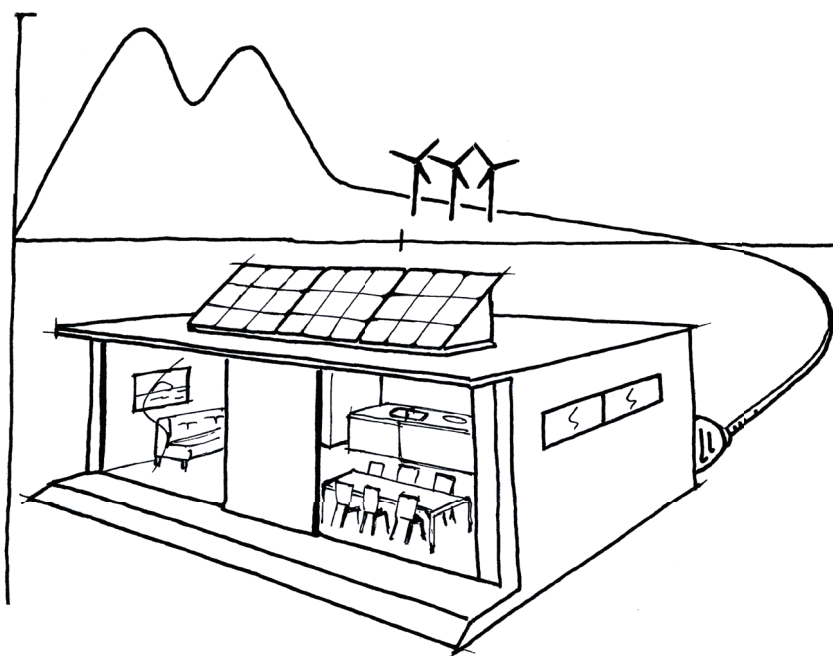
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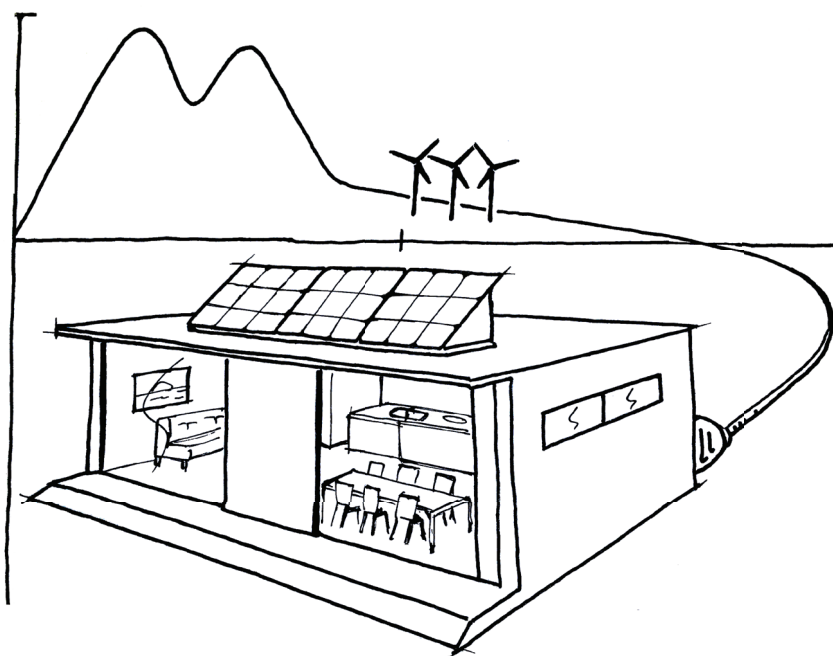
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LIST OF ABBREVIATIONS

<i>ACER</i>	Agency for Cooperation of European Regulators
<i>APX</i>	Power spot exchange
<i>BRP</i>	Balance responsible party
<i>CHP</i>	Combined heat and power
<i>CPP</i>	Critical peak pricing
<i>DA Market</i>	Day-ahead Market
<i>DCC</i>	Demand connection code
<i>DECC</i>	Department of Energy and Climate Change
<i>DER</i>	Distributed energy resources
<i>DR</i>	Demand response
<i>DG</i>	Distributed generation
<i>DOE</i>	Department of Energy (US)
<i>DSM</i>	Demand side management
<i>DSO</i>	Distribution system operator
<i>EC</i>	European Commission
<i>EED</i>	Energy Efficiency Directive
<i>ENTSO-E</i>	European Network of Transmission System Operators for Electricity
<i>EV</i>	Electric vehicle
<i>ETP</i>	European Technology Platform
<i>EU</i>	European Union
<i>FCR</i>	Frequency Containment Reserves
<i>FERC</i>	Federal Energy Regulatory Commission (US)
<i>FP</i>	Fixed price
<i>FRR</i>	Frequency Restoration Reserves
<i>GCT</i>	Gate Closure Time
<i>ICT</i>	Information and communication technology
<i>ID Market</i>	Intra-day market
<i>kW</i>	Kilowatt
<i>kWh</i>	Kilowatt
<i>MW</i>	Megawatt
<i>MWh</i>	Megawatt-hour
<i>NPV</i>	Net present value
<i>PV</i>	Photovoltaic system
<i>RES</i>	Renewable energy sources
<i>RR</i>	Replacement Reserves
<i>RTP</i>	Real time pricing
<i>SEDC</i>	Smart Energy Demand Coalition
<i>TOU</i>	Time-of-use
<i>TSO</i>	Transmission system operator
<i>TWh</i>	Terawatt-hour
<i>VAT</i>	value added tax (Europe)



APPENDIX

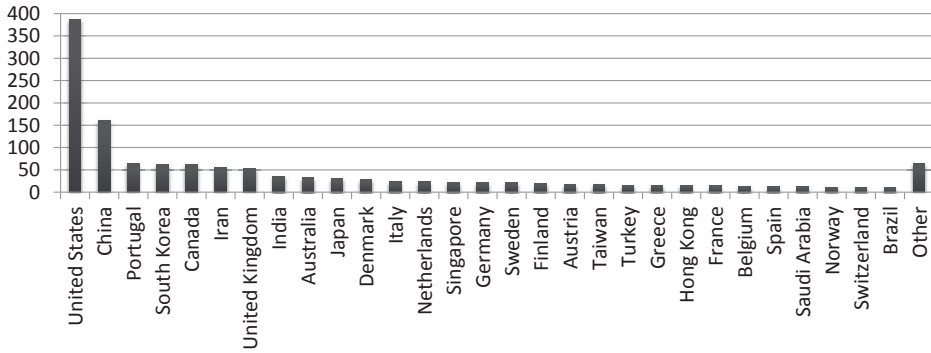


Figure 50: Scopus 'smart grid' AND 'demand response' publications 2007 to 2014 by country

Table 28: Average own-price elasticity summary of studies

	Reference	Tariff	Elasticity value
Residential	(Kohler and Mitchell, 1984)	TOU	-0.06 to -0.2
	(Taylor and Schwarz, 1990)	TOU	-0.38 to -0.39
	(Summit Blue Consulting, 2007)	Day-ahead RTP	-0.08
	(Tishler, 1984)	TOU	-0.02 to -0.09
Industrial	(Park and Acton, 1984)	TOU	-0.014
	(Taylor et al., 2005)	Day-ahead RTP	-0.15

Table 29: Summary of average elasticity of substitution values from studies

	Reference	Tariff	Elasticity value
Residential	(Baladi et al., 1998)	TOU	-0.12 to -0.17
	Midwest Power Systems of Iowa; 1991-1992; voluntary		
	(Caves et al., 1989)	TOU	-0.37
	PG&E; 1983~84; voluntary		
	(Caves et al., 1984)	TOU	-0.07 to -0.21
	DOE Utilities in five states; 1977~80; mandatory & voluntary		
	(Aigner and Ghali, 1989)	TOU	-0.09 to -0.21
	DOE Utilities in five states; 1977~80; mandatory & voluntary		
	(Braithwait, 2000)	CPP (fixed)	-0.35 to -0.40
	GPU; 1997; voluntary		
	(Charles River Associates, 2005)	CPP (fixed)	-0.03 to -0.12
	CA-SPP (PG&E, SCE, and SDG&E); 2003~04; voluntary		
	(Charles River Associates, 2005)	CPP (variable)	-0.05
	CA-SPP (PG&E, SCE, and SDG&E); 2003~04; voluntary		
	(Faruqui and Sergici, 2008)	CPP	0.096 to 0.193
Commercial	BGE's Smart Energy Pricing Pilot, Summer 2008 Impact Evaluation		
	(Aigner and Hirschberg, 1985)	TOU	0.04
	SCE; 1980-1982; voluntary		
	(Charles River Associates, 2005)	CPP (variable)	0.06
	CA-SPP (PG&E, SCE, and SDG&E); 2003~04; voluntary		
	(Boisvert et al., 2004)	RTP	0.10 to 0.27
	Central and Southwest Service; 1998-2001 Summer; voluntary		
	(Schwarz et al., 2002)	RTP	0.03 to 0.04
	Duke Power 1994-1999; voluntary		
	(Goldman et al., 2005; Hopper et al., 2006)	RTP	0.11
	NMPC (Niagara Mohawk, a National Grid Com.); Summers of 2000-2004; voluntary		
	(Herriges et al., 1993)	RTP	0.09
	NMPC; 1985; voluntary		

Household type	Convenience	Conscious	Costs	Climate
Single	● ○ ○ ○ ○	● ● ● ○ ○	● ● ● ● ●	● ○ ○ ○ ○
Two adults below the age of 60	● ● ● ○ ○	● ● ● ○ ○	● ● ○ ○ ○	● ● ○ ○ ○
Single parent family	● ○ ○ ○ ○	● ● ● ● ○	● ● ● ● ○	● ○ ○ ○ ○
Family (two parents)	● ○ ○ ○ ○	● ● ● ○ ○	● ● ● ● ○	● ● ○ ○ ○
Seniors above the age of 60	● ● ● ○ ○	● ○ ○ ○ ○	● ● ● ● ○	● ● ○ ○ ○

Figure 51: Classification of household types into preferences (Pauw et al., 2009), from TNO and ECN 2007, memo Building Future, Samenvatting van de resultaten van onderzoek door studenten van de InHolland Hogeschool naar energie en huishoudprofielen in 2005, (unpublished data, in Dutch)

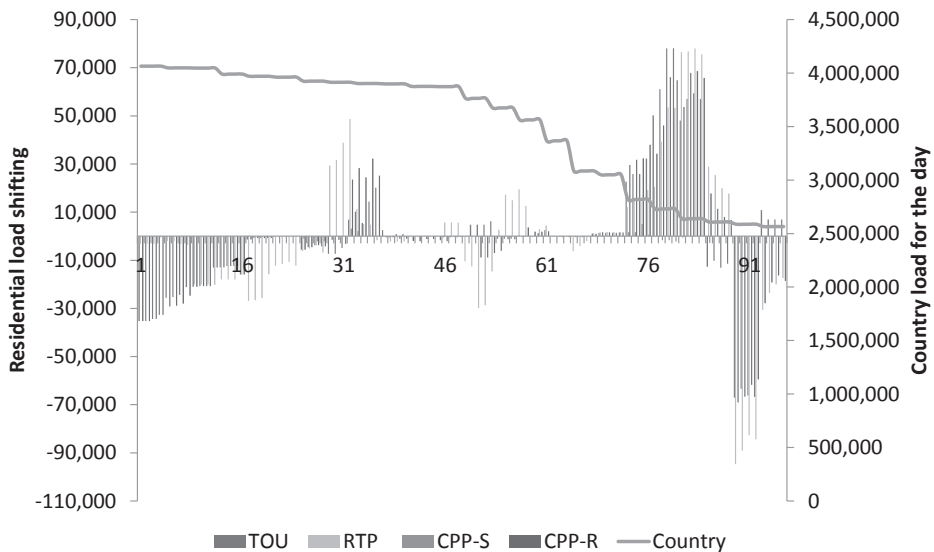


Figure 52: Load duration curve for the whole residential load produced from the model and the load shifting that results from the application of each price based mechanism

Table 30: Cost assessment for increasing levels of PV and EV.

Scenario 1		Average household cost (Euro)					Country cost (million Euro)				
EV	PV	FP	TOU	RTP	CPP-S	CPP-R	FP	TOU	RTP	CPP-S	CPP-R
7500	27700	2.32	2.23	2.59	2.63	5.29	16.39	16.47	18.45	31.29	34.25
7500	100000	2.32	2.23	2.57	2.62	5.28	16.10	16.17	18.14	30.28	33.87
7500	500000	2.30	2.21	2.55	2.55	5.26	14.55	14.53	16.41	24.73	31.75
7500	700000	2.29	2.20	2.54	2.52	5.25	13.77	13.70	15.55	21.95	30.70
7500	1000000	2.28	2.18	2.52	2.47	5.23	12.60	12.47	14.26	17.78	29.11
7500	1500000	2.25	2.16	2.50	2.39	5.19	10.65	10.41	12.10	10.83	26.47
Average cost		2.29	2.20	2.55	2.53	5.25	14.01	13.96	15.82	22.81	31.02

Scenario 2		Average household cost					Country cost (million Euro)				
EV	PV	FP	TOU	RTP	CPP-S	CPP-R	FP	TOU	RTP	CPP-S	CPP-R
7500	27700	2.32	2.23	2.59	2.63	5.29	16.39	16.47	18.45	31.29	34.25
100000	27700	2.34	2.24	2.59	2.64	5.30	16.61	16.69	18.68	31.69	34.51
500000	27000	2.38	2.28	2.63	2.67	5.32	17.56	17.62	19.69	33.42	35.62
700000	27700	2.40	2.30	2.66	2.68	5.33	18.04	18.09	20.20	34.29	36.18
1000000	27700	2.44	2.34	2.69	2.70	5.35	18.76	18.78	20.95	35.59	37.01
1500000	27700	2.50	2.39	2.75	2.73	5.39	19.95	19.95	22.22	37.75	38.40
Average cost		2.40	2.30	2.65	2.67	5.33	17.88	17.93	20.03	34.00	35.99

Scenario 3		Average household cost					Country cost (million Euro)				
EV	PV	FP	TOU	RTP	CPP-S	CPP-R	FP	TOU	RTP	CPP-S	CPP-R
7500	27700	2.32	2.23	2.59	2.63	5.29	16.39	16.47	18.45	31.29	34.25
27700	27700	2.33	2.23	2.58	2.64	5.29	16.43	18.05	18.50	31.38	34.30
100000	100000	2.33	2.25	2.58	2.63	5.33	16.32	16.39	18.37	30.68	34.12
500000	500000	2.36	2.26	2.61	2.59	5.29	15.72	15.67	17.66	26.86	33.12
700000	700000	2.37	2.27	2.62	2.57	5.29	15.42	15.32	17.30	24.95	32.63
1000000	1000000	2.39	2.29	2.64	2.53	5.29	14.97	14.78	16.76	22.08	31.88
1500000	1500000	2.43	2.31	2.67	2.48	5.29	14.21	13.89	15.87	17.30	30.63
Average cost		2.36	2.26	2.61	2.58	5.30	15.64	15.80	17.56	26.36	32.99

Table 31: Model verification**I. Recording and tracking**

Checking the inputs, states and outputs of all agents (Appendix **Error! Reference source not found.**) in the model is critical in the sequence (initialization, simulation and data plotting) of running the model. The agents in the model i.e. household archetypes (Table 8 and **Error! Reference source not found.**) own a list of appliances which are used based on pre-defined rules in electricity consumption behavior. Agent activity is checked at every step in the sequence for consistency and correctness.

II. Single agent testing

Each agent (household and archetype) is tested individually and verified for consistency and accuracy in data input and output. The response to price mechanisms is dependent on the archetype, household type and controllable appliance(s) available in the hour which load shifting occurs. For each of these agents the model outputs differ when load is shifted, hence verification is done on a case-by-case basis for each agent. Manual calculations of expected price outputs of each agent response to a price signal were conducted in MS Excel. These manual calculations were compared with the model outputs for accuracy.

III. Interaction testing

Where agents are dynamic, this step would check for the interaction between two agents. With respect to the space in the model, the household agents are considered to be 'static agents'. Interaction occurs between the various price-based DR mechanisms, hence, their interaction is observed and checked for consistency.

IV. Multi-agent testing

Multi-agent testing is the last step in the model verification where the outputs of the model as a whole are verified. This testing involved the interaction of agents and emergent patterns. For this mode, the emergent pattern consists of two an aggregate country load profile curves (i) before load shifting and (ii) after load shifting. These curves were verified with previously build load curves in MS Excel. In order to check for stability of the model, multiple runs with the same set of parameters for the agents were performed and repeated for all the implemented price-based mechanisms.

Table 32: List of agents representative of each household type and each preference type

Household type	Name of the agent
Single adult under the age 65	• Single Adult Under 65 Conscious Household • Single Adult Under 65 Cost Household • Single Adult Under 65 Convenience Household • Single Adult Under 65 Climate Household
Single adult over the age of 65	• Single Adult Over 65 Conscious Household • Single Adult Over 65 Cost Household • Single Adult Over 65 Convenience Household • Single Adult Over 65 Climate Household
Couple below the age of 65	• Couple Under 65 Conscious Household • Couple Under 65 Cost Household • Couple Under 65 Convenience Household • Couple Under 65 Climate without PV And EV Household • Couple Under 65 Climate With EV Only Household • Couple Under 65 Climate With PV Only Household • Couple Under 65 Climate With PV And EV Household
Couple at least one over the age of 65	• Couple Atleast One Over 65 Conscious Household • Couple Atleast One Over 65 Cost Household • Couple Atleast One Over 65 Convenience Household • Couple Atleast One Over 65 Climate Household
Single parent family	• Single Parent Family Conscious Household • Single Parent Family Cost Household • Single Parent Family Convenience Household • Single Parent Family Climate Household
Family with two parents	• Family With Two Parents Conscious Household • Family With Two Parents Cost Household • Family With Two Parents Convenience Household • Family With Two Parents Climate without PV And EV Household • Family With Two Parents Climate With EV Only Household • Family With Two Parents Climate With PV Only Household • Family With Two Parents Climate With PV And EV Household

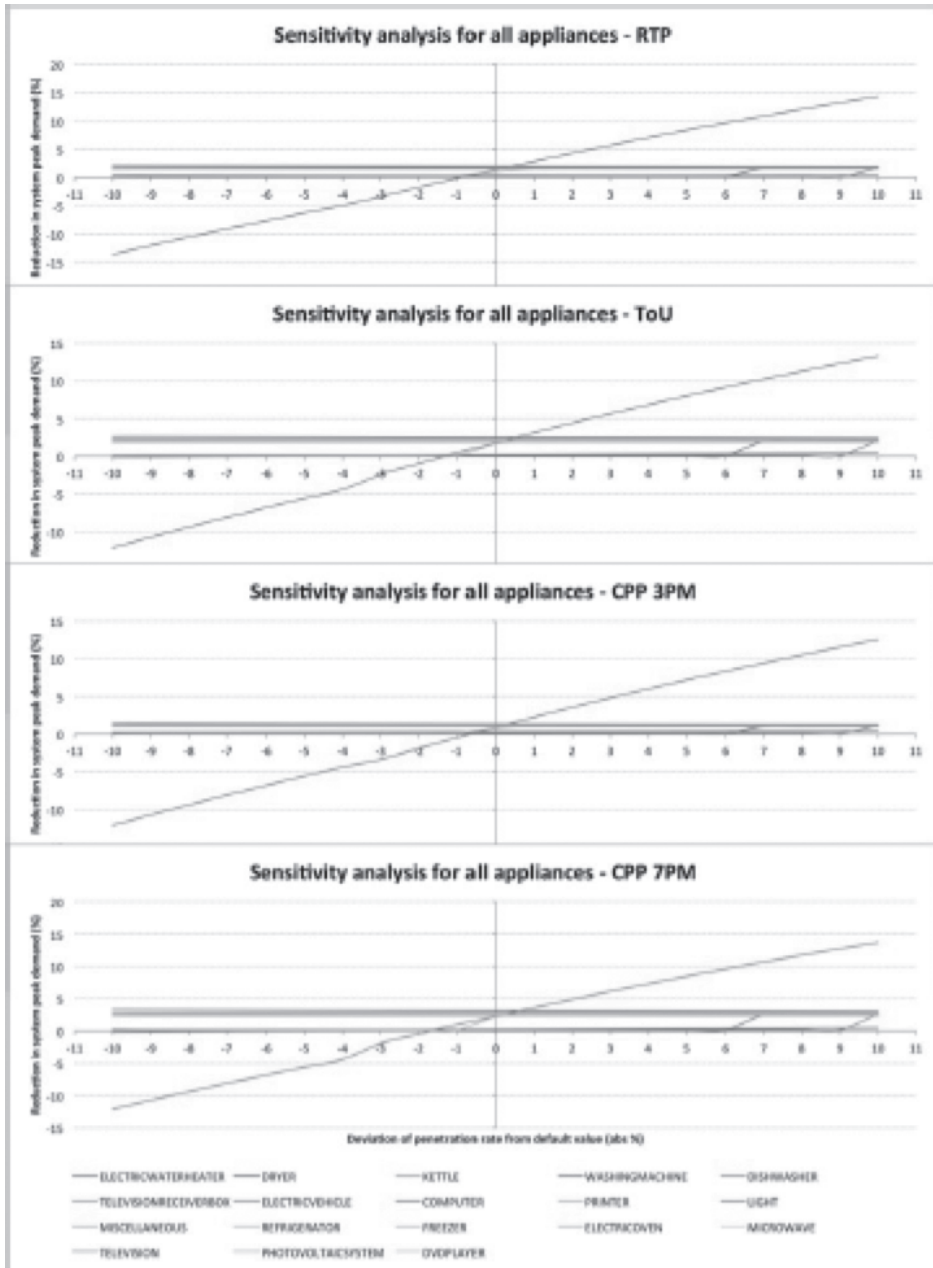


Figure 53: Sensitivity analysis for all appliances

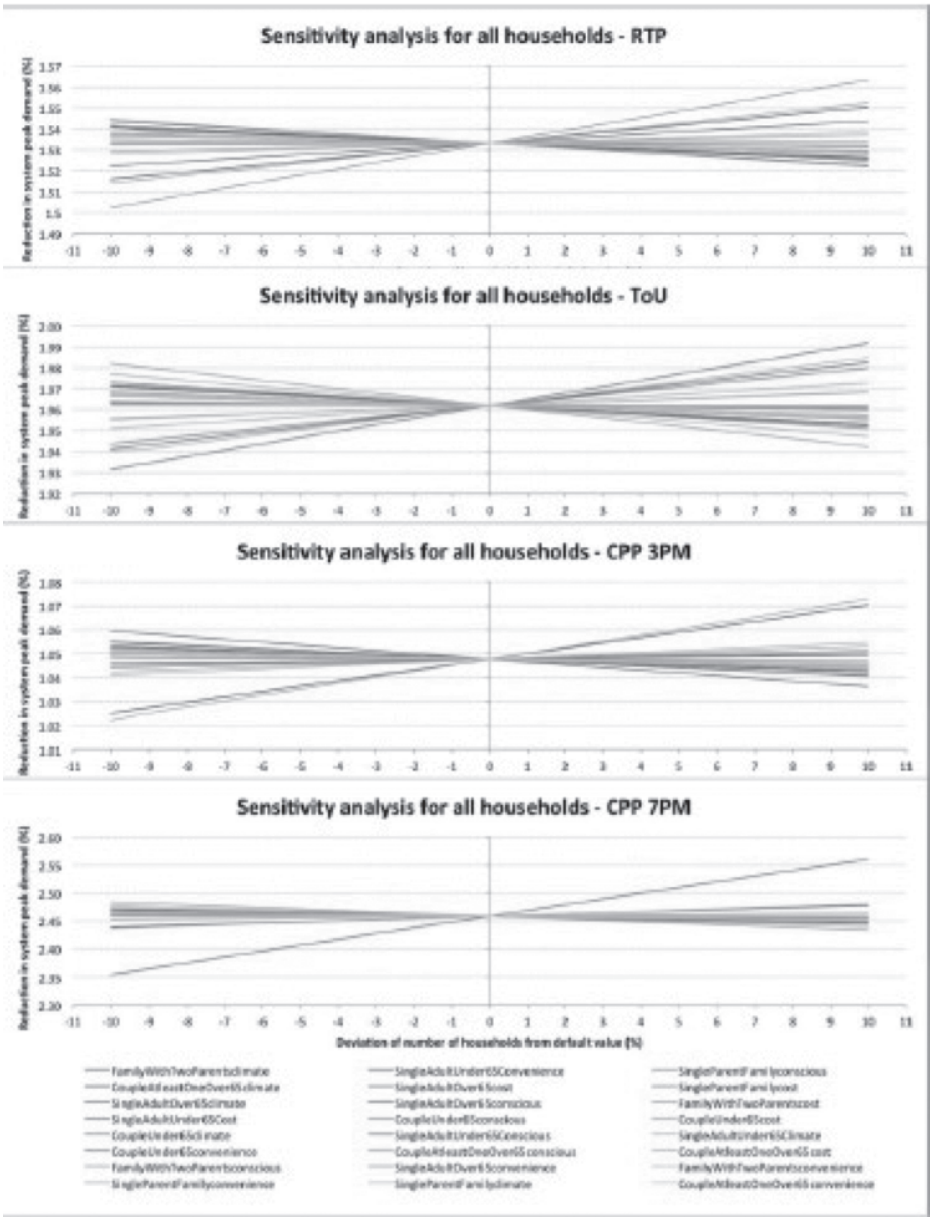


Figure 54: Sensitivity analysis for all households with each price mechanism

Table 33: Description of the nine (conceptual) solutions to the coordination problem, with some pros and cons (Hakvoort and Koliou, 2015).

Model	Description	Advantages	Disadvantages
A	<i>The grid operator and the supplier both have access to the flexibility of customers.</i>	Flexibility is allotted to the party that attaches the greatest value to Demand Response, depending on the 'market' for flexibility, where the price and the type of contract (duration, size and condition) is determined.	Coordination Problem. There is no guarantee that the operator can access the control as needed without investments in control and signaling technology. If sufficient flexibility is not available then network expansions are inevitable. Ergo, limited benefits for the network operator.
B	<i>The supplier (has priority) access to customers and the flexibility. The system operator may receive a portion of the flexibility from the supplier.</i>	The optimization of the value of flexibility is achieved by one party (the supplier). In consultation with the network operator, the supplier provides (part of) the flexibility to the operator. For the network it is clear how much flexibility will be available (with certainty).	It is necessary to arrange the interaction between the supplier and the network operator in new market models.
C	<i>The system operator (has priority) access to the flexibility of customers and the supplier may receive a part of it through the network.</i>	The network operator has maximum certainty about the availability of flexibility. In this case, unused flexibility can be offered to the market by the network operator.	The operator will have the key role in assigning flexibility instead of the market. In this case there will only be limited flexibility available for the market and there will not be optimal use of flexibility on all sides.
D	<i>The network operator and supplier shall agree on the use of flexibility.</i>	The grid operator and the supplier will co-optimize the combined use of flexibility.	Coordination between the operator and the various suppliers may prove to be a struggle under the current market (including competition between suppliers and independent network).
E	<i>Only the supplier has access to flexibility.</i>	Complete and optimal deployment of flexibility for the market.	No possibility to use for savings in network investment flexibility.
F	<i>Only the operator has access to flexibility.</i>	Complete and optimal deployment of flexibility for savings in network investment.	No possibility to use for market flexibility.
G	<i>Breakdown of flexibility in the market network operators and suppliers.</i>	Both the operator and the suppliers have (any part of) the flexibility.	The arbitrary (not market) allocation of flexibility to the operator and the supplier can result to be suboptimal. In this case it must be determined how this allocation will take place.

H	<i>Breakdown of flexibility in the market for the network operators and suppliers. In this case the operator can obtain additional flexibility for suppliers.</i>	Both the operator and the suppliers have (any part of) the flexibility. The unused portion can be sold to the grid (according to model B).	The arbitrary (not market) allocation of flexibility to the operator and the supplier can result to be suboptimal for the network operator. A separate market model should be implemented that facilitates the sale of flexibility.
I	<i>In the market both network operators and suppliers can obtain additional flexibility to provide the grid.</i>	Both the operator and the suppliers have (any part of) the flexibility. The unused portion can be resold to the supplier (according to model C).	The arbitrary (not market) allocation of flexibility to the supplier and network operator can result suboptimal for the network operator. A new market model should be implemented that facilitates sale of flexibility.

SUMMARY

Introduction

The European Commission is in need of coherent and consistent set of policies and measures which will bring Europe into a new energy era of sustainability, competitiveness and security of supply. Accordingly, the smart grids vision launched in 2006 in a movement towards reforming and modernizing electricity markets and networks in a bold and visionary program of research, development and demonstration. On this foundation, the European Union is taking a user-centric stance to developing smart grid systems as *"electricity networks that can intelligently integrate the behavior and actions of all users connected to it generators, consumers, and those that do both in order to efficiently deliver sustainable, economic and secure electricity supplies"*¹⁰⁴. Smart grids for Europe employ both products and services in combination with ICT to meet the challenges and opportunities of the 21st century.

Stating the problem

Market liberalization has forced utility unbundling in Europe, hence altering the relationship between market players and the system operator. Several European countries have an established tradition of contracting large energy intensive end-users (accounting for over one third of the total electricity demand) flexibility either through pricing schemes or some form of load control mechanism. Also, residential demand accounts for almost one third of a flexibility resource that remains to be tapped. In a liberalized electricity sector with a smart grid vision that is committed to market-based operation, consumers have now become the focal point of decision-making at every level of the process of producing, delivering and consuming electricity. Hence, the incorporation of end-users into electricity markets becomes the focus of this work.

With the grasp of smart grid solutions in sight, discussions have shifted the focus of system security measures away from generation capacity; apart from modifying the supply side, demand may also be exploited to keep the system in balance. Specifically, demand response (DR) is the concept of consumer load modification as a result of price signaling generation adequacy or state of grid reliability. Implementation of DR mechanisms (in various forms) is one of the smart grid solutions investigated towards improving the efficiency of electricity markets and maintaining system-wide stability.

Although a smart grid paradigm in theory obliges the incorporation of an active demand side through DR, there exist some unavoidable barriers to market. Firstly, when compared to other factors of household expenditure, electricity accounts for a relatively low cost and therefore becomes a low priority for end users. Secondly, enabling DR

¹⁰⁴ European Technology Platform for Smart Grids (2011)

smart grid solutions is costly, with the brunt of the investments lying on the distribution system operator that is bound by regulatory remuneration. Finally, there is hype at present in implementing DR solutions that will allow end users to become active market participants; the existing market mechanisms are not properly designed to handle an active demand side. Accordingly, this research tackles the following research question:

How can residential end-user consumption flexibility be promoted successfully through demand response methods in a smart grid?

Analysis

This work began on the premise of researching *policies for the implementation of smart grids*. In view of that, the work evolved towards the implementation of demand response. Herein is a summary of the contributions of this thesis to the state-of-the-art on the implications of accessing, signaling and releasing end-user flexibility into the electricity system.

An extensive analysis of demand response activation of end-user flexibility through price-based mechanisms indicates that consumers can be approached with a menu of price programs which reflect the market conditions more dynamically. A simulation case study of the Netherlands points to time-of-use pricing as the optimal program, followed by critical-peak pricing in accordance with the residential peak hours. Although real-time-pricing is a desired program by policymakers in a smart grid environment, the results indicate limited demand responsiveness.

When considering the active volume-based market participation of end-users aggregation is critical. A detailed analysis of the processes, costs and potential gains from active spot market participation is presented. The investigation reveals the importance of balance responsibility throughout the settlement and delivery of trades, with timing, volume and program specifications as the principal barriers to demand-side integration in short term European electricity markets.

An assessment of the various short term electricity markets reveals that the balancing mechanisms can integrate aggregated demand response as a reserve. An analysis of the German balancing mechanism illustrates that demand response is undermined by three mechanism design aspects: minimum bidding volume, minimum bid duration and binding up and down bids. Moreover, demand response is further hindered by the vagueness in the specifications for (i) balance responsibility, (ii) balance service provision and (iii) imbalance settlement procedures.

Often DR is discussed in terms of the implementation by competitive market parties, leaving out the load shifting impacts for the distribution system operators. A study is conducted on the economic effect of consumption flexibility under current regulatory remuneration on distribution-system operators using Sweden as a case study is also presented. Results indicate DR leads to savings for the distribution-system operator, which might be used towards smart-grid investments. Peak demand is and will continue to be a

main driver for grid costs and therefore should be a focal point in tariff design adopting capacity based tariffication.

Conclusions

It is important to note that the smart grid changes anticipated through the incorporation of an active demand side pose at least some threat to a system that already works quite well in balancing supply and demand. Accordingly, demand response is more a desired solution for future power systems with vast renewable integration.

Security of supply, sustainability and economic efficiency represent the energy policy drivers of Europe. Such policy pillars are not “*naturally aligned vectors*”¹⁰⁵ yet need to find the right balance of market and regulation to co-exist harmoniously. For demand response this means designing innovative remuneration schemes that ensure the alignment of short-run operational and long-run investment and recovery objectives.

When it comes to billing, regulators need to communicate to suppliers the importance of dynamic pricing as an initial step towards electricity market awareness through transparency. The results in this work point to a time-of-use tariff in accordance with the hours pertaining to the base, shoulder and peak hours of the spot market exchange. Although this research reveals little monetary value for consumers to have real-time pricing, because of the awareness and transparency brought by such pricing it should still become an available option. Additionally, Tariffs can also be designed per distribution system in order to make sure that peak grid hours coincide with the tariff as well. Dynamic network tariffs can also be considered with a capacity component. Capacity based grid tariffs should incentivize consumers to stay below a certain threshold power level.

For volume-based demand response solutions aggregators are pivotal facilitators in the market processes. Aggregators are already showing their influence by stirring the conversation on the existing market mechanisms and their favoritism for large generators. From this work, it is advised that national regulatory bodies lead the way in the next phase of aggregated demand response by tackling the issue of balance responsibility of the aggregator. The various short term electricity markets can only be accessed through transparent arrangements instigating mutual cooperation between balance responsible parties, retailers and aggregators. The aggregators are already leading the movement in activating demand, but it is the regulators who hold the key in both birth and sustainability of demand side activation and integration.

An important overall observation is that a smart grid is simply a means to an end but an end in itself. Note, active end-users represent a small piece of the physical smart grid, but they are the most powerful movers in realizing the vision. This work has revealed that the involvement of consumers in market dynamics is both complex and costly yielding

¹⁰⁵ (Mott MacDonald, 2013)

little benefit for the customers. Rather, is the overall awareness that transparency in market process that will yield understanding and in the end acceptance and support for the smart grid.

SAMENVATTING

Introductie

De Europese Commissie heeft behoefte aan een set van coherente en consistent beleidsmaatregelen die Europa brengen in een nieuw energie tijdperk van duurzaamheid, concurrentievermogen en continuïteit van de energievoorziening. In deze trend is de smart grids visie in 2006 gelanceerd om hervorming en modernisering van energiemarkten en elektriciteitsnetwerken in een visionair programma te plaatsen voor onderzoek, ontwikkeling en demonstratie. Op dit fundament plaatst de Europese Unie de gebruiker centraal in de ontwikkeling van smart grid-systemen als “electriciteitsnetwerken die op intelligente wijze het gedrag en de acties van alle aangesloten gebruikers, producenten, consumenten te integreren, en van deze die zowel consumeren als produceren voor efficiënte, duurzame, economische en zekere levering van elektriciteit”. Smart grids in Europa dienen zowel producten en diensten aan in combinatie met ICT om de uitdagingen en kansen van de 21ste eeuw aan te gaan.

Probleemstelling

De liberalisering van de markt heeft geleid tot gedwongen splitsing van nutsbedrijven in Europa, dus het veranderen van de relatie tussen marktpartijen en de netbeheerder. Verscheidene Europese landen hebben een grote aantal energie-intensieve eindgebruikers (goed voor meer dan een derde van de totale vraag naar elektriciteit) die flexibiliteit aanbieden, hetzij via prijsregelingen of enige vorm van directe controlemechanismen op de energievraag. Ook residentiële energievraag is goed voor bijna een derde van een flexibiliteit, welke nog niet werkelijk gebruikt wordt. In een geliberaliseerde elektriciteitssector met een smart grid visie welke zich inzet voor een markt gebaseerde operatie, worden consumenten nu het middelpunt van de besluitvorming op elk niveau van het proces van de productie, levering en verbruik van elektriciteit. Vandaar dat de integratie van de eindgebruikers in de elektriciteitsmarkten de focus van dit werk is.

Met het oog op smart grid-oplossingen is het waarborgen van continuïteit van de electriciteitsvoorziening niet alleen weggelegd voor productie capaciteiten, door vraagverschuivingen kan nu ook de electriciteits vraag worden benut om het systeem in evenwicht te houden. In het bijzonder, is vraag en respons (DR) het concept voor het wijzigen van de electriciteitsvraag als gevolg van de prijs signalering of de toestand van de betrouwbaarheid van het net. Implementatie van vraag response mechanismen (in verschillende vormen) is een van de smart grid-oplossingen die onderzocht is richting de verbetering van de efficiëntie van de elektriciteitsmarkten en het onderhoud van stabiliteit in het hele systeem.

Hoewel een smart grid paradigma in theorie de een actieve vraagzijde door middel van vraag response vereist, bestaan er een aantal onvermijdelijke barrières voor de

markt. Enerzijds, in vergelijking met andere gezinsuitgaven vertegenwoordigt elektriciteit relatief lage kosten en vormt daarom een lage prioriteit voor eindgebruikers. Ten tweede zijn vraag response smart grid-oplossingen kostbaar, waar de meeste investeringen op last van de distributienetbeheerder valt die is gebonden door de gereguleerde inkomsten. Tot slot is er hype op dit moment bij de uitvoering van vraag response oplossingen waarmee eindgebruikers actieve deelnemers vormen op markt; de bestaande marktmechanismen zijn niet goed ontworpen om een actieve vraagzijde te hanteren. Dit onderzoek behandelt hierdoor de volgende onderzoeksvraag:

Hoe kan flexible elektriciteitsvraag van de eindgebruiker met succes worden bevorderd door vraagrespons mechanismen in een smart grid?

Analyse

Dit werk begon met het uitgangspunt om beleid voor de implementatie van smart grids te onderzoeken. Hier vanuit is dit werk geëvolueerd richting de implementatie van vraag response. Hierin is een samenvatting van de bijdragen van dit proefschrift aan de huidige status van de implicaties van de toegang tot, signalering en het vrijgeven van de gebruikersflexibiliteit in het elektriciteitssysteem.

Een uitgebreide analyse van de activatie van vraag response van de eindgebruiker via prijs mechanismen geeft aan dat de consument kan worden benaderd met een menu van prijs programma's die een dynamische weerspiegeling geven van de marktomstandigheden. Een simulatie casus van Nederland wijst dat time of use pricing (TOU) als het meest optimale werkt, gevolgd door Critical Peak Pricing (CPP) welke overeenkomt met de residentiële piekuren. Hoewel de real-time-pricing een gewenst programma is door beleidsmakers in een smart grid-omgeving, geven de resultaten beperkte responsiviteit aan met deze methode.

Aggregatie van de eindgebruikers is van cruciaal belang bij het overwegen van het actieve participatie in de markt. Een gedetailleerde analyse van de processen, kosten en potentiële voordelen van actieve deelname spotmarkt is gepresenteerd. Uit het onderzoek blijkt dat de belangrijkste belemmeringen gevormd worden door balancerings verantwoordelijkheid binnen de afwikkeling en levering van de transacties met tijd, volume en programma specificaties voor de integratie van vraag response op korte termijn markten van de Europese elektriciteitssector.

Uit een analyse van de verschillende korte termijn markten blijkt dat in de balanceringsmechanismen de geaggregeerde vraag response als reserve kan worden geïntegreerd. Een analyse van de Duitse balanceringsmechanismen illustreert dat de vraag response wordt ondermijnd door drie ontwerp aspecten: minimum volume van biedingen, minimum duur van het bod en gebonden op en neer biedingen. Bovendien is de vraag en respons verder gehinderd door de onduidelijkheid in de specificaties van

(i) balancerings verantwoordelijke, (ii) de balans dienstverlening en (iii) procedures voor de onbalansverrekening.

Vaak wordt vraag response besproken in termen van uitvoering door concurrerende marktpartijen, waardoor belasting verschuiven voor de distributienetbeheerders wordt ondermijnd. Een onderzoek is uitgevoerd naar de economische gevolgen van flexibele vraag onder de huidige regelgeving voor de distributie-netbeheerders in Zweden. De resultaten geven aan dat vraag response leidt tot besparingen voor de distributie netwerk beheerder, die kunnen worden gebruikt voor investeringen in de smart-grid. Pieken in de vraag blijven een van de belangrijkste drivers voor netwerkkosten en zou daarom een centraal punt in het tarief ontwerp moeten zijn met vaststelling van tarieven die op capaciteit gebaseerd zijn.

Conclusies

Het is belangrijk op te merken dat met smart grids veranderingen worden geanticipeerd door een actieve vraagzijde welke een bedreiging kan vormen voor een systeem dat al redelijk goed werkt met het in evenwicht brengen van vraag en aanbod. Daarom is vraag response meer een gewenste oplossing voor toekomstige energiesystemen met grotere integratie van duurzame integratie.

Continuïteit van de energievoorziening, duurzaamheid en economische efficiëntie vertegenwoordigen de het energie beleid in Europa. Deze pijlers zijn niet "van nature uitgelijnde vectoren" en daardoor is het nodig om de juiste balans tussen markt en regelgeving te vinden om dit geheel harmonieus te kunnen laten werken. Voor vraag response betekent dit dat innovatieve beloningsregelingen moeten worden ontworpen die de uitlijning waarborgen van korte termijn operationele doelen en lange termijn investeringen en het terugverdienen van deze kosten.

Als het gaat om facturering, moeten reguleerders het belang van dynamische prijsstelling aan leveranciers communiceren als een eerste stap in de richting van elektriciteitsmarkt bewustzijn door middel van transparantie. De resultaten in dit werk richten op een time-of-use tarief, overeenkomstig met de uren die betrekking hebben tot de basis, schouder en piekuren van de spothandel van elektriciteit. Hoewel uit dit onderzoek blijkt dat er weinig monetaire waarde voor de consument is om real-time prijzen te hebben, toch zou het door de bewustwording en transparantie die zulke prijzen met zich meebrengen nog steeds een beschikbare optie blijven. Daarnaast kunnen tarieven ook worden ontworpen per distributiesysteem in om ervoor te zorgen dat de piek uren van het netwerk samenvallen met het tarief. Dynamische nettarieven kunnen ook worden beschouwd met een capaciteit component. Op capaciteit gebaseerde nettarieven moeten de consument stimuleren om onder een bepaalde vermogensdrempel te blijven,

Voor volume gebaseerde vraag response oplossingen zijn aggregatoren onmisbare zijn facilitators in de markt processen. Aggregatoren hebben al hun invloed laten zien door het opbrengen van de discussie op de bestaande marktmechanismen en de bevoorrechte positie voor grote generatoren. Het is geadviseerd dat de nationale regelgevende instanties het voortouw nemen in de volgende fase van de geaggregeerde vraag response door het aanpakken van het probleem van de balans verantwoordelijkheid van de aggregatoren. De verschillende korte termijn markten kunnen alleen toegankelijk worden via transparante regelingen die aanzetten tot onderlinge samenwerking tussen de balans verantwoordelijke partijen, leveranciers en aggregatoren. De aggregatoren leiden op dit moment al de beweging in het activeren van de vraagzijde, maar het is de toezichthouders die de sleutel in had heeft voor zowel de initiele fase en de duurzaamheid van de activatie van de vraagzijde.

Een belangrijke algemene observatie is dat een smart grid een gewoon middel is tot een doel, maar geen doel op zich. Actieve eindgebruikers vertegenwoordigen een klein stukje van de fysieke smart grid, maar ze zijn de meest sterke drijfveren in het realiseren van de visie. Uit dit werk is gebleken dat de betrokkenheid van de consument in de markt dynamiek complex is en kostbaar, met weinig voordeel voor de eindgebruikers. Toch brengt de transparantie in het markt proces begrip en uiteindelijke acceptatie en steun voor de smart grid.

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Elta Koliou, Cherrelle Eid, José Pablo Chaves Ávila and Rudi A. Hakvoort. *Demand response in liberalized electricity markets: Analysis of aggregated load participation in the German balancing mechanism*. Energy Journal, Volume 71, July 2014, Pages 245–254.

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CURRICULUM VITAE

Elta Koliou was born on July 27th, 1987. She grew up in Tenafly, a town in the state of New Jersey in the United States. Elta was an active member of the local community, volunteering as an Emergency Medical Technician for the local ambulance association. In 2005 she graduated from Tenafly High School and obtained a Bachelor of Arts in 2009 from Union College (New York) with a double major in Economics and Classics and a minor in Spanish.



Elta went on to complete an Erasmus Mundus Joint Master in Economics and Management of Network Industries. As part of the Master's program, she spent one year at Comillas Pontifical University (Madrid, Spain) where she obtained a Masters in the Electric Power Industry (2010) and one year at the University of Paris-Sud XI (Paris, France) where she received a Master's in Numerical Economics and Network Industries (2011).

In September 2011 she began an Erasmus Mundus Joint Doctorate in Sustainable Energy Technologies and Strategies (SETS) at Delft University of Technology (Delft, the Netherlands). As part of the SETS program, she spent 10 months at KTH Royal Institute of Technology (Stockholm, Sweden). During her research Elta published 3 journal papers, presented in international conferences, collaborated with other researchers and supervised master thesis projects.

Demand Response Policies for the Implementation of Smart Grids

Elta Koliou

With the grasp of a smart grid in sight, discussions have shifted the focus of system security measures away from generation capacity; apart from modifying the supply side, demand may also be exploited to keep the system in balance. Specifically, Demand Response (DR) is the concept of consumer load modification as a result of price signaling, generation adequacy, or state of grid reliability. Implementation of DR mechanisms is one of the solutions being investigated to improve the efficiency of electricity markets and to maintain system-wide stability.

In a liberalized electricity sector, with a smart grid vision that is committed to market-based operation, end-users have now become the focal point of decision-making at every stage of the process in producing, delivering and consuming electricity. DR program implementation falls within the smart grid domain: a complex socio-technical energy system with a multiplicity of physical, economic, political and social interactions. This thesis thus employs both qualitative and quantitative research methods in order to address the ways in which residential end-users can become active DR flexibility providers in deregulated European electricity markets. The research focuses on economic incentives including dynamic pricing contracts, dynamic distribution price signals and the aggregation of load flexibility for participation in the various short-term electricity markets.

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